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BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking to Develop an Electricity Integrated Resource Planning Framework and to Coordinate and Refine Long-Term Procurement Planning Requirements.	Rulemaking 16-02-007 (Filed February 11, 2016)

ASSIGNED COMMISSIONER'S RULING ADOPTING ASSUMPTIONS AND ONE SCENARIO FOR USE IN LONG-TERM PLANNING IN 2017

This Assigned Commissioner's Ruling adopts the attached standardized Assumptions and Scenario for use in the California Independent System Operator's (CAISO's) 2017-2018 Transmission Planning Process and any other long-term planning that occurs in 2017 until such time as the Commission adopts further guidance on integrated resource planning (IRP) policy and procedures.

Commission staff has coordinated with the California Energy Commission (CEC) and the CAISO to recommend these Assumptions and Scenario. The process is similar to the one used in previous years in long-term procurement planning (LTPP) proceedings.

On January 18, 2017 the Administrative Law Judge (ALJ) provided that parties could comment on the staff proposed Assumptions and Scenario. Parties commented on February 3, 2017[1] and replies were filed February 10, 2017.[2] I

[1] Comments were filed by: the California Environmental Justice Alliance and Sierra Club, jointly; the Cogeneration Association of California; Eagle Crest Energy; the Green Power Institute; L. Jan Reid; LS Power Development, LLC; the Natural Resources Defense Council; NRG Energy, Inc.; the Office of Ratepayer Advocates; Pacific Gas & Electric

Footnote continued on next page

thank the parties for their thoughtful comments. After consideration of these comments and in consultation with Commission staff, this ruling adopts the attached updated standardized Assumptions and Scenario.

I note that this adopted document intentionally hews toward consistency with past assumptions in previous LTPP and TPP processes. To the extent that some parties have longstanding concerns with our approaches used in the past few LTPP cycles, I anticipate that the IRP process will afford an opportunity for a more comprehensive reexamination of all assumptions and scenarios for going forward to meet our 2030 greenhouse gas and clean energy goals.

In the meantime, the updates in the attachment include the following key changes from the draft, in response to comments from some parties:

- **Section 3.2, Supply-side Assumptions**: Clarifying language has been added regarding the use of effective load carrying capability methods.
- **Section 3.2.4, Energy Storage**: Language has been added to clarify the relationship of electric service providers and community choice aggregators to energy storage procurement. The assumption of no further growth in energy storage capacity targets after 2024 has been removed.
- **Section 3.2.5, Demand Response**: Estimated 2026 Load Impacts for SCE's residential and non-residential air-conditioning cycling programs have been decreased due to forecasted program attrition. Further footnotes have also been added to clarify differences between demand response program load impacts filed on April 1, 2016 and the load

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Company (PG&E); Protect Our Communities Foundation; San Diego Gas & Electric Company (SDG&E); SolarCity Corporation; Southern California Edison Company (SCE); Transcanyon, LLC; the Union of Concerned Scientists; and the Utility Consumers' Action Network (UCAN).

[2] Reply comments were filed by the AWEA California Caucus; the California Energy Storage Alliance; the Large-Scale Solar Association; PG&E; SCE; and UCAN.

impacts shown in Table 8 of the 2017 Assumptions and Scenario attachment.

- **Section 3.1.10, Renewable and Hydro Retirement Assumptions**: Language has been added to clarify that if a facility announces a specific retirement date, that date will override the assumptions in the 2017 Assumptions and Scenario document.
- **Section 3.2.11, Other Retirement Assumptions**: The Long Beach peaker plants are assumed to retire at the end of their current contract(s) in 2017.
- **Section 3.2.12, Export Assumptions**: It is clarified that the 2000 MW mid-case export assumption should be used for the Reliability Scenario. The high-case export assumption has been raised from 5000 MW to 8000 MW.
- **Section 3.2.14, SDG&E Approved and Pending Storage Applications**: Table 12 has been amended to reflect 25 MW of energy storage authorized by Decision (D.) 14-03-004 and 20 MW of energy storage contained in Application (A.) 16-03-014 that was later terminated by SDG&E.

Attached to this ruling is the updated document containing the final adopted standardized Assumptions and Scenario for 2017.

Should any minor technical errors in the standardized Assumptions and Scenario be discovered after this ruling is issued, I hereby direct the Commission's Energy Division Staff to collaborate with the staff of the CEC and the CAISO to correct the errors, notify parties of the corrections, and ensure that the corrections are applied consistently across each organization.

IT IS RULED that the standardized Assumptions and Scenario attached to this Assigned Commissioner's Ruling are adopted for use in this Rulemaking and the California Independent System Operator's 2017-2018 Transmission Planning Process and any other long-term planning that occurs in 2017 prior to the adoption of a new process for integrated resource planning.

Dated February 28, 2017 at San Francisco, California.

/s/ LIANE M. RANDOLPH
Liane M. Randolph
Assigned Commissioner

ATTACHMENT A
2017 Assumptions and Scenario for Long-Term Planning

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1 Introduction

The California Public Utilities Commission (CPUC or "Commission,") staff has prepared this Draft 2017 Assumptions and Scenario for Long-Term Planning (Draft 2017 A&S) document in collaboration with staff from the California Energy Commission (CEC) and California Independent System Operator (CAISO).

In previous years, the Assumptions and Scenarios have been released in the CPUC's Long-Term Procurement Plan (LTPP) proceeding as the LTPP A&S Document.[1] This year's document, the Draft 2017 A&S, memorializes common assumptions to be used for long-term electricity system planning in the state of California. The Draft 2017 A&S is being issued within the 2016 Order Instituting Rulemaking to Develop an Electricity Integrated Resource Planning Framework and to Coordinate and Refine Long-Term Procurement Planning Requirements (R. 16-02-007), which incorporates LTPP and acts as the successor proceeding to R.13-12-010. It is anticipated that future Assumptions and Scenarios for use in long-term planning will be generated by the Integrated Resource Planning (IRP) process within R.16-02-007. Historically, a Scenario Tool was issued along with the LTPP A&S. The Scenario Tool acts as an annual load and resource table which follows the assumptions outlined by the LTPP A&S document to illustrate how the planning reserve margin is met up to 20 years into the future. There will be no Scenario Tool update provided with this 2017 A&S. The August 2016 Scenario Tool[2] will remain the reference long-term planning load and resource table for California's electricity system until a successor is produced within this proceeding.

Similar to previous LTPP cycles, this document provides demand-side and supply-side planning assumptions that should, where appropriate, inform the CAISO 2017-2018 Transmission Planning Process (TPP) studies and long-term planning for the state of California. While both the CAISO TPP and IRP processes are expected to respond to stakeholder input, the objective is to maintain consistency between planning processes to the greatest extent possible.

Demand-side assumptions are based on the CEC's draft 2016 Integrated Energy Policy Report California Energy Demand Updated Forecast 2017-2027 (CEDU 2016). Supply-side assumptions reflect an annual projection of the mix and attributes of the future resource fleet, including existing and new conventional and renewable resources, as well as future retirements. Unlike previous LTPP cycles, this document does not propose multiple scenarios for study. This type of guidance will be provided by other processes within R.16-02-007, and successor proceedings, as the IRP process develops. Included in the Draft 2017 A&S is a single scenario, the Reliability Scenario. The Reliability Scenario is very similar to the Infrastructure Investment Scenario articulated in the previous version of the LTPP A&S (May 2016).[3]

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[1] http://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M162/K005/162005377.PDF.

[2] http://cpuc.ca.gov/WorkArea/DownloadAsset.aspx?id=12332.

[3] http://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M162/K005/162005377.PDF.

Previous versions of the LTPP Assumptions & Scenarios document contained information intended for use in policy-driven analyses in the CAISO's TPP process. Policy-driven analysis historically focused on identifying any transmission infrastructure needed to support the state's Renewable Portfolio Standard (RPS) program. By mutual agreement, no RPS-related policy-driven analyses to identify new infrastructure needs beyond what is necessary for a 33% RPS scenario are being provided by the CPUC for consideration in long-term planning and for use by the CAISO for its 2017-18 TPP, as explained in more detail in Section 4.1.

Comments:

Parties to R.16-02-007 will be given the opportunity to provide comments and reply comments on this Draft 2017 A&S.

1.1 Terminology

Acronym	Definition
1-in-10	1-in-10 year weather peak demand forecast
1-in-2	1-in-2 year weather peak demand forecast
AAEE	Additional Achievable Energy Efficiency
AB	Assembly Bill
ACR	Assigned Commissioner Ruling
BTM	Behind-the-meter
CAISO	California Independent System Operator
CEC	California Energy Commission
CED	California Energy Demand Forecast
CEDU 2016	Draft 2016 Integrated Energy Policy Report California Energy Demand Updated Forecast, 2017-2027
CHP	Combined Heat and Power
CPUC	California Public Utilities Commission or "Commission"
DCPP	Diablo Canyon Power Plant
DR	Demand Response
Draft 2017 A&S	Draft 2017 Assumptions and Scenario for Long-Term Planning
EE	Energy Efficiency
ELCC	Effective Load Carrying Capability
GHG	Greenhouse Gas
GWh	Gigawatt Hour
IEPR	Integrated Energy Policy Report
ILR	Inverter Loading Ratio
IOU	Investor Owned Utility
LCR	Local Capacity Requirement

Acronym	Definition
LSE	Load Serving Entity
LTPP	Long Term Procurement Plan
MW	Megawatt
MWh	Megawatt Hour
NMV	Net Market Value
NQC	Net Qualifying Capacity
OIR	Order Instituting Rulemaking
OTC	Once-through cooling
PG&E	Pacific Gas & Electric
POU	Publicly Owned Utility
PV	Photovoltaics
RFO	Request for Offers
RNS	Renewable Net Short
RPS	Renewable Portfolio Standard
SB	Senate Bill
SCE	Southern California Edison
SDG&E	San Diego Gas & Electric
SWRCB	State Water Resources Control Board
TEPPC	Transmission Expansion Planning Policy Committee
TOU	Time-of-Use
TPP	Transmission Planning Process
WECC	Western Electricity Coordinating Council

1.2 Definitions

- **Load Forecast**: refers to the electricity demand served by the electric grid, measured by both peak demand and energy consumption. Load forecasts are influenced by a number of factors, such as State economics, demographics, behind-the-meter (BTM) resources and retail rates.
- **Assumption**: a statement that is made regarding the future for a given load forecast, or demand side or supply side energy resource, that should be used for procurement and transmission modeling purposes. For example, a forecasted load condition is an "assumption."
- **Scenario**: a set of assumptions about future conditions that is used in power system modeling performed to support generation or transmission planning.
- **Sensitivity**: is a variation on a scenario where only one variable is modified in order to assess its impact on the overall scenario results. Changing the retirement date of Diablo Canyon Power Plant, while holding other assumptions constant, is an example of a sensitivity.

- **Managed Forecast**: refers to the California Energy Demand Update (CEDU) Forecast that has been adjusted to account for the impact of load modifying programs that are expected to come online but that are not embedded into the baseline load forecast. An example of a "managed forecast" is a forecasted load that has been adjusted to account for energy efficiency programs that are not yet funded but that are expected to be implemented over the course of the planning horizon – frequently referred to as Additional Achievable Energy Efficiency (AAEE).
- **Probabilistic Load Level**: refers to the specific weather patterns assumed in the study year. For example, a 1-in-10 load level indicates a High load event due to weather patterns expected to occur approximately once every 10 years. The probabilistic load level primarily impacts annual peak demand (and other demand characteristics, such as variability) but does not significantly impact annual energy consumption.

1.3 Load Type Definitions

The CPUC, CEC, and CAISO have agreed upon a common modeling lexicon to facilitate modeling discussions across agencies. Note that in the CPUC production cost modeling work CPUC staff models behavior at the system level, and does not differentiate between sales and system load (i.e. staff grosses sales to the system level, accounting for distribution level losses).

Load Types	Relation to Other Terms	Rationale	Measurement
Consumption	Sum of electrical energy used to operate end-use devices excluding charge/discharge of storage	Consumption is the term used in CEC forms to capture onsite energy usage.	With increased self generation, and when relying on net energy metering to apply cost responsibility to end-users, consumption becomes counterfactual.
Sales	Consumption less BTM onsite generation including storage charge/discharge	Sales is the energy term to indicate the net energy delivered through the meter to the end-use customer	Metered by the utility on a short interval basis if the utility has deployed interval metering systems for end-users; otherwise could be estimated using load research practices
System	Sales load plus T&D losses plus theft and unaccounted for	Standard electricity industry term. CEC defines "hourly system load" in its data collection regulations	Generally measured by power plant output and import flows, e.g. a top down measurement inferring loads rather than a bottom up summation of individual customer loads

Load Types	Relation to Other Terms	Rationale	Measurement
Net Load	System load less system intermittent renewable generation	This is the same definition as being used by CAISO	Balancing Area Authority estimation of system load less measured output of wind and solar supply-side renewables

1.4 Background

The Long-Term Procurement Plan (LTPP) proceedings were established to ensure a safe, reliable, and cost-effective electricity supply in California.[4] The LTPP proceeding addresses the overall long-term need for new system and local reliability resources, including the need for resources that provide operational flexibility.

