DOCKETED

Docket Number:	15-IEPR-08
Project Title:	Transmission and Landscape Scale Planning
TN #:	205656
Document Title:	Assesing Local Reliability in Southern California Using A Local Capacity Annual Assesment Tool
Description:	08-17-2015 Back UP Documentation Staff Report
Filer:	Raquel Kravitz
Organization:	California Energy Commission
Submitter Role:	Commission Staff
Submission Date:	8/7/2015 3:20:25 PM
Docketed Date:	8/7/2015

California Energy Commission

STAFF REPORT

ASSESSING LOCAL RELIABILITY IN SOUTHERN CALIFORNIA USING A LOCAL CAPACITY ANNUAL ASSESSMENT TOOL

CALIFORNIA
ENERGY COMMISSION

Edmund G. Brown Jr., Governor

AUGUST 2015

CEC-200-2015-004

CALIFORNIA
ENERGY
COMMISSION

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ACKNOWLEDGEMENTS

This spreadsheet model is derived from the Scenario Tool developed by Patrick Young of the California Public Utilities Commission/Energy Division for the 2014 Long-Term Procurement Planning rulemaking, which in turn is derived from an earlier scenario tool developed by Nathaniel Skinner of the California Public Utilities Commission/Energy Division.

PREFACE

The staffs of the California Energy Commission (Energy Commission), California Public Utilities Commission (CPUC), California Independent System Operator (California ISO) and California Air Resources Board (ARB) are working together to track energy resource development and electricity demand and are identifying contingency mitigation options, should they be required, to assure electric system reliability in Southern California. The Energy Commission has hosted workshops on this topic in both the *2013 IEPR* and the *2014 IEPR Update* and a workshop is scheduled as part of the *2015 IEPR*. The focus of this effort is local capacity requirements, or the amounts of in-area generation for 10 local areas in California needed to meet peak loads reliably. These requirements can be satisfied only by a restricted set of options compared to system reliability concerns. If needed, the mitigation measures developed in the plan will be available to guard against the adverse reliability impacts resulting from preferred energy resources, planned generation additions, or California Independent System Operator-approved transmission system upgrades not developing on schedule. Decisions to implement specific mitigation measures will use appropriate decision-making processes of the implementing agency. Two types of mitigation measures are being developed: (1) short-term once-through-cooling compliance date deferral for selected power plants, and (2) a conventional generator option. It is possible that other methods of mitigating expected shortfalls in local capacity will be considered as well. The California Independent System Operator has also analyzed additional transmission alternatives if other resources fail to materialize.

Agency staffs are closely monitoring resource development and expectations for future development that would be used to project whether local capacity requirements were likely to be satisfied, and if not, to recommend that one or more of the mitigation measures be triggered. Modeling tools that can provide annual forward projections are necessary to provide the starting point for additional studies that could lead to a recommendation to trigger mitigation options in sufficient time to forestall contingencies from affecting reliability. This report describes the development and use of a screening named Local Capacity Area Assessment Tool (LCAAT) focused on the local capacity areas, and selected subareas, of Southern California impacted by the unplanned closure of the San Onofre Nuclear Generating Station (San Onofre).

This report describes one facet of the overall contingency mitigation effort. Other reports and presentations flesh out the balance of the overall project.

ABSTRACT

This report describes a new computer model developed by California Energy Commission staff that projects annual surpluses or deficits for energy resources versus local capacity requirements for several areas of Southern California. This tool uses as the baseline inputs the common body of assumptions developed for the California Public Utility Commission's (CPUC) 2014 Long-Term Procurement Plan rulemaking and the California Independent System Operator's (California ISO) *2014-15 Transmission Plan,* as well as the California ISO's power flow modeling study results estimating 2015, 2019, and 2024 local capacity requirements. This tool provides part of the analytic basis for determining that a future shortfall is likely and the pattern of such a shortfall, which are intended to be used by decision makers in deciding whether mitigation measures ought to be considered to resolve a contingency affecting local electric service reliability. Energy Commission staff reports results for baseline assumptions, a sensitivity study examining the impact of uncertainty for key variables on an individual basis, and a scenario study examining the effects of a collective set of changes to the baseline assumptions. The analytic results provide a basis for several recommendations for future efforts at the CPUC and California ISO.

Keywords: Reliability, local capacity requirements, projections, electricity system requirements

Jaske, Michael R. and Lana Wong, 2015. *Assessing Local Reliability in Southern California Using a Local Capacity Annual Assessment Tool*. California Energy Commission. Publication Number: CEC-200-2015-004.

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CHAPTER 1: Introduction

Southern California Reliability Project

Shortly following the June 2013 announcement by Southern California Edison Company (SCE) that they would retire San Onofre Nuclear Generating Station (San Onofre) rather than repair the damaged steam generators, Governor Brown asked the energy agencies, utilities, and air districts to prepare a plan for the replacement of the power and energy that had been provided by San Onofre. The result of this effort was a document called *Preliminary Reliability Plan for LA Basin and San Diego* that was prepared jointly by the technical staff of the involved agencies and utilities. The document was filed in the *2013 Integrated Energy Policy Report* docket and a presentation made at a workshop hosted by the California Energy Commission in September 2013.[1] Although the technical staff anticipated that the executive management of the energy agencies would finalize the document based on the draft and the comments made at the workshop, this step did not occur. Nonetheless, certain implementation activities were initiated and an interagency team put in place that has met regularly since fall 2013. This team came to refer to its efforts as the Southern California Reliability Project (SCRP). The team members made presentations at an August 2014 workshop hosted by the California Energy Commission as part of the *2014 IEPR Update*.[2] A similar workshop is planned as part of the *2015 IEPR* proceeding.

Local Capacity Area Requirements

One of the key components of ensuring reliability in the Southern California region impacted by San Onofre is ensuring sufficient resources in the *local capacity areas* (LCA). Each local capacity area is established by examining the set of transmission line segments between pairs of substations and calculating the maximum combined import capacity. LCAs exist because the topology of the bulk transmission system does not allow peak load within such an area to be fully supported from resources anywhere in the balancing authority area, because transmission lines would overload or voltage would be unstable. Each local capacity area must have sufficient generation located within the local area to meet peak load less the maximum import capacity of the transmission lines connected that area to the high-voltage transmission system . Local capacity requirements (LCR) describe the amount of generating capacity that must be available within the local area. LCAs and the respective LCRs became a more visible element of electricity reliability planning when such local requirements became part of the resource adequacy program implemented by the California

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1 See http://www.energy.ca.gov/2013_energypolicy/documents/#09092013.

2 See http://www.energy.ca.gov/2014_energypolicy/documents/#08202014.

Public Utilities Commission (CPUC), California Independent System Operator (California ISO) and supported by the Energy Commission.[3]

Beginning in 2006, the California ISO began preparing annual assessments for each of 10 load pockets for 1- and 5-year forward time horizons. One-year ahead studies form the basis of local resource adequacy requirements that each load-serving entity must satisfy by securing net qualifying capacity to meet its peak load ratio share of total LCR requirement in the load pocket. The 5-year ahead study results were informational. The California ISO began conducting 10-year ahead LCR studies as part of its support for the Assembly Bill 1318 project,[4] then for the CPUC in the 2012 LTPP/Track 4 proceeding, and they have become a key element of the California ISO's annual transmission planning process.

LCR studies use power flow modeling techniques to determine LCR results. These are highly labor-intensive and require great effort to set up and run. Accordingly, the number of specific cases with alternative sets of assumptions that the California ISO staff can assess is limited.

3 CPUC, D.06-06-064.

4 Assembly Bill 1318 (Wright, Chapter 206, Statutes of 2009) requires the State Air Resources Board (ARB or Board), in consultation with the Energy Commission, CPUC, California ISO, and the State Water Resources Control Board (SWRCB), to prepare a report for the Governor and Legislature that evaluates the electrical system reliability needs of the South Coast Air Basin.

CHAPTER 2: Method and Inputs

Energy Commission staff developed a spreadsheet tool to support the overall contingency mitigation effort within the larger SCRP. The tool is designed to make projections annually to 2024 for local capacity requirements versus available resources for each of five areas within Southern California. The tool provides an accounting of resources versus requirements, which might identify a year when resources no longer exceed requirements, for example, a shortfall is encountered. Standard planning assumptions developed by the CPUC and California ISO as part of Long-Term Procurement Planning (LTPP) or annual Transmission Planning Process (TPP), respectively, are used as the baseline assumptions in the tool. The effect of alternative assumptions, either as single variable sensitivity studies or multivariable alternative scenarios, can be explored using the tool. This section will describe the method, baseline inputs, and two studies exercising the model – one examining the sensitivity of results to individual variables and other an assessment of alternative scenarios.

Method

Energy Commission staff developed a local capacity annual assessment tool (LCAAT) designed to supplement the in depth power flow studies prepared on an annual basis by the California ISO. A key feature of this tool is embodied in its name—annual projections. LCAAT closely replicates the results of local capacity requirements that emerge from California ISO studies conducted for 1- and 5-year forward time horizons in its Local Capacity Technical Assessment (LCTA) studies, and the 10-year forward results prepared as part of recent cycles of the annual TPP. LCAAT develops complementary results for the intervening years for which in-depth California ISO studies are not available. This year-by-year feature is essential in supporting the purpose of the SCRP. SCRP seeks to assure that electric service reliability is maintained in the areas of Southern California affected by the unplanned retirement of the nuclear units at San Onofre and the planned retirements of many fossil-fueled plants in response to the once-through cooling (OTC) policy adopted by the State Water Resources Control Board.[5] Although the OTC policy makes no explicit reference to retirements, the implementation plans submitted by the owners of the affected generating units have generally decided that making investments to satisfy the OTC policy is infeasible or not cost-effective. Retirement or retirement plus replacement is the general method of complying with the OTC policy.[6] LCAAT can also explore the consequences on projected balance between resources versus requirements for a range of alternative

5 SWRCB, see http://www.waterboards.ca.gov/water_issues/programs/ocean/cwa316/docs/otc_2014.pdf/.

6 http://www.waterboards.ca.gov/water_issues/programs/ocean/cwa316/powerplants/.

assumptions different than those studied in depth using power flow modeling techniques.[7] If expected resources fall short of the local capacity requirements, then policy makers need this information to determine whether and what contingency mitigation measures to trigger. LCAAT is the analytic means to provide the look ahead needed to have adequate time remaining before the shortfall actually occurs to allow mitigation measures to be effectively implemented.

LCAAT develops these annual projections for five areas within Southern California: Los Angeles Basin (L.A. Basin), the West Los Angeles subarea within the L.A. Basin, the San Diego/Imperial Valley, San Diego subarea, and the combined L.A. Basin/San Diego area most directly affected by the loss of SONGS. Two of these areas are so influenced by the loss of capacity from fossil-fueled OTC power plants that the own surpluses/deficits of these areas are critical to understand how various mitigation measures might satisfy local capacity shortfalls from multiple perspectives.

LCAAT is implemented as an Excel© spreadsheet with multiple worksheets. As such, it is easy to operate, and input assumptions can be readily modified. This paper will document a sensitivity study that embodies 10 key variables for which there is substantial uncertainty about future assumptions.

LCAAT is designed to project local capacity requirements in each of the five areas described, compute the total amount of resources expected to be available in such an area using standard capacity values for each resource, and thus determine in each future year whether there is a surplus or deficit of resources compared to requirements.[8]

Appendix A provides a generalized schematic of the information flows and associated sources within LCAAT.

Antecedents

The CPUC, California ISO, and Energy Commission have worked previously to develop tools conceptually similar to LCAAT to provide annual projections of local capacity area surpluses or deficits through time.[9] Such tools have long been considered an important means of evaluating the implications of OTC-based retirements of power plants throughout California. In particular, the fixed schedules established by the SWRCB for OTC facility retirements can raise questions about the timing of replacement resources.

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7 Within some range around the baseline assumptions, the LCAAT results are probably equivalent to those using power flow modeling. Outside this range then LCAAT's results may not be valid.

8 Staff uses net qualifying capacity values for each unit, which is the standard listing of the capacity of a power plant for use in satisfying resource adequacy requirements established by the CPUC and California ISO. See CPUC D.15-06-063, page 15.

9 See *Overview of Load & Resource Scenario Study Tool for Use in Conjunction with Once-Through Cooling Reliability Assessments*, December 2010, for description of a prior tool developed, http://www.caiso.com/Documents/UpdatedLoadandResourceAnalysisScreeningToolDescription.pdf.

The CPUC has developed a "scenario tool" in the several LTPP rulemakings that was a useful starting point for LCAAT since the CPUC staff had assembled an augmented net qualifying capacity list of resources for the entire California ISO balancing authority area and developed Excel logic that computed age-based retirements for each of several classes of resources.[10] This tool operates only on a California ISO balancing area authority level.

The CPUC 2014 LTPP Scenario Tool was modified by adding data attributing each generator to a local area or subarea, and the retirement logic was modified to perform these calculations for each of the areas included within LCAAT. Local capacity area and subarea requirements were added and wholly new display tables were constructed to be able to understand results from the local capacity perspective. Numerous input assumptions, similar to those used in the CPUC's Scenario Tool, had to be added to enable accurate calculation of local capacity area results.

Inputs

LCAAT draws upon the majority of the variables and specific assumptions developed by the CPUC in its biennial LTPP rulemaking.[11] Since these are also the basis for most of the variables important to power flow modeling by the ISO, there is close consistency between LCAAT inputs and those used in these planning processes.

LCAAT obtains local capacity requirements for each local capacity area from California ISO power flow studies released for 1 and 5 years forward as part of the local capacity technical analysis (LCTA) reports submitted by the California ISO to the CPUC in the resource adequacy rulemaking, and for 10 years forward from the annual TPP report and appendices. These LCR values need to be adjusted in some instances to address changes in LCR stemming from new expectations of transmission upgrades affecting LCR, or other factors affecting local capacity requirements. Although, theoretically, almost any change in input assumption within a power flow modeling study could result in a different LCR value, it is impractical for the California ISO to actually set up and run power flow studies for the many combinations of such assumptions. Thus, within a range LCAAT uses rules of thumb to adjust LCR values for the impact of alternative assumptions. For example, reductions from the base load forecast by energy efficiency, BTM DG, BTM storage are assumed to reduce local capacity requirements on a 1:1 basis; for example. each megawatt (MW) of net load reduction equals 1 megawatt of reduction in LCRs. Such adjustments are most prevalent for various demand-side preferred resources—energy efficiency (EE), behind-the-meter (BTM) energy storage, BTM distributed generation (DG)[12], but have also

10 CPUC, http://www.cpuc.ca.gov/PUC/energy/Procurement/LTPP/ltpp_history.htm, see Scenario Tool 2014.

11 ACR, http://docs.cpuc.ca.gov/SearchRes.aspx?DocFormat=ALL&DocID=88489746.

12 *Distributed generation* is power generated on the site of an end-use customer or by a connection to the distribution voltage system.

been assumed when new information about the scheduled in service date for a transmission system upgrade differs from that assumed at the time of an LCR power flow study.

Projecting generating resources forward in time starts with a historical net qualifying capacity (NQC) list developed jointly by the CPUC and California ISO each year as part of the resource adequacy proceeding. Such existing resources are then tested in each future year to determine whether the resource has encountered its technology-specific lifetime, if it has it is retired/removed from the resource list for that year and future years. Should such a resource still be under contract to a load-serving entity, then retirement is delayed until the expiration date of the current contract.[13] Some resources—OTC fossil-fueled facilities most notably—are retired when they meet the official OTC compliance date for that specific facility. New energy resources are added in two ways: (1) power plants large enough to be readily known and tracked through Energy Commission permitting or CPUC approval of a power purchase agreement, and (2) projections of renewable and DG resource portfolios as part of the biennial LTPP rulemaking.

Tracking large energy resources is made more manageable because only those resources located within a local capacity area are relevant for this model. Similarly, the subset of renewable and DG resources that is relevant to local capacity area studies is only a portion of all resources included within a Renewables Portfolio Standard (RPS) portfolio. Some challenges exist in translating the geo-locational information about renewable and DG projects projected by the CPUC Staff's RPS calculator into local capacity areas and subareas.

