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Exhibit Number	:	
Commissioner	:	Michel Florio
Admin. Law Judge	:	David Gamson
DRA Project Mgr.	:	
	:	
DRA Witnesses		Nika Rogers

DIVISION OF RATEPAYER ADVOCATES
CALIFORNIA PUBLIC UTILITIES COMMISSION

REPLY TESTIMONY
OF
NIKA ROGERS

Order Instituting Rulemaking to Integrate and Refine Procurement Policies and Consider Long-Term Procurement Plans Track 4 – SONGS Outage

(R.12-03-014)

San Francisco, California
September 30, 2013

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EXECUTIVE SUMMARY

On behalf of the Division of Ratepayer Advocates (DRA), the prepared direct testimonies of Radu Ciupagea and Robert Fagan, and my own testimony (Nika Rogers) address the local reliability impacts of the permanent shut-down of the San Onofre Nuclear Generation Station (SONGS) generating facilities in Track 4 of this proceeding. DRA replies to the August 5, 2013 testimony of the California Independent System Operator (CAISO), and to the August 26, 2013 testimonies of Southern California Edison Company (SCE) and San Diego Gas & Electric Company (SDG&E).

Mr. Fagan's testimony focuses on certain input assumptions, methodology, and results of the transmission system modeling (power flow modeling) conducted by the CAISO, and conducted jointly by SCE and SDG&E. In particular, it focuses on mitigation options that include use of special protection systems (SPS) under certain contingency situations, and it explains why reactive power support considerations are critical in any examination of SONGS area local reliability.

Mr. Ciupagea's testimony addresses the role of energy efficiency (EE), demand response (DR) modeling assumptions, and the role of energy storage in meeting local capacity requirements (LCR) in the SONGS study area (comprised of the Los Angeles (LA) basin and SDG&E's service territory). Mr. Ciupagea explains that the incremental EE and DR input assumptions adopted in the CPUC's Revised Scoping Ruling (Scoping Memo) and modeled in the CAISO power flow studies are very conservative and allow for the Commission to pursue a more aggressive procurement authorization of LCR quality preferred resources, to the extent there is a LCR need determination for the SONGS study area.

My testimony discusses contingency plans that SCE and SDG&E propose in the event that resources (preferred, energy storage and/or conventional resources authorized in Track 1) do not materialize as expected, as well as the possibility of the extension of the retirement date of one or more once-through cooling (OTC) plants. My testimony also discusses the possibility of utility-owned generation (UOG) as a means to mitigate market power in the SONGS-study area.

DRA recommends that the Commission consider the CAISO's 2013/2014 Transmission Planning Process (TPP) before authorizing SCE and/or SDG&E to procure additional LCR resources. At a minimum, any determination of LCR need in Track 4 should be based on power flow study results that include scenarios with additional reactive power support, SCE and

SDG&E's conceptual transmission solutions, and other relevant transmission system solutions identified by CAISO or the utilities. This information should help guide the Commission in identifying the specific resource combination that ensures local reliability for the entire SONGS study area (not just for LA Basin and SDG&E service area separately), that does so cost-effectively, and that aligns with the state's policy goals on loading order and greenhouse gas emission reduction.

If the Commission determines to move forward with consideration of Track 4 procurement authorization without comprehensive information on how incremental reactive power support and SCE and SDG&E's conceptual transmission solutions can minimize overall resource need in the SONGS study area, then it should adopt a cautious approach to such authorization. A cautious approach is appropriate given the expectation in the September 16, 2013 "Assigned Commissioner and Administrative Law Judge's Ruling regarding Track 2 and Track 4 Schedules" that "any procurement authorization will not be subject to further review based on additional evidence in this proceeding."[1] Accordingly, any procurement authorization, if based on a record that lacks comprehensive information on how incremental reactive power support and SCE and SDG&E's conceptual transmission solutions can minimize overall resource need in the SONGS study area, should be limited to authorization of preferred resources only.

Q1. What is the purpose and scope of your testimony?

A1. My testimony addresses Administrative Law Judge Gamson's questions about whether there should be contingency plans in case expected levels of certain resources do not materialize in a timely manner and whether the Commission should consider methods to address market power in the San Onofre Nuclear Generation Station (SONGS) area.[2] In this context, I discuss Southern California Edison Company's (SCE's) two proposals for contingent generation development in the LA Basin and San Diego Gas & Electric Company's (SDG&E's) proposal for development of an energy park in the San Diego

[1] Assigned Commissioner and Administrative Law Judge's Ruling regarding Track 2 and Track 4 Schedules, September 16, 2013, pp. 3-4.

[2] Reporter's Transcript, September 4, 2013, Prehearing Conference 4 (RT) at 319.

local area.[3] In addition, I discuss once-through cooling (OTC) retirement assumptions and the potential for OTC compliance dates to impact reliability in the LA Basin and San Diego local areas.

Q2. What are DRA's recommendations regarding the use of contingency plans in the event resources do not materialize as expected?

A2. DRA supports exploring the idea of local generation development reserves (DRA's term for the concepts reflected in SDG&E's proposed energy park and SCE's proposed contingent site development) that would allow SCE and SDG&E the option to develop gas-fired generation (GFG) or other resources in a short time frame (less than seven years) to meet local reliability needs. However, DRA does not support SCE's proposal to pursue bilateral options or contingency contracts with third party developers as a backup for resource development that does not materialize. This approach would expose ratepayers to costly termination payments in the event the contracts prove unnecessary. Lastly, DRA supports a process whereby stakeholders and regulatory agencies work together to evaluate modifications to once-though cooling (OTC) compliance deadlines as a short-term mechanism to maintain reliability in transitional years of planning to meet the absence of SONGS.

Q3. Please describe SCE's two proposals for contingent generation development in the LA Basin, and the stated purpose of these proposals.

