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

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[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

[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,

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[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

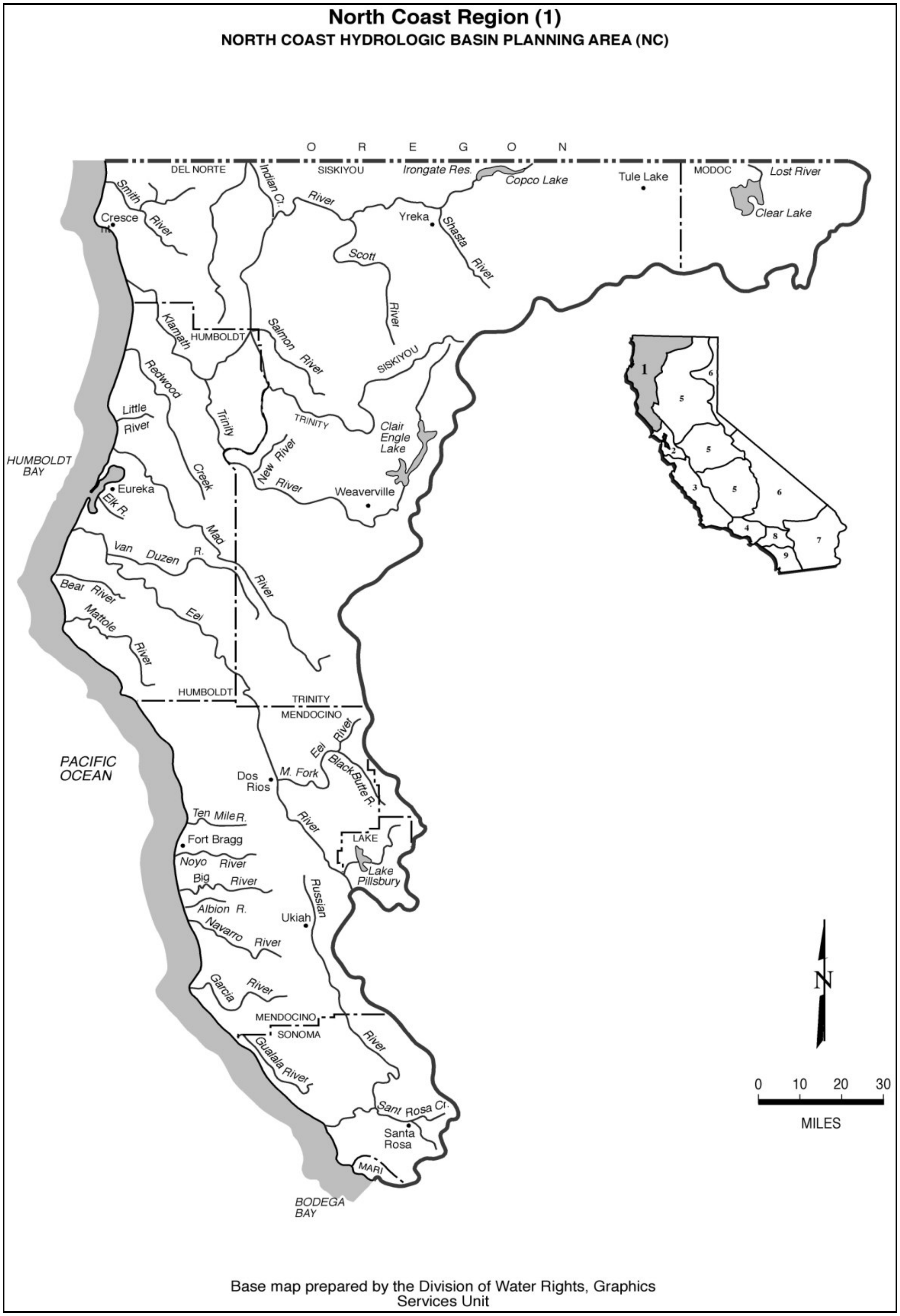

Figure 1. North Coast Region

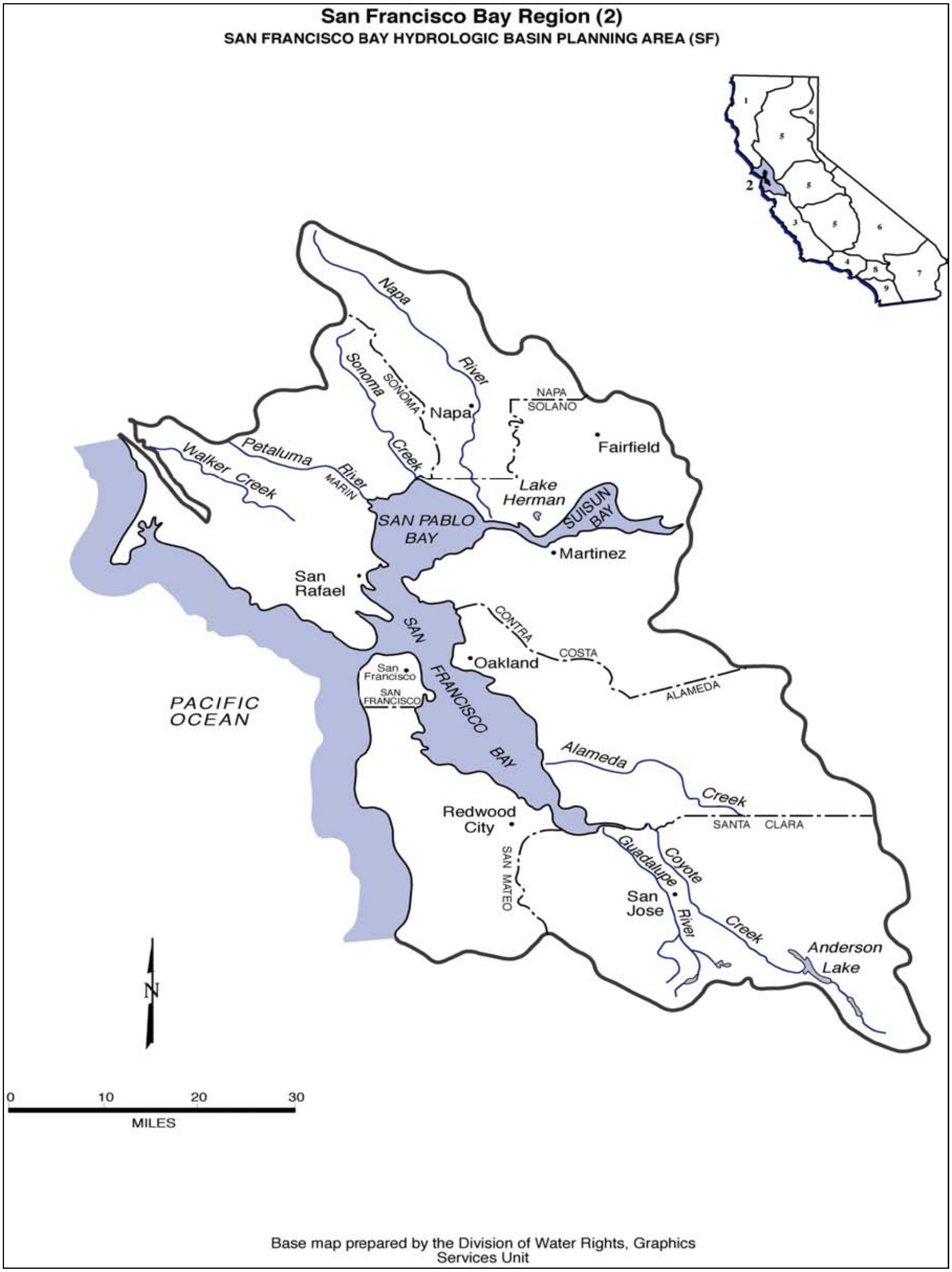

Figure 2. San Francisco Bay Region

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.

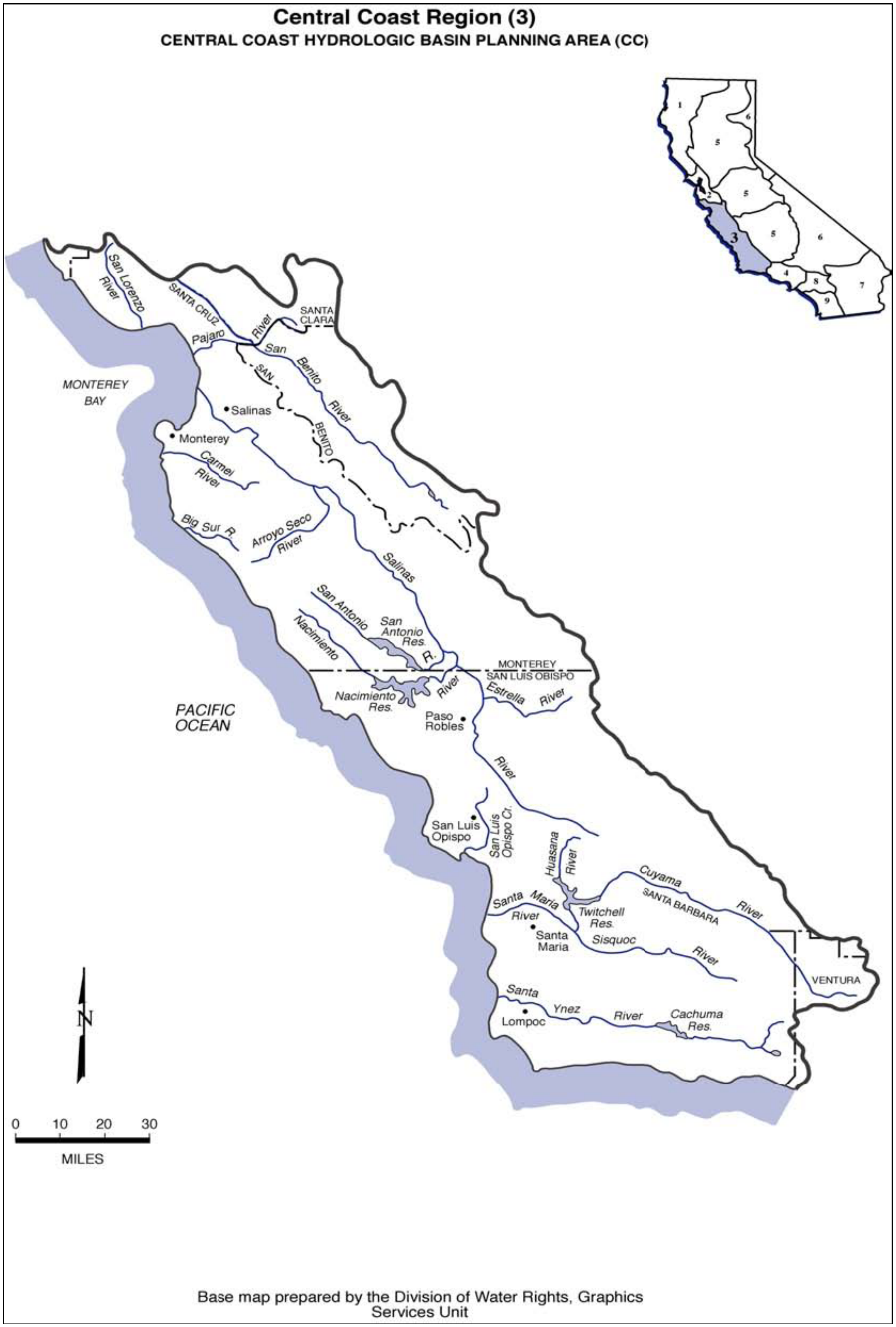

Figure 3. Central Coast Region

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.

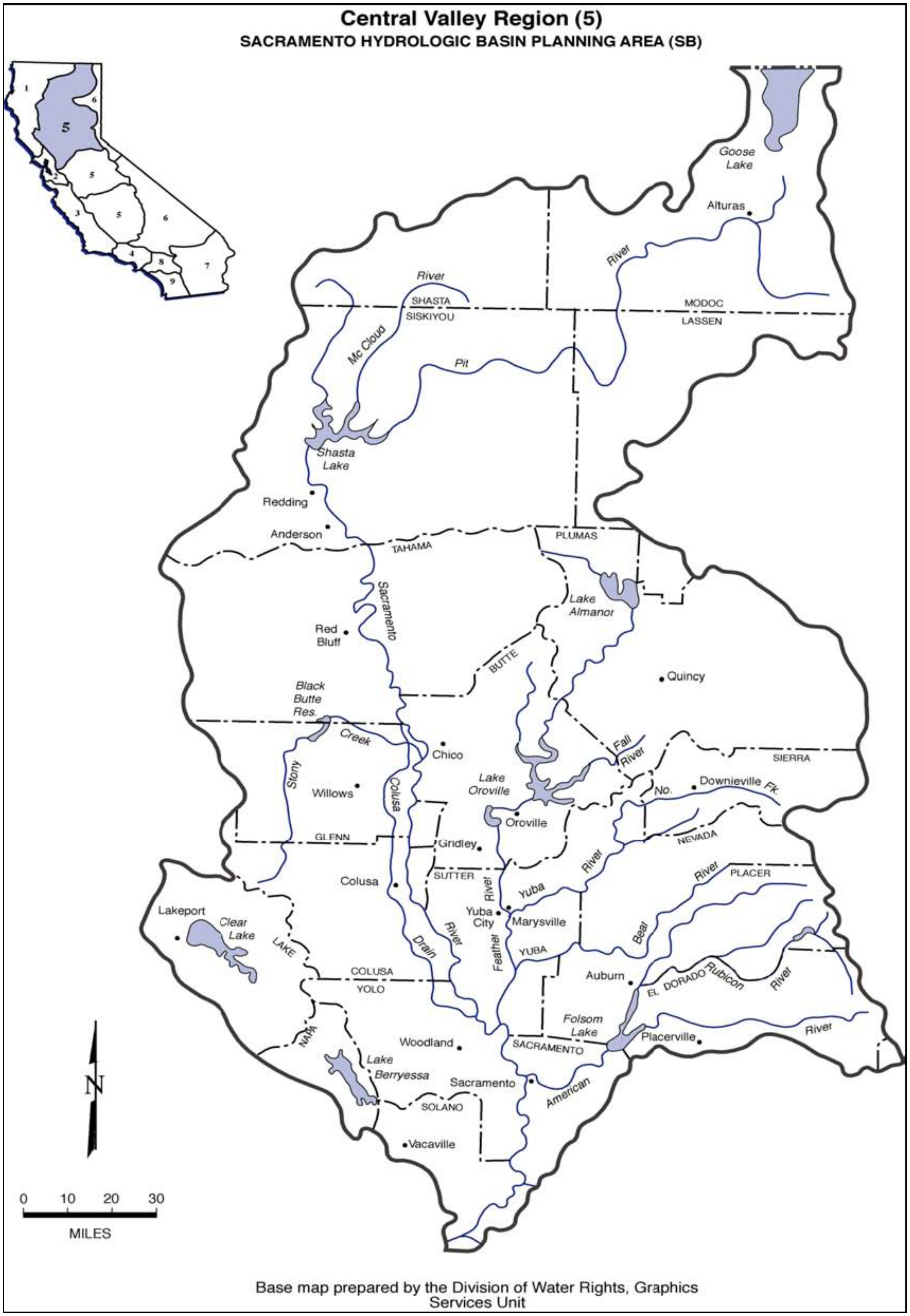

Figure 5. Central Valley Region (Sacramento)

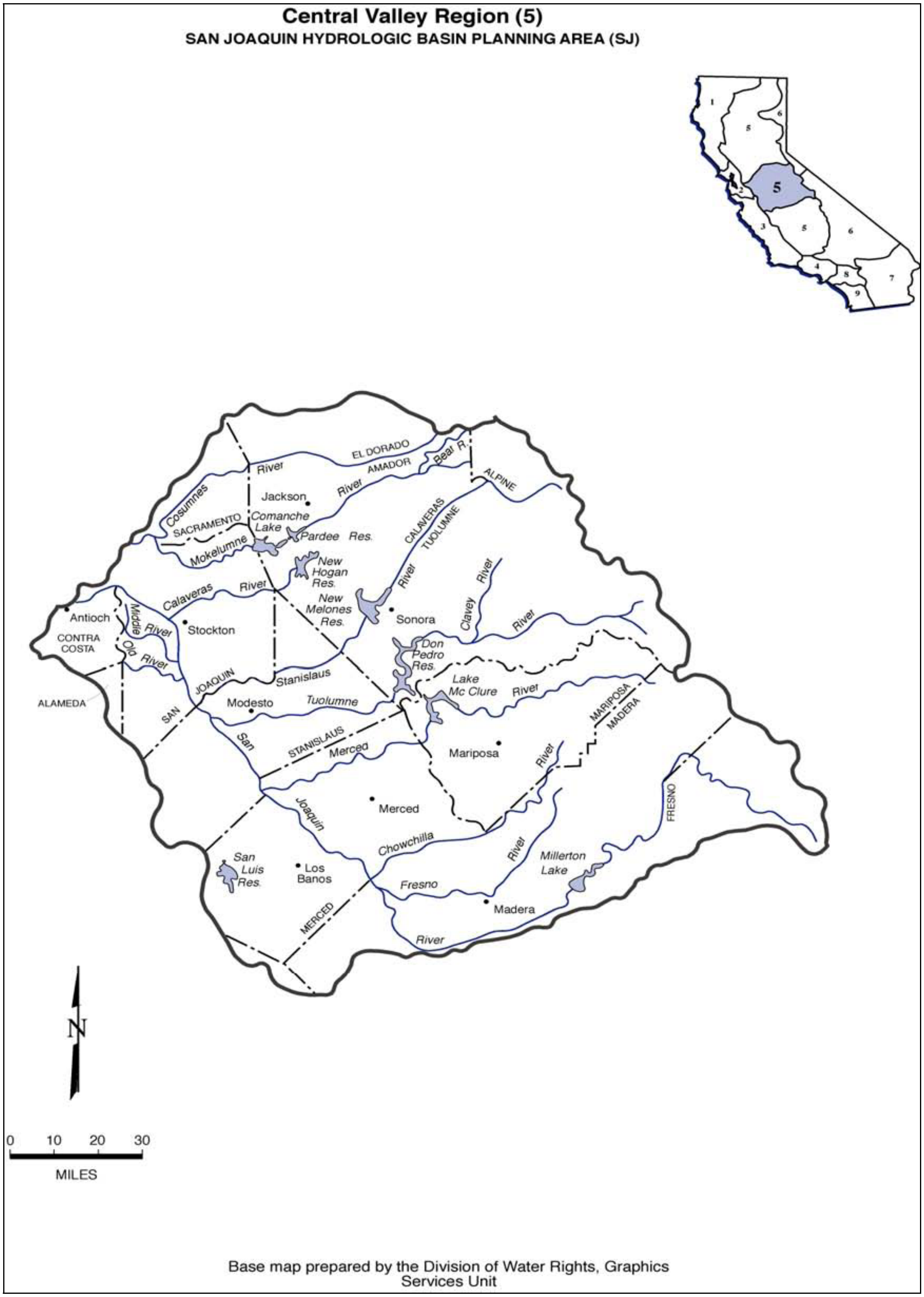

Figure 6. Central Valley Region (San Joaquin)

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.

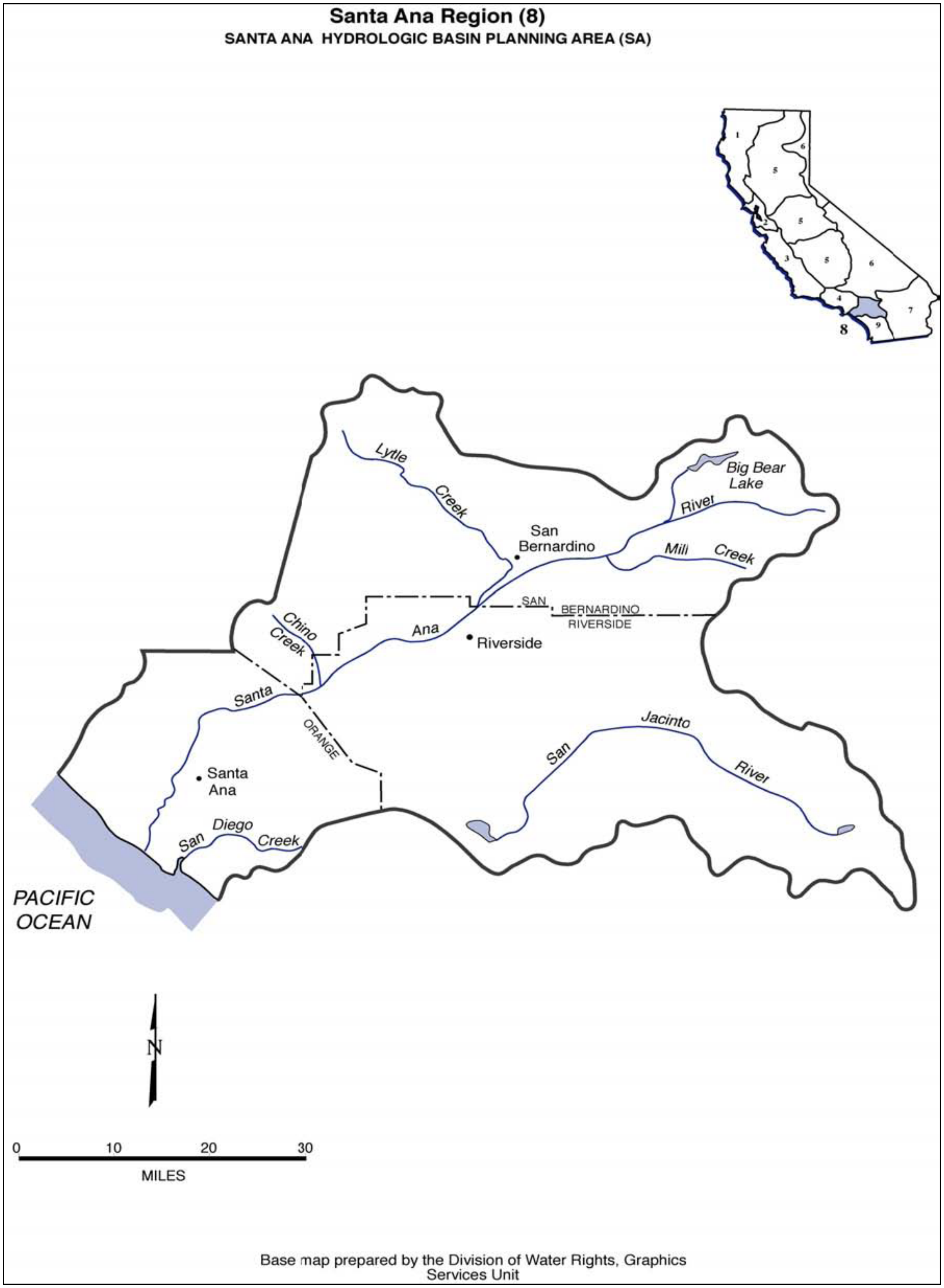

Figure 7. Santa Ana Region

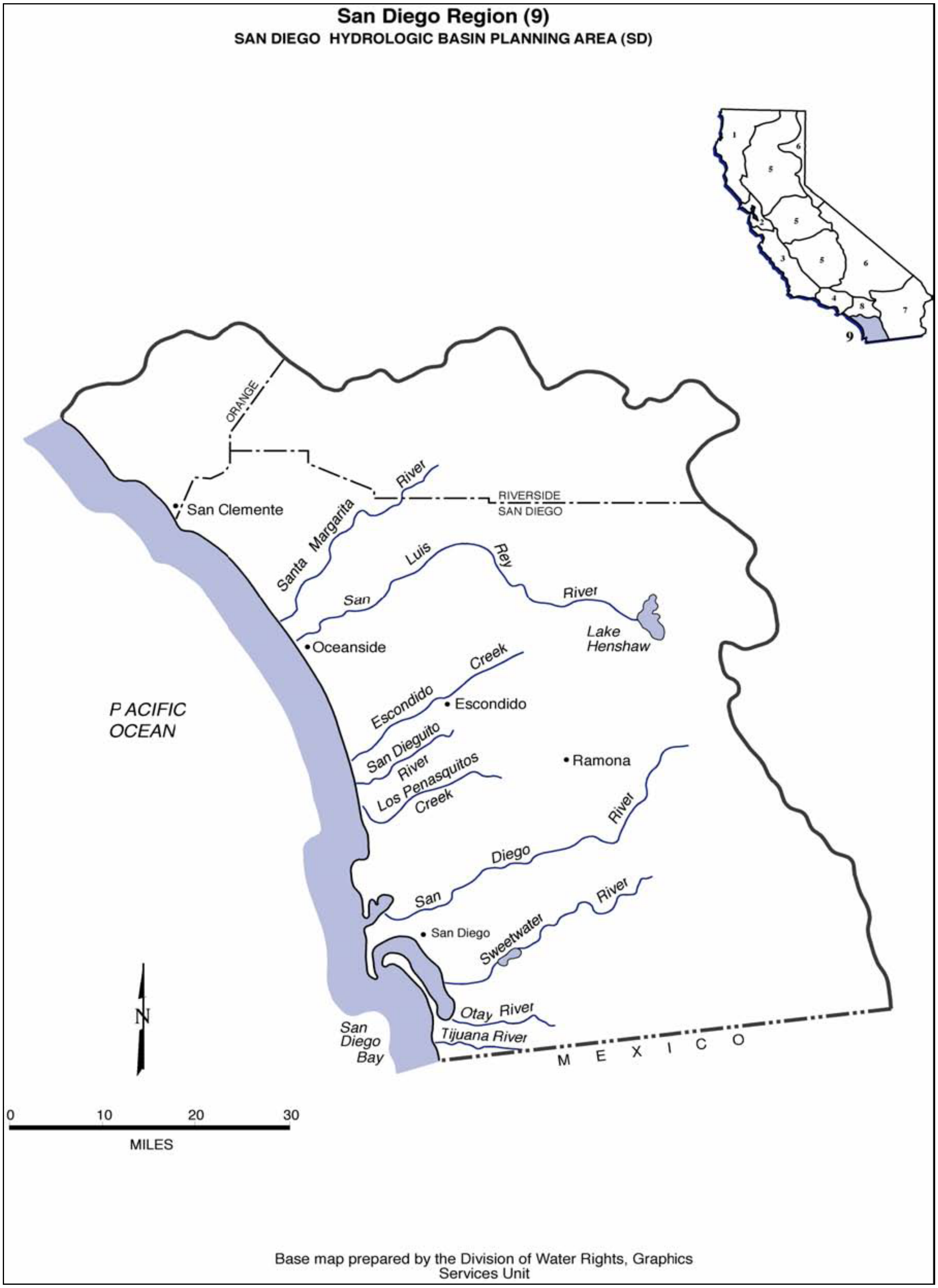

Figure 8. San Diego Region

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

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[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

[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].

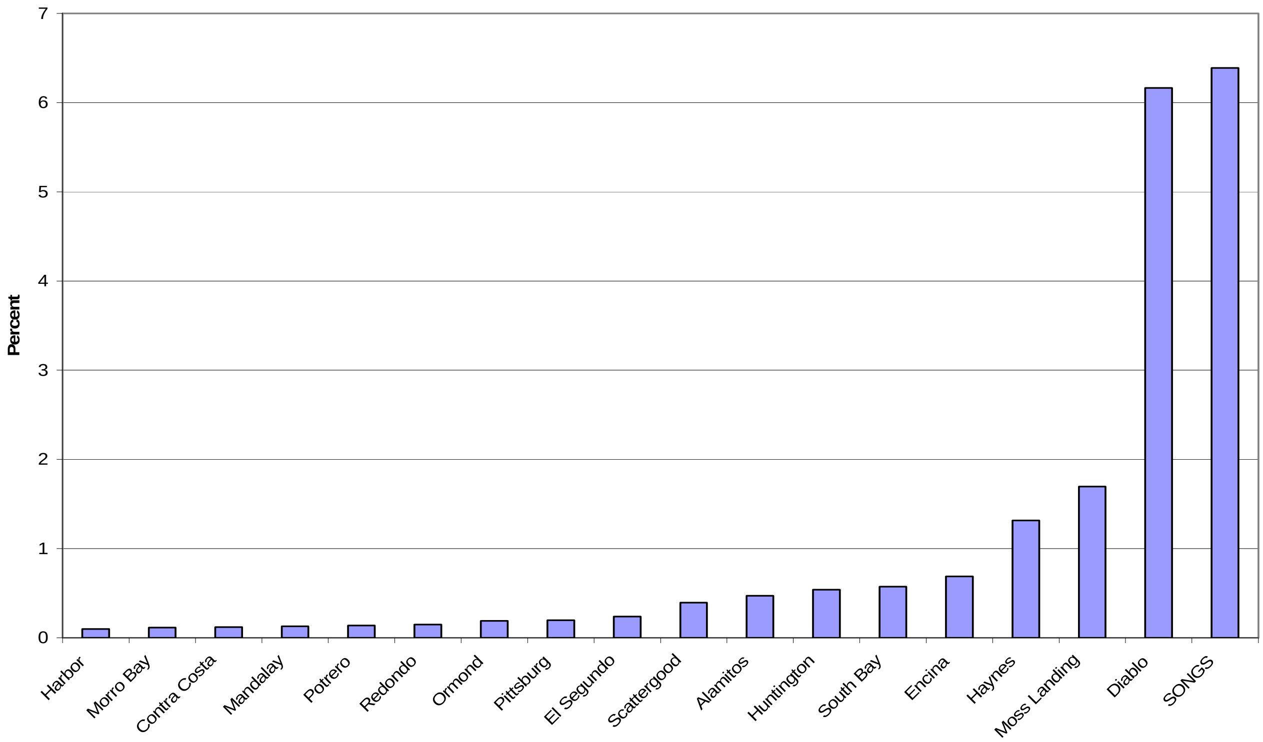

Figure 9. Percentage of Total Energy Production by OTC Power Plants in 2005

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.

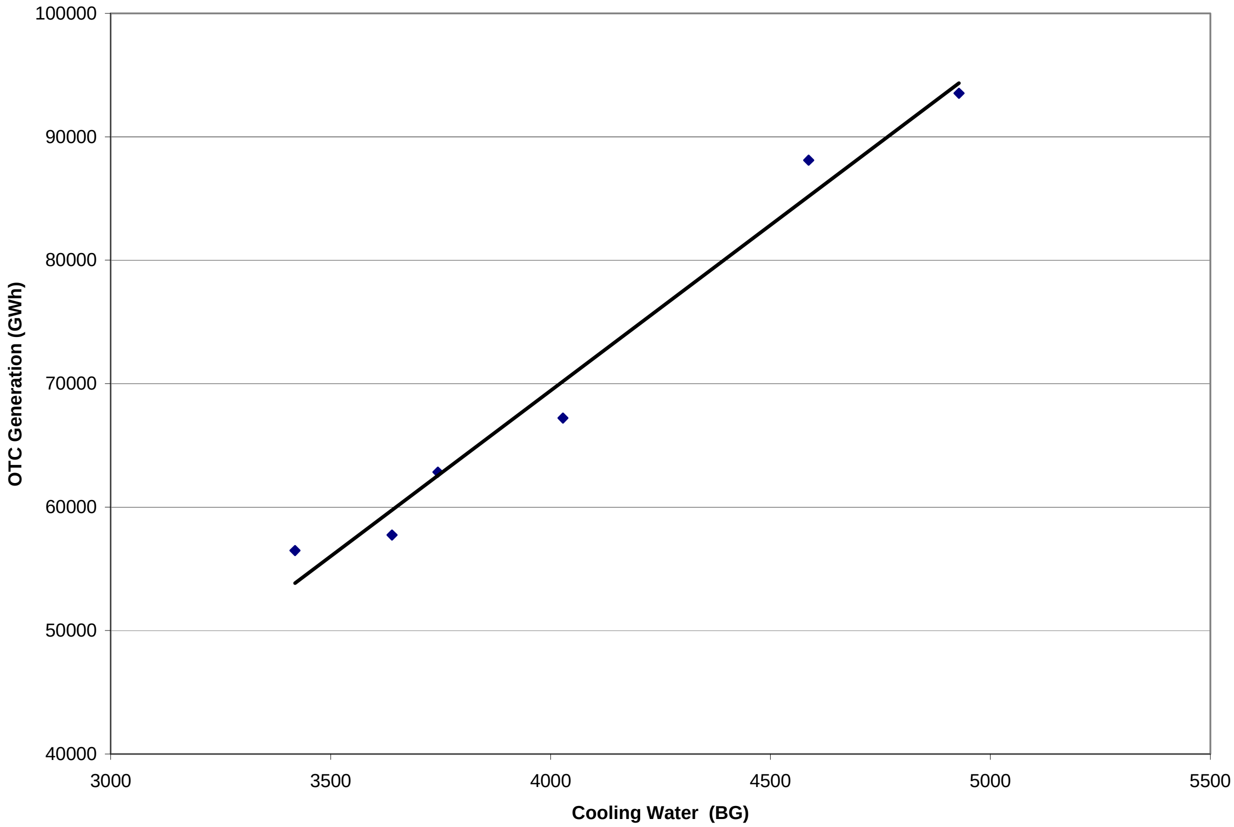

Figure 10. 2000-2005 Combined Annual Cooling Water Flow Versus Total Energy Generated by the OTC Power Plants

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,

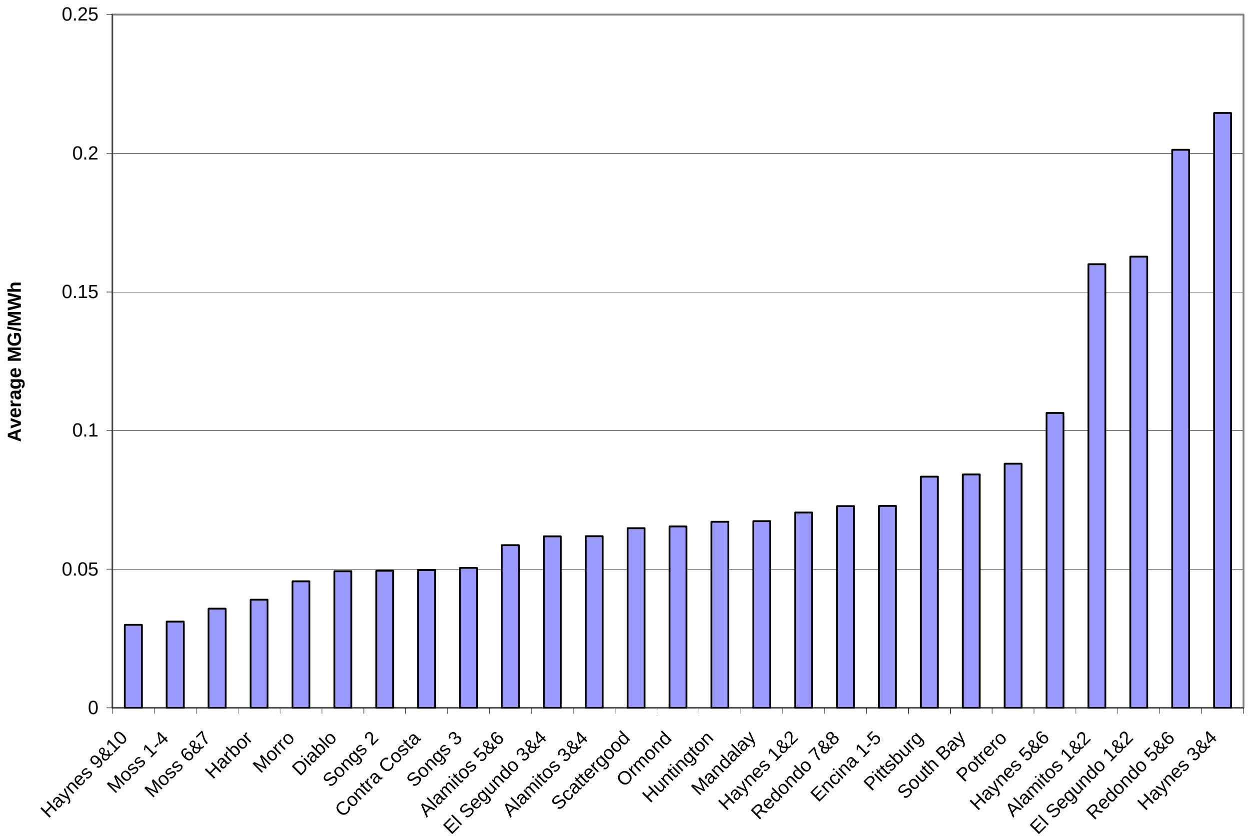

Figure 11. Ratios of Average Cooling Water Flow to Energy Generation

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

	Gross Output	SO2	NOx	CO	TOG	ROG	PM10
Facility	**(MWh)**	**(tons/yr)**	**(tons/yr)**	**(tons/yr)**	**(tons/yr)**	**(tons/yr)**	**(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.

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[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

[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.

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[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.

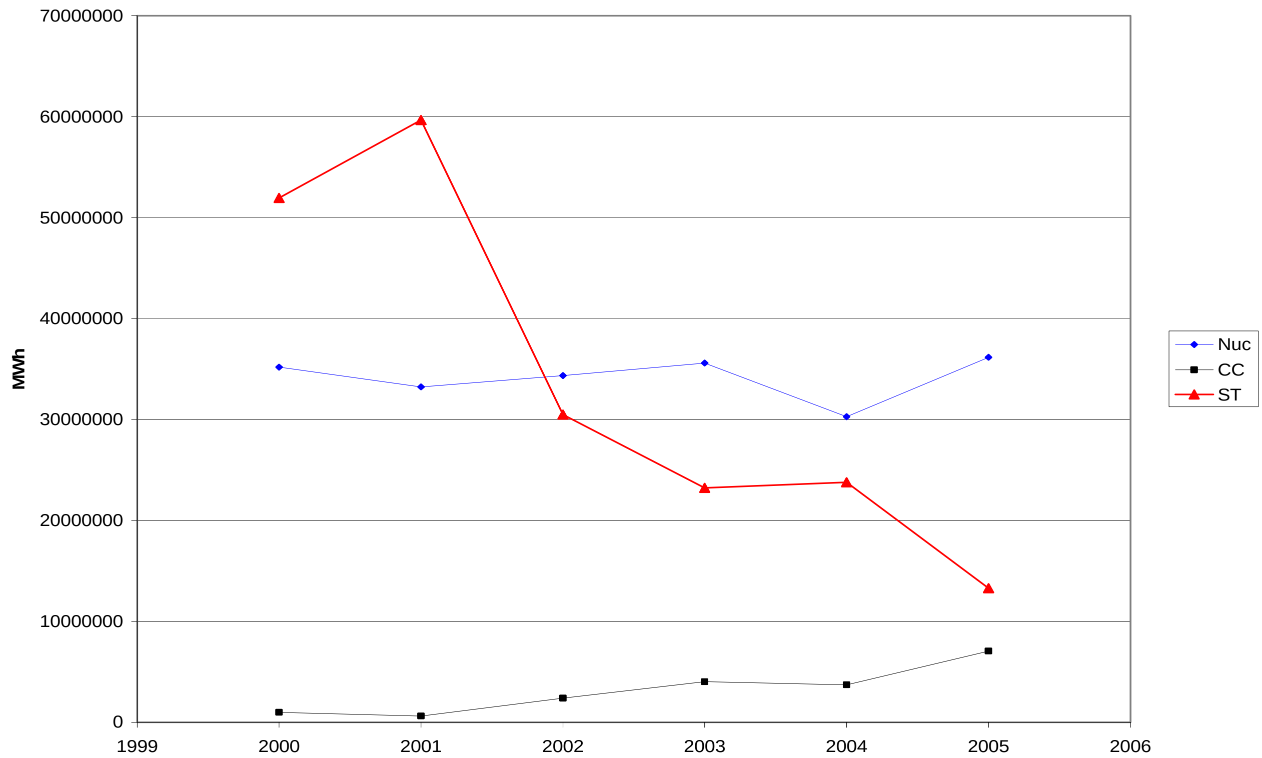

Figure 12. OTC Energy Generation by Technology

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.

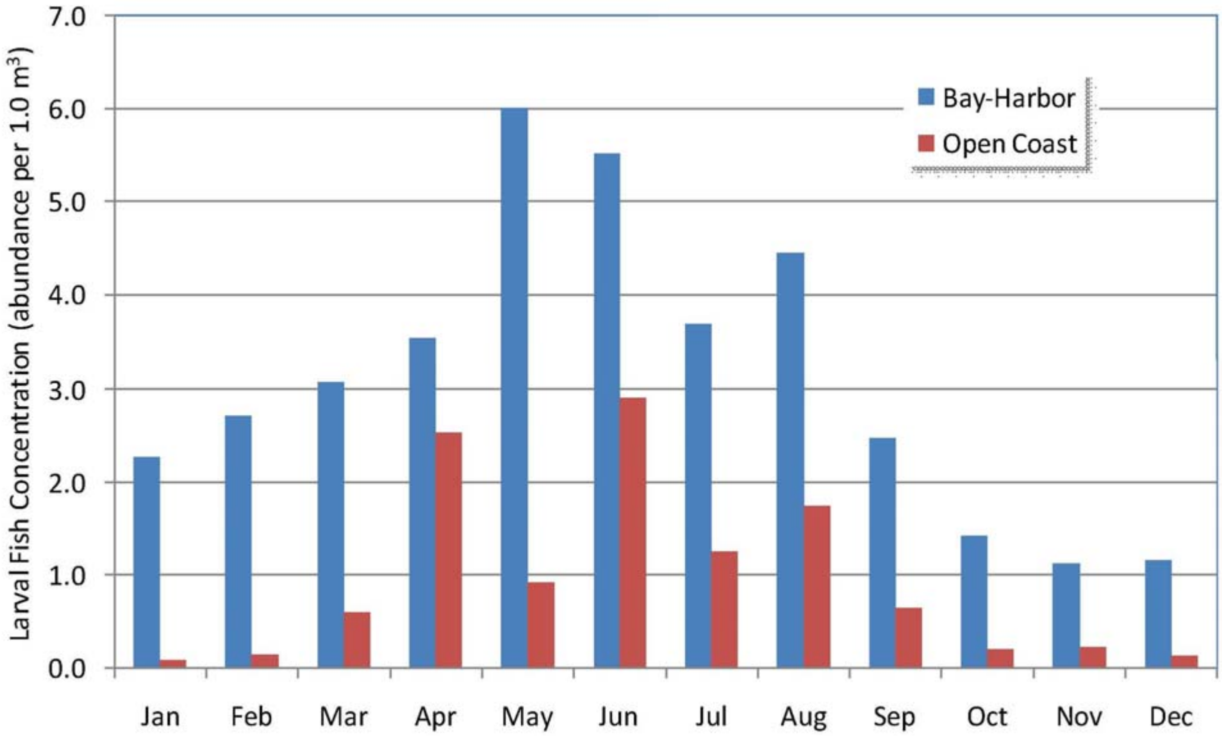

Figure 13. Larval Fish Concentrations at Southern OTC Facilities

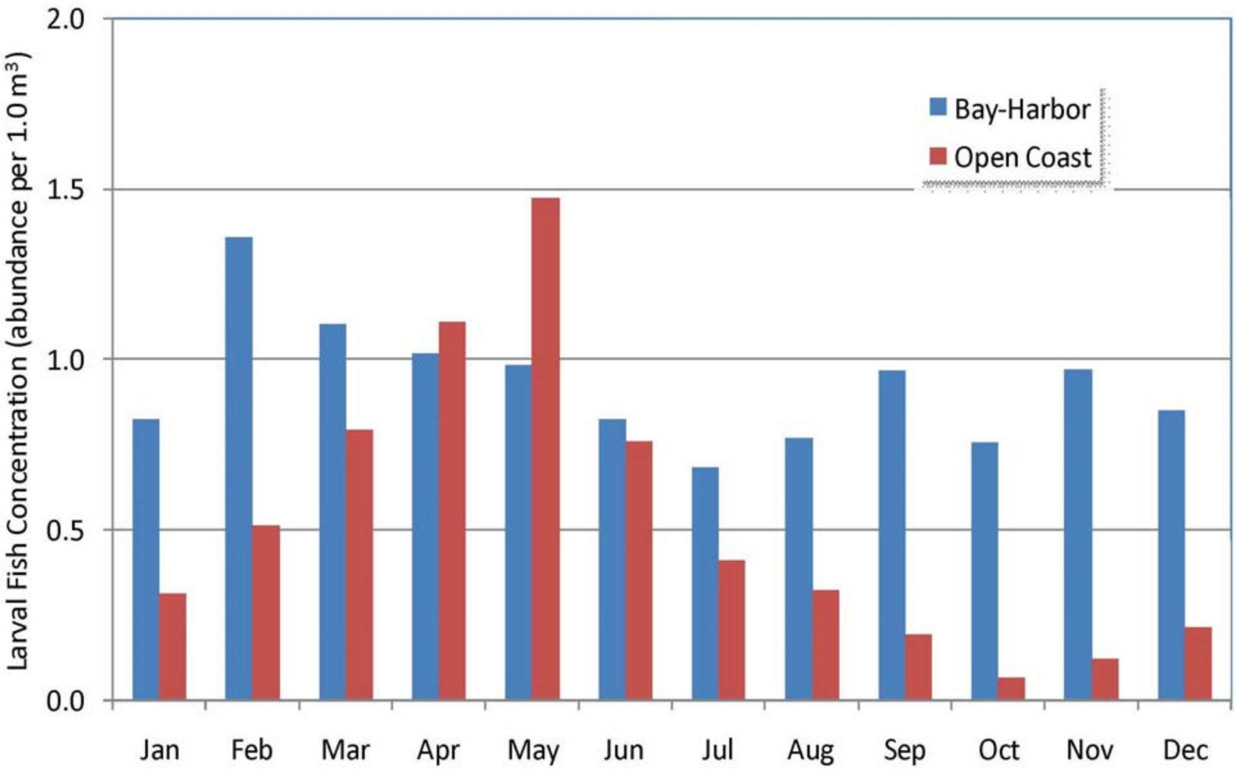

Figure 14. Larval Fish Concentrations at Northern OTC Facilities

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

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

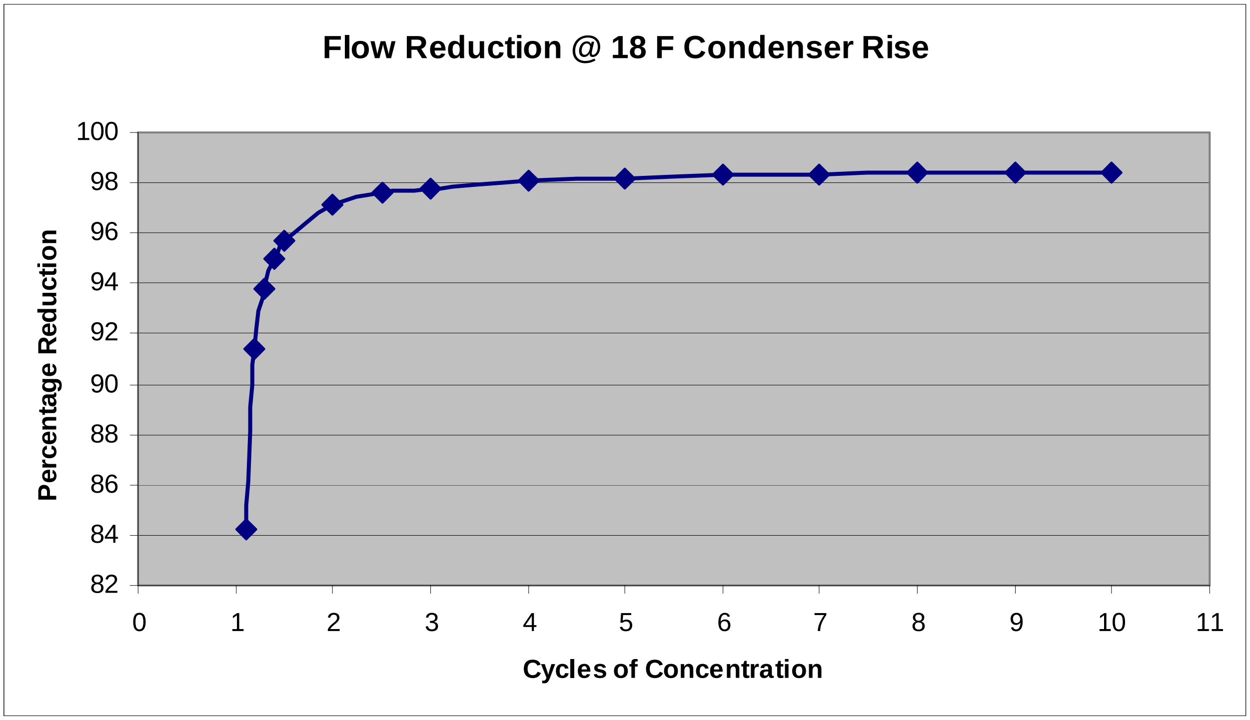

Figure 15. Flow Reductions at Different Cycles of Concentration

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.

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[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.

Alternative 2

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 dry cooling (Track 1) rather than wet 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.

[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

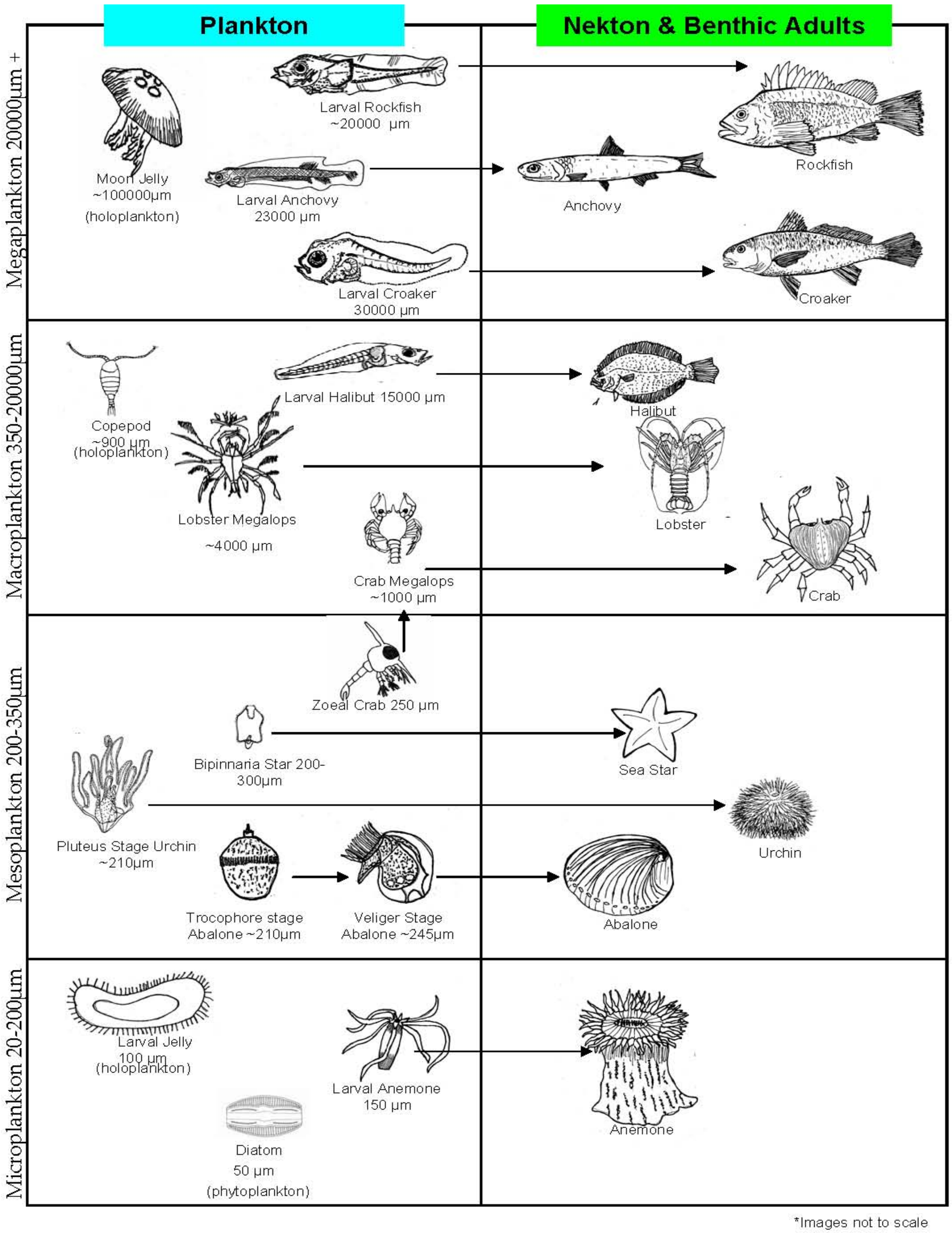

Figure 16. Planktonic Stages and Approximate Sizes of Fish Larvae (Ichthyoplankton), Invertebrate Meroplankton, Invertebrate Holoplankton and Phytoplankton.

(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

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

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[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.

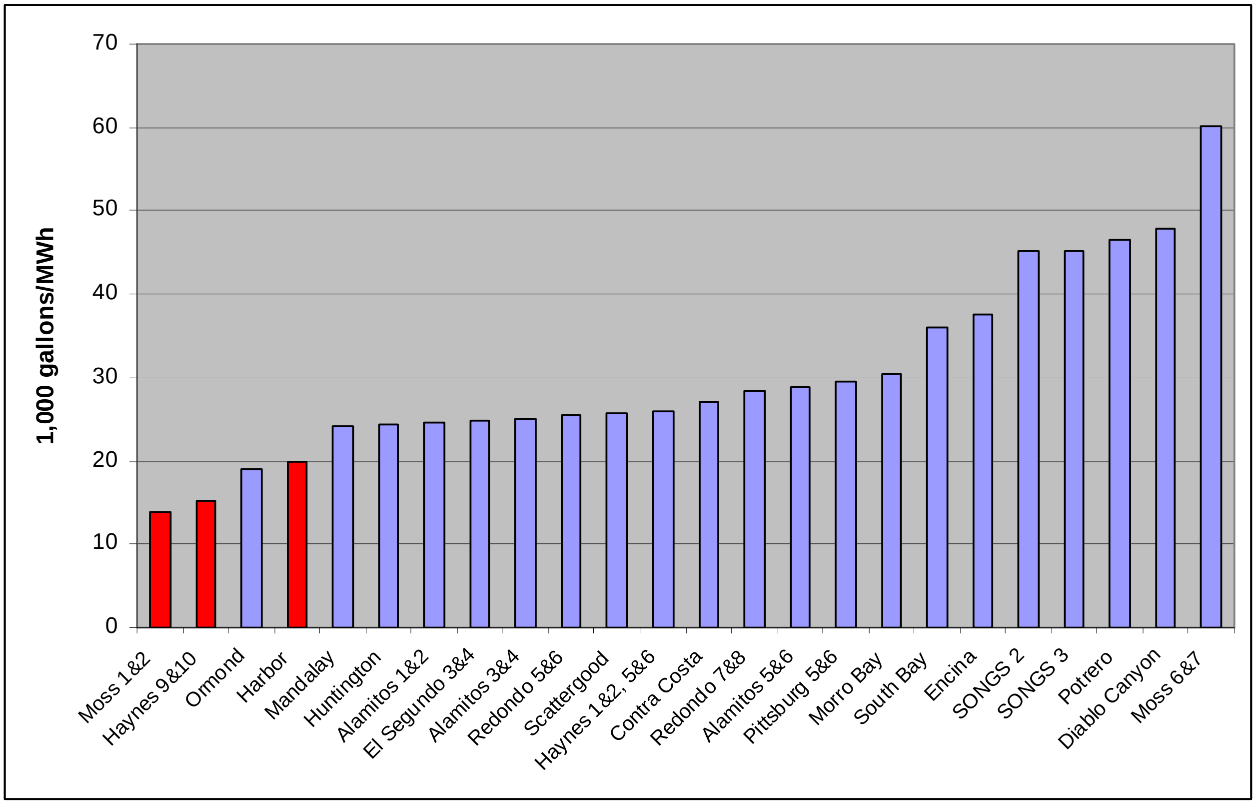

Figure 17. Design Cooling Water Demand

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	Italco 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

[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]

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[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

[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.

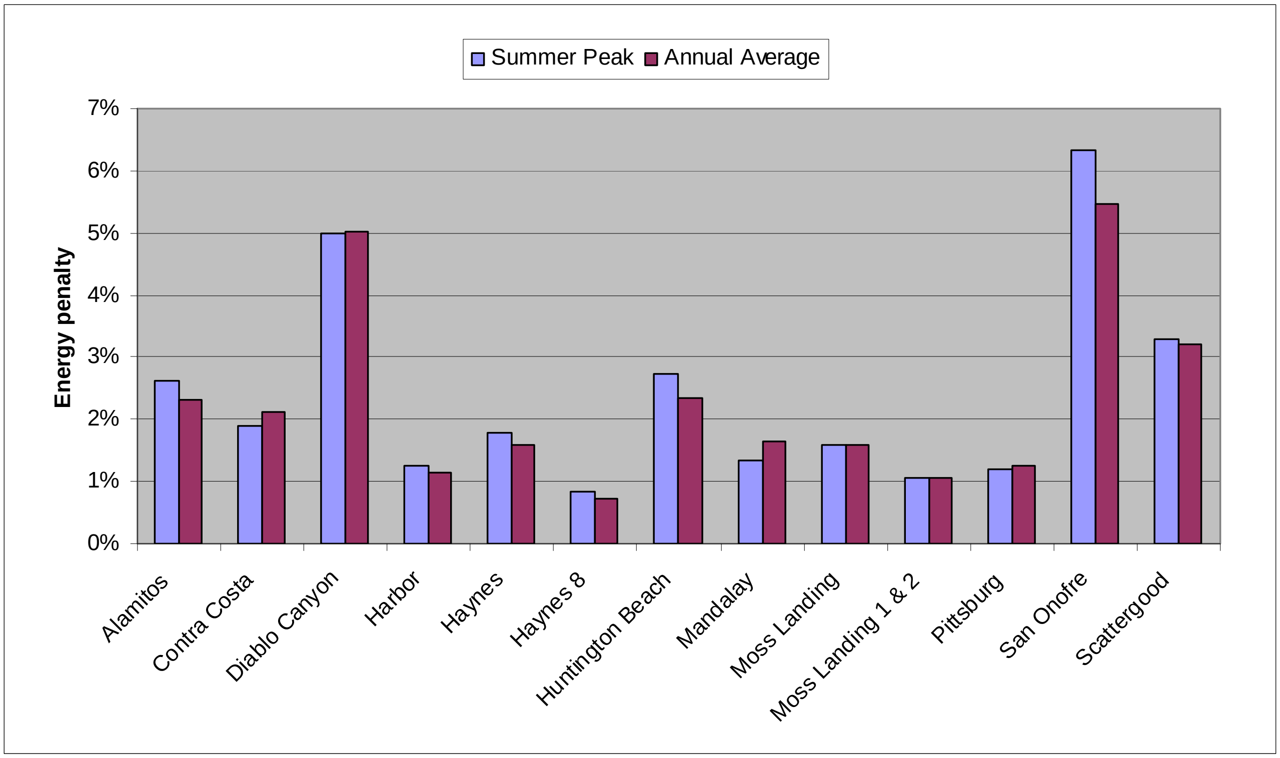

Figure 18. Cumulative Energy Penalties for Wet Cooling Tower Retrofits

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.

<u>PM10 Calculation Methods</u>

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.

<u>PM10 Emissions</u>

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

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[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))

<u>*Assessment*</u>
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.

<u>*Assessment*</u>
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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>
> *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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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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>
> *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).*

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Appendix A – Statewide Water Quality Control Policy on the Use of Coastal and Estuarine Waters for Power Plant Cooling

MARCH 22, 2010 DRAFT

1. Introduction

   A. Clean Water Act Section 316(b) requires that the location, design, construction, and capacity of cooling water intake structures reflect the best technology available (BTA) for minimizing adverse environmental impact. Section 316(b) is implemented through National Pollutant Discharge Elimination System (NPDES) permits, issued pursuant to Clean Water Act Section 402, which authorize the point source discharge of pollutants to navigable waters.

   B. The State Water Resources Control Board (State Water Board) is designated as the state water pollution control agency for all purposes stated in the Clean Water Act.

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

   D. Currently, there are no applicable nationwide standards implementing Section 316(b) for *existing power plants**[1]. Consequently, the Water Boards must implement Section 316(b) on a case-by-case basis, using best professional judgment.

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

   F. This Policy establishes requirements for the implementation of Section 316(b), using best professional judgment in determining BTA for cooling water intake structures at existing coastal and estuarine power plants that must be implemented in NPDES permits.

   G. The intent of this Policy is to ensure that the beneficial uses of the State's coastal and estuarine waters are protected while also ensuring that the electrical power needs essential for the welfare of the citizens of the State are met. The State Water Board recognizes it is necessary to develop replacement infrastructure to maintain electric reliability in order to implement this Policy and in developing this policy considered costs, including costs of compliance, consistent with state and federal law.

   H. During the development of this Policy, State Water Board staff has met regularly with representatives from the California Energy Commission (CEC), California Public Utilities Commission (CPUC), California Coastal Commission (CCC), California State Lands Commission (SLC), California Air Resources Board (ARB), and California Independent System Operator (CAISO) to develop realistic implementation plans and schedules for this

[1] An asterisk indicates that the term is defined in Section 5 of the Policy.

Policy that will not cause disruption in the State's electrical power supply. The compliance dates for this Policy were developed considering a report produced by the energy agencies (CEC, CPUC, and CAISO), titled "Implementation of OTC Mitigation Through Energy Infrastructure Planning and Procurement Changes", and the accompanying table, titled "Draft Infrastructure Replacement Milestones and Compliance Dates for Existing Power Plants in California Using Once Through Cooling", included in the Substitute Environmental Document for this Policy. The energy agencies' approach seeks to address the replacement, repowering, or retirement of power plants currently using OTC that (1) maintains reliability of the electric system; (2) meets California's environmental policy goals; and (3) achieves these goals through effective long-term planning for transmission, generation and demand resources. The energy agencies have stated that the dates specified in their report may require periodic updates.

I. To prevent disruption in the State's electrical power supply when the Policy is implemented, the State Water Board will convene a Statewide Advisory Committee on Cooling Water Intake Structures (SACCWIS), which will include representatives from the CEC, CPUC, CAISO, CCC, SLC, ARB, and State Water Board. SACCWIS will review implementation plans and schedules submitted by dischargers pursuant to this Policy, and advise the State Water Board on the implementation of this Policy to ensure that the implementation schedule takes into account local area and grid reliability, including permitting constraints. The State Water Board recognizes the compliance dates in this Policy may require amendment based on, among other factors, the need to maintain reliability of the electric system as determined by the energy agencies included in the SACCWIS, acting according to their individual or shared responsibilities. The State Water Board retains the final authority over changes to the adopted policy.

J. While the CEC, CPUC and CAISO each have various planning or permitting responsibilities important to this effort, the approach relies upon use of competitive procurement and forward contracting mechanisms implemented by the CPUC in order to identify low cost solutions for most OTC power plants. The CPUC has authority to order the investor-owned utilities (IOUs) to procure new or repowered fossil-fueled generation for system and/or local reliability in the Long-Term Procurement Plan (LTPP) proceeding. In response to the Policy, the CPUC anticipates modifying its LTPP proceeding and procurement processes to require the IOUs to assess replacement infrastructure needs and conduct targeted requests for offers (RFOs) to acquire replacement, repowered or otherwise compliant generation capacity. LTPP proceedings are conducted on a biennial cycle and plans are normally approved in odd-numbered years. The next cycle, the 2010 LTPP, is estimated to result in a decision by 2011. The subsequent cycle, the 2012 LTPP, would in turn result in a decision by 2013. Once authorized to procure by a CPUC LTPP decision, the IOUs need approximately 18 months to issue an RFO, sign contracts, and submit applications to the CPUC for approval. Approval by the CPUC takes approximately nine months. If the contract involves a facility already licensed through the CEC generation permitting process, then financing and construction can begin. A typical generation permitting timeline is 12 months, but specific issues such as ability to obtain air permits can delay the process. IOUs often give preference to RFO bids with permits already (or nearly) in place. From contract approval, construction usually takes three years, if generation permits are approved, or approximately five years, if generation permits are pending or other barriers present delays. In total, starting from the initiation of an LTPP proceeding (2010 LTPP or 2012 LTPP), seven years are expected to elapse, before replacement infrastructure is operational. Due to the number of plants affected, efforts to replace or repower OTC power plants would need to be phased.

K. Because the Los Angeles region presents a more complex and challenging set of issues, it is anticipated that more time would be needed to study and implement replacement infrastructure solutions. Therefore, total elapsed time is expected to begin in 2010 and end in 2017 for the Greater Bay Area and San Diego regions, which would be addressed beginning in the 2010 LTPP. For the Los Angeles region, which would be addressed beginning in the 2012 LTPP, total elapsed time is expected to begin in 2012 and end in 2020. A transmission solution is expected to have approximately the same timeframe, but could be delayed by greater potential for significant local opposition. In order to assure that repowering or *new power plant** development in the Los Angeles basin addresses unique permitting challenges, the SACCWIS will assist the State Water Board in evaluating schedules for power plants not under the jurisdiction of the CPUC or operating within the CAISO Balancing Authority Area.

L. The Global Warming Solutions Act of 2006 requires California to reduce greenhouse gas emissions to 1990 levels by 2020 and then to maintain those reductions. California presently has two *nuclear-fueled power plants** that provide approximately 4,600 megawatts of baseload electricity and do not emit greenhouse gases during energy generation. Energy generation by facilities that do not emit greenhouse gases will be critical to meeting the mandates of the Global Warming Solutions Act and emerging national and international greenhouse gas reduction requirements. The *nuclear-fueled power plants** are entering into United States Nuclear Regulatory Commission (Commission) license renewal proceedings unique to the nuclear power industry and relicensing may extend the plants operating lives to approximately 2045. Unlike older era fossil-fueled plants, if the *nuclear-fueled power plants** undergo modernization as part of relicensing or cooling structure upgrades, that modernization will not reduce greenhouse gas emissions, and in fact, extended downtime during modernization may result in short-term increases in greenhouse gases as other greenhouse gas emitting facilities provide makeup power. In recognition of these considerations and others, this Policy requires special studies for the *nuclear-fueled power plants** to address their unique issues, and to evaluate appropriate requirements for those plants.

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

N. Nothing in this Policy precludes the authority of Regional Water Boards to regulate discharges from *existing power plants** through NPDES permits, consistent with water quality standards.

2. Requirements for *Existing Power Plants**

A. Compliance Alternatives. An owner or operator of an *existing power plant** must comply with either Track 1 or Track 2, below.

(1) Track 1. An owner or operator of an *existing power plant** must reduce *intake flow rate** at each unit, at a minimum, to a level commensurate with that which can be attained by a *closed-cycle wet cooling system**. A minimum 93 percent reduction in *intake flow rate** for each unit is required for Track 1 compliance, compared to the unit's design *intake flow rate**. The through-screen intake velocity must not exceed

0.5 foot per second. The installation of closed cycle dry cooling systems meets the intent and minimum reduction requirements of this compliance alternative.

(2) Track 2. The owner or operator of an *existing power plant** must reduce impingement mortality and entrainment of marine life for the facility, as a whole, to a comparable level to that which would be achieved under Track 1, using operational or structural controls, or both.

(a) Compliance for impingement mortality shall be determined either:

(i) For plants relying solely on reductions in velocity, by monthly verification of through-screen intake velocity not to exceed 0.5 foot per second, or

(ii) By monitoring required in Section 4.A, below. For measured reductions determined by monitoring, the owner or operator must reduce impingement mortality to a comparable level to that which would be achieved under Track 1. A "comparable level" is a level that achieves at least 90 percent of the reduction in impingement mortality required under Track 1.

(b) Compliance for entrainment shall be determined either:

(i) For plants relying solely on reductions in flow, by recording and reporting reductions in terms of monthly flow, in which case a minimum of 93% reduction in terms of design flow must be met, or

(ii) For plants relying in whole or in part on other control technologies (e.g., including but not limited to screens or re-location of intake structures), by measured reductions in entrainment determined by monitoring required in Section 4.B, below. The owner or operator must reduce entrainment to a comparable level to that which would be achieved under Track 1. A "comparable level" is a level that achieves at least 90 percent of the reduction in entrainment required under Track 1. If screens are employed to reduce entrainment, compliance shall be determined based on *ichthyoplankton**, and on the crustacean phyllosoma and megalops larvae, and squid paralarvae fractions of *meroplankton**.

(c) 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.

(d) The owner or operator of an *existing power plant** with *combined-cycle power-generating units** installed prior to [the effective date of the Policy] may choose one of the following compliance options:

(i) The owner or operator may count prior reductions in impingement mortality and entrainment resulting from the replacement of steam turbine power-generating units with *combined-cycle power-generating units**, towards meeting Track 2 requirements for the entire power plant where those units are located. Reductions in entrainment shall be based on reductions in intake flows, calculated as the difference between:

1. the maximum permitted discharge (expressed as million gallons per day (MGD)) for the entire power plant as identified in the plant's prior NPDES permit that authorized the steam turbine power-generating units which were subsequently replaced with the *combined-cycle power-generating units** and
2. the maximum permitted discharge (expressed as MGD) for the entire power plant, including the combined cycle units, as identified in the plant's NPDES permit authorizing the *combined-cycle power-generating units**.

The owner or operator may also count as prior entrainment reductions any permitted discharges from the *combined-cycle power-generating units** for which the CEC and/or a Regional Water Board imposed mandatory mitigation requirements (such as expenditures of substantial funds for habitat restoration or enhancement) based upon substantial evidence in the record of the prior proceeding showing that the CEC and/or Regional Water Board required mitigation after a BTA determination for the *combined-cycle power-generating units** and required the mitigation to further offset the entrainment impacts of the permitted intake cooling water.

(ii) For *combined-cycle power-generating units** only, and not the facility as a whole, the owner or operator may be deemed in compliance by:

1. Reducing the through-screen intake velocity to a maximum of 0.5 foot per second, and
2. Complying with the immediate and interim requirements described in Section 2.C, below, for the life of the *combined-cycle power-generating units*.*

B. Final Compliance Dates

(1) *Existing power plants** shall comply with Section 2.A, above, as soon as possible, but no later than, the dates shown in Table 1, contained in Section 3.E, below.

(2) Based on the need for continued operation of an *existing power plant** to maintain the reliability of the electric system, a final compliance date may be suspended under the following circumstances:

(a) **Suspension of Final Compliance Date for Less Than 90 Days for *Existing Power Plants** Within CAISO Jurisdiction.** If CAISO determines that continued operation of an *existing power plant** is necessary to maintain the reliability of the electric system in the short-term, CAISO shall provide written notification to the State Water Board, the Regional Water Board with jurisdiction over the *existing power plant**, and the SACCWIS. If the Executive Directors of the CEC and CPUC do not object in writing within 10 days to CAISO's written notification, the notification provided pursuant to this paragraph will suspend the final compliance date for the shorter of 90 days or the time CAISO determines necessary to maintain reliability. In the event either CEC or CPUC objects as provided in this paragraph, then the State Water Board shall hold a hearing as expeditiously as possible to determine whether to suspend the compliance date in accordance with paragraph (d).

(b) **Suspension of Final Compliance Date for Longer Than 90 Days for *Existing Power Plants** Within CAISO Jurisdiction.** If CAISO determines that continued operation of an *existing power plant** is necessary to maintain the reliability of the electric system, CAISO shall provide written notification to the State Water Board, the Regional Water Board with jurisdiction over the *existing power plant**, and the SACCWIS If the Executive Directors of the CEC and CPUC do not object in writing within 10 days to CAISO's determination, the notification provided pursuant to this paragraph will suspend the final compliance date for 90 days. During the 90-day time suspension or within 90 days of receiving a written notification from CAISO, the State Water Board shall conduct a hearing in accordance with paragraph (d) to determine whether to suspend the final compliance date for more than the original 90 days pending, if necessary, full evaluation of amendments to final compliance dates contained in the policy.

(c) **Suspension of Final Compliance Date for *Existing Power Plants** Within Los Angeles Department of Water and Power (LADWP) Service Area.** If the LADWP Commission determines, through a public process, that continued operation of an *existing power plant** operated by LADWP is necessary to maintain the reliability of the electric system in the short-term, LADWP shall provide written notification to the State Water Board, the Regional Water Board with jurisdiction over the *existing power plant**, and the SACCWIS. Within 45 days of receiving a written notice from LADWP, the State Water Board shall conduct a hearing in accordance with paragraph (d) to determine whether to suspend the final compliance date. In considering whether to suspend or amend the final compliance dates the State Board shall consult with the CAISO.

(d) **State Water Board Hearings on Suspension of Final Compliance Dates.** In considering whether to suspend or amend the final compliance dates, the State Water Board shall implement the recommendations of the CAISO unless the State Water Board finds that there is compelling evidence not to follow a recommendation and makes a finding of overriding considerations.

C. Immediate and Interim Requirements

(1) No later than [one year after the effective date of this Policy], the owner or operator of an *existing power plant** with an *offshore intake** shall install large organism exclusion devices having a distance between exclusion bars of no greater than nine inches, or install other exclusion devices, deemed equivalent by the Regional Water Board.

(2) No later than [one year after the effective date of this Policy], the owner or operator of an *existing power plant** unit that is not directly engaging in *power-generating activities**, or *critical system maintenance**, shall cease intake flows, unless the owner or operator demonstrates to the Regional Water Board that a reduced minimum flow is necessary for operations.

(3) The owner or operator of an *existing power plant** must implement measures to mitigate the interim impingement and entrainment impacts resulting from the cooling water intake structure(s), commencing [five years after the effective date of this Policy] and continuing up to and until the owner or operator achieves final compliance. The owner or operator must include in the implementation plan, described in Section 3.A below, the specific measures that will be undertaken to comply with this requirement. An owner or operator may comply with this requirement by:

(a) Demonstrating to the State Water Board's satisfaction that the owner or operator is compensating for the interim impingement and entrainment impacts through existing mitigation efforts, including any projects that are required by state or federal permits as of [the effective date of this Policy]; or

(b) Demonstrating to the State Water Board's satisfaction that the interim impacts are compensated for by the owner or operator providing funding to the California Coastal Conservancy which will work with the California Ocean Protection Council to fund an appropriate *mitigation project**; or

(c) Developing and implementing a *mitigation project** for the facility, approved by the State Water Board, which will compensate for the interim impingement and entrainment impacts. Such a project must be overseen by an advisory panel of experts convened by the State Water Board.

(d) The *habitat production foregone** method, or a comparable alternate method approved by the State Water Board Division of Water Quality, shall be used to determine the habitat and area, based on replacement of the annual entrainment, for funding a *mitigation project**.

(e) It is the preference of the State Water Board that funding be provided to the California Coastal Conservancy, working with the California Ocean Protection Council, for mitigation projects directed toward the implementation, monitoring, maintenance and management of the State's Marine Protected Areas.

D. *Nuclear-Fueled Power Plants**

If the owner or operator of an existing *nuclear-fueled power plant** demonstrates that compliance with the requirements for *existing power plants** in Section 2.A, above, of this Policy would result in a conflict with any requirement established by the Commission, with appropriate documentation or other substantiation from the Commission, the State Water Board will make a site-specific determination of best technology available for minimizing adverse environmental impact that would not result in a conflict with the Commission's requirements. The State Water Board may also establish alternative, site-specific requirements in accordance with Section 3.D(8).

3. Implementation Provisions

A. With the exception of *nuclear-fueled power plants**, which are covered under 3.D, below, no later than [six months after the effective date of this Policy], the owner or operator of an *existing power plant** shall submit an implementation plan to the State and Regional Water Boards.

(1) The implementation plan shall identify the compliance alternative selected by the owner or operator, describe the general design, construction, or operational measures that will be undertaken to implement the alternative, and propose a realistic schedule for implementing these measures that is as short as possible. If the owner or operator chooses to repower the facility to reduce or eliminate reliance upon OTC, or to retrofit the facility to implement either Track 1 or Track 2 alternatives, the implementation plan shall identify the time period when generating power is infeasible and describe measures taken to coordinate this activity through the appropriate electrical system balancing authority's maintenance scheduling process.

(2) If the owner or operator selects *closed-cycle wet cooling** as a compliance alternative, the owner or operator shall address in the implementation plan whether recycled water of suitable quality is available for use as makeup water.

B. The SACCWIS shall be impaneled no later than [three months after the effective date of this Policy], by the Executive Director of the State Water Board, to advise the State Water Board on the implementation of this Policy to ensure that the implementation schedule takes into account local area and grid reliability, including permitting constraints. SACCWIS shall include representatives from the CEC, CPUC, CAISO, CCC, SLC, ARB, and State Water Board.

(1) SACCWIS meetings shall be scheduled regularly and as needed. Meetings shall be open to the public and shall be noticed at least 10 days in advance of the meeting. All SACCWIS products shall be made available to the public.

(2) The SACCWIS shall review the owner or operator's proposed implementation schedule and report to the State Water Board with recommendations no later than [one year after the effective date of this Policy]. The SACCWIS may consult with other appropriate agencies, including but not limited to the Regional Water Boards, air quality districts, and the LADWP, in the process of reviewing implementation schedules and providing recommendations to the State Water Board.

(3) The CAISO and the LADWP shall each submit to the SACCWIS by December 31, each year a grid reliability study, for their respective jurisdictions, that has been developed pursuant to a public process and approved by their governing bodies. In order to assure that SACCWIS can provide annual reports to the State Water Board by March 31, the SACCWIS shall promptly meet to consider the reliability studies submitted by CAISO and the LADWP.

(4) The SACCWIS will report to the State Water Board with recommendations on modifications to the implementation schedule every year starting in 2012. If members of SACCWIS do not believe the full committee recommendations reflect their concerns they may issue minority recommendations that the State Water Board shall consider as part of the SACCWIS recommendations.

(5) The State Water Board shall consider the SACCWIS' recommendations and direct staff to make modifications, if appropriate, for the State Water Board's consideration. In the event that the SACCWIS energy agencies (CAISO, CPUC, and CEC) make a unanimous recommendation for implementation schedule modification based on grid reliability, the State Water Board shall implement the recommendation unless the State Water Board finds that there is compelling evidence not to make the recommended modification and makes a finding of overriding considerations. In the event that (i) an owner or operator is unable to obtain permits required for a facility upgrade to comply with a final compliance date established in this policy, and (ii) the State Water Board finds that the owner or operator used best efforts to obtain the required permits, then the State Water Board shall suspend a final compliance date specified in this policy for a period not to exceed two years.

C. The Regional Water Boards shall reissue or, as appropriate, modify NPDES permits issued to owners or operators of *existing power plants** to ensure that the permits conform to the provisions of this Policy.

(1) The permits shall incorporate a final compliance schedule that requires compliance no later than the due dates contained in Table 1, contained in Section 3.E, below. If the State Water Board determines that a longer compliance schedule is necessary to maintain reliability of the electric system per SACCWIS recommendations while other OTC power plants are retrofitted, repowered, or retired or transmission upgrades take place, this delay shall be incorporated into the compliance schedule and stated in the permit findings.

(2) The Regional Water Boards shall reopen, if necessary, the relevant permits and modify the final compliance schedules, if appropriate, based on modifications to the policy approved by the State Water Board or the suspension of final compliance dates pursuant to this policy.

(3) If an owner or operator selects Track 2 as the compliance alternative, the NPDES permit shall include a monitoring program that complies with Section 4 of this Policy.

(4) NPDES permits issued by the Regional Water Boards shall include appropriate permit provisions to implement suspensions of final compliance dates authorized in Section 2.B(2) and modifications to final compliance dates specified in this policy, without reopening the permits.

D. No later than [three months of the effective date of this Policy] the Executive Director of the State Water Board, using the authority under section 13267(f) of the Water Code, shall request that Southern California Edison (SCE) and Pacific Gas & Electric Company (PG&E) conduct special studies for submission to the State Water Board.

(1) The special studies shall investigate alternatives for the *nuclear-fueled power plants** to meet the requirements of this Policy, including the costs for these alternatives.

(2) The special studies shall be conducted by an independent third party, selected by the Executive Director of the State Water Board.

(3) The special studies shall be overseen by a Review Committee, established by the Executive Director of the State Water Board no later than [three months of the effective date of the Policy], which shall include, at a minimum, representatives of SCE, PG&E, SACCWIS, the environmental community, and staffs of the State Water Board, Central Coast Regional Water Board, and the San Diego Regional Water Board.

(4) No later than [one year after the effective date of this Policy], the Review Committee, described above, shall provide a report for public comment detailing the scope of the special studies, including the degree to which existing, completed studies can be relied upon.

(5) No later than [three years after the effective date of this Policy] the Review Committee shall provide the final report and the Review Committee's comments for public comment detailing the results of the special studies and shall present the report to the State Water Board.

(6) Meetings of the Review Committee shall be open to the public and shall be noticed at least 10 days in advance of the meeting. All products of the Review Committee shall be made available to the public.

(7) The State Water Board shall consider the results of the special studies, and shall evaluate the need to modify this Policy with respect to the *nuclear-fueled power plants**. In evaluating the need to modify this Policy, the State Water Board shall base its decision to modify this Policy with respect to the *nuclear-fueled power plants** on the following factors:

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

(b) 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;

(c) Potential environmental impacts of compliance with Track 1 or Track 2, including, but not limited to, air emissions;

(d) Any other relevant information.

(8) If the State Water Board finds that the costs for a specific *nuclear-fueled power plant** to implement Track 1 or Track 2, considering all the factors set forth in paragraph (7), are wholly out of proportion to the costs considered by the State Water Board in establishing Track 1, then the State Water Board shall establish alternate requirements for that *nuclear-fueled power plant**. The State Water Board shall establish alternative requirements no less stringent than justified by the wholly out of proportion (i) cost and (ii) factor(s) of paragraph (7). The burden is on the person requesting the alternative requirement to demonstrate that alternative requirements should be authorized.

(9) In the event the State Water Board establishes alternate requirements for *nuclear-fueled power plants**, the difference in impacts to marine life resulting from any alternative, less stringent requirements shall be fully mitigated. Mitigation required pursuant to this paragraph shall be a *mitigation project** directed toward the implementation, monitoring, maintenance and management of the State's Marine Protected Areas. Funding for the *mitigation project** shall be provided to the California Coastal Conservancy, working with the Ocean Protection Council to fund an appropriate *mitigation project**.

E. Table 1. Implementation Schedule

Milestone		Responsible Entity/Party	Due Date[2]
1	Request SCE and PG&E to conduct special studies to investigate compliance options for *nuclear-fueled power plants** [Section 3.D]	State Water Board Executive Director	[three months after the effective date of the Policy]
2	Establish Review Committee [Section 3.D(3)]	State Water Board Executive Director	[three months after the effective date of the Policy]
3	Establish SACCWIS [Section 3.B]	State Water Board Executive Director	[three months after the effective date of the Policy]
4	Submit a proposed implementation plan to the State and Regional Water Boards [Section 3.A]	Owner/operators of existing fossil-fueled power plants	[six months after the effective date of the Policy]
5	Provide a report for public comment, detailing the scope of the special studies on compliance options for *nuclear-fueled power plants** [Section 3.D(4)]	Review Committee	[one year after the effective date of the Policy]
6	Review the owners or operators' proposed implementation schedules and report to the State Water Board with recommendations [Section 3.B(2)]	SACCWIS	[one year after the effective date of the Policy]
7	Humboldt Bay Power Plant in compliance	Owner/operator	[one year after the effective date of the Policy]

[2] These compliance dates were developed considering information provided by the CEC, CPUC, CAISO, and LADWP.

Milestone		Responsible Entity/Party	Due Date[2]
8	Potrero Power Plant in compliance	Owner/operator	[one year after the effective date of the Policy]
9	Install large organism exclusion devices with a distance between exclusion bars of no greater than nine inches, or equivalent device [Section 2.C(1)]	Owner/operators of *existing power plants** with *offshore intakes**	[one year after the effective date of the Policy]
10	Cease intake flows for units not directly engaging in *power-generating activities** or *critical system maintenance**, or demonstrate to the Regional Water Board that a reduced minimum flow is necessary for operations [Section 2.C(2)]	Owner/operators of *existing power plants**	[one year after the effective date of the Policy]
11	Report to State Water Board on status of implementation of Policy [Section 3.B(3)]	SACCWIS	3/31/2012
12	South Bay Power Plant in compliance	Owner/operator	12/31/2012
13	Report to State Water Board on results of special studies on compliance options for *nuclear-fueled power plants** [Section 3.D(5)]	Review Committee	[three years after the effective date of the Policy]
14	Report to State Water Board on status of implementation of Policy [Section 3.B(3)]	SACCWIS	3/31/2013
15	Report to State Water Board on status of implementation of Policy [Section 3.B(3)]	SACCWIS	3/31/2014
16	Commence to implement measures to mitigate the interim impingement and entrainment impacts due to the cooling water intake structure(s) [Section 2.C(3)]	Owners/operators of *existing power plants**	[five years after the effective date of the Policy]
17	Report to State Water Board on status of implementation of Policy [Section 3.B(3)]	SACCWIS	3/31/2015
18	El Segundo, Harbor, and Morro Bay power plants in compliance	Owner/operator	12/31/2015
19	Report to State Water Board on status of implementation of Policy [Section 3.B(3)]	SACCWIS	3/31/16
20	Report to State Water Board on status of implementation of Policy [Section 3.B(3)]	SACCWIS	3/31/2017

Milestone		Responsible Entity/Party	Due Date[2]
21	Power plants in CPUC 2010 LTPP Cycle in compliance: Encina, Contra Costa, Pittsburg, Moss Landing [Section 1.J]	Owner/Operator	12/31/2017
22	Report to State Water Board on status of implementation of Policy [Section 3.B(3)]	SACCWIS	3/31/2018
23	Report to State Water Board on status of implementation of Policy [Section 3.B(3)]	SACCWIS	3/31/2019
24	Haynes generating station in compliance	Owner/operator	12/31/2019
25	Report to State Water Board on status of implementation of Policy [Section 3.B(3)]	SACCWIS	3/31/2020
26	Power plants in CPUC 2012 LTPP Procurement Cycle in compliance: Huntington Beach, Redondo, Alamitos, Mandalay, Ormond Beach [Section 1.J]. Scattergood generating station in compliance.	Owner/operator	12/31/2020
27	Report to State Water Board on status of implementation of Policy [Section 3.B(3)]	SACCWIS	3/31/2021
28	Report to State Water Board on status of implementation of Policy [Section 3.B(3)]	SACCWIS	3/31/2022
29	San Onofre Nuclear Generating Station in compliance with implementation provisions resulting from State Water Board action on special studies from Section 3.D	Owner/operator	12/31/2022
30	Report to State Water Board on status of implementation of Policy [Section 3.B(3)]	SACCWIS	3/31/2023
31	Report to State Water Board on status of implementation of Policy [Section 3.B(3)]	SACCWIS	3/31/2024
32	Diablo Canyon Power Plant in compliance with implementation provisions resulting from State Water Board action on special studies from Section 3.D	Owner/operator	12/31/2024

4. Track 2 Monitoring Provisions

A. Impingement Impacts: The following impingement studies are required to comply with Section 2.A.(2)(a)(ii):

(1) A baseline impingement study shall be performed, unless the discharger demonstrates, to the Regional Water Board's satisfaction, that prior studies accurately reflect current impacts. Baseline impingement shall be measured on-site

and shall include sampling for all species impinged. The impingement study shall be designed to accurately characterize the species currently impinged and their seasonal abundance to the satisfaction of the Regional Water Board.

(a) The study period shall be at least 12 consecutive months.

(b) Impingement shall be measured during different seasons when the cooling system is in operation and over 24-hour sampling periods.

(c) When applicable, impingement shall be sampled under differing representative operational conditions (e.g., differing levels of power production, heat treatments, etc.).

(d) The study shall not result in any additional mortality above typical operating conditions.

(2) After the Track 2 controls are implemented, to confirm the level of impingement controls, another impingement study, consistent with Section 4.A(1)(a) to (d), above, shall be performed and reported to the Regional Water Board.

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

B. Entrainment Impacts: The following entrainment studies are required to comply with Section 2.A.(2)(b)(ii):

(1) A baseline entrainment study shall be performed, unless the discharger demonstrates, to the Regional Water Board's satisfaction, that prior studies accurately reflect current impacts. Prior studies that may have used a mesh size of 333 or 335 microns for sampling are acceptable for compliance with the review and approval of the Regional Water Board. If the Regional Water Board determines that a new baseline entrainment study shall be performed to determine larval composition and abundance in the source water, representative of water that is being entrained, then samples must be collected using a mesh size no larger than 335 microns. Additional samples shall also be collected using a 200 micron mesh to provide a broader characterization of other *meroplankton** entrained. The source water shall be determined based on oceanographic conditions reasonably expected after Track 2 controls are implemented. Baseline entrainment sampling shall provide an unbiased estimate of larvae entrained at the intake prior to the implementation of Track 2 controls.

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

(b) The study period shall be at least 12 consecutive months, and shall occur during different seasons, including periods of peak use when the cooling system is in operation (such as the summer months when energy is in high demand). Sampling shall be designed to account for variation in oceanographic conditions and larval abundance and behavior such that abundance estimates are reasonably accurate.

(2) After the Track 2 controls are implemented, to confirm the level of entrainment controls, another entrainment study (with a study design to the Regional Water Board's satisfaction, with samples collected using a mesh size no larger than 335 microns, and with additional samples also collected using a 200 micron mesh) shall be performed and reported to the Regional Water Board.

(3) The need for additional entrainment studies shall be evaluated at the end of each permit period. Entrainment studies shall be required when changing operational or environmental conditions indicate that new studies are needed, at the discretion of the Regional Water Board.

5. Definition of Terms

Closed-cycle wet cooling system – Refers to a cooling system, which functions by transferring waste heat to the surrounding air through the evaporation of water, thus enabling the reuse of a smaller amount of water several times to achieve the desired cooling effect. The only discharge of wastewater is from periodic blowdown for the purpose of limiting the buildup of concentrations of materials in excess of desirable limits established by best engineering practice.

Combined-cycle power-generating units - Refers to units within a power plant which combined generate electricity through a two-stage process involving combustion and steam. Hot exhaust gas from 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.

Critical system maintenance – are activities that are critical for maintenance of a plant's physical machinery and absolutely cannot be postponed until the unit is operating to generate electricity.

Existing power plant(s) – Refers to any power plant that is not a *new power plant**.

Habitat production foregone – Refers to the product of the average annual *proportional mortality** and the estimated area of the water body that is habitat for the species' source population. Habitat production foregone is an estimate of habitat area production that is lost to all entrained species on an annual basis.

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

Intake flow rate – Refers to the instantaneous rate at which water is withdrawn through the intake structure, expressed as gallons per minute.

Meroplankton – For purposes of this Policy, refers to that component of the *zooplankton** community composed of squid paralarvae and the pelagic larvae of benthic invertebrates.

Mitigation project – 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, for example through the funding of implementation and/or management of Marine Protected Areas.

New power plant – Refers to any plant that is a “new facility”, as defined in 40 C.F.R. § 125.83 (revised as of July 1, 2007), and that is subject to Subpart I, Part 125 of the Code of Federal Regulations (revised as of July 1, 2007) (referred to as “Phase I regulations”).

Nuclear-fueled power plant(s) – Refers to Diablo Canyon Power Plant and/or San Onofre Nuclear Generating Station.

Offshore intake –refers to any submerged intake structure that is not located at the shoreline, and includes such intakes that are located in ocean, bay and estuary environments.

Power-generating activities – Refers to activities directly related the generation of electrical power, including start-up and shut-down procedures, contractual obligations (hot stand-by), hot bypasses, and *critical system maintenance** regulated by the Nuclear Regulatory Commission. 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.

Proportional mortality – the proportion of larvae killed from entrainment to the larvae in the source population, as determined by an Empirical Transport Model.

Zooplankton – For purposes of this Policy, refers to those planktonic invertebrates larger than 200 microns.

Appendix B – Final Environmental Checklist

I. Background

Project Title:	Water Quality Control Plan on the Use of Coastal and Estuarine Waters for Power Plant Cooling
Lead Agency:	State Water Resources Control Board
Address:	1001 I Street Sacramento, CA 95814
Contact Person:	Joanna Jensen (916/341-5582)
Project Description:	See Appendix A and the Substitute Environmental Document, above, for details.

II. Environmental Impacts

The environmental factors checked below could be potentially affected by this project. See the checklist on the following pages for more details.

☐	Aesthetics	☐	Agriculture and Forestry Resources	☐	Air Quality
☐	Biological Resources	☐	Cultural Resources	☐	Geology/Soils
☐	Greenhouse Gas Emissions	☐	Hazards & Hazardous Materials	☐	Hydrology/Water Quality
☐	Land Use/Planning	☐	Mineral Resources	☐	Noise
☐	Population/Housing	☐	Public Services	☐	Recreation
☐	Transportation/Traffic	☐	Utilities/Service Systems	☐	Mandatory Findings of Significance

ISSUES

	Potentially Significant Impact	Less Than Significant with Mitigation Incorporated	Less Than Significant Impact	No Impact
1. AESTHETICS -- Would the project:				
a) Have a substantial adverse effect on a scenic vista?	☐	☑	☐	☐
b) Substantially damage scenic resources, including, but not limited to, trees, rock outcroppings, and historic buildings within a state scenic highway?	☐	☐	☐	☑
c) Substantially degrade the existing visual character or quality of the site and its surroundings?	☐	☑	☐	☐
d) Create a new source of substantial light or glare which would adversely affect day or nighttime views in the area?	☐	☐	☐	☑
2. AGRICULTURE AND FOREST RESOURCES: In determining whether impacts to agricultural resources are significant environmental effects, lead agencies may refer to the California Agricultural Land Evaluation and Site Assessment Model (1997) prepared by the California Dept. of Conservation as an optional model to use in assessing impacts on agriculture and farmland. In determining whether impacts to forest resources, including timberland, are significant environmental effects, lead agencies may refer to information compiled by the California Department of Forestry and Fire Protection regarding the state's inventory of forest land, including the Forest and Range Assessment Project and the Forest Legacy Assessment project; and forest carbon measurement methodology provided in Forest Protocols adopted by the California Air Resources Board. Would the project:				
a) Convert Prime Farmland, Unique Farmland, or Farmland of Statewide Importance (Farmland), as shown on the maps prepared pursuant to the Farmland Mapping and Monitoring Program of the California Resources Agency, to non-agricultural use?	☐	☐	☐	☑
b) Conflict with existing zoning for agricultural use, or a Williamson Act contract?	☐	☐	☐	☑

	Potentially Significant Impact	Less Than Significant with Mitigation Incorporated	Less Than Significant Impact	No Impact
c) Conflict with existing zoning for, or cause rezoning of, forest land (as defined in Public Resources Code section 12220(g)) or timberland (as defined by Public Resources Code section 4526)?	☐	☐	☐	☑
d) Result in the loss of forest land or conversion of forest land to non-forest use?	☐	☐	☐	☑
e) Involve other changes in the existing environment which, due to their location or nature, could result in conversion of Farmland, to non-agricultural use or conversion of forest land to non-forest use?	☐	☐	☐	☑
3. AIR QUALITY -- Where available, the significance criteria established by the applicable air quality management or air pollution control district may be relied upon to make the following determinations. Would the project:				
a) Conflict with or obstruct implementation of the applicable air quality plan?	☐	☐	☐	☑
b) Violate any air quality standard or contribute substantially to an existing or projected air quality violation?	☐	☐	☑	☐
c) Result in a cumulatively considerable net increase of any criteria pollutant for which the project region is non-attainment under an applicable federal or state ambient air quality standard (including releasing emissions which exceed quantitative thresholds for ozone precursors)?	☐	☐	☑	☐
d) Expose sensitive receptors to substantial pollutant concentrations?	☐	☐	☐	☑
e) Create objectionable odors affecting a substantial number of people?	☐	☐	☐	☑
4. BIOLOGICAL RESOURCES -- Would the project:				
a) Have a substantial adverse effect, either directly or through habitat modifications, on any species identified as a candidate, sensitive, or special status	☐	☐	☐	☑

	Potentially Significant Impact	Less Than Significant with Mitigation Incorporated	Less Than Significant Impact	No Impact
species in local or regional plans, policies, or regulations, or by the California Department of Fish and Game or U.S. Fish and Wildlife Service?				
b) Have a substantial adverse effect on any riparian habitat or other sensitive natural community identified in local or regional plans, policies, regulations or by the California Department of Fish and Game or US Fish and Wildlife Service?	☐	☐	☐	☑
c) Have a substantial adverse effect on federally protected wetlands as defined by Section 404 of the Clean Water Act (including, but not limited to, marsh, vernal pool, coastal, etc.) through direct removal, filling, hydrological interruption, or other means?	☐	☐	☐	☑
d) Interfere substantially with the movement of any native resident or migratory fish or wildlife species or with established native resident or migratory wildlife corridors, or impede the use of native wildlife nursery sites?	☐	☐	☐	☑
e) Conflict with any local policies or ordinances protecting biological resources, such as a tree preservation policy or ordinance?	☐	☐	☐	☑
f) Conflict with the provisions of an adopted Habitat Conservation Plan, Natural Community Conservation Plan, or other approved local, regional, or state habitat conservation plan?	☐	☐	☐	☑
5. CULTURAL RESOURCES -- Would the project:				
a) Cause a substantial adverse change in the significance of a historical resource as defined in §Section 15064.5?	☐	☐	☐	☑
b) Cause a substantial adverse change in the significance of an archaeological resource pursuant to §Section 15064.5?	☐	☐	☐	☑
c) Directly or indirectly destroy a unique paleontological resource or site or unique geologic feature?	☐	☐	☐	☑
d) Disturb any human remains, including those interred outside of formal cemeteries?	☐	☐	☐	☑

	Potentially Significant Impact	Less Than Significant with Mitigation Incorporated	Less Than Significant Impact	No Impact
6. GEOLOGY AND SOILS -- Would the project:				
a) Expose people or structures to potential substantial adverse effects, including the risk of loss, injury, or death involving:	☐	☐	☐	☑
i) Rupture of a known earthquake fault, as delineated on the most recent Alquist-Priolo Earthquake Fault Zoning Map issued by the State Geologist for the area or based on other substantial evidence of a known fault? Refer to Division of Mines and Geology Special Publication 42.	☐	☐	☐	☑
ii) Strong seismic ground shaking?	☐	☐	☐	☑
iii) Seismic-related ground failure, including liquefaction?	☐	☐	☐	☑
iv) Landslides?	☐	☐	☐	☑
b) Result in substantial soil erosion or the loss of topsoil?	☐	☐	☐	☑
c) Be located on a geologic unit or soil that is unstable, or that would become unstable as a result of the project, and potentially result in on- or off-site landslide, lateral spreading, subsidence, liquefaction or collapse?	☐	☐	☐	☑
d) Be located on expansive soil, as defined in Table 19-1-B of the Uniform Building Code (1994), creating substantial risks to life or property?	☐	☐	☐	☑
e) Have soils incapable of adequately supporting the use of septic tanks or alternative waste water disposal systems where sewers are not available for the disposal of waste water?	☐	☐	☐	☑
7. GREENHOUSE GAS EMISSIONS -- Would the project:				
a) Generate greenhouse gas emissions, either directly or indirectly, that may have a significant impact on the environment?	☐	☐	☑	☐

	Potentially Significant Impact	Less Than Significant with Mitigation Incorporated	Less Than Significant Impact	No Impact
b) Conflict with any applicable plan, policy or regulation of an agency adopted for the purpose of reducing the emissions of greenhouse gases?	☐	☐	☐	☑
8. HAZARDS AND HAZARDOUS MATERIALS -- Would the project:				
a) Create a significant hazard to the public or the environment through the routine transport, use, or disposal of hazardous materials?	☐	☐	☐	☑
b) Create a significant hazard to the public or the environment through reasonably foreseeable upset and accident conditions involving the release of hazardous materials into the environment?	☐	☐	☐	☑
c) Emit hazardous emissions or handle hazardous or acutely hazardous materials, substances, or waste within one-quarter mile of an existing or proposed school?	☐	☐	☐	☑
d) Be located on a site which is included on a list of hazardous materials sites compiled pursuant to Government Code Section 65962.5 and, as a result, would it create a significant hazard to the public or the environment?	☐	☐	☐	☑
e) For a project located within an airport land use plan or, where such a plan has not been adopted, within two miles of a public airport or public use airport, would the project result in a safety hazard for people residing or working in the project area?	☐	☐	☐	☑
f) For a project within the vicinity of a private airstrip, would the project result in a safety hazard for people residing or working in the project area?	☐	☐	☐	☑
g) Impair implementation of or physically interfere with an adopted emergency response plan or emergency evacuation plan?	☐	☐	☐	☑
h) Expose people or structures to a significant risk of loss, injury or death involving wildland fires, including where wildlands are adjacent to urbanized areas or where residences are intermixed with wildlands?	☐	☐	☐	☑

	Potentially Significant Impact	**Less Than Significant with Mitigation Incorporated**	**Less Than Significant Impact**	**No Impact**
9. HYDROLOGY AND WATER QUALITY -- Would the project:				
a) Violate any water quality standards or waste discharge requirements?	☐	☐	☑	☐
b) Substantially deplete groundwater supplies or interfere substantially with groundwater recharge such that there would be a net deficit in aquifer volume or a lowering of the local groundwater table level (e.g., the production rate of pre-existing nearby wells would drop to a level which would not support existing land uses or planned uses for which permits have been granted)?	☐	☐	☐	☑
c) Substantially alter the existing drainage pattern of the site or area, including through the alteration of the course of a stream or river, in a manner which would result in substantial erosion or siltation on- or off-site?	☐	☐	☐	☑
d) Substantially alter the existing drainage pattern of the site or area, including through the alteration of the course of a stream or river, or substantially increase the rate or amount of surface runoff in a manner which would result in flooding on- or off-site?	☐	☐	☐	☑
e) Create or contribute runoff water which would exceed the capacity of existing or planned stormwater drainage systems or provide substantial additional sources of polluted runoff?	☐	☐	☐	☑
f) Otherwise substantially degrade water quality?	☐	☐	☐	☑
g) Place housing within a 100-year flood hazard area as mapped on a federal Flood Hazard Boundary or Flood Insurance Rate Map or other flood hazard delineation map?	☐	☐	☐	☑
h) Place within a 100-year flood hazard area structures which would impede or redirect flood flows?	☐	☐	☐	☑
i) Expose people or structures to a significant risk of loss, injury or death involving flooding, including flooding as a result of the failure of a levee or dam?	☐	☐	☐	☑
j) Inundation by seiche, tsunami, or mudflow?	☐	☐	☐	☑

	Potentially Significant Impact	Less Than Significant with Mitigation Incorporated	Less Than Significant Impact	No Impact
10. LAND USE AND PLANNING - Would the project:				
a) Physically divide an established community?	❐	❐	❐	☑
b) Conflict with any applicable land use plan, policy, or regulation of an agency with jurisdiction over the project (including, but not limited to the general plan, specific plan, local coastal program, or zoning ordinance) adopted for the purpose of avoiding or mitigating an environmental effect?	❐	❐	❐	☑
c) Conflict with any applicable habitat conservation plan or natural community conservation plan?	❐	❐	❐	☑
11. MINERAL RESOURCES -- Would the project:				
a) Result in the loss of availability of a known mineral resource that would be of value to the region and the residents of the state?	❐	❐	❐	☑
b) Result in the loss of availability of a locally-important mineral resource recovery site delineated on a local general plan, specific plan or other land use plan?	❐	❐	❐	☑
12. NOISE -- Would the project result in:				
a) Exposure of persons to or generation of noise levels in excess of standards established in the local general plan or noise ordinance, or applicable standards of other agencies?	❐	☑	❐	❐
b) Exposure of persons to or generation of excessive groundborne vibration or groundborne noise levels?	❐	☑	❐	❐
c) A substantial permanent increase in ambient noise levels in the project vicinity above levels existing without the project?	❐	☑	❐	❐
d) A substantial temporary or periodic increase in ambient noise levels in the project vicinity above levels existing without the project?	❐	❐	❐	☑
e) For a project located within an airport land use plan				

	Potentially Significant Impact	Less Than Significant with Mitigation Incorporated	Less Than Significant Impact	No Impact
or, where such a plan has not been adopted, within two miles of a public airport or public use airport, would the project expose people residing or working in the project area to excessive noise levels?	☐	☐	☐	☑
f) For a project within the vicinity of a private airstrip, would the project expose people residing or working in the project area to excessive noise levels?	☐	☐	☐	☑
13. POPULATION AND HOUSING -- Would the project:				
a) Induce substantial population growth in an area, either directly (for example, by proposing new homes and businesses) or indirectly (for example, through extension of roads or other infrastructure)?	☐	☐	☐	☑
b) Displace substantial numbers of existing housing, necessitating the construction of replacement housing elsewhere?	☐	☐	☐	☑
c) Displace substantial numbers of people, necessitating the construction of replacement housing elsewhere?	☐	☐	☐	☑
14. PUBLIC SERVICES				
a) Would the project result in substantial adverse physical impacts associated with the provision of new or physically altered governmental facilities, need for new or physically altered governmental facilities, the construction of which could cause significant environmental impacts, in order to maintain acceptable service ratios, response times or other performance objectives for any of the public services:				
Fire protection?	☐	☐	☐	☑
Police protection?	☐	☐	☐	☑
Schools?	☐	☐	☐	☑
Parks?	☐	☐	☐	☑
Other public facilities?	☐	☐	☐	☑

	Potentially Significant Impact	Less Than Significant with Mitigation Incorporated	Less Than Significant Impact	No Impact
15. RECREATION				
a) Would the project increase the use of existing neighborhood and regional parks or other recreational facilities such that substantial physical deterioration of the facility would occur or be accelerated?	❒	❒	❒	☑
b) Does the project include recreational facilities or require the construction or expansion of recreational facilities which might have an adverse physical effect on the environment?	❒	❒	❒	☑
16. TRANSPORTATION/TRAFFIC -- Would the project:				
a) Exceed the capacity of the existing circulation system, based on an applicable measure of effectiveness (as designated in a general plan policy, ordinance, etc.), taking into account all relevant components of the circulation system, including but limited to intersections, streets, highways and freeways, pedestrian and bicycle paths, and mass transit?	❒	❒	❒	☑
b) Conflict with an applicable congestion management program, including, but not limited to level of service standards and travel demand measures, or other standards established by the county congestion management agency for designated roads or highways?	❒	❒	❒	☑
c) Result in a change in air traffic patterns, including either an increase in traffic levels or a change in location that results in substantial safety risks?	❒	❒	❒	☑
d) Substantially increase hazards due to a design feature (e.g., sharp curves or dangerous intersections) or incompatible uses (e.g., farm equipment)?	❒	❒	❒	☑
e) Result in inadequate emergency access?	❒	❒	❒	☑

	Potentially Significant Impact	Less Than Significant with Mitigation Incorporated	Less Than Significant Impact	No Impact
f) Conflict with adopted policies, plans, or programs supporting alternative transportation (e.g., bus turnouts, bicycle racks)?	☐	☐	☐	☑
17. UTILITIES AND SERVICE SYSTEMS -- Would the project:				
a) Exceed wastewater treatment requirements of the applicable Regional Water Quality Control Board?	☐	☐	☐	☑
b) Require or result in the construction of new water or wastewater treatment facilities or expansion of existing facilities, the construction of which could cause significant environmental effects?	☐	☐	☐	☑
c) Require or result in the construction of new storm water drainage facilities or expansion of existing facilities, the construction of which could cause significant environmental effects?	☐	☐	☐	☑
d) Have sufficient water supplies available to serve the project from existing entitlements and resources, or are new or expanded entitlements needed?	☐	☐	☐	☑
e) Result in a determination by the wastewater treatment provider which serves or may serve the project that it has adequate capacity to serve the project's projected demand in addition to the provider's existing commitments?	☐	☐	☐	☑
f) Be served by a landfill with sufficient permitted capacity to accommodate the project's solid waste disposal needs?	☐	☐	☐	☑
g) Comply with federal, state, and local statutes and regulations related to solid waste?	☐	☐	☐	☑
h) Result in electrical transmission grid impacts?	☐	☑	☐	☐

18. MANDATORY FINDINGS OF SIGNIFICANCE

a) Does the project have the potential to degrade the quality of the environment, substantially reduce the habitat of a fish or wildlife species, cause a fish or wildlife population to drop below self-sustaining levels, threaten to eliminate a plant or animal community, reduce the number or restrict the range of a rare or endangered plant or animal or eliminate important examples of the major periods of California history or prehistory?	☐	☐	☐	☑
b) Does the project have impacts that are individually limited, but cumulatively considerable? ("Cumulatively considerable" means that the incremental effects of a project are considerable when viewed in connection with the effects of past projects, the effects of other current projects, and the effects of probable future projects)?	☐	☐	☐	☑
c) Does the project have environmental effects which will cause substantial adverse effects on human beings, either directly or indirectly?	☐	☐	☐	☑

Explanations of Impact Assessment (may also follow checklist sections)

Checklist items are discussed in Section 4 of this staff report.

PRELIMINARY STAFF DETERMINATION

☐ The proposed project COULD NOT have a significant effect on the environment, and, therefore, no alternatives or mitigation measures are proposed.

☐ The proposed project MAY have a significant or potentially significant effect on the environment, and therefore alternatives and mitigation measures have been evaluated.

Appendix C – Joint Proposal of Energy Agencies (July 22, 2009)

Implementation of OTC Mitigation Through Energy Infrastructure Planning and Procurement Changes by the CEC, CPUC, and California ISO May 19, 2009

Background

In March 2008, the State Water Resources Control Board (SWRCB) issued a preliminary once-through cooling (OTC) policy report for electric power plants establishing reliability as a condition for the design and implementation of an OTC mitigation policy. The proposed policy contemplates a phased compliance schedule that would allow sufficient time for the energy agencies and the transmission and generation industries to build new infrastructure or identify new resources in a timely manner, thus assuring adequate electrical system reliability. The following outline identifies the steps that the California Public Utilities Commission (CPUC), California Energy Commission (CEC), and California Independent System Operator Corporation (ISO) intend to undertake to support the SWRCB efforts. This proposal seeks to address the replacement or repowering of OTC power plants through an approach that (1) maintains reliability of the electric system; (2) meets California's environmental policy goals; and (3) achieves these goals through effective long-term planning for transmission, generation and demand resources. The proposal relies upon use of competitive procurement and forward contracting mechanisms in order to identify low cost solutions.

The SWRCB recognized that its implementation process could create transitional problems, so it created an Inter-agency Working Group (IWG) to review these implementation challenges and other aspects of the proposed policy.

In a December 15, 2008 paper, the CEC and CPUC in conjunction with the ISO proposed an alternative approach to the fixed time schedule to reduce OTC in existing coastal power plants, while assuring reliability of the electrical grid.[1] That paper broadly sketched out changes to planning, procurement and project permitting processes to encourage repowering or new infrastructure so that retirement of OTC facilities can occur without threatening reliability. In subsequent meetings and discussions, SWRCB staff and other members of the IWG communicated broad support and requested refinements that defined milestones and accelerated compliance timelines wherever possible. In particular, SWRCB staff requested consideration of applying the general approach on a regional, rather than statewide basis.[2] This paper modifies the original proposal, focusing on regional analysis and implementation.

Proposal

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[1] For purposes of expressing collective recommendations, this paper will refer to these three organizations as the Energy Agencies.

[2] While there are several alternative regional definitions in use among agencies for various specific purposes, for this purpose the local capacity areas used as the basis for resource adequacy requirements are the starting point. The relevant regions that are local capacity areas are San Diego, Los Angeles Basin, Ventura/Big Creek, Greater Bay Area, and Humboldt. To these the Central Coast has been added to encompass all OTC facilities.

In order to accomplish the retrofitting, repowering or retirement[3] of more than 30 percent of the power generating capacity in California, significant planning decisions, procurement authorization, and ultimately permitting of specific energy infrastructure projects will be necessary. Of the five balancing authorities in California, only two (the California ISO and the Los Angeles Department of Water and Power (LADWP)) are needed to encompass all of the 19 generation plants with OTC units. Of the 16 OTC plants in the ISO, 13 are located in transmission constrained regions. Transmission constraints on the LADWP system also influence both the need for and options among refitting, repowering and replacing the three OTC plants within the LADWP balancing authority. In sum, the need for OTC plants and options for repowering or replacing them are more readily understood at this regional level. Thus, the Energy Agencies propose a process that does not have uniform schedules for all OTC facilities; rather, the regions whose problems are better understood and where solutions are at hand should be required to reduce OTC harm more quickly than those regions where constraints on implementing solutions are more extensive.

Specific Proposal for Planning and Procurement of Electricity Infrastructure

Listed below are the key steps of this approach that will result in an OTC Power Plant Replacement Infrastructure Plan (Plan) and the permitting and procurement steps that will implement it.

1. Establish regional basis for analyses and identify existing transmission and system operations studies relevant to establishing constraints on the retirement of specific OTC plants/units:
    a. Review definition of the regions to understand local reliability issues and assign OTC facilities to each region.
    b. Review existing Local Capacity Requirement (LCR) studies of those regions containing OTC plants. Review specific new generation and transmission project proposals and licensing decisions by regulatory agencies for impacts on future LCR values.
    c. Review other regional and system studies[4] to determine the operating characteristics of the current generating fleet, how the amount of needed characteristics could change going forward under preferred resource (energy efficiency, renewable, and demand response) and transmission to support those resources, and the implications of OTC plant/unit retirements for the necessary characteristics of replacement facilities.
    d. Compile results of Steps 1.a through 1.c and identify, to the extent possible, a realistic development schedule for needed replacement

[3] Retrofitting refers to the installation of a cooling system that complies with the proposed SWRCB policy. Repowering entails replacement of the existing boiler with advanced generation technology – improving thermal efficiency – and installing a compliant cooling technology. Retirement may, and often does, require replacement of the foregone capacity with generation at another location.

[4] As an illustration, the CAISO study of the implications of 20 percent penetration of renewable generation, November 2007.

infrastructure to establish the dates by which existing OTC power plants/units will no longer draw in and discharge ocean water above levels allowed by the SWRCB policy. For those plants/units requiring further analyses, Step 2 is needed.

2. Complete an enhanced[5] Local Capacity Requirement evaluation, or other relevant assessment, for each region that contains OTC power plants, and update amounts of necessary operating characteristics as needed.
    a. The Energy Commission and CPUC will develop scenarios of annual load projections for each region, any projected generation or resource additions or non-OTC retirements for each region, and any transmission project upgrades or additions+ in each year from 2012 up to and including 2019 reflecting alternative ways in which preferred resource development policies could be implemented. The CEC and CPUC, in consultation with the CAISO, will review these scenario results and select the assumptions to be used for the following enhanced LCR evaluation.
    b. The ISO will prepare an enhanced LCR evaluation for each year 2012 to 2019 based on those projections and available ISO –performed transmission studies.[6] These enhanced LCR evaluations will identify expected generation capacity needed within the LCR Areas and OTC regions for each year for given transmission system configurations.
    c. The Energy Agencies will then compare projected LCR needs with total expected generation less the capacity represented by OTC power plants/units in each LCR Area to identify the necessary capacity to replace OTC power plants/units in each region. The sequence for removing OTC plants/units through time will be based on effectiveness in mitigating various system contingencies, plant/unit-specific characteristics, and other operational needs in maintaining reliability.
    d. The CAISO, in consultation with CPUC and CEC, will identify the specific characteristics of that capacity (e.g. ramping ability, minimum load

[5] Enhanced implies conducting an LCR-style analysis of capacity needs, but doing so 10 years forward and identifying the impacts of specific OTC retirements or transmission developments on the area's LCR projections.

