Assembly Bill 1318: Assessment of Electrical Grid Reliability Needs and Offset Requirements in the South Coast Air Basin

Prepared by the Air Resources Board in consultation with:

California Energy Commission
California Independent System Operator
California Public Utilities Commission
State Water Resources Control Board
Los Angeles Department of Water and Power

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DRAFT FINAL REPORT

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Assembly Bill 1318 – Summary of Findings and Recommendations

This report meets the directives of Assembly Bill 1318 (AB 1318), which requires an assessment of the generation resources required to maintain electric grid reliability in the South Coast Air Basin and an evaluation of whether permitting constraints related to air pollutant emission offsets exist in siting any of the fossil generation identified as needed for reliability. The California Air Resources Board is the primary author of this report. The analytical studies supporting the reliability assessment were conducted by the California Independent System Operator (ISO) and the Los Angeles Department of Water and Power (LADWP). The report was drafted in consultation with, and through contributions made by the AB 1318 Technical Team. The technical team is comprised of senior technical staff from the California Energy Commission (CEC), the California Public Utilities Commission (CPUC), ISO, the State Water Resources Control Board (State Water Board), and LADWP.

During the period that this report was being prepared, the San Onofre Nuclear Generating Station (SONGS) in northern San Diego County suffered an outage that was eventually determined to be so costly to repair that its utility owners announced their decision to retire the entire facility on June 7, 2013. Analyses prepared assuming SONGS was online were replaced by studies assuming SONGS was permanently retired. Multiple versions of such studies emerged during the period from spring 2012 through summer 2013 using a variety of assumptions. Although this report is selective about the studies used to characterize a range of resource additions needed to assure reliability in Southern California, the studies selected are representative of this range.

The decision to retire SONGS also kicked-off a concurrent effort to examine reliability needs in the greater Southern California area via directive from the Governor's Office that the State's top energy experts prepare a plan on how reliability will be maintained in the Los Angeles and San Diego areas with the permanent loss of SONGS. A Preliminary Reliability Plan has been prepared by senior staff of the CEC, CPUC, and ISO, in consultation with the State Water Board, SCAQMD, and the affected utilities. The Preliminary Reliability Plan was introduced at a CEC 2013 Integrated Energy Policy Report (IEPR) workshop on September 9, 2013. The Preliminary Reliability Plan examines the near-term needs (2014 through 2017) and longer-term plan (2020 and beyond) and actions that should be taken to replace the energy, capacity, and voltage support previously supplied by SONGS. This includes an evaluation of the best mix of resources to meet reliability at the lowest cost with an emphasis on pursuing mitigation options that minimize reliance on gas-fired generation and how preferred resources and transmission enhancements can play a role in minimizing conventional generation solutions. The Reliability Plan and AB 1318 project are separate but related efforts, and the grid studies conducted for the AB 1318 project were used to inform the Preliminary Reliability Plan.[1]

[1] It should be noted that the Preliminary Reliability Plan cites the CPUC's 2012 Long-Term Procurement Plan (LTPP) proceeding (R.12-03-014) as the expected forum to evaluate reliability needs driven by the retirement of SONGS and authorize any needed generation procurement.

Major Findings

- Grid studies conducted with the loss of SONGS have identified an electric reliability linkage between the Orange County portion of the LA Basin local capacity area and San Diego local capacity area, and the loss or gain of generation in San Diego affects generation requirements in the ISO's LA Basin area and vice versa.

- By 2020, nearly 4,500 MW of conventional gas generation resources at existing once-through cooling (OTC) power plants in LA Basin[2] are required by State Water Board Policy to phase-out OTC practices through retrofit, replacement, or retirement. In San Diego, over 900 MW of gas-fired capacity must phase-out OTC practices through retrofit, replacement, or retirement by 2017.

- Within the next 10 years, reliability concerns in the Los Angeles Basin are driven largely by 2020 OTC compliance dates leading to the potential loss of the 4,500 MW of existing OTC generation, the retirement of SONGS, and load growth in the region. Retirement of additional non-OTC aging capacity could further exacerbate the situation as units reach ages beyond their design life.[3]

- Generator Implementation Plans submitted to the State Water Board indicate the desire to repower existing OTC capacity in LA Basin and San Diego with more-efficient, state-of-the-art combined cycle or simple cycle natural gas power plants employing dry or closed-cycle wet cooling systems, if the necessary regulatory approvals and power purchase agreements can be secured.

- Replacement of lost capacity due to OTC retirements and SONGS shut down within the next 10 years in the range of 3,300 to 4,600 MW for the ISO Balancing Authority is needed to meet electricity demands and maintain grid reliability through 2022 within the South Coast Air Basin.[4] Capacity associated with OTC generating units with post-2020 compliance dates for the LADWP Balancing Authority Area must also remain available through 2022 to maintain reliability. The identified range of capacity needs is contingent upon the following assumptions:

    - All existing non-OTC, aging power plants located in South Coast Air Basin will continue to operate through 2022.
    - The levels of energy efficiency, demand response, and other load-reducing policies identified in this report are realized.
    - Replacement of lost capacity due to OTC retirements occurs in the most effective locations identified in the grid studies, or other electrically equivalent locations.

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[2] Including both California ISO and LADWP Balancing Authority Areas.

[3] The CPUC's LTPP proceeding has been planning for the impact of expected resource retirements – OTC (including SONGS) and non-OTC. In the Track 1 Decision (D.)13-02-015, the 2012 LTPP (R.12-03-014) authorized 1,400 to 1,800 MW of gas-fired and preferred resources to meet local reliability needs in the LA Basin primarily driven by the retirement of OTC units through 2020. Separately in D.13-03-029, the CPUC authorized 343 MW of resources to meet local reliability needs in the San Diego local area primarily driven by the retirement of Encina in 2018. Track 4 will evaluate local reliability needs post-SONGS, and is expected to make a decision in Q1 2014.

[4] Note that this report does not intent in its assessment of needed procurement to prejudge any potential local area or system reliability need determination in the CPUC's LTPP proceeding.

- Replacement of lost capacity due to OTC retirements in the range of 820 to 1,120 MW occurs in the San Diego area, beyond the 3,300 to 4,600 MW needed in the LA Basin.

Failure to realize the minimal levels of preferred resources and replacement of OTC capacity at the locations identified in the report may result in the need for additional generation or transmission resource capacity, while load reductions beyond those forecast in the studies, due to increased energy efficiency and demand response, will reduce the need for generation capacity. The ISO is currently evaluating various transmission alternatives as part of the 2013-2014 Transmission Planning Process to determine potential further reduction of conventional generation need. The results of these evaluations are scheduled to be available in the early spring 2014 time frame.

- The scarcity and cost of emission reduction credits in the SCAQMD essentially limits the available options for replacing any lost capacity under the current air permitting program to those that already own existing steam boiler generation available for repower. The necessary offsets for these repower projects are provided by the SCAQMD from a finite pool of credits in its internal offset bank.

- This report shows it is possible to meet electricity demands and maintain grid reliability through 2022 within the South Coast Air Basin, even without the power provided by SONGS, and remain within the total existing power plant capacity, if the following assumptions are realized:

    - Virtually all existing OTC power plants that are required by the State Water Board's policy phasing out OTC practices will be able to repower onsite or be replaced at an electrically equivalent location, consistent with their submitted repowering or replacement plans, subject to the requirements of the Public Utilities Code.[5]

    - The levels of energy efficiency, demand response, and other load-reducing policies identified in this report are realized. It should be noted that there are already mechanisms in place to ensure energy saving programs are implemented; therefore this assumption is based on firm, existing state energy policy commitments. However, the analyses upon which this report are based require the load reducing programmatic efforts to deliver specific impacts in particular locations, and this geographic specificity is unprecedented.

    - The SCAQMD's permitting program continues to be able to address the offsets obligation for the OTC power plants identified in this report. SCAQMD Rule 1304 covers offset requirements for power plants that repower or replace existing capacity with newer, cleaner technologies by providing those offsets from the SCAQMD internal offset bank. It is expected that as the OTC power plants upgrade their equipment consistent with their OTC repowering/replacement

[5] The Public Utilities Code, including Section 454.5(b) sets forth guidelines that support competitive procurement of electric generation. These guidelines have implications for whether generation will be repowered or replaced at other locations.

plans, cleaner technologies will be installed to take advantage of this offsets provision, as well as meet business needs to improve operating efficiency.

❖ While it is estimated that the SCAQMD presently has an adequate amount of credits in its internal offset bank to repower all of the existing utility boiler OTC capacity affected by the State Water Board Policy with compliance dates through 2020, this strategy is not a sustainable permitting option for the long-term. A strategy focused solely on repowers of OTC units would limit projects to generators who already own existing capacity and would result in a large draw from the SCAQMD internal offset bank and whose credits are also intended to be used by essential public services such as hospitals; schools; and policy, fire-fighting, and wastewater treatment facilities. Beyond the timeline of the studies available for this project, load growth will continue and may accelerate if SCAQMD's energy policy results in extensive electrification, and an additional 1,700 MW of existing gas-fired OTC capacity in LA Basin owned by LADWP must comply with the State Water Board Policy by 2029.[6]

Major Recommendations

Although repower or replacing all existing OTC power plants with conventional gas-fired generation would meet grid reliability requirements in the South Coast Air Basin through 2022, this strategy has limited longevity and is inconsistent with the State's loading order and air quality and climate change goals. Rather, the State should use this opportunity to align replacement resources with preferred resources to the greatest extent possible, consider transmission enhancements to move electricity more efficiently, and then meet residual needs with conventional gas resources.

While non-fossil generation options should be explored as a high priority, some conventional generation resources will still continue to be needed to replace OTC retirements by 2022, particularly if preferred resource and transmission enhancement projects do not materialize. The technical team has formed several recommendations to help ensure that grid stability continues to be realized into the future:

- It is recommended that the State energy agencies continue to coordinate with the State Water Board to ensure the aggregate capacity of the OTC and replacement power plants identified in this report be continuously maintained, and power plant owners repower or replace their equipment in a manner that does not disrupt grid stability. This coordination should be implemented through the existing Statewide Advisory Committee on Cooling Water Intake Structures (SACCWIS).

- It is recommended that the State develop and implement achievable energy efficiency, demand response, and other load-reducing programs to ensure that the greatest level of benefits are realized from existing generation. The energy savings realized from these programs reduces the need for new generation.

[6] LADWP is scheduled to repower Scattergood Units 1 and 2 by 2020; Harbor Units 1, 2, and 5 by 2026; and Haynes Units 1, 2, 8, 9, and 10 by 2029.

- The SCAQMD internal offsets bank is a finite pool from which to draw, and cannot support power plant repowering and replacement needs indefinitely. Given the amount of time required to obtain the necessary approvals to build new power plants, and the expectation that new generation will be required at some point past 2022, the Air Resources Board should partner with the SCAQMD to immediately form a Working Group that will identify options and make recommendations at the earliest practicable date to address long-term permitting needs.

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I. Executive Summary

This report fulfills the legislative directive outlined in Assembly Bill 1318 (AB 1318, Perez, Chapter 285, Statutes of 2009)[7] that requires the California Air Resources Board (ARB), in consultation with the California Energy Commission (CEC), California Public Utilities Commission (CPUC), California Independent System Operator (California ISO or ISO), State Water Resources Control Board (SWRCB), and Los Angeles Department of Water and Power (LADWP)[8], to evaluate the electrical generation resources needed to maintain grid reliability in the South Coast Air Basin, while ensuring compliance with State and federal law, and to report the results of that assessment to the Governor and Legislature. If the assessment concludes that additional fossil generation is needed to maintain grid reliability, the report is required to outline options that could be pursued to ensure sustainable permitting of the identified capacity with a focus on solutions that address the limited availability of air pollutant emission offsets for power plant projects located within the jurisdiction of the South Coast Air Quality Management District (SCAQMD or District).

At the project outset, the staff of the State agencies and ISO (AB 1318 Technical Team) determined that a comprehensive assessment was not feasible under the legislation's original July 1, 2010, timeframe as existing electric reliability studies, completed or underway, were inadequate to answer the expectations of AB 1318 and incorporate a public process. Therefore, the AB 1318 Technical Team produced an Interim Report and Work Plan outlining the schedule, responsibilities, studies, and overall strategy for conducting the evaluation. The Interim Report was submitted to the Governor's Office in September 2010, which approved an extension of the original report due date. The report deliverable date was further extended in early 2012 due to the outage of the 2,246-MW San Onofre Nuclear Generating Station (SONGS) to allow for further grid reliability assessments. The AB 1318 reliability studies conducted up to that point relied on capacity contributions from both generating units at SONGS since the units were fully operational prior to January 2012. By early 2012, the magnitude of the issues at SONGS prompted the critical need to re-examine reliability requirements for the Los Angeles Basin (LA Basin) and San Diego areas without SONGS due to the possibility of its extended outage or permanent retirement. Now that Southern California Edison has announced its plans to permanently retire the twin reactors at SONGS, the need to look at reliability requirements without that capacity is even more critical.[9] Although SONGS is located outside of the South Coast Air Basin, it plays an important part in energy

[7] See text of Assembly Bill 1318 in Appendix A.
[8] Although not specifically named in the legislation, LADWP was asked to participate and conduct its own grid reliability studies as another balancing authority, separate from ISO, whose jurisdiction lies within the South Coast Air Basin.
[9] On June 7, 2013, Southern California Edison, the majority owner of the San Onofre Nuclear Generating Station, announced its decision to retire the plant, citing mounting costs and uncertainty about when and if federal regulators would clear the way for the plant to restart.

reliability in the greater Southern California area – particularly in the Orange County and San Diego local capacity requirement (LCR) areas.

The additional time to complete the report has allowed the AB 1318 Technical Team to conduct a more comprehensive analysis that extends out to 2022, evaluates the extent to which demand-side programs, renewables, and potential transmission development can help reduce requirements for in-basin fossil-fueled generation; and assesses the potential aggregated impacts on reliability due to the mandate to retire, repower, or retrofit power plants that use once-through cooling (OTC) systems at coastal and estuarine sites to comply with the SWRCB's "Policy on the Use of Coastal and Estuarine Waters for Power Plant Cooling (OTC Policy)."[10] Statewide, thermal power plants affected by the OTC Policy provide near 20,000 MW of capacity, which is approximately 33 percent of currently installed statewide generation. Southern California has the highest concentration of OTC power plants in the State, and the impacts from their potential retirement as a compliance strategy could have a significant effect on reliability.[11]

Although it preceded the formal date that Southern California Edison (SCE) announced its retirement of SONGS, the CPUC initiated a new Track 4 of its 2012 Long-Term Procurement Plan (LTPP) rulemaking to obtain local capacity studies of Southern California that assumed SONGS would be offline throughout the planning horizon. With the June 7, 2013, decision by SCE to retire SONGS, the Governor's Office directed that the State's top energy experts prepare a plan on how reliability will be maintained in the Los Angeles and San Diego areas with the permanent loss of SONGS. A Preliminary Reliability Plan has been prepared by senior staff of the CEC, CPUC, and ISO, in consultation with the State Water Board, SCAQMD, and the affected utilities. The Preliminary Reliability Plan was introduced at a CEC Integrated Energy Policy Report (IEPR) workshop on September 9, 2013. The Preliminary Reliability Plan examine the near- and long-term actions that should be taken to replace the capacity and voltage support previously supplied by SONGS in addition to the retirement of various fossil-fueled OTC plants. Although the Preliminary Reliability Plan is based on ISO local capacity studies prepared for and submitted to the CPUC in early August 2013, the assumptions and results of these new studies are sufficiently similar to those prepared by the ISO for AB 1318 in spring 2013 that it is not necessary to shift to exclusive use of these new Track 4 results. In addition, the Preliminary Reliability Plan focuses on recommendations for the mitigation options that minimize reliance on gas-fired generation and how preferred resources and transmission enhancements can play a role in minimizing conventional generation solutions. The Preliminary Reliability Plan and the AB 1318 project are separate but related efforts, and the grid studies conducted for AB 1318 were used to inform the Preliminary Reliability Plan.

This report documents the methodology and results of the 10-year forward-looking electric reliability and emission offset assessment conducted by the AB 1318 Technical

[10] See text of OTC Policy at http://www.swrcb.ca.gov/water_issues/programs/ocean/cwa316/.
[11] Power plants located in the greater Southern California area that are affected by the OTC Policy are listed in Appendix B.

Team. The reliability assessment is comprised of several studies completed by the ISO and LADWP. The ISO studies used simulation modeling tools to identify generation capacity needs in the 2021-2022 timeframe to maintain local-level grid reliability in the LA Basin area and the greater Southern California area, as well as provide an assessment of whether the capacity identified as needed for grid reliability is of sufficient quantity and has the flexible operational attributes needed to support the higher penetration of intermittent wind and solar resources expected to be in place by 2020 to meet the State's 33 percent Renewables Portfolio Standard (RPS). LADWP studies were limited to the topic of local capacity requirements. The offset assessment uses the identified fossil capacity to estimate the corresponding range of potential emissions and compares those emissions to the current offset supply projections in the SCAQMD to identify the magnitude of any demand-supply offset gap.

Due to the SONGS retirement announcement by SCE, the findings and recommendations in this report are focused on the results of the more recent nuclear backup plan studies conducted by the ISO rather than the results of the earlier studies completed while SONGS was operational. ISO studies for AB 1318 were a combination of studies conducted using the assumptions developed for its 2011-2012 and 2012-2013 Transmission Planning Processes augmented by sensitivities to explore topics important for AB 1318. The LADWP Balancing Authority Area (BAA) is essentially isolated from the ISO BAA and is unaffected by the SONGS retirement.

The electricity demand forecasts and generation resource project projections used for the studies are a moving target that will change over time. In the coming years, the results could be subjected to further refinement through other separate studies, as needed, to reflect the most up-to-date grid conditions and as generator OTC Policy implementation plans and offset regulations and policies become more concrete.

General Assessment Framework

The convergence of overlapping ambient air quality, climate change, water quality, and energy-related regulations and policy goals affecting the electric utility industry, particularly within the next 30 years or more, complicate long-term grid planning efforts. In addition, although the Implementation Plans submitted to the SWRCB indicate the intent to repower OTC generating units as long as power purchase agreements can be secured, the inherent uncertainties associated with the processes of permitting, financing, and construction, mean that the online availability of these projects is subject to change from year to year. However, an assessment that focuses on reliability requirements at the 10-year mark (2021-2022 in this case) has the benefit of looking at generation needs at a point in time when the OTC Policy compliance dates for the majority of these projects are in effect and the projects are expected to be in place and online even if short-term delays are experienced in the interim years.

Because this is a future year assessment, there are inherent difficulties in selecting, with certainty, a single set of resource assumptions to evaluate that will represent how the grid will actually look in 10 years. In addition, providing an assessment based on only worst-case conditions produces an incomplete picture that does not capture the potential benefits of demand-side management policy goals that are not yet realized. To manage the uncertainty surrounding all of these variables, the State agencies agreed that a “bookends” approach was a reasonable method to define the scope of the studies to produce a potential range of generation capacity needed for grid reliability. The upper bookend represents reliability requirements under higher demand conditions based on the CEC-adopted demand forecast without incremental[12] demand-side management factored in the forecast. The high bookend is also based on the current build out pattern for resources and assuming compliance with applicable State regulations and mandates, including the 33 percent RPS (referred to herein as the “high bookend”). The lower bookend represents a reduced demand scenario that factors in additional incremental demand-side management programs[13] (referred to herein as the “low bookend”). The actual thermal resource mix that may materialize by the 2021-2022 time frame will depend upon the degree to which preferred resources can be relied upon to diminish the need for conventional generators.

Conceptually, the range of capacity needs identified in this report should be the combined result of grid planning (1) “local capacity requirements” (LCR) that require minimum generation needs in transmission constrained load areas, (2) zonal capacity requirements to satisfy planning reserve margin targets in larger regional areas[14], and (3) renewable integration requirements (also referred to as flexible capacity requirements) that evaluate the amount of capacity and necessary attributes that generation resources must have to handle the variability of generation and loads (e.g., to support the integration of intermittent renewable technologies such as wind and solar). The two “bookends” were assembled from various individual studies rather than from a comprehensive, internally consistent assessment of each of the three possible elements for each of the scenarios examined due to time and resource limitations. Future studies conducted after the AB 1318 effort is completed could reconcile these inconsistencies, along with providing updated results based on the most up-to-date data.

The identified capacity from the reliability studies was translated into a corresponding range of estimated emission offset requirements. Mitigation for these emissions was then evaluated under the SCAQMD’s current rules to identify whether any issues related to issuance of air permits for the capacity are expected.

[12] “Committed” savings are those which result from market forces and from policy initiatives that are fully authorized and funded for which a sufficient program design exists to allow accurate savings assessments. “Incremental” savings (sometimes also referred to as “incremental uncommitted” savings) are the result of policy initiatives, usually with goals but not yet specific programs or funding, and thus not considered committed.

[13] Demand-side management program examples include the California Energy Efficiency Strategic Plan, demand response programs, California Solar Initiative, CPUC Self-Generation Incentive Program, combined heat and power programs, and Governor’s Clean Energy Jobs Plan. Some impacts of these programs, such as the California Solar Initiative, are considered in both bookend scenarios.

[14] To meet zonal capacity need, generation does not need to be located only in the local areas within the South Coast Air Basin. The generation needed to satisfy the zonal area can be met by locating resources outside of South Coast Air Basin but within the zonal area.