A3. SCE witness Rumble states that SCE plans to pursue two forms of contingent generation development. The first proposal is to pursue option contracts with third party developers that would allow GFG to be developed quickly in the event a need arises, reducing the development and procurement lead-time by two years.[4] SCE plans to bilaterally negotiate these option contracts and will require "the seller to perform the necessary pre-development work to site, permit, and construct a specified GFG resource…."[5] SCE cites

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[3] *See* Track 4 Testimony of Southern California Edison Company (SCE Opening Testimony), Chapter VII, Testimony of Jonathan Rumble, pp. 61-62, and Chapter VI, Testimony of Colin Cushnie, pp. 58-59; and Prepared Track 4 Direct Testimony of San Diego Gas and Electric Company (SDG&E Opening Testimony/Anderson), pp. 16-17.

[4] SCE Opening Testimony, pp. 58:20 through 59:13; 61: 4-6.

[5] SCE Opening Testimony, p. 58: 22-23.

four situations that may prompt the need to activate this contingency plan: (1) failure to develop GFG procured through the Track 1 LCR RFO, (2) inability to develop sufficient preferred resources as part of Track 1 authorization, (3) the inability of planned local area grid enhancements to develop, and (4) the inability of planning assumptions on the availability and effectiveness of resources to materialize.[6]

SCE's second proposal for contingent generation development is to develop generation sites near the Johanna and Santiago substations for use by third party developers as backup for SCE's Preferred Resource Living Pilot Program (Preferred Resource Pilot).[7] SCE witness Rumble notes that SCE will seek to obtain the necessary site and development permits for these reserve areas but will not seek to have new generation built on these sites without Commission approval.[8]

SCE witness Rumble notes that three uncertainties warrant SCE's pursuit of contingent generation development: (1) uncertainties regarding the approval and permitting of the proposed development of the Mesa Loop-in transmission project, 2) uncertainties around preferred resource development, and 3) concerns that the CAISO may not accept some preferred resources as valid LCR resources.[9]

Q4. Please describe SDG&E's proposal for an energy park and the stated purpose of the energy park.

A4. SDG&E witness Anderson discusses the uncertainties of forecasting future LCR needs and the long lead-time associated with constructing new generation resources as significant factors in the ability to meet local need.[10] SDG&E is currently exploring the feasibility of developing an energy park to be used to meet a potential, future local resource need with the goal of reducing the time currently needed between identifying a "finding of generation need and the in-service date of generating plants necessary to meet

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[6] SCE Opening Testimony, p. 58: 15-19.

[7] SCE Opening Testimony, p. 61: 3-8.

[8] SCE Opening Testimony, p. 62: 1-6.

[9] SCE Opening Testimony, pp. 62-64.

[10] SDG&E Opening Testimony/Anderson, p. 16: 10-16.

that need."[11] The proposed energy park would consist of "lots" that would be made available in future requests for offers (RFOs) solicitations to independent generators as part of a fully-licensed park with necessary transmission and gas infrastructure as well as access to water.[12]

Q5. Are SCE and SDG&E seeking approval of the proposals in this proceeding?

A5. Both SCE and SDG&E note that they are not seeking approval for these proposals in Track 4 of the LTPP but that approval of these proposals would be requested through separate applications filed with the Commission.[13]

Q6. Does DRA support SDG&E's energy park and SCE's contingency site development proposals?

A6. DRA's support for these proposals depends on information that will be provided outside of this LTPP proceeding, most likely in SDG&E and SCE's respective applications filed with the Commission at a future date. DRA's support would likely be informed by whether SDG&E and SCE are able to work with the appropriate regulatory agencies to develop a process that provides sufficient assurance that preliminary development efforts will retain value over time even though the sites may not be used until future years and in future LTPP cycles.

Q7. What potential benefits do the proposed energy park and contingency site development plan offer?

A7. Conceptually, these proposals offer the potential to lessen the pressure to build GFG under the current paradigm, which requires 7 – 9 year lead-time to develop these resources. This extended lead-time for GFG development requires state agencies and the utilities to hedge against the potential threat to future reliability should planned resources not perform or develop as expected. However, if these GFG resources are procured before they are needed, this current paradigm has the potential to expose ratepayers to

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[11] SDG&E Opening Testimony/Anderson, p. 16: 19-20.

[12] SDG&E Opening Testimony/Anderson, pp. 16-17.

[13] SDG&E caveats submitting an application before the Commission with "to the extent [SDG&E] elects to pursue this energy park proposal, SDG&E will file a separate application with the Commission seeking approval to move forward with such a plan." (SDG&E Opening Testimony/Anderson, p. 17: 8-10.) Also see SCE Opening Testimony, p. 50: 17-18, p. 51: 4-8.

unreasonably high costs, as well as undermine California's greenhouse gas (GHG) reduction goals.

Rather than invest in GFG as an expensive hedge for reliability, it may be more prudent for the utilities to invest in the development of sites that have high effectiveness factors to address local contingencies identified by the CAISO in its power flow studies. Moreover, land designated for local GFG could also be used for circumstances that require SCE or SDG&E to pursue new local GFG. If future LTPP decisions authorize procurement of additional local generation, these contingent GFG sites might be available to develop this generation on a much shorter time frame.

SDG&E and SCE provide limited information on their specific plans to accomplish the proposed energy park (SDG&E) or contingent site development (SCE). Whether the proposals are a prudent use of ratepayer funds depends on the utilities' ability to preserve the use of the sites until future years and across future LTPP cycles in the event that new GFG is not needed in the current LTPP cycle. Due to the potential unique value of these locations on the transmission grid, it is likely that these sites will be developed at some point in the future. It would not be a prudent use of ratepayer funds to prepare these sites for resource development only to see their authorization expire and the process for obtaining approval start from the beginning. If the utilities can work with state regulatory agencies to establish a process that allows for staged approval, then investing in conditional resource site development now for use at some point in the future would be a reasonable hedge against unforeseen local reliability issues and just-in time procurement.[14]

[14] Also see Reply Testimony of DRA witness Fagan (September 20, 2013), Question and Answer #17, regarding the use of a special protection system (SPS) for mitigation of the N-1-1 contingency ("[T]he SPS could serve as a cost-avoidance measure to bridge the gap between when need is first seen, and when preferred resources (and/or transmission) come online.").