[6] Three of the facilities that use OTC are operated by LADWP. As a publicly-owned utility, LADWP makes investment decisions in the interests of its customers and does not come under the jurisdiction of the CPUC. As a separate control area it is responsible for its own reliability studies and is not part of the ISO balancing authority area. The Energy Agencies believe the elimination of OTC at these facilities will require the development of new infrastructure. Therefore, it is possible that LADWP will need to compete with generator owners to secure Emission Reduction Credits (ERCs) in the air shed under SCAQMD jurisdiction. The Energy Commission hopes to facilitate LADWP's cooperation in the Plan; however, absent such cooperation the Energy Agencies will proceed to develop the Plan as it pertains to OTC power plants within the ISO's balancing authority area.

constraints, regulation requirements, etc.) needed to meet systems needs once the OTC plants are retired.

e. The Energy Agencies will jointly identify what additional system capacity is needed in connection with replacing each OTC power plant/unit. While replacement capacity needed in an LCR area may be less than that provided by OTC plants/units, system-wide capacity needs may require additional power plant development elsewhere in the ISO balancing authority area.
f. The ISO envisions performing enhanced LCR studies each year that can support efforts to refine capacity requirements set forth in the Plan. Any updates to the Plan would occur in consultation and agreement by the Energy Agencies and would be made available to the IWG (or the Statewide Task Force) which would be formalized upon approval of the OTC Policy and the SWRCB. Any Plan updates may also reflect transmission and/or generation infrastructure constructed and completed).
g. For those OTC power plants that are not located in LCR Areas, the Plan would consider the need for capacity located within the ISO balancing authority area (or LADWP balancing authority area) to serve system need.

3. The Energy Agencies will review the results of Steps 1 and 2 and, for each region, describe the course of action required to eliminate reliance upon a power plant/unit using OTC as a cooling technology. A specific schedule for each existing OTC plant/unit would be developed that identifies the latest date it would operate using OTC technology. After such date, the plant/unit will lose its reliability designation. New generating capacity would satisfy the characteristics identified in Step 2d. Collectively this set of decisions about OTC elimination and replacement infrastructure would be referred to as the "Plan." This initial version of the Plan would be updated periodically as a result of actual experience with generation and transmission project development timelines, or other material changes in assumptions affecting infrastructure needs.

4. The SWRCB and its regional boards would use the Plan as the basis for establishing an OTC mitigation policy and for issuing NPDES permits for each plant/unit based on its reliability designation. The projected date of operation of the specific replacement infrastructure needed to assure reliable operation of the grid without the facility using OTC technology should be the basis for the expiration date for that plant/unit's permit.

5. The CEC would review the Plan to determine how its power plant licensing process may be affected, and to facilitate air quality management district (AQMD) review by:

   a. Providing an estimate to each local AQMD of the magnitude of air quality credits likely to be required for licensing the new or repowered generating facilities included within the Plan.
   b. Obtaining AQMD concurrence that the volumes of credits used in the studies were credible, or working with an AQMD to devise valid sources of credits and estimates of their costs.
   c. Communicating any significant change in assumptions about air credit availability and costs back to other entities involved in studies and procurement activities.

6. The CPUC would authorize IOU procurement mechanisms to require the IOUs to conduct a large set of targeted RFOs following the 2010 and subsequent long-term procurement proceedings. These targeted RFOs would focus on acquiring needed replacement capacity in appropriate locations with operational characteristics that would allow existing OTC plants/units to retrofit, repower or retire consistent with the Plan.

7. The CAISO will consider SWRCB directives and schedules limiting or canceling water permits required to operate OTC plant/units in the 2011 and subsequent annual Transmission Planning Process. The CAISO will conduct an analysis as part of its Transmission Planning Process reflecting projected OTC plant/unit retirements as a result of SWRCB permitting directives and schedules, which shall be incorporated into the CAISO's annual Transmission Plan that serves as a basis for further economic or reliability based transmission upgrades or additions.

8. Once each targeted RFO was complete, generator retrofits, repowers or new generating facility development assumptions would be updated in the Plan, to the extent the results from the RFOs differ from the previous edition of the Plan. Any updates to the Plan would result in SWRCB, or its regional boards, modifying permits for various power plants/units depending upon their role in carrying out the Plan.[7]

9. If there are changes (e.g. delays in project development or major modifications to forecast assumptions) in the infrastructure development assumptions (e.g. transmission upgrades or additions are not on schedule, or new generating

[7] For some OTC power plants, this would mean issuing a time-limited permit allowing the plant to operate without change until a specific date at which time it would be shut down and no permit extensions allowed. For other power plants with longer timelines for continued operations, some modification of water intake structures and water usage patterns would be required, but still the plant would not be required to undergo major change because it is scheduled to be retired by a specific date. For still other plants, shifts to closed cycle cooling would be required consistent with long-term continued usage of the power plant.

capacity is not operational) upon which the Plan is based, the Energy Agencies will perform appropriate analysis and inform the SWRCB, or its regional boards, of the new time period that a specific OTC plant/unit is required for system reliability.

10. The Energy Agencies will periodically update the Plan to reflect changing system conditions and transmission and generation developments to ensure that OTC mitigation is timely while preserving system reliability. It is possible that transmission upgrades and additions associated with California's Renewable Energy Transmission Initiative may address some system reliability concerns raised by OTC power plant retirements. The Energy Agencies intend to review these developments and incorporate them into the Plan for OTC power plant retirements.

11. The SWRCB would periodically review the Plan and, for each unit with an official reliability designation, modify the OTC permit expiration date to match the reliability designation of the unit. For units without such a designation, the SWRCB would establish compliance requirements and a schedule that transforms these into a water use permit.

Unresolved Issues for this Proposal

Some elements of this proposed approach remain unresolved. These include:

- Air pollution credits in South Coast Air Quality Management District (SCAQMD) for new power plants displacing OTC power plants, or repowers of existing OTC plants/units to eliminate OTC cooling technologies,
- Sequencing of bidding into utility RFOs versus permitting of a facility,
- Reliance upon conventional generating facilities or preferred technologies,
- Analyses of nuclear generating units at San Onofre and Diablo Canyon, and
- Development of a comprehensive Plan and preferential treatment of elements of the Plan in licensing proceedings compared to proposed facilities not included within the Plan.

Air Pollutant Credits in SCAQMD. Acquiring sufficient air credits through a revitalized Priority Reserve or some other mechanism is necessary for new or repowered generators in the SCAQMD. Only limited OTC retirement can happen without serious reliability consequences unless new or repowered plants can be constructed in the

SCAQMD's jurisdiction.[8] The July and November 2008 court decisions in the challenge of the SCAQMD's "priority reserve" requirements has complicated the situation, making it extremely difficult for new power plants to be sited in the Los Angeles Basin. This challenge will make it difficult for most aging power plants to be closed in the Los Angeles coastal region, until new generation or transmission can be constructed. Tradeoffs exist between the need to protect water quality, satisfy air quality requirements and ensure electrical system reliability, while moving toward greater levels of renewable generation as called for by Assembly Bill 32 (AB32) and the Governor's recent Executive Order calling for increased levels of renewable generation.

Sequence of Bidding and Permitting of Proposed Facilities. The sequence of Energy Commission permitting versus generator bidding into an IOU RFO raises several questions:

- whether power plants would be required to have an Energy Commission permit as a condition of bidding into an IOU RFO,
- whether power plants would be required to have entered the CEC permitting process and have satisfied specific milestones as a condition of bidding into an IOU RFO,
- whether winners of an IOU RFO would receive expedited treatment from the Energy Commission in the permitting process compared to other applicants, or
- whether advance guidance can steer proposed power plants into locations likely to be permitted by the Energy Commission.

Conventional versus Preferred Technologies to Replace OTC Facilities. A straightforward solution to the OTC problem is to repower existing OTC facilities by installing a new prime mover that does not use ocean water for cooling.[9] This approach makes use of the existing electrical switchyard, perhaps eliminates consideration of new transmission lines that would allow retirement of some facilities without replacement on site, and essentially preserves the existing electrical system as much as possible. However, this approach would likely have considerable problems in SCAQMD in finding needed air credits and it would fail to address the policy preferences established by the Energy Agencies through the Energy Action Plan process or the need to reduce reliance upon fossil power plants to achieve AB32 GHG emission reduction goals. Assessing the feasibility of major changes to the system through increased reliance upon renewable, resources, upon rooftop solar PV and other distributed generation technologies, enhanced energy efficiency program impacts reducing load, etc. is necessarily more complex and time consuming than simply endorsing a repowering strategy with little thought to the very long term consequences.

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[8] Energy Commission Draft Staff Paper, *Potential Impacts of the South Coast Air Quality Management District Air Credit Limitations and Once-Through Cooling Mitigation on Southern California's Electricity System*, February 2009, CEC-200-2009-002-SD.

[9] A prime mover is the basic source of heat energy for running the generating turbine, e.g. a steam boiler, a combustion turbine, a nuclear reactor.

Analyses of Nuclear Generating Units. The four nuclear generating units located at San Onofre and Diablo Canyon represent unique elements of California's electrical generating system and both its positive and negative dimensions. From the perspective of the SWRCB, these four units are the largest source of biologic harm. From traditional air quality criteria pollutant or GHG perspectives, nuclear plants are viewed as highly beneficial, and OTC mitigation requirements that might cause them to shut down would exacerbate overall problems to be overcome. The nuclear units supply a significant percentage of the energy used by California end-users, operating as baseload units with very high capacity factors. Refitting these plants with alternative cooling systems or replacing their capacity and energy require special studies. Unfortunately, studies of the generation versus transmission tradeoffs of the aging fossil fleet may have different results depending on whether the nuclear units are assumed to operate as they do today for an indefinite future, or whether they are retired when their current Nuclear Regulatory Commission permits expire in 2021-2023.

Creation of a Comprehensive Plan to Enable Preferential Treatment for Some Projects. Creating a formal Plan and adopting that Plan through a CEQA-compliance process could have value by subsequently providing preferential treatment (reduced consideration of alternatives, accelerated time schedule, etc.) in the applicable licensing processes for individual projects or facilities included within the Plan. Multiple agencies now have licensing authority over various infrastructure projects, although the Energy Commission licenses the majority of the likely power plant additions and the CPUC licenses the majority of the expected transmission line upgrades. The individual CEQA reviews now implemented for new power plants and transmission lines might be conducted *en masse* for infrastructure additions part of the Plan. Since the Plan represents a comprehensive, multi-facility replacement of multiple existing facilities, it may be appropriate to revise Energy Agencies' review processes to consider multiple facilities as a package, and to accelerate this consideration. This will be among the alternatives that Energy Agencies will consider when fully developing this alternative approach to OTC mitigation.

Next Steps

This present document represents an attempt to incorporate the feedback to date and internal discussions among the Energy Agencies. The Energy Agencies are now compiling information about the evaluations that are relevant to the OTC power plants in the various regions, and preparing a workplan for those further analyses which are needed. The analytic work will be conducted over the second quarter of 2009.

The CEC will conduct a joint workshop as part of the Energy Commission's 2009 Integrated Energy Policy Report proceeding on May 11, 2009 to solicit input from the generator community, environmental groups, agencies with environmental responsibilities, and the public. The Energy Agencies will participate in this workshop.

JOINT PROPOSAL OF ENERGY AGENCIES – 06/22/2009

Draft Infrastructure Replacement Milestones and Compliance Dates for Existing Power Plants in California Using Once-Through Cooling

Region (Balancing Authority)	Existing Facility Name	Infrastructure Replacement Milestones[1]							
		CAISO Enhanced LCR Study[2]	CAISO-CPUC-CEC Infrastructure Replacement Plan[3]	CPUC Procurement[4] LTPP Approval[5]	CPUC Procurement[4] Gen Project Approval[6]	CAISO Annual Transmission Plan[8]	CPUC Transmission Permitting[7]	Known Replacement Infrastructure Operational[9]	Unspecified Replacement Infrastructure Operational[9]
Humboldt	Humboldt Bay Power Plant[10]	Not required[19]	Pre-Plan[20]	Complete	Complete	Gen solution	N/A	Q3 2010	N/A
San Diego	South Bay Power Plant (partial capacity)[11]	Not required[19]	Pre-Plan[20]	Complete	Complete	Gen solution	N/A	Q4 2009	N/A
San Diego	South Bay Power Plant (remaining units)[12]	Not required[19]	Pre-Plan[20]	Trans solution	Trans solution	Complete	Complete	Q3 2012	N/A
San Diego	Encina Power Plant	Q4 2009	Q1 2010	2011	2013	2011	2015	N/A	2017
Bay Area	Potrero Power Plant (Unit 3)[13]	Not required[19]	Pre-Plan[20]	Trans solution	Trans solution	Complete	Complete	Q1 2010	N/A
Bay Area	Contra Costa Power Plant (1 of 2 units)[14]	Not required[19]	Pre-Plan[20]	Complete	Complete	Gen solution	N/A	Q2 2009[21]	N/A
Bay Area	Contra Costa Power Plant (second unit)	Q4 2009	Q1 2010	2011	2013	2011	2015	N/A	2017
Bay Area	Pittsburg Power Plant								
Central Coast	Moss Landing Power Plant[15,16]	Q4 2009	Q1 2010	2011	2013	N/A	N/A	N/A	2017
Central Coast	Morro Bay Power Plant[16]	Not required	Pre-Plan	complete	complete	N/A	N/A	Q1 2009[22]	N/A
Ventura/Big Creek[17]	Mandalay Generating Station	Q4 2010	Q2 2011	2013	2015	2012	2016	N/A	2020
Ventura/Big Creek[17]	Ormond Beach Generating Station								
Los Angeles Basin[17] (CAISO)	El Segundo Generating Station	Q4 2010	Q2 2011	2013	2015	2012	2016	N/A	2020
Los Angeles Basin[17] (CAISO)	Huntington Beach Generating Station								
Los Angeles Basin[17] (CAISO)	Redondo Generating Station								
Los Angeles Basin[17] (CAISO)	Alamitos Generating Station								
Los Angeles Basin[17] (LADWP)	Haynes Generating Station[18]	Not under CAISO balancing authority or CPUC jurisdiction. CEC is conferring with LADWP to understand in-basin capacity requirements and processes for accomplishing OTC mitigation.							
Los Angeles Basin[17] (LADWP)	Harbor Generating Station[15,18]								
Los Angeles Basin[17] (LADWP)	Scattergood Generating Station[18]								
Nuclear Plants	Diablo Canyon Power Plant								
Nuclear Plants	San Onofre Nuclear Generating Station								

JOINT PROPOSAL OF ENERGY AGENCIES – 06/22/2009

Notes:

[1] These infrastructure milestones assume no litigation about facility permits following appropriate agency approvals.

[2] California Independent System Operator Corporation (CAISO) would conduct an enhanced Local Capacity Requirement (LCR) study identifying the impacts of specific OTC retirements or transmission developments on the local area's LCR projections 10 years out. CAISO will use assumptions about load and generation developed jointly with the California Energy Commission (CEC) and the California Public Utilities Commission (CPUC).

[3] The Infrastructure Replacement Plan developed jointly and updated by the CAISO, CEC, CPUC would identify the complete set of infrastructure needed to make OTC plants/units redundant for grid reliability. It would advise the SWRCB about the reliability designations of specific power plants.

[4] CPUC would modify its Long-Term Procurement Plan (LTPP) proceeding and procurement processes to require the investor-owned utilities (IOUs) to assess replacement infrastructure needs and conduct targeted request for offers (RFOs) to acquire replacement or repowered generation capacity. CPUC also has authority to approve cost-based contacts under AB 1576.

[5] CPUC has authority to order the IOUs to procure new (or repowered) fossil generation for system reliability in the LTPP proceeding. LTPP proceedings are conducted on a biennial cycle and plans are normally approved in odd-numbered years.

[6] Once authorized to procure by a CPUC LTPP decision, it takes 18 months for the IOUs to issue an RFO for generation (new or repowered), sign contracts and submit applications to the CPUC for approval. Approval by the CPUC takes 9 months. If the contract involves a facility already licensed by the CEC, then financing and construction can begin. Generation permitting for thermal technologies >50 MW in capacity is under CEC authority, and may take place before, after or during the CPUC contract approval process. The Warren-Alquist Act authorizes CEC to license certain categories of power plants and related structures. CEC's siting process has been determined to be a certified regulatory program under the California Environmental Quality Act (CEQA) and the functional equivalent of preparing environmental impact reports (EIRs). CEC is the lead agency and consults with other relevant agencies. The standard licensing process is normally conducted in 12 months, but streamlining of the permitting process may be an option so multiple facilities can be considered as a package (planning level EIR). Reviews should be somewhat faster because impacts to water resources are by definition minimized; impacts to the grid reliability are already considered and mitigated; and conformity to state laws and regulation has been considered under the Plan.

[7] Transmission permitting is under CPUC authority. Proposed transmission facilities to meet needs identified in the CAISO Annual Transmission Plan to replace OTC plants/units would be brought to the CPUC for approval.

[8] Transmission solutions (upgrade and/or new addition) that would make specified OTC system redundant would be analyzed in the CAISO Annual Transmission Plan. The CAISO will consider SWRCB directives and schedules limiting or canceling water permits required to operate OTC plants/units in the 2011 and subsequent annual Transmission Planning Process (TPP). The CAISO will conduct analysis as part of its TPP reflecting projected OTC plant/unit retirements as a result of SWRCB directives and schedules, which shall be incorporated in to the CAISO's annual Transmission Plan that serves as the basis for further transmission upgrades or additions.

[9] These compliance dates may change subject to the CAISO-CEC-CPUC Infrastructure Replacement Plan produced in Q1 2010 and updated periodically. All dates assume a generation solution which requires a CEC permit. If a permit has been acquired prior to CPUC contract approval, then an earlier on line date is possible. If transmission solutions are selected, then longer time lines would be expected.

[10] Humboldt Repower generation project is approved by the CPUC and expected operational by Q3 2010. This new infrastructure will eliminate OTC at the Humboldt Power Plant.

[11] Otay Mesa Power Plant is in construction and expected operational by Q4 2009. This new infrastructure is expected to displace a portion of the need for the capacity of the South Bay Power Plant.

[12] Sunrise Powerlink transmission project is approved by the CPUC and expected operational in 2012. This new infrastructure is expected to displace the need for remaining South Bay Power Plant capacity.

[13] TransBay Cable transmission project is expected operational by Q1 2010. This new infrastructure is expected to replace the need for Portrero Unit 3.

[14] The new Gateway Generating Station became operational in January 2009. This new infrastructure is expected to replace the need for one unit at the Contra Costa Power Plant.

[15] Units that have recently been repowered will be addressed separately.

[16] Not needed for local network reliability, according to a November 26, 2008 preliminary CAISO Study, although may be needed for system resource adequacy requirements.

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[17] Due to siting/land use and air quality constraints, it is likely that a combination of new generation and transmission infrastructure will be necessary to replace the need for OTC plants/units in the Ventura/Big Creek and L.A. Basin regions.

[18] Owned and operated by the Los Angeles Department of Water and Power, its own balancing authority (not controlled by CAISO).

[19] No further study is required. Existing studies are sufficient to determine reliability designation of specified OTC facilities.

[20] Replacement infrastructure sufficient to determine reliability designation of specified OTC facility was identified prior to development of the Infrastructure Replacement Plan.

[21] Contra Costa Power Plant is under contract to PG&E until 2011.

[22] Morro Bay units 3-4 have contracts with SCE through Q4 2011.

Appendix D – Final Expert Review Panel Responses (July 31, 2008)

Final SWRCB OTC Expert Review Panel Responses to Questions Related to "Scoping Document: Water Quality Control Policy on the Use of Coastal and Estuarine Waters for Power Plant Cooling, SWRCB/CEPA March 2008

Responses summarized by Michael Foster, ERP Project Director, from minutes taken at 8 July 2008 ERP meeting in Sacramento. Primary responses in **bold**.

Current "CEQA Baseline" Impacts and Related Issues

1. *Have current statewide and individual power plant impingement and entrainment mortality been correctly estimated?*

Background: It had been determined by some of the ERP, and stated in some of the public comments, that the estimates in the 2008 Scoping Document were incorrect, in some cases not based on the most current data. ERP member John Steinbeck was tasked with providing a report summarizing the most current and accurate information available in order to update these estimates. The other ERP members are asked to deliberate and comment on Steinbeck's report.

Responses:

A. The primary entrainment data available and reported by Steinbeck are number of fish larvae entrained / flow volume/ individual power plant. Assuming 100% larval mortality, the only "impact" indicated by the data is mortality of larval fish.

B. Fish larval mortality and other biological and oceanographic data can be used in the Empirical Transport Model (ETM) to estimate the percent of the total larvae lost due to entrainment in the volume of ocean water from which the larvae can be entrained. This estimate may also reflect % losses to organisms in sea water that are not sampled in entrainment studies (e.g., invertebrate larvae and other zooplankton, and phytoplankton) and is thus a more comprehensive measure of entrainment impacts. .

C. **The number of fish larvae entrained has been correctly estimated** in the Steinbeck report given the available data. Note there are no data for the Pittsburg and Contra Costa Power Plants given the lack of recent, comprehensive 316b studies at these plants. The Ormond Beach Generating Station datum may be an exception as the Average Larval Fish Concentration (0.0446/m3) seems low. This should be checked.

D. **Adult fish mortality from impingement has been correctly estimated** in the Steinbeck report given the available data.

E. Data on entrainment and impingement mortality to fish eggs, adult and larval invertebrates, and other planktonic organisms are not available or only available from a few facilities, making it impossible to accurately estimate total mortality to all marine organisms from entrainment and impingement. Modeling using ETM, however, could be used to estimate entrainment mortality for these other groups.

1a. *For CEQA baseline, is it sufficient to base entrainment impacts only on fish and selected invertebrate larvae? Should other invertebrate meroplankton be considered (and require 200 micron mesh size)? Other groups?*

Responses:

A. Question should be reworded: "For CEQA baseline, are entrainment estimates and associated estimates of impacts sufficient to characterize impacts due to entrainment in the state? Can models such as ETM be used to characterize impacts to species not well sampled?"
B. **Overall entrainment impacts on fish larvae can be estimated using larval fish data and ETM modeling.**
C. There are insufficient data to accurately consider meroplankton or other groups. At present general impacts to these can only be estimated using modeling approaches such as ETM.
D. Entrainment effects on species of special interest (e.g., abalone) could be examined in special studies at power plants where these species may be affected. Very few such studies have been done.

1b. *Could the I/E be normalized for flow for each of the plants (i.e., I/E per million gallons of flow)?*

Response:

Yes for each individual plant but not across all plants due to differences in larval abundance in the water entrained.

1c. *For entrainment, what are the periods/seasons of greatest larval abundance (i.e., greatest potential impact) for each plant or at least per region: southern Calif. coast, southern Calif. bays, central California, and San Francisco Bay/Delta? For impingement, what are the periods/seasons of greatest potential impact for adult fish?*

Responses:

A. **Temporal variation in the abundance of fish larvae, determined from power plant entrainment studies and by region is provided in the Steinbeck report.** Similar data for invertebrates are not available, but general estimates could be obtained from the literature for particular species.
B. **Temporal variation in impingement would be very difficult to determine using current sampling methodology.** Seasonality is confounded by numerous factors including the timing of impingement sampling and heat treatments.

1d. *In a qualitative way, what are the possible effects of I/E on the ecosystem (e.g., selective removal of certain predatory species from impingement or prey species due to entrainment)?*

Response: **There are certainly ecosystem effects but these are impossible to accurately estimate directly or by modeling.** There may be effects on trophic interactions but these are difficult to determine given that both predatory and forage fish are entrained and impinged. Moreover, because of larval dispersal, the effects on adult populations may occur in geographic areas separate from where entrainment occurs.

1e. Is it possible to accurately consider cumulative impacts? Should they be considered?

Responses:

A. **This could be done using ETM based on recent entrainment studies combined with larval dispersal modeling and recently available oceanographic data.** It could be done for the southern California Bight where numerous OTC power plants occur relatively close to each other. A preliminary assessment of OTC power plant cumulative impacts was for the Huntington Beach Generating Station in 2005. The same approach could be used for the San Francisco Bay-Delta if appropriate entrainment studies were available for the Contra Costa and Pittsburg Power Plants.

B. Prior California OTC power plant cumulative impact analyses other than the Huntington Beach study should be used with caution or disregarded because of questionable accuracy.

1f. *Are reference sites needed to accurately determine entrainment and impingement impacts?*

Responses:

A. **Because it is recognized that marine populations subject to entrainment and impingement may already be altered by human activities, including those associated with power plants, it would be difficult if not impossible to find comparable, unaltered (reference) sites to assess the magnitude of alteration.** Moreover, entrainment impacts are likely widely distributed, making it extremely difficult to quantify impacts.

B. It might be possible to assess alteration due to impingement for species with small home ranges by sampling a gradient of similar habitats away from a power plant. It might be possible to assess alterations in more enclosed water bodies using a comparative life history approach.

C. The concept of reference sites (temporal and spatial) is appropriate for assessing the thermal effects from power plant discharges.

2. *Should possible positive impacts of cooling water flow (e.g., increased circulation through areas with low water flow) be considered in the baseline and the impact assessment?*

Background: Some public comments stated that if cooling water flows are eliminated, this might be considered a negative impact. Certain anthropogenic habitats (harbors and shallow canals) may be benefiting from circulation due to OTC. Stagnation may result from the elimination of OTC. The ERP was informed by SWRCB legal counsel that positive effects must be considered in the context of establishing a baseline under CEQA.

Response:
Determining the original condition of habitats and benefits to them from power plants may be difficult. **Priority should be given to consideration of options other than power plant flows for maintaining or improving water quality.**

Track 2, Calculation Baseline and Related Issues

3. *Should Track 2 compliance be allowed on a plant basis or units within a plant basis? If on a plant basis could a 90 and 95% or better control (entrainment/ impingement) from baseline be achieved?*

Background: Some public comments indicated that Track 2 may be feasible with some combinations of conversion to closed cycle cooling and limited use of remaining OTC units as peakers; another example is the potential for use of treated wastewater as a partial replacement for OTC water.

Response:
Track 2 compliance should be allowed on whatever basis that achieves the required reductions in entrainment and impingement while allowing maximum flexibility in plant operations. This could be by plant, by intake, or by units within a plant. On a larger scale, it could be by plants in a given area cooperating such that they comply as a group versus individually. Compliance, however, needs to be based on reductions in number of larvae entrained or fish impinged, not just flow, as the number of larvae or adult fish /volume varies among plants, and can vary among units or intakes within a plant as well as seasonally (see Steinbeck report).
Note: There are technological limits on using currently available screens to reduce entrainment such that screening out small life stages (anything that would not be excluded or collected by a < ~ 0.5 mm mesh size) is not possible without affecting flow. If compliance included reducing entrainment of these small organisms, then flow reduction would be the only way to comply.

4. *Should the calculation baseline for Track 2 be design (currently permitted), actual (and if so, what averaging period), or generational flow? Alternatively, provide a statement about the pros and cons of each approach.*

Responses:
The ERP decided to list the pros and cons-

Design flow: **Pro -reflects potential entrainment and impingement**
Con -entrainment and impingement mortality will be less than if actual flows were used

Actual flow: **Pro -better characterizes actual entrainment and impingement and will achieve more reduction in mortality.**
Con -may not be considered fair for plants that have recently reduced flows -may decrease state-wide generating capacity during peak demand as plants already at very low capacity may not be able to operate.

Note: One ERP member who was not at the 8 July 08 meeting when these questions were discussed has stated that the baseline for Track 2 should be design flow.

1. If flow reductions are used to accomplish Track 2, should the reduction be based on simply gallons per day, or should it be weighted by considering seasonal larval abundance for that region?

Response:
As indicated in responses to question 3., **reductions should be based on larval abundance, not simply flow, and larval abundance should be weighted (monthly?) based on temporal variation** (see responses to 1b, lc, 3 and 7).
Note: One ERP member was not present at the 8 July 2008 meeting when these questions were discussed. This member previously stated that reductions should be based on simply flow.

6. *Should Track 2 credit be given for existing control technology (e.g., fish returns) above the EPA baseline (= shore intake with opening at or near surface and 3/4 inch mesh traveling screens oriented parallel to shore)?*

Response:
If California chooses to apply the EPA baseline and credit is given for existing technologies, the effectiveness of the technologies should be demonstrated for each facility using them. The SWRCB might provide a list of accepted technologies to help reduce debate over what technologies qualify for potential credit. Currently used technologies to reduce impingement include velocity caps and a fish return system (SONGS). Technologies currently used at some facilities to reduce both impingement and entrainment include variable speed pumps and closed cycle cooling.

7. *Should plants operating at very low % capacity factor (e.g., 10%) be limited to a 90% of their design flow, or current permitted flow, whichever is lower?*

Response:
See response to 4. It is not clear that these plants could continue to operate if actual flow were used. Perhaps with a combination of variable speed pumps and if the reduction were averaged over a permit cycle (~ 5 yrs.). Regulation might be via penalties that escalate with the amount exceeded.

Note: One ERP member suggested it was unlikely that older plants would upgrade with variable speed pumps.

Note: One ERP member pointed out that the proposed Track 2 compliance is actually ~ 80% reduction, 90% of a 90% effective cooling tower. Another member stated that if flow reductions were set at 80% this would provide a huge reduction in potential OTC impacts and provide industry the necessary flexibility to comply with the new regulations and meet energy needs during peak demand. The 80% level would be especially appropriate if the percentage reduction is based on actual entrainment, not just flow, since this would be difficult for many of the plants to meet especially in southern California where peak demand coincides with periods of peak larval abundance.

7a. *What capacity factor averaging period should be used? 2005, 2005-2007, 20062007?*

Background: The Energy Commission comments indicated that 2006 and 2007 are more representative of current conditions and should be added to the next staff report.

Response:
Use the most recent flow period (5 yrs.?) if actual flow is used. The five year period is consistent with the duration of NPDES permits.

7b. *If flow reductions relative to design flow are used to accomplish Track 2 for very low capacity factor plants, should these become the absolute allowable flows permitted by Regional Water Boards?*

Response:
Yes and as mentioned previously, these should be based on entrainment-weighted flows.

7c*. Should the limit be based on daily flow restrictions with seasonal restrictions (i.e., 10% of design MGD but only during allowable seasons), or some other method (monthly maximums during allowable seasons)?*

Background:
In this scenario, plants would still be required to reduce impingement by reducing the velocity at the intake (for shoreline intakes) to a maximum of 0.5 feet per second and comply with the interim controls (becoming permanent) and restoration fees. If these plants later decide to opt out of this approach, they would be required to re-power or retrofit with closed cycle cooling on a whole plant basis (i.e., Track 1), and the flow restriction would continue until the re-power or retrofit is completed.

Response:
The limit should be based on entrainment-weighted flows over a yearly or perhaps longer period (see previous responses to similar questions).

8. *For Track 2, should the policy require monitoring appropriate to determine percent reductions in mortality?*

Response:
Previous ERP consensus on this issue was yes, but how this would be done depends on what is done for compliance. For technology, verification that the technology works is required, and this may require monitoring.

8a. *If compliance were by flow reduction, would monitoring of flows be sufficient?*

Response:
Yes, monitoring by entrainment-weighted flows that will also capture seasonal adjustments where necessary.

8b. *If compliance were with new entrainment or impingement reduction technology (e.g., screens or fish returns), how should I/E compliance be determined?*

Response:
Compliance should be determined in some scientifically acceptable way, and may include before-after installation measurements, or after measurements made outside versus inside a structure such as a screen. Pilot tests of a technology may be useful, but may not scale up to the full installation.

Interim Controls

9. *What tetrapod exclusion devices should be required to eliminate wildlife impacts? What have power plants (even out of State) currently installed and how effective are exclusion devices at reducing the take of marine life?* **a)** *For offshore intakes can a nine-inch bar spacing be employed with little or no effect on plugging or fish impingement? Would this also exclude large fish?* **b)** *Are there Delta T&E or otherwise protected species that would benefit from exclusion devices? Are plugging or incidental impingement when plugged issues in the Delta vs. marine applications?*

Background: Federal law requires protection of marine mammals, and endangered or threatened species. The NMFS is currently considering an incidental take permit with restrictions, including exclusion devices. While some comments received suggest that only federal wildlife authorities should handle this, the NMFS comments supported the State Water Board's preliminary draft policy. Thirteen facilities have applied for NMFS incidental take permits. Dan Lawson of NMFS has reported that he is considering requiring 18" minimum spacing on offshore intake structures, including SONGS. Public comments indicate that some plants with offshore intakes have recently installed exclusion bars. For example DWP Scattergood has installed bars with 9 in. spacing.

Response:
The Steinbeck report summarizes current tetrapod (as "Mammal Exclusion") exclusion devices currently used at California OTC power plants with offshore intakes. The sizes of tetrapods impinged should be reviewed to determine appropriate spacing (9 or 18 in.). The sizes of threatened or endangered fish impinged at San Francisco Bay-Delta plants should be reviewed to determine if there is a feasible screening technology that could reduce entrainment of these fish.

Note: One ERP member not present on 8 July 2008 when these questions were discussed has previously stated that regulation of tetrapod impacts should be left up to the NMFS.

9c. *For onshore intakes, can 4-6" spaced trash racks as currently designed be considered adequate exclusion devices? Are modifications necessary to reduce ability of mammals to enter from the bottom?*

Response:
Some tetrapods become trapped between the face of intakes and the bar racks. Further studies are needed to determine if this can be prevented by requiring modifications to intake structures.

10. *If flow reduction is adopted as an interim control, should the reduction in impacts be evaluated according to yearly flow or as seasonal variation in flow as it interacts with seasonal variation in larval availability?*

Response:
It should be evaluated based on entrainment-weighted flows (see previous responses to similar questions).

11. *What are the pros and cons involving the restriction of flows to <10% of the permitted flow rate if the plants are not generating electricity for two or more consecutive days?*

Response:
The ERP did not have a response to this question.

Interim Restoration

12. *If restoration is adopted as an interim control measure, should it be done on a plantby-plant basis (with companies having responsibility for restoration projects, monitoring and success)?If plant-by-plant, should restoration fully compensate for all impacts? What approach would be used to determine the amount and kind of restoration? (e.g., Habitat Production Foregone?)* ***OR*** *via a mitigation fee based on flow, with the fee going to a restoration committee or State agency involved in coastal restoration? How would the fee be calculated (e.g., based on experience with the "going rate" for existing restoration projects plants like Moss Landing or SONGS, possibly converted to flow or MW production)? For example the fee could go to the California State Coastal Conservancy who could decide how best to use that money for coastal restoration, and how to monitor resulting projects.*

Response:
If restoration is adopted as an interim control measure then, based on experience with determining mitigation on a plant-by-plant basis, **the ERP favors using a mitigation fee based on entrainment-weighted flow.** This fee might best be "pooled" from all power plants and administered by a one institution that collects and allocates funds for projects based on consultation with the Regional Water Quality Control Boards responsible for power plant regulation. The process should include independent technical review of proposed projects and their success. The funds should be used in a timely manner, for

mitigation relevant to impacts, as close to the impact as possible while balancing the need for regional planning, and in a way that involves regional stakeholders. The fee should be based on entrainment-weighted flow. The amount of the fee might be based on existing restoration projects, but this requires further discussion.

12a. *Should the existing "restoration /compensation" done at Moss Landing, Huntington Beach and San Onofre Power Plants be counted towards the interim restoration?*

Response:
If restoration is adopted as an interim control measure, the answer is **Yes.** Because of restoration/mitigation done by these plants, they should be considered in full compliance with interim restoration.

Note: The ERP was informed by SWRCB staff that, for legal reasons, this restoration cannot be considered as compliance for Track 1 or 2.

Track 1

13. *For Track 1, are adverse impacts associated with conversion to closed-cycle cooling adequately considered?*

Response:
No. The energy penalty may be underestimated (especially during summer), there is no estimate of actual increases in air emissions, and no discussion of impacts of noise, land required for dry cooling, and possible heat trapping during inversions. SWRCB should involve appropriate experts to determine and evaluate adverse impacts associated with closed-cycle cooling.

Appendix E – Entrainment and Impingement Estimates (Steinbeck, July 2008)

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

July 18, 2008

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Introduction

The purpose of this report is to compile the most complete and most recent information on the biological effects of entrainment and impingement by coastal power plants in California that use once-through cooling (OTC). The information will be used by the California State Water Resources Control Board (SWRCB) in developing policy for regulating the use of OTC by power plants in the state. The sources for much of the information presented in this report are 316(b) studies that have been completed at many of the coastal power plants in California in the past five to ten years.

To put the results into context it was necessary to compile accurate information on the actual volume of cooling water used by the plants. The design flows for the systems (i.e., maximum pumping capacity) were compiled from information already provided in the March draft of the SWRCB Scoping Document. These values were checked against information published in the recent 316(b) studies and 316(b) Proposals for Information Collection (PIC). Some of the reported design flow values that differed between sources were also checked with plant staff. It is important to point out that the design flows may not reflect the maximum possible intake volumes for some of the plants, since the values typically include the volumes for the main circulating water pumps, and not the smaller service water pumps in the systems. The total volumes for these smaller pumps are generally less than 5 percent of the main circulating pump capacities. Actual cooling water flows reported to the RWQCBs under the NPDES permits for the plants were used to calculate average daily flows for the six-year period from 2000–2005. The sources used in compiling the flow information are provided in **Appendix A**.

The methods used for compiling the entrainment and impingement estimates presented in **Tables 1 and 2** and are described in the following sections.

Entrainment Estimates

The entrainment data presented in **Table 1** were mostly compiled from recent 316(b) studies of cooling water systems at 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. Entrainment of the larval stages of some commercially important macroinvertebrates was assessed at some of the plants, but limited to later stage larvae of crabs and lobster, and recently-hatched immature squid. Earlier larval stages of these and other macroinvertebrates are not effectively collected by the mesh of the nets used in the sampling and would have required additional sampling efforts. Many macroinvertebrates have multiple larval stages that have varying periods of development further complicating the planning of an appropriate sampling program and further complicating the assessment. The entrainment assessment method used for most of the studies was the Empirical Transport Model which can be used in assessing the potential entrainment impacts on other macroinvertebrates using assumptions regarding the distribution of the larvae in the source water and the extent and volume of the source water for the populations relative to the cooling water volume. The focus on fish larvae in these studies is appropriate since larval fishes are much more limited in number in the water column and the adults for many species are limited in distribution, increasing the potential for population-level effects.

The table presents two sets of entrainment estimates. The first set is simply calculated using annual average larval concentrations multiplied by annual design and average actual 2000–2005 flows. The other set of entrainment estimates is from the published studies, which takes into account month-by-month differences in larval concentrations and therefore provide more accurate estimates of actual entrainment for the periods of study (**Appendix B**). Some of these studies did not include estimates for both design and actual flows (shown as 'nc' in **Table 1**). The only plants where recent representative entrainment data were not available were the Contra Costa and Pittsburg power plants located in the Sacramento-San Joaquin Delta (Delta) system. The table does present annual entrainment estimates for those two plants from studies completed thirty years ago in 1978–1979. No estimates were calculated from the larval concentrations measured during those studies because there have been so many long-term changes in flows and species composition within the Delta system that the historical estimates are unlikely to be representative of current conditions.

The entrainment estimates calculated using the average annual larval concentrations are very similar to the published entrainment estimates for the two nuclear plants (SONGS and DCPP) and units at other plants that operate at high capacity factors. There are greater differences between the two sets of estimates for plants and units that operate at low capacity factors. This is due to seasonal changes in larval concentrations that can significantly affect estimates of annual entrainment, especially when peak pumping capacity is occurring during periods with high concentrations of larvae. The seasonality in larval abundances varies between central and southern California, and also between open coast and protected bays and harbors (**Figures 1** and **2**).

Impingement Estimates

Similar to entrainment, the impingement data presented in **Tables 2a** and **2b** were mostly obtained from recent studies (**Appendix B**) at power plants in California using the same flow data used in **Table 1** and documented in **Appendix A**. Impingement estimates are only presented for fishes because this is the only taxonomic group that was sampled consistently across all of the facilities. Data on macroinvertebrate impingement were collected at all the facilities, but the data collected varied among plants. At some facilities all invertebrate groups were counted, and at others only invertebrates that could be characterized as shellfish (e.g., crabs, shrimp, squid, and octopus) were counted, while the other invertebrate categories were only recorded as 'present' when they were collected. At some facilities only shellfish were collected and quantified. Besides the inconsistencies in the sampling among plants, it is sometimes difficult to distinguish the invertebrates that are collected after they are dislodged from the intake conduit walls from organisms that are impinged from the source water. Even crabs, shrimp, and other invertebrates that could be characterized as 'shellfish' that are collected during impingement sampling probably settled in the biofouling community inside the cooling water intake system as larvae. As a result of these issues, only data on fish impingement is summarized in **Tables 2a** and **2b**.

The information in **Tables 2a** and **2b** 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' in **Table 2b**). These estimates include both normal operations and heat treatment impingement. As with the entrainment studies, the only plants where recent representative data were not available were the Contra Costa and Pittsburg power plants located in the Delta system. The table does present annual impingement estimates for those two plants from studies completed thirty years ago in 1978–1979.

Intake Structure

Information on the intake structures at the California power plants is presented in **Table 3**. The various fish protection measures in use at each plant are listed and details are provided on the dimensions of screening used at the openings to the cooling water systems. This information could be used in evaluating the potential for entrapment of marine mammals and sea turtles into the systems. Note that the only plants with variable speed drives that allow flow to be adjusted to meet load capacity are installed at the Contra Costa and Pittsburg power plants in the Delta. San Onofre is the only plant with a sophisticated fish return system.

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Table 1. Entrainment estimates for larval fishes from California coastal power plants. Estimates include calculated values from design and average annual 2000–2005 flows using larval concentrations from recent studies and also estimates from recently published entrainment studies. References used in compiling the information in the table are provided in Appendix B.

Plant	Design Flow (mgd)	Average Flow (mgd) based on 2000-2005 data	Average Larval Fish Concentration (# per million gallons)	Average Concentration and Design Flow Entrainment Estimate	Average Concentration and Average Flow Entrainment Estimate	Study Result Entrainment Estimate (Design flow)	Study Result Entrainment Estimate (Actual flow)
Alamitos Generating Station Units 1&2	207	121	9880.6	748,306,544	437,854,835	nc	121,970,937
Alamitos Generating Station Units 3&4	392	281	9880.6	1,414,971,165	1,013,733,478	1,109,972,442	728,944,910
Alamitos Generating Station Units 5&6	674	413	9972.2	2,455,020,121	1,503,394,233	nc	835,841,962
Contra Costa Power Plant Units 6&7	440	257	no recent representative data available			nc	95,110,000
Diablo Canyon Power Plant	2,528	2,287	1912.5	1,765,916,778	1,597,319,020	nc	1,481,948,383
El Segundo Generating Station Units 1&2	207	69	1953.7	147,969,610	49,437,254	nc	35,743,328
El Segundo Generating Station Units 3&4	399	265	1953.7	284,430,472	189,290,759	276,934,913	186,532,003
Encina Power Plant	857	621	13950.2	4,366,667,796	3,162,648,118	4,494,849,115	3,627,641,744
Harbor Generating Station	108	59	3961.9	156,285,731	85,447,634	153,331,013	65,298,000
Haynes Generating Station	968	258	12305.3	4,349,235,947	1,159,662,085	4,527,644,084	3,649,208,392
Huntington Beach Generating Station	514	179	1596.1	299,647,084	104,339,074	344,570,635	nc
Mandalay Generating Station	253	234	1514.5	140,195,151	129,201,071	141,736,337	33,422,317
Morro Bay Power Plant	668	257	3404.0	830,540,168	318,942,511	859,337,744	nc
Moss Landing Power Plant Units 1&2	361	193	4429.9	584,101,411	311,537,103	522,319,740	nc
Moss Landing Power Plant Units 6&7	865	387	2958.3	934,658,478	418,350,825	888,204,836	nc
Ormond Beach Generating Station	685	521	168.9	42,276,804	32,133,537	40,810,043	6,351,783
Pittsburg Power Plant Units 5&6	462	274	no recent representative data available			nc	175,230,000
Potrero Power Plant	231	193	3593.3	303,519,077	252,843,159	289,731,811	nc
Redondo Generating Station Units 5&6	217	51	4485.6	354,702,404	83,037,227	356,000,276	101,659,379
Redondo Generating Station Units 7&8	675	254	3133.5	772,198,644	290,801,357	744,808,585	189,537,344
San Onofre Nuclear Generating Station U	1,219	1,139	7439.6	3,311,307,168	3,095,251,683	nc	3,555,787,272
San Onofre Nuclear Generating Station U	1,219	1,154	7439.6	3,311,307,168	3,136,923,690	nc	3,261,783,562
Scattergood Generating Station	495	309	2796.9	506,083,227	315,634,578	524,202,652	365,258,133
South Bay Power Plant	601	417	10951.6	2,404,046,574	1,667,406,878	2,420,527,779	nc
Totals	**15,245**	**10,191**	**119682.2**	**29,483,387,521**	**19,355,190,108**		
Average			**5440.1**				

nc = not calculated

CA Power Plant CWS Estimates

Table 2a. Impingement estimates for fish numbers and biomass (lb) from California coastal power plants. Estimates include calculated values for normal operations for design and average annual 2000–2005 flows using impingement rates from recent studies. These estimates are combined with estimates of impingement during heat treatments to estimate total impingement. References used in compiling the information in the table are provided in Appendix B.

					Annual Normal Operations Impingement				Heat Treatments (HT)			Total Estimated Impingement			
Plant	Design Flow (mgd)	Average Flow (mgd) based on 2000-2005 data	Average # fish per million gal	Average Biomass (lbs) fish per million gal	Based on Count and Design Flow	Based on Biomass (lbs) and Design Flow	Based on Count and Average Flow	Based on Biomass (lbs) and Average Flow	Average # per HT	Average Biomass (lb) per HT	Average Number of HT per year (2000-2005)	Design Flow Total # Estimate	Design Flow Total Biomass (lb) Estimate	Actual Flow Total # Estimate	Actual Flow Total Biomass (lb) Estimate
Alamitos Generating Station Units 1&2	207	121							n/a	n/a	n/a				
Alamitos Generating Station Units 3&4	392	281	0.1750	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 Generating Station Units 5&6	674	413							n/a	n/a	n/a				
Contra Costa Power Plant Units 6&7	440	257	no recent representative data available						n/a	n/a	n/a	—	—	—	—
Diablo Canyon Power Plant	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 Generating Station Units 1&2	207	69	0.0103	0.0035	779	265	260	89	227.25	72.16	1.3	1,074	359	556	182
El Segundo Generating Station Units 3&4	399	265	0.0220	0.0068	3,209	995	2,138	662	229.00	94.60	3.7	4,057	1,345	2,983	1,012
Encina Power Plant	857	621	0.6128	0.0256	191,624	8,016	138,932	5,806	15,831.63	747.70	6	286,615	12,502	233,923	10,292
Harbor Generating Station	108	59	0.4945	0.1622	19,506	6,399	10,666	3,498	n/a	n/a	n/a	19,506	6,399	10,666	3,498
Haynes Generating Station	968	258	0.1893	0.0041	66,901	1,462	17,838	390	n/a	n/a	n/a	66,901	1,462	17,838	390
Huntington Beach Generating Station	514	179	0.4079	0.0227	76,582	4,270	26,666	1,487	5,867.00	338.70	4.8	104,840	5,895	54,924	3,112
Mandalay Generating Station	253	234	0.7940	0.0299	73,497	2,771	67,739	2,553	101.90	4.20	1.4	73,640	2,776	67,876	2,559
Morro Bay Power Plant	668	257	0.3497	0.0140	85,315	3,419	32,763	1,313	n/a	n/a	n/a	85,315	3,419	32,763	1,313
Moss Landing Power Plant Units 1&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 Power Plant Units 6&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 Generating Station	685	521	0.0711	0.0164	17,806	4,094	13,534	3,112	677.80	87.20	4.5	20,856	4,487	16,584	3,504
Pittsburg Power Plant Units 5&6	462	274	no recent representative data available						n/a	n/a	n/a	—	—	—	—
Potrero Power Plant	231	193	1.5090	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 Generating Station Units 5&6	217	51	0.0075	0.0034	593	268	139	63	10.08	7.32	2	613	282	159	77
Redondo Generating Station Units 7&8	675	254	0.0240	0.0085	5,913	2,084	2,227	785	157.50	37.90	4.8	6,669	2,266	2,983	967
San Onofre Nuclear Generating Station Unit 2	1,219	1,139	1.5787	0.0335	1,405,342	29,854	1,322,490	28,094	2,494.00	627.80	7.5	1,424,047	34,563	1,341,195	32,802
San Onofre Nuclear Generating Station Unit 3	1,219	1,154									7.8				
Scattergood Generating Station	495	309	0.8226	0.0814	148,840	14,727	92,829	9,185	10,155.00	788.40	5.2	201,646	18,827	145,635	13,285
South Bay Power Plant	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
Totals	15,245	10,191			3,301,730	96,685	2,427,607	67,584							

nc = not calculated

Table 2b. Impingement estimates for fish numbers and biomass (lb) from California coastal power plants. The impingement estimates from recently published impingement mortality studies include impingement during heat treatment. Studies where impingement estimates were not calculated for design or actual flow conditions during the study are indicated as "nc". References used in compiling the information in the table are provided in Appendix B.

Plant	Design Flow (mgd)	Average Flow (mgd) based on 2000-2005 data	Reported Total Impingement Estimates			
			Design Flow Total # Estimate	Design Flow Total Biomass (lb) Estimate	Actual Flow Total # Estimate	Actual Flow Total Biomass (lb) Estimate
Alamitos Generating Station Units 1&2	207	121				
Alamitos Generating Station Units 3&4	392	281	nc	nc	29,013	1,252
Alamitos Generating Station Units 5&6	674	413				
Contra Costa Power Plant Units 6&7	440	257	—	—	107,621	2,741
Diablo Canyon Power Plant	2,528	2,287	nc	nc	nc	nc
El Segundo Generating Station Units 1&2	207	69	nc	nc	186	63
El Segundo Generating Station Units 3&4	399	265	2,521	542	1,527	473
Encina Power Plant	857	621	289,562	12,878	215,583	9,609
Harbor Generating Station	108	59	19,861	6,478	8,851	2,903
Haynes Generating Station	968	258	56,613	1,227	53,442	1,168
Huntington Beach Generating Station	514	179	nc	nc	51,082	2,848
Mandalay Generating Station	253	234	30,347	1,308	8,979	199
Morro Bay Power Plant	668	257	nc	nc	78,139	2,957
Moss Landing Power Plant Units 1&2	361	193	75,133	804	57,554	600
Moss Landing Power Plant Units 6&7	865	387	135,699	2,297	118,778	2,033
Ormond Beach Generating Station	685	521	7,821	844	517	76
Pittsburg Power Plant Units 5&6	462	274	nc	nc	220,364	2,580
Potrero Power Plant	231	193	146,096	3,035	108,727	2,446
Redondo Generating Station Units 5&6	217	51	263	71	133	60
Redondo Generating Station Units 7&8	675	254	2,910	1,315	1,101	388
San Onofre Nuclear Generating Station Unit 2	1,219	1,139	nc	nc	1,353,158	28,746
San Onofre Nuclear Generating Station Unit 3	1,219	1,154				
Scattergood Generating Station	495	309	108,843	11,619	95,241	9,422
South Bay Power Plant	601	417	385,588	1,226	nc	nc
Totals	**15,245**	**10,191**				

nc = not calculated

Table 3. Information on cooling water intake system design at California power plants. Acronyms used for the various intake components and fish protection systems and provided below the table.

Region	Plant	Intake Location	Type of Intake	Screening or Fish Protection Devices*	Size of openings at Entrance to Intake	Vertical Distance from Riser to VC	Mammal Exclusion Bars Offshore?
NoCal	Contra Costa Power Plant	tidal river	shoreline	BR-TS-VFD	Bar racks 3.5" spacing	n/a	n/a
NoCal	Pittsburg Power Plant	tidal river	shoreline	BR-TS-VFD	Bar racks 3.5" spacing	n/a	n/a
NoCal	Potrero Power Plant	bay/harbor	shoreline	BR-TS	Bar racks 3.5" spacing	n/a	n/a
NoCal	Moss Landing Power Plant Units 1&2	bay/harbor	shoreline	BR-TS	Bar racks 3.5" spacing	n/a	n/a
NoCal	Moss Landing Power Plant Units 6&7	bay/harbor	shoreline	BR-TS	Bar racks 3" spacing	n/a	n/a
NoCal	Morro Bay Power Plant	bay/harbor	shoreline	BR-TS	bar racks 4" on center	n/a	n/a
NoCal	Diablo Canyon Power Plant	ocean	shoreline	BR-TS	bar racks 3" on center	n/a	n/a
SoCal	Mandalay Generating Station	bay/harbor	canal	BR-SS	bar racks 2.5" spacing	n/a	n/a
SoCal	Ormond Beach Generating Station	ocean	offshore	VCap-BR-TS	4' at VCap with bars every 18"	4'	18" spacing
SoCal	Scattergood Generating Station	ocean	offshore	VCap-BR-TS	5' at VCap with bars every 9"	5'	9" spacing
SoCal	El Segundo Generating Station Units 1&2	ocean	offshore	VCap-BR-TS	2' at VCap	2'	?
SoCal	El Segundo Generating Station Units 3&4	ocean	offshore	VCap-BR-TS	3' at VCap	3'	?
SoCal	Redondo Generating Station Units 5&6	bay/harbor	offshore	VCap-BR-TS	4' at VCap with bars every 18"	4'	18" spacing
SoCal	Redondo Generating Station Units 7&8	bay/harbor	offshore	VCap-BR-TS	4' at VCap with bars every 18"	4'	18" spacing
SoCal	Harbor Generating Station	bay/harbor	shoreline	BR-TS	bar racks 4.5" on center	n/a	n/a
SoCal	Haynes Generating Station	tidal river	canal	BR-TS/SS	bar racks 6" on center	n/a	n/a
SoCal	Alamitos Generating Station Units 1&2	bay/harbor	shoreline	BR-TS	bar racks 3" spacing	n/a	n/a
SoCal	Alamitos Generating Station Units 3&4	bay/harbor	shoreline	TS	no bar racks	n/a	n/a
SoCal	Alamitos Generating Station Units 5&6	bay/harbor	shoreline	BR-TS	bar racks 3" spacing	n/a	n/a
SoCal	Huntington Beach Generating Station	ocean	offshore	VCap-BR-TS	5' at VCap with bars every 18"	5'	18" spacing
SoCal	San Onofre Nuclear Generating Station Unit 2	ocean	offshore	VCap-Vanes-Fish Elevator-BR-TS	7' at VCap	7'	No
SoCal	San Onofre Nuclear Generating Station Unit 3	ocean	offshore	VCap-Vanes-Fish Elevator-BR-TS	7' at VCap	7'	No
SoCal	Encina Power Plant	bay/harbor	shoreline	BR-TS	bar racks 3.5" on center	n/a	n/a
SoCal	South Bay Power Plant	bay/harbor	shoreline	BR-TS	bar racks 3" spacing	n/a	n/a

* - VCap = velocity cap, BR = bar racks, TS = traveling screens, SS = Slide screens, Vanes = structures inside intake to divert fishes, VFD = variable frequency drive pumps

CA Power Plant CWS Estimates

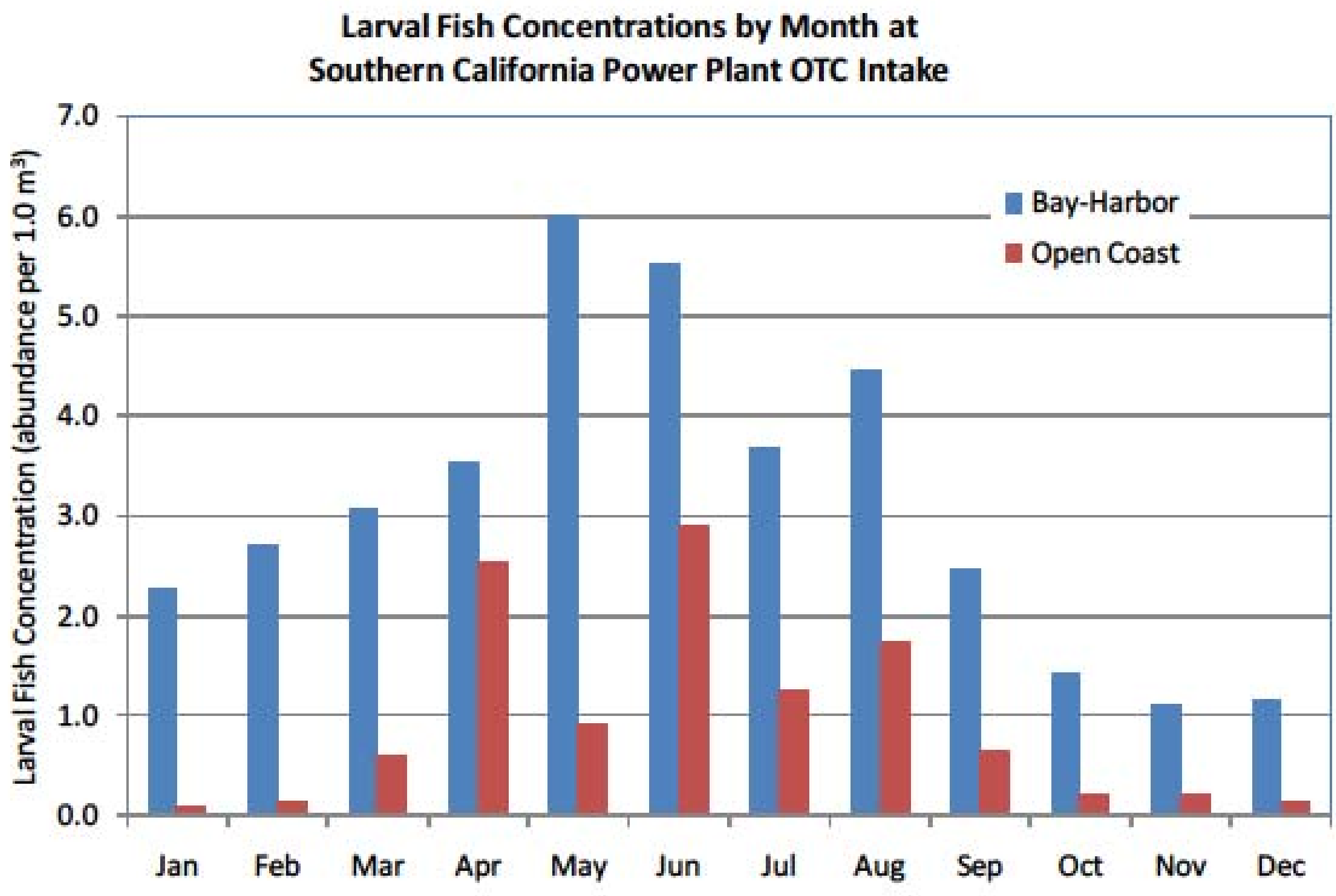

Figure 1. Total concentration of larval fishes by month at OTC intakes in southern California. Data sources based on most recent 316(b) sampling conducted at each power facility. Plants combined for bay-harbor concentrations were South Bay, Encina, Haynes, Alamitos, and Harbor, and the plants combined for the open coast concentrations were San Onofre, Huntington Beach, Redondo Beach, El Segundo, and Scattergood.

CA Power Plant CWS Estimates

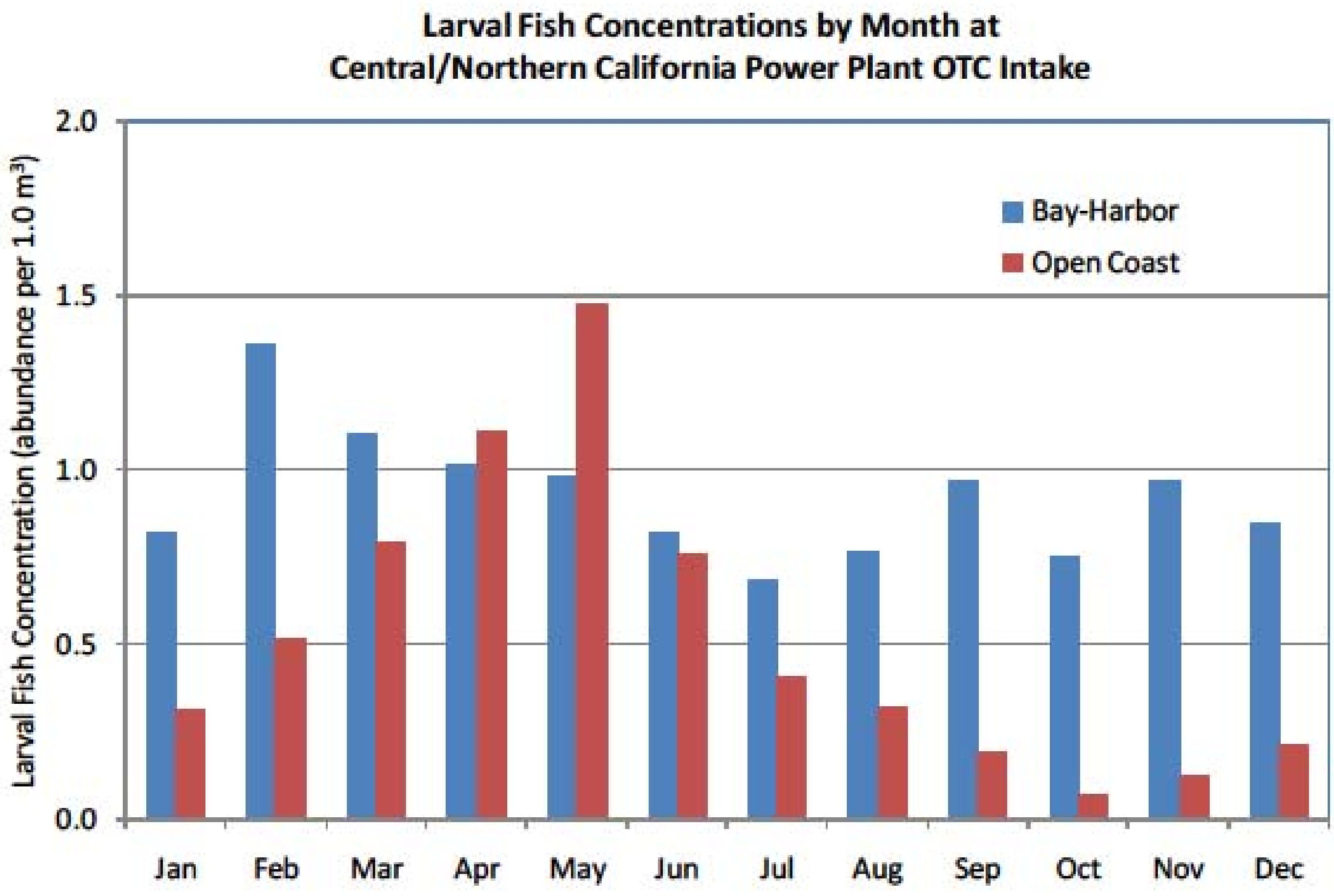

Figure 2. Total concentration of larval fishes by month at OTC intakes in central California. Data sources based on most recent 316(b) sampling conducted at each power facility. Plants combined for bay-harbor concentrations were Morro Bay, Moss Landing, and Potrero, and the plants used for the open coast concentrations was Diablo Canyon.

Appendix A. Sources for cooling water data used in calculations of entrainment and impingement estimates.

Plant	Design Flow (mgd)	Average Flow (mgd) based on 2000-2005	Data Sources
Alamitos Generating Station Units 1&2	207	121	data from SWRCB staff - 2000-05 actual monthly flows
Alamitos Generating Station Units 3&4	392	281	data from SWRCB staff - 2000-05 actual monthly flows
Alamitos Generating Station Units 5&6	674	413	data from SWRCB staff - 2000-05 actual monthly flows
Contra Costa Power Plant Units 6&7	440	257	data from plant staff - daily flows for 2000-2005
Diablo Canyon Power Plant	2,528	2,287	flows from plant source complete for 2000-05
El Segundo Generating Station Units 1&2	207	69	data from SWRCB staff - daily flows for 2000-2005
El Segundo Generating Station Units 3&4	399	265	data from SWRCB staff - daily flows for 2000-2005
Encina Power Plant	857	621	flows from plant source complete for 2000-05
Harbor Generating Station	108	59	data from SWRCB staff - 2000-01 actual monthly flows, 2002-05 daily flows
Haynes Generating Station	968	258	data from SWRCB staff - 2000-01 actual monthly flows, 2002-05 daily flows, 2005 missing for Units 3&4
Huntington Beach Generating Station	514	179	data from SWRCB staff - 2004-05 actual monthly flows, 2000-03 calculated from megawatt output
Mandalay Generating Station	253	234	data from SWRCB staff - 2000-05 actual monthly flows
Morro Bay Power Plant	668	257	flows from plant source complete for 2000-05
Moss Landing Power Plant Units 1&2	361	193	flows from plant source complete for 2000-05
Moss Landing Power Plant Units 6&7	865	387	flows from plant source complete for 2000-05
Ormond Beach Generating Station	685	521	data from SWRCB staff - 2000-05 actual monthly flows
Pittsburg Power Plant Units 5&6	462	274	data from plant staff - 2000-05 daily flows
Potrero Power Plant	231	193	data from SWRCB staff - 2000-05 actual monthly flows - also plant data provided same average
Redondo Generating Station Units 5&6	217	51	data from SWRCB staff - daily flows for 10/1/01-9/30/02 and 1/1/03-12/31/05
Redondo Generating Station Units 7&8	675	254	data from SWRCB staff - daily flows for 10/1/01-9/30/02 and 1/1/03-12/31/05
San Onofre Nuclear Generating Station Unit 2	1,219	1,139	data from SWRCB staff - 2004-05 actual monthly flows, 2000 and 2003 calculated from megawatt output
San Onofre Nuclear Generating Station Unit 3	1,219	1,154	data from SWRCB staff - 2004-05 actual monthly flows, 2000 and 2003 calculated from megawatt output
Scattergood Generating Station	495	309	data from SWRCB staff - 2000 -2005 actual monthly flows
South Bay Power Plant	601	417	flows from plant source complete for 2000-05

Appendix B. References and information on studies used in compiling the data presented in Tables 1 and 2.

Plant	Entrainment collection period & frequency / Reference	Impingemement collection period & frequency / Reference
Alamitos Generating Station Units 1&2	Jan-Dec 2006, bi-weekly / MBC and Tenera 2008a	Jan 2006 - Dec 2006; weekly / MBC and Tenera 2008a
Alamitos Generating Station Units 3&4	Jan-Dec 2006, bi-weekly / MBC and Tenera 2008a	Jan 2006 - Dec 2006; weekly / MBC and Tenera 2008a
Alamitos Generating Station Units 5&6	Jan-Dec 2006, bi-weekly / MBC and Tenera 2008a	Jan 2006 - Dec 2006; weekly / MBC and Tenera 2008a
Contra Costa Power Plant	Apr 1978 - Apr 1979, weekly / Ecological Analysts 1981a	Apr 1978 - Apr 1979; weekly sampling / Ecological Analysts 1981a
Diablo Canyon Power Plant	Oct 1996 - Jun 1999, weekly / estimates from Oct 96-Oct 98 Tenera 2000a	Feb 1985 - Mar 1986; weekly sampling / Tenera 1988
El Segundo Generating Station Units 1&2	Jan-Dec 2006, monthly / Tenera and MBC 2008	Jan 2006 - Dec 2006; monthly / Tenera and MBC 2008
El Segundo Generating Station Units 3&4	Jan-Dec 2006, monthly / Tenera and MBC 2008	Jan 2006 - Dec 2006; monthly / Tenera and MBC 2008
Encina Power Plant	Jun 2004 - May 2005, monthly / Tenera 2008	Jun 2004 - Jun 2005; weekly / Tenera 2008
Harbor Generating Station	Jan-Dec 2006, bi-weekly / MBC, Tenera, and URS 2008b	Jan 2006 - Dec 2006; weekly / MBC, Tenera, and URS 2008b
Haynes Generating Station	Jan-Dec 2006, bi-weekly / MBC, Tenera, and URS 2008a	Jan 2006 - Dec 2006; weekly / MBC, Tenera, and URS 2008a
Huntington Beach Generating Station	Sep 2003 - Aug 2004, weekly / MBC and Tenera 2005	Jul 2003 - Jul 2004; weekly / MBC and Tenera 2005
Mandalay Generating Station	Feb 2006 - Feb 2007; biweekly / ENSR Corp. 2008a	Feb 2006 - Feb 2007; biweekly / rates and totals from ENSR Corp. 2008a; average rates and HT data from NPDES data supplied by MBC
Morro Bay Power Plant	Jan 2000 - Dec 2000, weekly / Tenera 2001	Sep 1999 - Sep 2000; weekly / Tenera 2001
Moss Landing Power Plant Units 1&2	Mar 1999 - Feb 2000, weekly / Tenera 2000b	Nov 2005 - Nov 2006; weekly / Tenera 2007b
Moss Landing Power Plant Units 6&7	Mar 1999 - Feb 2000, weekly / Tenera 2000b	Nov 2005 - Nov 2006; weekly / Tenera 2007b
Ormond Beach Generating Station	Feb 2006 - Feb 2007; biweekly / ENSR Corp. 2008b	Feb 2006 - Feb 2007; biweekly / rates and totals from ENSR Corp. 2008b; average rates and HT data from NPDES data supplied by MBC
Pittsburg Power Plant Units 5&6	Mar 1978 - Mar 1979, weekly; Ecological Analysts 1981b	Mar 1978 - Mar 1979; weekly sampling / Ecological Analysts 1981b
Potrero Power Plant	Jan 2001 - Feb 2002, weekly (Dec-Mar) or monthly Apr-Nov) / Tenera 2007a	May 2006 - May 2007; weekly / Tenera 2007a
Redondo Generating Station Units 5&6	Jan 2006 - Jan 2007, monthly / MBC and Tenera 2008b	Jan 2006 - Jan 2007; weekly / MBC and Tenera 2008b
Redondo Generating Station Units 7&8	Jan 2006 - Jan 2007, bi-weekly / MBC and Tenera 2008b	Jan 2006 - Jan 2007; weekly / MBC and Tenera 2008b
San Onofre Nuclear Generating Station Un	Mar 2006 - Apr 2007; biweekly inside plant, monthly at offshore intakes /	Mar 2006 - May 2007; biweekly / MBC 2008
San Onofre Nuclear Generating Station Un	Mar 2006 - Apr 2007; biweekly inside plant, monthly at offshore intakes / MBC	Mar 2006 - May 2007; biweekly / MBC 2008
Scattergood Generating Station	Jan 2006 - Jan 2007, bi-weekly / MBC, Tenera, and URS 2008c	Jan 2006 - Jan 2007; weekly / MBC, Tenera, and URS 2008c
South Bay Power Plant	Feb 2001 - Jan 2002, monthly / Tenera 2004	Dec 2002 - Nov 2003; weekly / Tenera 2004

Appendix F – Entrainment and Impingement Estimates Updated for Delta Plants (Steinbeck, January 2010)

Impingement Reported Values – Fish

Impingement Reported Values - Fish only

Plant	Design Flow (mgd)	Average Flow (mgd) based on 2000-2005 data	Reported Total Impingement Estimates: Design Flow Total # Estimate	Design Flow Total Biomass (lb) Estimate	Actual Flow Total # Estimate	Actual Flow Total Biomass (lb) Estimate
Alamitos Generating Station Units 1&2	207	121	nc	nc	29,013	1,252
Alamitos Generating Station Units 3&4	392	281				
Alamitos Generating Station Units 5&6	674	413				
Contra Costa Power Plant Units 6&7 [1]	440	257	44,702	849	26,110	496
Diablo Canyon Power Plant	2,528	2,287	nc	nc	nc	nc
El Segundo Generating Station Units 1&2	207	69	nc	nc	186	63
El Segundo Generating Station Units 3&4	399	265	2,521	542	1,527	473
Encina Power Plant	857	621	289,562	12,878	215,583	9,609
Harbor Generating Station	108	59	19,861	6,478	8,851	2,903
Haynes Generating Station	968	258	56,613	1,227	53,442	1,168
Huntington Beach Generating Station	514	179	nc	nc	51,082	2,848
Mandalay Generating Station	253	234	30,347	1,308	8,979	199
Morro Bay Power Plant	668	257	nc	nc	78,139	2,957
Moss Landing Power Plant Units 1&2	361	193	75,133	804	57,554	600
Moss Landing Power Plant Units 6&7	865	387	135,699	2,297	118,778	2,033
Ormond Beach Generating Station	685	521	7,821	844	517	76
Pittsburg Power Plant Units 5 - 7 [2]	506	274	26,360	390	14,274	211
Potrero Power Plant	231	193	146,098	3,035	108,727	2,446
Redondo Generating Station Units 5&6	217	51	263	71	133	60
Redondo Generating Station Units 7&8	675	254	2,910	1,315	1,101	388
San Onofre Nuclear Generating Station Unit 2	1,219	1,139	nc	nc	1,353,158	28,746
San Onofre Nuclear Generating Station Unit 3	1,219	1,154				
Scattergood Generating Station	495	309	108,843	11,619	95,241	9,422
South Bay Power Plant	601	417	385,588	1,226	nc	nc
Totals	**15,289**	**10,191**				

nc = not calculated in report

Impingement Estimated Values – Fish

Impingement Estimated Values - Fish only

					Annual Normal Operations Impingement				Heat Treatments (HT)			Total Estimated Impingement			
Plant	**Design Flow (mgd)**	**Average Flow (mgd) based on 2000-2005 data**	**Average # fish per million gal**	**Average Biomass (lbs) fish per million gal**	**Based on Count and Design Flow**	**Based on Biomass (lbs) and Design Flow**	**Based on Count and Average Flow**	**Based on Biomass (lbs) and Average Flow**	**Average # per HT**	**Average Biomass (lb) per HT**	**Average Number of HT per year (2000-2005)**	**Design Flow Total # Estimate**	**Design Flow Total Biomass (lb) Estimate**	**Average Flow Total # Estimate**	**Average Flow Total Biomass (lb) Estimate**
Alamitos Generating Station Units 1&2	207	121							n/a	n/a	n/a				
Alamitos Generating Station Units 3&4	392	281	0.1750	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 Generating Station Units 5&6	674	413							n/a	n/a	n/a				
Contra Costa Power Plant 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 Power Plant	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 Generating Station Units 1&2	207	69	0.0103	0.0035	779	265	260	89	227.25	72.18	1.3	1,074	359	556	182
El Segundo Generating Station Units 3&4	399	265	0.0220	0.0068	3,209	995	2,136	662	229.00	94.60	3.7	4,057	1,345	2,983	1,012
Encina Power Plant	857	621	0.6128	0.0256	191,824	8,016	138,932	5,806	15,831.83	747.70	6	286,815	12,502	233,923	10,292
Harbor Generating Station	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 Generating Station	968	258	0.1893	0.0041	66,901	1,462	17,838	390	n/a	n/a	n/a	66,901	1,462	17,838	390
Huntington Beach Generating Station	514	179	0.4079	0.0227	76,582	4,270	26,666	1,487	5,887.00	338.70	4.8	104,840	5,895	54,924	3,112
Mandalay Generating Station	253	234	0.7940	0.0299	73,497	2,771	67,733	2,553	101.90	4.20	1.4	73,640	2,776	67,876	2,559

Morro Bay Power Plant	668	257	0.3497	0.0140	85,315	3,419	32,763	1,313	n/a	n/a	n/a	85,315	3,419	32,763	1,313
Moss Landing Power Plant Units 1&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 Power Plant Units 6&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 Generating Station	685	521	0.0711	0.0164	17,806	4,094	13,534	3,112	677.80	87.20	4.5	20,856	4,487	16,584	3,504
Pittsburg Power Plant Units 5-7	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 Power Plant	231	193	1.5090	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 Generating Station Units 5&6	217	51	0.0075	0.0034	593	268	139	63	10.08	7.32	2	613	282	159	77
Redondo Generating Station Units 7&8	675	254	0.0240	0.0085	5,913	2,084	2,227	785	157.50	37.90	4.8	6,669	2,266	2,983	967
San Onofre Nuclear Generating Station Unit 2	1,219	1,139	1.5787	0.0335	1,405,342	29,854	1,322,490	28,094	2,494.00	627.80	7.5	1,424,047	34,563	1,341,195	32,802
San Onofre Nuclear Generating Station Unit 3	1,219	1,154									7.8				
Scattergood Generating Station	495	309	0.8226	0.0814	148,840	14,727	92,829	9,185	10,155.00	788.40	5.2	201,646	18,827	145,635	13,285
South Bay Power Plant	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
Totals	**15,289**	**10,191**			**3,301,730**	**96,685**	**2,427,607**	**67,584**				3,572,664	113,883	2,667,863	84,250

n/a = not applicable

Entrainment Estimates - Larval Fish

Entrainment - larval fish only

Plant	Design Flow (mgd)	Average Flow (mgd) based on 2000-2005 data	Average Larval Fish Concentration (# per million gallons)	Average Concentration and Design Flow Entrainment Estimate	Average Concentration and Average Flow (2000-2005) Entrainment Estimate	Study Result Entrainment Estimate (calculated for Design flow)	Study Result Entrainment Estimate (for Actual flow during study period)
Alamitos Generating Station Units 1&2	207	121	9,880.6	748,306,544	437,854,835	nc	121,970,937
Alamitos Generating Station Units 3&4	392	281	9,880.6	1,414,971,165	1,013,733,478	1,109,972,442	728,944,910
Alamitos Generating Station Units 5&6	674	413	9,972.2	2,455,020,121	1,503,394,233	nc	835,841,962
Contra Costa Power Plant Units 6&7 [1]	440	257	230.8	37,098,716	21,669,023	37,098,716	21,669,023
Diablo Canyon Power Plant	2,528	2,287	1,912.5	1,765,916,778	1,597,319,020	nc	1,481,948,383
El Segundo Generating Station Units 1&2	207	69	1,953.7	147,969,610	49,437,254	nc	35,743,328
El Segundo Generating Station Units 3&4	399	265	1,953.7	284,430,472	189,290,759	276,934,913	186,532,003
Encina Power Plant	857	621	13,950.2	4,366,667,796	3,162,648,118	4,494,849,115	3,627,641,744
Harbor Generating Station	108	59	3,961.9	156,285,731	85,447,634	153,331,013	65,298,000
Haynes Generating Station	968	258	12,305.3	4,349,235,947	1,159,662,085	4,527,644,084	3,649,208,392
Huntington Beach Generating Station	514	179	1,596.1	299,647,084	104,339,074	344,570,635	nc
Mandalay Generating Station	253	234	1,514.5	140,195,151	129,201,071	141,736,337	33,422,317
Morro Bay Power Plant	668	257	3,404.0	830,540,168	318,942,511	859,337,744	nc
Moss Landing Power Plant Units 1&2	361	193	4,429.9	584,101,411	311,537,103	522,319,740	nc
Moss Landing Power Plant Units 6&7	865	387	2,958.3	934,658,478	418,350,825	888,204,836	nc
Ormond Beach Generating Station	685	521	168.9	42,276,804	32,133,537	40,810,043	6,351,783
Pittsburg Power Plant Units-5-7 [2]	506	274	377.0	69,678,481	37,731,035	69,678,481	37,731,035
Potrero Power Plant	231	193	3,593.3	303,519,077	252,843,159	289,731,811	nc
Redondo Generating Station Units 5&6	217	51	4,485.6	354,702,404	83,037,227	356,000,276	101,659,379
Redondo Generating Station Units 7&8	675	254	3,133.5	772,198,644	290,801,357	744,808,585	189,537,344
San Onofre Nuclear Generating Station Unit 2	1,219	1,139	7,439.6	3,311,307,168	3,095,251,683	nc	3,555,787,272
San Onofre Nuclear Generating Station Unit 3	1,219	1,154	7,439.6	3,311,307,168	3,136,923,690	nc	3,261,783,562
Scattergood Generating Station	495	309	2,796.9	506,083,227	315,634,578	524,202,652	365,258,133
South Bay Power Plant	601	417	10,951.6	2,404,046,574	1,667,406,878	2,420,527,779	nc
Totals	**15,289**	**10,191**		**29,590,164,718**	**19,414,590,166**		
Average			**5,012.1**				

nc = not calculated

[1] Calculated and reported estimates for Contra Costa based on sampling from March - July 2008 using 1,600 micron mesh. No annual estimates reported.

[2] Calculated and reported estimates for Pittsburg based on sampling from March - July 2008 using 1,600 micron mesh. No annual estimates reported.

IM&E Sources and notes

Revised January, 2010

Plant	Entrainment collection period & frequency / Reference	Impingemement collection period & frequency / Reference
Alamitos Generating Station Units 1&2	Jan-Dec 2006, bi-weekly / MBC and Tenera 2008a	Jan 2006 - Dec 2006; weekly / MBC and Tenera 2008a
Alamitos Generating Station Units 3&4	Jan-Dec 2006, bi-weekly / MBC and Tenera 2008a	Jan 2006 - Dec 2006; weekly / MBC and Tenera 2008a
Alamitos Generating Station Units 5&6	Jan-Dec 2006, bi-weekly / MBC and Tenera 2008a	Jan 2006 - Dec 2006; weekly / MBC and Tenera 2008a
Contra Costa Power Plant	March 2008 - Jun 2008, ca. bi-weekly / Mirant Delta LLC 2009	Nov 2007 - Oct 2008; monthly sampling / Mirant Delta LLC 2009
Diablo Canyon Power Plant	Oct 1996 - Jun 1999, weekly / estimates from Oct 96-Oct 98 Tenera 2000a	Feb 1985 - Mar 1986; weekly sampling / Tenera 1988
El Segundo Generating Station Units 1&2	Jan-Dec 2006, monthly / Tenera and MBC 2008	Jan 2006 - Dec 2006; monthly / Tenera and MBC 2008
El Segundo Generating Station Units 3&4	Jan-Dec 2006, monthly / Tenera and MBC 2008	Jan 2006 - Dec 2006; monthly / Tenera and MBC 2008
Encina Power Plant	Jun 2004 - May 2005, monthly / Tenera 2008	Jun 2004 - Jun 2005; weekly / Tenera 2008
Harbor Generating Station	Jan-Dec 2006, bi-weekly / MBC, Tenera, and URS 2008b	Jan 2006 - Dec 2006; weekly / MBC, Tenera, and URS 2008b
Haynes Generating Station	Jan-Dec 2006, bi-weekly / MBC, Tenera, and URS 2008a	Jan 2006 - Dec 2006; weekly / MBC, Tenera, and URS 2008a
Huntington Beach Generating Station	Sep 2003 - Aug 2004, weekly / MBC and Tenera 2005	Jul 2003 - Jul 2004; weekly / MBC and Tenera 2005
Mandalay Generating Station	Feb 2006 - Feb 2007; biweekly / ENSR Corp. 2008a	Feb 2006 - Feb 2007; biweekly / rates and totals from ENSR Corp. 2008a; average rates and HT data from NPDES data supplied by MBC
Morro Bay Power Plant	Jan 2000 - Dec 2000, weekly / Tenera 2001	Sep 1999 - Sep 2000; weekly / Tenera 2001
Moss Landing Power Plant Units 1&2	Mar 1999 - Feb 2000, weekly / Tenera 2000b	Nov 2005 - Nov 2006; weekly / Tenera 2007b
Moss Landing Power Plant Units 6&7	Mar 1999 - Feb 2000, weekly / Tenera 2000b	Nov 2005 - Nov 2006; weekly / Tenera 2007b
Ormond Beach Generating Station	Feb 2006 - Feb 2007; biweekly / ENSR Corp. 2008b	Feb 2006 - Feb 2007; biweekly / rates and totals from ENSR Corp. 2008b; average rates and HT data from NPDES data supplied by MBC
Pittsburg Power Plant Units 5&6	March 2008 - Jun 2008, ca. bi-weekly / Mirant Delta LLC 2009	Nov 2007 - Oct 2008; monthly sampling / Mirant Delta LLC 2009
Potrero Power Plant	Jan 2001 - Feb 2002, weekly (Dec-Mar) or monthly Apr-Nov) / Tenera 2007a	May 2006 - May 2007; weekly / Tenera 2007a
Redondo Generating Station Units 5&6	Jan 2006 - Jan 2007, monthly / MBC and Tenera 2008b	Jan 2006 - Jan 2007; weekly / MBC and Tenera 2008b
Redondo Generating Station Units 7&8	Jan 2006 - Jan 2007, bi-weekly / MBC and Tenera 2008b	Jan 2006 - Jan 2007; weekly / MBC and Tenera 2008b
San Onofre Nuclear Generating Station Unit 2	Mar 2006 - Apr 2007; biweekly in plant, monthly offshore / MBC 2008	Mar 2006 - May 2007; biweekly / MBC 2008
San Onofre Nuclear Generating Station Unit 3	Mar 2006 - Apr 2007; biweekly in plant, monthly offshore / MBC 2008	Mar 2006 - May 2007; biweekly / MBC 2008
Scattergood Generating Station	Jan 2006 - Jan 2007, bi-weekly / MBC, Tenera, and URS 2008c	Jan 2006 - Jan 2007; weekly / MBC, Tenera, and URS 2008c
South Bay Power Plant	Feb 2001 - Jan 2002, monthly / Tenera 2004	Dec 2002 - Nov 2003; weekly / Tenera 2004

Appendix G - Final Response to Comments

on the

Proposed Statewide Water Quality Control Policy on the Use of Coastal and Estuarine Waters for Power Plant Cooling

State Water Resources Control Board
May 4, 2010

Table of Contents

I. COMMENT LETTERS RECEIVED

Letter Number	Affiliation	Representative
1	AES Southland	Eric Pendergraft
2	Bay Area Municipal Transmission Group	Ed Chang
3	California Coastkeeper Alliance Heal the Bay Surfrider Foundation Pacific Coast Federation of Fisherman's Associations Defenders of Wildlife Sierra Club California Alliance for Nuclear Responsibility Pacific Ecosystem Protection Ocean Conservancy Food & Water Watch Pacific Environment Coastal Environmental Rights Foundation General Public San Francisco Baykeeper San Diego Coastkeeper Southern California Watershed Alliance Environmental Health Coalition Santa Monica Baykeeper Coastal Alliance on Plant Expansion Orange County Coastkeeper San Luis Obispo Coastkeeper	Angela H. Kelley Mark Gold Joe Geever Zeke Grader Joshua Basofin JIm Metropulos Rochelle Becker Kaitilin Gaffney Mark Schlosberg Rory Cox Marco Gonzalez Steve Fleischli Sejal Choksi Bruce Reznki Conner Everts Laura Hunter Tom Ford Jack McCurdy Garry Brown Gordon Hensley
4	California Council for Environmental and Economic Balance	Robert Lucas Gerald Secundy
5	California Energy Commission California Independent System Operator Corporation California Public Utilities Commission	Karen Douglas Yakout Mansour Michael Peevey
6	California State Senate	Senator Fran Pavley
7	Central Coast Regional Water Quality Control Board	Roger W. Briggs
8	City and County of San Francisco	Dennis Herrera
9	Coastal Alliance on Plant Expansion	Jack McCurdy David Nelson
10	Coastal Environmental Rights Foundation	Marco Gonzalez
11	Dynegy	Daniel Thompson
12	Ellison, Schneider & Harris L.L.P. on behalf of RRI Energy	Robert Donlan
13	Environmental Health Coalition	Laura Hunter

Letter Number	Affiliation	Representative
14	Environmental Law & Justice Clinic at Golden Gate University School of Law on behalf of Bayview Hunters Point Community Advocates and Communities for a Better Environment	John Harrington Helen Kang
15	General Public	Henriette Groot
16	General Public	Frank Brandt
17	General Public	Steve Fleischli
18	Heal the Bay University of Southern California Sea Grant Program Wildcoast Avian Species Conservationist General Public Catalina Offshore Products, Inc. California Sea Urchin Commission Coastal Band of the Chumash Nation The Surfers Party	Sarah Sikich Phyllis Grifman Serge Dedina David Weeshoff Scott Dunn Dave Rudie Bob Bertelli Roberta Cordero Garth Murphy
19	Los Angeles Regional Water Quality Control Board	Tracy J. Egoscue
20	MBC Applied Environmental Sciences	Shane Beck
21	MBC Applied Environmental Sciences	Eric Miller
22	Mills Legal Clinic	Deborah A. Sivas
23	Mirant California, LLC	Sean P. Beatty
24	Natural Resources Defense Council	Leila Monroe Noah Long
25	NRG West	George L. Piantka
26	Orange County Coastkeeper	Garry Brown
27	Oxnard Chamber of Commerce	Nancy Lindholm
28	Pacific Environment	Rory Cox
29	Pacific Gas and Electric Company	Mark Krausse (2)
30	Powers Engineering	Bill Powers
31	RRI Energy, Inc.	Fred McGuire
32	San Diego Coastkeeper	Gabriel Solmer Joe Geever
33	San Francisco Baykeeper	Rosalind Becker
34	Sierra Club	Edward Kimura
35	Sierra Club California	Jim Metropulos
36	SLO Coast Alliance	Andrew Christie

Letter Number	Affiliation	Representative
37	Southern California Edison	Michael M. Hertel
38	Tenera Environment	John Steinbeck
39	United States Environmental Protection Agency	Dean Ward
40	US Department of Commerce, National Oceanic and Atmospheric Administration	Robert S. Hoffman
41	Los Angeles Department of Water and Power	Aram Benyamin
42	California Coastal Commission	Alfred Wanger
43	California State Lands Commission	Paul D. Thayer
44	City of Morro Bay	Janice Peters Rick Grantham Carla Borchard Noah Smukler
45	Morro Bay National Estuary Program	Dan Berman
46	AES Southland	Eric Pendergraft
47	California Council for Environmental and Economic Balance	Robert Lucas Gerald Secundy
48	California Independent System Operator Corporation	Andrew Ulmer
49	Coastal Alliance on Plant Expansion	Jack McCurdy David Nelson
50	Dynegy Inc	Daniel P. Thompson
51	Industrial Environmental Association	Patti Krebs
52	Los Angeles Department of Water and Power	Aram Benyamin Mark J. Sedlacek
53	MBC Applied Environmental Sciences	Shane Beck
54	Natural Resources Defense Council	Noah Long Leila Monroe
55	NRG West Region	George L. Piantka
56	Pacific Gas and Electric Company	Mark Krausse (2)
57	RRI Energy, Inc.	Fred McGuire
58	Santa Lucia Chapter of the Sierra Club	Andrew Christie
59	Southern California Edison	Michael M. Hertel

Letter Number	Affiliation	Representative
60	Surfrider Foundation Sierra Club California Ocean Conservancy Residents for Responsible Desalination Pacific Environment Coastal Environmental Rights Foundation California Coastkeeper Alliance Heal the Bay Pacific Coast Federation of Fisherman's Association Environment Now Southern California Watershed Alliance	Joe Geever Jim Metropulos Kaitlin Gaffney Merle Moshiri Rory Cox Sara Honadle Linda Sheehan Mark Gold Zeke Grader Terry O'Day Conner Everts
61	Tenera Environmental Inc.	John Steinbeck
62	US Dept. of Commerce, National Oceanic and Atmospheric Administration	Steven A. Edmondsen
63	AES Southland	Eric Pendergraft
64	California Coastal Commission	Peter Douglas
65	California Coastkeeper Alliance Pacific Coast Federation of Fisherman's Associations Center for Energy Efficiency & Renewable Technologies Southern California Programs – Clean Power Campaign Heal the Bay Defenders of Wildlife California Sportfishing Protection Alliance Santa Monica Baykeeper Food & Water Watch Surfrider Foundation Sierra Club California Center for Biological Diversity Ocean Conservancy Pacific Environment Clean Water Action Friends of Trinity River Butte Environmental Council Southern California Watershed Alliance Environmental Health Coalition Coastal Alliance on Plant Expansion Coastal Alliance of Plant Expansion San Luis Obispo Coastkeeper Alliance for Nuclear Responsibility Voices of the Wetlands San Francisco Baykeeper Orange County Coastkeeper San Diego Coastkeeper Coastal Environmental Rights Foundation	Linda Sheehan Zeke Grader V. John White Rhonda Mills Mark Gold Joshua Basofin Bill Jennings Tom Ford Adam Scow Joe Geever Jim Metropulos Andrea Treece Kaitilin Gaffney Rory Cox Jennifer Clary Byron Leydecker Carol Perkins Conner Everts Laura Hunter Jack McCurdy David Nelson Gordon Hensley Rochelle Becker Patricia Matejcek Jason Flanders Garry Brown Bruce Rexnik Marco Gonzalez

Letter Number	Affiliation	Representative
66	California Council for Environmental and Economic Balance	Robert Lucas Gerald Secundy
67	California Energy Commission California Public Utilities Commission California Independent System Operator Corp.	Karen Douglas Michael Peevey Karen Edson
68	California Legislature	Senator Ellen Corbett Senator Loni Hancock Senator Mark Leno Senator Alan Lowenthal Senator Jenny Oropeza Senator Fran Pavley Senator Pat Wiggins Assembly Member Pedro Nava Assembly Member Ira Ruskin
69	California State Lands Commission	Paul Thayer
70	Central Coast Regional Water Board	Michael Thomas
71	City of Morro Bay	Robert Schultz
72	Coastal Environmental Rights Foundation	Marco Gonzalez
73	Dynegy	Daniel Thompson
74	Environmental Health Coalition	Laura Hunter
75	Environmental Law and Justice Clinic at Golden Gate University of Law on behalf of Bayview Hunters Pont Communities for a Better Environment	Patrick Sullivan
76	General Public	Adam Cimino
77	General Public	Alan and Amanda Miller
78	General Public	Avi Lenchner
79	General Public	Barbara Renton
80	General Public	Beatriz & Thomas Ferguson
81	General Public	Bill Woodbridge
82	General Public	Billy Quealy
83	General Public	Carilyn Goldammer

Letter Number	Affiliation	Representative
84	General Public	Carolyn Bazzani
85	General Public	Daniel Hitt
86	General Public	Diane Dolden
87	General Public	Donald Bennett
88	General Public	Eileen Murphy
89	General Public	Eric Foxman
90	General Public	Eric Wood
91	General Public	Geoff Ward
92	General Public	Jack McCurdy
93	General Public	Jacques Couture
94	General Public	Jason Halal
95	General Public	Jon Cornelius
96	General Public	Jurek Zarzycki
97	General Public	Katharine McLean
98	General Public	Laureen Mitchell
99	General Public	Mark Strauch
100	General Public	Marvin Verano
101	General Public	Matthew Heberger
102	General Public	Michael Marriner
103	General Public	Paul Putter
104	General Public	Peter Whelan
105	General Public	Philip Salomone
106	General Public	Pinky Kushner
107	General Public	Randy Nichols
108	General Public	Richard Gallegos
109	General Public	Steve Gosschke
110	General Public	Steven & Carolyn Conner
111	General Public	Thomas Harrison
112	General Public	Tynan Wyatt
113	General Public	Vida Walsh
114	General Public	Vikky Anders

Letter Number	Affiliation	Representative
115	Los Angeles Department of Water and Power	Aram Benyamin Mark Sedlacek
116	MBC Applied Environmental Sciences	Shane Beck
117	Mills Legal Clinic at Stanford Law School	Jacob Hale Russell
118	Mirant California LLC	Peter Landreth
119	National Oceanic and Atmospheric Administration	Steve Edmondson
120	Natural Resources Defense Council	Noah Long
121	Pacific Gas and Electric Company	Mark Krausse
122	RRI Energy	Fred McGuire
123	San Luis Obispo Mothers for Peace	Jill ZamEk
124	Sierra Club California Pacific Environment	Jim Metropulos Rory Cox
125	Southern California Edison	Michael Hertel
126	Tenera Environmental	John Steinbeck
127	The Otter Project	Allison Ford
128	This comment letter is a copy of the same form letter or of similar text that the State Water Board received from other individuals that totaled approx. 9,000	General Public

II. COMMENTS

A. NEED FOR THE PROPOSED POLICY

1. Meeting legal obligations

Comment 9.03:
There is no assurance in the policy that OTC will be ended or restricted appropriately at all, given the inexplicit wording of compliance requirements and the lack of definition of many enforcement measures, allowing power plant owners to exploit opportunities for delays potentially indefinitely. The policy would therefore not comply with the 2007 Second Circuit decision in the Riverkeeper case requiring use of Best Technology Available (BTA) for plant cooling and ensure an end to the killing of aquatic life by stopping the use of bay, estuary and ocean water for plant cooling by a time certain.
Response:
Section 316(b) requires that the location, design, construction, and capacity of cooling water intake structures reflect the best technology available for minimizing adverse environmental impact. *Riverkeeper II* provides additional direction on determination of BTA, noting that the standard is technology-driven. Neither the statute nor *Riverkeeper II* requires cessation of the use of cooling water by a time certain. The proposed policy requires measures designed to make specific reductions in use of cooling water and thereby the impingement and entrainment of organisms. The policy is to be implemented through National Pollution Discharge Elimination System (NPDES) permits, for which enforcement measures are set forth in the Porter-Cologne Water Quality Control Act, Cal. Wat. Code §§13000 et. seq.

Comment 9.22:
The policy contains no legal precedent or guidance for development of the OTC policy and ignores the 2004 (new plants) and 2007 (existing plants) Riverkeeper decisions by the U.S. Court of Appeals for the Second Circuit, which gave rise to the board's effort to adopt new OTC policy several years ago. This omission is misleading because it conveys the notion that the board's pursuit of a new policy is voluntary, not a legal obligation, hence less urgency. The failure to mention any authority to guide exercise of best professional judgment is a serious omission, allowing the potential for arbitrary and subjective findings in implementation.
Response:
The State Water Board has authority to develop and adopt state policy for water quality control pursuant to California Water Code §13140. While the Commenter appears to claim that adoption of the policy is a legal obligation, no authority for this argument is provided. The cases cited concerned U.S. Environmental Protection Agency (USEPA) regulations for new facilities (*Riverkeeper I*) and existing facilities *(Riverkeeper II*). While the latter decision continues to provide some legal authority for implementation of Section 316(b) at existing facilities, its determinations as to the permissibility of cost-benefit analyses were reversed by the U.S. Supreme Court. USEPA withdrew the regulations at issue in *Riverkeeper II*, and “best professional judgment” now remains the applicable standard for determination of BTA for existing facilities. Specific requirements contained in the policy reflect the State Water Board’s exercise of best professional judgment in determining BTA. The Commenter has not clearly identified specific aspects of the proposed policy that fail to reflect those portions of *Riverkeeper I* and *II* that remain applicable.

Comment 11.56:

The proposed Policy's effect, if not its express purpose, is to force the replacement, repowering or retirement of existing OTC power plants. Neither CWA Section 316(b) nor the California Energy Commission (CEC)'s policy on aging power plants supports that result or intent. The stated purpose for the proposed Policy is the State's need to implement Section 316(b) in light of the continuing absence of national uniform performance standards. Section 316(b) does not, however, require elimination of OTC or favor repowering of existing OTC facilities. It simply requires that cooling water intake structures reflect BTA. Nor do the CEC's recommendations regarding orderly retirement or repowering of aging power plants, originally articulated in the 2005 Integrated Energy Policy Report (IEPR), support an OTC policy that seeks to eliminate OTC plants because of their environmental impacts. Rather, the CEC's policy explicitly supports the modernization of aging plants, recognizing that, in the absence of transmission upgrades, existing OTC plant sites are needed for modem power plant generation to solve local reliability needs Indeed, in recent years the CEC approved modernization projects at both Moss Landing and Morro Bay that involved continued use of OTC after hearing much more extensive scientific evidence regarding the impact of OTC and the feasibility of alternative cooling systems than the State Water Board has considered in this proceeding.

Response:

The purpose of the Policy is to implement CWA Section 316(b) and to establish BTA for cooling water intake structures at existing coastal and estuarine power plants that must be implemented in NPDES permits. Staff realizes that there will be some plants that will decide to re-power and in some cases even shut down, but that will be based strictly on business decisions by the operators of those plants. The Policy clearly provides a Track 2 compliance path that would allow a continuation of OTC as long as impingement and entrainment are controlled comparable with Track 1.

Comment 11.65:

Paragraph G states that the intent of the Policy is to ensure that beneficial uses of the State's waters are protected. Industrial use (e.g., cooling water) is one such legally recognized beneficial use, yet the Draft Policy fails to explain how such use is protected by the Policy. The Board must expressly recognize that industrial use is a beneficial use.

Response:

The State Water Board must implement the federal requirement for use of best technology available to minimize adverse environmental impact from cooling water intake structures. Moreover, while beneficial uses of ocean waters do include industrial water supply, the State Water Board must also protect any more sensitive uses, such as those affecting aquatic life.

Comment 31.02:

The policy fails to explain why the Draft Policy is better than the current approach used by the Regional Water Boards, and therefore does not appropriately meet the State Water Board's obligations under Section 316(b) or its duties under the California Environmental Quality Act (CEQA).

Response:

Staff has developed the Draft Policy using BPJ to determine BTA for minimizing adverse environmental affects associated with use of once-through-cooling, in accordance with requirements set forth in CWA Section 316(b). The Substitute Environmental Document (SED) sets forth an analysis of impacts associated with continued use of OTC and examines alternatives in accordance with the requirements of CEQA.

Comment 31.06:

RRI believes that the Draft Policy has been created without the requisite analyses and information required by CEQA, fails the test of reasoned decision-making, and goes far beyond the stated objectives of adopting uniform technology-based standards to ease the administrative burden of the Regional Water Boards for implementing Section 316(b) of the CWA. The Draft Policy creates a BTA standard that ignores the primary purpose of Section 316(b) to regulate cooling water intake structures, not generation technology, and that ignores more than 30 years of consistent USEPA interpretation of this statue by creating a one-size-fits-fits-all Draft Policy that offers alternate compliance pathways that in fact are unavailable to the great majority of the affected plants. Indeed, State Water Board staff has explicitly stated in meetings that they do not want the affected facilities to actually install the selected BTA; rather the intent is to force the shutdown of the existing facilities. RRI believes that a reasonable OTC policy allows all of the individual facilities to cost-effectively minimize environmental impact; not one that requires achievement of the greatest possible reduction at a cost that is wholly disproportionate to the benefits of compliance.

Response:

Comment noted. Staff has responded to issues and concerns specifically identified in further detail in the commenter's submission. Staff believes that the proposed Policy and supporting SED meets the requirements of all applicable State and federal law, including CEQA, Porter-Cologne, and the CWA. The Policy clearly states that the purpose of the policy is to implement CWA Section 316(b) and to establish BTA for cooling water intake structures at existing coastal and estuarine power plants. Staff does not believe that the proposed Policy would force most OTC plants to shut down, although some plants may decide to do so or re-power based on business decisions by the operators of those plants. The Policy clearly provides an alternative Track 2 compliance path that would allow a continuation of OTC as long as impingement and entrainment are controlled comparable with Track 1. The Supreme Court in Entergy vs. Riverkeeper, 129 S.Ct. 1498 (2009) found that a cost-benefit analysis is permissible for both BTA determination and for setting variances, but not required. However, the State Water Board staff has determined that the purposes of a wholly disproportionate analysis limited to plants that have previously invested in combined-cycle technology can be more appropriately addressed through a credit for prior reductions via Track 2. Nuclear facilities will be subject to a separate compliance alternatives determination once appropriate studies are completed.

Comments 35.04 and 35.06:

The policy fails to assure that the existing coastal plants--some a half century old and the epitome of technological inefficiency--will actually stop using bay, estuary and ocean water for cooling. The policy is guided by an "Energy Agencies" staff report that states, "The State Water Board's mission is to create policy that guides OTC mitigation for existing power plants." That is grossly misguided because the court-mandated mission is ending OTC.

Response:

Reports of the Energy Agencies are used in determining a compliance schedule that ensures grid reliability. The State Water Board, in adopting the proposed Policy, is not acting under a mandate from a court decision, but rather exercising BPJ in implementing Section 316(b). That Section does not require elimination of OTC, but rather best technology available for minimizing adverse environmental impact.

Comment 36.03:

The compliance requirements are so compromised with caveats and opportunities for evasion that there is no assurance that termination of OTC at any or all OTC plants will actually occur. For example, under the draft policy, if the owner of an OTC plant demonstrates to a Regional Water Board that achieving compliance under Track 1 (virtually ending the fish killing) is not feasible, the owner can seek compliance under weaker Track 2 requirements. Then, if the owner believes that Track 2 compliance would be too costly, the owner can seek to comply with "alternative, less stringent requirements." And the Regional Water Board can grant that relief based on “any relevant information." For its part, the plant must reduce the killing of fish "to the extent practicable.” How much the killing of fish would be reduced and how long the "less stringent" requirements will be the standard for allowing the plant to operate are not addressed. This seems to be a far cry from what the U.S. Court of Appeals had in mind when it handed down a ruling which, in effect, banned the use of water from bays, estuaries and the ocean for plant cooling. That ruling is the driving force and legal justification behind a new court-ordered OTC policy nationwide. Yet that landmark decision is nowhere mentioned in the proposed policy. That omission may help explain why the proposed policy does not comply with the decision’s requirements and allows continued use of OTC by power plants, perhaps indefinitely, given the loopholes contained in the policy's compliance requirements. We urge you to recast the policy into a clear-cut and timely mandate for the 19 remaining power plants on our coast to terminate OTC which will help our ocean waters to recover from the many years of destruction that power plants have visited upon them.

Response:

Please see the response to Comment 9.03. Staff has since revised the proposed Policy to eliminate a feasibility test for eligibility to pursue Track 2 compliance. In addition, staff disagrees that Track 2 represents a less stringent compliance option.

Comment 49.01:

Currently, there are no applicable nationwide standards implementing Section 316(b) for *existing power plants.* Consequently, the Water Boards must implement Section 316{b) on a case-by-case basis, using best professional judgment. Comment: This wording implies that the Water Boards will implement Section 316(b) indefinitely' as supra powers, which is misleading and inaccurate. The USEPA is in the process of developing new regulations to comply with the *Riverkeeper //* decision (January, 2007) by the US Court of Appeals for the Second Circuit, which stated that best professional judgment could be used by administrative agencies pending revised USEPA regulations. But it also indicated that BPJ should be based on the decision's rulings. Yet, reference to that decision is completely absent from the Policy. The USEPA's role in adopting regulations that must be taken into account in regulating power plant OTC must be stated to provide a fair and accurate description of how nationwide Section 316(b) standards will be applied in California.

Response:

USEPA guidance issued following the remand of the Phase II regulations provides that permits issued for existing facilities should include conditions for compliance with Section 316(b), developed on a BPJ Basis. “Best professional judgment” is a term of art used in developing technology-based limitations under CWA Section 402(a)(1)(B)(“such conditions as the Administrator determines are necessary to carry out the provisions of this chapter”) with factors set forth at 40 CFR Section 125.3. The commenter has not specified any manner in which the proposed Policy is inconsistent with those aspects of *Riverkeeper II* that remain in effect following the US Supreme Court’s decision in *Entergy*.

Comment 49.02:

This Policy establishes uniform requirements governing the exercise by the Water, Boards of for the implementation of Section 316(b), using best professional judgment in the implementation of Section 316(b) determining BTA for cooling water intake structures at existing coastal and estuarine power plants that must be implemented in NPDES permits. Comment: This statement requires identification of the authority under which the Board will establish uniform requirements using best professional judgment. Also, best professional judgment needs to be defined. Otherwise, it is too broad and ambiguous, and also leaves too much room for inappropriate political influences and influence by the power industry. Also, best professional judgment, without definition, could serve to extend old technology rather than stimulate use of best technology available. Moss Landing is an example of this; rather than require best technology available, such as dry cooling, the Central Coast Regional Water Board stayed with the status quo and allowed payment of money for habitat restoration as mitigation.

Response:

The State Water Board has delegated authority to administer and enforce the CWA in California, including interpreting and implementing Section 316(b), as well as state law authority to formulate and adopt state policy for water quality control. State policy for water quality control includes a variety of principles, guidelines and objectives deemed essential for water quality control. Following the remand of the Phase II regulations, USEPA issued guidance providing that permits issued for existing facilities should include conditions for compliance with Section 316(b), developed on a BPJ Basis. "Best professional judgment" is a term of art used to describe development of technology-based limitations under CWA Section 402(a)(1)(B)("such conditions as the Administrator determines are necessary to carry out the provisions of this chapter"), consistent with factors set forth at 40 CFR Section 125.3, in the absence of any EPA-promulgated standards. The most recent Moss Landing permit was adopted in the absence of specific state or federal standards governing Section 316(b).

2. Reducing impacts to marine and estuarine life

Comment 3.03:

Coastal OTC power plants have been in operation for decades and present a considerable threat to California's coastal ecosystems. Today's impacts are not reflective of the 40-50 years of marine life impacts due to OTC, where adjacent ecosystems have suffered a long history of entrainment and impingement. This is especially true for once-through cooled plants located on enclosed bays and harbors, such as Haynes and Alamitos Generating Stations on Alamitos Bay. It is estimated that these power plants take in the entire volume of Alamitos Bay every five days. It is likely that the abundance and community structure of life in Alamitos Bay and other source water areas for OTC have been significantly impacted by decades of water intake. Ecological impact assessment based on current impingement rates does not reflect true damages and rewards power plants that have caused long-term ecological impacts.

Response:

Staff agrees that OTC has caused serious and substantial harm to marine life for a very long time, as the commenter suggests, approximately 40 to 50 years for many plants. Staff also agrees that it is possible that biological community composition and structure have been impacted not only in embayments but also in the coastal ocean, due to the overall effects of OTC, both intakes and discharges.

Comments 3.04 and 26.02:

A 2005 study estimated that for the 12 power plants in the Southern California Bight, there is an overall cumulative entrainment mortality of 1.4 % of larval fish in the Bight. Further, when considering only recreational fish species, impingement was somewhere between 8-30 % of the number of fish caught in the Bight. All of the federally listed and imperiled salmon species that migrate in and out of the Sacramento and San Joaquin River watersheds, including the Chinook salmon, Coho salmon, and steelhead trout, must pass the intakes for two aging power plants on the San Francisco Bay-Delta Estuary (Pittsburg and Contra Costa) on their way in and out of the Delta. Records for both of these plants demonstrate that they illegally entrain and impinge endangered species, including the Delta smelt and the Chinook salmon. In bays such as the Santa Monica, Monterey, and San Diego, and estuaries such as the Elkhorn Slough and the Morro Bay National Estuary, the impacts from OTC can be more pronounced due to the high biological productivity of these areas. In Santa Monica Bay, three power plants using OTC (Scattergood, El Segundo, and Redondo Generating Stations) cycle 13% of the Bay's water every six weeks.

Eliminating this significant impact on marine life may allow many depleted or "overfished" species to recover to population abundance well beyond what we see in population assessments today. In other words, the reduction of entrainment and impingement goes beyond the value of saving the individuals entrained and impinged -- their survival and recruitment to maturity can have an exponential benefit in restoring robust populations that may be currently in decline or stabilized at far less than past levels of abundance.

Response:

Staff agrees that the OTC intakes have a detrimental effect on marine and estuarine life, including listed or protected species such as the Delta Smelt. Reductions in IM/E can only help marine and estuarine life, especially those species recovering from a multitude of stressors including but not limited to fishing, habitat change (including fresh water withdrawals in the Delta), and pollution.

Comments 3.05 and 26.03:

In a state where the foundation of our economic activity is fueled by the health of our coastal resources, and in a state leading the nation in a strong commitment to sustainable energy, there is no question that California has the right and responsibility to move past this antiquated cooling technology. It has been over 35 years since the CWA first outlined requirements for power plant cooling technology. We are long overdue for a clear, consistent statewide policy on cooling water technology that protects marine ecosystems and advances greener and more efficient energy production.

Response:

Staff agrees.

Comment 6.02:

The Ocean Protection Council (OPC) passed a resolution in 2006 calling on the State Water Board to implement more stringent requirements on existing coastal power plants to achieve a 90-95% reduction in environmental impacts. Given the dire state of our natural resources and our immediate need for new, clean sources of energy, it is imperative that we undertake this effort immediately and begin the process of converting from OTC technology. The proposed policy falls somewhat short of these goals. There are several exemptions, such as the wholly disproportionate option, that fail to achieve the 90-95% reduction in impacts requested by the OPC. The State Water Board should refine the policy so that it reduces environmental impacts by the intended 90-95% without exception.

Response:

The OPC resolution in 2006 was based on the upper end of the USEPA Phase 2 regulation performance standards in effect at that time, for entrainment (90%) and impingement (95%). Since that time, the Phase 2 regulation has been rescinded. The State Water Board's proposed policy actually has more stringent BTA proposed, with Track 1 being 93% for entrainment and virtually 100% for impingement (due to a restriction in velocity at or below 0.5 foot per second). Track 2 must be comparable to Track 1. Staff has removed the WDD. Staff instead proposes special conditions relative to combined cycle units, while nuclear plants will be subject to studies and a separate compliance determination, based upon enumerated factors.

Comment 8.03:

We fully support the State Water Board's effort to develop a clear OTC policy that will be more protective of the environment and the public. The harms from OTC have been well-documented over many years yet the adoption of a State policy has lagged.

Response:

Staff thanks the commenter for their support. We acknowledge that the development of this policy has taken years but this is due to the complexities of this issue as well as changing legal requirements (e.g., the RiverKeeper II and Entergy decisions).

Comment 9.01:

The State Water Board is to be congratulated in moving to enact a policy aimed at addressing the use of OTC by power plants along the California coast and their widespread killing of aquatic life, which the CEC in 2005 recognized in an IEPR report as a major source of destruction to marine resources and the economies of coastal communities.

Response:

Comment noted. Staff appreciates the support for the Draft Policy. Staff agrees that OTC has major impacts to the State's marine resources. When implemented, the Policy should significantly reduce the harmful IM/E impacts of OTC on marine life.

Comment 11.04:

The SED is silent on both establishing the specific level of harm to various marine resources, and quantifying the benefits to marine resources that are assumed to be achieved by the proposed Policy. Such factual information is essential if decision makers are to make an informed choice in weighing the trade-offs between the positive and negative environmental consequences of the proposed Policy.

Response:

The SED provides an estimate of the larval fish mortality due to impingement and entrainment from the OTC facilities. The benefit of the proposed Policy would be the survival of these larval fishes. Note that there is absolutely no requirement that the State Water Board provide quantitative technical information regarding fishery improvements achieved by the Policy. The Water Board's legal responsibility is to focus on the harmful effects (i.e. mortality) to marine life, and therefore we have instead focused on reducing the number of organisms killed or injured. Furthermore the Water Board is not required to consider population level impacts.