Summary of Assessment Results

The AB 1318 Technical Team constructed the two bookend cases using reliability studies prepared as part of other processes and forums that reflect relevant federal, State, and local laws and policy goals currently in place, or to be implemented, during the 10-year study period. Due to overlapping regulations and policies, paired with a highly integrated and complex electrical transmission and generation system, the study results are strongly dependent on the underlying assumptions and the reader is cautioned about applying the results of this report to other scenarios that are based on a different set of parameters. Chapters II and III of this report provide details on the methodology, assumptions, and results of the electric reliability and offset needs assessment. Complete reports documenting the studies that were drawn upon for this report are presented in the supporting appendices as follows:

- *California ISO Reliability Assessment in Support of the California Air Resources Board for Meeting Assembly Bill (AB) 1318 (Appendix C);*
- *LADWP 2021 Local Capacity Technical Analysis: Final Report and Study Results (Appendix D);*
- *California ISO Study Report: Assembly Bill 1318 Grid Reliability Results for San Onofre Nuclear Generation Backup Plan Studies (Appendix E);* and
- *California ISO Renewable Integration Study in Support of the California Air Resources Board for Meeting Assembly Bill (AB) 1318 (Appendix F)*.

With respect to the retirement of SONGS, the studies show there may be multiple reliability issues in both the LA Basin and San Diego local reliability areas as OTC generating units face compliance deadlines under the SWRCB's OTC Policy. The studies reflect the need for new, repowered[15], or replacement[16] generation resources in both LA Basin and San Diego. The study results take into account OTC retirements based on OTC Policy compliance dates and new already-planned and accounted for generation coming online within the study period. The major findings associated with the electric reliability and offset assessment are listed below.

Major Findings

- The SONGS outage study scenario has identified an electric reliability linkage between the Orange County portion of the LA Basin local capacity area and the San Diego local capacity area, and the loss or gain of generation in San Diego affects

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[15] In the context of this report, "repower" refers to the retirement of an existing utility boiler and its replacement with new combined cycle or simple cycle gas turbines at the same existing facility site.
[16] In the context of this report, "replacement" refers to the retirement of an existing utility boiler at one site and the replacement of its capacity with new combined cycle or simple cycle gas turbines located at a new brownfield or greenfield site. This transfer of capacity for repowers is allowed under SCAQMD Rule 1304(a)(2) if the new project owner is the same as the existing utility boiler owner.

generation requirements in the ISO Balancing Authority Area's (BAA) LA Basin area and vice versa.[17]

- Within the next 10 years, without an aggressive program to ensure additional development of preferred resources and other non-conventional generation options beyond what is already accounted for in the demand forecast, both OTC repowers and additional new generation projects in LA Basin and San Diego will be needed to meet local capacity requirements to maintain local grid reliability due to projected load growth, based on the retirement of OTC plants subject to the SWRCB's OTC Policy and retirement of SONGS.[18] OTC repowers refers to the replacement of existing utility steam boilers with advanced generating technologies such as combined-cycle turbines or new simple cycle gas turbines. New generation refers to the construction of new power generating units, which are typically a combination of combined-cycle and simple-cycle turbines. OTC generating units located in LA Basin and San Diego are listed in Appendix B. New generation requirements can also be met with additional OTC repowers or replacement and vice versa provided that they occur in electrically equivalent locations, or met with potentially preferred resources such as additional renewable energy or reductions in demand.

Findings Specific to ISO Balancing Authority Area

- **Range of Capacity Needed for Local Capacity Requirements and Renewable Integration.** In the ISO balancing authority area of the South Coast Air Basin, based on the assumptions used in this assessment, approximately 3,300 to 4,600 MW of combined OTC repowerings, replacement, and new generation resources, and 500 MVAR to 1,050 MVAR of dynamic reactive support[19], are needed by 2022 to meet local capacity requirements and to maintain grid reliability in the LA Basin and San Diego areas without SONGS.[20] Table I-1 shows the total generation need in the LA Basin and San Diego local capacity areas under the high and low bookend scenarios in relation to available existing non-nuclear OTC generation. The high bookend range reflects a high potential generation need for LA Basin in the event incremental demand-side management does not materialize as forecasted in the assumed locations. Alternative scenarios incorporating preferred resources and mitigation options were also explored resulting in a low bookend, which could result in lower total generation needs for LA Basin if the data input assumptions materialize as forecasted. Those alternatives are discussed in Chapter II and Appendix E.

[17] See Appendix G for map of California ISO local capacity areas.
[18] An alternative to repowering at the existing OTC power plant sites is to replace the capacity with electrically-equivalent generation located elsewhere; however, alternative locations were not specifically evaluated using modeling for purposes of AB 1318.
[19] The dynamic reactive support requirement refers to equipment, such as a static VAR (volt ampere reactive) compensator, or SVC, that provides fast-acting reactive power on high-voltage electricity transmission networks that help regulate voltage and stabilize the grid.
[20] Due to interdependency of the LA Basin and San Diego LCR areas, the reliability need encompasses both of these two areas. However, for the purpose of air emission impacts to South Coast Air Basin, only generation need in the LA Basin is mentioned here.

Table I-1. California ISO Balancing Authority Area – 2022 Replacement Generation Needed to Meet Local Capacity Requirements without SONGS

Local Capacity Requirement Area	OTC Capacity Available for Repower (MW)[21]	OTC Repowering (MW)	Additional OTC Replacement or New Generation (MW)	Total Generation Need (MW)	System-wide Renewable Integration Need (MW)	Dynamic Reactive Support Need (MVAR)
AB 1318 High Bookend						
LA Basin	4150	2900	1400-1700	4300-4600	4870[22,23]	1050-500
San Diego	946	620-820	300	920-1120		960
AB 1318 Low Bookend						
LA Basin	4150	2900	400-560	3300-3460	Not evaluated	1000-500
San Diego	946	520	300	820		960

- **<u>Location of Generation Needed to Meet Local Capacity Requirements</u>.** Local capacity requirements are location-specific and are important for siting, planning, and procurement purposes for meeting local reliability needs. The tables in Chapter II identify the sub-regions within the local capacity areas where the total generation and dynamic reactive support requirements in Table I-1 above are indicated. Due to the location of SONGS at the border of San Diego and Orange Counties, most of the LA Basin generation resource needs are concentrated in the southwestern portion of the local capacity area.

- **<u>Location of Additional Capacity Needed for Renewable Integration</u>.** As identified in Table I-1 above, given assumptions circa spring 2013, the ISO has identified approximately 4,870 MW of flexible capacity is required across the entire ISO control area (which encompasses most of California) to manage variations between load and supply for renewable integration under high bookend conditions. Because this is a system-wide need, ISO analyses are not able to specify a location for this incremental capacity at this time; however the historic pattern of north to south transmission constraint flow along Path 26[24] means it is prudent to locate a portion of this capacity in the South of Path 26 (SP26) zone. Additional OTC repowers within SP26 beyond what is needed to meet local capacity requirements can help meet the renewable integration requirement, if the capacity is developed

[21] Refers to existing non-nuclear OTC generating units that have not already repowered or received a CEC license or air district permit to construct to repower.
[22] *ISO Renewable Integration Study in Support of the California Air Resources Board for Meeting Assembly Bill (AB) 1318* determined an incremental system-wide renewable integration need of 5,300 MW. The study should have included 430 MW of LCR generation for Big Creek/Ventura, but due to internal communication error, it was omitted. ISO advised subtracting the 430 MW from the total need to get the corrected value of 4,870 MW.
[23] Current studies do not indicate a specific locational need to meet operational flexibility needs.
[24] Path 26 refers to the three 500 kV transmission lines from Midway to Vincent, a major transmission artery connecting the Northern California portion of the CAISO control area with the Southern California area. The South of Path 26 zone encompasses a region south of Path 26, and includes Ventura, Los Angeles Basin, and San Diego areas.

with the appropriate characteristics for load following and cycling, and is permitted to operate in that manner.[25]

- **OTC Capacity Available for Repower to Help Meet Local Capacity and Renewable Integration Requirements.** As shown in Table I-1, there is 4,150 MW of existing OTC capacity within the ISO balancing authority area under the jurisdiction of the SCAQMD that has not already received air permits to repower (see Appendix B). Depending on the location and quantity of generation and dynamic reactive support projects that materialize, the generation need in LA Basin to meet local capacity requirements could be met solely with OTC repowers or could face a shortfall of up to 450 MW under a worst-case, high bookend condition. The 450-MW shortfall is computed as 4,600 MW of capacity requirements less 4,150 MW of OTC capacity not yet repowered.

- **Effect of Preferred Resources on Local Generation Needs.** Sensitivity local capacity requirement studies conducted by the ISO show that additional incremental demand-side management programs, if located in the right locations, have the ability to reduce the need for in-basin fossil generation. The low bookend represents a reduction in generation need of nearly 24 percent compared to the high bookend. The low bookend analysis is a sensitivity case aimed at determining the impacts of incremental energy efficiency, combined heat and power, and demand response programs on the need for in-basin fossil generation. . Due to uncertainties surrounding whether incremental programs will materialize at specific locations as forecasted by the State agencies, the ISO used values from the lower range of the program options that were developed by the technical team. The study assumptions are discussed in Chapter II. The CEC-adopted forecast that the ISO used for the studies already includes committed energy efficiency savings which are embedded in the demand forecast in the range of about 8,000 MW of peak demand savings in the Southern California Edison (SCE) planning area.

- **Effect of SONGS Retirement on Local Generation Needs.** The SONGS retirement scenario has the potential to nearly double the low end of the OTC generation repower or replacement resources needed to address local reliability concerns in the LA Basin when compared to the results of the AB 1318 initial high bookend studies conducted when SONGS was operational, as shown in Table I-2.[26] This is because SONGS is located in an electrically critical location, which provides not only baseload generation to both SCE and San Diego Gas and Electric (SDG&E), but also critical voltage support to Southern Orange County and San Diego areas.

[25] For example, ISO flexibility studies show the need for the dispatchable fleet to collectively follow steep ramps up and down, and to undergo more frequent starts and stops than most combined cycle power plants have been designed to accommodate.

[26] The range shown in Table I-2 is for year 2021 based on the CEC-approved 2009 IEPR demand forecast and CPUC 2010 LTPP Trajectory RPS portfolio. In contrast, the SONGS out need is for year 2022 based on the CEC-approved 2012 mid-load forecast and CPUC 2012 LTPP Commercial Interest RPS portfolio. While not exactly the same, the Trajectory portfolio from the 2010 LTPP is roughly equivalent to the Commercial Interest portfolio of the 2012 LTPP.

Table I-2. 2021 Replacement Generation Needed to Meet Local Capacity Requirements *with SONGS Online*

Local Capacity Requirement Area	OTC Replacement Generation Need (MW)
Los Angeles Basin	2370 – 3741[27]
San Diego	531[28] - 950

- **Effectiveness of Demand Response Resources in Integrating Renewables.** Renewable integration studies conducted by the ISO show demand response resources are effective in reducing ramping capacity shortage, as results produced a 1-to-1 match between demand response increases and fossil reductions to meet ramping capacity needs for renewable integration. Demand response, if available, is one of the desirable types of resources for integrating renewable generation.

- **Reliance upon Demand Response Resources to Reducing Local Generation Needs.** With respect to local capacity requirements, the ISO advises that demand response can be an effective resource provided it has sufficient dispatch and operational capabilities and is placed at specific locations that could mitigate local reliability concerns. ISO is currently working with the utilities and State agencies to identify the appropriate characteristics that will enable demand response resources to be utilized to their full potential in reducing local capacity requirements in addition to the benefits observed in meeting flexible capacity needs for renewable integration. The principal issue in developing assumptions for planning studies is whether enough customers with the appropriate loads will be willing to participate in programs in a sustained manner through time.

- **Correlation between Higher Penetration of Intermittent Renewables and Cycling of Peaking Turbines to Balance Load.** Renewable integration studies conducted by the ISO show that the increase in intermittent renewable resources causes some flexible fossil generation units to cycle more to respond to the intermittency of renewable generation. The results show a much higher number of start-ups for new simple cycle turbines than new combined cycle turbines in the Southern California Edison service territory (nearly 12 times more). Table II-11 shows that the modeling results project that the annual number of start-ups for new simple cycle turbines in the Southern California Edison service territory will be almost three times higher than the overall simple cycle fleet annual average in the ISO balancing authority area.

- **New Fast Response Gas Turbine Power Plants Predicted to Cycle More in High Renewables Future.** Some existing fossil steam boilers are expected to be replaced with some combination of natural gas-fired combined cycle and simple

[27] The capacity range reflects alternative locations for replacement capacity within LA Basin. The lower requirement corresponds to more effective locations and vice versa.
[28] The lower range of capacity needs reflects the operation of the proposed Pio Pico, Quail Brush, and Escondido generating facilities in SDG&E's service territory. Since the studies were conducted, the CPUC has approved the Escondido repower, but denied without prejudice the contracts for Pio Pico and Quail Brush.

cycle turbines.[29] The renewable integration studies conducted by the ISO show that these new resources will be used differently under the 33 percent renewables future than baseload facilities have been used in the past – not only generating energy but providing ancillary services and load following capabilities as well.

Findings Specific to LADWP Balancing Authority Area

- **Repower of All Existing OTC Generation Needed for Local Capacity Requirements.** LADWP's balancing authority area expects to repower all existing OTC capacity. LADWP completed the repowering of Haynes Units 5 and 6 in June 2013 and has started construction to repower Scattergood Unit 3. The last units are not repowered until 2029 (see Appendix B). A shortfall of local generation will remain due to transmission constraints. To address this shortfall, an additional 358 MW of load curtailment would be needed by 2021 to meet local capacity requirements under high bookend conditions. Under low bookend conditions, increasing levels of energy efficiency and employing full utilization of existing cogeneration resources do not alter the need to repower all LADWP LA Basin OTC generation. A shortfall in local generation still remains due to transmission constraints; however the level of load shed drops to 130 MW. Table I-3 shows the generation need for the LADWP control area.

Table I-3. LADWP Balancing Authority Area – 2021 Replacement Generation Needed to Meet Local Capacity Requirements

	System Limiting Condition	Currently Installed LADWP In-Basin Thermal Generation (MW)	OTC Capacity Available for Repower (MW)[30]	Existing Capacity Needed including OTC (MW)	Deficiency in Terms of Loadshed Needed (MW)	Total Generation Capacity + Loadshed (MW)
High Bookend	High Pacific DC Intertie (PDCI)	3471	2152	3386	358	3744
Low Bookend	High PDCI	3471	2152	3386	130	3516

- Under high bookend conditions, all existing LADWP LA Basin thermal generation is required, and because of a shortfall of generation, 358 MW of controlled customer load curtailment will be required to meet reliability requirements. The amount of load curtailment might be potentially reduced based on the implementation and effectiveness of LADWP's Demand Response program.

[29] ISO studies have not been conducted in a manner to reveal an "optimal" mix of combined cycle and simple cycle turbines. The ISO used judgment in making an initial split between these for modeling purposes. The mix has implications for emissions of criteria pollutants as well as greenhouse gases.

[30] Refers to existing OTC generating units that have not already repowered or received a CEC license or air district permit to construct to repower and includes the following: Scattergood 1-2, Haynes 1-2 and 8-10, Harbor 1, 2, 5. For consistency within the report, this total also includes Scattergood 3, even though the unit received a permit to construct for repower in May 2013.

- The low bookend analyses are sensitivity analyses performed by the LADWP at the request of the State agencies to determine the impacts of incremental demand side management programs (i.e., energy efficiency) in the event that these materialize. It is uncertain at this time whether these incremental programs will materialize at the level modeled in the low bookend analysis. LADWP's 2011 Integrated Resource Plan provides a timeline with target dates for their repowering projects, subject to an evaluation of reliability and system needs.

- Subsequent to the studies LADWP prepared for AB 1318, LADWP is evaluating options to make up for the shortfall of generating capacity in the LADWP LA Basin area, including measures such as transmission upgrades, demand-side management, and distributed generation programs.

Offset Assessment Findings

- **<u>Availability of OTC Repowers to Meet Generation Needs</u>.** The range of generation needed for local reliability in the ISO high and low bookend scenarios can almost exclusively be covered with OTC generation repowerings or generation replacement.

    - In the South Coast Air Basin portion of the ISO balancing authority area, the available OTC repowering or replacement pool of 4,150 MW is within the range of local capacity requirement generation needs identified in the AB 1318 studies of 3,300 to 4,600 MW. The worst-case high bookend generation need is about 10 percent higher than available OTC repower capacity; however, the ISO plans to conduct further studies related to long-term mitigations as part of the ISO annual transmission planning process or at other State regulatory forums to incorporate forecasted low savings of incremental energy efficiency as well as other relevant demand-side management programs. The inclusion of these incremental demand-side management programs in ISO planning studies, as indicated in the most recent ISO local capacity studies[31], could potentially help reduce the local capacity requirements for the local areas under the South Coast Air Basin when compared to the high bookend scenario where none of these incremental programs were included previously. It is important to monitor these programs to determine if they materialize at the specific locations as forecasted to ensure that the planning standards for local reliability are met.

    - In testimony filed before the CPUC in 2012 as part of Long-Term Procurement Plan Track 1, the ISO identified a need for 2,400 MW in the LA Basin. Based on increased use of preferred resources beyond those the ISO studied, the CPUC authorized SCE to procure 1,000 to 1,200 MW of fossil generation, a minimum of 50 MW of energy storage, a minimum additional 150 MW of preferred resources consistent with the Loading Order or energy storage resources. SCE is

[31] ISO, Testimony of Robert Sparks on Behalf of the California ISO, CPUC R.12-03-014, submitted August 5, 2013.

authorized to procure up to an additional 600 MW of capacity from preferred resources or energy storage.

- In the LADWP balancing authority area of the South Coast Air Basin, all available OTC capacity must be repowered to meet demand under both high and low bookend conditions. Even with all OTC capacity available, load shedding may be required to maintain reliability during some contingencies. LADWP's Demand Response programs may potentially decrease the amount of load shedding that is needed.

- **Limitations on Identifying Specific Location for Incremental Capacity for Renewable Integration.** The location of flexible generation needed for renewable integration is not as constrained as is the case for generation needed for local capacity requirements.

  - It is likely that some portion of the incremental capacity shown to be needed for the overall ISO system must be located within the South Coast Air Basin. No studies exist to show what split of the 4,870-MW need in the high bookend between northern and southern portions of the ISO is acceptable.

  - LADWP has not completed studies to identify the amount or type of fossil capacity it might need to integrate the renewable resources it will add to satisfy the RPS mandate.

- **Difference between Location of Existing OTC Capacity and Where New Generation is needed.** To the extent that approved new generation is proposed at different locations or under different ownership than the current pool of OTC units, increased attention is needed on methods for selling or transferring emission reduction credits between entities, consistent with federal and State regulations.

- **Offsets Corresponding to Range of Generation Required.** The estimated amount of emission offsets that SCAQMD will need to address through their New Source Review (NSR) program to permit generation corresponding to the high and low bookends is shown in Table I-4.[32] For the ISO balancing authority area, these calculations assume 3,895 MW of repower or replacement of existing OTC capacity to maximize the use of these generating units' capacity under SCAQMD rules and 450 MW of new capacity for the high bookend.[33] For the LADWP balancing

[32] Although SCAQMD Rule 1304(a)(2) exempts generators from having to submit offsets covering the potential to emit of their proposed facilities, SCAQMD itself has to provide credits from its Rule 1315 internal bank to satisfy federal NSR requirements. The AB 1318 technical team developed a set of assumptions to use in making potential to emit calculations that are consistent with the local capacity and operating flexibility studies, but it is unknown whether SCAQMD would utilize similar assumptions in determining the amount of internal bank credits to deduct from its Rule 1315 balances when issuing a permit to a specific generating facility.

[33] 3,985 MW results from the generator implementation plans submitted to SWRCB in April 2011. The lower repowering amount reflects a somewhat slower schedule of repowering than the official OTC compliance dates included in the amended OTC Policy of summer 2011. Generator owners'

authority area, these calculations assume 1,335 MW of repower or replacement of existing OTC capacity for both high and low bookends, based on LADWP's most recent repowering plans.[34]

Table I-4. Estimate of Emission Offsets Corresponding to the Range of Generation Need for Local Capacity Requirements in ISO and LADWP Balancing Authority Areas of South Coast Air Basin (tons per day)

Scenario	For Generation Associated with:	NOx	CO	VOC	PM10	SOx
High Bookend	OTC Repowers with Access to Internal Offset Bank	7.47	8.19	3.77	2.65	0.72
	New Units without Benefit of Existing Utility Boiler Capacity (Require Market ERCs)	0.76	0.93	0.45	0.32	0.12
Low Bookend	OTC Repowers with Access to Internal Offset Bank	6.84	7.54	3.40	2.42	0.64

- **Availability of District Internal Bank to Offset Power Plant Projects.** Generators that do not increase basin-wide capacity for the same owner upon repowering or replacement of electric utility steam boilers with advanced generation technologies do not incur an emission offset obligation under SCAQMD rules regardless of whether the existing units have operated at much lower capacity factors than the new units that will replace them. Instead, mitigation of the emission increases are currently accomplished through the District's internal bank as outlined in Rule 1315 Federal New Source Review Tracking System. SCAQMD staff estimates that there is presently an adequate amount of credits in its internal offset bank to cover the OTC repower projects, but this strategy would potentially deplete the bank whose credits are also intended for use by essential public services.[35] Even if there are

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implementation plans show proposed schedules that have some repowering after 2022, thus outside of the timeline of the ISO studies. 450 MW is the difference between the high bookend maximum LCR need of 4600 MW less the 4,150 MW of existing OTC capacity that could be repowered for the ISO area. An additional 165 MW of capacity was included as new generation in the emission calculations to account for the MW difference between 3,985 MW and the 4,150 MW of capacity available for OTC repowers.