For the numerous demand-side variables that affect load, efforts undertaken by the Energy Commission staff for additional achievable energy efficiency (AAEE) and by the CPUC staff for demand response (DR) for the California ISO's use in TPP power flow studies have been reused here.[14] SCE has provided local capacity area or specific substation for the demand-side preferred resources that it has proposed to the CPUC in A.14-11-007. All of the resources that San Diego Gas & Electric Company (SDG&E) will procure pursuant to CPUC D.14-03-040 are located within the San Diego subarea, so no further geographic disaggregation is needed.

Table 1 provides an overview of the source of key inputs that LCAAT uses to generate annual projections of surpluses or deficits of resources versus capacity requirements for each of the LCAs or subareas within LCAAT.

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13 Such contract data are confidential, thus limiting public release of LCAAT and the detailed inputs.

14 *Demand response* is providing wholesale and retail electricity customers with the ability to choose to respond to time-based prices and other incentives by reducing or shifting electricity use, particularly during peak demand periods, so that changes in customer demand become a viable option for addressing pricing, system operations and reliability, infrastructure planning, operation and deferral, and other issues. (See http://www.energy.ca.gov/glossary/glossary-d.html.)

Table 1: Input Sources for LCAAT by Type

Type of Variable	Underlying Source	Projection Method
Demand		
Base Demand	CEC 2013 IEPR	CEC forecast by local area/region
Planning Adjustments (AAEE, DR, etc.)	CPUC or CEC	Reprocessing projections by substation to obtain local area values
IOU Procurement Adjustments	IOU RFO results	IOU PPA details
Capacity Requirements		
Base LCR	ISO studies	Explicit for study years, interpolated for intervening years
Demand Adjustments	various	Assumed to reduce LCR by user-defined parameter[15]
Transmission Adjustments	ISO project tracking, TPP studies, and private communication from ISO	Citations in various ISO studies and special requests by CEC staff to ISO transmission planning staff
Resources		
Base Year Projects	2014 NQC List	NA
Retirements		
General	2014 LTPP ACR	Age-based retirement
OTC Adjustments	SWRCB	Compliance dates
Contract Term Adjustments	JRP contract database	Contract terms override age-based retirement
Additions		
Identifiable Projects	IOU PPAs	PPA details
Renewables/DG	2013/14 TPP RPS portfolios	RPS calculator project output reprocessed to provide results by local capacity areas
Surplus/(Deficit)	Calculated within LCAAT	Surplus/Deficit equal to resource total less adjusted LCR in each local area or subarea

Source: Energy Commission.

15 This parameter is set to a value of 1.0, but additional assessments are underway that may lead to a change.

Outputs

LCAAT provides a requirements/resources summary table for each of the five areas. **Table 2** illustrates such results for the L.A. Basin area for the baseline set of assumptions. Four "blocks" of related types of data exist within the summary table:

- The top set of rows provides the baseline 1:10 peak demand forecast and related adjustments by various demand-side measures. A base load forecast adjustment reflects nonspecific changes to the adopted Energy Commission demand forecast. AAEE is the principal energy efficiency assumption complementing the base Energy Commission peak load forecast. Demand-side power purchase agreement (PPA) results from SCE and SDG&E request for offer (RFO) pursuant to CPUC D.14-03-004 further reduce demand.
- Gross LCRs show the gross amounts of capacity required in the area prior to the impacts of demand-side or transmission system upgrades, followed by the net local capacity requirements.
- A large block of data provides a resource summary by type of supply-side resource. Most demand response is included as a resource type rather than as a load modifier consistent with CPUC and California ISO practice. Storage additions in front of the meter can be taken from investor-owned utility (IOU) RFO results or for sensitivity/scenario purposes from the CPUC storage decision.
- The final block is the resource versus requirement projection of surpluses or deficits. The surplus/deficit is calculated as total resource base less adjusted LCR base. In the results provided in Table 2, there is a surplus in years up to and including 2020 and then deficits for 2021 and beyond.

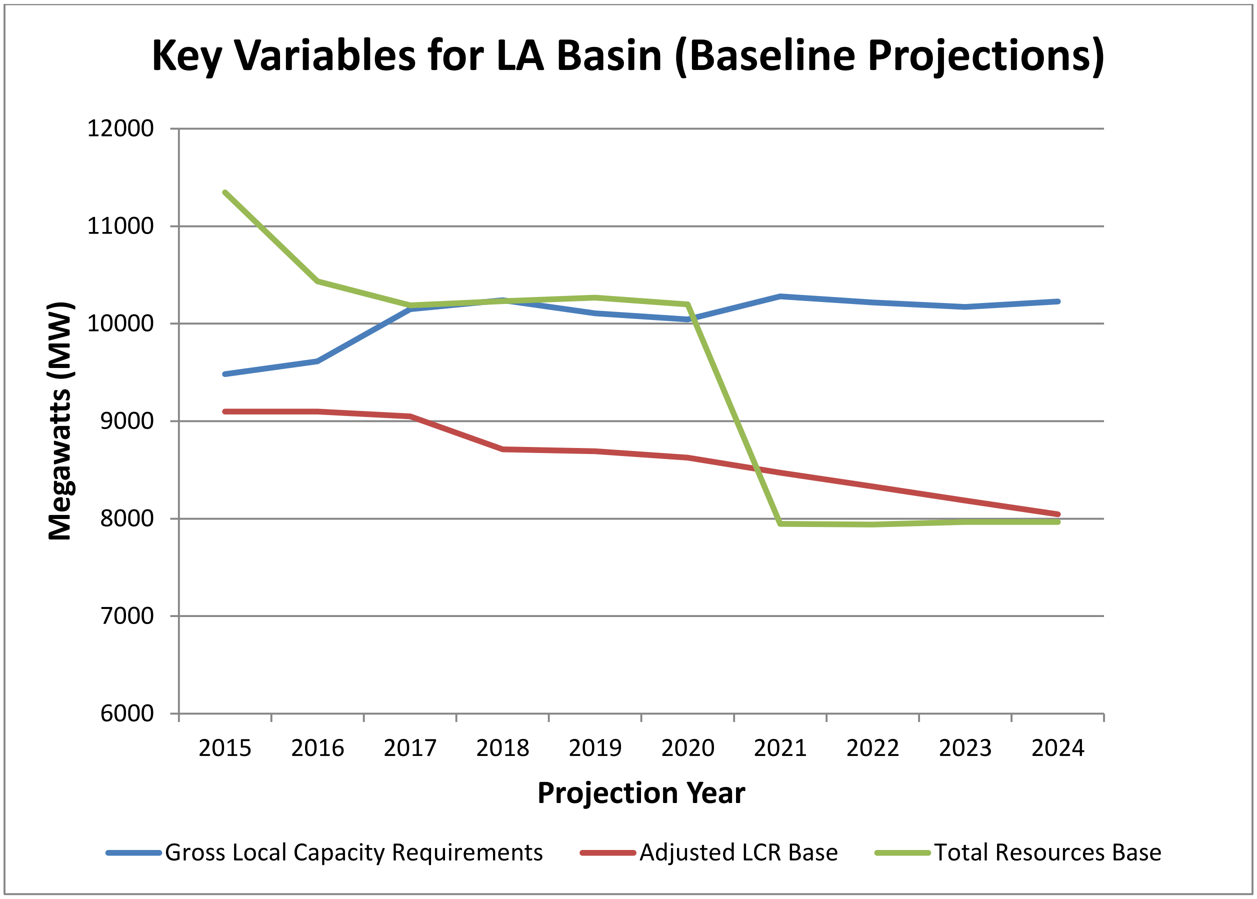
Various graphical presentations can be developed to show how principal variables change through time. **Figure 1** highlights a few key variables showing total resource base, gross LCR requirements and adjusted LCR requirements. The figure should be read such that whenever total resource base is below adjusted LCR requirements, then a shortfall (deficit) would exist. As shown in **Table 2**, it is the loss of substantial OTC resources between the summers of 2020 and 2021 that creates the L.A. Basin deficit beginning in 2021.

Table 2: Illustrative Output for Each Area—Example for L.A. Basin Baseline Case

	Variables (Summer Peak MW)	Source	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
LA Basin														
	Base Load Forecast	2013 IEPR	20378	20812	21210	21490	21762	22039	22344	22662	22964	23237	23488	23716
less	Load Forecast Adjustment		0	0	0	0	0	0	0	0	0	0	0	0
less	AAEE	2013 IEPR	0	22	147	273	399	488	588	680	769	861	969	1078
less	Preferred EE	SCE RFO	0	0	0	5	24	99	120	128	130	117	106	95
less	Preferred BTM Energy Storage	SCE RFO	0	0	0	0	25	163	169	172	170	172	172	172
less	Preferred BTM DG	SCE RFO	0	0	0	0	11	40	40	40	40	40	40	40
=	Managed Load Forecast		20378	20789	21064	21213	21304	21250	21426	21642	21854	22047	22202	22332
	Gross Local Capacity Requirements			10692	9484	9615	10147	10242	10107	10045	10280	10218	10173	10228
less	T-system Upgrade Impacts			(240)	(240)	(240)	(640)	(740)	(500)	(400)	(700)	(700)	(700)	(800)
less	LCR Change from Demand Adjustments			(22)	(147)	(277)	(458)	(790)	(917)	(1020)	(1110)	(1190)	(1286)	(1384)
=	Adjusted LCR Base			10430	9097	9098	9049	8712	8690	8625	8471	8328	8186	8043
	OTC Non Nuclear	ScenTool		4153	4153	3818	3818	3818	3818	2462	0	0	0	0
plus	OTC Nuclear	ScenTool		0	0	0	0	0	0	0	0	0	0	0
plus	Hydro	ScenTool		309	309	309	309	309	309	309	309	309	309	309
plus	Solar	ScenTool		2	2	2	2	2	2	2	2	2	2	2
plus	Wind	ScenTool		62	252	252	252	252	252	252	252	252	252	252
plus	Geothermal	ScenTool		0	0	0	0	0	0	0	0	0	0	0
plus	Biomass	ScenTool		97	97	97	97	97	97	97	97	97	97	97
plus	Cogeneration	ScenTool		554	710	710	710	710	710	710	710	681	681	681
plus	Pump	ScenTool		0	0	0	0	0	0	0	0	0	0	0
plus	Non OTC Peaker	ScenTool		1927	1927	1882	1622	1622	1622	1622	1622	1622	1622	1622
plus	Non OTC Thermal	ScenTool		3576	3591	2951	2951	2951	2951	2951	2951	2951	2951	2951
plus	Various and Unknown	ScenTool		77	77	77	77	77	77	77	77	77	77	77
plus	Incr. Peaker Additions	SCE RFO		0	0	0	0	0	0	0	98	98	98	98
plus	Incr. Thermal Additions	SCE RFO		0	0	0	0	0	0	1280	1280	1280	1280	1280
plus	Incr. RPS Calc - Renew	14/15 Port		7	14	14	14	14	14	14	14	14	14	14
plus	Incr. RPS Calc - DG	14/15 Port		29	52	154	155	159	162	166	174	195	222	222
plus	Storage Additions	SCE RFO		0	0	0	0	0	0	0	100	100	100	100
plus	DR Program/Preferred DRCapability			162	164	167	180	219	253	256	258	261	261	261
=	Total Resources Base			10953	11347	10433	10186	10230	10267	10198	7945	7939	7966	7966
=	Resource Need (Surplus/Deficit) Base			523	2250	1336	1137	1518	1577	1573	(526)	(389)	(220)	(77)

Source: Energy Commission.

Figure 1: Key Variables—Example for L.A. Basin Baseline



Source: Energy Commission.

CHAPTER 3: Baseline Results

The baseline results for the LCAAT stem from a package of input assumptions described generically in **Table 1**. Detailed results using the format of **Table 2** are provided in Appendix B for each of the six areas.

Table 3 provides one way of summarizing the baseline results, for example, the numeric resource surplus/deficit compared to requirements through time for each of the six areas.

Table 3: Baseline Resource Surplus/Deficit by Area (MW)

AREA	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
LA Basin/San Diego Subarea	(159)	2136	1396	1702	1806	1955	2156	(108)	(144)	(173)	(237)
LA Basin	523	2250	1336	1137	1518	1577	1573	(526)	(389)	(220)	(77)
West LA Basin Only (subset of LA Basin)	2711	2461	2058	1737	1894	1830	1813	(399)	(376)	(321)	(291)
San Diego/Imperial Valley Area	964	664	923	1466	1328	1456	1220	1067	907	720	522
San Diego Sub-Area	(682)	(114)	60	565	387	477	324	254	178	74	(40)
Eastern-Metro Sub-Area (a subarea within LA Basin)	2506	2537	1897	1897	1897	1897	7	7	7	7	7

Source: Energy Commission.

As noted earlier, the negative values in 2024 closely match those provided by the California ISO in its 2014-15 TPP study results.[16] What is new is the LCAAT identification of the year in which the ISO findings might actually occur.

The appearance of local capacity resource shortfalls in 2021 should be no surprise—December 31, 2020, is the date that major capacity reduction occurs when all of the remaining L.A. Basin OTC capacity must comply with State Water Resources Control Board OTC policy. Of the original list of affected facilities, a considerable proportion have already complied by retiring.[17] The owner/operators of OTC power plants almost universally state that they intend to shut down existing facilities rather than to attempt to retrofit the water intake structures for these power plants.[18] This date has been known since May 2010 when SWRCB adopted its OTC policy. The resources that have been authorized by the CPUC just barely cover the minimum required, and when these are placed on the same accounting basis as used for resource adequacy, a small shortfall occurs in the combined L.A. Basin/San Diego subarea affected by the SONGS outage. This small deficit grows slowly each year and reaches 238 MW by summer 2024. Conversely, the deficit is largest in 2021 in the L.A. Basin

16 California ISO, *2014-15 Board Approved Transmission Plan*, page 147.

17 See http://www.energy.ca.gov/renewables/tracking_progress/documents/once_through_cooling.pdf.

18 See SWRCB, OTC Web page, "Power Plants That Are Affected for Facility-Specific Letters," http://www.waterboards.ca.gov/water_issues/programs/ocean/cwa316/powerplants/.

load pocket and diminishes as each year goes by and is approaching zero somewhere between 2024 and 2025. One of the key drivers contributing to the diminishing deficit is the ramp-up in AAEE. The low-mid AAEE, assumed in the baseline assumptions, ramps up an additional 300 MW between 2021 and 2024. For the West Los Angeles subarea of the L.A. Basin (the area with the greatest concentration of old OTC facilities), the deficit shrinks slowly but is still sizeable by 2024.

Farther south, the San Diego subarea has a small deficit in 2024. The larger San Diego/Imperial Valley load pocket has a substantial surplus, since the loads are nearly identical to the San Diego subarea and the associated resources are larger due to renewables in Imperial Valley and thermal generators in Mexico that are dynamically scheduled into the California ISO balancing authority area in San Diego/Imperial Valley. Although relatively little attention is played to the eastern metro subarea within the L.A. Basin, California ISO TPP studies show that only this portion of the eastern L.A. Basin subarea is relevant to the combined L.A. Basin/San Diego area beginning in 2021. It has a substantial surplus in early years but suffers age-based retirements from old steam boiler facilities like Etiwanda.[19]

The relatively small deficits in some local areas could easily be covered by additional DR, as the California ISO assumed in its 2014-15 TPP studies, or by other resource additions that have been authorized by the CPUC but not yet acted upon by SCE —for example, additional storage amounts that the CPUC directed in D.13-10-040. Just as some alternative assumptions could reduce or eliminate these small deficits, however, there are additional assumptions that are uncertain. Some of these could drive the results in the opposite direction— for example, to worsen the baseline surplus/deficit projections in one or more areas. The following section describes a sensitivity study that evaluated the range that might occur for key input variables, an alternative set of projections for each variable, and the results of using these alternative inputs in LCAAT to determine impacts of surpluses/deficits. Some of these variables (such as base load forecast growth) reflect inherent uncertainties that cannot be controlled through policy, while others (such as AAEE) are generally thought to be highly influenced by policy maker decisions that shape program design and thus the degree of end-user participation through time.

The baseline results for the combined L.A. Basin-San Diego subarea closely match the California ISO's own studies for 2024. The California ISO reported a small deficit in 2024 that could be accommodated by a "repurposing" of DR capability that it did not count in its baseline assumptions.[20] The LCAAT results for this year are extremely close to the

19 Most steam boiler generating plants are located along the coastline or within estuaries to use sea water for cooling. There are a few similar plants at inland locations that use other water sources than the ocean. These are not subject to the SWRCB's OTC policy, which is limited to power plants using ocean and estuarine water sources.