Comment 11.05:

With respect to marine resources, the SED only provides a superficial and conclusory environmental analysis and completely ignores previous environmental analyses by CEC's CEQA-equivalent process that included a robust analysis of potential impacts and mitigation measures. Most significantly, the SED ignores the project-specific findings from the CEC's power plant siting proceedings at both Moss Landing and Morro Bay that closed-cycle cooling was neither feasible nor preferable to OTC at each of those sites. For example, at Morro Bay, the CEC's Conclusions of Law included that: "There is no need to consider alternatives to once-through ocean cooling pursuant to CEQA because *such cooling will not have a significant adverse environmental impact* pursuant to CEQA." Indeed, the CEC went so far as to state that even if dry cooling were feasible and cost nothing, it would still not recommend dry cooling at Morro Bay. These conclusions were reached after extensive site-specific hearings that relied heavily upon the Regional Water Board staff and the same experts being relied upon by State Water Board here. The SED's sweeping and unsupported generalizations regarding the impacts of OTC (and the feasibility and merit of alternatives) cannot withstand an objective comparison to the hearing record and determinations of the CEC for either the Morro Bay or Moss Landing facilities. Any reasoned analysis consistent with CEQA must explicitly acknowledge these contrary findings and either accept them or explain in detail why the Board is reaching a contrary conclusion. The SED does neither.

Response:

The Moss Landing and Morro Bay projects did not entail the initiation of OTC, but rather evaluated the continued use of OTC for the new projects. Under CEQA, the base condition for these projects would be OTC with its accompanying impacts. Since the projects would continue to use OTC, there would be no "new" significant adverse environmental impacts "pursuant to CEQA." The purpose of the proposed Policy is to eliminate the environmental effects of OTC. A comparison to prior analyses for projects with far different criteria would be inappropriate.

Comment 11.43:

We are mainly concerned that the proposed Policy fails to account adequately for the numerous and variable site-specific considerations that determine the feasibility and impacts of cooling water intake technologies at a particular site. The SED sweepingly concludes that OTC causes, without exception, unacceptable aquatic environmental impacts at all coastal power plant locations in California, with the only support being absolute numbers from impingement and entrainment monitoring results. Impingement and entrainment monitoring results are meaningful only in a site-specific context. OTC has been employed at numerous locations throughout the State for decades yet there is no substantial evidence in this record of specific harm to species populations attributable to such use at any site. The reality is that species populations in locations where OTC is employed do not differ substantially from similar locations where it is not employed. The Policy and SED fail to recognize the multitude of other factors impacting the health of California's coastal ecosystem, such as over-fishing, sediment erosion, non-point source pollution from urban and agricultural areas, sewage contamination, and exotic species invasion. The Board's rush to judgment without any scientific support on an issue with such far reaching implications for California is not only ill advised but also arbitrary and an abuse of discretion. The Policy, for example, inexplicably ignores findings made in recent years through extensive CEC permitting proceedings at Moss Landing and Morro Bay regarding not only the infeasibility of closed-cycle cooling and the absence of significant adverse environmental impact from OTC at each of those facilities, but also that closed-cycle cooling at Morro Bay would cause greater overall environmental harm than continuing the use of OTC. While the Policy's revised Track I and II approach is an improvement over the 2008 draft, it is critically important that the Board provide additional flexibility that allows for consideration of all relevant site-specific considerations. The State Water Board should use sound science to evaluate site-specific environmental harm of OTC and the environmental impacts of alternative technologies, including site-specific adverse environmental impacts associated with closed-cycle cooling.

Response:

The data from impingement and entrainment monitoring results are the best data available for determining the effects of OTC. The Expert Review Panel (ERP) found, "Because it is recognized that marine populations subject to entrainment and impingement may already be altered by human activities, including those associated with power plants, it would be difficult if not impossible to find comparable, unaltered (reference) sites to assess the magnitude of alteration. Moreover, entrainment impacts are likely widely distributed, making it extremely difficult to quantify impacts." The ERP also states that "because of larval dispersal, the effects on adult populations may occur in geographic areas separate from where entrainment occurs." Staff acknowledges that there are other factors affecting coastal ecosystems, but that does not detract from the ongoing impacts from OTC.

Comment 12.04:

The proposed policy should be changed to account for site-specific environmental criteria, including consideration of the environmental implications of various compliance options. For example, the environmental impact for RRI's plants is an insignificant fraction of the total anthropogenic impact to coastal fish and wildlife resources, yet the policy would require expenditure of over $200 million to comply with the proposed Policy. The Policy should be tailored to address and minimize environmental impacts as required in Section 316(b).

Response:

This is a statewide policy and not tailored to individual plants. Section 316(b) requires the use of BTA to minimize environmental impacts. The extended compliance schedule and integration into the SACCWIS process is the approach the policy proposes to deal with cost and effectiveness issues.

Comment 16.03:

I take issue with the people who studied the effects of warm cooling water on the aquatic life near power plant discharge points. Will they explain why fishermen cast their lines in the warm water discharge at river and seawater power plants? If there is an aquatic flora and fauna desert there the fishermen would avoid rather than favor them. I suspect there may be change in the nature of aquatic flora and fauna caused by the warm water discharge but as a ratepayer I want to know if it is worth spending million of dollars for a cooling tower to avoid an insignificant change?

Response:

The Policy is only intended to directly address intake effects, not discharge effects. The Policy is intended to comply with an existing federal law, the CWA, specifically section 316(b). Furthermore the intake effects of OTC are substantial and detrimental, and those are the harmful effects that this Policy would reduce dramatically.

Comment 18.02:

Addressing the impacts of OTC is long overdue. OTC has decimated California’s marine and estuarine ecosystems for decades. For example, all of the federally listed and imperiled salmon species that migrate in and out of the Sacramento and San Joaquin River watersheds, including Chinook salmon, Coho salmon, and steelhead trout, must pass the intakes for two aging power plants on the San Francisco Bay-Delta Estuary (Pittsburg and Contra Costa) on their way in and out of the Delta. Records for both of these plants demonstrate that they illegally entrain and impinge endangered species, including the Delta smelt and the Chinook salmon. Coastal power plants that use OTC also have devastating impacts to southern California coastal ecosystems. The three power plants using OTC (Scattergood, El Segundo, and Redondo Generating Stations) in the Santa Monica Bay cycle 13% of the Bay’s water every six weeks. A 2005 study estimated that for the 12 coastal power plants in the Southern California Bight, there is an overall cumulative entrainment mortality of 1.4% of larval fish in the Bight. Considering only recreational fished species, impingement amounted to 8-30% of the number of fish caught recreationally in the Bight in 2003. In enclosed bays as estuaries such as Alamitos Bay, San Diego Bay and Elkhorn Slough, the impacts from OTC can be even more pronounced than in coastal waters. It is estimated that the Haynes Generating Station and Alamitos Generating Station take in the entire volume of Alamitos Bay every five days. In a state where our economic activity is largely fueled by the health of our coastal resources and that leads the nation in a strong commitment to sustainable energy, there is no question that California has the right and responsibility to move past this antiquated cooling technology. It has been over 35 years since the CWA first outlined requirements for power plant cooling technology. Multiple federal and state agencies, including the USEPA, CEC, Ocean Protection Council, and State Lands Commission, have recognized that OTC causes significant, ongoing devastation to our valuable marine resources. Yet, this outdated technology is still broadly used along our coast; the 19 coastal power plants combined are permitted to withdraw up to 16 billion gallons of sea water, and associated marine life, every day.

Response:
Staff agrees and is intending to provide a solution to this problem with the subject policy.

Comment 18.07:
The persistent use of OTC at coastal power plants has clearly contributed to the loss of biodiversity and the documented population decline of many marine species over the past 50 years. Although we support a simple approach to phasing out OTC along California's coast, it should be recognized that today's impacts are not reflective of the 40-50 years of marine life impacts caused by OTC, where adjacent ecosystems have suffered a long history of entrainment and impingement. We cannot go back in time to gauge the true impact of these facilities; however, we recommend the State Water Board ensure that reference location studies are conducted to better determine ecological productivity in areas without impacts from OTC to more accurately assess impingement and entrainment impacts. Accurate monitoring and assessment of biological and resource impacts (both past and present) is critical, and the subsequent information should be used to inform interim restoration requirements for coastal generators.
Response:
Staff agrees that OTC has contributed substantially to detrimental marine life impacts for over half of a century. However, staff does not believe that the identification of reference stations is feasible, in that the entire coastal zone of California is no longer pristine and has experienced a myriad of impacts such as from coastal development, pollution, and fishing. Unlike reference areas for water quality studies, where locations may be found that do not experience serious pollution, it will be difficult or impossible to find reference locations untouched by all of the various stressors on coastal ecosystems, including current OTC impacts which are cumulatively substantial over large stretches of the coast.

Comment 19.01:
We support the overall goal of the policy, which would require the owner/operator of an existing power plant to reduce the intake flow rate at each power-generating unit, at a minimum, to a level commensurate with what can be attained by a closed-cycle wet cooling system. We agree that such a measure is necessary to reduce the harmful effects on marine and estuarine life associated with cooling water intake structures and OTC.
Response:
Comment noted. Staff appreciates the support for the Draft Policy. Staff agrees that OTC has major impacts to the State's marine resources. When implemented, the Policy should significantly reduce the harmful IM/E impacts of OTC on marine life.

Comment 20.03:
As in the previous two scoping documents, the State Water Board has not presented any quantitative technical information to describe the nature of fishery improvements that would be achieved by the proposed policy. A recent analysis of cooling water system effects on California's nearshore fisheries determined that a large-scale conversion to closed-cycle cooling may result in no measurable benefit to California fish populations (EPRI 2007). Multiple investigations into nearshore fish populations in Southern California have demonstrated that population sizes fluctuate independently of power plant operations, and population trends are better explained by changes in oceanographic conditions, commercial/recreational fishing pressure, or both.

MBC Applied Environmental Sciences (MBC), in collaboration with other scientists, has published several documents in the last two years that provide some context for the entrainment and impingement estimates presented in the draft SED. These include Section 316(b)

Impingement Mortality and Entrainment Characterization Studies for eight coastal generating stations submitted in 2007-8, the report Assessment of Cooling Water Intake Structure Impacts to California Coastal Fisheries, and several peer-reviewed, scientific papers analyzing trends in coastal fish populations in relation to climatic/oceanographic changes, as well as trends in cooling water flow at coastal power plants. The Section 316(b) IM&E Characterization Studies included impact assessments, addressing the underlying question of IM&E impacts. Where possible, numbers of larvae were expressed in terms of (1) the numbers of adult fishes they would represent had they survived entrainment, (2) the reproductive output of female fishes lost as a result of entrainment, and (3) proportional entrainment, or the fraction of the source population at risk of entrainment that was lost due to operation of cooling water withdrawals. In many cases, losses were compared to long-term monitoring efforts to determine if there were detectable effects due to operation of cooling water intake systems. Losses were also compared with regional and/or statewide commercial and recreational fishing landings. All of this information is available to the State Water Board, yet none of it appears to have been considered in drafting the proposed policy.

Response:

There is absolutely no requirement that the State Water Board provide quantitative technical information regarding fishery improvements achieved by the Policy. The Water Board's legal responsibility is to focus on the harmful effects (i.e. mortality) to marine life, and therefore we have instead focused on reducing the number of organisms killed or injured. Furthermore the Water Board is not required to consider only population level impacts. The RiverKeeper II court decision clearly rejected the view that we only "regulate impingement and entrainment where they have deleterious effects on the overall fish and shellfish populations in the ecosystem." Staff agrees that in general population trends are often better explained by oceanographic conditions and fishing pressure. Still, other anthropogenic pressures such as habitat change, pollution, and IM/E all contribute to harm to marine life and therefore should be minimized to promote healthy ecosystems.

Comment 20.05:

Mitigation is discussed briefly on pages 75-76 of the proposed SED, but never taken into account when discussing IM&E impacts. While some of the mitigation efforts undertaken to offset IM&E losses are summarized, the IM&E losses presented in the document are never presented in this context. Entrainment at SONGS accounts for nearly 40% of the statewide total listed in the draft SED, yet the fact that these losses have been mitigated as required by another state agency is never mentioned.

Response:

The Policy is intended to comply with CWA section 316(b). Mitigation may not be considered BTA under Section 316(b) of the CWA. Mitigation may not be substituted for BTA in terms of compliance with the CWA. Mitigation projects have been allowed by other agencies, but those agencies were not bound to comply with the CWA.

Comment 21.01b:

A reference is made to a declaration by staff that once through cooling causes an adverse environmental impact on coastal populations (reported to be on page 28 of the SED). This requires further examination to better estimate the net effect of the proposed policy, and is supported by two staff reports (CEC 2005; USEPA 2004). Neither document included reviews of long-term data on population trends in coastal fish populations that would have provided insights both into prior adverse environmental impact and the potential benefits to be realized through the implementation of the State's proposed policy.

Response:

Staff never specifically declares in the SED, page 28, that OTC on its own causes declines in coast-wide fish populations. While IM/E does undoubtedly cause mortality and therefore affects populations, it is impossible to quantify the overall effect on regional standing stock for many species. It is true that the CEC and USEPA references do not include long term population trend data, but the Water Board is not required to consider population trends. Overall population trends are influenced by a variety of natural and anthropogenic pressures, of which OTC is just one of many. However staff does believe that OTC contributes to the overall degradation of aquatic life and therefore does cause adverse impacts, particularly in the vicinity of the power plant intakes and discharges. The SED (page 28) does cite (and staff generally agrees with) the conclusion made by the CEC that OTC systems are "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. Any reduction in IM/E will protect fish and invertebrate species, and therefore will contribute to a healthier marine ecosystem.

Comment 21.02:
When viewed in relation to OTC flow across the five facilities examined by Miller et al. (2009), no relationship was detected between flow and plankton biomass. Furthermore, after the startup of San Onofre Nuclear Generating Station Units 2&3 in the early 1980s, the source of a marked increase in OTC intake, OTC flow and zooplankton biomass indices have shown similar declines. This indicates that the operation of OTC and zooplankton community dynamics were unrelated. A lack of any prior relationship between zooplankton and OTC suggests that any future alterations to OTC use, such as its cessation, will not result in a corresponding change in the zooplankton community. (The commenter presented a figure showing plankton volumetric biomass (ml) recorded by California Cooperative Oceanic Fisheries Investigations (CalCOFI) cruises, and in King Harbor, Redondo Beach adjacent to the Redondo Beach Generating Station Units 7&8 intake structure, and the total OTC flow in billion cubic meters for the five southern California facilities, including SONGS.)
Response:
The plankton biomass information presented in the commenter's figure from the CalCOFI data is not relevant to OTC impacts, since it is based on collections well offshore and mostly not in the source waters for the plant intakes. King Harbor plankton biomass is relevant only to the Redondo Power Plant intake (and possibly to a lesser extent the El Segundo Power Plant), so the intake levels for the other facilities are irrelevant. Since the OTC flow in the graph is cumulative for five plants, and since the cumulative flow is obviously dominated by SONGS, the OTC flows in the graph must be disregarded. Zooplankton in King Harbor is exposed to both the Redondo Power Plant and replenishment from the open ocean. The fact that King Harbor plankton biomass appears on the decline is due to a combination of factors, including plant intakes and changing oceanographic conditions; staff does believe that the 1977 oceanographic regime shift has obviously played a role in the decline. However, that particular oceanographic regime lasted until the mid 1990s, yet plankton biomass in King Harbor remained depressed. Staff believes that the Policy when implemented will reduce one stressor on King Harbor zooplankton biomass, namely entrainment from the Redondo Plant.

Comment 21.03:
[The commenter presented a figure showing queenfish entrainment ("entrapment index") for five southern California facilities, and plankton biomass (1972 -2007). The commenter also presented a figure showing mean monthly entrainment ("entrapment index") at SONGS (1984-2007) and mean monthly sea surface temperature (1984-2007). The commenter stated that the pattern exhibited by queenfish populations were found to significantly follow that observed in nearshore plankton biomass, which has been previously described (Roemmich and McGowan

1995) as a clear indicator of oceanographic conditions. The decline in both communities, queenfish and plankton, has been in response to the environmental conditions present after the 1977 regime shift. Moreover, the pattern in each community shows no indication of any alteration in the area due to OTC, such as the startup of San Onofre Nuclear Generating Station Units 2&3 or the progressive decline in OTC water flow in southern California. Lastly, while entrainment has been frequently identified as a principle vector for the reported impact of OTC, the queenfish larval densities have continued to decline in King Harbor in samples taken adjacent to the Redondo Beach Generating Station Units 7&8 OTC intake structure (the commenter also presented graphs at the Sept. 16 hearing of queenfish larvae entrainment vs. flow at Redondo Beach Power Plant and impingement results for queenfish at four Southern California Power Plants).]

Response:

Staff understands that queenfish populations are dependent on nearshore plankton biomass, and that both are definitely influenced by oceanographic conditions. However, OTC also has some influence on both queenfish and zooplankton in nearshore southern California. Queenfish entrainment and impingement according to the figures presented does appear to have declined quite dramatically since the 1980s. There are many potential interpretations. For example one interpretation is that the queenfish population may be depressed due to exposure to OTC over the entire period. According to the Marine Review Committee for SONGS, loss in queenfish standing stock due to entrainment at SONGS was considered to be substantial (Foster 2005). At the Redondo Beach plant, while flows have decreased they are still substantial, and the apparent reduction in queenfish larvae may be related to continued power plant intake. Another contribution to a depressed queenfish population may be reduced plankton biomass. Staff believes that these and other pressures are likely all contributing to the status of queenfish.

Comment 21.04:

Seven croaker species are impinged by the five coastal plants analyzed, but in highly variable numbers. The population indices range from 905.1, on average, for queenfish to 0.8 for white seabass. Entrainment sampling, recent and historic, has recorded few croakers other than white croaker and queenfish, although spotfin croaker and black croaker were both abundant offshore of Huntington Beach Generating Station in 2004. Cumulatively, the croakers accounted for 6% of all entrainment recorded at four of the five power plants analyzed by Miller et al. (in review). While the differences in the impingement abundances vary by greater than three orders of magnitude, on average, the species exhibited remarkable similarity in their historic patterns, consistent with oceanographic forces and commercial fishing practices regulating their populations (Figure 3). Most notably was the depressed period in nearly all species circa 1982-1995, or the period during which the nearshore white croaker gill-net fishery operated (Miller et al. in review). The data suggests this fishery, as either bycatch or the targeted species (queenfish and white croaker), influenced all seven species' population. After the fishery's closure in 1995, most species remained depressed while spotfin croaker and yellowfin croaker increased. Comparisons with sea temperature, or a similar index such as the Pacific Decadal Oscillation or North Pacific Gyre Oscillation, recorded significantly negative relationships between a temperature index and four of the seven species while spotfin croaker and yellowfin croaker were positively related to the temperature parameters….Patterns in the croaker populations observed over the last 37 years, especially their similarities to oceanographic conditions and zooplankton biomass, provides further insight into what may be expected from the implementation of the State's draft policy. Like the queenfish analysis, changes in OTC were not evident in the croaker population analysis. Furthermore, the correspondence between the populations and oceanographic conditions, specifically seawater temperature, pose the greatest concern. (The commenter presented a figure showing population fluctuations in terms of an "index anomaly" (deviation from the mean ± 1 standard deviation) for sciaenid species for the period 1972-2008.)

Response:

Staff agrees that oceanographic conditions like water temperature and food availability likely have the greatest effect on Sciaenid populations, and that fishing pressure also has a great influence. It should also be mentioned, however, that while fish species status correspond with changing environmental conditions such as sea surface temperature, such changes have occurred naturally over time. It is possible that anthropogenic climate change may be playing a role, or may play a role in the future, but there is no incontrovertible evidence to date in California waters of such an effect.

Since IM/E does not have as large of an effect on regional population levels as oceanographic and fishing pressures, it may not to be reflected in regional population trends, especially those provided by the commenter who appears to be based on the demographics of those species. Such demographic approaches are not suitable to determining the role of OTC in population effects. Still OTC has a tangible local effect (mortality) on those croaker species that are entrained and impinged in the vicinity of the power plant. In addition, a different approach, the Empirical Transport Model has been applied to OTC entrainment impacts and has shown been shown to be substantial for certain species including queenfish. That impact must be curtailed.

Comment 21.05:

Twenty-one species cumulatively represent 98% of all impinged fishes recorded at five facilities (Southern CA) examined. These include both forage and fished species (recreational and/or commercial). Their patterns further illustrate a defining pattern of oceanographic forcing with no clear relationship to changes in OTC use. These observed patterns are consistent with more extensive longer term studies, such as the CalCOFI program. Each of the 21 species were compared to a suite of oceanographic indices, all of which have some indication to coastal productivity and/or temperature, including: sea surface temperature, seafloor temperature, Pacific Decadal Oscillation, North Pacific Gyre Oscillation, and nearshore plankton biomass. Of these 21 species, nine peaked during or before 1980, three from 1981-1990, while 10 have increased since 1990 (The commenter presented a figure showing population trends in terms of an "index anomaly" (deviation from the mean ± 1 standard deviation) for the 21 common southern California marine fishes). Furthermore, nearly all those species with declining patterns prefer cooler-water conditions (Miller 2007) or have biogeographic ranges extending further into more northern latitudes. These data clearly show that while the rising seawater temperatures, and associated effects of climactic forcing, has driven down the abundance of cool water affinity species, a corresponding rise in warm water affinity species has occurred. The overall community has declined due to the significant proportion of the historic catch constituted by white croaker and queenfish. As with the croakers previously discussed, there is no representation in the population trends of these 21 species to indicate that any changes related to OTC use have occurred since 1972. The lack of such an indication in the past suggests that any future changes, such as cessation of OTC use, will not result in a positive response on the part of these species, including those targeted by recreational or commercial fisheries. (the commenter also presented graphs at the Sept. 16 hearing of sciaenid and northern anchovy larvae [from Moser et al. 2001] showing decreased abundance over time, based on warmer seawater temperatures).

Response:

Again, staff does agree that oceanographic conditions have the greatest effect on fish populations than OTC. For example it is clear that northern anchovies have declined and sardines have increased in recent years. Population trends as depicted by the commenter are relevant to larger regional pressures such as oceanographic change, but are not relevant to

OTC impacts. Staff is not required to link impingement to population change, and in fact it is unlikely that impingement influences regional population. Nevertheless impingement does cause direct quantifiable mortality to these 21 species in the vicinity of the power plants, affecting the marine community there, and must be reduced.

Comment 21.06:
A reference is made to a declaration by staff that the increased emission of greenhouse gases (GHG) such as carbon dioxide as a result of the policy will have a “less than significant impact” (Pg. 101 of the SED). Whether or not an adverse environmental impact is occurring as a result of OTC use, the direct loss of marine life by the cessation of OTC use will occur. The principle question is will the State’s draft policy result in a net benefit to the coastal marine resources. When evaluated in total, the answer is no due to the dramatic increase in GHG emissions that will result from the conversion to a less efficient technology. As written, the State’s draft policy on once through cooling will force significant increases in GHG emissions statewide. Various regulatory and scientific agencies have determined that anthropogenic GHG emissions, including that from power plants, are accelerating climate change to previously unseen rates. These changes are felt by the marine species through the variety of modifications to oceanographic conditions, specifically water temperature, upwelling, nutrient concentration, ocean acidification, etc….This, especially in light of AB32 and other pending State and Federal legislation, cannot be considered “less than significant”.
Response:
Staff believes that there will be a net benefit to marine life and environmental protection by the Policy. We know that OTC as currently practiced kills marine life at quantified and unacceptable levels, and must be curtailed. While staff is very concerned about the potential effects of increased GHG on marine life, such effects have yet to be quantified in California waters. Staff believes the net effect of the Policy on GHG emissions will likely be between scenarios 1 and 3, and probably closer to scenario 3. Staff believes most plants will be re-powering with air cooling and more fuel efficient power generating technology, thereby producing less air pollution and carbon dioxide per MGW of electricity produced.

Comment 23.01:
Mirant California, LLC indirectly owns three power plants in the San Francisco Bay Area: Potrero Power Plant; Pittsburg Power Plant; and the Contra Costa Power Plant. Of the nine operating units at Mirant's three plants, five use OTC: Potrero Unit 3, Pittsburg Units 5 & 6, and Contra Costa Units 6 & 7. Together, Mirant's OTC units have a generating capacity of 1,509 megawatts. Mirant recently announced the settlement of a lawsuit with the City and County of San Francisco that will lead to the retirement of Potrero Unit 3, subject to approval by the California Independent System Operator (CAISO), shortly after the on-line date of the Trans-Bay Cable, which is anticipated to occur during the first half of 2010. Mirant also recently announced an agreement with Pacific Gas and Electric Company (PG&E) that will lead to the retirement of Contra Costa Units 6 & 7 by the end of April 2013. After April 2013, Mirant will operate only two units relying on OTC, down from its current total of five. These reductions come on top of the previous retirement of nine OTC units at the Pittsburg and Contra Costa Power Plants that occurred between 1995 and 2004. These developments buttress Mirant's conviction that an OTC regulation as onerous as that proposed in the draft OTC Policy and draft SED which effectively would mandate the retirement of OTC units is not only unnecessary, but also would impose significant costs on California residents that substantially outweigh any attendant benefits, at a time when the cost to combat climate change will certainly result in increased costs for electricity. Without the interference of a regulatory mandate, market forces influenced by overarching policy goals are accomplishing in an orderly manner the elimination of OTC units in California.

Response:
Comment noted. Staff commends Mirant for taking early steps to be in compliance with the proposed Policy. Please see the responses to Comments 57.02 and 27.02.

Comment 23.02:
Given the paucity of any scientifically conclusive evidence that reducing water flow at these OTC plants will benefit marine ecosystems, one must conclude that the real motivation for the draft OTC regulation perhaps is to further climate change goals. However, this policy objective is directly at odds with the AB 32 Scoping Plan, which incorporates a cap-and-trade system to ensure that greenhouse gas reductions occur in the most cost-effective manner possible. Instead of letting the cap-and-trade system identify efficient outcomes, the Draft Policy would effectively seek to mandate the retirement of productive units that typically have low capacity factors. For example, a recent PG&E filing estimated the cost to construct a 560 megawatt facility at approximately $850 million. Using this figure as a ball park replacement cost for the approximately 630 megawatts of capacity represented by Mirant's Pittsburg OTC units which only run several weeks per year (about a 4% annual capacity factor), one wonders whether that money could be better spent on developing renewables or building transmission. The cap-and-trade system would give us that answer, but the Draft Policy would prevent us from realizing the intended benefits of the cap-and-trade system.
Response:
The compliance alternatives specified in the policy will allow an OTC to operate with mitigation actions taken. Therefore, the operator of an older plant could participate in the cap-and-trade program, if approved OTC mitigation has been made.

Comment 24.02:
Phasing out OTC is of great importance to California. California ocean habitats are among the most productive and diverse in the world. For example, the Farallon Islands support a growing population of the almost extirpated northern fur seals, threatened Steller sea lions, numerous other marine mammals and the largest seabird colony in the continental U.S, with thirteen different species breeding on the islands. The ocean economy generated about $43 billion for the state in 2000. Uncounted in that number is the enormous contribution oceans make to our quality of life and the high value of coastal real estate. 77% of Californians live in coastal counties. California has the highest value ocean tourism and recreation sector in the nation. The ecological, social, and economic value of California's coast and ocean depends on restoring and maintaining healthy natural systems. The State, private, and public supporters have invested millions of dollars and tens of thousands of hours to protect and improve the health of our ocean ecosystems, for example, through the implementation of the Marine Life Protection Act (MLPA), which establishes marine protected areas (MPAs) throughout the state's waters. Multiple federal and state agencies, including the USEPA, CEC, OPC, and SLC, have recognized that OTC causes significant, ongoing devastation to our valuable marine resources and significant efforts to protect and restore these resources. Coastal power plants are permitted to withdraw more than 16 billion gallons of cooling water daily and kill an estimated 79 billion fish and other marine life annually. In a state leading the nation in a strong commitment to sustainable energy and where the foundation of our economic activity is fueled by the health of our coastal resources, there is no question that the State Water Board has the right and responsibility to move past this antiquated cooling technology. We are long overdue for a clear, consistent statewide policy on cooling water technology that protects marine ecosystems and advances greener and more efficient energy production.
Response:
Staff appreciates the support for the Draft Policy. We agree that OTC has major impacts to the State's marine resources, and believe that the Policy, when implemented, should significantly

reduce these harmful IM/E impacts of OTC on marine life. Staff is working diligently toward bringing this policy to the State Water Board for consideration as soon as possible. The Policy was developed with input from many agencies and the public, which has considerably strengthened and improved the Policy. Staff looks forward to the continuing support and advice from many agencies through SACCWIS, the Review Committee, and other avenues during the implementation phase of the Policy.

Comment 25.03:
The State Water Board's stated intent is to protect marine and estuarine life from the impacts of OTC without disrupting the critical needs of the State's electrical generation and transmission system. To assess potential impacts to marine and estuarine life at El Segundo and Encina, NRG conducted Impingement Mortality and Entrainment (IM&E) characterization studies in 2005 and 2006 and submitted the reports to the Los Angeles and San Diego Regional Water Boards in January 2008. The 1977 USEPA guidance for assessing Adverse Environmental Impacts (AEI) was used in evaluating the results of the IM&E characterization studies. The information from these and other recent studies obtained from most of the power plant in California addresses some of the questions regarding levels of significance and relative magnitude of the impact at the California OTC plants raised by Board members. Based on the findings from these recent IM&E studies at El Segundo and Encina, there was no evidence that OTC resulted in AEI to fish and shellfish populations using USEPA guidelines. We recommend that results from these recent IM&E studies for El Segundo and Encina and any other California OTC plants be considered in the SED, where such results may otherwise not have been analyzed. Furthermore, we recommend that such characterization studies need not be repeated as part of the implementation of the OTC Policy.
Response:
Please see the response to Comment 20.03. The Policy states that previous studies may be used to determine baseline IM/E impacts if the discharger demonstrates, to the Regional Water Board's satisfaction, that prior studies accurately reflect current impacts.

Comment 27.01:
We have substantial concerns about the proposed OTC policy and do not believe the proposal is reasonable public policy. The dominant concern driving the proposed policy appears to be the impingement of fish and smaller organisms. According to a 2008 study conducted by MCB Applied Environment Services, a generating station in our community had no detectable adverse effects of its OTC operations. Their research indicated only a daily average of 12.25 fish and macroinvertebrates impinged during the plant's operations. This differs remarkably from the State Water Board estimates of nearly 100 per day. Our point is that by implementing the proposed OTC policy, energy supplies, dependability and costs would be significantly impacted by unverified data.
Response:
Comment noted. Staff believes that OTC has major impacts to the State's marine resources based on prior studies. The IM/E data in the SED were produced and reviewed by an independent expert review panel. The expert review panel's findings were included as an appendix to the SED. Staff therefore disagrees that the data were "unverified". It is possible that other or future studies will produce different results for individual plants; this will be considered during the implementation phase if Track 2 is chosen as the compliance alternative for that facility.

Comment 29.05:
PG&E strongly believes that as further work is done to quantify the benefits of compliance, site-specific assessments of biological impact are required. Facilities such as Diablo Canyon have

over 30 years of biological data available to demonstrate that there has been no significant impact to fish populations since the commencement of plant operations. Further data from the SED indicates that Diablo Canyon contributes a disproportionately small percentage of both impingement and entrainment. These factors must be considered in quantifying the benefits of policy implementation. Diablo Canyon is a base load facility that runs at nearly continual full capacity. Based on the SED data of average flows from 2000 to 2005, Diablo Canyon circulates roughly 22% of the state's OTC flow. However, only 1% of the impingement and 8% of entrainment are associated with Diablo Canyon. Thus, the location and design of the plant's cooling water intake system ensures that its impact, if any, is far less than its proportion of cooling water flow. Diablo Canyon's impingement impact is not just "less" than other plants – it is virtually non-existent (totaling less than 1600 pounds per year) and was found by the Central Coast Regional Water Board to be "so minor that no alternative technologies are necessary to address impingement at DCPP, and the cost of any impingement reduction technology would be wholly disproportionate to the benefits to be gained." Additionally, Diablo Canyon has not documented a single sea turtle or marine mammal death due to impingement. Diablo Canyon's entrainment is estimated at an average of approximately 11% of fish larvae in the source water body. This must be understood in the context that over 99% of fish larvae do not reach adulthood. Available data demonstrate that the operation of Diablo Canyon has not caused any detectable impacts on adult fish populations in the region. As part of the plant's biological monitoring program, PG&E has collected data on fish populations at control stations in the Diablo Canyon area since 1976 – ten years prior to plant operation. Graphs of this data demonstrate that there have been no shifts in population that can be attributed to entrainment. Further, a previously submitted study by researchers from California Polytechnic University indicated no evidence of a declining trend for Rockfish along the Central Coast. This study began in 1980 – five years before plant operation. If the operation of Diablo Canyon was impacting rockfish populations, this study should have found declining populations of species susceptible to entrainment. PG&E believes it is important to stress that the focus on fish and shellfish is appropriate. USEPA has determined that phytoplankton and zooplankton do not warrant assessment as there is a very low probability of impact given their extremely short generation times, ability to continually reproduce, and abundance throughout California's coastal waters and beyond. Second, both Section 316(b) and Porter-Cologne recognize the potential for some effects due to once through cooling. Section 316(b) requires that adverse impacts be minimized – not eliminated. Thus, it is not appropriate to equate a fish kill from a chemical spill or other non-compliance activity to impingement from a permitted OTC facility. There is no direct evidence that OTC is causing adverse environmental impacts at all OTC facilities. Impacts are site specific and should be assessed as such.

Response:

First, it must be noted that the State Water Board does not have to show population level effects in order to adopt and implement this Policy. Furthermore it is the position of the staff that Diablo Canyon's OTC impacts are substantial. There is no test, nor is staff proposing a test, to base this policy strictly on the relative impacts from one plant to another. All OTC plants must comply with CWA Section 316(b).

Diablo Canyon has substantial entrainment impacts. For just nine taxa of rocky reef fish 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. Other fish species are also entrained, as well as the larvae of benthic invertebrates. The plant is responsible for entrainment at least 1,481,948,383 fish larvae alone, annually.

Based on the proportional mortality in the source water, and using Habitat Production Foregone, it is estimated that the entrainment from the plant represents between 296 and 593 acres of rocky reef larval production.

Comment 31.07:
The Draft Policy would clearly require considerable investment in transmission and generation infrastructure, which would inevitably carry significant environmental impacts not even considered in the SED - yet no specific benefits to the improved health of the marine environment are even asserted, let alone demonstrated in the SED. In fact, the scientific evidence in the record indicates that entrainment at OTC plants does not negatively affect coastal populations. For instance, John Steinbeck, the biologist who wrote Appendix E to the SED, which documents the estimates of impingement and entrainment on which the State Water Board staff relied, pointed out during the September 16 Public Hearing, that the SED provided no evidence of the ecological significance of the impingement and entrainment numbers, and nothing about the benefits of the proposed Draft Policy. Mr. Steinbeck went on to explain that benefits from reduced entrainment are limited for species such as gobies, which make up 40% of the entrained larvae, which experience no apparent impact on the spawning population. He further explained that the limiting factor is not the number of larvae but the size of available habitat. Another experienced biologist stated that "it is not clear from the evidence that OTC by coastal generating stations creates an adverse environmental impact on the biological value of the southern California Bight. Clearly, the State Water Board should understand and provide some evidence of ecological benefits of its proposed Draft Policy before imposing billions of dollars of cost on California and its taxpayers.

Response:
First, it must be noted that the State Water Board does not have to show population level effects in order to adopt and implement this Policy. However the SED is clear in that OTC has a tangible and substantial effect (mortality) on species that are entrained and impinged. The benefits of the policy in dramatically reducing those impacts are equally clear.

Staff appreciates John Steinbeck's work on the ERP to develop the IM/E estimates, and the full ERP has agreed with those estimates. However, staff disagrees with the premise that there is no population level or ecological effect from OTC. To the contrary, there is evidence that populations have been reduced due to OTC. Staff asserts that the available science does indicate an effect on certain key populations. The SED highlights a study that modeled a reduction in queenfish in the Southern California Bight.

The best available scientific approach, recommended by the ERP, is the Empirical Transport Model (ETM). The ETM has been applied to OTC entrainment impacts and has shown that entrainment can affect fish populations.

With regard to impacts on goby populations, staff does agree that in some cases their adult population levels are likely not reduced because there is only so much habitat space for them to occupy; their larval numbers far exceed what is necessary for replacement of adult stock. However, that is not evidence as to the ecological effect of goby larval entrainment. Those organisms that prey on goby larvae (and other entrained ichthyoplankton) are deprived of that energy resource by entrainment. While there is no method or study currently available to quantify that effect, there is still no scientific evidence to disprove ecological harm from goby entrainment. Given the facts, and the lack of evidence to the contrary, staff must assume that there are ecological consequences when such large numbers of gobies are entrained and therefore removed from the predatory food chain. It is also very important to remember that 60%

of the species entrained are not gobies, and the removal of those species also has ecological consequences.

Comment 31.28:
At page 28, the SED statement that "the ongoing fish kills from the OTC plants essentially constitute a de facto "take" permit from the State's coastal waters" is inflammatory and unsupported. It appears to rely on a conclusory statement from the CEC that such plants were partly responsible for ocean degradation. However, the CEC is not an environmental agency capable or authorized to make a "take" determination. The SED also references the Phase I and Phase II record at USEP A as support for this statement, but it fails to note that the EPA did not find this a justification to establish closed cycle cooling as BTA for existing OTC facilities. The tables on impingement and entrainment (IMIE) show that 6 plants account for 90% of the IMIE problem. Why then is the focus of the Draft Policy to force the retirement of the other OTC plants? If the purpose of the policy was to minimize adverse environmental impacts on California's coastal waters as Section 316(b) calls for, then clearly the IMIE impacts of the individual or closely-situated OTC plants should have been a consideration. The SED fails to include information supporting its assumptions that all OTC plants contribute to decline of fish populations. Furthermore, it appears this information does not exist and that the Draft Policy was developed without that information as the SED indicates that a future study is needed on the cumulative effects of all the closely situated plants.
Response:
The IM/E of fish does cause mortality. Impinged fish are removed completely from the ecosystem and entrained organisms are largely rendered into detritus and therefore removed from the predatory food chain. Therefore IM/E does absolutely constitute "take" from the State's coastal waters.
Staff of the State Water Board, an agency with environmental science expertise and water resource protection authority, agrees with the CEC that OTC contributes to ocean degradation.

While staff does use the USEPA rulemaking record as a reference in certain cases in the SED, with regard to BTA the EPA's Phase II rule was largely invalidated under RiverKeeper II. The performance standards, based on a range of % controls (e.g. the reduction in entrainment by 60-90%) in that rule were found by the court not to comply with CWA Section 316(b)'s requirement for BTA. In contrast the policy does set BTA as comparable to closed cycle wet cooling. While impacts are not uniform from plant to plant, all of the OTC impacts, regardless of plant, are still substantial. BTA once established must be applied consistently throughout the State.

The State Water Board does not have to show population level effects in order to adopt and implement this Policy. The SED does not state that all OTC plants contribute to declines in fish populations. Instead the SED does describe the IM/E impacts, which are substantial, and does give information on population effects where known in certain cases. Most importantly, all OTC plants do contribute to the overall degradation of marine life through mortality from impingement and entrainment.

Comment 31.58:
Previous and current studies for both Ormond and Mandalay show that while a variety of species are impinged and entrained at the two facilities, the largest quantity are limited to a very few marine species. At Mandalay, Drums and Croakers comprise 74.6% of all species impacted. At Ormond, three groups of fishes, Specked Sanddab (41 %), Queenfish (29%), and Drums and Croakers (17%) comprise 87% of all species impacted. These data reveal that these two generating facilities have very little impact on the sport and commercial fisheries of

the California coast. Furthermore, the Proteus Study (submitted) found that no endangered species were impacted at either facility. A distribution of the species impinged and entrained at each facility was prepared that formed the basis for monetizing their value in RRI's cost/benefit analysis prepared by NERA (submitted). Based on the IM/E studies which determined the actual flow annual eggs entrained for 2006-6007, the researcher, Mr. McCormick, estimated the adult fish needed to replace the entrained eggs at Ormond and Mandalay. RRI used the "adults needed to replace" estimates to form the basis of its determination that the $200 million dollar cost for installing cooling towers at both facilities results in an effective cost of $3,000 per saved fish. The study also concluded that neither facility has a significant adverse environmental impact to the fish populations therein. Mr. McCormick concluded that the El Nino-like water circulation pattern in the northern Pacific that causes sea water temperature shifts has a significant impact on the species that live in the California Bight. Another source of stress on the health of the aquatic environment is municipal waste and other industrial discharge.

Response:

Please see the response to Comment 31.07.

Comment 35.03:

The policy represents a significant opportunity to transform California's dependence on pollution-emitting power plants--which the EPA has concluded imposes a severe risk to public heath ranging from asthma to premature death in people with heart or lung disease—via the placement of solar panels (photovoltaic) on rooftops, mainly on parking lots and warehouses, the most practical, available and cost-effective sites. On June 17, the CEC recognized photovoltaic's vast potential to revolutionize energy generation. The Commission's groundbreaking ruling concluded that PV is a feasible, cost-effective alternative to conventional gas-fired power plants, which means it now will be considered in the regulatory process of selecting the most efficient, effective and environmentally safe ways to generate electricity and serve California markets. As the Energy Commission's June 17 ruling elevating PV to its new status as a replacement for gas-fired power plants may have come after the drafting of the Board policy on power plant cooling, the policy should be revised in light of the CEC ruling. Additionally, the policy Is based in part on a report by the "Energy Agencies" (CEC , CAISO, California Public Utilities Commission) that focuses on means to avoid relying on existing power plants in order to end use of OTC. But the report cites as a main way to accomplish this goal is "to rely more upon remote generation." That means building more, very costly and environmentally-damaging transmission lines, which PV on warehouse and vehicle shelters, as well as home and business, roofs would not require because they would be in local areas where power plants to be phased out are located. Therefore, this report has not taken localized PV into account as a source of energy to replace that of power plants, a major omission. The Energy Agencies report cites the lack of air credits to upgrade or replace gas-fired plants in the Los Angeles Basin because of its poor air quality as a significant obstacle to replacing a large percentage of plants now using OTC. It fails to recognize the potential of localized PV to sharply reduce or eliminate the need for pollution-producing plants, making air credits irrelevant. The newest and most promising alternative is PV, which also on a broader scale has the potential of quickly reaching the state's widely-praised goal of converting its energy generation to 33% renewables by the year 2020.

Response:

The State Water Board’s authority to require that the location, design, construction and capacity of cooling water intake structures reflect BTA for minimizing adverse environmental impact does not extend to specifying technology for electricity generation. Setting energy policy is outside of the scope of this Statewide Water Quality Control Policy.

Comment 36.01:

For many years, we have been deeply troubled about the killing of marine life in the Morro Bay National Estuary by the Morro Bay Power Plant and the resulting impacts on the wildlife that are directly affected by the loss of fish and other aquatic species. We also are concerned about OTC impacts on estuary, bay and ocean water elsewhere on the coast. We cherish the Estuary, but we are fearful that continued use of OTC could jeopardize its future as a healthy water body, as has happened elsewhere. We were hopeful that the State Water Board would seize the opportunity to adopt an OTC policy that would prevent these impacts and protect the Morro Bay Estuary. We are particularly disappointed, therefore, that the draft policy seems to provide no assurances that the more than 50 years of damage to the Estuary and its wildlife will end, nor are there any reliable expectations that the impacts to other coastal waters and communities in California will stop. Therefore, we respectfully request that you delay adoption of this policy and devote your efforts to revising it into a regulatory document that will prohibit OTC once and for all, and that the millions of residents of the California coast can be proud of.

Response:

Comment noted. Staff appreciates the support for the Draft Policy. Staff agrees that OTC has major impacts to the State's marine resources. When implemented, the Policy should significantly reduce the harmful IM/E impacts of OTC on marine life. However, note that the primary goal of the Policy is not to phase out OTC; rather a primary goal of the Policy is to establish a BTA for cooling water intake structures at existing coastal and estuarine power plants to reduce IM/E impacts to acceptable levels.

Comment 40.01:

According to the March 2008 Scoping Document, the OTC plants impinge up to 9 million, and entrain 79 billion fish and other organisms on an annual basis. This impact represents an adverse effect to Essential Fish Habitat (EFH) as defined under the Magnuson Stevens Fishery Conservation and Management Act (MSA), which NMFS administers for the conservation and preservation of the Nation's fishery resources. Impacts to salmonids, as well as Delta smelt listed under the Endangered Species Act (ESA), have been noted at the Contra Costa power plant in San Francisco Bay (State Water Board 2008). NMFS supports the proposed policy because it is expected to result in significant reductions in impacts to marine and estuarine ecosystems affected by these facilities. We congratulate the State Water Board staff for their hard work over the several years it took to research this topic, develop this policy, and work with the other pertinent state agencies and entities to propose a regulatory system that will not only protect the affected marine and estuarine beneficial uses, but does so in a manner that will not compromise electrical reliability for the general public.

Response:

Staff appreciates your agency's support of the Policy. The impingement and entrainment estimates have been revised since the 2008 Scoping Document was released. In the Draft SED, impingement of fish is now estimated at 2.6 million fish annually, and entrainment is estimated at 19 billion fish larvae annually. These revised figured do not include invertebrates, nor do they include IM/E for Contra Costa and Pittsburgh Power Plants. Staff has recently reviewed documentation submitted to Regional Water Boards for Contra Costa and Pittsburgh Power Plants; Delta Smelt is impinged and entrained at Pittsburgh, and is entrained at Costa Costa.

Comment 61.03:

Section 1.1 of the SED states that OTC presents a "considerable and chronic stressor…" to aquatic ecosystems without presenting any evidence that this is true, other than statements that the impacts are recognized as significant by state and federal agencies.

Response:

Staff stands by its position that OTC presents a considerable and chronic stressor to marine life. 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 CA 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.”

Comment 61.05:
Section 1.1 of the SED states that the policy addresses an "ongoing, critical impact…" without presenting any evidence to support the statement.
Response:
Please see the response to Comment 61.03.

Comment 61.07:
Section 1.3 of the SED states that Section 316(b) includes a statement that BTA is required for "minimizing adverse environmental impact." This seems to require some assessment of the existence of an adverse environmental impact. Analyses of adverse environmental impact from recent IM&E studies done in southern California indicate that there is no evidence of adverse environmental impact using criteria established by USEPA.
Response:
Staff strongly disagrees that there is no adverse impact. Please see the response to Comment 61.03.

Comment 61.11:
SED, pg. 9, par. 2: The text here seems to imply that the threshold for determining adverse environmental impact has been lowered due to the Riverkeeper I and II decisions by implying that any cooling water intake structure results in some impairment or stress. Again, the guidance on adverse environmental impact presented a reasonable approach for these determinations and does not include showing as stated "that any impacts must be shown to have deleterious effects..."
Response:
Staff stands by the statement: “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.”

Comment 61.13:
SED, pg.29 par. 2-4: Discussion of entrainment equates the small size of the organisms with susceptibility to mortality. Also, the assumption used in most of the studies of 100 percent mortality is discussed. Although this assumption has been used in most of the studies in California, the assumption was meant to apply to fish eggs and larvae, which are soft-bodied and particularly susceptible to many of the factors mentioned in these paragraphs. The assumption was never meant to apply to other planktonic organisms, such as phytoplankton or zooplankton, which have hardened shells. For these organisms, the rates of survival undoubtedly vary among species but it could be very high. The EPA has correctly focused the concerns regarding entrainment on fish and shellfish larvae which have much more limited distributions and capacities for reproduction than phytoplankton and zooplankton. The logic of this approach is based on the concept of adverse environmental impacts that-focus IM&E

studies on organisms with some potential for adverse environmental impact and not on life forms with little or any potential for adverse environmental impact.

Response:

The “shellfish larvae” mentioned in the comment are crustaceans zooplankton and have chitin exoskeletons, making them no less or no more susceptible to mortality than other forms of benthic invertebrate larvae in the zooplankton. There is no evidence that invertebrate larvae have a better chance of survival than fish larvae. Staff stands by its opinion that entrainment of all species results in 100% virtual mortality.

Comment 61.14:

SED, pg. 30, par.1: Impingement at the Diablo Canyon Power Plant not only is less than impingement at SONGS but it also has the lowest estimated impingement rates of any power plant in the state. The policy presents the entrainment effects based on estimates of habitat production foregone (HPF) without any context as to why the effects are presented as area instead of numbers. It is important to provide some context for the estimates since the methodology includes several important assumptions. There is also no way to compare the effects of Diablo Canyon with other facilities where estimates of HPF are not provided.

Response:

Staff agrees that Diablo Canyon has lower impingement than SONGS and this is clearly stated in the SED. However Diablo Canyon does have greater impingement than several other plants. See Table 3 of the SED. Regarding the remainder of this comment staff is unclear as to what is being said. That section of the SED refers to source areas and proportional mortality at Diablo based on a reference: “Diablo Canyon Power Plant Independent Scientist’s Recommendations to the Regional Water Quality Control Board, Item no. 15 Attachment 1, Sept. 9, 2005 Meeting.” HPF is not mentioned in the paragraph in question.

3. Promoting statewide consistency and conserving Regional Water Board resources

Comment 31.30:

The SED recommends a statewide policy, arguing it achieves consistency among the Regional Water Boards and is less burdensome to the agency's staff. The SED acknowledges that use of BPJ allows for "more consideration of site-specific issues" but asserts that it is more costly and labor-intensive to the agency. However, the Regional Water Boards have been making site-specific BPJ determinations for many years, so they already have the expertise and resources necessary to make site specific BTA evaluations. The SED erroneously over-simplifies the state of the coastal environment, feasible intake structure technology, geographic locations, and other local concerns (legal, social, and economic) when it asserts that there is "relative similarity between most facilities." It also fails to provide any evidence that the proposed policy will either achieve greater consistency or reduce the burden of the BPJ permitting process. The proposed statewide Policy will result in enormous adverse environmental, economic and social impacts to the State and should not be justified on the primary bases that it is needed for statewide consistency and will be less burdensome to the Regional Water Boards' staff. Consideration of site-specific factors is exactly what is required to properly balance protection of water resources with other State goals and policies. Consistent statewide guidance to the Regional Water Boards on the use of BPJ would be both effective and appropriate - and would be consistent with the approach used in every other State in the country addressing once through cooling. This would also have the effect of reducing the workload for the Regional Water Boards' staff.

Response:

It is true that the Regional Water Boards have been making site-specific BPJ determinations to the best of their abilities in terms of expertise and resources for many years. However, due to the lack of guidance on how to reissue and modify NPDES permits for OTC plants with requirements that will protect marine and estuarine life, each Region has taken their own approach, leading to permittees being treated differently from Region to Region, varying levels of environmental protection, and lengthy and contentious permit hearings. A statewide policy will ensure consistency across Regions while providing the guidance necessary for the Regional Water Boards to reissue and modify permits. The Regional Water Boards support this approach. Furthermore, a statewide approach is necessary to ensure that issues that cut across Regions, such as electrical grid reliability, air quality, and costs to the ratepayers, are identified and addressed in a comprehensive fashion. Based on the SED's analysis, staff disagrees that the proposed statewide Policy will result in enormous adverse environmental, economic and social impacts to the State. The Policy will reduce the impacts of OTC on the State's marine resources and will likely encourage more efficient power plants at reasonable cost to the consumer. Please also see the response to Comment 61.03.

Comment 31.27:
The goals listed in the SED do not include the goal to shut down the steam boiler OTC units, which was stated as a goal by State Water Board staff at the September 16, 2009 hearing. Moreover, the SED does not explain how the stated goals will be achieved. For example, there is no information to indicate the Draft Policy would either reduce the workload of the Regional Water Boards, or improve the consistency of their decisions.
Response:
It is NOT the goal of the Policy to shut down the steam boiler OTC units; rather it is to implement Section 316(b) of the CWA. Please see the response to Comment 31.30.

Comment 61.06:
Section 1.2 of the SED states that the existing BPJ approach represents a "considerable resource burden…", but doesn't consider the economic burden the proposed policy places on the utilities and citizens of California. No evidence is provided of the burden on resource.
Response:
Staff disagrees that the economic burden the proposed policy places on the utilities and citizens of California is not considered. The costs of compliance are provided in terms of cost per MWh in the SED: When based on 2006 net output, the costs are $11.34/MWh (1.13 cents/KWh); when based on rated capacity, the costs are $4.48/MWh (0.45 cents/KWh). Please also see the response to Comment 31.30.

B. SCOPE OF THE PROPOSED POLICY

1. Addressing discharge impacts from OTC facilities

Comment 6.03:
The policy addresses only impacts from water uptake and not those resulting from plant discharge.
Response:
The proposed Policy is only intended to directly address intake effects. Nothing in the Policy, however, precludes the authority of Regional Water Boards to regulate discharges from existing power plants through NPDES permits, consistent with water quality standards, including the California Ocean Plan and the Thermal Plan.

Comment 13.04:
As an OTC policy, the policy overall should target elimination of OTC discharges and intakes, not merely reduction of intake. We are concerned that the policy does not have as a goal the elimination of toxic OTC discharges, even though both state and federal law prohibit the discharge of toxic pollutants in toxic amounts. Elimination of impacts from both intake and discharge should be our goal and, thus, should be the goal of an OTC policy.
Response:
Please see response to Comment 6.03 regarding discharges of toxic wastes. The primary goal of the Policy is not to phase out OTC; rather it is to implement CWA Section 316(b) and to establish a BTA for cooling water intake structures at existing coastal and estuarine power plants to reduce IM/E impacts to acceptable levels.

Comment 13.09:
An assessment of intake impacts should not trump assessment of discharge impacts. Our Regional Water Board (and perhaps others) is attempting to hold off on any action on the NPDES permits until this policy is adopted. However, the policy does not evaluate the discharge impacts of these systems, meaning that the State Water Board's intake policy is effectively trumping the regular required evaluation of the discharge impacts to surface waters. This is not appropriate and should not be allowed to be the cause of the Regional Water Boards abandonment of the NPDES process of re-evaluating discharges every five years.
Response:
NPDES permits for power plants impose both intake and discharge requirements, thus, impacts of both are evaluated. The backlog in permit renewals is due to resource constraints and has nothing to do with evaluation of discharge impacts or lack thereof.

2. Addressing carbon dioxide sequestration projects

Comment 7.03:
There are currently several potentially beneficial research projects that propose using power plant OTC water to remove power plant atmospheric carbon dioxide emissions. For example, Calera proposes to precipitate “green cement” by combining OTC water with power plant carbon dioxide emissions. Unlike power plants converted to closed-cycle cooling, power plants with subsurface intakes would not prevent the co-location of such carbon dioxide sequestration projects. If successfully combined, the technologies (subsurface intakes and carbon sequestration) could help California in its efforts to reduce or eliminate OTC impacts and to meet greenhouse reduction levels (AB 32).
Response:
Staff believes the proposed OTC policy would not prohibit the use of seawater to make cement. Subsurface intakes would eliminate both impingement and entrainment and would meet the proposed Policy requirements.

Comment 11.25:
There are several new technologies in development that would utilize the seawater from a plant's cooling system to reduce the power plant's GHG emissions and could potentially reduce GHG emissions from other sources as well. Should the use of seawater for cooling purposes become infeasible upon implementation of the proposed Policy, this potential means of GHG reductions would be lost, thereby exacerbating the GHG impact of the proposed Policy.

A potential sequestration opportunity currently being pursued at a pilot plant level at Moss Landing Power Plant involves processing power plant emissions using the calcium and magnesium in seawater to make cement. Calera Cement's demonstration facility, which should be in operation in 2010, would create cement from the carbon dioxide contained in 10 MW worth of exhaust diverted from Moss Landing Unit 2. Not only would more than 90% of the carbon dioxide be captured from Unit 2's exhaust, but each ton of cement created would ultimately displace one ton of cement created the traditional way, which uses large kilns and is one of the larger sources of industrial GHG emissions. A second proposed project at Moss Landing would use an Accelerated Weathering of Limestone process whereby carbon dioxide gas is converted into compounds that can be disposed in the ocean. The process involves reacting carbon dioxide from the power plant with water and calcium carbonate from crushed limestone. A DOE grant has been applied for to fund the design of a pilot plant utilizing this technology at Moss Landing. While both of these technologies are as yet commercially unproven, they each hold promise for cost-effective carbon capture and storage.

Response:

Staff believes the proposed OTC policy would not prohibit the use of seawater to make cement or prohibit the use of seawater in other carbon dioxide sequestration processes. Furthermore, the Policy would not preclude the use of sea water for the pilot studies on GHG reductions.

C. ISSUES AND ALTERNATIVES

1. Should the State Water Board Adopt a Statewide OTC Policy?

Comments 3.06 and 26.04:

We have reviewed the Draft Policy and, although it is a step in the right direction, some important clarifications must be made in order to ensure that the final policy will actually protect the beneficial uses of the state's coastal and estuarine waters and that it will be consistently applied throughout the state. The Draft Policy follows five separate tracks that can be pursued by operators – any combination of which may or may not result in reduction in impingement and entrainment: These tracks are as follows: (1) Track 1, setting forth best technology available ("BTA"); (2) Track 2, providing an exception to BTA where Track 1 proves not feasible; (3) Nuclear exceptions; (4) Grid Reliability exceptions; and (5) a Wholly Disproportionate exception. We are concerned that the numerous loopholes in the various tracks will allow operators to comply without actually achieving the goal of protecting marine life.

Response:

Comment noted. Staff appreciates the submission of suggestions for possible improvement of the Policy and the SED. Staff has responded to issues and concerns specifically identified in further detail in the commenter's submission.

Comment 7.01:

Central Coast Water Board staff supports the proposed Policy to clarify how NPDES permits may address impacts of power plant OTC intakes on marine and estuarine environments. We appreciate that the Policy addresses the goal of statewide consistency while retaining some flexibility for the coastal Water Boards, as the consensus among marine scientists with extensive experience studying the effects of OTC are that impacts from ocean intakes are often site-specific. Thank you for incorporating Central Coast Water Board staff's ongoing comments during the development of the Policy.

Response:

Staff appreciates the support for the Draft Policy from the Central Coast Water Board staff. The Central Coast Water Board will be crucial to implementing the proposed Policy by permitting the OTC facilities in their Region.

Comment 8.03:

We fully support the State Water Board's effort to develop a clear OTC policy that will be more protective of the environment and the public. The harms from OTC have been well-documented over many years yet the adoption of a State policy has lagged.

Response:

Staff thanks the commenter for their support. We acknowledge that the development of this policy has taken years but this is due to the complexities of this issue as well as changing legal requirements (e.g., the RiverKeeper II decision).

Comment 9.01:

The State Water Board is to be congratulated in moving to enact a policy aimed at addressing the use of OTC by power plants along the California coast and their widespread killing of aquatic life, which the CEC in 2005 recognized in an IEPR report as a major source of destruction to marine resources and the economies of coastal communities.

Response:

Comment noted. Staff appreciates the support for the Draft Policy. Staff agrees that OTC has major impacts to the State's marine resources. When implemented, the Policy should significantly reduce the harmful IM/E impacts of OTC on marine life.

Comment 18.01 and 18.03:

California has consistently set high standards for the protection of the state's world-renowned coastal and marine resources, through the Marine Life Protection Act, the California Ocean Protection Act, and the Marine Life Management Act, among others. We urge the State Water Board to expeditiously adopt and implement a state policy on OTC that protects its marine and estuarine ecosystems, while advancing to greener, more energy efficient, and more sustainable energy production by phasing-out OTC. We believe the draft policy is a step in the right direction, but we encourage the State Water Board to strengthen the final policy by addressing loopholes that currently exist within the draft policy to ensure that beneficial uses of the state's coastal and estuarine waters are protected and that the policy be consistently applied throughout the state.

Response:

Please see the response to Comment 3.06. Staff believes the proposed Policy will be protective of marine and estuarine ecosystems by significantly reducing the harmful IM/E impacts of OTC on marine life. However, the primary goal of the Policy is not to phase out OTC; rather it is to establish a BTA for cooling water intake structures at existing coastal and estuarine power plants to reduce IM/E impacts to acceptable levels. Furthermore, the State Water Board is not attempting to use this Policy to implement a state energy policy.

Comment 19.01:

We support the overall goal of the policy, which would require the owner/operator of an existing power plant to reduce the intake flow rate at each power-generating unit, at a minimum, to a level commensurate with what can be attained by a closed-cycle wet cooling system. We agree that such a measure is necessary to reduce the harmful effects on marine and estuarine life associated with cooling water intake structures and OTC.

Response:

Comment noted. Staff appreciates the support for the Draft Policy. Staff agrees that OTC has major impacts to the State's marine resources. When implemented, the Policy should significantly reduce the harmful IM/E impacts of OTC on marine life.

Comment 28.01:

Pacific Environment, an organization dedicated to protecting the living environment of the Pacific Rim, is in strong support of the Board's on-going commitment to examining options for the phase out of OTC, and we appreciate the opportunity to offer our perspective on the matter. We have signed on to extensive comments spearheaded by California Coastkeeper Alliance regarding specific sections of the draft policy, and potential loopholes in the policy's language. These specific comments submitted are meant to be supplemental, and address the role the OTC power plants play in grid reliability. These comments are specific to California's fleet of 17 natural gas OTC power plants. We expect much of this data will be useful in the implementation of the policy.

Response:

Comment noted. Staff appreciates the support for the Policy and the submitted information. Staff has responded to issues and concerns specifically identified in further detail in the commenter's submission.

Comment 29.01:

Pacific Gas and Electric Company (PG&E) supports the protection of California's marine resources through development of a consistent statewide policy implementing Section 316(b). We support efforts to transition away from OTC and have clearly demonstrated that support through the construction of our two new dry-cooled facilities, Gateway and Colusa, as well as through the repowering of our Humboldt facility without the use of OTC. Additionally, subject to approvals from the CPUC and CEC, we have entered into a power purchase agreement with Mirant that will retire Contra Costa Units 6 & 7 and replace these units with combustion turbines at the adjacent Mirant Marsh Landing facility – eliminating OTC at the Contra Costa facility. The only PG&E-owned facility that will continue to utilize OTC is the Diablo Canyon Power Plant, a 2,300 MW baseload facility located on the Central Coast.

Response:

Comment noted. Staff appreciates the support for the Policy and, especially, PG&E's efforts to transition away from OTC. PG&E is to be commended for taking the lead in moving away from using OTC at their facilities. Staff has responded to issues and concerns specifically identified in further detail in the commenter's submission.

Comment 32.04:

We appreciate the State Water Board's efforts in proceeding with the Draft Policy and phasing out of the destructive OTC technology.

Response:

Staff appreciates the support for the Draft Policy. However, Staff does not agree that the Policy is proposing to phase out OTC; rather a primary goal of the Policy is to establish a BTA to reduce IM/E impacts to acceptable levels.

Comment 33.02:

Baykeeper strongly supports the State Water Board's decision to adopt a statewide policy to implement federal CWA section 316(b). A statewide policy will ensure consistency across regions while providing the guidance necessary for the Regional Water Boards to reissue and modify permits with requirements that will protect marine and estuarine life. We appreciate the efforts of the State Water Board staff to create this policy; however, we see several areas that can be strengthened to ensure better compliance.

Response:

Comment noted. Staff appreciates the support for the Draft Policy and the submitted suggestions for strengthening the Policy and the SED. Staff has responded to issues and concerns specifically identified in further detail in the commenter's submission.

Comment 33.13:

We hope that by adopting this statewide policy, the State Water Board will ensure the rapid phase-out of OTC by power plants. In the interim, however, San Francisco Baykeeper would like to see power plants take meaningful steps to mitigate the destructive impacts of OTC, thereby making significant progress in the protection of imperiled marine and estuarine wildlife.

Response:

Comment noted. Staff appreciates the support for the Draft Policy. However, Staff does not agree that the Policy is proposing to phase out OTC; rather a primary goal of the Policy is to establish a BTA to reduce IM/E impacts to acceptable levels.

Comment 34.02:

We support the adoption of a statewide policy to provide statewide consistency in implementing Section 316(b).

Response:

Comment noted. Staff appreciates the support for the Draft Policy.

Comment 36.01:

For many years, we have been deeply troubled about the killing of marine life in the Morro Bay National Estuary by the Morro Bay Power Plant and the resulting impacts on the wildlife that are directly affected by the loss of fish and other aquatic species. We also are concerned about OTC impacts on estuary, bay and ocean water elsewhere on the coast. We cherish the Estuary, but we are fearful that continued use of OTC could jeopardize its future as a healthy water body, as has happened elsewhere. We were hopeful that the State Water Board would seize the opportunity to adopt an OTC policy that would prevent these impacts and protect the Morro Bay Estuary. We are particularly disappointed, therefore, that the draft policy seems to provide no assurances that the more than 50 years of damage to the Estuary and its wildlife will end, nor are there any reliable expectations that the impacts to other coastal waters and communities in California will stop. Therefore, we respectfully request that you delay adoption of this policy and devote your efforts to revising it into a regulatory document that will prohibit OTC once and for all, and that the millions of residents of the California coast can be proud of.

Response:

Comment noted. Staff appreciates the support for the Draft Policy. Staff agrees that OTC has major impacts to the State's marine resources. When implemented, the Policy should significantly reduce the harmful IM/E impacts of OTC on marine life. However, note that the primary goal of the Policy is not to phase out OTC; rather a primary goal of the Policy is to establish a BTA for cooling water intake structures at existing coastal and estuarine power plants to reduce IM/E impacts to acceptable levels.

Comment 39.01:

We have reviewed the draft "Statewide Water Quality Control Policy on the Use of Coastal and Estuarine Waters for Power Plant Cooling," dated June 30, 2009. We commend the State Water Resources Control Board staff for their work in crafting an approach that provides protection of coastal marine life and incorporates other State priorities such as the needs of the energy grid. Although we understand some minor changes to the draft may be necessary, we support moving forward with the adoption of this policy as soon as possible. USEPA Region 9 believes the draft policy is a robust approach that will provide substantial environmental benefits, while appropriately balancing other statewide interests as well as the needs of the various State agencies and other stakeholders.

Response:

Comment noted. Staff appreciates the support for the Draft Policy. USEPA's support is very important on this issue.

Comment 40.02:
We are pleased that the State has not chosen to wait for the USEPA to complete its long delayed Section 316(b) implementation planning for existing power plants. We are confident that the proposed policy, as presented in the July 2009 document, will be equivalent if not more stringent than the national standards USEPA eventually proposes.
Response:
Comment noted. Staff appreciates the support for the Draft Policy, and is working diligently toward bringing this policy to the State Water Board for consideration as soon as possible.

Comment 42.01:
I am writing to express the support of the staff on the CCC for the proposed Policy. Commission staff has appreciated the opportunity to participate in discussions regarding the development of the OTC Policy through the Inter Agency Workgroup, convened by the State Water Board staff. We believe that the proposed OTC policy will help meet California's environmental policy goals to reduce or eliminate the significant impacts of OTC systems while maintaining the reliability of the state electrical power supply system.
Response:
Comment noted. Staff appreciates the assistance of the support of the CCC staff in developing the Draft Policy and the continued support of the Draft Policy. We look forward to future cooperation with the CCC staff on the SACCWIS and the Review Committee for the special studies for the nuclear facilities.

Comment 40.01:
According to the March 2008 Scoping Document, the OTC plants impinge up to 9 million, and entrain 79 billion fish and other organisms on an annual basis. This impact represents an adverse effect to Essential Fish Habitat (EFH) as defined under the Magnuson Stevens Fishery Conservation and Management Act (MSA), which NMFS administers for the conservation and preservation of the Nation's fishery resources. Impacts to salmonids, as well as Delta smelt listed under the Endangered Species Act (ESA), have been noted at the Contra Costa power plant in San Francisco Bay (State Water Board 2008). NMFS supports the proposed policy because it is expected to result in significant reductions in impacts to marine and estuarine ecosystems affected by these facilities. We congratulate the State Water Board staff for their hard work over the several years it took to research this topic, develop this policy, and work with the other pertinent state agencies and entities to propose a regulatory system that will not only protect the affected marine and estuarine beneficial uses, but does so in a manner that will not compromise electrical reliability for the general public.
Response:
Staff appreciates your agency’s support of the Policy. The impingement and entrainment estimates have been revised since the 2008 Scoping Document was released. In the Draft SED, impingement of fish is now estimated at 2.6 million fish annually, and entrainment is estimated at 19 billion fish larvae annually. These revised figured do not include invertebrates, nor do they include IM/E for Contra Costa and Pittsburgh Power Plants. Staff has recently reviewed documentation submitted to Regional Water Boards for Contra Costa and Pittsburgh Power Plants; Delta Smelt is impinged and entrained at Pittsburgh, and is entrained at Costa Costa.

Comment 58.01:
In light of the Board's welcome and appropriate action, we urge you to make further revisions that will eliminate the many vague and unclear parts of the revised policy in order to ensure that it will phase out the use of OTC in a reasonable time period. A policy that is not forthright in its requirements for compliance opens up the possibility of noncompliance through disputed terms and phrasing.

Response:
Comment noted. Staff appreciates the support for the Draft Policy. Staff has responded to issues and concerns specifically identified in further detail in the commenter's submission. In response to comments, Staff has revised the Draft Policy to make it clearer and easier to understand. Staff believes that the Policy, when implemented, will significantly reduce the harmful IM/E impacts of OTC on marine life. However, the primary goal of the Policy is not to phase out OTC; rather a primary goal of the Policy is to establish a BTA for cooling water intake structures at existing coastal and estuarine power plants to reduce IM/E impacts to acceptable levels.

Comment 1.01:
Although we still have significant concerns about the consequences of the Policy as proposed, the multi-agency working group has contributed to an improved Policy compared to previous versions. AES Southland recognizes the enormous complexities associated with developing an OTC Policy that protects our marine environment and also takes into account electric reliability, climate change, criteria pollutants, electricity rates, water supply and implementation feasibility. We believe that California is at a critical juncture in determining the long term future of its energy infrastructure, and urge the Water Board to be cautious about moving forward too quickly without regard to the significant reliability, environmental, societal, and economic impacts that will occur if the policy is not well thought out and feasible to implement. We urge the Water Board to carefully consider our recommendations, which will improve the overall cost and implementation feasibility of the Policy, yet still achieve the desired environmental benefits.
Response:
Comment noted. Staff has responded to issues and concerns specifically identified in further detail in the commenter's submission.

Comment 4.01:
The California Council for Environmental and Economic Balance (CCEEB) believes that although this draft is an improvement over prior versions, it is still fundamentally flawed and that substantial modifications to the current approach must be made to provide a policy that assures protection of the marine environment, minimizes significant adverse environmental impacts, avoids costs that are wholly disproportionate to the benefit gained, and avoids threats to the reliability of the electric supply system. The Draft Policy does not provide a reasonably foreseeable compliance path. The proposed Policy would force all but perhaps the two coastal nuclear plants and a few higher efficiency combined cycle units to face a decision to shutdown or repower when their compliance dates are reached. Though the Draft Policy proposes two alternative compliance tracks, in our opinion, the ability for a generator to cost-effectively comply with either track is largely illusory. We believe that the practical effect of the Draft Policy is to create a pool of non-compliant coastal power plants that will face closure or extensive re-powering.
Response:
Comment noted. Staff appreciates the submission of suggestions for possible improvement of the Policy and the SED. Staff has responded to issues and concerns specifically identified in further detail in the commenter's submission. Staff does not believe that the Draft Policy would force most OTC plants to shut down and have been working with representatives from the CEC, CPUC, CCC, SLC, ARB, and CAISO to develop realistic implementation plans and schedules for this Policy that will not cause disruption in the State's electrical power supply.

Comments 11.42 and 11.55:

Dynegy has a substantial interest in the Draft Policy as it owns and/or operates three OTC power plants in California -- Moss Landing, Morro Bay, and South Bay, 3,885 MW in total. Any OTC policy adopted by the Board that addresses BTA will have far reaching implications for the State, including environmental, electric grid stability, and the economy. While we appreciate the State Water Board's and staff's efforts to address substantively many concerns raised by the 2008 scoping document, the proposed Policy remains flawed in several important respects. Those flaws must be resolved, and other aspects of the Policy must be refined, if the Board is to adopt a viable OTC policy that achieves consistency in BTA determinations and reasonably accommodates environmental, electric reliability, and economic concerns. Dynegy has filed separate comments on the SED.

Response:

Comment noted. Staff has responded to issues and concerns specifically identified in further detail in the commenter's submission, including comments on the SED. To the extent that the commenter takes issue with the staff's failure to incorporate concerns raised through the 2008 scoping process, staff cannot determine which of the many comments or concerns raised through that process but not specifically identified in comments on the current draft proposal that have not been adequately satisfied through the process of consideration and reconsideration. Without specific information and explanation, staff does not have a fair opportunity to address these issues.

Comment 23.03:

Mirant opposes adoption of the Draft Policy. Nonetheless, if a version of the Draft Policy is to be adopted, there are improvements that the State Water Board can make by (1) Improving Track I and Track 2 provisions to eliminate potential compliance ambiguity; (2) Modifying the timing of and clarifying the intent behind the implementation plan; (3) Clarifying that existing mitigation measures satisfy the Draft Policy's interim requirements; (4) Making the role of SACCWIS more concretely responsible as the guarantor of electric reliability; (5) Opening the "WDD" to all operators of OTC units; and (6) Improving the analysis in the SED.

Response:

Comment noted. Staff has responded to issues and concerns specifically identified in further detail in the commenter's submission.

Comment 31.01:

RRI Energy, Inc.'s wholly-owned subsidiaries own and operate two electric generation facilities (Ormond Beach Station and Mandalay Station) that will be subject to the regulations under consideration in the Draft Policy. Unfortunately, we believe that the Draft Policy falls far short of reasonably balancing the complex set of issues involved in adopting such a policy, which would force the retirement of over 24% of the state's generating capacity and threaten the reliability of the state's electric system. Californians will be faced with the enormous cost of replacement transmission and generation, at a cost that is wholly disproportionate to any conceivable public or resource benefit.

Response:

Comment noted. Staff has responded to issues and concerns specifically identified in further detail in the commenter's submission. Staff does not believe that the Draft Policy would force most OTC plants to shut down and have been working with representatives from the CEC, CPUC, CCC, SLC, ARB, and CAISO to develop realistic implementation plans and schedules for this Policy that will not cause disruption in the State's electrical power supply.

2. Definition of "New" and "Existing" Power Plants

Comment 23.06:
"Existing Power Plants" are defined to be any power plant that is not a new power plant. Mirant believes the State Water Board intended its Draft Policy to impose a closed-cycle cooling system on OTC plants, but as currently written, the Draft Policy appears to require any power plant using water to reduce its flow by the enumerated standard. So, for example, it would appear that adoption of the Draft Policy in its current form would require Mirant's Pittsburg Unit 7, which already employs a closed-cycle wet cooling system, but is also by definition arguably an Existing Power Plant, to reduce its water flow by 93%. To correct this presumably unintended consequence, Mirant recommends modifying the definition of "Existing Power Plant" as follows: "Refers to any power plant using OTC that is not a *new power plant.*
Response:
Because Track 1 requires reductions to a level commensurate with that which can be attained by a *closed-cycle wet cooling system*, the clear intent is that previous installation of a closed-cycle wet cooling system would comply with Track 1 rather than requiring additional reductions. Staff does not believe that the definition of "Existing Power Plants" needs to be changed.

Comment 31.31:
The Policy recommends using USEPA's definition and distinction between new and existing facilities and RRI concurs.
Response:
Comment noted.

3. Addressing Nuclear Facilities

a. Feasibility of nuclear facilities complying with Track 1 and 2

Comment 16.02:
I believe that this project started as a means to shut down the state's nuclear plants, but someone then realized that this would cause a major disruption in power production and GHG mitigation so fossil plants were included. Now there is the implication that AB32 renewables will save everything. That is pure pie in the sky analysis. There is no way that an intermittent, unreliable energy source can substitute for reliable 24/7 energy sources.
Response:
Comment noted. Staff never intended that the Policy would be used as a means to shut down nuclear power plants. The purpose of this policy is to implement Section 316(b), while ensuring grid reliability.

Comment 29.12:
The SED's cooling tower discussion highlights advancements in saltwater cooling technology; which unfortunately, is based on a Draft CEC study on cooling towers that is not yet available to the public. The SED also includes a list of facilities with saltwater cooling towers. None of the facilities are coastal nuclear facilities and the majority are not coastal sites. PG&E is very concerned about the issues raised by the potential installation of large scale saltwater towers at nuclear facilities, particularly those with limited options for cooling tower sitting. The significant potential for arcing on high voltage transmission systems that deliver electricity from power plants to the grid and also provide emergency auxiliary power from offsite sources is a serious concern. For nuclear facilities in particular, loss of transmission system integrity will result in reactor trips and exercise of nuclear safety systems. At Diablo Canyon, the 500 kV main bank

transmission systems would be vulnerable to extensive salt deposition with any cooling tower configuration, and the 230 kV auxiliary power systems would be significantly vulnerable with placement of saltwater towers north of the facility. An unreliable auxiliary or emergency power supply would essentially make operation of the facility unacceptable from a nuclear safety perspective. In addition to the arcing of high voltage systems, accelerated aging of plant equipment would also occur due to extensive saltwater induced corrosion. Given our significant concern over the inadequate evaluation of cooling tower feasibility, PG&E commissioned Enercon Services Inc. to perform a detailed feasibility study of the Diablo Canyon site.

Response:

Comment noted. The Draft CEC study on cooling towers is available to the public; however, the report has not been finalized. Staff appreciates the detailed feasibility study of the Diablo Canyon site. The concerns raised about the feasibility of installing cooling towers at the Diablo Canyon power plant is precisely the reason that an unbiased third party study to examine cost and feasibility will be required for nuclear OTC power plants as part of the Policy.

Comment 29.19:

The 2007 Tetra Tech study is cursory and not sufficiently detailed to provide a foundation to determine the feasibility of cooling tower retrofits at any of the OTC plants. No one from Tetra Tech visited the Diablo Canyon plant or talked to anyone at PG&E regarding the feasibility of retrofitting Diablo Canyon. It is quite clear that in most cases the real outcome would be retirements and repowers, rather than retrofits. While closed-cycle cooling may be BTA for a new facility, there is no evidence that it is BTA for all existing facilities. PG&E commissioned a more detailed study by Enercon Services, which concludes that retrofitting Diablo Canyon is a highly speculative project with likely insurmountable permitting obstacles, substantial engineering challenges, significant adverse environmental impacts, costs exceeding $4 billion dollars, and uncertainty regarding the post-retrofit operating capacity factors. The Diablo Canyon site is very geographically constrained, limiting the placement of cooling towers. The necessary configuration requires the excavation of over 2 million cubic yards of soil/rock, the demolition of over 170,000 square feet of existing buildings and parking areas, and major modifications to existing in-plant systems such as condensers, electrical systems, and service cooling water heat exchangers. The project's construction would take 45 months, with an outage of at least 17 months. Replacement power during this period would emit between 9-10 MMT of greenhouse gases. There are also significant permitting challenges. The necessary PM10 credits do not exist in the San Luis Obispo Air District. The plume would be over half a mile high roughly 35% of the year and visible from San Luis Obispo approximately 20% of the year. The warmer, saltier discharge would require installation of a diffuser in Patton Cove south of the plant. This would eliminate rocky reef habitat in the area and destroy the 33-year old control station for Diablo Canyon's biological monitoring program. The retrofit also raises a number of potential NRC safety concerns which would require formal review and approval through the license amendment process. These include an increased risk of flooding from the cooling tower water, accelerated aging due to salt deposition, security concerns due to opening of the protected area during construction, and rerouting of the Independent Spent Fuel Storage Installation haul road. The plant would be derated an average of 55 MW, with up to a 70 MW derate in the summer, causing the on-going emission of 164,000 MT per year of greenhouse gases from replacement power generation.

Response:

State Water Board staff believes that the Tetra Tech report has sufficient detail to serve its purpose, since staff does not know what specific measures individual facilities will take to comply with the proposed Policy. The SED is a programmatic document and each retrofit or re-powering project will need to comply with CEQA and various permitting requirements individually with project-level detail. The SED acknowledges that closed-cycle cooling may have a significant adverse effect on the environment, but also identifies available technology to mitigate these potential impacts. Staff does not believe that Diablo Canyon will need to shut down for one and a half years during construction of retrofit facilities. Rather power production would continue during construction and the facility would only shut down during the time needed to tie into the new cooling system (Please see Comment 30.02.) However, conflicting information regarding the nuclear OTC facilities ability to comply with the proposed Policy is precisely the reason that an unbiased third party study to examine cost and feasibility will be required for nuclear OTC power plants, as part of the Policy.

Comments 30.01 and 30.02:
The OTC water withdrawals from the two nuclear plants, at 2.5 BGD of seawater each, dominate power plant water withdrawals along California's coast. These two plants, 2,160 MW Diablo Canyon and 2,200 MW SONGS, account for approximately two-thirds of the OTC water utilized by all the State's OTC plants. However, retrofitting nuclear plants with cooling towers is technically straightforward and will not result in long outages. The entire cooling tower and piping construction process can take place while reactors continue to operate using OTC. A shutdown is only required to allow final tie-in of the cooling tower piping to the existing surface condensers at each reactor. The 2008 Jones & Stokes report states that properly scheduled conversion shutdowns, including those for nuclear plant conversions, should have no effect on overall grid reliability in the state. One US nuclear plant and several US coal-fired plants have been retrofitted to cooling towers. The hook-up of the new cooling system has generally been carried-out: 1) in four weeks or less with little or no downtime beyond the typical outage period, and/or 2) in non-summer months when power demand is low. In the case of Diablo Canyon and SONGS, each reactor is shut down for 30-40 days every two years or so for refueling. Longer outages of 100 days or more occur every 3-5 years. There are regular opportunities to plan the cooling tower tie-in with scheduled outages at Diablo Canyon and SONGS. Far more invasive and expensive retrofits are currently taking place at both Diablo Canyon and SONGS. Reactor steam boiler replacements have just been completed at Diablo Canyon and are underway at SONGS. The CPUC-approved cost of the boiler replacements is approximately $350 million per reactor. The four steam generators at Diablo Canyon Unit 2 were replaced in 2008 with a total outage time of 69 days. The work was done concurrently with a planned refueling outage. Since the containment building and original installation of the steam generators was not intended to provide for boiler replacement, a completely customized system was needed to remove them. In contrast, the connection of cooling tower piping is far simpler technically and is the only phase of the cooling tower retrofit that would require shutdown of the reactor.
Response:
Comment noted. Please see the response to Comment 29.19. Conflicting information regarding the nuclear OTC facilities ability to comply with the proposed Policy is the reason that an unbiased third party study to examine cost and feasibility will be required for nuclear OTC power plants as part of the Policy.

Comment 30.03:
Retrofitting the nuclear plants with cooling towers will not jeopardize nuclear safety in any way. No modification is required to the core components of the nuclear plant. Many U.S. nuclear plants already use wet cooling towers, and a number of these plants are equipped to switch between wet cooling towers and OTC. One US nuclear plant, 800 MW Palisades Nuclear in Michigan, has already been retrofit to closed-cycle cooling. NRC participants in the CEC's June 2007 workshop on California nuclear plants identified no nuclear safety requirements that would preclude retrofitting California's nuclear plants to cooling towers when questioned on this topic by CEC commissioners.
Response:

Comment noted. The proposed Policy includes an exception for the OTC nuclear power plants, if the NRC states it is needed for nuclear safety or other reasons.

Comment 30.04:
Retrofitting the nuclear plants with cooling towers is cost-effective and would have very little impact on the cost of power generated by these plants, on the order of a 2% increase. Dominion Nuclear's 2001 estimate for a conventional cooling tower retrofit on 1,130 MW Unit 3 at Millstone in Connecticut was $126 million. This is equivalent to approximately $160 million in mid-2009. Millstone Unit 3 is slightly bigger than the reactors at Diablo Canyon and SONGS. This cost is consistent with the cooling tower cost estimated for the reactors at Diablo Canyon and SONGS in June 2009 by the nation's largest power plant cooling tower manufacturer, SPX Cooling Technologies. SPX estimated a cost of approximately $155 million for a conventional cooling tower for each reactor and $230 million for a plume-abated tower that minimizes visible vapor plumes. PG&E's public comments that a cooling tower retrofit at Diablo Canyon would cost $4 to 4.5 billion is unsupported and contradicts available industry cost estimates. Diablo Canyon generates more than $2 billion per year in revenue for PG&E. The annualized cost of a cooling tower retrofit, assuming a plume-abated tower, would be on the order of $40 million per year. That is approximately 2% of the annual revenue generated by the plant.
Response:
Staff finds these comments interesting and recognizes that estimating retrofit costs can vary widely and are difficult to estimate. Evaluation of nuclear plant OTC compliance options will be further evaluated through the special studies, Review Committee and subsequent implementation determinations of the State Water Board.

Comment 30.06:
The conversion to cooling towers will have little impact on the efficiency of the nuclear plants. The overall energy penalty of a nuclear plant wet cooling tower retrofit is approximately 1 to 2%. USEPA cites a range of 1.2 to 1.5% total energy penalty depending on where the nuclear plant is located in the country. These estimates are thoroughly substantiated with technical support documentation developed for the Section 316(b) regulatory process.
Response:
Comment noted. Please see the responses to Comments 3.23 and 29.19.

Comment 30.07:
Particulate emissions from the cooling towers will have little or no impact on local air quality. Some solids are contained in the small amount of circulating water that is emitted from the cooling towers as fine mist, and has the potential to become airborne particulate. In San Luis Obispo County, where Diablo Canyon is located, these emissions can be offset by paving dirt roads. In San Diego County, where SONGS is located, cooling towers are exempt from air quality permit requirements. Use of reclaimed wastewater as cooling water, which is an option in the case of SONGS, would reduce particulate emissions due to the lower solids content of reclaimed water compared to seawater.
Response:
Comment noted. As stated in the policy, the State Water Board supports the use of reclaimed water in wet cooling towers when feasible. Please see the response to Comment 3.23.

Comment 37.08:
SCE believes that implementing closed-cycle cooling at SONGS, which SCE operates, is infeasible. A retrofit with a closed-cycle cooling system would face unparalleled and truly one-of-a kind engineering challenges, insuperable permitting obstacles, and adverse environmental impacts likely greater than those associated with OTC. The land use issue represents a

significant obstacle. The conversion to cooling towers would involve tunneling beneath Interstate 5, construction of six hybrid cooling towers, and the creation of hot- and cold-water reservoirs immediately adjacent to each unit's turbine building. The likelihood of obtaining the permitting necessary for the construction of cooling towers is questionable at best. The cooling towers would need to be relatively large, directly impacting at least 14 acres of land just for tower placement. Due to various space restraints, the cooling towers would have to be located east of Interstate 5, requiring the tunneling of 12-foot diameter re-circulating water pipes beneath Interstate 5. Additionally, new pumps would be needed to pass cooling water through the condenser and to pump circulating water from the hot water reservoir up to the cooling towers. It should be noted that operation of cooling towers at a nuclear power plant with such a large degree of elevation change between the cooling towers and the condenser is unprecedented, and additional engineering design would be required to ensure that public safety would not be compromised by the discharge of cooling water across the SONGS seawall during a loss-of-power event. Drift impacts due to the operation of cooling towers would be significant, producing annual PM10 emissions between 828 and 837 tons in a non-attainment area. A major-source Title V air permit would be required from the San Diego County Air Pollution Control District. It is unlikely that SONGS could locate and purchase a sufficient number of PM10 emission credits to cover these emissions. Salt would be deposited downwind of the cooling towers creating the need for significant additional maintenance requirements for the existing equipment and facilities and the potential for unplanned unit outages from electrical arcing in the switchyard, a potential safety hazard. Salt deposition could also cause adverse impacts to sensitive and protected vegetation and habitat. The conversion would result in an annual average loss of power generation of approximately 143 megawatts, which if replaced by a natural-gas powered generating facility, would emit an estimated additional 227,000 metric tons per year of CO_2. Various permits, including a Coastal Development Permit, would be required for the conversion of SONGS to closed-cycle cooling. All of these permits would be acquired in accordance with regulatory public participation requirements, which would likely incur intense public opposition due to project cost, adverse aesthetic/visual impacts, air emissions, traffic, and potential ecological impacts prohibited by various federal and state statutes and regulations. CPUC approval would also be required for recovery of the conversion cost from the ratepayers as well as for ongoing annual costs. Additionally, it should be noted that SCE does not own the land on which SONGS is located, and as such, all construction activities necessary for the conversion involving additional lands not now held under lease would need to be approved by the Department of the Navy. Failure to receive approval from any of these agencies would render the construction and operation of closed-cycle cooling at SONGS impossible.

Response:

Comment noted. Conflicting information regarding the nuclear OTC facilities ability to comply with the proposed Policy is precisely the reason that an unbiased third party study to examine cost and feasibility will be required for nuclear OTC power plants as part of the Policy.

Comment 37.13:

The NERA analysis assumes that it is feasible to switch to closed-cycle cooling at SONGS, ignoring the conclusion that insuperable physical, practical, and regulatory barriers make the installation of cooling towers at SONGS infeasible. It would be important to expand the cost-benefit assessment for SONGS to include evaluations of the costs and benefits of other technologies that could reduce impingement and entrainment.

Response:

Please see the responses to Comments 37.03 and 37.08.

Comment 37.20:

Nuclear facilities should be exempt from Policy standards that would essentially require wet cooling towers. We believe that this is the environmentally superior alternative. According to the ENVIRON Report, the construction and operation of cooling towers at SONGS could cause an array of significant environmental impacts associated with air quality, noise, biological resources, recreation, and water quality. The SED did not analyze or address any of these impacts. Moreover, because impingement and entrainment impacts have been mitigated to less than significant levels at SONGS in accordance with the facility's Coastal Commission permit, the Policy's adverse impacts would not be offset with a commensurate benefit. The SED does not discuss in much detail the potential environmental benefits if the nuclear facilities were exempted from the Policy, which might include less air emissions, less GHG emissions, less biological impacts, and less noise impacts than the Policy.

Response:

Staff believes that the SED adequately addressed the proposed Policy's environmental impacts associated with air quality, noise, biological resources, recreation, and water quality. Please see the responses to Comments 51.02 and 29.19.

b. The safety exception, and other special provisions for nuclear facilities

Comment 3.23:

Nuclear plants should not be exempted. The two nuclear plants, Diablo Canyon and San Onofre Nuclear Generating Station (SONGS), each use 2.5 BGD of seawater and account for nearly two-thirds of the OTC water used by the state's OTC power plants. The nuclear plants' impacts on the local marine ecosystem are therefore quite significant. For example, SONGS has destroyed over two hundred acres of kelp forest, which in turn has caused the displacement or death of thousands of individuals from numerous other species. In total it is estimated that the kelp fish population in the area has declined by 80%. The argument that SONGS has already mitigated environmental harm does not hold up because of the court ruling prohibiting mitigation as a substitute for compliance with Section 316(b).

Despite these clear harms from the nuclear plants, these facilities are given numerous exceptions in the proposed Policy: an exception for nuclear safety and an exception if special studies result in "alternative" recommendations. These exceptions are in addition to the Track 2 and Wholly Disproportionate exceptions, which are also available to the nuclear facilities. Although the safety of nuclear power plants should always be an important concern, in *Riverkeeper II* the court found that there was "adequate consideration by the USEPA of the nuclear plants concerns" and upheld that Section 316(b) does apply to nuclear facilities and that additional exceptions beyond safety were not required. Yet, leaving the compliance determination solely to the operator is inappropriate in providing a safety exception. The Nuclear Regulatory Commission (NRC), the State Water Board and the plant owner/operator should all be part of any safety exception in order to ensure accountability, and the decision and information leading to it should be made available to the public. The State Water Board should clarify in its final policy what information that is required for "appropriate documentation" to make any decision about safety and nuclear plant requirements under the policy. A formal recommendation or requirement from the NRC is an important and necessary part of any such safety consideration.

Response:

Staff agrees that both SONGS and Diablo Canyon have significant impacts on the local marine ecosystem due to the large volumes of cooling water that these plants withdraw, and staff is not proposing to exempt these plants from complying with the proposed Policy. However, staff also believes that it is appropriate to provide alternative requirements for these nuclear plants if compliance with Track 1 or Track 2 of the proposed Policy would result in a conflict with safety requirements established by the NRC for nuclear facilities. The proposed Policy explicitly states that owners/operators must provide "appropriate documentation or other substantiation" from the NRC in order to request a site-specific BTA determination from the State Water Board based on safety concerns. Any documentation considered by the State Water Board in making a site-specific BTA determination for a nuclear facility will be made available to the public. The public will be able to submit comments during the public process required to make such a site-specific BTA determination for a nuclear facility. Staff has not heard back from the NRC in response to inquiries on what type of documentation they would be able to provide, under what circumstances, and how long they need to reach a conclusion].

Based on public comment, State Water Board staff has decided to eliminate "WDD" option (please see the responses to Comments 7.06 and 29.10). The proposed Policy continues to give special consideration to the two nuclear-fueled facilities and three facilities with combined-cycle units due to their unique technology, but removes the potential burden placed on the Regional Water Boards and facility owners/operators in having to make the WDD.

Public comments have also persuaded State Water Board staff to allow power plant owners and operators the flexibility to choose between the Track 1 and 2 compliance alternatives without being required to demonstrate that Track 1 is infeasible (please see the responses to Comments 11.48 and 11.49). Track 2 will be available to all facilities as a compliance option.

Furthermore, because of conflicting information regarding the cost and feasibility of the nuclear facilities' ability to comply with the proposed Policy, staff believes that "special studies" conducted by an independent third party are needed in order to determine how the OTC nuclear power plants can reduce their entrainment and impingement impacts at reasonable cost without compromising public safety and affect grid reliability.

Comment 60.05:
We agree that compliance with the regulations by nuclear power plants needs to be deemed safe by the NRC. We also agree that it is the facility's burden to show, through some documentation by the NRC that compliance with the regulations would create a public safety hazard before any exceptions to the rule are considered. We also urge the Board to adopt a policy that, aside from the special consideration of public safety concerns, eliminates any special considerations or exemptions for the nuclear facilities.
Response:
Comment noted. Please see the response to Comment 3.23.

Comment 29.24:
Although the policy sets out a compliance exemption if compliance would cause a conflict with a nuclear safety requirement, the NRC does not have any existing process in place to provide such a determination. It is our understanding that the Water Board staff has not talked to the NRC about the form of approval necessary. In general, the NRC makes formal approvals or findings in conjunction with standard applications – such as a license amendment. Thus, in order to obtain any formal determination from the NRC, the nuclear plant operator would likely have to fully develop plans to install cooling towers and present these to the NRC as a license amendment. There is no process to receive a preliminary determination on a license amendment – the NRC would perform a full review. This undertaking would cost millions of dollars – and if the operator found in the early stages of design that the design would conflict with a safety requirement, they would not further pursue it. Without the operator pursuing the license amendment, the NRC would likely not provide a preliminary or advisory opinion as to whether the proposal would conflict with a safety requirement. The bottom line is that this

"exemption" does not provide a realistic compliance exemption as no plant would undertake the level of work that would be necessary to obtain a license amendment denial. In most cases, if enough money is spent, safety issues could likely be engineered away with additional modifications. The real question is how efficiently the plant would operate after a retrofit. When making the level of modifications necessary to implement a retrofit – the primary concern is that the plant will not operate anywhere near its current 95-100% capacity factor after installation.
Response:
Comment noted. Staff has contacted NRC for further information but has not received any response.

Comment 29.04:
We are pleased to see that the draft policy addresses the unique contribution of the state's nuclear plants. These baseload plants provide roughly 12% of the state's electric generation – Diablo Canyon provides 22% of PG&E's power needs – and do so efficiently and without greenhouse gas or criteria pollutant emissions. They also represent tremendous capital investments for the state's ratepayers. PG&E strongly supports the inclusion of a cost-benefit variance in the policy. While there is certainly a need to develop many details regarding the scope and implementation of the variance, we believe that acknowledging the need to balance the costs and benefits of compliance is central to establishing a workable policy.
Response:
Comment noted. Please see the responses to Comment 7.06 and 29.10.

c. Special studies

Comment 3.24:
Special studies on nuclear plants should be conducted by a third party and peer reviewed. The Draft Policy calls for special studies to "investigate alternatives" for the nuclear plants to meet the requirements of this policy and calls for a review committee to oversee the special studies and to provide a report for public comment detailing the results of the studies within three years of the effective date of the policy. Other than for safety reasons, we disagree with the general notion that nuclear facilities should be given another special exception to the policy or from the requirements to achieve BTA. Rather, the only purpose of this special study should be to determine *how* nuclear facilities will achieve either Track 1 or Track 2 (not "alternatives" to those provisions), and the policy language should be clarified accordingly. In that vein alone, we would support the inclusion of a review committee and ask that the State Water Board clarify that the review committee will also be involved in setting the parameters for the third party study before it begins. Further, we urge the State Water Board to ensure that all studies included in the decision making process are peer-reviewed.
Response:
Comment noted. Staff agrees that the special studies for the nuclear-fueled facilities should be conducted by an independent third party. The proposed Policy states that the special studies on nuclear-fueled facilities shall be conducted by an independent third party, and overseen by a Review Committee. Please see response to Comment 3.23.

Comment 4.13:
The Draft Policy requires "special studies" to investigate alternatives for nuclear plants to meet the requirements of the Draft Policy. SONGS, in particular, was already subjected to such studies by the CCC, which stretched over a decade and included many public hearings, and resulted in a decision by the CCC that the cost and environmental impact of cooling towers at SONGS were not warranted compared to restoration and mitigation options designed by the CCC. Utility ratepayers have already paid for these studies in addition to the mitigation

measures, and they should not be required to fund the same studies and mitigations allover again.

Response:

Previous studies did not consider how the nuclear power plants can feasibly comply with the proposed Policy (including the Track 2 compliance alternative) since the Policy was not adopted at that time; however the results and data collected by previous studies will be considered by the Review Committee and may well influence the scope of the special studies.

Comment 29.09:

In general, PG&E supports the Board's approach of ensuring a more detailed, thorough investigation of alternatives to OTC at the nuclear plants. The plants have the ability to provide electricity for years to come – playing a pivotal role in ensuring that the state meet its AB 32 goals of GHG emission reductions and providing a key foundation to greater reliance on renewable resources. Further, the retrofitting of a nuclear plant is an extraordinarily complex, site-specific undertaking which warrants extensive evaluation. PG&E has continued to look at a variety of alternatives to once through cooling at Diablo Canyon – from its design phase in the 1970s to more recent efforts including the review of options in 2000 as part of our updated Section 316(b) Demonstration Study prepared by Tenera with oversight by the Central Coast Regional Water Board's Technical Work Group, a study by Burns Engineering in 2003, and a more detailed study of cooling tower feasibility by Enercon in 2009. As a first step to any further review of feasibility, the latest report prepared by Enercon for PG&E, as well as the report developed by SCE for the SONGS facility, should be reviewed by the Water Board's proposed nuclear review group. There is likely no need to initiate yet another study of cooling tower feasibility. These existing studies should be peer reviewed, perhaps by EPRI or another qualified consultant, before any additional studies are commissioned.

Response:

Staff appreciates the support for the special studies. Because previous studies did not consider how the nuclear power plants can feasibly comply with the entire proposed Policy (including the Track 2 compliance alternative), more studies may be needed. However the results and data collected by previous studies will be considered by the Review Committee in determining the need for and scope of the special studies. Review of the existing studies will likely be part of the hired consultant's work.

Comment 29.25:

If additional studies are required, PG&E strongly recommends that the independent consultant be selected with input from members of the nuclear review committee. It is absolutely critical that the consultant have significant nuclear engineering expertise. To date, the various reports prepared for the Water Board on cooling tower feasibility and grid stability have proven to be superficial at best – and clearly insufficient to provide a strong foundation for policy choices.

Response:

Please see the response to Comment 29.19 regarding previous reports prepared for the State Water Board on cooling tower feasibility and grid stability. Staff disagrees that these reports are insufficient to provide a solid foundation for the proposed Policy. However, staff agrees that it is critical that the selected independent consultant for the special studies have nuclear engineering expertise. The proposed Policy specifies that the Executive Director of the State Water Board will select the consultant conducting the special studies, but this does not in any way preclude input from the Review Committee.

Comment 30.05:

The proposed study of nuclear plant retrofits should be independent of the utilities and TetraTech. Both have stated indefensibly high costs for nuclear plant cooling tower retrofits. The difference in cost estimates for cooling tower retrofits at Diablo Canyon and SONGS is driven by faulty assumptions on the need to demolish existing onsite structures, outage duration, and contingency costs. The 2008 TetraTech Report estimated approximately the same cost as SPX, $150 million per reactor, for conventional cooling towers at Diablo Canyon. However, in the case of Diablo Canyon, the TetraTech cost estimate also includes $300 million per reactor for demolition of existing onsite structures, undefined indirect costs, and 30% contingency. In addition, TetraTech assumes an 8-month outage for the cooling tower tie-in, at an estimated lost revenue cost of over $350 million per reactor. All of these additional costs are avoidable if better locations are chosen for the cooling towers and a realistic tie-in outage time is assumed. For example, TetraTech assumes a 4-week tie-in outage for the 700 MW units at Moss Landing. This is a reasonable assumption. An 8-month outage at Diablo Canyon for the same type of tie-in is not reasonable. The TetraTech cost estimate for SONGS, at approximately $230 million per reactor for a plume-abated cooling tower (without the 30% contingency), is the same as the SPX estimate. However, again without supporting justification, TetraTech assumes a 6-month outage to tie-in each cooling tower which results in $300 million in lost power generation revenues per reactor.

Response:

Please see the responses to Comments 3.24.

Comment 37.07:

The State Water Board should revise the "special study" provision. Section 3(D) of the Policy requires the Board to request special studies from SCE and PG&E investigating alternatives for the nuclear-fueled power plants to meet the Policy's requirements. The Board must "consider" the study results in evaluating whether to modify the requirements for nuclear-fueled power plants. SCE recommends that instead of requiring additional studies, the Policy require the Board to examine first all independent studies performed by other regulatory agencies and any Comprehensive Demonstration Study ordered by Regional Water Boards. The Board should request additional studies only if it concludes the existing studies contain insufficient information regarding alternatives for the nuclear-fueled power plants to comply with the Policy's intent, (including the costs for these alternatives).

Response:

Please see the response to Comment 4.13.

Comment 37.29:

The State Water Board should consider an alternative that would require that grid stability thresholds are achieved before Policy deadlines initiate for the nuclear facilities. This alternative would be limited to the nuclear facilities, given their disproportionate importance for providing base load generation and securing grid reliability. This alternative would avoid the potentially significant grid reliability issues identified in the ENVIRON Report and may temporarily or permanently reduce the Policy's air quality, GHG, and other significant environmental impacts.

Response:

Special provisions governing compliance alternatives for the nuclear fueled facilities are included in order to take in account their differing circumstances as well as importance for grid reliability**.** The State Water Board will consider the need to modify the Policy with respect to the nuclear facility after the requisite studies are completed.

Comment 60.05(a):

We strongly urge the Board to remove any reference to cost considerations in section 3(D). Arguably, "cost" is less of a concern for the nuclear facilities than other generators. We strongly support the clarification that "cost" is not a factor in defining "feasibility" under Track 2. However, there is a conflict created by allowing "cost" as a factor to be considered for nuclear facilities. We recommend eliminating the conflicting rules by eliminating cost as a factor for the nuclear facilities to create an even playing field and consistent application of the policy and regulations.

Response:

Staff has received many conflicting comments regarding the feasibility and costs of compliance for the nuclear OTC power plants. Some public comments stated that compliance costs far exceed the estimates provided in previous reports and the draft SED, if feasible at all. Staff believes that there is a need for the special studies to independently investigate the feasibility and cost of the OTC nuclear-fueled facilities complying with the proposed Policy. If it is not possible for these facilities to meet Policy requirements, or if the compliance costs are astronomical for the rate payers, the State Water Board will consider setting a site-specific BTA for one or both facilities. Staff does not see any conflict with considering costs under section 3(D).

d. The Review Committee

Comment 15.06(b):

The planned inclusion of “the environmental community” in the Review Committee is appreciated, but too vague. It would be more correct to recognize that there are certain environmental stakeholders who have long concerned themselves with the environmental damage from power plants and nuclear plants. It is to be hoped that their voice will be welcomed, particularly in view of the fact that this very attempt at creating a better policy is due, at least in part, to their dedicated participation.

Response:

Staff recognizes that there are many dedicated environmental stakeholders with expertise that would be willing to serve on the Review Committee. It will be difficult to choose between the candidates; however, the selection is left to the discretion of the Executive Director of the State Water Board. Because the meetings of the Review Committee is open to the public, it is hoped that many from the environmental community will be able to lend their voices and talents to the process to ensure successful implementation of the Policy, even if not directly serving on the Review Committee itself. Other stakeholders are also invited to participate.

Comment 29.26:

The proposed policy defines the Review Committee membership, at a minimum, as a representative from each operator, the Water Board, the Central Coast and San Diego Regional Water Boards, the environmental community, and the SACCWIS. PG&E strongly recommends that the membership include a representative from the CPUC, the CEC, and the CAISO. Representation from the Energy Agencies will ensure that grid reliability and stability -along with ratepayer considerations - continue to play a predominant role in assessing alternatives to once through cooling for the nuclear plants.

Response:

Comment noted. The selection of representatives from SACCWIS is left to the discretion of the Executive Director of the State Water Board.

Comment 43.05:

Under Section 3.D., we suggest that the composition of the "review committee" that will oversee the special studies be expanded to include two or more independent scientific experts.

Response:

The special studies themselves will be conducted by an independent third party with scientific expertise available. In addition, the Review Committee is free to consult with other scientific experts if needed. Staff therefore does not believe that the review Committee should be expanded to include two or more independent scientific experts. It is preferable to keep the Review Committee at a workable size.

4. Alternative requirements for low capacity utilization facilities

Comment 12.09:
The SED does not fully consider the importance of low capacity factor units to grid reliability and achievement of California's renewable portfolio targets.
Response:
See response 11.34.

Comment 23.04:
In the Tracks I and 2 compliance framework, the Draft Policy omits the 15% threshold exemption that had been included in both the USEPA's Phase II rule and the State Water Board's 2006 draft policy. The Phase II Rule exempted those facilities with a capacity utilization rate of 15% or less from the requirement to meet the entrainment performance standard. USEPA provided a clear justification for the exemption in the preamble to the Phase II Rule, finding that (1) entrainment control technologies were not economically practicable given the already-low operating levels of these facilities; (2) these facilities tended to operate during those peaking periods when the abundance of entrainable life stages of aquatic species was relatively low; and (3) given the proportional relationship between intake flows and entrainment, these facilities had already achieved substantial entrainment reductions from design flows. The Draft Policy arbitrarily dispenses with the 15% threshold without offering any support or rationale. For facilities like Mirant's Delta Plants, which consistently operate at capacity utilization rates in the low single digits, it would be both impracticable and unjustified for them to be required to retrofit to closed-cycle cooling. Entrainment at Mirant's Delta Plants has already been reduced by over 90% from design flows due to their decreased operations. The Draft Policy would nonetheless force these facilities to retrofit to closed-cycle cooling or shut down, imposing a disproportionate economic burden relative to facilities that operate at much higher capacity utilization rates. Accordingly, the State Water Board should revise the Draft Policy to include a compliance exemption for units that operate at less than a 15% capacity utilization rate.
Response:
Please see the response to Comment 61.20.

Comment 31.13:
The State Water Board should establish a reasonable BTA for all facilities or provide a specific exclusion for low-capacity factor units. Track 1 and Track 2 of the Draft Policy should be replaced with a single standard that defines the BTA to be any technology, or combination of technologies and operating conditions, that allows a facility to achieve an 80% reduction from a facility's annual intake design flow (provided that any facility could demonstrate an alternate BTA for site-specific reasons). Adopting this BTA standard will give credit for technological and operational conditions that already exist at an individual facility, such as operating at low-capacity factors for the steam units. More importantly, it would allow the facilities to install equipment other than cooling towers, such as variable speed pumps, to achieve the 80% reduction. Establishing this reasonable BTA standard would achieve the goal of minimizing the adverse impacts and mitigating the damage to California's coastal waters from the use of once through cooling without threatening the reliability of the electric grid. Adopting this threshold would also avoid imposing billions of dollars in unnecessary costs on the citizens of California. Should the State Water Board decline to adopt this standard, RRI believes it is necessary to give low-capacity factor units an explicit compliance alternative to the Track 1 or Track 2 threshold in the Draft Policy.
Response:
CWA Section 316(b) requires that the location, design, construction and capacity of cooling water intake structures reflect the best technology available for minimizing adverse environmental impact. State Water Board staff believes that closed-cycle wet cooling or commensurate reductions represent the best technology available, based upon factors explained and set forth in the SED. Track 2 allows for flexibility in using different technologies to meet the requirements set forth in the Policy.

Comment 34.03:
Concur with Staff Alternative 2: Make no distinction based on capacity utilization.
Response:
Comment noted.

Comment 61.20:
SED, pg. 51, Discussion: This argument also seems to be based on the fact that the concentration of organisms in the source water is not constant throughout the year. This was thoroughly discussed by the Expert Panel. The panel was in general agreement that the policy should focus on the plants that withdraw large volumes of seawater and have high CUR. We also discussed having smaller capacity units calculate CUR using a seasonally weighted average that would account for regional variation in ichthyoplankton abundance. The Panel also agreed that there were enough entrainment data statewide to allow calculation of a seasonally adjusted CUR. This would allow more flexibility for operating plants that are only used during periods of peak demand. Since these plants only operate a small percentage of the time (and this was thoroughly discussed by the Expert Panel) it is not clear how the draft policy could make the statement that these plants do not "cause appreciably less harm than a high capacity facility." This statement is contradicted on pg. 56 of the document which states "that the number of organisms entrained is more or less proportional to the water volume withdrawn through the intake structure ... " By adopting this approach the policy places the greatest burden on the least efficient units that are the least able to justify retrofitting and have the lowest levels of impingement and entrainment due to their limited CUR.
Response:
The concentration of organisms in most source water bodies is not constant throughout the year, as supported by the findings of the ERP. There are relatively more ichthyoplankton (> 1 larvae/m3) along the southern open coast during April and June-August and there are relatively

more ichthyoplankton (> 3 larvae/m3) during the spring and summer in southern embayments. Further north, there are relatively more ichthyoplankton (> 1 larvae/m3) along the open coast during mid-spring, and in embayments from late winter to early spring. OTC during these periods would have more of entrainment per MGD than during other periods.
The statement referred to on page 51 of the draft SED ("cause appreciably less harm than a high capacity facility") is correct in the following context. Given the same flow rates per day, a plant with a lower CUR withdrawing water during periods of peak ichthyoplankton concentrations would have a greater entrainment impact per day than a plant with a higher CUR withdrawing water during a period of low icthyoplankton concentrations. Also, very importantly, plants with lower CURs may still have significant flow rates (non-generational flow), i.e. CUR is not necessarily an indicator of lower flow rates. For example Scattergood, with higher CUR (25% for period 2000-2005, and 21% for 2006) has a lower average flow of 309 MGD than Ormond (CUR of 22% for period 2000-2005, and 6% for 2006) with 521 MGD.
The statement referred to on page 56 of the draft SED was incompletely quoted. It states in its entirety: “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 <u>during a limited time period</u>.” Staff stands by that statement, which is generally supported by the ERP findings.
With regard to plants that currently have low CUR the ERP stated, “It is not clear that these plants could continue to operate if actual flow were used.” Also with regard to using actual flows the ERP stated that it “may not be considered fair for plants that have recently reduced flows” and “may decrease state-wide generating capacity during peak demand as plants already at very low capacity may not be able to operate.” With regard to design flows, the ERP stated “using design flows reflects potential entrainment and impingement.” Since staff is recommending the calculation of reductions for BTA from the design flows (based in part upon the ERP’s findings), and not actual flows, those low CUR facilities would only need to control entrainment by a smaller increment than if compliance were based on actual flows. Therefore staff decided not to recommend an exemption based on capacity utilization rate (CUR).

Finally, plants that currently are at low CUR often have higher permitted flows (close to or at their design capacity) and most current permits do not prevent these plants from increasing their CUR and therefore their flows. The policy would result in Regional Water Boards placing a permit limit on flows/entrainment, thereby ensuring compliance with the entrainment reduction targets in the policy.

Comment 31.32:
The Policy should recognize that facilities with low utilization rates inherently have reduced total flow and hence reduced IM/E impacts. The Policy should allow such facilities to take credit for the reduced IM/E impacts as a result of their current and projected operating rates. Appropriate conditions could be placed in a facility's NPDES permit to ensure the reduced IM/E impacts are maintained. The SED dismisses Alternative 1, which would establish an alternative requirement for low capacity factor units, with the non-sequitar 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. While that may be true, it is specious reasoning to then leap to the conclusion that a low capacity factor unit could have greater impact than one that operates base-loaded.
Response:
Please see the response to Comment 61.20.

5. Addressing desalination facilities

Comment 1.12:

The Policy does not fully consider the potential reduced environmental impacts of co-located desalination and power generating facilities. While AES·SL agrees that it is more appropriate to establish compliance requirements for desalination facilities in a separate policy, we are concerned that the proposed Policy may not allow a power plant to use the intake flow from a legally permitted and constructed desalination facility for cooling purposes, even if it resulted in no incremental impacts to the marine environment. Desalination plants operate nearly constantly and could provide cooling water to a co-located power plant, and not a single additional organism would be entrained or impinged. Co-location would prevent the unnecessary added environmental impacts of the closed-cycle cooling system such as reduced efficiency, more greenhouse gas emissions and criteria pollutants, and the visual impact of the wet or dry cooling system. We recommend modifying Track 1 to make it clear that if an OTC power plant is a secondary user of water required by a legally permitted and constructed primary user (provided the primary user is not also a power plant), then the power plant is in full compliance with the Policy.

Response:

The commenter is correct that the Draft Policy does not directly address the situation where an existing power plant uses the already filtered discharge flows from a desalination facility (or other primary user) for some, or all, of its cooling needs. However, this would be permissible under either Track 1 or 2, provided the required reductions in IM/E are met. In essence, the power plant would recycle the discharge from another user. Staff agrees that using the filtered discharge from desalination plants for power plant cooling would result in less overall impact to the marine environment from IM/E than if both the desalination plant and the power plant used separate intakes.

Note that the State Water Board plans to address desalination intakes and discharges through a separate policy action in the near future, as there currently are no state or federal regulations that specifically apply to desalination intakes. Section 316(b) specifically applies to cooling water intake structures, and federal regulations governing new facilities are inapplicable to those facilities using less than 25% of intake water for cooling purposes. While any new desalination facility using a seawater intake must demonstrate compliance with Cal. Wat. Code §13142.5(b), such facilities present issues distinct from those affecting power plants.

Comment 10.01:

While we greatly appreciate the efforts to further the ocean protection goals underlying the draft OTC Policy, any action taken to establish or affirm interpretation of BTA for power plants will be rendered meaningless if ocean desalination facilities are allowed to co-locate with open ocean intake structures currently associated with power plants. It boggles the mind to imagine that after decades of work to reach a point where the devastating impacts of OTC are on the verge of being addressed, an entirely new industry *with exactly the same impacts as OTC* would be allowed to proliferate almost within the same footprints of the very plants we are seeking to now address. The quantities of source water to be taken in for desalination are as boundless as our thirst for fresh water, and as such, it would be an absolute travesty to pass a policy that does not address on a meaningful level the absurdity of allowing desalination facilities to piggy-back on outgoing OTC technologies. The Policy should be supplemented to include the following restrictions: (1) No seawater desalination facility shall be approved co-located with a OTC power plant unless it is shown by the applicant that, upon cessation of the need for OTC infrastructure for energy generation, alternative seawater intake structures (i.e. sub-seafloor) would be viable at the facility's optimum freshwater production design requirements; (2) BTA for seawater intake for desalination is sub-surface; (3) New desalination facilities should be sized appropriately and located in areas of the state where sub-seafloor intakes are viable. The analysis of BTA in the *Riverkeeper II* decision is analogous to establishment of BTA for desalination facilities under

Water Code section 13142.5(b), meaning that because the standard is technology driven, consideration of environmental impacts is not required prior to establishment of appropriate technological requirements.

