Report of the Statewide Advisory Committee on Cooling Water Intake Structures

April 2013

I. Introduction

The Statewide Advisory Committee on Cooling Water Intake Structures (SACCWIS)[1] has prepared this report for the State Water Resources Control Board (Water Board) in connection with implementation plans submitted by non-nuclear power plant owners on April 1, 2011, as contemplated by the Water Board's Statewide Water Quality Control Policy on the Use of Coastal and Estuarine Waters for Power Plant Cooling (Statewide Policy).[2] The Statewide Policy requires SACCWIS to advise the Water Board annually on whether the Statewide Policy's compliance schedule takes into account local area and electric grid reliability, including permitting constraints. Section 3.B(4) of the Statewide Policy provides that SACCWIS will report to the Water Board with recommendations on modifications to the implementation schedule each year starting in 2012.[3] Similar to SACCWIS' report adopted in March 2012, this report generally focuses on generating facilities within the ISO balancing authority area[4] with near-term final compliance dates (i.e. 2015 and 2017). At this time, SACCWIS does not recommend a change to the final compliance schedule in the Water Board's Statewide Policy. However, the potential need for generating capacity in the Los Angeles Basin and San Diego local capacity requirement areas still exists, especially in light of the ongoing outage at San Onofre Nuclear Generating Station (SONGS).

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[1] SACCWIS includes 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), the California Independent System Operator Corporation (ISO), and the Water Board.

[2] A copy of the Water Board's Statewide Policy, effective on October 1, 2010, is available at the following Web site: http://www.waterboards.ca.gov/water_issues/programs/ocean/cwa316/docs/policy100110.pdf

[3] The Implementation Schedule contained in Policy Section 3.E, Table 1 requires that the SACCWIS report to the Water Board no later than March 31 each year. By letter dated March 19, 2013, the Water Board's Chief Deputy Director requested that SACCWIS deliver this report in April 2013 to accommodate scheduling difficulties.

[4] LADWP compliance dates were reviewed and modified by the Water Board in July 2011.

Southern California could face serious electric reliability concerns if SONGS remains offline and if no replacement capacity is built for generating facilities with near term compliance dates under the Water Board's Statewide Policy.[5]

II. Operational Developments Relevant to the Water Board's Statewide Policy

Several operational developments have occurred or are anticipated to occur involving power plants subject to the Water Board's Statewide Policy. In the first quarter of 2012, units 2 and 3 at SONGS went offline to address wear in the units' steam generator tubing.[6] SACCWIS understands that these units will return to service only after the Nuclear Regulatory Commission is satisfied that the plant can operate without risk to public health and safety. Until that time, these units will remain offline.

In the fourth quarter of 2012, AES retired units 3 and 4 at the Huntington Beach Power Plant. SACCWIS understands that the air emission offsets associated with these units are now committed to support Edison Mission Energy's Walnut Creek Energy Center in the Los Angeles Basin. As a result, Huntington Beach Units 3 and 4 are now in compliance with the Water Board's Statewide Policy.

In the first quarter of 2013, NRG Energy (formerly GenOn) notified the CPUC that it intends to retire Contra Costa units 6 and 7 when the Marsh Landing Generating Station reaches commercial operation, expected later this year. Once this occurs, Contra Costa units 6 and 7 will be in compliance with the Water Board's Statewide Policy.

Last year, SACCWIS reported that NRG plans to retire El Segundo unit 3 as part of the El Segundo Repowering Project. SACCWIS understands that NRG expects the El Segundo Repowering Project to reach commercial operation by August 1, 2013, at which time El Segundo unit 3 will be in compliance with the Water Board's Statewide Policy.

[5] In 2013, the CPUC plans to evaluate 's the need for new resources given the SONGS outage in its long-term procurement plan proceeding.

[6] *See generally* http://www.nrc.gov/info-finder/reactor/songs/tube-degradation.html

III. Regulatory Developments Relevant to the Water Board's Statewide Policy

Over the last year, several regulatory developments have occurred involving infrastructure planning and permitting activities to facilitate implementation of the Water Board's Statewide Policy. SACCWIS provides a brief description of these developments in the following paragraphs.