[34] 1,335 MW results from the generator implementation plans submitted to SWRCB in April 2011. The amount is lower than the full OTC capacity, because it only represents steam boiler units. Under the current planning horizon, LADWP plans to replace the gas turbines at its Harbor and Haynes OTC plants but would be able to utilize the SCAQMD Rule 1304(a)(1) offset exemption; by remaining within the maximum rating and emissions of the existing units, the replacement project would have no emission increases and there would be no offset obligation for the facility or for the SCAQMD for federal equivalency determination. This total also includes MWs from the Scattergood 3 repower, which received its permit to construct this year, but has not been accounted for in the SCAQMD federal equivalency determination yet.

[35] As defined in Rule 1302, "essential public services" include publicly owned or operated sewage treatment facilities, prisons, police facilities, fire-fighting facilities, schools, hospitals, landfill gas control or processing facility, water delivery operations, and public transit.

sufficient credits in the near-term, it is predicted that internal bank credits will be in limited supply over the long-term and may constrain need for further capacity additions as electricity load grows and additional facilities retire.

- **Solution for Offsets Needed to Ensure Sustainable Permitting Beyond 2022.** While this assessment has identified OTC repowers as a potential strategy for meeting reliability needs through 2022 under the current permitting program, the upper limit of the high bookend exceeds the OTC repowering or replacement pool, and any increased electricity demand beyond the CEC-adopted forecast will likely require additional generation and/or increased demand-side reductions, especially due to the retirement of SONGS. While SCAQMD is presently estimated to have an adequate amount of credits in its internal bank to cover the OTC repower projects, these credits are also intended for use by essential public services[36] and will be in limited supply over the long-term. In addition, the scarcity and cost of emission reduction credits in SCAQMD means new power plants that do not own existing capacity that can be retired and replaced are unlikely able to secure the necessary emission reduction credits to obtain their air permits. Therefore, it is prudent to explore other options that reduce the withdrawal of credits from the internal bank to maintain future sustainability of the District's permitting system. This indicates a potential future reliability issue exists without additional mitigation due to the already limited offset supply in the open emission reduction credit (ERC) market in the SCAQMD and the constraints it poses for permitting of new greenfield generation resources. This conclusion is exacerbated if incremental capacity needed for renewable integration must be located within the South Coast Air Basin for the ISO and LADWP. Previous ISO efforts to work with the CPUC to expand the existing resource adequacy program to include a flexibility requirement has been justified by the timeline on which the renewable integration need occurs as soon as 2016-2017 rather than the 2020 or later timeline associated with compliance with the SWRCB's OTC Policy. ARB staff should partner with SCAQMD and other stakeholders to explore long-term permitting solutions for stationary sources using energy agency projections of future load growth and expected resource additions through time.

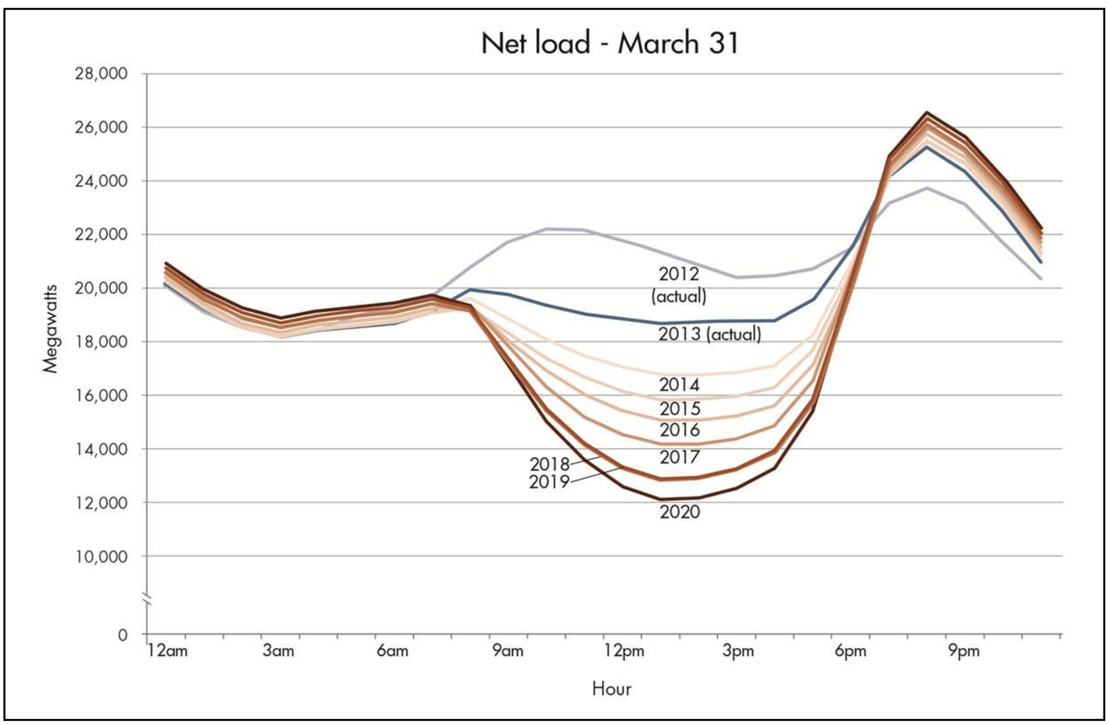
Need for Flexible, Dispatchable Generating Resources

The State policy to achieve 33 percent renewables on an annual energy basis by year 2020 is well underway, and has been assumed to be achieved in the studies completed by the ISO and LADWP for this project. Since the majority of the capacity that is operational or being developed, is delivered to load serving entities through "must take" contracts, the balance of the systems operated by balancing authorities responds to customer load net of renewable power production. The concept of a "net load curve" has been developed to show on an hour by hour basis what power production profile is

[36] As defined in Rule 1302, "essential public services" include publicly owned or operated sewage treatment facilities, prisons, police facilities, fire-fighting facilities, schools, hospitals, landfill gas control or processing facility, water delivery operations, and public transit.

needed after intermittent renewables (wind and solar) are subtracted from load. Figure I-1 illustrates the concept of the net load curve using historic load and intermittent resource production data for a specific day in March of 2012 and 2013, and ISO projections of the net load curve forward for each year through year 2020. Net load curves can be expected to be more volatile than ordinary load shapes of consumer demand because the inherent variability of wind and solar production due to weather phenomenon is added the uncertainty of loads. In the data shown in Figure I-1, the system operator needs to assure that sufficiently flexible capacity is online that it can ramp up in the early morning hours, ramp down in the middle of the day, and then rapidly ramp up in the afternoon and evening. Further, the magnitude of the afternoon-evening ramp is growing through time, meaning that more flexible resources will be needed in future years than are used today. Studies by the ISO seek to quantify the amount of flexible capacity that must be developed to both replace the OTC generators being retired and increase amount of such capacity required as intermittent resources increase over time.

Figure I-1. ISO Net Load Curve



Observations Regarding Interaction between LA Basin and San Diego Local Capacity Areas

ISO studies of resource adequacy requirements from 2004 until the SONGS outage resulted in ten local reliability areas (LRA) within the overall ISO balancing authority area. Among them were San Diego (essentially coterminous with the SDG&E service area) and the LA Basin portion of the Southern California Edison service area. These areas were independent of each other under the generating resource mix assumptions and contingencies that were investigated. Immediately following the outage of both units at SONGS in January 2012, the ISO undertook studies of the consequences of further outages assuming SONGS was offline due to extended outage or permanent retirement. The results of these studies revealed the extent to which the adverse consequences fell upon the San Diego LRA and only secondarily to the LA Basin portion of the ISO balancing authority area. Further studies undertaken by the ISO as part of its 2012-2013 Transmission Planning process revealed the extent to which this consequence of outage at SONGS affects the two areas in years 2018 and 2022 (See Appendix E).

Contingencies that had been thought to be isolated to the San Diego region were revealed to have been buffered by SONGS from affecting the LA Basin. Without SONGS, voltage stability problems threaten system collapse unless mitigated will strongly affect Southern Orange County as well as San Diego.

The recently completed ISO studies indicate there are tradeoffs between generation development in San Diego versus the LA Basin. Two alternative generation development strategies were studied: one focused on the LA Basin, and the other in San Diego. These studies revealed that increasing San Diego generation by about 1,000 MW would reduce generation needs in the LA Basin by 500 to 800 MW. . For purposes of developing a high bookend projection, the AB 1318 Technical Team chose to select the generation development strategy that maximizes LA Basin development, hence, offset requirements under the jurisdiction of SCAQMD.

As part of the 2012 Long-Term Procurement Plan proceeding, the CPUC has requested the ISO study the LA Basin and the San Diego local area together to better understand and assess these interactions and potential infrastructure needs.

Role of System Inertia on Grid Stability, Import Capability, and Minimum In-Basin Generation Requirements

State energy and environmental goals have steered efforts toward new investments in transmission, energy efficiency, demand response, smart grid applications, increased use of renewable resources, and combined heat and power. In the absence of transmission and generation additions and modifications, the current configuration of the electric grid places some inherent limitations on the type and amount of renewable generation resources that can be integrated into the system and still maintain reliability. This section broadly describes the dynamics that produce these limitations to provide context for some of the complexities that exist as the State moves toward greater reliance on both locally-supplied and imported electricity from renewable technologies.

Power in an electric network does not travel along a set path. This means that changes in generation and transmission at any point in the system will affect generators and transmission lines at other points in an interconnected network, often in ways that are not easily controlled. To maintain this balance, generation and transmission operations must be monitored and controlled in real time to ensure a consistent and adequate flow of electricity through the broad interconnected power grid system.

To avoid system failures, the amount of power flowing over each transmission line or facility must remain below its ability to carry its loadings without potentially affecting other transmission facilities. Exceeding the transmission facility's capability could generate too much heat beyond acceptable limits, which can cause the facility to fail and potentially causing power instability such as phase and voltage fluctuations. In addition, for an alternating current power grid to remain stable, the frequency and phase of all power generation units must remain synchronized within narrow limits established by reliability organizations such as the North American Electric Reliability Corporation (NERC) or the Western Electricity Coordinating Council (WECC).[37] System frequency is a continuously changing variable that is determined and controlled by the real time balance between consumer demand (i.e., load) and total generation. If demand is greater than generation, the frequency falls, while if generation is greater than demand, the frequency rises. Without grid-friendly frequency response, the rate of change of frequency fall will be dependent upon the initial power mismatch and system inertia. A grid-friendly device can respond to changes in frequency by reducing or interrupting the demand for electric power when the frequency drops below a certain threshold and increasing load when the frequency rises.

System inertia in the context of an electric power system refers to the ability of the electric power system to resist changes in the grid frequency during an imbalance in load and generation. This property is tied to the physical inertia of the spinning mass of electrical generators. If the load is greater than the generation, the speed of the electric generator will slow down and vice versa. This causes decreases and increases in frequency. Typically, electric generators receive their power input from a rotating turbine in a power plant. Thermal and hydroelectric power plants, which currently form the majority of generation capacity, are composed of multiple, heavy rotating parts interacting with each other. These rotating parts have physical inertia, which prevents them from slowing down or speeding up too quickly when energy is injected into or extracted from them. This acts to prevent the electrical generator from slowing down too quickly when the load demand exceeds the generation on the grid, and vice versa, when the load demand is less than the generation. The electric power system consists of thousands of power plants, each with their own inertia. The combined inertia of all of the power plants is what gives the power system the ability to delay changes in grid frequency during an imbalance. Not all power plants have a high degree of inertia. For example, wind or solar photovoltaic plants have no spinning mass, and therefore do not contribute to the inertia of the system. Therefore, without some means of providing inertia or inertia-like properties in an interconnected grid, as in a system that relies

[37] The Western Interconnection encompassing California is such an alternating power grid.

solely on solar photovoltaic generators, the ability to keep the system operating is greatly challenging.

System inertia is also important in determining the allowable level of import power that a balancing authority can procure. Since import power contributes to the balancing of load and generation within a balancing area, it can therefore affect the grid frequency within that area. If system inertia is low, variations in the import power will cause larger variations in the grid frequency for that area. Furthermore, a sudden loss in import power due to a contingency, such as a downed transmission line or the loss of a large generator in the exporting area, may cause the frequency in the importing area to drop too far before response measures can act if the inertia of the importing area is too low. Therefore, a power system in a given balancing area must have high inertia to reliably use a large amount of import power from another balancing area. The lower the system inertia of a given balancing area, the lower the amount of import power that it can use and guarantee the reliability of the system.

Determining minimum in-basin generation capacity for the LA Basin is a much more challenging task than the 10-year reliability outlook provided in this report. It will depend on the demand forecast, the amount and type of generation portfolio development in the future, operational needs, what other entities in the Western Electricity Coordinating Council[38] will have in terms of generation, and transmission configurations at the time. Radical changes in the transmission system could eliminate local capacity areas and provide greater flexibility in locating generation to serve aggregate Southern California load; however, such changes are well beyond what is feasible within the next ten years.[39]

Considerations for Future Reliability Assessments

Some key legislative and planning strategies affecting the long-term demand for electricity in the LA Basin were not incorporated into the AB 1318 studies due to timing, lack of sufficiently detailed data that would be required to incorporate into the grid simulation models, and insufficient resources available from the participating agencies to conduct comprehensive, internally consistent studies. Regardless, these strategies are important to highlight for incorporation into future assessments. In some instances, the strategies rely on technology improvements and infrastructure development with target milestones that extend well beyond the 10-year outlook of this report.

Retirement of Aging Non-OTC Power Plants

About 2,000 MW of aging non-OTC natural gas power plants are located in the LA Basin and San Diego local areas. These are old facilities sold by the investor owned

[38] The Western Electricity Coordinating Council (WECC) is the regional entity responsible for coordinating and promoting bulk electric system reliability in the Western Interconnection.
[39] This option is not without challenges as Rights-of-Way needed for siting bulk transmission facilities is either unavailable or difficult to obtain due to local resident opposition to new transmission facilities in high-density populated areas.

utilities (IOU) as a condition of electricity restructuring, small municipal projects, qualifying facilities, and self-generation projects associated with industrial plants with steam use. Because there is no policy comparable to the SWRCB OTC Policy, there is uncertainty surrounding the potential retirement or replacement of aging non-OTC power plants. The ISO's power flow studies used to determine local capacity requirements in this AB 1318 project assumed that these aging non-OTC power plant are still operating. The CPUC chose to assume in its 2012 LTPP Track 4 studies that any facility satisfying a technology-specific age criteria would be assumed to retire.[40] Many of these power plants supporting this local reliability are old, inefficient, run very little, and could be replaced or retired by their owners. While it may be doubtful that all of these aging power plants will retire and need to be replaced, a portion of these old, inefficient plants may need to be replaced or repowered to more modern, efficient facilities, ensuring that California has adequate supplies to meet reliability.

The retirement of these aging power plants and whether they are repowered or replaced in the footprint governed by SCAQMD's air permitting rules would impact the results of the studies and the aggregate amount of emission offsets required to permit such repowers or replacement projects. Some of these facilities use steam boiler technologies that would appear to qualify for Rule 1304(a)(2) allowing a repowering project to avoid providing scarce offsets, while other are older combustion turbines that could not qualify for that exemption, but might qualify using the Rule 1304(a)(1) exemption. An assessment of the impact of the potential retirement and replacement of aging non-OTC power plants should be incorporated into future grid reliability studies.

Locational Aspects of Renewable Integration Needs

Neither ISO or LADWP studies provide much clarity about the location of incremental capacity needed for renewable integration. Studies of the amount and type of dispatchable capacity needed for renewable integration are still not standardized within the industry. ISO studies reveal some of the sensitivity of results to input assumptions, e.g., the tradeoff between the amount of demand response versus incremental flexible capacity, but they have not addressed the locational issue critical to a full assessment of offset requirements with the South Coast Air Basin. ISO studies also reveal something of the changes in patterns of use of flexible capacity across the months of the year compared to traditional patterns of use for dispatchable power plants to satisfy summer peak load. Increased emphasis on winter month operations compared to summer month operations raises different issues for air quality modeling.

Electric Energy Storage

Since grid operators must constantly match electricity supply and demand, intermittent renewable resources are more challenging to incorporate into the electricity grid than

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[40] The CPUC's 2012 LTPP (R.12-03-014) assumed retirements based on facility age (more than 40 years old) and on compliance with the State Policy on Cooling Water Intake Structures. The amount of non-OTC capacity assumed retired based on the 40 year old rule is 1,883 MW by 2018, comprised of 238 MW in San Diego subarea and 1,665 MW in LA Basin local area.

traditional generation technologies. Renewable energy production can often occur at times when there is little need for that power (i.e., wind generation is typically at its maximum at night when the demand is lower than during the day). However, electric energy storage technologies, if economically feasible on a larger scale, could provide an additional means for optimizing the use of intermittent and off-peak renewable generation, and for providing ancillary services currently provided by gas-fired peakers and other fossil fuel generation.

Recent advancements have been achieved and certain storage technologies have progressed through pilot and demonstration phases but more information is needed about storage costs and benefits to form a basis for policy action. The CPUC is currently holding a proceeding to examine the issues associated with storage in accordance with Assembly Bill 2514 (AB 2514, Skinner, Chapter 469, Statutes of 2010). AB 2514 requires the CPUC and municipal utilities to determine the appropriate targets, if any, for procurement of energy storage systems by load serving entities by October 1, 2013. If procurement targets are appropriate, then the CPUC must adopt targets to be achieved by 2015 and 2020. Municipal utilities have an additional year to meet these requirements. Therefore, while storage is being considered, at the time of the studies, there were no quantitative storage procurement targets set that could be incorporated into the AB 1318 reliability studies. If quantitative storage targets are established under AB 2514, then they could be incorporated into future studies as can other updated information. At this time, the only storage procurement requirement comes from the 2012 LTPP Track 1 decision on local capacity requirements, wherein the CPUC has ordered Southern California Edison to procure up to 50 MW of storage in the LA Basin that can meet identified reliability needs. However, the characteristics and location of these resources have not yet been determined.

Vision for Clean Air

The June 2012 draft *Vision for Clean Air: A Framework for Air Quality and Climate Planning* is a collaborative planning document done by staff of the ARB, SCAQMD, and San Joaquin Valley Air Pollution Control District that estimates the magnitude of emission reductions needed to attain air quality standards by federal regulatory deadlines in the areas with the worst air quality in California, and outlines the nature of the technology transformation needed to meet the State's multiple air quality and climate change program milestones through 2050. Broad deployment of zero- and near-zero emission technologies in the South Coast and San Joaquin Valley air basins will be needed in the 2023 to 2032 timeframe to attain current national health-based air quality standards as required by federal law. For the South Coast Air Basin, it is estimated that oxides of nitrogen, one of the key ingredients in ozone and fine particulate formation, must be reduced by around 80 percent from 2010 levels by 2023, and almost 90 percent by 2032.

The federally approved State Implementation Plans for these two regions rely on a mix of currently available technologies and the development of advanced technologies to attain the ozone air quality standard by 2023. Reaching the longer-term 2032 ozone air quality standard and the 2050 climate goal requires even greater transformation. This includes, for example, nearly complete transformation of passenger vehicles to zero-emission technologies, approximately 80 percent of the truck fleet to zero-or near-zero technology, and nearly all locomotives operating in the South Coast air basin to be using some form of zero-emission technology. This mobile source electrification strategy requires transformation of the upstream energy sector concurrent with the transformation to advanced technologies downstream. In the *Vision for Clean Air* document, upstream emissions from generation resources were derived independently of the end-using sector, and therefore, more robust analyses are needed to connect downstream mobile source needs to the upstream generation infrastructure needed to meet the associated increased electrical load. The scenarios analyzed for the *Vision for Clean Air* are not refined analyses that would be directly used for program development, but rather provide input into future planning efforts by air quality agencies. As more detailed analyses emerge as part of these efforts, the results should be incorporated into future grid reliability studies. In all likelihood, to the extent these results suggest that expectations of electrification are greater than what has already been incorporated into the CEC's demand forecasts, then even more generation development ought to be expected somewhere in Southern California.

Public Process for Report Development

The AB 1318 report was developed using a public process. Public outreach efforts for the project included creating an *Electrical System Reliability Needs of the South Coast Air Basin (AB 1318)* webpage[41] where information pertaining to the report development was posted, including: public meeting notices, agendas, and presentations; the interim report and Draft Work Plan; a draft of the final report; and comment letters received in response to workshop solicitations. In addition, an electronic list serve was created to notify stakeholders and interested parties of upcoming meetings and postings of new material to the webpage. Over 1,400 individuals or companies have subscribed to the list serve.

As directed by AB 1318, ARB staff collaborated closely with staff members of the CEC, CPUC, ISO, SWRCB, and LADWP to complete the reliability and offset assessments and produce a report summarizing the results. Staff members of these agencies provided technical advice and data support to ensure the reliability studies reflect State energy laws and policies, built the power flow study cases and performed the modeling studies to determine the capacity needed for grid reliability, assisted with the translation of study results into emissions for the offset projections, and participated in public workshops.

In developing the report, the AB 1318 Technical Team held or participated in four public workshops in Southern California, as noted below, which included presenting information about the project at CEC-sponsored meetings.

[41] http://www.arb.ca.gov/energy/esr-sc/esr-sc.htm

Public Meetings Held During the AB 1318 Report Development

Meeting	Date
Kick-off Meeting	November 10, 2010
Joint Agency Workshop on Emission Offset Challenges for Fossil Power Plants in Southern California	February 15, 2011
2012 IEPR Lead Commissioner Workshop on Electricity Infrastructure Issues in California	June 22, 2012
2013 IEPR Joint Workshop on Electricity Infrastructure Issues Resulting from SONGS Outage	July 15, 2013

Both the Work Plan and a draft of the final report were made available for public review and comment prior to finalization.

