



Staff Report Item 18

TO: East Bay Community Energy Board of Directors
FROM: Stefanie Tanenhaus, Principal Regulatory Analyst, Public Policy
SUBJECT: Integrated Resource Plan Update (Informational Item)
DATE: September 16, 2020

Recommendation

Receive update on EBCE's Integrated Resource Plan (IRP) Compliance Filing.

Background and Discussion

The IRP proceeding includes two primary components: the biennial study workstream and the mandated procurement workstream. This memo refers only to the biennial study workstream.

The IRP is a long-term planning proceeding intending to evaluate all of the CPUC's electric procurement policies and programs and the reliability and cost-effectiveness of the CPUC-jurisdictional entities'¹ electric supply with the goal of reducing the cost of achieving GHG reductions and other CPUC policy goals. The IRP proceeding looks 10 years forward to determine the least-cost resource mix required to meet these goals while maintaining system reliability.

The IRP also evaluates the contribution of individual entities' resource portfolios to the State's greenhouse gas (GHG) emissions. This IRP cycle, the CPUC required each entity to submit distinct portfolios that achieve their proportional share of two different statewide electric sector GHG targets. On September 1, 2020, EBCE submitted resource portfolios that provide the desired portfolios of resources based on a statewide electric sector goal of 46 million metric tons (MMT) and a maximum of 38 MMT of GHG emissions by 2030. In July, these portfolios were shared with the Community Advisory Committee and the Board. At that time, the Board also authorized the CEO to approve the final IRP reports and file the two compliance portfolios with the CPUC.

The CPUC permitted entities to submit an alternative portfolio that used different assumptions, provided they were identified and justification for the discrepancies described.

¹ In context of IRP requirements, includes Investor Owned Utilities (IOUs), Energy Service Providers (ESPs), and Community Choice Aggregators (CCAs).

EBCE elected not to file an alternative portfolio and instead has focused its efforts on analysis to develop a portfolio of resources that will contribute to more aggressive GHG emission reductions and organizational goal-setting related to achieving those reductions. This supplemental analysis will be presented environmental and community stakeholders for input and to the Board later in the fall.

Per the CPUC's requirements, EBCE's September 1st IRP filing included three documents provided by the CPUC: the Narrative Template, the Resource Data Template, and the Clean System Power (CSP) Calculator.² Each document and the associated data that populated the document is described in the July 15, 2020 Board memo³ and the final, public versions are attached herein. Information on EBCE's IRP process and materials are also publicly available on our webpage at: ebce.org/integrated-resource-plan.

Financial Impacts

There is no financial impact. Actual procurement authorization will be brought forth to the board in accordance with EBCE's risk management policies.

Next Steps

Staff will complete additional study to evaluate the possibility of setting more aggressive organizational goals related to GHG emissions reduction. The results of this study will also identify: Carbon Free metrics of the proposed Portfolio, Forecast Costs, Resource Mix, Risk Management, and Reliability of the proposed portfolio. Staff will share this analysis with environmental and community stakeholders before presenting to the Board later in the fall.

Attachments

- A. EBCE's Public IRP Filing; and
- B. Integrated Resource Plan Compliance Filing PPT

² CPUC Decisions 18-02-018, 19-11-016, and 20-03-028 define these filing requirements.

³ Available on EBCE's website at: <https://ebce.org/uploads/item-22-approval-of-irp-study-for-compliance-filing-action-item.pdf>

**BEFORE THE PUBLIC UTILITIES COMMISSION OF THE
STATE OF CALIFORNIA**

Order Instituting Rulemaking to Continue
Electric Integrated Resource Planning and
Related Procurement Processes.

Rulemaking 20-05-003
(Filed May 7, 2020)

**EAST BAY COMMUNITY ENERGY
2020 INTEGRATED RESOURCE PLAN**

(PUBLIC VERSION)

September 1, 2020

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Order Instituting Rulemaking to Continue
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Rulemaking 20-05-003
(Filed May 7, 2020)

**EAST BAY COMMUNITY ENERGY
2020 INTEGRATED RESOURCE PLAN**

(PUBLIC VERSION)

Pursuant to the California Public Utilities Commission (“Commission”) *Decision Setting Requirements for Load Serving Entities Filing Integrated Resource Plans* (D.18-02-018) and *2019-2020 Electric Resource Portfolios to Inform Integrated Resource Plans and Transmission Planning* (D. 20-03-028),¹ East Bay Community Energy (“EBCE”) hereby submits its 2020 Integrated Resource Plan (“IRP”).

/s/

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September 1, 2020

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¹ The deadline for load serving entities to file and serve their 2020 IRPs was extended to September 1, 2020. D.20-03-028, at 107 (Ordering Paragraph 11).

Standard LSE Plan

East Bay Community Energy

2020 INTEGRATED RESOURCE PLAN

September 1, 2020



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Appendix A - Ascend Fundamental Forecasts

Appendix B - Clean System Power Calculators - 38 MMT and 46 MMT

Appendix C - Resource Data Template - 38 MMT (Public Version)

Appendix D - Resource Data Template - 46 MMT (Public Version)

Appendix E - Senior Executive Attestation (D.19-11-016)

I. Executive Summary

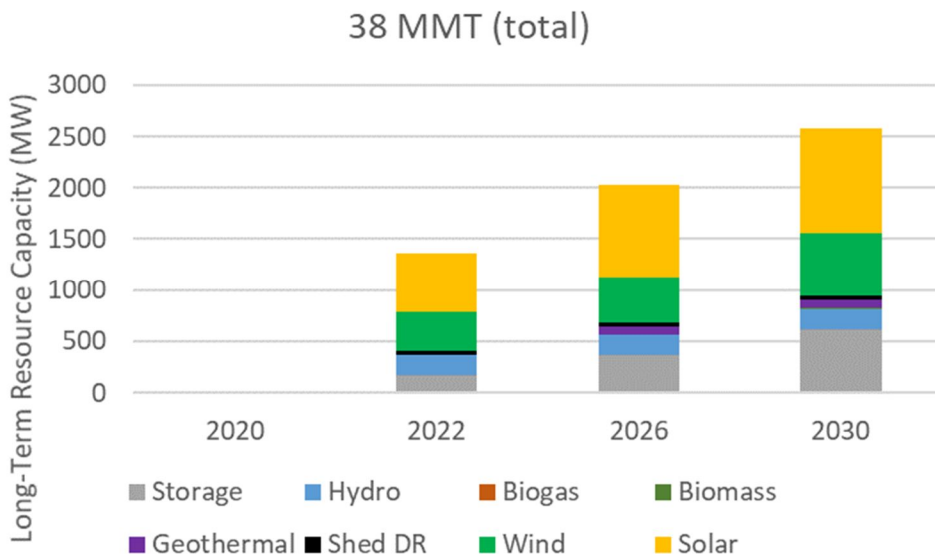
East Bay Community Energy (EBCE) is a Community Choice Aggregator (CCA), a public agency and Load Serving Entity (LSE) formed under California Assembly Bill 117 (2002). EBCE is structured as a Joint Powers Authority (JPA) and is governed by a 15-member Board of Directors. EBCE began serving commercial, industrial and municipal customers from 12 communities in Alameda County in June 2018 and added residential customers in November 2018. In April of 2021, EBCE will add three new member cities to its jurisdiction.

This Integrated Resource Plan (IRP) describes EBCE's 46 MMT and 38 MMT Conforming Portfolios and is consistent with the relevant statutory requirements of Public Utilities (PU) Code Section 454.52(a)(1) and California Public Utilities Commission (CPUC) Decision (D.) 20-03-028, which provides the filing requirements for LSEs required to participate in the Commission's IRP process. Pursuant to D. 20-03-028, this IRP is filed timely. EBCE's Board of Directors approved the analysis that underlies this submission and delegated final review of filing materials to EBCE's CEO on July 15, 2020.

EBCE plans to procure resources informed by the 38 MMT portfolio to achieve carbon reductions compared to its current portfolio. Actual procurement may result in emissions below the LSE-specific GHG Emissions Benchmark published by the CPUC to achieve statewide emissions of 38 MMT by 2030. By 2030, this portfolio will allow EBCE to serve customers with energy that is 76.4% carbon-free and under long-term contract. To achieve emission reductions, EBCE plans to procure RPS resources at a level that exceeds the state compliance requirements. Additional low-carbon resources that are non-RPS eligible are procured to increase portfolio diversity, integration and achieve EBCE's overall emissions targets. In 2021, approximately 40% of EBCE's target RPS-eligible energy is under contracts with a term of at least 10 years (long-term). In the 38 MMT portfolio, by 2030 EBCE will achieve close to 70% RPS procurement, all from resources under contracts of term 10 years or longer. The balance of EBCE's open position will be procured under short-term contracts to allow for any unanticipated load changes.

The total resource mix in EBCE's 38 MMT portfolio is shown in Figure 1 below. The chart includes EBCE's currently contracted generation that is incremental to the baseline resources assumed in the development of the CPUC's Reference System Plan (RSP) Portfolio, planned new long-term contracts and planned contracts with existing resources (or resources that may be allocated to EBCE in the future). The resources included in this portfolio reflect the categories and characteristics of the resources identified in the CPUC's modeling, including short and long-duration storage, demand response and a mix of renewables dominated by solar and wind resources. EBCE expects a significant portion of expected solar additions to be co-located with battery storage or hybrid solar and storage projects, particularly prior to the expiration of the Investment Tax Credit.

Figure 1: Nameplate Capacity of 38 MMT Portfolio



To develop both of its Conforming Portfolios, EBCE used inputs that were consistent with CPUC RSP. These include the 2019 California Energy Commission Integrated Energy Policy Report (IEPR) load forecast¹, generic RPS-eligible long-term power purchase agreement (PPA) costs and generation profiles, and hourly shapes for load modifiers including behind-the-meter (“BTM”) solar PV and electric vehicles (“EVs”). Assumptions specific to EBCE include actual procurement to-date incremental to the CPUC’s assumed baseline, and expectations regarding resource availability, EBCE customer procurement preferences, risk and market exposure. All demand-side resources including energy efficiency were modeled based on IEPR assumptions. These inputs were employed in the IRP model developed for EBCE by Ascend Analytics to determine a least cost portfolio of resources achieving EBCE’s procurement goals.

Once the conforming portfolios were established, EBCE used the Clean System Power (“CSP”) Calculator published by the CPUC to calculate its emissions and ensure compliance with the emissions benchmarks assigned to EBCE.² Net of BTM combined heat and power (“CHP”) emissions, the resulting emissions in 2030 are 0.976 MMT associated with the 38 MMT Portfolio and 1.221 MMT associated with the 46 MMT Portfolio.

¹ With specific modifications pursuant to *Administrative Law Judge’s Ruling Correcting April 15, 2020 Ruling Finalizing Load Forecasts and Greenhouse Gas Benchmarks for Individual 2020 Integrated Resource Plan Filings*, issued on May 20, 2020.

² Copies of the CSP Calculators are available on EBCE’s website. See Appendix B.

II. Study Design

The following subsections describe EBCE’s analytical approach to its IRP study.

a. Objectives

The objectives for the analytical work described herein include:

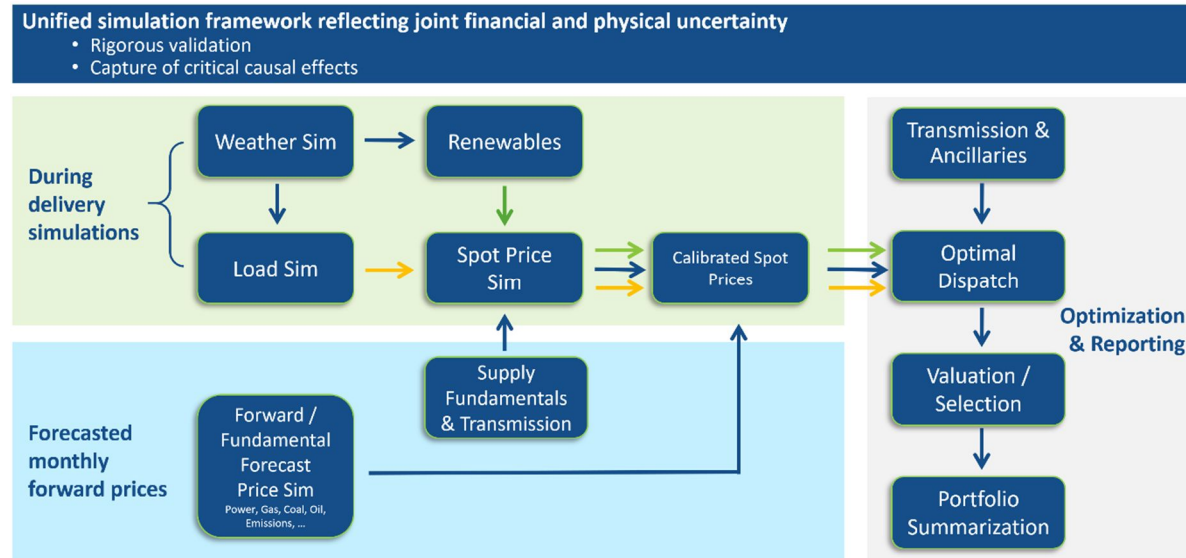
- Satisfying the regulatory requirements of PU Code Section 454.52(a)(1).
- Satisfying all CPUC specifications for required conforming portfolios.
- Demonstrating how future portfolios achieve EBCE’s 46 MMT and 38 MMT 2030 GHG Benchmarks.
- Demonstrating continuous progress towards meeting or exceeding the state’s renewables portfolio standard (RPS) targets.
- Showing how EBCE’s future portfolios will contribute to overall system reliability, particularly between the hours of 5 – 9 PM.
- Providing insight into how costs to EBCE customers might change over time as a result of state policy mandates and achieving GHG emission reduction goals.

b. Methodology

i. Modeling Tool(s)

EBCE worked with Ascend Analytics, LLC (“Ascend”) to perform production cost modeling of candidate portfolios using their software platform, PowerSIMM. PowerSIMM differs from other models in its ability to capture realistic market conditions and “meaningful uncertainty” by co-simulating loads, renewable generation, and power prices. As a “hybrid model,” PowerSIMM uses both market data and long-term fundamentals to simulate load, renewables, and the CAISO spot market prices against which resources are dispatched and valued. The model diagram for PowerSIMM is shown in Figure 2 below.

Figure 2: PowerSIMM model diagram



PowerSimm simulates hourly spot price conditions (i.e. during delivery simulations) as a function of weather, system load, and renewables. The simulated spot prices are then scaled so that the average of on-peak/off-peak spot prices equals the simulated monthly forward price for that time period. These simulated forward prices blend market forward data in the near term (1-5 years) with Ascend’s long-term fundamental forecasts of power prices (“Ascend curves”), which incorporate supply fundamentals across the Western Electricity Coordinating Council (WECC). The Ascend curves are based on the natural gas price projections used in the modeling for the RSP. More information on Ascend’s long-term fundamental price forecasts is included in Appendix A.

PowerSimm’s “hybrid approach” captures the uncertainty in the factors that create price risk in power markets, including variability in weather, load, renewable output, congestion risk, and forward price volatility. PowerSimm trains its econometric “sim engine” model with up to 30 years of historical weather to estimate the impact weather has on load and renewable production. Ascend parameterizes its weather uncertainty using both time (month, day, hour) and autoregressive terms to create discrete chronological weather simulations, which are used to model EBCE and CAISO system load, as well as output from renewable generation. EBCE’s IRP study included 30 “sim-reps,” each one an hourly simulation across the planning time horizon. Results are summarized across these sim-reps to capture the full distribution of outcomes, including the mean, median, P5, and P95 estimates.

ii. Modeling Approach

EBCE's approach to developing the 46 MMT and 38 MMT conforming portfolios involved an iterative portfolio build-up to achieve the required GHG targets and serve customer load while accounting for organizational-specific preferences. Pursuant to *Administrative Law Judge’s Ruling Correcting April 15, 2020 Ruling Finalizing Load Forecasts and Greenhouse Gas Benchmarks for Individual 2020 Integrated Resource Plan Filings*, issued on May 20, 2020, EBCE assumed an annual load forecast consistent with

the “mid Baseline mid AAEE” version of Form 1.1c of the California Energy Commission’s (CEC) 2019 IEPR demand forecast with specific modifications, approved by the Commission, to better align with EBCE’s expected load forecast.³ For its hourly load and load modifier shapes, EBCE opted to use the default 2019 IEPR “mid Baseline mid AAEE” hourly CAISO system average forecast but modified the percentage of baseline load that is commercial and industrial (C&I) to better reflect EBCE’s customer composition.

To construct its conforming portfolios, EBCE began by incorporating details of existing contracts as baseline resources. While PowerSIMM is capable of using an optimization algorithm to pick optimal portfolios from a pool of candidate resources, the analysis team opted to create conforming portfolios beginning with its implied proportional share of the nameplate capacity resource additions in the 46 MMT RSP and 38 MMT system-wide scenario. EBCE believed this approach leveraged the CPUC’s perspective of what constitutes a reliable resource mix for the state while allowing for refinements to reflect organizational resource preferences and EBCE’s approach to risk management; specifically, a lower tolerance for risk associated with over-procuring long-term resources. Adjustments were made to the portfolios to represent these organizational and customer preferences, as well as staff’s knowledge of the electric system and resource availability (e.g. the likelihood that resources currently under contract will become available for re-contracting during the planning horizon). These adjustments include: not selecting any energy to be produced directly by nuclear, coal or natural gas generation facilities; assuming a lower share of portfolio energy from hydro facilities (both in- and out-of-state) due to the limited availability of these resources, risk of low production drought years, and the strong appetite amongst California LSEs, especially CCAs, to contract with these resources.

EBCE then calibrated the GHG emissions associated with each portfolio using the appropriate CSP calculator to ensure it met the assigned GHG emissions benchmark, adjusted for BTM CHP emissions. EBCE’s two conforming portfolios achieve compliance with the respective emissions targets. As estimated by the CSP calculator, the 46 MMT portfolio achieves 1.221 MMT CO₂ emissions by 2030; the 38 MMT portfolio achieves 0.976 MMT CO₂ emissions by 2030; consistent with the emissions targets for each portfolio, adjusted to account for the impact of BTM CHP resources, of 1.222 for the 46 MMT portfolio and 0.9777 for the 38 MMT portfolio. The portfolios were also designed to assure EBCE met its RPS obligations and satisfied the long-term contract requirement. EBCE staff also considered the portion of its system Resource Adequacy (RA) obligations that each portfolio would fill through existing and proposed long-term contracts versus bilateral and solicitation-based transactions that comprise the current RA market. In accordance with the Narrative Template instructions, EBCE assumed its future RA needs are reduced by its proportional share of the RA capacity value reflected in the year-ahead cost allocation mechanism (CAM) list. As instructed, this share is assumed to be static through 2030.

