Proposal for Monthly Loss of Load and Solar and Wind Effective Load Carrying Capability Values for 2018 Resource Adequacy Compliance Year

RESOURCE ADEQUACY PROCEEDING R.14-10-010
CALIFORNIA PUBLIC UTILITIES COMMISSION – ENERGY DIVISION

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I. List of Acronyms

AAEE – Additional Achievable Energy Efficiency	LOLH – Loss of Load Hours
BAA – Balancing Authority Area	MW - Megawatt
BTM PV – Behind the Meter Photovoltaic	NQC – Net Qualifying Capacity
CAISO – California ISO	PU Code – Public Utilities Code
CEC – California Energy Commission	RA – Resource Adequacy
ELCC – Effective Load Carrying Capability	RPS – Renewables Portfolio Standard
IEPR – Integrated Energy Policy Report	SERVM – Strategic Energy Risk Valuation Model
LCR – Local Capacity Requirements	TEPPC – Transmission Expansion Policy Planning Committee
LOLE – Loss of Load Expectation	WECC – Western Electric Coordinating Council

II. Summary of ELCC Proposals and Key Updates for 2018

Pursuant to PU Code 399.26(d) Energy Division staff has been working to develop an analytically sound method to calculate Effective Load Carrying Capability (ELCC) for wind and solar resources to quantify their qualifying capacity for the Commission's Resource Adequacy (RA) program. An ELCC study is a form of reliability assessment, which seeks to quantify and measure the reliability contribution of certain generators or classes of generators to aggregate system electric reliability. Energy Division staff measures ELCC as either the quantity of Perfect Capacity that provides equivalent reliability value to the reliability value provided by the nameplate MW of generators being studied, or a ratio between 0 and 1 that reflects the ratio of the equivalent quantity of Perfect Capacity[1] in Megawatt (MW) to the nameplate MW quantity of the generators being studied. For example a 100 MW solar generator would have an ELCC of 20% if it provided equivalent LOLE reduction to 20 MW of Perfect Capacity.

Aggregate system reliability is measured by indices such as the Expected Unserved Energy (EUE), Loss of Load Hours (LOLH), and Loss of Load Expectation (LOLE).[2] Contribution to reliability is measured in terms of ability to reduce LOLE found in reliability studies. Loss of load is found whenever, on aggregate, electric demand exceeds the capability of the modeled generation resources to serve demand plus some level of operating reserves either by not having sufficient capacity installed or by being unable to dispatch generators upwards to meet load.

Energy Division has released a number of proposals[3] that demonstrate advances in Energy Division's modeling effort, as well as periodically revising and reposting the Inputs and Assumptions Paper to the CPUC website[4] that details Energy Division's overall effort to develop and maintain the data that goes into reliability and ELCC modeling. Details such as development of electric demand and generation profiles, fuel price and other generator inputs, and delineation of regions in the model are outlined in the Inputs and Assumptions paper which is posted to the CPUC website.

Via the RA proceeding (currently R.14-10-010), parties and staff have been collaboratively developing policy and analytical guidance for the execution of LOLE and ELCC studies, and the presentation of

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[1] Perfect Capacity refers to fictional generators created in the model that have perfect capabilities, such as zero forced and maintenance outage rates and zero startup times. They serve as a standard against which to compare real existing generators.

[2] LOLE equals the expected number of loss of load events, regardless of length, in a given year. LOLH equals the expected number of hours with loss of load in a year. EUE equals the total MW of load lost in a given year. LOLE is a measure of frequency, not duration or magnitude. LOLH is a measure of duration, not frequency or magnitude. EUE is a measure of magnitude, not frequency or duration.

[3] The most recent previous ELCC proposal is the "Revised ED Staff ELCC and LOLE proposal" issued to R.14-10-010 on March 23 is linked to the CPUC website on this page: http://www.cpuc.ca.gov/General.aspx?id=6265

[4] Posted to the CPUC Website here: http://www.cpuc.ca.gov/General.aspx?id=6442451972

results. Energy Division most recently issued a proposal in December 2016 to create month specific ELCC values for solar generators that is based on a month specific LOLE study. Previously Energy Division issued proposals to establish locationally specific ELCC factors for wind and solar generators in March 2016. The Commission ultimately chose not to adopt Energy Division's proposals from earlier in 2016, noting as it did so that a more analytically robust allocation of ELCC credit to individual months was within reach and urged Energy Division to develop the proposal for adoption in the 2018 RA compliance year.

In response to Commission guidance, Energy Division pursued the development of month specific ELCC values for wind and solar generators. Since March of 2016, Energy Division Staff developed a methodological process which we lay out here, including updated data inputs and improvements to the underlying Energy Division dataset to incorporate revised inputs.

Since the March 2016 proposal, significant new generation (particularly solar generation) has been added to the CAISO generating fleet, including 3,082 MW of RPS supply side solar generation and 5,527 MW of Behind the Meter Solar (BTM PV) generation. Energy Division staff attempted to model BTM PV as a resource in order to gauge its effect on overall solar ELCC, and thus study the overall value of all the solar generation that is projected to be online in 2018. The current solar fleet being modeled in this proposal totals 16,033 MW and results in a month specific ELCC ranging from about 1% in December to about 34% in June. To contrast, the March 2016 Energy Division proposal modeled a solar fleet that included a total of 7,424 MW of solar generation, which resulted in an ELCC of 57.75% over the peak months.

The March 2016 RA proposal modeled 6,492 MW of wind resources which provided an annual ELCC of 13% compared to this current proposal that includes 6,891 MW of wind resources and ELCC ranging from 0% in December to 48% in June.