Response:

Comment noted. As stated in the SED, the State Water Board plans to address the intakes and discharges from desalination facilities through a separate policy action in the near future, as there currently are no state or federal regulations that specifically apply to desalination intakes. Section 316(b) specifically applies to cooling water intake structures, and federal regulations governing new facilities are inapplicable to those facilities using less than 25% of intake water for cooling purposes. While any new desalination facility using a seawater intake must demonstrate compliance with Cal. Wat. Code §13142.5(b), such facilities present issues distinct from those affecting power plants. Thus, the State Water Board does not propose including requirements for desalination facilities in the proposed Policy.

Comment 11.27:

The SED does not evaluate the impacts of the proposed Policy on desalinization plants in California, including the resulting diminished freshwater resources. This approach fails to recognize that many of the current and planned desalinization plants are co-located at OTC power plants and use a portion of the same saltwater that passes through the power plant. Nor does the current document assess and quantify the potential significant adverse impact of the loss of freshwater resources to coastal communities that desalinization plants do or could provide and which may be lost if the Policy is adopted, as proposed. Alternatively, if the Staff chooses to conclude there would be no impacts to current or planned desalinization plants, then Staff needs to establish the ongoing impacts to marine resources from the use of saltwater resources to "feed" the desalinization plants. Seven desalination plants have been proposed to be co-located at California OTC power plants, which would use the power plant's seawater intake and outfall. It is anticipated that these desalination facilities will provide a minimum of 183 MGD of freshwater. Given the difficulty of permitting coastal industrial uses, it is unclear that these desalination plants would be able to secure the necessary approvals and build any necessary infrastructure to continue providing an uninterrupted supply of freshwater to local communities. The assessment of these impacts needs to be part of any legally sufficient SED.

Response:

The draft SED in Section 3.5 clearly states that the proposed Policy will not address desalination facilities. As stated in the SED, the State Water Board plans to address the intakes and discharges from desalination facilities through a separate policy action in the near future, as there currently are no state or federal regulations that specifically apply to desalination intakes. Section 316(b) specifically applies to cooling water intake structures, and federal regulations governing new facilities are inapplicable to those facilities using less than 25% of intake water for cooling purposes. While any new desalination facility using a seawater intake must demonstrate compliance with Cal. Wat. Code §13142.5(b), such facilities present issues distinct from those affecting power plants. Thus, the State Water Board does not propose including requirements for desalination facilities in the proposed Policy.

Comment 32.03:

The State Water Board should develop a policy on co-located and independent desalination plants. In light of current and prospective plans to build desalination plants throughout the state, and the real possibility that desalination plant flows will exceed power plant flows, the State Water Board must act now to develop and implement a policy concerning these facilities. The State Water Board will soon find itself in the same predicament it is facing with existing power plants in the difficulty in implementing a technology-forcing statute once a desalination facility has already been built. The largest desalination plant in the Western Hemisphere is moving forward in the City of Carlsbad, recently approved by the San Diego Regional Water Board in a fragmented approval process, which set a terrible precedent for future Regional Water Boards. In order to prevent proliferation of this process while a state-wide desalination policy is developed, the State Water Board should: (1) Preclude permitting of co-located desalination plants if they would perpetuate OTC longer than the expected lifetime of the power plant; (2) Apply a new facility BTA test under Section 316(b) to the desalination plant intake in so far it proposes to co-locate with an OTC power plant; or (3) Apply a Water Code Section 13142.5(b) BTA test that assumes baseline operating conditions for a co-located power plant are zero flow from the power plant.

Response:

Staff appreciates the suggestions. Please see the response to Comment 10.01.

6. Best Technology Available (BTA) for existing power plants

a. Closed-cycle dry cooling should be set as BTA

Comment 10.02:

Dry Cooling should be considered BTA. The Draft Policy and SED fail to provide sufficient analysis and rationale for establishing closed cycle wet cooling as appropriate BTA for energy generation. The genesis for establishment of closed cycle wet cooling as BTA rests with USEPA's assertion that 316(b) only applies to facilities that utilize cooling water intake structures, and because a dry-cooled plant would not require an intake structure, Congress could not have contemplated elimination of intake structures altogether without saying so in the statute. This rationale fails to take into consideration Water Code section 13142.5. If regulators first apply section 316(b)'s plain meaning, California's existing OTC power plants do not meet BTA (regardless of whether BTA is closed cycle wet or dry cooling). Therefore, the OTC plants must be significantly retrofitted or entirely repowered. In either of these scenarios, State law can be interpreted to mandate dry-cooling as BTA. Water Code section 13142.5 (annotated) states: For each [1] new or expanded coastal power plant or [2] other industrial installation using seawater for cooling, heating, or industrial processing -- 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. Therefore, once the Section 316(b) analysis requires an essentially *new* coastal power plant to be built, State law requires that best available technology (BAT) be used to minimize intake and mortality of marine life. The statute is not drafted such that the BAT can only include cooling water intake structures. So, while a straightforward reading of Section 316(b) might require closed cycle wet cooling, once construction of a new plant is triggered, Water Code section 13142.5(b) requires dry cooling as BAT.

Response:

Courts have considered the argument that dry cooling represents a greater reduction in adverse environmental impacts than closed cycle wet cooling, but have concluded that cost and efficiency factors are appropriately considered when establishing BTA as closed-cycle cooling. (*Riverkeeper I*, 358 F.3d at 195). The State Water Board considered feasibility, cost-effectiveness, and other environmental effects in concluding that the loss of efficiency and greater cost relative to incremental improvements did not justify mandating dry cooling as BTA. Although the commenter argues that Section 316(b) mandates construction of essentially new or expanded power plants subject to Water Code § 13142.5(b), the argument fails to establish that only dry cooling meets the requirements of Section 316(b).

Comment 13.05:

The State Water Board should define air cooling as BTA for the State. We now know that, in virtually all applications, the best off-the-shelf cooling system with respect to water resources on the whole is air or dry cooling. Air cooling can be further enhanced by pre-cooling' or chilling units for the air intakes which is being done to combined-cycle plants in our region. If these units are solar-powered, the impact of the system is reduced even further. This should be the BAT standard for existing power plants.

Response:

Please see the response to Comment 10.02.

Comment 14.06:

The Policy erroneously sets closed-cycle cooling as BTA without providing adequate justification for its decision. The Policy must clarify why it has made this decision even though dry cooling has been demonstrated as superior technology.

Response:

Please see the response to Comment 10.02. As noted, courts have stated that an agency may consider matters of cost and efficiency in determining that dry cooling is not required for BTA. The State Water Board considered both cost, cost-effectiveness, other environmental effects and implementation issues in determining that closed-cycle cooling or equivalent constitutes BTA for coastal power plants in California. This analysis is set forth in the SED.

Comment 31.57:

The statement that a facility owner should look to eliminate OTC through repowering needs comment. Repowering means tearing down the old steam boiler facility and replacing it with a new facility. That is not a technology available to minimize adverse environmental impact from an existing facility, it is an economic decision to build a new facility. Taking a law that governs cooling water intakes for existing facilities and forcing the owners to comply by tearing down that facility and building a new one can only be described as Orwellian. It certainly will not attract investment to California, nor will it improve the aquatic environment or lower air emissions. It will increase costs and threaten reliability.

Response:

Please note that the purpose and intent of the Policy is to implement CWA Section 316(b) and to establish BTA for cooling water intake structures at existing coastal and estuarine power plants to reduce IM/E impacts to acceptable levels. The intent is not to force OTC power plants to repower. The proposed Policy provides the Track 1 and Track 2 compliance alternatives to choose between, and the SED offers several examples of how to meet the Policy requirements. Clearly, repowering of all, or some, power-generating units at a power plant may be a compliance option for some owners/operators, but that will be based strictly on business decisions by the owners/operators of those plants, and is in no way required by the Policy.

Comment 34.04:

We disagree that wet cooling is the BTA for Alternative 1; instead it should be dry-cooling. Dry cooling reduces impingement and entrainment losses to zero.

Response:

BTA for retrofits is closed cycle wet cooling (cooling towers). If a plant decides to re-power, which is very likely for most of the fossil fuel steam boilers, closed cycle dry cooling is BTA. To the extent that the commenter contends that dry cooling should represent BTA for all facilities, please see Response No. 10.02.

Comment 34.06:

The alternatives presented are based on Track I using wet cooling as the BTA. Impingement and entrainment is reduced based on the flow reduction of the water body of concern. On the other hand if the cooling water is recycled water then the flow reduction would be 100%; likewise, if Track I requires dry cooling.

Response:

Comment noted.

b. Closed-cycle (wet or dry) cooling should be set as BTA

Comments 3.07 and 26.05:

The Policy should set closed-cycle cooling as BTA, as in the 2008 Draft Policy. Under that language, a plant could choose to either retrofit or repower to closed-cycle wet or air cooling. As the court articulated in *Riverkeeper, Inc. v. U.S. EPA*, 475 F.3d 83 (2d Cir. 2007) *("Riverkeeper II"),* Section 316(b) of the CWA does not allow "second best" technology to the best technology available requirement. As currently written, the Draft Policy sets closed-cycle wet cooling as BTA and does not mention that in some cases closed-cycle air cooling could be the better option. Further, the Draft SED does not provide a complete analysis of why dry cooling was rejected as BTA, nor does it provide a complete analysis of why Track 1 alone (without Track 2) was rejected as the best alternative. This latter point is particularly important given the State Water Board's previous acknowledgement that the type of alternative technologies available under Track 2 to meet the required reduction in entrainment are unproven.

Response:

Track 1 would require a reduction in intake flow rate at each unit, at a minimum, to a level commensurate with that which can be attained by a closed-cycle wet cooling system, which is a 93% reduction in flow. Since dry cooling would have zero flow, that 100% reduction in flow would meet the requirement. Therefore closed cycle dry cooling would comply with Track 1 if applied to all of the units at a plant (or in combination with closed cycle wet cooling for all of the units at a plant).

Comment 18.04:

Congress intentionally drafted Section 316(b) in 1972 to force improvements in technology by requiring BTA to minimize adverse impacts. Although industry has raised concerns about the costs of shifting away from OTC, the State Water Board and Ocean Protection Council have conducted studies that find a transition to closed-cycle cooling technically feasible for most coastal power plants in California, even at the largest OTC plants, SONGS and Diablo Canyon. In reality, most of the coastal generators would likely repower to transition away from OTC. Long Beach Generating Station transitioned to dry cooling in 2007 through repowering and El Segundo Generating Station submitted a permit request to the CEC to repower two of its OTC units to dry cooling. Both of these plants have relatively limited space, but have demonstrated that repowering to dry cooling is a feasible, efficient option. These studies and examples should be used as guiding information to shape the final policy, and we urge the State Water Board to define BTA as closed-cycle cooling. We further urge the State Water Board to ensure that cost considerations are not given an upper-head over technological considerations in compliance with the final policy.

Response:

The State Water Board considered many factors in determining that closed-cycle cooling (or commensurate reductions in impingement and entrainment) constitutes BTA for coastal power plants currently using OTC. Although studies have attempted to address feasibility of alternatives to OTC at the nuclear power stations, the additional information needed includes factors that include cost, reliability of existing studies, safety and licensing issues, and importance to the electrical grid. Cost is only one factor.

Comment 19.02:

Track 1 of the draft policy proposes technology-based requirements to significantly reduce impingement and entrainment impacts, presumably via a shift from OTC to closed-cycle wet cooling. Although closed-cycle wet cooling would reduce these impacts by an estimated 93% compared to OTC, it appears that dry cooling would be even more effective. We believe that the proposed policy should discuss the rationale for designating closed-cycle wet cooling as BTA. We also would recommend that the draft policy contain provisions for implementation of dry cooling where circumstances warrant this approach (e.g., for a re-powered facility).

Response:

Please see the responses to Comments 10.02 and 31.13. The Policy and the SED has been modified to clarify that closed-cycle dry cooling may be used to meet Track 1 or Track 2 requirements.

c. The BTA should include a site-specific approach

Comment 4.08:

Instead of defining closed-cycle cooling as BTA, the State Water Board should adopt cost beneficial performance standards; i.e., technology and in-plant operational solutions that do not result in significant adverse environmental impacts and costs that are wholly disproportionate to the environmental benefit gained. Such technologies could include fish handling and return systems; fine mesh traveling screens; redesigned intake structures with fine mesh, handling and return systems; fish barrier nets; relocation of cooling water intake structures; velocity caps; and other technologies to reduce impingement and entrainment that are functional and technically appropriate at each location. To the extent that these BTA performance standards do not sufficiently minimize marine impacts, or an exception is granted, the State Water Board may direct Regional Water Boards to require mitigation measures commensurate with those actual impacts, such as by restoration of coastal wetlands. Facilities should be given the opportunity to invest in local or statewide funds designed to restore coastal wetlands and engage in other activities that benefit the coastal environment. Subsequent cost benefit analysis should fully account for the environmental benefit achieved by such mitigation when assessing if costs are wholly disproportionate. This approach is consistent with the application of BPJ, which CCEEB believes is possible with the development and support of a well thought-out guidance document for use by the various Regional Water Boards. A guidance document would ensure consistency in the site-specific selection of control technologies and mitigation measures throughout the state. Proceeding in this manner allows the Board to adopt a Policy that is protective and supportive of marine resources while mindful of economic resources that are required for other beneficial improvements in the overall performance of our electrical infrastructure. It also avoids the known significant adverse environmental impacts of closed-cycle cooling, both wet and dry.

Response:

Staff is recommending two tracks for BTA, Track 1 as closed cycle cooling with a minimum control of 93%, and Track 2 that provides plants the flexibility to meet a comparable control level to Track 1 while using other operational and structural controls. The State Water Board is not legally required to do cost-benefit analysis when developing water quality plans and policies. It is our general policy not to perform cost benefit analyses.

Comment 12.01:

RRI remains concerned, however, that the proposed OTC Policy is unnecessarily restrictive and does not yet adequately reflect the site-specific flexibility contemplated in Section 316(b) and proposed in USEPA'S federal regulations (which has been upheld by the federal courts on most of the key issues). We believe that the framework proposed in the EPA's Phase II regulations provide a good starting point for the California OTC Policy.

Response:

The commenter has not specifically explained the manner in which the policy is unduly restrictive. The State Water Board has determined, using BPJ, the best technology available to reduce adverse environmental impacts, setting forth a two-track system to encompass variables. While the Phase II regulations provided a suite of technological options for compliance, some of the performance standards were rejected as allowing overly broad ranges that did not constitute BTA, a determination undisturbed by *Entergy*. Other features of the Phase II regulations were remanded as lacking support or requiring clarification.

Comment 31.47:
The SED states that if all facilities were allowed to use a wholly disproportionate cost test, they would likely do so, requiring a site-by-site application of BPJ, and negating the benefits of a coordinated statewide policy. There is nothing that prevents the State Water Board from developing consistent statewide guidance on the application of BPJ and other criteria to the Regional Water Boards so that standards are applied uniformly. In addition, this statement is also a testament to the fact that Tracks 1 and 2 compliance as proposed are impossible.
Response:
Unenforceable statewide guidance allowing for site-specific compliance determinations would be very unlikely to result in consistent (or effective) implementation of Section 316(b). Benefits are difficult to quantify, and the likelihood of facilities seeking to available themselves of any cost-benefit variance would reflect this imbalance rather than the impossibility of more expensive compliance options.

Comment 51.02:
The policy should also contain a variance provision that will allow each generating station to do a site specific assessment that due to environmental impacts, real estate issues, or permitting issues that could preclude those facilities from constructing cooling towers to be in compliance with the policy, and thus be exempted from the policy.
Response:
The June 30, 2009 version of the proposed Policy allowed an OTC power plant owners/operators to meet the alternative Track 2 requirements, if it was shown infeasible to meet Track 1 requirements due to site-specific feasibility criteria, such as to environmental impacts, real estate issues, or permitting issues that could preclude those facilities from constructing cooling towers. However, staff has changed the Policy language in response to comments, so Track 2 is now available to all OTC plant owners/operators that prefer this compliance alternative. Staff therefore does not believe that a variance from Track 1 requirements is necessary. Furthermore, the policy is a statewide policy and individual circumstances can be accounted for within the SACCWIS process and the Regional Water Board permit proceedings based on the Policy.

Comment 59.02(b):
SCE proposes the addition of the following definitions to Section 5 of the Revised Policy:
Alternative protective technologies - Refers to available protective technologies for compliance with the Policy when the State Water Board determines that Track 1 and Track 2 do not apply. Alternative protective technologies that may be available include: a fish-handling and return system; fine-mesh traveling screens; a redesigned intake structure with fine mesh, handling and return , system; fish barrier net; filter fabric barriers (i.e. Gunderboom) that reduce aquatic impacts at cooling water intake structures; the relocation of cooling water intake structures; velocity caps for cooling water intake structures; passive fine-mesh screens at the inlet of an offshore submerged intake structure (i.e. Wedgewire); and double-entry, single-exit cooling-water intake structures with fine mesh screens and a fish-handling and return system.
Response:

OTC power plants must meet the established BTA; i.e., either Track 1 or Track 2 requirements. Track 2 controls include the referenced technologies. The Policy does not allow for a lesser level of compliance; therefore, there is no need for a definition of "*Alternative protective technologies"*

Comment 61.18:
SED, pg. 43, par. 5: The very inconsistencies between Regional Water Boards presented in this paragraph demonstrate the wisdom of the case-by-case BPJ approach. The declines in several populations of fish in the San Francisco Bay-Delta region that have resulted in listing species under the ESA and CESA are issues specific to that region. The same issues do not apply in southern California and other areas of the state just as entrapment of sea turtles does not occur in the San Francisco Bay-Delta Region.
Response:
Please see the response to Comment 31.30. The current BPJ-permitting approach has not been beneficial to the environment and may have contributed to the decline in several populations of fish, in the San Francisco Bay-Delta Region and elsewhere. Staff agrees that Southern and Northern California have different species that requires different levels of protection, and these differences are best addressed during the permitting process. However, the need for a statewide Policy to implement Section 316(b) and provide guidance to the permit writers, remains.

Comment 61.19:
SED, pg. 44, par. 4 and 5: As noted in Comment 16, the issues relative to Section 316(b) vary among plants. While it may be expedient to implement a statewide BTA standard relative to the technology aspect of Section 316(b), the BTA necessary to minimize adverse environmental impact will vary among plants.
Response:
The BTA requirements in the Policy incorporate a two track approach, which allows for flexibility for the operators to comply. This addresses the issue of different case-by-case situations at each plant.

d. Can the costs of the selected BTA (Track 1 and 2) be reasonably borne?

Comment 4.02:

Track 1 proposes to adopt closed-cycle cooling as BTA, thus requiring all plants to install closed-cycle cooling systems. We believe that this determination results in poor public policy and needs to be reconsidered. This is an unachievable standard that would result in exorbitant costs to California that is wholly disproportionate to benefits by a factor of over 90 to 1. NERA Economic Consulting reached this conclusion in a study commissioned by CCEEB based upon existing information on the likely costs and benefits. Installing cooling towers at coastal power plants is acknowledged as virtually impossible, with the possible exception of one or two facilities. Though the Tetra Tech study concluded that salt water towers might be technically feasible at some sites, their study scope was too limited to explore resolution of problems caused by the lack of air emission credits and other permitting and physical obstacles faced by facilities in a coastal. CCEEB believes that it is not good public policy to create obligations that cannot be met short of plant shut down or a very expensive re-powering that will be largely driven by market factors out of the control of many generators. Nor should a policy be adopted knowing that it will have to be continually revised every 6 months or every year because of unrealistic compliance dates and other structural problems. It is conceivable that some plant operators may see the handwriting on the wall and shut down before their compliance deadline

because the costs of compliance and the potential lack of long-term contracts could force a business decision to discontinue operations. Any early plant shutdowns would be extremely problematic for the electrical system operators and will become troubling for the Board as well.
Response:
Please see the response to Comment 1.02, 4.05, and 31.03.

Comment 4.05:
The Board should conduct a policy-wide cost-benefit analysis of the draft OTC policy to help it determine the appropriate BTA. Currently, the draft Policy requires closed-cycle cooling, or its equivalent, as BTA. If the Board conducted a system-wide cost benefit analysis, it is likely to show that the cost of meeting closed-cycle cooling performance standards statewide at existing coastal power plants is likely to be wholly disproportionate to the environmental benefit gained, by a ratio of over 90 to 1 (as demonstrated by the NERA Study). The US Supreme Court in Entergy v. Riverkeeper, Inc. decided agencies responsible for enforcing the CWA are allowed to reject technology solutions whose cost is wholly disproportionate to its benefits. Attempting to meet a predetermined arbitrary standard of BTA, at all costs, is inherently unnecessary and unreasonable when other less expensive, but workable solutions can be chosen. The question of the relationship between the cost of compliance with this draft Policy and the benefits of doing so is an important question that allows policymakers to weigh the reasonableness of the requirements of the Policy, and is key to the question of the feasibility of implementing the proposed Policy and the resulting impact to grid stability. Comprehensive Demonstration Studies (CDS) and Impingement Mortality & Entrainment (IM&E) Reports that have been submitted to the appropriate Regional Water Boards for compliance with their existing NPDES Permits also provide the base data needed to conduct a benefit determination in a cost benefit study as conducted by NERA using USEPA guidelines. Thus this data is readily available for a cost benefit study at individual plants.
Response:
The State Water Board is not legally required to do cost-benefit analysis when developing water quality plans and policies. It is not appropriate to equate the substantial mortality of marine life associated with OTC to monetary costs of compliance. The only monetary value associated with impacts to marine life is based on commercial values of fish, which is completely inadequate to characterize the ecological effects of OTC. As with previous plans and policies, staff does not recommend that the Board perform a cost-benefit analysis.

Comment 31.03:
RRI urges the State Water Board to align with more than 30 years of consistent USEPA interpretation and court-approved guidance regarding the BTA standard and the use of a wholly disproportionate demonstration. The EPA, the U.S. Supreme Court, the U.S. Courts of Appeal, and California Courts have found that in implementing Section 316(b): (1) the use of cost benefit tests is reasonable, (2) industry must be able to reasonably bear the cost of compliance, and (3) it is unreasonable to force individual facilities to bear costs that are wholly disproportionate to the benefit to be gained. Yet the Draft Policy would set BTA, without using cost-benefit tests, at a level that cannot be reasonably borne by the facilities and does not allow forty-five of the fifty-three OTC units the ability to demonstrate that costs are wholly disproportionate to the resulting benefits. The Draft Policy adopts a BTA standard and compliance approach that will be infeasible for virtually all of the OTC plants and goes beyond even that of the USEPA Phase I regulations for *new* generating facilities. The Phase I regulations contain two compliance tracks, both based on closed cycle wet cooling thresholds, but it allows new facilities to ask for site-specific alternatives based on a cost-benefit determination. The USEPA Phase II regulations did not adopt closed-cycle wet cooling as BTA, but rather established compliance at reductions in IM/E of between 60% - 95% of a baseline with a variety of alternative compliance paths based

on site-specific conditions. The proposed Phase II regulations did not require low capacity factor units to meet the new compliance requirements and exceptions would also have been available to all affected facilities under a variety of methods, including site-specific methods using a cost-cost test (where a facility could show its costs were significantly above those analyzed by EPA), and a cost-benefit test (where a facility could show that costs were significantly greater than benefits). The cost-cost test has been previously upheld by the Supreme Court. The site specific cost-benefit test was challenged and the Second Circuit court held that the only permissible cost test is whether the compliance cost could be "reasonably borne by industry." The Supreme Court overturned the Second Circuit Court and determined that a test of whether costs significantly exceeded benefits was proper. The State Water Board's own legal memorandum on the Supreme Court's decision in *Entergy* found that the "Supreme Court decision in many ways returns the landscape for Section 316(b) decision-making to the status quo," and that "decisions based on the *more restrictive* "wholly disproportionate" standard are no longer required. The State court's findings in *Voices of the Wetlands* are consistent with the latest US Supreme Court ruling.

For over 30 years, the EPA has held that the application of a BTA standard "should not impose an *impractical and unbearable* economic burden". Yet, this is exactly what the Draft Policy does, by relying on the standard created by the Second Circuit of "costs reasonably borne by industry," although the Supreme Court held that the EPA was not limited to considering cost in this manner alone and that the level of benefit achieved was certainly a consideration in determining whether it was reasonable to bear a certain level of costs. Furthermore, the record demonstrates that the costs of closed cycle wet cooling are ***not*** reasonably borne by industry. The SED's discussion of costs is cursory and based on retail cost. However, the competitiveness of an OTC facility is determined by the wholesale price, and is therefore a more the appropriate point of reference for determining whether the cost can be reasonably borne by the industry. Under that metric compliance cost as a percent of price is almost 24%. But ultimately what really matters is revenues after fuel costs. These are the net revenues that are available to cover operations and maintenance expense, capital additions, and a return of and on capital. Using TetraTech's own numbers for gross revenues, compliance costs, and fuel prices, and using official fuel burns from EIA, the cost of compliance amounts to 83% of revenues after fuel costs for almost 9 out of 10 OTC units, which does not leave enough money to cover operations and maintenance expenses, much less leave anything available for continued capital expenditures, recovery of depreciation, or return on investment. When 9 out of 10 units cannot cover their operating expense based on the installation cost of a mitigating technology, that technology cannot be considered viable under the CWA.

The Draft Policy purports to allow a Track 2 compliance alternative that requires a lesser (83%) reduction for those facilities that can demonstrate that Track I is infeasible, but the Policy changes the baseline for Track 2 from an instantaneous flow rate to what is effectively the current actual annual average IMIE impacts. The result is that Track 2 becomes at least as onerous for low capacity factor plants – requiring an 83% reduction in actual impingement and entrainment relative to their already low *average* usage. For example, under Track 2, a plant with a 10% capacity factor must reduce its flow by 83%, yielding a 1.7% equivalent capacity factor as the maximum amount it could run. Finally, the Draft Policy denies these very same units the opportunity to make a wholly disproportionate cost showing, even though these units have a significantly smaller impact on fish and other aquatic life than nuclear units and combined cycle units due to significantly fewer operating hours. Since both Track I and Track 2 are infeasible for most of the facilities, these technologies cannot be considered "available" and therefore do not meet the plain language of BTA. RRI believes that a reasonable Policy must include a BTA standard that includes a range of site-specific compliance alternatives to replace Tracks 1 and 2 and that is economically feasible.

Response:

State Water Board staff has considered costs of compliance as part of its evaluation of BTA for minimizing adverse environmental impacts resulting from use of OTC, as well as in determining a compliance schedule and alternative provisions for nuclear-powered facilities and facilities employing previously-installed combined-cycle units. The U.S. Supreme Court's *Entergy* decision determined not that a cost-benefit analysis was required, but rather that an agency may permissibly rely on a cost-benefit analysis either in setting performance standards or in providing for cost-benefit variances. The Court did not address portions of the 2nd Circuit decision in which broad performance ranges were remanded as failing to require the best technology available for minimizing adverse impacts.

Comment 31.44:
The staff states that it selected the BTA of Track 1 and 2 using a "reasonably borne" cost analysis. However, no description of that analysis or data is presented to demonstrate it has any applicability to the facilities affected by the proposed Policy.
Response:
According to RiverKeeper II, costs may be considered insofar as they can be "reasonably borne" by the industry. Reasonably borne costs are estimated at the programmatic level based on the TetraTech report for the OPC, which are 0.45 cents per KWhr. The TetraTech report is clearly cited in the SED.

Comment 31.45:
Staff correctly notes that "the possibility that the Track 1 or Track 2 compliance costs might be unreasonable compared to overall benefits." This is exactly the scenario the Supreme Court indicated was not intended by the CWA. Consequently, the State Water Board must provide an opportunity for every facility affected by the Proposed Policy to be eligible for an alternate compliance plan if they can demonstrate that costs are wholly disproportionate to benefits.
Response:
Please see the response to comments 7.06, 29.10 and 53.01. A cost-benefit analysis is not required. The Supreme Court made no determination that CWA 316(b) required a specific interpretation, instead finding that USEPA's Phase II interpretation was a permissible reading of the statute.

Comment 37.04:
If costs of closed-cycle cooling are disproportionate to benefits, BTA should be defined as a suite of technologies to reduce impingement and entrainment to the maximum extent that is feasible and cost-beneficial. This approach allows regulated parties a reasonable opportunity to comply with a level of protection that is feasible - i.e. one that can be achieved successfully in practice. To the extent that maximum reduction through BTA is not feasible or results in a wholly disproportionate cost compared to benefit at specific sites, the owner/operator should be allowed to petition the Regional Water Board for relief from this requirement. If the Regional Water Board grants relief, it should impose mitigation or restoration requirements on the owner/operator that achieve the practical equivalent of reducing marine life intake and mortality to the maximum extent feasible without imposing costs that are wholly disproportionate to the benefit achieved, guided by the by the Supreme Court's discussion in Entergy of when a cost/benefit ratio may be considered wholly disproportionate (4.7 to 1). Defining a more reasonable and flexible BTA standard is fully consistent with the CWA, USEPA guidance, and California law. BTA should be defined as reductions that are achieved through application of a technology or a combination of the following technologies: (1) Fish handling and return system; (2) Fine-mesh traveling screens; (3) Redesigned intake structure with fine mesh, handling and return system; (4) Fish barrier net; (5) Filter fabric barrier; (6) Relocation of cooling water intake structures; (7) Velocity cap for cooling water intake structures; (8) Passive fine-mesh screen (i.e.

Wedgewire); and (9) Double-entry, single exit cooling water intake structure with fine mesh screens and fish handling and return system. The owner/operator should be required to provide a periodic report, of new and updated impingement and entrainment reduction technology to ensure that each facility that continued to use OTC was in fact using the best technology available for reduction of impingement and entrainment overtime.

Response:

A cost-benefit analysis is not required, and State Water Board staff has noted the difficulty in monetizing benefits relative to costs. Continued site-specific determinations of BTA would not support the State Water Board's goal of achieving consistency in implementing Section 316(b). The two-track approach set forth in the proposed Policy allows for the use of differing technologies to meet the required reductions. The proposed Policy would also allow development of new technologies over time. Mitigation is not itself a technology for minimizing adverse environmental impact from cooling water intake structures.

Comment 37.11:

The Policy and SED contain an inadequate analysis of the environmental benefit of closed-cycle cooling. In the Phase II rulemaking process, EPA reviewed a mass of scientific and technological evidence, including a database of 154 studies of entrainment and impingement. It is at best unclear from the Policy whether Board staff conducted a similarly exhaustive review of intake technologies when it chose to define BTA as closed-cycle cooling. Indeed, the Policy takes the overly simplistic approach of measuring "environmental impact" on the single dimension of intake flow and choosing the technology (closed-cycle cooling) that minimizes intake flow. A host of factors (such as the type of water body and the local species present) affects which technology is best. The Board should follow USEPA's lead and conduct a similarly robust analysis to define BTA in a cost -beneficial manner that can be implemented successfully at California's existing OTC generating facilities. There likely are numerous significant environmental impacts associated with requiring cooling towers at the OTC plants that the SED did not properly analyze or disclose.

Response:

Please see the responses to Comments 21.01(b) and 31.28.

Comment 57.01:

RRI commented on BTA and the need for a wholly disproportionate test in its September 30 response to the June 30, 2009 Policy (Draft Policy). Unfortunately, Staff has failed to meaningfully modify the BTA standard in the revised Draft Policy so few, if any, of the gas-fired steam boiler plants will be able to comply with either track of the standard. For instance, it is widely recognized even by the State Water Board in its SED that cooling towers cannot feasibly be installed at RRI's Ormond Beach facility. Furthermore, the cost to benefit ratio for installation of cooling towers at our Mandalay facility is 500 to 1. Without a "wholly disproportionate" standard or some other feasible BTA standard, the Revised Draft Policy dictates that these two facilities be retired since cooling towers are infeasible and there currently are no suite of technologies and operational measures that will enable these facilities to meet the Track 2 standard. As RRI demonstrated in its earlier comments, the same holds true for the vast majority of the other gas-fired plants, equivalent to 14,689 MWs of generating capacity in total and 24.5% of California's installed generation capacity. Failure to offer the vast majority of facilities any path to compliance or the ability to show a wholly disproportionate cost impact is inconsistent with all prior regulatory efforts under Section 316(b), and is arbitrary, capricious, and contrary to law.

Response:

Please see the responses to Comments 51.01 and 53.01.

e. Is the selected BTA (Track 1 and 2) attainable?

Comment 1.02:
The proposed two track system does not leave any feasible compliance alternatives aside from shutting down or retrofitting to closed-cycle cooling, which is not possible at many existing locations. Implementing a policy that essentially forces units to shut down prematurely is not equitable.
Response:
Staff believes that most OTC power plants will be able to comply with the OTC Policy, using either of the Track 1 or 2 compliance alternatives. Under Track 1 plants may either retrofit their units with closed-cycle wet cooling or re-power using closed-cycle dry cooling. The draft Policy has been changed so plant owners or operators may also choose to comply by using Track 2. Under Track 2 plants may retrofit certain units with closed-cycle wet cooling or re-power those units using closed-cycle dry cooling, and may use operational or structural controls (e.g., variable frequency drive pumps) to limit flows at the remaining units so that the entire plant flows are comparable in terms of percent reduction to Track 1. Another approach allowable under Track 2 would be the installation of screens to prevent entrainment of fish larvae and the reduction of intake velocity to reduce impingement, comparable to that achieved with flow reductions under Track 1.

Comment 11.47:
The STATE WATER BOARD should define Track 2 in terms of an achievable level of reduction in impingement and entrainment mortality to be determined by site-specific evaluation. Assuming a Regional Water Board determines that Track 1 is '"not feasible", it is questionable whether many OTC facilities can realistically achieve Track 2's minimum 83% reduction in impingement mortality and entrainment. The performance of any individual cooling water intake technology (e.g., aquatic filter barrier, fish returns, wedgewire screens, behavioral devices) can vary greatly depending on site-specific factors. During the CEC siting process for both Moss Landing Units 1 & 2 and Morro Bay, all known mitigation technologies were examined and rejected. At Moss Landing, the CEC rejected screens, nets, aquatic micro filtration barriers, and fish pumps because they were not expected to substantially reduce impingement or entrainment. Further, the NPDES permit proceeding rejected wedgewire screens, fine-mesh screens, and aquatic micro filtration barriers as not being demonstrated technologies for reducing entrainment. Thus, for the many power plants where Track 1 is infeasible, there is no known exclusion technology that would allow a facility to comply with the Track 2 requirement. The only possible compliance strategy for a plant in such a position would be to seek compliance through the adoption of operational restrictions, coupled with the application of technologies which, while insufficient in and of themselves to achieve compliance, would contribute to a reduction in the flow of cooling water through the plant. Through a combination of unit retirements, variable speed pump installation, modification of daily dispatch rates, screenhouse modifications, and prohibitions on dispatch during defined periods of time during the year, some facilities may be able to approach the Track 2 standard. Moreover, even if some combination of controls is thought to be able to achieve 83% reduction, actual monitoring after installation of Track 2 controls may show otherwise.
Response:
Please see the response to Comment 1.02.

Comment 11.58:
Reducing intake flow and velocity to a level equal to that which can be attained in a closed-cycle cooling system (Track I) will not be feasible at many of the OTC plants. Indeed, permitting authorities have rejected closed-cycle cooling at Moss Landing (Units 1 & 2) and Morro Bay as

infeasible for numerous reasons, including a lack of PM10 ERCs, conflict with local zoning policies and ordinances, site restrictions, salt drift, noise impacts, visual impacts, and lack of recycled water.

Response:

Please see the response to Comment 1.02.

Comment 31.46:

The SED claims that it is not possible or feasible to evaluate each facility's ability to comply with the performance standards, yet this is precisely what the Tetra Tech Study attempts. This study finds cooling towers infeasible at Ormond Beach and two other sites. It comes up with cost per MWh of compliance for almost all of the other facilities.

Response:

Please see the response to Comment 4.06.

f. The Track 1 performance standard

⇒ *The calculation baseline*

Comments 3.08 and 26.06:

"Intake Flow Rate" should be clarified. Track 1 sets a standard for reducing "intake flow rate" and highlights the definition of this term. However, there is no clear guidance defining *when* the reduction of intake flow rate is applicable. We assume from the prohibitions in the "Immediate and Interim Requirements" that prohibit seawater intakes during times when the generating unit is not generating electricity (with the limited exception for "critical system maintenance") that the definition and regulation of intake flow rate in Track 1 is applicable to times when the units are generating electricity. A minor clarification of the definition would eliminate any confusion. The definition for "intake flow rate" should be clarified to read "refers to the instantaneous rate at which water is withdrawn through the intake structure, expressed as gallons per minute (gpm) per kilowatt hour generated."

Response:

Section 2.A(1) of the proposed Policy specifies that "A minimum 93 percent reduction in *intake flow rate** for each unit is required for Track 1 compliance, compared to the unit's **design** *intake flow rate**." (emphasis added). *"Intake Flow Rate"* is defined in Section 5 of the proposed Policy as "the instantaneous rate at which water is withdrawn through the intake structure, expressed as gallons per minute." The design intake flow rate does not vary over time. It is simply the maximum pumping rate that the intake pumps are designed for. For instance, a power-generating unit may have two intake pumps, one designed to pump 100,000 gpm, the other designed to pump 120,000 gpm. The design intake flow rate for that power-generating unit would be 220,000 gpm, which is the sum of the two pumps' intake flow rates. Under Track 1, the intake flow rate for the unit must be reduced by 93% of the design intake flow rate, which in this case would be 7% of 220,000 gpm, or 15,400 gpm.

The November 23, 2009 revised Draft Policy did not specify the time interval over which compliance would be determined for those power plants that would meet Track 2 requirements, partly, or completely, through flow reductions. Staff has added language to Section 2.A(2) of the proposed Policy to clarify that compliance with required flow reductions would be on a monthly basis, as recommended by the ERP to account for seasonal variability in fish larvae. In the example given above, the power-generating unit would be allowed to pump 665,280,000 gallons per month (15,400 gallons/minute X 60 minutes/hour X 24 hours/day X 30 days/month). If the unit ran both pumps at full speed, it would be able to operate about 50 hours per month

(665,280,000 gallons per month / (220,000 gallons/minute X 60 minutes/hour)). However, the owner/operator could also choose to just run one of the pumps for about twice as long, or reduce the pumping rates by other means.

Comments 3.12 and 26.10:
Calculation baseline should be based on generational flow and take into account the seasonal variability of larvae to ensure actual reduction in entrainment. We are concerned that the ambiguity in the Draft Policy for calculating impact reductions could result in little-to-no operational change for many of the plants, in direct contravention of the CWA and the intent of this policy to minimize marine impacts. It is unclear how reductions in marine life mortality will be measured and a calculation baseline for Track 2 reductions will be determined. Track 2 requires reduction in "impingement mortality and entrainment of all life stages of marine life for the facility, as a whole, to a comparable level to that which would be achieved under Track 1; however it does not specify how reductions will be measured. Ironically, in 2002 the State Water Board raised similar concerns about the challenges of measuring impact reductions when submitting comments on the federal Phase II Rule: "The Proposed Rule is unclear as to how to measure the required reduction in impingement and entrainment. Do you measure the reduction by counting the organisms impinged and entrained? Do you weigh the organisms impinged and entrained? If so, do you use dry weight over wet weight? Do you have to measure the reduction for each life stage, or do you lump all life stages together and use a combined count or weight?"

We see the same problems with the proposed Policy and urge the State Water Board to set flow as a proxy for entrainment by using generational flow as a baseline. This approach was supported by the OTC Expert Review Panel and is a simple and clear method of calculating entrainment reductions. State Water Board staff has considered various options for establishing a baseline on flow, including permitted maximum flow (also known as design flow), actual flow and generational flow. Generational flow is an appropriate metric to achieve actual reductions in marine life mortality, as it reflects the flow actually required to generate electricity, and would not allow compliance to be based on elevated intake during periods of non-generation. Reductions based on permitted maximum or actual flow raise further concern. Simply reducing flows based upon the permitted maximum flow will not truly achieve entrainment reductions at many OTC plants in California, as most facilities operate well below their permitted maximum flows at what is commonly called, actual flow. Furthermore, at some coastal power plants, such as the El Segundo Generating Station, actual flow is significantly greater than the generational flow. Therefore, if the State Water Board chooses to base entrainment reductions on permitted maximum flow or actual flow instead of generational flow, actual entrainment reductions may not be achieved. If flow is used as a proxy for entrainment, the policy should also specify a time period for the determination of baseline flow from which to establish entrainment reductions. Otherwise, if facilities are given discretion to independently establish their baseline flow and actual flow is used as the metric, they may elevate their actual flow levels beyond the necessary amount for generation to augment the baseline (yet still remain within their permitted flow levels). This would make it easier for generators to comply with the policy without actually achieving true entrainment reductions. There has been a steady decline in the use of cooling water at coastal power plants over the past decade. It is critical that recent flow information be used to establish a calculation baseline to best reflect current conditions. Therefore, we recommend that average generational flow over the 5-year period preceding this policy (2004-2009) be used as the baseline.

Response:
Section 2.A(1) of the proposed Policy specifies that "*A minimum 93 percent reduction in intake flow rate* for each unit is required for Track 1 compliance, compared to the unit's* ***design intake***

flow rate." (emphasis added). During policy development, staff considered various calculation baselines and compliance periods for calculating the required flow and entrainment reductions: Actual average flow measured over a year (or month, week, or day), actual maximum flow (with various compliance periods), permitted flow (with various compliance periods), generational flow (with various compliance periods), and design flow (with various compliance periods). If using actual, permitted, or generational flow as the basis, it is also necessary to specify what period to specify for calculation purposes, which for instance could be the last five-year period or the last ten-year period. Actual and generational intake flows have shown to be quite variable over time, depending on the weather, maintenance, and other factors. However, the design flow rate does not vary over time. It is simply based on the maximum pumping rate that the intake pumps are designed for, and is therefore a readily available and known number.

Staff has established that a power plant switching from OTC to closed-cycle wet cooling should be able to reduce intake flows by at least 93%. If actual or generational flows were used as a baseline for calculating reductions, this would result in the electrical output of the power plant being permanently reduced below the current permitted capacity. If the design flow rate is used as baseline, the facility may switch to closed-cycle wet cooling without losing capacity. Staff also determined that while many OTC facilities have low capacity utilization rates when measured annually (see Table 11 in the SED), these facilities would nonetheless need to substantially reduce flows, and thereby entrainment, if measured monthly (for Track 2 compliance). Staff is therefore recommending using the design intake flow rate as the basis for required flow reductions for both Track 1 and 2, because it is easy to determine and not disputable, will not reduce electrical capacity, and will nonetheless significantly reduce entrainment.

The November 23, 2009 revised Draft Policy did not specify the time interval over which compliance would be determined for those power plants that would meet Track 2 requirements, partly, or completely, through flow reductions. Staff agrees that this clarification is vital and has added language to Section 2.A(2) of the proposed Policy to clarify that compliance with required flow reductions would be on a monthly basis, as recommended by the ERP to account for seasonal variability in fish larvae. Please also see the response to Comment 3.08 regarding the calculation of intake flow rates. Staff has also added new language to Section 2.A(2), Section 4, and Section 5 of the proposed Policy to further detail how compliance with Track 2 will be determined and monitored.

Comment 11.64:
Dynegy strongly supports the proposed Policy's use of design flow baseline in determining compliance with the Track 1 and 2 standards. Use of a design flow baseline has numerous advantages over performance-based baselines *(e.g.,* historic actual flow), is consistent with OTC requirements in other states and, for those power plants where Track I is infeasible, will be essential to enabling a power plant to have any realistic chance of meeting the proposed Track 2 standard. A design flow baseline may also allow certain low use plants to operate only when needed and would preserve the ability of power plants to operate at their maximum flow when needed to meet California's electricity demands. Use of a design baseline ensures fairness among energy producers; recognizes that every electric generating facility has the potential to operate at full-flow conditions given the deregulated nature of the electric generating industry; is consistent with federal requirements; is consistent with the intent to reduce adverse effects from cooling water intake structures because any reductions in flow, regardless of subjective motivation, reduce entrainment and impingement; does not unfairly punish facilities that have recently operated at lower flow levels by not allowing them credit for flow reductions that have

already been implemented; and is an appropriate regulatory approach because of the inherent variability in operating capacity that electric generators face from year to year.

Response:

Comment noted. Staff agrees.

Comment 32.01:

Under "Compliance Alternatives", intake flows must be minimized to only those flows directly related to energy production. The definition of intake flow rate and reference to design flow is highly problematic. Track 1 of the Draft Policy requires 93% reduction of "design intake flow rate." However, such a reduction would allow for artificially increased flow rates and would not meet the State Water Board's intended 93% reduction goal. For those plants with reduced actual flows, such as Encina Power Station (EPS), the "design intake flow rate" would be much higher than actual historical flows. For instance, in June 2009, EPS flows averaged 178 MGD, by having zero flow for nine days in June, while it is designed to draw in 857 MGD. Assuming an actual 178 MG daily flow, a 93% reduction in design intake flow would actually only result in a 66% reduction from 178 MGD. For Track 2, the comparable level of reduction in flow rate is within 10% of Track 1, resulting in only a 63% reduction from actual flows. Thus, clarifying that intake flow rate is only the actual flow rate directly related to energy production instead of design intake flow rate is of critical importance. The definition of intake flow rate should be clarified to mean "instantaneous rate at which water is withdrawn through the intake structure, expressed as gallons per minute per kilowatt hour generated." Further, if actual flows as baseline for reduction are calculated after Policy adoption, power plants may artificially increase flows. Because intake flows have steadily declined at most power plants in recent years, any baseline calculation should reflect actual historical flows for the previous 5-year period directly related to energy production. Making this change, and removing the reference to "design" intake flow rate would ensure that the State Water Board's Policy comes as close as possible to achieving its intended purpose of 93% reduction in flows.

Response:

Please see the response to Comment 3.08.

Comment 44.02:

The Draft Policy states on Page 3, Paragraph 2.A.(I), that pursuant Track 1, "an existing power plant must reduce intake flow rate at each unit, at a minimum, to 93% reduction in intake flow rate for each unit compared to the facility's design intake flow rate. " The draft policy should be amended to clarify whether the design intake flow rate must be calculated at maximum design or average operating capacity levels based on actual historical data for a specific period of time.

Response:

Please see the response to Comment 3.08.

Comment 60.02:

Section 4(B): We recommend establishing a baseline for each facility that is calculated as an average of monthly "generational flow" from data collected over the 5-year period proceeding adoption of this regulation. For generators that have re-powered some or all of the units to combined-cycle generators, the baseline data would be an average of five years of monthly "generational flow" prior to commencing operation of the new generators; The Track 2 standard for reducing marine life mortality commensurate with the achievement of implementing the "best technology available", including the court's exception for a "margin of error", would be a reduction of "generational flow" by 90%, per month, from the baseline defined above. "Generational flow" should be defined in the policy as the intake flow required for the generation of electrical power as currently articulated in the definition of "power-generating activities." Basing entrainment reductions on generational flow would not allow for such flow adjustments and achieve results consistent with the intent of the Board's discussion and goal of "beneficial outcomes" from operational changes rather than the arguably legal mandate of technological changes.

Response:

Please see the response to Comment 3.08.

Comment 60.05(e):

The definition for "intake flow rate" should be clarified to read "refers to the instantaneous rate at which water is withdrawn through the intake structure, expressed as gallons per minute per kilowatt hour generated."

Response:

Please see the response to Comment 3.08.

⇒ ***The 93% flow reduction standard***

Comment 11.59:

The Track 1 performance standard -- a minimum 93% reduction in intake flow rate" -- is arbitrary. The Board has offered little support for, let alone substantial evidence, that this standard is either necessary for achieving environmental benefits or achievable at all OTC facilities using closed-cycle cooling. The SED justifies the 93% minimum standard based on a study prepared for the STATE WATER BOARD by Tetra Tech and an EPRI report. However, both reports are initial analyses using approximations and assumptions that are not based on the detailed engineering required to determine the actual flow reductions achievable at each facility. The Tetra Tech report itself only includes facility profiles for 15 facilities and, furthermore, the 93% minimum standard is apparently based on that report's statement that the plant at low end of the range of intake capacity reduction will reduce the intake flow by "approximately 93%." In contrast, USEPA had concluded that closed-cycle cooling systems using saltwater can reduce water usage by anywhere from 70% to 96%.

Response:

Staff believes that the required 93% reduction in intake flow rate is adequately explained and supported in the SED. As stated in the SED, while the percentage reduction a facility can achieve when converting from OTC to a closed-cycle wet cooling system is variable based on site-specific factors, the reduction can generally be reasonably estimated based on the maximum dissolved solids concentration permissible in the circulating water, or "cycles of concentration". Higher cycles of concentration typically correspond to lower makeup water demands. Flow reductions vary most between one and two cycles of concentration. The 2008 Tetra Tech report (prepared for the OPC) examined 15 of the 19 OTC facilities affected by the Policy, and developed closed-cycle wet cooling tower configurations for these facilities using 1.5 cycles of concentration. Tetra Tech found that intake flow reductions ranging from 93-97% of the original OTC flow was possible. An independent analysis of the same facilities prepared by EPRI in 2007 used a similar design basis and reached the same overall flow reduction estimates. Staff chose to recommend the lowest number in the range (93%) as the performance standard for entrainment, to allow for site-specific factors possibly lowering the performance of wet closed-cycle cooling. Note that different climates and other factors influence the evaporation rates and the overall performance of wet closed-cycle cooling systems. Because the USEPA study included plants throughout the nation, their study would naturally have a greater variability than a study targeted solely at California's coastal and estuarine power plants.

Comment 14.05:

The Policy fails to provide adequate justification for its compliance objectives of 93% reduction in Track I and 82.7% in Track 2.
Response:
Please see the responses to Comments 11.59 and 3.09.

Comment 23.05:
The Draft Policy establishes compliance as "A minimum 93% reduction in *intake flow rate* * for each unit ... " Intake flow reductions that may be achieved through cooling tower retrofits are variable due to site-specific conditions, so while some facilities could potentially achieve the 93% reduction target through a conversion to closed-cycle cooling, others might not be able to meet this precise standard. To eliminate this compliance concern, Mirant recommends that the STATE WATER BOARD revise Section 2.A.(I) to make the use of Closed-Cycle Wet Cooling per se compliance and to leave in place a flow reduction standard as an alternative Track 1 compliance method. If the State Water Board is concerned that this approach will somehow lead to loopholes, it could tighten the definition of "Closed-Cycle Wet Cooling" to track that adopted by the USEPA in its Phase II Rule. As a less preferred alternative, the State Water Board could reduce the 93% standard down to 88%, which should provide some margin of compliance without sacrificing what appears to be the State Water Board's ultimate goal: making closed-cycle wet cooling the technology of choice for cooling power plants.
Response:
Staff appreciates the suggestions for revisions to the Policy. However, staff does not believe that the policy's 93% flow reduction requirement is especially onerous for closed-cycle wet cooling technology to meet. Please see the response to Comment 11.59. Therefore, staff does not believe that it is necessary to lower this standard in any way by providing other alternatives.

Comment 61.21:
Is there any basis for selecting the required level of reduction at 93 percent? None seems to be provided in the SED.
Response:
93% is the minimum level of control based on the application of closed cycle cooling determined through the Tetra Tech report for the OPC.

⇒ ***The 0.5 ft/sec through-screen velocity reduction standard***

Comment 31.34:
The decision to use 0.5 ft/sec through-screen intake velocity as an impingement mortality performance standard has no basis in the record and otherwise does not comply with CEQA. The SED's only basis for the standard is the USEPA's Phase I rule which relied on a single study conducted in 1973 and a safety factor developed based on three additional fish swim studies. The SED does not properly incorporate these materials by reference. CEQA requires that materials incorporated by reference must be made available for inspection and the environmental document must state where that inspection may take place, describe its relationship with the incorporated portion of the referenced documents, briefly summarize the incorporated materials, and briefly describe the relevant data or information. Therefore, the documents discussed in the USEPA's rule cannot support the Draft Policy's recommendation. At a minimum, the State Water Board should have cited and described the studies relied on by the USEPA and conducted a search of recent literature on the issue to determine whether recent information supports or undermines the USEPA's analysis. The State Water Board also failed to analyze any alternatives to the impingement mortality performance standard, such as another number for through-screen velocity or another type of measurement like an approach velocity. In addition, the STATE WATER BOARD did not consider any alternative compliance

levels, such as a different impingement reduction measure for Track 2 compliance. The BTA alternatives considered in the SED only involve the entrainment reduction standard.
Response:
Staff believes that the SED adequately support the 0.5 ft/sec through-screen intake velocity requirement.

Comment 49.09:
Section 2. A. (1) of the Policy states that "A minimum 93 percent reduction in *intake flow rate ** for each unit is required for Track 1 compliance, compared to the facility's unit's design *intake flow rate*.* The through-screen intake velocity must not exceed 0.5 foot per second." References to evidence of the scientific validity and feasibility of 0.5 foot per second is needed, as well as explanations on how flow rates are to be monitored and by whom and whether this intake velocity limit would be measured per hour, per day, per year or by some other average.
Response:
Please see the responses to Comments 3.08 and 31.34.

⇒ ***Seasonal impacts***

Comment 18.06:
State Water Board should address seasonal impacts in the final policy. Many of California's coastal power plants currently operate as "peaker" plants, during times of peak energy demand. This is typically during hot summer months, which is also the time when peak larval abundance for most species in Southern California is at its highest. It is critical that compliance with marine life mortality reduction requirements takes into account these seasonal variations to truly reduce entrainment impacts.
Response:
Staff agrees and has added language specifying that compliance with required flow reductions would be on a monthly basis, as recommended by the ERP to account for seasonal variability in fish larvae. Please also see the response to Comment 3.08.

g. Infeasibility demonstration

Comments 3.11 and 26.09:
"Feasibility" must be defined to ensure consistent implementation among Regional Water Boards. Under the current language for Track 2, plants can avoid meeting the best technology standard under Track 1 if they can show to a Regional Water Board's satisfaction that it is "not feasible" for them to do so. Of great concern is the fact that "feasibility" is not defined. Without a definition, there is risk that interpretations of "feasible" by Regional Water Board staff are likely to be extremely divergent. Implementation of the policy will result in a hodgepodge of compliance measures determined mainly by the persuasiveness of industry representatives at the regional level, rather than by consistent and fair application of the performance standards across the state. The policy must include a definition for the term "feasibility" in order to achieve the stated goal of the Draft SED of providing "clear standards and guidance to permit writers to ensure consistent implementation across Regional Water Boards." Staff have indicated that their intention was not to include economic considerations in the definition of feasibility, but rather physical and technological feasibility. We strongly urge the State Water Board to define feasibility in the final policy that articulates clear physical, and technological standards for the Regional Water Boards to use. New York State, for instance, defines "feasible" as "capable of being done" with respect to the physical characteristics of the facility site but does not involve consideration of cost." We also encourage the State Water Board to direct Regional Water

Boards to consider the state funded feasibility studies already completed on behalf of the State Water Board and the OPC when evaluating technical feasibility.

Response:

Staff agrees that “feasibility” need to be defined (if used in the Policy to determine eligibility for Track 2) in order to ensure consistent implementation by Regional Water Boards. Staff therefore added the following definition of “not feasible” to the November 23, 2009 version of the revised Draft Policy: “*Not Feasible – Cannot be accomplished because of space constraints or the inability to obtain necessary permits due to public safety considerations, unacceptable environmental impacts, local ordinances, regulations, etc. Cost is not a factor to be considered when determining feasibility under Track 1.”*

However, after considering further public comments received after the December 1, 2009 Meeting, staff is now recommending that permittees be allowed to freely choose between the Track 1 or Track 2 compliance alternatives. The “infeasibility” test has therefore been removed completely from the Track 2 provisions, thereby reducing the workload for both Regional Water Board staff and allowing more flexibility for permittees, while still providing the same level of environmental protection.

Comment 11.46:

The State Water Board should allow Track 2 if the plant can demonstrate that its compliance approach will achieve equivalent or lower impingement and entrainment mortality than Track 1. The Draft Policy must be revised to expressly recognize the acceptability of innovative technologies that achieve superior or equivalent reductions in impingement and entrainment impacts without necessarily reducing intake flow. As currently drafted Track 1 requires a minimum 93% reduction in flow (and an intake velocity not exceeding 0.5 feet per second) and Track 2 can only be used if Track 1 is not feasible. Thus, the Draft Policy precludes a facility for which Track 1 is not determined to be infeasible from pursuing an innovative technological solution that reduces (or eliminates) impingement and entrainment impacts by more than 93% but does not necessarily reduce its intake flow rate by at least 93 percent (or meet the maximum intake velocity). The Board should not adopt a Policy that precludes innovative solutions. For example, Dynegy is investigating the utilization of a technology known as a "Substratum Intake System", which would replace a plant's current cooling water intake system with a network of wells drilled horizontally beneath sand beds on the ocean floor. If proven feasible, this technology would provide near 100% reduction in impingement and entrainment, yet yield no reduction in cooling water intake flow. As a result, under the Draft Policy, the plant could find itself required to build closed-cycle wet cooling under Track 1, despite the presence of an alternative that would possess superior environmental benefits in all aspects *(i. e.,* impingement, entrainment, land use, air quality, aesthetics, etc.)

Response:

After reviewing public comments, staff agrees that owners/operators should have the choice between Track 1 or a Track 2 and is therefore recommending that the “infeasibility” test be removed from the Track 2 provisions (please see the response to Comment 3.11). An owner/operator is now free to pursue a Track 2 solution that reduces impingement and entrainment instead of flow as long as the Track 2 requirements are met. For example with regard to entrainment, the only requirement is that reductions in an innovative Track 2 solution must be at least comparable with the 93% reduction in Track 1. Please note that nothing in the policy precludes permittees from pursuing reductions in entrainment that exceed 93%.

Comment 11.60:

The Draft Policy does not define "not feasible", the gatekeeper for entrance to Track 2. In addition, the "not feasible" determination is to be made in each Regional Water Board's discretion. Thus, Track 2 may be no option at all: it can only be pursued if Track I is "not feasible", an undefined, vague term that is ripe for conflicting Regional Water Board determinations, resource intensive evaluation by Regional Water Boards and, ultimately, paralyzing legal challenges. At the very least, the Board needs to provide clear guidance on what "not feasible" means. However, the definition of "not feasible" must not be exclusive and limiting, as in the 2008 Scoping Document. Rather, the Board should explain that “not feasible" recognizes all appropriate factors affecting feasibility at a specific power plant, including costs. Additionally, the STATE WATER BOARD should explicitly deem as presumptively valid any prior CEC site-specific determination that closed-cycle cooling is not feasible. Any such CEC determination was made on a site-specific basis after a detailed and comprehensive review process that was open to public participation and which gave great weight to the views of the respective Regional Water Boards. The State Water Board should not now second-guess those determinations or require an owner/operator to demonstrate infeasibility a second time. To do so would unnecessarily impose substantial costs and needlessly delay the implementation process.

Response:
Please see the response to Comment 3.11.

Comment 19.04:
Since the policy does not define or discuss the factors that the Regional Water Board's should use to determine that Track 1 is not feasible, it is unclear how this decision would be made and unlikely that there would be statewide consistency.

Response:
Please see the response to Comment 3.11.

Comment 23.07:
The Draft Policy fails to define "feasible" with respect to the language in Track 2. This is a critical omission that will create uncertainty in the regulated community and will inevitably lead to inconsistent application by the various Regional Water Boards. A defensible and readily available definition is found in the CEQA statute at Section 21061.1: "'Feasible' means capable of being accomplished in a successful manner within a reasonable period of time, taking into account economic, environmental, social and technological factor." This definition has been consistently applied throughout California for over 30 years and provides a sensible definition for a critical term in the Draft Policy that will otherwise be subject to inconsistent and competing interpretations.

Response:
Staff appreciates the suggestion. Please see the response to Comment 3.11.

Comment 29.20:
The proposed policy does not include a definition of “feasible” so it is unclear how a Regional Water Board would determine whether closed-cycle cooling is “feasible” for any particular facility. The 2006 version of the policy used a definition of “feasible” that was equivalent to a CEQA-related definition and the 2008 version included a different definition. PG&E supports the use of the 2006 draft OTC policy definition: “capable of being accomplished in a successful manner within a reasonable period of time, taking into account economic, environmental, legal, social, and technological factors.”

Response:
Staff appreciates the suggestion. Please see the response to Comment 3.11.

Comment 35.08:

The policy sets specific dates for various plants to virtually end use of OTC but then offers an escape clause if the plant owner can demonstrate that compliance is "not feasible." No criteria, explanation or definition of “feasible” is provided.

Response:

Please see the response to Comment 3.11.

Comment 37.02:

The Policy should be revised to define the term "feasible" to allow for realistic relief when compliance cannot be implemented successfully given physical and regulatory constraints, such as at SONGS. Track 2 purports to provide relief from Track 1 when an owner or operator of an existing power plant demonstrates that compliance with Track 1 is not “feasible”. The term "feasible" is not defined. SCE believes it is unreasonable for the Board to adopt an OTC Policy that cannot be implemented successfully in light of engineering capability, a site's physical constraints, and reasonably foreseeable regulatory or permitting conflicts. For purposes of the Policy, the term "feasible" should be defined as "capable of being implemented successfully without contradicting proven facts, laws, or circumstances.” This definition provides reasonable opportunity for relief when Regional Water Boards accept that barriers (physical or regulatory) cannot be overcome through any reasonable effort on the part of the owner/operator of an existing OTC plant.

Response:

Staff appreciates the suggestion. Please see the response to Comment 3.11.

Comment 44.03:

The Draft Policy states that pursuant Track 2, if an owner or operator of an existing power plant demonstrates to the Regional Water Board’s satisfaction that compliance with Track 1 is not feasible, the owner or operator must reduce impingement mortality and entrainment of all life stages of marine life for the facility, as a whole, to a comparable level to that which would be achieved under Track 1, using operational or structural controls, or both," The Draft Policy should be amended to establish criteria for determining feasibility and define operational or structural controls.

Response:

Please see the response to Comment 3.11. Staff does not believe that it is necessary to define operational or structural controls.

Comment 45.01:

Implementation of the proposed policy hinges entirely on future decisions about whether compliance is ‘feasible’ or ‘wholly disproportionate’. The policy would be strengthened by providing more detailed definitions of these terms, as they have been used and upheld in recent legal decisions on related matters. More detailed definitions will certainly not avoid disagreements between plant operators, regulatory agencies, and other stakeholders, but it would provide more clarity to the policy.

Response:

Staff agrees, and is proposing to eliminate both terms. Please see the response to Comment 3.11, regarding the definition of “feasible”. Please see the response to Comment 7.07, regarding the definition of “wholly disproportionate”.

Comment 47.01:

The exclusion of economic considerations in determining "feasibility" is unprecedented and flies in the face of the pervasive incorporation of economic considerations in the Water Code. Indeed, it is the fundamental policy of the Porter Cologne Water Quality Control Act "to attain the highest water quality *which is reasonable, considering all demands* being made and to be made on those waters *and the total values involved,* beneficial and detrimental, *economic and social,* tangible and intangible." The State Water Board has no authority to adopt policy that contravenes the intent of the Legislature by jettisoning consideration of all demands on waters, of reasonableness, and of economic and social values. There is, of course, no question that the State Water Board's proposed OTC Policy is more stringent than federal law, since EPA has yet to re-establish any federal BTA standards for existing facilities under Section 316(b). When EPA does develop new Phase II regulations, it may properly apply a cost-benefit analysis in determining what the standards should be, as upheld by the U.S. Supreme Court in *Entergy CO/po* v. *Riverkeeper, Inc.,* 129 S. Ct. 1498 (2009). The corrective action program regulations require the Regional Water Boards to determine whether it is technologically *or economically infeasible* to achieve the background levels of constituents, in order to establish concentration limits above background. 23 Cal. Code Regs. § 2550.4(c). Similarly, containment zones are authorized where it is technically-or *economically infeasible* to clean up to water quality objectives, and water quality objectives are not exceeded outside the zone. State Water Board Res. No. 92-49; 23 Cal. Code Regs. § 2911. When dischargers are required to provide technical reports under Water Code 2 section 13267, the burden, including costs, of the reports must bear a reasonable relationship to the need for and benefits to be obtained from the reports. Moreover, the Water Code and State Water Board regulations require "feasibility studies" for a variety of control and conservation projects, and those studies must analyze economic as well as technical factors.

Response:

Please see the response to Comment 3.11.

Staff disagrees, however, with the statement that the exclusion of economic considerations in determining "feasibility" would have been unprecedented and in conflict with the Water Code. State Water Board staff has extensively considered costs throughout the process of assessing available technologies and determining BTA and compliance options, such that the claim that the Draft Policy contravenes the intent of the Legislature as set forth in Water Code Section 13000 is unsupported. The statutes and regulations cited (governing waste management units, investigations, and containment zones) are inapplicable to the State Water Board's exercise of authority in establishing state policy for water quality control and pursuant to CWA Section 316(b), requiring the standards established for NPDES permits require that the location, design, construction and capacity of cooling water intake structures reflect the best technology available for minimizing adverse environmental impact. The Supreme Court's decision in *Entergy* interpreted that Section to accord agencies with discretion to determine if and how costs may be considered. While a cost-benefit analysis was found "permissible", it was not found to be a required element. EPA's Phase II regulations remain suspended, and BPJ is the currently-applicable standard in making BTA determinations. Thus, the proposed Policy is not more stringent than federal law.

Comment 47.02:

CEQA provides another widely recognized definition of "feasibility" which would be appropriate for the OTC Policy: "'Feasible' means capable of being accomplished in a successful manner within a reasonable period of time, taking into account economic, environmental, social and technological factors."

Response:

Staff appreciates the suggestion. Please see the response to Comment 3.11.

Comment 49.11:

The revised Draft Policy states: "If an owner or operator of an *existing power plant** demonstrates to the Regional Water Boards' satisfaction that compliance with Track 1 is *not feasible*,* the owner or operator must reduce impingement mortality and entrainment ~~of all life~~

~~stages~~ of marine life for the facility, as a whole, to a comparable level to that which would be achieved under Track 1 using operational or structural controls, or both." The criteria for determining whether an owner or operator can demonstrate infeasibility should be required here. To be clear, the relevant section of Section 316 (b) cited by the asterisk should be quoted in a footnote. "All life stages" should remain in the Policy because if all life stages are not considered in determining reduction in entrainment and impingement, then only a partial analysis of the impacts of OTC and the standard for compliance with Track 1 is required.

Response:

Please see the response to Comment 3.11 regarding the definition of "*not feasible*". The asterisk notes a definition set forth in a separate section of the policy. The commenter has not explained what additional clarity is needed and how it relates to Section 316(b). Staff removed the words "all life stages" for clarity reasons, because not all life stages will be monitored for compliance under Track 2. In general, entrainment impacts are based on sampling for ichthyoplankton and invertebrate meroplankton species greater than 200 microns in size. If screens are employed, compliance will be based on ichthyoplankton, crustacean phyllosoma and megalops larvae, and squid paralarvae.

Comment 55.01(a):

We share the concerns of CCEEB, utility and fellow independent power producers on the exclusion of cost considerations in assessing feasibility in Track 2.

Response:

Please see the responses to Comments 3.11 and 47.01.

Comment 58.03:

The policy's provisions for Track 1 and 2 appear to provide potential loopholes that could be exploited to allow unreasonable extensions of the use of OTC by power plants. Owners or operators would be allowed to "demonstrate" that Track 1 is "not feasible" without adequate standards required to show infeasibility. Under the policy, if such a demonstration is accepted by a regional water board, the owner or operator will be allowed to meet compliance under Track 2, which has less demanding requirements for reducing OTC. Compliance with those lower requirements would be measured by monthly verification of through-screen intake velocity or monitoring of impacts on fish and larvae, as described in Section 4 A. The policy does not state who will choose among those two options or how that will be done. But assuming monitoring is the means chosen for measuring compliance under the two options, there is no standard referenced for determining what level of entrainment and/or impingement would be acceptable for compliance. Baseline entrainment sampling would provide an "unbiased estimate of larvae entrained," but to what use would that estimate be put in determining whether a plant were in compliance with the new policy? What is the point of the process?

Response:

Please see the response to Comment 3.11 regarding the "feasibility test". Staff is now recommending that permittees be allowed to freely choose between the Track 1 or Track 2 compliance alternatives, and the "infeasibility" test has therefore been removed completely from the Track 2 provisions, Compliance monitoring is required if the Track 2 compliance option is chosen. Staff has clarified that the type of compliance monitoring required depends on the type of Track 2 controls chosen by the power plant owner or operator, as described in Section 2.A(2) of the proposed Policy. This section of the proposed Policy also states that, under Track 2, IM/E must be reduced for the facility, as a whole, to a level comparable with Track 1. If flow and velocity reductions are the only means of complying with Track 2, flow must be reduced to 93% of the design intake flow rate and velocity must be reduced to 0.5 ft/sec. No entrainment and impingement monitoring would be required under this option. If other types of Track 2 controls are chosen, IM/E must be reduced to at least 90% of the level required under Track 1. (The

10% difference is intended as a reasonable margin of error in estimating the actual performance of Track 2 technologies.) If screens are employed to reduce entrainment, compliance would be determined based on ichthyoplankton, and on the crustacean phyllosoma and megalops larvae, and squid paralarvae fractions of meroplankton. Section 4 of the Policy describes the compliance and baseline monitoring required if a Track 2 compliance option, other than strictly flow and velocity reduction, is chosen. By doing baseline sampling, it is possible to determine the concentration and composition of larvae entrained by the facility seasonally, and convert it to the total number entrained by the facility by multiplying the concentration with the flow. By multiplying the design intake flow over a compliance time period with the measured concentration of larvae, you derive the maximum entrainment possible. This number must be reduced by 83.7% (90% of the 93% reduction required under Track 1).

Comment 59.01:
SCE proposes the addition of the following definition of "feasible" to the Revised Policy:
Feasible - Means capable of being accomplished in a successful manner within a reasonable period, taking into account economic, environmental, legal, social and technological factors.
Response:
Staff appreciates the suggestion. Please see the response to Comment 3.11.

Comment 60.05(b):
Further. given the apparent trend in the industry's focus on exemptions to the rule, there is a major concern that a facility can "game" the "not feasible" considerations by simply not attempting to comply through exhausting every conceivable opportunity. For example, for those 10 operators resistant to complying with Track 1, there is an incentive to passively accept the denial of a permit without creatively exhausting all remedies. An example may be the recent denial of air quality credits for the El Segundo re-power project. Because NRG was compelled in their own interest to remedy the permit problem, we understand they now have voluntarily offered to de-commission one more of their units to create the air quality credits needed to complete the repower project. We are deeply concerned that this type of creativity and diligence to alleviate the considerations listed in the "not feasible" definition, in a strategic effort to be granted the Track 2 exception to the rule, will not be commonplace. We strongly recommend some standard to ensure full diligence in exploring ways to comply with other laws while still complying with this cooling water policy. Therefore, we recommend inserting language at the appropriate place to guide the Regional Water Boards to exercise BPJ and seek the assistance of an unbiased third-party review if necessary.
Response:
Please see the response to Comment 3.11.

h. The Track 2 compliance alternative

⇒ ***The 10% margin of uncertainty***

Comments 3.09 and 26.07:
We believe that all plants should reduce entrainment and impingement consistent with Track 1. The current phrasing of the policy suggests that plants that fall under Track 2 will have to achieve a 90% reduction of the reduction that could be achieved under Track 1; in other words, 90% of 93%, which is 83%. We urge the State Water Board to require that all plants reduce entrainment and impingement consistent with the Track 1 standard. The Ocean Protection Council (OPC) passed a resolution in 2006, which encourages the State to implement the most protective controls to achieve a 90-95% reduction in impacts. Track 2 falls short of this clear

guidance set by the OPC by allowing plants to only reduce 83% of their total impacts. Maintaining Track 2 so separate technologies may be used from Track 1 to comply with the ultimate policy is understandable, but the percent reduction targets should be equivalent in both Tracks. As the court articulated in *Riverkeeper, Inc. v. U.S. E.P.A.,* 358 F.3d 174 (2nd Cir. 2004) (*Riverkeeper I*), there is a reasonable margin of error in the actual performance records given the complexities of monitoring dynamic physical processes and seasonal, annual or decadal changes in fish abundance and location. However, allowing for a margin of error in the performance monitoring should not be confused with allowing a margin for the targeted reduction in entrainment. The court noted that a "facility must aim for 100%, and if it falls short within 10%, that will be acceptable. It may not, however, aim for 90 percent and achieve only an 89 percent reduction in impingement and entrainment." We urge the State Water Board to avoid actions that conflict with the *Riverkeeper cases*, and to instead follow the guidance sent by the OPC to reduce entrainment by at least 93% at all plants with no exceptions.

Response:

Staff disagrees that Track 2 is less stringent than Track 1. The Policy requires under Track 2 that IM/E be reduced to a ***comparable level*** to that which would be achieved under Track 1. Staff has modified the Policy to further specify that facilities relying strictly on flow and velocity reductions to meet Track 2 must reduce IM/E by 93%, as under Track 1. This is because flow reductions are relatively easy to accomplish and verify. For permittees relying on other control technologies, such as barriers, to meet reduction requirements, a 10% uncertainty allowance is provided when determining compliance because many of the Track 2 control technologies are largely untested in marine waters and compliance monitoring is relatively difficult.

Comment 11.61:

To the extent, the Board does not make Track 2 workable by providing additional flexibility and certainty in implementation, the Track 2 performance standard -- "within 10%" of Track 1 -- is arbitrary and capricious. The Board has not offered any support for this standard as either necessary for achieving environmental benefits or achievable at all OTC facilities using a combination of technology and operational controls that do not install closed-cycle cooling. Put another way, why is the standard within 10% and not, for example, within 15%? Moreover, the arbitrariness of the Track 2 performance standard is further apparent in that it is pegged to a Track 1 minimum performance standard that is itself arbitrary.

Response:

Please see the response to Comment 3.09. Staff believes that 10% is a reasonable margin for uncertainty to provide in assessing compliance with Track 2 controls, and does not believe that this margin needs to be set higher.

Comment 18.05:

The draft policy offers two tracks for final compliance: Track 1, which is currently defined as closed-cycle wet cooling and Track 2, which allows for the use of alternate technologies to achieve marine life mortality reductions. Unfortunately, as currently written, Track 2 is less stringent and allows for higher impingement and entrainment rates - only an 83% reduction in marine life mortality as opposed to the 90% required for Track 1. The final policy should require that all plants reduce entrainment and impingement consistent with the Track 1 standard to ensure consistent marine life mortality reductions regardless of the approach taken to achieve compliance. Maintaining Track 2 so separate technologies may be used from Track 1 to comply with the ultimate policy is understandable, but the percent reduction targets should be equivalent in both compliance tracks to adequately protect our coastal marine resources from this antiquated technology.

Response:

Please see responses to Comments 3.09 and11.59.

Comment 19.03:
The proposed policy allows the owner or operator of an existing power plant to demonstrate compliance with the policy via Track 2 (i.e., via operational and/or structural controls) if they can demonstrate to the satisfaction of the Regional Water Board that compliance with Track 1 is not feasible. Compliance with Track 2 requires reduction of impingement and entrainment within 10% of the level achievable under Track 1 (i.e., 83% reduction under Track 2, compared to 93% under Track 1). We recommend elimination of the Track 2 compliance alternative due to the lower level of environmental protection provided by this option and also because we do not believe that technology is available to allow power plants to adequately reduce entrainment losses via operational or structural controls.
Response:
Please see the response to Comment 3.09. Staff disagrees that Track 2 provides a lower level of protection than Track 1, and believes that it adds needed flexibility for power plant owners or operators to choose methods of compliance. Staff has therefore changed the Policy so that an owner or operator may freely choose between Track 1 or Track 2.

Comment 43.02:
Under Track 2 the owner or operator must reduce impingement mortality and entrainment to a level comparable to what would be achieved under Track 1. A "comparable level" is defined as within 10% of what would be achieved under Track 1. An explanation of how the 10% basis was determined should be provided, perhaps as a footnote to the Policy.
Response:
Comment noted. Please see the responses to Comments 3.09 and 11.61.

Comment 49.10:
Section 2. A. (2) of the Policy states that “For the purposes of this policy, a "comparable level" is a level that achieves at least 90 percent of the reduction in impingement mortality and entrainment achievable required under Track 1.” Does this calculate to 83.7%? If so, it should be so stated to avoid confusion or misinterpretation.
Response:
Please see the response to Comment 3.09. Indeed, 90% of 93% reduction in IM/E is 83.7%. Staff wanted the Track 2 reduction to be compared to the reduction required under Track 1.

Comment 11.48:
The State Water Board should revise Track 2 implementation by providing that if compliance technologies installed to meet Track 2 ultimately fall short of the compliance standard due to circumstances beyond the owner/operator's control, installation of additional controls or shutdown is not required. The efficacy of alternative cooling water technologies is highly variable and subject to a multitude of factors over which the discharger has no control. If the approved technology is appropriately installed, operated and maintained but does not, through no fault of the owner/operator, reach the compliance standard, the owner/operator should not be punished by then having to install new controls.
Response:
The Policy has been revised to allow owner/operators the choice between either Track 1 or Track 2 compliance alternatives. It is the owner/operator’s responsibility to wisely choose the method of compliance. Installation of wet or dry closed-cycle cooling assures compliance; if less proven methods are chosen that fall short of the requirements, it is the owner/operators responsibility to reduce flows or install other technology to make up the difference. Note that the Policy already allows a 10% reasonable margin in estimating the actual performance of

Track 2 technologies (other than solely flow and velocity reductions). Please see the response to Comment 3.09.

⇒ ***Determining compliance for the facility as a whole***

Comments 3.10 and 26.08:
Reduction of intake should be required for each *unit* of a plant. While Track 1 would apply to each unit of a plant, Track 2 currently allows for the plant "as a whole" to achieve reductions in impingement and entrainment, thereby creating a loophole where a plant could convert some of the units away from OTC and still run OTC on the remaining units. This loophole is significant because the remaining OTC "peaker" plants would likely run during times of peak energy demand – during the summer – when peak larval abundance for most species in Southern California is at is highest. So while a power plant in Southern California might be able to reduce its annual water intake at an OTC unit by only running it in the summer, this would not result in the desired reduction of entrainment and impingement impacts. This loophole undermines and is contradictory to the "technology based" and "technology forcing" policies in the CWA. Further, as written, Track 2 violates the clear mandate in Section 316(b) by allowing a change in "operation" of the plant as a substitute for "best technology available" to reduce adverse impacts. Allowing a reduction or other juggling of the operation of one or more units at a power plant is not the same as meeting the mandate to improve the technology itself. Staff has suggested that allowing Track 2 as a compliance alternative for limited types of facilities rewards these owners that have invested in more efficient generating units. While encouraging greater efficiency in our overall generating capacity is a laudable goal, it is not a factor in crafting guidance for full enforcement of the CWA. Further, these facilities have obviously found a financial incentive to greater efficiency and re-powered some of their units without any incentive provided by an unrelated exception to the rule.
Response:
Staff disagrees that Track 2 violates any mandate in Section 316(b). It is staff's intent that Track 1 controls would be strictly structural controls, i.e., either wet or dry closed-cycle cooling technology. No compliance monitoring is required for Track 1, once the technology has been verified to meet the flow rate reduction requirement. Staff's intent in specifying that each unit must meet this flow rate reduction requirement was to avoid the situation where an owner/operator switched four units to dry cooling and used the remaining two OTC units as needed, thus allowing the plant, as a whole, to meet the flow rate reduction requirements. This scenario is allowed under Track 2, but monitoring is required. Under Track 2, an owner or operator must reduce IM/E to a level **comparable** to that which would be achieved under Track 1, using operational or structural controls, or both, for the facility **as a whole**. Staff wanted to provide an owner/operator the flexibility of choosing between a combination of operational and structural controls to meet these entrainment and impingement reduction goals, if IM/E reductions comparable to Track 1 could be accomplished for the facility as a whole. Some technologies may only provide a 60% reduction in IM/E, but if combined with dry cooling units, substratum wells, variable speed pumps, or other technology may overall meet the 93% goal. However, because many Track 2 technologies are unproven, this approach requires monitoring to confirm that the required reductions are indeed accomplished and a 10% uncertainty factor is therefore provided.

It is true that entrainment is seasonal and that OTC intake during a summer day may have greater entrainment impacts than at some other time of the year. However, the goal of reducing entrainment by 93% of design flows, when a plant relies on using flow controls, is still a very large reduction in entrainment, essentially comparable with Track 1 (Please also see the response to Comment 3.08 and 58.03). It is important to note that closed-cycle wet cooling towers under Track 1 would also entrain organisms during summer months when taking in water. Both structural and operational controls are technological and are clearly allowable under the USEPA Phase I regulations. Therefore, the use of only an operational control, e.g., to reduce flows, thereby reducing a plant's overall impingement and entrainment by 93% would have virtually the same result as the reduction in flows commensurate with closed cycle wet cooling.

Regarding the apparent reference to the inclusion of an allowance for combined cycle units in Track 2, staff believes that these units are more efficient in terms of water (resulting in less entrainment than steam boiler OTC) and fuel use, and were installed with stringent conditions under recent NPDES permits issued by Regional Water Boards. Still, staff is proposing further requirements on plants with combined cycle units. Either the reductions associated with the installation of combined cycle units may be counted toward compliance with Track 2, in which case further controls would be needed to bring the entire plant in compliance, or reductions in velocity would be required on combined cycle intakes combined with complying with the immediate and interim requirements described in Section 2.C of the proposed Policy.

Comments 9.14 and 15.02:
Track 1 calls for reduction of the intake flow rate at each unit, while Track 2 calls for a reduction for the facility as a whole. Why are these different standards used? The State Water Board should only consider the intake flow rates at each, individual intake structure for reduction and all other purposes.
Response:
Under Track 1, an owner or operator must reduce intake flow rates to a level commensurate with that which can be attained by closed-cycle wet cooling system, which is specified as a minimum 93% reduction in intake flow rate for **each unit**, compared to the design intake flow rate. It is staff's intent that Track 1 controls would be strictly structural controls, i.e., either wet or dry closed-cycle cooling technology. No compliance monitoring is required for Track 1, once the technology has been verified to meet the flow rate reduction requirement. Staff's intent in specifying that each unit must meet this flow rate reduction requirement was to avoid the situation where an owner/operator switched four units to dry cooling and used the remaining two OTC units as needed, thus allowing the plant, as a whole, to meet the flow rate reduction requirements. This scenario is allowed under Track 2, but monitoring is required.

Under Track 2, an owner or operator must reduce IM/E to a level **comparable** to that which would be achieved under Track 1, using operational or structural controls, or both, for the facility **as a whole**. Staff wanted to provide an owner/operator the flexibility of choosing between a combination of operational and structural controls to meet these entrainment and impingement reduction goals, if IM/E reductions comparable to Track 1 could be accomplished for the facility as a whole. Some technologies may only provide a 60% reduction in IM/E, but if combined with dry cooling units, substratum wells, variable speed pumps, or other technology may overall meet the 93% goal. However, because many Track 2 technologies are unproven, this approach requires monitoring to confirm that the required reductions are indeed accomplished. Staff did consider requiring compliance per intake structure for Track 1, but decided that compliance on a per unit basis would better accomplish the intended reductions.

Comment 11.49:
The State Water Board should revise Track 2 implementation by providing that site-specific credit for entrainment and impingement survival is allowed, where demonstrated. Dynegy supports applying Track 2 to an existing power plant "as a whole", rather than on a unit-by-unit or intake-by-intake basis. For example, at Moss Landing, habitat restoration projects have

already been implemented to offset the OTC environmental impacts of Units 1 & 2. Nevertheless, if it is feasible and makes economic sense to retrofit Moss Landing Units 1 & 2 with dry cooling (rather than pursue infeasible reductions from Units 6 & 7), the reduction realized from doing so should be credited to Unit 6 & 7's compliance with Track 2. Similarly, at Morro Bay, the permanent retirement of Units 1 & 2 (if ultimately pursued) should be credited toward the plant's compliance with Track 2. The facility-wide approach properly recognizes that a power plant may have multiple units that often are very different in physical and operation characteristics and have complex interrelationships that may significantly impact BTA decisions and feasibility determinations.

Response:

Please see the response to Comment 11.66 stating providing site-specific credit for entrainment and impingement survival is allowed. Staff agrees that the owner or operator should have flexibility to choose the most appropriate compliance methods for their facility as a whole, as the proposed Policy specifies. For example, this could be accomplished by using a combination of retrofitting and reducing/eliminating flows at individual units as described by the commenter. Please see the response to Comment 9.14.

Comment 43.01:

Under Track 1, compliance is required for each unit of the existing power plant. If compliance cannot be achieved using Track 1, Track 2 is provided as an alternative. However, under Track 2, compliance is determined based on the whole facility. We suggest that compliance for both Tracks 1 and 2 be required on a unit basis. We also suggest that "feasible be further defined in the Policy as technical feasibility.

Response:

Please see the response to Comment 9.14 regarding compliance under Track 2 for the facility as a whole, rather than on a per unit basis. Please see the response to Comment 3.11 regarding the “feasibility” test.

⇒ ***Track 2 control technology***

Comment 4.04:

Track 2 authorizes plants to use alternative technology and operational controls to achieve 90% of a 93% reduction in flow rates and protecting all marine organisms, even microscopic marine organisms down to 200 microns in size. These requirements are unattainable without the use of closed-cycle cooling. If the technology existed and allowed a unit to function without fouling, the use of 0.2 mm mesh screens might stop entrainment, but would instead impinge these organisms as well as eggs and larvae. Such operation could result in 100% mortality.

Response:
Note that permittees are not required to pursue Track 2; it is an option that has been requested by several permittees to allow for flexibility in complying with the proposed Policy's reduction requirements. Under the Track 2 approach, the owner/operator may choose to employ a combination of operational and structural controls (such as variable speed pumps, filters, or seasonal operation) to meet entrainment and impingement reduction goals. An example of a Track 2 technology that would provide 100% elimination of impingement and entrainment is subsurface intake wells. Please see Comment 7.02. Staff acknowledges that wedgewire screens are currently untested in marine waters, and may foul easily or cause smaller larvae to be impinged rather than entrained. Certainly, wedgewire screens would effectively prevent larger organisms from impingement. Nonetheless, staff has modified the proposed Policy to specify that if screens are employed to reduce entrainment, compliance would be determined based strictly on ichthyoplankton, the crustacean phyllosoma and megalops larvae, and squid paralarvae fractions of meroplankton.

Comment 7.02:
The proposed Policy requires that an owner or operator of an existing once-through-cooling plant must protect marine life by either of two tracks. Compared to the Track 1 option of essentially committing to closed-cycle cooling, the Track 2 option requiring operational and/or structural controls to reduce impingement and entrainment is not as straight forward. Marine life (e.g., plankton, larvae, etc.) occurs at such a small scale that entrainment cannot be reduced by filtering to a level anywhere near comparable to the benefits gained by closed-cycle cooling. The draft SED mentions some of the technologies that are considered reasonably foreseeable means of compliance. Many of the technologies to reduce entrainment are untested and/or are not applicable to estuarine or marine waters where conditions are vastly different than in lakes or rivers. For example, large waves would tear aquatic filter barriers apart in ocean environments and their enormous size, needed for sufficient power plant cooling flow, is a limitation in harbor environments. Likewise wedge wire screens may work in river environments where currents come in one direction, but this technology is untested in marine environments where currents vary in direction. Additionally, compared to freshwater environments, extremely high rates of biofouling in marine and estuarine environments would rapidly decrease the pore size of wedge wire screens, fine mesh screens, and aquatic filter barriers, likely rendering such technologies useless. Even if freshwater entrainment technologies could be deployed in a marine system, such technologies do not preserve or protect the environment if they simply trade one method of mortality for another. The question of whether filtering kills fewer organisms than entrainment has never been established for marine settings. Reducing entrainment by filtering organisms with very small filters may simply replace entrainment mortality with impingement mortality. However, there are technologies that power plants can use to reduce OTC impacts in marine environments. Impingement is more easily addressed by technologies although, impingement is generally considered of minor concern with the exception of the open ocean intake at SONGS. With regards to entrainment technologies, subsurface intake wells designed to provide cooling water from below the sediment surface may be possible at certain facilities. In locations where underlying geologic conditions are favorable to provide adequate water for power plant cooling, a properly designed array of intake wells that spreads out and slows the intake of cooling water through diffuse subsurface sediment layers could potentially eliminate both entrainment and impingement.

Response:
Comment noted. Staff agrees that Track 2 is not as straightforward as Track 1. However, under the Track 2 approach, the owner/operator may choose to employ a combination of operational and structural controls (such as variable speed pumps, filters, or seasonal operation) to meet entrainment and impingement reduction goals.

Comment 20.01:
No technologies have been identified under Track 2 that would provide the entrainment reductions sought by the proposed statewide policy. We note that there are no known technologies currently available that would exclude zooplankton from entrainment, other than retrofit closed-cycle cooling.
Response:
Please see the response to Comment 4.04. An example of a technology that would provide 100% elimination of impingement and entrainment is subsurface intake wells. Please see Comment 7.02. Under the Track 2 facility-wide approach, a combination of closed-cycle cooling and other flow reductions (e.g., variable speed pumps, seasonal operation) could be employed to meet entrainment reduction goals. The SED identifies these and other IM/E reduction technologies. In addition, there are other technologies, for example re-location of intakes, which may be considered by plant operators and could be proposed in their implementation plans for Track 2.

Comment 29.06:
Other than closed cycle cooling, there are no technologies are available – even in combination – that will provide the 84% level of reduction required under Track 2. For this compliance option to be meaningful there must be available technology to achieve the 84% benchmark. The SED utilized a USEPA document and an EPRI document to evaluate various types of potential compliance measures: flow reduction, physical barriers, collections systems, behavioral barriers, and operational modifications. We believe that the SED greatly overestimates the ability of plants to use alternative technologies to meet Track 2 requirements. The wide mesh barrier nets discussed in the SED are for the reduction of impingement only and are best suited for seasonal installations involving high impingement events. This technology is obviously of very limited value, and of no value at all for Diablo Canyon. The discussion in the SED on aquatic filter barriers suggests that this technology may have more applicability than is likely the case. At the Lovett installation, reliability was low and there were significant maintenance problems. As described, Mirant, the owner of both Lovett and Contra Costa decided not to install AFBs at Contra Costa based both on the results at Lovett as well as the results of preliminary testing at Contra Costa. Furthermore, there is no experience with this technology in an open-ocean environment. The relocation of intakes further offshore would, in most cases, simply exchange one type of entrainment for another. At Diablo the costs would be exorbitant and productive, pristine rocky reef habitat would be lost. It would also simply switch entrainment to more commercially and recreationally important species – which is not likely to be a positive outcome. The consideration of seasonal operation restrictions is not a feasible alternative for a facility that provides base load power. Further, nuclear plants in particular are designed to run at full capacity and are not well suited to ramp up and down or run at partial capacity. For fossil plants, this option may be difficult as well. Plants are often needed in the summer, when larval densities can be at their highest at some locations. In any case, it is unlikely to provide the level of reduction required under Track 2. The last technology mentioned in the discussion is wedge wire screens. This technology is limited in use to river environments, and thus, not viable at most California OTC facilities. The other technologies or operational measures assessed all raise significant concerns for many facilities. Thus, the analysis does not identify any technologies that are readily available and well tested to meet the requirements set out in Track

2. Without such flexibility, facilities are left with no compliance option, and must retire unless repowering makes sense. The Water Board should reconsider whether it may make the most overall sense to provide a greater degree of compliance flexibility so as to allow facilities options other than cooling towers and create incentives to do what is truly feasible in the short term. This is particularly true for plants that are required to maintain grid stability.

Response:

Please see the responses to Comments 4.04, and 20.01.

Comment 31.11:

RRI has not identified any practical technology that can be applied that would allow Track 2 compliance (as outlined in the Draft Policy) using 2007-08 circulating water flow estimates as a base. Significant flow reductions, on the order of about 20% to 25% for operational modifications, and up to about 40% to 45% if variable frequency drives are installed on the circulating water pumps, can be achieved without impacting operation at levels similar to what was required to support system reliability requirements in the 2007-08 timeframe. To approach 83% reductions from 2007-08 flow levels would necessitate significant reductions in operating hours/loads from the levels required during that base period. Our best estimates are that, even with application of such technologies, reductions in net capacity factor on the order of 70% to 75% would be required to achieve an 83% reduction in circulating water flow from the proposed Track 2 baseline. This would have had the effect of reducing net Capacity Factors on Mandalay Unit 1 from 10.5% to 2.6%, Mandalay Unit 2 from 17.5% to 4.3%, Ormond Beach Unit 1 from 4.9% to 1.2%, and Ormond beach Unit 2 from 8.5% to 2.1 %. Restricting the units' operation to this degree will likely render the plants inadequate for meeting the local reliability needs in the Los Angeles region or for justifying the fixed expense and capital additions needed to keep the plants operating.

Response:

Please see the responses to Comments 4.04 and 20.01. Please note that required reductions will be based on design flows, not actual flows as used in the commenter's example calculations.

Comment 37.10:

The Policy provides relief from closed-cycle cooling performance upon a showing that meeting such a standard is not feasible. However, the relief provided in Track 2 is illusory. Track 2 authorizes plants to use alternative technology and operational controls to achieve 90% of the Track 1 protection of all stages of life of marine organisms, including very small fish eggs, larvae, and plankton. No known technology exists that can achieve the level of reduction of entrainment required in Track 2, other than closed-cycle cooling. Achieving the level of reduction of all stages of marine life required in Track 2 would require the use of screens with 0.2 millimeter spacing. The use of such finely spaced barriers, especially in an ocean environment, is not feasible because the screens would become clogged by all manner of marine organisms and plants larger than fish eggs and larvae. These blockages would prevent the operation of the generation unit.

Response:

Please see the responses to Comments 4.04, 20.01, and 41.01. Based on public comments, staff has revised the Policy to remove the wording "all life stages". Staff has also specified that if screens are employed to reduce entrainment, compliance would be determined based strictly on ichthyoplankton, the crustacean phyllosoma and megalops larvae, and squid paralarvae fractions of meroplankton. Staff would not expect 0.2 millimeter wedgewire screens to be used. Note, however, that these screens could be used in conjunction with other controls, such as variable speed drives, to accomplish the required reduction.

Comment 41.01:
Eliminate the requirement to protect zooplankton. Currently there is no data or information provided to indicate zooplankton suffer mortality as a result of entrainment. Further, due to the short life cycle and rapid reproduction of these organisms significant impacts are unlikely to occur. Making this change to the Policy will create a viable Track 2 option. To achieve Track 2 compliance, zooplankton would have to be protected at the expense of fish and shellfish eggs and larvae which would become impingeable on the 200 micron screens.
Response:
Technically, zooplankton is a comprehensive term that is inclusive of ichthyoplankton (fish eggs and larvae), invertebrate meroplankton (larvae of benthic invertebrates), and holoplankton (invertebrates that are planktonic their entire lives). Of course we know that ichthyoplankton and meroplankton experience 100% virtual mortality due to entrainment. For purposes of the policy, ichthyoplankton and meroplankton are defined separately. For purposes of the policy, meroplankton is defined as only those zooplankton that are pelagic larvae of benthic invertebrates, and zooplankton is defined to include only planktonic invertebrates larger than 200 microns. Therefore the zooplankton definition in the policy does not include holoplankton, such as copepods, that have short life cycles and rapid turnover.

Monitoring is recommended by staff for all meroplankton greater than 200 microns, because for example this includes organisms such as abalone (which for some species are threatened), bivalves and sea urchins which are important members of benthic communities. It is important to know the impact on these organisms.

Based on public comments, staff has revised the Policy to remove the wording “all life stages”. Staff has also specified that if screens are employed to reduce entrainment, compliance would be determined based strictly on ichthyoplankton, the crustacean phyllosoma and megalops larvae, and squid paralarvae fractions of meroplankton. Staff would not expect 0.2 millimeter wedgewire screens to be used. Note, however, that these screens could be used in conjunction with other controls, such as variable speed drives, to accomplish the required reduction. The requirement for monitoring at a lower size would not interfere with the use of screens as a Track 2 compliance measure.

Lastly, staff is hopeful that screening devices would not impinge the organisms that they are designed to exclude from entrainment. Such devices should be designed to prevent mortality either from entrainment or by impingement.

Comment 50.04:
At the December 1, 2009 workshop, Dominic Gregorio, Environmental Scientist, Division of Water Quality" State Water Resources Control Board, explained that the “reference to 200 microns" in the definition of "zooplankton" pertained to the size of entrainment sampling nets and was not applicable to intake screening devices. This distinction is very important because the 200 micron size essentially eliminates any reasonable means of compliance under Track 2 since there are no existing technologies that can screen out 200 micron organisms. However, the Revised Draft Policy does not clearly make that distinction. The Board must make that distinction explicit in the Policy given its importance to compliance determinations. We suggest that a size of 2 mm or greater be applied to screening devices based on consideration of reducing fouling opportunities and a mesh size that would meet with the intentions of the Policy
Response:
Staff stands by the statement made at the Dec.1, 2009 workshop. Please see the response to Comment 41.01.

Comment 61.04:
Section 1.1 of the SED states that "policy adopts appropriate technology-based standards…", but there is very little information presented relative to technology-based methods for reducing IM&E. The policy for the most part eliminates OTC at all fossil facilities since compliance includes screening zooplankton down to 200 microns in size. There are no technologies available that would provide screening of small zooplankton, and therefore, the feasibility of using Track 2 for compliance is virtually eliminated.
Response:
Please see the responses to Comments 4.04, 20.01, and 41.01.

Comment 9.21:
One of the "Reasonably Foreseeable Means of Compliance" technologies listed in the SED is the aquatic barrier net. It should be removed from the list of technologies that can be used to comply with the policy because numerous studies, including those submitted to the Energy Commission during its review of Duke Energy's application for a new power plant in Morro Bay, as well as to other governmental agencies, have shown that such technology is not effective mitigation for OTC.
Response:
The SED discusses both the benefits and short comings of barrier nets. In some situations their use may be appropriate. Site specific evaluations will be needed to determine if the use of barrier nets will meet the goals of the policy. A categorical prohibition of their use is inappropriate.

⇒ ***Miscellaneous comments***

Comment 11.50:
The STATE WATER BOARD should revise Track 2 implementation by providing that where flow reduction is the sole compliance approach, impingement and entrainment studies are not required and flow reduction will be determined over an annual period. Any shorter-term flow reduction measure is unworkable and would potentially cause grid reliability issues by limiting electricity production during periods when the need for electricity is the greatest. Given the difficulties in and high cost of directly measuring cooling water volume flows, the proposed Policy should also allow the use of appropriate calculations to demonstrate flow reduction where flow reduction is selected as a compliance strategy, rather than requiring direct measurement of cooling water volume.

Response:
Staff agrees and has revised Section 2.A(2) of the Policy, to clarify that where to flow reduction is the sole compliance approach, entrainment studies are not required. However, monthly verification of the flow reductions is required. Staff determined that flow reductions should be determined on a monthly basis, because this time period was recommended by the ERP to account for seasonal variability in fish larvae. If the compliance period was set to a year, a power plant could use OTC for the entire month of June, when the fish larvae were most plentiful, and shut down the rest of the year. Please also see the response to Comment 3.08. Regarding measuring intake flows, there are several established indirect methods, which are routinely used in power plants. For instance, if you turn on a pump and have established the pumping rate, you can easily calculate the volume pumped.

Regarding impingement, if a plant has reduced through-screen intake velocities to 0.5 ft/sec, no impingement studies are required. However, monthly verification of the reduction in through-screen intake velocities is required.

Comment 11.66:
The proposed Policy should give credit for both entrainment and impingement survival. As currently drafted, Track 2 would require a comparable level (i.e., within 10% of the reduction achievable under Track 1) of reduction for both "impingement mortality and entrainment". Thus, credit apparently would be given for impinged fish that survive, but not allowed for entrained organisms that survive. The standard should be clearly expressed in terms of both ""impingement mortality and entrainment mortality since the objective is to reduce mortality.
Response:
Staff agrees that the objective of the proposed Policy is to reduce both entrainment and impingement mortality. However, although some experts believe that a very small fraction of entrained organisms may survive, this fraction is likely so negligible that State Water Board staff is assuming 100% mortality for ease of determining compliance.

Comment 31.33:
Under Track 2, a facility can use either technological or operational options to comply. Credit is given to technological changes installed prior to the adoption of the Policy, but not to operational options. But if operational options (i.e., running less) can qualify as BTA going forward, why do they not qualify retrospectively? The SED is silent on that question. It is unreasonable to make that distinction however, and Track 2 should be modified to allow lower run hours to qualify as BTA regardless of when the lower run hour regime started.
Response:
Track 2 is based on Track1, requiring comparable level of reductions. The proposed Policy specifies under Track 1 that "*A minimum 93 percent reduction in intake flow rate* for each unit is required for Track 1 compliance, compared to the unit's* ***design intake flow rate***." (emphasis added). The design intake flow rate does not vary over time, as it is based on the maximum pumping rate that the intake pumps are designed for. Compliance is determined on a monthly basis.

By using the design intake flow rate as the baseline for calculating flow reductions, a facility gets full credit for any reduction they make below the maximum possible intake flow rate. A facility thus may be able to comply by running less.

Staff does not understand what is meant by the comment that operational options should be able to qualify retroactively. As explained above, permittees will be able to claim full credit for any flow reductions they make to be in compliance with the Policy.

Comment 43.03:
Since there is a difference in reduced impingement mortality and entrainment between Tracks 1 and 2, we suggest that if an owner or operator selects Track 2, they should be required to provide mitigation, as provided under section 2.C.(3)(a)(b)(c) of the policy, for the difference.
Response:
Please see the response to Comment 3.09. The Policy specifies that owners or operators must reduce impingement mortality and entrainment to a level comparable with Track 1; thus there should be no difference in IM/E between Track 1 and 2.

Comment 46.02:
If comparison between historical and actual facility-wide OTC flow is going to be used as a proxy for IM/E reductions, then the averaging period must be sufficiently long to allow for the year to year variations in relative monthly electricity consumption. Ideally, the averaging period would be annual; however, this may not accommodate the variability of larval production across the year. To deal with the variability of larval production from month to month, it may be necessary to use a semi-annual or other seasonal averaging period. Alternatively, monthly flows could be translated into estimated impacts by applying a monthly impact weighting. The weighting factor could be higher in months with high larval productivity and lower in months with less larval production. The fundamental point is that straight monthly averaging will not provide the flexibility needed to address year to year weather fluctuations.
Response:
Please see the response to Comment 3.08. Historical and actual facility-wide OTC flow is not going to be used as a proxy for IM/E reductions. Regarding the averaging period for compliance purposes, staff has changed the proposed Policy to clarify that under Track 2, if Track 2 compliance is solely based on flow and velocity reductions, compliance with required IM/E reductions will be determined on a ***monthly*** basis based on comparisons to the facility's design flow. Staff chose a monthly basis because the ERP recommended determining compliance on a monthly basis and applying a monthly impact weighting. Staff has not specified the "averaging period" for determining compliance with other types of Track 2 controls, as the need for compliance monitoring may depend on the type of control used. For structural controls, such as screens, a baseline monitoring study before the control is installed, followed by a monitoring study afterwards to determine the efficiency of the control in reducing IM/E, may be all that is needed, unless conditions change.

Comment 49.13:
The proposed Policy states that "Reductions in impingement mortality and entrainment resulting from the replacement of steam turbine power-generating units with *combined-cycle power-generating units*,* installed prior to [the effective date of the Policy], may also be counted towards meeting Track 2 requirements." No previous data should be allowed because there is no assurance that old data are relevant to contemporary operations and impacts on marine life. The Water Board and other state agencies do not follow the practice of considering past historical damage caused by OTC to determine the effectiveness of contemporary measures to reduce or eliminate that damage; therefore, past measures to reduce or eliminate damage under the Policy have no place in requiring compliance with Track 2 requirements. Only those efforts following adoption of the Policy should be considered. How the reductions are to be determined for compliance must also be stated.
Response:
Prior data are relevant to determining the appropriate reductions to be achieved under the proposed Policy. Note that Track 1 reductions are based on the design intake flow rate. The

proposed Policy now includes a description of the method by which reduction credits are calculated.

Comment 62.01:
It is our understanding that achieving at least 90% of the reduction in impingement and entrainment mortality required by Track 1 at a Track 2 facility will not result in a reduction of efficacy down to only 83%. STATE WATER BOARD staff clarified at the hearing that an 83% reduction was not sufficient. The following is an example of our understanding of how this provision works: A facility that utilizes OTC technology uses 100 MGD of cooling water. They are required under Track 1 of the Policy to reduce this now by a minimum of 93% by using the BTA, down to a rate of no more than 7 MGD. Therefore they are permitted to entrain or impinge a number of organisms correlated to this flow which will be based upon monitoring conducted by the facility. If it is determined that they can not meet the BTA requirement of Track 1, then under Track 2 they must reduce their mortality rates to a comparable level as Track 1 ("at least 90% of the reduction required under Track 1") Given that entrainment rates are generally proportional to intake rates (but ignoring the very important component of seasonality addressed by several presenters), the facility would be permitted to impact an equivalent amount of organisms as if their intake rate was 7.7 MGD (comparable level to Track 1 with some variance because track 1 is not feasible at this site), They would then be required under the Immediate and Interim Requirements section of the Policy, to mitigate for their remaining impacts until they can achieve BTA under Track 1 or the production from the facility is replaced by other sources and it ceases operation. If this interpretation is correct, then it is more proper to state that Track 2 facilities may receive an additional variance in allowable levels of impact up to, but no greater than 10% from Track 1 levels. Please inform us if this interpretation is incorrect as that would represent a significant change from the July 2009 version of the policy.
Response:
Please see the response to Comment 3.09.

7. Monitoring Requirements

Comment 3.13:
Impingement and entrainment impact monitoring provisions should be strengthened. The Draft Policy only requires 12 consecutive months for facilities to determine past impingement and entrainment impacts to use as a basis for future impingement and entrainment reductions under Track 2. This design fails to account for annual variability and source water depletion in the determination of baseline impingement impacts. It also gives discretion to power plant operators to choose an advantageous 12-month period that would potentially create a scenario where impingement and entrainment reductions are easier to meet. Instead, we recommend generational flow be used as a proxy for entrainment. We further recommend that current source water monitoring be used to help provide a basis for compliance monitoring of Track 2 controls. Most facilities have conducted impingement monitoring (species impinged and impingement rates) for the last decade or more; this data should be used to help determine baseline impingement impacts to minimize any bias due to annual variability and provide a reference for Track 2 compliance monitoring. Section A.1(b) of the monitoring provisions requires that impingement and entrainment be measured during "different seasons" when the cooling system is operating. This requirement is overly general and may provide the power plant operator discretion to choose monitoring times that reflect select impingement and entrainment reductions, but do not accurately reflect true reductions. Periods of peak use (such as the summer months when energy is in high demand) and biofouling maintenance should be included in the monitoring provisions to ensure accurate reflection of impingement and entrainment impacts and reductions.
Response:
The impingement and entrainment studies are not necessarily limited to just 12 months. Twelve months is the minimum period allowed for monitoring. The Policy clearly states that the Regional Water Board has the discretion to require further impingement studies when changing operational or environmental conditions indicate that new studies are needed. Likewise, with regard to entrainment monitoring the Regional Water Board has the discretion to require the monitoring to determine larval composition and abundance in the source water, <u>representative</u> of water that is being entrained. The source water for sampling shall be based on <u>reasonably expected oceanographic conditions</u>. The Regional Water Board may require further entrainment studies when changing operational or environmental conditions indicate that new studies are needed. Staff believes that monitoring flow is a better proxy for entrainment when flow reductions are used for compliance. Staff is proposing to include this requirement in the Policy for those Track 2 plants that intend to rely strictly on flow to reduce the Plant's entrainment impacts. Regarding clarity of staff's intent in the entrainment monitoring requirements, staff is proposing to add a requirement that sampling shall occur during different seasons, including periods of peak use when the cooling system is in operation (such as the summer months when energy is in high demand).

Comment 3.14:
After Track 2 controls are implemented, permittees should be required to perform regular (monthly) impingement and entrainment monitoring. The monitoring provisions in the Draft Policy currently require 12 consecutive months of monitoring after Track 2 controls are implemented. This limited time frame will not reflect annual variability or any changes in the effectiveness of Track 2 controls (e.g. increased impingement due to biofouling or other complications). Regular monitoring should be required to accurately reflect the ability of Track 2 controls to meet impingement and entrainment reduction requirements. NPDES dischargers are required to perform continuous monitoring of constituents in their discharges for the entire lifespan of their permit, and OTC permittees should have a similar requirement.

Response:
Under the proposed monitoring provisions the Regional Water Board has the option to require additional studies when changing operational or environmental conditions. In addition, staff is proposing to provide further clarity in the monitoring provisions. For those plants relying on reduced flows, for example plants installing a combination of closed cycle cooling at some units and variable speed drives with reduced intake velocity (at or below 0.5 ft/sec) at other units, impingement monitoring would not be cost effective, but instead flow velocity monitoring would provide a sufficient proxy. In other cases, such as the installation of screens, direct monitoring of impingement and entrainment impacts would be required. In short, one approach for monitoring does not “fit” all of the potential compliance options under Track II, but staff is providing clarifying edits to the draft policy to address this.

Comment 4.14:
As currently written, the Draft Policy would require a baseline entrainment study unless the discharger demonstrates that any prior study is acceptable to the Regional Water Board. The Impingement Mortality and Entrainment Characterization Studies required to comply with the 2004 Federal Rule, which were approved by the respective Regional Water Boards and have since been completed by all California utilities, may have utilized a net size larger than 200 microns. A 333-micron mesh entrainment sampling net is considered the standard sampling protocol. If this were the case, another round of sampling would be required.
Response:
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. Examples include both abalone and sea urchin larvae, which are not captured by a 333 micron net. Future entrainment studies should include a sampling for these and other important planktonic invertebrate larvae. Furthermore, it is staff’s understanding that 333 micron plankton nets do not sample even all of the ichthyoplankton, since some species can swim through a 333 micron mesh. For future entrainment studies a 333 micron net may be nested within a 200 micron net, thereby preventing plugging of the 200 micron net and allowing a subsample of the 200-333 micron size fraction.

Comment 14.09:
The Policy fails to consider in its monitoring provisions the substantial impacts that OTC has on plant life. Any environmental impact assessment of OTC that fails to consider affected aquatic plant life is simply inadequate. For example, the discharge of organisms that are impinged "clouds the water around the discharge area, blocking light from the ocean . . . which further kills plant and animal life by curtailing light and oxygen."
Response:
The impact described in the comment appears related to a discharge effect. While staff agrees that such effects occur, the Policy is only intended to directly address intake effects. Nothing in the Policy, however, precludes the authority of Regional Water Boards to regulate discharges from existing power plants through NPDES permits, consistent with water quality standards.

Comment 14.10:
The monitoring provisions should similarly require that impacts to water flows be considered. Hydrological cycles differ depending on the season and the time of the day and month; and thus withdrawals and discharges that alter the variability may impact the ecosystem's health. Even

though intakes and discharges into the ocean may not be as dramatic as those from and into lakes and rivers, impacts on plant and animal life from the practice should still be monitored.

Response:

The draft policy's entrainment monitoring provisions would require that source water shall be determined based on oceanographic conditions reasonably expected after Track 2 controls are implemented. Furthermore monitoring would be required to account for variation in oceanographic conditions and larval abundance and behavior. While temporal variability in hydrologic cycles (i.e., different runoff conditions as in wet vs. dry years) do affect oceanographic conditions, such hydrologic variability is more relevant to discharges than intakes.

Comment 18.07:

The persistent use of OTC at coastal power plants has clearly contributed to the loss of biodiversity and the documented population decline of many marine species over the past 50 years. Although we support a simple approach to phasing out OTC along California's coast, it should be recognized that today's impacts are not reflective of the 40-50 years of marine life impacts caused by OTC, where adjacent ecosystems have suffered a long history of entrainment and impingement. We cannot go back in time to gauge the true impact of these facilities; however, we recommend the State Water Board ensure that reference location studies are conducted to better determine ecological productivity in areas without impacts from OTC to more accurately assess impingement and entrainment impacts. Accurate monitoring and assessment of biological and resource impacts (both past and present) is critical, and the subsequent information should be used to inform interim restoration requirements for coastal generators.

Response:

Staff agrees that OTC has contributed substantially to detrimental marine life impacts for over half of a century. However, staff does not believe that the identification of reference stations is feasible, in that the entire coastal zone of California is no longer pristine and has experienced a myriad of impacts such as from coastal development, pollution, and fishing. Unlike reference areas for water quality studies, where locations may be found that do not experience serious pollution, it will be difficult or impossible to find reference locations untouched by all of the various stressors on coastal ecosystems, including current OTC impacts which are cumulatively substantial over large stretches of the coast.

Comment 20.02:

Furthermore, the rationale for the requirement to collect and analyze all zooplankton in entrainment samples, and to provide for their protection, is unclear. Zooplankton are generally excluded from entrainment assessments since the potential for detectable impacts to these organisms is minimal. Reasons for this low potential of impact to zooplankton include: (1) the widespread distributions (spanning large oceanic areas) of most taxa, (2) the relatively short reproductive times of most taxa, and (3) their ability to withstand physical entrainment stresses compared to ichthyoplankton. Studies performed for the Marine Review Committee at SONGS, which accounts for approximately one-fourth of permitted cooling water withdrawal in southern California, determined that "in fact no substantial changes have occurred in the zooplankton…" due to plant operations.

Response:

It is true that staff intends for entrainment monitoring, when Track 2 is selected by a plant operator, to include sampling for all ichthyoplankton and invertebrate meroplankton species/taxa. Invertebrate meroplankton are clearly defined in the Policy as pelagic larvae of "benthic invertebrates" and does not include all invertebrate zooplankton. Many benthic invertebrates are important members of benthic communities (e.g., crab, lobster, urchins) and some are actually endangered or otherwise protected (e.g. abalone). Staff is clarifying the Policy to make it clear that only ichthyoplankton and meroplankton would be monitored under Track 2 for entrainment.

Comment 22.06:
The Board should specify that all species be monitored for impingement and entrainment, not just those which are commercially and recreationally important.
Response:
Staff agrees. Please see the response to Comment 3.21.