³ In preparing EBCE’s updated load forecast, EBCE and the CEC discovered an error in the process used to generate EBCE’s 2019 IEPR forecast. In response, the CEC provided a corrected forecast which EBCE used as a baseline to make the load forecast updates allowed by the Commission in the *Administrative Law Judge’s Ruling Allowing Updated Load Forecasts* issued on January 24, 2020. Relative to this updated forecast, EBCE included two adjustments for inclusion in the IRP process reflecting additional information about (1) Direct Access (“DA”) load departures and (2) EBCE’s 2021 expansion to new communities.

EBCE then evaluated market exposure and curtailment associated with each portfolio using the production cost modeling tool PowerSimm, described in Section II.a. The primary evaluation metrics used to score candidate portfolios include:

- **GHG Emissions** – GHG emissions in PowerSimm are calculated as a function of the hourly system emissions factors multiplied by the amount of CAISO system purchases without a counter-balancing clean resource.
- **Cost to serve load** – This is calculated as the cost of market purchases to serve EBCE load minus the net wholesale market revenues from EBCE contracted resources.
- **RA position** – The forecasted system RA requirement as a function of the IEPR load forecast plus 15% compared with the NQC of EBCE contracted resources.
- **Renewable Content** – The amount of contracted renewable energy, through both short-term “index plus” contracts and long-term PPAs, as a percentage of retail load.
- **Reliability** – The average shortage and position in MW and in percent of load during the reliability assessment hours of HE 5 – 9 PM as well as across all time intervals. While ‘Loss of Load Hours’ (LOLH) is often used for reliability planning for balancing authorities, EBCE does not have a balancing obligation, making LOLH not appropriate as a reliability metric.
- **Risk Premium** – The risk premium is also a measure of market exposure risk. Since PowerSIMM simulates resource and market conditions, the resulting production cost is also a distribution with a mean and P95 tail risk. The risk premium is an actuarial calculation of the portfolio cost risk between the mean and the P95 of portfolio cost. It allows comparing and quantifying the susceptibility (or conversely the robustness) of different portfolios to weather volatility in power prices and renewable intermittency.

The table below summarizes the sources for the inputs and assumptions used in EBCE’s conforming portfolio analyses. Presentation and discussion of Ascend price forecasts are included in Appendix A.

Table 1: Summary of Data Sources for Inputs and Assumptions

Category	Input/Assumption	Data Source	
		Conforming 46	Conforming 38
Constraint	GHG Targets	CPUC Assigned Benchmark	CPUC Assigned Benchmark
Constraint	RPS Targets	SB 100 requirements	SB 100 requirements
Constraint	RA requirements	CPUC Assigned	CPUC Assigned
Price	Gas Price Forecast	RESOLVE inputs	RESOLVE inputs
Price	Power Price Forecast	Ascend 46MM Scenario	Ascend 38 MM Scenario
Price	RA Price Forecast	Ascend Core CA RA Price Forecast	Ascend Core CA RA Price Forecast
Load	Load Forecast	IEPR Mid AAEE	IEPR Mid-AAEE

Load	EV Load	IEPR	IEPR
Load	BTM Solar	IEPR	IEPR
Load	EE	IEPR	IEPR
Cost	Existing/contracted resources	Actual costs	Actual costs
Cost	Battery costs	RESOLVE inputs	RESOLVE inputs
Cost	Renewable PPA cost	RESOLVE inputs	RESOLVE inputs
Generation	Candidate resource generation profiles	RESOLVE inputs	RESOLVE inputs
Generation	Hydro annual generation	Historical weather-driven generation for NW, CA, and small hydro projects	Historical weather-driven generation for NW, CA, and small hydro projects

III. Study Results

The portfolios resulting from EBCE’s IRP study process are described in the following subsections.

a. Conforming and Alternative Portfolios

Although EBCE’s study process included additional scenarios and potential alternative portfolios, to ensure EBCE satisfied the CPUC’s requirements it is electing to file the results of its 46 MMT and 38 MMT preferred analyses. EBCE expects these conforming portfolios to serve as a baseline against which more aggressive GHG emissions reduction measures may be considered in the future.

For its Conforming Portfolios, EBCE evaluated the volumes of new build resources, existing resources (i.e. resources that have been built and are currently operational within the CAISO), EBCE-existing contracts (i.e. resources EBCE already has under long-term contract that are not online yet), and its open position in each scenario. EBCE’s 46 MMT portfolio results in total contracted nameplate capacity of 2,277 MW by 2030. Of it, 1,341 MW result from new-build resources; 937 MW expected to be contracted from existing CAISO resources and 660 MW from EBCE resources already under contract.⁴ EBCE’s 38 MMT portfolio results in total contracted nameplate capacity of 2,578 MW by 2030. Of it, 1,634 MW result from new-build resources; 944 MW expected to be contracted from existing CAISO resources and 660 MW from the resources already contracted to EBCE. Further detail on the make-up of existing, in development and new resources in each portfolio is provided below.

Existing resources EBCE owns or contracts with:

⁴ EBCE’s total nameplate capacity of generating resources and tolling energy storage at the time of this filing is 660 MW. EBCE has additional energy storage resources under contract through an RA-only structured agreements.

EBCE does not have any long-term contracts with currently existing, operational resources but does have contracts in place for future resources. These resources are described below as physical, in development resources, consistent with the definitions provided in the Resource Data template. To date, EBCE has contracted with six RPS-eligible generating resources of varying types and in some cases with co-located energy storage, to help further our emissions goals and to cover our load. These contracts are not included in the CPUC’s Baseline resource list and were added to the Resource Data Templates as physical resources in development for EBCE’s 46 MMT and 38 MMT conforming portfolios to ensure completeness.⁵

Altamont Winds: This project signed into PPA on 07/9/2019 is for a 57.5 MW wind facility developed by Salka Energy. It is solely a wind facility and will be located within Alameda county, making it the first in-county generating facility with energy off-take that EBCE has contracted. The expected commercial operation date (COD) is 12/31/2020 and the term of the PPA is 20 years.

Golden Fields Solar (Rosamond): This project signed into PPA on 07/26/2019 is for a 112 MW solar facility developed by Clearway Energy Group. It is solely a solar facility and will be located within Kern county. The expected COD is 03/31/2021 and the term of the PPA is 15 years.

Luciana: This project signed into PPA on 06/10/2019 is for a 55.8 MW solar facility developed by Solar Frontier Americas. It is solely a solar facility and will be located within Tulare county. The expected COD is 12/31/2021 and the term of the PPA is 15 years.

Sonrisa: This project signed into PPA on 06/21/2019 is for a 100 MW solar plus 30 MW/120 MWH battery facility developed by EDPR Renewables North America. It is a co-located solar plus storage facility and will be located within Fresno county. The expected COD is 12/31/2022 and the term of the PPA is 20 years.

Raceway North: This project signed into PPA on 09/25/2019 is for a 125 MW solar plus 80 MW/160 MWH battery facility developed by sPower. It is a solar plus storage facility and will be located within Kern and Los Angeles counties. The expected COD is 12/31/2022 and the term of the PPA is 20 years.

Edwards Solar: This project signed into PPA on 09/25/2019 is for a 100 MW solar facility developed by Terra-Gen. It is solely a solar facility and will be located within Kern county. The expected COD is 12/31/2021 and the term of the PPA is 15 years.

Table 2: EBCE’s current list of contracted long-term generation (“development resources”)

Developer	Project Name	Technology	Nameplate MW	Storage MW	County	Expected COD	Term (Years)
Salka Energy	Altamont Winds	Wind	57.5	N/A	Alameda	12/31/2020	20

⁵ See Appendix C (Resource Data Template – 38 MMT) and Appendix D (Resource Data Template – 46 MMT).

Clearway Energy Group	Rosamond Golden Fields	Solar	112	N/A	Kern	3/31/2021	15
Solar Frontier Americas	Luciana	Solar	55.8	N/A	Tulare	12/31/2021	15
EDPR Renewables North America	Sonrisa	Solar+Storage	100	30MW/120MWh	Fresno	12/31/2022	20
sPower	Raceway North	Solar+Storage	125	80MW/160MWh	Kern	12/31/2022	20
Terra-Gen	Edwards Energy Center	Solar+Virtual Storage	100	TBD	Kern	12/31/2022	15

Existing resources EBCE plans to contract with in the future:

EBCE, like most CCAs, has a preference for energy produced by non-GHG emitting resources. As such, existing in and out of state hydro resources are desirable to EBCE. Staff actively monitors the market to identify opportunities to contract with existing hydro resources – either through short term transactions or through long-term contracts. EBCE does not have any long-term hydro resources in its portfolio at this time but will attempt to secure such resources in the coming years. Existing hydro resources are therefore assumed in the 46 MMT and 38 MMT portfolios. To address availability concerns that EBCE may not be able to execute contracts with its full pro rata share of these resources, a discount was applied to the pro rata shares: in the 46 MMT portfolio, EBCE assumed no more than 70% of its pro rata share of large in state hydro and out of state hydro could be achieved; in the 38 MMT portfolio, EBCE assumed no more than 74% of its pro rata share of large in state hydro and out of state hydro could be achieved. EBCE also included small amounts of existing biomass and small hydro in its portfolios but discounted its pro rata share by approximately 50% and 40% respectively. Existing geothermal is reflected as a slightly higher share of EBCE’s portfolio relative to the RSP to provide baseload, GHG-free generation. As previously mentioned, EBCE assumes 0% of either portfolio will be served by contracted coal or nuclear resources.

While EBCE will evaluate opportunities to contract with existing clean resources, there are currently no specific existing CAISO resources EBCE has plans to contract with in the future. Due to the limited and uncertain availability, EBCE’s approach to contracting with existing resources should be regarded as opportunistic and resulting from such resources submitting offers for long-term or short-term contracts to EBCE at a price that is competitive with new-build resources.

New resources that EBCE plans to invest in:

Table 3 lists EBCE’s additional resource procurement requirements for the 46 MMT portfolio, beyond its currently contracted, in development resources. As described above, the portfolio is generally based on a pro-rata share of the RSP, but includes caps on the available large and small hydro, does not include

nuclear, natural gas or coal resources, and includes a mix of other non-emitting resources to reach the GHG target as calculated by the CSP calculator. A gradual resource buildout was assumed between 2020 and 2030 to reflect realistic timelines and constraints on resource procurement and contracting.

Table 3: Summary of 46 MMT procurement requirements (MW) by resource category

	Category	2020	2022	2026	2030
2-hr Battery Storage	Storage	0	0	0	201
4-hr Battery Storage	Storage	0	176	196	196
Pumped Storage (long-duration)	Storage	0	0	0	64
Large Hydro	Hydro	0	100	100	100
Imported Hydro	Hydro	0	67	67	67
Coal	Coal	0	0	0	0
Biogas	Biogas	0	0	0	5
Biomass	Biomass	0	0	0	10
Geothermal	Geothermal	0	12	75	75
Small Hydro	Hydro	0	20	20	20
Shed DR	DR	0	41	41	40
Nuclear	Nuclear	0	0	0	0
S. CA Desert S. Nevada Wind	Wind	0	123	134	134
Sacramento River Wind	Wind	0	0	0	0
Tehachapi Wind	Wind	0	123	134	134
Generic CA Wind	Wind	0	0	0	24
New Mexico Wind	Wind	0	61	67	67
Southern PGE Solar	Solar	0	0	0	0
S. CA Desert S. Nevada Solar	Solar	0	187	187	187
Tehachapi Solar	Solar	0	187	187	187
Generic CA Solar	Solar	0	0	0	106

Figure 3 illustrates the nameplate capacity by resource type and year in the 46 MMT scenario, shown as both the total nameplate capacity, and nameplate capacity of resources additional to EBCE’s currently contracted portfolio.

Figure 3: Nameplate Capacity of 46 MMT Portfolio by Resource Type

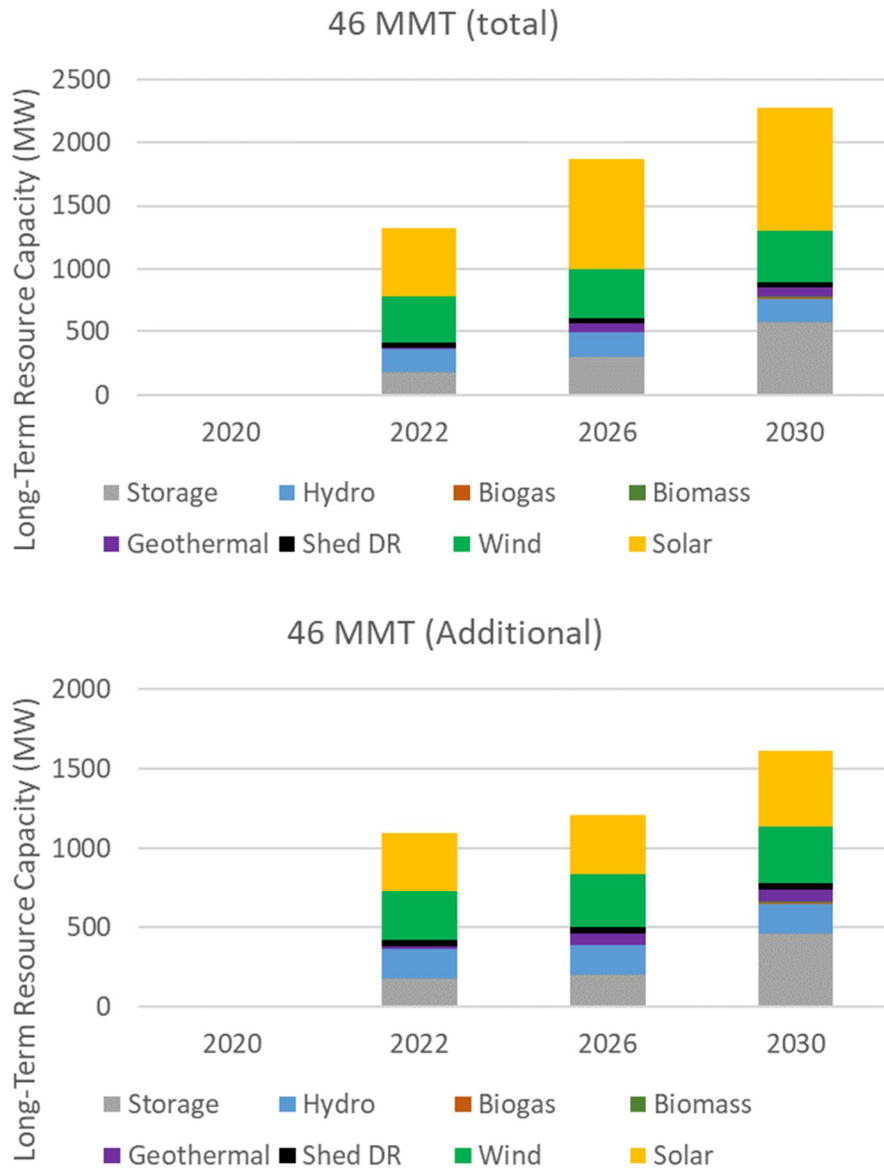


Table 4 illustrates how EBCE’s planned resources in its 46 MMT portfolio compares to the mix of new resources identified in the RSP. EBCE is expected to be approximately 3.3% of CAISO’s total load in 2030.

Table 4 shows that in the 46 MMT scenario, EBCE would exceed its implied pro rata share of the RSP additions for new storage, wind, and solar.

Table 4: EBCE 46 MMT Comparison of New Resources to RSP

	2020		2022		2026		2030	
	Pro-Rata	Actual	Pro-Rata	Actual	Pro-Rata	Actual	Pro-Rata	Actual
Storage	0	0	95	176	238	196	340	397
Long Duration Storage	0	0	0	0	32	0	32	64
Large Hydro	0	0	0	0	0	0	0	0
Imported Hydro	0	0	0	0	0	0	0	0
Coal	0	0	0	0	0	0	0	0
Biogas	0	0	0	0	0	0	0	0
Biomass	0	0	0	0	0	0	0	0
Geothermal	0	0	0	0	0	0	0	0
Small Hydro	0	0	0	0	0	0	0	0
DR	0	0	7	41	7	41	7	40
Nuclear	0	0	0	0	0	0	0	0
Wind	0	0	68	306	94	335	117	359
Solar	0	0	151	374	217	374	317	480

Table 5 lists EBCE’s additional procurement requirements for the 38 MMT portfolio, beyond the currently contracted, in development resources described above. Similar to the 46 MMT, the portfolio is generally based on a pro-rata share of the CPUC’s 38 MMT scenario, but includes caps on the available large and small hydro, does not include nuclear or coal resources, and includes a mix of other non-emitting resources to reach the GHG target as calculated by the CSP calculator. A gradual resource buildout was assumed between 2020 and 2030 to reflect realistic constraints and timelines on resource procurement and contracting.