20 California ISO, *Board Approved 2014-15 Transmission Plan*, pp. 147-149. http://www.caiso.com/Documents/Board-Approved2014-2015TransmissionPlan.pdf.

California ISO's results.[21] Of interest are the LCAAT projections for 2021 through 2023 showing that the deficit begins as soon as summer 2021. Depending upon the area, the deficit can be larger in 2021 and then shrink as years go by, as is the case for the L.A. Basin and West Los Angeles subarea, or start smaller in 2021 and then gradually grow larger, as is the case for the combined L.A. Basin-San Diego subarea. The need to solve West Los Angeles deficits with resources located in West Los Angeles subarea—only a portion of the overall combined area—may suggest that there is no ideal resource addition that minimizes the surplus for all areas.

21 Comparison of LCAAT results with those provided by the ISO in the *2014-2015 Transmission Plan,* Appendix E, shows a difference in accounting treatment for local capacity deficits. In ISO practice, a deficit in a subarea cascades up to the local capacity area, and in the context of Southern California studies, to the combined L.A. Basin/San Diego area. As an example, the ISO reports the same deficit of 268 MW for the West L.A. subarea, L.A. Basin, and overall L.A. Basin/San Diego area. In contrast, for LCAAT, a deficit in West Los Angeles does not necessarily mean a deficit of the same magnitude for L.A. Basin. The LCAAT method allows surplus resources in Eastern LA Basin to dilute deficits in West LA Basin when discussing the overall LA Basin. Reviewing results for both load pocket and subareas is necessary to understand where resources should be located to eliminate projected deficits.

CHAPTER 4: Assessing the Range Around Baseline Results Using Sensitivity and Scenario Studies

As noted above, alternative input assumptions to those selected for the baseline could increase or decrease the projected amounts or pattern of surpluses/deficits in one or more local areas. To gain a more complete understanding of the range of possible results, the Energy Commission staff decided to perform sensitivity and alternative scenario assessments.

This section provides a description of the specific values used to test sensitivity for each of the key variables, the increase or decrease of the alternative assumption relative to the baseline assumption, and some background for these variables.

Variable-Specific Sensitivity Cases

As with any planning tool, there are a large number of variables with future assumptions that are uncertain. As noted above, baseline assumptions are generally consistent with the CPUC 2014 LTPP assumptions or those used by the California ISO in its 2014 – 2015 TPP. A set of sensitivity cases was developed to test the impacts of alternative assumptions for a limited set of variables.

Key variables tested are the following:

- Demand-side variables
- Load forecast
- EE (AAEE)
    - SCE/RFO RFO preferred resources
    - SCE/SDG&E preferred resource project success
- Supply-side variables
- DR effectiveness
- Storage (IFM only)
    - Transition of QFs to wholesale generators
- RPS portfolio

Each of these was assessed using LCAAT with all other assumptions and parameters set at baseline values; for example, these were single-variable sensitivities. The discussion below provides a brief overview about each variable intended to summarize issues giving rise to uncertainty about future projections.

Load Forecast

The baseline demand forecast is the mid-case peak demand forecast without AAEE adopted in the *2013 IEP*.[22] This demand forecast incorporates the impacts of committed energy efficiency programs, expected growth of rooftop PV, load-modifying demand response programs, and numerous other policies. Like any demand forecast, it is subject to uncertainties. Energy Commission staff now prepares, and the Energy Commission adopts, demand forecasts each year in support of CPUC LTPP rulemaking and for various California ISO transmission planning proceedings.

Two sensitivities have been assessed for this project: (1) the *IEPR* cycle from which the demand forecast is derived, and (2) hypothetical growth higher than the mid-case normally used for planning purposes. The increment of load for the first of these sensitivities is derived from the difference between the *2013 IEPR* baseline assumption and the adopted *2014 IEPR Update* mid-case (both using the mid-case base forecast without AAEE demand reductions). This latter demand forecast is being assessed by the California ISO as part of the 2015 – 2016 TPP cycle, so this sensitivity essentially presages the results of what will become the "baseline" for LCAAT when the next cycle of input assumption updates is made.[23]

A higher level of load growth provides an understanding of the extent to which higher load forecasts than those adopted by the Energy Commission affect the assessment of local capacity results of the LCAAT. **Table 4** provides a comparison of the *2013 IEPR* and *2014 IEPR Update* 1:10 weather peak demand projections for each of the areas in LCAAT. All areas have lower peak demand forecasts in the newer Energy Commission forecasts. All else being equal, these lower demand forecasts would likely result in smaller deficits or larger surpluses in the areas evaluated using LCAAT, because previous California ISO studies have demonstrated that power flow modeling generally increased LCR requirements by about the same amount as load is increased— for example, a 1:1 relationship.[24] In the current LCAAT model, staff assumes that this relationship is symmetric; for example, load reductions **reduce** LCR requirements by a comparable amount.

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22 AAEE is subtracted from the baseline loads at the power flow modeling step so that the geographic distribution of its effects on local capacity area requirements can be modeled more accurately than if it were subtracted at the climate zone/regional level.

23 The California ISO has already released its Local Capacity Technical Analysis reports for 2016 and 2020 that use the adopted *2014 IEPR* peak demand forecast as an input into power flow modeling. Additional changes made by the California ISO mean that those results are not directly comparable to LCAAT results using the 2014 – 2015 TPP cycle of analyses. The California ISO's 2025 assessment of local capacity requirements is forthcoming in November 2015 (preliminary) and February 2016 (final) as part of the 2015 – 2016 TPP effort. Once these results are available, LCAAT's entire package of assumptions will be updated.

24 California ISO, *Board Approved 2014 – 2015 Transmission Plan*, Appendix E, pp. 76-77. See, http://www.caiso.com/Documents/AppendixEBoardApproved2014-2015TransmissionPlan.pdf.

Table 4: Comparing *2013 IEPR* and *2014 IEPR Update* Peak Demand Forecasts (MW)

			2016	2020	2024
2014 IEPR	SCE TAC Area		26384	27699	28872
	L.A. Basin		21418	22517	23493
	West L.A. Subarea		12658	13307	13884
	Eastern-Metro Subarea		7047	7408	7729
	Eastern-Other		1713	1801	1879
	SDG&E		5372	5654	5814
2013 IEPR	SCE TAC Area		26737	28141	29419
	L.A. Basin		21490	22662	23716
	West L.A. Subarea		12701	13393	14016
	Eastern-Metro Subarea		7070	7456	7803
	Eastern-Other		1719	1813	1897
	SDG&E		5471	5785	5973
Increment	SCE TAC Area		-353	-442	-547
(2014 – 2013)	L.A. Basin		-72	-145	-224
	West L.A. Subarea		-42	-86	-132
	Eastern-Metro Subarea		-24	-48	-74
	Eastern-Other		-6	-12	-18
	SDG&E		-99	-131	-159

Source: Energy Commission.

The higher growth sensitivity reflects slightly higher growth that could occur in one or more specific regions of Southern California. **Table 5** provides base and incremental values assuming peak load forecasts are 2 percent higher in 2024 than the base forecast. This is roughly one-half of the difference between the mid and high cases prepared by Energy Commission demand forecasting staff in the past two *IEPR* cycles. The difference is assumed to be zero in 2014 and to grow linearly, each year reaching a cumulative effect of 2 percent in 2024. There are many possible explanations that could create this outcome—for example, committed energy efficiency savings not persisting as long as assumed, higher usage per customer reflecting more intensive electricity-using habits than assumed in the Energy Commission's demand forecasts, higher penetration of electric cars and the impact on loads at peak times, and so forth. Dozens or hundreds of such phenomena are included within Energy Commission staff demand forecasts, and the incremental impacts shown in **Table 5** are only a portion of the possible range that could encompass the base and low-/high-case alternatives prepared by Energy Commission staff. However, since the Energy Commission now prepares these forecasts each year, there is a limited amount of error than can compound through time.

Table 5: Incremental Peak Load for High Growth Sensitivity (MW)

	Area		2016	2020	2024
2013 IEPR	SCE TAC Area		26,737	28,141	29,419
	L.A. Basin		21,490	22,662	23,716
	West L.A. Subarea		12,701	13,393	14,016
	Eastern-Metro Subarea		7,070	7,456	7,803
	Eastern-Other		1,719	1,813	1,897
	SDG&E		5,471	5,785	5,973
Increment for	SCE TAC Area		107	338	588
Higher Growth	L.A. Basin		86	272	474
Assuming	West L.A. Subarea		51	161	280
1.02 Ratio	Eastern-Metro Subarea		28	89	156
By Year 2024	Eastern-Other		7	22	38
	SDG&E		22	69	119

Source: Energy Commission.

AAEE Planning Assumptions

The Energy Commission, CPUC, and California ISO have adopted as a planning practice the use of a "Mid-Low" set of AAEE projections for local capacity studies. In contrast, the California ISO uses a "Mid" set of AAEE projections for other transmission planning studies. The rationale for this difference is the sensitivity of local capacity study results to the precise location of load reductions and the inability of the energy efficiency program planning process to assure that general purpose EE programs will achieve any specific geographic pattern of customer participation and/or results. A targeted effort like SCE's Preferred Resource Pilot is the kind of effort required to assure participation in specific targeted locations.

However, to assess the sensitivity of LCAAT to the higher level of savings in the mid AAEE case compared to the low-mid AAEE case,

Table 6 identifies an increment of savings by location from use of the mid AAEE case. Generally the L.A. Basin areas all increase the same percentage, the San Diego area increases at a larger percentage than do the L.A. Basin areas, and thus the combined area increases a slightly larger percentage than does the L.A. Basin alone.

Table 6: AAEE Planning Assumption Sensitivity by Area and Subarea (MW, With Distribution Losses)

		2016	2020	2024
Baseline AAEE Projections (Low-Mid)				
Combined L.A. Basin/San Diego		354	896	1,439
L.A. Basin		273	680	1,078
West LA Subarea		161	402	637
Eastern-Metro Subarea		90	224	355
San Diego		81	216	361
Mid AAEE Projections				
Combined L.A. Basin/San Diego		499	1,342	2,252
L.A. Basin		381	1,018	1,698
West LA Subarea		225	602	1,004
Eastern-Metro Subarea		125	335	559
San Diego		118	324	554
Sensitivity Increment				
Combined L.A. Basin/San Diego		145	446	813
L.A. Basin		109	338	620
West L.A. Subarea		64	200	367
Eastern-Metro Subarea		36	111	204
San Diego		36	107	193

Source: Energy Commission.

Realizing Energy Efficiency Savings Projections

As noted above, AAEE is an important factor affecting LCR results because it reduces load, but also because the distribution across substations may be different than that of baseline loads. For example, the programmatic emphasis of AAEE is utility retrofit programs and impacts of building and appliance standards. The industrial and agricultural sectors have much less emphasis in AAEE projections than do baseline load forecasts. Agricultural load is relatively unimportant for local capacity area studies since it takes place mostly outside the L.A. Basin and almost entirely outside of the West Los Angeles subarea, but there are high concentrations of industrial load at some substations and little or no industrial load at other substations. In its local capacity studies the California ISO incorporates AAEE savings distributed to substations according to a pattern developed by the Energy Commission staff; thus, AAEE projections shift power flows compared to cases without AAEE. [25]

LCAAT cannot test the impacts of alternative AAEE distributional patterns unless a full power flow study is completed. However, LCAAT can assess the impact of different amounts of AAEE distributed in the same proportions as in full power flow studies—reflecting the basic uncertainty of whether end-use customers will engage in energy efficiency programs at the level now being assumed in agency planning studies.

Table 7 provides the *2013 IEPR* vintage of AAEE projections. AAEE ramps up over time, and more than 1,000 MW are assumed in the L.A. Basin and nearly 400 MW in San Diego by 2024. These AAEE projections assume continuation of IOU retrofit programs, Energy Commission Title 20 Appliance Standards upgrades, and Energy Commission Title 24 Building Standard upgrades through time. A recently published CPUC report more thoroughly documents actual savings found from IOU programs for programs implemented in 2010 through 2012. [26] Among the results found from intensive evaluation, measurement, and verification (evaluation, measurement, and verification) studies is that peak savings per unit of energy savings are below the level assumed in developing the AAEE projections. Table 1 of that report shows that peak load impacts versus energy savings are substantially below the values assumed in the CPUC's adopted goals. Net evaluated savings achieved 844 MW whereas gross goals assumed 1,537 MW, which is a 45.1 percent shortfall.

To assess the impact of this facet of AAEE uncertainty, a sensitivity case was designed that assumes a reduction in all future years of 40 percent of future expected AAEE peak load savings for the mid-low AAEE case.[27] This sensitivity assumes the same level of effort is undertaken, but fewer peak load savings occur as a result. This could occur because program participants "take back" more of the energy savings through increased comfort levels, through differences in the mix of measures resulting in less on peak load reductions than assumed in AAEE projections, or other similar reasons. Table 6 provides the assumed peak load reductions of this 40 percent shortfall.

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25 Power flow modeling techniques are used by the California ISO and by transmission system developers to simulate how power might actually flow on the transmission system. Various contingencies are defined that would stress individual elements of the system by overloading specific transmissions lines, or affect the ability of the system to maintain voltage stability. Loads and adjustments to loads, such as AAEE projections, must be defined at the level of high-voltage substations, if not with greater granularity, to be accurate about these estimates of power flow.

26 CPUC, *2010-2012 Energy Efficiency Annual Progress Evaluation Report*, March 2015.

27 *Peak load savings* are all that is relevant in local capacity studies. By design, August peak LCR values are the basis for year-round requirements in load-serving entities as part of the resource adequacy program.

Table 7: AAEE Realization Sensitivity (MW)

		2016	2020	2024
Baseline AAEE	L.A. Basin	273	680	1078
(Low-Mid)	West L.A. Subarea	161	402	637
	Eastern-Metro Subarea	90	224	355
	San Diego	81	216	361
Sensitivity	L.A. Basin	164	408	647
(40% Reduction)	West LA Subarea	97	241	382
	Eastern-Metro Subarea	54		213
	San Diego	49	130	217
Increment	L.A. Basin	-109	-272	-431
	West L.A. Subarea	-64	-161	-255
	Eastern-Metro Subarea	-36	-89	-142
	San Diego	-32	-87	-145

Source: Energy Commission.

SCE RFO Preferred Resources

Under the direction provided in D14-03-004, SCE conducted an all-source RFO and submitted a package of preferred resource power purchase agreements (PPAs) to the CPUC for approval.[28] SCE acquired five types of preferred resources in this RFO: (1) energy efficiency, (2) energy storage behind the meter (BTM) (3) renewable distributed generation BTM, (4) demand response, and (5) energy storage projects connected on the utility side of the meter. Demand response and energy storage in front of the meter are treated in LCAAT as a supply resource, but the first three items are treated as load modifiers.

There are two issues with the numerous small contracts SCE submitted to the CPUC for approval. First, will all of these projects be approved, and if approved, will all projects be developed on the schedule assumed? Second, for the projects that are developed, how will they perform in terms of summer peak condition load reductions? The structure of the contracts that SCE has with the project developers reveals some uncertainty about results—the contracts call for a minimum delivery of 50 percent of the nominal capacity reductions. Within the portfolio of proposed PPAs, only energy efficiency projects have some very short contract terms. For energy efficiency PPAs with short contract terms (4 – 6 years), Energy Commission staff assumed that measure savings would decay at a rate of 10 percent per year following the end of the contract guarantee period. No other category of program had such short-term contracts, so there is no comparable reduction for energy storage or distributed generation following completion of the contract term.

28 SCE submitted its proposed PPAs to the CPUC in November 2014 as Application A.14-11-012.

Table 8 provides two sets of projections: (1) baseline projections—a summary of the capacity development patterns assuming all contracts are approved and that all contracts are successfully developed on the schedule submitted to the CPUC, and (2) a sensitivity projection, in which not all of the contracted resources will be approved or, if approved, develop to the full contracted capacity. The value of 0.72 is obtained as the product of two assumptions—only 90 percent of projects will be approved, and of projects approved, only 80 percent of the contracted capacity will be achieved. Clearly, many other assumptions could be made.