To facilitate that ability of the public, staff, and decision-makers to compare and interpret the results of studies performed in different planning processes, the underlying study assumptions should align and be consistent. In order to ensure this alignment, consistency is needed for California's long-term planning assumptions. This Draft 2017 A&S document acts as a set of agreed-upon long-term planning assumptions until a successor document is adopted in this proceeding at a later date. The CPUC updates the planning assumptions on an annual basis in coordination and collaboration with the CAISO and the CEC. This document contains those updates.

1.5 History of LTPP Planning Assumptions

Since the 2006 LTPP the CPUC has worked to make the long-term procurement planning process more streamlined and transparent. The main effort of the 2008 LTPP was the creation of the *Energy Division Straw Proposal on LTPP Planning Standards*.[5] The 2010 LTPP took strides towards implementing that proposal, with adjustments based on party comments. CPUC Energy Division staff held several workshops in the summer of 2010, and in December of that same year, the *2010 LTPP Standardized Planning Assumptions* were issued via a Joint Scoping Memo and Ruling.[6] Following a similar process of workshops and comments in 2012 and 2013, the CPUC established LTPP planning assumptions for the 2012 and 2014 LTPP that build upon previous planning efforts to further improve the LTPP process.

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[4] Pursuant to Assembly Bill (AB) 57 (Stats. 2002, ch. 850, Sec 3, Effective September 24, 2002), added Pub. Util. Code § 454.5., enabling resources to resume procurement of resources. *See also* OIR 3/27/2012, Scoping Memo 1.

[5] *Energy Division Straw Proposal on LTPP Planning Standards*, http://docs.cpuc.ca.gov/published/Graphics/103215.PDF.

[6] *See* Assigned Commissioner and Administrative Law Judge's Joint Scoping Memo and Ruling, issued December 3, 2012, http://docs.cpuc.ca.gov/EFILE/RULC/127542.htm.

The Order Instituting Rulemaking for R.16-02-007 was issued on February 19, 2016. R.16-02-007 is the Commission's primary venue for implementing the requirements related to Integrated Resource Planning mandated by Senate Bill 350: the Clean Energy and Pollution Reduction Act (de León, Chapter 547, Statutes of 2015) (SB 350). This proceeding also incorporates LTPP activities from R.13-12-010. This Draft 2017 A&S document acts as a bridge between the previous LTPP process and the successor IRP process. It is intended to provide continued coordination with the CAISO TPP process, keeping in accordance with the Joint Agency Process Alignment Agreement[7].

2 Planning Scope: Area & Time Frame

The 2017 Assumptions and Scenario are created specifically with regards to the loads served by, and the supply resources interconnected to, the CAISO-controlled transmission grid and the associated distribution systems.[8] Similar to the historic LTPP planning period, the Draft 2017 A&S for long-term planning forecasts 20 years out in order to study the impacts of major infrastructure decisions under consideration. The long term nature of resource planning is necessary given that resources procurement decisions typically take three to nine years until fruition. While detailed planning assumptions are used to create an annual loads and resources assessment in the first 10-year period (2017-2027), more generic long-term assumptions are used in the second 10-year period (2027-2037), reflecting the greater uncertainties associated with forecasting a more distant future.[9] Nonetheless, shorter-term (present to 10 years out) implications for infrastructure policy decisions can be assessed in conjunction with the longer term (10 to 20 year out) implications that each decisions carries.

This document supersedes the previous versions of assumptions and scenarios in this proceeding.

3 Planning Assumptions

A description of assumptions is provided in this section.

[7] Infrastructure planning in California is split among the California Public Utilities Commission (CPUC), California Energy Commission (CEC), and California Independent System Operator (CAISO). These agencies collaborate to ensure that planning activities use common assumptions and are periodically updated.

More information is available here: http://cpuc.ca.gov/WorkArea/DownloadAsset.aspx?id=6630

[8] The technical studies will model the entire Western Electricity Coordinating Council (WECC); this document describes the assumptions that should be used for the balancing areas located inside the CAISO service territory. For assumptions pertaining to the balancing authorities located outside of the CAISO service territory, modelers shall rely upon the latest TEPPC common case data: https://www.wecc.biz/Reliability/WECC_2026CC_V1.5%20Package.zip.

[9] The updates incorporated in this document will also inform the 2017-18 TPP studies.

3.1 Demand-side Assumptions

Through joint-agency coordination processes such as the Joint Agency Steering Committee (JASC) and the Demand Analysis Working Group (DAWG), the CPUC, CEC, and CAISO work together to ensure no double-counting of demand-side resources in the CEDU 2016.

3.1.1 Baseline, Incremental, and Managed Forecasts

The CEC-adopted CEDU 2016[10] is used as the "baseline" forecast. Demand-side assumptions are either embedded in the baseline forecast or consist of adjustments made to the baseline forecast. Incremental resource projections, such as Additional Achievable Energy Efficiency (AAEE),[11] are not embedded in the baseline forecast, but can be used to modify the baseline forecast to create a net or "managed" forecast. As an example, in the CEDU 2016 the CEC embeds an amount of energy efficiency representing current codes and standards and established energy efficiency programs. AAEE represents future expected energy and capacity savings from programs not yet established or funded; as such, AAEE is considered an incremental resource projection to the Energy Efficiency (EE) embedded in the CEDU 2016. In addition to its "baseline" demand forecast, the CEC publishes managed load forecasts which embed different levels of AAEE assumptions.

For modeling purposes the CEC provides its AAEE savings projections at the transmission bus-bar level to the CAISO; this information offers AAEE locational specificity to the CAISO and is provided on yearly basis for the given TPP's 10-year planning horizon.

3.1.2 Locational Certainty

As California chooses to meet its electricity needs with increasing proportions of demand-side management resources, such as energy efficiency and customer-sited solar photovoltaic (PV) self-generation, it becomes increasingly important to accurately forecast the locations of these demand-side impacts in order to capture the benefits that these resources provide to the system. Reliability studies in transmission-constrained local areas depend on these demand-side resources being capable of providing capacity value within the electrical areas in which they are forecasted to be located; ideally, their capacity value and location would be forecasted at specific transmission-level bus-bar or substation locations so that they can offset local capacity requirements in these subareas. Historically, demand-side resource projections lacked the locational certainty needed to contribute to local reliability. Fortunately, the current CED set of forecasts, with its embedded demand-side resources and incremental AAEE projections, is increasingly incorporating greater locational certainty by providing impacts at the climate zone level for BTM resources. The CEC defines 15 climate zones in California.[12] Efforts are underway to further refine the

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[10] See the CED: California Energy Demand 2017-2027 Forecast, http://www.energy.ca.gov/2016_energypolicy/.

[11] AAEE projections: https://efiling.energy.ca.gov/Lists/DocketLog.aspx?docketnumber=16-IEPR-05.

[12] See p. 51 of http://www.energy.ca.gov/2013publications/CEC-200-2013-004/CEC-200-2013-004-V1-CMF.pdf.

locational certainty of all BTM demand-side resources[13], to the transmission substation level, so that the capacity benefit provided by these resources can be appropriately counted on as a potential alternative to local conventional generation. [14]

3.1.3 Load

The CEC's CEDU 2016 set of forecasts, serves as the source for the "managed demand forecasts;" it consists of a base load forecast coupled with several alternative AAEE projections (see subsection on Energy Efficiency below). CEDU 2016 is an update of the full CED 2015 forecast, developed to incorporate more recent economic and demographic projections and the latest historical data. All other factors, such as projected load-modifying demand response, efficiency impacts, and rates are unchanged from CED 2015. The CEDU base forecasts include three load cases, "Low," "Mid," and "High," each factoring in variations on economic and demographic growth, retail electricity rates, fuel prices, and other elements. Each load case also has peak demand weather variants, for example, 1-in-2 weather year and 1-in-10 weather year.

While the CED forecasts use the best available information, they do not include all future expected activity. For example, the CEDU 2016 base forecast does not include the impact of the CPUC's recently adopted rate changes. Additionally, the CEDU 2016 does not incorporate changes expected to result from the adoption of Senate Bill 350.

The CEDU 2016 forecasts do account for the electrification of the transportation sector. However, development of policies that drive higher electrification growth is underway and may result in a different level of penetration of electric vehicles (EVs) across all vehicle types, including rail electrification, than what is embedded in the CEDU 2016 base load forecast.

The CEDU 2016 forecasts also included sensitivity analysis to account for the "peak shift" effect resulting from high penetrations of behind-the-meter rooftop photovoltaic solar systems, as discussed in further detail in subsequent sections. The CEC published the CEDU 2016 forecasts in December 2016.

For planning studies that utilize an 8760 hour load profile as input, the load profile should have annual peak and energy values consistent with the CEDU forecasts for the year being studied. The base load profile should be adjusted by using CEC-provided AAEE load shapes described in the following subsection. For planning studies that utilize a single historical

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[13] Distribution Resources Plan Proceeding: R.14-08-013 and Integrated Distributed Energy Resources Proceeding: R.14-10-003.

[14] For the past three TPP cycles, the CEC staff have developed load bus projections of AAEE peak savings to enable the CAISO to include these savings in its power flow studies. These "translations" of the approved AAEE projections, for use in the TPP, are not explicitly adopted by the CEC.

year as the basis for 8760 hour load shapes, the historical year should match the year used in the TEPPC 2026 Common Case.[15]

3.1.4 Energy Efficiency

Energy efficiency forecasts are developed from the CEDU 2016 base forecasts and its supplemental AAEE projections. Each load case of the CED base forecasts contains an embedded EE component that will be paired with an AAEE projection scenario representing additional savings. CEC staff, with input from the Demand Analysis Working Group and in consultation with CPUC staff and CAISO staff, developed the AAEE projections. In general, the lowest savings scenario includes only the EE savings most certain to materialize while the highest savings scenario includes all EE potential including aspirational goals (e.g. emerging technologies). Depending on the type of planning study, finer granularity of EE savings projections may be required.

Some planning study types may utilize EE savings projections allocated at the transmission-level bus-bar, and/or daily and seasonal load-shape EE savings projections. The CEC is developing 8760 load shapes for AAEE that match to the aggregate AAEE projections documented as part of the revised demand forecast. This task was undertaken so that modelers will not have to make up their own hourly shape, or debit it from peak and annual energy, and then effectively apply the same shape to AAEE as they do for the base forecast. We require that modelers use these 8760 hourly load reduction values when submitting studies to the CPUC, CEC or the CAISO. Transmission and distribution loss-avoidance effects shall be accounted in all studies.

The CEDU 2016 1-in-2 and 1-in-5 weather year, Mid-Baseline-Mid-AAEE forecasts should be used for the CAISO's system and bulk reliability studies in the 2017-18 TPP cycle.[16] The 1-in-10 weather year, Mid-Baseline-Low-AAEE forecast should be used for local reliability studies. The Mid-Baseline-Low AAEE scenario is appropriate for local reliability studies given the difficulty of forecasting load and AAEE at specific locations.

The May 2016 A&S document included a methodology to derive an AAEE forecast that corresponded to SB 350 AAEE goals. The Draft 2017 A&S does not attempt to approximate the additional AAEE envisioned by SB 350. SB 350 tasks the CEC with identifying AAEE savings and establishing targets for statewide energy efficiency savings and demand reductions to achieve doubling of energy efficiency by January 1, 2030. Agreement on how to implement SB 350's AAEE goals and how to model them will be arrived at in a separate venue after they are established by the CEC, in coordination with the CPUC, and later will be reflected in the Integrated Resource Planning (IRP) process ordered by SB 350.

The CPUC staff will work with the CEC staff to develop, in a manner consistent with the CAISO-wide aggregate energy efficiency savings: (1) the specific hourly values appropriate

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[15] The TEPPC 2024 Common Case used the year 2005 as the basis for load shapes because it reflected an average weather year. TEPPC uses 2009 as the basis for load shapes in the 2026 Common Case.

[16] See the "Reliability Scenario" included in section 5.1 "2017 Planning Scenario – Reliability Scenario".

to production simulation modeling, and (2) load bus modifiers that can be used in power flow modeling.

3.1.5 Solar Photovoltaics

Embedded Impacts

The Mid BTM PV assumption included in this document assumes no change to the BTM PV embedded in the Mid-demand IEPR forecast; the Mid-demand IEPR forecast incorporates a Mid-level assumption for installed PV capacity.