A. ISO 2011-2012 Transmission Planning Process

In its 2011-2012 transmission planning process, the ISO performed long-term local capacity requirement studies for the local areas with generating facilities using once through cooling: Greater Bay Area, Big Creek/Ventura, Los Angeles Basin and San Diego areas.[7] The ISO modeled the existing transmission system and generation resources, as well as ISO approved transmission projects that were estimated to reach commercial operation on or before June 1, 2021. Consistent with all previous local capacity assessments, the ISO used a 1-in-10 year summer peak load from the California Energy Demand forecast that was adopted by the CEC in 2009. In addition, since these studies were largely completed in December 2011, predating the SONGS outages beginning in January 2012, they assumed that SONGS would be operational in the study year of 2021. These studies continue to reflect projected local capacity needs as of 2021 in areas that contain generating capacity currently using once through cooling technology. Table A identifies a range summary of generating capacity currently using once through cooling that the ISO determined is needed in 2021 to maintain local reliability in local capacity requirement areas under a trajectory renewable portfolio standard.[8]

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7 http://www.caiso.com/Documents/Board-approvedISO2011-2012-TransmissionPlan.pdf

8 The trajectory renewable portfolio standard utilized the same approach as the commercial interest renewable portfolio standard, which the ISO used in its 2012-2013 transmission planning process.

Table A

Local Capacity Requirement Area	Replacement Generation Need (MW)
Greater Bay Area	0
Big Creek/Ventura (Moorpark sub-area)	430
Los Angeles Basin	2,370 – 3,741[9]
San Diego	531[10] - 950

B. CPUC Procurement Process

The CPUC has authorized the construction of between 1600-2100 MW of new resources in the Los Angeles Basin and Big Creek/Ventura local capacity requirement areas and 343 MW of resources in the San Diego local capacity area to plan for the impact on electrical reliability of the Water Board's Statewide Policy. In 2012, the CPUC conducted proceedings to examine reliability in the Los Angeles Basin and San Diego in connection with the Water Board's Statewide Policy. Neither of these proceedings has yet to examine the reliability impacts of SONGS ceasing to operate. The CPUC expects that it will address this issue later in 2013 as part of the Long-Term Procurement Plan proceeding. [11]

2012 Long-Term Procurement Plan Track I Decision 13-02-015

Track I of the 2012 Long-Term Procurement Plan proceeding specifically sought to assess the need for new electrical generation arising by 2020 in connection with implementation of the Water Board's Statewide Policy. Pursuant to a settlement agreement in the 2010 Long-Term Procurement Plan proceeding,[12] the ISO conducted

[9] The range of capacity in the Los Angeles Basin reflects alternative locations for replacement capacity within the Los Angeles Basin.

[10] The lower range of capacity needs reflects the use of SDG&E's proposed Pio Pico, Quail Brush and Escondido generating facilities.

[11] The Long-Term Procurement Plan proceeding is the CPUC's biennial process to assess integrated resource planning for California's system and local capacity needs ten years forward. Track I evaluates the need for new local capacity resources. Track II assesses the overall long-term need for new system reliability resources.

[12] Decision 12-04-046 (Decision on System Track I and Rules Track III of the Long-Term Procurement Plan Proceeding and Approving Settlement), *available* here.

power flow studies in the 2011-2012 transmission planning process to assess the long-term local capacity needs ten years forward arising from implementation of the Water Board's Statewide Policy.[13] The ISO's study reflected a need for replacement generation in the Los Angeles Basin and Big Creek/Ventura local capacity areas. In February 2013, the CPUC issued Decision 13-02-015[14], authorizing Southern California Edison to procure at least 1400 MW and up to 1800 MW of electrical capacity[15] in the West Los Angeles sub-area of the Los Angeles Basin local capacity requirement area. Decision 13-02-015 also authorized at least 215 MW and up to 290 MW in the Moorpark sub-area of the Big Creek/Ventura local capacity requirement area.