Comment 25.03:
The State Water Board's stated intent is to protect marine and estuarine life from the impacts of OTC without disrupting the critical needs of the State's electrical generation and transmission system. To assess potential impacts to marine and estuarine life at El Segundo and Encina, NRG conducted Impingement Mortality and Entrainment (IM&E) characterization studies in 2005 and 2006 and submitted the reports to the Los Angeles and San Diego Regional Water Boards in January 2008. The 1977 USEPA guidance for assessing Adverse Environmental Impacts (AEI) was used in evaluating the results of the IM&E characterization studies. The information from these and other recent studies obtained from most of the power plant in California addresses some of the questions regarding levels of significance and relative magnitude of the impact at the California OTC plants raised by Board members. Based on the findings from these recent IM&E studies at El Segundo and Encina, there was no evidence that OTC resulted in AEI to fish and shellfish populations using USEPA guidelines. We recommend that results from these recent IM&E studies for El Segundo and Encina and any other California OTC plants be considered in the SED, where such results may otherwise not have been analyzed. Furthermore, we recommend that such characterization studies need not be repeated as part of the implementation of the OTC Policy.
Response:
Please see the response to Comment 20.03. The Policy states that previous studies may be used to determine baseline IM/E impacts if the discharger demonstrates, to the Regional Water Board's satisfaction, that prior studies accurately reflect current impacts.

Comment 26.11:
See Comment 3.13.
Response:
Please see the response to Comment 3.13.

Comment 26.12:
See Comment 3.14.
Response:
Please see the response to Comment 3.14.

Comment 29.05:
PG&E strongly believes that as further work is done to quantify the benefits of compliance, site-specific assessments of biological impact are required. Facilities such as Diablo Canyon have over 30 years of biological data available to demonstrate that there has been no significant impact to fish populations since the commencement of plant operations. Further data from the SED indicates that Diablo Canyon contributes a disproportionately small percentage of both impingement and entrainment. These factors must be considered in quantifying the benefits of policy implementation. Diablo Canyon is a base load facility that runs at nearly continual full capacity. Based on the SED data of average flows from 2000 to 2005, Diablo Canyon circulates

roughly 22% of the state's OTC flow. However, only 1% of the impingement and 8% of entrainment are associated with Diablo Canyon. Thus, the location and design of the plant's cooling water intake system ensures that its impact, if any, is far less than its proportion of cooling water flow. Diablo Canyon's impingement impact is not just "less" than other plants – it is virtually non-existent (totaling less than 1600 pounds per year) and was found by the Central Coast Regional Water Board to be "so minor that no alternative technologies are necessary to address impingement at DCPP, and the cost of any impingement reduction technology would be wholly disproportionate to the benefits to be gained." Additionally, Diablo Canyon has not documented a single sea turtle or marine mammal death due to impingement. Diablo Canyon's entrainment is estimated at an average of approximately 11% of fish larvae in the source water body. This must be understood in the context that over 99% of fish larvae do not reach adulthood. Available data demonstrate that the operation of Diablo Canyon has not caused any detectable impacts on adult fish populations in the region. As part of the plant's biological monitoring program, PG&E has collected data on fish populations at control stations in the Diablo Canyon area since 1976 – ten years prior to plant operation. Graphs of this data demonstrate that there have been no shifts in population that can be attributed to entrainment. Further, a previously submitted study by researchers from California Polytechnic University indicated no evidence of a declining trend for Rockfish along the Central Coast. This study began in 1980 – five years before plant operation. If the operation of Diablo Canyon was impacting rockfish populations, this study should have found declining populations of species susceptible to entrainment. PG&E believes it is important to stress that the focus on fish and shellfish is appropriate. USEPA has determined that phytoplankton and zooplankton do not warrant assessment as there is a very low probability of impact given their extremely short generation times, ability to continually reproduce, and abundance throughout California's coastal waters and beyond. Second, both Section 316(b) and Porter-Cologne recognize the potential for some effects due to once through cooling. Section 316(b) requires that adverse impacts be minimized – not eliminated. Thus, it is not appropriate to equate a fish kill from a chemical spill or other non-compliance activity to impingement from a permitted OTC facility. There is no direct evidence that OTC is causing adverse environmental impacts at all OTC facilities. Impacts are site specific and should be assessed as such.

Response:

First, it must be noted that the State Water Board does not have to show population level effects in order to adopt and implement this Policy. Furthermore it is the position of the staff that Diablo Canyon's OTC impacts are substantial. There is no test, nor is staff proposing a test, to base this policy strictly on the relative impacts from one plant to another. All OTC plants must comply with CWA Section 316(b).

Diablo Canyon has substantial entrainment impacts. For just nine taxa of rocky reef fish 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. Other fish species are also entrained, as well as the larvae of benthic invertebrates. The plant is responsible for entrainment at least 1,481,948,383 fish larvae alone, annually.

Based on the proportional mortality in the source water, and using Habitat Production Foregone, it is estimated that the entrainment from the plant represents between 296 and 593 acres of rocky reef larval production.

Comment 31.35:

The staff recommends that IM/E monitoring would be conducted in association with each NPDES permit renewal to provide a baseline but does not justify why additional data must be obtained and how it would be utilized. Most facilities have accumulated years of monitoring data as required by their NPDES permits as well as recent monitoring pursuant to the EPA Phase II rule. This monitoring has been conducted at considerable expense. These data can be extrapolated to represent the estimated IM/E levels over a range of a facility's projected operating levels to assist in establishing a baseline. Assuming a facility has met the Track 2 compliance target based upon previous IM/E monitoring, what assurance would that facility have that it could continue to operate if new sampling data indicated IM/E levels had increased? Would this result in denial of the NPDES permit renewal? If so, the facility would suddenly be faced with closure within a very short timeframe. Again, all of these decisions are to be made in an unspecified way "to the Regional Water Board's satisfaction".

Response:

Staff disagrees. Baseline studies would only be required fro those operators selecting compliance through Track 2. Track 1 compliance would not necessitate any new baseline studies upon NPDES permit renewal. For Track 2, new baseline studies may be required but only if the Regional Water Board determines that previous studies do not accurately reflect current impacts. Staff is not aware of any OTC facility in the state that currently meets the Track 2 compliance target based upon previous IM/E monitoring. In cases where previous monitoring does not reflect current operating and environmental conditions, the Regional Water Board must retain the authority to require additional monitoring, in order to be protective of marine and estuarine aquatic life.

Comment 31.36:

The staff is recommending that those entities utilizing Track 2 compliance would perform IM/E monitoring to verify the measures taken have enabled the facility to achieve Track 2 compliance levels. The scope, duration and frequency of the monitoring are, again, at the discretion of the Regional Water Board. Post-implementation compliance monitoring should only be required once to verify compliance.

Response:

Different oceanographic and operating conditions must be considered and therefore the monitoring requirements must be at the discretion of the Regional Water Board. Depending on the specific Track 2 compliance method, the Regional Water Board may need to require additional monitoring in order to verify compliance.

Comment 33.09:

Under Monitoring Provisions, baseline studies should account for yearly variations in populations. Salmon populations, for example, vary due to several factors affecting recruitment and delta smelt populations change according to differences in water year.

Response:

Staff agrees, and is of the opinion that the language in the policy allows for annual variability. Baseline studies must accurately reflect current impacts, which would be inclusive of population variability, and that must be proven to the Regional Water Board's satisfaction. For entrainment, the source water shall be determined based on oceanographic conditions reasonably expected and sampling must provide an unbiased estimate of larvae entrained.

Comment 33.10:

The public and appropriate wildlife agencies need to be given an opportunity to review and comment on these studies.

Response:

Monitoring plans submitted to Regional Water Boards are public records and are therefore available upon request. Since the monitoring plans are reviewed associated with the issuance of NPDES permits, the staff recommendations are also made in a public process and would include consideration of public comments, including the comments from other agencies.

Comment 33.11:
It may also be necessary to require a Technical Advisory Committee to review and evaluate baseline studies if the Regional Water Boards do not have sufficient expertise.
Response:
As with other statewide plans and policies, the staff of the State Water Board Division of Water Quality would be available to consult with the Regional Water Boards with regard to the adequacy of baseline monitoring studies. If necessary the State Water Board staff could re-convene the ERP if there is sufficient reason to consult with academic and other scientists.

Comment 34.01:
The focus of the biological and cumulative impacts caused by once through cooling has been on impingement and entrainment of fish and fish larvae and loss of the commercial value of the fish. Impingement and entrainment studies have not addressed the impacts on the aquatic life from an ecosystems based view point. Very little has been done to quantify by direct monitoring the entrainment of the benthic organisms, the organisms that are at the bottom of the food web. These organisms besides being the source of food also provide other important biological services such as scavenging detritus. It should be pointed out that the State Water Board Sediment Quality Objectives Part 12 for Enclosed Bays and Estuaries was recently approved by EPA. It is based on multiple lines of evidence; toxicity, chemistry, benthic community. Of particular interest is the line of evidence for the benthic community, which include three new benthic indices that were developed for Part 1. We recommend that these new benthic indices be evaluated for monitoring and assessing the impact of OTC power plants located in enclosed bays and estuaries. The best technology available should also apply to monitoring technology.
Response:
Staff generally agrees with the comment as it relates to past studies for many power plants. Ecosystem effects and effects on early life stages of benthic invertebrates are considered by staff to be very important and must be considered. However staff also understands the technical difficulty in sampling and identifying invertebrate larvae, and the current inability to model ecosystem effects. Staff also agrees that presenting IM/E in terms of commercial fish values is inappropriate but it does not take into account the ecological values of the marine life impinged and entrained. The three lines of evidence approach as required for direct effects in our Sediment Quality Objectives Part 1 for Enclosed Bays and Estuaries is designed around chemical contamination and toxicity to marine life/communities, and is not appropriate for assessing the effects of power plant intakes.

Comment 34.05:
We support Alternative 2. Staff argument for Alternative 3, which eliminates monitoring for Track 1 while not needed for compliance, will provide the baseline data needed for comparing the pre Track I to post Track I changes in the aquatic ecosystem. This section does not clearly define the monitoring requirements. Monitoring only the larvae in the water column and not the benthic community is not adequate to assess the aquatic ecosystem.
Response:
Staff is recommending BTA under Track 1 as a means to reduce entrainment by 93% or more. Closed cycle cooling will achieve that, so there is no need to monitor before and after. Impacts from the intakes of OTC directly impact fish and plankton in the water column. Benthic impacts are relevant only to determine the presence and abundance of species whose larval forms are affected by entrainment; however other stressors (pollution, fishing, etc.) may affect the benthic community as well.

Comment 40.10:

In the Track 2 monitoring provisions of the proposed policy, State Water Board proposes to give the Regional Water Boards complete discretion in determining if and when additional biological monitoring to determine entrainment and impingement impacts is needed. This follows the initial "baseline" monitoring and monitoring post implementation of Track 2 controls. NMFS disagrees with this approach. Preferably, those facilities which continue to withdraw from ambient water sources for cooling would be required to monitor more frequently to show that they are not impacting the beneficial uses managed by State Water Board. Indeed, increased monitoring is necessary to determine what a "representative" year is and to make sure that it is captured in the monitoring scheme. A more appropriate requirement for facilities that choose to continue utilizing antiquated OTC systems would include long-term sampling in source waters with reference stations to determine impacts to the ecosystem.

Response:

As in other statewide plans and policies the State Water Board relies on the Regional Water Boards to carry out their legal mandate for implementation. This is true in all NPDES permitting the Regional Water Boards perform, including NPDES monitoring and reporting programs. The State Water Board staff is always available to consult with when additional expertise or interpretation is necessary. Therefore the approach for Regional Water Board monitoring discretion is consistent with existing state law and policy. The purpose of the policy is to discontinue the uncontrolled use of OTC. Therefore BTA relies on operational and structural controls which would permanently reduce impacts to levels comparable to closed cycle cooling. Depending upon the specific compliance approach, the Regional Water Boards have discretion to require monitoring to verify reductions in impacts.

Comment 40.12:

The proposed policy should clarify that the use of the Adult Equivalent Loss and Fecundity Hindcast models to determine impacts are not sufficient. These methods have typically only been used for a limited subset of impacted species and the assumptions built into the models contain significant uncertainties, such as the lack of data for California fishes, a lack of site-specific data and inadequate accounting for unknown environmental compensatory or other factors operating on population levels. (see the presentations posted on the State Water Board website from the January 2008 Research Results Symposium at the University of California, Davis by Stratus Consulting (presented by Dr. Elizabeth Strange) and by Dr. John Steinbeck (Tenera Environmental) for additional information on this subject).

Response:

Please see the responses to Comments 7.06, 3.21, and 22.05. Staff agrees that Adult Equivalent Losses and Fecundity Hindcast models are insufficient to assess IM/E impacts. These are both demographic fish population models that require a great deal of life history and other information, and much of that information is unknown or quite uncertain for the vast number of species impacted by OTC. A far superior approach is the Empirical Transport Model.

Comment 41.01:

Eliminate the requirement to protect zooplankton. Currently there is no data or information provided to indicate zooplankton suffer mortality as a result of entrainment. Further, due to the short life cycle and rapid reproduction of these organisms significant impacts are unlikely to occur. Making this change to the Policy will create a viable Track 2 option. To achieve Track 2 compliance, zooplankton would have to be protected at the expense of fish and shellfish eggs and larvae which would become impingeable on the 200 micron screens.

Response:

Technically, zooplankton is a comprehensive term that is inclusive of ichthyoplankton (fish eggs and larvae), invertebrate meroplankton (larvae of benthic invertebrates), and holoplankton (invertebrates that are planktonic their entire lives). Of course we know that ichthyoplankton and meroplankton experience 100% virtual mortality due to entrainment.

For purposes of the policy, ichthyoplankton and meroplankton are defined separately. For purposes of the policy, meroplankton is defined as only those zooplankton that are pelagic larvae of benthic invertebrates, and zooplankton is defined to include only planktonic invertebrates larger than 200 microns. Therefore the zooplankton definition in the policy does not include holoplankton, such as copepods, that have short life cycles and rapid turnover. Monitoring is recommended by staff for all meroplankton greater than 200 microns, because for example this includes organisms such as abalone (which for some species are threatened), bivalves and sea urchins which are important members of benthic communities. It is important to know the impact on these organisms. However, staff recognizes that if screens are employed 200 microns is not advisable. Therefore, staff is recommending, if screens are employed under Track 2, that the minimum size openings in the screens be 500 microns. The requirement for monitoring at a lower size therefore would not interfere with the use of screens as a Track 2 compliance measure.

Lastly, many ichthyoplankton and some meroplankton are larger than even 500 microns, and staff is hopeful that screening devices would not impinge the organisms that they are designed to exclude from entrainment. Such devices should be designed to prevent mortality either from entrainment or by impingement.

Comment 43.10:
Page A-9, Section 5 - Track 2 Monitoring Provisions Subsection A.(1)(a) - Rather than prepare current studies, this subsection allows the use of prior studies as documentation for current impacts. Should the Regional Water Board choose to allow prior studies, those studies should be subjected to third party independent scientific review.
Response:
Please see the response to Comment 11.53. Staff does not believe that third party independent scientific review of prior studies is necessary.

Comment 43.11:
Page A-9, Section 5 - Track 2 Monitoring Provisions Subsection A.(1)(a) - We suggest incorporating the language used on page A-10, subsection B.(1)(b) which requires that sampling be designed to account for variation in oceanographic conditions, larval abundance, and larval behavior such that abundance estimates are reasonably accurate.
Response:
Please see the response to Comment 3.13.

Comment 43.12:
Page A-1 0, Subsection B.(1) As with the baseline impingement study, if prior studies are used to establish current impacts, those data should be subjected to, independent third party scientific review.
Response:
Please see the response to Comment 43.10.

Comment 44.08:
The "Track 2 Monitoring Provisions" requires that a "baseline entrainment study shall be performed, unless the discharger demonstrates, to the Regional Water Board's satisfaction, that prior studies accurately reflect current impacts.” The Draft Policy should be amended to include standards and criteria to clarify "The Regional Water Board’s satisfaction".
Response:
Please see the response to Comment 43.10.

Comment 49.12:
(2) (a) Compliance for impingement mortality shall be determined either (1) by monthly verification of through-screen intake velocity not to exceed 0.5 foot per second, or (2) by monitoring required in Section 4.A, below. Comment: This compliance mandate should state the grounds for using one or the other determination.
Response:
Staff has revised the Policy to clarify the grounds for using one or the other determination.

Comment 50.04:
At the December 1, 2009 workshop, Dominic Gregorio, Environmental Scientist, Division of Water Quality" State Water Resources Control Board, explained that the “reference to 200 microns" in the definition of "zooplankton" pertained to the size of entrainment sampling nets and was not applicable to intake screening devices. This distinction is very important because the 200 micron size essentially eliminates any reasonable means of compliance under Track 2 since there are no existing technologies that can screen out 200 micron organisms. However, the Revised Draft Policy does not clearly make that distinction. The Board must make that distinction explicit in the Policy given its importance to compliance determinations. We suggest that a size of 2 mm or greater be applied to screening devices based on consideration of reducing fouling opportunities and a mesh size that would meet with the intentions of the Policy
Response:
Staff stands by the statement made at the Dec.1, 2009 workshop. In order to clarify the policy staff is including language in the Track 2 provisions that if screens are employed, the minimum size openings in the screens shall be 500 microns. However, staff wants to make it clear that a 2 mm (2000 micron) screen will not protect most ichthyoplankton from entrainment, and would likely need to be employed along with flow reductions (or some other controls) in order to reduce entrainment, for plankton > 500 microns, comparable to that achieved with closed cycle cooling.

Comment 53.02:
The definition indicates that HPF is the area of production *"lost to all entrained species."* The proportional mortality estimates, which are used as input to HPF, cannot be calculated for all entrained species. Therefore, at present, HPF can only be used for (1) those species with sufficient abundance in both entrainment and source water samples, and (2) species with sufficient life history information for calculation of larval duration (exposure to entrainment). In addition, there must also be some level of confidence in estimates of the size and extent of the source water. The correct application should also take into account variations in habitat in the source waters. The example listed in the definition assumes the habitat is homogenous, and the affected species all utilize this same habitat. This is unlikely to ever be the case, and we recommend deleting the example. The HPF, if used appropriately, can be one of many methods used in scaling restoration projects to offset IM&E losses. However, like all other scaling methods, it has limitations on its use. Lastly, any restoration scaling application, such as the HPF, is limited by the state of science with regards to relevant knowledge of the life history parameters of affected species. This problem was further identified by the Water Intake Structure Environmental Research program (WISER) administered by the CEC. Characteristics such as mortality, growth, fecundity, and more general concepts of population regulation and stressors are still unknown for the majority of fish species occurring along the California coastline.
Response:
Staff agrees that the estimates of proportional mortality are for certain target species for which adequate knowledge is available. Still, the HPF method, when based on the results of the ETM,

provides a best estimate of the habitat that may replace all entrained species. The Expert Review Panel clearly states that: "Fish larval mortality and other biological and oceanographic data can be used in the Empirical Transport Model (ETM) to estimate the percent of the total larvae lost due to entrainment in the volume of ocean water from which the larvae can be entrained. This estimate may also reflect % losses to organisms in sea water that are not sampled in entrainment studies (e.g., invertebrate larvae and other zooplankton, and phytoplankton) and is thus a more comprehensive measure of entrainment impacts."

Upon consideration of comments, staff is recommending deletion of the example in the definition of HPF.

Comment 53.03:
Compliance for Track 2 impingement can be determined *"by monthly verification of through screen intake velocity not to exceed 0.5 foot per second, or* (2) *by monitoring required in Section 4.A, below."* The velocity monitoring is straightforward. However, it is not clear how monitoring could demonstrate compliance when it is not understood what impingement mortality would result from a 93% reduction in flow.
Response:
For impingement mortality, Track 1 requires the through-screen intake velocity must not exceed 0.5 foot per second. Based on available information a through-screen intake velocity of 0.5 foot per second or less will result in virtually no impingement mortality. For Track 2 plants may rely solely on reductions in velocity not to exceed 0.5 foot per second (even if the flows are not reduced by 93%, as may be the case with the installation of fine mesh screens); the other option is reduce impingement mortality to a comparable level as under Track 1. A "comparable level" is a level that achieves at least 90 percent of the reduction in impingement mortality required under Track 1. This may be achieved by comparing baseline (pre-control) impingement with impingement after controls are instituted. The difference between baseline impingement and controlled impingement should be only 10% of the baseline (i.e. 90% controlled).

Comment 53.04:
The policy requires *"sampling for all ichthyoplankton and meroplankton species"* (Section ' 4.8.1.a). The definition of "meroplankton" in Section 5 is incorrect. It is currently defined as: "*Meroplankton - Refers to that component of the zooplankton community composed of the pelagic larvae of benthic invertebrates."* Meroplankton are those organisms that only spend part of their life cycles in the planktonic phase, and is not limited to benthic invertebrates (e.g., fishes and barnacle nauplii are considered meroplanktonic) (see for example: Nybakken, J. 1988, 1997. Marine Biology: An Ecological Approach).
Response:
Staff is aware and agrees that the definition provided in the comment is correctly stated as applied in marine biology and oceanography. However, in order to describe entrained plankton organisms, staff recommends the definitions in the policy, with the caveat that the recommended definitions are only applicable within the context. To emphasize that, staff recommends clarification by adding the statement "For purposes of this Policy" at the beginning of the meroplankton definition. That was always the intent as evidenced by the fact that staff had previously included that same statement in the definition of zooplankton, of which meroplankton is a component.

Comment 53.05:
MBC performed some of the original Section 316(b) demonstrations in California in the 1970s, and designed and performed studies in southern California from 2004 to 2008 for multiple power plants. All of these studies utilized 333- or 33S-micron mesh plankton nets. Recent Section

316(b) IM&E Studies utilized 333- or 33S-micron mesh for sampling, and target invertebrates included spiny lobster phyllosoma, market squid paralarvae, and crab megalopae. The language in the current policy implies that new studies would have to be performed. There is still no justification or reasoning for the 200 micron requirement. Sampling with finer mesh, could affect study results; the finer mesh clogs faster, reducing sampling efficiency of the plankton net(s). Finer mesh has been used in some surveys targeting specific invertebrate larvae on in Northern California; this could still be performed without the requirement to sample and analyze all meroplankton for a 12-month period.

Response:

Upon considering public comments received, staff is recommending clarifying language in section 4.B.(1) of the policy, as follows: "*Prior studies that may have used a mesh size of 333 or 335 microns for sampling are acceptable for compliance with the review and approval of the Regional Water Board. If the Regional Water Board determines that a new baseline entrainment study shall be performed to determine larval composition and abundance in the source water, representative of water that is being entrained, then samples must be collected using a mesh size no larger than 335 microns. Additional samples shall also be collected using a 200 micron mesh to provide a broader characterization of other meroplankton* entrained.*" Staff feels strongly that although many studies have used 333 or 335 micron screens, new studies should subsample for the 200 – 335 micron size fraction in order to identify smaller invertebrate larvae, and for ichthyoplankton that may escape capture in 335 micron nets (by moving through the mesh head or tail first. A subsample of the 200 – 335 micron size fraction may be obtained, without undue clogging, simply by nesting a 350 micron net within a 200 micron net.

Comment 55.01:

We share the concerns of CCEEB, utility and fellow independent power producers (IPPs) on the omission of wholly disproportionate demonstration and exclusion of cost considerations in assessing feasibility (in Track 2); and potential necessity of dischargers to repeat comprehensive Impingement Mortality and Entrainment (IM&E) studies (as noted, El Segundo and Encina conducted IM&E and submitted voluntarily the Comprehensive Demonstration Studies).

Response:

Please see the response to Comment 43.10.

Comment 61.02:

Sampling was not done with smaller mesh nets because they rapidly clog reducing the effectiveness of the net and affecting the quality of the sampling. Also, there is limited taxonomic knowledge of the early larval stages of many invertebrate limiting the ability to determine what is even being collected. There has also been a general recognition that the potential for impacts to invertebrates due to entrainment is very limited due to their large reproductive capacity. In addition, there is probably a high level of entrainment survival for many invertebrate larvae which, unlike delicate, soft-bodied larval fishes, have chitonous or calcareous shells that protect them from damage while passing through a cooling water system. Finally, the scientists involved in these studies realized that the large abundances of invertebrate larvae in the coastal waters allow the mortality due to entrainment to be estimated based on the volume of cooling water relative to the volume of the source water. Using this assumption there was no need to include sampling for smaller invertebrate meroplankton.

Response:

While previous studies have not focused on organisms smaller than 335 microns, any future studies should perform sampling to identify the 200-335 micron fraction of plankton, particularly for meroplankton of benthic invertebrates. These organisms are important ecologically, and in some cases commercially, and the fact that they have not been consistently sampled in the past

is not a reason to ignore them if any future studies are performed. Furthermore, staff is only recommending a sample for the 200-335 micron fraction, not an elimination of the sampling for 335 micron and above. One way a subsample may be obtained, without undue clogging, is simply by nesting a 335 micron net within a 200 micron net. However there are other ways in which a sample for organisms larger than 200 microns may be obtained.
Regarding taxonomic knowledge, staff only recommends identification to the lowest taxa, and not necessarily to the species level when that is not scientifically valid. There is no evidence that invertebrate larvae have a better chance of survival than fish larvae. Staff stands by its opinion that entrainment of all species results in 100% virtual mortality. Staff agrees that there are large abundances of invertebrate larvae in the coastal waters, and that entrainment may be estimated based on the volume of cooling water. Therefore staff is recommending when plants rely solely on reductions in flow to meet Track 2 entrainment compliance, monitoring may be performed simply by recording and reporting reductions in terms of monthly flow, in order to verify a minimum of 93% reduction in terms of design flow; in such cases no entrainment sampling would be required.

8. Immediate and Interim Requirements

Comment 1.08:
The requirement to mitigate or offset impacts for units that have not complied within five years forces many facilities to comply twice - the first time by funding a mitigation project and the second time by shutting down or taking other action to achieve full compliance with Track I or Track 2. Mitigation should be eliminated as a required interim measure, especially since many facilities do not have the ability to achieve full compliance within five years given the need to ensure a sufficient supply of electricity in critical local reliability areas.
Response:
Staff is proposing an implementation schedule that is quite long, and IM/E impacts during that interim period will likely be substantial. Those IM/E impacts during the interim period should be offset to protect and conserve the environment. However, there is no requirement that a plant operator need to wait the entire period of its respective implementation deadline to comply with BTA, and those plants that can install BTA within five years would not need to perform the required interim mitigation.

Comment 1.09:
The habitat production forgone methodology specified in the SED estimates the amount of habitat (in acres) it would take to offset the estimated loss of habitat due to the ongoing operation of a plant's OTC system. The estimated lost habitat is typically compensated for by completing a wetland restoration project or constructing an artificial reef. The bulk of the cost of this project would be associated with the initial restoration effort. Once the wetland is created or restored, the ongoing cost to maintain the wetland is minimal compared to the initial investment. The inequity of requiring interim mitigation results from the fact that as long as the restoration project is maintained it will produce benefits indefinitely, while the impacts of the OTC system will be eliminated as soon as full compliance with the Policy is achieved. The elimination of impacts could occur as early as one year after the interim restoration project is funded while the project itself could go on producing benefits for 40, 50 or 100 years.
Response:
Staff agrees that mitigation (e.g., restoration) projects have the potential to produce substantial benefits. That is why staff is proposing the interim mitigation measure as a way to offset substantial losses to marine/estuarine life due to IM/E. It is likely that such restoration projects will have long lasting benefits, but OTC has been employed for many years prior to the Policy and many plant operators have not performed any mitigation during that historical period.

Comment 1.10:
If the Water Board is unwilling to eliminate mitigation as an interim requirement, the Policy needs to provide more clarity to Regional Water Boards about how to determine the requirement so that plants are not forced to comply twice. AES-SL has two suggestions for how an equitable and simple interim mitigation requirement could be structured. One, rather than requiring a generator to identify a specific restoration project to fund, the Water Board should establish an annual *$/acre* mitigation fee that would be paid into an overall state-wide fund and managed by one agency. Two, the required annual mitigation fee should be based on actual annual OTC flow rather than on a conservative forward estimate of expected flow. In addition, the habitat production foregone calculation must be scaled based on a typical power plant life of 30 years so that the annual mitigation fee is 1/30 of the calculated total habitat impacted by ongoing plant operation.
Response:
Staff is in favor of using the habitat production foregone (HPF) method to determine the area for a mitigation project. Once the HPF acreage is determined a $/acre mitigation fee may then be determined depending on site specific conditions. For example a rocky reef project may have a different per acre cost than a wetland project. Once these are determined, and then approved by the Regional Water Board the plant operator would have the option to either directly fund the restoration project or the same amount of money may be provided to a third party to oversee the restoration project. Staff disagrees with the recommendation to scale mitigation fees to a fraction of the typical power plant life.

Comments 3.25 and 26.21:
We support the general intent of the interim requirements to immediately reduce negative impacts to our marine and estuarine ecosystems; however the complexity of these requirements raises concern. We urge the State Water Board to clarify that compliance with the actual policy is of primary importance, and further refine the requirements for the interim measures to ensure streamlined compliance. Technology to prevent the entrainment of organisms such as marine mammals and turtles (such as large organism exclusion bars) and restoration are beneficial measures in the interim, but neither will satisfy the compliance goal of reducing impingement and entrainment by 90%. By comparison, NPDES permits often have interim requirements while new technology is installed. There is no reason that power plants should be provided special treatment or credit for mechanisms employed to remediate the past and present environmental damages caused by OTC. For improved clarity, it should be stated in the “Immediate and Interim Requirements” that the prohibition of seawater intakes is not an “interim” requirement – but a permanent and “immediate” requirement.
Response:
Compliance with BTA is the ultimate goal of the Policy, and staff believes that this is clear. We agree that wildlife exclusion and mitigation/restoration are very beneficial measures. Staff has never stated or implied that these measures satisfy BTA. However, it is true that reductions in flows, as required in the interim measures, is also a potential component, along with other controls, to a plant’s ultimate compliance with BTA under Track 2.

Comments 3.26 and 26.22:
Currently interim requirement allows the intake of water to occur only during “power generating activities or critical system maintenance.” While “power generating activities” are defined in the Draft Policy, “critical system maintenance” is not. “Critical system maintenance” needs to be clearly defined so that it does not allow for continued flows for co-located desalination facilities or other practices not included in “critical system maintenance.” Without definition, this provides a significant loophole for plants to continue intake flows, which is contrary to the intention of this

policy to actually reduce impacts to marine life. We suggest defining "critical system maintenance" to only include activities that are critical for maintenance of a plant's physical machinery and absolutely cannot be postponed until the unit is operating to generate electricity. This will help protect against the intake of excess cooling water when no power generation or essential maintenance operations are being performed.

Response:

The definition of power generating activities in the draft policy clearly states certain activities that are not considered directly related to the generation of electricity, which include 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. Staff agrees that the term critical system maintenance is not clearly defined but was intended to include activities that are critical for maintenance of a plant's physical machinery and absolutely cannot be postponed until the unit is operating to generate electricity. Critical system maintenance is not intended to allow flows to supply desalination plants or other industrial facilities co-located at a power plant.

Comments 3.27 and 26.23:

Restoration should not be confused with mitigation**.** We are concerned by the use of the term "mitigation" in section C(3), as that is a term also used in California Water Code Section 13142.5(b) which establishes standards for regulating new power plant cooling technology and other industrial seawater intakes. "After the fact" restoration as an alternative to implementing BTA has been plainly rejected by the Courts. However, we are not opposed to mandating restoration as an interim measure while all units come into compliance. To avoid future confusion in defining the term "mitigation" when enforcing the Water Code for all intakes of seawater for industrial purposes, we encourage the replacement of "mitigation" with the term "restoration." We do not believe the two terms are synonymous. Furthermore, we urge the State Water Board to not only account for interim damages caused by OTC between adoption of this policy and compliance by facilities in this section, but also for past entrainment and impingement by coastal power plants. We also urge the State Water Board to prohibit credit for past mitigation efforts as counting toward compliance with interim requirements. The general intent of the interim requirements is meaningless if the State Water Board chooses to give credit to power plants for their past mitigation efforts through Coastal Commission or other permitting processes. Therefore, we recommend the deletion of interim requirement section C(3)(a).

Response:

Staff agrees that restoration is not a technology and is not allowable to substitute for BTA. However staff believes that restoration and other forms of mitigation have a value during the interim period until BTA is implemented.

Staff does agree that more clarity is required in the use of the term mitigation and therefore is proposing a definition for "*mitigation projects"* to include projects to restore marine life. 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, for example through the funding of implementation and/or management of Marine Protected Areas. Past mitigation project commitments by power companies were intended, among other things, to replace entrained larvae from larvae of the same species produced by new or improved natural habitat. These projects were funded through permit requirements with the understanding that new mitigation projects would not be required. It is important to note that very few of the power plants have funded mitigation projects, and therefore if certain other plants do not comply with BTA within five years then mitigation, which can be very beneficial to the ecosystem, would be employed as an interim measures.

Comments 3.28 and 26.24:

Plant owners and operators should fund restoration projects designed and implemented by government agencies. Due to the complexity of restoration projects, we urge the State Water Board to exclude section C(3)(b) and (c) of the Immediate and Interim Requirements Section and instead require that coastal power plant owner and operators participate in funding of restoration projects that are designed and managed by experienced entities with knowledge in restoration scaling and ecosystem-level restoration project design and implementation, such as the California Coastal Conservancy or Santa Monica Bay Restoration Commission. The design and execution of ecosystem-level restoration projects requires significant time, resources and expertise– without the right expertise and direction, restoration efforts can be very expensive without the intended results. How will the Regional Water Boards streamline these processes and ensure the development of a restoration plan that results in ecosystem-level benefits? Furthermore, how will the State Water Board address the problem of maximizing restoration, but avoiding compromises to ecosystem integrity? For example, fish hatcheries are often used as restoration measures, but are a species-specific approach that can cause adverse environmental impacts such as habitat degradation and water quality impairments when not properly designed. Another critical question is: what is the appropriate restoration ratio for the impacts caused by OTC? The California Coastal Commission spent years trying to identify an appropriate mitigation ratio for various damages, and this issue still comes up for debate before the Commission for many restoration and mitigation projects. Clearly, restoration for ecosystem-level impacts is complex and many questions need to be addressed before moving forward with appropriate measures.

Response:

Staff agrees that restoration for ecosystem-level impacts is complex and many site specific project design issues need to be addressed when projects are funded. Staff also agrees that it would be very preferable for these projects to be designed and implemented by state government agencies experienced in these issues. Staff is proposing that funding for mitigation projects, including projects implementing or managing Marine Protected Areas, be funneled through the Calif. Ocean Protection Council, and this is the preferred alternative for funding mitigation projects.

Comment 3.29:

Historic source water depletion should be analyzed with the use of reference sites and incorporated into Interim Requirements. We cannot go back in time to gauge the true impact of these facilities; however, we urge the State Water Board to include reference location studies to better determine ecological productivity in areas without impacts from OTC to more accurately assess impingement and entrainment impacts. These studies must be multiyear studies to account for seasonal and annual variability and should be used to inform interim restoration requirements. If local source water studies are used to assess current OTC impacts, the impacts will be vastly underestimated. Accurate monitoring and assessment of biological and resource impacts is critical, and the information must be used in an appropriate manner that does not artificially underestimate historical abundance and diversity and the requirements of restoration costs in the Immediate and Interim requirements. The persistent use of OTC at coastal power plants has clearly contributed to the loss of biodiversity and documented population decline of many marine species over the past 50 years. Although we support the simple approach of using generational flow as a proxy for entrainment to achieve marine life mortality reductions in Track 2, this approach does not account for potentially depleted source waters surrounding OTC facilities, and may bias the actual achievement of marine life mortality reductions. To maintain the simplicity of the policy, we urge the State Water Board to account for historic impacts caused by OTC in the final policy as an interim requirement. We recommend an approach involving reference site monitoring to help gauge larval and planktonic marine life densities at similar sites not impacted by power plants, stormdrains or point sources, and utilize

this information to help designate the interim requirement to mitigate past and present impingement and entrainment impacts before policy compliance. Reference baseline characterization studies should be conducted over multiple years (at least four years and repeated at least once every five years thereafter) to account for seasonal and annual variation.
Response:
Unfortunately the substantial cumulative impacts of power plants for approximately a half century has changed the marine ecosystem, and along with coastal development, pollution, and fishing, there are few if any reference areas for planktonic larval condition. While reference areas in the coastal ocean are available for studies on water quality condition and benthic community condition, these types of studies are quite different from a comparison of planktonic larvae, which are the offspring of fish and benthic invertebrates, many of which are depleted from historic levels. Staff agrees that cumulative impacts have resulted in impacts to biodiversity, but by the same token these impacts have been widespread (huge source areas) resulting in the unlikely existence of untouched reference areas.

Comment 7.04:
According to the proposed Policy, beginning five years after the policy's effective date, the owner or operator of an existing power plant must implement interim measures (e.g., technology based and restoration) to lessen marine life impingement and entrainment, and must continue to do so until full compliance is achieved. Central Coast Water Board staff supports the Policy requirement that mitigation/compensation is achieved during the interim period. Additionally, Central Coast Water Board staff is pleased that the draft SED allows Regional Water Boards to use the habitat production foregone method in the decision making process for restoration projects. Mitigation based on such approaches provides many environmental benefits. For example, with mitigation funds related to the Moss Landing Power Plant's withdrawal of OTC water, the Elkhorn Slough Foundation has preserved and enhanced thousands of acres of wetlands and surrounding watersheds in and around Elkhorn Slough.
Response:
Staff agrees with and thanks the Regional Water Board for its support of interim mitigation and the habitat production foregone method.

Comment 7.05:
Although not in the proposed Policy, Central Coast Water Board staff supports the principal of establishing a water/organism use fee (e.g., so many dollars per million gallons) as interim mitigation for the use of the public resource and impacts caused by OTC. Central Coast Water Board staff suggests that if such an approach were adopted, appropriate fees should be directed to implement beneficial coastal environmental projects, including watershed projects.
Response:
Staff has considered a water use fee but there are several technical and administrative details that make that approach somewhat difficult to impose through the Policy. Determining the actual dollar per MGD at this time without the HPF information for all plants is one difficulty, another is that wastewater fees are imposed through another State Water Board process. Therefore staff is not proposing the water use fee approach.

Comment 7.08:
The proposed Policy requirement to mitigate and compensate for impacts that can not be addressed by technological "fixes" will avoid situations where OTC is "banned" while power plants continue to use OTC water for decades without any benefits to the environment. For example, power plants in New York State continue to use OTC rather than converting to closed-cycle cooling while in litigation. Allowing mitigation in certain circumstances will allow for

compliance that has many other environmental benefits and thereby makes the Policy stronger and more protective of the environment than federal regulations.

Response:

Staff agrees that mitigation has an important role, and have therefore included it in the interim measures. However staff is precluded from using restoration or other non-technology mitigation in place of BTA, and therefore mitigation will not be a final compliance option.

Comment 9.11:

We question whether mitigation is permissible under a cost-benefit or a wholly disproportionate analysis since the Second Circuit decision explicitly prohibited habitat restoration by name as compensation for OTC impacts.

Response:

Riverkeeper II concluded that restoration measures are not a part of the location, designed, construction or capacity of cooling water intake structures, such that restoration measures may not substitute for use of best technology available (BTA) to minimize adverse environmental impact. However, restoration measures may be used where a facility first employs technology to minimize adverse impacts through BTA or an appropriate variance.

Comment 9.12:

If mitigation, under circumstances that may be permissible under the Riverkeeper decisions, is incorporated into the policy, we strongly believe that it should be used, not to compensate for and potentially prolong OTC, but to finance new alternative energy sources as planned substitutes for power plants, especially photovoltaic solar energy, which has been recognized by the CEC as a feasible, cost-effective alternative to existing power plants. Urban photovoltaic could directly serve to replace coastal power plants, especially the oldest and least needed plants, and thereby contribute to earlier attainment of the state's global warming goals. We are also concerned that mitigation funds paid to the water boards could become habit-forming and might influence the agencies to not pursue aggressively the goal of ending OTC.

Response:

Use of mitigation or restoration measures other than directly to reduce impingement and entrainment effects from OTC may lack appropriate nexus to reduction of intake water and its effectiveness may be difficult to measure. The policy implementation schedule is designed to limit the period required for plants to come into compliance. Use of mitigation funds to reduce environmental harm during that interim period would do nothing to artificially extend that period.

Comment 9.20:

To make “habitat production foregone” a valid instrument in measuring marine impacts, the State Water Board must provide in the policy a reference to the regulatory or scientific basis for its use in order to bestow legitimacy as a standard. Further, evidence must be presented as to why it is acceptable to measure impacts in terms of the average proportional mortality, rather than several species that may be most significantly impacted, both in numbers and in proportion of the species inhabiting a water body area. With proportional mortality measured in acres, what standard would be used to determine acceptable and unacceptable impacts in terms of acreage?

Response:

Based on staff discussions with Expert Review Panel members, Habitat Production Foregone (HPF) is the best available method to convert proportional mortality into area and thence a dollar value of procuring and/or restoring that area. Staff has included a requirement that proportional mortality must be based on the Empirical Transport Model. The Expert Review Panel clearly states that: “Fish larval mortality and other biological and oceanographic data can be used in the Empirical Transport Model (ETM) to estimate the percent of the total larvae lost due to entrainment in the volume of ocean water from which the larvae can be entrained. This estimate may also reflect % losses to organisms in sea water that are not sampled in entrainment studies (e.g., invertebrate larvae and other zooplankton, and phytoplankton) and is thus a more comprehensive measure of entrainment impacts."

The Expert Review Panel also stated that "If restoration is adopted as an interim control measure then, based on
experience with determining mitigation on a plant-by-plant basis, the ERP favors using a mitigation fee based on entrainment-weighted flow. This fee might best be "pooled" from all power plants and administered by a one
institution that collects and allocates funds for projects…" Staff therefore is including a statement in the policy that "*The habitat production foregone* method, or a comparable alternate method approved by the State Water Board Division of Water Quality, shall be used to determine the habitat and area for funding a *mitigation project."* For situations in which an operator opts to providing funding to the California Coastal Conservancy/California Ocean Protection Council to fund an appropriate mitigation project, staff may then consider a fee based on entrainment weighted flow to be "a comparable alternative method" if that fee were based on costs of previous mitigation projects which in turn were determined using HPF.

Finally, staff also realizes that HPF has practical limitation when the primary habitat is unconstrained (open coastal) soft bottom, in that there are little or no opportunities to restore such habitat. However, protecting that habitat in a Marine Protected Area, and providing funding to implement, manage and monitor that habitat is a viable, even preferred option.

Comment 11.53:
The State Water Board should give full credit for purposes of meeting the required interim mitigation measures, as well as the wholly disproportionate mitigation requirements, to existing, permit-required mitigation projects that already address a power plant's OTC environmental impacts. While the proposed Policy provides that existing mitigation efforts may meet the interim mitigation requirements, section 2.C(3)(a) of the policy leaves it to the Regional Water Board's satisfaction the determination of whether an existing mitigation effort required by state or federal permits/approvals will be given credit. That is unacceptable. Where existing mitigation is already required by permit, such as Moss Landing, the proposed Policy should clearly state that the interim mitigation requirement is deemed satisfied or does not apply.
Response:
Staff does recommend that existing mitigation efforts, including any projects that are required by prior state or federal permits, be allowed credit toward meeting the interim mitigation requirement; staff has changed this section to require that such mitigation be to the State Water Board's (instead of Regional Water Board's) satisfaction. In making that determination the State Water Board would review the record of the relevant state or federal permits, and determine if the prior mitigation project in fact mitigates both the interim impingement and entrainment impacts. For example a mitigation project may mitigate entrainment impacts but not impingement mortality.

Comment 11.67:
The proposed Policy should clarify that funding of interim mitigation requirements may be based on projected or actual annual flows during the interim period. Because interim mitigation is short-term temporary measure, detailed, complex biological models should not be required. In addition, up-front, one-time payments should not be required, given that the retirement date of certain power plants may not be certain.
Response:

An accepted and tangible approach must be used in determining the funding for a mitigation project, such as Habitat Production Foregone with proportional mortality based on an Empirical Transport Model, or some other comparable method such as flow weighted entrainment in which the fees are in turn based on previous Habitat Production Foregone determined mitigation projects. Nothing in the Policy precludes the use of actual annual flows, but projections would need to be based on historical averages or based on committed reductions in flow due to the interim measures.

Comment 11.68:
The proposed Policy should clarify that once the approved mitigation project has been fully funded, the owner/operator's obligation is deemed fulfilled. Follow-up studies should not be required and, because it is only an interim measure, the owner/operator should not be held responsible if the efficacy of the mitigation project ultimately falls short of what was anticipated.
Response:
Staff does not intend that mitigation be based on continual monitoring; instead it would be based on existing baseline studies and the Plant's flow. Interim mitigation is not intended as a technological solution as is Track 2, which requires monitoring.

Comment 13.08:
Continued operation due to alleged reliability needs should be charged commensurately. Many of these aging power plants enjoy lucrative contracts from CAISO for reliability purposes. In the case of the South Bay Power Plant, the operators received $32 million this year - down from $33 million last year. The water boards should increase the fees significantly for permitting these facilities due to the extended impacts to water quality and their known noncompliance with BTA. Clearly, the revenues enjoyed by the owners of the plants will be sufficient to pay increased fees. The additional funds should be used to restore degraded water bodies in the region.
Response:
Staff believes the approaches taken in this policy are balanced between the needs of the electricity generators and the requirements of Section 316(b). The time schedules proposed for OTC phase out incorporate many competing policy goals. Short term power company revenues are a necessary aspect for long term construction funding for power replacement.

Comment 14.07:
The mitigation requirements set forth in the "Immediate and Interim Requirements" provide an unnecessary exemption for any facility with a compliance date within five years of the effective date of the Policy. The Policy provides no justification for allowing such a broad cushion for mltigation of interim impacts. Under the proposed scheme, Mirant would not be required to mitigate any of its interim impacts. The Policy's justification for this exemption is insufficient.
Response:
For plants meeting final compliance within five years, staff would prefer that the plant operator dedicate resources toward reducing impingement and entrainment by installing BTA. Staff believes that compliance for most plants can be attained within five years. However, staff believes mitigation is an appropriate interim measure for those plants opting to take a longer time to install BTA.

Comment 15.05:
Restoration as an interim mitigation for marine impacts seems paradoxical; it is posed as an alternative if final compliance with the policy cannot as yet be achieved. However restoration itself is a time consuming process which will only reveal its effectiveness over time, if at all. Would the restoration project be abandoned when compliance is attained? An interim mitigation

measure really should be capable of immediate implementation as soon as the decision is made that final compliance is not yet achievable. Examples that come to mind are: shutting down one of several operating units, or shutting down operation during the spawning season. If restoration is selected it certainly should be stipulated that the project will be maintained even after final compliance.

Response:

Staff believes that restoration can be a cost-effective method that can be implemented in a reasonable timeframe without placing an undue burden on the facility. However, restoration and other mitigation projects may have drawbacks, include the one example in the comment regarding showing effectiveness over time. For this and other reasons, staff is proposing that operators have the option to contribute toward a fund implemented by the Ocean Protection Council that would be used to implement, manage and monitor MPAs.

Comment 18.07:

The persistent use of OTC at coastal power plants has clearly contributed to the loss of biodiversity and the documented population decline of many marine species over the past 50 years. Although we support a simple approach to phasing out OTC along California's coast, it should be recognized that today's impacts are not reflective of the 40-50 years of marine life impacts caused by OTC, where adjacent ecosystems have suffered a long history of entrainment and impingement. We cannot go back in time to gauge the true impact of these facilities; however, we recommend the State Water Board ensure that reference location studies are conducted to better determine ecological productivity in areas without impacts from OTC to more accurately assess impingement and entrainment impacts. Accurate monitoring and assessment of biological and resource impacts (both past and present) is critical, and the subsequent information should be used to inform interim restoration requirements for coastal generators.

Response:

Staff agrees that OTC has contributed substantially to detrimental marine life impacts for over half of a century. However, staff does not believe that the identification of reference stations is feasible, in that the entire coastal zone of California is no longer pristine and has experienced a myriad of impacts such as from coastal development, pollution, and fishing. Unlike reference areas for water quality studies, where locations may be found that do not experience serious pollution, it will be difficult or impossible to find reference locations untouched by all of the various stressors on coastal ecosystems, including current OTC impacts which are cumulatively substantial over large stretches of the coast.

Comment 19.05:

The proposed policy requires the owner or operator of an existing power plant to implement measures to mitigate the interim impingement and entrainment impacts resulting from cooling water intake structures for the period commencing five years after the effective date of the proposed policy and continuing up to and until the owner or operator achieves final compliance. We agree with the requirement for mitigation or restoration to offset interim impacts until power plants achieve full compliance with the proposed policy. However, we would recommend that mitigation for interim impingement and entrainment impacts should be required starting with the effective date of adoption of the proposed policy, rather than providing a five-year grace period.

Response:

For plants meeting final compliance within five years, staff would prefer that the plant operator dedicate resources toward reducing impingement and entrainment by installing BTA. Staff believes that compliance for most plants can be attained in five years. However, for those plants opting to take a longer time to install BTA then staff believes mitigation is an appropriate interim measure. Please see the response to Comment 43.04.

Comment 19.06:
The policy does not define or discuss how the level of impacts and required mitigation should be calculated, what types of mitigation should be required (e.g., in-kind mitigation versus general habitat restoration), or how to monitor and evaluate the success and effectiveness of mitigation projects. We would recommend that State Water Board develop guidance on these issues to assist the Regional Water Boards and promote statewide consistency.
Response:
Please see the response to Comment 31.41.

Comment 23.10:
Section 2.C.(3) requires operators to implement mitigation measures prior to the compliance deadlines set for Tracks 1 and 2. Mirant has already undertaken mitigation measures at its OTC units, including the use of variable speed drives and the payment of compensation to the Department of Fish & Game. The Policy should confirm that Section 2.C.(3) does not necessarily impose new requirements on operators if existing mitigations satisfy the standards set forth in that subsection.
Response:
The proposed Policy allows owners/operators to take full credit for already installed controls, such as variable speed drives, designed to limit entrainment and impingement impacts. Existing mitigation measures may also be counted.

Comment 29.08:
The current proposal requires the development and implementation of major capital equipment and mitigation projects on an interim basis. There are a myriad of issues which suggest that establishing a fund to which plant operators could contribute mitigation funds would provide much more efficient, effective water quality improvements. Water Board or Regional Water Board staff could oversee projects and ensure timely implementation.
Proposed interim compliance measures include large organism exclusion devices for offshore intakes, ceasing intake flows when power is not being generated and developing restoration measures. The policy contains no details as to how these provisions would be implemented. This should be clarified to ensure more consistent and efficient compliance.
Response:
Staff has clarified that it is the preference of State Water Board staff that mitigations projects be performed by third parties and that such projects be associated with the implementation of the State's Marine Protected Areas. Staff has also defined "critical system maintenance", but believes that the section on large organism exclusion devices for offshore intakes is sufficiently clear.

Comment 29.21:
Because Diablo Canyon does not have an offshore intake, PG&E generally has no opinion on the use of exclusion devices for large organisms. However, as with any technology requirement, the Board should ensure that this is a cost-effective approach. If a facility plans to retire, repower or retrofit in the longer term, it may not make economic sense to install such a device for the short term.
Response:
Comment noted.

Comment 29.22:
The proposal calls for the elimination of cooling water flows unless a facility is engaged in "power-generating activities" or "critical system maintenance." Nuclear power plants generally

must operate the cooling system for several days prior to reactor start up following either a refueling outage or a forced outage. This is due to the need to heat-up the secondary (turbine) condensate system and establish the required condensate chemistry and condenser vacuum before reactor start and systems feed forward can commence. PG&E believes that this required procedure meets the definition of a "critical system maintenance" activity. It should be noted that the time in which cooling system flow will be required when power generation is not occurring will likely be significantly longer for nuclear facilities in comparison to most fossil fueled facilities.

Response:

Staff has defined “critical system maintenance” and believes that the described activity falls within this definition.

Comment 29.23:

The third component of the interim requirements poses the greatest challenge. Mitigation measures must be implemented to mitigate for the interim impact through existing programs, funding new projects, or developing a new project. This approach raises several complex questions: 1) how to define the mitigation period; 2) how to scale mitigation; and 3) how to quantify the mitigation. Additionally, the timeframe to develop and receive approval to implement projects may be longer than the interim mitigation period. Assuming that issues of scaling and timeframe can be overcome, PG&E supports the concept of establishing a fund to which the discharger could contribute mitigation funds. The Board staff could then develop projects on a more holistic basis that may provide a greater overall benefit to the State’s water quality.

Response:

Staff agrees that it is preferred if the plant operators contribute to a fund implemented by a state agency to appropriate mitigation projects. In fact, staff is recommending as a preference that funding be provided to the California Coastal Conservancy, working with the California Ocean Protection Council, for mitigation projects directed toward the implementation, monitoring, maintenance and management of the State’s Marine Protected Areas.

With regard to quantifying temporal aspects, scaling and quantification and ultimately funding levels for mitigation projects, the Policy provides Habitat Production Foregone (HPF) based on the proportional mortality determined by the Empirical Transport Model. A comparable method may be approved by the State Water Board staff, such as when an operator opts to providing funding to the California Coastal Conservancy/California Ocean Protection Council to fund an appropriate mitigation project; in such cases staff may then consider a fee based on entrainment weighted flow to be “a comparable alternative method” if that fee were based on costs of previous mitigation projects and similar examples using HPF.

Comment 31.39:

The use of exclusion devices where applicable is a cost-effective means to minimize impingement of large aquatic organisms.

Response:

Staff agrees.

Comment 31.40:

Many plant operators are not running intake pumps when the facility is not generating electric power due to the costs of running the pumps. Allowing for pump operation during facility startup, shutdown and standby conditions is necessary and appropriate.

Response:

Staff agrees.

Comment 31.41:

We agree with the staff that restoration is a valuable means to offset IMIE impacts. We further agree that the effectiveness of restoration is inherently site-specific. Flexibility in the selection of restoration options is essential. The effective use of restoration however, requires establishing specific criteria for the Regional Water Boards to use in assessing restoration proposals. The criteria should be developed through a public stakeholder process to ensure goals and expectations are realistic and not cost-prohibitive.

Response:

Staff has already recommended HPF, based on a proportional mortality estimate developed through the ETM, as the best available method to determine the habitat and area for a mitigation project. Staff also recognizes that comparable methods may be employed, which may be approved by the State Water Board Division of Water Quality. This should eliminate any burden on the Regional Water Boards and provide statewide consistency.

Comment 31.42:

The Ormond Beach facility currently has a 14" exclusion device as opposed to the18" grid listed in the SED.

Response:

Comment noted. Staff has made the correction to the SED.

Comment 31.43:

The Mandalay facility intake is not a shoreline structure but is located at the end of a 2.5-mile long canal originating at the Channel Islands Harbor in Oxnard.

Response:

Comment noted. Staff has correctly identified the location of the Mandalay intake on page 21 of the SED, but considers it a nearshore intake for purposes of complying with the immediate and interim requirements of the proposed Policy.

Comment 32.02:

Intake flows not directly related to power-generating activities should not be allowed under Immediate and Interim Requirements. Under the Draft Policy, power plants will be required to cease intake flows unless the power plant is “directly engaging in power-generating activities or critical system maintenance…” As undefined, the “critical system maintenance” exception creates an opportunity for significant intake flows completely unrelated to power-generation. Several desalination plants are proposed throughout the state, and more will surely follow. Part of the temptation to co-locate a desalination facility with an OTC power plant is the ability to divert flows from the power plant intake without having to address resultant entrainment and impingement as the water is diverted from the discharge. However, this incentivizes prolonged and/or increased power plant flows for the benefit of the desalination plant. The San Diego Regional Water Board recently approved a plan in which the desalination is the main driver for intake flows with no Section 316(b) implication for the power plant as the conduit for such flows. A best technology available evaluation pursuant to CWA was also not required for the desalination plant, as section 316(b) does not directly apply to desalination plants. In San Diego, this has resulted in a permitted intake of 304 MGD to produce only 50 MGD of potable water, for 365 days per year. Although we appreciate the State Water Board’s intention of addressing desalination plants through a subsequent policy, this does not address the current problem facing Regional Water Boards or the reality of co-located desalination plants being permitted today. In the interim period during which the State Water Board develops a desalination policy under state law, the possibility of circumventing the CWA through state permitting of co-located desalination plants must be foreclosed. “Critical system maintenance” must be defined to only include activities that are necessary for maintenance of a power plant’s physical machinery. Further, a power plant owner must not be able to show “a reduced minimum flow is necessary for operations" for the benefit of a co-located desalination plant. Any "necessary" flow must be directly related to energy generation.

Response:

Staff agrees that intake flows not directly related to power-generating activities should not be allowed under Immediate and Interim Requirements, and has further defined "critical system maintenance". Please see the response to Comment 3.26. However, staff believes that the co-location of a power plant and a desalination plant can result in an overall benefit to the environment. Please see the response to Comment 1.12.

Comment 33.03:

Under Immediate and Interim Requirements, the policy should clearly state that the mitigation requirements are being imposed pursuant to the Board's authority under the Porter-Cologne Act and are in no way intended as a means of complying with Section 316(b) of the CWA.

Response:

Immediate and interim requirements for mitigation are set forth separately from the BTA requirements in the Policy. Because the Policy does not allow the immediate and interim requirements to substitute for Track 1 or Track 2 beyond the immediate compliance schedule set forth, it is unnecessary to state exclusively state or federal authority for these interim measures.

Comment 33.04:

Power plants should demonstrate to the Regional Water Boards that their existing mitigation efforts effectively mitigate impacts to all species. Mitigation efforts enacted solely for the benefit of protected species (like those undertaken by the Mirant plants) are not sufficient.

Response:

Because mitigation is not mandated as part of BTA pursuant to Section 316(b), implementation of any mitigation or restoration alternatives are within the discretion of the State and Regional Water Boards.

Comment 33.05:

The Regional Water Boards must be provided with the information and guidance necessary to quantify the amount of mitigation that is needed. We also recommend that the payments to compensate for interim impingement and entrainment be collected in a fund to be managed by the State Water Board.

Response:

Variables resulting from length of compliance schedule and site-specific intake usage generally preclude specifications as to amount of necessary mitigation for continuing impacts during the period preceding full compliance with the Policy. Centralized collection of payments for management by the State Water Board would limit flexibility in allowing Regional Water Boards to use their localized expertise to approve beneficial projects.

Comment 34.09:

We support Staff Alternative 4: establishing interim IM/E requirements using technology-based methods) and requiring interim restoration.

Response:

Comment noted. Staff appreciates the support for the proposed Policy.

Comment 35.09:

The policy orders plants that are not generating electricity or are engaged in critical system maintenance to "cease intake flows" within one year of adoption of this policy, but allows intakes

to continue if the owner can demonstrate (no definition or criteria provided) it "is necessary for operations."
Response:
Staff has defined “critical system maintenance”.

Comment 35.10:
The policy allows plants to mitigate, or compensate, for the killing of aquatic life commencing five years after the OTC policy is adopted, even though the 2007 court decision explicitly banned habitat restoration, which is defined as mitigation.
Response:
Riverkeeper II found that mitigation or restoration measures do not constitute technology for minimizing adverse environmental impact. Thus, restoration measures may not substitute for other measures to meet BTA. The use of mitigation in this Policy is only an interim measure until BTA is implemented, and is not intended to substitute for or qualify as BTA.

Comment 37.09:
The Policy's requirement for SONGS to install a marine mammal prevention cage around the Unit 2 and 3 circulating water intake velocity caps by the end of 2010 will be very difficult to achieve. Such a barrier would require several months to design and review for nuclear safety concerns. It would also take additional time to deploy if it is determined to be feasible. SCE is currently working with the National Marine Fisheries Service on receiving a marine mammal take permit that would require SCE to study the issue. Therefore, this requirement is redundant and unnecessarily restrictive and should be removed from the Policy.
Response:
Staff disagrees that the requirement is redundant because SCE is working with the NMFS on receiving a marine mammal take permit. Staff also believes that it is possible to design and install the required marine mammal barrier within one year of the effective date of the Policy. Please also see the response to Comment 40.05.

Comment 40.05:
NMFS supports the requirement for large organism exclusion devices to be installed on facilities which do not yet have them within one year of policy approval.
Response:
Comment noted. The support is appreciated.

Comment 40.06:
NMFS supports the requirement to cease intake flows when the facility is not generating power or conducting critical system maintenance within one year of policy approval.
Response:
Comment noted. The support is appreciated.

Comment 40.07:
NMFS supports the requirement for mitigation of interim impacts up to and until the facility achieves compliance with the entrainment and impingement reduction measures specified under section 2.A. of the proposed policy. The necessary level of mitigation is to be determined through the use of a biologically based model, such as the habitat production foregone method, in order to account for all "non-use" impacts to affected biota.
Response:
Comment noted. The support is appreciated.

Comment 40.08:

NMFS recommends that mitigation be required for any impacts to aquatic resources remaining after a facility has upgraded their cooling system to closed-cycle wet cooling, if the facility continues to draw their make-up water from ambient sources.

Response:

Comment noted. While it is legally possible to require ongoing mitigation for any remaining impacts to marine and estuarine life after facilities have implemented BTA, staff believes that any remaining impacts would be relatively minimal.

Comment 40.09:

NMFS recommends the use of a habitat equivalency analysis method, such as the habitat production foregone method, to determine the scope of the needed mitigation.

Response:

Comment noted. The support is appreciated.

Comment 41.07:

In the interim, allow for mitigation until compliance is achieved; and/or, Provide a “staged” approach to compliance, i.e., rather than a final milestone deadline for a facility's compliance, define interim milestones with interim reductions.

Response:

The Policy does allow for mitigation until compliance is achieved and also establishes an adaptive management approach to determining deadlines for compliance.

Comment 43.04:

In Section 2.C(3) of the Policy, it is stated that if the owner or operator has not achieved compliance within five years of the effective date of the Policy, they must implement measures to mitigate the interim impingement and entrainment impacts. The cumulative effect of the, many preceding years of impingement mortality and entrainment coupled with an additional five years of continued impacts is substantial. We therefore suggest that the five-year period be reduced to two years.

Response:

Comment noted. Staff believes that it is reasonably to allow the power plant owner/operator a reasonable period of time to comply with Track 1 or 2 before requiring mitigation for interim impingement and entrainment impacts. Two years is too short of a time frame. For plants meeting final compliance within five years, staff would prefer that the plant operator dedicate resources toward reducing impingement and entrainment by installing BTA. Staff believes that compliance for most plants can be attained in five years. However, for those plants opting to take a longer time to install BTA then staff believes mitigation is an appropriate interim measure.

Comment 44.04:

The Draft Policy states at Page 4, Paragraph C. (1), that no later than one year after the effective date of this Policy, the owner or operator of an existing power plant with an offshore intake shall install large organism exclusion devices having a distance between exclusion bars of no greater than nine inches, or install other exclusion devices, deemed equivalent by the Regional Water Board." The Draft Policy should be amended to ensure that the definition of "Offshore Intake" includes a “bay or estuary”.

Response:

A bay or estuary is not “offshore”; it is nearshore.

Comment 44.05:

The Draft Policy states at Page 4, Paragraph C. (2), that no later than one year after the effective date of this Policy, the owner or operator of an existing power plant unit that is not directly engaging in power-generating activities, or critical system maintenance, shall cease intake flows, unless the owner or operator demonstrates to the Regional Water Board that a reduced minimum flow is necessary for operations," The Draft Policy should be amended to include standards and criteria to determine how "necessary for operations" must be demonstrated.

Response:

Staff has defined “critical system maintenance”.

Comment 44.06:

The Draft Policy states at Page 4, Paragraph C. (3) (b) that "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". The Draft Policy should be amended to include standards and criteria to determine an "appropriate mitigation project".

Response:

Staff has clarified that it is the preference of State Water Board staff that mitigations projects be performed by third parties and that such projects be associated with the implementation of the State’s Marine Protected Areas.

Comment 46.01:

There is no precedent for applying the HPF methodology, or any comparable methodology, to compensate for impacts that could end as early as one year after the mitigation is required. It would be unfair to require the same level of mitigation from a facility that expected to operate for five more years at most, compared to what would be required from a new facility that had an expected operating life of thirty to fifty years. Without more direction and clarity provided to the Regional Water Boards it is highly likely that the HPF methodology, or any comparable alternate method, will be applied unfairly and inconsistently.

Response:

Please see the response to Comments 1.09.

Comment 49.15:

2 C (3) The owner or operator of an *existing power plant** must implement measures to mitigate the interim impingement and entrainment impacts resulting from the cooling water intake structure(s), commencing [five years after the effective date of this Policy] and continuing up to and until the owner or operator achieves final compliance. The owner or operator must include in the implementation plan, described in Section 3.A below, the specific measures that will be undertaken to comply with this requirement. Comment: This authorization of mitigation as stated is deficient and highly objectionable, as was explained in CAPE's Sept. 29, 2009, comments: The Second Circuit court stated in its *Riverkeeper* II decision, “As we noted in *Riverkeeper I,* restoration measures substitute after-the-fact compensation for adverse environmental impacts that have already occurred for the minimization of those impacts in the first instance .... Restoration measures are not part of the location, design, construction, or capacity of cooling water intake structures, *Riverkeeper* /, 358 F.3d at 189 .. ,' Therefore, mitigation required under the board policy may not under the decision be used for "restoration measures. This should be made clear in the policy and to regional water boards that will administer the policy. In our comments on the board's previous draft OTC policy, we expressed strong reservations about use of mitigation because of concern that mitigation funds paid to the water board or Regional Water Boards could become habit-forming and might influence the agencies to not pursue aggressively the goal of ending OTC. However, if mitigation, under circumstances that may be permissible under the *Riverkeeper* decisions, is incorporated into the policy, we strongly believe that it should be used, not to compensate for and potentially prolong OTC, but to assist in development of new alternative energy sources, particularly urban photovoltaic, that would

directly serve to rep/ace coastal power plants, especially the oldest and least needed plants, and thereby contribute to earlier attainment of the state's global warming goals.
Response:
Please see the response to Comments 9.11 and 9.12.

Comment 49.16:
(3)(a) Demonstrating to the Regional Water Board's satisfaction that the owner or operator is compensating for the interim impingement and entrainment impacts through existing mitigation efforts, including any projects that are required by state or federal permits as of [the effective date of this Policy]; Comment: It should be made clear whether existing mitigation efforts can be used to compensate for OTC impacts, if those same efforts are under challenge in the courts.
Response:
The proposed Policy clearly states that the Regional Water Board will decide whether existing mitigation efforts can be used to compensate for interim OTC impacts.

Comment 49.17:
(b) Demonstrating to the Regional Water Board's satisfaction that the interim impacts are compensated for by the owner or operator's participation in funding through a third party of an appropriate mitigation project; or ... Comment: Third party should be explained.
Response:
Staff has clarified that it is the preference of State Water Board staff that mitigations projects be performed by third parties and that such projects be associated with the implementation of the State's Marine Protected Areas.

Comment 49.18:
(c) Developing and implementing a mitigation program for the facility, approved by the Regional Water Board, which will compensate for the interim impingement and entrainment impacts. Comment: Scientific evidence that mitigation effectively compensates for entrainment losses should be required as a basis for authorizing such a program. CEC staff in the Morro Bay sitting case argued "that a critical nexus both can and should be measured. This nexus should be increases in larval production of those species impacted by the CWIS. If the Energy Commission approves the HEP (habitat enhancement program) as mitigation, it should require that the Applicant actually measure and monitor the fish and invertebrate larvae that will be increased as a direct result of its actions, as well as, how much this increase in productivity offsets the losses caused by the CWIS.II (Page 9, SUPPLEMENT TO THE FINAL STAFF ASSESSMENT - PART 3 MORRO BAY POWER PLANT (OO-AFC-12), September 20, 2002 at http://www.energy.ca.gov/sitingcases/morrobay/documents/2002-09-20 AQUATIC BIOLOGIC.PDF). The staff report also stated, "Without adequate baseline monitoring and on-going project-specific monitoring it would be impossible to determine whether the projects attain predetermined performance standards and result in successful mitigation." (Page 9, op.cit.) Staff concluded, "In staff's opinion, avoidance of the impacts of the proposed MBPP by eliminating or avoiding OTC is the only certain way to mitigate the significant adverse impacts of OTC." (Page 27 op.cit.) Based on this sitting experience dating back at least seven years, the Board is obligated to establish standards governing any mitigation program to assure effectiveness and protection of invaluable resources.
Response:
Please see the response to Comment 49.16.

Comment 49.19:
(d) *The habitat production foregone** method, or a comparable alternate method approved by the Regional Water Board, shall be used to determine the habitat and area for a mitigation

project. Comment: The board cannot justify authorizing habitat production foregone or any alternative method for mitigating the killing of marine life by power plants without citing (a) scientific evidence that this method or any alternative is effective in mitigation using a nexus and (b) a record of performance in California. These requirements must be established by the board as guidance for Regional Water Boards so that they meet reasonable standards of performance and there is consistency among Regional Water Boards in supervising this program.

Response:

Based on staff discussions with Expert Review Panel members, Habitat Production Foregone (HPF) is the best available method to convert proportional mortality into area and thence a dollar value of procuring and/or restoring that area. Staff has included a requirement that proportional mortality must be based on the Empirical Transport Model. The Expert Review Panel clearly states that: "Fish larval mortality and other biological and oceanographic data can be used in the Empirical Transport Model (ETM) to estimate the percent of the total larvae lost due to entrainment in the volume of ocean water from which the larvae can be entrained. This estimate may also reflect % losses to organisms in sea water that are not sampled in entrainment studies (e.g., invertebrate larvae and other zooplankton, and phytoplankton) and is thus a more comprehensive measure of entrainment impacts." Regarding the use of comparable methods, staff is now recommending that those be approved by the State Water Board Division of Water Quality, thereby eliminating the need for preparing guidance to the Regional Water Boards.

Comment 51.03:

The requirement for a marine mammal protection barrier should also be either removed or redone to allow for a feasibility determination for nuclear power plants and a more flexible compliance schedule to allow for stations to be more able to comply if such barriers were determined to be feasible.

Response:

Please see the response to Comments 37.09.

Comment 60.04:

We strongly urge deleting the current language in sub-section (3) (C) and replacement with: "The best available restoration-scaling methodology approved by the Regional Water Board shall be used to determine the habitat and area to meet the full replacement value of marine life lost to operation of the facility's cooling system." We strongly urge removal of the terms "mitigate" and "mitigation" in the section – and replacement with the term "restorative measures to fully replace marine life losses". We strongly encourage designating the California Coastal Conservancy as the recipient of compensation coasts paid by power plant owners, and that the funding be earmarked for habitat restoration and/or creation projects to meet full replacement value. To the extent the funds account for additional replacement value above what would have been achieved in the absence of the funding. Lastly, these funds should be deposited in the Coastal Trust Fund of the State Coastal Conservancy. The Coastal Fund has the proper structure to best assure that the monies dedicated to restoration are applied in full and continuous and adaptive manner.

Response:

Staff respectfully disagrees with the removal of Habitat Production Foregone. Based on staff discussions with Expert Review Panel members, Habitat Production Foregone (HPF) is the best available method to convert proportional mortality into area and thence a dollar value of procuring and/or restoring that area. Staff has included a requirement that proportional mortality must be based on the Empirical Transport Model. The Expert Review Panel clearly states that: "Fish larval mortality and other biological and oceanographic data can be used in the Empirical Transport Model (ETM) to estimate the percent of the total larvae lost due to entrainment in the volume of ocean water from which the larvae can be entrained. This estimate may also reflect % losses to organisms in sea water that are not sampled in entrainment studies (e.g., invertebrate larvae and other zooplankton, and phytoplankton) and is thus a more comprehensive measure of entrainment impacts."

In order to clarify the policy with regard to mitigation, staff is recommending a definition of mitigation project as follows: 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, for example through the funding of implementation and/or management of Marine Protected Areas.

Staff agrees that it is preferred if the plant operators contribute to a fund implemented by a state agency to appropriate mitigation projects. In fact, staff is recommending as a preference that funding be provided to the California Coastal Conservancy, working with the California Ocean Protection Council, for mitigation projects directed toward the implementation, monitoring, maintenance and management of the State's Marine Protected Areas.

Regarding the use of comparable methods, staff is now recommending that those be approved by the State Water Board Division of Water Quality, thereby eliminating the need for preparing guidance to the Regional Water Boards. A comparable method may be approved by the State Water Board staff, such as when an operator opts to providing funding to the California Coastal Conservancy/California Ocean Protection Council to fund an appropriate mitigation project; in such cases staff may then consider a fee based on entrainment weighted flow to be "a comparable alternative method" if that fee were based on costs of previous mitigation projects and similar examples using HPF.

Comment 60.05(d):
"Power Generating Activities" We strongly believe that if the Board's discussion of "beneficial outcomes" is to be achieved, the elimination of marine life mortality from enforcement of this rule for the electrical generating industry cannot be undermined by allowing other industrial seawater withdrawals to take the electrical industry's place.
Response:
Staff agrees.

Comment 61.01:
Currently the Draft Policy implies that HPF would be a preferred method for scaling interim restoration projects. I would recommend that reference to HPF be deleted as the method of restoration scaling should be chosen based on site-specific conditions such as the species affected, and data available on source populations, habitats, and currents.
Response:
Staff respectfully disagrees with the removal of Habitat Production Foregone. Based on staff discussions with other Expert Review Panel members, Habitat Production Foregone (HPF) is the best available method to convert proportional mortality into area and thence a dollar value of procuring and/or restoring that area. However, based on discussions with members of the ERP, staff has included a requirement that proportional mortality must be based on the Empirical Transport Model. The Expert Review Panel clearly states that: "Fish larval mortality and other biological and oceanographic data can be used in the Empirical Transport Model (ETM) to estimate the percent of the total larvae lost due to entrainment in the volume of ocean water from which the larvae can be entrained. This estimate may also reflect % losses to organisms in sea water that are not sampled in entrainment studies (e.g., invertebrate larvae and other

zooplankton, and phytoplankton) and is thus a more comprehensive measure of entrainment impacts."
A study performed by the commenter (J. Steinbeck) along with other ERP members (P. Raimondi, G. Cailliet) in 2007 for the CA Energy Commission, entitled "Assessing power plant cooling water intake system entrainment impacts" makes the point that entrainment effects are best evaluated using an empirically based source water body information and the ETM model. That same study also supports the use of ETM coupled with "Area Production Foregone" (a synonym for HPF) for determining the area of adult habitat in extrapolated source water. Staff recognizes that the study cautions that HPF may not be applicable to all habitats and species, such as the case with open water pelagic habitat. Therefore in recognition of the limitations of HPF in certain cases, staff is recommending that a comparable alternative method may be used, and that option is clearly included in the policy.

Comment 61.12:
SED, pg. 9 par. 5: The appellate court decision on the restoration plan for Moss Landing Power Plant is described but not further mention is made until pg. 76 where the restoration package is again described. There is no discussion of how the decisions for the Moss Landing Power Plant restoration plan or the restoration package for Huntington Beach Generating Station are affected under the proposed policy. If these were acceptable mitigation for impacts at these facilities, why is it unacceptable at other facilities?
Response:
The Immediate and Interim Measures" portion of the policy allows an owner or operator credit towards the interim impingement and entrainment impacts through existing restoration (i.e. mitigation) efforts. However, restoration is not allowed as BTA according to RiverKeeper II, and therefore does not constitute final compliance with the Policy's BTA requirements (Tracks 1 and 2). The examples in the comment were for permits issued prior to the policy.

Comment 61.22:
SED, pg. 77, par. 3: The statement that habitat production foregone (HPF) can address losses across all habitat types is not true. HPF is really only applicable to species where the habitat associated with adult production can be identified. The approach is problematic for fishes such as northern anchovy that release eggs into the water column.
Response:
The statement ("This method can address all losses across all habitat types.") was actually on page 78 of the draft SED. However, staff agrees that the statement is overly broad due to the example provided in the comment. The statement has been changed in the SED to state: "HPF is applicable to species where the habitat associated with adult production can be identified. This method can address losses across most habitat types."

9. Wholly Disproportionate Demonstration (WDD)

a. Support for the WDD

Comment 7.06:
Consistent with the Supreme Court decision, the proposed Policy includes an allowance, in limited circumstances, for a Wholly Disproportionate Demonstration (WDD). During the process of developing a state OTC policy, experts testified that in some cases after-the-fact redesigning of large scale power plants to implement closed cycle cooling may not be possible and/or cost effective and that mitigation may be the only effective solution to address OTC effects. Central Coast Water Board staff supports that the proposed Policy allows for mitigation both as an

interim measure and to compensate for OTC impacts in certain circumstances where technological fixes such as closed cycle cooling are not possible and/or cost effective.

Response:

The Supreme Court in *Entergy vs. Riverkeeper*, 129 S.Ct. 1498 (2009) found that a cost-benefit analysis is permissible for both BTA determination and for setting variances. However, the State Water Board staff has determined that the purposes of a wholly disproportionate analysis limited to plants that have previously invested in combined-cycle technology can be more appropriately addressed through a credit for prior reductions via Track 2. Nuclear facilities will be subject to a separate compliance alternatives determination once appropriate studies are completed, a process that will include opportunity for public review and input, and include a cost-cost analysis. While the Central Coast Water Board staff states its support for mitigation in specified circumstances, it should be noted that mitigation is allowable only as a supplement to compliance with BTA as set forth in the proposed policy. According to RiverKeeper II mitigation is not a technology for minimizing adverse environmental effects and may not be used as a substitute for operational or structural controls that constitute BTA.

Comment 29.10:

PG&E strongly supports the inclusion of a WDD in the proposed policy. This is an absolutely critical component to ensuring that the policy is implemented in a reasonable, cost-effective fashion. It should be noted that the CPUC has also registered its support for this approach stating concerns with the cost of alternatives and disinclination to trade water impacts for air impacts. Given the Supreme Court's decision in *Entergy*, it makes fundamental sense for the Water Board to include, at a minimum, a cost-benefit variance within its policy. While many facilities will eventually repower or retire, recently updated facilities and the nuclear facilities represent a substantial capital investment and are poised to provide cost effective, efficient, and cleaner power to the state for years to come and a variance which allows these facilities to weigh the costs of compliance and the potential benefits is essential to ensuring that compliance dollars are spent cost effectively. Furthermore, the policy would require such facilities to fully mitigate any impacts that cannot be reduced through technology or operational measures. It is very likely that the funds spent on mitigation may provide for a greater overall environmental benefit than the elimination of OTC – at least at some facilities.

Response:

The State Water Board is not required to perform or include a cost-benefit analysis in developing and adopting its statewide water quality control plans and policies. It is important to remember that the Supreme Court, in *Entergy*, does not require that the permitting authority perform a cost-benefit test. The Court viewed the statute's silence on the point of cost as supporting agency discretion on how costs are considered. As per the response to Comment 7.06, Staff is proposing to eliminate the WDD provisions. Regarding nuclear plants, staff believes that the implementation provisions for special studies, and evaluation thereof, for the two nuclear plants generally accomplishes the same objective as previously provided in the WDD section. The revisions set forth specified factors to be considered in evaluating the need to modify the Policy and consideration of costs that may be wholly out of proportion to those considered by the State Water Board in establishing Track 1. Staff is proposing to address fossil-fueled combined cycle units in the Track 2 provisions, whereby these plants (Haynes, Moss Landing and Harbor power plants) will need to meet Track 2 reductions but may take credit for reductions in IM/E due to installation of the combined cycle technology.

Comment 51.01:

We request that the State Water Board policy contain a WDD cost provision as it did in the previous draft of the policy.

Response:

Please see response to comment 29.10, above.

Comment 53.01:
The WDD compliance option (Section 4 of the previous version of the policy) has been removed. Therefore, it is now unclear how a facility could be in compliance if (1) closed-cycle cooling were not feasible per Track 1, and (2) operational and/or structural controls could not achieve the 83.7% IM&E reduction as required by Track 2.
Response:
Please see response to comment 29.10, above. A BTA technology must be "available" in the sense that it is technically and logistically feasible for most facilities subject to the proposed Policy, and must in addition be an economically viable method. The 2008 Tetra Tech report evaluated the technical and logistical feasibility and cost of retrofitting most of the State's OTC power plants with closed-cycle wet cooling (plants with stated plans to cease OTC operation were not included). The report found that closed-cycle wet cooling was technically and logistically feasible at 12 facilities out of the 15 facilities studied. Two of the twelve facilities are the nuclear plants. The 2008 Tetra Tech report and the SED both state that retrofitting the 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. Diablo Canyon would have to shut down its operations for months to integrate the new cooling system into the existing facility but cannot stagger implementation because Units 1 and 2 share a common intake structure. 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. SONGS would also have to shut down its operations for months to integrate the new cooling system into the existing facility. However, at SONGS, Units 2 and 3 can be taken offline separately since each essentially operates as an individual unit. Lastly, any nuclear plant system modification would require approval by the NRC to ensure compliance with all relevant safety standards. For these reasons, and others, the Policy will include a provision for "Special Studies" for the nuclear plants.

It should be noted that closed-cycle dry cooling is a cooling technology that has no entrainment or impingement impacts, and would be available to fossil fuel fired plants, especially for re-powering projects. A facility may completely convert to closed-cycle dry cooling to be in compliance with the policy, or may use air cooling at some units to meet the Track 2 requirements for the facility as a whole. A facility may also choose to lower intake flow rates to be in compliance.

Comment 56.01:
The language of the Revised Policy regarding cost and feasibility in Section 3.D (special studies for nuclear facilities) provides only an opportunity to further amend the Policy, but no framework with which to make the decision to amend the policy or any guidance as to what form that amendment would take. Therefore the substantive standard providing for application of alternative requirements in specific situations has been replaced with an undefined and ambiguous process to amend the Revised Policy. PG&E believes that this is a significant and detrimental change to the proposed policy. The Board clearly has the ability to implement a cost-benefit test, under both Porter Cologne (see e.g. Water Code Section 13000) and the Supreme Court's *Entergy* decision, *Entergy Corp. v. Riverkeeper,* Inc.129 S. *Ct. 1498 (2009).* A clear concise standard would be far more effective than merely allowing for the potential amendment of the Revised Policy.

Response:
Staff is recommending inclusion of specific factors for evaluating the need to modify this Policy for nuclear plants, including: costs of compliance in terms of dollars per megawatt hour of electrical energy produced over an amortization period of 20 years compared to the costs estimated in the SED; the 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; potential environmental impacts of compliance with Track 1 or Track 2, including, but not limited to, air emissions; and any other relevant information. Thus, a clear process with defined factors will govern amendments to the Policy with respect to the nuclear facilities.

Comment 56.02:
PG&E acknowledges the Board's need to minimize administrative burdens where possible and ensure efficiency and consistency when implementing the Policy. However, we strongly believe the WDD, or a similarly well-defined consideration of costs, must be included In the Policy. Without such an approach, the Policy will treat all electric generation facilities in the same fashion regardless of their specific attributes. At a minimum, the WDD cannot be eliminated without a detailed discussion of how cost and feasibility will be considered or a justification as to why they will not be considered. **Response:**
Please see the response to comments 7.06 and 29.10, above. The proposed Policy continues to give special consideration to the two nuclear-fueled facilities and three facilities with combined-cycle units due to their unique technology, but removes the potential burden placed on the Regional Water Boards and facility owners/operators in having to make the WDD.

b. The WDD should be available to all OTC facilities

Comment 4.09:
Currently, the Draft Policy limits use of a site-specific cost-benefit analysis that could demonstrate wholly disproportionate costs to benefit to nuclear plants and fossil plants with an 8,500 BTU/KWhr heat rate or less. The 8500 BTU/KWhr standard is an arbitrary criterion unrelated to water resource issues that are being used in this instance to restrict the use of this analysis by virtually all of the fossil-fueled plants. We believe that it is inappropriate and poor public policy and outside the jurisdiction of the State Water Board to attempt to use this Policy to implement an inferred state energy policy and to accelerate the closure of coastal power plants. The State Water Board should provide an option for all OTC plants to demonstrate whether the costs of implementing the Policy are wholly disproportionate to the environmental benefits to be gained. If the cost-benefit analysis shows a disproportionate cost to benefit ratio, the State Water Board should specify practical and cost-beneficial steps to protect marine organisms that are cost-beneficial at each site.
Response:
The State Water Board is not attempting to use this Policy to implement a state energy policy. As stated in the draft SED, the goals of the proposed OTC policy is to: (1) reduce IM/E impacts from OTC facilities; (2) implement Section 316(b); (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 grid stability; and (5) reduce the resource burden on the Regional Water Boards that would continue under the existing BPJ-permitting approach.

Based on public comments received, Staff is concerned about the WDD section not meeting the goals of the policy because of the potential burden placed on the Regional Water Boards in having to make determinations regarding the WDD, and the potential for statewide inconsistency in implementing this provision due to lack of guidance. Staff is therefore proposing to remove the WDD section of the policy, while continuing to give special consideration to the two nuclear-fueled facilities and three facilities with combined-cycle units due to their unique technology. Please see response to comment 29.10, above. Staff wanted to acknowledge that the existing OTC combined-cycle units generally produce more electricity per gallon of OTC flow than older steam boiler technology, and also produce more electricity per BTU of fuel with less air pollution produced. The 8500 BTU/KWhr standard was intended to limit the wholly disproportionate consideration to power-generating units with combined-cycle technology. Under the revised policy, a fossil-fueled plant with all or some of its units using combined cycle technology may take credit for IM/E reductions due to the installation of combined-cycle in calculating their Track 2 reductions. Regarding nuclear plants, staff believes that the implementation provisions for a special study for the two nuclear plants generally accomplishes the same consideration as what was stated in the WDD section, with the addition of a consideration of specific factors, including costs of compliance compared to the costs specified in the SED and potential impacts of compliance, along with ability to achieve compliance. Please also see the response to Comment 11.45, below, regarding the use of “heat rate”.

Comments 11.45 and 50.01:
The State Water Board should apply the WDD standard to *all* units at *all* facilities. While Section 316(b) may not require that BTA determinations consider site-specific cost-benefit analyses, the Board's decision to preclude consideration of site-specific costs and benefits in determining BTA for almost all OTC plants is unreasonable, arbitrary, capricious, and an abuse of discretion. Failing that, the State Water Board should clarify that the WDD standard applies to all units at a plant with an ***average facility-wide design heat rate*** of 8,500 Btu/KWhr or less. As currently drafted, this provision may exclude the most efficient steam boiler units that are capable of providing load following services necessary to meet California's renewable energy standards. In the event a heat rate value is retained as the criterion for applicability of the wholly disproportionate alternative, the Board must clearly define the term "heat rate". We recommend that "heat rate" be defined as the higher heating value (HHV) at designed maximum sustainable capacity. Utilization of the design heat rate is appropriate to avoid issues regarding determination of actual heat rate.
Response:
Please see response to comments 7.06, 29.10, and 4.09 above, regarding applying the WDD standard to *all* units at *all* facilities. For some of the reasons mentioned in the comment, Staff agrees that the use of “heat rate” is problematic and proposes to eliminate this term entirely from the policy. Instead, the proposed Policy now uses the term “combined-cycle power-generating unit”, which has been defined in the Policy.

Comment 12.03:
The proposed policy should be changed to account for site-specific feasibility criteria, including cost-benefit considerations that realistically account for the practical implications of the Policy at the affected facilities. All facilities affected by the Policy must be allowed to demonstrate that the cost of compliance is unreasonable and/or wholly disproportionate to the benefits derived from compliance. This scenario is inconsistent with the requirements and purpose of Section 316(b). The proposed policy should include fair and reasonable thresholds and compliance options that allow facilities to implement economically feasible technologies to minimize environmental impacts.
Response:
Please see response to comment 53.01, above. Staff does not believe that the policy must be changed to account for site-specific feasibility criteria. The policy is a statewide policy and individual circumstances can be accounted for within the SACCWIS process and the Regional

Water Board permit proceedings based on the Policy. Furthermore, staff has changed the Policy language in response to comments, so Track 2 is now available to all OTC plant owners/operators that prefer this compliance alternative.

Comments 23.14, 25.05, and 41.02:
As a matter of fairness to California's ratepayers, the WDD should be a route open to all OTC facilities in California. By doing this, the State Water Board would permit a determination of whether it really makes sense, for example, to shutter a unit that runs less than 5% of the time on a yearly basis, but would cost a billion dollars or more to replace through new generation and transmission upgrades. The State Water Board may ultimately conclude that this is an expense worth incurring, but at least some analysis will have gone into the conclusion.
Response:
Staff is proposing to remove the WDD section of the policy, while continuing to give special consideration to the two nuclear-fueled facilities and three facilities with combined-cycle units due to their unique technology. Please see response to comments 7.06, 29.10, and 4.09 above, regarding applying the WDD standard to *all* OTC facilities. We do recognize the potential costs imposed and look to this as a statewide policy and not tailored to individual plants. Section 316(b) requires the use of BTA to minimize environmental impacts. The extended compliance schedule and integration into the SACCWIS process are the approaches the policy proposes to deal with cost and effectiveness issues.

Comment 31.45:
Staff correctly notes that "the possibility that the Track 1 or Track 2 compliance costs might be unreasonable compared to overall benefits." This is exactly the scenario the Supreme Court indicated was not intended by the CWA. Consequently, the State Water Board must provide an opportunity for every facility affected by the Proposed Policy to be eligible for an alternate compliance plan if they can demonstrate that costs are wholly disproportionate to benefits.
Response:
Please see response to comments 7.06, 29.10 and 53.01, above. A cost-benefit analysis is not required. The Supreme Court made no determination that CWA 316(b) required a specific interpretation, instead finding that EPA's Phase II interpretation was a permissible reading of the statute.

Comment 31.08:
The Draft Policy unreasonably limits the use of a WDD to just a few facilities, contrary to federal and state precedent. The U.S. Supreme Court confirmed that the USEPA could rely on a cost-benefit analysis in establishing national performance standards and in providing for cost-benefit variances from those standards. RRI believes that a reasonable Policy must include the opportunity for all facilities to demonstrate that the cost of compliance is significantly above and/or wholly disproportionate to the benefits of compliance.

Staff has acknowledged that the cost to comply with the Draft Policy may be prohibitive for almost all of facilities. While the Draft Policy includes a cost-benefit approach for the nuclear units and for the repowered OTC units, the justification for limiting the use of a "WDD" has no merit. RRI is not challenging the ability of any nuclear or combined cycle facility to seek alternative compliance options by means of a WDD, but questions the basis for concluding that these facilities should be the only ones allowed to make such a determination.

With respect to the nuclear units, the SED claims the compliance costs for the nuclear facilities were determined to be "uniformly higher" than that for non-nuclear units, and, because they are deemed "critical" to the state's electric generating system, they were deemed eligible for alternative compliance considerations. This argument fails, because the fossil steam units have higher costs of compliance on both the cited measure (c/kWh) and on the most relevant measure (cost/revenues after fuel costs). Moreover, these fossil steam units are also critical to grid reliability and "must continue to operate." Thus, the main arguments advanced in the SED on why nuclear plants deserve separate treatment do not justify excluding this option for the other facilities. The repowered OTC plants were deemed eligible for a WDD because they are able to "generate electricity more efficiently" which "translates to... lower intake water demands when expressed on a per MWh basis." No rationale is given for why a flow per MWh standard is appropriate for providing access to a wholly disproportionate test. Since combined cycle units are slightly more fuel efficient at full load on this standard, State Water Board staff concludes that the environmental harm is less significant as compared to a slightly less efficient steam generator. But harm to the aquatic environment does not occur based on heat rate, it occurs based on actual impingement and entrainment, which the SED assumes elsewhere to be proportional to gallons used. The reality is that the lower heat rate units run more, use more gallons and impinge and entrain vastly more fish and larvae than the fossil steam units with lower capacity factors. For instance, the Moss Landing combined cycle units have a rated capacity of 1080 MW compared with Ormond Beach at 1500 MW. Yet Moss Landing 1 and 2 entrains ten times more fish larvae than Ormond Beach (311 million larvae vs. 32 million). The numbers for fish impingement are even more pronounced with a hundred-fold difference between the two facilities (57,000 for Moss Landing compared to 517 for Ormond Beach). The Draft Policy allows the lower heat rate plants, even though they entrain and impinge orders of magnitude more larvae and fish, to demonstrate wholly disproportionate costs to benefits, while denying that ability to the plants with the lower impact. This simply makes no sense if the concern is minimizing adverse environmental impact on coastal waters. It only makes sense if the goal is to force retirement of fossil steam boiler generation in California. Furthermore, the SED's conclusion that heat rate is a good measure is based on the mistaken assumption that the value of electric generation is measured solely by the value of energy produced. It ignores reactive power, capacity, and ancillary services. A more appropriate index for the purpose of determining environmental harm in relation to a unit's value to the electric grid might be the number of operating hours or gallons of seawater pumped per MW of Resource Adequacy capacity. No reasonable electric system planner would use a single heat rate standard as the basis for deciding what units to retire. Moreover, Ormond Beach and Mandalay are shown to be essentially as efficient as the combined cycle units in the 1000 gallons/MWh metric created in the SED.

Ultimately, from an environmental viewpoint the unreasonableness of the approach to only allow high capacity factor units the ability to demonstrate wholly disproportionate cost is self-evident. The units that run the most and have the most impact on entrainment are allowed the exemptions, while the units that have less flow and less impingement and entrainment impact are deliberately denied the ability to demonstrate wholly disproportionate cost. The SED's next line of reasoning in rejecting the ability of all plants to seek a wholly disproportionate test is that this would "encourage most facilities, if not all, to opt for this compliance strategy." This rationale is arbitrary and an admission both that Tracks 1 and 2 are likely infeasible for most, if not all of the OTC units, and that the costs of requiring BTA as defined in the Draft Policy are wholly disproportionate to the benefits derived for most plants. The SED then reasons that nuclear units and the repowered units required large investments to build and provide cost-effective energy relative to units with higher heat rates. The relevance of that fact to reducing IM/E is a mystery. The reasoning supporting the eligibility criteria to make the wholly disproportionate demonstration makes little sense, is arbitrary and should be eliminated.

Response:

Please see response to Comment 11.45, above, regarding the use of "heat rate" in the Draft Policy. Please see response to Comments 7.06, 29.10 and 53.01, 4.09, and 23.14 regarding extending the WDD option to all facilities. The SED does state that compliance costs, when based on 2006 net output, for the nuclear facilities are only slightly lower ($12.43/MWh, or 1.2 cents/KWh) than for steam turbine units ($14.48/MWh or 1.4 cents/KWh). However, when based on rated capacity, the compliance costs for nuclear facilities are much greater ($11.34/MWh or 1.1 cents/KWh) than for steam turbine units ($1.64/MWh or 0.2 cents/KWh). An even more important point is that nuclear plants are an entirely different technology, with very important safety considerations, and that has been included in Staff's recommendations for special studies for nuclear plants.

c. Specific comments or suggested revisions to the WDD Section

Comment 9.07:
The policy contains use of the Moss Landing plant as a possible model for wholly disproportionate analysis, which is inappropriate because of the plant's age, continued litigation over its operational status and the questionable record of mitigation for OTC impacts.
Response:
There are only three coastal OTC plants in California that have repowered with combined cycle units, and Moss Landing is the only one of those that has funded mitigation. It is true that the steam boilers at Moss Landing are quite old, but these must be retrofitted or repowered using BTA, either under Track 1 or Track 2. Staff is proposing to remove the WDD but will continue to recommend specific requirements for combined cycle units.

Comments 3.21 and 26.19:
The State Water Board should set clear standards for calculating the benefits of reducing entrainment: (1) the methodology must be the "best science available"; (2) the method should include the "precautionary principle"; (3) the method should calculate "full replacement"; and (4) opportunities for public comment should be provided. "Habitat production foregone" (HPF) fall short of these standards and should not be a suggested methodology. We strongly urge the State Water Board to consider a "restoration scaling" methodology in an effort to more accurately reflect "full replacement" value. Additionally, the policy should incorporate a strict and definitive margin of error to compensate for the lack of certainty inherent in calculating the benefits to a natural ecological system that is so poorly understood. Further, in order to avoid an underestimate of benefits, care should be taken to assure that quantitative factors do not dominate important qualitative factors in decision-making. It also should be clear that it is perfectly appropriate for the Regional Water Boards to include non-monetized and qualitative benefits in their consideration. It is not clear why the sub-section concerning impingement is not similar in detail to the section on entrainment, but the State Water Board should include similar standards to calculate the benefits of reducing impingement.
Response:
As per the response to Comments 7.06 and 29.10, Staff is proposing to eliminate the WDD provision and will therefore no longer recommending calculating the monetary benefits of reducing IM/E in this section. Staff disagrees with the inclusion in the policy of a vague reference to "restoration scaling." Staff is still proposing the using the HPF method to estimate interim impacts and required mitigation under the section titled "Immediate and Interim Requirements". HPF (or a comparable method) is really the only methodology that has been employed successfully in California for mitigation of power plant entrainment. While the state of the science regarding the estimation of impacts from power plant intakes is less than desirable, HPF, based on an Empirical Transport Model (ETM) is still the best method currently available to convert entrainment impacts into a tangible area for restoration and enhancement. ETM

does not rely on uncertainties in fish life history as did previous demographic models. Instead ETM is a more elegant model combining the presence of entrained species in the source water with oceanographic characteristics of that source water. While still not without assumptions, ETM is a more ecologically based approach with fewer uncertainties than previous demographic models. Staff has consulted with biologists on the ERP and they have confirmed this. A study performed by the J. Steinbeck, J. Hedgepeth, P. Raimondi, G. Cailliet, and D. Mayer in 2007 for the CA Energy Commission, entitled "Assessing power plant cooling water intake system entrainment impacts" makes the point that entrainment effects are best evaluated using an empirically based source water body information and the *ETM* model (CEC-700-2007-010, see http://www.waterboards.ca.gov/water_issues/programs/npdes/docs/cwa316b/symposium_2007jan/john_steinbeck.pdf). That same study also supports the use of ETM coupled with "Area Production Foregone" (synonym for HPF) for determining the area of adult habitat in extrapolated source water. The study does caution that HPF may not be applicable to all habitats and species, such as the case with open water pelagic habitat. Therefore, in recognition of the limitations of HPF in certain cases, a comparable alternative method may be used, and that option is clearly included in the policy.

Regarding impingement, staff believes that monitoring results provide more direct estimates of mortality, and therefore a complex approach like the ETM coupled with HPF is not applicable for impingement.

Comment 7.07:
The proposed Policy allows Regional Water Boards to decide what is considered wholly disproportionate. Although Central Coast Water Board staff appreciates this flexibility, permitting decisions may be strengthened and clarified if the Policy would include parameters the Water Boards could use to value and compare the loss of natural resources with the monetary costs of compliance. For example, what do the Water Boards use to compare the value of the natural resource to the monetary cost of compliance, in order to determine if the cost is wholly disproportionate?
Response:
Staff is also concerned about the potential burden placed on the Regional Water Boards in having to make the WDD. Upon considering these and other comments Staff is therefore proposing to remove the WDD section of the policy (please see responses to comments 7.06 and 29.10.). However we will continue to recommend specific requirements for combined cycle units and nuclear facilities. Staff is not proposing to include a cost benefit analysis and therefore does not need to provide a conversion factor for biological resources lost to monetary terms.

Comment 9.15:
The policy requires that the owner or operator of an existing power plant must reduce impingement mortality and entrainment impacts to the extent practicable, as evidenced by the WDD, and as determined by a Regional Water Board. The difference in impacts to marine life resulting from alternative, less stringent requirements shall be fully mitigated. A required process for measuring those impacts should be stated. How is compensation for impacts to be demonstrated? In the absence of an answer to this question, funding alone could be accepted as adequate to mitigate with no evidence of effectiveness and with no direction on how that money will be allocated or whether it would be related in any way to OTC impacts on marine life.
Response:
Please see the response to Comment 3.21.

Comment 20.07:
As part of a WDD, the owner/operator of a power plant is required to quantify the environmental benefits of compliance, including (1) the reduction in entrainment expressed as HPF, (2) the reduction in impingement mortality, and (3) the improvement in receiving water quality due to reduction of thermal discharge. It is not clear how these different metrics would eventually be analyzed.
Response:
Staff is proposing to remove the WDD section, and therefore the owner of a power plant would not need to quantify benefits, and Regional Water Boards would not need to assess that information. Please see the response to Comments 7.06 and 29.10, above.

Comment 22.04:
If the Board retains the WDD exemption, the Policy should significantly clarify and constrain the circumstances under which it can be employed. The open-ended wording of the Draft Policy invites manipulation, controversy, and litigation at each step. To protect the uniformity of the permitting process and the integrity of our marine resources, the Policy will need to substantially reduce the permit writer's discretion by (1) crafting a more robust and scientifically defensible approach to valuing ecological benefits than the "habitat production forgone"; (2) specifying that the burden of showing that the methodology employed reflects the best available science rests on the applicable Regional Water Board; (3) incorporating corporate procedural protections in the form of both expert peer review; (4) allowing for a full and fair opportunity for the public to review and comment; (5) articulating clear standards for how costs per acre will be calculated, if the Policy sanctions any valuation methodology that relies upon an acreage restoration calculation; (6) providing strict sideboards for interpreting the term "wholly disproportionate" to limit the exemption to circumstances where costs are truly extraordinary compared to the fully valued environmental benefits and out-of-line when compared to the costs incurred by similarly situated facilities to achieve compliance. **Response:**
Staff is proposing to eliminate the WDD exemption for some of the reasons mentioned in the comment. Please see the response to Comments 7.06 and 29.10, above.
Staff is proposing to include a requirement for using HPF (based on proportional mortality from the ETM), or a comparable alternative method, in the policy for purposes of determining area and habitat for interim mitigation projects. Staff has consulted with biologists on the ERP and they have confirmed this. A study performed by the J. Steinbeck, J. Hedgepeth, P. Raimondi, G. Cailliet, and D. Mayer in 2007 for the CA Energy Commission, entitled "Assessing power plant cooling water intake system entrainment impacts" makes the point that entrainment effects are best evaluated using an empirically based source water body information and the ETM model (CEC-700-2007-010, see http://www.waterboards.ca.gov/water_issues/programs/npdes/docs/cwa316b/symposium_2007jan/john_steinbeck.pdf). That same study also supports the use of ETM coupled with "Area Production Foregone" (a synonym for HPF) for determining the area of adult habitat in extrapolated source water. The study does caution that HPF may not be applicable to all habitats and species, such as the case with open water pelagic habitat. Therefore in recognition of the limitations of HPF in certain cases, a comparable alternative method may be used, and that option is clearly included in the policy.

Comment 22.05:
The HPF Model does not accurately or adequately quantify ecological benefits. For an accurate cost-benefit analysis, the regulations must ensure that the environmental benefit calculations capture the full ecological impact of OTC to the greatest extent possible, not just the immediate impact on commercial and recreational species. To that end, using only the HPF method to measure impacts is insufficient. USEPA has found that where, as here, the environmental

assessment focuses on impacted fish species alone, the analysis is likely to lead to a potentially significant underestimate of baseline losses and, therefore lead to understated estimates of the regulatory benefits from a closed cycle system. This underestimation is due to several factors: (1) There is substantial uncertainty surrounding the accuracy of entrainment and impingement monitoring data because usually only a subset of commercial and recreational fish species are monitored, leading to an underreporting of the mortality of all other affected species; (2) The cumulative, ecosystem-wide effects are entirely ignored in the HPF formula. In the National Benefit-Cost Analysis that USEPA prepared in connection relation to the section 316(b) Phase II requirements, the agency noted it was not able to monetize the benefits associated with 98.2% of the marine life that would be saved by compliance with the Phase II regulations. Moreover, USEPA has recognized the cumulative effects that multiple coastal power plants can have and has stated that "this type of cumulative impact is largely unknown and has not adequately been accounted for in evaluating impacts; (3) The HPF methodology fails to consider the effects of fish kills on the rest of the food web, e.g., on invertebrates or on fish-eating birds and mammals which depend on them as a food source. The interrelated nature of climate, habitat, predator-prey relationships, and other environmental factors make it difficult to credit an environmental benefit directly to a reduction in OTC, even if such a reduction would dramatically improve the health of an ecosystem. In addition, because of the dynamic nature of ecosystems, it may be difficult to attribute any proportion of a change in a population to the operation of a cooling water intake structure. The cumulative result of this uncertainty is that the ecological benefits are extremely difficult to quantify under any methodology. The HPF model makes no attempt to grapple with these issues, ensuring that facilities will vastly underestimate the benefits of closed-cycle cooling systems and overstate (relatively) the costs. The "considerable uncertainties" inherent in the simple HPF method render it wholly incapable of reliably measuring ecological processes and benefits for complex marine systems. Thus, even though this methodology is attractive because the cost of restoring or enhancing a certain acreage of habitat can quantified, the estimate becomes meaningless if the ecological impact is inaccurate or incomplete.

Response:

Please see response to Comment 3.21. Staff agrees with these comments and specifically wishes to highlight the commentators point: “In the National Benefit-Cost Analysis that USEPA prepared in connection relation to the section 316(b) Phase II requirements, the agency noted it was not able to monetize the benefits associated with 98.2% of the marine life that would be saved by compliance with the Phase II regulations.” Staff, however, disagrees that the HPF method, when based on proportional mortality determined through the empirical transport model (ETM), does not account for the ecological impact of entrainment. To the contrary, the HPF, although often based on target species proportional mortality via ETM, is the best available method to mitigate ecological effects. When target species represent a range of life history types, the area determined through HPF should be sufficient to support the other non-targeted PM species. In addition, setting aside that habitat area for protection also accounts for the ecological impacts (e.g., a organisms protected from anthropogenic impacts in the habitat set aside continues to serve its same ecological function, and its offspring are available as both prey and/or predators within the ecosystem, thereby effectively replacing the entrained organisms.

Comment 22.06:

The Board should specify that all species be monitored for impingement and entrainment, not just those which are commercially and recreationally important. **Response:**

Staff agrees. Please see response to Comment 3.21.

Comment 22.07:
The Policy should require that facilities attempting to invoke the WDD exemption using an HPF model must supplement their valuation estimates using other methodologies to better capture the non-use value of the ecological impact from OTC. USEPA recommends simultaneously conducting three broad types of economic impact analyses (benefit-cost, economic impact and equity assessment, and cost-effectiveness) in order to determine a particular policy's impact. The Board should also require facilities to provide more than one measurement of the ecological impacts from their OTC operations. Thus, HPF should be supplemented using estimates from other market-based approaches, revealed preference methods, or stated preference methods. Over the past decade, federal agencies and non-profits have been hard at work developing best practices for valuating difficult-to-measure ecosystem impacts. The Board should specifically require facilities to use some of these recommended methodologies when providing Regional Water Boards with their cost-benefit analysis of incorporating new technology.
Response:
Staff is proposing to eliminate the WDD exemption. Please see response to Comment 3.21. In addition, staff recognizes the difficulty in quantifying the economic benefits of ecological impacts with only market based assessments. Any study attempting to do cost-benefit analysis should include non-market based methods such as revealed preference, stated preference or other methods that attempt to value the entire ecosystem and not just the commercially availably fish.

Comment 29.27:
Further details are required to ensure a consistent application of the WDD provision. The proposed policy does not include sufficient definitions and explanations of how costs are calculated, how benefits are calculated, and how the two are compared. Much time, effort, and energy has been spent by staff at the USEPA, NOAA and other agencies to develop tools for the estimation of costs and benefits. The Water Board should be careful not to reinvent the wheel or to be overly concerned that such estimations cannot be made. Environmental costs and benefits are calculated frequently in the regulatory setting and USEPA has published a guidance document on the subject. If there is no definition, each Regional Water Board is free to make its own determination and this will lead to the very inconsistency that the Water Board is trying to avoid by developing the OTC policy. It is entirely appropriate for the Water Board to establish a minimum threshold over which costs are found to be wholly disproportionate. While there is no clear cut answer, several court cases suggest a range of two to three times benefits would be reasonable. (Comment letter 29.27).
Response:
Please see responses to Comments 7.06, 29.10, and 7.07.

Comment 29.28:
As proposed, the Regional Water Board *may* grant a variance if a discharger demonstrates that the cost of compliance is wholly disproportionate to the benefits achieved. PG&E believes that the Water Board should establish a clear framework for making such a demonstration – and if the discharger meets this burden, the variance must be granted. Assuming that the variance is established to avoid the irrational outcome of spending billions of dollars to achieve a very small benefit, allowing it to be granted on a discretionary basis could lead to inconsistent results that contradict the objective of the statewide policy.
Response:
Staff agrees that the WDD could lead to inconsistent results that contradict the objective of the statewide policy, and is therefore proposing to eliminate the wholly disproportionate exemption. Please see responses to Comments 7.06, 29.10., and 7.07.

Comment 29.29:

The proposed policy requires the discharger to provide information on the costs of compliance in terms of "dollars per megawatt hour of electrical energy produced over an amortization period of twenty years." While the calculation of benefits appears to be "lump sum" in nature, the costs are presented on an amortized basis and further divided by the number of megawatt hours of electricity produced. This appears to create two different types of cost streams. Costs and benefits need to be presented in a manner that allows for accurate comparison and evaluation.
Response:
Staff agrees that to the extent possible that costs should be defined in comparable manners. Ecologic benefits cannot be quantified monetarily by normal economic analysis of damage to market fish stocks. Staff is proposing to eliminate the WDD exemption. Please see responses to Comments 7.06 and 29.10.

Comment 29.30:
The proposed policy's approach to benefits calculation should be reviewed. Currently, it states that HPF or some other appropriate method approved by the Regional Water Board" must be used to determine the benefits from impingement and entrainment reductions. First, PG&E believes that the Water Board should set a standard for the Regional Water Boards to follow. Individual Regional Water Boards should not be able to select different benefit assessment models, as this would lead to inconsistent results. The SED suggests that an ecological approach to benefits calculation is necessary because only 2% of what is entrained and impinged is accounted for under standard processes for quantifying benefits. This misstates the situation. In standard economic analysis, all fish and shellfish are accounted for through tropic transfer modeling. All that is not accounted for is phytoplankton or zooplankton. USEPA has found that there is a very low potential impact to these species due to their extremely short generation times, continual reproductive capabilities, and abundance along the entire California coast. Thus, there is no need to include zooplankton and phytoplankton in any benefits assessment. The proposed policy's recommended approach, the HPF model, has not been subject to significant peer review. The HPF model was developed by scientists working with the Central Coast Water Board on various entrainment studies during the 1990s. As stated in our 2006 and 2008 comments concerns with the HPF model include: 1) failure to provide a necessary linkage between impingement and entrainment effects, ecological services, and human services; 2) failure to consider discounting, and thus a high likelihood of overestimating the size of a restoration project; 3) no accounting for uncertainty in its analysis; and 4) failure to consider biological compensation, especially in relationship to larval losses – further overestimating the size of a restoration project. Further, reviews of the HPF approach by resource economists have found that the approach violates fundamental economic principles by using habitat replacement as a proxy for the value of the lost resource. Additionally, the results of the HPF model are based on averaging the various entrainment rates for all fish that are evaluated and the source water body size for each species. This averaging process introduces a great deal of uncertainty as to what the calculation represents. The final result is presented as a range of habitat size and the evaluation done for Diablo Canyon demonstrates the potential breadth of such a range. The Independent Scientists' Report to the Central Coast Water Board estimated the size of an artificial reef to compensate for entrainment losses ranged from 85 hectares to 412 hectares – a factor of five. There is no obvious mechanism to choose a point within the range and thus, there is a great deal of discretion that goes into making a final determination. The Water Board should review existing cost-benefit models developed and used by other agencies, as well as the cost-benefit guidance document prepared by USEPA, and provide clear guidance to the Regional Water Boards on how to perform such an assessment.
Response:
Please see responses to Comments 7.06, 29.10., and 7.07. Staff does not believe that the

standard market based analysis of ecologic impacts is sufficient or adequate. However, monetized ecological benefits are not a major factor under BTA requirements of Section 316(b). Staff is proposing to include a requirement for using HPF (based on PM from the ETM), or a comparable alternative method, in the policy for purposes of determining area and habitat for interim mitigation projects. Staff has consulted with biologists on the ERP and they have confirmed this. A study performed by the J. Steinbeck, J. Hedgepeth, P. Raimondi, G. Cailliet, and D. Mayer in 2007 for the CA Energy Commission, entitled "Assessing power plant cooling water intake system entrainment impacts" makes the point that entrainment effects are best evaluated using an empirically based source water body information and the ETM model (CEC-700-2007-010, see http://www.waterboards.ca.gov/water_issues/programs/npdes/docs/cwa316b/symposium_2007jan/john_steinbeck.pdf). That same study also supports the use of ETM coupled with "Area Production Foregone" (a synonym for HPF) for determining the area of adult habitat in extrapolated source water. The study does caution that HPF may not be applicable to all habitats and species, such as the case with open water pelagic habitat. Therefore in recognition of the limitations of HPF in certain cases that a comparable alternative method may be used, and that option is clearly included in the policy.

Comment 30.08:
It is not advisable to have the affected parties conduct a WDD analysis. These parties are on record as opposed to cooling tower retrofits. There is sufficient public domain information, much of it paid for by the state, for review, identification of data gaps, and decision making.
Response: Staff proposes removing the WDD. See responses to Comments 7.06 and 29.10.

Comment 31.14:
The cost amortization period utilized in making a WDD should be changed from 20 years to no more than 10 years and costs and benefits should be measured in net present value, not in $/MWh. An amortization period of 20 years is not reasonable. For example, the plants that have an early compliance date, such as 2015, are presumably no longer needed for reliability purposes after that date. With the potential for only five more years of operation, it makes no sense to assume that the investments made to comply with the OTC policy could be recovered over a 20 year period! Additionally, it makes no sense to have a wholly disproportionate test with costs based on dollars per MWh and benefits based on an indeterminate measure. How can one determine whether costs are wholly disproportionate to benefits if the bases are not comparable? Are the Regional Water Boards supposed to calculate HPF per MWh? As the NERA report shows, the widely accepted way to compare cost and benefits is to use net present value, and that should be adopted here.
Response:
Please see responses to Comments 7.06, 29.10., 7.07, and 29.30.

Comment 37.12:
The Policy would allow owners and operators of affected nuclear and fossil-fueled power plants with a heat rate of 8,500 BTU/kWh or less to request alternative reduction targets from the Regional Water Board if they demonstrate that the costs of the Policy for their power plants would be wholly disproportionate to the benefits. The Policy does not provide specific guidance on how the cost-benefit analysis should be performed, although it does indicate that costs should be measured in terms of cents-per-kWh and that benefits should be measured in terms of "habitat production foregone" (an estimate of habitat area production that is lost to all entrained species). As discussed in NERA's report, these measures of costs and benefits are not consistent with state or federal guidelines and raise a number of conceptual and practical difficulties.

Response:
Please see responses to Comments 7.06, 7.07, 22.05 and 29.30.

Comment 37.27:
The State Water Board should consider assuming that the costs of cooling towers are wholly disproportionate to the environmental benefit for nuclear facilities. Under this alternative, the covered facilities would be assumed to demonstrate that the costs of cooling towers would be wholly disproportionate to the environmental benefits. Because this alternative would not result in cooling towers at the nuclear facilities, it may greatly minimize the Policy's significant environmental impacts.
Response:
Please see responses to Comments 7.06 and 29.10.