The increase in solar generation in the model resulted in lower ELCC for solar resources because it shifted the timing of reliability events to later in the evening. While that shift interacted beneficially with wind production and likely boosted wind ELCC overall, the relative decline in value for solar generation as more of it is added is an expected and understood outcome. For that reason, parties are encouraged to consult the March 2016 Energy Division proposal as added context and as a bookmark for the effect of the additional solar generators on the ELCC value of solar generators overall. Parties are encouraged to review the impact of these decisions in their comments.

Explicit inclusion of BTM PV in the calculation of solar ELCC raises important questions about the overall structure of the RA program. The current RA program requires LSEs to procure an amount of qualifying capacity (comparable to the effective capacity referenced in this proposal) that can be reasonably relied on to meet reliability conditions. RA obligations are set by adding a 15% reserve margin to the peak sales in each month, as forecasted by the California Energy Commission (CEC) via the Integrated Energy Policy Report (IEPR) study. Inclusion of BTM PV requires the reconstitution of consumption forecasts that add back the embedded effects of BTM PV to the net sales forecasts prepared by the CEC.

Were RA obligations meant to be calculated through this process, the RA obligations would be set relative to consumption forecasts, not sales, and BTM PV would explicitly receive RA capacity credit. Changing the calculation of the RA obligation in the manner discussed here is currently not in the scope of the RA proceeding R.14-10-010, thus is not part of this proposal. It is possible that in the future that could be scoped in pursuant to party input and consultation.

In this revised proposal, Energy Division makes two proposals. First, presented in section III.C Energy Division proposes to adopt monthly ELCC values calculated by staff for both wind and solar generators for use in the 2018 RA compliance year. These month specific ELCC values would reflect the ability of all wind or solar generators (including BTM PV generators) to mitigate LOLE, as a ratio of the nameplate capacity of Perfect Capacity added to the system to provide equivalent LOLE mitigation as the wind or solar facilities that were removed. Second, Energy Division proposes an alternative in section III.D, to take the wind and solar ELCC values calculated by staff, and to back out the estimated effect of BTM PV generators from the calculated solar ELCC values.

Energy Division presents these data updates and software upgrades, along with these proposed ELCC values for wind and solar generators to be adopted for use in the 2018 RA compliance year.

A. Key Study Process and Data Updates

Energy Division staff performed several important data updates since March of 2016. Staff downloaded and migrated to the latest version of the 2026 TEPPC Common Case (v1.5). Since staff did not use the load, wind, or solar profiles from TEPPC, staff was confident that the listing of generators and the forecasts of load for each area in v1.5 of the 2026 Common Case were sufficient. Staff disaggregated the areas external to California from ten different areas aggregated by state to seventeen different balancing authority areas (BAA). Finally, staff authorized Astrape Consulting to restudy and redevelop all load, solar, wind, and hydro shapes to incorporate actual historical data from 2013 and 2014, to map weather and load to the new utility BAA areas, and to make corrections to the mapping of hydroelectric facilities within California.

In general, there was good conformance between the 2024 Common Case and the 2026 Common Case; the required updates to the SERVM database were relatively minimal. Out of roughly 3,200 generators included in the 2026 TEPPC Common Case located external to the CAISO BAA, less than 150 did not match what was already in the SERVM dataset derived from the 2024 Common Case dataset. Staff matched most of the facilities between the 2026 Common Case and the SERVM dataset with the exception of hydroelectric facilities. Since staff model hydroelectric generation with aggregated units to incorporate all of the historical hydro generation from the various areas, individual hydroelectric units do not need to be distinguished in the dataset.

There were also six large planned generating facilities that were included in the 2024 Common Case, but have since been canceled, and thus were not included in the 2026 Common Case. Staff ensured that the maximum and minimum operating levels (capmax and capmin) as well as the fuel inputs and heat rates for each generator in the SERVM dataset agreed with the 2026 Common Case. Units were also placed in the correct BAA. This step was easier than it had been previously due to the realignment of areas in WECC to match the BAAs rather than states which sometimes cut across BAAs.

Staff updated the wind, solar, and hydro profiles to add recent weather and performance data from 2013 and 2014 to the pool of available historical data. Astrape then used the recent data to create predictor relationships and new hourly profiles. Hydroelectric generation data was recreated to correct unit mapping between areas in California. In addition, recent drought conditions have resulted in lower predicted hydroelectric generation for recent weather years. Hydro, wind, and solar shapes now represent 35 years of weather history, from 1980 through 2014.

Hourly BTM PV impacts are explicitly modeled using installed capacities from the target study year and historical hourly weather data and a technology factor appropriate for BTM PV. The technology factor provides the relationship between insolation and generation. Insolation is the solar radiation that reaches the earth's surface, measured by the amount of solar energy received per square centimeter per minute.

Staff made several updates to reflect expected generation retirements between now and 2018, and added in the latest RPS portfolios resulting from the RPS calculator.[5] About 5,183 MW of RPS wind and solar facilities reached commercial operation and became part of the CPUC dataset since the March 2016 study results were posted, including 3,082 MW of expected RPS solar projects and 2,100 MW of expected RPS wind projects.

1. Proposed Monthly LOLE Metrics

Before the development of today's advanced computing, planners calculated probability of LOLE in the peak hour of each day, and only on weekdays. That means calculating about 260 data points in total. Today's computers perform simulations, not simple calculations, and perform simulations of each hour of the year thousands of times with multiple stochastic variables. Thus, the LOLE metric of 0.1 (often referred to as one day in ten years standard) that arose out of previous generations of simple calculations may no longer be appropriate given the expanded scope of hourly simulations with more advanced computers.