Although BTM PV is generally regarded as a demand-side resource, both the CED forecast-embedded BTM PV and any incremental amounts could be modeled as supply resources (e.g. as a non-dispatchable resource with a fixed annual energy profile) in resource planning models. Under this modeling convention, the corresponding demand forecast assumptions in the resource planning model would need to be adjusted upward to remove the impact of BTM PV resources, since BTM PV resources would be separately accounted for as a supply-side resource. The appropriate upward adjustment would require adding back the peak and energy reduction impact of the BTM PV resources, plus avoided losses, to the demand forecast. Production cost modeling, including production cost modeling employed by the CAISO in transmission planning proceedings, often uses this modeling convention (modeling BTM PV as supply resources). Power flow and dynamic stability models, such as used in the CAISO's TPP transmission planning studies employ "composite load models" that model the BTM PV as a discrete subset of the load model.

The BTM PV resource assumptions described above are forecasts of the installed AC output of these resources, and reflect estimates of capacity contribution during IOU peak periods and annual energy production. The capacity contributions of BTM PV resources during IOU peak periods in different load areas are calculated by multiplying installed AC capacity by the "peak impact factor." In order to calculate the BTM PV resources annual energy production one must multiply the BTM PV resource "capacity factor" by the MW of installed BTM PV resource capacity and multiply the result by 8760 hours. The table below summarizes the IOUs' peak impact factor and capacity factor that should be used in resource planning studies. These factors are derived from the embedded BTM ("self-generation") PV resource assumption for each of the three major IOUs.

Table 1: Small Solar PV Operational Attributes

Variable	**PG&E**	**SCE**	**SDG&E**	**Average of all 3 IOUs**
Peak Impact factor	0.353	0.383	0.385	0.369
Capacity factor	0.184	0.186	0.172	0.185

The physical configuration of BTM PV resources influences the shape of hourly generation profiles and has material impact on the outcome of resource planning studies that inform the TPP and the LTPP. Two important physical attributes are the PV mounting type and the DC-AC inverter loading ratio. For BTM PV resources, the Mid assumption for mounting type is fixed-tilt, south-facing. The ratio of panel capacity to inverter capacity is the "DC-AC inverter loading ratio;" a higher loading ratio tends to flatten or clip the production profile of a PV unit. Industry practice for PV installations has been to install a panel capacity larger than the inverter capacity in order to compensate for de-rate factors such as DC-AC conversions and losses and to maximize economic value. For BTM PV resources, the Mid assumption for DC-AC inverter loading ratio is 1.2,[17] which is consistent with the assumption used in the Transmission Expansion Policy Planning Committee (TEPPC) Common Case.[18]

Granular information on the location and physical attributes of installed BTM PV resources can be derived from public databases such as those found on the "Go Solar California" web portal.[19] However, CPUC staff believes the benefit of incorporating such granular information in long-term planning assumptions is small because the overall uncertainty in BTM PV aggregate installed capacity in the long term is a much larger driver of modeling results. Therefore CPUC staff defers consideration of this granular information to a future long-term planning cycle.

As mentioned above, models such as hourly production simulation models need to model BTM PV as a supply resource with a fixed profile, rather than as a load reduction in order to account for the hourly shape of solar generation. The source of underlying irradiance profiles and method for creating 8760 hour generation profiles for BTM PV should be documented by the modeler. The 8760 hour generation profiles should also be consistent with the technical attributes described above: fixed-tilt, south-facing, and DC-AC inverter loading ratio 1.2. By building 8760 hour generation profiles according to the BTM PV installed AC capacity and the assumed technical attributes specified in this subsection, the resulting annual energy production implied by the profiles may deviate slightly from the annual energy production forecasted by using the capacity factors in

Table 1.

Peak Shift

The CEDU 2016 includes an analysis of the "peak shift" effect. Demand modifiers such as BTM PV, AAEE, time-of-use-pricing, and electric vehicles may affect load in such a way that hourly load profiles change. This change in load profile can lead to a shift in the hour during which LSEs serve their peak load. This peak shift effect can result in peak load shifting to later hours in the day than the historical hour that the peak had occurred which

[17] For BTM PV technology assumptions, the RPS Calculator uses the default settings of the National Renewable Energy Lab's PV Watts tool, including DC to AC size ratio of 1.1, fixed-tilt, and azimuth south-facing.

[18] https://www.wecc.biz/TransmissionExpansionPlanning/Pages/Datasets.aspx.

[19] https://www.californiasolarstatistics.ca.gov/.

is included in the CEDU base forecast. The CEDU 2016 includes a scenario analysis of potential peak shift and the resulting impact on peak demand served by utilities. The results of this analysis are provided as an alternative scenario to the managed forecast of the CEDU 2016 for use in CAISO's TPP process for the review of previously-approved projects or procurement of resource adequacy resources to maintain local reliability, but not for identification of new needs that could result in new transmission projects.

The CEDU 2016 peak shift scenario analysis consisted of three main components:

- Hourly load profiles for PV generation
- Hourly load profiles for AAEE savings
- Projected weather normalized hourly end-use loads for each of 8760 hours for each year

The impacts of time-of-use and electric vehicles were not included in this analysis. Estimated load shapes for these modifiers are at a preliminary stage, and require more data and study.

The preliminary analysis of the "peak shift" effect included in the CEDU 2016 indicates a clear upward trend in LSEs' peak load, demonstrating a peak load increase relative to the 2015 IEPR CED managed forecast due to a smaller contribution of peak reduction by BTM PV resources at the later hour due to the "peak shift" effect. Annual adjustments were calculated to be incremental to 2016 load.

3.1.6 Combined Heat and Power

The CEC traditionally forecasts a "consumption" energy demand forecast and then subtracts onsite self-generation, such as behind-the-meter Combined Heat and Power (CHP) generation, in order to compute the net energy for load. As such, the default assumption for BTM CHP resources assumes no change from what the CED forecasts embed. The BTM CHP resource capacity that does not export to the grid will not be modeled as a supply resource; its impact will be implicitly modeled by virtue of being embedded in the CEC load forecast. Any CHP resource that serves both BTM load and exports to the grid (or in some cases which only exports to the grid) will have its export component (net of the capacity and energy used onsite) modeled as a supply resource, as described in Section 3.2.3.

3.1.7 Demand Response

The CED forecasts embed the impacts of load-modifying[20] demand response (DR) programs. These programs are generally non-event-based and/or tariff-based and include

[20] See D.14-03-026 in the Demand Response Rulemaking, R.13-09-011, for further background on "load-modifying" and "supply-side" DR programs and the meaning of these terms with respect to DR resource attributes.

existing Time-of-Use (TOU) rates,[21] Permanent Load Shifting, and Real Time Pricing. Certain event-based, price-responsive programs are also embedded in the CED forecasts and include Critical Peak Pricing and Peak Time Rebate programs.[22]

There may also be additional DR impacts that need to be explored. For example, a future DR impact may come from defaulting residential customers to TOU rates.[23] Commission staff will collaborate with CEC's staff to facilitate the study of the default residential customer TOU rate impact in the next major CEC IEPR CED planning cycle.

3.1.8 Energy Storage

Energy storage units shall be modeled as supply-side resources; therefore this document describes the planning assumptions for distribution-connected and customer-connected storage, as well as transmission-connected storage, within the "Supply-side Assumptions" section.

3.1.9 Transportation Electrification

The CEDU 2016 Mid-demand case includes a transportation electrification assessment reflecting the best available California specific EV penetration information. This forecast, which is based on current policy trends, also includes expected electrification in airport ground support equipment, port cargo handling equipment, shore power, truck stops, forklifts, and truck refrigeration units through 2027. The default transportation electrification assumption included in this document assumes no change to the transportation electrification assumption that is embedded in the Mid-demand IEPR forecast.

3.1.10 Avoided Transmission and Distribution Losses

Demand-side resource projections need to account for avoided transmission and distribution losses when calculating the balance of projected supply and demand. The table below specifies factors supplied by the CEC for accounting of avoided transmission and distribution losses. These factors are applied to the demand-side resource projections

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[21] The latest CED forecasts embed the impact of the TOU rates and periods existing in 2014, as they were forecast in the IOU's April 2015 load impact reports. These do include: (for residential customers) continuation of the TOU rates existing in 2014, with essentially no growth in participation – no default – and no late-shift in TOU periods; and (for non-res customers) mandatory TOU but no late-shift in TOU periods.

[22] DR programs whose impacts are *not* embedded in the CED forecasts include several event-based, price-responsive and reliability programs. Within the LTPP planning horizon, these programs shall achieve full integration into the CAISO wholesale market and therefore count as supply-side DR. Section 3.2.5 describes assumptions about DR treated as supply-side resources.

[23] The CED forecasts embed the impacts from existing TOU rates but do not include potential impacts from TOU rate changes being considered such as default TOU rates and shifting price periods/seasons.

in order to determine the avoided supply-side generation replaced by the presence of demand-side resources.

Table 2: Factors to Account for Avoided Transmission and Distribution Losses

	PG&E	SCE	SDG&E
Peak, distribution losses only	1.067	1.051	1.071
Peak, transmission and distribution losses	1.097	1.076	1.096
Energy, transmission and distribution losses	1.096	1.068	1.0709

3.2 Supply-side Assumptions

All supply-side resource assumptions are solely for planning study purposes. Inclusion or exclusion of a specific project or resource in the planning cycle has no implications on existing or future contracts. To the extent a specific project or resource turns out to not be available, the planning study assumes an electrically equivalent resource will be available. All supply-side resources should be categorized as either a local resource (specific to a local area), a generic system resource, or a non-CAISO resource. At this time, no degradation of resource production is accounted for in these planning assumptions.

Resource Representation In Planning Models

A variety of planning studies can use the supply-side resource assumptions described by this document. Production simulation models should use the actual physical resource attributes of the supply-side (as well as demand-side) resource portfolios specified by this document. Power flow (load flow) and stability studies such as those used in the CAISO's TPP typically need to translate actual physical resource attributes into expected resource output levels under the specific conditions being modeled in such studies.

For variable energy resources such as wind or solar energy resources, hourly production simulation models should use 8760-hour generation profiles for modeling production. The source of the underlying wind and irradiance profiles, and the method for creating the 8760-hour generation profiles, should be documented by the modeler. The 8760-hour generation profiles should also be consistent with the resource technologies and locations specified in the renewable resource portfolios described in Section 3.2.6 and (for solar PV) the specific technical attributes described in Section 3.2.7.

In the power flow and stability studies typical of the CAISO's TPP, a required input is the expected output level of variable resources under the specific conditions being modeled, usually a specific time-of-day during a particular season. The CAISO has historically relied on one of two mechanisms for calculating the expected output level.

One mechanism used the 8760 hour generation profiles for variable resources, described above; this mechanism requires extracting resource output levels corresponding to the time period being studied (e.g. peak, off-peak, partial peak, and light load base cases). The other mechanism relied on the historical Net Qualifying Capacity (NQC) of a variable resource (calculated in the Resource Adequacy proceeding using an exceedance methodology) as the basis for the expected output level from variable resources that share similar technological and locational attributes during the specific conditions being studied.

This document provides no additional guidelines for modifying the current modeling practices associated with the output levels of variable resources. The CPUC is actively considering the use of Effective Load Carrying Capability (ELCC) methods, which assign capacity value to wind and solar resources. ELCC methods are typically used to characterize the reliability contribution of a resource or class of resources over the course of an entire year. The Resource Adequacy proceeding will determine how the use of ELCC methods will inform NQC calculations for the purpose of system and/or local Resource Adequacy compliance. For 2017-18 TPP modeling purposes, the current Resource Adequacy exceedance methodology for estimating NQC of wind and solar should continue to be utilized to model output levels of variable resources in the power flow (load flow) and stability studies typical of the CAISO's TPP.

3.2.1 Existing Resources

Existing resources are itemized by the 2017 Resource Adequacy compliance year NQC list. This list includes all online resources with a CAISO Resource ID and that qualify for provision of Resource Adequacy, regardless of resource type. The CAISO and CPUC both publish these lists annually on their respective websites.

3.2.2 Conventional Additions

The default values for conventional resource additions 50 MW or larger derive from the list of power plant siting cases maintained on the CEC website.[24] The default values for conventional resource additions smaller than 50 MW derive from other databases maintained by the CEC. The CEC updates these lists several times per year. A power plant project shall be counted if it (1) has a contract, (2) has been permitted, and/or (3) has begun construction. A power plant project that does not meet these criteria may be counted if the staff of the agency with permitting jurisdiction expects the project to come online within the planning horizon.

3.2.3 Combined Heat and Power

Combined Heat and Power resources identified in this section export electricity to the grid.[25] The default projection for exporting CHP assumes that all retiring CHP resources

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[24] http://www.energy.ca.gov/sitingcases/all_projects.html.

[25] The NQC list includes values for only that portion of the exporting CHP facility that is used to export. For example, if a CHP facility has a 100 MW capacity and 40MW of that capacity is dedicated to meet onsite energy consumption, the NQC list only reports NQC values associated with 60 MW of that facility.

less than or equal to 20 MW that are on the 2016 NQC list would be replaced on a one-to-one basis by similar CHP resources; CHP resources that are greater than or equal to 20 MW will be assumed to retire based on a 40 year life cycle, or contract expiration date (whichever is furthest out).