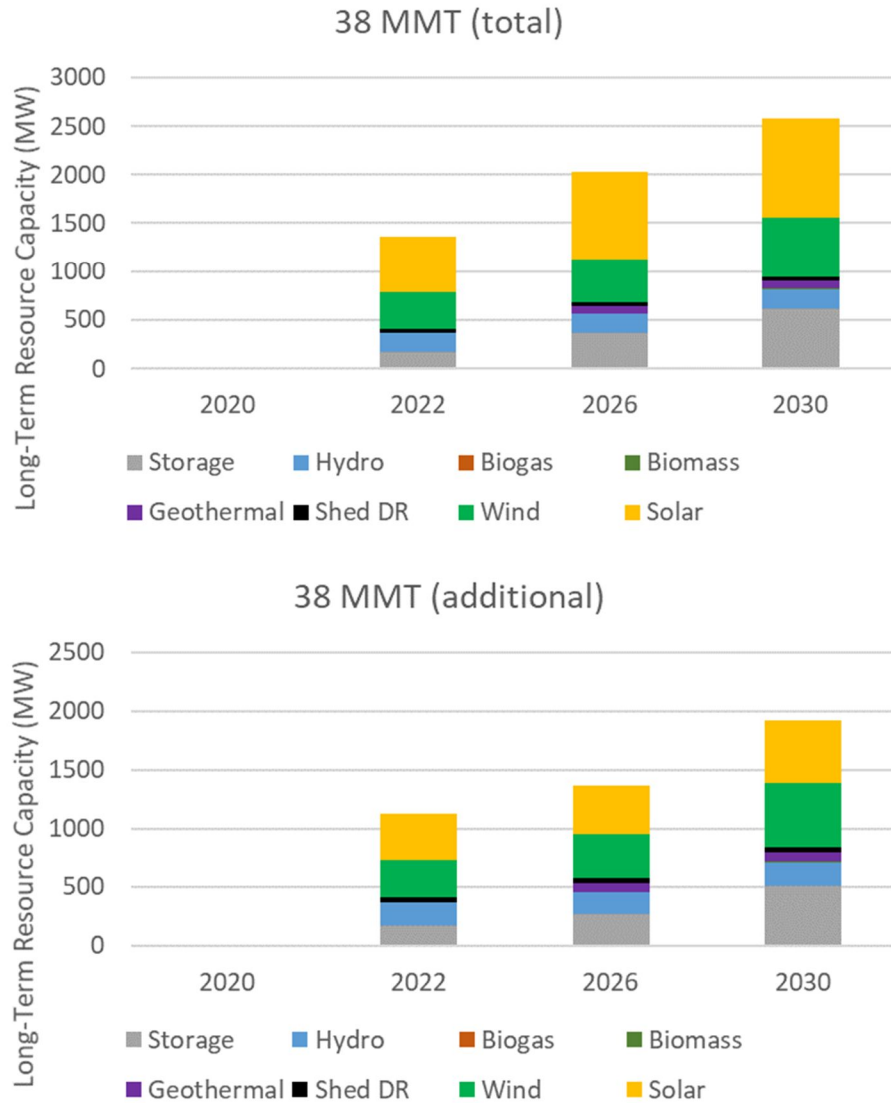
Table 5: Summary of 38 MMT procurement requirements (MW) by resource category

	Category	2020	2022	2026	2030
2-hr Battery Storage	Storage	0	0	0	144
4-hr Battery Storage	Storage	0	176	264	288
Pumped Storage (long-duration)	Storage	0	0	0	80
Large Hydro	Hydro	0	100	100	100
Imported Hydro	Hydro	0	71	71	70
Coal	Coal	0	0	0	0
Biogas	Biogas	0	0	0	5
Biomass	Biomass	0	0	0	10
Geothermal	Geothermal	0	0	78	78
Small Hydro	Hydro	0	20	20	20
Shed DR	DR	0	41	41	40
Nuclear	Nuclear	0	0	0	0

S. CA Desert S. Nevada Wind	Wind	0	126	154	154
Sacramento River Wind	Wind	0	0	0	0
Tehachapi Wind	Wind	0	126	154	154
Generic CA Wind	Wind	0	0	0	170
New Mexico Wind	Wind	0	63	77	77
Southern PGE Solar	Solar	0	0	0	0
S. CA Desert S. Nevada Solar	Solar	0	205	205	205
Tehachapi Solar	Solar	0	205	205	205
Generic CA Solar	Solar	0	0	0	118

Figure 4 illustrates the nameplate capacity by resource type and year in the 38 MMT scenario, shown as both the total nameplate capacity, and nameplate capacity of resources additional to EBCE’s currently contracted portfolio.

Figure 4: Nameplate Capacity of 38 MMT Portfolio by Resource Type



The following table illustrates how EBCE’s planned resources in its 38 MMT portfolio compares to the mix of new resources identified in the RSP. Like in the 46 MMT scenario, EBCE would exceed its implied pro rata share of the RSP for new storage, wind, and solar.

Figure 5: EBCE Share of Reference System Plan for 38 MMT Scenario

	2020		2022		2026		2030	
	Pro-Rata	Actual	Pro-Rata	Actual	Pro-Rata	Actual	Pro-Rata	Actual
Storage	0	0	95	176	202	264	367	432
Long Duration Storage	0	0	0	0	53	0	53	80

Large Hydro	0	0	0	0	0	0	0	0
Imported Hydro	0	0	0	0	0	0	0	0
Coal	0	0	0	0	0	0	0	0
Biogas	0	0	0	0	0	0	0	0
Biomass	0	0	0	0	0	0	0	0
Geothermal	0	0	0	0	0	0	0	0
Small Hydro	0	0	0	0	0	0	0	0
DR	0	0	7	41	7	41	7	40
Nuclear	0	0	0	0	0	0	0	0
Wind	0	0	100	316	129	384	276	555
Solar	0	0	151	409	240	409	349	528

b. Preferred Conforming Portfolios

Detailed descriptions of EBCE’s 46 MMT and 38 MMT conforming portfolios are provided in Section III.a above. These portfolios seek to align EBCE’s procurement activities with the overall system plans under each GHG target. The portfolios do not overly rely on imported or out-of-state hydro given the concern about hydro availability due to drought and increased demand from Pacific Northwest states. If all other LSE’s procure in this manner, then the system level procurement should roughly align with the RSP.

EBCE’s selected portfolios meet the CPUC’s requirements of “conforming” and are consistent with the relevant statutory requirements of PU Code Section 454.52(a)(1). Specifically, EBCE’s two conforming portfolios achieve compliance with the respective emissions targets of 1.221 MMT CO₂ emissions by 2030 in the 46 MMT scenario and 0.976 MMT CO₂ emissions by 2030 in the 38 MMT scenario. These benchmarks reflect EBCE’s expected share of the range of statewide electric sector emissions that are consistent with achieving an economy-wide carbon reduction goal of 40 percent below 1990 levels by 2030. EBCE also exceeds the 60% RPS-eligible procurement required by December 31, 2030 in both its conforming portfolios, reaching 66% and 76% RPS in the 46 MMT and 38 MMT scenarios respectively. The selected portfolios are constructed to achieve these environmental goals while minimizing EBCE customer rate impacts (see Section III.e for cost analysis) and ensuring EBCE adequately contributes to system reliability needs. While local reliability resources are not explicitly represented in its conforming portfolios, EBCE’s solicitations account specifically for local area RA. For example, EBCE sought and procured battery resources in downtown Oakland to provide local reliability and displace an aging fossil emitting generator and local RA from an in-county based utility scale wind farm. Other resources were additionally procured in other PG&E local RA areas as well as local RA sub areas in Southern CA. The conforming portfolios realize these objectives and strengthen the diversity, sustainability, and resilience of the bulk transmission and distribution systems and local communities through a geographically dispersed, diverse selection of new and existing demand and supply side resources, energy storage focused procurement, and a commitment to fair wage practices in procurement processes. Further, they demonstrate enhanced distribution systems and demand-side energy management with a commitment to achieving the CEC Mid-AAEE targets for EBCE. Finally, as discussed in Section III.d, EBCE prioritizes

local, clean resource selection and siting that both lowers electric sector GHG emissions and minimizes harmful pollutants for our most vulnerable customers.

Guidance from EBCE's Board and Community Advisory Committee indicate a preference to pursue more aggressive GHG emissions reductions than are contemplated in the 46MMT portfolio. Both bodies noted the results of EBCE's analysis indicated that compared to the 46 MMT portfolio, the 38MMT portfolio would result in more emissions reductions while (1) securing a marginally higher long-term hedged position, albeit one that remains consistent with organizational preferences to mitigate risk of over-procurement; and (2) resulting in total annual costs only marginally greater (in the vicinity of \$448M for the 46 MMT portfolio versus \$459M for the 38 MMT portfolio in 2030), using the CPUC's cost assumptions.

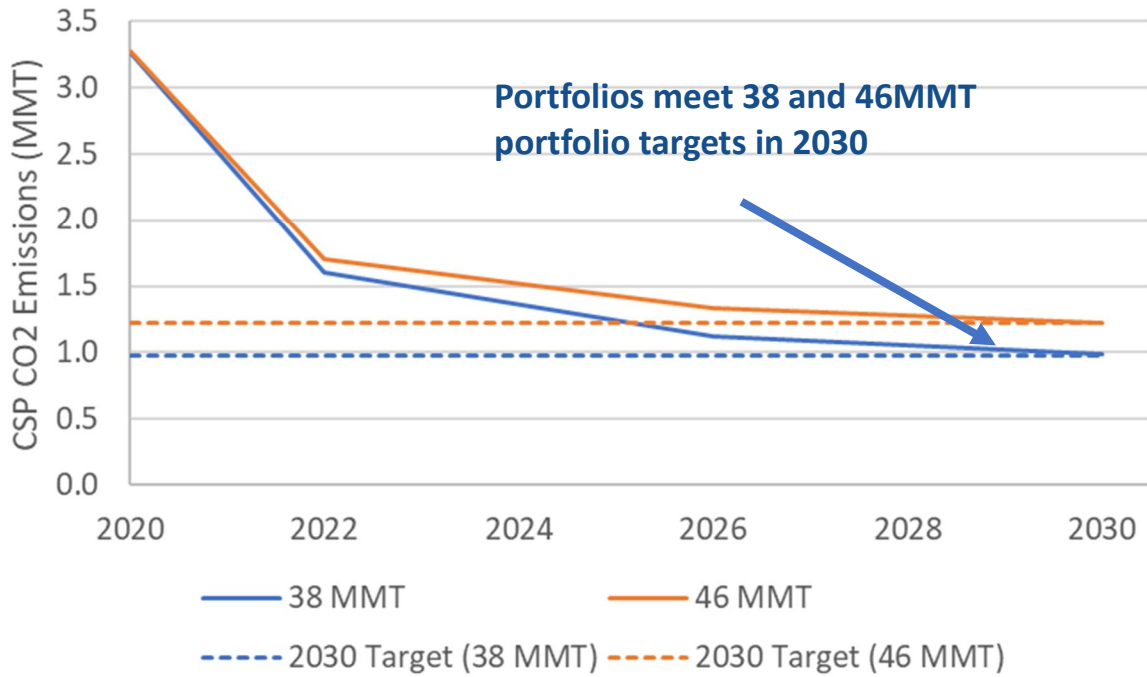
EBCE staff plans to develop a procurement strategy for further discussion with its Community Advisory Committee, other interested members of the public, and the Environmental Stakeholder community. This strategy will be informed by the IRP analysis but final guidance and direction to procure EBCE's portfolio will be subject to the oversight of EBCE's Board of Directors. Any long-term transactions entered into will be the result of procurement strategy and availability of resources in the market at the time EBCE seeks to transact. EBCE therefore presents its 38 MMT portfolio as representative of the direction its procurement strategy will pursue. While actual procurement decisions may deviate, EBCE's investment in specific new resource types will be informed by the 38 MMT conforming IRP study and resource availability, pricing and contribution to EBCE's portfolio as measured using a net present value calculation at time of resource evaluation.

c. GHG Emissions Results

EBCE's GHG targets net of BTM CHP emissions for the 46 MMT and 38 MMT scenarios are 1.222 MMT and 0.977 MMT respectively. Both portfolios meet the emissions reduction targets in 2030 according to the CSP calculator. Because EBCE does not plan to own or contract with any thermal resources, all GHG emissions stem from open market purchases. While the CSP tool was used to calibrate EBCE's portfolios to its assigned targets, PowerSimm also provides emissions estimates from production cost modeling simulations. The emissions associated with each portfolio between 2020 and 2030 as calculated by PowerSimm are shown in Figure 6 below.⁶

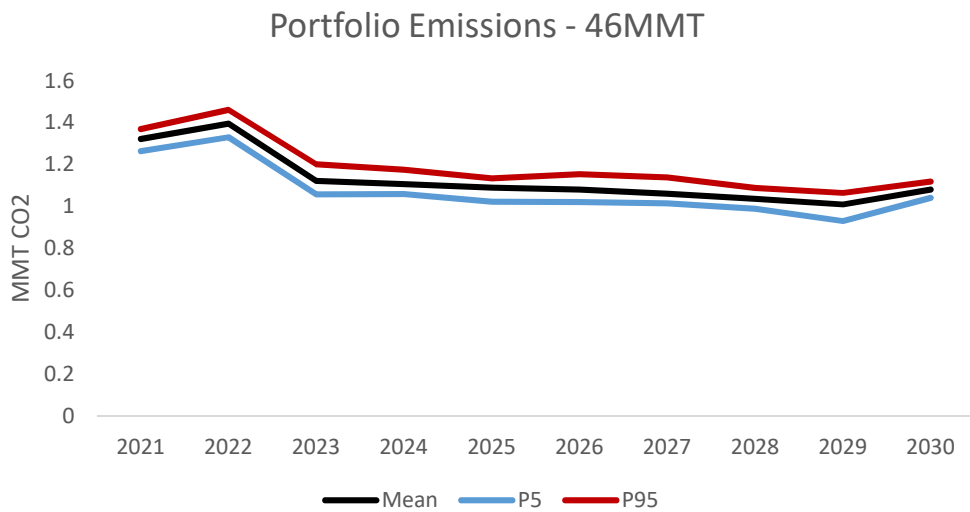
⁶ Differences between the values calculated by PowerSimm and the CSP calculator are due to small differences in accounting for EBCE's existing clean energy contracts.

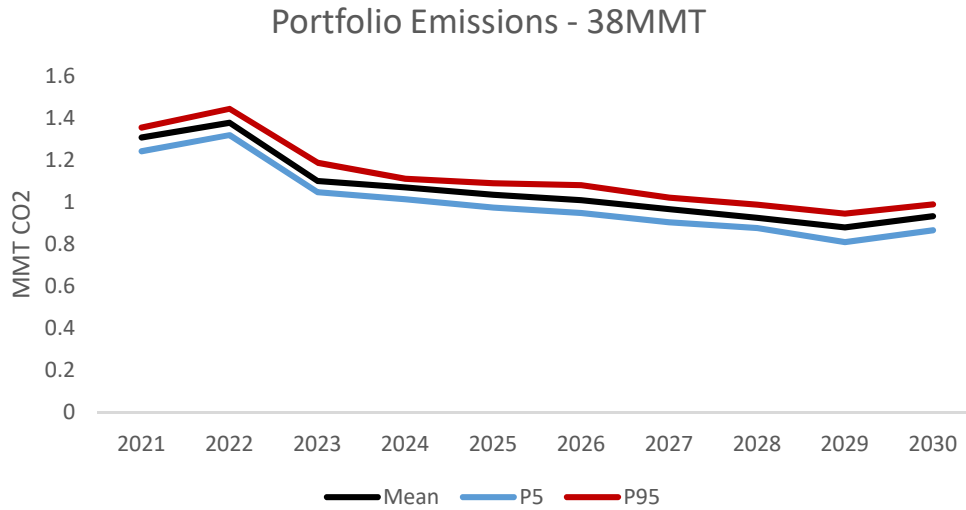
Figure 6: GHG Emissions by Portfolio 2020 – 2030



EBCE also simulated market purchases and therefore can calculate the P5, mean, and P95 emissions associated with each portfolio. Figure 7 below shows the emission uncertainty for each portfolio.

Figure 7: PowerSimm-simulated emissions with uncertainty for the 46 MMT (top) and 38 MMT (bottom) portfolios





The charts show that there is a very tight distribution of emissions outcomes. The portfolios’ investment in solar (a highly regular resource in California) and storage minimizes production uncertainty. In the near-term, load is also relatively predictable, therefore EBCE is highly confident that emissions reductions targets would be achieved under these portfolios. To the extent that load forecasts deviate significantly from those used in this analysis over longer time periods, EBCE expects to have sufficient time to adjust procurement strategies to reflect updated forecasts and continue to meet emissions goals.

d. Local Air Pollutant Minimization and Disadvantaged Communities

i. Local Air Pollutants

EBCE’s air pollutant emissions associated with each portfolio as calculated by the CSP are shown in the tables below.

Table 6: Total Air Pollutant Emissions Associated with 46 MMT Portfolio

Emissions Total	Unit	2020	2022	2026	2030
PM2.5	tonnes/yr	119	68	53	85
SO ₂	tonnes/yr	11	6	5	20
NOx	tonnes/yr	187	118	105	193

Table 7: Air Pollutant Emissions by Resource Type Associated with 46 MMT Portfolio

PM2.5	Unit	2020	2022	2026	2030
Coal	tonnes/yr	-	-	-	-
CHP	tonnes/yr	8	7	8	8
Biogas	tonnes/yr	-	-	-	4

Biomass	<i>tonnes/yr</i>	-	-	-	25
System Power	<i>tonnes/yr</i>	111	60	45	48
Total	<i>tonnes/yr</i>	119	68	53	85
Average emissions intensity	<i>kg/MWh</i>	0.0159	0.0098	0.0076	0.0123

SO₂	<i>Unit</i>	2020	2022	2026	2030
Coal	<i>tonnes/yr</i>	-	-	-	-
CHP	<i>tonnes/yr</i>	1	1	1	1
Biogas	<i>tonnes/yr</i>	-	-	-	5
Biomass	<i>tonnes/yr</i>	-	-	-	10
System Power	<i>tonnes/yr</i>	10	6	4	5
Total	<i>tonnes/yr</i>	11	6	5	20
Average emissions intensity	<i>kg/MWh</i>	0.0015	0.0009	0.0007	0.0029

NO_x	<i>Unit</i>	2020	2022	2026	2030
Coal	<i>tonnes/yr</i>	-	-	-	-
CHP	<i>tonnes/yr</i>	42	37	38	39
Biogas	<i>tonnes/yr</i>	-	-	-	16
Biomass	<i>tonnes/yr</i>	-	-	-	68
System Power	<i>tonnes/yr</i>	145	81	67	70
Total	<i>tonnes/yr</i>	187	118	105	193
Average emissions intensity	<i>kg/MWh</i>	0.0248	0.0171	0.0152	0.0279

Table 8: Total Air Pollutant Emissions Associated with 38 MMT Portfolio

Emissions Total	<i>Unit</i>	2020	2022	2026	2030
PM2.5	<i>tonnes/yr</i>	120	67	49	72
SO ₂	<i>tonnes/yr</i>	11	6	5	19
NO _x	<i>tonnes/yr</i>	186	116	100	173

Table 9: Air Pollutant Emissions by Resource Type Associated with 38 MMT Portfolio

PM2.5	<i>Unit</i>	2020	2022	2026	2030
Coal	<i>tonnes/yr</i>	-	-	-	-
CHP	<i>tonnes/yr</i>	8	7	8	8
Biogas	<i>tonnes/yr</i>	-	-	-	4
Biomass	<i>tonnes/yr</i>	-	-	-	24
System Power	<i>tonnes/yr</i>	111	60	41	36
Total	<i>tonnes/yr</i>	120	67	49	72
Average emissions intensity	<i>kg/MWh</i>	0.0159	0.0097	0.0071	0.0104

SO₂	Unit	2020	2022	2026	2030
Coal	<i>tonnes/yr</i>	-	-	-	-
CHP	<i>tonnes/yr</i>	1	1	1	1
Biogas	<i>tonnes/yr</i>	-	-	-	5
Biomass	<i>tonnes/yr</i>	-	-	-	9
System Power	<i>tonnes/yr</i>	10	6	4	3
Total	<i>tonnes/yr</i>	11	6	5	19
Average emissions intensity	<i>kg/MWh</i>	0.0015	0.0009	0.0007	0.0027

NO_x	Unit	2020	2022	2026	2030
Coal	<i>tonnes/yr</i>	-	-	-	-
CHP	<i>tonnes/yr</i>	42	37	38	37
Biogas	<i>tonnes/yr</i>	-	-	-	15
Biomass	<i>tonnes/yr</i>	-	-	-	65
System Power	<i>tonnes/yr</i>	144	80	62	55
Total	<i>tonnes/yr</i>	186	116	100	173
Average emissions intensity	<i>kg/MWh</i>	0.0247	0.0169	0.0144	0.0250

As demonstrated in the CSP calculator results, EBCE’s only air pollutant allocations from both portfolios are the result of its reliance on system power and biomass procurement in the late 2020s. While considered carbon neutral in California emissions accounting, biofuels produce significant pollutant emissions when combusted. EBCE seeks to balance the increase in harmful pollutants caused by including biofueled generation in its portfolios with the desire to demonstrate a balanced, diverse and reliable portfolio. For these reasons, while EBCE included a small amount of biomass in the later years of its IRP, EBCE significantly reduced the amounts of these resources from its implied proportional share of all existing biomass in the RSP and 38 MMT portfolios. EBCE will continue to monitor the cost and availability of alternative high capacity factor renewables that could avoid air pollutant emissions, particularly in disadvantaged communities.