Energy Division staff is assessing each month individually to determine the adequate level of effective capacity to maintain reliability in each individual month. This runs counter to the traditional means of performing LOLE studies in which sufficient effective capacity is made available for the peak months and held year round, without releasing surplus capacity in off-peak months. In light of this, 0.1 LOLE no longer appears to be the appropriate target. A target that represents a tolerable level of reliability stress in each individual month is more appropriate, and may total greater than a probability weighted average of 0.1 LOLE. Key questions include the definition of the appropriate level of LOLE in each

[5] The current RPS calculator is linked to the CPUC website here: http://www.cpuc.ca.gov/RPS_Calculator/

month, and whether each month is to be treated equally. There is no standard approach or industry accepted metric for a month specific LOLE target, so Energy Division staff proposes to calculate a monthly LOLE target by taking the 0.1 LOLE target over the four peak months of June through September (equal to one third) of the year and spreading that level of LOLE across the year (translating to three times that level over the year). In other words, LOLE over the entire year would be targeted towards a total of 0.3, and each month would have a target LOLE of 0.3/12 or 0.025.

2. Updated Load Forecasts – Consumption versus Sales

Energy Division staff updated peak and total energy forecasts based on the CEC 2015 IEPR load forecast for 2016 through 2026.[6] The CEC forecast provides estimates of peak and annual average sales, while Energy Division staff's approach requires use of a consumption forecast due to the explicit modeling of BTM PV. Table 1 defines the difference between consumption and sales as used in this document. Sales are equal to consumption less BTM self-generation. Energy Division staff explicitly calculated hourly behind the meter self-generation – as the sum of BTM PV self-generation and additional achievable energy efficiency (AAEE) – and thus required a forecast of the total demand forecast in terms of consumption, not sales. In order to adjust the CEC sales forecast back to a forecast of consumption, Energy Division staff added back the forecast hourly production of BTM PV that preserved the exact same forecast peak and annual average BTM PV generation modeled in the CEC forecast.

Table 1 Definition of Terms - Energy Demand

Load Type	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 behind the meter onsite generation including storage charge/discharge and less AAEE	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 transmission and distribution losses plus theft and unaccounted for energy	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 sum of individual customer loads
Net Load	System load less intermittent renewable generation	This is the same definition used by CAISO	BAA estimation of system load less measured output of wind and solar supply-side renewable generators

Table 1: Load type definitions. Note that for the CPUC production cost modeling work we are modeling behavior at the system level, and we do not differentiate between sales and system load. Said another way, we gross sales to the system level, accounting for distribution level losses.

[6] CEC IEPR 2015 Forms 1.2, 1.4, 1.5a and 1.5b

Embedded in CEC Forms 1.5a and 1.5b is an estimate of the peak and average annual BTM PV self-generation. Energy Division staff extracted this same value[7] using an ancillary CEC calculation and added the original peak and annual average BTM PV generation back to the CEC calculation resulting in a forecast for consumption only. One benefit of this approach is that propagation of error is minimized because staff added back an almost identical value as was originally subtracted from the consumption. We then use the same BTM PV capacities used in the original CEC calculation as the basis for our BTM PV installed capacity by IOU service area and by year through 2026, consistent with forecasts of BTM PV penetration. 5,526 MW of BTM PV were modeled as being available in 2018.

3. Updated Regions and New Weather Data

Weather is an integral input into probabilistic reliability modeling. It is used both in the development of synthetic load shapes, which are highly correlated to temperature, and in the development of generation profiles for weather-sensitive resources such as wind and solar. In order to balance the need to model the diversity of weather across the state and the need to keep modeling times feasible, a set of representative weather stations are selected and grouped to create regions that are modeled as homogeneous areas. This section details the weather data utilized, the sources for this data, the regions modeled, and the process by which these regions were created.

SERVM models eight distinct regions within California and seventeen BAAs outside of California. This represents a significant increase in granularity and complexity (total of 25 areas versus 18) over the work Energy Division staff performed during 2015. These regions are utilized throughout SERVM to associate groups of generation facilities with common weather, load, weather-related generation profiles, transmission constraints, and BAAs. The regions modeled are listed in Table 2 below. The regions below do not correspond to Local Areas, and are not granular enough for transmission planning. In the future, higher granularity could be achieved by splitting the regions into smaller areas. That is not the purpose of Energy Division staff's current efforts.

Table 2. Regions Modeled in SERVM

California Regions	**Regions external to California**	
IID (Imperial Irrigation District) BAA	Arizona Public Services including Gila River	Portland General Electric
		Western Area Power Lower Colorado
Los Angeles Department of Water and Power BAA	BC Hydro and Alberta Electric System Operator	Tucson Electric Power Company
PG&E Bay Area *(Greater Bay Area Local Capacity Requirements Area)*	Public Service Company of Colorado	Western Area Power Colorado and Missouri
PG&E Valley *(Non-Bay PG&E Service Territory)*	Comission Federal de Electricidad (Mexico)	Pacificorp East

[7] Because of small differences between how the CPUC and CEC approaches define service areas, there may be very small discrepancies due to slight misalignment in geographical mapping.

SCE Service Area	Northwestern Energy Montana with Naturener and Western Area Power Montana	Bonneville Power including Puget Sound and City of Tacoma
SDG&E Service Territory	Nevada Power Company	Idaho Power Company
Balancing Authority of Northern California (aka SMUD)	Public Service Company of New Mexico and El Paso Electric Co.	Sierra Pacific Power Company
TID (Turlock Irrigation District)	Pacificorp West BAA	Salt River Project

Energy Division staff delineated regions in SERVM to correspond to both the TEPPC 2026 Common Case, and the CAISO modeling dataset. Energy Division staff no longer delineates areas by state boundaries and now delineates by BAA; for example, New Mexico, Idaho, and Utah will be represented instead by Public Service New Mexico, Idaho Power Company, and Pacificorp East respectively. Please consult the Energy Division Inputs and Assumptions document for a more detailed description of the study areas and a map illustrating their location.