Exporting CHP resources will be modeled as follows. First, one half of the exporting CHP capacity of each CHP resource will be assumed to operate on a historic profile as reflected by its monthly values on the 2016 NQC list and should be modeled as non-dispatchable resources. Secondly, the remaining half of the exporting capacity of each CHP resource will be assumed to be resources that are dispatchable by the CAISO.

3.2.4 Energy Storage

CPUC D. 13-10-040 established a 2020 procurement target[26] of 1,325 MW of newly installed energy storage capacity within the CAISO planning area. Of that amount, 700 MW needs to be transmission-connected, 425 MW needs to be distribution-connected, and 200 MW needs to be customer-side-connected. Unless otherwise noted via the IOUs' energy storage Applications, CPUC staff has assumed that 40% of the megawatts associated with transmission-connected and distribution-connected projects will provide two-hour storage, 40% of these projects' megawatts will provide four-hour storage, and the remaining 20% will provide six-hour storage. For energy storage projects connected on the "customer-side" – that is, behind-the-meter – CPUC staff assumes that 50% of these projects' megawatts will provide two-hour storage and 50% will provide four-hour storage.

Decision D.13-10-040 allocated a portion of the 1,325 MW energy storage procurement target to each of the three major IOUs.[27] Energy storage that is operational after January 1, 2010 and no later than December 31, 2024 shall count towards the procurement target. Energy storage resources that are procured to satisfy a local capacity requirement also count towards satisfying the 1,325 MW energy storage target. Because such projects satisfy the local capacity RA requirement, they should be modeled as having at least a four-hour storage attribute, absent more specific information in the relevant procurement application.

Additionally, ESPs and CCAs must either pay their share of the energy storage procurement costs to utilities through the Cost Allocation Mechanism or procure energy storage projects on their own, commensurate with their load share.[28]

Assumptions about storage attributes and capabilities

[26] The Decision specifies that resources must be online by 2024 so in the planning assumptions, target amounts are reached in 2024.

[27] The CPUC also established an additional procurement target of 1% of load for ESPs and CCAs. The storage assumptions included herein do not include ESPs' or CCAs' storage resources.

[28] D.13-10-040, pg. 43.

For modeling purposes, the entire 1,325 MW energy storage target shall be assumed to be operated such that the storage provides energy shifting, capacity, and flexibility services. The interconnection point of a storage resource does not determine its effectiveness for providing resource adequacy capacity, including flexible capacity, or ancillary services. In other words, regardless of interconnection domain (transmission-connected, distribution-connected, BTM), all storage shall be modeled as dispatchable and providing Resource Adequacy capacity and operational flexibility services. This represents a change in assumptions from the previous LTPP A&S.

Table 3: Total Energy Storage Procurement To-Date (Based On IOU Data Received In Late 2016)

Domain	Transmission-connected	Distribution-connected	Customer-connected
SDG&E	40	44	20
SCE	55	204	199
PG&E	60	16	4
Total	155	264	268

Table 4: Residual Energy Storage Procurement To Meet D.13-10-040 Targets (MW)

Domain	Transmission-connected	Distribution-connected	Customer-connected
Total Capacity	545	160	0
Amount Providing RA Capacity	545	160	0
Amount Providing Flexibility	545	160	0
Amount with 2 hours of storage	218	64	0
Amount with 4 hours of storage	218	64	0
Amount with 6 hours of storage	109	32	0

In the CAISO's TPP Base local area reliability studies the transmission bus-bar identification numbers, names, etc., included in Table 5, Table 6 and Table 7, below, should be used for locational information regarding energy storage resources located in PG&E's,[29] SCE's and SDG&E's service territories.

[29] PG&E explained the following in regards to the energy storage resources listed in the "PG&E Energy Storage Resources" table: "The majority of the projects listed did not have completed interconnection studies nor were they included in the CAISO Full Network Model at the time of offer submittal. The list has also not been confirmed with

Footnote continued on next page

<u>Summary: Energy Storage Assumptions Regarding RA, Flexibility and Depth/Duration used when project details are not known</u>

Transmission-connected energy storage projects:

- All megawatts count for RA except:
    - If the energy storage project has a two-hour depth then it is de-rated by 50% in order to convert it MW into the amount of capacity actually counting towards RA (since by RA rules output must be sustained for minimum four-hours)
- All megawatts are assumed to provide operational flexibility to the grid
- For those projects whose duration/depth information was unavailable, we assume that 40% of their cumulative total megawatts provide two-hour storage, 40% provide four-hour storage, and 20% provide six-hour storage

Distribution-connected energy storage projects:

- All of the distribution-connected energy storage project's capacity counts towards RA and assumed to provide operational flexibility to the grid
- If the energy storage project only provides two-hour storage depth, it is derated by 50% in order to convert its capacity into an amount that can count towards meeting the RA obligation (since by RA rules output must be sustained for minimum four-hours)
- Energy Storage projects for which no duration/depth information was made available, we assume 40% of their cumulative total megawatts provide two-hour storage, 40% provide four-hour storage, and 20% provide six-hour storage

Customer-connected energy storage projects:

- All of a customer-connected energy storage project's capacity can count towards RA compliance, and is assumed to provide operational flexibility
- Energy storage projects for which no duration/depth information was made available, we assume 50% provide two-hour storage, 50% provide four-hour storage and 0% six-hour storage

It is reasonable to assume that cost-effectiveness requirements applicable to new storage capacity will lead to it being sited at the most optimal locations in order to allow these resources to help satisfy the local area reliability requirement. As CAISO staff identifies transmission constraints in the local areas in the current and future TPP technical studies they will also identify which transmission busses most optimally mitigate transmission constraints. Transmission, distribution and customer-side connected storage amounts providing capacity and flexibility identified in Table 4 should be distributed among the transmission busses which most optimally mitigate transmission constraints within local

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the CAISO. Therefore the list is PG&E's current estimate of the nearest Transmission Point of Delivery / Receipt, nearest Resource ID, and nearest Bus ID, and should not be assumed to exactly denote the final bus-bar location."

reliability areas. As such, the identified transmission bus locations are potential development sites for storage and should help inform the procurement of storage resources necessary to meet the storage procurement target.

In regards to expedited storage procurement authorized through CPUC Resolution E-4791 (May 26, 2016), not all new storage facilities that are co-located at existing plants provide no net increases in the deliverable capacity available for meeting system or local capacity needs. Instead, IOUs have in some cases requested that a portion of the deliverable capacity associated with the existing plants be transferred to the new storage facilities to enable those facilities to achieve full capacity deliverability status, or have requested but not yet received deliverability. For those projects that have not received incremental deliverability through the ISO's 2017 Distributed Generation Deliverability process or an earlier process, those batteries will be treated as energy-only in normal scenarios.

In studying Aliso Canyon gas storage outage scenarios, the batteries will be studied with full capacity for the BESS and with 0 MW output from the associated gas plants due to assumed gas constraints. New storage facilities that are co-located at existing plants provide no net increase in the deliverable capacity available for meeting system or local capacity needs. Instead, IOUs have requested that a portion of the deliverable capacity associated with the existing plants be transferred to the new storage facilities to enable those facilities to achieve full capacity deliverability status.

Table 5: Locational Information for PG&E's Energy Storage Resources

PG&E Energy Storage Resources						
Counterparty (Project Name)	Point of Interconnection (POI)	Approximate Transmission Point of	Approximate Nearest Resource ID (ResID)	Approximate Bus ID (BusID)	MW	Point of Connection
Amber Kinetics (Energy Nuevo)	New 70 kV position in PG&E New Kearney Substation	New 70 kV position in PG&E New Kearney Substation	KERNEY_6_LD1	34480_KEARNEY _70.0_LD1	20	Transmission
Convergent (Henrietta)	Henrietta Distribution Substation (12kV)	Henrietta 70kV Substation	HENRTA_6_LD1	34540_HENRITTA_70.0_LD 1	10	Distribution
Hecate Energy (Molino)	Molino Transmission (69kV) Substation	Molino Transmission (69kV) Substatior	MOLINO_6_LD1	31364_MOLINO _60.0_LD1	10	Transmission
NextEra Energy (Golden Hills)	Tesla Substation 115kV	Tesla Substation 115kV	TESLA_1_QF	33540_TESLA _115_GUM1	30	Transmission
Stem BTM	Customer Meter	Aggregated Sub Lap (TBD)	N/A	N/A	4	Customer
Yerba Buena Pilot Battery Project	21kV Swift 2102 Feeder (into Swift 21kV Substation)	Swift 115kV Substation	SWIFT_1_NAS (not yet operational)	35622_SWIFT _115_GUNS	4	Distribution
Vaca Dixon Pilot Battery Project	Vaca Dixon 12 kV Substation	Vaca Dixon 115kV Substation	VACADX_1_NAS	31998_VACA- DIX_115_GUNS	2	Distribution

Table 6: Locational Information for SCE's Energy Storage Resources

SCE's Energy Storage Projects Locational Information by Busbar & Attributes (MW)						
	Project	**Storage MW**	**Product Type**	**Locational Information**	**Bus ID**	
LCR RFO 264 MW	Ice Bear	28.64	ES BTM PLS (customer-side)	N/A (Distributed)		
	AES	100	IFOM (distribution)	**Point of Interconnection:** 230kV bus at the Alamitos A-Bank Substation **Bus Name:** ALMITOSW **Bus Number:** 24007		
	Stem	85	ES BTM (customer-sde)	N/A (Distributed)		
	Hybrid Electric	50	ES BTM (customer-sde)	N/A (Distributed)		
2016 ACES RFO/RFP	**Project**	**Storage MW**	**Product Type**	**Locational Information**		
	Powin	2	IFOM (distribution)	**Point of Interconnection:** 12kV Virgo Distribution line (Santiago A Bank Substation)	66 kV +H11:H35Bus Name: SANTIAGO 66 kV Bus Number: 24133	*No bus number for 12 kV Bus. 66 kV bus where B-station that feeds circuit is located used
	Western Grid [2]	5	IFOM (distribution)	**Point of Interconnection:** Wakefield Petit 16 kV Distribution line (Santa Clara A Bank Substation)	66 kV Bus Name: S.CLARA 66 kV Bus Number: 24127	
	AltaGas	20	IFOM (distribution)	**Point of Interconnection:** Ganesha-Simpson 66kV line Distribution line (Chino A Bank Substation)	66 kV Bus Name: CHINO 66 kV Bus Number: 24024	*No bus number for 66 kV Transmission Line Tap. Chino 66 kV bus utilzied
	Project	**Storage MW**	**Product Type**	**Locational Information**		
2016 ACES DBT	Tesla	20	IFOM (distribution)	**Point of Interconnection:** Mira Loma A Bank Substation	66 kV Bus Name: MIRALOMW 66 kV Bus Number: 24210	
PRP 2	**Project**	**Storage MW**	**Product Type**	**Locational Information**		
	AMS CTEC 1-5	40	ES BTM (customer-sde)	N/A (Distributed)		
	Convergent OCES 1-3	35	IFOM (Transmission)	**Point of Interconnectio:** Chestnut 66kV bus out of Johanna 220/66kV substation	66 kV Bus Name: JOHANNA 66 kV Bus Number: 24207	
	Nextera OCES 1	8.5	ES BTM (customer-sde)	N/A (Distributed)		
	Nextera OCES 2	1.5	ES BTM (customer-sde)	N/A (Distributed)		
	SEF1	5	ES BTM (customer-sde)	N/A (Distributed)		
	Valencia Energy Storage	10	IFOM (distribution)	**Point of Interconnection:** Aquarius 12 kV circuit Santiago 220/66kV substation	66 kV Bus Name: SANTIAGO 66 kV Bus Number: 24133	*No bus number for 12 kV Bus. 66 kV bus where B-station that feeds circuit is located used
	HEJF1-2	15	IFOM (distribution)	**Point of Interconnection:** 12 kV bus at the Johanna substation	66 kV Bus Name: JOHANNA 66 kV Bus Number: 24207	*No bus number for 12 kV Bus. 66 kV bus where B-station that feeds circuit is located used
	NRG Hybrid 1-5 [1]	10	ES BTM (customer-sde)	N/A (Distributed)		
Bilateral	**Project**	**Storage MW**	**Product Type**	**Locational Information**		
	SCE EGT - Grapeland	10	IFOM (Transmission)	**Point of Interconnection:** Integrated with SCE's Grapeland Peaker	66 kV Bus Name: ETIWANDA 66 kV Bus Number: 24055 13.8 kV Bus Name: ETWPKGEN 13.8 kV Bus Number 29305 Project will share same 13.8 kV Bus where exsting peaker is located.	
	SCE EGT - Center	10	IFOM (Transmission)	**Point of Interconnection:** Integrated with SCE's Center Peaker	66 kV Bus Name: CENTER 66 kV Bus Number: 24203 13.8 kV Bus Name: CTRPKGEN 13.8 kV Bus Number 29308 Project will share same 13.8 kV Bus where exsting peaker is located.	
ES RFO 16.3 MW	**Project**	**Storage MW**	**Product Type**	**Locational Information**		
	Stanton Energy Reliability Center	1.3	RA Only (distribution)	**Point of Interconnection:** Barre Substation **Bus Name:** BARRE **Bus Number:** 24201		
	Western Grid	10	RA Only (distribution)	**Point of Interconnection:** Wakefield Petit 16 kV Distribution line (Santa Clara A Bank Substation) **Bus Name:** S.CLARA **Bus Number:** 24127		
		5	RA Only (distribution)			
EXISTING SCE STORAGE APPROVED AS ELIGIBLE IN D.14-10-045	**Project**	**Grid Domain**	**MW in Plan**	**MW Actually Installed**	**A-Bank Substation**	**Bus Numbers at the 230kV used by TSP and CAISO**
	Tehachapi Storage	Distribution	8	8	Windhub 220/66	29407
	Irvine Smart Grid-Community Energy Storage	Distribution	0.03	0.03	Santiago 220/66	24134
	Irvine Smart Grid-Containerized Energy Storage	Distribution	2	2	Santiago 220/66	24134
	Irvine Smart Grid-Residential ES Unit	Customer	0.06	0.06	Santiago 220/66	24134
	Large Storage Test	Distribution	2	2	Barre 220/66	24016
	Discovery Museum	Distribution	0.1	0.1	Villa Park 220/66	24154
	Catalina Island	Distribution	1	1	N/A	N/A
	V2G-LA AFB	Distribution	0.65	0.5	TBD	TBD
	Self-Generation Incentive Program	Customer	10.9	9.66	TBD	TBD
	Permanent Load Shifting	Customer	4.74	1.14	TBD	TBD
	Home Batter Pilot	Customer	0.08	0	N/A	N/A
	Distribution Energy Storage Integration 1	Distribution	2.4	2.4	Villa Park 220/66	24154