2012 LTPP Track II Decision 12-12-010

Track II of the 2012 LTPP is focused on system-wide resource needs. In December 2012, the CPUC adopted updated planning assumptions and standards in Decision 12-12-010[16] to form the basis for assessing system-wide resource needs. In 2013, this proceeding will examine the need for flexible capacity resources as well as the need for resources to maintain system reliability should SONGS retire. The CPUC expects to issue a decision on these issues toward the end of 2013 or early 2014.

Separately, in response to an application filed by San Diego Gas and Electric Company, the CPUC considered the need for new local capacity generation in the San

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[13] Table A on page 3 of this report outlines the needs assessments derived from these studies.

[14] Decision 13-02-015 (Decision Authorizing Long-Term Procurement for Local Capacity Requirements), *available* here.

[15] In the LA Basin, at least 1000 MW, but no more than 1200 MW of this capacity must be procured from conventional gas-fired or combined heat and power resources. At least 50 MW must be procured from energy storage resources. At least 150 MW of capacity must be procured through energy storage resources or preferred resources consistent with the Loading Order in the Governor's Energy Action Plan, which places energy efficiency and demand response resources first in the Loading Order, followed by renewable and combined heat and power resources, and then fossil-fuel resources. SCE is also authorized to procure up to an additional 600 MW of capacity from preferred resources and/or energy storage resources. In San Diego, the CPUC authorized San Diego Gas & Electric (SDG&E) to procure 298 MW of electric capacity in 2018, and approved a purchase power tolling agreement with Escondido Energy Center for 45 MW. This power purchase agreement will support the repowering of an existing 35 MW facility.

[16] Decision 12-12-020 (Decision Adopting Long-Term Procurement Plans Track 2 Assumptions and Scenarios), *available* here.

Diego local capacity area. The proceeding assumed that the Encina Power Station will retire by December 31, 2017 and that SONGS will continue to be in-service. In March 2013, the CPUC directed SDG&E to procure up to 298 MWs of local generation beginning in 2018, and authorized the utility to enter into a purchase power tolling agreement with Escondido Energy Center, which is in the process of repowering from a 35 MW facility to 45 MWs.[17]

<u>Examining Additional Resource Needs</u>

The CPUC considers its need authorizations a "measured first step in a longer process."[18] As explained, the CPUC anticipates assessing the replacement need for SONGS in 2013. In the 2014 Long Term Procurement Plan proceeding, the CPUC plans to evaluate whether there are additional local capacity needs over a ten year horizon. The CPUC expects the ISO's 2012-2013 Transmission Planning Process, or subsequent process, to serve as the basis for these future assessments.

C. ISO 2012-2013 Transmission Planning Process

In its 2012-2013 transmission planning process, the ISO also examined once through cooling generation replacement or repowering needs, as well as new generation requirements in the sub-areas of the Los Angeles Basin and San Diego local capacity requirement areas. As part of the 2012-2013 transmission planning process, the ISO also examined the long-term grid reliability impact in the absence of the two nuclear generating stations, Diablo Canyon Power Plant and SONGS.[19] The studies, based on commercial interest renewable portfolio standard assumptions, reflect an extended outage scenario at these facilities for an intermediate time frame (2018) and longer term timeframe (2022). The ISO's study results reflect the mid-term (2018) and long-term (2022) generation alternatives as well as mid-term and long-term combined

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[17] Decision 13-03-029 .

[18] Decision 13-02-015, p. 3.

[19] ISO 2012-2013 Transmission Plan dated March 20, 2013 at 159-199. These studies only address grid reliability impact assessments and are not sufficient to determine whether Diablo Canyon and SONGS may retire.

transmission and generation alternatives.[20] The results of either approach reflect generation replacement or repowering needs, as well as new generation requirements in the Los Angeles Basin and San Diego local capacity areas. These results do not identify generation needs in Greater Bay Area local capacity requirement area.

With respect to Diablo Canyon, the results of these studies reflect that there are no material mid- or long-term transmission system impacts associated with an extended outage at the facility. Resource requirements, however, such as planning reserve criteria and flexible resource needs, would require further study. Of relevance to the Water Board's Statewide Policy, in order to balance loads and resources without Diablo Canyon, the ISO's power flow model required an additional 1600 - 1700 MW of capacity in Northern California if generation using once through cooling was assumed to be unavailable due to compliance deadlines under the Water Board's Statewide Policy.