Recommendations

The studies show reliability in LA Basin and San Diego is challenged by the permanent retirement of SONGS and the compliance timeline of regulations for OTC power plants. Repowering the existing OTC power plants is one strategy to ensure reliability in the basin. SCAQMD's internal offset bank contains sufficient credits to cover units repowering under the offsets exemption provided in Rule 1304(a)(2) in the near-term. However, the long-term sustainability of this strategy is limited due to a finite amount of credits in the internal bank and the already scarce availability and cost of emission reduction credits on the open market in SCAQMD. In addition, while not as constrained as SCAQMD, offset availability limitations exist in the San Diego Air Pollution Control District as well, particularly for new, greenfield projects. Rather than rely solely on OTC repowers to meet electric reliability needs, an opportunity exists now to align replacement generation with preferred resources, fostering a loading order that recognizes their clean, low carbon attributes while ensuring reliability, followed by transmission solutions and conventional fossil generation.

To further inform the process started by AB 1318 and to help ensure Southern California's electricity needs and air quality requirements are met into the future, the staffs of the State agencies and ISO recommend that the following additional post-project tasks be conducted:

- ARB staff should work with the CEC, CPUC, and ISO staff to provide the quantitative and locational data necessary to more accurately forecast demand and the extent to which the dispatchable, fossil generating fleet will need to evolve in the Southern California area to handle a shift in the transportation energy sector from liquid fuels to electricity (i.e., electric vehicles), which is identified as a long-term strategy for meeting the State's criteria pollutant and climate change air quality goals.[42]

- ARB staff should partner with SCAQMD, the CEC, and other interested parties through the SCAQMD's New Source Review Working Group, or other appropriate forum, to immediately start a discussion that will identify long-term permitting options for stationary sources in light of future load growth and an absence of SONGS and make recommendations to address permitting needs by the earliest practicable date.

- ISO's Transmission Planning Process and CPUC's Long-Term Procurement Plan proceedings should examine demand-side and other preferred resource types in greater depth than was possible for this study to ensure the potential for these resources is appropriately considered. This project caused the participating agencies to realize that there are unresolved issues about the extent to which such preferred resources can substitute for generating capacity and/or transmission system upgrades in satisfying local reliability requirements. It is possible that further study will reveal that different criteria exist for determining the extent to which preferred resources can substitute from a local, regional, or system reliability perspective.

- Further assessment of the need for incremental capacity for renewable integration over and above that needed for local capacity requirements is needed, especially having to do with any locational constraints or preferences that raise offset issues within specific air basins.

    - ARB staff should conduct an analysis of regional air permitting constraints in the South of Path 26 zone, outside South Coast Air Basin, should be conducted once updated renewable integration studies are completed in the CPUC's Long-Term Procurement Plan proceeding. A decision is expected in early 2014.

    - LADWP should continue in its efforts to identify how to maximize imports of renewables into its system. That study should include the dispatchable capacity additions needed in its balancing authority area for this integration.

- ARB staff should partner with the CPUC to help long-term planning more effectively incorporate constraints in Southern California that can impact resource procurement authorizations.

[42] See "Vision for Clean Air: A Framework for Air Quality and Climate Planning" prepared by the staffs of the ARB, SCAQMD, and San Joaquin Valley Air Pollution Control District, public review draft dated June 27, 2012.

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II. Electric Reliability Assessment

This chapter is intended to provide a framework for the findings contained in Chapter I by providing an overview of the methodology and assumptions used in the reliability studies. For additional details, the reader should refer to the complete reports by ISO and LADWP that document the study parameters and results, which are presented in the supporting report documents as Appendix C, *California ISO Reliability Assessment in Support of the California Air Resources Board for Meeting Assembly Bill (AB) 1318;* Appendix D, *LADWP 2021 Local Capacity Technical Analysis: Final Report and Study Result;*" Appendix E, *California ISO Study Report: Assembly Bill 1318 Grid Reliability Results for San Onofre Nuclear Generation Backup Plan Studies;* and Appendix F, *California ISO Renewable Integration Study in Support of the California Air Resources Board for Meeting Assembly Bill (AB) 1318.*

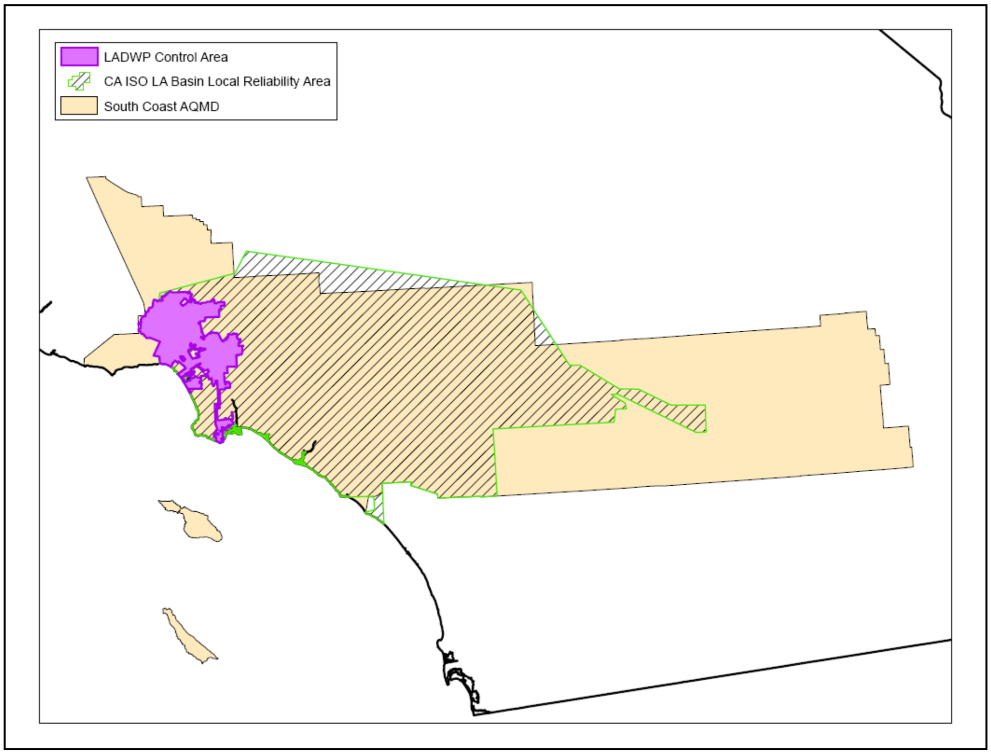
A. Reliability Assessments

In the context of the bulk power system, reliability is generally defined as the ability to meet the electricity loads of end-use customers, even when unexpected equipment failures or other factors reduce the amount of available generation and/or transmission to serve such loads. Electric system reliability is governed by a range of federal and state laws, Federal Energy Regulatory Commission (FERC) orders affecting the North American Electric Reliability Corporation (NERC), and NERC standards, which may then be modified to suit the particular circumstances within regional grid areas (e.g., Western Electricity Coordinating Council) and smaller balancing authority areas.[43] There are nine balancing authorities serving California and two balancing authorities responsible for the grid in the South Coast Air Basin (SCAB) – California ISO and LADWP. A geographic overlay of the ISO LA Basin local capacity area, the LADWP control area, and the SCAQMD is shown in Figure II-1.

Reliability standards apply to interconnected electric systems and are intended to address the reality that within an integrated network, whatever one balancing authority area does can affect the reliability of other balancing authority areas. This means that sufficient generation capacity must exist and be available for dispatch to meet demand, even under adverse conditions. These conditions include failure of a major generator and transmission line during periods of extremely high demand. The Transmission Planning reliability standards are organized by performance categories. The reliability studies for AB 1318 assessed capacity needs under Category A (normal conditions), Category B (system performance following loss of a single bulk electric system element, that is a generator or transmission line) and Category C (system performance following loss of two or more bulk electric system elements) contingencies.

[43] A balancing authority is the entity responsible for integrating electrical resource plans for a control area ahead of time, maintaining the control area's load-resource balance, and supporting the control area's interconnection frequency in real time. A map of the balancing authority areas in California can be found at: http://www.energy.ca.gov/maps/serviceareas/balancing_authority_areas.pdf .

Figure II-1. Overlay of California ISO and LADWP Reliability Areas in Relation to SCAQMD Boundaries



As stated, ISO and LADWP are the two balancing authorities managing the flow of electricity in the South Coast Air Basin. The ISO does not own any generation or transmission; its job as grid operator is to manage the flow of electricity across the high-voltage power lines that make up 80 percent of California's power grid. Due to the large geography and interplay of all the resources providing electricity within the ISO balancing authority area, ISO assessments include capacity evaluations at three different geographic levels:

- **Control area level**: Control area reliability requires sufficient capacity across the entire ISO control area to ensure system-wide reliability under peak demand conditions.
- **Zonal area level**: Zonal reliability requires sufficient capacity in the northern and southern halves of the ISO control area (North of Path 26 [NP26] and South of Path 26 [SP26])[44] to meet demand under peak load conditions and with the failure of a major system component. A map of California with the major transmission lines identified is included in Appendix H.

[44] Path 26 refers to the three 500 kV transmission lines from Midway to Vincent, a major transmission artery connecting the Northern California portion of the CAISO control area with the Southern California area. SP 26 encompasses a zonal area South of Path 26, and includes Ventura, Los Angeles basin, and San Diego areas.

- **Local capacity area level**: Local reliability requires sufficient capacity in each of several local capacity areas in the ISO control area to meet peak demand given the sequential failure of two major system components. Local capacity areas are transmission-constrained "load pockets", and limits on the ability to import energy into the local capacity area create requirements for generation capacity within the area to serve it reliably.

Compared to ISO, LADWP manages a much smaller geographic area, and therefore evaluated the generation needed for reliability under AB 1318 for its entire control area, which consisted of assessing local capacity area level requirements. Also, as a vertically-integrated utility, LADWP owns and operates its generation, transmission, and distribution, and therefore has much greater certainty and planning control over its available resources than ISO.

The AB 1318 Technical Team's initial approach was to define and conduct studies specifically customized to satisfy the requirements of AB 1318, but the ISO later decided that its contributions to AB 1318 had to be limited to studies that it was undertaking for its own 2012-2013 Transmission Planning Process, or minor sensitivities around such studies. Since neither the ISO nor the State agencies were capable of assessing local capacity requirements for the LADWP system, the analyses contributed by LADWP also constrained the depth of the studies that became available.

While specific study results define the AB 1318 bookends, in total, 13 studies were used to inform the AB 1318 project. Each of the local capacity area requirement studies and operating flexibility studies are comparatively summarized in a technical paper prepared by CEC staff and included as Appendix I. This paper includes the local capacity requirement studies completed by the ISO and other modeling parties as part of Track 4 of the CPUC's 2012 LTPP proceeding (R.12-03-014) will provide another set of results for comparison. There is a key distinction between these two sets of studies. The AB 1318 analysis was aimed at assessing the need for air pollutant emission offsets in the South Coast Air Basin, and not at driving procurement decisions. The purpose of the Track 4 studies, on the other hand, is to evaluate whether any reliability need exists in the LA Basin and San Diego local areas (collectively referred to as the "SONGS Study Area"), and guide any resulting procurement authorization. The Track 4 studies are examining an alternative set of assumptions that incorporate more demand-side resources than the AB 1318 low bookend, but also factor in additional capacity loss from retirement of non-OTC, aging generation. This and subsequent study efforts and regulatory proceedings underway or planned will help further refine the regional needs as the State moves through the coming years.

B. Assessment Scope and Results

The reliability assessment includes two types of studies that help determine the location, amount, and type of generation needed for grid reliability:

1) Local capacity requirements (ISO and LADWP); and

2) Renewable integration requirements (ISO only).

Local capacity requirements are the most critical type of study since it is not possible to locate generating facilities outside of the SCAB when satisfying them, whereas there is somewhat greater flexibility in siting new power plants stemming from renewable integration needs outside of SCAB.

Within each type of assessment that was undertaken, some examination was made of the degree to which transmission system upgrades, energy efficiency, combined heat and power (CHP), and demand-side management programs can reduce the need for in-basin capacity was examined. Local capacity, zonal capacity, and renewable integration requirements, as well as the load and resource assumptions, used in the AB 1318 assessment studies are described below.

1. Local Capacity Requirements

Local capacity area requirements (also referred to as local capacity requirements, or LCR), identify capacity within a transmission-constrained area that needs to be available to respond when 1-in-10 peak loads occur, given the available generation fleet, and while transmission imports are at their maximum, under various electrical contingencies. The minimum LCR is determined for a defined local capacity area using a power flow simulation modeling program. Building individual scenarios for the modeling tool, running the program, and analyzing the model outputs is a time-consuming process; therefore, the ability to run numerous iterations based on various futures and combinations of assumptions was not feasible with the resources available for this project.

Because limited resources dictated that high and low bookends would be assessed rather than a narrower “most likely” range, the composition of these two bookends is critical. The high bookend captures reliability requirements under anticipated worst-case conditions. This involves higher demand than truly expected because no adjustments were made to assess the impacts of preferred, demand-side resources beyond those already directly addressed within the CEC’s baseline load forecasts. Similarly, increased penetration of combined heat and power (CHP) facilities, as called for in ARB’s AB 32 Scoping Plan, were omitted. The low bookend captures the effect of implementing a limited amount of additional incremental demand reduction programs and a very small increment of CHP development, but does not illustrate a “best case” scenario in which these alternatives are pursued in a vigorous manner. Both bookends assume achievement of the 33 percent RPS.

a. Assumptions for ISO Balancing Authority Area

The ISO conducts a comprehensive evaluation of the ISO grid under its annual Transmission Planning Process (TPP). During each annual TPP cycle, the ISO completes a number of technical studies that provide the basis for identifying potential physical and economic limitations of the ISO balancing authority area and potential upgrades to maintain or enhance system reliability. To avoid duplication of work, the grid reliability studies required for AB 1318 were carried out as part of the ISO's 2011-2012 TPP ("SONGS in" studies) and 2012-2013 TPP ("SONGS out" studies). Due to the June 2013 announcement of SONGS permanent retirement, only the "SONGS out" studies are discussed below for the ISO balancing authority area. However, the complete documentation of the ISO study results for the "SONGS in" scenarios are included in Appendix C for informational purposes.

The ISO evaluates local capacity area requirements for ten local areas within the ISO controlled grid where operational history has shown that local reliability issues exist. Seven of these areas are in Pacific Gas & Electric's service area (Humboldt, North Coast/North Bay, Greater Bay, Sierra, Stockton, Fresno, and Kern); two are in Southern California Edison's service area (LA Basin and Big Creek/Ventura); and one in San Diego Gas & Electric's service area (San Diego). A number of these areas are further subdivided, as needed, into sub-areas. For AB 1318 purposes, generating unit needs specific to the SCAQMD are determined through the LCR studies for the ISO's LA Basin local capacity area. A map of the ISO's local capacity areas is included in Appendix G.

i. Load Forecast and Demand Side Reduction Assumptions

The CEC staff develops forecasts of electricity consumption and peak electricity demand for each major utility planning area within California for a 10-year period during each two-year Integrated Energy Policy Report (IEPR) cycle. Once adopted by the CEC, the forecasts are used in a number of applications, including the CEC's IEPR, the CPUC's planning and procurement processes, and the ISO's grid studies. The CEC staff produces multiple forecasts based on various weather-related conditions, economic growth patterns, and demand-side management impacts. The most recently-adopted demand forecast is used in each ISO TPP cycle to represent load in future years.

The most recently-adopted CEC demand forecast is used in each ISO TPP cycle to represent load in future years. Study assumptions specified by the CPUC in its Long-Term Procurement Plan (LTPP) rulemaking guide ISO renewable integration assessments. The CPUC study assumptions also require use of CEC demand forecasts with various levels of adjustments for prospective demand-side policy initiatives. Due to the timing of the ISO's annual TPP cycle versus the CPUC's biennial LTPP cycle, the vintage of CEC baseline demand forecast used within the studies may differ.

The ISO studies for local capacity requirements are based on the CEC baseline demand forecast for a 1-in-10 peak demand. The high bookend case for LCR is based on the CEC forecast without any further adjustments to demand-side programs of energy efficiency, CHP, and demand response. The low bookend case for LCR is based on the same CEC baseline forecast but also includes a low level of incremental demand-side programs. The ISO studies for renewable integration are based on the CEC baseline demand forecast for 1-in-2 peak conditions, adjusted down for various demand-side programs beyond those included in the baseline forecast. This adjusted peak capacity and energy demand is then scaled up by ten percent to create a High Load scenario to account for incremental demand-side programs that do not materialize or higher than forecasted demand.

Case with SONGS Extended Outage or Permanent Retirement

The electricity demand used to represent the high bookend is the 1-in-10 year[45] summer peak load forecast from the CEC's 2012 adopted mid-case load forecast.[46] This forecast includes 22,924 MW of statewide committed energy efficiency in year 2022 from residential and non-residential building and appliance standards, utility and public agency programs, and price and other effects, or savings associated with rate changes and certain market trends not directly related to programs or standards. Committed programs are defined as (1) programs that either have been implemented or for which funding has been approved and include some form of program plan, and (2) revisions to federal and State codes and standards.

For the low bookend, the magnitude of the peak energy savings from incremental energy efficiency and CHP were modeled with ISO-recommended alternative program amounts for incremental energy efficiency and CHP in the following amounts: 1,160 MW of energy efficiency and 15.1 MW of CHP. The CEC and CPUC staff provided individual load bus reductions in expected peak demand to ISO for purposes of mapping the reduction in demand to specific load buses, rather than spreading the reductions proportional to peak load across the service territory, in order to more accurately capture the effects of these programs on local generation needs. Incremental programs are defined as the additional impacts of the level of future programs (for example, savings associated with new equipment that exceeds current standards or early replacement of existing stock), new programs, and the expansion of current programs, all beyond those embedded in the CEC forecast. While there is little guarantee that incremental program goals will materialize exactly as planned, particularly in specific locations, the effect of these programs on generation needs is of significant importance to the State as they reflect the preferred "loading order" in the *2003 Energy Action Plan*. The loading order is the foundation for the State's recommended energy policies and is outlined in the Energy Action Plan as follows:

[45] The 1-in-10 peak demand forecast assumes the same weather conditions encountered at the 90th percentile of the historical annual peak load distribution and has a 10 percent probability of being exceeded.

[46] The CEC forecast includes three full scenarios: a high energy demand case, a low energy demand case, and a mid energy demand case. The high energy demand case incorporates relatively high economic/demographic growth, relatively low electricity and natural gas rates, and relatively low efficiency program and self-generation impacts. The low energy demand case includes lower economic/demographic growth, higher assumed rates, and higher efficiency program and self-generation impacts. The mid case uses assumptions at levels between the high and low cases.

- First, the agencies will optimize all strategies for increasing conservation and energy efficiency to minimize increases in electricity and natural gas demand;
- Second, the agencies recognize that new generation is both necessary and desirable and these needs should be met first by renewable energy resources and distributed generation; and
- Third, because preferred resources require both sufficient investment and adequate time to get to scale, the agencies will support additional clean, fossil fuel, central-station generation.

In concert with the loading order, the agencies will simultaneously improve the bulk electricity transmission grid and distribution facility infrastructure to support growing demand centers and the interconnection of new generation.

The 1,160 MW of incremental energy efficiency in the low bookend case is from the CEC's 2012 IEPR incremental energy efficiency study.[47] The 15.1 MW of CHP is based on SCE's identification of two projects: Calgren Renewable Fuels (2.1 MW) and Houweling Tomatoes (13 MW). SDG&E recommended not modeling any incremental CHP based on information they acquired that 100 MW or more of supply-side CHP is likely to be closed and retired from service by 2020, because the long-term contracts for these facilities are expiring and the steam host no longer has a need for the steam. The incremental energy efficiency and CHP assumptions used as load adjustments for the low bookend are summarized in Table II-1.

Table II-1. Summary of Incremental Energy Efficiency and CHP Assumptions Modeled by the ISO in Local Capacity Requirement Studies[48]

Service Area	Incremental EE 2022 Peak Savings (MW)	Incremental CHP 2022 Peak Savings (MW)
SCE	973	15.1
SDG&E	187	0
Total	1160	15.1

With respect to the incremental energy efficiency and incremental CHP assumptions modeled by the ISO in the range of studies conducted for AB 1318, there has been an evolving dialogue among energy agencies about reliance upon demand-side policy initiatives versus "steel on the ground." Through multiple channels and efforts, such as the Long-Term Procurement Plan proceeding at the CPUC, the Demand Analysis Working Group at the CEC, and in response to Senator Padilla, the CPUC, CEC, and ISO staff are working together to come to common assumptions for future studies and planning efforts.

[47] A joint ISO, CPUC, and CEC letter to California State Senators Padilla and Fuller communicating an agreement to use Low Savings for incremental energy efficiency in the ISO's 2013-2014 Transmission Planning Process facilitated this specification for the low bookend. For future transmission planning processes, selection of an appropriate case will be made in each cycle.