[1] Although these agreements are for 2 MW each, only 1 MW of the capacity will be comprised of storage as such only 1 MW is countable. (The remaining 1 MW is from renewable technology.)

[2] ACES Western Grid contract is an acceleration of the 2014 Energy Storage RFO Western Grid contract. As such, ACES Western Grid is not incremental to what is already counted for 2014 Energy Storage

Table 7: Locational Information for SDG&E's Energy Storage Resources

SDG&E's Energy Storage Projects Locational Information by Busbar & Attributes (MW)				
Domain	**Project Name**	**Capacity MW**	**Bus ID Number**	**Interconnection Substation**
Transmission	Lake Hodges Pumped Storage	40	22603	Lake Hodges LHM
Total Trasmission		**40 MW**		
Domain	**Project Name**	**Capacity / MW**	**Bus Number at Transmission Substation to which Distribution Circuit Connects**	**Interconection Substation**
Distribution	Escondido BESS 1	10	22256	Escondido
Distribution	Escondido BESS 2	10	22256	Escondido
Distribution	Escondido BESS 3	10	22256	Escondido
Distribution	El Cajon BESS 1	7.5	22208	El Cajon
Distribution	Borrego Microgrid Yard- SES1	0.5	22084	Borrego
Distribution	Pala Energy Storage Yard	0.5	22624	Pala
Distribution	Mission Valley- Skills Training Center	0.025	22496	Mission
Distribution	Clairemont	0.025	22136	Clairemont
Distribution	Poway	0.025	22668	Powey
Distribution	Borrego Springs CES	0.025	22084	Borrego
Distribution	Borrego Springs CES	0.025	22084	Borrego
Distribution	Borrego Springs CES	0.025	22084	Borrego
Distribution	Century Park CES	0.05	22372	Kearny
Distribution	Energy Inovation Center- Indoor	0.0045	22136	Clairemont
Distribution	Energy Inovation Center- Outdoor	0.01	22136	Clairemont
Distribution	San Diego Zoo	0.1	22868	Urban
Distribution	UCSD MESOM	0.006	22864	UCM
Distribution	Suites at Paseo (SDSU Private Dormitories)	0.018	21008	Stremview
Distribution	Del Lago Academy	0.1	22602	Olivenheim
Distribution	Ortega Highway 1243 SES1	1	22678	Margarita
Distribution	Ortega Highway 1243 SES2	1	22364	Margarita
Distribution	Pala Energy Storage Yard SES	1	22624	Pala
Distribution	Canyon Crest Academy	1	22581	North City West
Distribution	Borrego Microgrid Yard- SES2	1	22084	Borrego
Distribution	Santa Ysabel Substation	0.006	22736	Santa Ysabel
Distribution	Santa Ysabel Substation	0.03	22736	Santa Ysabel
Distribution	Del Lago Park & Ride	0.2		Felicita
Distribution	Integrated Test Facility	0.2	22256	Escondido
Total Distribution		**44.37 MW**		
Domain	**Project Name**	**Capacity / MW**	**Nearest Bus ID Number**	
Customer	SGIP/Non-SGIP Installed	14.64	Varies	Varies
Customer	SGIP/Non-SGIP In Progress	3.65	Varies	Varies
Customer	Permanent Load Shift Program	1.3	22864	Varies
Total Customer		**19.59 MW**		

All energy storage projects described here are exclusive and incremental to any similar technologies that are accounted for as non-dispatchable DR (e.g. Permanent Load Shifting) embedded within the CEC's CEDU forecasts.

Adjustments due to actual and expected storage projects

The 50 MW of storage that D.13-02-015 ordered SCE to procure, and the 25 MW[30] of storage that D.14-03-004 ordered SDG&E to procure, are assumed to count towards the D.13-10-040 storage procurement target; they should not be double counted.

The 40 MW Lake Hodges storage project located in the San Diego area is assumed to satisfy a portion of SDG&E's share of the D.13-10-040 storage procurement target, and is reflected as doing so in

Table 3.

3.2.5 Demand Response

Demand response (DR) programs whose impacts are not embedded in the CEDU 2016 forecasts include several event-based, price-responsive and reliability programs. Within the Draft 2017 A&S planning horizon, these programs should achieve full integration into the CAISO wholesale market and therefore count as supply-side DR. Per Decision D.14-12-024, and reinforced by D.15-11-042, the Commission found that, as of January 1, 2018, DR programs must be fully bifurcated. DR programs must also be either fully integrated into the CAISO wholesale market (supply-side DR) or embedded in the CEDU forecasts (load-modifying DR), otherwise these programs will no longer have capacity value and thus will no longer receive resource adequacy credit.[31] As of December 2016, SCE has integrated most of its DR programs into the CAISO market, while PG&E and SDG&E are working to integrate their program portfolios. With the adoption of D.15-11-042, CPUC staff anticipates that the IOUs will integrate their DR programs into the CAISO market by the January 1, 2018 deadline.

The DR Load Impact Reports[32] filed with the CPUC on April 1, 2016, and other supply-side DR procurement[33] incremental to what is assumed in the Load Impact Reports, serve as the basis for the supply-side DR planning assumptions included herein. Transmission and distribution loss-avoidance effects shall continue to be accounted for when considering the load impacts that supply-side DR has on the system. The following table describes the total 2026 supply-side DR capacity assumptions, the details of which will be discussed in the remainder of this subsection.

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[31] That is, "supply-side" DR bids into the CAISO market and can receive resource adequacy credit, while "load-modifying" DR is embedded in the CED forecast and contributes by lowering the load forecast, thus lowering resource adequacy requirements.

[32] See Load Impact Report filings by each IOU on April 1, 2016, in R.13-09-011.

[33] Referring to procurement authorized by D.14-03-004, DRAM, D.16-06-029, and IOU DR applications filed in accordance with D.16-09-056 in January, 2017.

Table 8: Demand Response Supply-side Modeling Assumptions Summary

DR not embedded in IEPR demand forecast (values in MW):	PG&E	SCE	SDG&E	All IOUs	Assumed Market	Assumed to respond within 30 minutes
IOU Load Impact Report DR in 2026 (a)						
BIP	255.0	607.0[34]	1.4	863.4	RDRR	Yes
AP-I	0.0	63.0[35]	0.0	63.0	RDRR	Yes
AC Cycling Res (b)	54.0	142.0[36]	11.5	277.0	PDR	Yes
AC Cycling Non-Res	1.0	27.0[37]	3.1	44.1	PDR	Yes
CBP	120.0[38]	141.0[39]	12.2	263.0	PDR	No
DBP	0.0	0.0	0.0	0.0	PDR	No
AMP (DRC)	0.0	0.0	0.0	0.0	PDR	No
Other procurement program DR						
SCE LCR RFO (c), post 2018		5.0		5.0	RDRR	Yes
DRAM (d) (e) in 2017 and beyond				124.6	PDR[40]	No

Notes:
(a) Load Impact Report values are portfolio-adjusted August 2026 1-in-2 weather year condition ex-ante impacts at CAISO peak

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34 D.16-06-029 authorizes SCE to use existing BIP funds to gain 5 MW of incremental load impact for the program.

35 D.16-06-029 authorizes SCE to use existing AP-I funds to gain 4 MW of incremental load impact for the program.

36 Updated from the April 1, 2016 Load Impact filings to reflect changes in enrollment assumptions contained in SCE's 2018-2022 portfolio filing, January 17, 2017.

37 Updated from the April 1, 2016 Load Impact filings to reflect changes in enrollment assumptions contained in SCE's 2018-2022 portfolio filing, January 17, 2017.

38 D.16-06-029 approved PG&E's request to terminate its AMP program. It is assumed that 82 MW from PG&E's AMP program will migrate to PG&E's CBP program.

39 D.16-06-029 approved SCE's request for an extension of its AMP program through 2017. However, it is assumed that 93 MW from SCE's AMP program to its CBP program by 2026.

40 Although the 2017 DRAM solicitation could include a mix of Reliability Demand Response Resource (RDRR) and Proxy Demand Resource (PDR), for modeling we will assume it is all PDR absent more definitive information.

(b) AC Cycling programs include Smart AC, SDP, and Summer Saver
(c) SCE LCR RFO refers to procurement authorized in D.14-03-004 with contract approved in D.15-11-041
(d) Demand Response Auction Mechanism is a 2-year pilot program of a maximum of one-year contracts
(e) For modeling purposes we assume capacity from existing programs described in the Load Impact Reports are a reasonable proxy for DR in 2026. It could turn out that by 2026, capacity from existing programs will be "retired" and "replaced" by significant growth in DRAM capacity.

In system resource planning studies, DR capacity based on the Load Impact Reports shall be counted using the portfolio-adjusted 1-in-2 weather year condition ex-ante forecast of monthly load impact at individual IOU peak.[41] This is consistent with the current DR capacity value calculation practice used in the CPUC's Resource Adequacy program. For the purpose of building load and resource tables, DR capacity shall be counted using the portfolio-adjusted 1-in-2 weather year condition ex-ante forecast of August load impact at CAISO peak.

For planning models that require hourly impacts of DR, the aggregate DR capacity for a given hour is assumed to be the sum of the capacity of all DR programs that operate during that hour. The capacity of a DR program outside its operating hours is assumed zero. For DR programs described in the Load Impact Reports, CPUC staff assumes the average capacity during operating hours specified in Resource Adequacy accounting rules (1pm to 6pm) is representative of DR capacity for all of a given program's operating hours (which may include hours outside of 1pm to 6pm). For a DR program described by other procurement processes (e.g. SCE LCR RFO and DRAM in Table 8), the capacity procured is the hourly capacity to be modeled during that program's operating hours. CPUC staff intends to improve upon this coarse assumption of hourly DR capacity in future planning cycles. Developing temporally granular assumptions about future DR capacity at this time would embody a lot of uncertainty due to DR bifurcation and other program changes happening within the DR proceeding (R.13-09-011).

For planning models that require assumptions about how DR would be expected to dispatch, DR is assumed to be available at times of system stress, subject to program operating constraints but not limited to the operating hours specified in the Resource Adequacy accounting rules. Near-term studies, such as one or two years ahead, may reasonably model DR operating constraints based on the current tariffs associated with each program.[42] Longer-term studies (e.g. more than five years ahead) should model DR

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[41] Previous iterations of the LTPP A&S document used monthly load impact figures at the CAISO peak. Going forward, modelers should use the individual IOU peak.