4. Redevelopment of Load Shapes for 35 Years of Weather History

The most recent five years of historical load and weather are used to train a neural network model, developing a relationship between weather and load. The historical data is corrected for demand response and behind the meter photovoltaic effects. This relationship between weather and load is then used to develop hourly load curves for all 35 historical weather years in the CPUC dataset, which are then scaled using a linear stretching algorithm to the appropriate peak and annual average forecasts as defined by the CEC IEPR consumption forecast described above. Staff posted all 35 load shapes to the CPUC website, where parties were able to review them. Calpine staff discovered a discrepancy related to daylight savings time and together with Energy Division's consultant, Astrape Consulting, arrived at a means to correct the load shapes to remedy the missed correlation between loads not adjusted for daylight savings time and the wind and solar production shapes that reflected the daylight savings time adjustments. The problem was corrected, all modeling was redone to use the corrected load shapes, and Energy Division staff is preparing to repost the load shapes to the CPUC website.

5. Order of Studies Performed

Energy Division staff and Astrape Consulting performed a series of studies to assess reliability levels and reliability contributions of generators or class of generators.

The calibration and sequence of these studies depends on the objectives of the study. Energy Division staff begins by taking the "as found" system, which has an unknown reliability level. In order to establish the LOLE of a system, generation is removed or added and the system is simulated iteratively until the desired reliability level is reached. If the study is attempting to ascertain reliability on a month specific level, generation is added or subtracted to each month individually. In addition to facilities that have already retired prior to the start of 2017 RA compliance year, Energy Division staff retired further generation in order to achieve the desired LOLE target. In particular, generation in Northern California (in PGE_Valley area specifically) was retired in order to balance the LOLE across regions of the CAISO system. Moss Landing units 6 and 7 as well as the Diablo Canyon Nuclear Power Plant were removed to reduce energy trapped in PGE_Valley by transmission constraints.

Energy Division staff began by calibrating the balance of generating capacity in the CAISO aggregated area in order to create a monthly LOLE level of between 0.02 and 0.03 across the CAISO. After reading party comments, Energy Division staff decided to revise their proposal. Instead of moving directly to the ELCC values of solar and wind individually, Energy Division staff first established the portfolio value of wind and solar generation together as a group, and used the "Portfolio ELCC" as a benchmark on the overall standalone values of either wind or solar generators.

To value the portfolio of wind and solar generators together, all wind and solar resources were removed as a group from the total generating fleet, and replaced by Perfect Capacity until each individual month returned to the original 0.02 to 0.03 monthly LOLE range. Once the Portfolio ELCC of wind and solar together was determined, Energy Division staff was able to assess the standalone value of wind or solar individually and assess the benefit that diversity provides to individual standalone wind or solar ELCC values. In summary, wind and solar facilities in CAISO provide value in terms of offsetting LOLE, and their value is measured in ELCC. The ELCC of either wind or solar generators in CAISO was established pursuant to the following steps:

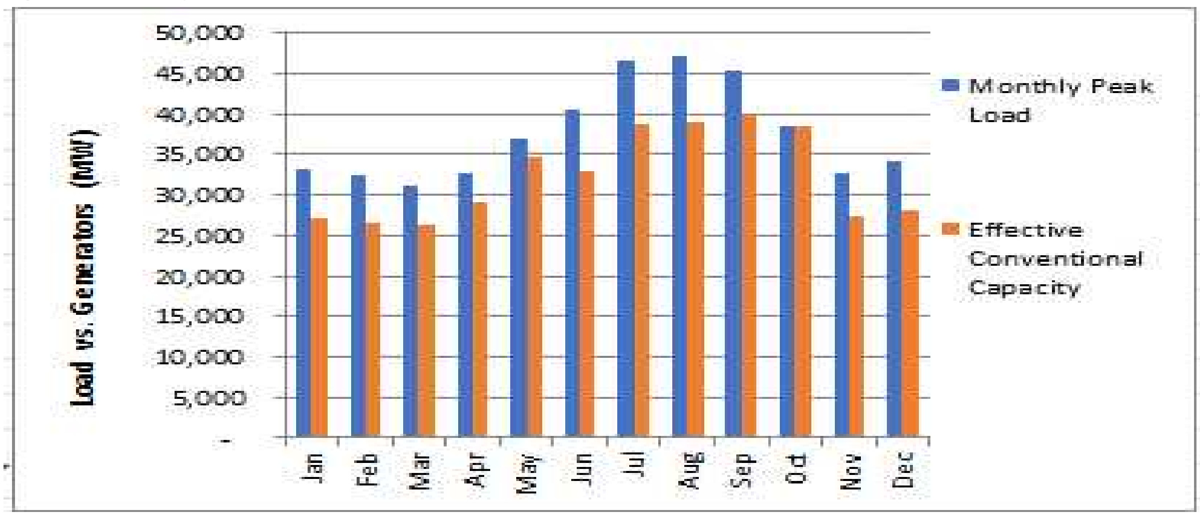
1. Study the entire study year with projected loads and expected resources. However, resources must be added or subtracted until the results equal a probability weighted average LOLE in the CAISO aggregated area of between 0.02 and 0.03 in each month of the year. Save all required output reports.
2. Remove all wind and solar facilities inside the CAISO aggregated region. Add or remove "Perfect Capacity" in each individual month until the probability weighted LOLE in each individual month falls between 0.02 and 0.03. The result is the Portfolio ELCC of all wind and solar generators. Save all required reports.
3. Add back wind generators and leave solar generators removed. Remove blocks of Perfect Capacity iteratively from each month. Remove Perfect Capacity until the probability weighted average LOLE in each month again falls within the range of 0.02 and 0.03 in each month. The result is the standalone ELCC of solar generators. Record the monthly levels of Perfect Capacity modeled and save all required reports.
4. Perform Step 3 in reverse by adding back solar generators and removing wind generators. Remove blocks of Perfect Capacity iteratively from each month. Remove Perfect Capacity until the probability weighted average LOLE in each month again falls within the range of 0.02 and 0.03 in each month. The result is the standalone ELCC of wind generators. Record the monthly levels of Perfect Capacity modeled and save all required reports.
5. Add the standalone ELCC of wind and solar generators, and compare the total to the Portfolio ELCC calculated earlier. The difference (either positive or negative) is the diversity adjustment. Allocate the diversity adjustment to either wind or solar generators by prorating to the proportion of wind and solar standalone ELCC in each month.