Comment 40.12:
The proposed policy should at least clarify that the use of the Adult Equivalent Loss and Fecundity Hindcast models to determine impacts are not sufficient. These methods have typically only been used for a limited subset of impacted species and the assumptions built into the models contain significant uncertainties, such as the lack of data for California fishes, a lack of site-specific data and inadequate accounting for unknown environmental compensatory or other factors operating on population levels. **Response:**
Please see responses to Comments 7.06, 3.21, and 22.05. Staff agrees that Adult Equivalent Losses and Fecundity Hindcast models are insufficient to assess IM/E impacts. These are both demographic fish population models that require a great deal of life history and other information, and much of that information is unknown or quite uncertain for the vast number of species impacted by OTC. A far superior approach is the EMT.

Staff has determined that the purpose of allowing a limited WDD would be better served by providing credit for previous reductions at facilities with prior investments in combined-cycle technology and providing special options for the nuclear-fueled power plants. Thus, the WDD has been removed from the proposed policy.

Comment 43.06:
While we support requiring that the owner or operator of an existing power plant bear the burden of providing detailed, site-specific data to the Regional Water Board in support of a request to implement requirements that are less stringent than those in Tracks 1 and 2, we suggest that these data be subjected to independent third party scientific review.
Response:
Please see responses to Comments 7.06, 29.10, and 7.07.

Comment 43.07:
We are concerned about the use of the HPF method for estimating impingement mortality and entrainment.
Response:
Please see the response to Comment 3.21.

Comment 43.08:
The analysis of air emission impacts should include an analysis of the generation of greenhouse gases (GHG).
Response:
Please see responses to Comments 7.06 and 29.10. Staff is proposing to eliminate the WDD provisions. Regarding nuclear plants, staff believes that the implementation provisions for a

special studies and evaluation thereof for the two nuclear plants generally accomplishes the same objective as previously provided in the WDD section. The revisions set forth specified factors to be considered in evaluating the need to modify the Policy and consideration of costs that may be wholly out of proportion to those considered by the State Water Board in establishing Track 1. The special studies for the nuclear facilities will investigate alternatives for the nuclear-fueled power plants to meet the requirements of this Policy, including the potential environmental impacts of compliance with Track 1 or Track 2, including, but not limited to, air emissions.

Comment 43.09:
We support the requirement to fully mitigate the impacts of impingement mortality and entrainment when requirements less stringent than those under Tracks 1 and 2 are approved by the Regional Water Board and implemented by the owner or operator of an existing power plant.
Response:
Please see responses to Comments 7.06 and 29.10. Staff is proposing to eliminate the WDD provisions, and will therefore no longer recommending mitigating the impacts of impingement mortality and entrainment when requirements less stringent than those under Tracks 1 and 2 are approved by the Regional Water Board. However, staff is still proposing mitigation for interim impacts under the section titled “Immediate and Interim Requirements”.

Comment 59.02(a):
SCE proposes the addition of the following definition to the revised Policy: *Wholly disproportionate - Refers to situations where the costs of compliance unreasonably exceed the environmental benefits to be gained by compliance. Absent substantial evidence to the contrary on a case-by-case basis, costs are presumed to unreasonably exceed environmental benefits if the ratio of costs to benefits is greater than 5-to-1.* **Response:**
Please see responses to Comments 7.06 and 29.10. Staff is proposing to eliminate the “WDD” provisions.

d. The WDD should be eliminated

Comments 3.15 and 26.13:
The WDD exception is not required, not a common practice, and should be removed. Given the small number of OTC facilities and the work already performed by various state agencies, it seems the State Water Board should be able to adopt a policy without this exception. Indeed, based on available information, it is far easier for the State Water Board to conclude that the economic benefits of our coasts make closed-cycle cooling worth the costs to retrofit. In addition, the proposed Policy already contemplates economic considerations through selection of wet cooling as BTA. Moreover, not withstanding a recognized range of 93-97% achievable reduction in intake through closed-cycle cooling, the proposed Policy chooses the low end of that performance range – 93% reduction – rather than the high end of the range. While not completely clear in the Draft SED, the basis for this also seems to be economic in nature. Finally, economic considerations also appear inherent in the grid reliability exception.
Response:
Please see responses to Comments 7.06 and 29.10. Staff is proposing to eliminate the WDD provisions. With regard to setting the Track 1 BTA at 93%, staff believes this is necessary given the range of different conditions at the various plants, and certainly did not propose 93% for economic reasons. Staff freely admits that continued grid reliability is an important feature of the policy, but again this is not primarily due to economic considerations. Grid reliability is essential for public health and safety, which is the primary reason why it is included prominently in the

policy.

Comments 3.16 and 26.14:
Inclusion of a WDD does not promote the stated goals of the Draft Policy, namely producing clear guidance and reducing the burden placed on the Regional Water Boards. Indeed, the State Water Board is essentially leaving the most difficult decisions to the Regional Water Boards. Intensive economic studies will be required and even then Regional Water Boards will still be left determining what the remaining "extent practical" standard will be if a facility qualifies for the exception. This will not save time, create consistent permits, nor reduce the burden on the Regional Water Boards. **Response:**
Staff agrees. Please see response to Comment 7.07. Staff is proposing to eliminate the WDD provisions.

Comment 3.17 and 26.15:
Inclusion of the WDD invites litigation at both the State Water Board and Regional Water Board level. At the State Water Board level, industry has already expressed a desire that the exception apply to all facilities, not just those identified in the Draft Policy. This could lead to litigation instead of a shift to modernizing California's power plants. Litigation will be pursued at the Regional Water Board level because of the disparity in resources and inconsistent approaches. The numerous difficulties of accurately measuring both the benefits and the costs lend itself to extensive dispute and litigation. As discussed in the *Riverkeeper* cases and the analysis of the State Water Board itself, benefits also are typically undervalued and subject to inconsistent approaches, especially when compared to costs. For example, industry already disputes any non-use valuation methodologies and likely will continue to do so at the Regional Water Board level. Further, this approach moves the debate away from technology and more towards water impacts, which often is more contentious and more difficult. Moreover, Congress rejected a regulatory approach that relies on water quality standards, which is essentially what industry argues in focusing on fish populations and consequential environmental harm. The inevitable disputes invited by this exemption have the potential to undermine the Implementation Schedule. In contrast, the removal of this exemption is consistent with the US Supreme Court ruling in *Entergy,* because it would significantly reduce potential litigation, and eliminates an unnecessary loophole that undermines otherwise clear guidance for compelling use of the best technology available.
Response:
In itself, the likelihood of opposition and resulting litigation does not provide a basis for including or excluding any particular aspect of the proposed policy. The Supreme Court in Entergy found that a cost-benefit analysis is permissible for both BTA determination and for setting variances. However, the State Water Board has determined that the purposes of a WDD analysis limited to plants that have previously invested in combined-cycle technology can be more appropriately addressed through a credit for prior reductions via Track 2. Nuclear facilities will be subject to a separate compliance alternatives determination once appropriate studies are completed, a process that will include opportunity for public review and input. Please see responses to Comments 7.06 and 29.10.

Comments 3.18 and 26.16:
We agree with the rationale and ruling of the Second Circuit Federal Court in the *Riverkeeper* cases that benefit/cost analyses are unworkable. Accurately quantifying the impacts of entrainment and impingement from an ecosystem-wide perspective is beyond the abilities of the current state of marine sciences. Further, the numerous difficulties of accurately measuring both the benefits and the costs lend itself to unlimited dispute and litigation. In 2002, the State Water Board expressed uncertainty about the usefulness of a WDD analysis in the U.S. EPA's

draft Phase II rule: “Our experience is that it is difficult to obtain agreement on costs or benefits. The result is a long series of arguments involving dueling cost/benefit analyses. Cost estimates vary widely between estimates generated by the applicant and those generated by independent consultants. Estimates of biological impacts are even more variable, and the applicant often asserts that there will be no net impact. Even if agreement could be obtained on the benefits to a biological community of meeting the performance standards, agreeing on the monetary value on this benefit would still be difficult. If USEPA decides to adopt this portion of the Proposed Rule, we request that the Proposed Rule require the applicant to fund an independent analysis. We also request that "wholly disproportionate" be substituted for "significantly greater" to ensure that site-specific determinations will only be used in unusual circumstances. A rule that requires cost/benefit analyses for most decisions will be difficult to administer.”

Response:

Staff agrees that cost-benefit analyses are problematic and is proposing to eliminate the WDD provisions. Please see responses to Comments 7.06, 29.10, 7.07, and 3.17.

Comment 3.19 and 26.17:

We currently do not adequately understand the numerous complexities of the ocean environment, including the marine living resources and the physical processes, to accurately determine the impacts of entrainment and impingement either in an immediate “snap shot”, or more importantly, in the long-term. It is currently impossible to accurately determine what is considered a “sustainable yield” for the majority of species controlled under fishery management plans. Compounding this problem is that the data on non-commercial species is, for the most part, equally poor, if not more so. Further, there is limited information about the role of both commercially valuable species and non-commercial species in the marine ecological system and impossible to quantify in any discrete conclusions. Finally, the complexities of an ever-changing ocean physical environment results in unreliable data for long-term ecosystem based management. Not only is the ocean a physically dynamic place involving El Nino events, oscillating regime shifts, and other factors that have limited understanding, knowledge about these complex dynamics is complicated by the on-going effects of climate change. Traditional benefit analysis tends to reward facilities in degraded waterways because the benefits are more difficult to accurately calculate due to the long term degradation of the resource. Given the limits of science to accurately determine the adverse impacts on the environment, quantifying the impacts in monetary or any other comparable terms to compare the benefits of reducing entrainment and impingement to the cost of improved cooling technology is simply impossible. USEPA does not believe that it is necessarily required to prepare any monetized assessments at all, and has stated that “care should be taken to assure that quantitative factors do not dominate important qualitative factors in decision-making.” The Draft SED fails to mention benefits at all in the Economic Analysis section.

Response:

Staff agrees that it is very difficult to accurately estimate all the environmental benefits of many regulatory actions, and is proposing to eliminate the wholly disproportionate provisions. Please see responses to Comments 7.06 and 29.10. Staff and consultants have, to the best of their ability, documented environmental impacts of OTC, which because of long term degradation clearly understate current and past problems. Staff has not attempted to provide economic environmental benefits in the SED due to many of these reasons. Staff agrees that there are a myriad of complexities and unknowns regarding the ocean environment. Science still has a limited understanding of the complexities of the ocean ecosystem. Staff agrees that monetizing the impacts that, while substantial, are poorly understood on a scientific level, is not possible. The State Water Board is not legally required to do cost-benefit analysis when developing water quality plans and policies. It is our general policy not to perform cost-benefit analyses. However, in a greater sense, staff believes that the impacts of OTC are substantial and that there will be a great environmental benefit to the adoption and implementation of the Policy. That is the basis for our making this policy one of the Board's highest priorities.

Comment 3.20 and 26.18:
There is an assumption that the calculation of the cost to implement BTA is relatively straightforward in comparison to calculating the benefits. While it is true that estimating costs has the advantage of calculating variables that are "monetized" in the market, that relative ease of calculating costs does not eliminate disputes. Efforts at estimating the cost of compliance are a source of controversy amongst experts. For example, estimates are dramatically impacted by choice of discount values as well as terms of amortization (e.g. 20 or 30 years) for capital projects of this nature. It is also important to put costs in perspective. Hundreds of millions of dollars in capital expenses– once spread out over time and across the population – equal a change of 6-18 cents a month in terms of household costs, for example. Moreover, as EPA noted in the adoption of the Brayton Point power plant in Massachusetts, the courts have been clear that under the analogous BPT wholly disproportionate cost test, environmental controls might be required where costs could cause some "economic dislocation" and even plant closures to achieve the stated environmental objective. While this approach is generally supported by the environmental community, this also leads to debate with industry. In addition, there is another benefit that is often overlooked when viewing costs: costs drive conservation as well as the more efficient use of resources. There has been a great deal of effort already invested in trying to craft a benefit-cost rule for enforcing CWA Section 316(b), which has not resulted in a standard formula that is workable – nor would it benefit the industry with clear guidance for future planning or investment. Arguably, efforts to craft a benefit/cost exemption to the rule compelling the use of best technology available stand as a clear example of why a mandate passed by Congress in 1972 remains unenforced. We strongly believe that this exemption is simply unworkable and should be removed.
Response:
Staff agrees that cost-benefit analyses are problematic and is proposing to eliminate the WDD provisions. Please see responses to Comments 7.06, 29.10, 7.07, and 3.17.

Comment 3.22 and 26.20:
There is no basis for giving gas-fired facilities a WDD exception, given that based on capacity on a cost per MWh basis, all of the gas-fired facilities experience similar and only modest costs associated with phasing out OTC. To the extent that the final policy retains the wholly disproportionate exemption, it should do so on a more limited basis. The two nuclear plants are the most likely facilities to face real retrofit cost and downtime constraints, and when these two facilities are taken out of the equation, statewide costs of retrofit drop significantly. It is not clear why the gas-fired facilities that repowered over the last several years using antiquated and environmentally destructive cooling technology should now be given a competitive advantage over similar plants that will repower over the next several years. Although new gas turbine units are more efficient than older facilities and, therefore, tend to use somewhat less intake water per kilowatt of output, they nevertheless consume hundreds of millions of gallons of intake water per day and destroy billions of marine organisms in the process. Moreover, because these units are very new, unlike the nuclear plants, they will continue to wreak environmental destruction for many decades to come. We urge the State Water Board to exclude the gas-fired facilities from any available wholly disproportionate exemption. At the very least, older units at the same plant that have not yet been repowered clearly should not be entitled to utilize a cost exemption, either as part of a permit renewal or as part of a permit for a repower.
Response:
Please see responses to Comments 7.06 and 29.10. Staff is proposing to remove the WDD section of the policy, and in its place provide Track 2 provisions for the three plants now

operating with existing combined-cycle power-generating units. As mentioned in the comment, OTC combined-cycle units produce more electricity per gallon of OTC flow than older steam boiler technology, and also produce more electricity per BTU of fuel with less air pollution produced. Considering this, a fossil-fueled plant with all or some of its units using combined cycle technology may take credit for IM/E reductions due to the installation of combined cycle in calculating their Track 2 reductions. It is true that these units are newer and will likely continue to operate for decades with higher IM/E impacts than what would be required for traditional steam boiler technology. However, if addressed on a unit basis by reducing the through-screen intake velocity to a maximum of 0.5 foot per second, facilities must still comply with the stringent controls in the interim measures. If addressed within the context of the whole plant, then that plant, while taking credit for reductions in entrainment due to the combined cycle units, will need to comply with the Track 2 provisions to have comparable reductions to Track 1.

Comment 9.10:
The State of California undoubtedly has the right to enact standards more stringent than those proposed or initiated on a federal level. Now that the vast damage caused by OTC has been irrefutably proven, the State Water Board should adopt and even go beyond the standards set forth in the Second Circuit decision, and we urge the State Water Board to do so by declining to apply the WDD. Nothing in the policy makes the case that it is necessary to employ use of wholly disproportionate, instead of urgently pursuing the requirement that power plants convert to BTA if they choose to continue to operate. As one of the most environmentally-conscious states, California should be loathe to use an option, and nothing more, that has the clear potential of diverting us from our goal of ending the decimation of fish and other species in our coastal waters. **Response:**
Staff agrees that the State Water Board can enact standards more stringent than those proposed or initiated on a federal level. Based on comments, staff is recommending removing the WDD from the policy. Please see responses to Comments 7.06 and 29.10.

Comment 9.17:
A WDD is nothing new; it has been part of the CEC's power plant application process for many years. But use of WDD has accomplished nothing more than delays and diversions from reaching the policy goal of ending marine impacts. The enormous damage caused to marine life by OTC is essentially accepted through costs of mitigation, but it is virtually impossible to assign a cost to this damage. For one thing, we don't fully understand all impacts of OTC on all aspects of the marine ecosystem, which makes it scientifically impossible to identify that which is to be mitigated. For another, it's virtually impossible to translate these harmful impacts into a monetary amount. On top of this, power companies refuse to release profit data, claiming a proprietary interest. So, how can a WDD be accurately and effectively used when the costs of switching to best technology can't be compared to the profits achieved? To eliminate these inequities of the analysis -- and the uncertainty and cost of resulting legal challenges -- the WDD should be removed completely from the equation. This is especially true since it is well known that power plants all over the world--including three on the California coast--have been and are being built without OTC; the fair inference of this is that cost is not a disproportionate or unreasonable factor.
Response:
Staff agrees that cost-benefit analyses are problematic and is proposing to eliminate the WDD provisions. Please see responses to Comments 7.06, 29.10, 7.07, and 3.17.

Comment 9.18:
By not adopting the WDD, it is our belief that the State Water Board will promote investment in

new energy technologies, rather than wasting time, money and other resources on helping OTC plants limp along.

Response:

Staff is recommending removing the WDD from the policy. Please see responses to Comments 7.06, 29.10, and 4.09. The commenter may be correct that the OTC Policy will promote investment in new energy technologies; however, State Water Board staff is not attempting to implement a state energy policy.

Comment 9.19:

The key to avoiding policy compliance is for plant owners to use the WDD provision. This option was approved by the U.S. Supreme Court, despite there being no mention of any such caveat in the CWA. Cost-benefit was the only aspect of the wide-ranging Second Circuit decision that was successfully challenged by the power industry. It allows plant owners to argue that ending OTC would be too costly, compared to the benefit of saving sea life from destruction. The proposed policy also provides that opportunity, even though it contains no standards, criteria or ground rules on how cost versus benefit is to be decided by authorities. Adding such a standard will only increase the State Water Board's burden to implement and administer the policy and no doubt result in costly litigation.

Response:

Staff agrees that cost-benefit analyses are problematic and is proposing to eliminate the WDD provisions. Please see responses to Comments 7.06, 29.10, and 7.07.

Comment 13.07:

We do not believe that the policy should allow any WDD for plants over 40 years old. We agree that this will be the focus of many power plant operators who will not try to meet the other standards. If you keep this option, any WDD that is allowed should be amortized over 50 years - the actual life of a power plant even if designed for only 30 years.

Response:

Staff is recommending removing the WDD from the policy. Please see responses to Comments 7.06 and 29.10.

Comment 14.08:

The Policy fails to provide adequate justification for the inclusion of the WDD provision considering the Policy's ultimate goal of phasing out OTC altogether. Moreover, in the event that the State Water Board can provide adequate justification for this provision, the Policy should explain the basis for choosing 8500 Btu as the baseline measure for facility eligibility. The Policy should also clarify how this figure is to be calculated to avoid confusion and to ensure that this provision is not improperly invoked.

Response:

Staff is recommending removing the WDD from the policy. Please see responses to Comments 7.06, 29.10, and 11.45. Staff agrees that the use of “heat rate” is problematic and proposes to eliminate this term entirely from the policy. Instead, the proposed Policy now uses the term “combined-cycle power-generating unit”, which has been defined in the Policy. Staff does not agree that the goal of the Policy is to phase out the use of OTC; rather a primary goal of the Policy is to establish a BTA to reduce IM/E impacts to acceptable levels.

Comment 19.07:

We strongly recommend elimination of the WDD provision from the proposed policy. This provision simply provides a loophole for non-compliance with the required impingement and entrainment reductions if these particular power plants can demonstrate that compliance is too costly. Since the policy does not define or discuss the factors that the Regional Water Board's should use to determine that the costs are wholly disproportionate to the benefits or how to quantify environmental benefits, it is unclear how this decision would be made. In addition, since the Los Angeles Regional Water Board does not possess the expertise required to conduct or review cost-benefit analyses, we would need assistance to accomplish this difficult task for the Haynes and Harbor power plants if this provision is retained in the policy.

Response:

Please see response to Comment 7.07. Staff is also concerned about the potential burden placed on the Regional Water Boards in having to make the WDD, and is therefore proposing to remove this section of the policy.

Comment 22.01:

The Policy should not incorporate the WDD exemption or, at most, should limit its application to nuclear facilities. Although the Supreme Court recently held that section 316(b) allows USEPA to consider costs in the permit decision process, California can and should set a higher standard of protection. Additionally, California's Porter-Cologne act mandates that the Board minimize the negative impacts of OTC on all forms of marine life. California's robust public trust doctrine imposes the most exacting fiduciary obligations to preserve and protect the public's collective interest in our precious but increasingly imperiled marine resources. Thus, the State Water Board not only has the authority to adopt its own, more protective regulations to implement section 316(b), it has an affirmative state law mandate to ensure that water quality regulations and resulting permits minimize impacts to all living coastal resources. The Board should use its expansive legal authority to remove, or at the very least significantly improve upon, the WDD exemption.

Response:

Based on comments received, Staff is recommending removing the WDD from the policy. Please see responses to Comments 7.06 and 29.10.

Comment 22.02:

If the WDD is not either eliminated entirely or significantly narrowed and clarified, it may well undermine the State Water Board's efforts to achieve clear, uniform, and environmentally protective guidance for Regional Water Board permit writers. The WDD is unworkable as currently conceived. Not only does it leave the State with the same problem that it currently has squandering resources on the evaluation of complex technical and biological issues and leading to inconsistent power plant regulation - but it will also lead to the persistence of OTC and further environmental degradation. Given the dire state of our ocean and coastal resources, we urge the Board to close this egregious loophole. Our experience in watching Regional Water Boards as they attempt to implement the WDD at existing facilities strongly suggest that the approach is conceptually flawed. By their nature, the true environmental benefits of employing an alternative technology - or put differently, the ecological costs of utilizing OTC - cannot be monetized or quantified with any degree of precision or certainty. As a society, we simply have not yet figured out how to accurately or adequately capture the inherent complexities of ecological functions and ecosystem services in an "environmental benefit" calculation, especially in the marine realm. Thus, in applying a "wholly disproportionate" test, permit writers are forced to improvise by using speculative surrogates for ecological value that systematically undervalue the true ecosystem services and benefits. When the highly questionable results of this process are then weighed against the very precise compliance cost estimates provided by the permit applicant (and generally not questioned, documented, or verified by the permit writers), the inevitable conclusion is that costs exceed benefits. In this way, the WDD becomes a de facto loophole for every single facility at which it is applied. Accordingly, we urge the Board to delete the WDD exemption altogether from the final Policy or, at the very least, to limit its potential application to the two nuclear facilities where retrofit costs may be somewhat more problematic due to design and safety constraints.

Response:

Staff agrees that cost-benefit analyses are problematic for the reasons given. Staff is also concerned about the potential burden placed on the Regional Water Boards in having to make the WDD, and is therefore proposing to remove this section of the policy. Please see responses to Comments 7.06, 29.10, and 7.07.

Comment 22.03:

There is no evidence that such a significant and easily manipulated regulatory loophole is warranted for any of California's gas-fired coastal power plants. One by one, these plants are being or will soon be repowered (or shuttered) using state-of-the-art generating technology. Several of them already have committed to alternative cooling technologies for their repower projects. All facilities should be required to address the significant environmental externalities created by their antiquated cooling systems with installation of the best technology available to minimize environmental degradation, as required by state and federal law. The efficiency argument articulated in the Draft Policy for this exemption is not persuasive. While the particular gas-fired facilities identified as the targets of the WDD generally are newer and thus somewhat more efficient, they nevertheless continue to pump hundreds of millions of gallons of public trust marine resources through their cooling systems every single day and to destroy billions of marine organisms every year. Because these newer facilities are operating at higher efficiencies, they already are more competitive in the energy market than their older counterparts. There is, therefore, no reason why they cannot amortize any necessary retrofit costs in the same way that older or later repowered facilities will be required to do under the Policy. Indeed, in our view, the public policy arguments cut exactly the other way. These newer, more efficient units were constructed at a time when there could be no question that closed-cycle cooling was "best technology available." The fact that their owners knowingly chose to construct the new units in very recent years using an outdated, somewhat less expensive but enormously more environmentally destructive cooling technology, sometimes over strenuous public opposition, cannot possibly justify giving these units a "pass" from the best technology requirements for the next several decades over which they will continue to operate.

Response:

Please see response to Comment 3.22. Staff is proposing to remove the WDD section of the policy, and in its place provide Track 2 provisions for the three plants now operating existing combined cycle units (Haynes, Moss Landing and Harbor). OTC combined-cycle units produce more electricity per gallon of OTC flow than older steam boiler technology, and also produce more electricity per BTU of fuel with less air pollution produced. Considering this, a fossil fueled plant with all or some of its units using combined cycle technology may take credit for IM/E reductions due to the installation of combined cycle in calculating their Track 2 reductions.

Comment 24.06:

By allowing the WDD exception, the policy defers a critical, and highly contentious question to the Regional Water Boards. Intensive economic studies will be required and even then Regional Water Boards will still be left determining what the remaining “extent practical” standard will be if a facility qualifies for the exception. This exception will be particularly difficult because of the difficulty of accurately quantifying the impacts of entrainment and impingement from an ecosystem-wide perspective is beyond the abilities of the current state of marine sciences. Further, the numerous difficulties of accurately measuring both the benefits and the costs lend itself to dispute. Despite the known value of our ocean resources, it is very difficult to fully assess the economic value of our ocean environment, including the marine living resources and the physical processes, to accurately determine the impacts of OTC on these resources.

Moreover, traditional benefit analysis also tends to reward facilities in degraded waterways because the benefits are more difficult to accurately calculate due to the long term degradation of the resource. To the extent that this exemption is maintained, it should only be available for those plants where compliance would put grid reliability at risk, not because of the cost to the plant operator.

Response:

Staff agrees that cost-benefit analyses are problematic for the reasons given. Staff is also concerned about the potential burden placed on the Regional Water Boards in having to make the WDD, and is therefore proposing to remove this section of the policy. Please see responses to Comments 7.06, 29.10, and 7.07.

Comments 34.10, 54.02, and 60.01:

We support the removal of the WDD from the policy.

Response:

The State Water Board has decided to eliminate the limited WDD. Please see responses to Comments 7.06 and 29.10.

Comment 40.11:

NMFS recommends that the WDD provision be removed from the proposed policy. It is not a requirement that such an exception be offered by the State in this process and the provision, as written, would only apply to three natural gas fired facilities and the two nuclear power plants. However, it seems likely that allowing the WDD for this handful of facilities will lead to numerous requests by the remaining facilities for the same consideration. This will undercut two of the main goals of the proposed policy - to insure consistency across California and to level the playing field for the dischargers regulated by different Regional Water Boards. The proposed exception already requires that the facilities reduce the entrainment and impingement impacts to the extent practicable and that the remaining impacts (i.e., as if the intake flow rate had been reduced a minimum 93 percent and the through screen velocity no longer exceeds 0.5 feet per second) be fully mitigated in accordance with the benefits determined through the use of a habitat production foregone (or equivalent) analysis. Therefore, there does not seem to be much benefit to allowing this exception. If the facilities do not upgrade their cooling systems to the best technology available, even though they have already installed modern generating units, they should not be rewarded with a less stringent permitting process.

Response:

Staff agrees. Staff has determined that the purpose of allowing a limited WDD would be better served by providing credit in Track 2 for previous reductions at facilities with prior investments in combined-cycle technology. Thus, the WDD has been removed from the proposed policy. Please see responses to Comments 7.06 and 29.10. The nuclear facilities will be subject to a later determination of compliance alternatives after appropriate studies are completed and data made available.

10. Compliance Deadlines

Comment 1.06:

The compliance schedule is not sufficient to allow for the orderly replacement of AES-SL's fourteen units at the Redondo Beach, Alamitos, and Huntington Beach Generating Stations. We do not believe Track 1 is possible or practical at any of our three sites given their location, the age of the facilities and the higher closed-cycle cooling capacity needed for conventional thermal plants compared to combined-cycle or peaking facilities. AES-SL intends to modernize our entire fleet through the installation of more efficient, fast-ramping, environmentally friendly gas-fired peaking and combined-cycle technologies that do not rely on OTC. The compliance schedule outlined in the proposed policy may be feasible if we intended to retrofit our existing units or otherwise comply with Track 1 or Track 2, but due to the complexities of repowering as compared to retrofitting, a longer compliance timeline is needed. Given the size of the AES-SL portfolio and existing contractual commitments that run through 2018, we would not be able to modernize our entire fleet before the expected compliance deadline of 12/31/2020 and could be forced to shutdown multiple units in an important LCR region. The Policy and SED acknowledge that targeted RFO's for the replacement or repowering of facilities in the Los Angeles basin would stem from the 2013 LTPP. This proceeding would not result in approved PPA's until 2015, at the earliest. Given the additional time that may be needed to complete permitting, secure financing and construct the new units, AES-SL would need to be repowering our entire portfolio virtually simultaneously. This is not realistic or achievable. The Water Board should consider adopting a phased compliance schedule for each facility that is more consistent with how a modernization project would proceed. In addition, the final compliance dates should be extended to be more realistic - a fleet this size requires 15-20 years, not 10 years. AES-SL can outline a compliance schedule that it believes would be possible to achieve. We have begun formulating the long term plan for our portfolio and should be ready to communicate our goals in the next 3 to 4 months.

Response:
Staff applauds AES-SL's decision to modernize their three OTC facilities through the installation of more efficient and environmentally friendly peaking and combined-cycle technologies that do not rely on OTC. The Policy states that these plants are included in the 2012 LTPP, which should result in a decision by 2013, and approved PPA's in 2015. The schedule outlined in the Policy is based on the advice of the State's Energy Agencies (as explained in their joint report (Appendix C of the SED) and in the Policy findings), in order to implement CWA 316 (b) in an orderly fashion to protect grid reliability. Please see the response to Comment 2.04. The commenter does not explain why the policy's implementation schedule is not realistic or achievable.

Comment 1.11:
To provide an incentive for early action and additional compliance flexibility, the Policy should be modified to allow for the "banking" of entrainment and impingement reductions that are achieved prior to the required compliance date. The owner of a facility should be able to earn early action credits by achieving reductions before the applicable compliance date that can then be used to extend the compliance date for other reductions required at the same facility. Such an intra·facility banking system would encourage owners to make significant impact reductions as soon as possible in order to (1) decompress the compliance schedule which would allow the eventual repowering of most of the units on a schedule that is actually achievable, (2) reduce the perceived need for imposing an interim mitigation tax on top of the compliance obligation because an incentive for early action would already be in place, and (3) alleviate the stringency of the Track 2 requirements by allowing owners to not only bank large impact reductions made before the due date but also smaller impact reduction schemes associated with operational or structural modifications. Under the proposed Policy, facility owners do not have such an incentive.

[Various examples were given for calculating credits. The time credit would be calculated as the percentage of reduction in impacts achieved divided by the percentage of impact reductions still needed (100 percent impact reduction required for these calculations), then multiplied with the time difference between the date reductions were actually achieved and the final compliance deadline. If the still-operating OTC portion of the facility happened to exceed the historical flow rates that were used to determine the early compliance credit, the credit could be reduced proportionally].

Response:
Staff appreciates the submitted suggestion and the detailed example given for how the incentive would be implemented and calculated. However, upon closer examination, staff believes the suggested incentive program (1) would not be nearly as protective of marine life as the proposed Policy; (2) unnecessary because the interim mitigation requirements serve as incentive; (3) would create an additional staff work load to administer; and (4) may not be fair to all power plant owners/operators.

Firstly, any early reductions in impacts under the incentive program could be "banked" and used later, so there's no actual reductions in impacts to marine life overall compared to the proposed Policy. Furthermore, the listed compliance deadlines in the Policy are in staff's opinion very generous and may well be tightened once the individual implementation plans are received from the power plant owners and operators. The proposed Policy requires that BTA be met in a short a timeframe as possible without impacting the electrical grid in order to protect the State marine resources. Secondly, the Policy's interim mitigation requirements serve as an incentive to bring facilities into compliance as quickly as possible. Under the incentive program proposed by the commenter, interim requirements would be reduced. Thirdly, keeping track of early reduction credits could be quite challenging as the deadlines in the Policy could quite possibly change several times, thus presumably changing the allotted credits. Even if the deadlines did not change, the incentive program would require staff resources to administer. Lastly, some power plants may not be able to apply for early reduction credits because they would be designated as needed for grid stability while other plants repower, retrofit, etc.

Comment 2.04:
BAMx believes that more aggressive and accelerated compliance dates may be appropriate. Although substantial issues remain to be resolved in the Los Angeles basin, it appears some of the plants in Northern California, including the Greater Bay Area (GBA), in addition to Potrero Unit 3, could be considered for more aggressive compliance dates. For instance, the proposed Policy lists a 12/31/2015 compliance date for Morro Bay, but no indication is given as to how the compliance date was selected. Morro Bay is not part of any Local Reliability Area (LRA), so it is unclear why an earlier date could not be adopted for a target date. The CAISO 2010 LCR studies indicate that obeying the local area requirements of Pittsburg and Oakland Sub-areas, as well as the overall Greater Bay Area (GBA), can result in the retirement of nearly 1,200 MW of OTC capacity within the GBA itself without the addition of new generation or transmission capacity. The GBA OTC Retirement study prepared by Quanta Technology for Pacific Gas & Electric indicated that the existing grid with additional reactive compensation would allow 3,900 MW of OTC to be retired before major additions of transmission or new generation would be required on or before 2020. The reactive compensation needed would cost in the range of $37.5 million to $45 million. The Jones & Stokes study reaches similar conclusion, which indicates that all OTC capacity can be retired within the GBA in the presence of the transmission upgrades with a total cost $42 million. The study by Quanta Technology also pointed to the Russell City Project as allowing substantial retirement of GBA plants without the approximately $40 million of transmission upgrades indicated above. For example, even the Potrero Unit 3 compliance date could be accelerated since a settlement agreement for shut down and removal of Potrero has already been reached with the plant owners and CCSF without further delaying the compliance to "one year after the effective date of the Policy." Since we were not part of the discussions involving the recommended energy agencies' proposal to the State Water Board, we are not aware of the reasons the above observations did not lead to a more aggressive compliance dates for GBA OTC generation. No reasons were given for the 12/31/2017 compliance dates for Contra Costa, Pittsburg and Moss Landing. The basis given was the "CPUC 2010 Long Term Procurement Plan". The reader is left to speculate why this is a reason. Even if that

process is expected to lead to new generation capacity in the GBA, if some plants can be forced to comply with the OTC requirements before the installation date for the new capacity and still comply with reliability standards, the compliance dates should be accelerated. At a minimum, a clearer justification of the proposed dates and reconciliation of those dates with existing studies should be included in the SED.

Response:

Comment noted. The implementation schedule set forth in the policy is the result of consultation with state agencies and other entities responsible for, and experts in, energy policy and regulation. The period of time necessary to bring facilities into compliance is designed to allow necessary upgrades while ensuring reliability of the electrical grid. The State Water Board must balance its priorities and regulatory mandates with those of other agencies responsible for energy and the environment.

Regarding the final compliance deadlines, staff is mainly relying on the advice of the State's Energy Agencies (CAISO, CEC, and CPUC) (as explained in their joint report (Appendix C of the SED) and in the Policy findings), in order to implement CWA Section 316 (b) in an orderly fashion to protect grid reliability. While the CEC, CPUC and CAISO each have various planning or permitting responsibilities important to this effort, the approach relies upon use of competitive procurement and forward contracting mechanisms implemented by the CPUC in order to identify low cost solutions for most OTC power plants. The CPUC has authority to order the investor-owned utilities (IOUs) to procure new or repowered fossil-fueled generation for system and/or local reliability in the Long-Term Procurement Plan (LTPP) proceeding.

LTPP proceedings are conducted on a biennial cycle and plans are normally approved in odd-numbered years. The 2010 LTPP is estimated to result in a decision by 2011. The subsequent cycle, the 2012 LTPP, would in turn result in a decision by 2013. Once authorized by the CPUC to procure, the IOUs need approximately 18 months to issue targeted requests for offers (RFOs) to acquire replacement, repowered or otherwise compliant generation capacity, sign contracts, and submit applications to the CPUC for approval. Approval by the CPUC takes approximately nine months. If the contract involves a facility already licensed through the CEC generation permitting process, then financing and construction can begin. A typical generation permitting timeline is 12 months, but specific issues (such as ability to obtain air permits) can delay the process. IOUs often give preference to RFO bids with permits already (or nearly) in place. From contract approval, construction usually takes three years, if generation permits are approved, or approximately five years, if generation permits are pending or other barriers present delays. In total, starting from the initiation of an LTPP proceeding (the 2010 LTPP or 2012 LTPP), seven years are expected to elapse, before replacement infrastructure is operational. Due to the number of plants affected, efforts to replace or repower OTC power plants would need to be phased.

The OTC power plants included in CPUC's 2010 LTPP are the Encina, Contra Costa, Pittsburg, and Moss Landing power plants. These plants are therefore required to be in compliance seven years after the initiation of the 2010 LTPP proceeding, i.e., at the end of 2017. These plants were chosen for the 2010 LTPP because (1) they have been identified as currently completely or partially needed for local and/or grid reliability; and (2) they are not located in the Los Angeles Basin where new electrical transmission is difficult to construct due to land issues and air credits may be hard to obtain.

The OTC power plants included in CPUC's 2010 LTPP are the Huntington Beach, Redondo, Alamitos, Mandalay, and Ormond Beach power plants. These plants should have been required to be in compliance seven years after the initiation of the 2012 LTPP proceeding, i.e., at the end of 2019, but because these facilities are located in the Los Angeles Basin, they were given an extra year to comply. They have been identified as currently completely or partially needed for local and/or grid reliability.

The final compliance dates for the two nuclear OTC power plants (SONGS and Diablo Canyon Power Plant) were chosen to be concurrent with their NRC operating license renewals in 2022 and 2024, respectively. These plants were given more time to comply due to their unique and more complex generating technology requiring the need for special studies to assess feasibility and cost of compliance, their large energy contribution to the grid, and role in meeting the mandates of the Global Solutions Act requirements by not emitting green house gases while generating electricity.

As the commenter mentioned, Morro Bay Power Plant is not now needed for local area and/or grid reliability. However, State Water Board staff believes that it is fair to give all owners/operators of OTC power plants a reasonable opportunity to comply with the Policy and continue doing business, whether the plant is needed for reliability, or not. Staff believes that five years is a reasonable timeframe for retrofitting a plant, although less time may be needed if the Track 2 compliance alternative is pursued. The proposed Policy is therefore requiring Morro Bay Power Plant to be in compliance by the end of 2015, or about five years after the effective date of the Policy (if adopted in 2010).

South Bay Power Plant is a different story. Two of the four OTC units have been shut down since December 31, 2009, when they were no longer needed for local and grid reliability after the Otay Mesa Power Plant came online. The two remaining units may, according to the Energy Agencies' Joint Proposal, be needed for reliability until 2012, when the Sunrise Powerlink transmission project becomes operational. South Bay Power Plant is operated by Dynegy South Bay, LLC (Dynegy) and located on the southeastern shore of San Diego Bay in the City of Chula Vista. Chula Vista city officials and the Port of San Diego (who leases South Bay Power Plant to Dynergy) want the entire plant to be decommissioned and demolished as soon as possible. The proposed Policy is therefore requiring the South Bay Power Plant to be in compliance when no longer needed for reliability, which should be no later than the end of 2012.

Humboldt Power Plant should have finished repowering and will no longer use OTC by the end of 2010. Unit 3 of the Potrero Generating Station (which uses OTC) will no longer needed for local area and grid reliability once the TransBay Cable transmission project is finished in 2010. The owner/operator of the Potrero Generating Station (Mirant Potrero, LLC) has further reached an agreement with the City of San Francisco to close the plant, when no longer needed for electrical reliability. Because the Humboldt Bay Power Plant has almost finished repowering and because Mirant Potrero, LLC has agreed to close their facility at Potrero no later than December 31, 2010, staff believes that these two power plants should easily be able to be in compliance within one year of the effective date of the Policy and, most likely, half a year sooner than that. However, setting an earlier compliance date for these two plants would not accomplish much because the owners/operators of these plants have already committed to not using OTC by the end of 2010.

Three OTC power plants are not within CAISO's balancing authority area or CPUC's jurisdiction. These plants are the Haynes, Harbor, and Scattergood Generating Stations, which are within the service territory of the Los Angeles Department of Water and Power (LADWP). LADWP is a municipally owned utility that owns and operates its own generation, transmission, and distribution systems. Haynes, Harbor, and Scattergood Generating Stations represent about a third of LADWP's generating capacity and the majority of the in-basin generation. The final compliance dates for these three facilities are based on estimates provided State Water Board staff in the comment letter submitted by LADWP on December 8, 2009. LAWDP requested that final compliance dates for Haynes, Harbor, and Scattergood Generating Stations tentatively be set at 2019, 2015, and 2022, respectively. Staff believes that some of these timeframes are too long, but agreed to tentatively set the final compliance dates for these plants at 2019, 2015, and 2020, respectively.

Note that all the final compliance dates contained within the Policy's implementation schedule are subject to change, based upon SACCWIS and State Water Board review of proposed individual implementation plans submitted by the owners and operators of the OTC facilities within six months after the effective date of the Policy. In these implementation plans, the owners and operators will describe how they intend to comply with the Policy and how much time they estimate is needed for the various steps in the process. SACCWIS may well recommend that final compliance dates be adjusted based on review of these proposed individual implementation plans in the context of a statewide implementation schedule.

Comment 2.05:
BAMx believes that an aggressive signal is needed to counter slow adoption of an OTC Policy: The State Water Board has been very slow and tardy in finalizing a statewide policy on OTC since initiating the policy development process with workshops beginning in September 2005. The State Water Board initiated public workshops in September and December of 2005, released a CEQA Scoping Document in June 2006, conducted a scoping meeting in July 2006, issued another Scoping Document in March 2008, and conducted hearings in May 2008. It was not until the 2008 scoping document that electric reliability was addressed. As such very little has been done to re-enforce the transmission system. Long lead times that are provided in Section 3.E, Table 1, Implementation Schedule, provide insufficient incentives for compliance and serve to delay and prolong the start of compliance by using unnecessarily extended "but no later than dates." BAMx recommends more aggressive near-term, "but no later than" compliance dates. If truly needed replacement infrastructure is not in place in time, the proposed backstop should ensure that reliability standards will be met.
Response:
Staff does not believe that the State Water Board has been very slow and tardy in finalizing a statewide policy on OTC. Other states have not developed such a policy on implementing Section 316(b). The State Water Board, working within legal requirements for its public process, initially considered an overall approach based on the USEPA's Phase II rule. However, the USEPA's Phase II rule was challenged in court, and the overall approach for the statewide OTC Policy required significant changes based on the outcome of the RiverKeeper II decision in 2007. The State Water Board was required to go through the scoping process once more. Based on public comments, the State Water Board set up an Expert Review Panel to answer scientific questions and committed a significant amount of time to working with other agencies to assure grid reliability during the implementation of the Policy. Staff believes that the extra time spent in developing the OTC Policy has resulted in a much better Policy.

Regarding the length of the implementation schedule, please see the response to Comment 2.04.

Comments 3.30 and 26.26:
The statewide policy should be adopted and implemented as soon as possible and the compliance dates should reflect other state efforts to move California towards modern and efficient power generation. Extending the life of these antiquated power plants not only

prolongs the damage to our coastal and estuarine ecosystems, but also extends the life of inefficient power generation in California. We are long overdue for the state to embrace a policy on OTC that reflects Californians' desire to protect our valuable marine and coastal resources, while investing in a sustainable, environmentally sound future energy supply. The State Water Board has been working on this policy for over four years. We encourage the Board to move forward with adopting and implementing a policy with clear deadlines as soon as possible. In early 2007, after the Phase II Rule was suspended, USEPA directed permit writers to use their BPJ when permitting existing OTC power plants. Despite this directive, the Regional Water Boards have failed to properly reissue NPDES permits for power plants using OTC. Out of the 19 plants currently using OTC, 15 have NPDES permits that have already expired; Regional Water Board staff has stated that they are waiting for the statewide policy to update these overdue permits. At the end of 2009, one more plant will have an expired NPDES permit, which means that 84 % of the plants using OTC will have overdue permits by the end of 2009 because of the delayed policy.

Response:

Staff agrees that OTC has major impacts to the State's marine resources. When implemented, the Policy should significantly reduce the harmful IM/E impacts of OTC on marine life. The Policy will be implemented in NPDES permits, by the Regional Water Boards issuing NPDES permits for existing OTC facilities. A statewide approach is necessary to ensure that issues that cut across Regions, such as electrical grid reliability, air quality, and costs to the ratepayers, are identified and addressed in a comprehensive fashion. Please see the responses to Comments 2.05, 2.04, and 5.04.

Comment 4.10:

Flexible timelines are needed to conduct studies and feasibly implement the retirement of OTC fossil plants without undesirable reliability and rate impacts. Replacement of more than 30% of California's generating capacity is likely to take decades, not 7-9 years as contemplated in the Draft Policy, due to licensing, grid reliability, and other issues, such as the unavailability of pollution credits in the SCAQMD; sequencing of bidding into utility request for offers (RFO's) versus permitting of a facility; the degree of reliance on generating facilities versus preferred technologies; resolution of the nuclear plant issues; and, development of a comprehensive plan and preferential treatment of elements of the plan in licensing proceedings compared to proposed facilities not included within the plan.

Response:

Please see the responses to Comments 2.04 and 5.04.

Comment 5.01:

Our comments focus on the need for implementing any adopted policy in a manner that ensures the continued reliability of electric service in California. As a result of extensive work with State Water Board staff, we believe the draft policy contains a satisfactory mechanism to assure electric system reliability by allowing continued operation of existing power plants using once through cooling until replacement infrastructure obviates the need for such plants for reliability. The draft policy and attachment to the SED provide a preliminary schedule for the development of replacement infrastructure. The draft policy calls for periodic updates to this schedule in order to be responsive to delays or changes in energy policy not foreseen at this time. The draft policy incorporates a workable schedule and process to implement the State Water Board's objectives, while considering the need to maintain reliable operation of the electric grid. Adoption of this draft policy will create a long-term relationship between State Water Board, CEC, CPUC and CAISO as we develop more detailed plans for the necessary infrastructure to allow for implementation of the draft policy and as other complex issues affecting the need for power plants using once through cooling unfold. Implementation of the draft policy through time will require maintaining a close working relationship over many years that allows the State Water Board to satisfy its objectives, while not jeopardizing the reliability of California's electricity grid.

Response:

Staff agrees that the implementation schedule and process is workable and is looking forward to a continued close working relationship with the member agencies of SACCWIS, including the energy agencies, to successfully implement the Policy.

Comment 5.04:

Any adopted policy must realistically account for the time necessary to provide replacement power in the form of a repowered facility, a replacement facility in the same area, or new transmission to serve load coupled with replacement power procured from elsewhere on the system. Design, permitting and development for generation and transmission is a multi-year process, and current regulatory uncertainty, such as the availability of air emission reduction credits to meet Southern California air quality regulations, increase the uncertainty of these time lines. In addition, experience has taught us that assumptions in the area of energy infrastructure, including but not limited to the plans of existing power plant owners, may change materially during the implementation of any adopted policy. Thus, any policy should provide flexibility to accommodate development and permitting delays as well as other contingencies. The draft policy includes provisions for periodically revisiting the infrastructure replacement schedule, and we urge the retention of such scheduled updates as a key element of a final policy.

Response:

Staff agrees that an adaptive management approach that allows changes to the implementation schedule, as specified in the proposed Policy, is essential to successfully implementing the Policy requirements without causing disruption to the electrical grid reliability. Under the adaptive management approach outlined in the proposed Policy, SACCWIS is the entity assigned to ensure that the individual power plants move forward towards compliance with the Policy at a speedy, but even pace that does not disrupt the electrical grid. To do so, the SACCWIS representatives must meet on a regular basis to review progress and potential problems, such as permitting delays or early retirements.

Under the March 22, 2010 version of the proposed Policy, SACCWIS is required to report to the State Water Board annually with any recommendations on modifications to the implementation schedule. Note that the State Water Board may independently schedule a hearing at any time, at their discretion, to revisit the Policy, and if needed, revise the Policy.

Based on concerns that flexibility is needed to immediately suspend final compliance dates due to an unforeseen event, such as a wildfire disrupting electrical transmission, State Water Board staff has inserted language allowing for a suspension of a final compliance date of up to 90 days upon receipt of notification by CAISO (and if not objected to by the Executive Directors of CEC or the CPUC). CAISO is the agency that most firmly keeps its finger on the electrical pulse of the State, and the Policy clearly acknowledges that the Energy Agencies (CAISO, CEC, and the CPUC) are the experts on power generation and grid reliability.

Should CAISO determine that a suspension of a final compliance date for more than 90 days is necessary for grid reliability, CAISO will notify the Water Boards and SACCWIS within 10 days of its determination. If the Executive Directors of CEC or the CPUC do not object, the final compliance date will be suspended for 90 days. The State Water Board will hold a Hearing within these 90 days to fully evaluate an amendment to the Policy's implementation schedule. The LAWDP may likewise request that the State Water Board hold a Hearing and amend a final compliance date for the three OTC plants that are not within CAISO's jurisdiction but within LAWDP's service area.

Staff has also added language to clarify that NPDES permits issued by the Regional Water Boards shall include appropriate permit provisions to implement authorized suspensions and modifications of final compliance dates without reopening the permits. The Regional Water Boards are required to base compliance schedules in individual NPDES permits on the implementation schedule in the Policy.

Comment 6.04:
The policy timeline is of concern, which allows for plants to comply as late as 2020. Many of these plants impact more than the marine resources destroyed by OTC technology. They also impact the communities in which they are located by contributing to environmental degradation, visual blight, and depressed land values. Several are located in or adjacent to wetlands where they inhibit the ability of the community to properly restore wetlands necessary to achieve water quality and urban runoff abatement goals. A 2008 study commissioned by the OPC and State Water Board found that plants could be converted in a much shorter timeframe than 2020. I urge the State Water Board to consider the findings of this study and be as aggressive as possible in the implementation of this policy.
Response:
Staff agrees that OTC has major impacts to the State's marine resources, and that these impacts should be reduced as soon as possible, while taking into account electrical grid reliability and other important factors. The OPC/State Water Board-funded Jones and Stokes Grid Study in 2008 stated that final compliance would be possible by 2015, essentially providing a seven-year conversion period if the Policy were adopted at that time. Many of the OTC plants are scheduled for compliance by 2017 (or earlier), still a seven year period. Please see the responses to Comments 2.05, 2.04, and 5.04 regarding the need for longer compliance periods for the remaining OTC facilities.

Comment 8.04:
The Potrero Power Plant, operated by Mirant Potrero, LLC and located in southeast San Francisco, is one of the oldest plants in California. The City is concerned about the impacts on human health and the environment from the continued operation of the OTC system at Potrero Unit 3 in addition to the other adverse impacts from the plant's operation. The surrounding communities include some of San Francisco's most economically disadvantaged residents, many of which use the bay for recreation and subsistence fishing. In recent years, these communities have seen disturbingly high rates of cancer, asthma and other healthcare problems that are known to be influenced by environmental factors. The Policy establishes a compliance date for Potrero Unit 3 that is 1 year from the effective date of the Policy. We urge the State Water Board to modify this provision to adopt a date certain that is consistent with the expectations of the City, the plant owner, and the energy agencies regarding the closure of Potrero Unit 3, namely December 31, 2010. This is a conservative date that includes margins for error and allows for timelines to slip, and a reasonable requirement in view of the (a) the terms of the NPDES permit issued in May 2006; (b) the removal of the reliability need for Potrero Unit 3 during 2010; and (c) Mirant's agreement with the City to close the plant when it is not needed for reliability. Enforcement of the Potrero Unit 3 permit has been delayed since its expiration in December 2008, in part due to the pending adoption of a State policy on OTC. The State Water Board has an opportunity now to ensure that there is no further delay in the elimination of this source of OTC harm by establishing December 31, 2010 as the compliance date for Potrero Unit 3.
Response:

Comment noted. Staff fully understands the concerns and and supports the efforts of the citizens of San Francisco to close Potrero Unit 3 as soon as no longer needed for grid reliability, which is hopefully by December 31, 2010. The deadline established in the Policy for Potrero Power Plant ("one year after the effective date of the Policy") was originally established with this date in mind. Due to adoption of the Policy being delayed, these dates no longer coincide. However, nothing in the Policy prevents Mirant from shutting down Potrero Unit 3 when no longer needed for grid reliability at the end of this year, as agreed with the City of San Francisco.

Comment 8.05:
The proposed timeline for compliance is overly extended and the compliance standards are too open-ended. In adopting a state policy, the Board does not need to choose between electric reliability, environmental protection, and sound economics. The Board can adopt a policy to eliminate OTC with a timely compliance schedule that is fair to plant owners while also protecting electric reliability and electric ratepayers. Adoption of an aggressive timeline for compliance is particularly appropriate here in view of the long delays in developing this policy. The proposed policy also includes too many loopholes that invite delay and litigation. The Policy proposes an "adaptive management" approach, which means that feedback gained through the process will be incorporated to adjust requirements. Given this approach, there is no justification for the overly generous deadlines and unclear compliance standards that include a number of off ramps for plant owners. Adoption of a state policy to eliminate OTC cannot be a surprise to any facility owner. Forward-thinking generation owners have already been developing and implementing plans for OTC elimination. Plant owners will make appropriate investment decisions once a clear policy is adopted. Nor can the long compliance schedule be justified by electric reliability needs. According to recent studies of the Greater Bay Area electric system, OTC compliance can be implemented more aggressively than set forth in the Policy without threatening electric reliability or imposing substantial costs on electric ratepayers.
Response:
Please see the responses to Comments 2.04, 2.05, and 5.04.

Comment 9.02:
We conclude that the State Water Board's proposed Policy, is deficient and unacceptable. This is because it fails to terminate or sharply limit OTC within a reasonable time period. Its implementation schedule allows up to 13 years for all plants to comply with no reasonable justification.
Response:
Staff disagrees that proposed Policy is deficient or fails to limit OTC within a reasonable time period. Please see the responses to Comments 2.04, 2.05, and 5.04.

Comment 9.05:
There are numerous inconsistencies. For example, the policy Implementation Schedule calls for the Morro Bay Power Plant to achieve compliance by 2015. Yet the Schedule states that the "plant is not needed" after 2011 to help meet grid reliability requirements. There is no mention of the outfall lease expiring in 2012, which could be another significant factor in the operational status of the plant, and no explanation of why the policy would allow the plant to operate and use OTC for four years after it "is not needed." Therefore, we implore the State Water Board to require that the plant be required to be in compliance by 2012.
Response:
The additional three years allowed under the draft policy for Morro Bay (2012 to 2015) is an allowance for the plant operator to install BTA if they wish to keep running the plant for electrical generation, which is a business decision that have not formally made public yet. Staff is not

privy to any possible negotiations that may be taking place regarding the lease, and therefore did not include such information. Please also see the response to Comment 2.04.

Comment 9.13:
In terms of how to prioritize the phasing out of operating plants most logically and efficiently, we urge that the oldest, most inefficient plants (such as Morro Bay and Redondo) be the focus of such efforts because of their antiquated technology and relatively insignificant energy generation. At the same time, the phase-out of OTC should be designed to cover the relatively newer plants (like Moss Landing) as well as the nuclear plants, depending on their different circumstances.
Response:
Please see the response to Comment 2.04. The compliance schedule represents a realistic approach to phasing out harmful effects of OTC without adverse effects upon the power grid while maintaining progress toward achieving BTA.

Comment 11.33:
Ultimately, the state's energy agencies overseeing the state's electric infrastructure and supply should determine the timeline for OTC plant operation, not the state agency in charge of water quality.
Response:
Please see the response to Comment 2.04.

Comment 12.05:
The proposed policy should avoid rigid timelines that do not reasonably reflect electric grid reliability needs.
Response:
Please see the responses to Comments 2.04 and 5.04 regarding built-in flexibility in the proposed Policy’s implementation process.

Comment 12.11:
The CAISO has suggested that the transmission build out would take 5 to 10 years or more, while SCE has indicated that it may take decades in the Los Angeles area. The Policy and the SED do not accurately account for the regional impacts of the Policy in southern California.
Response:
Please see the responses to Comments 2.04 and 5.04.

Comment 13.01:
South Bay Power Plant is a special case, has damaging impacts to a sensitive marine area, and should be scheduled for termination immediately. We appreciate the reasons for phased compliance schedule, however, there is no reason that the South Bay Power Plant should be given until the end 2012 to come into compliance. There are many physical and biological attributes of the south San Diego Bay that make the impacts of OTC more devastating and insidious than some other plants. South San Diego Bay is warmer, shallower, more biologically diverse and sensitive than the receiving waters of virtually all of the other OTC plants, and functions as a fish nursery. The low tidal exchange (30 days) and flushing makes all of the impacts worse. Many of these impacts were outlined in detail in the findings of the 2004 permit for the plant, which found that biotic communities in the immediate vicinity of the discharge point and in the discharge channel have been degraded by exposure to the discharge due to several factors, including elevated temperature, flow volume, flow velocity, and turbidity. The permit also found that about 27% of the goby complex and 50% of the longjaw mudsucker larval source water populations are lost annually due to entrainment, and about 13% of equivalent

adult anchovy and 15% equivalent adult silverside fish populations are lost annually due to larval entrainment losses, constituting a significant adverse environmental impact. Studies of the distribution of juvenile halibut revealed that there are many fewer juveniles in shallow waters of San Diego Bay compared to Mission Bay even though it is many times larger. The SED also shows South Bay as having the third worst entrainment numbers in the state due to the high concentration of larval fish per cubic meter in the water, even though it operates at low capacity.

Response:

Staff agrees that the South Bay power plant has substantial damaging impacts to South San Diego Bay, and looks forward to the elimination of those impacts. Some of those impacts are a result of discharge effects and may be addressed by the Regional Water Board through additional NPDES requirements on the discharge, and nothing in this Policy precludes that. Regarding the final compliance date, staff is relying on the advice of the State's Energy Agencies in order to implement CWA Section 316 (b) in an orderly fashion to protect grid reliability. Please see the response to Comment 2.04 on how the dates for the individual plants, including South Bay Power Plant, were derived. Two of the four OTC units at South Bay Power Plant have been shut down since December 31, 2009, when they were no longer needed for local and grid reliability after the Otay Mesa Power Plant came online. The other two remaining OTC units may, according to the Energy Agencies, be needed for reliability until 2012, when the Sunrise Powerlink transmission project becomes operational. Because Chula Vista city officials and the Port of San Diego (who leases South Bay Power Plant to Dynergy) want the entire plant to be decommissioned and demolished as soon as possible, the proposed Policy is requiring the South Bay Power Plant to be in compliance when no longer needed for reliability, which should be no later than the end of 2012, and hopefully sooner.

Comment 13.02:

In accordance with the State Water Board's Environmental Justice policy, environmental justice should be a strong factor and basis for establishing your compliance priorities. If South Bay Power Plant is not shut down when Otay Mesa goes on-line (expected October 2009), it will exacerbate a clear environmental injustice for communities in the South Bay region. South Bay area has more energy infrastructure per 10,000 people than any other area of San Diego County, as measured by total online megawatts from natural gas or landfill gas energy plants. This area also has the greatest proportion of nonwhite population.

Response:

Please see the response to Comment 13.01 regarding how the final compliance date for South Bay Power Plant was derived. Staff agrees that there are many good reasons that South Bay Power Plant should be shut down, including to promote environmental justice. However, electricity is a vital requirement for any community. According to the Energy Agencies, South Bay Power Plant may be needed for electrical reliability until 2012, when the Sunrise Powerlink transmission project becomes operational. The proposed Policy therefore does not require South Bay Power Plant to be shut down until 2012.

Comment 13.03:

South Bay Power Plant is not needed after Otay Mesa Power Plant goes on-line as expected in October 2009. At the September 9, 2009 Regional Water Board hearing, CAISO presented evidence that the peak demand after Otay Mesa was on-line was 186 MW. However since that date, the CEC finalized its demand forecasts, showing that peak demand has dropped 171 MW, effectively eliminating this gap. With the revised forecasts and Otay Mesa going on-line the need for South Bay Power Plant has evaporated. While we appreciate the State Water Board's desire to coordinate with the energy agencies, the State Water Board should not take their input as gospel and need to make its own assessment of when power plants can be removed. CAISO is not a public agency subject to the same input and accountability as the State Water Board.

They have their own narrow mission that does not take into consideration things like environmental impacts, community health, or community impacts. CAISO's accounting is not transparent or objective. It's easier for CAISO to keep South Bay Power Plant, but it is not easier for us, for the people who live in the region and have to live with the plant. We ask that you use the updated and lowered peak demand numbers for your calculation of whether South Bay Power Plant is needed at all in 2010. In our case, CAISO has other options for closing any gaps in energy need. We also believe it to be significant that the South Bay Power Plant operators have had more than sufficient time to develop a compliance action, as their 2004 permit states that the plant only had 5 years of expected life remaining. This community has been patient. We have accepted another 596 MW power plant and multiple peaking power plants in the area. Chula Vista has adopted aggressive energy reduction programs and projects. We are doing our part and we are asking the State Water Board to do their part by ending the damaging and unnecessary discharges from South Bay Power Plant immediately.

Response:

Comment noted. Staff understands and supports the efforts of the citizens of Chula Vista to close the South Bay Power Plant as soon as possible. While the State Water Board retains final authority over the Policy and its compliance schedule and deadlines, the State Water Board recognizes the expertise of agencies and entities with specific responsibilities for energy policy and grid reliability within the state of California. The State Water Board must balance its priorities and regulatory mandates with those of other agencies responsible for energy and the environment. Please see the responses to Comments 2.04 and 13.01.

Comment 14.01:

We support the overall goal of adopting a policy that protects the State's coastal and estuarine waters without disrupting electrical generation and transmission. The State Water Board should, however, impose more stringent requirements to protect the state's waters, and the Policy should explicitly recognize the impending closure of certain power plants, including Potrero Generating Station, which Mirant Potrero, LLC owns and operates in the City of San Francisco. We have been actively advocating for the closure of the Potrero Plant for nearly a decade, in part because of the significant

environmental impacts associated with the facility's use of OTC. The NPDES permit for the Potrero Plant's Unit 3 was last issued in 1994 for a five-year term, and the San Francisco Regional Water Board administratively extended the permit until 2005. In 2006, the Regional Water Board granted the plant a limited extension of the NPDES permit until December 2008. In 2008, because of the continued operation of the Potrero Plant - despite the expiration of the permit and without the necessary demonstration of lack of harm to the Bay from Mirant - the City of San Francisco's Board of Supervisors unanimously enacted an ordinance in 2009, establishing city policy to take all feasible steps to close the facility as soon as possible. In a recent settlement agreement with the City, Mirant committed to, among other things, a shutdown of the Potrero Plant as soon as it is no longer needed for electric reliability. CAISO has indicated that new infrastructure is expected to replace the need for Unit 3 as early as March of 2010, and Potrero is expected to close by December 31, 2010. The Policy's proposed compliance date for the Potrero Plant is one year from the effective date of the Policy, which may be later than when the Potrero plant can be shut down. The implementation schedule should be revised to reflect the latest available data concerning local electric reliability requirements. Retirement should be listed as the appropriate compliance milestone for the Potrero Plant, and the due date should be changed to December 31, 2010, reflecting Mirant's agreement with the City of San Francisco. Alternatively, the compliance date could be the earlier of the two events that will allow the plant to close - the completion of the Trans Bay cable or the recabling of the Martin-Bayshore-Potrero lines.

Response:

Please see the response to Comment 8.04.

Comment 15.04:
There is a lack of urgency to the policy. The enormous damage to marine life from once-thru-cooling is recognized but the policy allows the problem to continue for years to come. The WDD option for nuclear plants and plants exceeding 8500 BTU is a loophole so large that it allows for years of postponement of any real action. The years of studies contemplated afterwards similarly postpone action. Where is the incentive for the industry to change? Use of the “free” ocean and estuary water for cooling purposes provides a monetary advantage that power plants cooled by other means do not have. The state policy needs to provide an incentive to change, in other words, a financial disadvantage to the use of its waters.
Response:
Comment noted. Staff agrees that OTC has major impacts to the State’s marine resources, and believe that the Policy, when implemented, should significantly reduce these harmful IM/E impacts of OTC on marine life. Staff also agrees that the Policy should be implemented as soon as possible, but recognizes that the electrical power needs essential for the welfare of the citizens of the State must also be met. Please also see the responses to Comments 2.04, 2.05 and 5.04. Because the nuclear facilities have more complex technology and safety concerns, special studies are needed to evaluate compliance alternatives for these facilities. Based upon comments, Staff is proposing to eliminate the WDD provisions.

Comment 24.03:
We encourage the State Water Board to move forward with adopting and implementing a policy with clear deadlines as soon as possible without compromising grid reliability or integration of renewable power sources. California is committed to the highly ambitious goal of integrating 33% of its electricity from renewable sources. At least of the short term, the intermittent nature of many renewable power sources requires back-up and support from fossil generation. Some of the OTC plants may be highly useful in this regard. However, new cooling technology should not eliminate the usefulness of these plants and in some cases may provide opportunity for plant upgrades that in addition to reducing make the plants more efficient, less polluting and more capable of providing ramping and other support services for renewable power. The current policy appears to provide a schedule compliance that accommodates the needs of the grid in integrating renewables over the coming years. We strongly urge the State Water Board to ensure that compliance is timed to provide for reliability, but allow no greater delay than is absolutely necessary.
Response:
Staff agrees with the comments and appreciates the support for the proposed Policy.

Comment 25.06:
El Segundo and Encina must be in compliance by 2015 and 2017, respectively. Target compliance dates for these facilities should be predicated on successful completion of the repowering permitting and development at both generating facilities. Unfortunately, permitting of natural-gas fueled, fast-start combined cycle generation using air cooling at either facility has taken far longer than the statutory mandate (one-year completion) for the CEC Application for Certification (AFC) process and the local air districts' processes. Specifically, the South Coast Air Quality Management District's permit moratorium, which affects the completion of permits for electrical generating facilities in the Los Angeles Basin that rely on SCAQMD Rules 1304, 1309.1 and 1315, has delayed El Segundo's repowering project by more than one year, and the resolution to this permit delay will not be solved in the immediate future. The city of Carlsbad are among the intervenors to the repowering of a portion of Encina to a more environmentally beneficial plant that will prompt the retirement of a portion of the existing OTC generation; this

intervention despite the environmental benefits of the repowering project has likewise delayed the CEC and air district permitting processes. Thus, the targeted compliance schedules must remain flexible, accounting for delays in permitting of new generation that would otherwise replace OTC generation, address demand and planning reserve capacity, and support future renewable energy sources. Compliance schedules must also account for the key attributes of the existing OTC generating capacity at the respective facilities attributes that include location within the respective load center and ramping rate.

Response:

The implementation schedule set forth in the Policy allows for flexibility in continued consideration of factors affecting compliance dates and amendments to those dates through recommendations of the SACCWIS. To the extent that litigation involving the South Coast Air Management District's permitting process has resulted in delays for repowering projects, California Health & Safety Code § 40440.13 now allows that the district may issue permits in reliance on, and in compliance with, south coast district Rule 1304. While the statute is in effect only until May of 1012, the apparent intent is for readoption of rules in compliance with adverse court decisions.

Comment 28.15:

Retirement of aging plants should be timed to deployment of new clean energy resources; this will minimize cost and is most protective of the future environment. The aging coastal natural gas plants operate almost exclusively to meet the summer demand, while idling the rest of the year. The 15,000 MW of aging plant capacity nearly matches the peak air conditioning demand in California. Thus, every megawatt of appropriate air conditioning efficiency and conservation measures could directly remove the need for a megawatt provided by the aging natural gas power plants. The CEC and CPUC have recognized in the 2007 Integrated Energy Policy Report that widespread adoption of the most efficient appliances available can reduce peak demand by 46% in homes and 13% in industrial building. By meeting the state's goal of 33% renewable energy by 2020, while implementing required efficiency measures, OTC power plants can be reduced or eliminated without building any more large natural gas plants. Regional peak load can be served by solar power, which is most productive on sunny, warm days when electricity demand is high, as well as by efficiency measures such as better insulation, and more efficient air conditioners and shade trees. All the aging OTC coastal plants should be retired on a schedule consistent with the rate at which renewables and efficiency can be brought on line, so that the state is not bound by a long-term commitment to new natural gas plants that would be around for 30 to 50 years. Coordinating the retirement of aging plants with the deployment of green energy supplies would allow the state to meet environmental commitments while assuring electric system reliability.

Response:

Please see the response to Comment 2.04 regarding how the final compliance deadlines were developed. The State Water Board's authority to require that the location, design, construction and capacity of cooling water intake structures reflect BTA for minimizing adverse environmental impact does not extend to specifying technology for electricity generation. Setting energy policy is outside of the scope of this Statewide Water Quality Control Policy.

Comment 29.07:

Effective implementation of the policy requires on-going review of the implementation schedule. The SACCWIS must provide input on a regular basis (preferably quarterly or semi-annually), the Energy Agencies must maintain a leadership role in providing input to the Water Board on the implementation schedule, and plant operators must have a clear process by which they can seek changes in the implementation schedule.

The proposed SACCWIS includes not only the Energy Agencies, but representatives from the

SLC, CCC, and ARB. While these additional agencies all have an important role to play in the permitting arena, it makes more sense for the Energy Agencies to maintain responsibility for recommending modifications to the implementation schedule. The primary driver to any schedule modifications should be preventing the disruption of the state's electrical power system. The Energy Agencies are best situated to provide input on each plant's role in maintaining system reliability. These agencies understand and have direct regulatory authority for power plants and transmission facilities. Other agencies can provide valuable input regarding permitting challenges or other regulatory hurdles, but it is the Energy Agencies that can integrate that information as it relates to maintaining the reliability and stability of the grid. Additionally, while the policy acknowledges the need to phase compliance so as to maintain grid reliability, the ability of the utilities to procure adequate resources to ensure reliability, through either the replacement or repowering of existing facilities, is dependent upon the outcome of several regulatory processes. Implementation of the process by which OTC facilities would be replaced or repowered -- the CPUC's Long Term Procurement Plan (LTPP) and, subsequently the utilities' Long Term Request for Offer (LTRFO) activities - includes a great deal of uncertainty. While utilities can plan for a particular outcome, the vagaries of the process require the need for significant flexibility. The multiple steps along the way - submittal of offers, negotiating of deals, approval by the CPUC, permitting through the CEC, and construction - all are subject to a variety of business and regulatory hurdles. Thus, there is a strong need to ensure adequate flexibility in the OTC policy implementation schedule in order to ensure that those facilities needed for grid reliability purposes can continue to operate as necessary. If the policy is adopted, the Water Board must understand that in many cases, the proposed schedule reflects a "best case" scenario and there may be a need to modify the proposed schedule based on developments in the aforementioned proceedings.

Response:

Staff agrees that there likely will be a need to revise the final compliance deadlines in the proposed Policy's implementation schedule during the implementation period for various reasons. Staff is therefore proposing the use of an adaptive management strategy (please see the responses to Comments 2.04 and 5.04) with the SACCWIS overseeing the implementation process and reporting back to the State Water Board. Staff initially proposed that SACCWIS would report to the State Water Board every other year or more often if needed; however, based on public comments, staff modified the Policy so it now requires that SACCWIS report to the State Water Board annually. Staff considers quarterly or semiannual reporting to not be necessary and also requires substantial agency staff time. The proposed Policy will allow for more frequent reporting, should it be necessary.

Staff has also added new Policy language to reiterate that it has always been the State Water Board's intent to rely on the expertise of the SACCWIS' Energy Agencies to determine whether changes to the implementation schedule will be needed for grid reliability. Nonetheless, as the commenter mentioned, the other agencies in SACCWIS are also very important players, which will be counted upon to provide valuable input in their area of expertise and possibly assist with overcoming regulatory delays. Therefore, staff finds it appropriate that the SACCWIS as a group presents its recommendation to the State Water Board (with allowance for minority views).

Comment 31.38:

Before the State Water Board approves a policy with fixed compliance dates, it should verify that (1) the federal Department of Homeland Security concurs that such a policy would in no way compromise the security of the Nation's critical electric infrastructure or violate the intent of Homeland Security Presidential Directive-7; and (2) The North American Electric Reliability Corporation (NERC) and Federal Energy Regulatory Commission concur that the State Water

Board's policy does not conflict with any mandatory and enforceable NERC Reliability Standards.

Response:

Please see the response to Comment 2.04. The compliance deadlines in the Policy's implementation schedule were developed in consultation with state agencies and other entities responsible for, and experts in, energy policy and regulation. The period of time necessary to bring facilities into compliance is designed to allow necessary upgrades while ensuring reliability of the electrical grid.

Comment 33.12:

The State Water Board should include an explanation as to how the Long-Term Procurement Plan led to the final compliance date of 2017 for Bay Area Plants.

Response:

Please see the response to Comment 2.04.

Comment 34.08:

We agree with the Staff Alternative 3 on establishing a compliance schedule. However, we do have a major concern about the December 13, 2012 compliance date for South Bay Power Plant. The existing power plant is located at the extreme end of San Diego Bay with cooling water intake and discharge located in the Bay. The water depth is very shallow, 1 to 4 meters. The low tidal exchange takes 30 or more days to flush the waters in South Bay. These conditions and along with the solar thermal loads can cause the water temperature to exceed 100 degrees Fahrenheit in the late summer months and the water to become hypersaline. The volume of the daily cooling water for this plant is a significant fraction of the source water volume, unlike a coastal power plant that draws in offshore waters with the source water much greater than the daily cooling water demand. Figure 13 of the SED shows the seasonal variation of larval fish abundance. The maximum occurs in the summer months when the power demand and cooling flow rate is the highest. The South Bay power plant data impingement and entrainment losses are the highest during this period. The cumulative environmental damage, thermal, impingement and entrainment for caused by the power plant for almost 50 years cannot be accurately assessed compared to the unknown preexisting conditions, especially the biodiversity of the aquatic life. The Duke Section 316(a) report that the benthic infauna tax in the discharge are less in abundance and lower frequency of occurrence compared to the stations away from the discharge channel. It is only within the past decade that environmental monitoring has revealed the unacceptable damage to the South Bay aquatic life, including the loss of eel grass, benthic infauna, shellfish, local and pelagic fish. There has been a strong community opposition to this power plant and effort to have it decommissioned. The City of Chula Vista has long sought to have the power plant removed and the property incorporated in their community redevelopment plans. The San Diego Regional Water Quality Control Board at their regularly scheduled meeting on September 9 this year heard testimony from elected officials, the public and environmental groups expressing the need to have this plant retired at the earliest date. The combined cycle power plant in Otay Mesa will be coming on line shortly and eliminates the need for a repowered South Bay Power Plant. We recommend that the Policy retire the existing South Bay Power Plant at the earliest date.

Response:

Comment noted. Please see the responses to Comments 2.04 and 13.01.

Comment 35.01:

California faces a federal mandate to prevent coastal power plants from continuing to decimate sea life along the coast, but the State Water Board is proposing a policy that will take up to 12 years to require all remaining 19 plants to comply. This long delay would be a violation of the spirit and intent of the law. In even 10 years, many of the plants will be 50 to 60 years old, highly inefficient and unnecessary ongoing sources of significant air pollution. The proposed timeline is unacceptable because little evidence has been provided to justify allowing the destructive and needless practice of destroying sea life to go on that much longer. In its 2007 historic ruling, the US Court of Appeals for the Second Circuit required technology-based cooling be used by all power plants and, in effect, banned the use of water from bays, estuaries and the ocean for plant cooling. California has an opportunity to stop the killing of billions of fish and larvae that has savaged the aquatic life of our coastal waters, which studies show has contributed significantly to the disappearance of fish and the deterioration of coastal economies. The State Water Board is poised to implement the policy requiring that modern technology replace the outmoded and now illegal use of ocean, river and lake water-- OTC--by power plants. But the long-awaited policy misses the opportunity to ensure that the killing will stop as soon as possible and to begin replacing or converting the outmoded power plants with technology-based cooling methods or alternative energy sources.

Response:

The compliance schedule set forth in the policy is the result of consultation with state agencies and entities responsible for energy policy and regulation. The period of time necessary to bring facilities into compliance is designed to allow necessary upgrades while ensuring reliability of the electrical grid. The State Water Board must balance its priorities and regulatory mandates with those of other agencies responsible for energy and the environment. *Riverkeeper II*, referenced by the commenter, remanded USEPA's Phase II regulations for existing power plants on various grounds, including need for clarification, impermissibility of cost-benefit analyses, and inappropriately-broad performances ranges. The decision was reversed on the issue of cost-benefit analyses and otherwise contains nothing to act as an effective ban on use of cooling water intake. Please also see the responses to Comments 2.04 and 5.04.

Comment 35.02:

The proposed policy allows unnecessary and unreasonable delays in complying with the court decision's requirements, a result of the fact that it is often vague, unclear, ill-defined, contradictory, lacking in essential information and, most importantly, without dates certain by which the court decision will be complied with and OTC will end. Instead, power plant owners are presented with opportunities to exercise options made available in the policy to avoid achieving the board's stated goal of "protecting the state's coastal and estuarine waters." Perhaps the clearest example of how the proposed policy plainly anticipates ongoing use of OTC is its stated requirement for developing and implementing a mitigation program for the facility, approved by the Regional Water Board, which will compensate for the interim...impacts." This mitigation for continuing to kill marine life would be in effect until five years after the policy is adopted. Whether OTC would actually end after five years is not clear because of the opportunities in the policy for plant owners to avoid final compliance. The key to avoiding compliance is the "cost-benefit" analysis in the policy, which would allow plant owners to argue that the cost of ending OTC exceeds the benefit of protecting marine life. The board's cost-benefit process contains no standards, criteria or ground rules on how cost versus benefit is to be decided by authorities.

Response:

Staff does not agree that the proposed policy allows unnecessary and unreasonable delays. Please see the response to Comments 35.01 regarding the court decision's requirements and the implementation schedule. The commenter is not correct about the mitigation being "in effect until five years after" the policy is adopted. The interim mitigation is required after the Policy has been in effect five years and until the facility is in compliance. Thus, the longer the facility is not in compliance, the more mitigation will be required. Based on public comments, staff has eliminated the WDD section of the policy which discussed using a cost-benefit analysis.

Comment 36.02:
Your draft policy provides a timeline for requiring power plant owners to ostensibly comply with the policy by phasing out OTC by various dates. But that implementation schedule is unnecessarily prolonged without justification. It calls for the large majority of plants to reach compliance with the policy over the next 8-13 years. In the case of the Morro Bay plant, the schedule requires compliance by 2015. Yet it states that the plant is not needed after 2011 and provides no explanation for why it should be allowed to operate for four more years, especially since the plant now operates only occasionally. Your own study concluded that the state's aging, existing plants are not needed for grid reliability after the next few years. There seems to be no good reason to adopt a schedule that will allow them to continue to operate for so long.
Response:
Please see the response to Comment 2.04.

Comment 40.04:
NMFS supports the inclusion of compliance dates for facilities to come into compliance with the policy.
Response:
Comment noted.

Comment 41.03:
Modify the compliance dates to reflect from date of Policy adoption.
Response:
The closest compliance dates for facilities reflect from date of Policy adoption because if there is a delay in approval of the Policy, these dates may be difficult to change. Later compliance dates for facilities are dates certain to coordinate with SACCWIS reporting to the State Water Board in March.

Comment 41.06:
Provide an additional compliance path whereby if utilities opt for repowering with closed cycle cooling rather than impingement and entrainment control technology retrofits and/or operational measures, they can have an extended schedule with milestone dates and increasing flow reductions until Track 1 levels are achieved.
Response:
The implementation schedule contained in the proposed Policy already accommodates the option of repowering with closed-cycle cooling. There is therefore no need to further extend the schedule.

Comment 41.07:
In the interim, allow for mitigation until compliance is achieved; and/or, provide a “staged” approach to compliance, i.e., rather than a final milestone deadline for a facility's compliance, define interim milestones with interim reductions.
Response:
Interim mitigation is required until compliance is achieved; however, note that mitigation is not a substitution for meeting BTA. Also, the schedule does allow for a “staged” approach to compliance, by allowing power plants to stagger implementation if needed for grid reliability. The NPDES permits for the OTC power plants must further comply with the statewide State water Board Compliance Schedule Policy, which requires interim milestones.

Comment 44.07:

The draft policy states at Page 8, Number 16 that the Morro Bay Power Plant shall be "in compliance" by 12/31/2015. According to footnote 2, this "Due Date" was developed considering information provided by the CEC, the CPUC, CAISO, and the LADWP. The City encourages the Board to examine the record very closely and determine whether the timeline for compliance can be shortened to minimize the adverse impacts from OTC systems and protect marine resources.

Response:

Please see the responses to Comments 2.04 and 5.04.

Comment 47.04:

CCEEB is concerned that if a "Final Compliance Date" as shown in Table 1 is included in an NPDES permit, 3rd parties may be able to bring legal action to enforce that provision of the permit without regard to whether that date has been confirmed by the appropriate balancing authority (CAISO or the Board of Water and Power Commissioners of the City of Los Angeles) as not raising a grid reliability concern. Such a suit could place a federal judge rather than the Water Board in the decision role and disrupt this Draft Policy's "adaptive management strategy." We believe that the dates in Table 1 should more appropriately be regarded as Preliminary Target dates and not be included in NPDES permits until after a reliability determination has been made by the appropriate balancing authority.

Response:

Staff does not believe it is appropriate to revise the planned implementation of the Policy based upon the possibility of litigation. The Policy has been revised to include additional provisions to address grid reliability needs. Please see the response to Comment 31.09.

Comment 47.05:

The change in Section 2.B. of the Draft policy to schedule "... a hearing to consider suspension of a compliance date applicable to an existing power plant" after being notified by an energy agency of a grid reliability concern is an insufficient safeguard of grid reliability. The CAISO suggestion that a compliance date be stayed upon notice by CAISO of a reliability concern should be the minimum response to an expression of concern. The responsibility to determine grid reliability matters should rest with the respective balancing authority. The State Water Board has no expertise to make such determinations and should defer to the appropriate balancing entity in all instances. Holding a hearing to "consider" suspension of a compliance date merely adds risk that a determination will be made contrary to the advice of the balancing entity.

Response:

The State Water Board retains final authority to make decisions about implementation of the Policy. However, the Policy as proposed would require the State Water Board to implement the recommendations of the CAISO unless the Board finds that there is compelling evidence not to follow a recommendation and makes a finding of overriding considerations. Based on concerns that flexibility is needed to immediately suspend final compliance dates due to an unforeseen event, such as a wildfire disrupting electrical transmission, State Water Board staff has inserted language allowing for a suspension of a final compliance date of up to 90 days upon receipt of notification by CAISO (and if not objected to by the Executive Directors of CEC or the CPUC). CAISO is the balancing authority overseeing most of the OTC facilities, and the Policy clearly acknowledges that the Energy Agencies (CAISO, CEC, and the CPUC) are the experts on power generation and grid reliability.

The new policy language further states that should CAISO determine that a suspension of a final compliance date for more than 90 days is necessary for grid reliability, CAISO will notify the Water Boards and SACCWIS within 10 days of its determination. If the Executive Directors of

CEC or the CPUC do not object, the final compliance date will be suspended for 90 days. The State Water Board will hold a Hearing within these 90 days to fully evaluate an amendment to the Policy's implementation schedule. The LAWDP may likewise request that the STATE WATER BOARD hold a Hearing and amend a final compliance date for the three OTC plants that are not within CAISO's jurisdiction but within LAWDP's service area.

Staff has also added language to clarify that NPDES permits issued by the Regional Water Boards shall include appropriate permit provisions to implement authorized suspensions and modifications of final compliance dates without reopening the permits. The Regional Water Boards are required to base compliance schedules in individual NPDES permits on the implementation schedule in the Policy, which is based on statewide and local reliability.

Comment 48.01:
Section 2.B (2) of draft policy: replace "shall hold a hearing to consider suspension of compliance date applicable to an existing power plant" with "shall suspend the compliance date applicable to the existing power plant" and add "The State Water Board's decision to amend the final compliance date for an existing power plant shall be conditioned on the need to maintain the reliability of the electric system as determined and communicated by the CAISO, CEC or CPUC acting according to their individual or shared responsibilities. Any final compliance shall be stayed by a CAISO determination that an existing power plant is needed for reliability purposes." The language changes identified above ensure that final compliance dates in the policy will not jeopardize electric grid reliability.
Response:
Staff has substantially revised the provisions governing suspension of compliance dates, addressing the standard for implementing CAISO recommendations and the need for grid reliability. Please see the response to Comment 47.05.

Comment 48.02:
The draft policy identifies a final compliance date for South Bay of December 31, 2012. At the December 1, 2009 workshop, commenters expressed an interest in accelerating the final compliance dates for South Bay to December 31, 2010. CAISO strongly recommends that the Water Board maintain the final compliance date for South Bay as December 31, 2012. The draft policy includes this date based on information jointly provided by CAISO, CPUC and CEC that projects that commercial operation of the Sunrise Powerlink transmission line will allow South Bay to retire.
Response:
Comment noted. Staff recommends retaining the final compliance date for South Bay as December 31, 2012. Please see the responses to Comments 2.04 and 13.01.

Comment 49.04:
The energy agencies have stated that the dates specified in their report may require periodic updates. Periodic updates on the state of marine resources affected by power plants and results of independent studies by qualified experts in that regard should also be required.
Response:
The power plants following Track 2 will be required by the Policy to monitor to show impact reduction. This may be part of SACCWIS' reports to the State Water Board.

Comment 49.05:
The State Water Board recognizes the compliance dates in this Policy may require amendment based on, among other factors, the need to maintain reliability of the electric system as determined by the energy agencies included in the SACCWIS, acting according to their

individual or shared responsibilities. Comment: This statement must identify "other factors" for clarity and completeness. The statement also indicates that only the energy agencies among the SACCWIS will determine if grid reliability is being met by the compliance dates, indicating that other members of the SACCWIS, i.e., the CCC and SLC will not be consulted, excluding the agencies primarily responsible for environmental protection. Clarification is required.

Response:

It is not possible to anticipate all the factors that may require that the Policy be amended. For instance, new legislative action on the state or federal level may require that the Policy be amended. Because the Energy Agencies are the experts on grid reliability, it is natural that these agencies will be relied for information on grid reliability. That is not to say that the other members of SACCWIS are not important, or will be relied on, for other types on information that affects how the Policy is implemented.

Comment 49.14:

Section 2.B. (1) of the Policy states that "*Existing power plants** shall comply with Section 2.A, above, as soon as possible, but no later than, the dates shown in Table 1, contained in Section 3.E, below." The vagary of "as soon as possible" fails to provide an effective means of enforcement and invites undocumented and unsubstantiated excuses for continuing to use OTC. Plant owners or operators should be required to justify why OTC operations cannot be ended as soon as the Policy is enacted.

Response:

Staff disagrees that Section 2.B.(1) of the Policy fails to provide an effective means of enforcement and invites undocumented and unsubstantiated excuses for continuing to use OTC. Section 3.A of the Policy requires plant owners and operators to submit an implementation plan that identifies the selected compliance alternative and describes the general design, construction, or operational measures that will be undertaken to implement the alternative, ***and propose a realistic schedule for implementing these measures that is as short as possible*** [emphasis added]. In other words, plant owners or operators ARE required to justify why OTC operations cannot be ended as soon as possible. However, as stated in Section 3.C.(1) of the Policy, "If the State Water Board determines that a longer compliance schedule is necessary to maintain reliability of the electric system per SACCWIS recommendations while other OTC power plants are retrofitted, repowered, or retired or transmission upgrades take place, this delay shall be incorporated into the compliance schedule and stated in the permit findings." That is, certain plants may be required to wait their turn to be allowed to be retrofitted, repowered, etc. because they are needed to provide support for the electrical grid while other plants get upgraded.

Comment 49.24:

Section 3.C.(1) of the Policy only takes into account the needs and convenience of grid reliability with no concern expressed for the victims of OTC: aquatic life and coastal communities whose economies are interconnected with coastal resources. A provision is needed to authorize the Water Boards to accelerate the compliance schedule if conditions of marine life go into accelerated downfall such as could happen, for example, with the Morro Bay National Estuary, which, the CEC staff has found, "is already impaired and in ecological decline ... " This is why stringent monitoring by power plant owners or operators is essential if OTC--and risks to aquatic life—are to continue for any time.

Response:

Staff agrees that regular monitoring, as specified in Section 4 of the proposed Policy, is essential to ensure compliance for those OTC plants that are following the Track 2 compliance alternative without reducing flows and/or through-screen velocities. Staff also acknowledges the ongoing impacts of OTC on marine resources, which the OTC Policy seeks to address. Staff further believes that an adaptive management approach that allows changes to the implementation schedule, as specified in the proposed Policy, is essential to successfully implementing the Policy requirements without causing disruption to the electrical grid reliability (please see the response to Comment 5.04). Note that the Policy requires SACCWIS to report to the State Water Board regularly (now annually) with recommendations on changes to the schedule or Policy. At these public meetings, anyone can bring their concerns about the OTC implementation schedule or need for revisions to the State Water Board's attention. The State Water Board may also, at its discretion, hold a meeting at any time to investigate the need to modify the schedule, for instance if conditions of marine life at an OTC plant goes into accelerated downfall, as described.

Comment 50.02:
In accordance with Dynegy's contractual obligation with CAISO to use its best efforts to oppose permit conditions that could make continued operation of South Bay illegal, uneconomical or otherwise impractical, Dynegy strongly opposes any acceleration of the proposed December 31, 2012 final compliance date. Given South Bay's limited remaining operating life as explicitly set out in and made enforceable through its current NDPES permit, an accelerated date is unwarranted and inappropriate and would only serve to: unnecessarily create potentially severe future burdens, including litigation, for the Board, Regional Water Board, and CAISO in the unexpected event that CAISO determines South Hay Units 1 and/or 2 are needed for electrical reliability purposes beyond December 31, 2010 (or one year of adoption of the Policy).
Response:
Comment noted. Staff recommends retaining the final compliance date for South Bay as December 31, 2012. Please see the responses to Comments 2.04 and 13.01.

Comment 52.01:
LADWP is very concerned with the compliance dates as published in the revised Draft Policy, along with the procedure used to evaluate whether or not these dates can be changed, both in the Policy and in the NPDES permits. LADWP has, and continues to recognize, that repowering efforts require a thorough and thought out replacement strategy. Concurrent repowering efforts do not allow for proper planning, and more importantly would remove needed megawatts (MWs) from the system without a source of replacement. LADWP cannot relinquish any of the MWs provided by the current plants, via repowering or retrofitting, without first installing replacement MWs in place at the site. The reality is that every MW of capacity from these plants is vital to the essential public service of electricity supply to the City and any loss of capacity must be made up by construction of new power generating facilities in essentially the same location.
Response:
Comment noted. Staff has changed the final compliance dates for the three LADWP OTC facilities, based on new information from LADWP.

Comment 55.03:
While NRG continues the pursuit of repowering at El Segundo and Encina stations with fast-start technology, we recognize the critical role that these existing steam boilers provide during the transition to a balance of new renewable generation shaped and supported by new natural gas-fueled generation, in particular in California where permitting challenges and delays affect the development of new energy sources. Such permitting challenges, including the lengthy (minimum of three years) CEC permitting process for thermal generation and potentially contentious air district permitting process, must be considered in review of compliance schedules.
Response:
Please see the response to Comment 31.09.

Comment 57.02:
Staff has been clear that retirement of existing OTC facilities is the intent of an OTC policy. If the State Water Board determines that a water quality policy adopted pursuant to Section 316(b) of the CWA is the appropriate mechanism to force removal of this important power source in California, it should fully consider the consequences of this agenda and ensure that the Policy does not jeopardize electric reliability. It is extremely dangerous and risky to set an implementation schedule to hold the energy industry's "feet to the fire," while hoping that grid reliability can be guaranteed by other agencies. In the Revised Draft Policy, State Water Board staff have recognized and confirmed that changes to the implementation schedule will likely be necessary to ensure grid reliability, yet have proposed a firm implementation schedule despite that reality. A firm implementation schedule cannot be accomplished in the future without impacts to reliability in the near term. Since the owners of most existing facilities are not expected to actually do anything but retire the facilities when the time comes, the feet being held to the fire do not belong to the OTC owners but rather to the other units of state government who are responsible for approving replacement infrastructure. And if these other state authorities fail to put the necessary infrastructure in place, the feet getting burned are those of the citizens of the State of California.
Response:
Please note that intent of the Policy is not to force the retirement of existing OTC facilities. The purpose of the Policy is to implement CWA Section 316(b) and to establish BTA for cooling water intake structures at existing coastal and estuarine power plants to reduce IM/E impacts to acceptable levels. Staff realizes that there will be some plants that will decide to re-power and in some cases even shut down, but that will be based strictly on business decisions by the owners/operators of those plants. The Policy clearly provides a Track 2 compliance path that would allow a continuation of OTC as long as impingement and entrainment are controlled comparable with Track 1. The implementation schedule was developed with the assistance of the CEC, CAISO, and the CPUC and is believed to be realistic. Nonetheless, the Policy employs an adaptive management strategy, which through SACCWIS will monitor the situation, and allows for changes to the schedule, if needed to ensure grid reliability.

Comments 57.03 and 57.05:
The Revised Draft Policy's current approach is to set a firm schedule in the policy and provide a future hearing opportunity to modify the Policy and the schedule if, in the State Water Board's discretion, reliability conditions in the State or regionally warrant a change to the implementation schedule for Track 1 or Track 2. The problems with this approach are twofold. The first is that such a policy will start creating reliability issues in the near-term, not just the indefinite future, and these issues will only snowball with the passage of time.

The second problem is that a modification to a firm implementation schedule will be subject to a host of legal and administrative requirements to amend the Policy, including notice and comment, CEQA review, and approval by the Office of Administrative Law. These onerous processes will in turn invite new rounds of litigation and delay, and will inevitably slow and possibly thwart the ability to implement the very amendments necessary to ensure grid reliability. It is arbitrary and capricious to subject such important Policy amendments to a lengthy and uncertain review that likely will take years to effectuate.
Response:
Staff anticipates that there likely will be a need to revise the final compliance deadlines in the proposed Policy’s implementation schedule during the implementation period for various reasons. The use of an adaptive management strategy to address this need for periodic updates of the compliance schedule (please see the responses to Comments 2.04 and 5.04) is

a well-tested approach for the State Water Board, when complex long-term compliance issues are addressed. Staff initially proposed that SACCWIS would report to the State Water Board every other year or more often if needed; however, based on public comments, staff modified the Policy so it now requires that SACCWIS report to the State Water Board annually. The proposed Policy allows for more frequent reporting, should it be necessary.

An amendment to the Policy's implementation schedule **does** require public notice, review, and comment, a staff report, CEQA review, and approval by the Office of Administrative Law. However, such an amendment would be very narrow and focused as it would just entail a change in dates and any public comments (or legal challenges) would need to be limited to addressing just this change in dates. The entire Policy would not be opened up for review and comment. Furthermore, mere changes to the implementation schedule in the Policy should not require many staff resources.

Comment 57.04:
The firm implementation schedule in the Revised Draft Policy very clearly creates an end-of-life date for many facilities covered by the Policy; including RRI's facilities, and begins to affect reliability immediately because it will affect spending on maintenance and capital additions necessary to keep these facilities running today. No prudent owner will expend the same amount for a plant with a known retirement date which is difficult - if not impossible to change. For instance, if one had a car with 100,000 miles on the odometer, a prudent owner would not buy new tires or perform certain maintenance procedures if he knew he had to junk the car in one year when the mileage is expected to be 120,000 miles and buy a new one. This decision to avoid maintenance will increase the likelihood that the car will break and the owner will be stranded prior to the purchase of the new car. Now assume that at 118,000 miles, the car owner is told his new car will not be ready for another year. Again, it may not make sense to spend money on new tires, and the deferral of maintenance is starting to dramatically increase the likelihood of breakdown.
Response:
Staff does not believe that a firm implementation schedule in the proposed Policy will affect electrical reliability due to lack of maintenance and capital additions. Power plants must meet minimum safety requirements, as must all cars on the road if they want to avoid a ticket. If anything, the proposed Policy will likely provide an incentive to upgrade old power plants to meet BTA if the ultimate intent is to stay in business. Prudent car owners do not drive on bald tires or with fading brakes.

Comment 57.06:
RRI suggests not setting a firm implementation schedule, because in addition to creating procedural, timing, and risk concerns for most facilities, including RRI's facilities, a firm schedule simply is not necessary to force compliance with the Policy or retirement of OTC facilities. The reality is that gas-fired steam boiler OTC facilities will be retired when replacement infrastructure is in place because they will no longer be economical. But until such time, California is better off if the OTC facilities that are needed for grid reliability continue to operate.
Response:
Staff believes that without the proposed Policy and firm deadlines to meet the proposed BTA, some facilities may choose to repower but keep using OTC, as the Moss Landing Power Plant recently did. Regarding grid reliability, the Energy Agencies have stated that the draft policy incorporates a workable schedule and process to implement the State Water Board's objectives, while considering the need to maintain reliable operation of the electric grid.

Comment 58.02:

In addition, the policy now allows 10-12 years for some existing plants to phase out OTC, without justification. With some owners already moving ahead to replace old plants without even waiting for a new policy and others considering alternative uses of plant sites, there seems to be no excuse for not stepping up the timeline on replacement of existing plants, especially with so many renewable energy opportunities, such as PV solar, now available to ensure grid reliability without relying on gas-fired plants. The destruction of marine life and other coastal resources should be paramount in determining priorities for continued operation of existing plants.
Response:
Please see the responses to Comments 2.04 and 5.04.

Comment 60.03:
We urge you to remove provision 2(B)(2). Giving these agencies individual discretion to recommend changes in compliance dates may cause unnecessary delays in compliance and take away from the goals of the policy. Further, we are strongly opposed to an automatic stay (or noticed stay) at the individual request of CAISO, which was raised in public comment at the December 1, 2009 workshop. Any potential request for changes to the compliance dates can be predicted far enough in advance to allow meaningful participation by the public; therefore adequate notice and time for review should be granted if such a provision is added to the policy. We suggest the request for a waiver to the Compliance Dates be: 1) published for public review immediately upon receipt by SACCWIS and 2) scheduled for review and public comment at the next scheduled SACCWIS meeting, but not sooner than 90 days.
Response:
It is possible, although highly unlikely, that an unforeseen event, such as a wildfire or an earthquake, could disrupt the electrical grid in such a way that an immediate suspension of a final compliance date(s) for a facility may be necessary. The Policy clearly acknowledges that the Energy Agencies (CAISO, CEC, and the CPUC) are the experts on power generation and grid reliability. CAISO and LADWP, as the balancing authorities overseeing the OTC facilities, are the agencies that keep the closest attention to the stability of the electrical grid. It is therefore appropriate that these agencies be able to suspend the final compliance deadlines immediately on a short-term basis (less than 90 days). Staff has added further language clarifying Section 2.B.2 (please see the response to Comment 47.05.)

11. Implementation Issues

a. SACCWIS

⇒ ***Purpose and Process***

Comment 2.01: The Bay Area Municipal Transmission group (BAMx) commends the Water Board for working closely with the state energy agencies (CEC, CPUC, CAISO) in developing a proposed plan to deal with the reliability impacts of the proposed OTC Policy. The principle mechanism of developing the proposed eleven step plan (OTC Power Plant Replacement Infrastructure Plan) to implement the Policy on an individual power plant or unit basis while maintaining electric reliability is appropriate. BAMx believes development of a feedback loop to allow for adjustments to the plan as time goes on is also very appropriate and provides for needed flexibility in complying with both the reliability requirements and proposed water policy objectives as part of the eleven step process.
Response:
Comment noted. Staff has responded to issues and concerns specifically identified in further detail in the commenter's submission.

Comments 3.31, 24.05, 26.27:
We applaud the State Water Board for its coordination and partnership with other involved agencies. However, it is imperative that such coordination facilitates, rather than delays, this process. SACCWIS should be used as a streamlining tool to expedite the various permitting processes before the multiple agencies involved. Because the relevant permitting agencies including the CEC, CPUC, and California Coastal Commission are members of the SACCWIS, we recommend using this group to expedite and streamline any permit requirements from multiple agencies related to this policy.
Response:
Staff appreciates the support for its coordination and partnership with other involved agencies. Staff believes that such coordination will facilitate the implementation phase, as it has facilitated and strengthened the proposed Policy. The intent is to streamline the OTC permit process by requesting owners/operators to submit proposed implementation plans and schedules within six months after the effective date of the Policy for the SACCWIS to review.

Comments 3.32, 24.04, 26.28:
SACCWIS's role in extending compliance deadlines should be better defined and opportunity for public comment should be given. The SACCWIS is required to report to the State Water Board with "recommendations on modifications to the implementation schedule every two years starting in 2013." The language as written is unclear and we urge the State Water Board to amend this language to make it clear that the SACCWIS should only make recommendations on modifications to the schedule if necessary for grid reliability. Furthermore, the required findings for the SACCWIS to recommend a delay in the compliance schedule are not defined, nor is the State Water Board's "appropriate" determination based on that recommendation defined or a procedure prescribed. We urge the State Water Board to include definitions in this section and to make clear that the State Water Board will retain decision making authority on when and if the compliance schedule is altered. Finally, the State Water Board's "appropriate" determinations of the SACCWIS timeline modifications should provide opportunity for public comment. These decisions should not be made behind closed doors, and the public should have the opportunity to review and provide comment on SACCWIS and State Water Board recommendations.
Response:
State Water Board staff agrees that SACCWIS's role in extending compliance deadlines should be better defined. Staff has added language under Section 2.B.(2) describing in further detail the circumstances under which a suspension of the final compliance date may be allowed, pending full evaluation of amendments to the implementation schedule. The proposed language lays out a method for how changes to the schedule that have a short lead time will be addressed and clarifies the roles and responsibility of the different agencies.

The SACCWIS is intended as an advisory body to the State Water Board and therefore will make no final decisions. The SACCWIS will have noticed public meetings and will receive public comment at those meetings. The SACCWIS will then provide its recommendations to the State Water Board and those recommendations will be considered according to the State Water Board's public process, including the consideration of new public comments at that stage.

The State Water Board Hearing itself, where the State Water Board will consider recommendations to change final compliance deadlines, is a noticed public meeting where the public will have full opportunity to comment, both orally and in writing, on any proposal to change the implementation schedule. The State Water Board will retain decision making authority on when and if the Policy, including the implementation schedule, is altered. For that reason, Staff cannot require the State Water Board to make a certain decision based on certain findings.

Staff does not intend the role of SACCWIS to be limited to advising the State Water Board on modifications to the schedule if necessary for grid reliability. The intended purpose of SACCWIS is to report to and advise the State Water Board on the overall implementation of the policy, which includes protection of marine life as a fundamental objective. Please also see the response to Comment 45.02.

Comment 8.01:
We commend the staff of the State Water Board as well as the staffs of CAISO, CPUC, and CEC for the substantial work they have done on this important matter.
Response:
Staff appreciates the comment.

Comments 12.14:
The Policy relies on an untested advisory process that involves multiple agencies and regulatory objectives.
Response:
The State Water Board staff is required by law to consult with appropriate, affected federal and state agencies during the development and implementation of any water quality policy or regulation. It is staff's experience that close collaboration with other agencies improves the overall effectiveness of a policy, and prevents unintended negative consequences. The purposes of the proposed Policy are listed in the SED under "Statement of Goals". Multiple purposes for a policy are not a problem as long as they are not mutually exclusive.

Comment 11.52(a):
By limiting the use or potentially causing the shutdown of any number of the 21 California OTC plants, the proposed Policy potentially would cause significant and serious negative impacts on the stability of the State's electrical grid, particularly with respect to peak demand periods and in localized service regions. Given the importance of maintaining electrical grid stability, it is imperative that the State Water Board and its staff work in close collaboration with the energy agencies (CEC, CPUC, and CAISO) - not only in determining what impacts the policy will have on grid stability, but also in the implementation process to ensure that grid reliability is, in fact, maintained. As written, the proposed Policy limits the role of energy agencies to participating in SACCWIS, which will only advise on proposed implementation schedules. The State Water Board should expressly define the SACCWIS's role to also include advising on the discharger's proposed implementation plan.
Response:
Staff disagrees that the Policy would cause significant and serious negative impacts on the stability of the State's electrical grid. However staff agrees with the importance of collaboration with the energy agencies (CEC, CPUC, and CAISO) to ensure that grid reliability is maintained. The proposed Policy states that SACCWIS will review the power plants' proposed implementation schedules and will report to the State Water Board with recommendations no later than one year after the effective date.

Comment 25.02:
We recognize the merits of obtaining input from CEC, CPUC, CCC, SLC, ARB, and CAISO when developing the draft OTC Policy, but believe the development of the current draft OTC Policy would have benefited from more inter-state agency workshops leading up to the release of the draft OTC Policy. The process to which SACCWIS will review implementation plans and

incorporate bi-annual Integrated Energy Policy Report findings into the compliance schedule for this policy is not well defined at this point. Thus, we encourage the State Water Board to initiate additional inter-state agency workshops regarding the OTC Policy and its implementation.

Response:

Many workshops addressing the use of OTC by power plants have already been held by the State Water Board and many of the other SACCWIS agencies to get input from the stakeholders and the general public on the proposed OTC Policy. The State Water Board held public three meetings and the CEC, CPUC, and CAISO held at least two public workshops on the proposed OTC policy in 2009 alone. State Water Board staff believes that sufficient workshops have been held to get a broad range of public input. Many, smaller inter-agency staff meetings to discuss inter-agency collaboration are likewise necessary when it comes to developing a policy.

Comment 29.03:

Overall, we believe that the draft policy is moving in a positive direction. We are very encouraged by the Water Board's on-going efforts to engage the CPUC, the CEC, and CAISO (collectively, the Energy Agencies) in both policy development and implementation strategy. This coordination is absolutely essential to ensure that implementation of an OTC policy maintains the reliability and stability of the state's electric grid.

Response:

Comment noted. The support is appreciated.

Comment 31.26:

The SED notes that the Draft Policy would establish an advisory committee made up of the Energy Agencies and certain other environmental agencies to assist the State Water Board as it establishes plans and to "prevent disruptions to the State's electrical supply." It is not clear how the State Water Board, which lacks legislative or budgetary authority, expects to require these other agencies to participate. Who is to pay for these meetings and reports? Is it in these agencies' budgets? What obligates an independent agency to participate? When did the State Water Board become responsible for preventing disruption to the State's electrical supply? The SED should have included such information to allow the public to understand the effects and reasonably foreseeable impacts of the proposed Policy, including the possibilities that funds may not be available for a particular agency to participate or an agency may decline to participate in the future.

Response:

Staff anticipates that a Memorandum of Agreement (MOA) be negotiated among the agencies and entities comprising SACCWIS, in order to define the functions and processes necessary to ensure effective performance of the advisory role of the SACCWIS. The MOA will address composition of the SACCWIS, meeting requirements, consultation of outside agencies, and formulation of recommendations. While the State Water Board cannot require the proposed SACCWIS member agencies to participate, staff from these agencies has already participated in IAWG meetings for several years. The proposed OTC Policy will directly affect these agencies workload and manner in which they fulfill their mission and it thus is in their interest to participate. The SACCWIS meetings will be public meetings. Various agency staff will be paid by their respective agencies to attend the meetings and participate in preparing reports. While funding levels are always uncertain, this issue is of very high priority for many of the participating agencies and it is unlikely that funding issues will cause any of these agencies to decline to participate.

As the commenter noted, the State Water Board is responsible for adopting state policy for water quality control, and is not responsible for preventing disruptions to the State's electrical supply. However, it is clearly essential that the electrical power needs for the welfare of the citizens of the State are met. It is also an obligation under CEQA for the State Water Board to consider possible adverse environmental impacts of any policy, including impacts to utilities, and identify ways of avoiding or mitigating these impacts. State Water Board staff has been working with representatives from the CEC, CPUC, CCC, SLC, ARB, and CAISO to develop realistic implementation plans and schedules for this Policy that will not cause disruption in the State's electrical power supply. Staff further believes that the advice and effort of SACCWIS, acting according to their individual or shared responsibilities, will prevent disruption in the State's electrical power supply.

Comment 45.02:
We support the creation of the proposed SACCWIS. However the purpose of SACCWIS appears to be limited in the current draft policy language to advising "…on the implementation of this Policy *to ensure that the implementation schedule takes into account local area and grid reliability*." The overall Policy is an explicit balancing act between protecting marine resources and beneficial uses while maintaining reliable electric supply. The limited mandate of SACCWIS seems to focus the group's work entirely on one side (grid reliability) of the equation. The same text is mirrored in the draft Board Resolution. We encourage you to consider striking the italicized text quoted above, so the sentence ends "...to advise the State Water Board on the implementation of this Policy." This change would better reflect the role suggested in the group's title, and would provide the SACCWIS with the broader purpose of advising on the overall implementation of the policy, which clearly includes ensuring grid reliability, but also includes the fundamental policy objective of protecting beneficial uses and marine resources. If the mandate is to remain limited as currently proposed, a more appropriate title would be 'Statewide Advisory Committee on Ensuring Grid Reliability' or something similar.
Response:
The support for SACCWIS is appreciated. Staff does not intend the role of SACCWIS to be limited to advising the State Water Board on grid reliability. The intended purpose of SACCWIS is to report to and advise the State Water Board on the overall implementation of the policy, which includes protection of marine life as a fundamental objective. Staff does not believe that the current Policy language precludes SACCWIS from advising on protecting beneficial uses and marine resources. Grid reliability is emphasized in the Policy because this is an important issue outside the State Water Board staff's purview where coordination with the SACCWIS agencies is especially crucial.

Comment 54.01:
We support the continued effort to formalize coordination with the state energy agencies.
Response:
Comment noted. The support is appreciated.

Comment 49.22:
The SACCWIS review of the owner or operator's proposed implementation schedule should be in nine months--six months after the SACCWIS is impaneled-in order to rightfully convey recognition of the ongoing death of marine life with every day that passes and the urgency to stop this slaughter as soon as possible.
Response:
Staff does not understand this comment. The proposed Policy requires that a power plant owner or operator submit a proposed implementation plan and schedule for the SACCWIS' review three months after the SACCWIS is impaneled and the SACCWIS must report to the State Water Board with recommendations within nine months after the SACCWIS is impaneled.

Comment 49.23:
Regarding the statement: "If members of SACCWIS do not believe the full committee recommendations reflect their concerns they may issue minority recommendations that the State Water Board shall consider as part of the SACCWIS recommendations": Does/this mean that all members of the SACCWIS have equal votes? If so, it should be made clear for members of the SACCWIS and the public.
Response:
It is not intended that the SACCWIS will vote. Rather the SACCWIS will issue recommendations, and as stated by the commenter, may issue minority recommendations, if necessary. This is clearly stated in the Policy.

Comment 49.08:
The Policy states that in order to assure that repowering or new power plant development in the Los Angeles basin addresses unique permitting challenges, the SACCWIS will assist the State Water Board in evaluating compliance for power plants not under the jurisdiction of the CPUC or operating within the CAISO Balancing Authority Area. LADWP, which has an expansive program of photovoltaic development under way, should be involved in this process of developing new generation sources.
Response:
LADWP is to be commended for their expansive program of photovoltaic development. LADWP will be asked by SACCWIS to be involved in planning issues when issues that pertain to LADWP are discussed.

⇒ ***Composition***

Comment 13.06:
We recommend that local community representatives, the people who live with the impacts of these plants, be included in SACCWIS.
Response:
SACCWIS is intended to be a smaller advisory group and only include representatives from statewide agencies with regulatory authority over OTC power plants. Staff considered including other representatives, but concluded that the group would be too large and unwieldy to effectively serve the purpose of an advisory group. However, the SACCWIS will have noticed public meetings and will receive public comment at those meetings, and local community representatives and other stakeholders are encouraged to attend these meetings and provide input to the process.

Comments 44.01 and 49.06:
The Ocean Protection Council should be included in SACCWIS.
Response:
Please see response to Comment 13.06.

Comment 15.06(a):
Regarding the composition of SACCWIS, the Ocean Protection Council should be included, as well as Fish and Game (Marine Branch) as the Marine Protection Act is very protective of marine resources. The MPA regulations allow recreational fishing only and no commercial fishing; once-thru-cooling is a taking of fish.
Response:
Please see response to Comment 13.06 regarding the inclusion of the Ocean Protection Council. Staff has added the following language to the Policy to address the need to consult with the Department of Fish and Game (among others): *"The SACCWIS may consult with other*

appropriate agencies, including but not limited to the Regional Water Boards, air quality districts, and the Los Angeles Department of Water and Power, in the process of reviewing implementation schedules and providing recommendations to the State Water Board."

Comment 23.11:
If, as the Draft Regulation states, the purpose of the SACCWIS is "to ensure that the implementation schedule takes into account local area and grid reliability", the appropriate agencies to sit on the SACCWIS are those with grid expertise, namely CAISO, CEC, and CPUC. Accordingly, other agencies without grid expertise which are tentatively identified for inclusion on the SACCWIS need not be included.
Response:
Please see responses to Comments 13.06 and 45.02.

Comment 41.05:
The SACCWIS should include a representative from LADWP for only those discussions that pertain to LADWP and a representative from the construction engineering industry who can bring an important and added perspective to the Committee.
Response:
Staff has added the following language to the Policy to address the need to consult with the LAWDP staff (among others): *"The SACCWIS may consult with other appropriate agencies, including but not limited to the Regional Water Boards, air quality districts, and the Los Angeles Department of Water and Power, in the process of reviewing implementation schedules and providing recommendations to the State Water Board."*

⇒ ***Public Involvement:***

Comment 49.21:
The meeting notice in Section B(1) should be amended to state 10 working days out of respect to the public.
Response:
The SACCWIS will certainly comply with California's open meeting laws, which just requires 10 days. Where possible, more notice will be given. In most cases, the meetings can be scheduled in advance and more than 10 days notice given. However, it is quite possible that SACCWIS will be required to meet with short notice, which may make it difficult to provide more than 10 days notice in some cases.

Comment 2.03:
It is not clear how public input will be received by SACCWIS, which is tasked with implementing this proposal and eleven step process. Section 3.B of the proposed Policy should explicitly identify where stakeholders will have an opportunity to contribute to and review the execution of these steps, especially 1-3, 8, 9, and 10. BAMx recommends there be broad stakeholder input in SACCWIS' deliberations and decisions, especially the "adaptive management" portion of the proposed Policy. We caution that the energy agencies may be conservative about compliance dates. The State Water Board should be careful that other State goals do not automatically trump the goal of reducing the impact of once through cooling. For instance, we believe that increased electricity imports may be a cost effective way to achieve OTC goals and achieve the Renewable Portfolio Standards (RPS), although some say that California is already too heavily reliant on imports to meet our reliability needs. And if meeting the RPS goals impedes eliminating OTC plants, then the required compromise needs to be made by policymakers (with input from stakeholders) and not the implementers of analytic studies that may include inherent and unintended policy decisions.

Response:
Comment noted. The SACCWIS is intended as an advisory body to the State Water Board and therefore will make no final decisions. The SACCWIS will have noticed public meetings and will receive public comment at those meetings. The SACCWIS will then provide its recommendations to the State Water Board and those recommendations will be considered according to the State Water Board's public process, including the consideration of new public comments at that stage.

Comment 11.52(b):
The SACCWIS must comply with California's open meeting laws, which require that all meetings of the SACCWIS, and meetings of the State or Regional Water Boards when considering recommendations from the SACCWIS, be open and public, that notice be provided, and that the public be allowed to directly address the state body on each agenda item.
Response:
The SACCWIS will of course be required to comply with California's open meeting laws.