[42] To access IOU demand response tariffs please click on the following links.
PG&E: http://www.pge.com/en/mybusiness/save/energymanagement/index.page.
SCE: https://www.sce.com/wps/portal/home/business/savings-incentives/demand-response/.
SDG&E: http://www.sdge.com/save-money/demand-response/overview.

operating constraints based on full integration into the CAISO market, implying that DR participates in the CAISO market using either the Proxy Demand Resource (PDR) or Reliability Demand Response Resource (RDRR) CAISO market constructs.[43] In the interest of ensuring comparability between studies conducted by different parties, CPUC staff recommends that modeling the expected dispatch of DR participating as PDR or RDRR use the following conventions:

- DR assumed to participate as RDRR[44]
  - shall trigger when market prices are $950/MWh
  - shall be dispatched for no more than 15 events and/or 48 hours total for June through September
  - shall be dispatched for no more than 15 events and/or 48 hours total for January through May and October through December
  - shall be consistent with other operating attributes specified by the RDRR construct, e.g. minimum load curtailment and run times
- DR assumed to participate as PDR [45]
  - shall trigger when market prices are $100/MWh
  - shall be dispatched for no more than 30 events and/or 120 hours total for the whole year
  - shall be consistent with other operating attributes specified by the PDR construct, e.g. minimum load curtailment and run times

Any party conducting Local Capacity Reliability Area planning studies must also make certain assumptions about available DR capacity under the grid conditions being studied. The CAISO conducts two types of planning studies related to Local Capacity Reliability Areas: Long-term Local Capacity Requirement (LCR) studies that study 10 years ahead and are conducted within the CAISO's annual Transmission Planning Process,[46] and Local Capacity Technical (LCT) Studies that study 1-5 years ahead and are used to inform the CPUC's Local Resource Adequacy requirements.[47] In these studies, the CAISO considers whether resources physically located within a Local Capacity Reliability Area can respond to a "first contingency".[48] The Resource Adequacy Rulemaking R.14-10-010 is currently considering whether to change Local Resource Adequacy rules in order to create a requirement regarding how quickly DR resources that are physically located in Local Capacity Reliability Areas would need to respond in order to count as Local RA capacity and whether there is a way to pre-dispatch slower responding resources so that they

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[43] See http://www.caiso.com/participate/Pages/Load/Default.aspx.

[44] Based on RDRR attributes described here: http://www.caiso.com/Documents/ReliabilityDemandResponseResourceOverview.pdf.

[45] It is difficult to know in advance if these specific modeling conventions for RDRR and PDR will result in models the produce realistic dispatches of DR. Modelers may use some discretion in adjusting trigger price and event or hour caps in order to achieve realistic dispatches of DR. Any adjustments must be transparently documented and shared with all parties.

[46] http://www.caiso.com/Documents/RevisedDraft2015-2016TransmissionPlan.pdf.

[47] http://www.caiso.com/informed/Pages/StakeholderProcesses/LocalCapacityRequirementsProcess.aspx.

[48] The terms "first contingency" and "second contingency" were described in decision D.14-03-004, and the May 21, 2013 revised scoping ruling found here: http://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M065/K202/65202525.PDF.

could also be counted. The CPUC's Resource Adequacy accounting rules currently have no requirement related to "first contingencies" or response times for a resource to count as Local Resource Adequacy capacity. If a new methodology is approved by the CPUC in 2016 it should be used as the basis for counting resources that meet Local Capacity Requirements in future long-term planning cycles.

Based on current program forecasts, CPUC staff estimate that in 2026, throughout the CAISO area, 1,259 MW of DR would be available to count towards Local RA capacity and meet LCR needs – to the extent that the DR is physically located within Local Capacity Reliability Areas. CPUC staff developed the 1,259 MW estimate by aggregating DR programs included in the Load Impact Reports that can deliver load reductions in 30 minutes, or less, from customer notification (which amounts to 1254 MW) with DR specifically procured to meet local reliability needs (5 MW). CPUC staff used the Load Impact Reports' August 2026 portfolio-adjusted 1-in-2 weather year condition[49] ex-ante forecast of load impact coincident with CAISO system peak. DR specifically procured to meet local reliability needs is the 5 MW of DR that was procured pursuant to SCE's LCR RFO (approved, by D.15-11-041).[50] This 5 MW is assumed to be incremental to the 928 MW[51] of 30-minute-responsive DR in SCE's territory as calculated from the Load Impact Reports.

In addition to DR specified in the Load Impact Reports and DR procured through SCE's LCR RFO, the CPUC has approved 56.2 MWs of SCE DR contracts for system RA capacity procured through the pilot Demand Response Auction Mechanism (DRAM) for deliveries starting January 1, 2017 through the end of 2017, for a mixture of system, local and flexible RA capacity[52]. PG&E's and SDG&E's 2017 DRAM auctions concluded in October 2016. However, both IOUs were ordered by the CPUC to procure more DRAM capacity than they had originally demonstrated. PG&E's 2017 DRAM auction resulted in the procurement of 56.4 MW, and SDG&E's resulted in the procurement of 12 MW. That auction has not yet occurred, so studies needing to make an assumption about DRAM capacity in 2017 should assume the minimum procurement target of 22 MW is procured and that the DRAM capacity will be used for system RA capacity. Note that at this time the pilot DRAM program is structured for contracts with lengths of up to one year, so long term planning assumptions can make no reasonable statement about expected long-term DRAM capacity. Therefore, CPUC staff continues to assume that the bulk of DR capacity expected to be

[49] Note that although Local Capacity Requirement assessments study 1-in-10 year weather conditions, we assume DR capacity based on 1-in-2 year weather ex-ante impacts because this is currently the basis of the Qualifying Capacity value given to DR for both system and local Resource Adequacy compliance purposes.

[50] Note that the CAISO's recently proposed Business Practice Manual (BPM) change (https://bpmcm.caiso.com/Pages/ViewPRR.aspx?PRRID=854&IsDlg=0) calls into question whether the DR procured to meet local reliability needs through SCE's LCR RFO will be counted by the CAISO as eligible to meet local reliability needs. This is because the CAISO's proposed BPM change imposes a 20 minute response time on local DR resources as opposed to the 30 minute response time assumed in D.14-03-004 which authorized SCE's LCR RFO and D.15-11-041 which approved the DR resource.

[51] 935 MW = 611 MW of base interruptible + 66 MW agricultural pumping + 218 MW residential ac cycling + 40 MW non-residential ac cycling.

[52] Energy Division approved SCE AL 3442-E via disposition letter.

present in the long term is best approximated by the DR projections in the Load Impact Reports. In the long term it may be possible that the capacity from existing DR programs described in the Load Impact Reports will be "retired" and "replaced" by significant growth in DRAM capacity.

For technical studies that require modeling DR capacity at individual transmission-level bus-bars, DR capacity should be allocated to bus-bar using the method defined in D.12-12-010, or to specific bus-bar locations provided by the IOUs. CPUC staff expects that the IOUs will provide updated bus-bar allocations to the CAISO for use in the 2017-18 TPP. The bus-bar locations also help determine which portion of aggregate 30-minute-responsive DR capacity within an IOU planning area is physically located within a Local Capacity Reliability Area.[53]

Given the uncertainty as to the DR amount that can be relied upon for mitigating first contingencies, the CAISO's 2014-15 and 2015-16 TPP Base Local Capacity Reliability Area studies examined two scenarios: one consistent with the 2012 LTPP Track 4 DR assumptions and one consistent with the 2014 LTPP DR assumptions of available 30-minute-responsive DR. CPUC staff expects that a similar two scenario approach will be used in the 2017-2018 TPP; that is, the CAISO would study one scenario assuming a base level of DR capacity[54] to meet first contingencies, followed by a second scenario assuming full availability of the 30-minute-responsive DR described in Table 8 above – to the extent that DR is physically located in the Local Capacity Reliability Area being studied.

3.2.6 RPS Portfolios

Historically, a set of additional future renewable resources needed for compliance with the state's RPS program were specified for each scenario articulated in the Assumptions and Scenarios document. These portfolios were produced by Energy Division staff using the RPS Calculator, a publicly vetted spreadsheet tool.

Various studies are underway that could inform planning beyond the 33% RPS goal. Thus, various pathways may eventually be identified that lead to a beyond-33% goal. To include a portfolio of increased renewables for long term planning would be to presuppose the conclusions of the various studies underway, particularly as it relates to potential infrastructure authorizations needed to meet future goals. Thus, no new RPS portfolios are specified this year for additional resources needed to meet RPS goals.

- The information-only 50% RPS special study completed by CAISO as a part of their 2015-16 TPP process suggested that no additional transmission may be needed to

[53] The CAISO noted that DR eligible for inclusion in the TPP must be allocated to bus-bars and must be a CAISO integrated resource, meaning that resource is mapped to specific PNodes.

[54] The CAISO has received updated information from SCE that increases the base level of DR capacity to meet first contingencies from what was assumed in previous TPP cycles. This is described in the CAISO's Draft 2016-2017 Transmission Planning Process Unified Planning Assumptions and Study Plan, p. 27 (http://www.caiso.com/Documents/Draft20162017StudyPlan.pdf.)

enable the state to achieve its RPS policy goal (though additional transmission may be economically justifiable).

- The IRP process is expected to include a new and more appropriate methodology for developing RPS portfolios than the RPS Calculator. As a result, it would be more prudent to incorporate the results of the IRP process in the 2018-2019 TPP.
- IOUs under CPUC jurisdiction for purposes of compliance with the states RPS program are generally long on RPS resources and may not require much additional procurement, if any, to achieve their 50% targets by 2030. A smaller need for new generation reduces the urgency of studying the transmission upgrades that might be required to enable that generation to serve load. In the 2018-19 timeframe, IRP is expected to address the question whether there is need for additional RPS procurement over and beyond the mandated 50% RPS in 2030.

For use in the 2017-18 TPP process, the CAISO anticipates updating the prior RPS forecast with projects that have begun construction since issuance of the 2016 LTPP A&S document in May 2016.

3.2.7 Technical Attributes of Solar PV projects

The physical configuration of solar PV projects influences the shape of their hourly generation profiles and has material impact on the outcome of resource planning studies. Two important physical attributes are the mounting-type and the DC-AC inverter loading ratio. Mounting-type includes the following:

- Fixed-tilt: stationary panels tilted, south-facing
- Tracking, 1-axis: panels track the sun on a single axis from East to West
- Tracking, 2-axis: panels track the sun on a dual axis (these projects are rare)[55]

The ratio of panel capacity to inverter capacity is the DC-AC inverter loading ratio and a higher ratio tends to flatten or clip the production profile of a PV project. Industry practice for PV installations has been to install a panel capacity larger than the inverter capacity to compensate for de-rate factors such as DC-AC conversions and losses and to maximize economic value.

[55] Dual-axis tracking solar PV projects represent a tiny portion of tracking projects CAISO-wide, just 12 MW of capacity out of over 5,600 MW of IOU-contracted projects. For simplicity, the tables in this section treat dual-axis projects as if they were single-axis projects.

Table 9: Contracted Solar PV Capacity (MW) & Capacity-Weighted Average ILR, By Mounting-Type

	PG&E	SCE	SDG&E
Fixed-tilt capacity	2,043	876	395
Fixed-tilt ILR	1.26	1.24	1.29
Tracking capacity	1,406	3,334	938
Tracking ILR	1.28	1.31	1.29

Table 9 summarizes the IOU-contracted solar PV capacity (as of June 2015) for each of the three major IOUs and the capacity-weighted average inverter loading ratio separated by mounting-type.[56] "IOU-contracted" means the project has a CPUC-approved power purchase contract and it can be an existing online project or a project still under development. Because these projects have a CPUC-approved power purchase contract, their physical attributes are known and the projects are likely to be completed successfully.

For planning purposes, studies need to assume a mounting-type and inverter loading ratio for "generic" projects. The trends of mounting-type and inverter loading ratio in the most recent IOU-contracted projects can be used as a proxy for the likely physical attributes of "generic" projects. Table 10 below categorizes IOU-contracted projects by online year and identifies the amount of each mounting-type by capacity and percentage of total capacity.

[56] This data was aggregated from individual project data obtained from the CPUC Energy Division's RPS Contract Database (formerly known as Project Development Status Reports), June 2015 vintage, and data request responses from each IOU that provided physical attribute information for all IOU-contracted projects. Projects that were from these two data sources are either existing online projects or projects in development that are assumed to meet the criteria for "commercial" projects in the RPS Calculator. Some of these projects are in fact IOU-owned. The aggregated data does not identify market-sensitive information about individual solar PV projects.

Table 10: Contracted Solar PV Capacity (MW) Grouped By Mounting-Type & Online-Year

	any year	%	2014 or later	%	2015 or later	%
PG&E						
Fixed-tilt	2,043	59%	1,560	61%	176	17%
Tracking	1,406	41%	1,000	39%	831	83%
SCE						
Fixed-tilt	876	21%	836	21%	525	15%
Tracking	3,334	79%	3,215	79%	3,040	85%
SDG&E						
Fixed-tilt	395	30%	17	3%	17	7%
Tracking	938	70%	552	97%	225	93%
3 IOUs						
Fixed-tilt	3,315	37%	2,414	34%	718	15%
Tracking	5,678	63%	4,767	66%	4,097	85%

The newest projects (online in 2015 or later) tend to consist of tracking mounting-types. Based on this trend, "generic" projects selected by the RPS Calculator shall be assumed 15% fixed-tilt and 85% tracking.[57] There does not appear to be a clear difference in inverter loading ratios for newer vs. older projects. Therefore, "generic" projects shall be assumed to have inverter loading ratios similar to the capacity-weighted average of all IOU-contracted projects. Table 11 below summarizes the mounting-type and inverter loading ratio assumptions for "generic" (i.e. not yet contracted) projects. The percentage represents the share of all generic solar PV projects.