Q8. Do the proposed energy park or contingent site development (collectively, local generation development reserve) offer the potential to help mitigate market power?

A8. The use of local generation development reserves could also help to address local market power concerns by providing more options for resource development in transmission-constrained areas. The local generation development reserves would allow the utilities to consider various options, including whether competitive solicitations, utility-owned generation (UOG), or bilateral negotiations would be the best use of these sites and what resources (large-scale renewables, energy storage, gas fired generation or a combination of these resources) would be most appropriate to meet need thus reducing overall ratepayer costs in the long run. The existence of multiple options may elicit more reasonable offers from generators and other developers.

Q9. Aside from their potential use on a local generation development reserve, should the Commission consider UOG and bilateral contracts as potential solutions to market power?

A9. DRA supports consideration of both UOG and bilateral contracts as possible tools to address local market power issues that may arise from the early retirement of SONGS. Assembly Bill (AB) 57, which established the biennial LTPP, envisions a hybrid market in California as one that consists of short-term transactions, new UOG plants, and long-term PPAs.[15] This combination of contracts permits the IOU to balance both short and long term risks through a variety of procurement options. Thus DRA finds that UOG generation, if balanced with PPA or third-party generation development, is consistent with AB 57 procurement authority.

Along with reliability, DRA's primary concern is the cost-effectiveness of the utilities' procurement decisions. The early retirement of SONGS exacerbates existing concerns about market power issues in both SDG&E and SCE's local areas. Due to the geographic proximity of these local areas, only a finite number of developers are able to compete for

[15] See D.04-01-050, p. 60. D. 04-01-050 also encourages the IOUs to pursue a balanced portfolio of short-term transaction, new UOG plants, and long-term PPAs as both appropriate and optimal.

contracts that are necessary to ensure reliability. This situation could result in the utility becoming the price taker in order to meet LCR need and come at the detriment to its ratepayers. To avert a market power situation or just-in time procurement,[16] DRA recommends that SCE and SDG&E pursue UOG or bilateral contracts for local generation as these developments may be the most cost-effective and reliable option for ratepayers. Decision (D.) 12-04-046, the *Decision on System Track I and Rules Track II of the Long-term Procurement Plan Proceeding and Approving Settlement*, states that it is appropriate to consider UOG projects (and to that extent bilateral projects) after a competitive RFO has been issued.[17] DRA agrees that the utilities should first attempt to pursue new generation through an RFO. In the event that the RFO is unsuccessful or offers are not competitively priced, UOG and bilateral development should be considered so long as the utility can develop a UOG project that is more price competitive than the bids it received through the third-party RFO. Applying least cost best fit (LCBF) methodology to the evaluation criteria of the UOG or bilateral project is a key way to determine the reasonableness of the offer.

Q10. Although SDG&E's energy park and SCE's contingent site development plan are not before the Commission in Track 4, does DRA recommend moving forward with consideration of the proposals?

A10. DRA anticipates that SCE will provide more information on the contingent site development plan as part of its application for approval of its Preferred Resource Pilot Program, and that SDG&E will do the same in an application should it decide to move forward with its conceptual energy park. The November 6, 2013 "Defining the Living Pilot: Symposium of Ideas" should allow stakeholders to comment on how SCE can use the pilot to fill the SONGS gap while ensuring grid stability and resiliency, including the proposed timeline for implementation and program specifics. If the contingent site development plan is not a topic for the November 6, 2013 workshop, then DRA

[16] In D.07-12-052 the Commission stresses the need to allow for seven year lead time for new resource development to avoid "just-in-time" or last minute procurement authorization. The Commission does not favor just-in-time procurement as this "threatens reliability, drives up the costs of delivering power, and typically does not result in additional preferred/renewable resources." (D.07-12-052, p. 90.)

[17] D.12-04-046, p. 33

recommends a separate forum for discussion of topics related to contingent site development.

DRA recommends that SDG&E consider a similar technical workshop to review the details and components of its proposed energy park and allow parties to comment in the event it moves forward.

Q11. What once-through cooling (OTC) generating unit assumptions are used in the power flow studies?

A11. In each of the CAISO, SDG&E, and SCE testimonies, all OTC units are assumed to be retired by their compliance deadlines and none of the OTC units are assumed to be repowered. The compliance deadlines for the OTC units in the LA Basin and SDG&E area range from 2015 – 2020.[18]

Q12. In evaluating Track 4 procurement authorization, should the Commission consider modification of OTC retirement dates as a contingency backup plan?

A12. Yes, DRA echoes the recommendation set forth in the draft *Preliminary Reliability Plan for LA Basin and San Diego* report (Draft Preliminary Reliability Plan), issued on August 30, 2013, by the California Energy Commission and the CPUC. The Draft Preliminary Reliability Plan states that contingency plans for fast-tracking additional generation should include consideration of flexibility to the OTC compliance deadlines to alleviate grid reliability issues that may temporarily result from delays in commercial operation dates and account for projects scheduled to come online but do not. The Draft Preliminary Reliability Plan notes that "[e]xtension to the OTC compliance dates, in part or whole, may be necessary in order for replacement resources (both preferred and conventional) to be developed or procured and achieve operation, without unduly limiting procurement options."[19] DRA therefore supports a process that would include

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[18] Track 4 Testimony of Robert Sparks on Behalf of the California Independent System Operator Corporation, pp. 11-12.