Historically, EBCE has targeted clean resource procurement from projects located within its service territory to the maximum extent possible. In previous solicitations, EBCE set targets for procurement from resources within Alameda County⁷, recognizing the economic benefits of these resources and the potential to reduce service area GHG emissions by displacing fossil fuel generation.

More recently, EBCE partnered with PG&E in the Oakland Clean Energy Initiative (OCEI) with the specific goal of reducing emissions in the City of Oakland by procuring sufficient capacity from non-emitting resources in a target sub-pocket to justify terminating the Reliability Must Run (RMR) designation granted to the Dynegy Oakland power plant. Eliminating the RMR designation will allow this jet fuel

⁷ EBCE 2018 California Renewable Energy Request for Proposals (RFP). https://ebce.org/uploads/ebce-2018-california-renewable-energy-rfp_revision1.pdf.

power plant to retire and begin decommissioning, substantially reducing emissions in Oakland and Alameda. In future procurement, EBCE will continue to prioritize investment within its service territory, while maintaining an economically efficient portfolio and contracting with emissions-free resources or low-emission RPS-eligible resources.

ii. Focus on Disadvantaged Communities

There are 16 zip codes in EBCE’s service area that are considered Disadvantaged Communities (DACs) according to the IRP definition that relies on CalEnviroScreen 3.0. These communities represent a total population of 69,746 ratepayers, or roughly 5% of EBCE’s total number of customers. Of the 16 zip codes, there are 42 census tracts that cover these areas.

The following zip codes are in the top 25%, in descending risk order beginning with the most at-risk:

1. 94621 – Oakland
2. 94604 – Oakland
3. 94601 – Oakland
4. 94606 – Oakland
5. 95376 – Tracy
6. 94607 – Oakland
7. 94608 – Emeryville
8. 95304 – Tracy
9. 94577 – San Leandro
10. 94578 – San Leandro
11. 94544 – Hayward
12. 94587 – Union City
13. 94560 – Newark
14. 94612 – Oakland
15. 94710 – Berkeley
16. 94545 – Hayward

While CalEnviroScreen 3.0 is a useful tool to provide information on EBCE’s customers living in areas of environmental and socioeconomic burdens, it is not the only resource. EBCE also collects its own data to provide a more complete picture of its communities. For example, EBCE is closely tracking disconnection and arrearage data based on zip code to inform program design that supports residents in need. EBCE’s CARE- and FERA-enrolled customers are integrated in local programs, marketing campaigns, and policy efforts. There are roughly 100,000 CARE- and FERA-enrolled customers in EBCE’s service area, which makes up about 7% of our total customers served. This number does not yet include EBCE’s new cities such as Pleasanton, Newark, and Tracy due to a lack of data.

EBCE is committed to serving its DACs through numerous cross-organizational efforts, including targeted resource procurement and local program offerings aimed towards benefiting these communities,

enhanced marketing to increase awareness of financial and programmatic resources, and advocacy around inclusive policies that prioritize benefitting underserved populations. Of importance to EBCE is increasing the deployment of clean energy resources in areas typically overburdened by air pollution. In the coming year, EBCE is deploying its Disadvantaged Communities - Green Tariff (DAC-GT) and Community Solar – Green Tariff (CS-GT) programs to advance the access of renewables in DACs. The DAC-GT program allows EBCE to procure 5.49 MW and the CS-GT permits 1.39 MW of solar. The CS-GT program prioritizes community stakeholder engagement by collaborating and partnering with a community sponsor. This structure not only strengthens EBCE’s relationships with community-based organizations, but also encourages the development of just, clean energy economies. In addition to the DAC-GT and CS-GT programs, EBCE has engaged in a variety of efforts to prioritize benefits to low-income residents and disadvantaged communities. Such efforts include resilience initiatives aimed towards deploying solar and storage systems, the recent launch of a Low-Income Energy Efficiency RFP and increasing EV charging infrastructure access in DACs.⁸ In particular, EBCE’s efforts to support increased EV adoption will reduce criteria air pollutants improving human health outcomes for all residents, especially those in the most vulnerable communities located along interstate corridors. These programs can be a model for intentional procurement of emission-free power to displace fossil-fueled generation and transportation fuel on behalf of our communities most at-risk of environmental injustices.

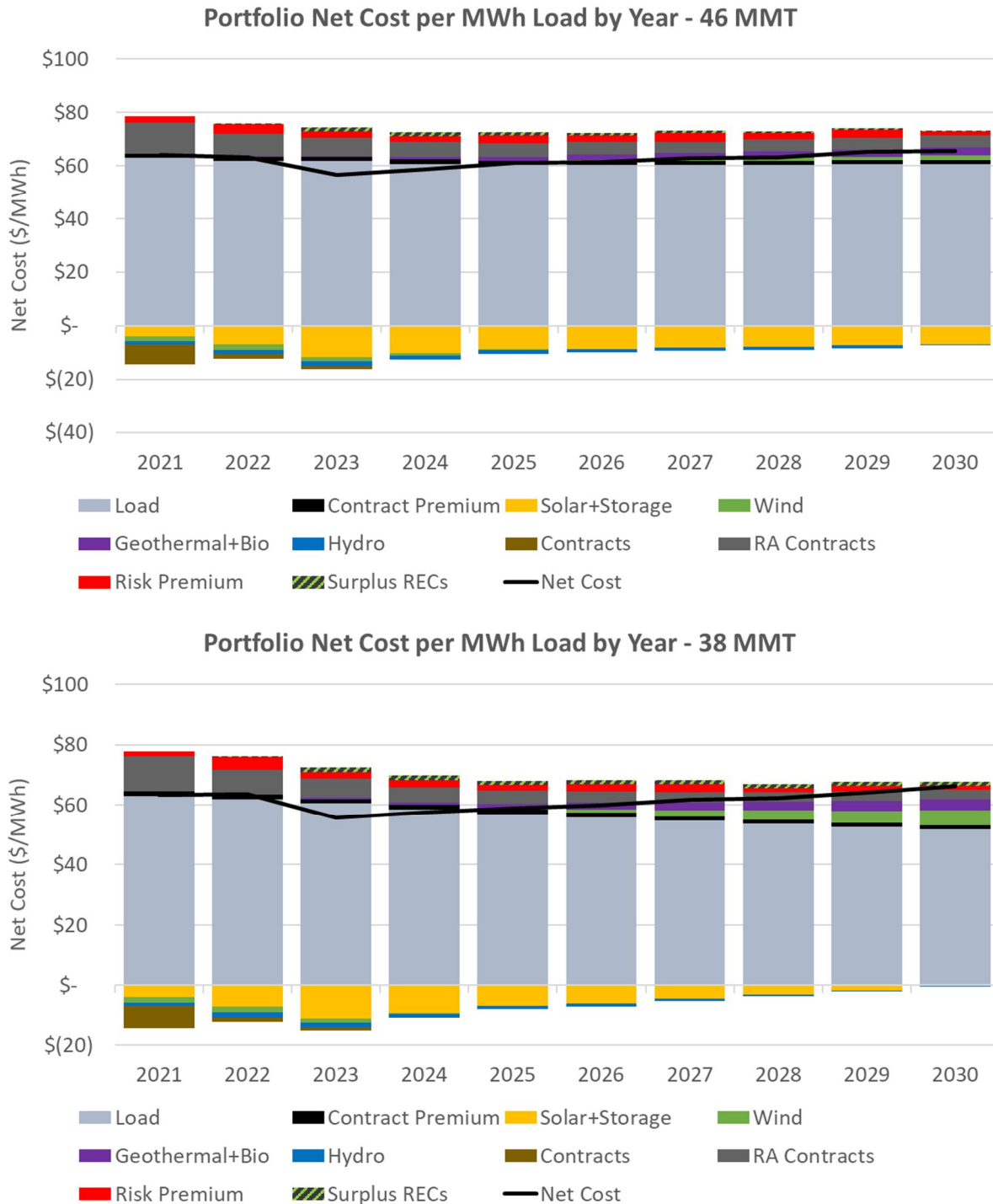
e. Cost and Rate Analysis

Ascend generated separate CAISO market price forecasts for the two conforming scenarios, reflecting different resource mixes in the surrounding CAISO footprint. Using these forecasts, portfolio costs were simulated for each EBCE portfolio, including price differences between simulated hubs and the settlement points for load and generation resources.

Portfolio cost breakdowns for the 46 MMT and 38 MMT portfolios are shown in Figure 8 and Figure 9 below. Resources that are cost-effective relative to the market purchases they displace generate positive revenues, shown as negative net costs in the chart below. In both portfolios, solar and hydro resources generate positive revenues, while wind and geothermal provide net costs in the later years, reflecting the cost premium associated with non-solar clean energy sources.

⁸ More Information on EBCE's recent efforts related to these programs and initiatives can be found at: <https://ebce.org/uploads/item-19-local-development-update-informational-item.pdf>.

Figure 8: PowerSimm-simulated portfolio costs for the 46 MMT (top) and 38 MMT (bottom) portfolios

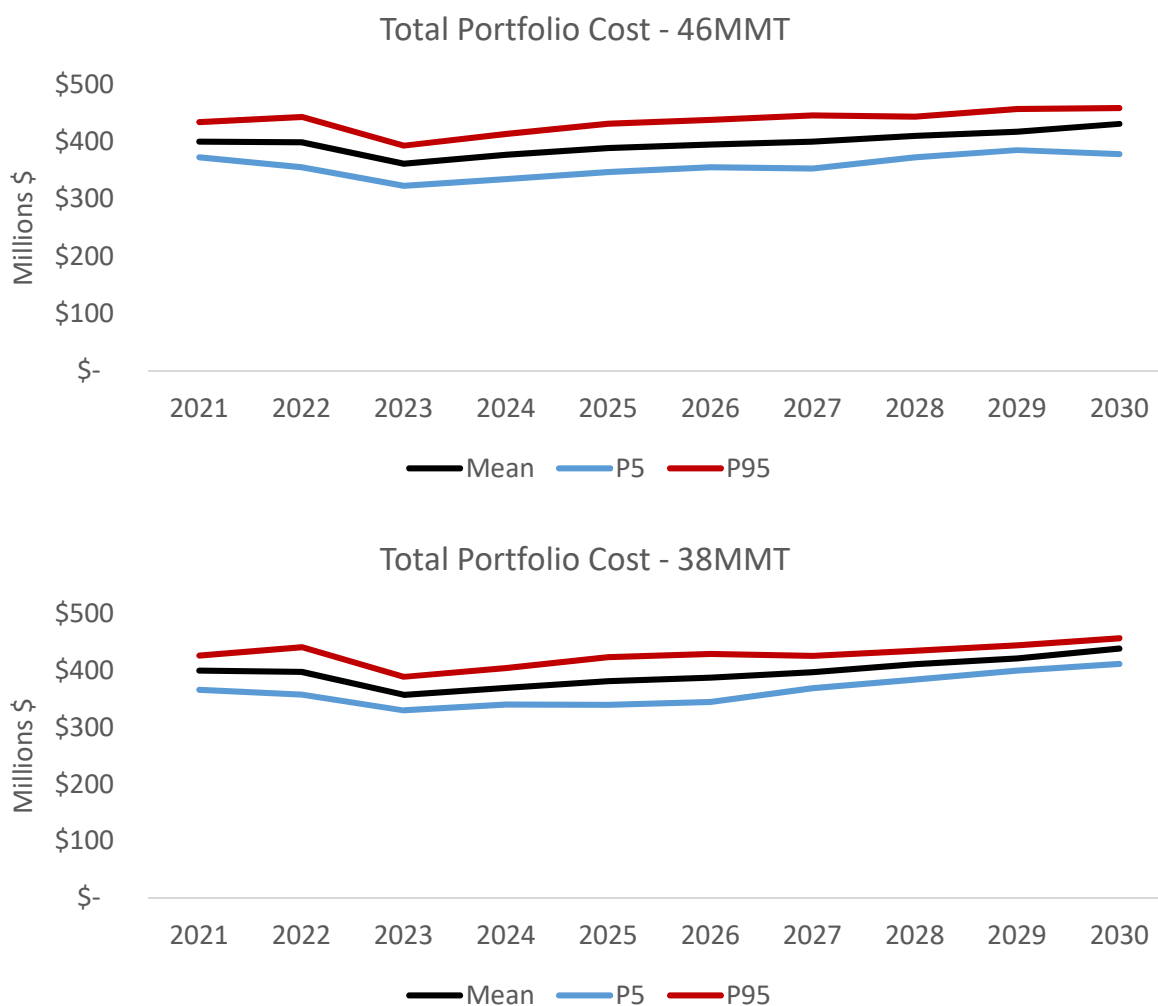


The charts above show that the cost per MWh supplied stays relatively flat. These values are in nominal dollars, thus on a real basis costs decline slightly. This reflects a general depression in real dollars of the

cost of energy, as zero marginal cost renewables come to dominate the supply stack. Therefore, EBCE does not expect these portfolios to result in rate shock for EBCE customers.

Figure 8 shows the P5, mean, and P95 of total power supply costs. The charts show a wider band (e.g. more risk) in the 46 MMT portfolio than the 38 MMT portfolio. In the 46 MMT portfolio, the mean cost in 2030 is \$437 million with a P95 cost of \$466 million (delta of \$29 M), while the 38 MMT scenario has a mean of \$451 million with a P95 cost of \$471 million (delta of \$20 M). This shows the greater risk and uncertainty of the 46 MMT portfolio. The 38 MMT portfolio invests in more fixed price resources to reduce the emissions associated with market purchases. As some of these clean energy resources are more expensive than market, the cost of the 38 MMT portfolio increases but the range of uncertainty is lower. Note that these mean costs are different than the average total portfolio costs described above because these do not include the “risk premium,” which is not relevant when looking at the range of individual simulated values.

Figure 9: Stochastic results of simulated portfolio costs for the 46 MMT (top) and 38 MMT (bottom) portfolios



The relationship between EBCE’s procurement costs and customer rates is mediated by the fact that EBCE does not currently offer direct cost-of-service rates, but instead calculates rates based on modifiers applied to the PG&E generation rates for each rate class. The uncertainty surrounding any forward-looking analysis of EBCE rates is further compounded by the impact of the Power Charge Indifference Adjustment (PCIA) paid to PG&E by EBCE customers. Despite the uncertain influence of these rate components, however, EBCE believes that average annual growth of less than 1% in its per-MWh portfolio net costs in both cases is consistent with a continued ability to serve its customers at competitive rates.

f. System Reliability Analysis

EBCE staff believes short-term contracts in the form of fixed-price energy transactions offer the best option to fill a portion of its un-hedged position. This ensures EBCE does not excessively rely on the CAISO system, which would negatively affect system reliability. It also serves as a means of insurance to protect customers from volatility in Spot Market prices. Staff assessed the total open position unhedged by long-term resources under the 46 MMT and 38 MMT scenarios and applied a 3:2 ratio (ratio of short-term contracts to spot market purchases) to fill this shortfall.

Over the 2021-2030 study timeframe, the long-term resources that comprise the 46 MMT portfolio are forecasted to provide approximately 4,150 GWh of energy per year that can be used to meet demand. This leaves an average forecasted open position in 46 MMT portfolio of 2,700 GWh per year (1,800 GWh in short-term transactions; 900 GWh in Spot Market purchases). During the same timeframe, the resources that comprise the 38 MMT portfolio are forecasted to provide approximately 4,500 GWh of energy per year that can be used to meet demand. This leaves an average forecasted open position in 38 MMT portfolio of 2,400 GWh per year (1,625 in short-term transactions; 775 GWh in Spot Market purchases). The percent breakdowns of each portfolio’s average contribution to demand from 2021 to 2030 is summarized here:

Annual Average	% Long-Term	% Short-Term	% Spot Market
46 MMT	60.5%	26.5%	13%
38 MMT	65%	24%	11%

In 2030, if EBCE pursued a 46 MMT portfolio, approximately 4,600 GWh of procurement would be attributed to long-term contracts, 1,380 GWh to short-term, and 923 GWh or 13.4% of EBCE demand would need to be purchased in the Spot Market. If EBCE pursued a 38 MMT Portfolio, approximately 5,280 GWh would come from long-term contracts, 976 GWh from short-term, and 650 GWh or 9.5% of EBCE demand would need to be purchased in the Spot Market in 2030. The percent breakdowns of each portfolio’s average contribution to demand in 2030 is summarized here:

2030 Snapshot	% Long-Term	% Short-Term	% Spot Market
46 MMT	66.6%	20.1%	13.4%
38 MMT	76.4%	14.1%	9.4%

To evaluate contribution to or impact on system reliability, EBCE analyzed portfolio reliability in relation to EBCE’s ability to meet its CPUC-designated RA obligations on an annual basis and in the month of September for every year during the study period. The results indicate that RA obligations can be achieved through a combination of existing RA contracts, long-term generation contracts (i.e. the resources described in the 46 MMT and 38 MMT portfolios) and with additional RA purchases, similar to those EBCE engages in today.