Table 11: Generic Solar PV Project Mounting-Type & ILR Assumptions

	PG&E	SCE	SDG&E
Fixed-tilt % share	15%	15%	15%
Fixed-tilt ILR	1.26	1.24	1.29
Tracking % share	85%	85%	85%
Tracking ILR	1.28	1.31	1.29

[57] Note that this subsection intends to override certain technical attributes of generic solar PV assumed by the RPS Calculator on the basis that trends in solar PV procurement are likely better indicators of the technical attributes of generic solar PV that would be realized in future procurement. This is partly because the RPS Calculator makes some simplifying assumptions about solar PV attributes in order to complete its calculations in a timely manner.

It is expected that technical modelers, especially those conducting production cost simulations, need to create 8760 hour annual energy profiles for bulk solar. Profile creation requires three key types of information: an 8760 hour solar irradiance profile varying by location, project installed capacity and location, and the technical attributes of each project. Solar irradiance data can be sourced from public datasets such as National Renewable Energy Laboratory's Solar Prospector[58] or Solar Integration National Dataset Toolkit.[59] Project installed capacity and location are provided by the RPS portfolio created by the RPS Calculator. Again, the technical attributes of bulk solar PV projects are specified by Table 9 and Table 11, above.

However, there is a potential for the annual energy outcome predicted by the RPS Calculator to be different from the annual energy profiles created by technical modelers and incorporating the technical attributes specified above. This is because the RPS Calculator uses simplified weather and technical attribute assumptions[60] to develop its RPS portfolio that meet a certain annual energy target and satisfy the desired RPS requirement (e.g. 50%). For consistency purposes the following method is adopted:

> Leave the installed capacity provided by the RPS portfolio unchanged. Create the annual energy profiles incorporating the technical attributes specified in this section and use those profiles as inputs to production cost simulations. This may result in annual energy outcomes somewhat different from what the RPS Calculator predicted (e.g. annual RPS energy percentage ended up at 48% or 52% instead of 50%).

Technical modelers are expected to document all details about how they create 8760 hour annual energy profiles for bulk solar, and how the profiles are used in technical studies (e.g. production cost simulations).

3.2.8 Nuclear Retirements

Both units of the Diablo Canyon Power Plant (DCPP) are proposed to be decommissioned, subject to Commission approval, and thus should be modeled as coming offline.

Unit 1 of DCPP is expected to retire on November 2, 2024 and Unit 2 is expected to retire on August 26, 2025.[61]

3.2.9 Once-Through-Cooled Technology Retirements

The default assumption is that power plants using once-through cooling (OTC) technology retire according to the current State Water Resources Control Board (SWRCB) OTC

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58 http://maps.nrel.gov/prospector.

59 http://www.nrel.gov/electricity/transmission/sind_toolkit.html.

60 http://www.cpuc.ca.gov/RPS_Calculator/.

61 *See* A.16-08-006.

compliance schedule, or sooner, per generation owners' latest implementation plans submitted to the SWRCB.

Moss Landing

The original compliance date for Moss Landing under the OTC compliance schedule was December 31, 2017. However, a settlement agreement signed by Dynegy (the owner of Moss Landing) and the SWRCB staff in October 2014 extended this compliance date to December 31, 2020 for Units 1 and 2 and Units 6 and 7. This OTC amendment, per the settlement agreement, was approved by the SWRCB on April 7, 2015 and is now in effect. The plant's ownership stated its intent to install technology on Units 1 and 2 which will allow them to continue operating at a projected maximum capacity factor of 78%. Dynegy filed its 90-day notice with the CAISO to make known that it intends to retire Moss Landing Units 6 and 7 in January 2017. Therefore, staff assumes that by December 31, 2020 Units 1 and 2 will be successfully retrofitted and that at the end of January 2017 Units 6 and 7 will retire.

Encina

The OTC compliance date for all five Encina units is December 31, 2017. The Commission approved a 500 MW re-power of all Encina units into a proposed Carlsbad Energy Center. That Commission Decision was contested, but was recently affirmed by the Court of Appeal of the State of California. NRG (the owner of Encina) intends to shut down and permanently retire Encina Unit 1 by February 2017. Encina Unit 1 should be modeled as coming offline February 2017 and the rest of the units coming offline December 31, 2017, subject to potential SWRCB extension, with Carlsbad coming online to replace them in Q4 2018.[62]

3.2.10 Renewable and Hydro Retirement Assumptions

Retirement assumptions are based on a facility's age as a proxy for determining a facility's remaining operational life. In previous versions of the LTPP A&S document, three options for renewable retirement levels were provided, which corresponded to "low-", "medium-", and "high-" levels of renewable retirement assumptions. In the 2017 A&S, it is assumed there will be no renewable retirements within the planning horizon. If a facility announces a specific retirement date, that date will override these assumptions.

3.2.11 Other Retirement Assumptions

Retirement assumptions are also based on facility age as a proxy for determining a facility's operational life. Similarly to renewable and hydro retirement assumptions, the operational history of non-renewable/hydro facilities will not be considered in this planning cycle. A "Low" level of retirement assumes that "Other" resource types stay online unless there is an announced retirement date. A "Mid" level assumes a retirement schedule based on resource age of 40 years or more. A "High" level assumes a retirement schedule based on

62 http://www.cpuc.ca.gov/WorkArea/DownloadAsset.aspx?id=11675.

resource age of 25 years or more. Facilities which have an existing contract that runs beyond their assumed retirement age shall instead be assumed to operate until the expiration of the contract. Thus, a 38 year old facility in the "Mid" level that has a three year contract should be assumed to retire at 41 years once that contract expires. Commission staff will periodically request confidential procurement data from the utilities to screen for such facilities. "Other" includes all resources whose retirement assumptions are not explicitly described above – for example, peaker and cogeneration facilities. The default assumption for planning studies is a "Mid" level of retirement for "Other" resources.

"Cold shutdowns" or "Mothballed" Facilities

Generator owners that announce they will shut down their facilities, but which do not send notifications of retirement,[63] will be treated as follows: we will assume that, if economic conditions merit, these facilities could be made operational. As such, they will be considered existing resources, subject to the retirement rules.

Long Beach Peakers

From a technical and operational standpoint, the Long Beach peaker plants can remain in operation at least through 2025 due to refurbishments that occurred in 2007. These peaker plants' economic lifespan, however, depends on whether this facility can successfully re-contract once its current contract expires in 2017. Otherwise, it is assumed this facility will retire after its current contract(s) expire.

3.2.12 Imports and Exports

For the purposes of load and resource tables the default value for imports shall be based on the CAISO Available Import Capability for loads in its control area. This import capability is equal to the CAISO Maximum Imports minus Existing Transmission Contracts (ETCs) outside its control area, and is published on its website annually.[64] For 2017 the total import capability is calculated at 11,310 MW.[65] The 11,310 MW value should be used throughout the planning horizon being modeled. An alternative assumption is historical expected imports as calculated by the CEC.[66]

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[63] As with what has happened when Calpine announced it would not operate the Sutter Energy Center Plant for the rest of 2016.

[64] 2017 Import Capability Assignment Process Steps 6 and 7; found here http://www.caiso.com/Documents/2017ImportCapabilityAssignmentProcessSteps6-7.html.

[65] For the source of the 11,665 MW of total import capability, look for "2016 Import Allocations" under "Import Allocation" here: "https://www.caiso.com/planning/Pages/ReliabilityRequirements/Default.aspx Click on "Step 6: 2016 Assigned and Unassigned RA Import Capability on Branch Groups."

[66] As described in Appendix D, http://www.energy.ca.gov/2012publications/CEC-200-2012-003/CEC-200-2012-003.pdf.

Technical planning studies require a more nuanced approach to accounting for imports. In the 2010 and 2012 LTPP studies the CAISO used a tool to calculate California statewide, and CAISO area maximum imports. That tool calculated import limits for each scenario being studied based on inertia changes in the Southern California Import Transmission (SCIT) area due to increased penetration of renewable resources and retirement of generation resources with inertia. It is anticipated that CAISO will update this tool and use it for the LTPP studies envisioned by this document for use in future planning studies.

For technical planning studies requiring information about infrastructure, resources, and loads outside of the CAISO area, the Transmission Expansion Policy Planning Committee (TEPPC) 2026 Common Case dataset should be used.

In regards to exports, the LTPP planning assumptions have historically been silent on the potential quantity of exports. The CAISO has, in the past, imposed a modeling constraint of "no net exports;" this reflects historical practice. As regionalization efforts continue to be examined, however, further work is required to establish appropriate assumptions on the potential exports in different planning futures. In the Draft 2017 A&S, zero net exports will be deemed as the Low-case; 2000 MW of net exports will be considered the Mid-case; and 8000[67] MW of net exports will be incorporated as the High-case. The net export constraint assumed by modelers should be set at the Mid-case for the Reliability Scenario.

3.2.13 Regional Generation Requirement and Frequency Response Constraints

In previous LTPP studies using production cost simulation models, a regional generation requirement constraint was imposed. This was modeled as a requirement for at least 25 percent of load to be met by generation from local resources within specific geographic areas in California. This constraint served as a crude proxy for ensuring sufficient local generation was online to supply both frequency response and the ability to respond to contingencies. Given recent infrastructure upgrades including new peaker resources in Southern California that enhance the ability to respond to contingencies, the 25 percent regional generation requirement constraint is removed. However, the need to supply sufficient frequency response must still be met, and this will be modeled by a new constraint in production cost simulation models that would ensure each balancing area can meet its obligations under the new NERC BAL-003-1 frequency response standard. According to the NERC BAL-003-1 standard and the CAISO's Frequency Response Stakeholder Process, the CAISO's current frequency response obligation is 258 MW/0.1 Hz, which can be interpreted to mean that the CAISO balancing area must have 752 MW of headroom at all times.

For consistency across different studies using production simulation models, modelers are directed to implement constraints to represent the CAISO balancing area's compliance with NERC BAL-003-1 as follows:

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[67] Senate Bill 350 Study, The Impacts of a Regional ISO-Operated Power Market on California, pp. I-4 – I-5, available at https://www.caiso.com/Pages/documentsbygroup.aspx?GroupID=4C17574F-73AE-40E3-942C-59C3A13BBDF1.

1. 50% of the headroom requirement (376 MW) is assumed to be met by hydro resources (excluding pumped hydro storage). However, no modeling constraint will be imposed on hydro. This is based on CAISO's operational experience that hydro can respond to under-frequency at any time without imposing explicit constraints on hydro operations.
2. 50% of the headroom requirement (remaining 376 MW) is assumed to be met by storage (excluding pumped hydro storage) and/or online combined cycle resources.
   a. Storage units assumed to provide flexibility services (as described in the storage assumptions section of this document) are allowed to meet the headroom requirement on a MW-for-MW basis, up to the available storage headroom.
   b. Combined cycle units can provide 0.08 MW toward the headroom requirement for each MW of online capacity, up to the available combined cycle unit head room.
3. Geothermal and nuclear typically operate at full load and are assumed to not contribute towards meeting the frequency response obligation.
4. The headroom requirement applies for all 8760 hours of the typical one-year production cost simulation model.

3.2.14 Existing Procurement Authorizations

Planning Assumptions Made With Pending Applications Data

Decision 15-11-041 approved the results of SCE's Local Capacity RFO (A.14-11-012) for the Western LA Basin pursuant to D.13-02-015 and D.14-03-004.

Decision 16-05-050 approved a portion of the results of SCE's Local Capacity Requirements RFO (A.14-11-016) for the Moorpark sub-area. A decision on the remaining resources is expected in 2017; the projects that would help satisfy Moorpark's LCR are those with "location": "Goleta" illustrated in Table 12.

SDG&E filled 500 MW of its 800 MW Track 4 LCR authorization via its power tolling agreement with Carlsbad Energy Center LLC.

The complete set of planning assumptions for existing LCR procurement authorizations are specified in Table 12, below, and should be used in all planning studies. These assumptions should also be utilized to inform CAISO TPP studies.