[48] Includes peak savings from incremental EE and CHP located within the local capacity area.

ii. Demand Response Assumptions

Reliance on intermittent renewable generation capacity like wind and solar requires additional balancing resources to manage any inconsistencies in generation. Ancillary services products address these short-term imbalances by dispatching resources within seconds or minutes of an unacceptable imbalance. Demand response can act as an ancillary service that responds just as quickly as an ancillary power plant would, in under a second or within minutes, depending on the type of ancillary service required. A variety of factors and attributes make some program designs more effective than others. Typical products traded in ancillary services markets from faster to slower are: regulation, spinning reserve, non-spinning reserve, and supplemental reserve. Regulation is used to control system frequency by instantaneously maintaining the balance of supply and demand. Resources providing regulation products are certified by the grid operator to increase or decrease their output to follow an automatic generation control signal sent by the system operator's energy management system. Regulation is split into two products, up and down, which means that the regulating resource will only be asked to provide a deviation from its normal operating point in one direction. Spinning reserves are the portion of unloaded capacity of units already connected or synchronized to the grid that can be delivered in 10 minutes. Non-spinning reserve is capacity that can be synchronized and ramping to a specified load within 10 minutes. Supplemental reserve is capacity that can be synchronized and delivered to the system within 30 minutes.

The term *demand response* encompasses a variety of programs, including traditional direct control (interruptible) programs and new price-responsive demand programs. A key distinction is whether the program is dispatchable. Dispatchable programs, such as direct control, interruptible tariffs, or demand bidding programs, have triggering conditions that are not under the control of, and cannot generally be anticipated by, the customer. Energy or peak load saved from dispatchable programs is treated as a resource and is therefore not accounted for in the CEC demand forecast. Non-dispatchable programs are not activated using a predetermined threshold condition but allow the customer to make the economic choice whether to modify usage in response to ongoing price signals. While impacts from committed nondispatchable programs represent a small fraction of total resources, they should be counted on the demand side of the CEC forecast.

To address *local reliability* needs, demand side management programs need to have more stringent and specific dispatch and operation capabilities for addressing local capacity needs than is needed for meeting overall system needs. In light of this, other than the small amount of non-dispatchable demand response that is included in the CEC load forecast, demand response resources that are system resources are not counted in the LCR studies.

Demand response programs have generally been considered an alternative to generation in meeting system-wide load and supply balances. To address local capacity requirements, the system must be able to withstand specific sequence of contingencies described as N-1-1.[49] Typically, following the first contingency event, the ISO must restore the system to a state positioned for the next, worst contingency within 30 minutes. Such contingencies are not as severe as two simultaneous outages known as N-2 contingencies. The requirements resulting from these contingency assessments are location specific and time specific. Unlike system needs, addressing LCR issues that are contingency-driven requires prompt and dependable response; grid operators cannot wait to see what materializes and still have time to respond to address a shortfall. Due to these limits, demand response, or other time-limited resources, must be dependable over a significant period of time.[50]

Although dispatch issues still need to be resolved, demand response resources are important in the State's loading order, and the ISO used demand response numbers based on verification with SCE in 2012 for 30-minute or less programs for Southern Orange County and South of Lugo based on identified reliability concerns in these areas.[51] All parties agree that the ISO, State agencies, and stakeholders should continue to develop a technically robust methodology for projecting demand response capabilities to the busbar level for use in performing power flow and stability studies. Appropriate demand response assumptions are currently being examined in the CPUC's 2012 LTPP proceeding. In addition, demand response program impacts are regularly quantified for inclusion in the CEC's biennial statewide energy demand forecast.

A summary of the demand response resource assumptions used in the "SONGS out" studies for the low bookend is summarized in Table II-2.

Table II-2. SCE and SDG&E Incremental Demand Response Assumptions for Use in Local Capacity Requirement Studies

Service Area	Demand Response Resources (MW)
SCE	382
SDG&E	25
Total	407

iii. Generation and Transmission Resources

As stated above, the ISO does not own any generation or transmission, so it has no direct ability to control the mix of resources that will be available in 2022 to meet demand. Instead, each load serving entity (with the oversight of the appropriate State

[49] A sequence of events consisting of the initial loss of a single generator or transmission component (Primary Contingency), followed by system adjustments, followed by another loss of a single generator or transmission component (Secondary Contingency).
[50] To date, no specific duration or other criteria have been established for demand response to meet.
[51] The aggregated amount of demand response for both LA Basin and the San Diego local capacity areas that the ISO used for the studies was close to the amount of demand response for these areas in the CPUC LTPP Track 1 Decision and San Diego Gas & Electric Power Purchase Tolling Agreement Decision 13-03-029.

agencies, as applicable) determines its own preferred manner of complying with the mandate that 33 percent of energy be satisfied by eligible renewable resources by 2020. However, the CPUC does generate multiple resource portfolios for use in its biennial LTPP proceeding that represent different procurement strategies aimed at reaching the State's 33 percent RPS target by 2020. The portfolios developed in the LTPP proceedings are the basis for the resource assumptions used by ISO in the LCR studies.

The "SONGS out" LCR studies were performed for the Commercial Interest and High Distributed Generation (DG) 2012 LTPP RPS portfolios using the CEC's adopted baseline, mid-case load forecast from the 2012 IEPR Update proceeding. The Commercial Interest portfolio was utilized as the base case and to represent the high bookend for AB 1318 purposes. The High DG portfolio was used as a sensitivity study to determine how much fossil generation in LA Basin and San Diego local capacity areas could be reduced from a higher penetration of DG resources. The Commercial Interest portfolio was also used for the low bookend with the load forecast reduced by the additional incremental energy efficiency, CHP, and demand response amounts discussed in the previous sections. The ISO did not assess a case that assumed both high DG levels and low demand due to incremental demand-side policies.

Due to the Water Board's OTC Policy that requires phase-out or installation of mitigation measures for power plants that use ocean water cooling systems, the ISO ran the models for the LCR studies without OTC generation based on OTC policy compliance dates at the outset, and added new capacity back into the existing OTC sites as the model produced reliability issues. This logic provided results that determine the minimum LCR in areas that have OTC power plants to identify whether there is a reliability need to run OTC plants, and if there is, what capacity at OTC sites is needed.

The identified transmission and generation system used in the model to reflect available resources to meet demand included all transmission and generation projects operating on or before June 1 of the study year, as well as all other feasible operational solutions[52] brought forth by the participating transmission owners (PTOs)[53] and as agreed to by the ISO (see ISO Board of Governors approved Transmission Plans[54]). All announced generation retirements were removed from available generation as of June 1 of the study year as well. Generation resources were dispatched up to the latest

[52] These include remedial action schemes (RAS) or special production systems (SPS) installed in certain areas of the transmission system. These protection systems drop load or generation upon detection of system overloads by strategically tripping circuit breakers under selected contingencies.

[53] A transmission owner who agrees to place its facilities under the operational control of an independent system operator.

[54] The 2011-2012 Transmission Plan and its supporting documents can be found at: http://www.caiso.com/planning/Pages/TransmissionPlanning/2011-2012TransmissionPlanningProcess.aspx . The 2012-2013 Transmission Plan and its supporting documents can be found at: http://www.caiso.com/Documents/2012-2013%20transmission%20planning%20process%20-%20Board-approved%20plan%20and%20appendices .

available net qualifying capacity (NQC) or historical output values (if NQC is not available).

Table II-3 below summarizes the RPS portfolios used in the “SONGS out” studies for AB 1318 purposes, as well as the renewable DG amounts in each portfolio, and the incremental energy efficiency (EE), combined heat and power (CHP), and demand response (DR) assumptions applied to select scenarios to establish the low bookend.

Table II-3. CPUC 33 Percent Renewable Resource Portfolios and Preferred Resource Assumptions Used for AB 1318 Studies

<table>
<tr><td colspan="4">SONGS Outage/Retirement
Analyses for Year 2022
Studies in 2012-13 TPP
2012 LTPP</td></tr>
<tr><td colspan="4">Renewable Portfolio Assumptions Used in Both High and Low Bookend Analyses</td></tr>
<tr><td>RPS Portfolio</td><td colspan="2">Commercial Interest</td><td>High DG</td></tr>
<tr><td>Portfolio Description</td><td colspan="2">Best forecast for RPS development using commercial interest as key selection factor</td><td>Prefers DG to central station generation; aggressive pursuit of CHP, incremental small PV, and DR policies</td></tr>
<tr><td>DG Development Assumption (MW)</td><td colspan="2">LA Basin: 486

San Diego: 404</td><td>LA Basin: 1538
San Diego: 490</td></tr>
<tr><td colspan="4">Incremental Preferred Resource Assumptions Used in Either High or Low Bookend Analyses</td></tr>
<tr><td></td><td>High</td><td>Low</td><td>No Demand-Side Adjustments</td></tr>
<tr><td>Incremental EE Projection (MW)</td><td>Assumed to be zero</td><td>SCE: 973
SDG&E: 187</td><td>Assumed to be zero</td></tr>
<tr><td>Incremental CHP Projection (MW)</td><td>Assumed to be zero</td><td>SCE: 15.1
SDG&E: 0</td><td>Assumed to be zero</td></tr>
<tr><td>Incremental DR Projection (MW_</td><td>Assumed to be zero</td><td>SCE: 382
SDG&E: 25</td><td>Assumed to be zero</td></tr>
<tr><td>AB 1318 Bookend</td><td>High</td><td>Low</td><td>Not a bookend</td></tr>
</table>

iv. Results with SONGS Extended Outage or Permanent Retirement

The ISO’s examination of the long-term (2022) grid reliability impact in the absence of SONGS also included an interim year assessment for 2018. The mitigation measures identified in ISO’s prior 2013 SONGS absence studies were modeled in-service for the 2018 studies (see list below). The Huntington Beach synchronous condensers were removed for the 2022 studies (with the exception of one sensitivity case) due to proposed repowering plans for the AES Huntington Beach power plant that are currently undergoing review at the CEC and SCAQMD.

1) Convert Huntington Beach Units 3 and 4 to 2x140 MVAR synchronous condensers[55];
2) Install one 79.2 MVAR capacitor bank each at Johanna and Santiago substations and two 79.2 MVAR capacitor banks at the Viejo Substation[56]; and
3) Reconfigure the Barre-Ellis 230kV lines from two to four circuits.[57]

2018 Mid-Term Results

Local reliability assessments were performed for LA Basin and its sub-areas and for San Diego and its sub-areas. The studies did not include capacity from the following OTC generating units based on 2015 and 2017 OTC Policy compliance dates: El Segundo Units 3 and 4, and Encina Units 1 to 5. The studies included capacity from the following OTC generating units: Alamitos Units 1 to 6, Huntington Beach Units 1 and 2, and Redondo Beach Units 5 to 8. Capacity from the 560-MW El Segundo Repower Project was also included. The study results identified critical reliability concerns in the San Diego area related to transmission overloads, post transient voltage instability, and thermal overloading. The ISO designed two mitigation alternatives to alleviate the voltage and facility loading concerns identified, which require generation resources in San Diego. ISO also identified two mitigation measures that are highly effective in mitigating a large number of the loading and voltage concerns: (1) continued reactive power support at Huntington Beach and (2) construction of a new transmission line connecting the Sycamore and Penasquitos Substations. Therefore, these measures are included as part of the two mitigation alternatives, which are listed below and also reflected in Table II-5.

<u>Mid-Term Alternative #1</u>

- Implement 820 MW of OTC replacement generation in northwest San Diego.
- Add 300 MW of new generation in southeast San Diego.
- Install 650 MVAR of dynamic reactive support at SONGS and San Luis Rey Substations.
- Common mitigations – Huntington Beach synchronous condensers and Sycamore-Penasquitos 230 kV transmission line.

<u>Mid-Term Alternative #2</u>

- Implement 965 MW of OTC replacement generation in northwest San Diego.
- Install 1,460 MVAR of dynamic reactive support at SONGS, Talega, Penasquitos, San Luis Rey, and Mission Substations.

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[55] Converting these retired generating units to synchronous condensers will provide 280 MVAR of additional reactive support in the electrical vicinity of SONGS. This conversion is underway and expected to be completed by June 26, 2013.

[56] SCE is in the process of completing installation of 80 MVAR capacitors at each of the Santiago and Johanna substations and a 160 MVAR capacitor at the Viejo substation. These transmission upgrade should be online by June 1, 2013.

[57] SCE is in the process of reconfiguring the Barre-Ellis 220 kV lines from the existing two circuits to four. This work is expected to be completed by June 15, 2013.

- Common mitigations – Huntington Beach synchronous condensers and Sycamore-Penasquitos 230 kV transmission line.

2022 Long-Term Results

For the long-term reliability assessment, the 2018 mitigations (with the exception of Huntington Beach synchronous condensers for one case) were included prior to performing the contingency studies. The following additional OTC generating units were assumed to be offline in the starting study cases based on 2020 OTC Policy compliance dates: Alamitos Units 1 to 6, Huntington Beach Units 1 and 2, and Redondo Beach Units 5 to 8.[58] The study results identified multiple reliability concerns in the LA Basin and San Diego areas related to transmission overloads, post transient voltage instability, thermal overloads, and post transient voltage deviation. The ISO designed two primary mitigation plans – one focused on generation solutions and the second focused on a combined generation and transmission solution. Each mitigation plan includes two alternative mitigation strategies.

Generation-Based Mitigation Plan
The two generation mitigation alternatives that were developed are summarized below and in Table II-4. Alternative #1 seeks to minimize generation needs in San Diego and Alternative #2 seeks to minimize generation needs in LA Basin. Except as noted, the mitigations listed for the long-term are incremental (additive) to the mitigations identified for the mid-term.

Long-Term Generation Alternative #1
- Huntington Beach synchronous condensers assumed *unavailable* due to Huntington Beach power plant repower project.
- Implement 2,900 MW of OTC replacement generation in southwest LA Basin.
- Add 1,000-1,200 MW of new generation in southwest LA Basin.
- Add 300 MW of new generation in northwest LA Basin.
- Add 100-200 MW of new generation in eastern LA Basin.
- Install 550 MVAR of dynamic reactive support at the San Onofre 230 kV switchyard.
- Add 240 MVAR of dynamic reactive support in northwest San Diego.
- Add 480 MVAR of dynamic reactive support in southwest San Diego.

Long-Term Generation Alternative #2
- Huntington Beach synchronous condensers assumed *available*.
- Implement 2,460 MW of OTC replacement generation in southwest LA Basin.
- Implement 1,360 MW of OTC replacement generation in northwest LA Basin.
- Implement 520 MW of OTC replacement generation in northwest San Diego.

[58] There is no need to assume that Huntington Beach Units 3 and 4 are offline, since these units have been retired so SCAQMD's Rule 1304(a)(2) can be used to enable the operation of Walnut Creek Units 1 to 5. Huntington Beach Units 3 and 4 have been rendered inoperable for generating electricity and no emissions will come from them in any future year. Eventually, they will be torn down.

- Implement 400 MW of OTC replacement generation in southeast San Diego.

It should be noted that local capacity requirement needs are location-specific based on inherent transmission constraints that exist in the local area being analyzed. Therefore, the OTC replacement and new generation needs from the studies are specific to the sub-areas shown in the tables and corresponding ISO reports in the appendices. Generation needs are likely to be higher if capacity is added in other locations within the LA Basin and San Diego regions other than the sub-areas identified.

Generation Option Alternative #1 is used to represent the high bookend for AB 1318 without SONGS, since the scenario produces the highest in-basin fossil generation need for the LA Basin.

Table II-4. Summary of Generation and Dynamic Support Need without SONGS – Generation Option

Area	2018			2022			Total Need by 2022	
	OTC Replacement Need (MW)	New Generation Need (MW)	Dynamic Reactive Support Need (MVAR)	OTC Replacement Need (MW)	New Generation Need (MW)	Dynamic Reactive Support Need (MVAR)	Total Generation Need (MW)	Dynamic Reactive Support Need (MVAR)
Common mitigations	Sycamore-Penasquitos 230 kV transmission line			Sycamore-Penasquitos 230 kV transmission line			Sycamore-Penasquitos 230 kV transmission line	
Generation Option, Alternative #1								
LA Basin								
Northwest	0	0	0	0	300	0	300	0
Southwest	0	0	280 (HB*) + 400-500	2900	1000-1200	550**	3900-4100	500-1050
Eastern	0	0	0	0	100-200	0	100-200	0
							4300-4600***	500-1050
San Diego								
Northwest	620-820***	0	240	0	0	240	620-820***	480
Southwest	0	0	0	0	0	480	0	480
Southeast	0	300	0	0	0	0	300	0
							920-1120	960
Generation Option, Alternative #2								
LA Basin								
Northwest	0	0	0	1360	0	0	1360	0
Southwest	0	0	280 (HB*) + 500	2460	0	0	2460	280 (HB) + 500
Eastern	0	0	0	0	0	0	0	0
							3820	280 (HB) + 500
San Diego								
Northwest	965	0	480	520	0	0	1485	480
Southwest	0	0	480	0	0	0	0	480
Southeast	0	0	0	400	0	0	400	0
							1885	960

*Refers to synchronous condensers at AES Huntington Beach. For Alternative #1, the synchronous condensers are no longer available by 2022 due to repower of the Huntington Beach power plant.

**550 MVAR at the San Onofre switchyard reduces the generation need by 300 MW but it is currently unknown whether there is available space at this location.

***Locating an additional 200 MW of generation in San Diego would reduce the generation need in LA Basin by 200 MW.

Combined Transmission and Generation Mitigation Plan

The ISO tested the efficacy of adding a major high voltage transmission line connecting the SCE and SDG&E territories[59] towards minimizing overall generation requirements in the long-term scenario. The mitigations for the mid-term are carried over and the effect on the generation needs for the long-term are summarized in Table II-5. A comparison of the results to those from Table II-4 shows the overall generation need in the LA Basin is reduced by 905 MW to 1,685 MW and the dynamic reactive support is reduced by 550 MVAR.

Table II-5. Summary of Generation and Dynamic Support Need without SONGS – Combined Transmission and Generation Option

Area	2018			2022			Total Need by 2022	
	OTC Replacement Need (MW)	New Generation Need (MW)	Dynamic Reactive Support Need (MVAR)	OTC Replacement Need (MW)	New Generation Need (MW)	Dynamic Reactive Support Need (MVAR)	Total Generation Need (MW)	Dynamic Reactive Support Need (MVAR)
Common mitigations	Alberhill and Suncrest Substation 500 kV transmission line							
	Sycamore-Penasquitos 230 kV transmission line							
Transmission and Generation Option, Alternative #1								
LA Basin								
Northwest	0	0	0	0	0	0	0	0
Southwest	0	0	280 (HB*) + 400-500	2915	0	0	2915	500
Eastern	0	0	0	0	0	0	0	0
							2915	500
San Diego								
Northwest	820	0	240	360	0	240	1180	480
Southwest	0	0	0	0	0	480	0	480
Southeast	0	300	0	0	100	0	400	0
							1580	960
Transmission and Generation Option, Alternative #2								
LA Basin								
Northwest	0	0	0	0	0	0	0	0
Southwest	0	0	280 (HB*) + 500	2915	0	0	2915	500
Eastern	0	0	0	0	0	0	0	0
							2915	500
San Diego								
Northwest	965	0	480	215	0	0	1180	480
Southwest	0	0	480	0	0	0	0	480
Southeast	0	0	0	0	400	0	400	0
							1580	960

*Refers to synchronous condensers at AES Huntington Beach. For Alternative #1, the synchronous condensers are no longer available by 2022 due to repower of the Huntington Beach power plant.

[59] Consists of a 65-mile 500 kV transmission line running from the Lake Elsinore, CA area to the Alpine, CA area.

vi. Sensitivity Study with SONGS Extended Outage or Permanent Retirement

At the request of the State agencies, the ISO conducted two sensitivity studies, which have been used to develop the low bookend under the “SONGS out” scenario. In the first study, incremental energy efficiency, CHP, and demand response adjustments were applied to the 2022 long-term Generation Option studies to determine OTC generation replacement or new generation requirements and dynamic reactive support requirements (refer back to Section B(1)(a) of this report for the exact amounts applied). Comparisons of the two sets of results provide an estimate of how much generation requirements could be reduced if additional demand-side management programs are realized. Table II-7 shows the results of the sensitivity study, which is labeled as the “low bookend.” The “high bookend” Generation Option Alternative #1 results are summarized again for comparison. The study results show a reduction in generation need of approximately 1,000 MW from 1,582 MW of incremental demand-side management programs.

For the second study, the ISO conducted a separate sensitivity analysis on the impact of higher DG penetration. Table II-6 provides the nameplate capacity values for two RPS portfolios provided as inputs into the 2012-2013 TPP process. The ISO then dispatched these RPS resources at the levels shown under the dispatch levels. The High DG portfolio therefore represents a 569-MW increase in local area resources over the base case. This resulted in a LCR requirement decrease of 488 MW.

Since the combination of the two separate sensitivities was not investigated, it is unclear whether or to what extent these results are additive. Only the results of the first sensitivity were used to develop the low bookend.

Table II-6. Study of Distributed Generation (DG) Impact on LA Basin LCR Requirements

	CPUC/CEC Commercial Interest Portfolio (Nameplate MW)	CPUC/CEC High DG Portfolio (Nameplate MW)	ISO Commercial Interest Sensitivity Assumption (Dispatch MW)	ISO High DG Sensitivity Assumption (Dispatch MW)
Southern California Edison (SCE)				
Big Creek/Ventura	140	710	N/A	N/A
LA Basin	486	1,538	243	769
Other	27	189	N/A	N/A
Total SCE	653	2,437	N/A	N/A
San Diego	404	490	202	245

Sources: ISO 2013 Transmission Plan and CPUC RPS Portfolio Spreadsheet.