In EBCE’s 46 MMT portfolio the long-term contracts anticipated do not represent sufficient capacity to meet annual or September RA obligations. Additional RA procurement will be necessary for each year from 2021 to 2030, which EBCE plans to fill with short-term RA-only contracts for 2021-2023, and unknown generic RA contracts after 2023. While the volume of long-term contracts anticipated in its 38 MMT portfolio contributes to a higher portion of EBCE’s annual and September RA obligations, additional RA procurement will be necessary for each year from 2021 to 2030 for this portfolio as well. EBCE similarly plans to fill this gap with short-term RA-only contracts for 2021-2023, and unknown generic RA contracts after 2023. The forecasted RA shortfalls in EBCE’s long-term portfolios are in addition to the IRP Procurement Track RA obligation. EBCE has executed agreements for the majority of its IRP Procurement Track obligation using resources that were not included in the CPUC’s baseline portfolio; EBCE will finalize execution of agreements to meet the Procurement Track obligation by October 1, 2020.

The reliability analysis also evaluated the number of “forced” & “simulated” hours of portfolio market exposure. In this case, “forced exposure” represents the number of hours where generating resources and energy storage are insufficient to meet demand. “Simulated exposure” represents the number of hours with net market purchases including energy storage charging; these represent hours where generating resources may be sufficient to meet demand, but modeling indicates the economically optimal outcome is to purchase market energy. It is important to note that forced and simulated hours of exposure measure the frequency, but not severity, of EBCE’s demand exposure to the CAISO market. Severity of market exposure is represented in Table 10 and discussed subsequently.

In this scenario, forecasted forced exposure hours decrease over time. By 2030, the mean forecasted forced exposure hours for this portfolio are approximately 6,300 hours per year. Analysis indicated a range of expected outcomes for forced exposure hours; the P5 is approximately 6,100 hour and P95 is approximately 6,500 hours. Given there are 8,760 hours in a calendar year, 6,300 hours of represents exposure in approximately 72% of hours in 2030 in which some portion of EBCE’s hourly position would be exposed to the CAISO spot market. Evaluation of simulated market exposure hours indicated a similar decrease over time. By 2030, the mean forecasted simulated exposure hours for this portfolio are approximately 6,700 hours per year. Analysis indicated a range of expected outcomes for simulated exposure hours; the P5 is approximately 6,500 hours and P95 is approximately 6,800 hours. 6,700 hours of represents exposure in approximately 76% of hours in 2030.

Analysis of forecasted forced exposure hours also decrease over time in the 38 MMT portfolio. By 2030, the mean forecasted forced exposure hours for this portfolio are approximately 6,000 hours per year. Analysis indicated a range of expected outcomes for forced exposure hours; the P5 is approximately 5,750 hours and P95 is approximately 6,400 hours. 6,000 hours represents exposure in approximately 68% of hours in 2030. Review of the forecasted *simulated* exposure hours also indicate a decrease in market exposure over time. By 2030 the mean forecasted simulated exposure hours for this portfolio are approximately 6,400 hours per year, which is 7% higher than the forced exposure hours. Analysis indicated a range of expected outcomes for simulated exposure hours; the P5 is approximately 6,100 hours and P95 is approximately 6,650 hours. 6,400 hours of represents exposure in approximately 73% of hours in 2030.

As noted above, it is important to understand that an hour of market exposure refers solely to an hour where some portion of EBCE’s demand is exposed to the market. It is not a representation of the volume or severity of demand exposed to the market. An hour in which one MW of demand is exposed to the market would contribute to the market exposure hours the same as an hour where 600 MW of demand is exposed to the market. Table 10 provides an estimation of severity of exposure to the Spot Market associated with both 46 MMT and 38 MMT portfolios in 2030. When planned short-term contracts are accounted for, the average position during the critical evening hours (4pm-9pm) is a shortage of 1% of load for the 38MMT portfolio, and less than 11% for the 46 MMT portfolio. When looking specifically at August and September, these decline further to 0.9% of load and 8.1% of load for the 38 and 46 MMT portfolios, respectively. These average positions are calculated based on the simulated dispatch, so actual forced market shortages would be even lower. Together, these results indicate that while the portfolios are short in a large number of hours, these shortages are generally a relatively small portion of load, particularly for the 38 MMT portfolio, and EBCE’s resource procurement plan avoids excessive dependence on system energy.

Table 10: Average Severity of Market Exposure across portfolios & procurement strategies

All Hours					
	Average MW Position (Purchases)	Average % of Load (Purchases)	Average MW Position (All)	Average % of Load (All)	# of Hours with Purchases
38MMT (w/ short-term)	139.7	18.5%	53.1	7.2%	6517
46MMT (w/ short-term)	176.4	23.1%	66.0	8.9%	6070
38MMT (w/o short-term)	349.4	46.1%	209.0	27.8%	6517
46MMT (w/o short-term)	441.0	57.9%	249.3	32.9%	6070

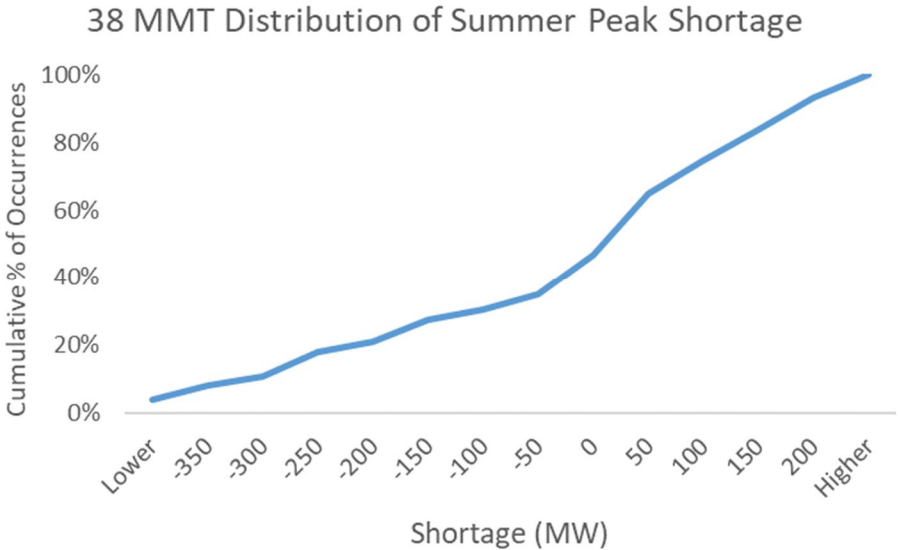
Evening Hours (4pm - 9pm)					
	Average MW Position (Purchases)	Average % of Load (Purchases)	Average MW Position (All)	Average % of Load (All)	# of Hours with Purchases
38MMT (w/ short-term)	120.8	13.0%	16.5	1.0%	1227
46MMT (w/ short-term)	193.0	21.1%	101.1	10.5%	1358
38MMT (w/o short-term)	301.9	32.6%	138.3	14.1%	1227
46MMT (w/o short-term)	482.4	52.7%	316.4	34.0%	1358

Table Key:

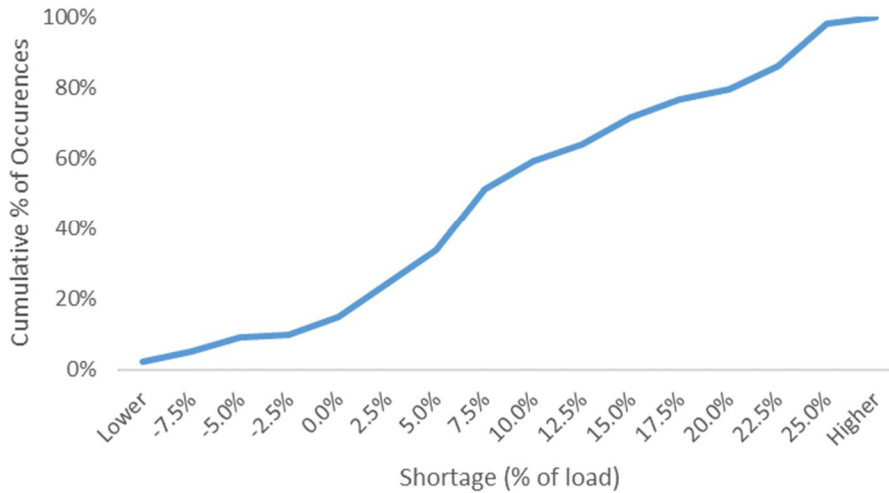
- “Purchases” only counts the intervals when the portfolio is short (i.e. the average does not include intervals when the portfolio is long).
- “All” counts all intervals (i.e. the average includes intervals when the portfolio is long).
- “w/ short-term” allows assumed future short-term contracts to reduce the shortages
“w/o short-term” calculates shortages relative only to long-term contracts

Figure 10 below shows the cumulative distributions of shortages by MW and by percent of load for the 38 MMT portfolio in 2030 during the 4pm-9pm period in August and September. The results indicate that the shortage is less than 100 MW and 15% of load in at least 70% of the summer peak hourly intervals.

Figure 10. Cumulative distributions of shortages in MW (top) and percent of load (bottom) for the 38MMT portfolio in 2030



38 MMT Distribution of Summer Peak Shortage



EBCE recognizes excessive market exposure of a single entity can result in significant economic risk to that entity and its customers. More perilous, however, is the risk that numerous market participants engage in similar procurement strategies, all exposing portions of their demand to the market at the same time. This could result in energy crisis-like outcomes. EBCE plans to mitigate this risk by executing short-term transactions to limit the volume (severity) of its demand that could be exposed to the spot market in any hour. EBCE’s objective is to minimize risks to customers by limiting the exposure to energy market costs due to under- or over-procurement. A benefit of using short-term transactions to close a portion of EBCE’s open position is that this commercial strategy allows EBCE to avoid over-procuring long-term resources but is flexible enough to allow EBCE to have a fully hedged portfolio (i.e. no market exposure) during seasons where there is greatest reliability risk to the CAISO system. For example, it is commercially desirable to have more market exposure in the spring and fall but a more fully hedged position in the summer to avoid exposure to day-ahead to real-time load forecasting errors that frequently drive high prices and reliability challenges.

EBCE recognizes its obligation to contribute to grid reliability and the challenges in balancing reliability with ambitious renewable energy goals. As such, EBCE also considers the load profile of the CAISO system in its optimization analysis. EBCE has identified the need to meet system peak and ramping requirements and values resources that can be dispatched or curtailed.

As requested by the Commission, the System Reliability Progress Tracking Tables for the 46 MMT and 38 MMT scenarios are included as Figure 11 and Figure 12 below.

Figure 11: System Reliability Progress Tracking Table for 46 MMT portfolio

System Reliability Progress Tracking Table (NQC MW) for month of September by contract status, 46 MMT		ELCC type	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
online	wind_low_cf	-	-	-	-	-	-	-	-	-	-	-	-
online	wind_high_cf	-	-	-	-	-	-	-	-	-	-	-	-
online	biomass	-	-	-	-	-	-	-	-	-	-	-	-
online	cogen	-	6	6	6	6	6	6	6	6	6	6	6
online	geothermal	-	-	-	-	-	-	-	-	-	-	-	-
online	hydro	-	-	-	-	-	-	-	-	-	-	-	-
online	thermal	-	99	99	99	99	99	99	99	99	99	99	99
online	battery	-	-	-	-	-	-	-	-	-	-	-	-
online	nuclear	-	-	-	-	-	-	-	-	-	-	-	-
online	solar	-	-	-	-	-	-	-	-	-	-	-	-
online	psh	-	-	-	-	-	-	-	-	-	-	-	-
online	unknown	1,277	599	438	-	-	-	-	-	-	-	-	-
development	wind_low_cf	-	9	9	9	10	11	13	13	13	13	13	13
development	wind_high_cf	-	-	-	-	-	-	-	-	-	-	-	-
development	biomass	-	-	-	-	-	-	-	-	-	-	-	-
development	cogen	-	-	-	-	-	-	-	-	-	-	-	-
development	geothermal	-	-	-	-	-	-	-	-	-	-	-	-
development	hydro	-	-	-	-	-	-	-	-	-	-	-	-
development	thermal	-	-	-	-	-	-	-	-	-	-	-	-
development	battery	-	-	28	28	28	28	28	28	28	28	28	28
development	nuclear	-	-	-	-	-	-	-	-	-	-	-	-
development	solar	-	69	69	69	60	52	43	44	44	44	44	44
development	psh	-	-	-	-	-	-	-	-	-	-	-	-
development	unknown	-	-	-	-	-	-	-	-	-	-	-	-
review	wind_low_cf	-	-	-	-	-	-	-	-	-	-	-	-
review	wind_high_cf	-	-	-	-	-	-	-	-	-	-	-	-
review	biomass	-	-	-	-	-	-	-	-	-	-	-	-
review	cogen	-	-	-	-	-	-	-	-	-	-	-	-
review	geothermal	-	-	-	-	-	-	-	-	-	-	-	-
review	hydro	-	-	-	-	-	-	-	-	-	-	-	-
review	thermal	-	-	-	-	-	-	-	-	-	-	-	-
review	battery	-	-	-	-	-	-	-	-	-	-	-	-
review	nuclear	-	-	-	-	-	-	-	-	-	-	-	-
review	solar	-	-	-	-	-	-	-	-	-	-	-	-
review	psh	-	-	-	-	-	-	-	-	-	-	-	-
review	unknown	-	-	-	-	-	-	-	-	-	-	-	-
planned_existing	wind_low_cf	-	-	-	-	-	-	-	-	-	-	-	-
planned_existing	wind_high_cf	-	-	-	-	-	-	-	-	-	-	-	-
planned_existing	biomass	-	-	-	-	-	-	-	3	7	10	14	-
planned_existing	cogen	-	-	-	-	-	-	-	-	-	-	-	-
planned_existing	geothermal	-	-	10	23	37	49	62	62	62	62	-	-
planned_existing	hydro	-	-	133	133	133	133	133	133	133	133	133	133
planned_existing	thermal	-	-	-	-	-	-	-	-	-	-	-	-
planned_existing	battery	-	-	-	-	-	-	-	-	-	-	-	-
planned_existing	nuclear	-	-	-	-	-	-	-	-	-	-	-	-
planned_existing	solar	-	-	-	-	-	-	-	-	-	-	-	-
planned_existing	psh	-	-	-	-	-	-	-	-	-	-	-	-
planned_existing	unknown	-	675	385	805	795	795	755	725	705	675	655	-
planned_new	wind_low_cf	-	-	36	37	43	50	58	59	60	61	64	-
planned_new	wind_high_cf	-	-	11	12	14	16	18	18	18	18	19	-
planned_new	biomass	-	-	-	-	-	-	-	-	-	-	-	-
planned_new	cogen	-	-	-	-	-	-	-	-	-	-	-	-
planned_new	geothermal	-	-	-	-	-	-	-	-	-	-	-	-
planned_new	hydro	-	-	-	-	-	-	-	-	-	-	-	-
planned_new	thermal	-	-	-	-	-	-	-	-	-	-	-	-
planned_new	battery	-	-	176	181	186	188	189	229	269	308	348	-
planned_new	nuclear	-	-	-	-	-	-	-	-	-	-	-	-
planned_new	solar	-	-	52	52	46	39	33	35	38	40	43	-
planned_new	psh	-	-	-	-	-	-	-	-	-	-	-	-
planned_new	unknown	-	-	-	-	-	-	-	-	-	-	-	-