[19] Draft *Preliminary Reliability Plan for LA Basin and San Diego*, August 30, 2013, p. 8. (Appended to this testimony as Attachment A.)

stakeholders and regulatory agencies working together to consider modifications to current OTC compliance deadlines as a potential interim solution for any Track 4 need.[20]

Relaxation of hard compliance deadlines for local OTC units in the LA Basin and San Diego is not only a cost-effective reliability hedging solution, but also consistent with the SWRCB's *Policy on the Use of Coastal and Estuarine Waters for Power Plant Cooling* (OTC Policy). The SWRCB's OTC Policy allows for two types of temporary suspension of OTC units; less than 90 days or more than 90 days for existing OTC power plants within CAISO's jurisdiction if "CAISO determines that continued operation of an existing power plant is necessary to maintain the reliability of the electric system...."[21]

DRA supports the SWRCB's OTC Policy but also recognizes, as does the Draft Preliminary Reliability Plan, the impact this environmental policy could have on grid reliability in the LA Basin. Most of the OTC units in Southern California are scheduled to retire between 2017 and 2020. Modifying the deadline could help SCE and SDG&E bridge any reliability needs that could emerge between planning years. This bridge in planning years predominantly refers to the potential gap between when preferred resources or other planned/expected resources are scheduled to come online and when they are actually available and online. In particular, SCE points out that there is a critical two-year period between 2020 – 2022, when the last OTC units are scheduled to retire and the year in which additional resources are needed to maintain reliability.[22] This time period is when the OTC compliance deadlines could be extended to allow scheduled retiring OTC units to serve as interim resources while SCE's Preferred Resource Pilot Program is still under evaluation and while the utilities are waiting for expected resources to come online.

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[20] That process might be an ongoing part or an extension of the same process used to develop the Draft *Preliminary Reliability Plan for LA Basin and San Diego*, and should include representatives from the State Water Resources Control Board, the South Coast Air Quality Management District, CPUC, the CAISO, the California Energy Commission as well as other interested stakeholders.

[21] *See* Statewide Water Resources Control Board's *Policy on the Use of Coastal and Estuarine Waters for Power Plant Cooling*, as amended July 19, 2011, pp. 6-7. (Appended to this testimony as Attachment B.)

[22] SCE Opening Testimony, p. 3: 21-25.

Extending OTC compliance deadlines could help SCE and SDG&E continue to meet their local reliability requirements and could also help to temporarily mitigate market power issues or potential price spikes for local capacity and avoid just-in time procurement authorization. Any such extension should be narrowly crafted to balance the important goals of meeting OTC retirement deadlines with preserving grid reliability and meeting GHG reduction goals.[23] To that end, power flow analysis such as used in Track 4 and the CAISO Local Capacity Technical (LCT) studies can help identify the OTC unit or units that would be most electrically effective in maximizing grid reliability, and thus would serve as good candidates for retirement date extension consideration.

Q13. Does DRA support SCE's first proposal to execute options or contingent contracts with third party developers to develop new GFG?

A13. No, DRA does not agree that SCE should pursue bilateral options or contingent contracts. The pursuit of options or contingent contracts as an insurance policy to resource development that does not materialize is costly and unreasonably risky to ratepayers as compared to other alternatives such as modifying OTC compliance deadlines or exploring the use of local generation development reserves. If the option contracts prove unnecessary, then ratepayers will face costly termination payments that will provide no additional benefit. In contrast, the local generation development reserves hold out the possibility of being assets that will provide value in the future. As SCE states in its September 10, 2013 opening comments on the Track 4 schedule, "SCE would pay resource developers to pursue their projects until certain regulatory approvals for the Mesa Loop-In were received. These contingent contracts would likely come with **substantial cost to ratepayers** [emphasis added], but would act as a hedge to assure electric system reliability. This is a very different "product" than what is effectively a "soft" interim authorization. In a contingent contract, SCE would make a termination payment if it elects not to proceed."[24]

[23] The Draft Preliminary Reliability Plan notes that it may make sense to consider a delay in Encina Units 4 and 5. *See* Draft *Preliminary Reliability Plan for LA Basin and San Diego*, August 30, 2013, p. 8.

[24] Opening Comments of Southern California Edison Company on Schedule, September 10, 2013, p. 4.

Accordingly, if SCE is authorized to pursue these options or contingent contracts, the contracts would in effect be a sunk cost since ratepayers would bear the cost of these contracts even if SCE choses to terminate the agreement. DRA recommends exploring the use of local generation development reserves rather than options or contingent contracts as a potentially more cost-effective and prudent backup for planned supply side and transmission resources that do not develop.

QUALIFICATION OF WITNESS - NIKA ROGERS

Q.1 Please state your name and address.

A.1 My name is Nika Rogers. My business address is Energy Procurement and Planning Branch, Division of Ratepayer Advocates, California Public Utilities Commission, 505 Van Ness Avenue, 4th floor, San Francisco, California.

Q.2 By whom are you employed and in what capacity?

A.2 I am employed by the California Public Utilities Commission as a Public Utilities Regulatory Analyst in the Division of Ratepayer Advocates (DRA) in the Energy Procurement and Planning Branch.

Q.3 Briefly describe your educational background and work experience.

A.3 I earned a Bachelor of Arts Degree in International Studies from the University of California, Santa Barbara and a Masters Degree in International Relations from the University of Chicago.

I have been employed by the California Public Utilities Commission since September 2008. Since joining the CPUC I have worked on the Renewables Portfolio Standard proceeding, Energy Resource and Recovery Account proceeding as well as the Long-term Procurement Planning proceeding.

Q.4 Does that complete your prepared testimony?

A.4 Yes, it does.

ATTACHMENT A

PRELIMINARY RELIABILITY PLAN FOR LA BASIN AND SAN DIEGO
PREPARED BY STAFF OF THE CALIFORNIA PUBLIC UTILITIES COMMISSION,
CALIFORNIA ENERGY COMMISSION, AND
CALIFORNIA INDEPENDENT SYSTEM OPERATOR
DRAFT AUGUST 30, 2013

Preliminary Reliability Plan for LA Basin and San Diego

Prepared by Staff of the California Public Utilities Commission, California Energy Commission, and California Independent System Operator

DRAFT August 30, 2013

Introduction

On June 7, 2013 Southern California Edison Company (SCE) announced that it would permanently close the San Onofre Nuclear Generating Station (San Onofre) in southern California. While resources are expected to be adequate in the remainder of California, the closure of San Onofre creates unprecedented challenges for maintaining reliable electric service to consumers located in the southern region of California. Additionally, the reliability risks created by the regulatory timeline for eliminating the use of once-through cooling (OTC) in the coastal areas' aging, inefficient gas-fired power plants (5,086 MW) and load growth in southern California of about 400 MW/year are also considered in this preliminary plan. These are large numbers and involve a complex mix of regulatory challenges.