Table 12: Procurement Assumptions With Approved and Pending Applications

Decision	Capacity (MW)	Assumed online	Location	Description
Approved: D.15-11-041	640	2020	Alamitos, Long Beach	Combined cycle gas turbine
Approved: D.15-11-041	644	2020	Huntington Beach	Combined cycle gas turbine
Approved: D.15-11-041	98	2020	Stanton	Peaker turbine
Approved: D.15-11-041	124	2020	W. LA Basin (Procured via SCE's LCR RFO)	Energy efficiency
Approved: D.15-11-041	5	2018	W. LA Basin (Procured via SCE's LCR RFO)	Demand response
Approved: D.15-11-041	38	2018	W. LA Basin (Procured via SCE's LCR RFO)	Distributed generation solar PV
Approved: D.15-11-041	135	2018	W. LA Basin (Procured via SCE's LCR RFO)	Battery storage – BTM
Approved: D.15-11-041	29	2020	W. LA Basin (Procured via SCE's LCR RFO)	Thermal storage – BTM PLS
Approved: D.15-11-041	100	2021	Long Beach (Procured via SCE's LCR RFO)	In-front-of-the-meter Battery storage – transmission-connected
Approved: D.16-05-050	6	2020	Big Creek/Ventura (Moorpark Sub-Area)	Energy efficiency
Approved: D.16-05-050	6	2018	Big Creek/Ventura (Moorpark Sub-Area)	Distributed generation solar PV
Approved: D.16-05-050	262	2020	Puente, Big Creek/Ventura (Moorpark Sub-Area)	Peaker gas turbine
Pending: A.14-11-016	0.5	2018	Goleta (Moorpark Sub-Area)	In-front-of-the-meter Battery storage transmission-connected
Approved: D.14-02-016	300	2016	Pio Pico site	Peaker gas turbine
Approved: D.15-11-041	500	2018	Encina site (Carlsbad)	Peaker gas turbine
Pending: A.16-03-014	18.5	2018	San Diego	Energy efficiency

Note that the 264 MW (100 MW + 35 MW + 29 MW) of energy storage projects included in Table 12 also counts toward achievement of the storage procurement target in D.13-10-040 and are therefore counted in Table 6. These 264 MW are shown here is listed for completeness, but should not be modeled twice (double counted). Also note that the table above does not encompass the entirety of SDG&E's existing LCR procurement authorizations. Pursuant to D.15-05-051, SDG&E's residual procurement authority limited to preferred resources or energy storage, was revised to 300 MW. On March 30, 2016 SDG&E filed an Application (A.16-03-014), seeking approval of a 20 MW energy storage contract and 18.5 MW of EE projects. Assuming SDG&E's Application is approved, SDG&E's remaining preferred resource authorization is 261.5 MW.

Since the portfolio of resources necessary to meet SDG&E's authorization has not been determined, power flow studies should exclude the authorized but unprocured energy capacity. To the extent power flow studies identify an LCR need, the remaining 261.5 MW of authorized LCR procurement need should be considered first before authorizing new resources.

The energy efficiency, demand response, and distributed generation resource assumptions listed in Table 12 above represent incremental LCR procurement and are therefore assumed to be incremental to the other energy efficiency, demand response,[68] and distributed generation assumptions described earlier in this document.

Interaction of LCR procurement and storage target

Some of the storage projects included in the applications that would fill existing LCR procurement authorizations are assumed to satisfy the D.13-10-040 storage procurement target; these storage projects are noted in Table 12. Technical studies shall not double count these resources.

Table 3 in the Energy Storage section (3.2.4) of this document does not include any adjustment to reflect how existing LCR procurement authorizations are assumed to satisfy the D.13-10-040 storage procurement target. SCE's share of the D.13-10-040 storage procurement target for customer-side storage is 85 MW. However, the CPUC via D. 15-11-041 approved SCE contracts to procure 164 MW[69] of customer-side storage via its LCR procurement Application. This results, combined with other customer-side storage procurement, in SCE exceeding its customer-side storage target (per D.13-10-040) 159.42 MW. Technical studies should therefore assume that SCE's share of the D.13-10-040 storage procurement target for customer-side storage is completely filled by its proposed LCR procurement. Note that all of the 164 MW of customer-side storage represented by SCE's LCR application should count as capacity in power flow studies because this storage is expected to be procured specifically to satisfy local capacity requirements.

SCE's share of the D.13-10-040 storage procurement target for transmission-connected storage is 310 MW. However, SCE proposes to procure about 100 MW of transmission-connected storage in its LCR procurement applications. Therefore technical studies should assume that SCE's share of the D.13-10-040 storage procurement target for transmission-connected storage is partly filled by its proposed LCR procurement of 100 MW and the remaining share of the storage procurement target is 210 MW.

[68] The "5 MW 2019 W. LA Basin Demand response" project included in Table 12 is the same 5 MW of incremental DR described in Section 3.1.7 and should therefore not be double counted.

[69] These 164 MW include the Ice Bear (28.64 MW project) and two "Hybrid Electric, stern" (85 MW + 50 MW) projects. See Table 6.

SDG&E's share of the D.13-10-040 storage procurement target for transmission-connected storage is 80 MW. After accounting for existing project Lake Hodges, the remaining share is 40 MW. Note that all of the 25 MW of transmission-connected storage represented by SDG&E's required LCR procurement, per D.14-03-004, counts as capacity in power flow studies because this storage is expected to be procured specifically to satisfy local capacity requirements.

3.3 *Other Assumptions*

3.3.1 The Second Planning Period

Planning studies which target years within the second planning period (2027-2036) will use simplified planning assumptions. Generally, these assumptions reflect extrapolation of the approaches of the first planning period.

- Net (managed) load growth will be extrapolated using the average, annual compound growth rate from the prior period. Only the net load will be extrapolated (i.e. the forecast load, after demand side adjustments such as AAEE), rather than extrapolating individual load or demand assumptions. The formula for calculating the growth rate is…

$$GrowthRate = \left(\frac{NetLoad_{2026}}{NetLoad_{2016}} \right)^{\frac{1}{(2026-2016)}} - 1$$

  …where Net Load is the gross load forecast minus AAEE. This annual growth rate is then applied to the 2026 Net Load to calculate the Net Load for 2027-2036.

- Resource retirements will be calculated based on resource age or other characteristic, as described for the first planning period of each scenario.
- Resource additions (except renewable resources) will be calculated based on known and planned additions for all scenarios.
- Imports will be assumed to remain constant from the 2026 value through the second planning period.
- Dispatchable DR will be assumed to remain constant from the 2026 value through the second planning period.
- The analytical work being undertaken in the Integrated Resource Planning Proceeding (R.16-02-007) will be making a projection of BTM PV beyond 2026. In the meantime, the BTM PV assumptions contained in CEDU 2016 should be used in long-term planning.

3.3.2 Deliverability

Resources can be modeled as Energy-Only or Fully-Deliverable. The CAISO's TPP, for purposes of identifying needed policy-driven transmission additions, uses renewable resource portfolios provided by the CPUC that historically require full-deliverability. As an alternative to full deliverability and in order to better allow for analysis of options for providing additional generic capacity, in Energy-Only portfolios any additional resource will only be assumed to be Deliverable if it meets one of two criteria:

> (1) Fits on the existing transmission and distribution system,[70] including minor upgrades,[71] or new transmission approved by both CAISO and CPUC, or
>
> (2) It is a baseload or flexible resource.[72]

This assumption is only for study and planning purposes and does not prejudge any future CPUC decisions on transmission or resource approvals.

3.3.3 Price Methodologies

The same methodologies that were used in the 2014 LTPP proceeding and the 2016 LTPP proceeding should be used for the Draft 2017 A&S.

Natural Gas

The CEC's Natural Gas Reference Case as put forward in CEDU 2016 shall be used as the base for calculating natural gas prices. This price series was constructed to be consistent in baseline assumptions with the CED forecast and therefore the two are congruent for planning purposes.

Greenhouse Gas

The GHG price forecast as put forward in the 2016 IEPR shall be used as the base for calculating GHG prices.

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[70] For this purpose, "fits" refers to the simple transmission assumptions listed in the "CAISO_Tx_Inputs" tab of the RPS Calculator. Staff shall collaborate with the CAISO to update these transmission assumptions and apply them to the resource portfolios.

[71] Minor upgrades do not require a new right of way.

[72] Flexibility currently does not have a standard definition, but a definition will be established either in this proceeding or in the Resource Adequacy proceedings (the current proceeding is R.14-10-010. Generally speaking, baseload resources are those that provide a constant power output, such as a nuclear plant, while flexible resources are those that can respond to dispatch instructions. There is some overlap between these two categories, for example a baseload design combined cycle plant could provide some flexibility.

4 Planning Scenarios

4.1 *2017 Planning Scenario – Reliability Scenario*

The Draft 2017 A&S document contains information regarding a single scenario: the Reliability Scenario. The Reliability Scenario maps closely to the Infrastructure Investment Scenario articulated in the previous version of the LTPP . This is for use in long-term electric system planning for the state of California, as well as for use as an input in the CAISO's 2017-18 TPP studies, set to commence in early-2017.

Previous versions of the LTPP Assumptions & Scenarios document contained multiple scenarios used to evaluate different potential futures for California's electric system. Typically, these scenarios contained varying assumptions used for reliability, economic, and policy-driven analyses. For example, previous LTPP A&S documents contained scenarios for analysis of possible futures that contained assumptions for higher RPS generation targets, greater regional coordination, or higher BTM PV adoption. Analyses of these scenarios could have highlighted the need for different investments, such as additional transmission infrastructure.

The Draft 2017 A&S document only contains information regarding a single reliability scenario: the Reliability Scenario. Policy-driven analysis historically focused on identifying any transmission infrastructure needed to support the state's Renewable Portfolio Standard (RPS) program. By mutual agreement, no RPS-related policy-driven analyses to identify new infrastructure needs beyond what is necessary to support a 33% RPS scenario are being provided by the CPUC in this document for consideration in long-term planning and for use by the CAISO for its 2017-18 TPP.

What this scenario helps us study: This scenario will be provided to the CAISO as the base-case to be used in the 2017-18 Transmission Planning Process (TPP) studies.[73]
Why this scenario is worthwhile to study: The renewable resources portfolio plays an integral role when modeling the electric system. The CAISO and the CPUC have a memorandum of understanding under which the CPUC provides a renewable resource portfolio for CAISO to analyze in the CAISO's annual TPP. The TPP analyzes the transmission system and determines the need for new transmission resources to ensure system reliability and meet policy goals.

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[73] The CAISO authorizes new transmission infrastructure based on studies of the Base-Case scenario; via reply comments on the Draft Assumptions and Scenarios document CAISO stated: "The CAISO strongly supports staff's recommendation to use the 33% RPS portfolios for the 2016-17 transmission plan. Changing the portfolios used to plan the 33% RPS goals at this point will cause the CAISO to revisit already approved transmission solutions designed to meet the 33% RPS goal. This would in turn cause serious industry uncertainty regarding the state of already approved transmission solutions.

This scenario updates critical operational variables of the transmission system but does not forecast an increase in renewable resources beyond the 33% goal used in previous trajectory scenarios. CPUC and CAISO staff believes that it would be inappropriate to plan significant transmission expansion investments to access increased renewable resources before the CPUC has fully analyzed alterative renewable portfolios and selected a preferred course of action for infrastructure investment enhancements. If a fully-deliverable portfolio consisting of a RPS percentage greater than 33% is studied by the CAISO as part of its "base-case" TPP scenario, such a portfolio would likely result in a CAISO assessment indicating that new transmission capacity is needed to bring renewable energy, beyond the 33% RPS threshold, to market. Thus, it would be imprudent to generate a renewable portfolio that might trigger new policy-driven transmission investment until more information is available.

Similarly, a new 33% RPS portfolio generated by the updated RPS calculator would be based upon increasing customer generation and declining IEPR CED load forecasts and therefore could be based upon a lower RPS net short than the RPS portfolio used in the 2016-17 TPP. Such a portfolio might not support currently approved transmission projects that will be needed to reach 50% RPS goals. Thus, no new renewable portfolio will be provided in the Draft 2017 A&S which may compel the CAISO to reexamine previously approved transmission investment decisions until more information is available.

Submitting the Reliability Scenario for the CAISO to study as part of the 2017-18 TPP therefore ensures that the CAISO study results will reflect known transmission needs, not transmission needs based on speculative renewable portfolios. On a practical level, transmission capacity exists to interconnect additional renewable projects without major new transmission expansion. Nevertheless, a new RPS portfolio – even one that models a 33% RPS target – could still lead to a CAISO finding that new transmission capacity is necessary if such portfolio is sufficiently different than the 33% RPS portfolios previously studied.

How this scenario will be created: This scenario uses the same RPS portfolio that was supplied by Commission staff to the CAISO for the 2016-17 TPP, the "33% 2025 Mid AAEE" trajectory portfolio.[74] It is expected that the CAISO will supplement the Reliability Scenario with information regarding contracted RPS projects that have begun construction since the May 2016 LTPP A&S document was published. As a result, the renewable GWh energy value contained in the Reliability Scenario will exceed 33% of forecast demand.

[74] *See* section "4.2.7 RPS Portfolios for the 2015-16 TPP" of "Attachment 2" (found here: PDF) from the "Assigned Commissioner's Ruling on updates to the Planning Assumptions and Scenarios for use in the 2014 Long-Term Procurement Plan and the California Independent System Operator's 2015-2016 Transmission Planning Process" (found here: PDF).