⇒ ***Meeting Schedule***

Comment 4.12:
In the proposed Policy, SACCWIS is scheduled to meet every two years. Issues associated with grid stability and performance that could easily be affected by unanticipated early shutdown of generating capacity are in too great a flux to be left to a two year oversight review. This situation needs to be carefully monitored on a continual basis. We suggest that a subgroup of the larger SACCWIS be formed to meet on a quarterly basis to track site-by-site information in real time. In addition, the Draft Policy should be revised to delegate the authority to the Executive Director to modify compliance dates for any reason at any time.
Response:
The June 30 version of the Policy did not explicitly state how often the SACCWIS would meet, but rather provided a schedule of minimum reports to the State Water Board. Staff envisions relatively frequent meetings of the SACCWIS. The intent is that SACCWIS would meet regularly and as needed, and the Policy has therefore been modified to more clearly express this intent. The SACCWIS would be convened three months after the effective date of the Policy. Once convened, SACCWIS would begin reviewing draft implementation plans and schedules which must be submitted by power plant owners/operators within six months after the effective date of the Policy. Based on the review of these submittals, SACCWIS would make recommendations to the State Water Board on changes to the implementation schedule no later than one year after the effective date of this Policy, and every other year following the first report to the State Water Board [Staff has now changed the proposed Policy to require annual reporting to the State Water Board]. To accomplish this schedule, SACCWIS would probably need to meet at least monthly.

The compliance dates can only be modified by readopting that portion of the Policy, which would probably take an estimated three months. The June 30, 2009 version of the Policy allowed for earlier compliance dates if recommended by SACCWIS (the "as soon as possible, but no later than" language in Section 3.C of the Policy); however, power plant owners and operators were concerned that Regional Water Boards would force compliance earlier than what the SACCWIS recommended, so this language has been removed in the March 22, 2010 version of the Policy. The March 22, 2010 version of the Policy also allows the suspension of a final compliance date if continued operation of the power plant is needed to maintain the reliability of the electric grid. Meanwhile, a new compliance date could be adopted.

Comment 11.52(c):
SACCWIS must be involved more often than only once initially (one year after the effective date of the Policy) and, thereafter, every two years starting in 2013. The importance of electrical grid stability and the complexity of changing conditions affecting grid stability dictates constant monitoring. The SACCWIS and Board should be engaged on grid stability as related to the OTC plants on an ongoing basis. We recommend that SACCWIS meet at least once every six months.
Response:
Please see the response to Comment 4.12.

Comment 23.12:
The Draft Policy contemplates the SACCWIS will operate on a two-year schedule. However, two years is a virtual eternity when measured against changes in circumstances impacting the grid. For example, the possibility that development in Southern California would grind to a halt due to a lack of emission credits was likely unknown two years ago. The Policy should make it clear that the two year reporting process is a minimum standard, and that the SACCWIS may report more frequently as it deems appropriate. We recommend the following revisions to Section 3.B.(2): “The SACCWIS will report to the State Water Board with recommendations on modifications to the implementation schedule at least every two years and more frequently if necessary starting in 2013.”
Response:
Please see the response to Comment 4.12.

Comment 41.04(a):
Allow for a more fluid and flexible process for SACCWIS to meet in order to review constantly changing information and recommend compliance date changes. Beginning in 2012, LADWP recommends that SACCWIS meet quarterly and report to the State Water Board semi-annually.
Response:
Please see the response to Comment 4.12 regarding the meeting and reporting schedule of SACCWIS.

Comment 55.02:
While the State Water Board acknowledges the importance of grid reliability considerations in the revised draft OTC Policy, we share concerns at the frequency at which SACCWIS will meet (every 2 years) and the process (State Water Board hearing) to which the changes to the compliance schedule may be affected.
Response:
Please see the response to Comment 41.04.

b. Implementation plans for individual facilities

Comment 11.62:
A concern is the apparent lack of flexibility in the process if market conditions change during the implementation period warranting a change in the implementation plan. For example, a plant may elect to shut down rather than repower based on current regulatory and market conditions, but, if, for example, three years from now the economy improves or if the LTPP provides an opportunity for a power purchase contract, repowering or retrofitting may become a viable option. The Draft Policy should expressly recognize that if so implementation plans may be amended.
Response:

Please see the responses to Comments 2.04 and 5.04 regarding built-in flexibility in the proposed Policy's implementation process. The owner/operator of an OTC power plant may certainly elect to shut down as a means of complying with the proposed Policy. Should the owner/operator decide to repower the facility later with dry (air) cooling, the owner/operator need not worry about complying with the proposed Policy, because no intake of cooling water is required for dry cooling and the Policy would therefore not apply in this situation. If the facility shuts down and the owner/operator later decides to start up again by retrofitting and using wet cooling, this is also not a problem as long as the facility is in full compliance when it starts back up.

Comment 11.63:
The proposed Policy requires an owner or operator to submit a proposed implementation plan within six months of the effective date of the Policy. That's simply not enough time to conduct the thorough engineering and operational studies and financial analyses needed to evaluate the feasibility of various complex compliance options. We request that the Policy be revised so that all facilities with compliance deadlines on or after December 31, 2012 not be required to submit the initial proposed implementation plan until one year after the effective date of the Policy. Extending the initial submittal deadline will not delay the ultimate compliance deadlines; to the contrary, it may eliminate delays by eliminating the need for changes to the implementation plan.
Response:
The policy has been in development since 2005 and the public has reviewed various drafts at different stages of the process since 2007. Companies have known throughout that period that regulation of OTC to comply with CWA Section 316(b) was moving forward, and has had ample opportunity to plan for the implementation of the policy. The draft policy only requires that implementation plans identify the compliance alternative selected by the owner or operator, and only would describe the **general** design, construction, or operational measures that would be undertaken, and to propose a realistic schedule that is as short as possible. It does not require "thorough engineering and operational studies and financial analyses needed to evaluate the feasibility of various complex compliance options."

Comment 14.03:
We support the proposed Policy requirement that all plants - whether retirement is being chosen as a compliance option or not - comply with the requirements in the policy. Where a power plant chooses retirement as a compliance alternative, the Policy should require - as it now appears to - that the plant submit an implementation plan to account for the possibility that the plant is required to continue operating beyond the target closure date for reasons relating to electric reliability. This requirement for a plan will ensure compliance with the CWA, should retirement fail to occur. Such a requirement should not be burdensome for the power plants because the Policy envisions a generous lead time for implementation of the compliance measures.
Response:
Staff agrees that the submittal of an implementation plan should not be burdensome for the power plants. However, the implementation plan submitted by plant operators would need to provide information on plant or unit retirement if that is intended as their compliance alternative.

Comment 14.04:
We want to ensure that the Regional Water Board responsible for reviewing the submissions from the power plants provide the public with a sufficient opportunity to review the submissions, receive public comments, and respond to them. The Board's responses to public comments should be supported with sufficient statement of basis to ensure that the Board adequately considers such comments.

Response:
Sections B.1 and B.2 of the Policy now state:
"(1) SACCWIS meetings shall be scheduled regularly and as needed. Meetings shall be open to the public and shall be noticed at least 10 days in advance of the meeting. All SACCWIS products shall be made available for public review and comment.
(2) The SACCWIS shall review the owner or operator's proposed implementation schedule and report to the State Water Board with recommendations no later than [one year after the effective date of this Policy]. The SACCWIS may consult with other appropriate agencies, including but not limited to the Regional Water Boards, air quality districts, and the LADWP, in the process of reviewing implementation schedules and providing recommendations to the State Water Board."
Thus, the public will be provided an opportunity to comment on each power plant's implementation plan. Note that it is SACCWIS that will initially review the implementation plans.

Comment 23.08:
The Draft Policy would require operators to file an implementation plan for complying within six months of its effective date. The six-month timeframe is absolutely unworkable. In Mirant's case, to try to predict in the first half of 2010 what route it will take to bring its Pittsburg Power Plant into compliance with a 2017 deadline would be nothing more than a guess. There are a number of factors that will impact a range of possibilities, for instance the result of a utility procurement cycle that likely won't conclude until sometime in 2012. Accordingly, to the extent an implementation plan is required, the deadline for submitting such plan should occur at most three years prior to the implementation deadline.
Response:
Please see the response to Comment 11.63.

Comment 23.09:
The primary concern surrounding a premature implementation plan filing is the possibility that representations made in such a plan might be seized upon by a Regional Water Board and incorporated into a permit. The Draft Policy nowhere establishes what the legal significance of the implementation plan will be. If the Draft Policy were updated to make it absolutely clear that the implementation plan will not have a binding consequence on the future compliance track an operator may choose to undertake, then there would be less concern about submitting a plan that amounts to little more than a guess. Accordingly, the Policy should include a statement that the details of an implementation plan shall not be binding upon an operator and in no event should an implementation plan's representations be incorporated into a future permit.
Response:
The implementation plan filed by the individual owners/operators will be used by SACCWIS to plan for an orderly progress towards meeting the established BTA without causing grid instability. In certain cases, power plant upgrades may need to be staggered to maintain sufficient grid reliability. For this reason, it is important that the submitted plant implementation plan is as accurate as possible. Please see the response to Comment 11.63. Certainly, Regional Water Boards will use the submitted implementation plans as a starting point for drafting future NPDES permits for the plants in question. This does not mean that the implementation plan cannot be further refined or changed, before the permit is issued.

SACCWIS may also recommend a modification of the implementation schedule, if necessary, to better reflect the proposed means of complying with the Policy. For instance, an owner/operator may propose to shut down the facility as a means of complying with the Policy. This will be reflected in future updates to the Policy as the plant being in earlier compliance than expected. Should the owner/operator decide to repower the facility later, this is allowed as long as the facility is in full compliance with the Policy when it starts up again.

Comment 33.06:
Under Implementation Provisions, the policy must emphasize that the final compliance dates are immutable. We suggest making the following change: "The implementation plan shall identify the compliance alternative selected…and propose a realistic schedule for implementing these measures that is as short as possible but, in no event, exceeds the milestone due dates listed in Table 1's Implementation Schedule."
Response:
The final compliance dates in the Policy are NOT intended to be immutable. Staff believes that an adaptive management approach that allows changes to the implementation schedule, as specified in the proposed Policy, is essential to successfully implementing the Policy requirements without causing disruption to the electrical grid reliability. Please see the responses to Comments 2.04, 2.05 and 5.04.

Comment 33.07:
Additionally, the public and wildlife agencies should have the opportunity to comment on the implementation plans, especially with regards to the mitigation plans.
Response:
The SACCWIS will be a public body subject to the provisions of the Bagley-Keene Open Meeting Act. The public will have an opportunity to provide comments to the SACCWIS when they meet publically to review the Implementation Plans. The public may also submit comments at a later point, when the SACCWIS makes recommendations to the State Water Board on possible changes to the Policy's Implementation Schedule.

Comment 37.15:
The Policy should require each of the Joint Energy Agencies to issue a formal finding that implementation plans submitted by generators will not adversely impact reliability. SCE appreciates the provisions in the Policy that provide for ongoing feedback from the Joint Energy Agencies through SACCWIS. Although SCE supports feedback from such a broad committee, SCE is concerned that the role of SACCWIS remains an advisory one, and that the committee is not accountable for the failure to prevent risks to the reliability of the system.
Response:
Please see the response to Comment 31.26.

Comment 40.03:
NMFS supports the requirement for the facilities to submit proposed implementation plans to State Water Board and appropriate Regional Water Board within 6 months of policy adoption. It would be surprising to find a facility that is not able to comply with this provision due to the long time period between the release of the scoping document in March 2008 (State Water Board 2008) and the current proposed policy.
Response:
Comment noted.

Comment 49.20:
The Policy states that "....no later than [six months after the effective date of this Policy], the owner or operator of an *existing power plant** shall submit an implementation plan to the State and Regional Water Boards." Comment: "Shall submit an implementation plan" is not clear and its ambiguity risks disputes and avoidance of compliance. This requirement should specify that the implementation plan is for compliance with board policy and milestones and due dates in the Implementation Schedule in order to make clear what the obligations of owners or operators are under the policy.

Response:
Staff disagrees that the cited Policy language is unclear. The Policy further specifies that "*The implementation plan shall identify the compliance alternative selected by the owner or operator, describe the general design, construction, or operational measures that will be undertaken to implement the alternative, and propose a realistic schedule for implementing these measures that is as short as possible. If the owner or operator chooses to repower the facility to reduce or eliminate reliance upon OTC, or to retrofit the facility to implement either Track 1 or Track 2 alternatives, the implementation plan shall identify the time period when generating power is infeasible and describe measures taken to coordinate this activity through the appropriate electrical system balancing authority's maintenance scheduling process."*

c. The NPDES permitting process

Comment 9.23:
The policy states that Regional Water Boards shall reissue or, as appropriate, modify NPDES permits issued to owners or operators of existing power plants to ensure that the permits conform to the provisions of this Policy. Given the long-expired and out-of-compliance permits among coastal power plants, including Morro Bay's nine-year expired permit, no permits should be reissued until demonstration of compliance with policy standards is achieved
Response:
The NPDES permit is the mechanism to impose the requirements of the policy on the power plants. Thus, the Regional Water Boards have to either reissue or modify the power plants' NPDES permits to include policy requirements. The Water Boards cannot require compliance without first reissuing or modifying the power plants' NPDES permits.

Comment 11.51:
The proposed Policy fails to provide flexibility in the implementation process to accommodate unforeseen circumstances, changes in market conditions and load growth, or problems with permitting and equipment contracting. As currently drafted, the Policy would require any change to the implementation Schedule to first go before the Board through a noticed rulemaking proceeding, and then the Regional Water Board would have to take up a permit amendment through a separate proceeding. Instead of requiring such a lengthy, cumbersome process with numerous points for indefinite delay, the Draft Policy should clearly provide that the Regional Water Board can directly amend the timeline for each plant as determined by the SACCWIS via an administrative permit amendment.
Response:
Please see the responses to Comments 2.04 and 5.04 regarding flexibility in the implementation process. Staff has changed the proposed Policy to require Regional Water Boards to include appropriate permit provisions to implement authorized modifications (or suspensions) of final compliance dates without reopening the NPDES permits.

Comment 31.09:
RRI believes that a reasonable Policy should not include explicit retirement dates in NPDES permits as enforceable conditions, unless Track 1 and 2 are changed as we recommend. The Draft Policy includes rigid compliance dates, while the Energy Agencies' staff proposal contained in Appendix C of the SED indicates that the operational dates for the replacement infrastructure is known for only six of the OTC plants. Even more troubling is that the Draft Policy makes the compliance requirements considerably more restrictive than the Energy Agencies envisioned. In order to have any planning flexibility on the part of the plant owners and the Energy Agencies, the Policy would need to be revised frequently, which would be a significant administrative burden on the Board and Staff, as well as the Regional Water Boards

and defeat the goal of reducing workload. These "draft" compliance dates become legally-binding as they are included in each facilities' NPDES permit and the addition of an "as soon as possible" mandate adds unnecessary ambiguity. Some might later argue that, since the Energy Agencies are only advisors, "as soon as possible" means that all OTC facilities would either have to immediately comply with Track 1 or Track 2 of the Draft Policy, or shut down. It is strongly recommended that the "as soon as possible" language be deleted. Lower investment is a foreseeable consequence of the current compliance schedule construct, and the reliability implications of this unintended consequence needs to be evaluated before the Draft Policy is adopted.

Response:

The implementation schedule set forth in the Policy allows for appropriate flexibility in continued consideration of factors affecting compliance dates and amendments to those dates through recommendations of the SACCWIS (please see the responses to Comments 2.04 and 5.04). Staff disagrees that the final compliance dates are onerous since these dates were developed with the consultation of the Energy Agencies and LADWP. Note that several of the dates are less stringent than recommended by the Energy Agencies to allow a reasonable timeframe for owners/operators of OTC power plants to come into compliance even if the facility is not needed for grid reliability.

Staff agrees that the “as soon as possible” language in Section 3.C. of the proposed Policy may cause unintended consequences and therefore deleted this language. Staff further added language to require Regional Water Boards to include appropriate permit provisions to implement authorized modifications (or suspensions) of final compliance dates without reopening the NPDES permits.

Comment 33.08:

The NPDES permit reissuance section should also include more specifics and deadlines. Permits should be reissued or modified within six months of the implementation plan being approved.

Response:

Permits will include the appropriate timelines and tasks to be completed. Reissuance of permits will likely coincide with permit renewals. Since most of the power plants’ permits have expired and have been administratively continued, the Regional Water Boards would prioritize their renewals. However, since the Regional Water Boards will include timelines and tasks from the implementation plans, they will have to wait for approval of those plans before the permits can be renewed.

Comment 41.04(b):

Allow for a better integration of the Regional Water Boards with the change of dates so modifications can be made to the NPDES permits without delays.

Response:

Staff has added language to the Policy to clarify that NPDES permits issued by the Regional Water Boards would include appropriate permit provisions to immediately implement authorized suspensions of final compliance dates, if necessary. If the State Water Board determines that a longer compliance schedule is necessary to maintain reliability of the electric system per SACCWIS recommendations while other OTC power plants are retrofitted, repowered, or retired or transmission upgrades take place, this delay would be incorporated into the NPDES compliance schedule and stated in the permit findings.

Comment 50.03:

The uncertainty regarding the final compliance schedule is extremely troublesome in terms of ability to plan for the future. Given the substantial and complex planning effort that will be needed to comply, power plant owner/operators - as well as the State's energy planning agencies - need certainty in the final compliance date. If the Regional Water Boards have the discretion to accelerate a plant's compliance schedule once the SACCWIS has made its recommendations, that needed certainty is lost, which will both disrupt the intricate planning upon which grid reliability decisions, were based and delay a plant's commencement and completion of compliance activities. In short, power plant owners/operators should propose final compliance schedules that achieve compliance as soon as possible but no later than the deadlines specified in Table 1, SACCWIS should make its recommendations in light of overall grid reliability considerations and the plant's proposal, and the Regional Water Boards should accept the decided upon dates without further adjustments.

Response:

Staff agrees. Staff has added language to clarify that NPDES permits issued by the Regional Water Boards shall include appropriate permit provisions to implement authorized suspensions and modifications of final compliance dates without reopening the permits. The Regional Water Boards are required to base compliance schedules in individual NPDES permits on the implementation schedule in the Policy.

d. Other Implementation Issues

Comment 4.11:

The issues of lack of long term contracts, lack of air emission credits, lack of freshwater resources, lack of permits, likely community opposition to the installation of cooling towers in coastal settings, conflicts with other state or regional laws, ordinances, and regulations, the lack of technology to allow Track 2 to provide a workable alternative to Track 1 are not adequately acknowledged or analyzed in the Draft Policy or the draft SED. As such, both documents as they now stand are technically and legally deficient. We question whether the state's energy agencies' staff has adequately considered all these potential destabilizing factors in their evaluation of the proposed Policy for impact on grid stability. All of the multiple caveats, clarifications and understandings about how this Policy may be successfully implemented are contained in a page of footnotes, to a Table, in an Appendix. This document stands alone as an unofficial (unadopted) draft staff paper that has not been formally acted upon by the governing body of any of these energy agencies.

Response:

The draft SED identifies the potential environmental impacts related to adoption of the Draft Policy. Since the State Water Boards do not know what specific steps power plant owners may take to comply with the policy, project specific environmental impact analyses will need to be conducted for each facility. State Water Board staff has been and continues to work with the State's energy agencies' staff to maintain grid reliability while OTC facilities come into compliance with the proposed Policy.

Comment 5.01:

Our comments focus on the need for implementing any adopted policy in a manner that ensures the continued reliability of electric service in California. As a result of extensive work with State Water Board staff, we believe the draft policy contains a satisfactory mechanism to assure electric system reliability by allowing continued operation of existing power plants using once through cooling until replacement infrastructure obviates the need for such plants for reliability. The draft policy and attachment to the SED provide a preliminary schedule for the development of replacement infrastructure. The draft policy calls for periodic updates to this schedule in order to be responsive to delays or changes in energy policy not foreseen at this time. The draft policy incorporates a workable schedule and process to implement the State Water Board's objectives, while considering the need to maintain reliable operation of the electric grid. Adoption of this draft policy will create a long-term relationship between State Water Board, CEC, CPUC and CAISO as we develop more detailed plans for the necessary infrastructure to allow for implementation of the draft policy and as other complex issues affecting the need for power plants using once through cooling unfold. Implementation of the draft policy through time will require maintaining a close working relationship over many years that allows the State Water Board to satisfy its objectives, while not jeopardizing the reliability of California's electricity grid.

Response:

Staff agrees and is looking forward to a continued close working relationship with the member agencies of SACCWIS, including the energy agencies, to successfully implement the Policy.

Comment 5.02:

The power plants affected by the draft policy represent approximately 32% of the installed capacity in California and have important local, zonal and system reliability benefits. Any adopted policy should accommodate replacement or repowering of at least some of these power plants and the construction of transmission upgrades.

Response:

Comment noted.

Comment 5.03:

Many of the affected power plants are those with the operating flexibility necessary to integrate intermittent renewable resources onto the electricity grid. California needs to ensure that compliance with the proposed policy does not compromise its renewable generation goals, which are a key element of state energy policy to achieve green house gas emission reduction targets along with other preferred resources such as energy efficiency, distributed generation, and demand response. While preferred resources will satisfy a portion of California's resource needs, retiring existing plants using once through cooling will require development of replacement infrastructure with comparable operating characteristics. This effort presents a challenge given current and possibly future restrictions on air permits for replacement generation in California.

Response:

Staff agrees, and understands that this effort presents a challenge with regard to air permits. Staff intends to work closely with the SACCWIS member agencies including the Air Resources Board, as well as the local air districts to implement the Policy within the complex air quality landscape found in many parts of the State.

Comment 5.05:

The CEC, CPUC and CAISO have worked together to develop a proposal for replacing or repowering of fossil plants using once through cooling consistent with maintaining reliability of the electric system and meeting California's environmental policy goals. The key elements of the proposal recommended a regional and phased approach to implementing any adopted policy in order to allow for the necessary planning, procurement, and construction of replacement infrastructure. The CEC, CPUC and CAISO are pleased that the State Water Board's staff has chosen to incorporate our infrastructure replacement concept into the draft policy. We urge the State Water Board to preserve this element in any final policy it adopts.

Response:

Staff agrees and plans to preserve this element.

Comment 5.06:

The draft policy includes the following elements which the CEC, CPUC and CAISO agree are critical to implementing any adopted policy in a way that ensures grid reliability: (1) a compliance schedule that reflects a phased, regional approach; (2) the creation of SACCWIS, which includes representatives from CEC, CPUC and CAISO; (3) the creation of a Review Committee to provide a public report and study to investigate alternatives to the use of once through cooling at SONGS and Diablo Canyon nuclear power plants to meet the requirements of the adopted policy, including the cost of alternative power sources; (4) consideration of less stringent requirements of nuclear-fueled plants and fossil-fueled plants with a heat rate of 8,500 BTU/kWh or less if the owner or operator can demonstrate that the cost of compliance is wholly disproportionate to the environmental benefits to be gained.

Response:

Staff agrees with elements 1, 2 and 3 discussed in the comment. However, with regard to element 4 staff has proposed alternate language to remove the WDD section. Instead staff is still providing special conditions for combined cycle units and nuclear plants, while not requiring the WDD. Nuclear plants may establish alternate requirements if costs considered by the agency in establishing Track 1 requirements are wholly out proportion to costs for the specific nuclear fueled plant.

Comment 9.09:

The plans to protect grid reliability, based on the asserted need for the existing coastal plants, fails to take into account the 2008 State Water Board study, "The Electric Grid Reliability Impacts from Regulation of Once-Through Cooling in California," conducted by a respected independent consultant, which concluded last year that "more than enough power plants are expected to be operating in 2015 to more than compensate for any or all OTC plant retirements." The proposed policy was drawn from recommendations of the CEC, CPUC and CAISO, but the policy makes no mention of the State Water Board's own study.

Response:

The 2008 State Water Board study, "The Electric Grid Reliability Impacts from Regulation of Once-Through Cooling in California," by Jones and Stokes, was used and considered in the development of the policy, and was specifically cited in the SED. Please also see the responses to Comments 2.04 and 5.04.

Comment 11.32:

The SED concludes that, by 2015, sufficient power will be online to compensate for older OTC plants that may choose to shut down rather than comply with the Policy. However, Staffs conclusion is contingent upon the State's ability to "ensure the transmission system is capable of delivering power from those plants to the loads presently served by OTC plants. The SED also states that new power plant siting, repowering and transmission projects will have less than significant impacts on the environment as long as the proposed Policy allows the State Water Board to consult with the state's energy agencies. Staffs analysis is overly simplistic and optimistic. Staffs view of transmission siting does not reflect reality: over the past four years, on average, it has taken 14 months to complete the permitting process. Once projects were permitted, it took an average of 29 months for transmission projects to become operational. The proposed Policy also does not allow for meaningful input from the CEC, CPUC, and the CAISO, since the role of these agencies in SACCWIS is limited to advising on each facility's proposed implementation schedule every two years. Given the dynamic nature of the energy industry and the long lead times necessary to repower or build new generation and transmission facilities, this infrequent input period of every two years will not be able to address issues in a timely manner.

Response:

Staff believes that the SED adequately addresses these issues. Regarding the role of the Energy Agencies as part of SACCWIS please see the responses to Comments 2.04, 3.32, and 5.04. Regarding the meeting schedule of SACCWIS, please see the response to Comment 4.12.

Comment 11.34:
The SED does not acknowledge the important role many of the OTC plants play in helping integrate renewable power into the state's energy grid. The older OTC plants, while they do not have high capacity utilization, are able to ramp up and channel energy onto the grid much faster than newer generation. For example, Moss Landing Units 6 & 7 can each ramp up at a rate of 30 MW/minute (from 200 MW to 730 MW), as compared to the new combined-cycle combustion gas turbine generation (Units I & 2) which can ramp up no faster than a rate of 20 MW/minute (from 290 MW to 510 MW). The rapid ramping characteristics of some of the older units allow them to adjust energy output to the grid when the power level falls off and picks up from less predictable wind and solar renewable sources. To replace the ramping abilities of Moss Landing Units 6 & 7, four new 510 MW combined cycle units would have to be built. It is difficult to see how this would have no material environmental impacts.
Response:
If a ramping rate of 30 MW/minute is critical for Moss Landing, Track 2 of the Policy would allow for this type of capacity within the plant while still getting closed cycle cooling for most of the units. Additionally, the Policy would not require replacement of Moss landing Units 6 & 7.

Comment 11.57:
The proposed Policy is premised on an incorrect understanding of the financing process needed to repower or retrofit an OTC plant. Most OTC plants are owned by independent power producers (IPPs) who, unlike utilities, have no assured recovery of investment via rate base treatment. For many of the older, low capacity-factor OTC plants, capital investment on the scale required to accommodate a retrofit with alternative cooling technology or repowering cannot be economically justified. Without a source of revenue to cover the level of investment in a cooling system retrofit, many of these IPP OTC plants will be retired. In order to repower a facility that would otherwise be retired, a generator must secure a contract for the replacement plant that is sufficient in term and price to allow for an appropriate return on the generator's investment in the repowered plant. However, the current LTPP is inadequate to deal with the number of facilities being retired, retrofitted or repowered. The LTPP is not transparent, repowering or replacement projects are not given due consideration, and all of the costs and benefits of proposed projects are not considered. A reformed procurement process is needed to provide contracts for new generation and retrofits. First preference should be given to the owners or operators of OTC facilities that are being forced out of business. Any RFO process must be structured such that repowered projects can compete on a level playing field with other alternatives, such as transmission lines or generation in other locations. Repowered plants must be offered a contract term that is similar in duration to the economic life of utility self-build options. New generation is capital intensive. Traditionally, the useful life of generation or transmission is considered to be 30 years or more, and utilities depreciate such large capital expenditures over the useful life of the asset, yielding an annual rate of recovery that is moderate. However, when IPPs respond to utility RFO's, IPP's are typically required to agree to contract terms of 10 years. It is also common that newly constructed power plants are unable to find contracts for capacity beyond the initial term of their contract. No structured capacity market exists, and existing units are often disqualified from participating in "'new source" utility RFO's, even when utilities seek contracts for incremental supply. Faced with this construct, IPPs must either seek to recover the bulk of their investment within the term of the contract, which makes their bid into RFO's appear expensive relative to utility self-build options, or chance recovery of

a significant portion of their investment from the energy market post-contract. Dynegy's experience is that capital markets are unwilling to finance new power plant projects that rely upon earnings beyond the initial term of the contract with the utility. For this reason, the terms and conditions associated with a contract for a repowered facility should be comparable to those conditions under which utilities might pursue alternative investments. Otherwise, the evaluation process skews the true cost to the ultimate consumer. Existing OTC plants not only provide local reliability benefits, but also supply important adequacy benefits and renewable power integration benefits. When evaluating the appropriate means of replacing a resource, it is important that the replacement facility truly replicate all of the benefits of the retiring plant deemed important by the ISO. If the benefit to be replicated is solely local reliability, a transmission only solution may (or may not) meet the need. If the need is resource adequacy and/or renewable power integration, incremental transmission is insufficient to meet the need unless it accesses truly incremental, uncommitted generation resources. Dynegy is currently unaware of any regions in the west that have large surpluses of generating resources waiting for market access. Incremental transmission most likely provides solutions only when coupled with the new, incremental generation required to fill the line. In such situations, evaluation of alternatives to on-site replacement generation must include the costs of both transmission and new generation for the evaluation to be valid. Transmission solutions must also account for other costs associated with displacing local generation, such as the cost of local reactive power support and increased transmission losses. Alternative evaluations must also recognize that the environmental impact of reutilizing an existing industrial site will be less than the siting and construction of new greenfield facilities. In many cases, repowering of existing plants would reduce local air emissions, result in little to no incremental visual blight, and reduce noise levels, in addition to conserving otherwise open spaces. All of these considerations suggest that repowering projects may possess advantages in the new-plant siting process over greenfield projects elsewhere in the State. Additionally, several OTC plants are located in small, rural communities in which the plant comprises a major component of local tax revenues and employment. Loss of these plants would eliminate the single largest employer in these towns and further stress the budgets of these communities, such as Morro Bay and Moss Landing. Repowering project approval would also sustain the continued presence in California of several IPPs that otherwise will be damaged commercially by the closure of much, if not all, of their California portfolios. The continued presence of IPPs in California will provide generation service benefits to the State's consumers that are unique to the IPP industry and unlikely to be replicated by utility owned generation (e.g., lower facility cost, lower cost of operation, willingness to accept operational performance risk, greater unit availability, etc.).

Response:

Staff acknowledges the complexities of financing replacement power plants and units. This is one reason State Water Board has worked with the power agencies to provide a extended and integrated schedule of compliance for the OTC processes at plants along the coast of California. These agencies will continue to provide recommendations and implementation input through the SACCWIS. Independent Power Producers must work with the California power agencies to insure and implement future power requirements. These provisions are, however, beyond the scope of this policy.

Comment 12.12:

There would be significant impacts to electric supply and reliability should 30% of the State's generation capacity be retired prematurely, as could result from implementation of the proposed Policy in its current form.

Response:

The Policy would not cause significant impacts to grid reliability due to the fact that the State Water Board is committing to continued close collaboration with the State’s energy agencies

(CAISO, CEC, and CPUC) after policy adoption. Please see the responses to Comments 2.04, 3.32, and 5.04.

Comment 14.02:
The Policy incorrectly omits facility retirement as a compliance alternative for existing power plants, although the SED recognizes this fact. A number of plants are already considering retirement as an option to reduce and eliminate environmental impacts from the use of OTC, as the SED recognizes. Many of these plants have been operating for many decades using inefficient and outdated technology, and now it appears that electric reliability demands on many of these plants will soon be replaced. It would seem that decommissioning these facilities is the most natural and reasonable outcome given these developments and should therefore be expressly recognized in the Policy

Response:
Even though not explicitly stated directly in the Policy, plant or unit retirement is clearly a compliance alternative.

Comment 25.01:
NRG owns and operates two California coastal power plants - El Segundo generates 670 MW from two steam boilers and Encina generates 950 MW from five steam. NRG is actively pursuing repowering at El Segundo and Encina station using air-cooled condensers and eliminating ocean water cooling for the MWs replaced. The NRG design incorporates a balance of cleaner, more efficient fast-start natural gas-fueled generation. NRG is also actively developing new renewable (wind and solar) energy sources or California. Despite these efforts, we recognize the critical role that these existing steam boilers provide during the transition to a balance of new renewable generation shaped and supported by new natural gas-fueled generation, in particular in California where permitting challenges and delays affect the development of new energy sources.

Response:
Comment noted.

Comment 28.03:
California has excess supply of natural gas generation at the expense of renewables. There has been a rapid build-up of nearly 20,000 megawatts in new natural gas power plants around the state, dramatically increasing California's capacity for natural gas generated electricity to a record high of over 40,000 megawatts. The failure to meet the state's renewable portfolio standard is directly connected to the relentless march of new natural gas plants. This is mainly because natural gas is the next prioritized energy supply resource after renewables. In other words, renewables have to lose in order for natural gas to win. Even though renewables are nominally a higher priority, a competitive struggle for existence between natural gas and renewables is embedded directly into state policy - by design. Not surprisingly, natural gas seems to win this game almost every time.

As a direct result of this failure to increase renewable energy, policymakers have come to assume that we "need" to build more natural gas power plants. Utility companies are only too happy to oblige and foster this impression, which is not surprising given that the other major product these utilities provide, in addition to electricity, is natural gas. A spree of construction since 1999 has resulted in major investment in new natural gas electric generation in California, at least $15 billion so far. Many of these plants replaced older, less efficient power plants, and for a time actually reduced consumption of natural gas fuel. However, this improved efficiency is undermined by the fact that while 7,500 megawatts of old plant capacity retired by 2008, over 18,000 megawatts have been built, or will be built; by the end of 2010. But the usage rate of natural gas plants will *need to decrease* if the clean energy policies are to achieve their goals. A study from 2003 by Lawrence Berkeley National Laboratory looked at the effects of increasing renewables and reducing growth in energy demand on the future need for natural gas plants in California, and projected that if the state implements both the 33 percent renewables requirement and aggressive efficiency programs, then over 20,000 megawatts could be retired by 2030; more than the capacity of the 15,400 megawatts of aging once-through cooled coastal natural gas plants. The policy to move to green energy directly conflicts with any new natural gas capacity beyond those already built or under construction. Even repowering existing plants would amount to pushing aside the state's green energy targets. The 2008 OPC report concluded that given their low usage, the shuttering of the OTC natural gas plants by 2015 could occur with no additional generation to replace it. The report states that "…the retirements could be compensated for with as little as $135 million in in-state transmission upgrades."

Response:

Comment noted. It is not within the State Water Board's authority to establish an energy policy for California, but rather to protect the beneficial uses of the State's waters. The purpose of this Policy is thus to protect marine and estuarine resources of the State by implementing section 316(b) of the CWA. Staff has been working with the State's Energy Agencies to develop a Policy that will implement section 316(b), but not have the unintended effect of causing grid instability. However, specifying options for replacement of electricity generation is beyond the scope of this Policy.

Comment 28.09:

At 17 to 29 cents per megawatt hour, efficiency and renewables are a cost effective OTC replacement strategy. These include accomplishing greater energy efficiency improvements, increasing renewable energy, and implementing programs for reducing peak demand. Certain functions of the aging plants — such as voltage regulation and the ability to modify generation over the course of the day — might have to be met with other technologies. However, such resources are not entirely lacking in California. There are currently 41,499 MW of natural gas power plants in California. If all of the 15,400 MW of aging plants retired by 2012, the state will still continue to operate 26,000 MW of existing natural gas plants. In addition, nearly 2,000 more megawatts of natural gas plants are currently under construction and due to come on-line by the end of 2010. Another 18,000 MW of power can be imported over existing transmission wires, and more transmission capacity is likely to be built in the future. There is also some capacity to vary the electric generation from hydroelectric plants, especially the 4,100 MW of pumped storage that is specifically designed to meet peak demand. One important function of the aging plants is to meet local reliability needs. Retiring these plants will require replacing this capacity as well. Local resources, such as solar built on rooftops or at substations, and energy efficiency measures, can help. And there are thousands of megawatts of natural gas peaking capacity that is already in place that can also meet local needs. Another issue is the increasing demand for electricity. At this point the state does not even have to meet all of its renewable targets to erase demand growth. The OPC report examined the option of retiring the natural gas plants, and concluded that the cost and resources necessary to assure grid reliability depended heavily on the timing of retirement. If retirement is staggered to 2015, and the nuclear plants are assumed to still be on-line, then no new electric generation would be needed, and only some relatively minor transmission upgrades. This represented the low range of cost, as the State Water Board states, "as little as $135 million in modest, low-impact transmission upgrades in the still unlikely event that all but the nuclear plants are retired in 2015." As retirement of the 4,472 MW of in-state nuclear is not likely until the mid-2020s due to long term contracts, this is a viable scenario. Photovoltaics, solar thermal power, and peak demand reduction should be able to allow retirement of all the aging natural gas power plants, allow for population growth, and dramatically reduce other fossil fuel energy. 3,000 MW of new photovoltaic capacity is planned in California by 2017 under the California Solar Initiative, with $3 billion n rebates committed toward this goal. An onsite solar system avoids the energy losses inherent in the transmission and distribution system, which can be 10% or higher on hot summer days. In 2009, RETI projected a range of 22 to 30 cents per kilowatt-hour. Other projections demonstrate that the cost of thin-film solar promises to dramatically change the equation. According to some industry projections, thin film solar may soon cost as low as 11.4 cents per kilowatt hour. Solar thermal generators use mirrors to focus the heat of the sun on to long tubes that carry a heat transfer fluid. The fluid boils water to steam which powers a turbine and generates electricity. Nearly 360 MW of solar thermal plants have operated for 20 years or more in the desert, providing reliable power to the grid. Steam turbines powered by solar thermal technology provide energy during the day. If this system is supplemented with storage or backup fuel supply, then reliability can virtually match that of a natural gas power plant. The CEC estimates that the cost of electricity from solar thermal power plants is about 28 cents per kilowatt-hour for a merchant power plant, and below 20 cents per kilowatt-hour for a publicly owned and financed facility. Several utility companies have committed to buying power from Concentrating Solar Power (CSP) installations with large megawatt capacities by 2014. Reducing peak demand with voluntary curtailments under conditions of stress in the electric system is a valuable and local resource. Like photovoltaic's, it does not require transmission, and the infrastructure blends into existing buildings with minimal footprint. Investor-owned utility companies are required by state regulators to get 5% of their power capacity needs, equivalent to at least 2,000 MW, from demand response programs. In 2002, the CEC projected cost curves for market based demand response resources and found them to be equivalent to operation of combustion peakers. At this point, demand response programs should be decisively cheaper than building a new natural gas plant to serve the same purpose. The CEC has also indicated that demand reduction programs may actually better meet the needs of grid reliability from a technical as well as a policy standpoint.

Response:

Comment noted. Staff recognizes that efficiency programs and renewable energy strategies may be more cost effective than retrofitting or repowering the existing OTC power plants. The policy cannot mandate, but does not preclude this response. Please see the response to Comment 28.03.

Comment 28.11:

Assembling a portfolio of options for replacing the aging plants and avoiding new ones would make the most sense. Because a green energy system includes demand reduction it does not require as much power plant infrastructure. In general, the energy efficiency and peak demand reduction programs are defined to be cost effective resources. In other words, the energy they save is worth more than the cost of the measures. Thus, they do not have a net cost. At worst they are zero net cost or—more typically—a net savings. Utility programs for energy efficiency have been measured and found to have a benefit to cost ratio that is better than one overall, thus verifying the assumption of zero net cost. Also, there is significant potential to improve the performance of the state's efficiency programs. California has allocated a regular budget of about $1 billion annually to achieve its energy efficiency goals. The combined efficiency and demand reduction program targets are 4,500 and 2,000 MWs respectively, for a combined savings of 6,500 MW. Assuming a program shortfall of 25%, results in a savings of 4,875 MW. Because this program is on the demand side it avoids transmission and distribution system losses, which can be 10% or higher on hot summer days when the current aging plants are most called upon. Thus the 4,875 MW of savings is worth about 5,300 MW. This portfolio is approximately equivalent to the load carrying capacity of the aging plants. However, if the state actually implements a requirement to build 33% renewables by 2020 that would create a larger reduction in need for replacement plants than what is proposed here. The efficiency component is effective in lowering the average cost per kilowatt-hour from 27.4 cents to 21.2 cents.

Response:
Comment noted. Staff recognizes that efficiency programs and renewable energy strategies may be more cost effective than retrofitting or repowering the existing OTC power plants. The policy cannot mandate, but does not preclude this response. Please see the response to Comment 28.03.

Comment 28.13:
Significant quantities of green resources can be deployed into the regions where they are needed for grid reliability. Clean energy plans for San Francisco, San Diego and the LA Basin have shown that there is a path to the future other than total reliance on new fossil fuel power plants. Resource decisions are made at the CPUC, and by the utility companies, according to a "least cost" criteria. For example, when energy efficiency measures are evaluated, they are compared to the cost of generating comparable amounts of electricity. If the efficiency measure is less costly, then it will be prioritized. The same is true of contracts for renewable energy. Contracts are signed and power plants are "dispatched" according to the cost ranking. If full and realistic costs are imposed on environmentally destructive practices, like OTC and carbon emissions, then priority will shift toward resources that are less destructive. Thus policymakers do not need to wait passively for an abstract "market" to take the lead on energy decisions, particularly when that market has not internalized the proper costs into its assessments.
Response:
Comment noted. Staff recognizes that efficiency programs and renewable energy strategies may be more cost effective than retrofitting or repowering the existing OTC power plants. The policy cannot mandate, but does not preclude this response. Please see the response to Comment 28.03.

Comment 31.12:
The Draft Policy has been developed without comprehensive consideration of all relevant issues. The Draft Policy relies much too heavily on highly speculative compliance dates based upon a limited number of preliminary electric reliability evaluations and leaves unresolved too many issues related to the possibility of the premature retirement of over 24% of the state's generation capacity. Furthermore, the economic implications of this Draft Policy are tremendous, yet the cost assessments that have been made to date are woefully lacking. Many significant issues have been identified either by the Energy Agencies or Staff in the SED as unresolved, analytically incomplete, or not addressed in the development of the Draft Policy. Much work remains to be done before a final OTC policy is adopted. While it is important to have a full understanding and management plan for dealing with each of the issues note above, it is imperative that the CAISO complete the regional reliability assessments and that work is just now beginning. The Los Angeles region has been identified as being the "most problematic" reliability area due to the current unavailability of sufficient air emission credits needed for new generation development, and difficulties in completing transmission solutions due to greater potential for significant local opposition. While the Draft Policy provides five additional years for compliance in that geographical area, the SED provides no evidence demonstrating that the necessary replacement transmission or generation infrastructure will be in place by 2015, 2020 or even 2025. A further complication is that LADWP does not fall within CAISO's balancing authority area.
Response:
Staff disagrees that the draft Policy and SED are inadequate. Staff has responded to issues and concerns specifically identified in further detail in the commenter's submission. Please see the response to Comment 2.04 regarding how the Policy's implementation schedule was developed based on input from the Energy Agencies. The proposed Policy establishes an adaptive management approach that allows changes to the implementation schedule, if needed

to prevent disruption to the electrical grid reliability. Please see the response to Comment 5.04 in regards to the adaptive management approach.

Staff agrees that it is important that regional reliability assessments be completed and has added new policy language in Section 3.B.(3) specifying that “The CAISO and the LADWP shall each submit to the SACCWIS by December 31, each year a grid reliability study, for their respective jurisdictions, that has been developed pursuant to a public process and approved by their governing bodies. In order to assure that SACCWIS can provide annual reports to the State Water Board by March 31, the SACCWIS shall promptly meet to consider the reliability studies submitted by CAISO and the LADWP.”

The Policy acknowledges that LADWP does not fall within CAISO’s balancing authority area. Staff has added new language clarifying that SACCWIS will consult with the LADWP, as appropriate, when reviewing implementation plans and schedules and proposing recommendations to the State Water Board.

Comment 31.37:
The staff recommends that power plant owners utilizing Track 1 be required to consider the feasibility of using reclaimed water as a makeup water source to wet cooling towers. The staff acknowledges that increasing demand for reclaimed water might impact the availability of such water. The SED does not specify what criteria would be applied to determine if a reclaimed water source was available or feasible. In many power plant locations, a reclaimed water infrastructure is not in place. Where plans for an infrastructure are underway, those plans do not automatically include service to intermittent users, such as power plants operating at low capacity utilization rates. Failure to develop criteria for this evaluation could lead to Regional Water Boards requiring a power plant owner to fund development of a reclaimed water infrastructure or rely on speculative development plans.
Response:
The Policy does not mandate the use of freshwater. Instead, it encourages the use of recycled water for cooling water in lieu of marine, estuarine, or fresh water. The amount of makeup water that would be needed in a closed-cycle wet cooling system would have to be determined by each facility and could not be included SED because the information is not yet available.

Comment 37.05:
The State Water Board should craft an OTC policy that protects electric system reliability. The Policy should explicitly acknowledge that OTC generation capacity cannot be retired until the replacement capacity needed for reliability is operational. Specified grid stability thresholds to be achieved would be determined by the Board and the applicable energy agencies. This alternative would avoid the potentially significant grid reliability issues identified in the ENVIRON Report. As the Joint Energy Agencies acknowledge, Southern California's electrical system poses unique challenges that make OTC policy implementation via investor-owned utility procurement actions extremely difficult. The South Coast Air Quality Management District's Priority Reserve dispute currently prevents the construction of new replacement generation, while at the same time, siting new transmission in the region is likely to run into extraordinary opposition, resulting in long lead times and unpredictable outcomes. These obstacles are separate and distinct from the broader complex exercise of understanding the eventual configuration of the electrical system in light of the state's renewables goals and A.B. 32 implementation. It is not clear to what extent the State Water Board intends to defer to the Energy Agency representatives where reliability concerns are at issue.
Response:

Staff believes that the adaptive management approach specified in the proposed Policy will ensure that grid reliability will not be jeopardized during the implementation period. Please see the responses to Comments 2.04 and 5.04. Staff has added new language recognizing the jurisdiction of the energy agencies over grid reliability in various sections of the Policy, notably Sections 2.B.(2) and 3.B.(5).

Comment 40.02:
We are also encouraged by the thoughtful participation and support for the development of the proposed OTC policy by the CEC, the CPUC, and CAISO. The report by these energy agencies entitled "Implementation of Once-Through-Cooling Mitigation through Energy Infrastructure Planning and Procurement Changes" and accompanying table identifying key infrastructure milestones and compliance dates for existing power plants provides a strong basis for developing a successful implementation plan to support the objectives of the OTC Policy, while ensuring the reliability of the state's electrical system.
Response:
Comment noted.

Comment 47.06:
The three OTC power plants operated by the LADWP are not subject to the CAISO balancing authority. Decisions regarding energy supply and reliability for the LADWP service territory are overseen by the Board of Water and Power Commissioners of the City of Los Angeles. This fact should be acknowledged and made an element of this policy. "Advice" regarding the ability to comply with the Policy Implementation Schedule without impacting energy supply and grid reliability should be issued by the Commission.
Response:
The Policy acknowledges that LADWP does not fall within CAISO's balancing authority area. Staff has added new language clarifying that SACCWIS will consult with the LADWP, as appropriate, when reviewing implementation plans and schedules and proposing recommendations to the State Water Board. Staff has also added new policy language in Section 3.B.(3) specifying that "The CAISO and the LADWP shall each submit to the SACCWIS by December 31, each year a grid reliability study, for their respective jurisdictions, that has been developed pursuant to a public process and approved by their governing bodies. In order to assure that SACCWIS can provide annual reports to the State Water Board by March 31, the SACCWIS shall promptly meet to consider the reliability studies submitted by CAISO and the LADWP." New provisions also allow LADWP to apply for a suspension of a final compliance deadlines, if needed for grid reliability within the LADWP service territory.

Comment 49.07:
The CPUC has authority to order the investor-owned utilities (I0Us) to procure new or repowered fossil-fueled generation for system *and or* local reliability in the Long-Term Procurement Plan (L TPP) proceeding. Comment: In this day and age with AB 32 in effect and guiding the state's mission to reduce emissions that contribute to global warming, this statement focusing on seeking fossil-fueled generation to procure new or repowered energy generation in order meet grid reliability with no mention of renewable energy sources, especially photovoltaic, now recognized as a feasible and desirable alternative to gas-fired power plants, is anachronistic and should be removed, unless reviewed by the ARB, which is supervising implementation of AB 32.
Response:
ARB and State Water Board do not have authority over the CPUC procurement process. The statement " The CPUC has authority to order the investor-owned utilities (IOUs) to procure new or repowered fossil generation for system and/or local reliability in the LTPP proceeding" reflects

the current CPUC process and is not an indication of how the LTPP process will be modified in the future when the 33% RPS is implemented.

Comment 59.03:
SCE supports the board's phased implementation of the revised policy pursuant to the long-term procurement planning process, provided that the revised policy recognizes the jurisdiction of the energy agencies over grid reliability.
Response:
Comment noted. Staff has added new language recognizing the jurisdiction of the energy agencies over grid reliability in various sections of the Policy, notably Sections 2.B.(2) and 3.B.(5).

D. ENVIRONMENTAL CONSIDERATIONS

1. General adequacy of SED

Comment 1.04:
We do not believe that the SED is sufficient to meet the California Environmental Quality Act (CEQA) and urge the Water Board to devote the necessary time to fully analyze the total impacts of the proposed policy to ensure that it is consistent with California law.
Response:
Staff believes that the SED meets the requirements of CEQA and the California Water Code.

Comment 11.01:
The Draft SED fails to meet the requirements of CEQA. The SED does not provide sufficient information regarding environmental impacts to foster informed public participation and to enable the State Water Board to make a reasoned decision on the proposed Policy. The SED fails to acknowledge, discuss and analyze reasonably foreseeable and significant negative environmental impacts that would result from implementation of the proposed Policy. The scope and depth of the analyses are insufficient and does not meet CEQA, CEQA case law precedent, or the State Water Board's own CEQA standards. In short, the SED requires significant revisions to satisfy the statutory requirements of the CEQA lead agency and provide the public and the State Water Board a clear understanding of the environmental impacts and trade-offs associated with the proposed Policy.
Response:
Staff disagrees. Staff believes that the SED meets the requirements of CEQA and the California Water Code. Since staff does not know what measures will be taken by power plant owners to comply with the proposed Policy, it would be pure speculation to try and identify project specific impacts for each facility. As such, this SED is programmatic in nature and meets CEQA requirements.

Comment 11.02:
The SED fails to meet CEQA's minimum requirements by a wide margin. It assumes more than a dozen wet or hybrid cooling towers would be built across the State, but ignores the potential for any significant cumulative impacts. It fails to mention the lack of available PM10 air emission reduction credits, disregards potential negative impacts on the freshwater water resources, minimizes potentially significant visual impacts, lacks any analysis of land use impacts resulting from noise and visual conflicts with local ordinances, and inadequately assesses greenhouse gas impacts, to name a few examples. The SED has a single conclusive statement regarding cumulative impacts: '"Implementation of the proposed Policy will not result in cumulative

impacts." This single sentence does not meet the statutory requirements for a cumulative impacts analysis; the SED needs to be revised to include this analysis. Nor is there any substantial evidence in the SED that would justify adopting a statement of overriding considerations necessary to overcome the negative impacts to air quality, greenhouse gases, visual resources, noise, freshwater resources, etc.

Response:

The compliance alternatives specified in the policy will allow an OTC plant to operate with mitigation actions taken. In addition, CO2 emissions could be reduced by the implementation of non-fossil fuel based power generation. Another option is for power plants to retrofit with dry cooling and use renewable energy sources to compensate for the reduced efficiency of the generating unit.

Statements made by the South Coast Air District (AQMD) permitting manager has lead the State Water Board to believe that SB 827 will temporarily allow the AQMD to issue air permits to facilities that meet SB 827 requirements. SB 827 was passed to give the AQMD time to resolve permitting issues for critical infrastructure.

The Policy states that the State Water Board will encourage the use of reclaimed water when wet cooling towers are proposed therefore reducing fresh water impacts.

The SED adequately identifies potential environmental impacts of the Draft Policy. The SED has also identified measures to reduce potential impacts. Since staff does not know what measures will be taken by power plant owners to comply with the proposed Policy, it would be pure speculation to try and identify project specific impacts for each facility. As such, this SED is programmatic in nature and meets CEQA requirements.

Comment 11.03:

The SED disregards the 2008 TetraTech report to the State Water Board, which recommended case-by-case analyses of the various sites.

Response:

The SED does not disregard TetraTech's recommendation. Rather, a case-by-case analysis will need to be conducted for each facility as they decide how they will comply with the proposed Policy.

Comment 11.06:

The SED fails to identify and evaluate a reasonable range of alternatives that would reduce or avoid environmental impacts of the proposed Policy and still attain most of the basic Policy objectives (e.g., the SED could evaluate installing partial wet (or dry) cooling technology combined with retaining partial OTC). Variations that could be analyzed to find the overall minimum environmental impact include 25, 50 and 75% conversion of current OTC to an alternative cooling technology. In addition, the SED fails to adequately explain why certain alternatives were rejected (with no facts and analysis, and only bare conclusions and opinions). The SED also does not analyze the alternatives in terms of their comparative environmental impacts, and instead focuses on feasibility and ability to attain the Policy's stated goals. The SED must evaluate the comparative merits of the alternatives, including their ability to reduce or avoid environmental impacts while still attaining most of the Policy's objectives.

Response:

The SED identifies thirteen issues related to the Policy and evaluates alternatives for each issue. The SED also evaluates the potential environmental impacts from the reasonable means of compliance identified by the State Water Board (closed-cycle wet cooling). There are multiple means of compliance that power plant operators may choose from. The SED does not need to analyze all of them since it would be speculation on the State Water Boards part as to which methods individual plants might use.

Comment 11.07:
The SED may intend that the "front of pipe" technologies and seasonal operation identified satisfy the reasonably foreseeable alternative means of compliance analysis. However, it not clearly stated in the document. These technologies and operational controls cannot be both reasonably foreseeable methods of compliance and alternative means of compliance, yet they seem to be treated this way by listing them along with other compliance methods.
Response:
Depending on the circumstances for each individual plant, these technologies and seasonal operations could be either foreseeable methods of compliance or alternative means of compliance.

Comment 11.08:
The SED either fails to identify impacts or, in other cases, does not adequately analyze reasonably foreseeable impacts from the proposed Policy (see comments 11.14-11. for details). Therefore, the document lacks the required identification and discussion of mitigation measures to substantially lessen or avoid the otherwise significant adverse environmental impacts of the proposed Policy.
Response:
The SED has identified potential environmental impacts for compliance with the Policy and provided mitigation measures to substantially lessen or avoid those impacts. Since the State Water Board does not know how each power plant will choose to comply with the Policy, there will need to be project-specific environmental reviews for each facility that will identify site specific environmental impacts along with appropriate mitigation.

Comment 11.09:
In addition, there are other reasonably foreseeable alternative means of compliance with the proposed Policy that were not analyzed. For example, the SED ignores use of Substratum Intake System, which would replace a plant's current cooling water intake system with a network of wells drilled horizontally beneath sand beds on the ocean floor.
Response:
The SED need not address all potential means of compliance. If an operator wants to use some other means of compliance like Substratum Intake System, then the potential impacts of that means of compliance will need to be evaluated in a subsequent environmental review.

Comment 11.11:
While CEQA does not require an agency to conduct a project level analysis in analyzing the reasonably foreseeable impacts of a rule or performance standard, in this case a more detailed, site-specific analysis is appropriate. The 19 power plants subject to the proposed Policy are known and can be readily analyzed. The SED could have included more site-specific analyses in its Tier 1 environmental document. The SED is deficient in that it defers more detailed analysis to a later date and therefore fails to identify significant effects of the proposed Policy.
Response:
Public Resources Code Section 21159 requires an environmental analysis of the reasonably foreseeable methods of compliance. As set forth in the SED, the analysis shall take into account “a reasonable range of environmental, economic, and technical factors, population and geographic areas, and specific sites, but does not require the agency to conduct a project-level analysis.” The possibility of a more extensive site-specific analysis does not render insufficient the analysis set forth in the SED. Further, Section 21159 provides that nothing in its provisions

"is intended, or may be used, to delay the adoption of any rule or regulation for which an analysis is required to be performed pursuant to this section."

Comment 11.12:
Environmental Checklist: For several subject areas the SED states that because no impacts were identified, no detailed discussion is included. As indicated in the *City of Arcadia* case, this is an inadequate approach. In addition, because the SED concludes there are no significant impacts in areas where there may in fact be, the checklist contains factual errors that must be corrected.
Response:
In *City of Arcadia v. State Water Board* the court found that "the Trash TMDL" sets forth various compliance methods, the general impacts of which are reasonably foreseeable but not discussed." The SED has discussed the reasonably foreseeable impacts identified in the Environmental Checklist.

Comment 12.06:
The SED fails to adequately analyze the reasonably foreseeable impacts from the proposed Policy, including but not limited to green house gas and other air emissions, use of fresh water supplies for make-up water, lack of reclaimed water infrastructure, available air credits, and visual and aesthetic impacts of large cooling towers.
Response:
Staff believes that the SED meets the requirements of CEQA and the California Water Code. See responses to Comments 11.02 and 11.08. Since staff does not know what measures will be taken by power plant owners to comply with the proposed Policy, it would be pure speculation to try and identify project specific impacts for each facility. As such, this SED is programmatic in nature and meets CEQA requirements.

Comment 12.07:
The SED does not consider a reasonable range of alternative policy options that could feasibly be implemented under Section 316(b).
Response:
See the response to Comment 11.06.

Comment 20.09:
There is a section titled 'Cumulative and Long-Term Impacts'. However, no cumulative or long-term impacts are even identified. It is unclear how a policy that would affect the state's power supply and distribution for the foreseeable future could not result in any cumulative or long-term impacts.
Response:
Staff does not believe there will be any cumulative or long term impacts, as defined by CEQA, from this programmatic level review of impacts. Power plant operators will need to modify their coastal plants, but given the compliance schedule these modifications would be conducted in concert with other overall improvements to our energy grid.

Comment 29.11:
In general, the SED's analysis of potential adverse environmental effects associated with implementation of the policy is quite cursory. The analysis glosses over many areas of concern and does not provide sufficient detail to adequately address the impacts from implementation.
Response:
Staff believes that the SED meets the requirements of CEQA and the California Water Code. See responses to Comments 11.02, 11.06 and 11.08. Staff disagrees. Staff believes that the

SED meets the requirements of CEQA and the California Water Code. Since staff does not know what measures will be taken by power plant owners to comply with the proposed Policy, it would be pure speculation to try and identify project specific impacts for each facility. As such, this SED is programmatic in nature and meets CEQA requirements.

Comment 31.15:
We believe that the SED fails to meet CEQA requirements in several respects. Specifically, the SED fails to analyze an appropriate range of alternatives to the proposed Draft Policy, fails to provide a reasoned explanation for why certain alternatives were rejected, and fails to adequately analyze the reasonably foreseeable environmental impacts of the proposed Draft Policy. The SED omits material that the State Water Board needs to make intelligent decisions and that the public needs to effectively participate in this process.
Response:
Staff believes that the SED meets the requirements of CEQA and the California Water Code. Please see the responses to Comments 11.02, 11.06 and 11.08.

Comment 31.16:
The SED identified several "alternative technologies" and operational controls, but failed to identify or analyze any of the reasonably foreseeable environmental impacts associated with those technologies and controls. The construction of these pollution controls would have at least some environmental impacts that are reasonably foreseeable, just by virtue of the fact that they require installation.
Response:
Staff believes that the SED meets the requirements of CEQA and the California Water Code. Please see the responses to Comments 11.02, 11.06 and 11.08. Since staff does not know what measures will be taken by power plant owners to comply with the proposed Policy, it would be pure speculation to try and identify project specific impacts for each facility. As such, this SED is programmatic in nature and meets CEQA requirements.

Comment 31.17:
The SED failed to identify any cumulative impacts, or explain whether any impacts were considered but rejected as not cumulative. The SED contains a single conclusory statement regarding cumulative impacts: "Implementation of the proposed Policy will not result in cumulative impacts." Yet the proposed Draft Policy would compel the installation of large cooling towers up and down the California coast and likely force the shut-down of several existing plants, leading to massive investment in transmission and replacement generation infrastructure. These reasonably foreseeable consequences of the proposed Policy would likely have incremental impacts that, when added to other closely related projects, will undeniably cause cumulative impacts in areas such as air quality, aesthetics, socioeconomic consequences and greenhouses gases.
Response:
Staff believes that the SED meets the requirements of CEQA and the California Water Code. Please see the responses to Comments 20.09. Since staff does not know what measures will be taken by power plant owners to comply with the proposed Policy, it would be pure speculation to try and identify project specific impacts for each facility. As such, this SED is programmatic in nature and meets CEQA requirements.

Comment 31.18:
The SED failed to identify or analyze reasonably foreseeable environmental impacts of retrofitting existing OTC units with closed-cycle wet cooling. For example, the SED failed to reasonably analyze the greenhouse gas and other air emissions and the use of fresh water

supplies for make-up water that will result from the implementation of the proposed Draft Policy, and the lack of reclaimed water infrastructure to serve-these projects. The SED does not disclose or assess the availability of air credits, or the visual and aesthetic impacts of large cooling towers. The SED also does not fully consider the practical difficulty and feasibility, the regulatory hurdles, or the economic impacts of constructing replacement transmission and generation necessary to offset the loss of the affected facilities.

Response:

Staff believes that the SED meets the requirements of CEQA and the California Water Code. Please see the responses to Comments 11.02, 11.06 and 11.08.

Comment 31.19:

CEQA requires an environmental analysis to consider a reasonable range of environmental, economic, and technical factors, population and geographic areas, and specific sites. In this case, however, the reasonably foreseeable potential environmental impacts of implementation of the proposed Draft Policy are not speculative or unknown. The proposed Policy would specifically target 19 identified facilities, contains strict implementation standards, few alternative compliance methods, and a rigorous schedule for compliance for each facility. Under these circumstances, CEQA requires a much more detailed, site-specific environmental analysis. Even as a programmatic document, the SED must take into account a reasonable range of site-specific factors. A first tier environmental document must not defer all analysis of reasonably foreseeable environmental impacts.

Response:

Staff believes that the SED meets the requirements of CEQA and the California Water Code. Please see the responses to Comments 11.01, 11.02, 11.06 and 11.08. Since staff does not know what measures will be taken by power plant owners to comply with the proposed Policy, it would be pure speculation to try and identify project specific impacts for each facility. As such, this SED is programmatic in nature and meets CEQA requirements.

Comment 31.20:

The SED does not consider a reasonable range of alternative policy options that could feasibly be implemented under Section 316(b) consistent with the Policy's goals. CEQA requires that agencies refrain from approving projects with significant environmental effects, if there are feasible alternatives or mitigation measures that can substantially lessen or avoid those effects. The discussion of alternatives in an environmental document prepared pursuant to CEQA should evaluate the comparative merits of the alternatives and foster informed decision-making and meaningful public participation. The alternatives analysis should contain facts and analysis, not just the agency's bare conclusions or opinions. An environmental document must state the objectives sought to be achieved. The range of potential alternatives to the proposed project "shall include those that could feasibly accomplish most of the basic objectives of the project and could avoid or substantially lessen one or more of the significant effects." The SED lists the goals of the Policy, which include: reducing impingement and entrainment, establishing technology-based performance standards that will implement CWA §Section 316(b), provide clear standards and guidance to permit writers, coordinate implementation at the state level to address cross-jurisdictional concerns, and reduce the resource burden on the Regional Water Boards. Not included is the goal that was stated orally by State Water Board staff at the September 16, 2009 hearing to force the shut-down of most OTC plants affected by the proposed Policy. Since this goal is neither a legitimate objective of Section 316(b) and was not included in the SED, it cannot be a basis for rejecting an alternative in the SED's analysis. The SED failed to include a reasonable range of potentially feasible alternatives that achieve legitimate objectives of the Policy. For example, the SED did not consider whether to provide consistent state-wide guidance to the Regional Water Boards on the use of BPJ either in analyzing alternatives to a state-wide performance standard or in alternatives to the wholly disproportionate standard. This is a logical alternative to include because it would actually reduce Regional Water Board workload, implement Section 316(b), and provide more flexibility to address cross-jurisdictional concerns and environmental impacts associated with forcing shut-down of the plants while still reducing impingement and entrainment. The SED also did not consider using the "significantly greater" test adopted by the USEPA in its Phase II Rules and upheld by the U.S. Supreme Court in the *Entergy* case. Rather, the SED analyzes a narrower version of the "wholly disproportionate" standard alone, which applies to only a few facilities based on heat rate criteria that has no basis in the objectives of Section 316(b). The SED provides no justification for rejecting EPA's long-standing interpretation of reasonable standards under Section 316(b).

Response:

Staff believes that the SED meets the requirements of CEQA and the California Water Code. Please see the responses to Comments 11.01, 11.02, 11.06 and 11.08. Since staff does not know what measures will be taken by power plant owners to comply with the proposed Policy, it would be pure speculation to try and identify project specific impacts for each facility. As such, this SED is programmatic in nature and meets CEQA requirements. The stated clear goal of the Policy is to implement Section 316(b); not to eliminate OTC or force the shutdown of OTC facilities. While individual facilities may choose to shut down, the Policy in no way forces them to do so. Staff is proposing to eliminate the WDD from the Policy (see the section of this document discussing the WDD)

Comment 31.21:

The SED failed to provide a reasoned explanation for why certain alternatives were rejected, and failed to provide a discussion based on facts and analysis rather than bare conclusions. For example, the SED rejected the alternative requirement, for low capacity units based on the incorrect assumption that all such plants have a greater environmental impact just because it is possible that they could be operated in certain ways. The SED contained no supporting facts or analysis of how these facilities actually operate. The SED also does not fully consider the importance of low capacity factor units to grid reliability and achievement of California's renewable portfolio targets. In another example, the SED rejects the alternative that would allow all plants to make the WDD, incorrectly assuming it would increase Regional Water Board workload without analysis of its other comparative merits.

Response:

Staff believes that the SED meets the requirements of CEQA and the California Water Code. Please see the responses to Comments 11.01, 11.02, 11.06 and 11.08. Staff is proposing to eliminate the WDD from the Policy (see the section of this document discussing the WDD)

Comment 31.46:

The SED claims that it is not possible or feasible to evaluate each facility's ability to comply with the performance standards, yet this is precisely what the Tetra Tech Study attempts. This study finds cooling towers infeasible at Ormond Beach and two other sites. It comes up with cost per MWh of compliance for almost all of the other facilities.

Response:

Please see the response to Comment 4.06. Staff believes that the SED meets the requirements of CEQA and the California Water Code. Since staff does not know what measures will be taken by power plant owners to comply with the proposed Policy, it would be pure speculation to try and identify project specific impacts for each facility. As such, this SED is programmatic in nature and meets CEQA requirements.

Comment 31.55:

After merely stating the definition of cumulative impacts and describing the purpose of assessing cumulative impacts, the SED concludes that the Policy "will not result in cumulative impacts". This conclusion is totally unsupported and does not include whether any impacts were considered but rejected as not cumulative. In locations where power plant facilities are in close proximity to each other, there are likely to be cumulative environmental impacts. These could include aesthetic, water use and local grid reliability impacts. There is no basis for the SED to conclude that there will be no cumulative impacts as a result of the Policy. While cumulative impacts will be considered in later site-specific environmental analysis, the SED must not defer all analysis of the Policy's cumulative impacts to future project-level reviews.

Response:

Please see the response to Comment 20.09.

Comment 37.25:

The SED does not adequately establish the baseline setting, which is limited to discussing the effects of impingement and entrainment from OTC plants and a short section on existing air quality emissions from OTC plants. No other environmental setting information is provided for any other environmental issue area. The baseline setting also does not consider the existing and required restoration measures at SONGS to mitigate impingement and entrainment impacts. No data are provided on GHG emissions from the energy sector or the state as a whole.

Response:

Comment noted. Staff believes that the SED meets the requirements of CEQA and the California Water Code. Please see the responses to Comments 11.01, 11.02, 11.06 and 11.08.

Comment 37.26:

The SED's one-sentence conclusory assessment of cumulative impact does not comply with the law. An environmental document prepared under a certified regulatory program must include a detailed and informative cumulative impacts analysis. The SED lacks even a minimum degree of specificity or detail and is devoid of any reasoned analysis, which makes it impossible for the public to participate fully in the assessment of the Policy's cumulative impacts.

Response:

Please see the response to Comment 20.09.

Comment 37.06:

The State Water Board should revise and re-circulate the SED to address CEQA requirements, including preparing a complete alternatives analysis, cumulative impacts analysis, and evaluation of the myriad significant environmental impacts identified in this comment letter and a technical review prepared by ENVIRON. The SED falls short of statutory and regulatory requirements for a CEQA document, even one prepared under a certified regulatory program. The document's defects are systemic, precluding meaningful review by the public and decision makers, and amounts to an abuse of discretion. Under an appropriate environmental review the SED likely would have concluded that the Policy would result in significant environmental impacts (the SED does not identify any significant impacts). To address these significant impacts, the SED must analyze and incorporate any feasible mitigation measure or alternative that would minimize them. If the SED cannot reduce the impact to less-than-significant levels, a Statement of Overriding Considerations must be adopted.

Response:

Staff believes that the SED meets the requirements of CEQA and the California Water Code. Please see the responses to Comments 11.01, 11.02, 11.06 and 11.08.

Comment 37.16:

The SED does not provide a meaningful analysis of the mandated "no project" alternative. In a directly analogous case, the California Supreme Court held that an agency's failure to include a "meaningful consideration of the 'no project' alternative" amounted to a prejudicial abuse of discretion for not "proceed[ing] in accordance with procedures mandated by law." In *Mountain Lion Found. v. Fish and Game Comm 'n, 16 Cal. 4th 105, 137 (1997).* The "no project" alternative is particularly appropriate for the SED because the Board is under no compunction to develop and promulgate a policy pursuant to CW A Section 316(b), which has existed for more than 30 years.

Response:

Staff believes that the SED meets the requirements of CEQA and the California Water Code. Please see the responses to Comments 11.01, 11.02, 11.06 and 11.08.

Comment 37.30:

The Board did not satisfy its obligations under Public Resources Code Section 21159 to analyze reasonably foreseeable methods of compliance, according to the ENVIRON report. For example, the SED does not appear to account for the potential impact on existing power plant infrastructure from the increase in corrosiveness and the potential increase in fouling of the condensers due to the use of salt water in closed-cycle wet cooling towers, which can result in off-cycle or unplanned shutdowns of a power generating unit which could lead to meaningful environmental impacts due to the need for alternative power generation during shutdowns. In addition to these shortcomings, there does not appear to be detailed analysis of the impacts associated with the methods of compliance. Nor are any mitigation measures or alternatives analyzed to address the impacts associated with the reasonable means of compliance. Thus, until these defects are addressed, the State Water Board likely will not have complied with Section 21159.

Response:

Staff believes that the SED meets the requirements of CEQA and the California Water Code. Please see the responses to Comments 11.01, 11.02, 11.06 and 11.08.

Comment 61.16:

SED, pg. 33, Sec. 2.3.1: Cumulative Impacts: The first paragraph in this section seems to confuse the issue of cumulative impacts. The first sentence defines it in the context of multiple power plants withdrawing from the same water body, while the second presents the more conventional definition of impacts due to multiple stressors. One of the concerns with multiple stressors is synergistic effects that might result from the interaction of multiple toxicants. This does not apply to impingement and entrainment where the effects of multiple power plants would be strictly additive. The study by MBC and Tenera cited in this section demonstrates the low potential for impacts due to OTC. The estimate cited in the draft policy is misleading since this was the maximum estimated entrainment mortality provided in the report which would only occur for species with larvae that were susceptible to entrainment for a period of 40 days. Even the maximum reported estimate of 1.4 percent demonstrates the low potential for adverse environmental impacts since it is hard to conceive of a situation where this level of additional mortality would pose any risk to a population. The estimated mortality decreases proportionally with shorter larval durations that are more representative of the estimates from the studies conducted in southern California. The estimates were recalculated using the average annual flows at the plant resulting in a
maximum mortality rate of less than one percent.

Response:

Please see the response to Comments 20.09 and 20.06.

Comment 61.27:

SED, pg. 107, sec 4.12: As noted, the potential for Cumulative and Long-Term Impacts of the policy could be significant and definitely should be discussed.
Response:
Please see the response to Comments 20.09 and 20.06.

2. Air Impacts

Comment 1.07:
The AES-SL units are exempt from ERC requirements, including those for PM-10, under SCAQMD Rule 1304(a)(2) for repowering units such as ours with new advanced gas turbine peaking and combined cycle technologies. However, in order to make use of this exemption, the development of the new generating unit must be contemporaneous with the retirement of the existing OTC unit. If the Policy resulted in the untimely retirement or an OTC unit such that AES-SL became ineligible to use the exemption for that unit, then ERCs would need to be procured from the market in order to eventually complete the replacement. Even if you assume it would be possible to procure ERCs from the market, which is not feasible today, such a requirement would unnecessarily add millions of dollars to the cost of developing the new unit and those costs would need to be passed on to ratepayers. Additionally, it would put additional pressure on the ERC market for all subsequent permit seekers resulting in higher costs that would also be ultimately borne by the ratepayers. Given the current difficulties in Southern California with respect to ERCs, it is important to all stakeholders that eligible OTC asset owners maximize the use of the exemption provided by Rule 1304(0)(2)
Response:
The compliance alternatives specified in the policy are designed to prevent untimely retirement of OTC units. In addition, statements made by the South Coast Air District (AQMD) permitting manager has lead the State Water Board to believe that SB 827 will temporarily allow the AQMD to issue air permits to facilities that meet SB 827 requirements. SB 827 was passed to give the AQMD time to resolve permitting issues for critical infrastructure. Issues affecting compliance dates contained within the Policy will be coordinated through SACWISS.

Comment 4.03:
Closed-cycle cooling creates significant negative environmental impacts, which were not properly evaluated in the draft SED as required by State Water Board regulations and state law. Policymakers should understand that closed-cycle cooling does have significant adverse environmental impacts and very significant costs, including a greater energy consumption and an increase in greenhouse gas (GHG) emissions and smog-forming and particulate (PM10 and PM2.5) emissions, which have significant negative human health impacts. The state's two nuclear plants play a critical role in meeting California's GHG emission reduction goals. Requiring a transition to closed-cycle cooling at these plants would mean the emission of large amounts of pollutants from replacement power during the time required (approximately 2 years) to retrofit the nuclear plants. Additionally, the lowered efficiency of the nuclear plants and all other plants after transitioning to closed-cycle cooling will result in increased emissions to replace the lost generation capacity.
Response:
The SED acknowledges that closed-cycle cooling may have a significant adverse effect on the environment. However, the SED also identifies available technology to mitigate these potential impacts. Since the State Water Board staff does not know what measures individual facilities will take to comply with the Policy, they cannot specifically identify potential impacts from each individual retrofit. As such, the SED is a programmatic document and each retrofit or re-powering project will need to comply with CEQA individually. Staff is also concerned about air quality and climate change. The SED therefore included a range of compliance scenarios with

estimated changes in air pollutants and carbon dioxide emissions. While the worst case scenario would increase CO_2 from coastal power plants by 14%, the best case scenario (re-powering fossil fuel plants and retrofitting nuclear plants) would decrease CO_2 emissions by 14%. Staff did make a qualitative determination of “less than significant impact” in the environmental checklist for air quality and greenhouse gasses, because we believe that final compliance by the fleet of coastal power plants will likely fall much closer to scenario 3, since there are other pressures on plant operators to upgrade their facilities (e.g., age of plants and the State’s GHG reduction efforts pursuant to AB 32). Staff does not believe that the state’s nuclear plants will shut down for two years during construction of retrofit facilities. Rather power production would continue during construction and the facility would only shut down during the time needed to tie into the new cooling system.

Comment 11.14:
The air quality impact analysis of reasonably foreseeable increases in criteria pollutant and air toxics emission was inadequate because Staff did not assume the maximum air quality impacts, did not adequately analyze PM10 and PM2.5 impacts, and ignored increases in toxic pollutants. Wet cooling towers will significantly increase PM10 and PM2.5 emissions in those areas where particulate air quality is already unhealthy and in nonattainment with State standards. Staff did not identify or analyze the significant adverse air quality impacts from additional criteria pollutant emissions, especially PM10. The required analysis must include not only an estimate of the increase in air toxics emissions, but also a health risk assessment associated with that increase to inform the public and the State Water Board about the incremental increase in health impacts from the change in cooling technology, as well as the total health impacts of each power plant. Deferring this discussion and its public disclosure to project-specific environmental reviews are unlawful.
Response:
Health risks for air quality are performed on a case-by-case basis by the local Air Quality Management District (AQMD). Some of the items they take into consideration include the type of equipment to be installed by the permit applicant. However, the power generator must specify how they will comply with the policy before the AQMD can evaluate the health risk. In addition, the energy penalty for retrofitting OTC plants can be made up by renewable generation or efficiencies gained at other power plants or facilities.

The SED identified the potential air quality impacts associated with wet cooling towers, and potential mitigation that could be used to reduce identified impacts to less than significant levels. As such, the site-specific analysis described by the commenter cannot be conducted until each power plant determines how they will comply with the Policy. Once the methods of compliance are determined, then tier two environmental review can cover the project-specific air quality impacts.

Comment 11.15:
The SED contains a preliminary evaluation of the resulting increase in criteria pollutant emissions from the energy penalty of retrofitting OTC plants to less efficient wet-cooling towers, with estimates ranges from an 18% increase in emissions to a 26% decrease in emissions, depending on the criteria pollutant. However, the SED states, “Staff cannot accurately assess air quality impacts related to criteria pollutants because it is difficult to estimate the method of compliance for each facility." Despite this admitted inability to accurately assess air quality impacts, the Environmental Checklist concludes, without any supporting scientific evidence, that there would be no significant air quality impacts. CEQA requires full disclosure of the reasonably foreseeable adverse impacts, and the SED must be revised to disclose the potential increase in

emissions of both criteria pollutants and air toxics from the increased fossil fuel combustion to compensate for the energy penalty and discuss possible mitigation measures.

Response:

Health risks for air quality are performed on a case-by-case basis by the local Air Quality Management District (AQMD). Some of the items they take into consideration include the type of equipment to be installed by the permit applicant. However, the power generator must specify how they will comply with the policy before the AQMD can evaluate the health risk. In addition, the energy penalty for retrofitting OTC plants can be made up by renewable generation or efficiencies gained at other power plants or facilities.

The SED identified the potential air quality impacts associated with wet cooling towers, and potential mitigation that could be used to reduce identified impacts to less than significant levels. As such, the site-specific analysis described by the commenter cannot be conducted until each power plant determines how they will comply with the Policy. Once the methods of compliance are determined, then tier two environmental review can cover the project-specific air quality impacts.

Comment 11.16:

The SED is silent on the emissions of PM2.5, despite the fact that approximately 13% of the PM emitted by closed-cycle wet cooling towers is in the PM2.5 size range, and four of the seven coastal districts containing the OTC plants are designated nonattainment areas for PM2.5. To meet CEQA's minimum requirements, the following reasonably foreseeable PM2.5 impacts must be identified and analyzed: (1) Potential PM2.5 emissions from the alternative cooling technologies; (2) Applicability of New Source Review to the estimated PM2.5 emissions; (3) BACT analysis if the PM2.5 emissions exceed applicability thresholds; and (4) Future requirements to offset the PM2.5 emissions with reductions of PM2.5 or PM2.5 precursor (i.e., NOx, SOx, or VOC) emissions from other sources through the creation of ERCs, using yet-to-be-determined interpollutant offset trading ratios between PM2.5 precursors and directly emitted PM2.5. By ignoring these impacts, Staff does not meet CEQA requirements to accurately identify the impacts of the implementation of the proposed Policy.

Response:

Staff agrees that the PM 2.5 standard may pose compliance challenges for power plants that retrofit with wet cooling. Therefore, the OTC policy allows OTC power plants to comply by following alternate compliance tracks.

Comment 11.17:

The SED estimates the amount of PM 10 that would be produced by wet cooling towers at only 13 of the 19 coastal power plants, excluding six plants without explanation. After a cursory analysis that does not include discussion of the availability of PM10 ERCs or possible exemptions from offsetting, Staff notes that five of the facilities evaluated may trigger federal NSR requirements due to increased PM10 emissions. This analysis may need to be revised because not all local air districts have accepted the alternative method for calculating cooling tower PM10 emissions.

Response:

Some of the OTC power plants have made changes to their water throughput that will help them comply with the proposed policy. Furthermore, if a power plant’s PM10 emission from wet cooling triggers NSR, the plant operator has the option of pursuing dry cooling, Track 1, or Track 2.

Comment 11.18:

An OTC power plant would not be able to build or operate a wet cooling tower without first obtaining sufficient local PM10 ERCs. In many districts, PM10 ERCs are not realistically available. For example, at Moss Landing, the quantity of PM10 ERCs required to offset the additional emissions associated with wet cooling for just Units 1 and 2 far exceeds the total inventory of all PM10 ERCs in the Monterey Bay Unified Air Pollution Control District. Wet cooling towers at Moss Landing would increase PM10 emissions by 466 tons per year, qualifying as a federal major modification subject to NSR offset requirement. This emission increase is over five times the amount of PM10 emissions currently produced by the Moss Landing power plant. The total credits perhaps available for purchase by Moss Landing is only 49 tons. Wet cooling towers at Morro Bay are likewise infeasible due to insufficient local PM10 ERCs.

Response:

The compliance alternatives specified in the policy will allow an OTC to operate with mitigation actions taken. In addition, the power plants could retrofit with dry cooling and low CO_2 emitting renewables could be used to compensate for the reduced efficiency of the dry cooled generating unit.

Comment 11.19:

The SED does not fully evaluate the ramifications of the New Source Review requirement. To the extent that certain cooling alternatives would not satisfy federal Best Available Control Technology ("BACT") requirements at a certain site, those alternatives must be rejected as infeasible.

Response:

NSR and BACT for air quality are performed on a case-by-case basis by the local Air Quality Management District (AQMD). Some of the items they take into consideration include the types of equipment installed by the permit applicant. However, the power providers must specify how they will comply with the policy before the AQMD can complete an accurate NSR and BACT analysis.

Comment 11.20:

The SED text that precedes the first four air quality-related questions in the Environmental Checklist does not provide adequate support for the conclusions marked “No Impact" or "Less Than Significant Impact." Under “Conflict with or obstruct implementation of the applicable air quality plan?”, the burden is on the State Water Board to demonstrate that applicable local air quality plans account for the increase in PM10 emissions that would result from implementation of the proposed Policy. Under “Violate any air quality standard or contribute substantially to an existing or projected air quality violation?, air dispersion modeling of the new emissions is required, adding the maximum ground-level concentrations to background levels, and comparison with ambient air quality standards. Comparison of the maximum project concentrations against Significant Impact Levels is also required to determine if a significant air quality impact is produced.

Response:

Air quality plans evaluate the emissions for an entire region on a specified interval. During an interval, air pollution sources move in and out of the region without any adjustments being made to the plan. Near the end of the interval, the plans are changed to reflect changes in the basin sources. Therefore, the plans are not modified on a case-by-case basis only on a regional basis.

Comment 11.21:

USEPA's recent proposal of Significant Impact Levels for PM2.5 at levels as low as 1.2 µg/m3 on a 24-hour average basis could also present a siting constraint impossible for wet cooling towers to meet.

Response:

Staff believes that the PM 2.5 emissions from wet cooling tower will not significantly impact any air quality basin's PM attainment status. In addition, the power plant could be retrofitted with dry cooling and low CO2 emitting renewables could be used to compensate for the reduced efficiency of the generating unit.

Comment 11.22:

The SED completely disregards the reasonably foreseeable increase in methane. Methane is another GHG generated by combustion of natural gas and other fossil fuels, whose contribution to total carbon dioxide-equivalent GHG emissions is approximately four times that of nitrous oxide emissions. Implementation of the Policy may result in a net increase in the amount of methane emissions from the OTC facilities as a result of increased combustion of natural gas to make up for the electric energy output lost to run the alternative cooling equipment.

Response:

Staff believes that some of the older OTC plants will repower with combined cycle power plants resulting in less than significant increase in GHG emissions. Please see the response to Comment 4.03.

Comment 11.23:

Based on the scenarios in the Air Quality section, Staff indicates that GHG emissions will increase between zero and five percent (net), and concludes this will be a less-than-significant impact. This conclusion is unsupported and does not follow CEQA guidelines. CEQA requires analysis of the potentially highest impacts, not the average. Hence, the GHG impact analysis should be based on the 14% increase in carbon dioxide emissions, 18% increase in nitrous oxide emissions, and yet-to-be calculated increase in methane emissions.

Response:

The SED identifies the potential for a significant impact from GHG emissions, but finds that there will be a less-than-significant impact. This determination is not based on an average value, but rather on what is expected to occur as the power plants come into compliance. (See also responses to Comments 4.09 and 11.22 above)

Comment 11.24:

The SED needs to address whether the potential increase of GHG emissions from the cooling alternatives would be cumulatively considerable, and hence require a CEQA analysis for each project. The Draft CEQA Guidelines indicate that a finding of less than significant needs to be based on showing that the proposed project is consistent with identified State plans and programs adopted to implement the GHG emission reduction goals of the California Global Warming Solutions Act of 2006 (AB32), or that the proposed project is a critical component of reducing the state's overall GHG emissions in the electrical sector. The latter basis will be difficult to establish if the alternative cooling technologies increase GHG emissions to generate the same net electrical energy. The assessment of the increase in GHG emissions must also be performed on a system-wide basis, and not just a project-specific basis. As discussed in the CEC guidance for the evaluation of GHG emissions from proposed new power generating facilities, changes at individual power generating facilities cannot be evaluated in isolation because of the inherent linkages within California's electric system. The DSED fails to undertake the GHG analysis required by CEQA and should be revised to evaluate the total increase in electrical energy that will be needed to replace that loss as a result of eliminating OTC; determine the most likely marginal generating resources that will be used to provide this incremental energy; and assess the increases in GHG emissions associated with those generating resources.

Response:

The estimated stack emissions for the three scenarios identified in the SED (Tables 23, 24, and 25) are cumulative across the fleet of OTC. The SED finds that there will be a less-than-significant impact from GHG emissions. This finding also includes cumulative effects. Please also see the response to Comment 20.09.

Comment 11.25:

There are several new technologies in development that would utilize the seawater from a plant's cooling system to reduce the power plant's GHG emissions and could potentially reduce GHG emissions from other sources as well. Should the use of seawater for cooling purposes become infeasible upon implementation of the proposed Policy, this potential means of GHG reductions would be lost, thereby exacerbating the GHG impact of the proposed Policy.

A potential sequestration opportunity currently being pursued at a pilot plant level at Moss Landing Power Plant involves processing power plant emissions using the calcium and magnesium in seawater to make cement. Calera Cement's demonstration facility, which should be in operation in 2010, would create cement from the carbon dioxide contained in 10 MW worth of exhaust diverted from Moss Landing Unit 2. Not only would more than 90% of the carbon dioxide be captured from Unit 2's exhaust, but each ton of cement created would ultimately displace one ton of cement created the traditional way, which uses large kilns and is one of the larger sources of industrial GHG emissions. A second proposed project at Moss Landing would use an Accelerated Weathering of Limestone process whereby carbon dioxide gas is converted into compounds that can be disposed in the ocean. The process involves reacting carbon dioxide from the power plant with water and calcium carbonate from crushed limestone. A DOE grant has been applied for to fund the design of a pilot plant utilizing this technology at Moss Landing. While both of these technologies are as yet commercially unproven, they each hold promise for cost-effective carbon capture and storage.

Response:

Staff believes the proposed OTC policy would not prohibit the use of seawater to make cement or prohibit the use of seawater in other CO_2 sequestration processes. Furthermore, the Policy would not preclude the use of sea water for the pilot studies on GHG reductions.

Comment 16.04:

Water vapor is much more effective GHG than CO2. How much global warming will be caused by the millions of tons of water vapor delivered to the atmosphere by cooling towers?

Response:

The amount of global warming that is caused by water vapor from power plant cooling tower is unknown. This is due to lack of accurate global water vapor measurements. It is very likely that some of the water vapor will condense into clouds and reflect some of the incoming solar radiation water vapor possibly causing global cooling. Staff believes that the water vapor emission rate from wet cooling towers installed at OTC power plants will make an insignificant contribution to global warming.

Comment 20.08:

Staff does not indicate what their significance criteria are in the SED or how they arrived at findings of significance. The policy could result in a 14% increase in CO2 emissions, and an 18% increase in NO2 emissions. However, “staff expects the actual net increase in greenhouse gas emissions will fall somewhere in between these extremes (0-5 percent increase).” Greenhouse gas levels have been linked to climate change, resulting in gradually increasing sea and air temperatures globally, glacial melting, sea level rise, and poleward shifts in population distributions. Increases in aerial CO2 levels are leading to increased ocean acidification, which has been linked to reduced calcification in primary producers, such as pteropods. Such effects will ultimately manifest themselves in the upper trophic levels. McGowan et al. (2003) reported on reduced zooplankton size, which may partially be the root cause of many of these upper trophic level declines. With the growing body of knowledge regarding climate change, the effects of greenhouse gas emissions, and long-term trends in marine resources, it is unclear how a policy that will increase such emissions can be seriously considered without a more rigorous effort to estimate potential impacts from various compliance strategies. It is difficult to fathom how implementation of the proposed policy could not result in any significant effects, particularly with respect to air quality. The findings of no significance for water quality are also questionable, particularly since the significance criteria are never spelled out.

Response:

Staff never applied any statistical significance criteria in the SED with regard to potential increases in air emissions. The only quantitative significance criteria presented for net emissions increases are those required by USEPA under the Clean Air Act for the New Source Performance Standards and the New Source Review. Staff is also concerned about air quality and climate change. The SED therefore included a range of compliance scenarios with estimated changes in air pollutants and carbon dioxide emissions. While the worst case scenario would increase CO2 from coastal power plants by 14%, the best case scenario (re-powering fossil fuel plants and retrofitting nuclear plants) would decrease CO2 emissions by 14%. Staff did make a qualitative determination of “less than significant impact” in the environmental checklist for air quality and greenhouse gasses, because we believe that final compliance by the fleet of coastal power plants will likely fall much closer to scenario 3, since there are other pressures on plant operators to upgrade their facilities (e.g., age of plants and the State’s GHG reduction efforts pursuant to AB 32).

Comment 28.04:

Natural gas power plants cause other damages and costs that go uncounted besides those to marine ecosystems. These include public health impacts due to emissions of nitrogen oxide and particulate matter, and the cost of climate change from carbon dioxide and other emissions. Unfortunately, most damage to human health, water resources, air quality and the global climate are not folded into the price that utility companies pay for electricity. However, the costs to human health and the environment are real, and consumers pay for them. Air pollution causes lost days of work, increases the cost of health care, adds to wear and tear on buildings, and causes billions of dollars in damage to crops every year. Destruction of ocean life may reduce commercial opportunities and increase the cost of seafood. Much of the damage is unquantified, or defies measurement. For example, it is difficult to estimate the burdens future generations will bear for climate change, or for the lack resources that have been wasted. Some of the damages caused by fossil fuel plants can loop back to increased utility bills as well. For example, climate change can lower snowpack, and this in turn reduces hydropower. To counter this risk, utility companies pay many millions of dollars for natural gas generators to be on call to provide backup power in years when hydro resources fall short. Rising temperatures also increase use of air conditioning on ever hotter summer days, which calls for increased use of natural gas to meet peak energy demand. Although new natural gas plants are preferable to the current aging plants from an environmental standpoint, pollution from the new plants would cause hundreds of millions of dollars in damages per year. The majority of this cost comes from carbon dioxide emissions, which California must curb if it is to reach the climate protection goals of AB32.

Response:

Staff supports the efficient use of natural resources and believes that the goals of the State Water Board policy and AB 32 can both be met without a significant impact to the consumer or the environment.

Staff recognizes the inherent trade off that comes with reduction of water use impacts. Certainly as is noted by the commenter "…new natural gas plants are preferable to the current aging plants from an environmental standpoint…" and they will still cause damage. Economic considerations will probably lead to fewer but more efficient natural gas plants.

Comment 28.02:
The adoption and implementation of the OTC policy provides California with an opportunity not only to help restore the state's marine ecosystems, but also to help meet the state's renewable and greenhouse gas reduction goals. In 2009, CEC rejected a proposed Chula Vista natural gas-fired gas turbine power plant partly because they found that solar photovoltaics (PV) could potentially achieve the same objectives for comparable cost. The proposed power plant was intended to serve "peak load," which is the function served by many of the currently operating OTC natural gas power plants. The use of the urban PV alternative as the litmus test that must be passed before a new or re-powered gas turbine plant can be approved should move the rooftop solar PV option onto center stage of how to replace lost generation from OTC power plants. Retirement of the aging plants would raise the question of how to replace over 15,000 megawatts of lost power supply—roughly 1/4 of the state's peak electricity demand on the hottest summer day. On the one hand they could be replaced by building new natural gas plants. This would commit billions of dollars to new plants that would continue to operate 50 years into the future. Such a path would eliminate the use of sea water cooling, but would also entail the continued depletion of our natural gas resources, more air pollution (often in disadvantaged communities), millions of tons of carbon emissions per year, and a need pay whatever the unpredictable price of natural gas will be in the coming decades to produce the power. On the other side of the coin are the state's greenhouse gas reduction and air quality commitments. These include a dramatic increase in the use of renewable energy, improving some of the nation's most polluted air, to reducing future energy demand through efficiency increases, protecting consumers from rising energy prices, and reducing carbon emissions. The state's own analysis—and common sense— demonstrate that if California is to achieve the existing mandates, the state must move now to renewable energy sources and improved energy efficiency, and not to more fossil fuel-fired power plants. For many of the OTC natural gas power plants, solar PV is a viable and preferable alternative to fossil replacement of any type.
Response:
Staff believes that the goals of the State Water Board policy and AB 32 can both be met without a significant impact to the consumer or the environment. Note that it is not within the State Water Board's authority to establish an energy policy for California, but rather to protect the beneficial uses of the State's waters. The purpose of this Policy is thus to protect marine and estuarine resources of the State by implementing section 316(b) of the CWA. Staff has been working with the State's Energy Agencies to develop a Policy that will implement section 316(b), but not have the unintended effect of causing grid instability. However, specifying options for replacement of electricity generation is beyond the scope of this Policy.

Comment 28.06:
New turbines have lower emission rates than older steam units, even those with SCR pollution reduction technology. Replacing aging plants with new simple cycle plants would reduce the nitrogen oxide emission rate by 27%; from 0.128 to 0.093 pounds per megawatt-hour. The largest environmental benefit is from CO_2 reduction, with relatively little economic value assigned for NO_x reduction. While NO_x is left out of account here, savings could be up to $1.33

million per year for all the plants combined. However, as stated above, the reduction in emission rates does not necessarily mean that absolute levels of pollutants would be lowered if the number of hours per year that new plant would operate increase. Annual CO2 savings, assuming a cost of carbon dioxide at $25 per ton, would be over $30 million per year, or approximately $600 million over the economic lifecycle of the plants. On the other hand, total carbon costs would still accrue at $163.8 million per year, which means between $4.9 and $8.2 billion in carbon costs over the 30 to 50 year lifecycle of the replacement plants. The actual climate damage depends on the carbon damage rate, which for this report is assumed to range from $12 to $80 per ton. Thus carbon savings achieved through a replacement of aging power plants with newer, more efficient plants would amount to 18%. This would meet the 15% reduction target for 2020 required under AB 32, the Global Warming Solutions Act of 2006. However, the plants would continue to operate for another 20 to 40 years, during which time the state plans to reduce carbon emissions by 80% below 1990 levels. The replacement plants would fall far short of carrying their weight over this longer timeframe.

Response:

Comment noted. Staff supports the efficient use of natural resources and believes that the goals of the State Water Board policy and AB 32 can both be met without a significant impact to the consumer or the environment. However, it is not within the State Water Board's authority to establish an energy policy for California, but rather to protect the beneficial uses of the State's waters. The purpose of this Policy is thus to protect marine and estuarine resources of the State by implementing section 316(b) of the CWA. Staff has been working with the State's Energy Agencies to develop a Policy that will implement section 316(b), but not have the unintended effect of causing grid instability. However, specifying options for replacement of electricity generation is beyond the scope of this Policy.

Comment 29.15:

The SED analysis does not adequately address the air quality permitting issues associated with saltwater cooling towers. The availability of PM10 credits is not discussed insufficient detail – and this is a key issue in the San Luis Obispo Air Pollution Control District. The SLOAPCD issued a letter to the Central Coast Regional Water Board in 2004 indicating that cooling towers were likely not permittable for the Morro Bay facility due to a lack of available credits, as well as consideration of whether cooling towers reflected BACT. The SED estimates PM10 emissions from cooling towers at Diablo Canyon to range from 993 tons per year (USEPA method) to 50 tons per year (alternative method). In either case, it is highly unlikely that cooling towers could be permitted.

Response:

The compliance alternatives specified in the policy will allow an OTC to operate with mitigation actions taken. Another option is for power plants to retrofit with dry cooling and use renewables to compensate for the reduced efficiency of the generating unit.

Comment 30.07:

Particulate emissions from the cooling towers will have little or no impact on local air quality. Some solids are contained in the small amount of circulating water that is emitted from the cooling towers as fine mist, and has the potential to become airborne particulate. In San Luis Obispo County, where Diablo Canyon is located, these emissions can be offset by paving dirt roads. In San Diego County, where SONGS is located, cooling towers are exempt from air quality permit requirements. Use of reclaimed wastewater as cooling water, which is an option in the case of SONGS, would reduce particulate emissions due to the lower solids content of reclaimed water compared to seawater.

Response:

Comment noted. As stated in the policy, the State Water Board supports the use of reclaimed water in wet cooling towers when feasible. Please see the response to Comment 3.23.

Comment 31.50:
The staff correctly notes that the installation of wet or dry cooling towers will cause a decrease in power plant efficiency and hence a decrease in electric power capacity. The lost energy capability will have to be provided by the increased generation from other fossil-fueled facilities, thereby increasing air emissions. If all facilities installed wet cooling towers, California could experience, by the staff's own estimates, a 13% increase in particulate matter emissions, a 15% increase in S02, a 17% increase in carbon monoxide and an 18% increase in the ozone-precursor N02. Such increases in air emissions will be problematic for air districts already struggling to meet air quality standards. The staff suggests that these increased emissions could be mitigated by the installation of emission controls but these opportunities are limited since most air districts are already requiring facilities to meet BARCT and BACT control levels. The staff concludes that it cannot accurately assess the air quality impacts of the Policy because it is too difficult to estimate the method of compliance.

Also, the inclusion of Scenario 3 and Table 25 is an unreasonable basis for decision-making. Dry cooling, assumed to be installed in this scenario, is not the BTA criteria proposed to be adopted. This scenario assumes that all of the fossil-fuel OTC units are torn down and replaced with dry-cooled combined cycle units. What this has to do with the Draft Policy is a mystery that is unexplained in the SED, but it is unreasonable to use in any analysis of the reasonably foreseeable environmental impacts of requiring wet cooling as BTA. Because the SED fails to consider a reasonable range of site-specific factors in its analysis of the Policy's impacts and fails to consider the impacts of all reasonably foreseeable methods of compliance, the potentially significant air quality impact of this Policy is unknown. Given the air quality challenges the State currently faces, a Policy that could result in significant increases in pollutants warrants a more detailed assessment.

Response:
The increase in emission that the scenarios indicate represents the increase at the power plants only. For example, the State average for PM10 emission is 2112 tons/day (ARB Almanac 2009). The 33 tons/day of PM10 increase that scenario 1 assumes will increase the state's daily PM10 emission by 1.5%.

The SED states that staff expects that the actual net increase of greenhouse gas emissions will fall somewhere between 0 and 5%. Therefore, staff does not think all the OTC units will be repowered with dry cooled combined cycle units. Furthermore, several mandates like AB32 and RPS are also going to be implemented over the next 10 years making it very difficult to evaluate the OTC compliance actions of utilities. To allow for some flexibility in complying with the OTC policy, the State Water Board included two alternate compliance tracks that would still allow the use of OTC cooling.

Comment 31.51:
The staff correctly notes that the installation of cooling towers will result in a net increase in carbon dioxide emissions. The retrofitting of cooling towers will cause a loss of thermal efficiency, requiring the lost electric generating capability to be provided by other facilities. This electric power will need to be provided by other fossil-fueled facilities, thereby increasing their total C02 emissions. The SED estimates that if all facilities were to convert to wet cooling towers, the net increase in carbon dioxide emissions could total 1,237,259 tons! This is equivalent to adding over 300,000 additional cars to California's highways. The staff notes that these estimates vary depending on whether facilities install wet or dry cooling towers, repower or replace the facility. But the only case that reduces emissions is the unsupported one that

assumes all non-nuclear units are destroyed and replaced with dry-cooled combined cycles. The two plausible cases have increases greater than 10%. The staff then makes the completely unsupported assertion that the net increase in carbon dioxide is expected to be between zero and 5% of its worst case scenario. The SED has not adequately addressed the potential environmental impacts of this Policy relative to C02 emissions or the Policy's impact on the State's efforts to meet aggressive GHG reduction goals.

Response:

The SED did not include specific emission results for each OTC power plant since the OTC power plant operators have not provided the State Water Board with specific information on how they would meet the new policy. Therefore, staff developed scenarios that represented possible configurations of the power fleet after the policy has been implemented. In addition, the compliance alternatives specified in the policy will allow an OTC to operate with mitigation actions taken. Furthermore, CO_2 emissions could be reduced by implementing non-fossil fuel based power generation to compensate for the reduced efficiency of retrofitted generating units.

Comment 37.18:

The SED does not compare the Policy's estimated emissions against established CEQA significance thresholds established by the regional air quality management districts. Based on estimates provided in the SED, Policy emissions would exceed significance thresholds for the following pollutants: PM10 and PM2.5 from cooling towers; and SOx, NOx, CO, VOC, PM10, and PM2.5 associated with replacement generation.

Response:

The SED analysis is based on a program wide approach not a case-by-case approach. Staff chose the three scenarios that would give the best and worst representation of air emissions due to compliance with the OTC policy.

Comment 37.19:

The heart of the SED's evaluation of air quality emissions involves three "scenarios" to "describe the range of potential air emission increases", which are with problems. Scenario 1 assumes all "units deemed feasible" will be retrofitted to "closed-cycle wet cooling" and replacement power will be met with "native replacement" for “fossil units” and by "excess capacity within the coastal fleets" for the nuclear units, but does not evaluate whether the OTC plants can feasibly make up energy losses with "native replacement" or whether there is a feasible amount of "excess capacity" available in the coastal fleet to address the nuclear facilities' replacement needs. If such capacity is not available, the Policy would either undermine system reliability or require the import of external generation (the effects of which are not analyzed). The SED makes no effort to evaluate the significance of the estimated emissions by comparing them to applicable air quality standards, nor does it address the practical infeasibility of retrofitting nuclear facilities with closed-cycle cooling towers. Scenario 2 makes the bare assertion that all "generation shortfall is replaced by new combined cycle units, but no evaluation of the feasibility of this key assumption is made and the SED does not acknowledge that other portions of the document seriously question the likelihood that new generation can be developed in time to provide replacement power given regulatory constraints. Further, no evaluation is made as to where the energy would come from. If the units are not located within the same load areas, new transmission lines would be necessary. Significant transmission-related constraints raise questions about the feasibility of this potential. Scenario 3 assumes "all fossil units are repowered to combined cycle systems with dry cooling. This assumption is made even though the SED relies on a Tetra Tech study that determined it was infeasible to retrofit some of the OTC plants and the SED acknowledges that dry cooling towers likely would not be utilized at OTC facilities. Despite the potential infeasibility of all three scenarios (particularly Scenarios 2 and 3), the SED makes no attempt to evaluate the scenario that likely would be the environmentally superior option: a scenario that assumes the nuclear plants are *not* retrofitted with closed-cycle cooling towers. The SED acknowledges that assuming the nuclear facilities will be retrofitted with cooling towers accounts for 80-90% of any increase in emissions from the Policy. Thus, if the nuclear facilities are not retrofitted, the Policy's air quality emissions would be cut dramatically.

Response:

Staff believes that the three scenarios represent the worst case, probable case and the most probable case based on the information provided to staff by the power generators, other state agencies, and current environmental laws. Evaluation of nuclear plant OTC compliance options will be studied as a major part of the SACCWIS process. In addition, OTC power plants have the option of following Track 1 or Track 2 as a way to comply with the policy.

Comment 37.21:

The SED does not include any discussion regarding the potential health effects of Policy-related air pollutants, including the potential impact of increased emissions of PM10 and PM2.5 from cooling towers. Exposure to elevated concentrations of particulate matter has been linked to a number of adverse health effects, including acute respiratory infections, lung cancer, and chronic respiratory and cardiovascular diseases. The SED does not report the increase in air toxic emissions due to the energy penalty associated with the installation of cooling towers. The SED should be revised to evaluate these legitimate health risks.

Response:

The SED did not include specific emission results for each OTC power plant since the OTC power plant operators have not provided the State Water Board with specific information on how they would meet the new policy. Therefore, staff developed scenarios that represented possible configurations of the power fleet after the policy has been implemented. In addition, the compliance alternatives specified in the policy will allow an OTC to operate with mitigation actions taken. Furthermore, PM emissions could be reduced by implementing non-fossil fuel based power generation to compensate for the reduced efficiency of retrofitted generating units.

Comment 37.22:

The SED does not provide an analytical framework for determining the significance of Policy GHG emissions. Staff does not explain how it was determined the "emissions will fall somewhere in between th[e] extremes" identified in scenarios 1-3, and why GHG impacts would be less than significant. No evaluation is made about the feasibility constraints raised above for Scenario 3, which is the only scenario that represents a decrease in GHG emissions, and thus tends to skew the averaging approach apparently taken by the SED.

Response:

Please see the response to Comment 37.19.

Comment 37.23:

The SED's approach does not comport with the Office of Planning and Research's draft CEQA Guidelines for GHG emissions, which call for a good-faith quantification of all direct and indirect GHG emissions. The SED does not quantify construction emissions, indirect emissions (e.g., from water use), or emissions related to the "interim" period when OTC plants may be offline. These undisclosed emissions may be very substantial.

Response:

Staff conducted a good-faith effort to quantify the GHG emissions due to the implementation of the Policy, as called for by the CEQA Guidelines for GHG emissions. The values expressed in the SED reflect the estimated emissions due to make-up energy production from other plants related to the "interim" period. Staff believes that there is sufficient information for the State Water Board to make an informed decision.

Comment 37.24:
Under A.B. 32, California needs to reduce GHG emissions by approximately 30% (a reduction of 169 million metric tons (MMT) of C02) by 2020. In order to achieve this objective, the grid must accommodate a significant amount of intermittent resources (solar and wind) that do not have certain specific performance requirements such as ramping and load-following needed to satisfy and maintain system reliability as the OTC plant do. If one assumes the business-as-usual scenario is the “no project" alternative, then the Policy results in an increase of potentially over 2 million metric ton per year of CO2 emissions (a significant impact on climate change) and be inconsistent with A.B. 32. Notably, if the SED had evaluated an alternative that did not include the nuclear facilities, the GHG emissions would have been substantially reduced. If it is determined that the Policy's GHG emissions are significant, the Board must implement any feasible alternative to reduce the significant impact. We request that the SED be revised to evaluate this scenario.
Response:
The proposed policy is not attempting to eliminate the existing OTC plants, just reduce their impacts by insuring that BTA is installed. Furthermore, many different power management methods can be used to address intermittent renewable power generation. The state power agencies that participated in the policy development wrote Implementation of Once-Through Cooling Mitigation Through Energy Infrastructure and Planning and Procurement to address some of the concerns regarding the proposed policy.

Comment 37.28:
The State Water Board should consider a more realistic range of scenarios to estimate air quality emissions. Currently, the SED assumes that replacement generation will come from excess capacity within the OTC fleet or from new, unidentified combined cycle units. Assuming current transmission and siting constraints continue over the next five to 10 years, these options may be infeasible. The SED should analyze the emissions associated with obtaining energy with an average in-state and average out-of-state emissions factor.
Response:
Staff believes that the three scenarios represent the worst case, probable case and the most probable case based on the information provided to staff by the power generators, other state agencies, and current environmental laws.

Comment 56.03:
Consideration must be given to nuclear plants' provision of GHG-free base load power: The implementation of a cost-benefit test allows the Board to fully consider and evaluate the fact that the state’s two nuclear plants provide roughly 4600 MW of GHG-free baseload power. These plants have significant useful lives remaining and can play a key role in ensuring that the state meets the GHG-emission-reduction-mandates of AB 32, the Global Warming Solutions Act of 2006. The adverse environmental impacts of replacing nuclear power with additional baseload fossil generation must be adequately evaluated. And without the on going reliance on the nuclear plants, meeting the state’s GHG reduction goals will be virtually impossible. As Porter-Cologne requires, these impacts, as well as the basic costs and benefits, must be balanced before making section 316(b) compliance decision.
Response:
Staff agrees that the nuclear plants require special consideration. The special studies related to the nuclear-fueled power plants are designed to provide a detailed analysis of the alternatives to meet the requirements of the Policy and the cost for these alternatives. The proposed Policy now has language which specifies the calculated costs be compared with the cost estimates in the SED.

Comment 61.26:
SED, pg. 91, sec. 4.2: Issue areas are presented that need to be addressed as part of the CEQA review of the policy, but Issue 4 - Biological Resources is not addressed in the following sections. It seems that the benefits of the policy would be included in this section. The implication that there are no effects of the policy on Biological Resources is not correct since the potential increases in greenhouse gases resulting from the policy may have a much more deleterious effect on fish populations than any potential benefits resulting from reduction in OTC.
Response:
Staff disagrees. While staff is very concerned about greenhouse gas emissions, there is no direct evidence at this time that any slight increases in greenhouse gasses will cause “more deleterious effect on fish populations.” However, we are very aware that IM/E currently causes substantial mortality to fish, other pelagic organisms, and even some forms of wildlife.

3. Water Impacts

Comment 11.26:
The SED needs to include an assessment of how much additional freshwater will be necessary to comply with the proposed Policy. Instead the SED merely asserts that the Board would "encourage use of reclaimed water". As demonstrated in the SED, the availability of reclaimed water for such purposes is limited and cannot fully mitigate the millions of gallons of freshwater needed to comply with the Policy.
Response:
The Policy does not mandate the use of freshwater. Instead, it encourages the use of recycled water for cooling water in lieu of marine, estuarine, or fresh water. The amount of makeup water that would be needed in a closed-cycle wet cooling system would have to be determined by each facility and could not be included SED because the information is not yet available.

Comment 11.27:
The SED does not evaluate the impacts of the proposed Policy on desalinization plants in California, including the resulting diminished freshwater resources. This approach fails to recognize that many of the current and planned desalinization plants are co-located at OTC power plants and use a portion of the same saltwater that passes through the power plant. Nor does the current document assess and quantify the potential significant adverse impact of the loss of freshwater resources to coastal communities that desalinization plants do or could provide and which may be lost if the Policy is adopted, as proposed. Alternatively, if the Staff chooses to conclude there would be no impacts to current or planned desalinization plants, then Staff needs to establish the ongoing impacts to marine resources from the use of saltwater resources to "feed" the desalinization plants. Seven desalination plants have been proposed to be co-located at California OTC power plants, which would use the power plant's seawater intake and outfall. It is anticipated that these desalination facilities will provide a minimum of 183 MGD of freshwater. Given the difficulty of permitting coastal industrial uses, it is unclear that these desalination plants would be able to secure the necessary approvals and build any necessary infrastructure to continue providing an uninterrupted supply of freshwater to local communities. The assessment of these impacts needs to be part of any legally sufficient SED.
Response:
The draft SED in Section 3.5 clearly states that the proposed Policy will not address desalination facilities. As stated in the SED, the State Water Board plans to address the intakes and discharges from desalination facilities through a separate policy action in the near future, as there currently are no state or federal regulations that specifically apply to desalination intakes.

Section 316(b) specifically applies to cooling water intake structures, and federal regulations governing new facilities are inapplicable to those facilities using less than 25% of intake water for cooling purposes. While any new desalination facility using a seawater intake must demonstrate compliance with Cal. Wat. Code §13142.5(b), such facilities present issues distinct from those affecting power plants. Thus, the State Water Board does not propose including requirements for desalination facilities in the proposed Policy.

Comment 11.28:
Using reclaimed water for make up water will be expensive. Staff's own analysis concludes, "'The overall cost savings may be negligible... if the cost to procure, treat, and transport the reclaimed water is substantial." Such rhetoric misses the point: under CEQA, it is the State Water Board's responsibility to disclose the potential adverse impacts from the potential increase in demand for additional fresh water resources, notwithstanding the Board's policy on the use of reclaimed water or its possible costs. For many of the State's OTC facilities, reclaimed water would require extensive new infrastructure that would be installed in urbanized areas. Increasing demands for reclaimed water in other uses, particularly in southern California, may compete for this resource and make it unavailable. At Moss Landing, diverting all the recycled water in the area to the power plant would only constitute 71% of the required make up water.
Response:
State Water Board staff does not anticipate an increase in demand of fresh water resources. The Policy does not preclude the use of sea water for make up water. The Policy encourages the use of reclaimed water, but does not require it. The selection of the source of make up water will need to be determined after the means of compliance has been identified for each power plant.

Comment 11.29:
The text that precedes the utilities and service systems-related questions in the CEQA checklist in Appendix B does not provide adequate support for the conclusions marked "'No Impact." The following question requires additional discussion: Have sufficient water supplies available to service the project from existing entitlements and resources or are new or expanded entitlements? Significant volumes of freshwater could be required to provide make up water to the cooling towers. The SED must acknowledge impacts to freshwater resources or determine the impacts or the feasibility of using freshwater at these sites.
Response:
Please see the response to Comment #11.28.
Comment 12.13:
The Policy's move to reduce the use of seawater for plant cooling creates potential conflicts with other State policies designed to reduce use of freshwater and other sources of water.
Response:
The Policy does not mandate the use of freshwater in lieu of seawater. It encourages the use of recycled water for cooling water in lieu of marine, estuarine, or freshwater, where feasible.

Comment 16.05:
Where will seaside plants get millions of gallons of fresh water to feed their cooling towers? Evaporating seawater in cooling towers will be fraught with high cost problems.
Response:
The Policy does not mandate the use of freshwater in lieu of seawater. It encourages the use of recycled water for cooling water in lieu of marine, estuarine, or freshwater, where feasible. Recent advances in technology make the use of seawater for closed-cycle wet cooling viable.

Comment 29.16:
The SED analysis does not reflect potentially serious water quality issues given that the cooling tower blowdown is saltier and warmer than the existing discharge. PG&E's Enercon study indicated that a new offshore diffuser would be necessary to ensure that the blowdown meets Ocean Plan requirements. The construction of the diffuser would cause environmental effects that must be properly assessed.
Response:
The Policy encourages the use of recycled water for cooling water in lieu of marine or estuarine water, where feasible, which would alleviate some of the problem with increase in concentration of salts in the blowdown. The selection of the source of make up water will need to be determined after the means of compliance has been identified for each power plant. Plants that switch to closed-cycle cooling may well need to handle their waste streams differently than in the past, due to less available mixing. Staff believes that the SED meets the requirements of CEQA and the California Water Code. Since staff does not know what measures will be taken by power plant owners to comply with the proposed Policy, it would be pure speculation to try and identify project specific impacts for each facility. As such, this SED is programmatic in nature and meets CEQA requirements.