San Onofre represented approximately 16% of the local electricity generation supply, serving an average of 1.4 million homes served by SCE, San Diego Gas & Electric (SDG&E) and City of Riverside in southern California. In addition to meeting essential energy needs, it was especially important because of its location on a critical transmission path between Orange County and San Diego. As a result, its closure creates more than a shortage of electricity. It also creates a shortage of voltage support – an electrical characteristic analogous to water pressure that is necessary to move power between Los Angeles and southern Orange County/San Diego.

Complicating the challenge of replacing resources that came from San Onofre is the nature of voltage support, which can only be supplied by conventional generation, combined heat and power, or specialized equipment such as synchronous condensers that operate like large electrical motors.[1] The technical discussion that follows was developed in consultation with SWRCB, SCE, SDG&E and SCAQMD and describes the coordinated actions the CPUC, CEC, and CAISO staff are pursuing in the near term (4 years) and the long-term (7 years). These actions collectively comprise a preliminary reliability plan in light of the closure of San Onofre, the expected closure of 5,068 MW of gas-fired generation that uses OTC, and the normal patterns of load-growth. The reliability plan can be summarized as three key actions identifying challenging goals that will be fully vetted in the public decision making processes of the appropriate agency:

[1] Solar photovoltaic systems, wind energy, battery storage, energy conservation, and demand response do not provide this characteristic but can reduce the amount needed.

(1) Consider to procure/develop about 3,250 MW of preferred resources -- local energy efficiency, demand response, renewable generation, combined heat and power, and storage – for a target of about 50% of needs.[2]

(2) Consider to procure/develop the transmission, including infrastructure that provides voltage support or enhances resource sharing between Orange County and San Diego, and procure/develop about 3,000 MW of conventional generation to meet the remaining needs in the region, including load growth.[3]

(3) Establish backstop permits so that once-through cooling requirements can be quickly deferred and/or generation resources can be quickly deployed in the event needed resources in (1) or (2) are not fully developed on a schedule to meet reliability needs.

These recommendations have a goal to ensure reliability. In order to realize the following plan, a variety of decisions must be approved by key state agencies, elevating the importance of beginning planning now to make sure regulatory actions are made in time to meet future electricity needs in the region. This report contains the recommendations of CPUC, CEC and ISO senior staff. However, implementing the specific mitigation options discussed below will require decisions to be determined through either a CPUC proceeding, and/or through the ISO planning process, and/or through the CEC siting process – depending on the specific option.

1. BACKGROUND

Electric grid reliability in the LA Basin and San Diego is challenged by the retirement of San Onofre and the enforcement timeline of OTC regulations for power plants using ocean or estuarine water for cooling. In total, approximately 7,332 MW of generation (5,086 MW gas-fired generation and 2,246 MW San Onofre) in the region are affected. While these changes present significant reliability challenges that must be addressed, they also present a unique opportunity to reduce reliance on conventional resources in favor of "preferred resources" such as energy-efficiency and demand response, renewable resources, combined heat and power, and energy storage , in a manner that recognizes their clean, low carbon attributes to meet reliability needs.

The electrical needs of the region and potential mitigation actions are discussed in this document for two time frames: near-term (2013-2017), and long-term (2020 and beyond). Prompt action is required to address both near-term and long-term needs given that major grid infrastructure investments take considerable time to implement. Previous 2012-2013 technical studies provide the basis for the recommendations and findings described in this report. Additional study efforts and regulatory

[2] This requires procurement of about 1,000 MW of preferred resources in addition to what is already being counted on.

[3] This requires procurement of about 1,500 MW of conventional generation in addition to what is already authorized.

proceedings are underway or planned that will help to further refine the regional needs and choice of solutions as the state moves through the coming years[4].

2. NEAR TERM NEEDS - 2014 THROUGH 2017

2.1 Identified Needs

Industry and the regulatory agencies reacted promptly to the initial outage of the San Onofre in early 2012, with plans developed and implemented to address the summer of 2012 and 2013. While these actions have supported reliability to date, an additional number of mitigations are underway or needing consideration to ensure reliability in the near term.

2.2 Mitigations

In anticipation of an extended or permanent shutdown of San Onofre, the ISO approved in March 2013 the following transmission enhancements: synchronous condensers at the Talega substation, a Static Var Compensator at the San Onofre Mesa substation, and a new Sycamore Canyon-Penasquitos transmission line. Appropriate steps are now underway to seek approval for implementing these additions as discussed in more detail below.

Preferred Resources

Maintain Flex Alert Program – Funding for the Flex-Alert program should be extended beyond its current 2013-2014 allocation. Since the reliability concerns for the region are more pronounced during extreme system conditions, public calls for conservation during such periods through the current Flex Alert program may be effective in reducing system demand and loading of the transmission system. The CPUC will review the funding needs for the program after an effectiveness study (currently underway) is completed.

Pursue additional preferred resources in both the LA Basin and San Diego – The CPUC will take steps in 2014 to accelerate the authorization and procurement of additional preferred resources to address the loss of conventional generation. These steps should include developing near-term options that will provide additional preferred resources in the LA Basin and San Diego. Traditionally preferred resource programs are statewide and geographically neutral. Therefore the CPUC will need to consider rule changes that can allow resource authorizations to better address the local reliability needs of the LA Basin and San Diego. The CPUC is looking at modifying energy efficiency, demand response, distributed generation, CHP and storage programs to increase the development of these resources so they can effectively meet the reliability needs of the affected areas. The decision-making process will also need to extend into consideration of longer term needs, as discussed in more detail in section 3.