Table II-7. Summary of Generation and Dynamic Support Need without SONGS – High and Low Bookends

Area	2018			2022			Total Need by 2022	
	OTC Replacement Need (MW)	New Generation Need (MW)	Dynamic Reactive Support Need (MVAR)	OTC Replacement Need (MW)	New Generation Need (MW)	Dynamic Reactive Support Need (MVAR)	Total Generation Need (MW)	Dynamic Reactive Support Need (MVAR)
Common mitigations	Sycamore-Penasquitos 230 kV transmission line							
AB 1318 High Bookend (Generation Option Alternative #1)								
LA Basin								
Northwest	0	0	0	0	300	0	300	0
Southwest	0	0	280 (HB*) + 400-500	2900	1000-1200	550**	3900-4100	500-1050
Eastern	0	0	0	0	100-200	0	100-200	0
							4300-4600***	500-1050
San Diego								
Northwest	620-820***	0	240	0	0	240	620-820***	480
Southwest	0	0	0	0	0	480	0	480
Southeast	0	300	0	0	0	0	300	0
							920-1120	960
AB 1318 Low Bookend (Generation Option Alternative #1 with Incremental DSM Adjustments)								
LA Basin								
Northwest				0	0	0	0	0
Southwest				2900	400-560	500-1000	3300-3460	500-1000
Eastern				0	0	0	0	0
							3300-3460	500-1000
San Diego								
Northwest				520	0	480	520	480
Southwest				0	0	480	0	480
Southeast				0	300	0	300	0
							820	960

*Refers to synchronous condensers at AES Huntington Beach. For Alternative #1, the synchronous condensers are no longer available by 2022 due to repower of the Huntington Beach power plant.

**550 MVAR at the San Onofre switchyard reduces the generation need by 300 MW but it is currently unknown whether there is available space at this location.

***Locating an additional 200 MW of generation in San Diego would reduce the generation need in LA Basin by 200 MW.

b. Assumptions and Results for LADWP Balancing Authority Area

LADWP's LCR studies were designed to mirror the ISO's methodology as closely as possible for comparable results; some reasonable adjustments were made to accommodate conditions specific to LADWP. As stated previously, LADWP owns and operates its generation, transmission, and distribution, and has much greater certainty and planning control over its resources compared to CAISO. As a result, LADWP based its LCR studies on its adopted 2011 Integrated Resource Plan, which assumes achievement of the 33 percent renewables requirement in 2020.

LADWP evaluated LCR requirements under high load and low load scenarios consistent with the State agencies' bookends approach, but it was unnecessary to run several different RPS scenarios. The 2021 electricity demand forecast used in the LCR studies is the LADWP's internally-derived 1-in-10 year summer peak load, factoring in the number of households, economic activity, temperature, and increased energy efficiency and distributed generation programs. This forecast is comparable to CEC's 2009 demand forecast for LADWP.

LADWP's high load case considers a high capacity need where only LADWP's existing and planned programs in energy conservation, demand-side management, demand response, and distributed generation are assumed to be in place in 2021, which is similar to the ISO's use of the CPUC's 2010 LTPP Trajectory portfolio. Cogeneration units are assumed off-line in the high load scenario to represent the total demand by the system. The low load case considers a lower capacity need where aggressive programs are assumed implemented by 2021. The low load case was built from the high load case by scaling down the loads by 636 MW – this includes a 373 MW load decrease from increased energy efficiency, a 337 MW load decrease representing dispatched existing cogeneration, and a 74 MW increase in load to correct for rooftop urban photovoltaic distributed generation, as the time of maximum generation from this generation does not coincide with the time of peak demand. Increased demand response was not modeled because of uncertainty of the amount and effectiveness of demand response. Additional cogeneration was not included as LADWP has seen no growth in cogeneration customers.

The 2021 transmission system was modeled including all projects operational on or before summer 2021, and all other feasible operational solutions brought forth by LADWP's system operations group. These solutions can reduce the need for procurement to meet the performance criteria. The 2021 generation resources were modeled and included all projects that will be online and commercial on or before summer 2021. Two summer transmission system import conditions were studied to capture the range of LCR: minimum Pacific DC Intertie (PDCI, also called Path 65)[60] of 600 MW and maximum PDCI of 3,100 MW. A number of simulations were run to determine the most critical contingencies within each local capacity area. If performance requirements were not met, generation was adjusted so that the minimum amount of generation required to meet the criteria was determined in the local capacity area.

The results of the LCR studies are summarized in Table II-8 for the upper and lower bookend scenarios. Both scenarios require maintenance of all existing capacity, and consequently, repower of all OTC generation. Even if all capacity levels are maintained, both scenarios indicate the potential need for load shed to meet reliability requirements.

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[60] The Pacific DC intertie is a high voltage direct current transmission line that runs from Celilo, near The Dalles, Oregon, to Sylmar, in Southern California. It is rated at 3100 MW bidirectional.

Table II-8. 2021 Local Capacity Requirements and OTC-Equivalent Generation Need in LADWP Balancing Authority Area under High and Low Bookends

	Local Capacity Requirements (MW)			
	System Limiting Condition	Existing Capacity Needed	Deficiency in Terms of Loadshed Needed	Total Generation Capacity + Loadshed
High Bookend	High Pacific DC Intertie (PDCI)	3386	358	3744
Low Bookend	High PDCI	3386	130	3516

LADWP local capacity requirement studies conducted for AB 1318 confirm that variations in load and resource planning input assumptions do not affect the requirements for local generation at their Scattergood, Haynes, or Harbor power plants. As an integrated utility, LADWP retains much greater control over how and when the OTC generating units at these facilities are replaced than do the generator owners of merchant power plants operating within the ISO control area. LADWP's studies are based on meeting power supply mandates as outlined in their 2011 Integrated Resource Plan, which includes energy efficiency measures and repower of in-basin power plants with efficient natural gas-fired generation to comply with the SWRCB's OTC Policy.

Appendix B tabulates the permitted capacity for each of the LADWP units which wholly or partially utilize OTC cooling technologies. Eleven units add up to 2,152.25 MW based on the permitted capacity rating from the SCAQMD air permits. Haynes Units 5 and 6 are excluded from Appendix B and from this summary of remaining OTC-related capacity. Haynes 5 and 6 capacity has already been designated to provide the capacity retirement to allow Haynes Units 11 to 16 to receive its permit to construct using SCAQMD Rule 1304(a)(2) exemption from offsets. The 2,152 MW includes the entire capacity of the two combined cycles at Haynes which include both combustion turbines not using OTC cooling technologies directly, but only indirectly through an OTC heat recovery steam generator (HRSG), as well as the capacity of the steam generator using waste heat from the HRSG. In the analyses of emissions described in Chapter III and in Appendix J, the AB 1318 assessment assumes that OTC-induced repowering encompasses not only the steam turbine using OTC-based HRSG but also the combustion turbines. At the time that these two combined cycles will be repowered, the entire combined cycle gas turbine facility will be 25 or more years old, so replacing the combustion turbines may be appropriate.

2. Renewable Integration Requirements

As described in Chapter I, maintenance of a stable grid system becomes more complex with a higher population of low-inertia, variable energy resources, such as wind and solar technologies, which is expected to be the case as the State increases its use of these resources to meet the 33 percent RPS. The integration of variable energy resources will require increased operational flexibility from other resources – notably the capability to provide load-following and regulation in wider operating ranges and at faster ramp rates than are currently experienced. The easiest way to envision the sort of changes that must be addressed is to convert from a gross load curve and count up the resources available to satisfy such a curve for each hour of the year to create a “net load” curve in which predicted output from intermittent, non-dispatchable resources are subtracted from gross load for each hour of the year. The remaining dispatchable generating resources must be flexible enough to follow this net load curve. Initial studies show that the net load curve has steeper ramps up and down, as well as maximum ramp amounts that occur in winter/spring months rather than under summer annual peak load conditions. Renewable integration requirements (also called flexible capacity requirements) would also constitute a separate requirement that a system must satisfy independent of other reliability planning criteria, such as the local capacity requirements. Flexible capacity requirements characterize the specific attributes that the generating fleet must possess in order to deal with the variability of generation and loads. However, definition of reliability and contractual requirements for operational flexibility needs is underway.

The ISO has produced several renewable integration/flexibility requirement studies for the CPUC’s 2010 and 2012 LTPP rulemaking proceedings. Since the ISO has conducted these studies under the direction of the CPUC, the studies use resource planning and demand-side assumptions specified by the CPUC, rather than the future assumptions used by the ISO in its own annual transmission planning proceedings that often occur simultaneously. The ISO has also adapted such studies to better reflect its own planning assumptions. In the 2012 LTPP, the CPUC developed a case designed to broadly reflect assumptions in the ISO’s transmission planning process. Although the CPUC cancelled the portion of its 2012 LTPP rulemaking addressing operating flexibility requirements[61], such studies remain necessary for use in gauging how capacity added for local reliability purposes would actually be operated over the course of a year. Clearly such results are needed in order to prepare estimates of the “potential to emit” for new capacity additions.

Although renewable integration was addressed within its Integrated Resource Plan, LADWP did not identify any new resources that are added specifically for renewable integration purposes. Further, LADWP did not conduct additional studies for AB 1318 that would reveal its needs for such resources.

Four study cases were used to inform the AB 1318 process. The ISO completed three cases specifically for AB 1318 purposes (Cases 2, 3, and 4). Case 4 is the only scenario that was modeled after the SONGS outage, but all cases are described herein as adjustments to various input parameters in each case is revealing regarding the contribution of available resources to system-wide renewable integration needs.

[61] CPUC, Assigned Commissioner Ruling and Administrative Law Judge’s Ruling Regarding Track 2 and Track 4 Schedules, R.12-03-014, September 16, 2013.

a. Model Structure and ISO Initial Analysis (Case 1)

Forecast uncertainty associated with wind and solar generation increases the need to have dispatchable capacity on reserve to ensure that demand is met in real-time. There is also the potential for increased occurrence of overgeneration, a condition where there is more supply from non-dispatchable resources, than there is demand. In providing these capabilities, the dispatchable portion of the generation fleet will likely need to operate longer at lower minimum operating levels and provide more frequent starts, stops, and cycling over the operating day.[62] Neighboring balancing authorities face similar increases in variable generation. This development has raised concerns about the ability and responsibility of each balancing authority to balance the variable output from renewable resources, including the need for additional flexible resources to compensate for the inherent variability of some renewable technologies.[63]

To understand the extent of these impacts from the 33 percent RPS, the ISO is using a production simulation model to evaluate the operational capabilities of the existing and future generation fleet. The Plexos simulation production cost model used for ISO renewable integration studies provides a refined approach to generation dispatch, identifying regulation and ramping operational response. The simulation as run chronologically through all hours of 2020 in the studies conducted for AB 1318. The simulation enforces generating unit constraints, including ramp rate, startup time, minimum run, and minimum down time.

Unlike LCR analyses, the geographic resolution of the model has zonal configurations for the entire Western Electricity Coordinating Council region. The ISO control area is divided into four zones: PG&E-Bay Area, PG&E-Valley, SCE, and SDG&E. The model assumes no transmission constraints inside each zone, but transmission limits between zones are enforced. Electricity demand can be met by resources located both inside and outside the zone. Imports are subject to transmission limits into the zone. There are also requirements for ancillary services[64] and load following capacity. In simplistic terms, generation that can provide ancillary services has the ramping capability to meet required capacity levels within minutes.

The model identifies any incremental system-wide capacity shortages based on variations between load and available resources. A separate need model run is then

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[62] Although the generation fleet is discussed here, there are similar analogues to other approaches to system management, such as demand response or renewable curtailment that can help provide services needed to operate the electrical grid in the real-time.

[63] The ISO and Pacificorp entered into memorandum of understanding to form an energy imbalance market in February 2013. One of the benefits of an energy imbalance market is to capture the benefits of geographical diversity of load and resources, which should help with the integration of renewables.

[64] The services other than scheduled energy that are required to maintain system reliability and meet WSCC/NERC operating criteria. As defined by FERC, they include: coordination and scheduling services (load following, energy imbalance service, control of transmission congestion); automatic generation control (load frequency control and the economic dispatch of plants); contractual agreements (loss compensation service); and support of system integrity and security (reactive power, or spinning and operating reserves).

conducted to translate the identified shortage into a generic resource capacity requirement.

In general, the ISO configured the assumptions it used in its renewable integration studies using assumptions specified by the CPUC in the 2010 LTPP rulemaking, and the CPUC is the principal client for the study results. As noted earlier, the ISO used the high-load scenario (increased peak and energy consumption by 10 percent) from the CPUC's 2010 LTPP. The ISO believes that it is a case more relevant to operation conditions in 2020.

The 33 percent renewable resource portfolio used for this study is the CPUC 2010 LTPP 33 percent RPS trajectory portfolio for 2020, as it represented the upper bound of expected emissions among the CPUC RPS scenarios for that proceeding.

The first set of results was available in July 2011 for year 2020 and resulted in a 4,600 MW additional need under the high load scenario, but no need under the other scenarios. However, ISO acknowledged the need to refine the analyses to include the results of the OTC studies being conducting by the ISO in the 2011-2012 TPP at the time, and which were also needed to complete the AB 1318 assessment.

b. Study Case with Local Capacity to Replace OTC Retirements (Case 2)

In support of AB 1318, the ISO conducted a production simulation run using the base model to evaluate system performance with local capacity requirement resources added to replace OTC generating units. For this case, SONGS was still operational, and 3,173 MW of generic generation resources were added in the SP 26 zonal area based on ISO's assessment of local capacity needs from the 2011-2012 TPP. The generic generation resources were assumed to be a combination of combined cycle and simple cycle gas turbines. Demand response resources in the amount of 4,816 MW were also included, consistent with assumptions from the CPUC's 2010 LTPP proceeding.
ARB staff advised ISO to run the models assuming no additional operational restrictions due to air permit limits, as staff was interested in observing the operating profile predicted by the model in the absence of any emission-related constraints.

The production cost run results show the new generic resources have higher capacity factors than average for the same type of units in the ISO control area and contribute significantly to ancillary services and load following. This is expected because the new resources are more flexible and have lower forced outage rates. Their heat rates are also lower than the average for the existing units. Table II-9 contains a comparison of the monthly capacity factors.

Table II-9. Comparison of Monthly Capacity Factors

Resource	1	2	3	4	5	6	7	8	9	10	11	12	Annual
SCE New GT[65]	9.5	11.2	10.0	9.8	12.0	16.5	20.3	17.9	7.9	10.0	8.0	10.2	11.9
SCE New CCGT[66]	53.1	60.0	61.4	64.2	59.4	64.1	73.7	83.4	80.9	66.9	61.1	68.3	66.4
SDG&E New CCGT	49.2	62.1	55.9	20.4	72.6	76.5	69.0	87.4	83.7	50.9	37.8	20.3	57.1
GT Average	10.9	10.7	8.0	10.8	10.9	12.0	11.2	9.5	6.6	8.4	9.3	10.4	9.8
CCGT Average	48.5	45.9	40.6	39.8	36.1	40.2	62.0	65.4	55.1	51.0	49.6	51.9	49.4

In addition to energy production, the generic turbine resources contribute to ancillary services and load following. Contributing towards upward ancillary services and load following requires that the generating unit maintain headroom in dispatch.[67]
Table II-10 shows the annual contribution to ancillary service and load following.

Table II-10. Ancillary Service and Load Following Contribution (GWh)

Resource	LF Down	LF Up	Non-Spin	Reg-D	Reg-U	Spin
SCE New GT	23.9	537.3	1.9	32.1	320.0	914.8
SCE New CCGT	1,888.0	849.2	0.5	101.8	11.6	577.2
SDG&E New CCGT	264.9	217.8	0	202.7	78.6	56.4

Contributions to ancillary services and load following are not reflected in the capacity factors. To correctly measure the actual utilization of a generating unit, the contribution to ancillary services and load following must be counted as well. For the SCE generic combined cycle turbines, the sum of generation and ancillary services and load following is equivalent to a combined capacity factor of 82.8 percent.

The model showed the system needs to deploy more flexible fossil generation to respond to the load variations of renewable generation, causing some units to cycle more. Table II-11 shows the number of start-ups for the new generic turbines compared to the average for existing turbines in the ISO control area. The results show a much higher number of starts for simple cycle turbines than combined cycle turbines.

[65] GT refers to natural gas-fired simple cycle gas turbines.
[66] CCGT refers to natural gas-fired combined cycle gas turbines.
[67] Headroom is defined as the difference between power plant dispatch level and its maximum power.

Table II-11. Comparison of Number of Start-ups

Resource	1	2	3	4	5	6	7	8	9	10	11	12	Annual
SCE New GT	26.2	20.3	21.8	20.9	18.7	16.8	25.4	27.4	20.8	24.8	24.1	25.3	272.6
SCE New CCGT	3.0	3.0	3.0	2.5	1.0	2.0	1.5	0.0	0.0	2.5	2.5	2.0	23.0
SDG&E New CCGT	2.0	3.0	3.0	2.0	1.0	1.0	1.0	0.0	0.0	2.0	1.0	3.0	19.0
GT Average	8.0	7.9	8.7	7.4	6.9	5.6	12.8	10.8	6.0	6.7	6.9	7.8	95.5
CCGT Average	3.7	3.7	4.3	3.8	3.4	3.6	5.0	4.8	3.0	4.7	3.7	3.8	47.4

Even with maximization of all available resources, including the additional of new generic turbines to replace a portion of the OTC retirements, the simulation model still found 8 hours in July with 20-minute ramping capacity shortages in the load following up requirement at a maximum shortage amount of 1,251 MW.

c. Study Case with Reduced Demand Response (Case 3)

A subsequent sensitivity study was requested by the State agencies based on a reduced level of demand response of 2,855 MW from the CPUC's 2012 LTPP proceeding, based on more current information. This case had the same assumptions as Case 2, with the exception of a 1,961-MW reduction in demand response resources. The model showed little change in utilization of the generic gas turbine units; however, the number of hours with load following up shortage in July increased from 8 to 12 hours, with a corresponding maximum generation shortage of 3,212 MW.

Both Case 2 and Case 3 scenarios show that demand response resources are used frequently in the summer months. The number of hours that demand response resources were deployed in the model are shown in Table II-12. The results highlight the flexibility of demand response capacity, which have no ramp rate constraints. These resources, however, are not dispatchable, as they do not have the ability to ramp up and down, but they do help free up dispatchable capacity once deployed and therefore contribute to grid reliability.

Table II-12. Demand Response Resource Deployment Hours

Case	July	August	September	October	Total
Original DR Capacity	44	22	3	2	71
Reduced DR Capacity (sensitivity)	47	23	2	2	74

d. Case 4 – SONGS Outage

For the simulation run with SONGS offline, the AB 1318 Technical Team considered updating the model to reflect new RPS portfolios from the CPUC's 2012 LTPP proceeding, as well as updating the load forecast and adjusting other parameters as well. However, due to resource and time limitations for the project, ISO could not adjust the original base model or load parameters. Instead, select input assumptions from the 2020 Plexos dataset developed for the 2010 LTPP rulemaking continued to be used, but were modified to be consistent with the “SONGS out” local capacity requirement studies and generate the most conservative incremental renewable integration need. For this case, SONGS capacity was removed, and 5,535 MW of generic generation resources were added in the SP 26 zonal area based on ISO’s assessment of local capacity needs from the 2012-2013 TPP.[68] The generic generation resources were assumed to be a combination of combined cycle and simple cycle gas turbines. Demand response resources were significantly reduced (826 MW) to match ISO’s recommendations for the “SONGS out” low bookend local capacity requirement study.

Table II-13 shows the capacity factors for the new generic turbines as well as average capacity factors for the existing turbines in the ISO control area. Table II-14 shows the annual contribution to ancillary service and load following.

Table II-13. Comparison of Monthly Capacity Factors

Resource	1	2	3	4	5	6	7	8	9	10	11	12	Annual
SCE New GT	4.6	2.9	2.2	2.2	1.8	8.3	13.2	12.1	4.2	4.0	4.6	4.6	5.4
SCE New CCGT	70.2	71.5	71.6	71.7	68.8	72.2	76.7	80.1	78.4	73.8	72.2	74.6	73.5
SDG&E New CCGT	57.2	58.5	54.7	39.2	70.8	69.3	66.4	80.3	79.1	61.0	58.8	53.1	62.4
SDG&E New GT	8.3	15.4	13.6	14.3	6.5	9.0	19.7	18.7	5.8	9.3	5.8	8.1	11.2
GT Average	9.4	10.1	6.4	8.7	10.1	8.8	10.5	7.9	5.2	6.3	7.5	7.6	8.2
CCGT Average	44.7	40.1	36.8	34.3	33.1	39.1	61.5	65.4	54.2	48.7	46.5	47.3	46.7

Table II-14. Ancillary Service and Load Following Contribution (GWh)

Resource	LF Down	LF Up	Non-Spin	Reg-D	Reg-U	Spin
SCE New GT	23.9	537.3	1.9	32.1	320.0	914.8
SCE New CCGT	1,888.0	849.2	0.5	101.8	11.6	577.2
SDG&E New CCGT	264.9	217.8	0	202.7	78.6	56.4

The generic resources in San Diego have higher capacity factors than the ISO average. In SCE, the generic combined cycle turbines have higher than average capacity factors, while the generic simple cycle turbines have lower than average capacity factors. Both SCE and SDG&E territories have import limits into Southern California. Transmission constraints on Path 26 also limits the flow of electricity from Northern to Southern

[68] The 5,535 MW is comprised of 4,615 MW of generic capacity in LA Basin and 920 MW in San Diego. The study should have included 430 MW of LCR generation for Big Creek/Ventura, but due to internal communication error, it was omitted.