Table 8: SCE RFO Preferred Resource Performance Patterns (MW, With Losses, by Type)

	Contract Amount	2016	2020	2024
Baseline				
EE	124	5	128	95
ES BTM	164	0	172	172
Renewable DG BTM	38	0	40	40
Total	326	5	340	307
Sensitivity (0.72 of Baseline)				
EE	124	4	92	68
ES BTM	164	0	124	124
Renewable DG BTM	38	0	29	29
Total	326	4	245	221
Increment				
EE		1	36	27
ES BTM		0	48	48
Renewable DG BTM		0	11	11
Total		1	95	86

Source: Energy Commission.

Demand Response Effectiveness

An important input assumption is the level of demand response in each of the load pockets, subareas, and the overall L.A. Basin/San Diego combined area. Although the CPUC has prepared projections of DR that approximate existing program capabilities and requested that the California ISO use these in its transmission planning process, the California ISO has asserted that only demand response in the southern Orange County area and only those programs capable of providing a response within 20 minutes are effective in addressing the contingency consequences they find drive local capacity values in the combined area.[29] By filtering existing DR capabilities for the subset that are "fast" and "effective," the resulting amounts are much smaller than the full capability of existing programs operated by SCE and SDG&E. LCAAT uses California ISO assumptions as the baseline input but can compute the consequences of three alternative sets of DR assumptions.

Table 9 shows the CPUC's projected DR capabilities, the subset that the California ISO believes are both "fast" and "effective" for various regions, and a moderate amount that is halfway in between. **Table 9** values exclude the 75 MW of DR that SCE procured through its 2014 RFO, but those values are included in the LCAAT resource summary tables when computing surplus/deficit calculations.

Storage

Like demand response, storage is one of the variables in which there is a difference between CPUC 2014 LTPP assumptions and California ISO 2014 – 2015 TPP study assumptions. Since California ISO LCR values are based on the ISO's own assumption about the penetration of storage resources, they were adopted as the baseline input assumptions for LCAAT.

To develop sensitivity assumptions to explore the implications of larger storage amounts, the storage procurement decision made by the CPUC in fall 2013 was the starting point.[30] D.13-10-040 does not allow customer storage values to affect compliance with transmission or distribution values, so the amounts of BTM storage acquired by SCE in its 2014 all source RFO that exceed the customer storage target in D.13-10-040 do not offset required transmission or distribution storage targets. Further, 2-hour storage does not count for resource adequacy purposes, so the proportions of 2-hour storage established in the refreshed scenarios and assumptions included within the Assigned Commissioner Ruling of the 2014 LTPP rulemaking issued on March 4, 2015, were used to discount the remaining storage target values for use in the LCAAT sensitivity assessment.[31] SDG&E was also provided a "credit" for the two Lake Hodges units totaling 40 MW of its 80 MW transmission-level target.

29 CPUC, Comments of the Staff of the California Public Utilities Commission on the 2014 - 2015 Transmission Planning Process Draft Unified Assumptions and Study Plan Posted February 20, 2014. http://www.caiso.com/Documents/CPUCCommentsDraft2014-2015StudyPlan.pdf.

30 CPUC D.13-10-040, Table 2, page 15.

31 CPUC, 2014 LTPP, http://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M147/K780/147780118.PDF.

Table 9: Alternative DR Program Capability Projections by Area (MW, With Loss Credit)

	2014	2020	2024
Effective Projections			
Combined L.A. Basin/S.D. Area	180	197	203
L.A. Basin	162	177	182
West L.A. (Effective)	162	177	182
West L.A. (Less Effective)	0	0	0
Eastern-Metro Subarea	0	0	0
Eastern Subarea Balance	0	0	0
San Diego Subarea	18	21	21
Moderate DR Capability Projections			
Combined L.A. Basin/S.D. Area	482	527	542
L.A. Basin	464	507	521
West L.A. (Effective)	162	177	182
West L.A. (Less Effective)	165	180	185
Eastern-Metro Subarea	126	137	141
Eastern Subarea Balance	12	13	13
San Diego Subarea	18	21	21
Full Capability Projections			
Combined L.A. Basin/S.D. Area	784	857	882
L.A. Basin	767	837	861
West L.A. (Effective)	162	177	182
West L.A. (Less Effective)	329	360	370
Eastern-Metro Subarea	251	275	282
Eastern Subarea Balance	24	26	27
San Diego Subarea	18	21	21

Source: Energy Commission.

Table 10 summarizes the original cumulative targets that must be operational by 2024, adjustments and LCAAT baseline assumptions, a revised cumulative target after such adjustments, and the remaining increment of D.13-10-040 that was tested as a sensitivity case. (See **Table 10**, rightmost column.)

Table 10: Comparison of Baseline and Sensitivity Projections for Storage in 2024 (MW)

IOU Area	Storage — Point of Interconnection	Original Cumulative Target	Existing Resource Adjustments	LCAAT Baseline Assumptions	Revised Cumulative Target	Increment for LCAAT Sensitivity[32]
SCE						
	Transmission	310	0	100	210	165
	Distribution	185			185	148
	Customer	85	0	162	0	0
	Subtotal SCE	580	0	262	395	313
PG&E						
	Transmission	310			310	244
	Distribution	185			185	148
	Customer	85			85	64
	Subtotal PG&E	580	0		580	456
SDG&E						
	Transmission	80	40	25	15	12
	Distribution	55			55	44
	Customer	30	0	100	0	0
	Subtotal SDG&E	165	40	125	70	56
IOU Total						
	Transmission	700	40	125	535	422
	Distribution	425	0	0	425	340
	Customer	200	0	262	85	64
	Total – All IOUs	**1,325**	**40**	**387**	**1,045**	**825**

Source: Energy Commission.

32 The increment for LCAAT sensitivity incorporates an adjustment for the 2-hour discount for resource adequacy purposes.

RPS Portfolio

Although utility plans for compliance with statutory mandates to achieve 33 percent of applicable energy using renewable generation by 2020 are well along, there is still some uncertainty about the portfolios that will ultimately develop. A sensitivity that tests the local capacity area implications can be conducted using the two portfolios prepared by the California Public Utilities Commission's Energy Division (CPUC/ED) and forwarded jointly by the CPUC and Energy Commission to the California ISO for use in the 2014 – 2015 TPP.[33] The 33 percent trajectory portfolio is meant to reflect a continuation of the general mix of renewable projects that have already become operational and those additional renewable projects that are approved and in the development/permitting pipeline. Any additional net short that must be satisfied is chosen on a least-cost basis using the RPS Calculator.[34] The 33 percent high DG + demand-side management portfolio satisfies the residual net short using a much larger level of distributed generation projects than does the trajectory portfolio. Since the RPS Calculator used to develop the renewable portfolios for the 2014 – 2015 TPP could not select DG projects on a least-cost basis, the DG mix is entered in the final portfolio manually.

An important issue for LCAAT and local reliability purposes is that it is uncommon that central station renewables are located in the load pockets and subareas of interest in Southern California. Compared to load, central station renewables in L.A. Basin load pocket or associated subareas is very small. Central station renewables are a much higher proportion of load in the San Diego/Imperial Valley load pocket, but the renewable projects are located almost entirely in the Imperial Valley, not in the more populated San Diego subarea. Since LCAAT and California ISO LCTA studies on San Diego/Imperial Valley both show very large surpluses, but much tighter surplus/deficit situation in San Diego subarea, it is the set of renewable projects located in the San Diego subarea that is of immediate interest.

Table 11 provides an overview of the two portfolios for areas of interest in Southern California for 2024. Energy Commission staff processed the two RPS portfolios to develop capacity projections in load pockets and subareas based on geographic identifiers for each project in the portfolio and converted the installed MW into dispatch MW using the same dispatch factor in the RPS Calculator. It is clear that the difference between the two portfolios is mainly in DG, not in central station renewables, and that this difference is numerically important in L.A. Basin and West Los Angeles subarea. It is not an important difference for either of the two San Diego areas.

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33 CPUC and Energy Commission, Joint Transmittal Letter Dated February 27, 2014, see http://www.caiso.com/Documents/2014-2015RenewablePortfoliosTransmittalLetter.pdf.

34 "Net short" describes the remaining amount of renewable energy that must be acquired by either a specific load-serving entity or the aggregate of all LSEs to satisfy their obligations. This takes into account the energy from projects already operational. It could also take into account projects now in the development pipeline that are assumed to be sure to become operational in a short period.

Table 11: Comparison of RPS Portfolios by Area in 2024 (MW)

NQC	33% Trajectory Mid-AAEE	33% High DG + DSM	Difference
L.A. Basin			
DG	222	904	682
Central Station Renewables	14	7	-7
Western L.A. Basin			
DG	209	785	576
Central Station Renewables	0	0	0
Eastern L.A. Basin			
DG	13	119	106
Central Station Renewables	14	7	-7
San Diego-Imperial Valley			
DG	78	86	8
Central Station Renewables	399	399	0
San Diego			
DG	78	86	8
Central Station Renewables	0	0	0

Source: Energy Commission.

Transition of Cogen QFs to Wholesale Generators

In D.10-12-035, the CPUC adopted the "Qualifying Facility and Combined Heat and Power Settlement Agreement," which resolved outstanding disputes between utilities and qualifying facilities (QFs) and established a new CHP procurement program through 2020.[35] D. 10-12-035 provides for an orderly transition from the existing QF program as a federal jurisdiction standard-offer pricing model under the Public Utility Regulatory Policies Act to a new QF/combined heat and power (CHP) program under state jurisdiction using a market-based approach for pricing [36]. Through a sequence of utility CHP RFOs, the utilities were to procure CHP on a competitive basis using market-based pricing. The settlement

35 A *qualifying facility* is a cogenerator or small power producer that under federal law, has the right to sell its excess power output to the public utility. (See http://www.energy.ca.gov/glossary/glossary-q.html.)

36 Combined heat and power (CHP) plants less than or equal to 20 MW are eligible for two programs with different energy pricing terms: the Assembly Bill 1613 Export Feed-in Tariff (Blakeslee, Chapter 713, Statutes of 2007) and the standard offer contract approved in the QF/CHP Settlement with short-run avoided cost pricing. CHPs larger than 20 MW are subject to competitive procurement and may (but do not automatically) receive compensation for exports at short-run avoided cost

agreement was also written to promote new, lower greenhouse gas- (GHG) emitting CHP facilities and encourage the repowering, operational changes through utility-prescheduling, or retirement, of existing, higher GHG-emitting CHP facilities in an effort to optimize the state's existing CHP as a GHG emissions reduction strategy.

The utilities have made progress in meeting the interim goals of the program, and new program goals have been set in D. 15-06-028 to provide regulatory certainty to the CHP community. Though new program goals have been set, not all parties are in agreement, and some parties feel there is uncertainty surrounding the viability of existing CHP facilities. As contracts end, CHP facilities are faced with the uncertainty of being able to recontract. The utilities no longer have the must-take obligation under the Public Utilities Regulatory Policies Act of 1978 (PURPA) for large facilities greater than 20 MW.[37] Those facilities able to recontract may repower or convert to a utility prescheduled facility in which the power plant converts baseload generation to utility-controlled, dispatchable generation. Other options available to CHP facilities are to obtain a new PPA, sell into the wholesale market, shut down, or cease to export. One of the potential outcomes is that a CHP plant is unable to recontract and shuts down, and the owner installs a boiler and buys power from the local utility. This scenario puts upward pressure on demand while decreasing the generating supply. Facilities whose thermal host steam needs are declining may also shutdown, putting further downward pressure on the generating supply. All parties agree on one issue—the existing cohort of inefficient, high GHG-emitting facilities, including those that use coal, petroleum coke, or diesel, is expected to retire or repower.

A sensitivity that captures the uncertainty surrounding CHPs as they transition from CHP QFs under PURPA to wholesale generators under the new state CHP program can be conducted using a change to the retirement assumption for CHP. **Table 12** presents the retirement assumptions for the baseline case and a sensitivity case for CHP. The baseline retirement assumption in LCAAT is based on the CPUC Assigned Commissioner's Ruling detailing assumptions and scenarios for use in the 2014 LTPP and 2014 – 2015 TPP[38] and used a 40-year lifespan assumption for conventional generators and cogeneration (not including OTC facilities that are assumed to retire on schedule with SWRCB compliance dates) in the mid-level assumption. In this sensitivity, the retirement assumption is changed to 35 years for cogeneration. LCAAT allows testing of varying retirement assumptions for different technologies. Changing thermal and peaker technologies retirement assumption to 35 years does not have an impact in the L.A. Basin local area during the period assessed

37 PURPA is federal legislation that, among other things, requires utilities to buy electric power from private "qualifying facilities," at an avoided cost rate. This avoided cost rate is equivalent to what it would have otherwise cost the utility to generate or purchase that power themselves. Utilities must further provide customers who choose to self-generate a reasonably priced back-up supply of electricity. (See http://www.energy.ca.gov/glossary/glossary-p.html.)

38 R. 13-12-010 Commissioner Picker Ruling, released 2/27/2014, available online at

http://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M088/K489/88489746.PDF.

here. **Table 13** presents the impact to cogeneration or CHP by using a 35-year retirement assumption, which shows that 428 MW more capacity is retired by 2024 in L.A. Basin.

Table 12: Assumed Lifetimes for Generating Technologies (Years)

Technology	Lifetime in Years	
	Basecase	CHP Sensitivity
Biomass	40	40
Cogeneration	40	35
Geothermal	40	40
Hydro	70	70
Peaker	40	40
Pump	50	50
Solar	25	25
Thermal	40	40
Wind	25	25

Source: CPUC, 2014 LTTP, ACR dated March 3, 2015.

Table 13: CHP Capacity Retired Assuming Alternative Technology Lifetimes (MW)

MW Cogeneration Retirement by Local Area	Lifetime 40 Years		Lifetime 35 Years		Difference in Computed Retirements using 35 yr - 40 yr Life	
	2020	2024	2020	2024	2020	2024
L.A. Basin	0	29	58	457	58	428
W L.A. Basin	0	29	29	370	29	341
Eastern Metro	0	0	29	86	29	86
San Diego	100	101	101	101	1	0

Source: Energy Commission.

CHAPTER 5:
Sensitivity and Scenario Assessments

To evaluate the impact of alternative assumptions on LCAAT results, both sensitivity studies and scenario studies were conducted.

Sensitivity Study Results

To understand the impact of each key variable on the local capacity surplus/deficits, sensitivity cases were run for *each* variable described in Chapter 4. The results report the bottom-line surplus/deficit of total resources in the local area compared to the adjusted LCR local requirements for the area. A positive value identifies a surplus, meaning that resources exceed requirements, and there is no local capacity concern. A negative value indicates an insufficient amount of capacity to satisfy reliability standards in that area for the given set of assumptions and requirements. Compared to the baseline results, some variables increase the projected amount of surplus/deficit while others decrease the amount. There may be differences in impact within the set of local areas. For example, some variables may have very little impact in the San Diego local area. In general, the following variables/sensitivities have a positive impact by 2024 and improve the outlook of local capacity surplus/deficits:

- Mid-AAEE as an LCR planning assumption
- Demand response full capability
- RPS high DG portfolio
- *2014 IEPR Update* as source for base demand forecast
- Storage high development pattern
- Demand response moderate capability
- Storage moderate development pattern

The following variables/sensitivities have a negative impact by 2024 and worsen the outlook of local capacity surplus/deficits:

- SCE RFO PPA performance
- Cogeneration transition to wholesale generators
- AAEE realization rate reduction
- Higher base demand forecast

Table 14 presents the local capacity surplus/deficit 2024, and Table 15 presents the difference in surplus/deficit for the sensitivity cases versus the baseline case for 2024. The local areas reported are the various geographic regions in Southern California affected by the retirement of San Onofre and within which various resource additions and transmission system upgrades area addressing the loss of San Onofre capacity and the loss of a substantial amount of fossil-fueled OTC capacity. The results show that for the combined

L.A. Basin/San Diego area, the mid-AAEE sensitivity has the greatest impact on local capacity surplus/deficits in 2024 and increases local capacity by 813 MW. The deficit of 237 MW in the baseline case is eliminated, resulting in a surplus of 576 MW. On the other extreme, the results show that the higher demand sensitivity of 2 percent higher growth in demand by 2024 has the greatest impact on local capacity deficits and decreases local capacity by 594 MW. The deficit of 237 MW in the baseline case grows to a deficit of 831 MW. The results for the other geographic areas show a similar pattern for these two sensitivities.