[4] The ISO annual transmission planning process (first quarter of 2014) and the CPUC 's long-term procurement planning proceeding (mid 2014) are both expected to review the need for new resource authorizations in San Diego and Los Angeles in light of the permanent shutdown of SONGS.

SCE, via its CPUC resource procurement authorization, adjustment of its existing EE/DR programs, and its Preferred Resource Pilot will prepare and pending CPUC approval execute an implementation plan for attaining competitively priced preferred resources to meet reliability needs in its service area, with a target focus on the loads in west LA Basin and south Orange County.

Further, the ISO is examining the feasibility of implementing a pilot multi-year auction for energy efficiency and demand response programs targeted in the LA Basin and San Diego areas.

Transmission

Additional Reactive Power Support -To address the regional voltage needs created by the absence of San Onofre, the ISO approved the installation of two projects that provide additional reactive support devices in the electrical vicinity of San Onofre in early 2013. The first project, the installation of synchronous condensers at Talega substation, does not require additional regulatory approvals and should be in service prior to Summer 2015. The second project, the installation of a Static Var Compensator at San Onofre Mesa substation, requires an additional approval from the CPUC. SDG&E is expected to file an application for approval by mid-2014, and if approved by mid-2015, the project could be online by summer 2016.

Sycamore Canyon – Penasquitos Transmission Line[5] ***–***To address local transmission overloads in the northern region of San Diego system, some of which are exacerbated by the absence of San Onofre, the ISO-approved a new 230 kV transmission line from the Sycamore Canyon to Penasquitos substations to improve power flows from east to west. The online date is targeted to 2017, although permitting and construction risk may delay the final operating date. There are multiple applicants seeking to build this line. As the CPUC is the lead siting agency for all of the applicants seeking to build this line, the CPUC is responsible for selecting the project sponsor to build the line. To meet the 2017 in-service date, the selected sponsor will need to be determined in early 2014 and file for a CPCN with the CPUC in mid 2014. The CPUC should process and approve the application by mid 2015.

Pursue a modification to the Nuclear Regulatory Commission (NRC)-required San Onofre-area voltage criteria – Reducing the minimum voltage criteria of the transmission system by a fractional amount in the area around San Onofre, can allow additional power to flow to San Diego without affecting reliability or power quality. A potential reduction of needs by approximately 100 MW could be achieved because of the change in the plant's status. This criteria modification will require NRC approval since spent fuel will remain at the San Onofre site for the foreseeable future even though the plant is no longer operating. Based on engineering analysis, SCE anticipates that relaxation of the 218kV requirement for San Onofre can be in place prior to summer 2014.

Consider converting one of San Onofre generators into synchronous condenser – Similar to what was done at the Zion Nuclear Station, there is a possibility of converting one of the San Onofre generators into a synchronous condenser. Preliminary engineering estimates indicate that this conversion is

[5] The Sycamore Canyon – Penasquitos line will also provide renewable integration benefits.

possible by the summer of 2015. A more detailed feasibility assessment will be completed by SCE in 2013.

Huntington Beach synchronous Condensers – The CAISO will be called upon to approve an expected filing from AES in each upcoming year to extend the existing Reliability Must Run contract. Current contract provisions call for the retirement of one of the synchronous condensers at the end of 2016 and the other at the end of 2017 in order for the plant owner (AES) to undertake its OTC compliance repowering plans for the entire facility, which AES has stated is contingent upon receiving a new long-term power purchase agreement. The current Reliability Must Run contract provisions would allow a yearlong extension of the synchronous condensers based on a mutual agreement by the ISO and AES. The evaluation of this option will need to consider how an extension of the synchronous condenser's operation beyond 2017 would impact the long-term repowering plans for the Huntington Beach facility.

Conventional Generation

Consider maintaining existing peaking generation in San Diego –. SDG&E has taken action to delay the retirement of Cabrillo II peaking generation (188 MW) until 2015. The unit is located in San Diego, and it is currently scheduled for retirement at the end of 2013. This effort will require CPUC approval of both the land lease and the power purchase agreement. SDG&E is expected to file at the CPUC for approval in 2013 of both a land lease and power purchase agreement.

Accelerate procurement of already authorized near term resources –The CPUC has approved 343 MW of procurement for the San Diego local area beginning in 2018. SDG&E has filed an application with the CPUC seeking CPUC approval of a Power Purchase Agreement with Pio Pico (305 MW). The application contemplates that the Pio Pico generator can be on line in 2015 provided SDG&E receives CPUC approval of the PPA by December 2013.

Authorize additional conventional resources (Replacing Encina in the near term) -A CPUC Long Term Procurement Proceeding (LTPP) decision is expected in early 2014 to address reliability needs in the LA Basin and San Diego. This decision should provide procurement authorization beginning in 2016 to address the need resulting from the Encina facility's December 2017 OTC compliance deadline. There may be a variety of options considered to meet the needs caused by the retirement of Encina (950MW). One option frequently discussed is the development of a new power plant referred to as Carlsbad Energy Center[6]. This would replace units 1-3 and the remaining Encina units (Units 4 and 5 with a combined capacity of 630 MW) would be retired in accordance with the OTC compliance schedule. In May of last year, the Carlsbad Energy Center received the CEC approval of the project's Application for Certification (AFC). At this time, there are no power purchase agreements (PPA) pending for the proposed repowering project for Carlsbad Energy Center.

Contingency Permitting in Southern California – Recent experience has shown that it can take seven years or more for new generation (including repowering existing generation) to be permitted and built.

[6] The Carlsbad Energy Center can be built without impacting the operation of the existing Encina generating station.

In light of the long lead times required that may not sync up well with procurement authorization and purely independent generation development, generation development contingency options are currently under consideration. Both SCE and SDG&E are looking into beginning to license sites in their service areas that would then be made available to independent generators under a competitive solicitation process based on identified and pre-determined resources needs. This proposal will require flexibility within the various state rules on licensing and development time frame, but could facilitate the addition of new generation in significantly shorter times if and once the need is authorized by the CPUC. The CEC has explored the options for this type of generation development contingency planning in Southern California. One option is for a utility to file an AFC with the CEC in the 4th Quarter of 2013 and then use the current 12 month CEQA permitting process.