Figure 12: System Reliability Progress Tracking Table for 38 MMT portfolio

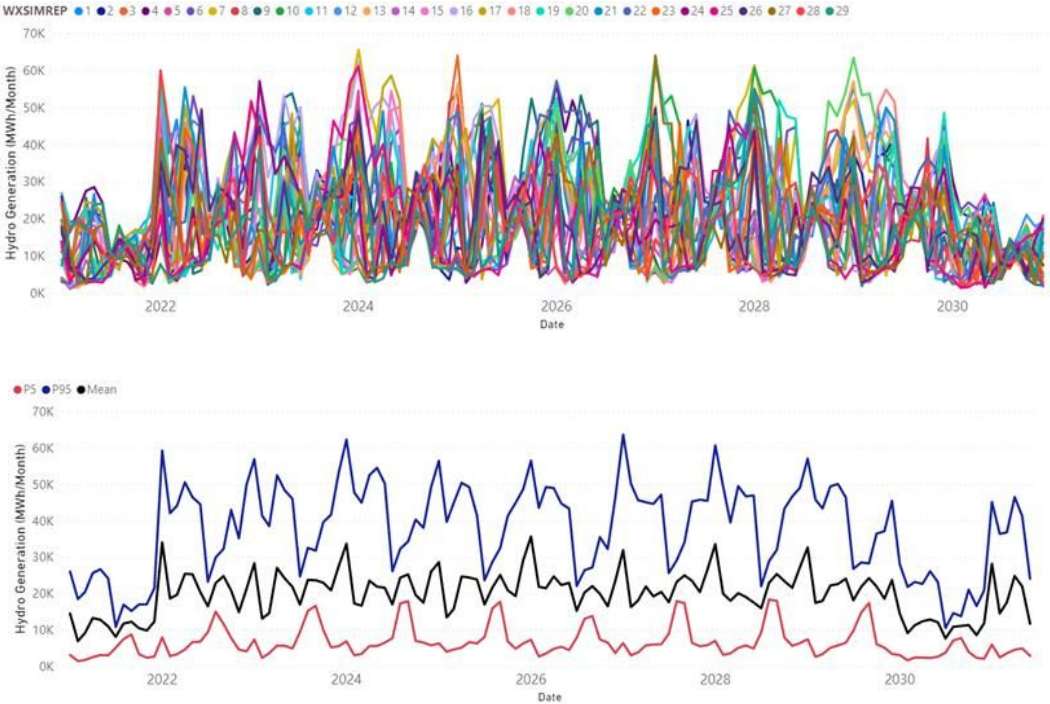
System Reliability Progress Tracking Table (NQC MW) for month of September by contract status, 38 MMT		ELCC type	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
online	wind_low_cf	-	-	-	-	-	-	-	-	-	-	-	-
online	wind_high_cf	-	-	-	-	-	-	-	-	-	-	-	-
online	biomass	-	-	-	-	-	-	-	-	-	-	-	-
online	cogen	-	6	6	6	6	6	6	6	6	6	6	6
online	geothermal	-	-	-	-	-	-	-	-	-	-	-	-
online	hydro	-	-	-	-	-	-	-	-	-	-	-	-
online	thermal	-	99	99	99	99	99	99	99	99	99	99	99
online	battery	-	-	-	-	-	-	-	-	-	-	-	-
online	nuclear	-	-	-	-	-	-	-	-	-	-	-	-
online	solar	-	-	-	-	-	-	-	-	-	-	-	-
online	psh	-	-	-	-	-	-	-	-	-	-	-	-
online	unknown	1,277	599	438	-	-	-	-	-	-	-	-	-
development	wind_low_cf	-	9	9	9	10	11	13	13	13	13	12	12
development	wind_high_cf	-	-	-	-	-	-	-	-	-	-	-	-
development	biomass	-	-	-	-	-	-	-	-	-	-	-	-
development	cogen	-	-	-	-	-	-	-	-	-	-	-	-
development	geothermal	-	-	-	-	-	-	-	-	-	-	-	-
development	hydro	-	-	-	-	-	-	-	-	-	-	-	-
development	thermal	-	-	-	-	-	-	-	-	-	-	-	-
development	battery	-	-	28	28	28	28	28	28	28	28	28	28
development	nuclear	-	-	-	-	-	-	-	-	-	-	-	-
development	solar	-	69	69	69	60	51	42	37	32	28	23	23
development	psh	-	-	-	-	-	-	-	-	-	-	-	-
development	unknown	-	-	-	-	-	-	-	-	-	-	-	-
review	wind_low_cf	-	-	-	-	-	-	-	-	-	-	-	-
review	wind_high_cf	-	-	-	-	-	-	-	-	-	-	-	-
review	biomass	-	-	-	-	-	-	-	-	-	-	-	-
review	cogen	-	-	-	-	-	-	-	-	-	-	-	-
review	geothermal	-	-	-	-	-	-	-	-	-	-	-	-
review	hydro	-	-	-	-	-	-	-	-	-	-	-	-
review	thermal	-	-	-	-	-	-	-	-	-	-	-	-
review	battery	-	-	-	-	-	-	-	-	-	-	-	-
review	nuclear	-	-	-	-	-	-	-	-	-	-	-	-
review	solar	-	-	-	-	-	-	-	-	-	-	-	-
review	psh	-	-	-	-	-	-	-	-	-	-	-	-
review	unknown	-	-	-	-	-	-	-	-	-	-	-	-
planned_existing	wind_low_cf	-	-	-	-	-	-	-	-	-	-	-	-
planned_existing	wind_high_cf	-	-	-	-	-	-	-	-	-	-	-	-
planned_existing	biomass	-	-	-	-	-	-	-	3	7	10	14	14
planned_existing	cogen	-	-	-	-	-	-	-	-	-	-	-	-
planned_existing	geothermal	-	-	-	16	32	48	65	65	65	65	65	65
planned_existing	hydro	-	-	136	136	136	136	136	136	136	136	136	136
planned_existing	thermal	-	-	-	-	-	-	-	-	-	-	-	-
planned_existing	battery	-	-	-	-	-	-	-	-	-	-	-	-
planned_existing	nuclear	-	-	-	-	-	-	-	-	-	-	-	-
planned_existing	solar	-	-	-	-	-	-	-	-	-	-	-	-
planned_existing	psh	-	-	-	-	-	-	-	-	-	-	-	-
planned_existing	unknown	-	675	385	785	755	725	665	635	595	555	525	525
planned_new	wind_low_cf	-	-	38	39	48	57	66	75	84	93	104	104
planned_new	wind_high_cf	-	-	12	12	15	18	21	21	21	21	21	21
planned_new	biomass	-	-	-	-	-	-	-	-	-	-	-	-
planned_new	cogen	-	-	-	-	-	-	-	-	-	-	-	-
planned_new	geothermal	-	-	-	-	-	-	-	-	-	-	-	-
planned_new	hydro	-	-	-	-	-	-	-	-	-	-	-	-
planned_new	thermal	-	-	-	-	-	-	-	-	-	-	-	-
planned_new	battery	-	-	176	198	220	242	264	303	340	376	410	410
planned_new	nuclear	-	-	-	-	-	-	-	-	-	-	-	-
planned_new	solar	-	-	57	57	50	42	35	33	31	28	25	25
planned_new	psh	-	-	-	-	-	-	-	-	-	-	-	-
planned_new	unknown	-	-	-	-	-	-	-	-	-	-	-	-

g. Hydro Generation Risk Management

In both the 46 MMT and 38 MMT conforming portfolios, hydro generation is included from both generic in-state large hydro resources and imported Pacific Northwest hydro resources. EBCE will not be

immune to drought conditions, however, and has implemented controls that allow for risk mitigation should a prolonged drought occur. To minimize EBCE’s exposure to hydro generation availability risk, the portfolios were constructed to rely on less than EBCE’s implied share of hydro resources from the RSP. Both portfolios rely on less than 2 percent of the system’s hydro resources rather than the 3.3% load share of the RSP, imposing caps of 100 MW and 20 MW for large and small hydro, respectively. In addition, the modeling approach captures variability caused by drought hydro years by simulating hydro generation using historical data from 2010 – 2019. To model Northwest hydro, EBCE used historical production data from a dam system in western Montana. Figure 13 shows simulated hydro generation for large in-state hydro by sim-rep and summarized by P5, mean, and P95, demonstrating variability both between years and between different sim-reps within a given year. Including both large in-state and Pacific Northwest hydro adds an additional layer of risk mitigation as, while both areas are roughly correlated in terms of weather patterns, there can be vast differences in water year outcomes between the regions depending on weather phenomenon such as atmospheric rivers events, El Nino, La Nina and California Off-Shore High Ridge.

Figure 13: Simulated Hydro Generation Captures Natural Variability



By capturing hydro variability in this way, EBCE is confident that the portfolios are robust from a reliability, environmental, and economic perspective. Figure 9 in section III.E shows that the P5 and P95 estimates for portfolio costs were within an acceptably tight band even with this amount of hydro generation variability. Figure 7 in section III.C shows that GHG targets were also met with a tight 95 percent confidence band. Therefore, uncertainty in hydro availability does not put the portfolios at risk of missing carbon targets or incurring unexpected costs. If EBCE is unable to procure even the small

amount of hydro identified in this plan, other resources with similar shapes and attributes, such as geothermal or wind paired with storage, would be evaluated as a suitable replacement.

EBCE understands that with the variability in hydro, additional uncertainties can arise, such as costs, emissions, and reliability. EBCE's hedging strategy is to have a healthy mix of both long-term, short-term, and spot market purchases that allow for the weathering of risks in any term bucket. Additional RPS attributes, specified source and asset control supplier (ACS) purchases will be used as contingencies to both make up reliability and emissions reductions. EBCE's robust budgeting process will account for the additional cost risks due to these potential purchases.

h. Long-Duration Storage Development

EBCE, joined by many CCAs, recognizes that widespread plans for expansion of intermittent renewable resources creates needs for storage that goes beyond the 4-hour standard energy storage product that exists in today's market. For EBCE's largest contracted hybrid solar plus storage projects, EBCE has a contractual right to extend duration on the existing storage capacity in future years by adding incremental lithium batteries at future installation costs. EBCE will continue to employ this strategy for future agreements. Additionally, EBCE participated in a Request for Information (RFI) with a group of 12 other CCAs.⁹ The RFI was launched in mid-June, 2020 with the stated goals of collecting information that may inform a subsequent long-duration storage request for offers, which may be issued as soon as this summer by each of the CCAs individually, or some combination of the Joint CCAs; and to collect information that will help the Joint CCAs in their long-term resource planning, including identifying candidate resources for the long-duration storage need identified in the 2019-2020 RSP. This RFI defined long-duration storage resources as those with the capability to discharge at full capacity for at least 8 hours. The RFI specifically requested the following information: (1) storage technology and commercial history; (2) project specifics, including location, permitting, financing and development risks; (3) contracting terms and preferences, including indicative pricing.

The Joint CCAs received responses from 31 entities representing numerous types of chemical, mechanical and thermal long-duration storage technologies, such as: lithium-ion batteries; vanadium redox and other flow batteries; used EV batteries; waste to fuels via ultrasound; hydrogen storage; pumped storage hydro; geomechanical pumped storage; crane and stacked blocks; compressed air; flywheels; and molten salt and other thermal storage technologies. Moreover, the respondents identified 25 specific projects that represent more than 9,000 MW of capacity, two thirds of which is advertised as able to achieve commercial operation by 2026. Because many longer lead-time resources including long-duration storage may requires multiple LSEs to enable efficient procurement, EBCE is engaged with a subset of the CCAs to evaluate potential of a "super Joint Powers Authority (JPA)" structure. The super JPA would be comprised of multiple CCAs and employed to act as a single contracting entity, capable of contracting with resources larger than an individual member CCA could

⁹ 2020 Request for Information on Long-Duration Storage, available at: https://www.mcecleanenergy.org/wp-content/uploads/2020/06/MCE-2020-Joint-CCAs-Long-Duration-Storage-RFI_061720.pdf.

contract with. EBCE intends to use the long-duration storage RFI responses to inform future procurement with the goal of improved RPS resource integration and grid reliability. Any resulting procurement decisions will be discussed with its Community Advisory Committee and members of the environmental stakeholder community, prior to presenting to EBCE’s Board of Directors for approval.

i. Out-of-State Wind Development

Recent cost declines in solar resources have largely resulted in lower costs, on a levelized basis, as compared to wind. However, the diurnal production profile of solar means that wind resources can act as an important complementary resource in LSEs’ portfolios, supplementing renewable production in overnight and winter hours and reducing the need for load shifting from battery or demand-side resources. Based on the resources selected in the RSP and organizational goals and capabilities, EBCE’s IRP includes 65 MW of wind from New Mexico by 2030 in the 46 MMT Compliant Case Portfolio and 76 MW of wind from New Mexico in the 38 MMT Compliant Case Portfolio.

The charts below provide a graphical representation of the production profiles in the CSP Calculator for four different RESOLVE candidate resources: (1) new solar resources in the Southern PG&E zone; (2) new wind resources in the Southern PG&E zone; (3) new wind resources in the Wyoming zone; and (4) new wind resources in the New Mexico zone, with the highest production month-hours in red and the lowest in blue. The overall annual capacity factor for each modeled resource is included for reference.

Figure 14: Average Production as % of nameplate capacity – RESOLVE Southern PG&E Solar Shape (Annual capacity factor: 30%)

		Hour																							
		1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
Month	1	0%	0%	0%	0%	0%	0%	0%	0%	28%	63%	62%	56%	52%	52%	55%	52%	26%	0%	0%	0%	0%	0%	0%	0%
	2	0%	0%	0%	0%	0%	0%	0%	4%	32%	53%	54%	51%	51%	48%	45%	38%	23%	4%	0%	0%	0%	0%	0%	0%
	3	0%	0%	0%	0%	0%	0%	0%	33%	69%	82%	84%	80%	76%	75%	72%	71%	58%	24%	0%	0%	0%	0%	0%	0%
	4	0%	0%	0%	0%	0%	0%	19%	55%	75%	84%	83%	83%	82%	79%	76%	70%	60%	41%	3%	0%	0%	0%	0%	0%
	5	0%	0%	0%	0%	0%	2%	39%	78%	90%	95%	91%	92%	91%	90%	90%	86%	76%	58%	16%	0%	0%	0%	0%	0%
	6	0%	0%	0%	0%	0%	7%	47%	81%	91%	94%	91%	92%	92%	91%	90%	88%	82%	67%	32%	0%	0%	0%	0%	0%
	7	0%	0%	0%	0%	0%	2%	40%	77%	89%	91%	90%	87%	86%	85%	86%	84%	77%	68%	33%	0%	0%	0%	0%	0%
	8	0%	0%	0%	0%	0%	0%	27%	69%	86%	89%	88%	86%	85%	85%	86%	84%	78%	61%	16%	0%	0%	0%	0%	0%
	9	0%	0%	0%	0%	0%	0%	9%	49%	77%	80%	80%	79%	77%	77%	74%	75%	64%	26%	0%	0%	0%	0%	0%	0%
	10	0%	0%	0%	0%	0%	0%	0%	31%	68%	74%	72%	69%	66%	64%	65%	59%	32%	2%	0%	0%	0%	0%	0%	0%
	11	0%	0%	0%	0%	0%	0%	9%	44%	64%	64%	58%	54%	57%	57%	47%	13%	0%	0%	0%	0%	0%	0%	0%	0%
	12	0%	0%	0%	0%	0%	0%	0%	0%	23%	45%	46%	46%	42%	43%	43%	38%	8%	0%	0%	0%	0%	0%	0%	0%

Figure 15: Average production as % of nameplate capacity – RESOLVE Southern PG&E Wind Shape (Annual capacity factor: 31%)

		Hour																							
		1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
Month	1	20%	20%	20%	19%	18%	16%	16%	17%	15%	11%	11%	10%	10%	12%	12%	12%	14%	17%	20%	21%	21%	22%	21%	21%
	2	25%	24%	22%	21%	20%	20%	21%	21%	18%	15%	13%	12%	14%	15%	16%	19%	21%	26%	33%	31%	30%	28%	25%	25%
	3	27%	23%	21%	22%	23%	22%	21%	18%	14%	13%	13%	14%	15%	17%	19%	22%	25%	30%	33%	35%	36%	36%	33%	31%
	4	45%	43%	41%	40%	37%	34%	30%	21%	19%	18%	19%	21%	24%	29%	32%	40%	45%	50%	60%	64%	63%	60%	56%	52%
	5	66%	59%	55%	51%	47%	44%	33%	27%	25%	24%	25%	28%	31%	35%	41%	49%	56%	63%	74%	83%	83%	81%	77%	70%
	6	58%	55%	50%	46%	43%	35%	25%	21%	19%	18%	19%	22%	25%	30%	38%	47%	56%	64%	77%	90%	88%	84%	76%	68%
	7	58%	53%	51%	46%	42%	37%	26%	22%	20%	18%	19%	21%	24%	28%	34%	43%	52%	59%	76%	87%	82%	78%	73%	66%
	8	48%	45%	41%	38%	35%	32%	26%	18%	15%	14%	13%	15%	17%	20%	24%	31%	39%	49%	69%	74%	72%	68%	61%	54%
	9	42%	38%	37%	37%	34%	31%	28%	21%	18%	17%	17%	16%	17%	21%	23%	29%	36%	45%	58%	58%	58%	55%	51%	45%
	10	27%	24%	23%	22%	21%	21%	21%	17%	11%	10%	10%	10%	11%	13%	16%	17%	19%	24%	28%	30%	30%	32%	31%	28%
	11	16%	15%	14%	14%	15%	17%	17%	15%	10%	6%	5%	5%	5%	6%	7%	8%	10%	15%	19%	19%	20%	19%	19%	18%
	12	28%	29%	29%	27%	25%	24%	20%	20%	15%	11%	11%	12%	12%	13%	13%	14%	15%	18%	21%	23%	23%	24%	24%	26%

Figure 16: Average production as % of nameplate capacity – RESOLVE New Mexico Wind Shape (Annual capacity factor: 41%)

		Hour																							
		1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
Month	1	63%	64%	64%	64%	64%	64%	64%	63%	61%	60%	59%	59%	58%	57%	57%	58%	58%	58%	58%	59%	60%	61%	62%	63%
	2	59%	60%	61%	61%	62%	62%	61%	61%	62%	63%	64%	65%	64%	62%	59%	56%	55%	54%	54%	54%	54%	55%	56%	57%
	3	55%	56%	57%	58%	58%	56%	53%	50%	50%	52%	53%	54%	55%	55%	55%	53%	53%	54%	55%	55%	56%	56%	56%	56%
	4	35%	35%	36%	36%	35%	32%	30%	29%	29%	29%	29%	30%	31%	31%	31%	31%	30%	30%	31%	31%	30%	30%	31%	32%
	5	39%	38%	38%	37%	34%	30%	27%	27%	27%	28%	29%	31%	33%	34%	34%	33%	33%	34%	36%	37%	38%	39%	39%	40%
	6	34%	33%	32%	30%	26%	22%	21%	22%	24%	28%	31%	34%	36%	36%	35%	34%	35%	37%	38%	38%	38%	38%	38%	37%
	7	24%	21%	19%	17%	14%	9%	8%	7%	7%	8%	11%	16%	20%	22%	23%	23%	24%	27%	30%	31%	31%	30%	29%	26%
	8	32%	33%	34%	33%	30%	24%	20%	19%	18%	18%	19%	22%	25%	28%	30%	31%	31%	31%	31%	31%	31%	32%	32%	32%
	9	44%	43%	42%	41%	40%	35%	31%	30%	30%	31%	32%	34%	36%	37%	36%	34%	33%	34%	36%	39%	41%	43%	44%	44%
	10	48%	49%	49%	49%	49%	48%	47%	45%	45%	46%	46%	46%	47%	47%	47%	47%	48%	48%	48%	48%	48%	48%	48%	48%
	11	56%	56%	56%	56%	55%	55%	54%	52%	51%	51%	51%	52%	51%	50%	48%	48%	50%	51%	52%	52%	53%	53%	54%	54%
	12	62%	63%	63%	64%	64%	64%	64%	63%	63%	63%	64%	64%	63%	62%	62%	61%	60%	61%	61%	61%	61%	62%	63%	64%

Figure 17: Average production as % of nameplate capacity – RESOLVE Wyoming Wind Shape (Annual capacity factor: 43%)

		Hour																							
		1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
Month	1	63%	64%	64%	64%	64%	64%	64%	63%	61%	60%	59%	59%	58%	57%	57%	58%	58%	58%	58%	59%	60%	61%	62%	63%
	2	59%	60%	61%	61%	62%	62%	61%	61%	62%	63%	64%	65%	64%	62%	59%	56%	55%	54%	54%	54%	54%	55%	56%	57%
	3	55%	56%	57%	58%	58%	56%	53%	50%	50%	52%	53%	54%	55%	55%	55%	53%	53%	54%	55%	55%	56%	56%	56%	56%
	4	35%	35%	36%	36%	35%	32%	30%	29%	29%	29%	29%	30%	31%	31%	31%	31%	30%	30%	31%	31%	30%	30%	31%	32%
	5	39%	38%	38%	37%	34%	30%	27%	27%	27%	28%	29%	31%	33%	34%	34%	33%	33%	34%	36%	37%	38%	39%	39%	40%
	6	34%	33%	32%	30%	26%	22%	21%	21%	22%	24%	28%	31%	34%	36%	36%	35%	34%	35%	37%	38%	38%	38%	38%	37%
	7	24%	21%	19%	17%	14%	9%	8%	7%	7%	8%	11%	16%	20%	22%	23%	23%	24%	27%	30%	31%	31%	30%	29%	26%
	8	32%	33%	34%	33%	30%	24%	20%	19%	18%	18%	19%	22%	25%	28%	30%	31%	31%	31%	31%	31%	31%	32%	32%	32%
	9	44%	43%	42%	41%	40%	35%	31%	30%	30%	31%	32%	34%	36%	37%	36%	34%	33%	34%	36%	39%	41%	43%	44%	44%
	10	48%	49%	49%	49%	49%	48%	47%	45%	45%	46%	46%	46%	47%	47%	47%	47%	48%	48%	48%	48%	48%	48%	48%	48%
	11	56%	56%	56%	56%	55%	55%	54%	52%	51%	51%	51%	52%	51%	50%	48%	48%	50%	51%	52%	52%	53%	53%	54%	54%
	12	62%	63%	63%	64%	64%	64%	64%	63%	63%	63%	64%	64%	63%	62%	62%	61%	60%	61%	61%	61%	61%	62%	63%	64%

The above tables show the potential role that wind resources can play in achieving EBCE’s goal of delivering clean energy to customers at competitive rates: all three wind resources (Southern PG&E,

New Mexico, and Wyoming) exhibit daily and annual production profiles that complement solar output with generation in the overnight hours and winter months, reducing the need for storage solutions to shift solar production into those hours.