III. Results of Modeling

Energy Division staff studied the reliability of the CAISO area to assess its reliability. Energy Division staff maintained LOLE at a probability weighted average between 0.02 and 0.03 in each month of the year by iteratively adding or subtracting generation from each month of the year. Each of the 175 cases modeled (representing a weather year matched with a load forecast error percentage) is weighted individually and impacts the weighted average LOLE resulting from that case.

Figure 1 illustrates the amount of conventional generation (not wind or solar) remaining in each month compared to the peak load of that month. Wind and solar generation provide significant capacity value as shown by the low level of capacity relative to load, but that amount varies by month depending on load and production curves. The figure shows that the most value is given in June, July and August, while the least value relative to load appears to be in May and October.

Figure 1 Monthly Load vs. Conventional Generators (MW)



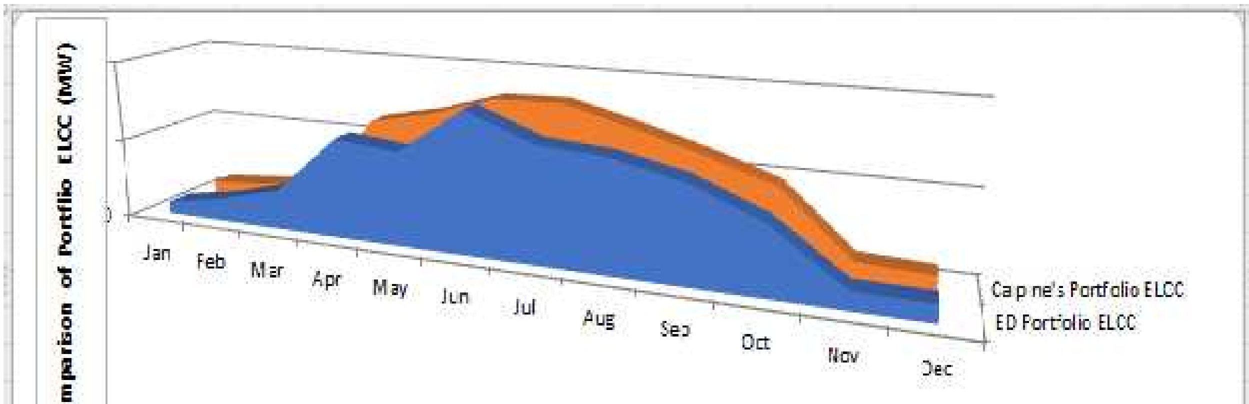
A. Monthly Portfolio ELCC

Once LOLE results in the CAISO area were calibrated to a probability weighted average LOLE range between 0.02 and 0.03 in each month, Energy Division staff removed all wind and solar generation fleet from the generating fleet and iteratively added Perfect Capacity. The Perfect Capacity (individual generators of about 100 MW each with 0 outage or maintenance rates) was added until a reliability study of the CAISO area again resulted in a probability weighted average LOLE between 0.02 and 0.03 in each month. This is called Portfolio ELCC, and represents the capacity equivalent of the wind and solar generators combined in terms of ability to reduce LOLE.

Figure 2 illustrates the amount of ELCC in MW of Perfect Capacity resulting from Energy Division's study. The figure also contrasts these amounts with the ELCC resulting from the similar study performed by

Calpine and submitted into the RA proceeding on December 16, 2016.[8] Energy Division's ELCC study results trend lower in the middle of the year, and are nearly equal in offpeak months. While these differences are small, the difference could be explained by a difference in the underlying reliability level to which the study is calibrated. The Portfolio ELCC illustrated below is equal to the figures presented at the CPUC workshop held on February 14, 2017.

Figure 2 Comparison of Portfolio ELCC between ED and Calpine Proposals



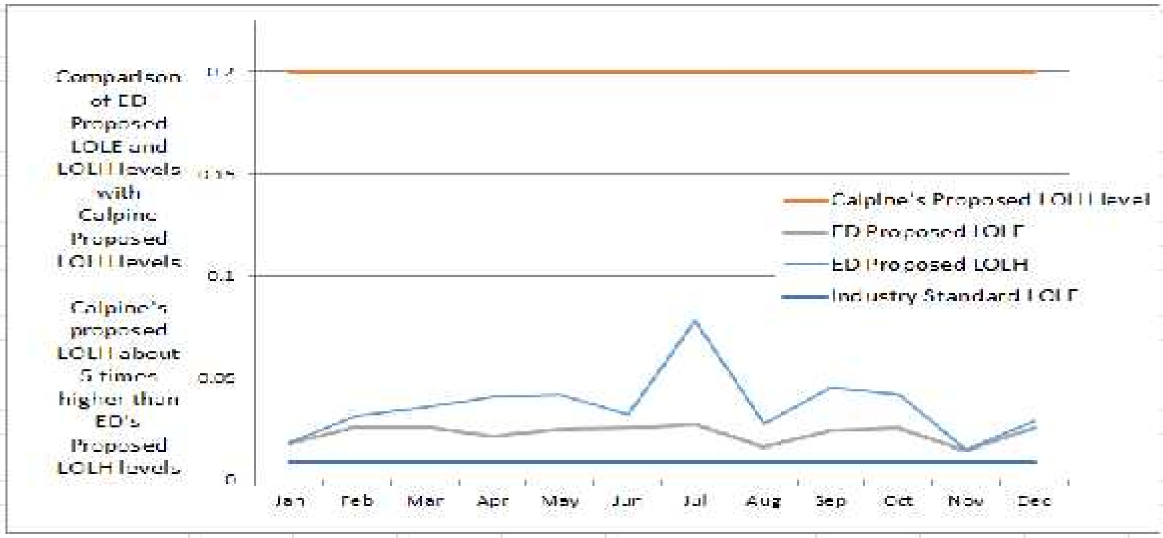
	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
ED Portfolio ELCC	778	1,475	2,511	5,146	5,758	6,645	7,046	6,746	5,832	4,136	1,071	1,044
Calpine's Portfolio ELCC	852	1,190	1,583	5,237	7,079	6,325	8,420	7,367	6,150	4,764	972	736