With respect to an intermediate and long-term loss of the SONGS, the studies reflected multiple reliability issues in both the Los Angeles Basin and San Diego local capacity requirements areas as once through cooled generation capacity in these areas faces compliance deadlines under the Water Board's Statewide Policy. The studies reflect the need for new resources in both the Los Angeles Basin and San Diego local capacity requirement areas. The reliability concerns identified by the ISO in the Los Angeles and San Diego areas include: (a) potential voltage instability under overlapping transmission outage condition; and (b) overloading of transmission facilities under various transmission contingencies. Table B provides a summary of new generation requirements, as well as dynamic reactive support need by 2022 time frame arising from the absence of SONGS.[21]

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[20] ISO 2012-2013 Transmission Plan dated March 20, 2013 at 182-190.

[21] Some elements of the potential mitigation alternatives for the long-term horizon (2022) without SONGS include the alternative of a 500kV transmission line connecting SCE and SDG&E transmission systems. For more details on the 2018 mid-term and 2022 long-term mitigations, please refer to Tables 3.5-10 and 3.5-11 on pages 184-189 of the ISO's 2012-2013 2012-2013 Transmission Plan. These tables reflect additional detail regarding generation replacement and new generation need, as well as dynamic reactive support need, for the both the Los Angeles Basin and San Diego local capacity requirement areas under various mitigation alternatives.

Table B – Overview of New Generation and Dynamic Reactive Support Need by 2022 for SONGS Absence Scenario[22]

LCR Area	Generation Need (MW)	Dynamic Reactive Support Need (MVAR)[23]
Los Angeles Basin	2,915 – 4,615	500 – 1,050
San Diego	920 – 1885	960

If SONGS remains offline and new resources are not constructed in sufficient time to meet the need identified in these studies, then the Water Board may need to extend compliance deadlines in the Statewide Policy.

In addition to evaluating intermediate and long-term outages at Diablo Canyon and SONGS using the commercial interest renewable portfolio standard assumptions, the ISO also performed sensitivity studies using high distributed generation renewable portfolio standard assumptions for comparing the resource requirements in 2022. With higher penetrations of system-connected distributed generation, the ISO projects reduced resource requirements in the Los Angeles and San Diego local capacity requirement areas.

D. CEC Siting Processes

The CEC is the lead agency for licensing thermal power plants 50 megawatts (MW) and larger under the California Environmental Quality Act (CEQA) and has a

[22] The range of generation replacement and new generation need, as well as dynamic reactive support need, reflects different mitigation alternatives. For further detail on how these needs are paired, please refer to the ISO's 2012-2013 Revised Draft Transmission Plan Transmission Plan. Any generation constructed in response to the authorization in CPUC's 2012 Long-Term Procurement Plan Track I Decision 13-12-015 would reduce the need identified in Table B.

[23] Reactive support is necessary to energize and transmit power in an alternating current transmission system and maintain voltage stability on the transmission system.

certified regulatory program under CEQA.[24] Under this program, the CEC conducts an environmental analysis of the project, including an analysis of alternatives and mitigation measures to minimize any significant adverse effect the project may have on the environment. These requirements do not, however, apply to the repowering or replacement of an existing power plant wherein the net increase in capacity is less than 50 MW.

As of January 2013, the CEC has received two applications for certification to replace some or all of the power production units at AES' Huntington Beach and Redondo Beach facilities. The Redondo Beach certification process has not started because the CEC has not determined the application is data adequate. The CEC has informed SACCWIS that it expects the filing of a third application for certification to repower AES' Alamitos facility by the end of 2013.

E. Generator Implementation Plans under Water Board's Statewide Policy

The Water Board has received implementation plans from all generators in the ISO's balancing authority area in connection with the Statewide Policy. On December 11, 2012, the Water Board issued a letter requesting that AES Southland, LLC and GenOn (now owned by NRG Energy) provide additional information to facilitate an assessment of future grid reliability issues in connection with these generator owners' implementation plans.[25] AES Southland is scheduled to submit a response to the Water Board's information request by March 31, 2013.