Though one of EBCE's core priorities is to promote the development of local clean energy resources in Alameda county (represented above by the wind and solar resources in the Southern PG&E zones), the higher capacity factor and winter production profiles of out-of-state wind resources may offer cost savings to EBCE customers. However, as noted in the RSP, fully unlocking the potential of out-of-state wind may require upgrades to the bulk transmission system across the WECC, which will affect the cost competitiveness of these resources. EBCE will continue to solicit and evaluate bids from a diverse range of resource options to ensure that customers are reliably served with clean and affordable generation.

j. Transmission Development

As mentioned in the previous section, EBCE's is committed to relying on local generating and demand-side resources where possible, in order to promote economic development in and around its member communities. To the extent that EBCE is able to site and develop quality resources close to its load sinks, this will reduce the need for upgrades to the bulk transmission system that facilitate large-scale transfers between regions.

EBCE evaluates three types of remote resources: energy-only resources (i.e. resources that do not provide any capacity attributes), partial capacity deliverability status, and full capacity deliverability status. EBCE's standard for evaluating long-term resources differentiates between these resource types and denotes a forecasted value for resources based on the resource's self-selected deliverability. The selected level of deliverability, including any necessary network upgrades, is incorporated into a resulting contract, thus developers are required to achieve the level of deliverability originally contemplated and contractually committed to.

While EBCE will not directly participate in development of new bulk transfer lines across the WECC, it plays a part in their development through contracting and the associated signals to transmission developers, as well as participation in this IRP process. As EBCE signs long-term contracts with deliverability requirements, this sends information about the need for and optimal sighting of additional bulk transfer lines to the state agency planning processes and transmission developers. These signals will inform the various public and private planning processes and promote a reliable and robust large-scale transmission system across the Western United States.

IV. Action Plan

EBCE's planning and procurement activities are described below.

a. Proposed Activities

Given guidance from EBCE's Board of Directors and Community Advisory Committee, it is likely that EBCE will pursue a procurement strategy seeking GHG emissions reductions in excess of those contemplated in the 46 MMT portfolio. Model results indicate that executing a larger portion of its portfolio from long-term contracts is the most cost-effective manner for EBCE to achieve greater emissions reductions. The 38 MMT portfolio, though not specifically characterized as EBCE's "preferred portfolio", is likely representative of the minimum level of procurement EBCE will pursue in the near term. Actual procurement strategy and planned procurement will be discussed with EBCE's Community Advisory Committee and members of the environmental stakeholder community, prior to presenting to EBCE's Board of Directors for approval, as described in sections III.B and III.H.

Per the Commission's request, EBCE provides a summary here of procurement plans, potential barriers and resource viability for each resource type selected in the 38 MMT portfolio:

- **2-Hr Battery Storage:** EBCE will launch an RFO later this year, in which 2-hr battery storage will be eligible to participate, provided it is included as part of an offer for an RPS-eligible generating resource.¹⁰ The most cost-effective supply of short-duration storage is currently primarily filled by lithium ion batteries, which are considered a commercially mature technology. At this time, the greatest barriers to incremental 2-hr battery storage is the reduced RA value as compared to the 4-hr battery and the expectation that the QC of Battery Storage resources will be lowered in the future, potentially by shifting to an ELCC approach. While EBCE believes a marginal ELCC would more accurately account for the actual reliability contribution of each new storage resource, uncertainty related to the ELCC or durability of the ELCC of any resource creates risk that procurement executed based on assumed RA value will be deemed uneconomic as a result of these administrative rule changes. The mitigating factor for battery storage is that it is relatively easy to extend battery durations in the future as lithium ion battery cells potentially decrease further in the future.
- **4-Hr Battery Storage:** 4-hr battery storage will also be eligible to participate in EBCE's 2020 RFO. The risks associated with changing QC values is a potential barrier to procurement of this resource type as well.
- **Pumped Storage:** EBCE regards the pumped storage resource type as representative of all potential forms of long-duration energy storage, including pumped hydro. As previously described, EBCE is evaluating responses to the Long-Duration Energy Storage RFI to determine if a follow up RFO is desirable in the near future. Each form of long-duration energy storage has unique barriers, including the novel and untested nature of some technologies, the high cost of many technologies, and the challenging environmental impacts of individual resource types, as is the case with pumped hydro.
- **Large Hydro:** Large hydro, as a non-RPS eligible resource, will not be eligible for participation in EBCE's 2020 RFO, however EBCE will pursue opportunities to transact with these resources in an

¹⁰ EBCE's upcoming plans for procurement are discussed further in section IV.B.

opportunistic manner when existing long-term contracts expire or should utility owners of these resources make their generating capacity available in future solicitations or via offer to EBCE carbon-free energy solicitations. These resources are a mature technology and are viable, although they are limited in their availability to market participants. Risks associated with large hydro include changing ELCCs and the potential for severe drought.

- **Imported Hydro:** Any imported small hydro that meets the definition of California RPS-eligible resources will be able to participate in EBCE's 2020 RFO. EBCE expects the universe of such RPS-eligible resources that are not under contract is small, however all imported hydro will be eligible to participate in future carbon-free energy solicitations. Imported hydro experiences the same barriers and viability challenges as in-state large hydro but also faces the added hurdle of recent CPUC changes to Import RA rules. These recent rule changes create more onerous requirements related to the delivery of energy from out of state resources and have resulted in increased prices and decreased capacity of all imports (fossil, hydro and unspecified) to California LSEs.
- **Biogas:** This resource type faces three primary challenges to contracting with EBCE: the expensive nature of the resource, the lack of known or planned biogas facilities in EBCE's service territory, and potential increase air pollutants. EBCE notes that it does have a preference for generating resources sited within its service territory, thus an Alameda County project may provide some value to partially offset the expense associated with this resource type. However, EBCE has not yet performed thorough analysis to determine the air pollutant emissions associated with biogas resources and if those emissions would be great enough as to counteract any economic benefits of citing a future resource in Alameda County.
- **Biomass:** The expensive nature of the resource, the lack of known or planned biomass facilities, and potential increase air pollutants in EBCE's service territory make it an unlikely candidate for near-term contracting.
- **Geothermal:** While these resources share the barriers of high price and not being located in Alameda County, EBCE hopes to learn about potential additional benefits associated with high capacity factor geothermal resources and technology advancements that may support more flexibility or dispatchability in geothermal resources than has existed to date.
- **Small Hydro:** Small hydro is a mature, viable technology. It faces potential barriers associated with limited resource availability and less operational flexibility than large hydro.
- **Shed DR:** EBCE currently procures much of its Demand Response portfolio through its Local Development team. While EBCE is actively looking for opportunities to incorporate more local demand side resources, regulatory barriers to participation of these resources and policy changes like the introduction of a Centralized Procurement Entity (CPE) for local RA depress the value of DR and create barriers to further procurement.
- **Wind (including out of state):** This is a mature and viable technology. It faces potential barriers associated with low ELCCs and risk of further administrative changes to its ELCC value. Out of state wind faces the additional barrier of long project development timelines.

- **Solar:** This is a mature and viable technology. New solar resources in California face barriers of declining ELCCs and potential curtailment of resources not paired with energy storage during the mid-day hours.

b. Procurement Activities

EBCE anticipates launching an RFO for RPS-eligible long-term resources later in 2020 to address its future compliance obligations and internal RPS procurement needs in exceedance of state compliance requirements. The RFO will address the current shortfall of contracted long-term generation in RPS compliance period four and will identify a preference for projects that can reach COD as early as in 2021 or 2022. In this RFO, EBCE will also evaluate opportunities to execute long-term agreements with existing RPS resources whose current contracts are at or near expiration.

For the 2021-2024 compliance period, EBCE expects to meet state RPS requirements with its existing resources under contract, additional procurement of eligible renewable resources, and renewable energy credit (“REC”) purchases. EBCE will increasingly rely on long-term agreements to meet its RPS goals to meet the requirement that 65% of RPS procurement comes from contracts of 10 or more years.

Participation in future PCIA-related auctions for RPS-eligible resources could impact EBCE’s IRP portfolio. With a decision still pending, however, EBCE has not included any assumptions about PCIA Phase 2 outcomes in its 2020 RPS Plan or in its 46 MMT or 38 MMT conforming IRP portfolios. Rather, EBCE has assumed volumes of planned existing resources consistent with its expectations regarding market availability. EBCE will pursue opportunities to transact with these resources when existing long-term contracts expire or should utility owners of these resources make their generating capacity available in future solicitations or via offer to EBCE carbon-free energy solicitations.

In addition to RPS resources, EBCE plans to procure energy storage to fulfill its commitment to GHG and air pollutant emissions reductions, reliability, and renewable integration. In its upcoming RFO, standalone energy storage and co-located or hybridized storage will be eligible to participate.

EBCE intends to exceed the applicable RPS procurement obligations and CPUC-assigned GHG planning targets over the 10-year planning horizon with the objective of best matching the expected generation profile of its supply to its electricity demand while considering risk factors such as variability in costs for customers. The exact portfolio characteristics selected may vary over time depending on market developments, legislative and policy changes, technological improvements, preferences of the community, or other developments. To manage this future uncertainty, EBCE examines and estimates supply and customer demand, and structures its procurement efforts to balance customer demand with resource commitments.

Finally, EBCE along with several other CCAs, has expressed interest in a multi-CCA Joint Powers Authority to collectively procure large capacity new buildout. EBCE looks forward to continuing these conversations and exploring the potential for such an entity.

IRP Incremental Procurement Milestone #1 Information

Per the emailed *LSE Instructions and Attestation for September 1, 2020 IRP Compliance Filing, R.20-05-003* dated August 13, 2020, EBCE is including information “Milestone #1” information requested in the June 5, 2020 *Administrative Law Judges’ Ruling Seeking Comments on Backstop Procurement and Cost Allocation Mechanisms*.¹¹ EBCE’s compliance with the IRP incremental procurement obligation will be met through a mix of new resources currently under contract and in negotiation. The contracted set of resources is comprised of nine resources, none of which have completed construction yet. REDACTED

REDACTED
REDACTED ¹² A list of EBCE’s contracted resources and their development status follows.

The resources under contract are also included in the Resource Data Templates. The development status is largely the same as was included in the May 6th, 2020 IRP Progress Report update requested by the Energy Division.

Because these are new resources the CAISO IDs for these resources have not yet been established, however EBCE has provided a description of each resource’s location and point of interconnection to help the CPUC differentiate between resources with similar names.

The values below represent EBCE’s estimate of September RA QC for each resource based on the revised Effective Load Carrying Capability percentages defined in R. 17-09-020. The Contract Capacity and resulting QC associated with the Oakland Energy Storage 1 resource has been increased as a result of an Amended and Restated contract between EBCE and the developer. EBCE notes that anticipated QCs are an estimate and are subject to revision.

Table 11: EBCE Procurement Track Project Status

Resource or Site Name	Date of Contract Execution	Resource ID or POI (in lieu of CAISO ID)	Technology Type	Contract Capacity (MW)	Expected September Qualifying Capacity (MW)	Expected COD / IDD
Altamont Winds LLC	7/9/2019	Busbar in Alameda County (Pnode not yet)	Wind	56.2	8	COD: 12/31/2020 IDD: 12/31/2020

¹¹ See also Appendix E, Senior Executive Attestation (D.19-11-016).

¹² *Administrative Law Judges’ Ruling Seeking Comments on Backstop Procurement and Cost Allocation Mechanisms*, June 5, 2020, Rulemaking 20-05-003

		established)				
Rosamond Central	7/26/2019	SCE Whirlwind substation	Solar pv	112	16	COD: 3/31/2020 IDD: 3/31/2021
Tierra Robles Energy Storage	7/19/2019	Oakland L Feeder	Energy Storage (front of meter)	7	7	COD: 12/1/2021 IDD: 12/1/2021
Luciana	6/10/2019	Vestal Substation	Solar pv	55.83	8	COD: 12/31/2021 IDD: 12/31/2021
Oakland Energy Storage 1	6/7/2019	Oakland C substation	Energy Storage (front of meter)	36.25	36	COD: 10/15/2021 IDD: 1/1/2022
Sunrun PDR	7/29/2019	BTM; Oakland, CA	Energy storage (BTM)	.5	.5	COD: 10/18/2021 IDD: 1/1/2022
Raceway Solar North Project	9/25/2019	SCE Antelope substation 220 kV bus	Solar pv + energy storage	solar pv - 125 storage (2 hr) - 80	56 ¹³ (16 solar; 40 storage)	COD: 12/31/2022 IDD: 3/31/2023
Sonrisa Solar Park	6/21/2019	PG&E Tranquility Switching Station 230kV bus	Solar pv + energy storage	solar pv - 100 storage - 30	43 ¹² (13 solar; 30 storage)	COD: 12/31/2022 IDD: 12/31/2022
Edwards Solar II	9/25/2019	Windhub 230 kV	Solar pv	100	14	COD: 12/31/2022 IDD: 12/31/2022 to 3/3/2022

REDACTED

¹³ Calculated based on modified additive methodology adopted in D.20-06-031, which determines effective QC of storage and solar components using 2021 ELCCs. In the Resource Data Templates, the estimated QCs use the ELCCs provided for years 2024-2030.

REDACTED

EBCE currently has nine resources under contract and one contract where EBCE is purchasing incrementally qualifying excess resources, all of which will be meeting our IRP procurement obligation. EBCE is in active negotiations with three other resources, one or some of which will further our contribution to the IRP procurement obligation. EBCE is not aware of any anticipated delays with our projects or contracted resources at this time.

c. Potential Barriers

Key market, regulatory, financial, or other resource viability barriers or risks associated with the renewable resources coming online in EBCE's conforming portfolios include uncertainty regarding the future RA value of renewable and storage resources, changes to the RA construct including the requirements for out of state resources providing RA and the introduction of a CPE for local RA, uncertainty around the cost declines forecasted for wind, solar and battery resources, and viability of long-lead time resources such as out of state or offshore wind. Additionally, uncertainty regarding future voluntary or mandated allocations of RA, GHG-free or RPS energy currently in IOUs' PCIA-eligible portfolios or allocated CAM resources puts LSEs at risk of developing and beginning to execute procurement plans that are not aligned with their eventual allocations. These issues are consistent between both conforming portfolios, however under the 38 MMT scenario a greater volume of EBCE's portfolio would be subject to the risks identified.

The impacts of COVID-19 may affect development timelines. Supply chain issues, labor shortages, and construction delays due to the ongoing crises could result in project delays. Currently, EBCE does not anticipate delays but there is still uncertainty whether COVID-19 will ultimately cause any project disruptions. Due to the widespread nature of COVID-19 impacts, EBCE notes that any potential delays would likely impact broad categories of resources and does not foresee any individual LSE being at a relative disadvantage. The economic uncertainty regarding the aftermath of COVID-19 also introduces load variability. While the long-term effects remain unknown, demand characteristics such as hourly profile, peak load and timing of peak demand may be influenced. EBCE will continue monitoring the status of its ongoing projects and the overall demand and industry trends to better understand these risks.

Key risks associated with the existing resources in the conforming portfolios include unavailability to the broader market or the potential retirement of these resources. This could result in under-procurement of long-term contracts and increased costs associated with filling this position.

Finally, the recently adopted CPE framework could impose some uncertainty for EBCE and its counterparties to appropriately value local resource premiums. The CPE mechanism would also

introduce uncertainty for System and Flex RA compliance product procurement, as LSEs need to consider the allocation of those attributes from the CPE to ensure that their activities do not lead to over-procurement of System and Flex RA resources. As compliance year 2023 approaches, EBCE will need to carefully evaluate its portfolio to manage its RA positions given these risks and uncertainties.

d. Commission Direction or Actions

EBCE appreciates the recent Proposed Decision¹⁴ (PD) granting CalCCA's Petition for Modification of D. 19-11-016, which requested clarification regarding the methodology for determining the qualifying capacity value of hybrid generation and storage resources. EBCE supports the PD's clarification that the counting methodology adopted in D.20-01-004, under Track 2 of R.19-11-019, will be used to assess compliance with the procurement orders required by D. 19-11-016 for all LSEs. If approved, this will provide certainty around the RA value of co-located and hybrid resources will enable more prudent planning towards meeting EBCE's IRP procurement track requirements.