Energy Division's study of LOLE targets a monthly level between 0.02 and 0.03 events per month. LOLE events tend to be between 1 and 2 hours in length, as evidenced by Figure 3 which illustrates LOLE and LOLH results from Energy Division's study. It also compares the LOLH in Energy Division's study (which equates to the underlying reliability target meant to be met with solar, wind, or Perfect Capacity) with the LOLH which was the underlying reliability target of Calpine's proposal. Energy Division staff based their ELCC study on a more conservative level of reliability that is much closer to the standard industry metric of one day in ten years, and that leads to different lower ELCC results than Calpine produces. Calpine's proposal illustrates the difference this change in underlying reliability level could produce on ELCC values.[9]

[8] Calpine's proposal submitted into R.14-10-010 on Dec 15, 2016 linked to CPUC website here: http://docs.cpuc.ca.gov/SearchRes.aspx?DocFormat=ALL&DocID=171206012

[9] Table 2 on page 9 of Calpine's proposal illustrates the effect of underlying LOLH on ELCC values. This document is linked to CPUC website: http://docs.cpuc.ca.gov/SearchRes.aspx?DocFormat=ALL&DocID=171206012

Figure 3 Comparisons of ED Proposal and Calpine Proposal - LOLH and LOLE Metrics



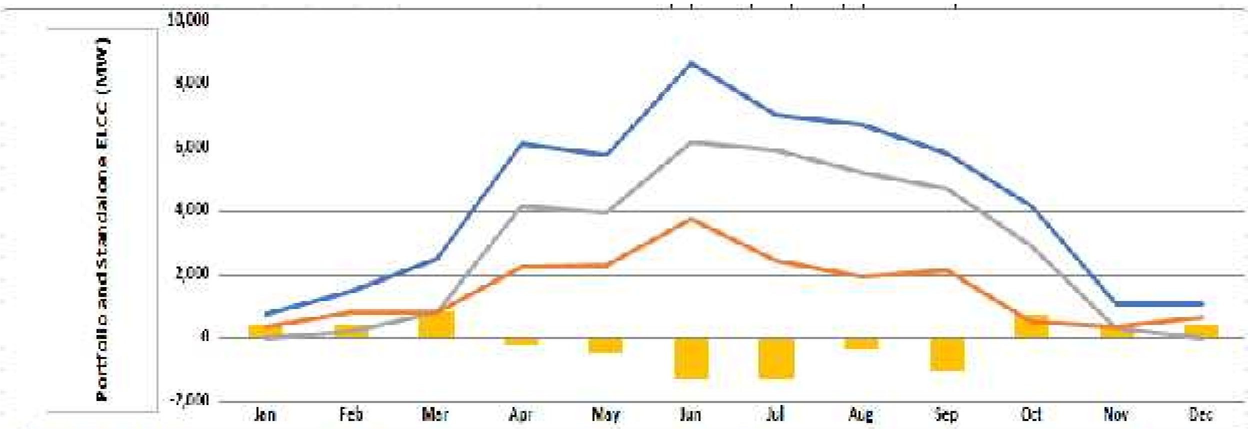
B. Month Specific ELCC for Solar and Wind Generators

Energy Division staff built on the basis of Portfolio ELCC to study the standalone ELCC of wind and solar generators. Energy Division staff put back the wind and solar generators that were removed for the Portfolio ELCC study, then selectively removed EITHER wind OR solar generators. The removed solar or wind generators were replaced with Perfect Capacity iteratively until the probability weighted average LOLE results again fell within the range of 0.02 and 0.03 each month. Standalone solar ELCC and wind ELCC values were calculated individually for each month. Since each group of either solar and wind generators were studied in the presence of the other (meaning when wind was removed, solar was preserved in the fleet and vice versa) the total standalone ELCC results from wind and solar generators added to a total that exceeded the Portfolio ELCC in several months. That means in each standalone calculation, each group gained some benefit from the other group. Thus the benefits of diversity were already included in the standalone values, and in this case, the whole is LESS than the sum of its parts. Figure 4 illustrates the standalone results for solar and wind ELCC studies as compared to the Portfolio ELCC values calculated previously, and shows the corresponding diversity adjustment which is often negative.

Energy Division staff performed the standalone study of solar ELCC by removing all 16,033 MW of solar facilities that delivered to CAISO (including 5,526 MW of BTM PV) and added in Perfect Capacity sufficient to return the system to the desired range of LOLE (between 0.02 and 0.03 LOLE per month) . Energy Division began by estimating the ELCC value, adding in Perfect Capacity to the estimated level, and then iteratively either adding or removing more Perfect Capacity until the probability weighted LOLE in each month fell within the desired range. Energy Division added Perfect Capacity to each study area within CAISO (either SCE, SDGE, PGE_Valley, or PGE_Bay) proportionately to the ratio of solar generators in each area.

Energy Division staff finalized the standalone solar ELCC values by running the final portfolio of generators and Perfect Capacity at higher level of iterations to ensure convergence. A similar process was followed to study the standalone ELCC of wind generators.