SACCWIS continues to assess NRG's response to the Water Board. Importantly, NRG's response makes clear it will seek to comply with the Water Board's Policy by either repowering or retiring the Encina Power Station and El Segundo unit 4 by their scheduled compliance dates.

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[24] Under this program, a project developer files an Application for Certification to initiate the siting process. The CEC Chairman then establishes a siting committee to preside over the process. Once the CEC determines the applicant has submitted adequate information to proceed (referred to as data adequate), the proceeding begins. The certification proceeding could take up to a year or longer. For example, the certification process for the Carlsbad Energy Center proceeding took almost five years. If constructed, the Carlsbad Energy Center will replace three of the units at Encina Power Station.

[25] SACCWIS understands that Water Board staff have chosen not to issue letters GenOn and Dynegy regarding their facilities at this time. These two companies have filed a petition for writ of mandate, challenging the State Water Board's adoption of the Statewide Policy on various grounds. .

F. South Coast Air Quality Management District (SCAQMD) Proposed Rule 1304.1

On January 4, 2013, the SCAQMD issued draft language for proposed Rule 1304.1 – Electrical Generating Facility Annual Offset Fee for Use of Offset Exemption. SCAQMD's existing Rule 1304(a)(2) exempts electric utility steam generating boilers that will be replaced by advanced generating technologies, such as combined cycle gas turbines, from emission offset requirements. To demonstrate equivalency with the federal New Source Review Program, which does not provide an exemption from offsets, SCAQMD uses emission credits from its internal accounts to offset any emission increase associated with these projects. No fee is currently being charged for this SCAQMD-provided offset credit. The purpose of Rule 1304.1 is to require electrical generating facilities that use the specific air emission offset exemption described in SCAQMD's Rule 1304(a)(2) [Electric Utility Steam Boiler Replacement] to pay annual fees for access to this exemption. The fee proceeds would be invested in air pollution improvement projects consistent with SCAQMD's Air Quality Management Plan. SCAQMD is proposing to require generation developers to make an upfront deposit of five years of these annual fees that would be 50 percent non-refundable prior to receiving a permit to construct. After issuance of a permit, the remaining 50 percent of the deposit would become increasingly non-refundable over a five-year period regardless of whether or not the generating plant is built. Several parties have expressed concern that the proposed rule could affect reliability by creating a disincentive for repowering of generating facilities using once through cooling in the Los Angeles Basin. SCAQMD has established a working group to provide input on the proposed rule, including whether the revenues at stake are large enough to seriously hinder generator development plans. Additionally, SCAQMD staff has stated that demonstrating equivalency with federal offset requirements through use of the fee rule would not be mandatory and generators could still exercise the option of procuring emission reduction credits on the open market.

IV. Final Compliance Dates for Generating Units with Near-term Compliance Dates Remain a Concern for Electric Grid Reliability

This section identifies specific issues associated with generating units or facilities in the ISO's balancing authority area with near-term (2015) and mid-term (2017) compliance dates under the Water Board's Statewide Policy. There are six such facilities: El Segundo and Encina are located in Southern California, while Contra Costa, Pittsburg, Morro Bay and Moss Landing are located in Northern California.

El Segundo

Units 3 and 4 at El Segundo use once through cooling technology. NRG, the plant owner, is constructing a repowering project that will consist of two combined cycle facilities, which will use dry air cooling and are currently expected to reach commercial operation in August 2013. As part of that repowering, NRG is retiring unit 3 (units 1 and 2 have already been retired). The final compliance date for El Segundo units 3 and 4 under the Statewide Policy is December 31, 2015. In its original April 1, 2011 implementation plan, NRG stated that it intended to repower El Segundo unit 4 and wanted an extension of its compliance date to 2017 to enable NRG to pursue repowering without the loss of operating capacity at the El Segundo facility. At this time, NRG does not have a power purchase agreement with a load serving entity to support repowering unit 4, and NRG has not submitted an application for certification to the CEC to repower unit 4. In a letter submitted to the Water Board dated January 30, 2013, NRG has stated it will retire unit 4 no later than December 31, 2015.