California. A rule of thumb created by production simulation modelers to approximate satisfaction of stability requirements is to require that 40 percent of the load in the SCE area be served with generators within that area and require that 25 percent of the load in the San Diego area be served with local resources. In the absence of SONGS, the new generic resources need to produce energy nearly equivalent to that of SONGS. Combined cycle turbines are more economical to run than simple cycle turbines and will thus be utilized more. Since these flexible resources also contribute to ancillary services and load following, the total capacity factor of SCE combined cycle turbines is 83.7 percent, which is close to full utilization. SCE combined cycle turbines are more flexible than SONGS, which provides baseload generation. The SCE combined cycle turbines generate energy to make up for the loss of SONGS but also provide the flexibility that SONGS cannot provide. This translates into reduced usage of SCE simple cycle turbines and therefore the model shows a lower than average capacity factor.

e. Summary of Results from All Cases

The major inputs and results of all the renewable integration studies being used to inform the AB 1318 process are summarized in Table II-15.

Table II-15. Summary of Assumptions and Incremental Capacity Need from ISO Renewable Integration Studies

Assumptions	Case 1	Case 2 – New Local Capacity	Case 3 – Demand Response Sensitivity	Case 4 – SONGS Outage
Base model	2010 CPUC LTPP Trajectory	2010 CPUC LTPP Trajectory	2010 CPUC LTPP Trajectory	2010 CPUC LTPP Trajectory
Load	2009 CEC IEPR peak load forecast + 10%	2009 CEC IEPR peak load forecast + 10%	2009 CEC IEPR peak load forecast + 10%	2009 CEC IEPR peak load forecast + 10%
SONGS (MW)	2264	2264	2264	0
Demand response (ISO-wide MW)	4816	4816	2855	826
Local capacity requirement resources (MW)				
LA Basin	Not included	2370	2370	4615
Big Creek/Ventura	Not included	430	430	430*
San Diego	Not included	373	373	920
Total LCR resources (MW)	Not included	3173	3173	5535
Plexos model output: generic capacity need for renewable integration (ISO-wide MW)	4600	1251	3212	4870

*Due to internal communication error, the LCR generation for Big Creek/Ventura was not included in the Case 4 study. ISO advised subtracting the LCR value from the model output to correct the oversight. The renewable integration need in the table reflects this adjustment. This is only applicable to the Case 4 study.

The results from these four cases appear to indicate that all types of available resources are needed to meet demand and ancillary services. If one resource is reduced by a sufficient amount, that shortfall materializes as a system-wide renewable integration need at an almost 1-for-1 MW rate.[69] The results also show that new generation added for local capacity requirements help to integrate renewable resources into the system if the resource characteristics are designed with this in mind. The study results also highlight that demand response resources are effective in reducing ramping capacity shortage and are one of the desirable types of resources for integrating renewable generation in lieu of construction of additional flexible fossil fuel-fired gas turbines.

Due to concerns over the need for better understanding of what demand response characteristics are needed to contribute to long-term local capacity requirements, the ISO, CEC, and CPUC are exploring the characteristics necessary to meet local and flexibility needs. This includes examining hours of operation within a day and across a year and how quickly the resources can respond to a contingency.

[69] This is a general observation based on a comparison of the primary input assumptions and output results, but is not intended to imply that resource needs can be predicted through a simplified spreadsheet rather than running a simulation model.

III. Emission Offset Assessment

Under AB 1318, ARB is tasked with assessing the ability for needed generation identified in the electric reliability studies to obtain air permits in the jurisdiction of the South Coast Air Quality Management District (SCAQMD or District) consistent with existing federal, State, and local regulations. In the case of SCAQMD, the ability to acquire a permit to replace an existing power plant or build a new or expanding power plant has become inherently tied to the ability to fulfill offset requirements. This offset assessment pertains to the SCAQMD's entire New Source Review (NSR) program – meaning it is not limited to the generator's offset obligation, but includes any District programmatic offset obligations under federal NSR as well.

A. Background

SCAQMD is the local air pollution control agency with jurisdiction over all of Orange County and the non-desert portions of Los Angeles, Riverside, and San Bernardino Counties. Its air quality is amongst the worst in the nation. The South Coast Air Basin is designated extreme nonattainment for the 1997 and 2008 federal ozone standards, and nonattainment for the 1997 and 2006 federal PM2.5 standards. The Basin was formerly nonattainment for the federal CO standard but is now classified as a maintenance area by the U.S. Environmental Protection Agency (U.S. EPA).[70] Los Angeles County was designated nonattainment for the 2008 federal lead standard in December 2010. SCAQMD adopted a lead State Implementation Plan (SIP) that demonstrates attainment by December 2015.[71] In July 2013, U.S. EPA approved the SCAQMD's PM10 redesignation request and maintenance plan and the Basin is now designated attainment for the 1987 federal PM10 standard, but is still nonattainment for the State PM10 standard.

All electrical generating facilities that operate equipment which emits or controls air contaminants are required to obtain air permits from SCAQMD. All new, modified, and relocated facilities need to obtain a Permit to Construct prior to start of construction and all existing equipment needs to obtain a Permit to Operate. In order to obtain an air permit from SCAQMD, the equipment has to operate in compliance with all federal, State, and local air quality rules and regulations. In addition, for thermoelectric facilities of 50 MW and larger, the CEC is the primary licensing agency, and SCAQMD works closely with CEC staff to issue a Preliminary Determination of Compliance and Final

[70] Maintenance areas are geographic areas that had a history of nonattainment, but are now consistently meeting the national ambient air quality standard.
[71] Lead concentrations throughout most of Los Angeles County are below the federal lead standard. However, violations have occurred in the area surrounding two large lead-acid battery recycling facilities. SCAQMD has identified emissions from these facilities as the sole contributor to the lead violations in Los Angeles. Lead concentrations have met the federal lead standard since the beginning of 2012.

Determination of Compliance, which CEC staff incorporate into their Preliminary and Final Staff Assessments. In addition, since SCAQMD is the implementing agency for the Title V program (federal operating permit program) and has a U.S. EPA-approved integrated Title V permit program[72], all power plants which are major sources under Titles I, III, or IV also need to obtain a Title V Permit to Construct from SCAQMD prior to start of construction. Recent power plant permitting activity shows it has taken from five to seven years from the time of permit/license applications submittal to SCAQMD and CEC to commercial operation.

One of the cornerstones of permitting is New Source Review (NSR) requirements. Federal NSR is divided into two permitting programs – (1) Prevention of Significant Deterioration (PSD) for areas that are in attainment with air quality standards, and (2) Nonattainment Area for areas that are designated as nonattainment with air quality standards. The primary requirements of NSR are the use of best available control technology (BACT), air quality impact analysis (air dispersion modeling), and emission offsets (for Nonattainment Area NSR only). As stated previously, the ability to secure offsets for projects with emission increases of nonattainment pollutants is the primary issue with respect to long-term, sustainable permitting in the SCAQMD and is the focus of the rest of this chapter.

B. Overview of Offset Requirements

The federal Clean Air Act requires new and expanding projects at major sources that will increase emissions of nonattainment criteria pollutants to provide equal or greater quantities of emission decreases (known as emission reduction credits [ERCs] or offsets) to mitigate the impacts. The specific quantity of emission decreases required to offset the increase in emissions is dependent upon the pollutant's federal nonattainment classification for the air basin in which the increase occurs.

SCAQMD's NSR program is defined in and established by the rules in Regulation XIII, which were approved by U.S. EPA into the SIP in 1996. The District's NSR program requires that emission increases are offset by ERCs provided by the applicant or by allocations from the Priority Reserve[73] unless they are exempt from offset requirements pursuant to *Rule 1304 Exemptions*. The federal NSR program does not provide any offset exemptions for most of the Priority Reserve sources nor for the sources that qualify for the exemptions listed in Rule 1304.

In order to demonstrate that SCAQMD's NSR requirements are programmatically equivalent to federal NSR requirements, the District is expected to track emission increases from major sources not required to provide offsets and offsetting emission

[72] The SCAQMD's Title V permit program is not just an operating permit program, but rather an integrated program which means that all Permits to Construct for new and modified Title V sources are issued in the form of a federal Title V permit and not a local permit.
[73] The Priority Reserve is a SCAQMD internal offset bank established to provide credits for specific priority sources.

reductions. The purpose of the tracking is to make annual showings that the aggregate emissions offsets provided by the District for emissions increases for sources exempt from offsets are equal to or greater than the aggregate emissions offsets that would be required for sources pursuant to the federal NSR offset requirements. The District tracks all disbursements from these offset accounts, as well as deposits to them as outlined in *Rule 1315 Federal New Source Review Tracking System*. Offset account credits include orphan shutdowns, orphan reductions, ERCs provided as offsets for minor sources, and the difference in emissions due to more stringent offset ratios for select pollutants. The results of the tracking are aggregated and reported to U.S. EPA and ARB on an annual basis.

In accordance with District *Rule 1303 Requirements*, offset ratios are 1.2 pounds of decrease for every 1.0 pound of increase for NOx and VOC and at least 1.0 pound of decrease for every 1.0 pound of increase for all other nonattainment pollutants and their precursors. The applicable offset ratios are shown in Table III-1 for each pollutant.

Table III-1. SCAQMD Offset Thresholds and Offset Ratios

NOx	VOC	PM10	CO	SOx	PM2.5
4 tpy	4 tpy	4 tpy	29 tpy	4 tpy	100 tpy
Offsets from ERCs: 1.2:1.0 Offsets from Priority Reserve: 1.2:1.0 Offsets from ERCs outside SCAB: 1.2:1.0	Offsets from ERCs: 1.2:1.0 Offsets from Priority Reserve: 1.2:1.0 Offsets from ERCs outside SCAB: 1.2:1.0	Offsets from ERCs: 1.2:1.0 Offsets from Priority Reserve: 1.0:1.0 Offsets from ERCs outside SCAB: 1.2:1.0	Offsets from ERCs: 1.2:1.0 Offsets from Priority Reserve: 1.0:1.0 Offsets from ERCs outside SCAB: 1.0:1.0	Offsets from ERCs: 1.2:1.0 Offsets from Priority Reserve: 1.0:1.0 Offsets from ERCs outside SCAB: 1.2:1.0	1.1:1

C. Offset Options for Power Plants

Under current District rules, there are two options for power plant project proponents related to offsets: (1) procure ERCs on the open market, or (2) qualify for an exemption under Rule 1304. Rule 1304 contains a specific exemption from offsets for repowers of existing power plants. Specifically, replacement of an existing electric utility steam boiler with advanced generating technology[74] does not trigger the offset requirements unless there will be an increase in basinwide capacity on a per-utility basis. If there is an increase in capacity, then only the emissions associated with the increased capacity must be offset. Therefore, repowers with advanced generation are essentially exempt from offsets (with the exception of PM2.5 which is discussed in further detail in Section E) if capacity is not increased.

[74] This includes combined cycle gas turbines, intercooled, chemically-recuperated gas turbines, other advanced gas turbines, solar, geothermal, or wind energy or other equipment.

Based on the SCAQMD's NSR program requirements, the amount of offsets needed to permit generation under AB 1318 fall into three primary categories:

1. Generator offset obligations for OTC repowers: Generators have stated their intention to utilize the Rule 1304 repower offset exemption and replace capacity at a 1-for-1 MW rate on a basin-wide basis as indicated in generator OTC Policy Implementation Plans submitted to the SWRCB.[75] Because there will be no capacity increase for a given repower project, the generator does not incur an offset obligation for the permit to construct.

2. District offset obligations under federal NSR (Rule 1315) for OTC repowers: While a repowered source may be exempt from offsets via Rule 1304(a)(2), there is still the need to determine the offset obligation under federal requirements, since SCAQMD has to balance these offset requirements through reductions made up elsewhere. Under federal NSR, new major sources are required to offset their projected maximum emissions (i.e., potential to emit), and major sources undergoing a modification, such as a repower, are required to offset their net emissions increase, which is determined by comparing historic actual emissions to either projected actual or potential to emit amounts. For power plant repowers that utilize the Rule 1304(a)(2) offset exemption, the SCAQMD debits emissions equivalent to the entire potential to emit of the repowered generating unit from its internal offset bank, not the amount of the net emissions increase only.

3. Offset requirements for new generation: This category covers the offset requirements for any new capacity that is not directly linked to retirement of existing steam boiler facilities. Based on new power plant projects filed with the CEC, the agencies expect that any new generation will consist of natural gas-fired combined-cycle or simple-cycle turbines. These projects do not have access to any existing utility boiler capacity and cannot use the internal offset bank. The only options available under the current permitting system include purchasing ERCs from other sources or funding emission reduction projects to generate their own ERCs. ERC generation projects can have their own issues, particularly related to meeting the "surplus" criterion, due to the needed stringency of regulations in SCAQMD related to the magnitude of the air quality problems in the region.

D. Offset Requirements for Individual Project Types

While the three main categories of offset obligations are described in the previous section, ERC availability in the open market and current offset provisions specified in District rules translates into different requirements depending on the type of power plant project proposed for permitting. Therefore, it is useful to describe the offset requirements in SCAQMD for individual possible project scenarios of repowered or new facilities.

[75] With the passage of time since initial filing of generator Implementation Plans in April 2011, some generators have updated their plans reflecting generator expectations for future capacity requirements.

1. Repowering an Existing Utility Boiler Power Plant

Some power plants have utilized the offset exemption in Rule 1304(a)(2), which exempts sources from offset requirements when an existing utility boiler is replaced with combined cycle gas turbines or other types of advanced gas turbines as long as there is no increase in the MW rating. Although utility boiler replacements are exempt from offset requirements, the SCAQMD still provides such offsets from its internal offset bank. The quantity of such offsets is equal to the potential to emit of the replacement new gas turbines capacity.

2. Repowering by Moving Capacity between Existing Power Plants

In some cases, existing power plants have proposed to use the Rule 1304(a)(2) utility boiler replacement offset exemption to retire utility boilers at one power plant and replace the capacity with new gas turbines at another existing power plant under common ownership. An example is the proposal by AES to transfer capacity from AES Redondo Beach for boiler Units 6 and 8 to AES Huntington Beach. Under this proposal, SCAQMD still provides credits from its internal offset bank to offset the emission increases from the new gas turbines being installed at the power plant location (e.g., Huntington Beach). Again, the quantity of such offsets is equal to the potential to emit of the replacement new gas turbines capacity.

3. Moving Capacity from an Existing Power Plant to a New Power Plant under Common Ownership

It is also possible for an existing power plant operator to retire its utility boilers and replace them with new gas turbines located at the site of a new power plant, also using the SCAQMD Rule 1304(a)(2) utility boiler replacement offset exemption. Once again, SCAQMD provides credits from its internal offset bank to offset the emission increases from the new gas turbines in an amount equal to the potential to emit of the new gas turbines capacity. In one case, a power plant owner went to a competitor and purchased their aged utility boilers and subsequently retired them in order to be able to use the Rule 1304(a)(2) utility boiler replacement offset exemption. As in the other cases described above, the SCAQMD provides internal bank credits to offset emission increases from operation of the new gas turbines at the new power plant. An example is the purchase of Huntington Beach Units 3 and 4 by Edison Mission Energy from AES, which then enabled Edison Mission Energy to retire Units 3 and 4 to utilize the offset exemption for the new Walnut Creek power plant located in the City of Industry.

4. Repowering Other Existing Power Plants

Existing power plants that do not use utility boiler technologies are not eligible for the Rule 1304(a)(2) exemption from offsets. These power plants consist of older combustion turbines, or combined cycles – the Long Beach combustion turbines are an example of the former, and Harbor Units 1,2 and 5 are an example of the latter.

However, such power plants can still undergo repowering to some extent as long as they are making identical replacement and can use another offset exemption provided by SCAQMD Rule 1304(a)(1). Rule 1304(a)(1) provides an offset exemption for a source that replaces a functionally identical source as long as there is no increase in maximum MW rating and the potential to emit of any air contaminant will not be greater from the new source than from the replaced source, when the replaced source was operated at the same conditions and as if current BACT were applied.

5. New Power Plants without the Benefit of Retired Capacity

New power plants that do not have associated retirement of steam boiler capacity are not exempt from offset requirements and, therefore, operators need to provide ERCs. One recent exception is the CPV Sentinel project in the Desert Hot Springs area of Coachella Valley. CPV sponsored legislation that allowed CPV to access credits from SCAQMD's internal offset bank and in turn pay a mitigation fee. The mitigation fee is being used to generate additional emission reductions in the area around the power plant.

E. Translation of Identified Capacity Needs into Emissions

The study results from ISO and LADWP both indicate that LA Basin local capacity requirements could be met almost entirely through existing OTC unit repowers. For renewable integration, the 4,870 MW of system-wide need for the ISO balancing authority area is incremental to the local capacity requirements, but the Plexos model is unable to apportion this system-wide need to specific geographical locations. Based on historic load patterns and transmission flow constraints from Northern to Southern California, it is reasonable to assume that some of this capacity be sited in the SP26 zone. However, since the ISO cannot provide a technical basis for apportioning renewable integration capacity within its balancing authority area at this time, any capacity associated with renewable integration need for the high and low bookends is assumed to be zero (i.e., located outside SCAQMD boundaries), since renewable integration requirements could be satisfied with generation located anywhere in the ISO control area outside of the South Coast Air Basin. The local capacity requirements and renewable integration generation assumptions are recapped in Tables III-2A and III-2B below for the ISO and LADWP, respectively.

Table III-2A. Summary of LA Basin Portion of ISO Resource Additions Needed in Year 2022

Balancing Authority Area / Scenario	OTC Capacity Available for Repower (MW)	OTC Replacement Need (MW)	New Generation Need (MW)	Total Generation Need (MW)	System-wide Renewable Integration Need (MW) After Adding New Generation	Renewable Integration Need Attributed to LA Basin (MW)
ISO / High Bookend	4150	2900	1400-1700	4300-4600	4870[76]	0
ISO / Low Bookend	4150	2900	400-560	3300-3460	Not evaluated	0

Table III-2B. Summary of LADWP Resource Additions Needed by Year 2029[77]

Balancing Authority Area / Scenario	OTC Capacity Available for Repower (MW)	OTC Replacement Need (MW)	New Generation Need (MW)	Total Generation Need (MW)	System-wide Renewable Integration Need (MW) After Adding New Generation	Renewable Integration Need Attributed to LA Basin (MW)
LADWP / High Bookend	2152[78]	2152	0	2152	Not evaluated	Not evaluated
LADWP / Low Bookend	2152	2152	0	2152	Not evaluated	Not evaluated

For the ISO balancing authority area, the total amount of generation that must be sited in LA Basin ranges from 3,300 to 4,600 MW to meet local capacity requirements. There is 4,150 MW of existing OTC capacity that can be repowered to meet this requirement, and the remaining 450-MW deficiency under the high bookend scenario would need to be met with new greenfield power plant construction.

[76] The renewable integration study without SONGS identified an incremental system-wide need of 5,300 MW. 430 MW should be located within Big Creek/Ventura for local capacity requirements, which leave a remainder of 4,870 MW system-wide renewable integration need.

[77] 2,152 MW includes the entire capacity of the two combined cycles – Harbor 1-2 and 5, and Haynes 9-10 and 8. Since these two combined cycles do not have to comply with the SWRCB's OTC Policy until 2029, most details associated with compliance have not been determined. Appendix B shows the complete list of generating units that have been counted to total 2,152 MW.

[78] 2,152 MW includes the capacity from Scattergood 3, which recently received a permit to construct to repower with one combined cycle plant and two simple cycle gas turbine generators. The estimated emissions from this project were included for purposes of federal NSR equivalency tracking. 2,152 MW also includes the capacity from OTC combined cycle gas turbines at Harbor and Haynes, each of which could be replaced using the SCAQMD Rule 1304(a)(1) offset exemption. By remaining within the maximum rating and emissions of the existing gas turbine, the replacement turbine would have no emission increases and there would be no offset obligation for the facility or for the SCAQMD for federal equivalency determination. 1,335 MW was used for purposes of federal NSR equivalency tracking.

For the LADWP balancing authority area, repowers of all 2,152 MW of existing OTC capacity are needed under both high and low bookend scenarios. The 2,152 MW includes capacity from both utility steam boilers and combined-cycle gas turbines. The turbines do not qualify for the Rule 1304(a)(2) repower offset exemption but may qualify for the Rule 1304(a)(1) offset exemption for functionally identical replacements. A functionally identical replacement of the turbines will be exempt from offsets if there is no increase in maximum rating of each gas turbine and the potential to emit will not be greater from the new equipment, when compared to the replaced equipment if operated at the same conditions and with current BACT applied.

As stated in Section C of this chapter, utility steam boiler repowers are able to use the Rule 1304(a)(2) offset exemption and have their credits provided by the SCAQMD through the internal offset bank. For federal equivalency determination, the SCAQMD debits the entire potential to emit from repower projects from the internal offset bank. New greenfield power plant projects without the benefit of existing capacity will need to secure ERCs on the open market or generate ERCs through funding projects that reduce emissions beyond current regulatory mandates. For conventional generating resources, these new projects are likely to consist of gas turbine combined cycle or simple cycle units, and corresponding offset obligations are calculated based on the potential to emit of the new equipment. Generators have specified their intent to repower existing OTC units with gas turbine combined cycle or simple cycle units as well. Therefore, for purposes of AB 1318, with the exception of combustion turbine-to-turbine repowers, the offset calculations consist of a straight potential to emit calculation of the maximum average monthly emissions from the advanced gas turbines generators regardless of whether the project is a new greenfield source or a replacement of steam boiler generating units at an existing OTC power plant. The main difference is the source of the offsets – steam boiler repowers that utilize the Rule 1304(a)(2) exemption have their credits supplied from the SCAQMD internal offset bank, but new greenfield sources (not associated with existing steam boiler capacity) will need to secure market ERCs or find other means to generate surplus emission reductions. The offset calculations for the potential 450 MW of additional new generation need for local capacity requirements are based on a generic state-of-the-art combined cycle turbine power plant. The offset calculations for OTC repowers are based on generic state-of-the art combined cycle or simple cycle turbine power plants, depending on what equipment was specified in generator Implementation Plans submitted to the State Water Board. While the mix of facilities specified by the generators is unlikely to precisely predict what will eventually get built, it is a tangible starting point. In addition, the emission calculations guided by the results of the ISO's operating flexibility studies helped develop the operating pattern over the course of the year, which is needed to implement the "potential to emit" calculations.