Figure 4 Standalone Solar and Wind ELCC and Diversity Adjustment



	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Diversity Adjustment	439	433	842	235	470	1,292	1,303	388	1,030	742	351	381
Portfolio ELCC	778	1,475	2,511	6,146	5,768	8,646	7,046	6,746	5,832	4,136	1,071	1,044
Draft Solar Standalone ELCC	-	201	831	4,135	3,955	6,174	5,925	5,206	4,715	2,894	335	-
Wind Standalone ELCC	339	841	838	2,246	2,282	3,764	2,425	1,928	2,147	500	385	663

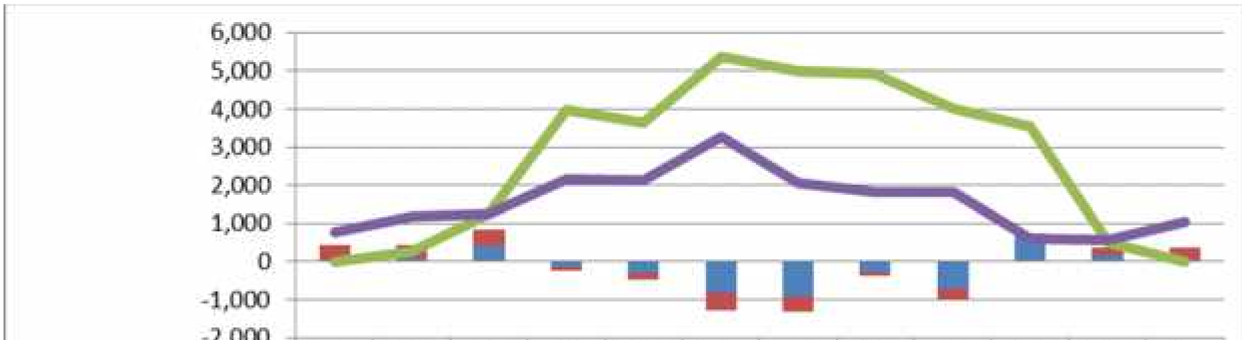
After completing the studies to establish the standalone ELCC of wind and solar generators, staff totaled the standalone ELCC values of wind and solar generators in each month and compared that total to the Portfolio ELCC for that month. When the Portfolio ELCC was greater than the total of the standalone ELCC values for wind and solar generators, a positive diversity adjustment was added to the standalone ELCC values for wind and solar generators to calculate the Final ELCC values for that month. When the total Portfolio ELCC was less than the standalone ELCC values for that month, the diversity adjustment was negative and subtracted from the standalone ELCC values to calculate the Final ELCC values for that month. Figure 5 illustrates the resulting diversity adjustments each month and the Final Monthly ELCC for wind and solar generators after diversity adjustments are added. The calculation of Final ELCC solar values for February 2018 follows, to illustrate the process with a numerical example.

Diversity Adjustment allocation:

(Solar Standalone ELCC/Total Standalone Wind and Solar ELCC)*Diversity Adjustment

*Example – February Solar Diversity Adjustment = (201/(201+841))*433 = 83.52*
Final February Solar ELCC = 201+83.52=285 MW

Figure 5 Diversity Adjustments and Final Solar and Wind ELCC (MW)



	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Wind Div Adjust	439	349	423	-83	-172	-489	-378	-105	-322	109	196	381
Solar Div Adjust	0	84	419	-152	-298	-803	-925	-283	-708	633	165	0
Final Solar ELCC	0	285	1,250	3,983	3,657	5,372	5,000	4,923	4,007	3,527	490	0
Final Wind ELCC	778	1,190	1,260	2,163	2,111	3,274	2,046	1,823	1,825	609	581	1,044

C. Proposed Implementation and Timeline for ELCC Values

Energy Division proposes to use the Final ELCC factors calculated by staff to establish the qualifying capacity of wind and solar generators beginning for the 2018 RA compliance year. The ELCC values calculated will be multiplied by the nameplate capacity of each solar generator individually, and the resulting month-specific value will equal the qualifying capacity of the generator. Although the ELCC for all solar generators as a group was calculated while including 5,526 MW of BTM PV, only the RPS supply side solar is given a qualifying capacity to count towards RA obligations. Energy Division does not propose to give BTM PV any qualifying capacity towards RA obligations. Energy Division proposes to forgo the locational factors calculated in the March 2016 RA proposal and the technology factors proposed in earlier RA proposals.

Parties are encouraged to see this proposal as connected to Energy Division's RA proposal from March 2016. To contrast the effect of including BTM PV in the ELCC calculations, parties are encouraged to compare the earlier calculated value of 57.75% with this current value of 33.5% and note that of the 8,609 MW of solar added to the CAISO since March, 5,526 MW of it was BTM PV and only 3,083 MW of it came from incremental RPS facilities that either came online or are projected to come online between now and 2018.

Table 3 summarizes the proposed Final ELCC values for wind and solar generators for 2018 RA compliance year.

Table 3 Proposed Final ELCC Values for Solar and Wind

	Solar ELCC	Wind ELCC
MW Install	16,033	6,891
Jan	0.0%	11.3%
Feb	1.8%	17.3%
Mar	7.8%	18.3%
Apr	24.8%	31.4%
May	22.8%	30.6%
Jun	33.5%	47.5%
Jul	31.2%	29.7%
Aug	30.7%	26.5%
Sep	25.0%	26.5%
Oct	22.0%	8.8%
Nov	3.1%	8.4%
Dec	0.0%	15.2%

D. Estimate of Effect of BTM PV on Solar ELCC

Due to the notable decrease in RA capacity credit given to solar generators when moving from the exceedance method and the ELCC proposal, Energy Division staff offers a second proposal that may ease the transition for LSEs and other parties.[10] Given that the decrease in ELCC value can be partially ascribed to the addition of BTM PV into the fleet, Energy Division proposes to estimate the effect that BTM PV has on ELCC and back that effect out of the average ELCC of solar resources in each month. The effect that BTM PV has on overall solar ELCC stems from the fact that as solar penetration increases, peak load net of solar generation shifts further into the evening when solar generators cease generating. This shift in load hours affects average solar ELCC. While it may not be the time to give RA value to BTM PV, the large quantity of BTM PV that is generating electricity in California makes its effect on ELCC important to quantify.