Comment 34.07:
We agree with Staff 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.
Response:
Comment noted.

Comment 31.53:
The staff concludes that water quality impacts as a result of the Policy will not be significant on the basis of examining three facilities and the irrelevant assertion that these facilities already face other water quality challenges. Other facilities were not assessed at all. Again by virtue of the fact that the SED does not analyze a reasonable range of site-specific factors, the SED makes broad, unsupported conclusions. Wet cooling towers will concentrate nonvolatile constituents in the cooling water loop, jeopardizing the ability of the facility to discharge blowdown water under its NPDES permit. This will make the installation of wet cooling towers infeasible. The staff indicates new dilution models will need to be developed to accurately estimate compliance with effluent limitations, inserting yet another major uncertainty in the feasibility of the staff BTA selection, wet cooling towers. If further wastewater treatment is required, costs of compliance will escalate even further.
Response:
Please see the response to Comment 31.53.

4. Other impacts

Comment 11.30:
The SED summarily concludes there are no significant aesthetic impacts for "most facilities" as they are already located in industrial and/or rural areas. Staff found less than significant impacts for Morro Bay, El Segundo, Scattergood and SONGS despite their proximity to popular recreational, residential, or commercial areas. These conclusions gloss over the significant impacts of placing large cooling towers in communities and underestimate local opposition to cooling towers that can make building them infeasible. Additionally, cooling towers at several locations potentially conflict with local laws, ordinances, regulations, and standards protecting scenic views and areas. For example, Morro Bay has scenic views from and towards Morro

Rock and is located along a State Designated Scenic Highway (Five OTC power plants are located on eligible scenic byways). Wet cooling towers and associated plumes would be visible from the highway and could impact the scenic views near OTC plants. The CEC proceeding for the proposed modernization project at the Morro Bay Power Plant explicitly found that cooling towers "'would have substantial adverse visual impacts relative to the proposed facility and would eliminate one of the principal benefits on the modernization Project from the perspective of the City residents. Additionally, the CEC concluded at Moss Landing that cooling towers were not optimal in part because of the visibility impacts of the towers themselves and visible vapor plume emissions. Additionally, the construction of cooling towers would expand the footprint of the industrial sites and would increase the night time light and glare impacts. These impacts are not addressed in the SED. The text that precedes the aesthetic-related questions in the CEQA checklist in Appendix B therefore does not provide adequate support for the conclusions marked "No Impact" or "Less Than Significant Impact." All of the questions require additional discussion in the DSED.

Response:

The SED discussed the potential adverse impacts to aesthetics and identified mitigation measures for those plants where there could be significant impacts, based on the Tetra Tech report. The Tetra Tech report took into account local ordinances. These issues have already been addressed in the SED.

Comment 11.31:

The DSED relies on the Tetra Tech report's conclusions that the OTC facilities can meet local noise ordinances by installing barrier walls and insulation, and fails to identify significant noise impacts resulting from the implementation of the proposed Policy. This conclusion ignores the analysis conducted during the CEC relicensing process at Morro Bay and Moss Landing. At Morro Bay, analysis of alternative cooling options showed increased noise at several sensitive receptors using "best case" modeling that incorporated all possible mitigation strategies. Even with mitigation, the alternative cooled project was on the cusp of compliance and it was unclear if a vendor would guarantee the necessary noise levels; once constructed, if the project exceeded the noise limit, no additional mitigations would be available, resulting in a significant adverse impact to the surrounding communities. The City of Morro Bay also adopted several resolutions in opposition to alternative cooling system proposals at this facility and concluded closed-cycle cooling would cause or exacerbate adverse effects on noise. Noise was also a factor when the CEC eliminated consideration of seawater cooling towers at Moss Landing. The SED text that precedes the noise-related questions in the CEQA checklist does not provide adequate support for the conclusions marked "Less Than Significant Impact", as the installation of closed-cycle cooling towers may exceed local noise requirements at some OTC sites, such as Morro Bay.

Response:

Comment noted. Staff still relies on Tetra Tech’s conclusion, and finds that sufficient mitigation is available to make a finding of less-than-significant impact with mitigation for the four plants identifies with potential significant impacts on noise (Haynes, Alamitos, Scattergood, and Morro Bay).

Comment 11.35:

The text that precedes several of the utilities-related questions in the CEQA checklist does not provide adequate support for the conclusions marked "No Impact" or "'Less Than Significant Impact." The following questions require additional discussion in the DSED: a) “Result in electrical transmission grid impacts?” - The DSED glosses over the potential impacts of upgrading the transmission infrastructure; no analysis is provided to support the "Less Than Significant" finding in the checklist. Examples of potential impacts of transmission lines include aesthetics, limitations on aviation, Electric and Magnetic Fields (""EMF"), impacts to Endangered/Threatened and Protected Species and their habitat, and impacts on cultural resources. b) “Require or result in the construction of new water or wastewater treatment facilities or expansion of existing facilities, the construction of which could cause significant environmental effects?” The SED defers analysis of impacts to desalinization facilities to a later proceeding. However, as discussed, this proceeding may negatively impact nine proposed co-located desalinization facilities and freshwater supplies in local communities.

Response:

Staff disagrees that the SED does not provide adequate support for the conclusions marked "No Impact" or "'Less Than Significant Impact." (See section 4.10 of the SED). Regarding desalination facilities, please see the responses to Comments 1.12 and 11.27.

Comment 11.36:

No impacts to Land Use was identified in the SED. However, for Moss Landing, the CEC concluded: [... Cooling tower salt water drift would significantly increase PM10 emissions, harm nearby agriculture, and be a significant source of increased noise.] An analysis by Duke Energy during the Morro Bay relicensing process also identified at least nine specific conflicts with existing land use regulations and ordinances stemming from the construction of alternative cooling technologies at this site.

The text that precedes the land use-related questions in the CEQA checklist does not provide adequate support for the conclusions marked ·'No Impact." The following question requires additional discussion in the DSED: a) Conflict with any applicable land use plan, policy, or regulation of an agency with jurisdiction over the project (including, but not limited to the general plan, specific plan, local coastal program, or zoning ordinance) adopted for the purpose of avoiding or mitigating an environmental effect? As noted above, the installation of closed-cycle wet or other cooling towers would create multiple conflicts with existing state and local LORS at both Moss Landing and Morro Bay. These conflicts result in significant impacts that cannot be mitigated without amending the Coastal Act or local General Plans, local coastal plans, etc. at both sites.

Response:

The Tetra Tech report identified the local zoning issues and ordinances for all of the OTC facilities and determined that alternative cooling structures could be constructed within the local land use requirements.

Comment 11.37:

The DSED does not acknowledge salt drift from seawater closed-cycle wet cooling towers as a potentially significant adverse environmental impact on agricultural resources. Staff assumes drift eliminators will greatly reduce salt deposition and the release of particulate matter from the cooling towers. The SED states, "No agricultural or forest areas were identified in close enough proximity to potentially warrant concern over drift deposition, but Moss Landing is located in the midst of prime agricultural land, and is in fact the upwind, next-door neighbor of a dairy. The accretion of significant salt drift on these farm lands raises potentially serious concerns regarding possible adverse impacts on the fertility of this agricultural production. The CEC rejected sea water cooling, in part, due to "saltwater drip impacts to agriculture. At Morro Bay and Moss Landing, the CEC rejected salt water wet cooling, in part, due to concern about salt from cooling towers.

Response:

See section 4.4 of the SED.

Comment 11.38:

The DSED does not discuss the potential public safety impacts of visible water vapor plumes in those situations where the placement of new closed-cycle wet cooling towers might allow the water vapor plumes to cross nearby grade-level or elevated roadways. These plumes could potentially cause traffic hazards or might be in the vicinity of airports and/or flight paths. Analysis conducted for implementation of sea water mechanical draft cooling at Moss Landing indicated that a water vapor plume would be visible approximately 95 percent of the time. This is likely to be typical for other central and northern California sites. An analysis is needed to determine if the resulting plumes might cause safety problems on nearby interstate highways and other roadways, or at nearby airports or flight paths.

Response:

The SED discusses potential impacts from water vapor plumes associated with cooling towers. The SED also found that there are technologies and design measures available to reduce a visible plume's size and frequency to a level that is considered insignificant (See section 4.3 of the SED).

Comment 11.39:

The SED does not identify any impacts to terrestrial biology resources. However, many of the OTC facilities have environmentally sensitive habitat on or adjacent to their site that must be identified and any impacts mitigated to avoid any potential conflicts with local LORS. The SED must be revised to acknowledge, analyze and, if possible, propose mitigations for these negative environmental impacts. The SED text that precedes the terrestrial biology-related questions in the CEQA checklist does not provide adequate support for the conclusions marked "No Impact." The CEC licensing proceeding identified riparian habitat candidate at Morro Bay and wetlands and sensitive, or special status species and/or habitat at both Moss Landing and Morro Bay which required mitigation. The SED should analyze potential impacts riparian habitat, wetlands, and candidate, sensitive, or special status species caused by the installation of closed-cycle wet cooling towers.

Response:

The Tetra Tech report identified areas for cooling tower placement that would not require disturbance of natural habitat. Therefore, the SED concluded that there should be no impacts to terrestrial habitat.

Comment 11.40:

The DSED does not identify any impacts to terrestrial cultural resources, although the CEC licensing proceeding identified cultural resources at the Morro Bay site which required mitigation. The SED should analyze potential impacts to cultural resource sites caused by the installation of closed-cycle wet cooling towers.

Response:

There is always the possibility for unknown cultural resources to occur within a project area. Procedures for handling cultural resources are fairly standard and the State Water Board believes that any cultural resources encountered during the implementation of this Policy will be handled appropriately during the site-specific evaluation for each facility. Staff believes that most alternative cooling facilities will be located in areas previously disturbed by past construction activities and no new discoveries are expected.

Comment 23.16:

The environmental impact analysis in the SED is insufficient and fails to meet the requirements of the State Water Board's CEQA regulations as it includes no discussion of at least one potentially significant impact category. The most prominent impact category that the environmental analysis excludes is Land Use and Planning. Staff simply indicates in the SED that there will be "no impact" in relation to Land Use Planning without any discussion. However, conflicts with local land use plans are a likely and predictable consequence of siting cooling towers. Given the limited number of existing facilities, a review of applicable local land use plans, policies and regulations would clearly be practicable and would enable the Board to determine whether the proposed Policy could result in potentially significant impacts associated with conflicts with such plans, policies and regulations.

Response:

The Tetra Tech report identified the local zoning issues and ordinances for all of the OTC facilities and determined that alternative cooling structures could be constructed within the local land use requirements.

Comment 29.13:

Staff's assessment that there are no significant aesthetic impacts is not accurate. For Diablo Canyon, PG&E believes that there are significant impacts. Given site constraints, plume-abated towers are not possible at the site. The Enercon study includes a detailed plume study and found that the plume would be visible in San Luis Obispo approximately 20% of the time. Additionally, the plume would be over half a mile high roughly 35% of the year. Thus, it would frequently be visible from Avila Beach and San Luis Obispo – as well as continually visible from the ocean. We believe that this is an aesthetic impact that warrants evaluation.

Response:

The SED discusses potential impacts from water vapor plumes associated with cooling towers. The SED also found that there are technologies and design measures available to reduce a visible plume's size and frequency to a level that is considered insignificant (See section 4.3 of the SED).

Comment 29.14:

There are agricultural activities both north and south of Diablo Canyon -- livestock grazing in both areas and various crops are grown to the south. Plume/drift abatement towers cannot be installed at Diablo Canyon due to space limitations. Salt drift at Diablo Canyon would be at least 15 million pounds per year and it would very likely impact agriculture – particularly to the south. This potential impact on agriculture warrants evaluation.

Response:

See section 4.4 of the SED.

Comment 31.10:

Mandalay is located at the end of the Edison Canal approximately 2.5 miles from the Channel Islands Harbor, which connects to the Pacific Ocean. The location of the cooling water intake structure at the end of a long canal isolates it from the natural shoreline habitat of the Pacific Ocean. Elimination of pumping at Mandalay would cause the 2.5 mile canal to become stagnant, imposing potential health impacts on residents, and aesthetic impacts that compromise the value of homes, businesses and public resources located along the canal-none of which have been considered in developing this proposed Draft Policy.

Response:

Since staff does not know what measures will be taken by power plant owners to comply with the proposed Policy, it would be pure speculation to try and identify project specific impacts for each facility. As such, this SED is programmatic in nature and meets CEQA requirements. For instance, the canal could be filled in and used as a bike trail or walkway, providing an aesthetic and health enhancement and an increase in value to the homes, businesses and public resources located along the canal.

Comment 31.48:

The staff states that it did not identify any significant aesthetic impacts of installing cooling towers at any of the sites utilizing once through cooling because the sites are already in developed areas. While that may be the case at some locations, installing the large cooling towers required for closed-cycle cooling would cause aesthetic impacts at many sites that the SED does not discuss. While cooling tower structures will be similar to other structures at or in the vicinity of the facilities, the plumes will create a visual impact more significant than the facility structures themselves. As one example, RRJ's Ormond Beach facility in Oxnard is located only 2.5 miles west of the Point Mugu Naval Air station, whose flight operations could easily be impacted by a cooling tower plume. Plume-abated towers might provide some mitigation, but such towers would be even larger and thus have even greater impact. Aesthetic impacts must be assessed on a site-specific basis and should include input from the responsible local jurisdictions regarding the likelihood they would ever approve of such an installation.

Response:

The SED discusses potential impacts from water vapor plumes associated with cooling towers. The SED also found that there are technologies and design measures available to reduce a visible plume’s size and frequency to a level that is considered insignificant (See section 4.3 of the SED).

Comment 31.49:

The staff did not identify any significant agricultural or forest impacts, based in large part on a study by Tetra Tech that assumed high efficiency drift eliminators would be installed on any wet cooling towers. Drift eliminators will increase the cost of the wet cooling towers and there is no basis to assume they would be included on all wet cooling towers.

Response:

See section 4.4 of the SED.

Comment 31.52:

The SED failed to analyze the reasonably foreseeable effects of the policy on noise resulting from construction of new facilities to meet the revised standards. The SED also did not consider other effects of construction due to implementation of the policy.

Response:

Please see the response to comment 11.31.

5. Renewable energy generation and grid reliability

Comment 9.08:

In planning for heavy, continued reliance on existing OTC plants to meet grid reliability demands, the policy fails to consider a new and promising alternative that would avoid the global warming and human health and marine life impacts of such plants. That viable option is urban photovoltaic, which the CEC determined on June 17, 2009 is a feasible, cost-effective option to the state's existing coastal plants. In light of that recent development, the proposed policy is outdated and should be revised to factor photovoltaic, and possibly other alternative energy sources, into planning for replacement of energy from OTC plants, and hence, earlier retirements of those plants. The proposed policy is based largely on a report by the "Energy Agencies", which discusses ways to avoid relying on existing power plants in order to end use of OTC. But it cites a main way to accomplish this goal is "to rely more upon remote generation." Reliance on remote solar sources would mean more, very costly and potentially environmentally-damaging transmission lines, which urban PV, as well as utilizing home and business roofs, would not require because they would be in local areas where power plants to be phased out are located.

Response:

The purpose of this Policy is to protect the beneficial uses of coastal and estuarine waters, mainly as it pertains to fish and wildlife. The CEC's determination that roof top photovoltaic is a viable alternative to a new 100-megawatt natural gas–fired gas turbine power plant does not alter then purpose of the Policy. Roof top photovoltaic may be an alternative to California's coastal OTC plants, and some owner/operators may choose to investigate this option, but the purpose of the Policy is to eliminate or significantly reduce the amount of OTC in the state. The method of compliance is up to the owner/operators.

Comment 12.08:
The SED does not fully consider the feasibility, regulatory hurdles, and the economic impacts of constructing replacement transmission and generation necessary to offset the loss of the affected facilities.
Response:
These issues were discussed in Section 4.10 of the SED.

Comment 28.07:
Even if some plants must continue to use seawater for closed-cycle cooling, the volume required for closed-cycle cooling is less than 5% of OTC cooling needs. Closed-cycle cooling has some minor disadvantages compared to OTC: the increased energy required to operate it, the extra cost to install it, cooling towers emit plumes of vapor that might be considered unsightly (but can be abated), and any pollutants in the source water will be discharged in higher concentrations. For all practical purposes, new gas turbines will inflict no significant marine damage. Aside from the nuclear power plants, the aging natural gas power plants are the only source of marine damage. Both the repowering and clean energy replacement options would eliminate this problem. Of the 12,174,404 MWh total generated by the aging power plants in 2005, 86% of the electricity, or 10,469,987 megawatt-hours, was produced by OTC plants. The environmental cost of OTC for marine damages ranges between $177 million and $540 million per year for existing power plants that would be avoided in the replacement scenarios.
Response:
Staff notes the comments. Our policy does not dictate which form of replacement power will be chosen for insuring electrical grid reliability.

Comment 28.12:
By applying its policy tools, California can retire its aging natural gas power plants while achieving significantly lower levels of greenhouse gas emissions, air pollution, and natural gas consumption. Among the most important policies are the state's mandate to increase renewable energy to 20% by 2010, and increasing renewables to 33% by 2020. A 33% renewable energy supply would allow a large amount of the state's natural gas power plants—about 10,000 MW—to be retired. The state has also adopted aggressive requirements for energy efficiency and conservation that have the aim of reducing 4,500 MW of future demand by 2020, a goal that state regulators expect to exceed. In addition, there are demand reduction programs, such as demand response and interruptible load that should reduce even further the need for the specific service the aging natural gas plants provide. Replacing the aging power plants with new natural gas plants is thus at odds with achieving the state targets for a range of green energy programs. Continuing to rely heavily on natural gas power plants may be technically and conceptually easier for grid operators than moving to renewable energy, and we will continue to need some amount of natural gas power for decades into the future. Yet, if the state is to achieve its environmental and policy goals, alternative ways of meeting our future energy needs must be given a higher priority than taking the technically easier path. The challenges of climate change and depletion of fossil fuels increasingly make it necessary to surmount the technical challenges of moving to an electric power grid that depends on renewable energy. An

impressive raft of policies, rules and legislation in California are aiming to address global warming, to increase environmental protection, to reduce dependency on fossil fuels, and to secure a stable and economical energy supply for the future. As the state contemplates retirement of aging natural gas power plants, it is important to keep in mind that there are a number of opportunities for meeting California's energy needs with alternatives to conventional power generation. These include preferred resources in the following priority ranking: (1) Energy efficiency and demand reduction; (2) Renewables and distributed generation; and (3) Clean fossil fuel. The need to enforce this order has become more acute under the pressure of AB 32's mandate to decrease greenhouse gas emissions. The higher loading order resources are potentially quite large. About 30% of normal summer peak demand, nearly 15,000 MW, is driven directly by air conditioning struggling against the California heat. There is great potential to reduce this need through more efficient technologies such as geothermal heat pumps, better home insulation, "cool roofs" , timed cycling of air conditioners, and shade trees. Only a fraction of the resources of renewable energy and reducing demand have been tapped.

Response:

Staff notes the comments. Our policy does not dictate which form of replacement power will be chosen for insuring electrical grid reliability.

Comment 29.17:

The SED analysis of impacts on the state's electric grid relies on the 2008 Jones and Stokes report. PG&E believes that this report did not provide significant value to the process and that the Water Board must look to the Energy Agencies and the CAISO in particular, for an accurate assessment of the overall risks associated with policy implementation, as well as recommendations on implementation of compliance schedules and strategies. The study itself acknowledged these shortcomings: (1) the modeling effort conducted for this study was limited in scope, capable of only taking a snapshot of the big picture, due to time constraints; (2) the key recommendation arising from this study is that the industry must continue comprehensive study of the issue, examining the reliability implications of retirement of each plant individually and in combinations with all other plants, and constantly reassess the reliability implications of the Board's new policy as it is planned and enacted; and (3) the Energy Agencies and SACCWIS must continue to inform the process to ensure that grid reliability remains an overarching priority.

Response:

While the 2008 Jones and Stokes report has its limitations (which are clearly stated), staff believes this report to be reliable and credible. Staff and consultants have spent considerable time and effort to evaluate compliance options, risks, and the potential costs imposed by this Policy. The decision to evaluate construction options to reduce IM/E by utilizing wet cooling towers was done to create a baseline cost analysis that is technologically feasible. It may never be possible to calculate all the potential technological decisions that each company must make for each individual generating unit and plant. Staff has further continued to work closely with the Energy Agencies to develop a workable Policy that will achieve its goals without jeopardizing grid reliability.

Comment 31.29:

While combined cycle power plants are relatively more efficient in producing energy, they are less cost-effective for providing ancillary services, since combined cycle plants may incur a maintenance cost penalty for cycling, while steam units can ramp at rates of up to 30 MW/minute and do not incur any significant increase in maintenance costs from cycling up and down within an operating day, as may often be required to follow load and integrate intermittent renewable energy. Combined cycle plants are no more efficient than steam units in providing firm capacity necessary to assure reliable operation of the electric grid. In terms of $C0_2$

emissions per MW of capacity, the non-combined cycle units are substantially more efficient, imposing less C02 emissions per MW than combined cycle facilities.

Response:

Pursuant to SB 1368 (Perata, Chapter 598, Statutes of 2006), neither the CPUC (for IOUs) nor the CEC (for POUs) will allow utilities to develop facilities or sign contracts with new base load power plants that have a CO2 emission rate of more than 1,100 lbs/MWh. Staff believes that the emission rate is approximately equal to the emission rate from a natural gas-fired combined-cycle power plant. In addition, pursuant to state policy, the CEC has been discouraging power plant applications that use OTC. It is unarguable that existing steam units are less efficient than new combined cycle power plants on a CO2 per MWh of energy produced basis due to the much lower heat rates of new combined cycles compared to older steam units. The only reason that existing steam units could have a benefit from the perspective of CO2 per unit of capacity is that old steam units run much less than would new combined cycles operating in the annual capacity factor range that would justify development of a new combined cycle unit. The generator development industry has already recognized the need for some combined cycles to cycle up and down, such as from the widespread development of intermittent renewables, and this has already led to new combined cycle units that can operate at 50% of load minimal degradation of efficiency. For this reason it is not expected that the basis of comparison is old steam units against older, inflexible combined cycles, but old steam units versus some combination of combustion turbines, fast start, fast ramp combined cycles, remote renewable, and other technologies that would make sense in an electricity system of the future. It is also staffs understanding that the CEC, CPUC, and CAISO considered the need to replace the ancillary services lost from possible retirement of existing capacity when they created the staff paper called Implementation of Once-Through Cooling Mitigation Through Energy Infrastructure and Planning and Procurement and sketched out the planning, procurement and permitting timelines included in Appendix C of the SED.

Comment 35.03:

The policy represents a significant opportunity to transform California's dependence on pollution-emitting power plants--which the EPA has concluded imposes a severe risk to public heath ranging from asthma to premature death in people with heart or lung disease—via the placement of solar panels (photovoltaic) on rooftops, mainly on parking lots and warehouses, the most practical, available and cost-effective sites. On June 17, the CEC recognized photovoltaic's vast potential to revolutionize energy generation. The Commission's groundbreaking ruling concluded that PV is a feasible, cost-effective alternative to conventional gas-fired power plants, which means it now will be considered in the regulatory process of selecting the most efficient, effective and environmentally safe ways to generate electricity and serve California markets. As the Energy Commission's June 17 ruling elevating PV to its new status as a replacement for gas-fired power plants may have come after the drafting of the Board policy on power plant cooling, the policy should be revised in light of the CEC ruling. Additionally, the policy Is based in part on a report by the "Energy Agencies" (CEC , CAISO, California Public Utilities Commission) that focuses on means to avoid relying on existing power plants in order to end use of OTC. But the report cites as a main way to accomplish this goal is "to rely more upon remote generation." That means building more, very costly and environmentally-damaging transmission lines, which PV on warehouse and vehicle shelters, as well as home and business, roofs would not require because they would be in local areas where power plants to be phased out are located. Therefore, this report has not taken localized PV into account as a source of energy to replace that of power plants, a major omission. The Energy Agencies report cites the lack of air credits to upgrade or replace gas-fired plants in the Los Angeles Basin because of its poor air quality as a significant obstacle to replacing a large percentage of plants now using OTC. It fails to recognize the potential of localized PV to sharply reduce or eliminate the need for pollution-producing plants, making air credits irrelevant. The newest and most promising alternative is PV, which also on a broader scale has the potential of quickly reaching the state's widely-praised goal of converting its energy generation to 33% renewables by the year 2020.

Response:

The State Water Board's authority to require that the location, design, construction and capacity of cooling water intake structures reflect BTA for minimizing adverse environmental impact does not extend to specifying technology for electricity generation. Setting energy policy is outside of the scope of this Statewide Water Quality Control Policy.

E. ECONOMIC CONSIDERATIONS

Comment 1.03:

The Policy does not adequately consider the actual economic impact of what is being required, which results in cost of compliance that is wholly disproportionate compared to the environmental benefits achieved. This is inconsistent with guidance given by the United States Supreme Court.

Response:

Staff has spent considerable time and effort to evaluate the potential costs imposed by this Policy[1],[2]. Staff feels that the environmental impacts of OTC are significant and our approach is a reasonable response to the requirements of Section 316(b).

Comment 1.13:

The economic analysis in the SED is inadequate and it fails to evaluate the cost of the most probable compliance alternatives of the Policy, which is repowering and replacement, rather than retrofitting the existing facilities with wet closed-cycle cooling. Not only is retrofitting not feasible at many of the existing sites, it is not consistent with the preferred and expected compliance plan for all but the two nuclear plants and the few existing combined cycle units. With the significant capital cost of new capacity, the state-wide impact of a policy that accelerates the retirement of the relatively inexpensive existing units should be carefully evaluated. Without a more thorough economic analysis, the SED is inadequate and the Board will not be able to make a fully informed decision that considers the true cost of the Policy. Water board staff acknowledges its intent to further support California's energy policy objectives by encouraging, or in this case, forcing the replacement of the existing coastal fleet. We recommend revising the economic analysis to include the cost of repowering or replacing the existing fleet. To be consistent and to allow the Board to make an informed decision, the SED must assess the economic impact of the most probable outcome, not the scenario that is the easiest to evaluate.

Response:

Staff feels that the environmental impacts of OTC are significant and our approach is a reasonable response to the requirements of Section 316(b). Note, that neither the California Water Code nor CEQA require any economic analysis for the Policy. Therefore, the SED is

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

[2] **Tetra Tech, Inc.** *California's Coastal Power Plants: Alternative Cooling System Analysis.* Prepared
for California Ocean Protection Council. Golden, CO. February 2008.

adequate for the purpose of identifying potential environmental impacts which may occur due to adoption of the Policy.

Staff has spent considerable time and effort to evaluate the potential costs imposed by this Policy. The decision to evaluate construction options to reduce IM/E by utilizing wet cooling towers was done to create a baseline cost analysis that is technologically feasible. It may never be possible to calculate all the potential technological decisions that each company must make for each individual generating unit and plant.

Comment 4.06:
The depth of inquiry and information in the two-page economic impact discussion included at the end of the draft SED is inversely proportional to the seriousness of the question of costs and woefully inadequate to inform the Board of the relative costs and benefits of the proposed BTA determination. In evaluating the cost of compliance to affected OTC facility owners and ratepayers, the current draft SED analysis is limited to providing only the cost of wet-closed-cycle cooling retrofits. The cost of OTC unit re-powering and/or replacement with wet or dry closed-cycle cooling was not evaluated and that cost could be significantly different than a wet-closed-cycle cooling retrofit. From the standpoint of the facility owner, the cost would also include the revenue lost during the extended outage required for demolition and new unit construction, which also does not appear to be considered. There are also higher costs associated with dry cooling due to the decrease in generation efficiency resulting from the need to use large amounts of energy to allow the cooling tower to function that is not currently considered.

Response:
Staff has spent considerable time and effort to evaluate the potential costs imposed by this Policy (SED references extensive studies see references [1&2]). The decision to evaluate construction options to reduce IM/E by utilizing wet cooling towers was done to create a baseline cost analysis that is technologically feasible. It is not possible for staff to calculate all the potential technological decisions that each company must make for each individual generating unit and plant. Staff feels that the environmental impacts of OTC are significant and our approach is a reasonable response to the requirements of Section 316(b).

Staff provided an estimate of the costs associated with retrofitting the existing power plants with wet closed-cycle cooling since it appears to be the least expensive option for complying with the Policy. If a facility chooses to use a more expensive option in order to comply with other requirements or goals unrelated to the Policy, there is no reason to include such an analysis in the SED. The US Supreme Court ruled that it is permissible (but not required) to use a cost-benefit analysis in setting performance standards [*Entergy v. Riverkeeper* 556 U.S., (2009)].

Comment 4.07:
The electric utility industry in California is undergoing significant transformations in the areas of addressing greenhouse gas emissions and adding renewable energy resources to its portfolio. Load-serving entities are facing costs for: (1) purchasing air emission allocations and/or offsets; (2) purchasing and/or developing renewable energy resources to meet a 20% (and potentially a 33%) renewable portfolio standard by 2010 and 2020 respectively; (3) making the necessary transmission line upgrades to integrate or renewable resources; (4) meeting new climate change program requirements; (5) re-powering aging, less efficient generating units; and, (6) retrofitting facilities to meet impending state and/or federal Section 316(b) requirements. Industry-wide costs in these six categories of contemporary investment could exceed more than $50 billion. The cost of implementing the OTC Policy, combined with the other noted, represent

costs that cannot be reasonably borne by the utility industry within the time frame set forth in the Draft Policy.

Response:

Staff is aware of the many constraints upon the industry and has worked closely with the California energy agencies responsible for managing the electricity grid (CALISO, CPUC, CEC) to incorporate these concerns to the maximum extent possible while being consistent with our duty to protect water quality.

Comment 11.10:

The SED evaluation of economic impacts and compliance costs is flawed because it does not fully and accurately analyze the costs of reasonably foreseeable compliance methods. The entire economic analysis covers only two pages and, among other things, fails to evaluate the cost of repowering, is limited to the cost of wet cooling retrofits, and does not include the costs of carbon dioxide emissions.

Response:

See response to 1.03, 1.13, and 4.06

Comment 11.44:

The State Water Board should perform an environmental impact analysis that identifies the foreseeable negative environmental impacts that would result from implementation of the Policy and conduct an overall, program-level cost-benefit analysis. In light of the U.S. Supreme Court's decision upholding cost-benefit analysis under Section 316(b), it is imprudent for the Board to determine BTA in the absence of any attempt at conducting an overall cost-benefit analysis. Without that analysis, the Board cannot make a reasoned decision and the public and other agencies cannot meaningfully understand the impacts of the Policy. Without that analysis, imposition of closed-cycle cooling as BTA is arbitrary. The concern with the State Water Board staffs' drive to impose closed-cycle cooling as BTA in the absence of an overall cost-benefit analysis is readily apparent in light of the cost-benefit analysis of the Draft OTC Policy prepared by NERA Economic Consulting (NERA) for CCEEB. NERA concludes that the costs of the Policy ($3.12 billion) exceed its benefits ($34.2 million) by 91 times. The State Water Board cannot simply ignore the economic impacts of its proposed OTC policy. Dynegy strongly urges the State Water Board to conduct an overall economic analysis of its proposed policy and revise the proposed policy to appropriately account for the results of that analysis.

Response:

Staff does not feel there should be any benefit/cost requirement in the policy. Estimated cost is just one of the factors to be considered in evaluating compliance with this policy. Staff and consultants have spent considerable time and effort to evaluate the potential costs imposed by this Policy. The decision to evaluate construction options to reduce IM/E by utilizing wet cooling towers was done to create a baseline cost analysis that is technologically feasible. It will not be possible for staff to calculate all the foreseeable technological options that companies must make for each individual generating unit and plant. Also see response to Comment 4.07.

Comment 12.10:

CAISO has determined that billions of dollars in transmission would have to be built to provide reliability if the affected plants are shut down, with $4.5 billion needed in the Los Angeles area alone. Statewide cost of replacement has been estimated to be in excess of $11 billion.

Response:

Staff notes that these costs are applicable for much shorter timelines than required by the policy. The policy has incorporated many concerns and suggestions from CAISO to mitigate these projected costs. The policy will not cause the sudden shut down of all affected plants. Some new transmission capacity is needed under any future energy scenario for California.

Comment 16.01:
As a tax and rate payer I am aghast. Has anyone run a real cost-benefit analysis of this project? Where is it? Do you realize that it is the ratepayers that will be stuck with the bill? It is nice to pretend that the IOU stockholders will be liable for the bill, but that is not true.
Response:
Staff recognizes that the ultimate bill for the required changes due to this policy will be bourn to a large extent by the ratepayers of California. Staff has spent considerable time and effort to evaluate the potential costs imposed by this Policy. Staff feels that the environmental impacts of OTC are significant and our approach is a reasonable response to the requirements of Section 316(b). Also see responses to Comments 1.03, 1.13, and 4.06.

Comment 16.06:
The efficiency of seawater plants will be adversely affected by cooling towers. Who will pay for this?
Response:
With regard to costs of conversion from OTC, please see response to Comment16.01.

Comment 23.13 :
The SED does not provide a cost-benefit analysis in connection with the Draft Policy's determination to eliminate OTC in California. Without even detailed analysis, it is clear that eliminating OTC will cost California billions of dollars for replacement capacity and/or transmission upgrades to account for the loss of these units. Principled rulemaking would dictate that a more detailed analysis of the actual cost of eliminating OTC should be a component of the policy determination.
Response:
The State Water Board is not legally compelled to do a cost benefit assessment for adopting the Policy. However, staff has spent considerable time and effort to evaluate the potential costs imposed by this Policy (SED references extensive studies [1&2]). The decision to evaluate construction options to reduce IM/E by utilizing wet cooling towers was done to create a baseline cost analysis that is technologically feasible. It is not possible for staff to calculate all the potential technological decisions that each company must make for each individual generating unit and plant. Staff feels that the environmental impacts of OTC are significant and our approach is a reasonable response to the requirements of Section 316(b). Also see responses to Comments 1.03, 1.13 and 4.06.

Comment 25.04:
The Draft Policy requires closed-cycle wet cooling, or its equivalent, as BTA. The State Water Board should first complete a comprehensive cost-benefit analysis of meeting closed cycle cooling performance standards (Track 1) statewide and alternatively complying with Track 2, if and where possible at existing plants. A similar study as the September 2009 NERA Report should be considered before selecting closed cycle wet cooling as BTA. We believe such a test will demonstrate that retrofitting these coastal OTC plants with closed cycle cooling will be wholly disproportionate to the cost versus environmental benefit. When considering El Segundo and Encina, compliance with Track 1 will cost hundreds of millions of dollars, if such changes could be permitted and built on spaced-constrained sites adjacent to nearby residences.
Response:
Staff does not feel there should be any benefit/cost requirement in the policy. Estimated cost is just one of the factors to be considered in evaluating compliance with this policy. Staff and consultants have spent considerable time and effort to evaluate the potential costs imposed by this Policy. The decision to evaluate construction options to reduce IM/E by utilizing wet cooling

towers was done to create a baseline cost analysis that is technologically feasible. In addition, the State Water Board considered many factors in determining that closed-cycle cooling (or commensurate reductions in impingement and entrainment) constitute BTA for coastal power plants currently using OTC.

Comment 27.02:
To the best of our knowledge, no cost-benefit analyses have been done on a site-by-site basis or collectively on the 19 existing coastal power plants. Many of the businesses and residents in our community are under severe economic stress. The unemployment rate in Oxnard now exceeds 15%. The proposed OTC policy will only result in higher energy rates. Should this OTC policy be implemented, it would compound the pressure on power generation along with AB 32 and the new mandate of one-third of all electricity to be generated from renewable sources by 2020. At a time when many businesses and residents are financially hanging on by a thread, this is not the time to implement an unsubstantiated policy.
Response:
Staff recognizes that the ultimate bill for the required changes due to this policy will be bourn to a large extent by the ratepayers of California. Staff has spent considerable time and effort to evaluate the potential costs imposed by this Policy. Staff does not believe that the policy must be changed to account for site-specific feasibility criteria. The policy is a state-wide policy and individual circumstances can be accounted for within the SACCWIS process. Staff feels that the environmental impacts of OTC are significant and our approach is a reasonable response to the requirements of Section 316(b).

Comment 28.03:
California has excess supply of natural gas generation at the expense of renewables. There has been a rapid build-up of nearly 20,000 megawatts in new natural gas power plants around the state, dramatically increasing California's capacity for natural gas generated electricity to a record high of over 40,000 megawatts. The failure to meet the state's renewable portfolio standard is directly connected to the relentless march of new natural gas plants. This is mainly because natural gas is the next prioritized energy supply resource after renewables. In other words, renewables have to lose in order for natural gas to win. Even though renewables are nominally a higher priority, a competitive struggle for existence between natural gas and renewables is embedded directly into state policy - by design. Not surprisingly, natural gas seems to win this game almost every time.

As a direct result of this failure to increase renewable energy, policymakers have come to assume that we "need" to build more natural gas power plants. Utility companies are only too happy to oblige and foster this impression, which is not surprising given that the other major product these utilities provide, in addition to electricity, is natural gas. A spree of construction since 1999 has resulted in major investment in new natural gas electric generation in California, at least $15 billion so far. Many of these plants replaced older, less efficient power plants, and for a time actually reduced consumption of natural gas fuel. However, this improved efficiency is undermined by the fact that while 7,500 megawatts of old plant capacity retired by 2008, over 18,000 megawatts have been built, or will be built; by the end of 2010. But the usage rate of natural gas plants will *need to decrease* if the clean energy policies are to achieve their goals. A study from 2003 by Lawrence Berkeley National Laboratory looked at the effects of increasing renewables and reducing growth in energy demand on the future need for natural gas plants in California, and projected that if the state implements both the 33 percent renewables requirement and aggressive efficiency programs, then over 20,000 megawatts could be retired by 2030; more than the capacity of the 15,400 megawatts of aging once-through cooled coastal natural gas plants. The policy to move to green energy directly conflicts with any new natural gas capacity beyond those already built or under construction. Even repowering existing plants would amount to pushing aside the state's green energy targets. The 2008 OPC report concluded that given their low usage, the shuttering of the OTC natural gas plants by 2015 could occur with no additional generation to replace it. The report states that "…the retirements could be compensated for with as little as $135 million in in-state transmission upgrades."

Response:

Comment noted. It is not within the State Water Board's authority to establish an energy policy for California, but rather to protect the beneficial uses of the State's waters. The purpose of this Policy is thus to protect marine and estuarine resources of the State by implementing section 316(b) of the CWA. Staff has been working with the State's Energy Agencies to develop a Policy that will implement section 316(b), but not have the unintended effect of causing grid instability. However, specifying options for replacement of electricity generation is beyond the scope of this Policy.

Comment 28.04:

Natural gas power plants cause other damages and costs that go uncounted besides those to marine ecosystems. These include public health impacts due to emissions of nitrogen oxide and particulate matter, and the cost of climate change from carbon dioxide and other emissions. Unfortunately, most damage to human health, water resources, air quality and the global climate are not folded into the price that utility companies pay for electricity. However, the costs to human health and the environment are real, and consumers pay for them. Air pollution causes lost days of work, increases the cost of health care, adds to wear and tear on buildings, and causes billions of dollars in damage to crops every year. Destruction of ocean life may reduce commercial opportunities and increase the cost of seafood. Much of the damage is unquantified, or defies measurement. For example, it is difficult to estimate the burdens future generations will bear for climate change, or for the lack resources that have been wasted. Some of the damages caused by fossil fuel plants can loop back to increased utility bills as well. For example, climate change can lower snowpack, and this in turn reduces hydropower. To counter this risk, utility companies pay many millions of dollars for natural gas generators to be on call to provide backup power in years when hydro resources fall short. Rising temperatures also increase use of air conditioning on ever hotter summer days, which calls for increased use of natural gas to meet peak energy demand. Although new natural gas plants are preferable to the current aging plants from an environmental standpoint, pollution from the new plants would cause hundreds of millions of dollars in damages per year. The majority of this cost comes from carbon dioxide emissions, which California must curb if it is to reach the climate protection goals of AB32.

Response:

Staff supports the efficient use of natural resources and believes that the goals of the State Water Board policy and AB 32 can both be met without a significant impact to the consumer or the environment.

Staff recognizes the inherent trade off that comes with reduction of water use impacts. Certainly as is noted by the commenter "…new natural gas plants are preferable to the current aging plants from an environmental standpoint…" and they will still cause damage. Economic considerations will probably lead to fewer but more efficient natural gas plants.

Comment 28.05:

Replacing old power plants with new power plants, either on the same site or elsewhere (fossil replacement scenario) would result in a cost of energy for the new plants of approximately 31 to 39 cents per kilowatt-hour—when external costs are included. The seventeen OTC natural gas power plants produce significant and quantifiable damages to the environment. To determine whether such impacts can be reduced in a cost-effective manner, we established a base-case scenario, in which aging units are repowered at existing sites with newer, more efficient units, and closed-cycle cooling replaces OTC systems. We calculated some, but not all, of the external costs associated with natural gas power plants and assumed that the plants were repowered with a simple-cycle (SC) gas turbine and that they were left operating at the same capacity as previously. For a load-following unit, the more cost-effective choice is usually a modern simple-cycle gas turbine. In estimating the costs to repower each plant, we use the CEC's 2007 "levelized costs" of Simple Cycle technology. This is a standard method for calculating the cost of operating power plants. The levelized cost takes an inventory of all the expenses involved in building and operating a power plant over its full expected lifecycle, then divides this total expense by the amount of electricity generated over that time. The net result is a cost of energy expressed as a rate per kilowatt-hour or per megawatt-hour. A cost per megawatt-hour is assigned to each repowering project based on the plant's size, with larger plants generally benefitting from some economy of scale. Even with the efficiency loses imposed by closed-cycle cooling, the new units will be more efficient. Replacement plants operating at existing capacity factors would generate electricity costing over $350 per MWh (i.e., over 35 cents per KWh). In order for power plants to have electricity costs under 20 cents per kilowatt-hour, they either require lower cost fuel than is assumed, or they would need to operate at a higher capacity factor than has been typical for the aging power plants. Although the total cost to plant owners of repowering is probably higher, fuel costs will usually decrease due to lower heat rates of newer turbines. Although the total cost to plant owners of repowering is probably higher, fuel costs will usually decrease due to lower heat rates of newer turbines. However, the common assumption the new plants would use less natural gas is probably unrealistic. The higher efficiency would make the new plants more competitive for more hours of the year; thus the electric generation would very likely be significantly higher than in the aging plants. This would tend to erase the fuel efficiency and carbon benefits of the new plants. Inefficient plants are generally only be competitive during the four summer months of June to September, when market heat rates usually soar above 12,000 BTU per kilowatt-hour during the peak demand hours. However, they must be kept idling at minimum power all night long in order to be ready to generate power in the morning, and cannot be shut completely off. This consumes a considerable amount of additional fuel that produces no salable electricity. The CEC report projected an effective heat rate of about 10,000 BTU per kilowatt-hour for a new natural gas combustion turbine, and this would allow a new plant to sell power nearly year round in a competitive manner, at least during the daytime. In some cases developers have even proposed building base load plants to replace aging plants, even when there is no market need for such a service. This would mean replacing aging plants that only produce at nine percent of annual capacity with base load plants that might operate at 60 percent capacity or more. Even though such plants would be much more efficient, there would be absolutely no fuel, cost or emission savings due to the much increased operation of the plant.

Response:

Staff cannot predict the future, but clearly it will be more economical to run new power plants at higher rates than previous plants. It is likely that not all current plants will be replaced and the net impact is impossible to predict.

Comment 28.07:

Even if some plants must continue to use seawater for closed-cycle cooling, the volume required for closed-cycle cooling is less than 5% of OTC cooling needs. Closed-cycle cooling has some minor disadvantages compared to OTC: the increased energy required to operate it, the extra cost to install it, cooling towers emit plumes of vapor that might be considered unsightly (but can be abated), and any pollutants in the source water will be discharged in higher concentrations. For all practical purposes, new gas turbines will inflict no significant marine damage. Aside from the nuclear power plants, the aging natural gas power plants are the only source of marine damage. Both the repowering and clean energy replacement options would eliminate this problem. Of the 12,174,404 MWh total generated by the aging power plants in 2005, 86% of the electricity, or 10,469,987 megawatt-hours, was produced by OTC plants. The environmental cost of OTC for marine damages ranges between $177 million and $540 million per year for existing power plants that would be avoided in the replacement scenarios.

Response:

Staff notes the comments. Our policy does not dictate which form of replacement power will be chosen for insuring electrical grid reliability.

Comment 28.08:

Replacing aging plants with new natural gas power plants will reduce marine damages, fuel consumption and greenhouse gas emissions, assuming that the new plant operates at a similar capacity as the aging plants—which is unlikely. Air pollution is likely to be relatively unchanged, since the aging power plants have generally been retrofitted to comply with modern air quality requirements. The new power plants may also have lower operation and maintenance expense due to reduced repair needs. On the other side of the coin, new power plants would require a large infusion of new capital spending. These new plants would be much more expensive than the older ones they would replace, at a projected total of $15.4 billion for all the plants combined. This borrowed and invested money must return a rate of interest and profit. Assuming an 11% average weighted cost of capital over a 20 year period would mean that the investment would need to return over $49 billion in combined interest and profit. Fuel would add another $1.3 billion per year, or $26 billion over 20 years. Combined lifecycle costs would approach $100 billion, not including environmental damages. Natural gas fuel prices are also expected to be higher in the future than they have in the past. The annual combined cost to the owners of all the plants is estimated to range between $3.68 and $4.22 billion to generate 12.1 billion kilowatt-hours. This translates into a wholesale energy rate of 30.3 to 34.8 cents per kilowatt-hour. The environmental damages range between 0.6 cents per kilowatt-hour to as high as 4.4 cents per kilowatt-hour. While this is significantly lower than the existing plants' environmental cost at 2.3 to 10.1 cents per kilowatt-hour, achieving this reduced environmental damage results in much higher cost of electricity. Thus, building newer plants could be interpreted as internalizing the environmental costs of the aging plants, especially since the environmental damage is a major factor for considering replacement in the first place. However, the new plants would also incur continuing external costs, particularly for carbon. All these figures assume that the replacement plant operates in a similar manner to the current plant. However, this may not be true since power plants have a strong motive to try to sell more electricity. If this is the case, then operation, maintenance, and fuel costs will increase and environmental damage may be much greater. These could rise to where the replacement plants would have more carbon and other air emissions than the current plants that they would replace. This is an important risk if new natural gas plants are built.

Response:

Staff recognizes that additional costs will certainly be imposed by this policy. However, staff does not believe that all older plants will be replaced and with fewer potential plants operating at higher efficiencies and rates, actual costs per kilowatt-hour may be lower than projected by this model.

Comment 28.09:

At 17 to 29 cents per megawatt hour, efficiency and renewables are a cost effective OTC replacement strategy. These include accomplishing greater energy efficiency improvements, increasing renewable energy, and implementing programs for reducing peak demand. Certain functions of the aging plants — such as voltage regulation and the ability to modify generation over the course of the day — might have to be met with other technologies. However, such resources are not entirely lacking in California. There are currently 41,499 MW of natural gas power plants in California. If all of the 15,400 MW of aging plants retired by 2012, the state will still continue to operate 26,000 MW of existing natural gas plants. In addition, nearly 2,000 more megawatts of natural gas plants are currently under construction and due to come on-line by the end of 2010. Another 18,000 MW of power can be imported over existing transmission wires, and more transmission capacity is likely to be built in the future. There is also some capacity to vary the electric generation from hydroelectric plants, especially the 4,100 MW of pumped storage that is specifically designed to meet peak demand. One important function of the aging plants is to meet local reliability needs. Retiring these plants will require replacing this capacity as well. Local resources, such as solar built on rooftops or at substations, and energy efficiency measures, can help. And there are thousands of megawatts of natural gas peaking capacity that is already in place that can also meet local needs. Another issue is the increasing demand for electricity. At this point the state does not even have to meet all of its renewable targets to erase demand growth. The OPC report examined the option of retiring the natural gas plants, and concluded that the cost and resources necessary to assure grid reliability depended heavily on the timing of retirement. If retirement is staggered to 2015, and the nuclear plants are assumed to still be on-line, then no new electric generation would be needed, and only some relatively minor transmission upgrades. This represented the low range of cost, as the State Water Board states, "as little as $135 million in modest, low-impact transmission upgrades in the still unlikely event that all but the nuclear plants are retired in 2015." As retirement of the 4,472 MW of in-state nuclear is not likely until the mid-2020s due to long term contracts, this is a viable scenario. Photovoltaics, solar thermal power, and peak demand reduction should be able to allow retirement of all the aging natural gas power plants, allow for population growth, and dramatically reduce other fossil fuel energy. 3,000 MW of new photovoltaic capacity is planned in California by 2017 under the California Solar Initiative, with $3 billion n rebates committed toward this goal. An onsite solar system avoids the energy losses inherent in the transmission and distribution system, which can be 10% or higher on hot summer days. In 2009, RETI projected a range of 22 to 30 cents per kilowatt-hour. Other projections demonstrate that the cost of thin-film solar promises to dramatically change the equation. According to some industry projections, thin film solar may soon cost as low as 11.4 cents per kilowatt hour. Solar thermal generators use mirrors to focus the heat of the sun on to long tubes that carry a heat transfer fluid. The fluid boils water to steam which powers a turbine and generates electricity. Nearly 360 MW of solar thermal plants have operated for 20 years or more in the desert, providing reliable power to the grid. Steam turbines powered by solar thermal technology provide energy during the day. If this system is supplemented with storage or backup fuel supply, then reliability can virtually match that of a natural gas power plant. The CEC estimates that the cost of electricity from solar thermal power plants is about 28 cents per kilowatt-hour for a merchant power plant, and below 20 cents per kilowatt-hour for a publicly owned and financed facility. Several utility companies have committed to buying power from Concentrating Solar Power (CSP) installations with large megawatt capacities by 2014. Reducing peak demand with voluntary curtailments under conditions of stress in the electric system is a valuable and local resource. Like photovoltaic's, it does not require transmission, and the infrastructure blends into existing buildings with minimal footprint. Investor-owned utility companies are required by state regulators to get 5% of their power capacity needs, equivalent to at least 2,000 MW, from demand response programs. In 2002, the CEC projected cost curves for market based demand response resources and found them to be equivalent to operation of combustion peakers. At this point, demand response programs should be decisively cheaper than building a new natural gas plant to serve the same purpose. The CEC has also indicated that demand reduction programs may actually better meet the needs of grid reliability from a technical as well as a policy standpoint.

Response:

Comment noted. Staff recognizes that efficiency programs and renewable energy strategies may be more cost effective than retrofitting or repowering the existing OTC power plants. The policy cannot mandate, but does not preclude this response. Please see the response to Comment 28.03.

Comment 28.10:
While California has aggressive energy efficiency programs, there has been only limited targeting of the primary driver of peak demand: air conditioning. Groundsource heat pumps, better home insulation and shade trees could go far toward reducing summer demand. A US Forest Service study showed that planting shade trees has the potential to avoid the need for over 700 MW of power plants in this state. These resources can be cost effective if programs are well run. California is investing $1 billion per year in energy efficiency improvements, and state regulators are planning for over 4,500 MW of capacity savings by 2020 relative to baseline growth assumptions. CPUC staff has estimated that the average cost of energy efficiency under the state's programs is between four and six cents per kilowatt-hour, which is significantly less than the average cost of generating electricity in California, and a small fraction of the cost of peak electric power that is supplied by the aging plants.
Response:
Comment noted. Staff recognizes that efficiency programs and renewable energy strategies may be more cost effective than retrofitting or repowering the existing OTC power plants. The policy cannot mandate, but does not preclude this response. Please see the response to Comment 28.03.

Comment 28.11:
Assembling a portfolio of options for replacing the aging plants and avoiding new ones would make the most sense. Because a green energy system includes demand reduction it does not require as much power plant infrastructure. In general, the energy efficiency and peak demand reduction programs are defined to be cost effective resources. In other words, the energy they save is worth more than the cost of the measures. Thus, they do not have a net cost. At worst they are zero net cost or—more typically—a net savings. Utility programs for energy efficiency have been measured and found to have a benefit to cost ratio that is better than one overall, thus verifying the assumption of zero net cost. Also, there is significant potential to improve the performance of the state's efficiency programs. California has allocated a regular budget of about $1 billion annually to achieve its energy efficiency goals. The combined efficiency and demand reduction program targets are 4,500 and 2,000 MWs respectively, for a combined savings of 6,500 MW. Assuming a program shortfall of 25%, results in a savings of 4,875 MW. Because this program is on the demand side it avoids transmission and distribution system losses, which can be 10% or higher on hot summer days when the current aging plants are most called upon. Thus the 4,875 MW of savings is worth about 5,300 MW. This portfolio is approximately equivalent to the load carrying capacity of the aging plants. However, if the state actually implements a requirement to build 33% renewables by 2020 that would create a larger reduction in need for replacement plants than what is proposed here. The efficiency component is effective in lowering the average cost per kilowatt-hour from 27.4 cents to 21.2 cents.
Response:
Staff recognizes that this is one path to meeting the requirements of this policy.

Comment 28.13:
Significant quantities of green resources can be deployed into the regions where they are needed for grid reliability. Clean energy plans for San Francisco, San Diego and the LA Basin have shown that there is a path to the future other than total reliance on new fossil fuel power

plants. Resource decisions are made at the CPUC, and by the utility companies, according to a "least cost" criteria. For example, when energy efficiency measures are evaluated, they are compared to the cost of generating comparable amounts of electricity. If the efficiency measure is less costly, then it will be prioritized. The same is true of contracts for renewable energy. Contracts are signed and power plants are "dispatched" according to the cost ranking. If full and realistic costs are imposed on environmentally destructive practices, like OTC and carbon emissions, then priority will shift toward resources that are less destructive. Thus policymakers do not need to wait passively for an abstract "market" to take the lead on energy decisions, particularly when that market has not internalized the proper costs into its assessments.

Response:

Comment noted.

Comment 28.14:

We recommend projecting appropriate internal and environmental costs onto the power plant, rather than on future ratepayers, those who pay for loss of health, or on the natural environment. A single fixed projection does not give a correct picture of the future cost of natural gas; thus the market price referent should be replaced with alternatives that better characterize risk. Market based assessments of environmental cost should be supplemented by econometric projections of future climate damages that account for the ethical implications of our choices.

Response:

Comment noted.

Comment 28.16:

The cost of the Green Energy Replacement scenario, using solar power, ranges from 22 to 29 per kilowatt-hour. If efficiency savings are included in the portfolio accounting, the average cost of green electricity is estimated to go down to about 17 to 21 cents per kilowatt-hour. This assumes that the cost of efficiency is zero. However, the state's efficiency program is more likely to result in a net savings in which case the cost of efficiency will actually be less than zero—it will generate a profit. The proposed Green Energy Scenario for aging power plants eliminates the prime externalities: damages to marine life, public health, and the global climate. Thus, the full cost of a portfolio of the Green Energy Scenario may be less than half that of new natural gas power plants.

Response:

Comment noted. Staff recognizes that efficiency programs and renewable energy strategies may be more cost effective than retrofitting or repowering the existing OTC power plants. The policy cannot mandate, but does not preclude this response. Please see the response to Comment 28.03.

Comment 29.18:

The SED's economic analysis clearly states that closed cycle cooling are more favorable when part of a new facility's initial construction or a repower of an existing facility and we agree with this position. Retrofits present significant economic and operational challenges at existing facilities. Further, the Jones and Stokes low-end estimate of $100 million to develop transmission and generation solutions in the event all of the OTC plants are eliminated has absolutely no credibility. This report cannot be relied on to develop a reasonable approach or cost estimate of policy implementation. PG&E commissioned a more detailed report from Enercon Services, Inc. and requests that the economic analysis be modified to reflect the additional detailed cost information developed by Enercon. PG&E estimates that a retrofit would raise rates by more than 10% during an estimated 17-month outage and up to 6% over a twenty year period. These are significant increases, especially when considered cumulatively with other large maintenance and construction projects undertaken to strengthen grid reliability and deliver renewable power.

Response:

Staff recognizes that there are many costs that are difficult to estimate and may be higher or lower than the SED economic analysis provides. The projected change in costs, while important, will not change the policy provisions and requirements. It is not clear that all plants will be required to retrofit and that there are several possible paths to meeting the requirements of this policy.

Comment 31.05:

RRI is committed to the California electric market and has no plans to retire Mandalay or Ormond Beach. RRI is environmentally responsible and will make economically rational investments to minimize the impact of OTC at its facilities. RRI is (1) planning to retrofit the Ormond Beach exclusion devices in a manner that would comply with the Draft Policy, (2) evaluating variable speed drives and others measures to reduce the volume of pumping at various operating levels without impacting the ability of the stations to operate when required, and (3) evaluating the seasonal nature of ecological sensitivity to determine whether some change in operations might significantly reduce the small residual impacts of operating these plants. RRI's two OTC plants currently operate as peaking facilities with low capacity utilization rates. As a result, heat treatments have been greatly curtailed and are conducted, at most, once a year. Both facilities minimize the use of circulating water pumps during non-generation periods, further reducing IMIE impacts. RRI's two OTC plants cause less than half of 1% of the impingement and entrainment impacts at all of the OTC plants, and an experienced independent biologist has found that the operation of RRI's two plants does not negatively impact fish or the aquatic environment in the areas they are located. Furthermore, the use of once through cooling at these facilities does not affect any endangered species. Yet this Draft Policy would force RRI to spend over $200 million to install cooling towers (if the space were even available) at an effective cost of $3,000 per saved fish. Also, a cost-benefit study performed by NERA found that costs to install wet cooling towers at RRI's plants exceeded benefits by a factor of 533 to 1. A policy that would require expenditures of this magnitude, when the benefits are so meager, is totally unreasonable and must be changed.

RRI believes that the intake flows at both plants can be reduced by nearly 50% from current levels under the current operating regime at a fraction of the cost of installing cooling towers, and that total annual pumping volume can be reduced to a small fraction of design flow at each unit without materially impacting the benefits to the California electric grid currently provided by these stations. If the changes RRI recommends are put into a final policy, then these two facilities are expected be able to make the necessary investments to minimize adverse environmental impacts in compliance with the policy and remain operational.

Response:

Staff commends RRI for its current and future planned efforts to minimize the impact of OTC at its facilities. Staff has considered the comments regarding removing the “feasibility” test under “Compliance Alternatives” and agrees that an owner/operator should be able to freely choose whether to meet Track 1 or Track 2 Policy requirements. Staff has therefore changed the proposed Policy accordingly.

Comment 31.54:

Section 4.10 of the SED relies on the Jones and Stokes report alone. The State Water Board should confirm that analyses performed by the Energy Agencies, and in particular the CAISO, support the conclusions in Section 4.10 of the SED. In some cases, the statements from this section beg additional analysis by the Energy Agencies. For instance, the SED states that modeling shows that the electric industry could compensate for mass OTC retirement at *"relatively modest costs to the ratepayer.*" However, Tetra Tech numbers from Table 2 show wholesale costs would need to go up 24%-30% which by any reasonable standard is a significant change. The SED also states that under all but the most extreme scenarios, more than enough power plants are expect to be operating to more than compensate for any or all OTC plant retirements. This is inconsistent with the Energy Agencies' Joint Proposal, which makes clear that no facilities can be retired without some additional transmission or generation infrastructure. The Joint Proposal also lays out a comprehensive process and schedule for additional study that the SED ignores. The SED also states that 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 projected to occur then. The CAISO has estimated that the cost of transmission upgrades for the L.A. Basin alone may be $4.45 billion or more and SCE estimated that replacing OTC capacity would likely take "decades" rather than seven to nine years as assumed in the draft policy. At the public hearing, the CPUC representative, Robert Strauss recommended that the State Water Board consider the cost impact of the Draft Policy, noting that replacing cooling systems will be "very expensive" and that the cost and environmental impacts of alternative power supplies may be high - meaning that the policy may impose billions of dollars of costs on customers. These are not "modest" costs, and a much more complete analysis of the cost impacts on electric customers and whether the benefits of the policy justify such enormous costs must be completed to comply with the economic analysis requirements of CEQA.

Response:

Staff is aware of the many constraints upon the industry and has worked closely with the California energy agencies responsible for managing the electricity grid (CALISO, CPUC, CEC) to incorporate these concerns into the policy deadlines to the maximum extent possible while being consistent with our duty to protect water quality.

Comment 31.56:

Section 5.0 of the SED states that the cost of compliance is 0.45 c/kWh based on collective generating capacity. That is a nonsensical calculation that assumes 100% operation. The annual cost of compliance divided by 2006 annual generation averages 1.13 c/kWh and ranges from 0.2 c/kWh at the combined cycle units to almost 7 c/kWh at one of the steam units. One should then compare the correct compliance cost to the wholesale price, to determine whether the cost are reasonably borne, because that is the price these units receive. That price was 4.7 c/kWh in 2006, making compliance cost 24% of price on average and a good deal more than that for the conventional steam boiler units. Ultimately what really matters for the wholesale industry is not the wholesale price, but revenues after fuel costs. These are the net revenues that are available to cover operations and maintenance expense, capital additions, and a return of and on capital. Using Tetra Tech's own numbers for gross revenues, compliance costs, and fuel prices, and using official fuel burns from EIA, a more relevant picture emerges. Thus, the cost of compliance amounts to 83% of revenues after fuel costs for almost 9 out of 10 OTC units. The 17% net revenue remaining does not leave enough money to cover operations and maintenance expense, much less continued investment or recovery of depreciation or profit. In short, when 9 out of 10 units cannot cover their operating expense based on the installation cost of a mitigating technology, that technology cannot be considered available under the CW A.

Response:

Staff does not believe industry would actually replace all the existing OTC plants and operate them at their current utilization rates. Certainly some plants will be repowered and operated at higher rates and others perhaps abandoned. Eventual cost of compliance will not equal 24% to 83% of revenues.

Comment 37.03:
The State Water Board should perform a statewide economic analysis of the Policy to evaluate whether a statewide policy would result in costs that are wholly disproportionate to its benefits as required by California law. California law requires the State Water Board to balance the environmental benefits against economic factors to determine the reasonableness of the policy. Balancing economics requires more than a mere awareness of the potential costs of the Policy; at a minimum, it requires the Board to determine whether the Policy is reasonable when its economic costs are weighed against environmental and other factors. SCE believes the Policy fails this reasonableness standard. The two-page economic analysis provided in the SED does not adequately describe or evaluate the costs (both economic and noneconomic) of the Policy and a sufficient balancing of costs and benefits is not provided. The SED's concerns regarding a detailed economic analysis that compares costs against benefits are misplaced. The "economic analysis" in the SED is inadequate and lacks context.

NERA's cost-benefit analysis of the Policy, commissioned by CCEEB, provides a starting point for complying with California law, which the State Water Board should find helpful in evaluating and further refining the Policy. The NERA report draws on guidance from federal and California agencies on methods to develop detailed cost-benefit assessments for the Policy at the affected facilities. The report provides illustrative estimates of the Policy's costs and benefits statewide. It also provides estimates of the Policy's cost and benefit at a single facility, SONGS, as an example of how to implement the site-specific alternative provided in the Policy. The primary source for cooling technology costs was the recent study by Tetra Tech for the OPC on alternative cooling systems at California's coastal power plants (Tetra Tech 2008). In addition, NERA estimated the costs of replacing power lost during construction of the cooling towers and as a result of lower net generating capacities with the towers. NERA also estimated the costs associated with changes in emissions of CO2 and other pollutants based on projected allowance prices. NERA based its benefits assessment on the methodology established by EPA for its Phase II rule to reduce impingement and entrainment from large existing power plants under Section 316(b). The primary sources for the benefits were SONGS biological studies and summary data from the SED on California's other coastal power plants. NERA also relied on species-specific information on the commercial and recreational values of fish impinged and entrained at California's coastal power plants. NERA used these values to express the potential benefits of the Policy in dollar terms. NERA made several conservative assumptions to avoid overstating the costs or understating the benefits of the Policy. It assessed whether the costs and benefits that were not monetized would likely affect the overall conclusions.

NERA's analysis shows that the statewide present-value costs of the Policy would be about $3.12 billion for only $34 million in benefits, and for SONGS about $1.7 billion in costs for only $12 million in benefits. As a result, substantial evidence suggests that if a statewide economic analysis were prepared that balanced costs against benefits, it would show that the Policy results in costs that are unreasonable and wholly disproportionate to the benefits provided. It is not good public policy to adopt a regulation with a cost that disproportionately outweighs its potential benefit. To do so puts the Board in the position of advocating that protection of marine organisms is necessary no matter what the cost, a position rejected by the Supreme Court as unreasonable.

Response:
Staff does not feel there should be any benefit/cost requirement in the policy. Estimated cost is just one of the factors to be considered in evaluating compliance with this policy. Staff and consultants have spent considerable time and effort to evaluate the potential costs imposed by this Policy. The decision to evaluate construction options to reduce IM/E by utilizing wet cooling towers was done to create a baseline cost analysis that is technologically feasible. It will not be possible for staff to calculate all the foreseeable technological options that companies must make for each individual generating unit and plant (See also response to Comment 11.44). In

addition, the State Water Board is not legally compelled to do a cost benefit assessment for adopting the Policy. Previous attempts to do such cost benefit assessments have monetized the benefits in terms of commercial fishing values. Staff strongly disagrees with that approach. Monetizing based on commercial fishery values does not take into account the ecological value of organisms lost through IM/E. Staff believes the ecological value to be of paramount importance in terms of environmental protection, and there are currently no means for providing monetary values to marine life in that context (Please also see response to Comment 20.04).

Comment 37.13:
The NERA analysis assumes that it is feasible to switch to closed-cycle cooling at SONGS, ignoring the conclusion that insuperable physical, practical, and regulatory barriers discussed above make the installation of cooling towers at SONGS infeasible. It would be important to expand the cost-benefit assessment for SONGS to include evaluations of the costs and benefits of other technologies that could reduce impingement and entrainment.
Response:
Please see response to Comment #37.03.

Comment 37.14:
The SED suggests that the owners of some plants may choose to repower plants in configurations that include closed-cycle cooling. This analysis is conflict with statements in the draft staff paper issued jointly by the CEC, CAISO, and CPUC indicating that "it is possible that the majority of power plant operators will retire their existing facilities rather than invest money to refit old technologies to meet the proposed State Water Board requirements. To the extent generators decide that it would be less costly for them, on net, to comply with the Policy by proposing to repower or simply shutting down, the incremental net cost of repowering or shutting down must be analyzed.
Response:
Please see response to Comment 37.03.

F. GENERAL COMMENTS

1. Process

Comments 3.02 and 24.01:
We thank the State Water Board and staff for their dedication to this important issue. Staff has done a commendable job of coordinating with the CEC, CAISO, the Ocean Protection Council ("OPC") and its member agencies, and other agencies in the continued development of this policy. Multiple federal and state agencies have recognized that OTC causes significant, ongoing devastation to our valuable marine resources.
Response:
Staff appreciates the comment and the support for the Draft Policy. Staff also appreciates the submission of suggestions for possible improvement of the Policy and the SED. We have responded to issues and concerns specifically identified in further detail in the commenter's submission. Staff agrees that OTC has major impacts to the State's marine resources, and believe that the Policy, when implemented, should significantly reduce these harmful IM/E impacts of OTC on marine life. The Policy was developed with input from many agencies and the public, which has considerably strengthened and improved the Policy. Staff looks forward to the continuing support and advice from many agencies through SACCWIS, the Review Committee, and other avenues during the implementation phase of the Policy.
Comment 6.01:

Staff has done a remarkable job of working with the various stakeholder groups in the development of this draft policy and incorporating many of the concerns of the OPC, on which I serve.

Response:

Staff appreciates the comment.

Comment 11.13:

The State Water Board failed to properly notice the completion of the SED and include the requisite information. The State Water Board also failed to provide public notice that the September 16, 2009 hearing would include an environmental review. Under CEQA, a public notice of the availability of a draft EIR must specify the period during which comments will be received, the date, time, and place or any public meetings or hearings on the proposed project, the significant effects on the environment, if any, anticipated as a result of the project, a brief description of the project, and the address where copies of the draft EIR are available (14 CCR § IS087(c)). The Board needs to remedy this failure before the hearing at which they will consider adopting the Policy.

Response:

Title 23, Cal. Code of Regulations, §3777 requires that for a certified exempt regulatory program, any plan proposed for board approval must be accompanied by a completed Environmental Checklist and a written report, containing a brief description of the proposed activity, reasonable alternatives to the proposed activity and mitigation measures to minimize any significant adverse environmental impacts of the proposed activity. The draft SED described the proposal and included sections exploring issues and alternatives as well as environmental effects and mitigation. The draft SED was posted on the State Water Board's website on July 15, 2009, and notification of its availability was circulated to interested parties on that date. The Notice of Public Hearing, circulated on July 9, 2009, stated the anticipated date of the draft SED availability. Although not required for a certified exempt regulatory program, the State Water Board also submitted a Notice of Completion and Environmental Document Transmittal for the SED to the State Clearinghouse and Planning Unit, which coordinates the state-level review of environmental documents pursuant to CEQA.

Comment 11.41:

The Board must prepare written responses to written comments raising significant environmental points received at least fifteen days "before the date the board intends to take action on the proposed activity. If written comments are received later than fifteen days before, the Board should prepare written responses if feasible; otherwise, the Board must respond orally to those late written comments and to any oral comments received at the Board meeting.

Response:

Comment noted. Staff is required to follow these requirements.

Comment 12.15:

Given the significance of the OTC Policy, it is critical that the State Water Board thoroughly consider all relevant factors in the development of the Policy. Although the State Water Board has been discussing and evaluating a Section 316(b) Policy for some time now, the current version of the Policy and SED were released just over two months ago. The owners and operators of the facilities affected by the Policy have not had adequate time to evaluate the Policy and SED and comment on those documents. Under these circumstances, it would be reasonable and appropriate for the State Water Board to provide the affected parties additional time to review, analyze and comment on the Policy and the SED. We are recommending and requesting an additional 30 days. RRI will use this additional time to prepare and provide specific comments on the SED and recommendations for amendments and revisions to the proposed Policy.

Response:

Comment noted. Staff agrees that it is critical that the State Water Board thoroughly consider all relevant factors in the development of the Policy, but disagrees with the statement that the owners and operators of the facilities affected by the Policy have not had adequate time to evaluate the Policy and SED and comment on those documents. The public is required to be given at least 45 days to review and respond to a new Policy. The public was given 90 days to submit comments on the OTC Draft Policy and SED, and an informal workshop and a Hearing was held during this period to allow the public further opportunities to ask questions and provide comment.

Comment 26.01:

Coastkeeper commends the State Water Board's commitment to increasing the water quality of south Orange County and sincerely hope to continue our partnership in making this coastal environment sustainable. We appreciate the amount of hard work and dedication the creation of a Draft SED and Draft Policy demands and hope our comments and recommendations are considered in the light they are delivered. Additionally, staff has done a commendable job of coordinating with the CEC, CAISO, the OPC and its member agencies, and other agencies in the continued development of this policy.

Response:

Staff appreciates the comment. Please see the response to Comment 3.02.

Comment 31.22:

The Board failed to properly notice the availability of the SED. Under the Board's own CEQA regulations, any standard, rule, regulation or plan proposed for Board approval or adoption must be accompanied by a written report analyzing the environmental impacts of the proposed activity, alternatives and mitigation measures. Upon completion of the report, the Board shall provide a Notice of Filing of the report to the public, which must specify the significant effects on the environment, if any, that are anticipated to result from the proposed activity. The notice dated July 9, 2009, states that the "proposed Policy and supporting documents* are available on the State Water Board website." The asterisk referred to a statement at the bottom of the page: "The Substitute Environmental Document that supports the policy is projected to be available by July 15, 2009." Upon completion of the SED, the Board did not notice its availability nor specify the anticipated significant effects on the environment.

Response:

Please see response to Comment 11.13.

Comment 31.23:

The Board failed to give adequate notice that the hearing on September 16, 2009 was to include environmental review. If an agency provides a public hearing on the project, environmental review should be expressly identified as one of the subjects for the hearing. The State Water Board provided notice that the September 16, 2009 hearing was to be held to "receive comments on a proposed statewide policy on the use of coastal and estuarine waters for power plant cooling." The notice, however, gave no indication that the hearing also included comments on the SED.

Response:

Please see response to Comment 11.13.

Comment 31.24:

The Board is required to submit the scientific portions of the proposed Draft Policy and SED, to the extent they support the conclusions and assumptions contained in the Draft Policy, to external scientific peer review. A prior version of the Draft Policy was submitted for peer review, but the SED was not. The proposed Draft Policy and SED were not re-submitted to peer review follow substantial changes to the Draft Policy, and therefore the Board cannot take any action or adopt the final version until they are evaluated by external peer reviewers.
Response:
The Draft Policy does not rely on any scientific data that need to be peer reviewed.

Comment 39.03:
USEPA has not yet promulgated national regulations for cooling water intake structures at existing power plants, and a definite schedule for final rule adoption is not yet in place. If the State Water Board adopts this policy on schedule, USEPA Region 9 Water Division is committed to working with the regulatory development team in Washington to coordinate EPA rulemaking with the California policy. We are hopeful the State Water Resources Control Board can adopt a final policy in December, and that the final Policy will serve to inform the national efforts to minimize the impacts of cooling water intakes on the environment.
Response:
Staff is working diligently toward bringing this policy to the State Water Board for consideration as soon as possible. Staff sincerely hopes that this Policy will serve to inform USEPA's national efforts on OTC, and appreciates USEPA Region 9 Water Division's support of the Draft Policy.

Comment 47.03:
The elimination of the "wholly disproportionate" test and the new definition of "feasibility" to exclude cost considerations are not minor, non-substantive language revisions. On the contrary, these changes have major consequences by potentially forcing more facilities into premature retirement, with attendant environmental impacts. In summary, the SED's one-page CEQA analysis of indirect and cumulative impacts is far more abbreviated than CEQA allows. The SED does acknowledge, albeit cursorily, that the OTC Policy foreseeable could result in increased infrastructure construction. By eliminating the "wholly disproportionate" test and narrowing the definition of "feasibility" to exclude cost, the revised Policy risks forcing additional facilities into potential retirement. The Revised Policy thus foreseeably could result in further increased infrastructure construction and attendant cumulative impacts. When project changes result in new or substantially more severe environmental impacts that were not analyzed in the initial draft CEQA document, the document must be revised and recirculated for additional public review and comment. CEQA Guidelines, § IS088.S(a). Accordingly, recirculation of the SED is essential in this instance.
Response:
Comment noted. The WDD previously included was available only to nuclear-fueled facilities and those having previously installed more efficient technology. New provisions allowing for alternative requirements for these facilities are now included. Thus, elimination of the WDD is not a major change because it does not alter the manner in which compliance will be required for most of the facilities and does not significantly alter the implementation provisions for nuclear facilities and those having previously installed combined-cycle technology. Feasibility (or infeasibility) is no longer defined in the proposed Policy, and a showing of infeasibility is no longer required for Track 2.

Staff believes that the SED is adequate and meets legal requirements. Recirculation of an environmental document is required only when "significant new information" is added. New information is not "significant" unless the environmental document is changed in a way that deprives the public of a meaningful opportunity to comment upon a substantial adverse environmental effect of the project or a feasible way to mitigation or avoid such an effect that the project's proponents have declined to implement. Minor modifications to cost considerations for subsequent compliance determinations for the nuclear facilities and allowances for previously-installed combined-cycle technologies do not come within the meaning of significant new information requiring recirculation.

Comment 54.04:
The development of the State's Section 316(b) policy is an iterative process. We encourage the State Water Board to circulate an associated revision to the November 23rd draft, providing more notice and time to which to comment.
Response:
Staff agrees that developing a solid Policy requires an iterative approach. Based on public comments, Staff has revised the November 23rd version of the Draft Policy and releasing it for public review and comment.

2. Incorporation of comments by reference

Comment 1.05:
We hereby incorporate by reference the comments submitted by CCEEB, SCE, LADWP, Dynegy, RRI, and NRG Energy.
Response:
Comment noted. Staff has responded to issues and concerns specifically identified in further detail in the commenter's submission. Staff has drafted separate responses to specific issues raised by other interested persons.

Comment 3.01:
We incorporate by reference our previous two comment letters on this topic, dated May 20, 2008 and September 15, 2006, which are attached separately. We also include and incorporate by reference testimony that California Coastkeeper Alliance provided to the Assembly Committees on Natural Resources and Utilities and Commerce at their joint hearing regarding OTC on March 2, 2009.
Response:
Comment noted. Staff has responded to issues and concerns specifically identified in further detail in the commenter's submission. Staff has considered comments received in response to earlier drafts, and the current proposal reflects changes based in part on earlier input. Staff cannot determine which of the many comments made by the commenter have been adequately satisfied through the process of consideration and reconsideration by the State Water Board, and which have not. Without specific information and explanation of the remaining issues applicable to the current proposal, staff does not have a fair opportunity to address these concerns. Comments directed to the legislative process must identify specific issues within the State Water Board's authority and relevant to the current proposal. The commenter has not provided such information.

Comment 4.15:
CCEEB appreciates that other commenters have focused more time on the shortcomings of the SED than has been the case with this letter and incorporates those comments by reference.
Response:
Staff has responded to issues and concerns specifically identified in further detail in the commenter's submission. Staff has drafted separate responses to specific issues raised by other interested persons.

Comment 8.02:
We have reviewed and support the comments submitted by the Environmental Law and Justice Clinic at Golden Gate University School of Law on behalf of Bayview Hunters Point Community Advocates and Communities for a Better Environment.
Response:
Staff has responded to issues and concerns specifically identified in the commenter's submission. Staff has drafted separate responses to specific issues raised by other interested persons.

Comment 29.02:
We incorporate our prior comments submitted in 2006 and 2008 by reference, which should already be a part of the administrative record in this proceeding.
Response:
Staff has considered comments received in response to earlier drafts, and the current proposal reflects changes based in part on earlier input.

Comment 33.01:
On behalf of San Francisco Baykeeper and our members, I would like to thank you for this opportunity to provide input on the State Water Board's proposed OTC policy. We fully support and integrate by reference the letter submitted on September 30, 2009 by the California Coastkeeper Alliance ("CCKA").
Response:
Comment noted. Staff has responded to issues and concerns specifically identified in further detail in the commenter's submission. Staff has drafted separate responses to specific issues raised by the California Coastkeeper Alliance.

Comment 37.01:
Southern California Edison (SCE) respectfully requests that the Board include all prior comments (written and oral) and attachments thereto, on the Policy or prior versions of the Policy, or scoping documents, to be included in the administrative record of this Policy. We have attached SCE's prior comments as Exhibits A, B, and C. SCE incorporates the contents of those letters by reference.
Response:
Comment noted. Staff has responded to issues and concerns specifically identified in further detail in the commenter's submission. Staff has considered comments received in response to earlier drafts, and the current proposal reflects changes based in part on earlier input. Staff cannot determine which of the many comments made by the commenter have been adequately satisfied through the process of consideration and reconsideration by the State Water Board, and which have no, and can therefore not address these concerns.

3. Submitted presentations

Comments 17.01, 21.01a, 30b, 38.01:
Presentation submitted for the September 16, 2009 Public Hearing in Sacramento.
Response:
These comments were responded to at the September 16, 2009 Hearing.

4. Identified discrepancies and errors

Comment 9.04:

The lack of reasonable expectation that OTC would be phased out by compliance dates listed in the policy is due to its failure to define such key terms as “demonstrate”, "wholly disproportionate," “necessary for operations,” "feasible," "cost-benefit," "alternative, less stringent requirements," "any relevant information" and "to the extent practicable." We are at a loss to understand how the policy could be enforced without such terms being defined and their proper application being explained. Such vague nomenclature has caused substantial uncertainty and controversy over statutory requirements, which have been--and continue to be--dealt with by the courts and other state and federal agencies. The State Water Board must recognize and learn from this, requiring staff to draft a clear and unambiguous policy, providing guidance as to what is meant or not meant by these terms that will be straightforward to implement and thereby avoid further legal disputes.

Response:

Staff has strived to write a policy that is as clear as possible, recognizing that it is also possible to be overly prescriptive and not allowing enough flexibility for the permit writers at the Regional Water Boards to address site-specific conditions. The commenter does not mention where in the Policy the terms that need defining are located; several of these terms are used in various places in the Policy. Based on public comments, staff has removed the “feasibility” test from Track 2 and the section on the “wholly disproportionate demonstration”, which had included the words "wholly disproportionate”, “demonstrating”, "alternative, less stringent requirements", "any relevant information", and "to the extent practicable. " Cost-benefit” was not used as a term, but was described in this section, which has now been removed. “Necessary for operations” is found in the section describing “Immediate and Interim Requirements”. Staff believes that this term is sufficiently clear when read in context.

Comment 9.06:

The data on plant intake flows in the SED, which may be used to determine enforcement, are sometimes outdated, invalid and inappropriate in the use of baseline figures from years past, given the significant changes that have occurred at plants in those respects over the past five to six years. For instance, Table 4 shows the design flow for Morro Bay Power Plant for the four original units (i.e., 668 mgd). This number should be reduced to reflect the flow for the two units currently operating since the other two have been permanently taken off line.

Response:

Although two of the original four units at the Morro Bay Power Plant have been taken off line, the original design structure of the seawater intake is 668 mgd. The actual use by the two remaining units is expressed in Table 35 as an average flow of 257 mgd. The actual use does not change the design flow. Staff used the most recent data available for the preparation of the SED, site specific information will need to be evaluated on a case-by-case basis for each facility as it determines how it will comply with the Policy. The SED evaluates the broad potential environmental impacts of the Policy, while project specific environmental review will be required for each facility as it comes into compliance.

Comment 9.16:

Using data based on historically permitted use instead of actual current capacity to determine how to phase out old plants overstates the amount of generation lost by the plants being phased out and distorts the need for the energy they produce.

Response:

Staff used the best historical data available at the time of developing this policy. We realize that there can always be better data made available in the future but we are unwilling to wait for that data in order to proceed. In addition, State Water Board staff are not energy experts and therefore are relying largely on the energy agencies on the IAWG to inform the implementation schedule.

Comment 9.24:
The Capacity Utilization figures listed in the draft SED are for the years 2001 to 2006. More recent data should be used to give a more accurate picture of the current situation. This includes dependable capacity as well as all utilization and operational realities, given the significant changes that have occurred at the plant in those respects over the past five to six years. For instance, though the design capacity of these two remaining units of Morro Bay Power Plant is 600 MW combined (not the 1002 MW listed for the four original units), the dependable capacity is far less than this because the plant cannot run anywhere near full capacity without exceeding air pollution limits. Furthermore, Table 13 on page 62 uses a different set of years than the Capacity Utilization chart on page 35, showing years 2000 to 2005 instead of 2001 to 2006. Again, data from more recent years AND data for the same years or time period should be used.
Response:
Capacity utilization rates (CURs) are provided in Tables 4 and 11. Table 13 provides flow information, but not CURs. Table 4 shows CUR information from 2001-2006 while Table 11 shows similar CUR information but for 2000-2005. Staff used the most recent data that were available at the time of report preparation. A cutoff date had to be made to analyze the data and write the report. The most recent data available at the time of information collection were used and included in the SED. The SED uses the most available data from the CEC and USEPA. While data from more recent years may be desirable, staff does not believe it would be appreciably different from the data presented, nor would it change anything in the analysis of the Policy.

Comment 15.01:
Several critical terms, “wholly disproportionate”, “feasible”, “cost/benefit” are left undefined. These concepts have been the subject of discussion in the courts. The State Water Board has an obligation to provide guidance as to what is meant or not meant by these terms in order to avoid an endless re-hash of the decisions dealt with by the courts.
Response:
Comment noted. Based upon comments, Staff is proposing to eliminate the “WDD” provisions, and thus there is no longer a need to define “wholly disproportionate” or “cost/benefit”. Staff defined “infeasible” in the November 23, 2009 version of the Draft Policy, but based on comments it was decided that operator/owners should be allowed to choose between Track 1 and 2 equally without having to prove that Track 1 was infeasible. Thus there is no longer a need for defining “feasible”.

Comment 15.03:
Why are outdated data used in the document? The information on the Morro Bay power plant is so incorrect as to be misleading. The Design Flow was for four units, two of which have been mothballed, so the Dependable Capacity for the remaining two units is not 300 MW per unit, particularly as the plant cannot run that much without exceeding air pollution limits. The Capacity Utilization figures listed are for 2001-2006; more recent years should have been used to give a more accurate picture of the current situation. Again, in Table 10, the Capacity is listed as 1002 MW, which was for the four original units, not the two remaining ones. In Table 13 a different set of years is used, 2000-2005, again not for the most recent years, and again listing the no longer valid Design Intake Flow of 668 which was for the original four units. The intent of the State Water Board policy presumably is to phase out aging, dysfunctional coastal plants as per the California Energy Action Plan; therefore the policy should provide the actual current capacity. That is what should be used as the baseline for phasing out old plants. To do

otherwise would overstate the amount of generation lost by the phasing out process. If the information on other plants is similarly outdated this should also be corrected.
Response:
A cutoff date had to be made to collect and analyze the data and write the report. The most recent data available at the time of information collection were used and included in the SED.

Comment 20.06:
Staff has misrepresented the cumulative impacts analysis performed by MBC and Tenera (2005). We object to the use of this data out of context from its original presentation. The SED states that MBC and Tenera (2005) "estimated that, for 12 coastal power plants in the Southern California Bight, there is an overall cumulative entrainment mortality of 1.4 percent of the larval fishes in the Bight." The 1.4 percent mortality was not based on empirical biological data, but several assumptions, including an assumed source water and maximum cooling water flow at the power plants. As shown in the draft SED, actual statewide cooling water flows are only about one-half of the permitted maximum. Another assumption included a relatively long larval duration (exposure to entrainment) of 40 days. Also cited is MBC and Tenera's estimation of Bight-wide impingement, which was required by the CEC . It is unclear why these estimations from 2005 are cited since there is now empirical impingement data for every power plant in southern California (see Table 3 of the draft SED). The comparison of impingement and recreational fish landings is also reported out of context, since there is a large disparity between the fish species impinged and those targeted by recreational anglers.
Response:
Staff disagrees. We correctly understood that the cumulative mortality figure was based on certain assumptions, and we clearly represented in the SED that the cumulative entrainment of 1.4% was an estimate. While the estimate is based on permitted maximum flow, this information is intended to give a cumulative worst case scenario for the Southern California Bight based on current permit limits. Regarding inclusion of the cumulative impingement estimate, again this was intended to present a worst case scenario based on permitted lows. The impingement data (in Table 3) currently available still does not include comprehensive numbers of fish impinged at design flows for four southern CA power plants. The cumulative impingement estimate presented in terms of % of recreational catch was intended only as a comparison with another form of pressure on fish. Please see the response to Comment 20.09.

Comment 20.10:
The relationship between cooling water flow and power generation are plotted in Figure 10, but there are only six data points. The statement is made that cooling water flow and power production are linearly correlated. It is unclear why there are only six data points in this graph.
Response:
Each data point in Figure 10 represents one of the years from 2000–2005, the period of study that was available when the study was being conducted. Although there are only six data points in Figure 10, each data point shows the combined annual cooling water flows of ALL power plants versus power generation by ALL power plants for that year. The power generated by all OTC power plants in each of the six years is represented by a point on the Y-axis in Figure 10. This is the same value that is shown in Table 10 under the row heading of "Gross OTC Power Produced (GW/h)." For example, the first point in Figure 10 corresponds to power generation in 2005.

Comment 20.11:
The titles for Tables 16 and 17 are incorrect, since many mammals and sea turtles are never 'impinged'. It should be clarified that marine mammal and turtle "impingement" is rare. Instead, animals are usually entrapped and subsequently removed from circulating water systems.

Response:
Staff agrees that a better term would be “entrapped”. Entrapment of threatened, endangered and otherwise legally protected species constitutes “take” as defined in federal and state law, even in the case of ultimate survival.

Comment 20.12:
The title for Table 18, for example, is “Existing IM/E controls and Mitigation Efforts at the OTC Facilities”. However, no mitigation information is listed.
Response:
Staff agrees and will edit the SED accordingly.

Comment 23.15:
The SED is misleading and flawed because its analysis of the Draft Policy relies on facility data from 2000-2005. This period includes the 2001 energy crisis and is accordingly wholly unrepresentative of current operating conditions. Operational data from the more recent and more representative five-year period of 2004 through 2008 are readily available and provide a much more accurate baseline against which to analyze the effects of the proposed Policy. For example, Table 11 of the SED identifies Contra Costa PP Units 6-7 and Pittsburg PP Units 5-6 as having a capacity utilization rate of 28% and 29%, respectively, for the period of 2000-2005, and notes further that, based on the capacity utilization rates, neither facility would be below the 15% capacity utilization threshold entrainment exemption provided in the Phase II Rule. Similarly, Table 13 shows Contra Costa PP Units 6-7 and Pittsburg PP units 5-6 as having an average flow of 257 mgd and 274 mgd, respectively. While these data are historically accurate, they are irrelevant in that they do not accurately represent current and likely future operating conditions. The capacity utilization rate for Pittsburg PP for the more recent five-year period of 2004-2008 is 8.8%, and the corresponding rate for the Contra Costa PP is 5.2%. Based on these data, the Delta Plants clearly would be far below the 15% threshold in the Phase II Rule. Annual average cooling water flows for the same period were 75 mgd at the Contra Costa PP and 87 mgd at the Pittsburg PP, or roughly just a third of the level of flows assumed in the SED. Thus, the operations of the Delta Plants are dramatically different than as documented in the SED, rendering the SED's baseline and environmental setting inaccurate and misleading. The SED should be revised to incorporate the readily available, more recent and representative operational data, and its analysis should reflect this more accurate baseline and environmental setting.
Response:
Comment noted. Staff appreciates the new data. However, at some point in developing the SED, staff had to stop collecting and analyzing data and finalize the draft SED. The most recent data available at the time of information collection were used and included in the SED. While it would be more informative to include newer data, staff does not believe newer data would substantially alter the conclusions reached in the SED.

Comment 29.31:
SED, Page 3, Table 1: There is no pending lawsuit regarding Diablo Canyon’s NPDES permit. The administratively extended permit contains a finding that the cooling water intake structure reflects best technology available. The Central Coast Board held a hearing regarding alleged thermal discharge non-compliance in March 2000. This hearing was closed and a tentative settlement reached, incorporating both thermal and Section 316(b) issues in October 2000. The settlement was reviewed and approved by the Central Coast Board in March 2003. The parties signed the document in June 2003. However, the Central Coast Board did not renew the NPDES permit in July 2003, as contemplated in the settlement agreement. Thus, the permit remains on administrative extension and the settlement is on hold.

Response:
Water Board staff have no knowledge of a pending lawsuit at this time. In 2000, Central Coast Water Board staff brought an enforcement action against PG&E for alleged permit violations regarding thermal effects. The Central Coast Water Board heard all the evidence and postponed their decision to a future meeting to allow staff and PG&E the opportunity to propose a settlement. Staff tentatively agreed to a settlement that incorporated both thermal effects and Section 316(b) issues (although staff did not allege any violations regarding Section 316(b)), and the Board members at that time agreed to consider the settlement during an NPDES permit renewal hearing at a public meeting. Staff then brought a draft NPDES permit with the tentative settlement to the Board in 2003, and the Board (with new Board members) did not accept the settlement and therefore did not adopt a new NPDES permit. Instead, the Central Coast Water Board directed staff to provide more information on additional mitigation alternatives, and staff completed this assignment. Since the Central Coast Water Board has not officially adopted a settlement, staff's enforcement action against PG&E regarding alleged thermal effects is still pending. Staff and the Central Coast Water Board have determined that it is best to hold this matter in abeyance pending the resolution of the federal court cases regarding Section 316(b), and wait until the State Water Board adopted its proposed OTC policy, and then negotiate a global settlement with PG&E and bring a new NPDES permit to the Board. In the meantime, the permit is on administrative extension. It is Central Coast Water Board staff's opinion that PG&E is in violation of its permit regarding thermal effects.

Comment 29.32:
SED, Page 85, Table 20: The salt water cooling tower facility list includes a facility that identifies PG&E as the project owner. This is Pittsburg Unit 7 and Mirant is the current owner.
Response:
The commenter is correct: Mirant Services LLC acquired the Pittsburgh plant in 1999.

Comment 29.33:
SED, Page 108: Gateway is a combined-cycle dry cooled facility. It has been operational since 2008.
Response:
The commenter is correct: PG&E's Gateway Generating Station is a combined-cycle dry-cooled facility.

Comment 31.25:
At page 13, the SED mischaracterizes the Draft Policy when it states, "In limited circumstances, a facility may request alternative requirements if it demonstrates that the costs of compliance under Track 1 or Track 2 would be wholly disproportionate to the benefits to be gained." There are no circumstances in which the vast majority of the affected facilities can request alternative requirements under the Draft Policy. While the Draft Policy should be changed, this statement should be changed to accurately describe the Policy as proposed - only a very limited number of facilities may seek such alternate requirements based on criteria that have nothing to do with water quality or impacts on marine life.
Response:
Based on public comments, Staff is proposing to eliminate the wholly disproportionate provisions, and has revised the SED accordingly. However, staff believes that the words “limited circumstances” accurately described the Policy as proposed – i.e., that only a limited number of facilities could apply for the WDD.

Comment 49.03:

The statement “The State Water Board recognizes it is necessary to develop replacement "infrastructure to maintain electric reliability in order to implement this Policy” implies that it is the State Water Board's responsibility to ensure that replacement energy generation is developed. This should be removed or clarified to make clear that it is the Board's statutory obligation to protect water resources first and foremost.

Response:

The STATE WATER BOARD is not attempting to use this Policy to implement a state energy policy. As stated in the draft SED, the goals of the proposed OTC policy is to: (1) reduce IM/E impacts from OTC facilities; (2) implement Section 316(b); (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 grid stability; and (5) reduce the resource burden on the Regional Water Boards that would continue under the existing BPJ-permitting approach.

Comment 61.08:

Under Section 1.3.2 of the SED, it would be useful to indicate that Track 1 and 2 are options under the Phase I Rule, so there isn't any confusion with the use of Track 1 and 2 under the proposed policy.

Response:

Staff believes this is clear in the SED, which states: “The Phase I rule is based on USEPA’s determination that, for new facilities, the Section 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.”

Comment 61.09:

SED, pg. 7 par. 4: Does not include industrial use as one f the beneficial uses listed under Porter-Cologne.

Response:

The SED previously simply referred to “other beneficial uses” but staff has added “industrial water supply” to the text.

Comment 61.10:

SED, pg. 8 par. 5: This text implies that the EPA draft guidance for evaluating Section 316(b) is out of date due to "the more accurate methods available to quantify the true nature of these impacts." In contrast to this statement, the methods and analyses used to quantify the effects of CWIS on marine organisms have actually changed very little over the decades since the first studies were conducted in the 1970s. The guidance actually lays out a methodology for a very thorough assessment of the potential for AEI that was used recently in assessing the effects of the LADWP facilities in southern California. The problem was the inconsistent quality of some of the earlier studies, not the guidance.

Response:

To avoid confusion staff is removing the clause “nor the more accurate methods available to quantify the true nature of these impacts.”

Comment 61.15:

SED, pg. 30, par. 3: The estimates of impingement for South Bay Power Plant are not correct. The estimate using design flow was 350,000 fishes not 390,000. The impingement and entrainment estimates presented for this plant are the design flow estimates even though the plant has a low capacity factor resulting in low average daily flow rates.

Response:

Staff was simply using the previous operator's (Duke Energy) Proposal for Information Collection dated November 8, 2005. That report is clearly referenced in the SED. However staff is also adding a statement to that paragraph referring to the more recent estimates for that plant, which is provided elsewhere in the SED.

Comment 61.17:

SED, pg. 42, Sec. 3.1: States that the USEPA has not provided any clear indication "as to its intent to revise or reissue the suspended Phase II Rule ..." In fact, the USEPA has notified EPRI and other stakeholders of its intent to reissue the rule.

Response:

Staff stands by its statement in the SED. In its letter of September 30, 2009 to the STATE WATER BOARD, the USEPA states that it has not yet promulgated regulations and a definite schedule is not in place.

Comment 61.23:

SED, pg. 81, par. 2: Incomplete sentence.

Response:

Staff is unclear on this comment; the incomplete sentence was not discovered on p.81 par.2.

Comment 61.24:

SED, pg. 81, par. 3: Paragraph repeated on Page 82.

Response:

Typo corrected.

Comment 61.25:

SED, pg. 81, par. 4: Table number missing.

Response:

Typo (formatting error) corrected.

III. DRAFT RESPONSE TO COMMENTS SUBMITTED BY THE APRIL13, 2010 DEADLINE ON PROPOSED CHANGES TO THE NOVEMBER 23, 2009 DRAFT OTC POLICY

Change	Comment Letter and position	Response
Overall Policy	Letters # 67, 89, 96, and100 in support of the Policy	Staff appreciates the support for the Policy.
	Letters # 63, 66, 75, 84, 85, 86, 101, 102, 103, 104, 106, 112, 118, 119, 126, and 127 mostly in support of the Policy if minor modifications are made	While staff acknowledges that the proposed changes may the readability of the Policy, the alterations would not change the meaning and are therefore not required for purposes of clarity.
	Letters #64, 65, 68, 70, 72, 73, 76, 77, 78, 79, 80, 81, 82, 83, 88, 91, 92, 93, 94, 95, 97, 98, 105, 107, 108, 110, 111, 113, 114, 115, 117, 120, 121, 122, 123, and 128 et al. against adopting the Policy without major modifications	While staff appreciates the submitted suggestions for improvement to the Policy, staff believes that the proposed changes to the November 23, 2009 Draft Policy are minor and have improved the clarity and readability of the Policy. In staff's opinion, the suggested modifications have been addressed earlier or do not improve the Policy.
	Letters #87, 90, and 109 against adopting the Policy	Comment noted.
Process	Letters #126 and 115 believes the process has been open and resulted in improvements	Staff appreciates the comment.
	Letters #64 and 115 believes more time is needed for stakeholder review and input	Staff disagrees that additional time is needed for public review of the latest modifications to the Policy. The public were given ample time to review the latest changes to the Policy.

Change	Comment Letter and position	Response
	Letters #65, 75, 121 believes that the State Water Board should provide written responses to public comments at least 15 days before an adoption meeting.	Title 23 of the California Code of Regulations, Section 3779, subsection (a), provides that the Board shall prepare written responses to comments containing significant environmental points raised, if such comments are received at least fifteen days before the date the Board intends to take action. Copies of such written responses are to be available at the Board meeting. For comments received less than fifteen days prior, the Board should prepare written responses to the extent feasible. There is no legal requirement for public review of the staff response to comments for any specified period before the Board intends to act. However, staff responses to comments are generally circulated for public review some days before an adoption meeting as a courtesy, to provide information to the public.
CEQA	Letters # 65, 73, 75, 92, 116, and 122 believes that changes to the Policy are not supported in the SED	Staff disagrees that the SED does not adequately support the Policy. The SED was modified to incorporate the latest changes to the Policy. Because these changes are minor and clarifying, the SED was accordingly only changed slightly.
	Letters #101 in favor but suggest modifications for better clarity	While staff acknowledges that the proposed change may make the SED more readable, the alteration would not change the meaning and is therefore not required for purposes of clarity.
Section 1.G modified	Letter # 92 against	Staff disagrees. The purpose of this change was to clarify that costs were considered when developing the Policy.
Section 1.L added	Letters # 115, 122, 123 against	Staff disagrees. The purpose of this change was to address greenhouse gas emissions from nuclear power plants.
	Letters #121 in favor	Staff agrees.
	Letters # 99 in favor but suggest modifications for better clarity	While staff acknowledges that the proposed change may be more readable, the alteration would not change the meaning and is therefore not required for purposes of clarity.
Section 1.N added	Letters # 74 in favor	Staff agrees. The purpose of this change was to clarify that the Policy does not limit Regional Water Boards from regulating discharges of wastes from power plants. The Policy was never intended to address discharges from power plants.

Change	Comment Letter and position	Response
	Letters # 92 in favor but suggest modifications for better clarity	While staff acknowledges that the proposed change may be more readable, the alteration would not change the meaning and is therefore not required for purposes of clarity.
Sections 2.A and 2.A.(2) modified Section 5 modified	Letters # 64, 65, 75, and 120 against	Staff disagrees. The purpose of this change was to allow the owner or operator of an existing power plant the flexibility of choosing either Track 1 or Track 2 as compliance alternatives. Since Track 1 and Track 2 have comparable level of protection there is no need to impose a feasibility test. The removal of the feasibility test alleviates additional Regional Water Board workload and the potential for inconsistent application between Regional Water Boards.
	Letters # 122 in favor but suggest modifications for better clarity	While staff acknowledges that the proposed change may be more readable, the alteration would not change the meaning and is therefore not required for purposes of clarity.
Sections 2.A.(2) and 2.A.(2)(a-b) modified	Letter # 65 against	Staff disagrees. The purpose of this change was to provide clarity on how compliance will be measured for entrainment and impingement under alternate approaches. Track 2 is meant to allow for alternate approaches to achieve compliance. Power plants relying solely on reductions in flow and velocity for compliance will not be allowed a 10% allowance for uncertainty in the performance and measurement of unproven technology and must report monthly. Plants relying on other control technologies must monitor as specified in Section 4 of the Policy. If screens are used, the Policy now specifies that compliance will be based on ichthyoplankton and on the crustacean phyllosoma and megalops larvae and squid paralarvae fractions of meroplankton.
	Letters # 73, 122, and 126 in favor but suggest modifications for better clarity	While staff acknowledges that the proposed change may be more readable, the alteration would not change the meaning and is therefore not required for purposes of clarity.
	Letters # 92 and 115 suggest substantive modifications	While staff appreciates the submitted suggestions for improvement to the Policy, staff believes that the proposed changes to the November 23, 2009 Draft Policy are minor and has improved the clarity and readability of the Policy. In staff's opinion, the suggested modifications do not improve the Policy.

Change	Comment Letter and position	Response
Section 2.A.(2)(d) modified	Letters # 117 and 122 against	Staff disagrees. The purpose of this change was to provide clarity on compliance options for facilities with combined-cycle power-generating units. The previous version of the policy stated that reductions in entrainment and impingement resulting from the prior installation of combined-cycle power-generating units could be counted towards meeting Track 2 requirements for the entire facility, but did not describe the method that would be used. Previously mitigated discharges may now also be counted towards meeting Track 2 requirements for the entire facility. The policy now also specifies, as a compliance alternative, that existing combined-cycle power-generating units that meet through-screen intake velocity of 0.5 foot per second and comply with the interim requirements of the policy may be deemed in compliance for those units only.
	Letter # 67 in favor	Staff agrees.
	Letters # 73 and 119 in favor but suggest modifications for better clarity	While staff acknowledges that the proposed change may be more readable, the alteration would not change the meaning and is therefore not required for purposes of clarity.
	Letters # 66 and 116, suggest substantive modifications	While staff appreciates the submitted suggestions for improvement to the Policy, staff believes that the proposed changes to the November 23, 2009 Draft Policy are minor and have improved the clarity and readability of the Policy. In staff's opinion, the suggested modifications do not improve the Policy.

Change	Comment Letter and position	Response
Section 2.B.(2) replaced with sections 2.B.(2)(a-d)	Letters #65, 70, 74, 75, 117 and 123 against	Staff disagrees. The purpose of this change was to allow for the suspension of a final compliance date specified in the policy because of unforeseen circumstances in order to maintain reliability in the electric system. The proposed modification lays out the method for how changes to the schedule that have a short lead time will be addressed and clarifies the roles and responsibilities of the different agencies. For plants within the California Independent System Operator (CAISO)'s balancing authority, suspension of less than 90 days would be effective upon receipt of written notification by the CAISO, absent objection from the energy agencies. Suspensions of greater than 90 days require the State Water Board to conduct a hearing within 90 days to consider modification to the schedule. For plants within LADWP's balancing authority, suspensions require the State Water Board to conduct a hearing within 45 days to consider modification to the schedule.
	Letters # 67, 69, 119 and 122 suggest modifications for better clarity	While staff acknowledges that the proposed change may be more readable, the alteration would not change the meaning and is therefore not required for purposes of clarity.
Section 2.C.(3)(b) modified and Section 2.C.(3)(e) added	Letters # 64 and 119 suggest substantive modifications	The purpose of this change was to identify the California Coastal Conservancy, working with the California Ocean Protection Council as the preferred third party to manage mitigation projects, preferably directed toward the implementation, monitoring, maintenance and management of the State's Marine Protected Areas. Staff agrees that funding used for monitoring, maintenance and management does not mitigate for identified impacts. However, monitoring, maintenance and management are elements of a mitigation project and therefore also need to be funded.
Sections 2.C.(3)(a-d) modified	Letter # 70 against	Staff disagrees. The purpose of this change was to ensure consistent and comparable application of the mitigation requirement across the State, the State Water Board Division of Water Quality is now identified as the body to approve mitigation projects and alternate methods for determining the type and amount of habitat to be mitigated, rather than the Regional Water Boards.

Change	Comment Letter and position	Response
Section 2.D. modified	Letter #65 against	Staff disagrees. The purpose of this change was to clarify that the State Water Board does not propose to adopt and enforce any requirements that are in conflict with requirements of the Nuclear Regulatory Commission, which has responsibility for issues involving safety and environmental protection at nuclear power plants. A sentence was also added to refer to the section of the Policy involving the special studies for nuclear facilities.
Section 3.B.(3) added	Letters # 67 and115 in favor but suggest modifications for better clarity	The purpose of this change was to specify that CAISO and LADWP must each submit a grid reliability study to the SACCWIS by December 31 each year, in order to assure that SACCWIS can provide annual reports to the State Water Board by March 31. While staff acknowledges that the proposed change may be more readable, the alteration would not change the meaning and is therefore not required for purposes of clarity.
Section 3.B.(4) modified Section 3.E.: Table 1 modified	Letter #115 in favor but suggest substantive modifications	Staff disagrees. The purpose of this change was to require SACCWIS to provide annual reports to the State Water Board, beginning in 2012.
Section 3.B.(5) modified	Letters #66, 70, and 75 against	Staff disagrees. The purpose of this change was to clarify that if energy agencies make a unanimous recommendation for implementation schedule modification based on grid reliability, the State Water Board will implement this recommendation unless the State Water Board finds that there is compelling evidence not to do so.
	Letters # 67 and 115 in favor but suggest modifications for better clarity	While staff acknowledges that the proposed change may be more readable, the alteration would not change the meaning and is therefore not required for purposes of clarity.

Change	Comment Letter and position	Response
Section 3.B.(5) modified	Letters # 65, 69, and 75 against with or without modifications	Staff disagrees. The purpose of this change was to clarify that if a plant owner/operator is unable to comply with a final compliance deadline because of an inability to obtain permits required for an upgrade, and the State Water Board finds that the owner or operator used best efforts to obtain the required permits, then the State Water Board shall suspend a final compliance date specified in this policy for a period not to exceed two years.
	Letters #115 in favor but suggest substantive modifications	Staff does not believe that compliance deadlines should be suspended for longer than two years for any reasons.
Section 3.C.(1) modified	Letter # 65 against with or without modifications	Staff disagrees. The purpose of this change was to remove the ability of the Regional Water Board to require a shorter compliance schedule than is contained in the policy's implementation schedule. The schedule contained in the policy is based on statewide and local grid reliability. It is therefore inappropriate for a Regional Water Board to require a shorter compliance schedule in the relevant NPDES permit.
Section 3.C.(4) added	Letter # 65 against	Staff disagrees. The purpose of this change was to clarify that permits issued by the Regional Water Boards to OTC power plants shall include appropriate permit provisions to implement authorized suspensions of final compliance dates and modifications to final compliance dates, without reopening the permits.
Section 3.D.(7) modified and sections 3.D.(7)(a-d) added	Letters # 65, 122, 123, and 125 against	Staff disagrees. The purpose of this change was to delineate the factors that the State Water Board will use to evaluate the need to modify the policy with respect to the nuclear-fueled power plants based on the results of the special studies. These factors include costs of the compliance, the ability to comply, and environmental impacts of compliance.
	Letter # 66 in favor but suggest modifications for better clarity	While staff acknowledges that the proposed change may be more readable, the alteration would not change the meaning and is therefore not required for purposes of clarity.

Change	Comment Letter and position	Response
Section 3.D.(8) added	Letters # 65 and 123 against with or without modifications	Staff disagrees. The purpose of this change was to clarify how estimated compliance costs for a nuclear facility will influence a decision of the State Water Board to establish alternate requirements for that facility. If the special studies determine that the costs to implement Track 1 or Track 2, considering all the factors set forth in paragraph 3.D.(7), are wholly out of proportion to the costs considered by the State Water Board in establishing Track 1, then the State Water Board shall establish alternate requirements for that facility no less stringent than can be justified by the results of the special studies.
	Letters # 121 and 125 in favor but suggest minor modifications for better clarity	While staff acknowledges that the proposed change may be more readable, the alteration would not change the meaning and is therefore not required for purposes of clarity.
Section 3.D.(9) added	Letters #65 and 123 against	Staff disagrees. The purpose of this change was to clarify that the difference in impacts to marine life resulting from any alternative less stringent requirements for nuclear-fueled power plants shall be fully mitigated by funding a mitigation project directed toward the implementation, monitoring, maintenance and management of the State's Marine Protected Areas.
	Letters #119 and 121 in favor	Staff agrees.
	Letter # 125 in favor but suggest substantive modifications	While staff appreciates the submitted suggestions for improvement to the Policy, staff believes that the proposed changes to the November 23, 2009 Draft Policy are minor and has improved the clarity and readability of the Policy. In staff's opinion, the suggested modifications do not improve the Policy.
Section 3.E., Milestones 18, 24, and 26, modified	Letter # 115 in favor	Staff agrees. The purpose of this change was to modify the compliance dates for the three LAWDP plants (Haynes, Harbor, and Scattergood). The original compliance dates for the three plants were based on staff understanding of LADWP plans for upgrading the facilities. Subsequent information from LADWP indicates that the schedule needed to be revised.

Change	Comment Letter and position	Response
Sections 4.(B)(1) and 4.(B)(2) modified	Letters #115 and 116 against with or without modifications	Staff disagrees. The purpose of this change was to clarify how the monitoring of entrainment impacts and reductions should be conducted, and language was added concerning the use of a 200 micron mesh net and the timing of the sampling.
	Letter #119 in favor	Staff agrees.
	Letter #73, 122, and 126 in favor but suggest modifications for better clarity	While staff acknowledges that the proposed change may be more readable, the alteration would not change the meaning and is therefore not required for purposes of clarity.
	Letter # 66 in favor but suggest substantive modifications	While staff appreciates the submitted suggestions for improvement to the Policy, staff believes that the proposed changes to the November 23, 2009 Draft Policy are minor and have improved the clarity and readability of the Policy. In staff's opinion, the suggested modifications do not improve the Policy.
Section 5 modified	Letters # 73, 115, and 126 in favor but suggest modifications for better clarity	For clarification purposes, definitions were added for *Critical System Maintenance*, *Mitigation Project*, and *Offshore Intake.* The definitions for *Closed-Cycle Wet Cooling System, Combined-Cycle Power-Generating Units, Habitat Production Foregone, Meroplankton,* and *Proportional Mortality* were modified slightly. While staff acknowledges that the proposed changes may be more readable, the alterations would not change the meaning and are therefore not required for purposes of clarity.
	Letter #66 in favor but suggest substantive modifications	While staff appreciates the submitted suggestions for improvement to the Policy, staff believes that the proposed changes to the November 23, 2009 Draft Policy are minor and have improved the clarity and readability of the Policy. In staff's opinion, the suggested modifications do not improve the Policy.

Comments #128-XXXX (>8000): (Form letter)

Power plants using OTC are currently allowed to withdraw more than 16 billion gallons of ocean and Delta water every day, killing aquatic life from all levels of the food chain. Larvae and small fish get sucked into the plants and die in the turbines. Larger fish (including the endangered Chinook salmon), turtles, and marine mammals get trapped by the force of the rushing water and die on the intake screens. All told, an estimated 79 billion fish and other marine life are killed every year by OTC.

The CWA called for the phase-out of this destructive practice almost four decades ago. We appreciate your past efforts to develop a state policy that would protect California's ecosystems from OTC. However, the recent, major changes to the latest draft of the OTC policy meet neither the letter nor the intent of the CWA to phase out these antiquated, inefficient, environmentally harmful cooling systems.

I urge the State Water Board to reject recently-proposed OTC policy amendments that move the state away from a path to phase out once-through cooling systems. The OTC policy needs to be strengthened significantly to reinforce the state's commitment to ensuring that these facilities adopt the "best technology available" based on swift, certain timeframes.

Prior, stronger versions of the policy were described by the state's top three power agencies as providing a "workable schedule" that "maintain[s] reliable operation of the electric grid." The electrical grid oversight agency itself found that many older power plants also have "higher greenhouse gas emission rates and other pollutants than new generation sources." Once-through cooling enables inefficient power plants to operate at the expense of the environment and undermines state goals to reduce greenhouse gas emissions.

California has invested significant attention and dollars to restoring and maintaining our marine, coastal and Delta habitats. A protective OTC policy that meets the letter and intent of the law is essential to maintain these ongoing investments in healthy ecosystems. Please reject proposed amendments that move us backwards from this goal.

Response:
Staff agrees that the use of OTC at the coastal power plants has major impacts to the State’s marine and estuarine life, including listed and protected species. Staff appreciates the support for the proposed OTC Policy, which should significantly reduce harmful impacts due to entrainment and impingement of marine and estuarine life at OTC power plants.

The Policy is intended to comply with CWA section 316(b), which requires that the location, design, construction, and capacity of cooling water intake structures reflect the best technology available (BTA) for minimizing adverse environmental impact. Note that Section 316(b) does NOT require the phasing out or complete cessation of OTC. The primary goal of the Policy is therefore to establish a BTA for cooling water intake structures at existing coastal and estuarine power plants to reduce IM/E impacts to acceptable levels, rather than the phasing out of OTC at coastal power plants. This goal is clearly stated in both the Policy itself and the supporting SED.

The commenter does not specify which of the latest changes to the OTC Policy amendments that the commenter believes will “move the state away from a path to phase out once-through cooling systems.” Staff can therefore not address these concerns other than noting that it was never the State Water Board’s stated goal to phase out OTC at coastal power plants.

The commenter also states that the “OTC policy needs to be strengthened significantly to reinforce the state's commitment to ensuring that these facilities adopt the "best technology available" based on swift, certain timeframes.” Again, the commenter does not specify how the policy could be strengthened further. Without specific explanation of the commenter’s concerns, staff cannot address them.

Staff agrees with the commenter's statement that many older power plants have "higher greenhouse gas emission rates and other pollutants than new generation sources." However, it is not within the State Water Board's authority and expertise to establish an energy policy for the State. Again, the purpose of the proposed OTC Policy is to establish a BTA for cooling water intake structures at existing coastal and estuarine power plants to reduce IM/E impacts to acceptable levels.