An emissions calculator spreadsheet was developed for this project. The methodology, assumptions, and resulting emission estimates using the calculator are documented below with additional details provided in Appendix I.

1. Potential to Emit for Boiler Repowers and New Units

Pursuant to SCAQMD Rule 1306(b), emission increases from new or modified sources are calculated using calendar monthly emissions divided by 30 for determination of the required amount of offsets, from permit conditions that directly limit emissions or, when no such conditions are imposed, from (1) the maximum rated capacity; (2) the maximum daily or monthly hours of operation; and (3) the physical characteristics of the material processed. The potential to emit of the new replacement generating units due to repowering is therefore calculated as the maximum emissions that a unit can emit, either based on maximum rated capacity and unrestricted hours of operation or some artificial cap that is enforceable through permit conditions. For purposes of this project, the potential to emit of the new replacement units is calculated by multiplying the unit's capacity by the applicable emission factor and the maximum monthly hours of operation.

The size and type of gas turbine configuration was determined from the OTC Policy Implementation Plans and subsequent updates submitted to the SWRCB. If no configuration was specified, combined-cycle turbines were assumed since ISO renewable integration studies have predicted close to full utilization of new replacement combined cycle turbines in the Southern California Edison territory.

The air pollutant emission factors that apply to new replacement generation during steady-state operation are dictated by best available control technology (BACT) requirements in the District's NSR rule. Current BACT for gas-fired simple-cycle and combined-cycle turbines is already very stringent at single-digit values for ozone precursors, and BACT for PM10, PM2.5, and SOx is use of CPUC-quality natural gas fuel. Although permit applications for many OTC generating units that have proposed to repower have not yet been submitted to the SCAQMD, ARB staff determined it was reasonable to apply current BACT emission levels to future repower projects for purposes of offset projections under AB 1318 since BACT emission levels would only get more stringent in the future and there is a reduced chance of underestimating emission offset needs. Emission factors for uncontrolled, or non-steady state periods (i.e., startup and shutdown), are based on the type of turbine selected and are typically supplied by the turbine manufacturer.

ARB staff selected two large generation projects in SCAQMD to represent the typical emissions profile for combined cycle and simple cycle (or peaking) gas turbine power plants. Corresponding lb/MWh emission factors were determined from project data and are summarized in Table III-3. Since SCAQMD Rule 1306(b) specifies that emission increases for new and modified sources are calculated using calendar monthly emissions divided by 30 for determination of the required amount of offsets, the lb/MWh emission factors are derived from the total monthly emissions, including startup and shutdown periods, divided by the corresponding electrical output. Catalytic emission controls, such as selective catalytic reduction, operate most effectively within a specific temperature window reflective of steady-state conditions. During reduced load periods such as startup and shutdown, emission rates are typically higher than those occurring at steady-state conditions. The ISO renewable integration Plexos production cost simulation model predicts an increased number of startups for simple cycle gas turbines in the SCE service territory compared to the ISO system-wide average. The emission factors in Table III-3 reflect much higher frequency of startup and shutdown periods than predicted by the ISO model; therefore the emission factors can be considered conservative for use in estimating the potential to emit.

Table III-3. Example Monthly Emission Factors for Natural Gas-Fueled Turbine Generating Units

Configuration	NOx (lb/MWh)	CO (lb/MWh)	VOC (lb/MWh)	PM10 (lb/MWh)	SOx (lb/MWh)
Combined cycle*	0.083	0.102	0.049	0.035	0.013
Simple cycle**	0.143	0.219	0.042	0.062	0.002

*Based on emissions data included in the Application for Certification for the Huntington Beach Energy Center.
**Based on emissions data included in the SCAQMD engineering evaluation for the LADWP Haynes Unit 5 and 6 repower project.

The ISO's renewable integration Plexos production cost simulation model produced an operating profile for repowered new generation, which was provided as both as monthly capacity factors and as contributions to ancillary services and load following. The ancillary service and load following contributions are not reflected in the capacity factors (refer to Tables II-13 and II-14 in Chapter II). Regulation is used to balance the system instantaneously, and the values reflect regulation capacity and not necessarily energy. However, deploying regulation-up capacity will increase generation and it is expected that some of the regulation-up capacity will be converted to energy. However, deploying regulation-down capacity will reduce generation. The emission impact of the two may offset each other. Regardless, its emission impact should be small. Spinning and non-spinning reserves cannot be deployed unless there is a contingency, which should be rare, and there should be a small or no energy component associated with emissions. Load following in the model is designed to cover the variations between hourly average and 5-minute average of load. Its utilization in the model is similar to regulation in operation; it also has up and down directions that may offset each other. Based on the combined operational response of ancillary service and load following resources, ISO advised that it is reasonable to assume that the emissions contribution from that portion is negligible.

The output from the "SONGS out" renewable integration study predicts replacement OTC units operating at monthly capacity factors ranging from 68.8 to 80.1 percent (with corresponding annual capacity factor of 73.5 percent) for new combined cycle units and monthly capacity factors from 1.8 to 13.2 percent (with corresponding annual capacity factor of 5.4 percent) for new simple cycle units in the Southern California Edison service area. For comparison, ARB staff surveyed large power plant projects located in SCAQMD that have received licenses, or are undergoing the licensing process, from the CEC and found monthly operating hours based on 64 to 100 percent capacity factors for simple cycle turbines and based on 100 percent capacity factor for combined cycle turbines. These capacity factors are higher than operation predicted by the ISO model. However, it is ARB staff's experience that sources will seek permit limits based on maximum potential emissions to provide greater operational flexibility, unless the trade-off between triggering additional regulatory requirements and maximizing potential to emit is not cost-effective and in these cases the source may take an emissions cap to remain under the applicability threshold for a regulation. In addition, generators may request permit limits consistent with operation needed to meet the obligations in power purchase agreements. Based on this information, ARB staff estimated emissions based on maximum monthly hours of operation, or 744 hours per month of operation for both combined cycle and simple cycle units. SCAQMD staff confirmed that up until now, power plants replacing their utility boilers with gas turbines have permitted their utility boiler replacements at 100 percent capacity (24 hours per day and 365 days per year) regardless of their actual expected usage. SCAQMD is currently developing Proposed Rule 1304.1 to require that utility steam boiler replacement sources pay a fee, calculated based on the amount of offsets used from the SCAQMD internal offset bank, as adjusted by the proposed maximum annual operating capacity of the new gas turbines compared to the operating capacity of the existing boilers in the last couple of years. The SCAQMD expects the rule would cause the power plants replacing boilers to take a more realistic and reasonable cap on their operation instead of 100 percent capacity and therefore reduce the amount of credits withdrawn from the internal offset bank (see also discussion in Section G.2.).

The potential to emit calculation for PM10 for the repower of AES Alamitos Unit 5 and Unit 6 is provided as an example. According to information from the OTC Policy Implementation Plan, AES may repower utility boilers 5 and 6 with 600 MW of combined cycle generation and 400 MW of simple cycle peaking generation. Using the specified replacement capacity, along with the emission factors in Table III-2 and assumed operating hours results in the following emissions:

PE_{PM10} (combined cycle)	=	600 MW x 0.035 lb PM10/MWh x 744 hr/mo x mo/30 days
	=	520.80 lb/day (equivalent to 95.05 tons/yr)
PE_{PM10} (simple cycle)	=	400 MW x 0.062 lb PM10/MWh x 744 hr/mo x mo/30 days
	=	615.04 lb/day (equivalent to112.24 tons/yr)
Total PE_{PM10}	=	1,135.84 lb/day PM10 (0.57 tons/day)

For the 450 MW of new greenfield generation required beyond OTC repowers under the worst-case high bookend scenario, the emissions are simply equal to the potential to emit of the new turbines, which are assumed to be combined cycle, at the applicable offset ratio. The potential to emit calculation is determined using the capacity of the new units, emission factors in Table III-2, and assumed operating hours. An example calculation is provided as follows:

PE_{PM10} (new combined cycle) = 450 MW x 0.035 lb PM10/MWh x 744 hr/mo x mo/30 days
= 390.60 lb/day PM10 (0.20 tons/day)

2. Offsets Required

In order to determine the amount of offsets required, the 30-day average daily potential to emit value is then multiplied by the applicable pollutant offset ratio to obtain the amount of offsets required. The resulting offset obligation for PM10 for the AES Alamitos Unit 5 and Unit 6 repower is continued below.

Offsets required = Total PE x Pollutant-Specific Offset Ratio
= 1,135.84 lb/day x 1.0
= 0.57 tons/day PM10

Credits are withdrawn from the SCAQMD internal offset bank for the year the permit to construct is issued. The corresponding offset amounts for each identified repower project are debited from the internal offset bank for the calendar year that the permit to construct was issued for projects utilizing the Rule 1304(a)(2) exemption. For new greenfield projects, ERCs must also be provided before a Permit to Construct is issued by SCAQMD (with the exception of RECLAIM Trading Credits, or RTCs, for RECLAIM sources, which must be provided before start of operation), since the required ERCs to offset new emission increases must coincide with the issuance of a Permit to Construct (or start of operation, in the case of RTCs) of the new units. Projected commercial online dates specified in the generator OTC Implementation Plans are include in Appendix J, Table J-2.

The estimated amount of credits to be debited from the internal offset bank for repowers and required in the form of market ERCs or emission reduction projects for new greenfield projects is listed in Table III-4 on a per project basis for the high bookend. It is difficult to predict the exact pattern of emission increases from OTC repower and new greenfield projects that will require offsets as permitting timelines can vary considerably based on individual project circumstances. Based on the amount of MWs with 2020 OTC compliance dates and the five to seven years it has taken to get generating units online from submittal of permit applications, it is possible that certain years could see clusters of offset needs.

Table III-4. Summary of Estimated Offset Needs for the AB 1318 High Bookend on a Per Project Basis for ISO and LADWP Balancing Authority Areas

Plant	Type of Project	Project Capacity (MW)	NOx (tons/day)	CO (tons/day)	VOC (tons/day)	PM10 (tons/day)	SOx (tons/day)	OTC Compliance Date
Alamitos	Repower Units 1-6	2,100	2.75	3.82	1.21	1.18	0.23	12/31/2020
Huntington Beach*	Repower Units 1-2	939	0.96	1.18	0.58	0.40	0.16	12/31/2020
Redondo Beach	Repower Units 5 and 7	511	0.53	0.65	0.31	0.22	0.08	12/31/2020
El Segundo	Repower Unit 4	435	0.45	0.55	0.26	0.19	0.07	12/31/2017
Harbor♣	Repower Units 1, 2, 5	277.45	0	0	0	0	0	12/31/2029
Haynes	Repower Units 1-2	444	0.46	0.56	0.27	0.19	0.07	12/31/2029
Haynes♣	Repower Units 8-10	596.8	0	0	0	0	0	12/31/2029
Scattergood◊	Repower Unit 3	524.3	0.69	0.96	0.30	0.30	0.06	12/31/2015
Scattergood	Repower Units 1-2	367	0.38	0.46	0.22	0.16	0.06	12/31/2024
OTC Repowers, total♠		5,320.3	7.47	8.19	3.77	2.65	0.72	
New Greenfield Generation (with 1.2:1 offset ratio)		615**	0.76	0.93	0.45	0.32	0.12	

* This projects includes moving capacity from Units 6 and 8 at Redondo Beach in accordance with SCAQMD Rule 1304(a)(2).

♣ It is expected that LADWP will utilize the SCAQMD Rule 1304(a)(1) offset exemption for functionally identical replacements to repower the existing gas turbines with new, more efficient gas turbines. To qualify for the exemption, the rule includes provisions that the post-project gas turbine rating and potential to emit be no greater than the pre-project gas turbine rating and potential to emit (as if current BACT were applied). Therefore, there is no emission increase and no offset need is assigned to this project at this time.

◊ Project already received its permit to construct from SCAQMD but emissions are included here since the SCAQMD has not made its year 2013 federal equivalency determination yet.

♠Applicable offset ratios for credits from SCAQMD internal offset bank are 1.2:1 for NOx and VOC and 1.0:1 for all other pollutants.

**Includes 450 MW of new generation above 4,150 MW of OTC repowers to meet local capacity requirements for the high bookend + 165 MW to correct the difference in repower capacity based on the OTC Implementation Plans, which is just short of the 4,150 MW.

F. Federal NSR Tracking System Projections

On September 6, 2013, SCAQMD staff presented their report on the final determination of equivalency for calendar year 2011 to the SCAQMD Governing Board. The report shows the federal account balances for 2011 and the projected balances for the next couple of years. The projected future balances only extend to the end of 2013, but based on a comparison of the balances and the estimated offset amounts for the AB 1318 high and low bookend scenarios, it appears there will be sufficient credits in the internal offset bank for OTC repowers of utility steam boiler power plants (see Table III-5). Again, this only addresses the repower of existing power generating boilers affected by the State Water Board's OTC Policy; it does not address additional repowers of non-OTC aging boiler power plants, repowers of combustion gas turbine power plants, and new, greenfield fossil generating units without the benefit of retired capacity.

Table III-5. Federal Offset Accounts Final Determination of Equivalency for 2011 and Projections of Account Balances for 2012 and 2013

Description	VOC	NOx	SOx	CO	PM10
2011 Ending Balance (tons/day)	**84.06**	**26.80**	**2.88**	**17.74**	**12.94**
2012 Projected Ending Balance (tons/day)	86.99	27.47	3.09	19.35	13.43
2013 Projected Ending Balance (tons/day)	89.82	28.12	3.30	20.96	13.91
AB 1318 Estimated Offset Need for Boiler OTC Repowers, High Bookend (tons/day)	3.77	7.47	0.72	8.19	2.65
AB 1318 Estimated Offset Need for Boiler OTC Repowers, Low Bookend (tons/day)	3.40	6.84	0.64	7.54	2.42

G. Other Regulations Affecting Power Plants

This section addresses other regulatory provisions aside from offset requirements that could have an effect on power plants in the South Coast Air Basin.

1. Federal PM2.5 New Source Review

PM offsets have proven to be the most scarce and costly offsets to obtain in recent years in the SCAQMD. As stated, SCAQMD Rule 1304 provides an exemption from offsets for the replacement of electric utility steam boilers with new, qualifying generation technology. This exemption includes PM10 but <u>not</u> PM2.5. The District adopted *Rule 1325 Federal PM2.5 New Source Review Program* on June 3, 2011, to incorporate federal NSR requirements for PM2.5 nonattainment areas. Stationary sources with PM2.5 emissions of 100 tpy or more are subject to the rule, which includes use of the lowest available emission rate (LAER) and providing offsets. A source can opt to take a 100 tpy limit as an enforceable permit condition to avoid triggering offsets. El Segundo Unit 3 and LADWP Haynes Units 5 and 6 repower projects are two examples of sources that received permits to construct from SCAQMD and opted for the 100 tpy emission cap.

Most PM emission factors for combined cycle and simple cycle turbines have been based on manufacturer guarantees, which often include a margin of safety to account for variability associated with source test methods. Rule 1325 requires use of U.S. EPA Methods 201A and 202 to demonstrate compliance. These methods were recently amended (December 2010) to improve accuracy, including reducing the formation of reaction artifacts that could lead to inaccurate measurements of condensable PM. As a newly promulgated method, the amount of source test data is currently limited.

The 939-MW Huntington Beach Energy Project, which is under review at the CEC, recently submitted an addendum to their application to demonstrate compliance with Rule 1325. The facility proposes to limit annual startup, shutdown, and duct burner firing hours to reduce PM2.5 emissions below the 100 tpy major source threshold; this corresponds to 6,835 annual operating hours per turbine (78 percent capacity factor). The highest monthly capacity factor for new combined cycle generation from the "SONGS out" renewable integration study was 80.1 percent with an average of 73.5 percent over the entire year. Therefore, it appears taking such a permit limit will still allow generation to operate at a level consistent with ISO predictions.

2. Proposed Rule 1304.1 Electrical Generating Facility Offset Fee

On January 4, 2013, the SCAQMD issued draft language for proposed *Rule 1304.1 Electrical Generating Facility Fee for Use of Offset Exemption* under direction from their Governing Board. The proposed rule was subsequently revised multiple times to reflect stakeholder input, with the most recent version released to the public on August 6, 2013. Proposed Rule 1304.1 was heard and a final version adopted by the SCAQMD Governing Board at a Public Hearing on September 6, 2013. 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 Bank to offset any emission increase associated with these projects. Prior to the rule adoption, no fee was being charged for this SCAQMD-provided offset credit. Rule 1304.1 now requires 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 fees for access to this exemption. The fee proceeds will be invested in air pollution improvement projects consistent with SCAQMD's Air Quality Management Plan, with a preference toward projects that reduce emissions in the vicinity of the power plant.

The rule requires repowering electrical generating facility operators electing to use the Rule 1304(a)(2) exemption to pay an offset fee for each pound of offsets debited from the SCAQMD internal offset accounts adjusted for the annual permitted capacity factors. The rule provides the operator with the option to pay the fee up front as a single payment prior to the issuance of the permit to contract or on an annualized fashion. The rule provides a credit for the prior usage of utility boilers being replaced and also provides a 75 percent discount for the first 100 MW installed. The rule further allows the facility operators to seek full refund of the offset fee remitted prior to commencement of operation (in which case the Permit to Construct will be automatically cancelled). Further, in the event the permitted capacity of the project is subsequently reduced prior to construction, the rule also allows the operator to see a partial refund corresponding to that portion of the permitted capacity reduced.

H. Offset Issues Requiring Legislation

While offsets as a whole are difficult to secure in SCAQMD, PM10 ERCs are particularly difficult to acquire, and if available, are offered at highly cost-prohibitive rates. As stated previously, the SCAQMD has been redesignated as attainment with the federal PM10 standard by U.S. EPA. SCAQMD NSR rules still require PM10 offsets, however, and it should be noted that the District is nonattainment for the State PM10 standard. Any proposed change to the SCAQMD's offset provisions to reflect attainment with the federal PM10 standard requires an amendment to the District's NSR rules and would trigger a Senate Bill 288 (SB 288) evaluation. SB 288, the "Protect California Air Act of 2003," was signed into State law on September 22, 2003, with an effective date of January 1, 2004. That law, developed in response to concerns regarding federal changes to NSR, places restrictions on changes that California air districts can make to their local NSR rules. SB 288 prohibits a district from amending its NSR rule to be less stringent than its rule that existed on December 30, 2002. SB 288 specifically prohibits air districts from making rule changes that would exempt a source or reduce its obligations relative to what they were on December 30, 2002, for any of the following program elements:

- Requirements to obtain permits to construct prior to beginning construction;
- Requirements to apply state-of-the-art air pollution control technology (i.e., California BACT);
- Requirements to conduct an air quality impact analysis;
- Requirements for monitoring, recordkeeping and reporting that make them representative, enforceable, and publicly accessible;
- Requirements for regulating any air pollutant covered by the NSR rules; and
- Requirements for public participation, including requirements for a public comment period, public notification, or a public hearing prior to issuing a permit to construct.

While offsets are not specifically included in the list of prohibitions, ARB legal staff's previous interpretation of the law is that offsets are covered by SB 288 on a programmatic basis. This interpretation allows some changes to the offset provisions in NSR rules as long as there is no relaxation in the stringency of an air district's NSR program as a whole. As a result, certain offset provisions could be relaxed as long as other offset requirements are increased in stringency. In an air district such as SCAQMD where ERCs are already scarce and costly, crafting a workable set of NSR rule amendments pertaining to offsets that would still satisfy SB 288 would be challenging. Unless new legislation is adopted that would clarify or modify elements of SB 288, or unless other innovative approaches to offsets are developed, potential offset strategies involving modifications to the District's NSR rules that may trigger SB 288 are likely to remain an issue in SCAQMD for permitting new and modified facilities.

I. Availability of Offsets in San Diego

The ISO's studies without SONGS show there is an electric reliability linkage between the LA Basin and San Diego areas. In addition to the 2,246-MW SONGS, there is 946 MW of OTC generation affected by the State Water Board's OTC Policy (see Appendix B). The high and low bookend studies done for AB 1318 determined a corresponding capacity need for San Diego ranging from 820 to 1,120 MW to meet local capacity requirements. ARB staff contacted staff at the San Diego County Air Pollution Control District (San Diego APCD) to obtain qualitative feedback on the current availability of ERCs in their jurisdiction. San Diego APCD staff confirmed that, while offset constraints are not yet at the magnitude of SCAQMD, the district is certainly not flush with ERCs. District staff confirmed that ERC holders have historically held on to credits for their own expansion needs and are unlikely to be willing to sell them to other parties. According to the San Diego APCD ERC Banking Registry Summary posted to the district website[79], there are a few power generators with banked ERCs, but even those companies may not hold enough credits on their own to cover the offsets for a large, new conventional greenfield power plant. The AB 1318 report recommends that ARB staff, at the earliest practicable date, conduct a post-project assessment of permitting constraints in the air districts located within the entire South of Path 26 zone, particularly in light of the identified need for incremental capacity for renewable integration above local capacity requirements, that can be sited anywhere within this larger Southern California zone.

[79] http://www.sdapcd.org/permits/ERCs.pdf

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