Key actions required for this option to move forward include a CPUC review of applications for funding this type of initial development work, cooperation of the CEC to provide substantial pre-issuance review of AFCs, and potential actions by Air Boards in providing paths for emission offsets.

3. LONGER-TERM PLAN - 2020 AND BEYOND

3.1 Identified Need

- Reliability concern in the LA Basin post-2020 is driven largely by December 2020 OTC compliance dates leading to the retirement of ~3,800 MW of conventional generation, in addition to the area's load growth. Additional needs in the San Diego area are driven by continuing load growth. Both areas may see further retirement of existing resources (1,200 MW) as certain non-OTC generation reaches ages well beyond their design life.
- ISO analysis indicates that by the end of 2020 there will be a need for additional resources in the LA Basin and San Diego area of approximately 4,600 MW. These studies presume the state's RPS mandate is satisfied, and include about 1,000 MW of distributed generation such as rooftop and distributed forms of photovoltaic resources. Further, they presume 1,000 MW of incremental energy efficiency savings from programs that have not yet been authorized and 200MW of reliability based demand response that will need to be developed. Subtracting from the identified need of 4,600 MW the approximately 2,100 MW of other resources that have been authorized in earlier proceedings, the residual need is approximately 2,500 MW (assuming that the authorized resources are developed and the incremental energy efficiency is also delivered).
- Varying combinations of generation (MWs) and reactive power support (MVARs) in the LA Basin and San Diego area could meet this need. Preferred resources with appropriate capabilities and in the proper locations also could meet many of these needs. A high voltage transmission connection between the two areas could reduce the overall needs by approximately 1,000 MW.

3.2 Mitigation Options under Consideration

Preferred Resources

Pursue additional preferred resources in both the LA Basin and San Diego **–** To meet the long-term identified local reliability needs, competitively priced preferred resource programs are expected to be continuously refined by the CPUC as noted in section 2.2 above. The expected amount and locations of dependable capacity that will be provided by preferred resources is currently under consideration by the CPUC staff with a goal of reliably meeting roughly 50 percent of medium to long-term needs with preferred resources. This percentage is roughly consistent with the CPUC's recent procurement authorization strategies (e.g. San Diego and LA Basin authorizations in early 2013). To achieve this goal, and considering recently prepared ISO studies prepared for, but not yet litigated in, the CPUC's LTPP "Track 4" proceeding, it is anticipated that preferred resources beyond those already counted upon will need to meet approximately 1000 MW of the residual need in 2022. [7] Note that this is in addition to already authorized preferred resources, and approximately 1000 MW of energy efficiency programs that are counted on in forecasting efforts but not yet authorized.

Three critical actions for relying on development of additional preferred resources are: (1) an assessment of whether physical capabilities exist to produce, procure, install, and interconnect a heightened level of preferred resources, 2) an operational assessment to review the degree to which preferred resources and conventional resources can in aggregate meet the local reliability needs, and (3) a monitoring system to ensure that programs are implemented and achieve the impacts that are being relied upon.

Transmission

Assess Transmission Alternatives as Mitigations **–** In its 2013/2014 transmission planning cycle, the ISO will evaluate a number of alternative transmission proposals that can assist in meeting local reliability needs, reducing the need for conventional generation in the coastal areas, and enabling a larger role for generation outside of the constrained areas. These include a range of high voltage AC, DC and submarine cable options. Feasibility, cost, and technical performance need to be considered for each of these alternatives–; obtaining rights of way and necessary permits will likely pose significant challenges to most or all of these alternatives. However, all have the potential to reduce the overall need for resource additions and, therefore, will be thoroughly considered.

Mesa Loop in Project -SCE has identified an upgrade to a transmission substation within the Los Angeles Basis that would improve regional power flows and reduce the amount of generation required within the Los Angeles Basin. Most of the upgrade activity would take place within existing SCE rights of way. SCE will submit this project to the CAISO for consideration in its regional transmission planning process in September, 2013. With appropriate approvals, the project could be online as early as 2020.

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[7] The ISO's recently filed analysis in the LTPP Track 4 proceeding indicated a residual need (after consideration of authorized resources and consideration of forecast uncommitted energy efficiency) of approximately 2300 to 2500 MW.

Conventional Generation

Authorize additional conventional resources for the long term) – In addition to authorizing procurement to address near term needs, the CPUC's LTPP process referred to in Section 2.2 and expected to be completed in early 2014, will address longer term needs as well. Beyond 2020, it is expected that some conventional resources may be necessary to address reliability concerns. The main challenge for the development of conventional resources will be the identification of viable power plant projects in light of the siting and air quality permitting challenges.

Contingency Plan

The advancement of preferred resources, transmission alternatives, and generation projects must be carefully monitored to ensure the resources are developing and performing as expected. Contingency plans for fast-tracking additional conventional generation may also be considered as a backstop in the event repowering projects do not proceed, preferred resources do not materialize on schedule or in the amounts required for meeting reliability needs, or in the event identified transmission projects are found to be infeasible or unavailable in a timeframe consistent with OTC policy. These contingency plans could also serve to facilitate a more competitive environment for securing the needed conventional generation at least cost to ratepayers.

Extension of OTC compliance schedule - Extensions to the OTC compliance dates, in part or whole, may be necessary in order for replacement resources (both preferred and conventional) to be developed or procured and achieve operation, without unduly limiting procurement options. It may be appropriate to complete the 558MW Carlsbad Energy Center, and then delay the retirement of the remaining Encina Units 4 and 5 (total 630 MW). After developing a detailed plan for replacing OTC capacity, approval by the State Water Resources Control Board to implement a change in compliance dates would be required. One of the first plants that will face this OTC deadline extension question will be the Encina plant, since it represents significant capacity in the area and has a compliance date at the end of 2017.