Table 15 shows that some of the sensitivities have a similar range of impact in 2024. The sensitivity cases using demand response full and the high DG renewable portfolio sensitivities have a similar impact in providing more local capacity. The sensitivity cases using 2014 demand, storage high, and demand response moderate have a similar range of impact in providing more local capacity. At the other end of the spectrum, the sensitivity cases using reduced transition of cogeneration QFs to wholesale generators, EE reduction, and higher demand sensitivities all have a similar range of impact in worsening the outlook for local capacity.

Table 14: 2024 Resource Surplus/Deficit by Area (MW)

Variable	L.A. Basin/San Diego	L.A. Basin	West L.A. Basin	Eastern-Metro Subarea	San Diego-Imperial Valley	San Diego
Mid-AAEE	576	543	76	211	715	153
Demand Response Full	441	602	79	289	522	(40)
RPS High DG	346	597	285	7	530	(32)
2014 Demand	145	146	(158)	80	681	119
Storage High	131	236	23	7	578	16
Demand Response Moderate	102	262	(106)	148	522	(40)
Storage Moderate	(53)	79	(134)	7	550	(12)
Baseline	(237)	(77)	(291)	7	522	(40)
RFO Performance	(378)	(163)	(376)	7	468	(94)
Cogen	(665)	(505)	(632)	(80)	522	(40)
AAEE Reduction	(813)	(508)	(545)	(135)	378	(184)
Higher Demand	(831)	(552)	(571)	(149)	403	(159)

Source: Energy Commission.

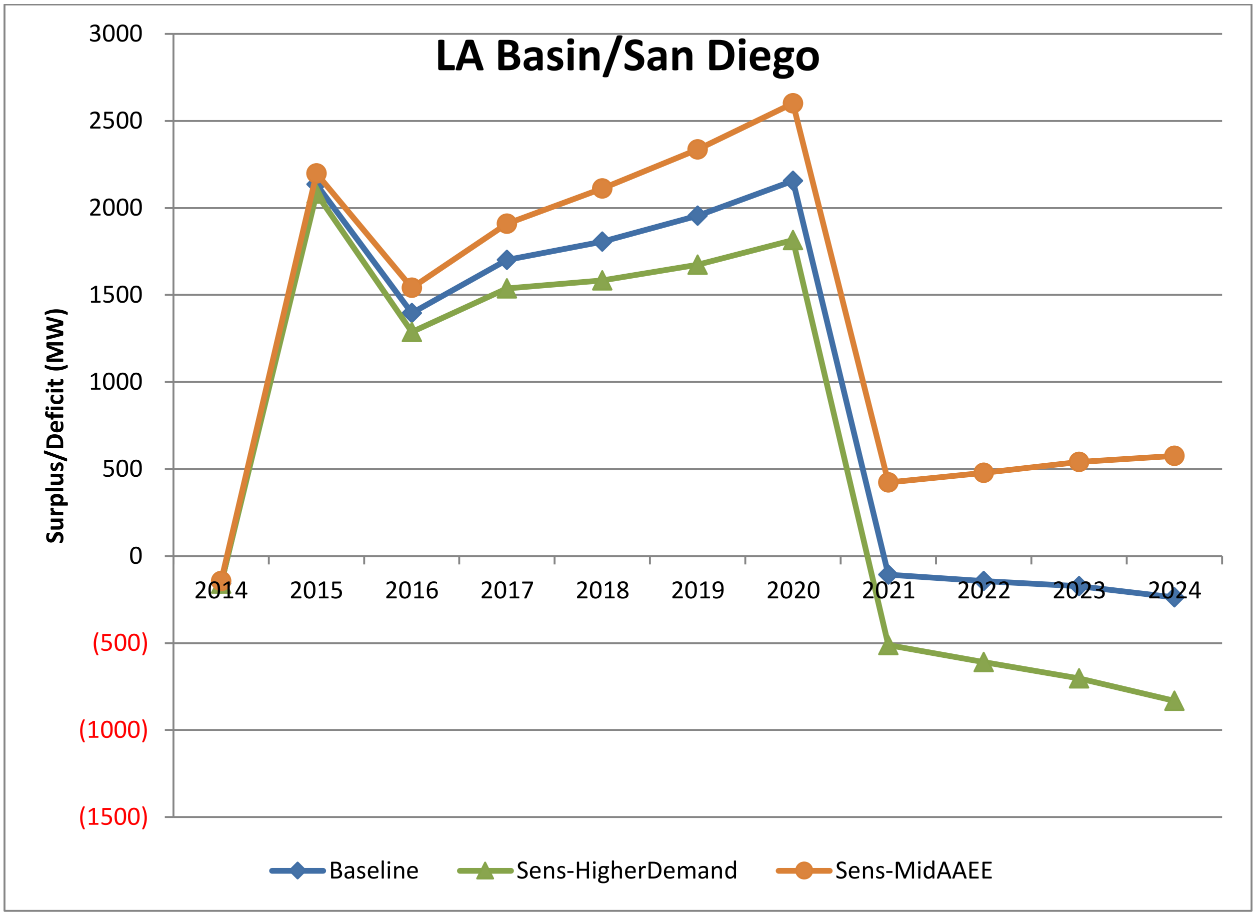
Table 15: 2024 Change in Resource Surplus/Deficit From Baseline Case (MW)

Variable	L.A. Basin/San Diego	L.A. Basin	West L.A. Basin	Eastern-Metro Subarea	San Diego-Imperial Valley	San Diego
Mid-AAEE	813	620	367	204	193	193
Demand Response Full	679	679	370	282	-	-
RPS High DG	584	674	576	-	8	8
2014 Demand	383	224	132	74	159	159
Storage High	369	313	313	-	56	56
Demand Response Moderate	339	339	185	141	-	-
Storage Moderate	184	157	157	-	28	28
Baseline	-	-	-	-	-	-
RFO Performance	(141)	(86)	(86)	-	(55)	(55)
Cogen	(428)	(428)	(341)	(86)	-	-
AAEE Reduction	(576)	(431)	(255)	(142)	(145)	(145)
Higher Demand	(594)	(474)	(280)	(156)	(119)	(119)

Source: Energy Commission.

Figure 2 (for the combined L.A. Basin/San Diego area) presents the annual results of the sensitivities that are the boundary of the envelope containing all sensitivities—the mid-AAEE sensitivity provides the greatest improvement, while the higher demand sets the worst outcome for this area. The mid-AAEE sensitivity provides 813 MW more capacity than the baseline case, while the higher demand sensitivity provides 594 MW less capacity than the baseline case in 2024. **Figure 2** shows that there is a substantial surplus through 2020, and then the loss of fossil-fueled OTC capacity at the end of 2020 causes a precipitous drop in the quantity of resource surplus. The baseline projection has a small resource deficit, in line with the recent California ISO 2014/2015 TPP results for 2024. The mid-AAEE sensitivity eliminates the deficit and maintains a surplus throughout the study period. The higher demand sensitivity case shows a surplus, albeit slightly smaller than the baseline case, prior to 2021, but in 2021, the resource deficit increases and grows larger by 2024. The results show that the deficit is occurring earlier than 2024 and that 2021 is a critical year since it is the first summer season following the date when a substantial portion of fossil OTC capacity retires.

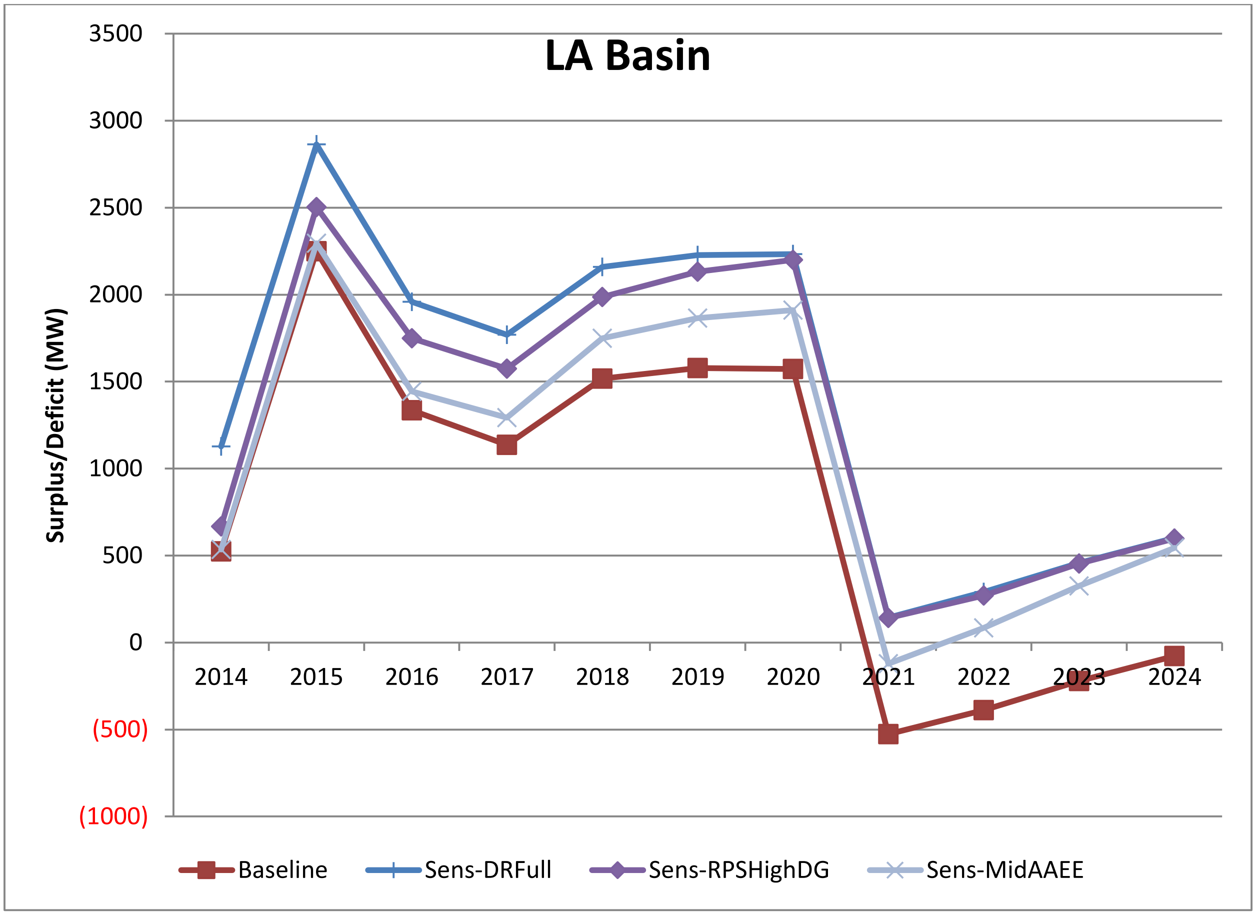
Figure 2: Higher Demand and Mid-AAEE Sensitivity Cases for the L.A. Basin/San Diego Area (MW)



Source: Energy Commission.

Figure 3 for the L.A. Basin local area presents the annual results for selected sensitivities that provide upside potential of local capacity. The mid-AAEE sensitivity provides the boundary condition in 2024 for the combined LA Basin/San Diego area, but for L.A. Basin, the demand response full and high DG sensitivities provide slightly more capacity by 2024. The mid-AAEE sensitivity demonstrates a higher growth rate between 2021 and 2024 than the other two sensitivities, resulting from the ramp up in AAEE projections across years, but does not quite eliminate the deficit in 2021. Of the seven sensitivities that provide upside potential of local capacity, the demand response full and high DG sensitivities are the only two that eliminate the deficit in 2021, and after 2020, these two sensitivities provide a similar amount of local capacity.

Figure 3: Selected Sensitivity Case Results for the L.A. Basin (MW)



Source: Energy Commission.

Design of Scenarios

Four alternative scenarios were designed to provide some sense of the range around the baseline results—resource surplus/deficit relative to requirements—when *multiple* variables are modified from their baseline values to an alternative. Two of these—the optimistic and the pessimistic cases—are intended as bookends with multiple variables revised to systematically induce higher levels (or lower levels) of resource surplus compared to requirements. Two additional scenarios were developed that reflect more moderate departures from baseline than the bookends, and these departures are driven in a thematic manner. **Table 16** outlines the general approach used to design the specific scenarios, and the final row of **Table 16** provides a highly simplified description of the resource surplus/deficit compared to local capacity requirements in the L.A. Basin for 2020. As can be seen, the two pessimistic and two optimistic scenarios are roughly symmetric around the baseline results.

Table 16: Variable Values for Alternative Scenarios

Variable	Scenarios				
	Optimistic Bookend	Markets Cooperate	Baseline	Incentives Fail	Pessimistic Bookend
Demand-Side					
Load Forecast Source	*2014 IEPR*	Baseline	Baseline	Baseline	Baseline
High Load Forecast	Baseline	Baseline	Baseline	1.02 Higher by 2024	1.02 Higher by 2024
AAEE Peak Savings/Participation	Baseline	Baseline	Baseline	0.6	0.6
SCE Pref RFO Contracting (BTM Only)	Baseline	Baseline	Baseline	Baseline	0.72
SDG&E Pref RFO Contracting (BTM Only)	Baseline	Baseline	Baseline	Baseline	0.72
Supply-Side					
DR Effectiveness	Full Cap	Moderate	Baseline	Baseline	Baseline
Storage (IFM Only)	High	Moderate	Baseline	Baseline	Baseline
Cogen Transition From QFs to Wholesale	Baseline	Baseline	Baseline	Baseline	35 Year
RPS Portfolio	Baseline	Baseline	Baseline	Baseline	Baseline
Impact on LA Basin Surplus/Deficit in Year 2024	Improve Surplus/Deficit by 1000 MW	Improve Surplus/Deficit by 400 MW	N/A	Worsen Surplus/Deficit by 500 MW	Worsen Surplus/Deficit by 700 MW

Source: Energy Commission.

A future scenario that combines the impact of multiple variables can move the surplus/deficit in the same direction or can be offsetting to one another. For example, higher demand growth can be mostly offset by using the 2014 demand forecast. In the next section, the results of several scenarios are presented. Staff designed these four scenarios to assess severe and moderate levels of change—all in the same direction. The two bookend cases—Optimistic and Pessimistic—define a wide range, while the two moderate scenarios—Markets Cooperate and Incentives Fail—are closer to the baseline.

Scenario Study Results

LCAAT was exercised using scenarios constructed from the set of baseline and alternative variable inputs outlined in **Table 16**. Results for each scenario were copied to an output workbook housing all sensitivity and scenario results from which figures comparing one scenario to another could be easily prepared. Appendix C provides numeric results.

Figure 4, **Figure 5**,

Figure 6, and **Figure 7** provide the results for four areas that are key to understanding the local capacity consequences of various future conditions, both baseline and for alternative sets of assumptions. Each of these four figures reports the bottom-line surplus/deficit of total resources in the area less the local requirements for the area. A positive value identifies a surplus, meaning that resources exceed requirements and there is no local capacity concern. A negative value indicates an insufficient amount of capacity to satisfy reliability standards in that area for the given set of assumptions and requirements.

Figure 4, **Figure 5**, and

Figure 6 are various layers of the overall geographic region in Southern California affected by the retirement of San Onofre and within which various resource additions and transmission system upgrades are addressing both the loss of San Onofre capacity and the loss of substantial fossil-fueled OTC capacity. **Figure 4**, **Figure 5**, and

Figure 6 have the same general shape; for example, there is a substantial surplus through 2020, and then the loss of fossil-fueled OTC capacity at the end of 2020 causes a precipitous drop in the quantity of resource surplus. **Figure 4**, **Figure 5**, and

Figure 6 have a small resource deficit in the baseline projections, made worse in the two cases that have more pessimistic outlooks. In the moderate Markets Cooperate case, some years in the interval 2021 – 2024 show very small surpluses, and some years show very small deficits. Again, in the Optimistic bookend case, even though the surplus drops similar to the baseline case and the other scenarios, a surplus is maintained throughout the projection period. **Figure 4**, **Figure 5**, and

Figure 6 show a considerable range between Optimistic bookend and Pessimistic bookend.