The analyses prepared by the ISO as part of the 2012-2013 transmission planning process for 2022 reflects that there is a need for only a portion of the capacity at the El Segundo facility to satisfy local capacity requirements in the El Nido subarea, which is part of the Los Angeles Basin local capacity area. The El Segundo repowering project, coupled with other generation not using once through cooling in the El Nido subarea, satisfies projected local capacity requirements in the El Nido subarea. However, the local capacity analyses for 2018 and 2022 prepared by the ISO to assess the consequences of SONGS being offline reflect a need for additional capacity to support local and system requirements. Notwithstanding these study results, SACCWIS does not recommend a change in compliance dates for any of the El Segundo units at this time.

Encina

The Encina facility consists of five steam boiler generating units using once-through cooling with an aggregate capacity of 950 MW. In its original April 1, 2011 implementation plan, NRG proposed different approaches for the five old steam-boiler units. For units 1-3 (an aggregate of 318 MW capacity), NRG proposed to repower these units with a new flexible combined cycle facility, the Carlsbad Energy Center, consisting of two combined cycle units with an aggregate capacity of 550 MW. NRG received a permit from the CEC for this facility in June 2012. For units 4-5 (an aggregate of 632 MW), NRG proposed to retrofit these units pursuant to the Track 2 option to reduce environmental impacts. In a letter dated January 30, 2013, NRG states: (1) it still plans to replace units 1-3 with the Carlsbad Energy Center; and (2) it no longer intends to pursue Track 2 compliance options and will retire units 4 and 5 no later than the final compliance date for Encina of December 31, 2017.

The local capacity analyses for 2018 and 2022, prepared by the ISO to assess the consequences of SONGS being offline, reflect a need for capacity at the Encina facility or an electrically equivalent site. For the San Diego area, the ISO studies examined alternative scenarios that include a range of different generation and transmission combinations in the San Diego and Los Angeles Basin to address this capacity need, including generation capacity in northwestern San Diego where Encina currently operates.

As discussed in Section III.B, the CPUC authorized SDG&E to procure a total of 343 MW of generating capacity beginning in 2018, in the San Diego local capacity requirement area. SACCWIS intends to examine whether the 2017 compliance date remains appropriate for all units at Encina and intends to advise the Water Board when more information is available. SACCWIS does not recommend a change in compliance dates for the units at the Encina facility at this time.

Contra Costa

As described in Section II of this report, SACCWIS anticipates that NRG's Contra Costa units 6 and 7 will retire before their final compliance date (December 31, 2017). The CPUC has approved a power purchase agreement between NRG and Pacific Gas and Electric Company that requires the existing capacity at Contra Costa units 6 and 7 to retire when Marsh Landing becomes operational. SACCWIS understands that NRG intends to bring the Marsh Landing facility into commercial operation this year. SACCWIS does not recommend a change in compliance dates for the units at the Contra Costa facility.

Pittsburg

NRG's Pittsburg units 5 and 6 are 312 MW and 317 MW steam boilers, respectively. Both units use once through cooling technology. Pittsburg unit 7 is a 682 MW steam boiler unit that has water-cooled cooling towers. Unit 7 is interconnected to units 5 and 6 and cannot operate independent of them. To start Pittsburg unit 7, NRG must start either unit 5 or 6 first. The final compliance date for Pittsburg under the Statewide Policy is December 31, 2017. In its implementation plan filed April 1, 2011, NRG proposed to sever the existing cooling towers from unit 7, connect them to units 5 and 6, and then retire unit 7. This sequence of steps would eliminate once through cooling at units 5 and 6 but also would result in the loss of capacity from unit 7. To finance and construct this new configuration, NRG asserts it needs a multi-year contract from a load serving entity.

In an earlier study of local capacity technical analyses, the ISO identified a capacity need within the Pittsburg sub-area of the Greater Bay Area for 2016. Based on this analysis, at least one Pittsburg unit would need to continue to operate or the sub-area would require between 100 and 200 MW of new electrically equivalent capacity. The ISO's 2017 local capacity analysis, however, performed as part of the 2012-2013 transmission planning process, reaches different conclusions. In its study of 2017, the ISO's analysis shows that the Pittsburg subarea no longer exists as a result of the assumed completion of four transmission system upgrades.[26] These upgrades should eliminate the local capacity needs that the Pittsburg units may help satisfy. SACCWIS does not recommend a change in compliance dates for the units at the Pittsburg facility.