San Diego Energy Park -SDG&E has been pursuing the development of an energy park that could host several independent developments. The park would have enough land and transmission capability to provide 1,000MWs of flexible gas-fired generation and could be located on federal lands at Camp Pendleton or in northwest San Diego County. Once secured, the site would obtain the necessary CEC license and CAISO interconnection. The licensed sites would then be made available to independent generators under a competitive solicitation basis based on identified and pre-determined resources needs. This proposal will require flexibility within the various state rules on licensing and development time frame, but could facilitate the addition of new generation in significantly shorter times once the need is authorized by the CPUC.

SCE Contingent Site Permits - SCE is pursuing the development of sites for potential new peaking generation in the LA Basin to prepare for the contingency that preferred resources do not materialize as planned. The contingent generation projects would be located at sites providing the highest values for meeting local reliability standards in the LA Basin. SCE would obtain the necessary CEC license and

CAISO interconnection permission for each of the sites. Should a contingency emerge, the licensed peaker sites could then be made available for development based on the CPUC identified need.

3.3 Air Permitting in LA Basin

Construction of new greenfield power plant sites and repowering of existing power plants present different challenges for facilities in the South Coast area under the jurisdiction of South Coast Air Quality Management District (SCAQMD). Under existing rules, new greenfield plants must provide emission reduction credits (ERCs) obtained from the open market, but these ERCs are scarce and expensive.[8] Developers wishing to repower old steam boiler facilities into modern combustion turbine facilities can use the exemption in SCAQMD Rule 1304(a)(2) to avoid providing their own emission offsets. However, in the case of repowering, in order to satisfy federal and state Clean Air Act requirements SCAQMD itself would have to provide the offsets by debiting credits from its internal bank. Such credits are limited and have other public policy uses and SCAQMD is developing a new rule to encourage developers to seek permits for the amount of emissions they realistically will have so SCAQMD can better manage the amount of credits debited from its internal offset bank. As such, without any changes in SCAQMD's rules and state law, bidding on RFOs to satisfy any new procurements will be limited to the facilities with existing utility boilers who can use SCAQMD's Rule 1304(a)(2) offset exemption. The AB1318 project report, expected later this year, uses previous local capacity studies but provides a more in-depth assessment of offset issues in SCAB.[9]

3.4 Natural Gas Availability in San Diego

Prior to the shutdown of San Onofre the capacity of the natural gas infrastructure in the San Diego region was occasional strained. Since San Onofre has shut down the natural gas fired plants located in the local reliability area have increased production. The availability of natural gas to fuel existing and new electric generation (EG) must be addressed in a post San Onofre environment to ensure gas pipelines and related infrastructure have the necessary capacity to deliver the supply to the plants. The San Diego region is already a gas capacity constrained area. Almost the entire electric generation gas load in this area is served on an "interruptible basis". This simply means if the gas supply is not sufficient to meet all gas demands, the electric generators will be the first curtailed (shut off). An additional issue that must be considered is the continuing reassessment work for Gas Transmission pipelines as required by the Transmission Pipeline Integrity regulations. This work requires extensive coordination with the CAISO as it may limit capacity in certain areas of the system as the assessments are conducted.

The key action required – Southern California Gas Company and SDG&E will be filing an application with the CPUC late in 2013 for transmission pipeline upgrades needed in both the Southern California Gas and SDG&E systems to address both system capacity and supply to address the generation

[8] SB 288 (Sher, Chapter 476, Statutes of 2003) prohibits districts from loosening their new source review regulations relative to those in effect in 2002.
[9] AB 1318(V. Manuel Perez, Chapter XXX, Statutes of 2009) requires ARB, in conjunction with various state agencies, to estimate capacity needed for reliability and to identify issues, if any, with permitting such capacity in SCAB.

reliability issues. The application will seek CPUC approval by the end of 2014. If approved, it is estimated that permitting and construction of the pipelines would take an additional 3-5 years.

3.5 Contingent Generator Permitting

Achieving the overall reliability in Southern California will require success in the development of preferred resources, transmission, and conventional generating resources. Yet, development in populated urban areas will most certainly raise local land use and development concerns and, in the case of conventional generation, air emission and other permitting issues. In the event these are infeasible when needed, it may be necessary to quickly bring on line some generating facilities that have already been permitted but only used on a contingency basis.

The Energy Commission's Application for Certification (AFC) process for large thermal power plants is designed to be a 12-month permitting process which includes multiple opportunities for public, agency, tribal and intervener participation. However, applicants may be able to finish the permitting process in less than 12 months if they propose good sites and provide exceptionally complete applications. If the generation is unnecessary within the 5 year permit time frame, the CEC can grant extensions of licenses. Land use planning benefits because of the early indication of potential interest in constructing a power plant. The alternative option would be for the AFC filing agent to begin discussions with the CEC about potential locations of power plants. The CEC and filing agent can then work over the next few years to identify the areas of least environmental resistance, so when the AFC is filed (if filed at all), many of the issues would have been resolved and the identified expedited approach would be possible.

4. CONCLUSION

The above identified needs and proposed mitigations are a direct response to the reliability needs in Southern California. The solution requires substantial effective coordination between the State Agencies, the ISO and the affected utilities serving load in the area. The near term approach requires monitoring to ensure it is put into service with the expected operating dates and require some specific actions to ensure they can receive the necessary regulatory approvals and be brought into operation in the timeframe needed. Finally, the long term creates more opportunities and flexibility to meet reliability needs. However, some of the solutions take many years to come into reality, thus the hard work needs to begin now.

ATTACHMENT B

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

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

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 W ater 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 st andards 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 adoptin g 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 imp lementation 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.

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

towards meeting Track 2 requirements. Reductions shall be based on reductions in intake flows, calculated as the difference between:

(i) the maximum permitted discharge (expressed as m illion 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

(ii) 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**.

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, or consecutive less than 90 day suspensions, 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

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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 afford significant weight to the recommendations of the CAISO.

C. Immediate and Interim Requirements

(1) No later than October 1, 2011, 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 State Water Board.

(2) No later than October 1, 2011, 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 State 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 October 1, 2015 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