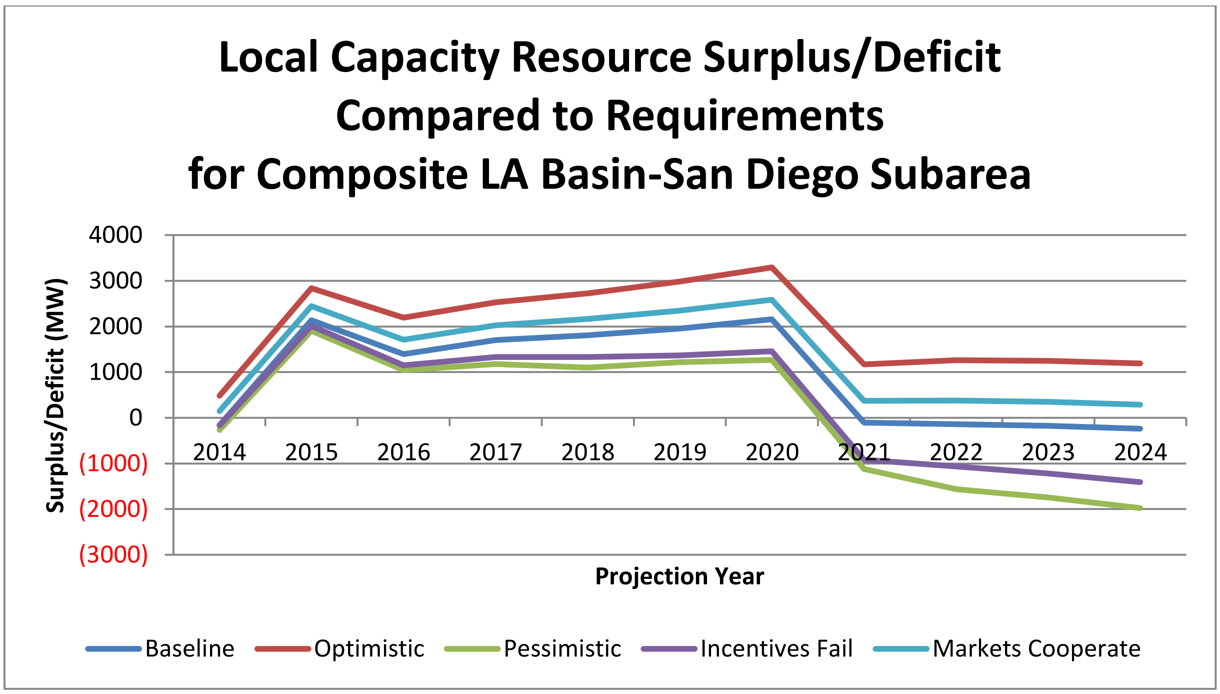
Figure 7 shows results for the same set of scenarios for the San Diego subarea. LCAAT results and California ISO LCTA studies for 2016 and 2020[39] show that there is never an issue about satisfying local capacity requirements in larger San Diego/Imperial Valley local capacity area. There is a large surplus of resources compared to requirements in the San Diego/Imperial Valley area as a result of the various transmission system upgrades that the California ISO identified, its board has approved, and that SDG&E is constructing. **Figure 7** has a considerably different shape than do the corresponding figures for the three L.A. Basin areas. The San Diego subarea loses its only OTC capacity with the closure of Encina at the end of 2017. Assuming that the Carlsbad facility is brought on-line by the end of 2017, then the San Diego subarea shows a capacity surplus dropping between 2017 and 2018, since the 960 MW Encina is replaced by the 500 MW Carlsbad and a set of preferred resources and storage that are not fully implemented until further out in time, thus reducing the surplus in the immediate years of the Encina/Carlsbad replacement. As a result, the San Diego subarea shows a steady, gradual loss of local capacity surplus as loads grows and few resources are added.. Knowledge of this pattern is highly useful because it suggests that the issue can be readily addressed in the standard electricity planning and procurement

39 California ISO, http://www.caiso.com/Documents/Final2020Long-TermLocalCapacityTechincalReportApr302015.pdf, pp. 98-99.

authorization processes, provided these efforts pay attention to intermediate years and do not focus exclusively on the 10th forward year.

However, in all cases if Carlsbad is delayed beyond a late 2017– early 2018 on-line date, then the San Diego subarea does not have sufficient excess resources to avoid a deficit condition. This could require that the SWRCB defer the compliance date for Encina to match the expected start date of Carlsbad. An OTC deferral request would be a logical response to an expected delay in the start date for Carlsbad since little or no investments are required to keep Encina running for another year or two. There is, of course, an environmental cost to continuing to operate Encina since the basis of the OTC policy—impingement and entrainment of sea life in the water intake structures of the facility—would continue as long as the facility was operational. The SWRCB has broadly outlined how it would consider an OTC compliance date deferral request.[40]

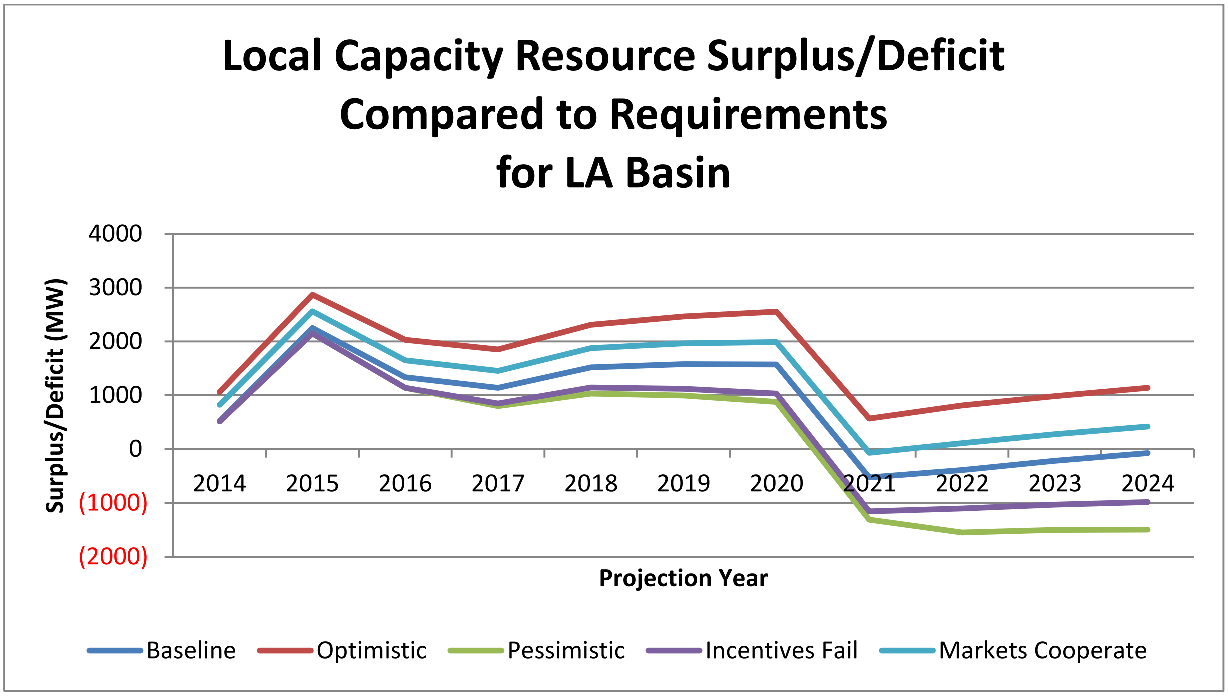
Figure 4: Resource Surplus/Deficit for Composite L.A. Basin-San Diego Subarea



Source: Energy Commission.

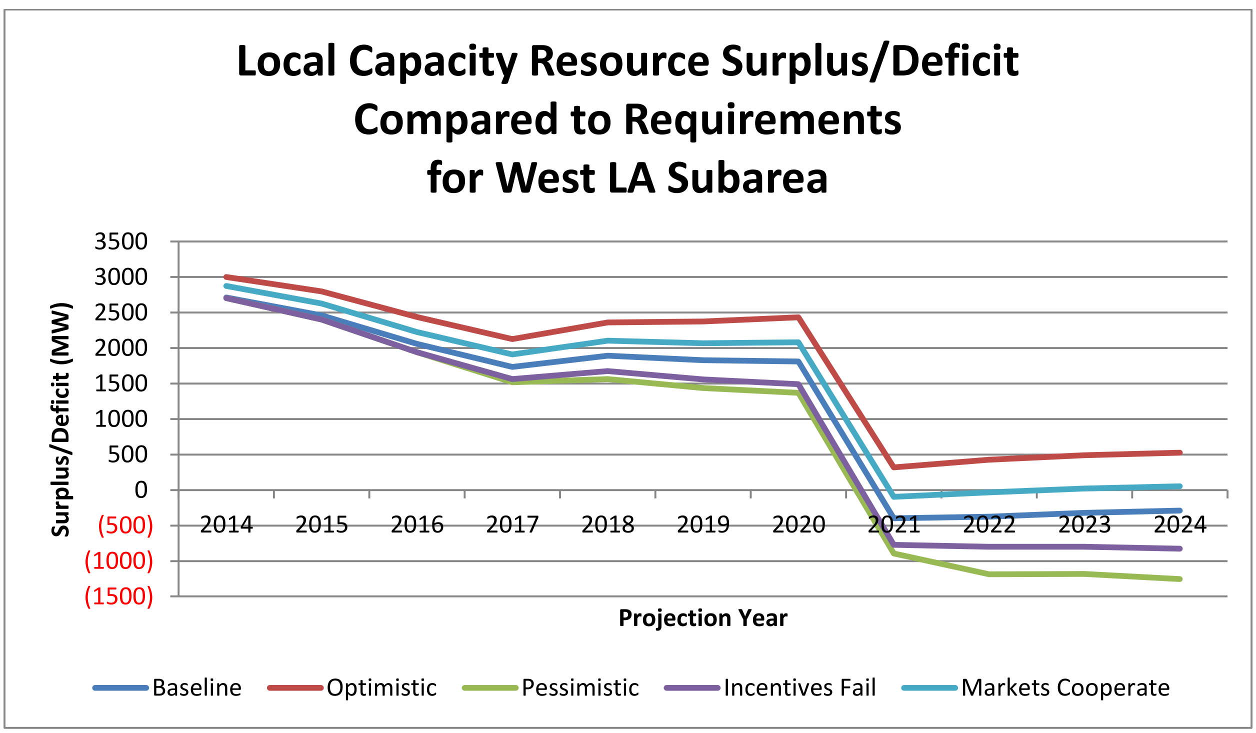
40 SWRCB, Testimony of Jon Bishop, August 20, 2014, in Energy Commission *2014 IEPR Update* workshop, see transcript pp. 152-159, http://www.energy.ca.gov/2014_energypolicy/documents/2014-08-20_workshop/2014-08-20_iepr_transcript.pdf.

Figure 5: Resource Surplus/Deficit for L.A. Basin Local Capacity Area



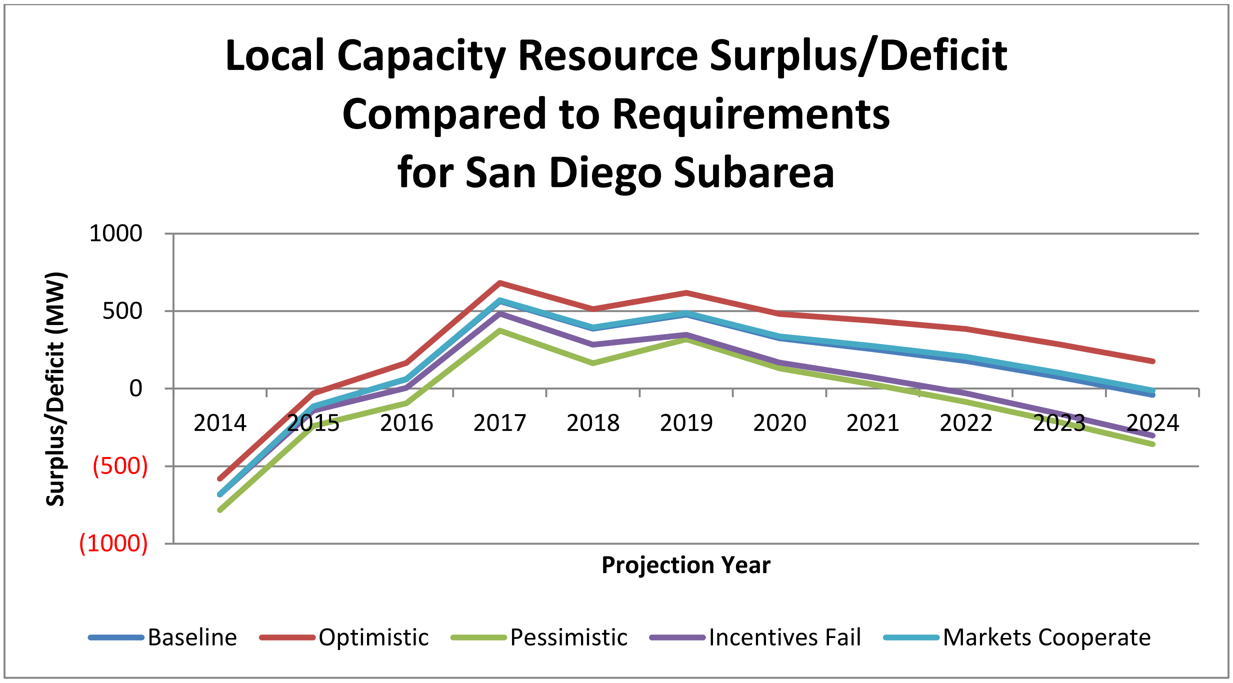
Source: Energy Commission.

Figure 6: Resource Surplus/Deficit for West Los Angeles Subarea



Source: Energy Commission.

Figure 7: Resource Surplus/Deficit for San Diego Subarea



Source: Energy Commission.

CHAPTER 6: Findings and Conclusions

Conclusions

Using LCAAT to assess baseline assumptions for intermediate years not explicitly studied by the California ISO shows deficits in the L.A. Basin local area and the West Los Angeles subarea in years 2021 – 2024. The 2024 baseline results are consistent with California ISO studies documented in the *2014/2015 Transmission Plan*. The deficits in 2021 through 2023 are not revealed in the California ISO's published local capacity studies since the California ISO only studied 2015, 2019, and 2024. Many uncertainties exist in the variables that constitute the planning assumptions for both LCAAT and the LCR studies prepared by the California ISO. To evaluate the consequences of these uncertainties, LCAAT was used to assess 11 single-variable sensitivities for eight variables and developed four alternative scenarios with multiples differences from the baseline set of assumptions. Not surprisingly, sensitivities and scenarios in which load was reduced or resources increased diminished the level of deficit and sometimes eliminated them. Correspondingly, sensitivities and scenarios in which either load was increased or resources were decreased exacerbated the shortfalls or reduced the surpluses found using the baseline set of assumptions. In **Figure 4**, **Figure 5**,

Figure 6, and **Figure 7,** the two moderate scenarios encompass a range for 2021 – 2024 that can be either a surplus or a deficit regardless of the results using baseline assumptions.

The alternative assumptions evaluated as sensitivities and as scenarios are not considered extreme, but the compounding effects over time imply one or more of the following: (1) lack of data about differences between real world activities and planning assumptions, (2) inattention to data revealing issues with the realization of such assumptions, (3) adherence to use of planning goals regardless of what contrary monitoring data might reveal, or (4) unresolved disputes about interpreting recent monitoring data as either "near-term growing pains" that will be overcome later versus clear evidence that planning assumptions are overly optimistic. One could hope that the planning processes of the agencies would detect and resolve these issues and not allow such errors to compound through time unnoticed or unresolved.

Development of LCAAT and the use of it to identify the consequences of uncertain input assumptions provides insights that could, in principle, be determined through the more in depth studies using power flow modeling techniques. In reality, these insights cannot be gained from the studies conducted and published by the California ISO because the California ISO does not have the resources to prepare this many studies. The highly intensive power flow modeling efforts are too resource-intensive to be exercised for the multiplicity of alternative input assumptions combinations that are reasonable future conditions.[41] *LCAAT is designed to complement these power flow modeling studies, not replace them.* In fact, LCAAT is specifically designed to make use of these resource-intensive studies to the greatest extent possible. California ISO study results through the LCTA process for 2015 and 2019, and through the 2014 – 2015 TPP for 2024, have been used as inputs into LCAAT. The proper role of LCAAT is as a screening tool to identify alternative combinations of future assumptions that reveal conditions that should be studied in depth using the power flow modeling techniques.