To estimate the effect that BTM PV has on the ELCC of solar generators, Energy Division staff looked at the results of the ELCC studies presented in early 2016.

- 7,424 MW of solar generators were equivalent to 4,288 MW of Perfect Capacity.
- 16,033 MW (including 5,526 MW of BTM PV) are equivalent to a maximum of 5,372 MW of Perfect Capacity, translating to a marginal ELCC value of 12.6%.

[10] The exceedance method is explained in section 8 of the Adopted QC Calculation Methodology manual posted to the CPUC website at this link: http://www.cpuc.ca.gov/WorkArea/DownloadAsset.aspx?id=9187

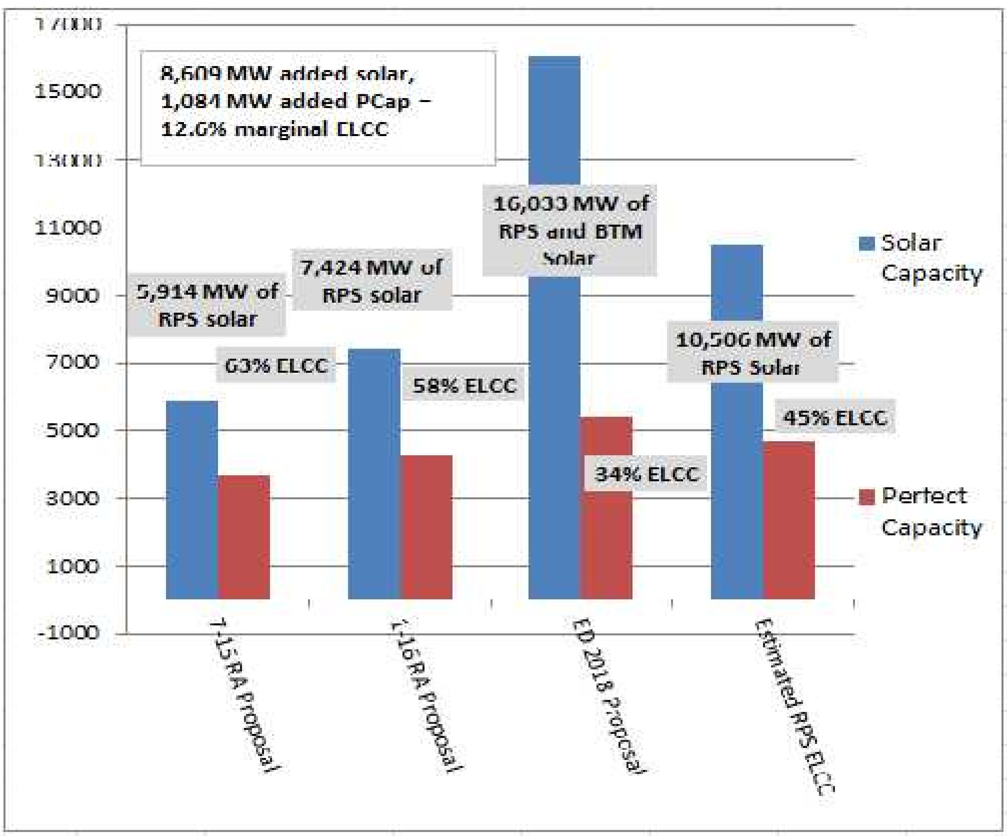
- An additional 8,609 MW of solar generators is equivalent to an additional 1,084 MW of Perfect Capacity.

- Prorating the marginal ELCC value of 8,609 MW of solar generators to the 3,083 MW of RPS solar generators results in a marginal ELCC value of 388.2 MW of Perfect Capacity.

- Adding that to the 4,288 MW of Perfect Capacity and adding the 3,083 MW of RPS solar generators to the 7,424 MW studied in early 2016 results in an ELCC value as follows.
    - (388.2 + 4,288) MW of Perfect Capacity is equivalent to (7,424 +3,083) MW of RPS supply side solar generators.
    - This translates to an ELCC of 44.5% for 10,506 MW of RPS only solar generators, which is equal to 133% of the 33.5% ELCC earlier calculated which covers the whole 16,033 MW solar fleet.

Figure 6 illustrates the progressive decline in the equivalent ELCC of solar generators as penetration increase.

Figure 6 Decreases in ELCC Ratio of Solar to Perfect Capacity as Solar Capacity Increases



Energy Division staff offers the second proposal to base the ELCC of wind generators on the values previously calculated, and to base the solar ELCC values on the values previously calculated scaled up by 33%. Table 4 lists the proposed values in the two blue columns at the right.

Table 4 Comparison of RPS and BTM PV Solar ELCC and Proposed RPS only Solar ELCC

	Total RPS and BTM Solar ELCC	Estimated RPS only ELCC	Wind ELCC
MW Install	16,033	10,506	6,891
Jan	0.0%	0.0%	11.3%
Feb	1.8%	2.4%	17.3%
Mar	7.8%	10.4%	18.3%
Apr	24.8%	33.2%	31.4%
May	22.8%	30.5%	30.6%
Jun	33.5%	44.8%	47.5%
Jul	31.2%	41.7%	29.7%
Aug	30.7%	41.0%	26.5%
Sep	25.0%	33.4%	26.5%
Oct	22.0%	29.4%	8.8%
Nov	3.1%	4.1%	8.4%
Dec	0.0%	0.0%	15.2%

IV. Conclusion

Energy Division offers these proposals to the parties in R. 14-10-010 for comment and to the Commission for deliberation during the course of the proceeding.