Moss Landing

Dynegy's Moss Landing facility consists of two types of units – older steam boiler units and new combined cycle units. Units 6 and 7 are steam boilers with a capacity of roughly 750 MW each for a total of 1510 MW. Power blocks 1 and 2 refer to two combined cycle facilities; each 510 MW power block consists of two combustion turbines and a heat recovery steam generator. The final compliance date for Moss Landing under the Statewide Policy is December 31, 2017. In its April 1, 2011 implementation plan, Dynegy proposed a 2032 compliance date for power blocks 1 and 2, and to implement Track 2 retrofit measures by 2017 for units 6 and 7. There is no updated implementation information from Dynegy even though Moss Landing represents the largest amount of capacity using once through cooling technology at a single facility in the entire state.

While Moss Landing is not located within an ISO local capacity area, power blocks 1 and 2 are newer dispatchable combined cycle facilities. They are also traditionally operated under high peak load conditions for the Greater Bay Area. They can also help balance system needs created by variability of renewable resources as well as load. The ISO has not conducted studies to determine the impacts if these two units were retired.[27] SACCWIS, however, does not recommend a change in compliance dates for the units at the Moss Landing facility at this time.

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[26] The ISO's 2017 local capacity study states that the Pittsburg subarea disappears with the completion of the Moraga #1 230/115 kV transformer replacement (expected to be completed by December 2015), Tesla-Pittsburg 230 kV lines reconductoring (expected to be in service by October 2015), Contra Costa-Moraga 230 kV reconductoring (expected in service by December 2014), and the Vaca Dixon – Lakeville 230 kV reconductoring project (expected to be in service by June 1, 2017).

[27] The ISO has not assessed the local reliability impacts to the Greater Bay Area if these two units retire. For the ten-year horizon study scenario (2022) without Diablo Canyon Power Plant, the ISO assumed power blocks 1 and 2 remained on-line in its power flow model to balance northern California (NP26) loads and resources. This zonal requirement, however, could also be met with other potential new resources located in NP26.

Morro Bay

Each of the two operating steam boiler units at Morro Bay is approximately 325 MW. In its April 1, 2011 implementation plan, Dynegy proposed to implement Track 2 retrofit measures for generating units 3 and 4 at its Morro Bay facility. Dynegy states that if it is unable to implement Track 2 retrofit measures, it may develop a small power plant of roughly 160 MW at a new site using the air credits from the shutdown of the existing Morro Bay facility. The final compliance date for Morro Bay under the Statewide Policy is December 31, 2015. Morro Bay is not located within a local capacity area, and therefore there are no local electric reliability issues if Dynegy retires Morro Bay. SACCWIS does not recommend a change in compliance dates for the units at the Morro Bay facility.

V. Conclusion

SACCWIS members are continuing to assess the reliability impacts to the electric grid in connection with implementation of the Water Board's Statewide Policy. Some facilities using once through cooling are retiring in advance of the compliance dates established by the Water Board's Statewide Policy. Others may require extensions to comply, if one or more uncertainties combine to threaten local or system reliability or if insufficient replacement infrastructure is developed. At this time, however, SACCWIS does not recommend an extension of the final compliance schedule in the Water Board's Statewide Policy for any facility. If, however, SONGS continues to remain offline, local generation in combination with other mitigation measures such as transmission upgrades and measures to implement demand side management are needed to maintain reliability in the Los Angeles Basin and San Diego areas. The Water Board may need to extend the compliance schedule if these replacement resources are not constructed in sufficient time to meet the identified need.

To better understand resource needs and current generator plans, State Water Board staff will request updates in the near-term from generators with compliance dates in 2017 or earlier. Next, State Water Board staff will request generators with compliance dates post-2017 to submit information to inform further studies and analysis of reliability impacts associated with those generators. In the future, SACCWIS plans to provide additional information to the Water Board concerning new infrastructure development in the ISO’s local capacity requirement areas and system to advance implementation of the Water Board’s Statewide Policy.