Preliminary Findings

The following preliminary findings derive from the development and exercise of LCAAT as described earlier in this report. These preliminary findings merit further review and discussion:

- Deficits using baseline assumptions in the L.A. Basin local area and the West Los Angeles subarea is a concern, but not a cause for alarm. North American Electric Reliability Corporation/Western Electricity Coordinating Council planning standards require that overlapping contingencies under adverse load conditions be studied. Unfortunately, alternative assumptions can both worsen or improve these results. Since the state of the art of planning does not allow assessments in a probabilistic framework to guide whether the combination of factors leading to deficits is sufficiently likely that action should be taken right now, decision-makers will have to rely upon judgment in deciding whether or how to act.
- The California ISO should study 2021 intensively with several alternative sets of input assumptions drawn from LCAAT scenarios. LCAAT baseline results show deficits, and credible alternative scenarios reveal such deficits can be much worse. The time horizon between now and summer 2021 is already beginning to constrain options for new resource development. Delays in undertaking such studies would further limit the range of options that could provide sufficient resources, either demand-side or supply-side, to assure that local capacity requirements are satisfied throughout the L.A. Basin.
- The CPUC should take two actions:
    - Include in its 2016 LTPP rulemaking an explicit focus on local capacity requirements. Further, the CPUC should not assume that such requirements in the intermediate period 5-8 years forward have been satisfied through decisions in the 2012 LTPP rulemaking and the procurement activities authorized by D.14-03-004. LCAAT results suggest that an assessment for future years should be part of each LTPP cycle

41 In crude terms, the California ISO has prepared three studies (one each for 2015, 2019, and 2024) for a single baseline set of assumptions, while LCAAT shows results for what would require 157 studies by the California ISO—seven additional years for baseline assumptions, and 150 additional studies of different combinations of assumptions—15 cases (11 sensitivities and 4 scenarios) for 10 years.

unless a convincing analytic determination shows intermediate years are fully satisfied using a credible package of planning assumptions.

  - Consider use of an expanded version of LCAAT that includes additional Northern California local capacity areas as a source of projections for local capacity needs in the Track 2 of the Joint Reliability Plan rulemaking.

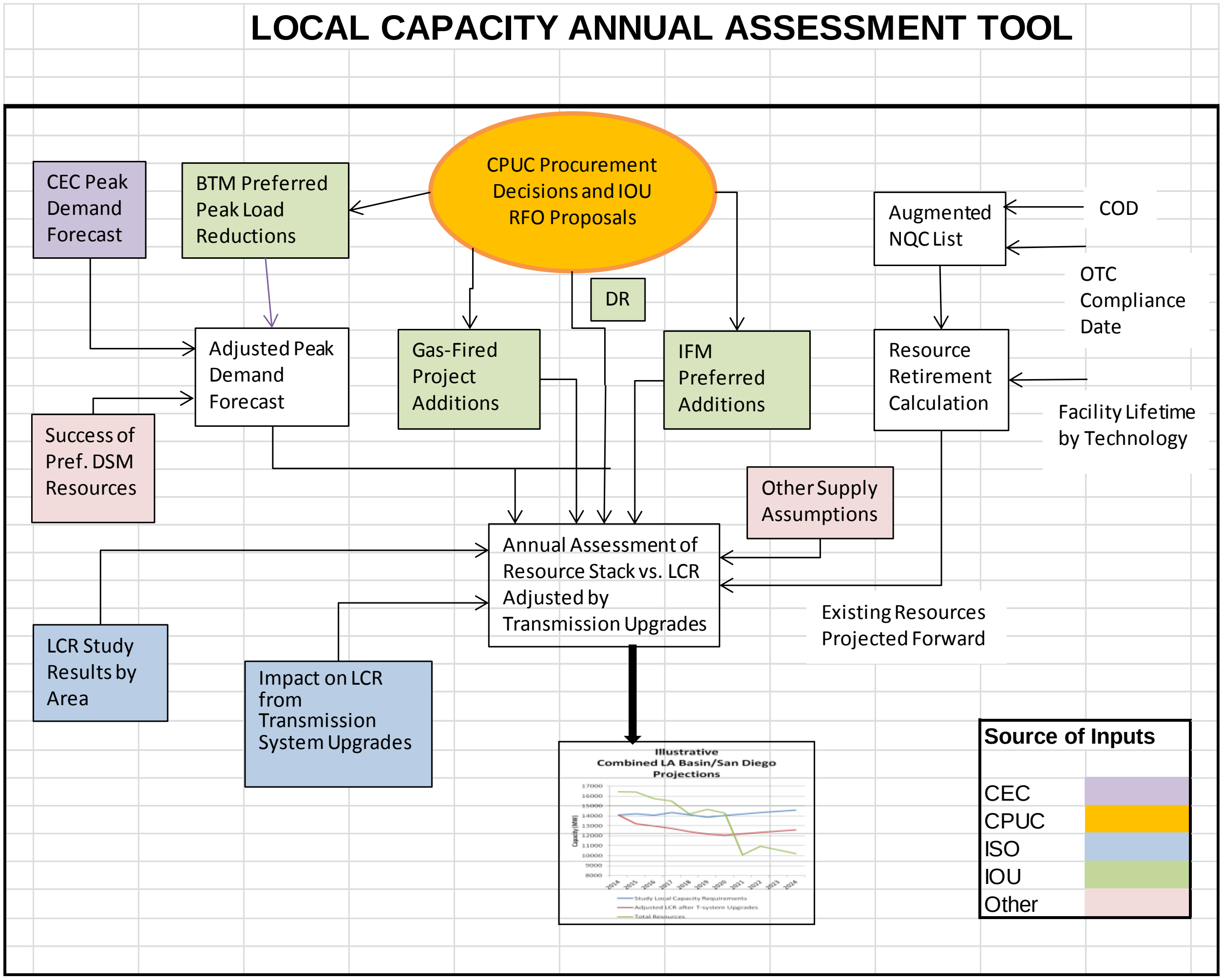
- Monitoring actual savings from demand-side programs designed to achieve energy and peak load reductions is critical to assuring reliability. The scale of future savings expected from such programs in Energy Commission, CPUC, and California ISO electricity planning studies is so large that credible degrees of failure can lead to resource shortfalls large enough to affect local reliability in one or more areas. Results of such monitoring need to be broadly shared among the energy agencies and results should be folded into planning assumptions for future planning studies as quickly as possible. Treating goals as credible planning assumptions *may threaten* future reliability and *will limit* resource choices as the time horizon to effectuate resource additions shrinks.

ACRONYMS

ACRONYM	DEFINITION
AAEE	Additional achievable energy efficiency
California ISO	California Independent System Operator
CPUC	California Public Utilities Commission
CHP	Combined heat and power
DG	Distributed generation
DR	Demand response
EE	Energy efficiency
Energy Commission	California Energy Commission
GHG	Greenhouse gas
IOU	Investor-owned utility
LA Basin	Los Angeles Basin
LCAAT	Local capacity annual assessment tool
LCR	Load capacity requirement
LCTA	Local capacity technical assessment
LTPP	Long-Term Procurement Planning proceeding
MW	Megawatt
OTC	Once-through-cooling
PPA	Power purchase agreement
QF	Qualifying facility
RFO	Request for offer
RPS	Renewables Portfolio Standard
SCE	Southern California Edison Company
SCRP	Southern California Reliability Project
SDG&E	San Diego Gas & Electric Company
SWRCB	State Water Resources Control Board

APPENDIX A:
LCAAT Schematic

Figure A-1: Local Capacity Annual Assessment Tool



Source: Energy Commission staff, 2014.

APPENDIX B:
Baseline LCAAT Results by Area

Table B-1: Baseline Results for Consolidated LA Basin/San Diego Area

	Variables (Summer Peak MW)	Source	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
LA Basin/San Diego Subarea														
	Base Load Forecast	2013 IEPR	25594	26118	26618	26961	27322	27680	28067	28447	28805	29129	29421	29689
less	Load Forecast Adjustment		0	0	0	0	0	0	0	0	0	0	0	0
less	AAEE	2013 IEPR	0	26	189	354	520	638	772	896	1018	1144	1292	1439
less	Preferred EE	SCE RFO/SD?	0	0	0	5	24	99	120	128	130	117	106	95
less	Preferred BTM Energy Storage	SCE RFO/SD?	0	0	0	0	42	199	223	243	260	279	279	279
less	Preferred BTM DG	SCE RFO/SD?	0	0	0	0	26	69	84	99	113	128	128	128
=	Managed Load Forecast		25594	26092	26429	26602	26710	26676	26868	27081	27284	27460	27617	27748
	Gross Local Capacity Requirements	2014/15 TPP		14548	12629	12650	13274	13394	13145	11197	11674	11855	12056	12357
less	T-system Upgrade Impacts			(240)	(240)	(240)	(840)	(1086)	(846)	(746)	(1046)	(1046)	(1046)	(1146)
less	LCR Change from Demand Adjustments			(26)	(189)	(359)	(612)	(1004)	(1199)	(1366)	(1521)	(1669)	(1805)	(1941)
=	Adjusted LCR Base			14282	12200	12052	11822	11304	11100	9084	9106	9140	9206	9270
less	OTC Non Nuclear	ScenTool		5117	5117	4782	4782	3818	3818	2462	0	0	0	0
less	OTC Nuclear	ScenTool		0	0	0	0	0	0	0	0	0	0	0
less	Hydro	ScenTool		313	313	313	313	313	313	301	301	301	301	301
less	Solar	ScenTool		23	23	23	23	23	23	21	21	21	21	21
less	Wind	ScenTool		70	261	261	261	261	261	17	17	17	17	17
less	Geothermal	ScenTool		0	0	0	0	0	0	0	0	0	0	0
less	Biomass	ScenTool		118	118	118	118	118	118	115	115	115	115	115
less	Cogeneration	ScenTool		693	849	849	849	849	749	762	762	733	732	732
less	Pump	ScenTool		40	40	40	40	40	40	40	40	40	40	40
less	Non OTC Peaker	ScenTool		2663	2475	2431	2171	2171	2171	1317	1317	1317	1317	1317
less	Non OTC Thermal	ScenTool		4745	4760	4120	4120	4120	4120	3450	3450	3450	3450	3450
less	Various and Unknown	ScenTool		117	118	118	118	118	118	159	159	159	159	159
less	Incr. Peaker Additions	SCE RFO		0	0	0	308	808	808	808	906	906	906	906
less	Incr. Thermal Additions	SCE RFO		0	0	0	0	0	0	1280	1280	1280	1280	1280
less	Incr. RPS Calc - Renew	14/15 Port		7	14	14	14	14	14	0	0	0	0	0
less	Incr. RPS Calc - DG	14/15 Port		37	66	194	205	211	217	216	230	251	287	287
less	Storage Additions	SCE RFO/D14-03-004		0	0	0	4	8	13	17	121	125	125	125
less	DR Program Capability/ Preferred DR			180	183	186	199	239	273	276	279	282	282	282
=	Total Resources Base			14123	14336	13448	13524	13109	13055	11240	8998	8997	9032	9032
=	Resource Need (Surplus/Deficit) Base			(159)	2136	1396	1702	1806	1955	2156	(108)	(144)	(173)	(237)

Source: Energy Commission staff, 2015.

Table B-2: Baseline Results for L.A. Basin Area

	Variables (Summer Peak MW)	Source	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
LA Basin														
	Base Load Forecast	2013 IEPR	20378	20812	21210	21490	21762	22039	22344	22662	22964	23237	23488	23716
less	Load Forecast Adjustment		0	0	0	0	0	0	0	0	0	0	0	0
less	AAEE	2013 IEPR	0	22	147	273	399	488	588	680	769	861	969	1078
less	Preferred EE	SCE RFO	0	0	0	5	24	99	120	128	130	117	106	95
less	Preferred BTM Energy Storage	SCE RFO	0	0	0	0	25	163	169	172	170	172	172	172
less	Preferred BTM DG	SCE RFO	0	0	0	0	11	40	40	40	40	40	40	40
=	Managed Load Forecast		20378	20789	21064	21213	21304	21250	21426	21642	21854	22047	22202	22332
	Gross Local Capacity Requirements			10692	9484	9615	10147	10242	10107	10045	10280	10218	10173	10228
less	T-system Upgrade Impacts			(240)	(240)	(240)	(640)	(740)	(500)	(400)	(700)	(700)	(700)	(800)
less	LCR Change from Demand Adjustments			(22)	(147)	(277)	(458)	(790)	(917)	(1020)	(1110)	(1190)	(1286)	(1384)
=	Adjusted LCR Base			10430	9097	9098	9049	8712	8690	8625	8471	8328	8186	8043
	OTC Non Nuclear	ScenTool		4153	4153	3818	3818	3818	3818	2462	0	0	0	0
plus	OTC Nuclear	ScenTool		0	0	0	0	0	0	0	0	0	0	0
plus	Hydro	ScenTool		309	309	309	309	309	309	309	309	309	309	309
plus	Solar	ScenTool		2	2	2	2	2	2	2	2	2	2	2
plus	Wind	ScenTool		62	252	252	252	252	252	252	252	252	252	252
plus	Geothermal	ScenTool		0	0	0	0	0	0	0	0	0	0	0
plus	Biomass	ScenTool		97	97	97	97	97	97	97	97	97	97	97
plus	Cogeneration	ScenTool		554	710	710	710	710	710	710	710	681	681	681
plus	Pump	ScenTool		0	0	0	0	0	0	0	0	0	0	0
plus	Non OTC Peaker	ScenTool		1927	1927	1882	1622	1622	1622	1622	1622	1622	1622	1622
plus	Non OTC Thermal	ScenTool		3576	3591	2951	2951	2951	2951	2951	2951	2951	2951	2951
plus	Various and Unknown	ScenTool		77	77	77	77	77	77	77	77	77	77	77
plus	Incr. Peaker Additions	SCE RFO		0	0	0	0	0	0	0	98	98	98	98
plus	Incr. Thermal Additions	SCE RFO		0	0	0	0	0	0	1280	1280	1280	1280	1280
plus	Incr. RPS Calc - Renew	14/15 Port		7	14	14	14	14	14	14	14	14	14	14
plus	Incr. RPS Calc - DG	14/15 Port		29	52	154	155	159	162	166	174	195	222	222
plus	Storage Additions	SCE RFO		0	0	0	0	0	0	0	100	100	100	100
plus	DR Program/Preferred DRCapability			162	164	167	180	219	253	256	258	261	261	261
=	Total Resources Base			10953	11347	10433	10186	10230	10267	10198	7945	7939	7966	7966
=	Resource Need (Surplus/Deficit) Base			523	2250	1336	1137	1518	1577	1573	(526)	(389)	(220)	(77)

Source: Energy Commission.

Table B-3: Baseline Results for West Los Angeles Subarea

	Variables (Summer Peak MW)	Source	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
West LA Basin Only (subset of LA Basin)														
	Base Load Forecast	2013 IEPR	12043	12300	12535	12701	12861	13025	13205	13393	13572	13733	13882	14016
less	Load Forecast Adjustment		0	0	0	0	0	0	0	0	0	0	0	0
less	AAEE	2013 IEPR	0	13	87	161	236	289	348	402	454	509	573	637
less	Preferred EE	SCE RFO	0	0	0	5	24	99	120	128	130	117	106	95
less	Preferred BTM Energy Storage	SCE RFO	0	0	0	0	25	163	169	172	170	172	172	172
less	Preferred BTM DG	SCE RFO	0	0	0	0	11	40	40	40	40	40	40	40
=	Managed Load Forecast		12043	12287	12449	12535	12566	12435	12528	12651	12776	12895	12992	13073
	Gross Local Capacity Requirements			4428	4910	5112	5315	5496	5444	5457	5768	5781	5804	5827
less	T-system Upgrade Impacts			(240)	(240)	(240)	(240)	(240)	0	0	(300)	(300)	(300)	(300)
less	LCR Change from Demand Adjustments			(13)	(87)	(166)	(295)	(590)	(677)	(742)	(795)	(838)	(890)	(944)
=	Adjusted LCR			4175	4583	4706	4781	4666	4767	4715	4673	4643	4614	4583
	OTC Non Nuclear	ScenTool		4153	4153	3818	3818	3818	3818	2462	0	0	0	0
plus	OTC Nuclear	ScenTool		0	0	0	0	0	0	0	0	0	0	0
plus	Hydro	ScenTool		15	15	15	15	15	15	15	15	15	15	15
plus	Solar	ScenTool		0	0	0	0	0	0	0	0	0	0	0
plus	Wind	ScenTool		9	9	9	9	9	9	9	9	9	9	8
plus	Geothermal	ScenTool		0	0	0	0	0	0	0	0	0	0	0
plus	Biomass	ScenTool		93	93	93	93	93	93	93	93	93	93	93
plus	Cogeneration	ScenTool		370	489	489	489	489	489	489	489	460	460	460
plus	Pump	ScenTool		0	0	0	0	0	0	0	0	0	0	0
plus	Non OTC Peaker	ScenTool		733	733	688	428	428	428	428	428	428	428	428
plus	Non OTC Thermal	ScenTool		1269	1284	1284	1284	1284	1284	1284	1284	1284	1284	1284
plus	Various and Unknown	ScenTool		55	56	56	56	56	56	56	56	56	56	56
plus	Incr. Peaker Additions	SCE RFO		0	0	0	0	0	0	0	98	98	98	98
plus	Incr. Thermal Additions	SCE RFO		0	0	0	0	0	0	1280	1280	1280	1280	1280
plus	Incr. RPS Calc - Renew	14/15 Port		0	0	0	0	0	0	0	0	0	0	0
plus	Incr. RPS Calc - DG	14/15 Port		27	48	145	145	150	152	156	164	184	209	209
plus	Storage Additions	SCE RFO		0	0	0	0	0	0	0	100	100	100	100
plus	DR Program/Preferred DR Capability			162	164	167	180	219	253	256	258	261	261	261
=	Total Resources Base			6886	7044	6764	6517	6561	6597	6528	4274	4267	4293	4293
=	Resource Need (Surplus/Deficit) Base			2711	2461	2058	1737	1894	1830	1813	(399)	(376)	(321)	(291)

Source: Energy Commission.

Table B-4: Baseline Results for San Diego/Imperial Valley Area

	Variables (Summer Peak MW)	Source	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
San Diego/Imperial Valley Area														
	Base Load Forecast	2013 IEPR	5216	5306	5408	5471	5560	5641	5723	5785	5841	5892	5933	5973
less	Load Forecast Adjustment		0	0	0	0	0	0	0	0	0	0	0	0
less	AAEE	2013 IEPR	0	4	42	81	121	149	184	216	249	284	323	361
less	Preferred EE	ISO 14/15 TPP	0	0	0	0	0	0	0	0	0	0	0	0
less	Preferred BTM Energy Storage	ISO 14/15 TPP	0	0	0	0	18	36	54	71	89	107	107	107
less	Preferred BTM DG	ISO 14/15 TPP	0	0	0	0	15	29	44	59	73	88	88	88
=	Managed Load Forecast		5216	5302	5366	5390	5406	5426	5441	5438	5430	5413	5415	5416
	Gross Local Capacity Requirements			3849	4192	4044	4496	4483	4090	4320	4550	4782	5019	5354
less	T-system Upgrade Impacts			(240)	(240)	(240)	(840)	(1086)	(846)	(746)	(746)	(746)	(746)	(846)
less	LCR Change from Demand Adjustments			(4)	(42)	(81)	(154)	(215)	(282)	(347)	(411)	(479)	(518)	(557)
=	Adjusted LCR Base			3605	3910	3723	3502	3182	2962	3227	3392	3557	3754	3952
less	OTC Non Nuclear	ScenTool		965	965	965	965	0	0	0	0	0	0	0
less	OTC Nuclear	ScenTool		0	0	0	0	0	0	0	0	0	0	0
less	Hydro	ScenTool		4	4	4	4	4	4	4	4	4	4	4
less	Solar	ScenTool		127	127	127	127	127	127	127	127	127	127	127
less	Wind	ScenTool		55	55	55	55	55	55	55	55	55	55	55
less	Geothermal	ScenTool		0	0	0	0	0	0	0	0	0	0	0
less	Biomass	ScenTool		20	20	20	20	20	20	20	20	20	20	20
less	Cogeneration	ScenTool		139	139	139	139	139	39	59	59	59	58	58
less	Pump	ScenTool		40	40	40	40	40	40	40	40	40	40	40
less	Non OTC Peaker	ScenTool		736	548	548	548	548	548	548	548	548	548	548
less	Non OTC Thermal	ScenTool		2249	2249	2249	2249	2249	2249	2249	2249	2249	2249	2249
less	Various and Unknown	ScenTool		41	41	41	41	41	41	41	41	41	41	41
less	Incr. Peaker Additions	Picker AD		0	0	0	308	808	808	808	808	808	808	808
less	Incr. Thermal Additions	D14-03-004		0	0	0	0	0	0	0	0	0	0	0
less	Incr. RPS Calc - Renew	14/15 Port		167	353	399	399	399	399	399	399	399	399	399
less	Incr. RPS Calc - DG	14/15 Port		9	14	39	50	51	55	60	66	67	78	78
less	Storage Additions	D14-03-004		0	0	0	4	8	13	17	21	25	25	25
less	DR Program Capability/Preferred DR Capab	multiple		18	19	19	19	20	20	21	21	21	21	21
=	Total Resources Base			4569	4574	4645	4969	4510	4419	4447	4459	4464	4474	4474
=	Resource Need (Surplus/Deficit) Base			964	664	923	1466	1328	1456	1220	1067	907	720	522

Source: Energy Commission.

Table B-5: Baseline Results for San Diego Subarea

	Variables (Summer Peak MW)	Source	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
San Diego Sub-Area														
	Base Load Forecast	2013 IEPR	5216	5306	5408	5471	5560	5641	5723	5785	5841	5892	5933	5973
less	Load Forecast Adjustment		0	0	0	0	0	0	0	0	0	0	0	0
less	AAEE	2013 IEPR	0	4	42	81	121	149	184	216	249	284	323	361
less	Preferred EE	ISO 14/15 TPP	0	0	0	0	0	0	0	0	0	0	0	0
less	Preferred BTM Energy Storage	ISO 14/15 TPP	0	0	0	0	18	36	54	71	89	107	107	107
less	Preferred BTM DG	ISO 14/15 TPP	0	0	0	0	15	29	44	59	73	88	88	88
=	Managed Load Forecast		5216	5302	5366	5390	5406	5426	5441	5438	5430	5413	5415	5416
	Gross Local Capacity Requirements			4096	3385	3275	3767	3792	3438	3584	3731	3880	4033	4285
less	T-system Upgrade Impacts			(240)	(240)	(240)	(840)	(1086)	(846)	(746)	(746)	(746)	(746)	(846)
less	LCR Change from Demand Adjustments			(4)	(42)	(81)	(154)	(215)	(282)	(347)	(411)	(479)	(518)	(557)
=	Adjusted LCR Base			3852	3103	2954	2773	2492	2310	2492	2573	2655	2769	2883
less	OTC Non Nuclear	ScenTool		965	965	965	965	0	0	0	0	0	0	0
less	OTC Nuclear	ScenTool		0	0	0	0	0	0	0	0	0	0	0
less	Hydro	ScenTool		4	4	4	4	4	4	4	4	4	4	4
less	Solar	ScenTool		21	21	21	21	21	21	21	21	21	21	21
less	Wind	ScenTool		9	9	9	9	9	9	9	9	9	9	9
less	Geothermal	ScenTool		0	0	0	0	0	0	0	0	0	0	0
less	Biomass	ScenTool		20	20	20	20	20	20	20	20	20	20	20
less	Cogeneration	ScenTool		139	139	139	139	139	39	59	59	59	58	58
less	Pump	ScenTool		40	40	40	40	40	40	40	40	40	40	40
less	Non OTC Peaker	ScenTool		736	548	548	548	548	548	548	548	548	548	548
less	Non OTC Thermal	ScenTool		1169	1169	1169	1169	1169	1169	1169	1169	1169	1169	1169
less	Various and Unknown	ScenTool		41	41	41	41	41	41	41	41	41	41	41
less	Incr. Peaker Additions	Picker AD		0	0	0	308	808	808	808	808	808	808	808
less	Incr. Thermal Additions	D14-03-004		0	0	0	0	0	0	0	0	0	0	0
less	Incr. RPS Calc - Renew	14/15 Port		0	0	0	0	0	0	0	0	0	0	0
less	Incr. RPS Calc - DG	14/15 Port		9	14	39	50	51	55	60	66	67	78	78
less	Storage Additions	D14-03-004		0	0	0	4	8	13	17	21	25	25	25
less	DR Program Capability/Preferred DR Capab	multiple		18	19	19	19	20	20	21	21	21	21	21
=	Total Resources Base			3170	2989	3014	3338	2879	2788	2816	2828	2833	2843	2843
=	Resource Need (Surplus/Deficit) Base			(682)	(114)	60	565	387	477	324	254	178	74	(40)

Source: Energy Commission.

Table B-6: Baseline Results for Eastern Metro Subarea

	Variables (Summer Peak MW)	Source	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
Eastern-Metro Sub-Area (a subarea within LA Basin)														
	Base Load Forecast	2013 IEPR	6704	6847	6978	7070	7160	7251	7351	7456	7555	7645	7728	7803
less	Load Forecast Adjustment		0	0	0	0	0	0	0	0	0	0	0	0
less	AAEE	2013 IEPR	0	7	48	90	131	161	193	224	253	283	319	355
less	Preferred EE	SCE RFO	0	0	0	0	0	0	0	0	0	0	0	0
less	Preferred BTM Energy Storage	SCE RFO	0	0	0	0	0	0	0	0	0	0	0	0
less	Preferred BTM DG	SCE RFO	0	0	0	0	0	0	0	0	0	0	0	0
=	Managed Load Forecast		6704	6840	6930	6981	7028	7090	7158	7232	7302	7362	7409	7448
	Gross Local Capacity Requirements			7	48	90	131	161	193	2114	2143	2173	2209	2245
less	T-system Upgrade Impacts			0	0	0	0	0	0	0	0	0	0	0
less	LCR Change from Demand Adjustments			(7)	(48)	(90)	(131)	(161)	(193)	(224)	(253)	(283)	(319)	(355)
=	Adjusted LCR Base			0	0	0	0	0	0	1890	1890	1890	1890	1890
less	OTC Non Nuclear	ScenTool		0	0	0	0	0	0	0	0	0	0	0
less	OTC Nuclear	ScenTool		0	0	0	0	0	0	0	0	0	0	0
less	Hydro	ScenTool		282	282	282	282	282	282	282	282	282	282	282
less	Solar	ScenTool		0	0	0	0	0	0	0	0	0	0	0
less	Wind	ScenTool		0	0	0	0	0	0	0	0	0	0	0
less	Geothermal	ScenTool		0	0	0	0	0	0	0	0	0	0	0
less	Biomass	ScenTool		2	2	2	2	2	2	2	2	2	2	2
less	Cogeneration	ScenTool		183	214	214	214	214	214	214	214	214	214	214
less	Pump	ScenTool		0	0	0	0	0	0	0	0	0	0	0
less	Non OTC Peaker	ScenTool		340	340	340	340	340	340	340	340	340	340	340
less	Non OTC Thermal	ScenTool		1637	1637	997	997	997	997	997	997	997	997	997
less	Various and Unknown	ScenTool		61	62	62	62	62	62	62	62	62	62	62
less	Incr. Peaker Additions	SCE RFO		0	0	0	0	0	0	0	0	0	0	0
less	Incr. Thermal Additions	SCE RFO		0	0	0	0	0	0	0	0	0	0	0
less	Incr. RPS Calc - Renew	na		0	0	0	0	0	0	0	0	0	0	0
less	Incr. RPS Calc - DG	na		0	0	0	0	0	0	0	0	0	0	0
less	Storage Additions	SCE RFO		0	0	0	0	0	0	0	0	0	0	0
less	DR Program Capability	multiple		0	0	0	0	0	0	0	0	0	0	0
=	Total Resources Base			2506	2537	1897	1897	1897	1897	1897	1897	1897	1897	1897
=	Resource Need (Surplus/Deficit) Base			2506	2537	1897	1897	1897	1897	7	7	7	7	7

Source: Energy Commission.

APPENDIX C:
Numeric Results of Alternative Scenarios

Table C-1: LCAAT Results for Baseline and Alternative Scenarios—Area-Specific Surpluses or Deficits (MW)

CASE	AREA	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
Baseline	LA Basin/San Diego Subarea	(159)	2136	1396	1702	1806	1955	2156	(108)	(144)	(173)	(237)
Baseline	LA Basin	523	2250	1336	1137	1518	1577	1573	(526)	(389)	(220)	(77)
Baseline	West LA Basin Only (subset of LA Basin)	2711	2461	2058	1737	1894	1830	1813	(399)	(376)	(321)	(291)
Baseline	San Diego/Imperial Valley Area	964	664	923	1466	1328	1456	1220	1067	907	720	522
Baseline	San Diego Sub-Area	(682)	(114)	60	565	387	477	324	254	178	74	(40)
Baseline	Eastern-Metro Sub-Area (a subarea within LA Basin)	2506	2537	1897	1897	1897	1897	7	7	7	7	7
Optimistic	LA Basin/San Diego Subarea	481	2839	2195	2532	2724	2982	3293	1172	1260	1244	1193
Optimistic	LA Basin	1062	2869	2031	1851	2311	2464	2552	570	808	986	1138
Optimistic	West LA Basin Only (subset of LA Basin)	3001	2798	2439	2129	2360	2374	2433	318	429	489	524
Optimistic	San Diego/Imperial Valley Area	1064	748	1027	1583	1453	1597	1377	1250	1113	931	737
Optimistic	San Diego Sub-Area	(582)	(30)	165	681	513	618	481	438	384	285	175
Optimistic	Eastern-Metro Sub-Area (a subarea within LA Basin)	2736	2793	2179	2186	2191	2205	329	345	357	360	363
Pessimistic	LA Basin/San Diego Subarea	(269)	1908	1045	1176	1097	1216	1265	(1119)	(1565)	(1743)	(1975)
Pessimistic	LA Basin	514	2149	1139	802	1033	997	875	(1309)	(1547)	(1500)	(1496)
Pessimistic	West LA Basin Only (subset of LA Basin)	2706	2402	1941	1520	1561	1438	1367	(895)	(1185)	(1183)	(1253)
Pessimistic	San Diego/Imperial Valley Area	863	536	769	1276	1104	1297	1027	839	643	429	204
Pessimistic	San Diego Sub-Area	(783)	(241)	(94)	374	164	318	131	26	(86)	(216)	(358)
Pessimistic	Eastern-Metro Sub-Area (a subarea within LA Basin)	2503	2503	1832	1801	1774	1746	(202)	(230)	(284)	(346)	(378)
Incentives Fail	LA Basin/San Diego Subarea	(169)	2008	1146	1330	1329	1365	1456	(918)	(1067)	(1220)	(1407)
Incentives Fail	LA Basin	514	2149	1141	847	1147	1119	1029	(1155)	(1105)	(1031)	(983)
Incentives Fail	West LA Basin Only (subset of LA Basin)	2706	2402	1942	1565	1675	1559	1492	(770)	(799)	(800)	(826)
Incentives Fail	San Diego/Imperial Valley Area	963	636	868	1385	1223	1326	1064	885	699	484	258
Incentives Fail	San Diego Sub-Area	(683)	(142)	6	483	282	346	168	73	(30)	(162)	(304)
Incentives Fail	Eastern-Metro Sub-Area (a subarea within LA Basin)	2503	2503	1832	1801	1774	1746	(172)	(200)	(229)	(260)	(291)
Markets Cooperate	LA Basin/San Diego Subarea	144	2443	1710	2023	2167	2350	2586	369	380	351	286
Markets Cooperate	LA Basin	825	2557	1647	1454	1873	1963	1990	(69)	107	276	419
Markets Cooperate	West LA Basin Only (subset of LA Basin)	2875	2628	2227	1909	2103	2068	2080	(94)	(34)	20	51
Markets Cooperate	San Diego/Imperial Valley Area	964	664	926	1471	1334	1466	1233	1087	935	748	550
Markets Cooperate	San Diego Sub-Area	(682)	(114)	63	570	394	487	337	275	206	102	(12)
Markets Cooperate	Eastern-Metro Sub-Area (a subarea within LA Basin)	2632	2664	2026	2028	2030	2032	144	146	148	148	148

Source: Energy Commission.