Participation in future PCIA-related auctions, as described in the Final Report of the working group to address portfolio optimization and voluntary auction frameworks for utility portfolio resources, could impact EBCE's RPS portfolio.¹⁵ However, while the report identified consensus proposals for a majority of the Phase 2 Scoping Memo's issues identified, as of the date of this filing, the Commission has not yet issued a decision on Portfolio Optimization and Cost Reduction, Allocation and Auction in the PCIA proceeding. With a decision still pending, EBCE has not included any assumptions about PCIA Phase 2 outcomes in its 2020 IRP. Because future mandated or voluntary allocation of PCIA resources may influence the timing and volumes of EBCE's planned procurement, EBCE asks for timely resolution by the Commission on this issue.

Finally, EBCE looks forward to working with the Commission and staff in Track 3.a of the RA proceeding to address disincentives for BTM investments in light of the recently adopted CPE framework. The uncertainty regarding the local RA value of these investments puts EBCE in a difficult position as it seeks to provide clean, affordable generation to local areas.

e. Diablo Canyon Power Plant Replacement

As discussed in Decision 19-04-040, embedding the planned retirement date of Diablo Canyon Power Plant (DCPP) in the modeling assumptions of each CPUC IRP cycle allows "LSEs collectively to plan for the purchase of power in an orderly fashion to serve the load that was previously served by Diablo Canyon

¹⁴ Proposed Decision of ALJ Fitch, *Grants California Community Choice Association Petition for Modification of Decision 19-11-016*, mailed August 24, 2020.

¹⁵ Final Report of Working Group 3 Co-Chairs: Southern California Edison Company (U-338e), California Community Choice Association, and Commercial Energy, available at: <https://cal-cca.org/wp-content/uploads/2020/02/R1706026-Final-Report-of-WG-3-Co-Chairs.pdf>.

output.” By largely mirroring the resource selection and the pace of additions included in the RSP and 38 MMT system-wide scenarios in its own conforming portfolios, EBCE is ensuring its contribution to replacing DCPD is embedded within its plans. Further, while the amount of baseload, GHG-free generation is not substituted MW for MW by replacement resources, the volume and mix of new resources selected in the RSP and 38-MMT system-wide scenario collectively fill the loss of energy and reliability caused by DCPD retirement due to Resolve’s modeling constraints.

Because of its commitment to procuring clean resources and satisfying system reliability requirements, EBCE can guarantee its replacement resources will not be GHG-emitting. And as demonstrated by the RSP and 38 MMT portfolio, DCPD replacement can be accomplished by a mix of wind, solar, DR and storage resources. EBCE therefore plans to rely on the same set of resource types to substitute for DCPD. However, EBCE recognizes that the production profiles of the new, GHG-free generating resources in its conforming portfolios do not match the baseload generation offered by DCPD and additional measures are needed to ensure replacement power does not result in an overall increase in GHG emissions. To address this, EBCE ensured that the qualifying capacity of new resources added in EBCE’s portfolios exceeded its implied load-share of DCPD’s system RA value over the modeling horizon in both 46 MMT and 38 MMT portfolios. EBCE demonstrated this by calculating the capacity contributions of incremental (i.e. not included in Resolve’s baseline) resources in its portfolios using the System Reliability Progress Tracking table in the Resource Data Template for its 46 MMT and 38 MMT portfolios. In 2022, the NQC of EBCE’s incremental capacity is over 280 MW greater than the implied load-share of DCPD’s RA value in the 46 MMT scenario and over 290 MW in the 38 MMT. By 2026, EBCE’s incremental capacity contributions remain in excess of its implied DCPD share by over 280 MW in the 46 MMT scenario and grow to over 370 MW in the 38 MMT scenario.¹⁶ As further support, EBCE compared the capacity contribution of its incremental resources to its implied load-share of the capacity contribution of the selected resources in the RSP and 38 MMT system-wide scenarios, using the NQC values in the Resource Data Template and again found its portfolios to far exceed its expected capacity contribution. Overall, because EBCE’s conforming portfolios demonstrate new capacity contributions by 2026 that exceed its load-share of the RSP and 38 MMT scenarios, EBCE is ensuring it is prudently planning for DCPD retirement.

V. Lessons Learned

EBCE recognizes and appreciates the enormous effort staff and the Commission have invested in improving the IRP process. Numerous clarifications and enhancements have been made in the 2019-2020 IRP cycle including criteria pollutant calculations and other improvements in the CSP calculator, additional detail in the Resource Data Template and improvements to the Narrative template. In

¹⁶ EBCE’s share of DCPD’s capacity value was derived using the allocation methodology for incremental procurement in D. 19-11-016, whereby LSEs’ responsibilities were determined based on an adjusted share of load after peak allocation by LSE type.

particular, EBCE appreciates the guidance provided to LSEs to ensure uniformity across conforming plans, while still allowing for LSEs to identify alternative portfolios if desired.

Providing this flexibility as well as clarity around allowable deviations is critical to ensuring the aggregation process is meaningful and robust. However, EBCE requests greater upfront certainty in future cycles. Because the guidance surrounding allowable deviations from the assigned GHG target under the 38 MMT scenario was modified well after EBCE had begun its IRP modeling efforts, it was unable to finalize alternative portfolios, including more ambitious GHG reductions targets, for its IRP submission to the Commission. EBCE asks that staff finalize its guidance as early as possible in the portfolio development process to allow LSEs sufficient time to analyze, complete and select their preferred portfolios from a range of meaningful conforming and alternate scenarios. Further, in future IRP studies, EBCE urges the Commission to include representation of the positive correlation between lower GHG portfolios and decreased reliance on system power.

Similarly, EBCE asks that in future IRP cycles more opportunity is provided for incorporating demand-side resources in conforming portfolios. EBCE, alongside many other CCAs, prioritizes DERs deployment to its customers to capture a number of benefits such as community enhanced resiliency, local job creation and targeted criteria pollutant reduction. While the IEPR serves as a valuable baseline against which comparisons should be made, it does not necessarily capture planned or current efforts for all LSEs, and removing the option to include alternative levels of DERs further distances conforming portfolio submissions from actual integrated procurement strategies.

EBCE appreciates the improved coordination between the IRP and overlapping proceedings. However, EBCE has identified several areas where greater alignment in the reporting requirements between the RPS and IRP would greatly improve LSE's ability to provide the Commission with accurate and consistent information across these proceedings. This year, RPS Procurement Plans (RPS Plans) were ultimately due July 6, 2020, two months prior to the submission deadline for IRPs. Despite this misalignment in timing, the RPS Ruling required LSEs demonstrate consistency between the information provided in their RPS Plans and their IRP filings. Further, the requirement of multiple different but prescriptive conforming IRP portfolios implied demonstrating alignment of two levels of potential RPS procurement with their individual RPS Plans. EBCE looks forward to greater alignment between the proceedings and supports staff's efforts to consolidate these planning requirements in the years LSEs file IRPs.

Finally, concern over reliability has risen to the forefront of California's planning processes. EBCE agrees that without well-coordinated, near-term action the state could face a reliability shortfall and commends the Commission and staff for highlighting this important issue. However, while staff provided input that individual LSE's reliability contributions would be closely considered, no upfront system reliability planning standard was implemented. This left LSEs in a difficult position of demonstrating achievement towards an undefined metric. To address this, EBCE evaluated its capacity contribution according to existing RA program metrics and the System Reliability Progress Tracking Tables, and analyzed its severity and timing of market exposure hours. EBCE looks forward to working with the Commission and staff on further developing the appropriate LSE-specific metrics for IRP portfolios in future cycles.

Glossary of Terms

Alternative Portfolio: LSEs are permitted to submit “Alternative Portfolios” developed from scenarios using different assumptions from those used in the Reference System Plan. Any deviations from the “Conforming Portfolio” must be explained and justified.

Approve (Plan): the CPUC’s obligation to approve an LSE’s integrated resource plan derives from Public Utilities Code Section 454.52(b)(2) and the procurement planning process described in Public Utilities Code Section 454.5, in addition to the CPUC obligation to ensure safe and reliable service at just and reasonable rates under Public Utilities Code Section 451.

Balancing Authority Area (CAISO): the collection of generation, transmission, and loads within the metered boundaries of the Balancing Authority. The Balancing Authority maintains load-resource balance within this area.

Baseline resources: Those resources assumed to be fixed as a capacity expansion model input, as opposed to Candidate resources, which are selected by the model and are incremental to the Baseline. Baseline resources are existing (already online) or owned or contracted to come online within the planning horizon. Existing resources with announced retirements are excluded from the Baseline for the applicable years. Being “contracted” refers to a resource holding signed contract/s with an LSE/s for much of its energy and capacity, as applicable, for a significant portion of its useful life. The contracts refer to those approved by the CPUC and/or the LSE’s governing board, as applicable. These criteria indicate the resource is relatively certain to come online. Baseline resources that are not online at the time of modeling may have a failure rate applied to their nameplate capacity to allow for the risk of them failing to come online.

Candidate resource: those resources, such as renewables, energy storage, natural gas generation, and demand response, available for selection in IRP capacity expansion modeling, incremental to the Baseline resources.

Capacity Expansion Model: a capacity expansion model is a computer model that simulates generation and transmission investment to meet forecast electric load over many years, usually with the objective of minimizing the total cost of owning and operating the electrical system. Capacity expansion models can also be configured to only allow solutions that meet specific requirements, such as providing a minimum amount of capacity to ensure the reliability of the system or maintaining greenhouse gas emissions below an established level.

Certify (a Community Choice Aggregator Plan): Public Utilities Code 454.52(b)(3) requires the CPUC to certify the integrated resource plans of CCAs. “Certify” requires a formal act of the Commission to determine that the CCA’s Plan complies with the requirements of the statute and the process established via Public Utilities Code 454.51(a). In addition, the Commission must review the CCA Plans to determine any potential impacts on public utility bundled customers under Public Utilities Code Sections 451 and 454, among others.

Clean System Power (CSP, formerly “Clean Net Short”) methodology: the methodology used to estimate GHG emissions associated with an LSE’s Portfolio based on how the LSE will expect to rely on system power on an hourly basis.

Community Choice Aggregator: a governmental entity formed by a city or county to procure electricity for its residents, businesses, and municipal facilities.

Conforming Portfolio: the LSE portfolio that conforms to IRP Planning Standards, the 2030 LSE-specific GHG Emissions Benchmark, use of the LSE’s assigned load forecast, use of inputs and assumptions matching those used in developing the Reference System Portfolio, as well as other IRP requirements including the filing of a complete Narrative Template, a Resource Data Template and Clean System Power Calculator.

Effective Load Carrying Capacity: a percentage that expresses how well a resource is able avoid loss-of-load events (considering availability and use limitations). The percentage is relative to a reference resource, for example a resource that is always available with no use limitations. It is calculated via probabilistic reliability modeling, and yields a single percentage value for a given resource or grouping of resources.

Electric Service Provider: an entity that offers electric service to a retail or end-use customer, but which does not fall within the definition of an electrical corporation under Public Utilities Code Section 218.

Filing Entity: an entity required by statute to file an integrated resource plan with CPUC.

Future: a set of assumptions about future conditions, such as load or gas prices.

GHG Benchmark (or LSE-specific 2030 GHG Benchmark): the mass-based GHG emission planning targets calculated by staff for each LSE based on the methodology established by the California Air Resources Board and required for use in LSE Portfolio development in IRP.

GHG Planning Price: the systemwide marginal GHG abatement cost associated with achieving a specific electric sector 2030 GHG planning target.

Integrated Resources Planning Standards (Planning Standards): the set of CPUC IRP rules, guidelines, formulas and metrics that LSEs must include in their LSE Plans.

Integrated Resource Planning (IRP) process: integrated resource planning process; the repeating cycle through which integrated resource plans are prepared, submitted, and reviewed by the CPUC

Long term: more than 5 years unless otherwise specified.

Load Serving Entity: an electrical corporation, electric service provider, community choice aggregator, or electric cooperative.

Load Serving Entity (LSE) Plan: an LSE’s integrated resource plan; the full set of documents and information submitted by an LSE to the CPUC as part of the IRP process.

Load Serving Entity (LSE) Portfolio: a set of supply- and/or demand-side resources with certain attributes that together serve the LSE's assigned load over the IRP planning horizon.

Loss of Load Expectation (LOLE): a metric that quantifies the expected frequency of loss-of-load events per year. Loss-of-load is any instance where available generating capacity is insufficient to serve electric demand. If one or more instances of loss-of-load occurring within the same day regardless of duration are counted as one loss-of-load event, then the LOLE metric can be compared to a reference point such as the industry probabilistic reliability standard of "one expected day in 10 years," i.e. an LOLE of 0.1.

Net Qualifying Capacity: Qualifying Capacity reduced, as applicable, based on: (1) testing and verification; (2) application of performance criteria; and (3) deliverability restrictions. The Net Qualifying Capacity determination shall be made by the California ISO pursuant to the provisions of this California ISO Tariff and the applicable Business Practice Manual.

Non-modeled costs: embedded fixed costs in today's energy system (e.g., existing distribution revenue requirement, existing transmission revenue requirement, and energy efficiency program cost).

Nonstandard LSE Plan: type of integrated resource plan that an LSE may be eligible to file if it serves load outside the CAISO balancing authority area.

Optimization: an exercise undertaken in the CPUC's Integrated Resource Planning (IRP) process using a capacity expansion model to identify a least-cost portfolio of electricity resources for meeting specific policy constraints, such as GHG reduction or RPS targets, while maintaining reliability given a set of assumptions about the future. Optimization in IRP considers resources assumed to be online over the planning horizon (baseline resources), some of which the model may choose not to retain, and additional resources (candidate resources) that the model is able to select to meet future grid needs.

Planned resource: any resource included in an LSE portfolio, whether already online or not, that is yet to be procured. Relating this to capacity expansion modeling terms, planned resources can be baseline resources (needing contract renewal, or currently owned/contracted by another LSE), candidate resources, or possibly resources that were not considered by the modeling, e.g., due to the passage of time between the modeling taking place and LSEs developing their plans. Planned resources can be specific (e.g., with a CAISO ID) or generic, with only the type, size and some geographic information identified.

Qualifying capacity: the maximum amount of Resource Adequacy Benefits a generating facility could provide before an assessment of its net qualifying capacity.

Preferred Conforming Portfolio: the conforming portfolio preferred by an LSE as the most suitable to its own needs; submitted to CPUC for review as one element of the LSE's overall IRP plan.

Preferred System Plan: the Commission's integrated resource plan composed of both the aggregation of LSE portfolios (i.e., Preferred System Portfolio) and the set of actions necessary to implement that portfolio (i.e., Preferred System Action Plan).

Preferred System Portfolio: the combined portfolios of individual LSEs within the CAISO, aggregated, reviewed and possibly modified by Commission staff as a proposal to the Commission, and adopted by the Commission as most responsive to statutory requirements per Pub. Util. Code 454.51; part of the Preferred System Plan.

Reference System Plan: the Commission's integrated resource plan that includes an optimal portfolio (Reference System Portfolio) of resources for serving load in the CAISO balancing authority area and meeting multiple state goals, including meeting GHG reduction and reliability targets at least cost.

Reference System Portfolio: the multi-LSE portfolio identified by staff for Commission review and adopted/modified by the Commission as most responsive to statutory requirements per Pub. Util. Code 454.51; part of the Reference System Plan.

Short term: 1 to 3 years (unless otherwise specified).

Staff: CPUC Energy Division staff (unless otherwise specified).

Standard LSE Plan: type of integrated resource plan that an LSE is required to file if it serves load within the CAISO balancing authority area (unless the LSE demonstrates exemption from the IRP process).

OFFICER VERIFICATION FORM

I am the Chief Executive Officer for East Bay Community Energy, a public agency, and am authorized to make this verification on its behalf. The statements in the foregoing document are true to my own knowledge, except as to matters which are therein stated on information or belief, and as to those matters I believe them to be true.

I declare under penalty of perjury that the foregoing is true and correct.

Executed on September 1, 2020 at Oakland, California.

DocuSigned by:

9DF68A3229CF44E

Nicolas Chaset
Chief Executive Officer
East Bay Community Energy
1999 Harrison Street, Suite 800
Oakland, CA 94612

Appendix A

Ascend Fundamental Forecasts



Better models. Better decisions.

ASCEND FUNDAMENTAL FORECASTS

FOR USE IN THE CONFORMING PORTFOLIOS

APPENDIX A

PREPARED FOR:



By:

DAVID MILLAR, DIRECTOR OF RESOURCE PLANNING CONSULTING
BRENT NELSON, PHD, MANAGER OF FORECASTING AND MARKET FUNDAMENTALS

AUGUST 11, 2020

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Introduction

The rapid deployment of renewables in California is causing major changes to CAISO market price dynamics and Ascend expects continued disruption of physical processes and market economics as renewables reach at least 60 percent of system energy over the next decade. Given these fundamental changes, Ascend's long-term forecasts of power prices not only match the dynamics of today but also anticipate the logical conclusions of current trends.

Fundamental forecasts generated by traditional production cost models suffer from a backwards looking paradigm, where gas always sets the marginal price and inexorably increasing gas prices keep the market price of power afloat. In reality, gas and power prices are flat or declining, curtailment of renewables is on the rise, and economic pressure on inflexible thermal and baseload generation is causing power plants that fail to collect enough in resource adequacy contracts to exit the market entirely.

The influx of renewable generation which bids into CAISO with zero or near-zero marginal cost, leads to lower average implied market heat rates (power price divided by gas price). In California, most renewable power is solar generation, which is also changing the hourly price shapes. These shapes show a depression of mid-day prices towards zero and scarcity pricing as the sun sets in the well-known 'duck curve' phenomenon. At the same time, power price volatility has increased sharply, especially in real-time markets, with more intermittent and less predictable generation growing within the supply stack. Ascend's proprietary market simulation software "PowerSIMM" captures these dynamics as part of the model architecture, with specific inputs for power price levels (as monthly on-peak and off-peak price averages), price shapes (by month-hour, by year), and spot price volatilities (input as standard deviation of prices). These inputs, as well as price forecasts for RA and ancillary services are outputs of an internal modeling framework that combines supply and demand fundamentals to generate price forecasts that satisfy the economic principle of long-run equilibrium. The combination of returns from the energy market, ancillary services market, and resource adequacy value will always combine to generate normal returns for a standalone battery entering the market in the future.

Ascend's Forecasts and Methodology

Ascend has developed a fundamental modeling framework to support resource planning activities, purposefully designed to capture the dynamics of structural change in the electricity sector. The framework is shown in Figure 1 below.

Fundamental Modeling Framework

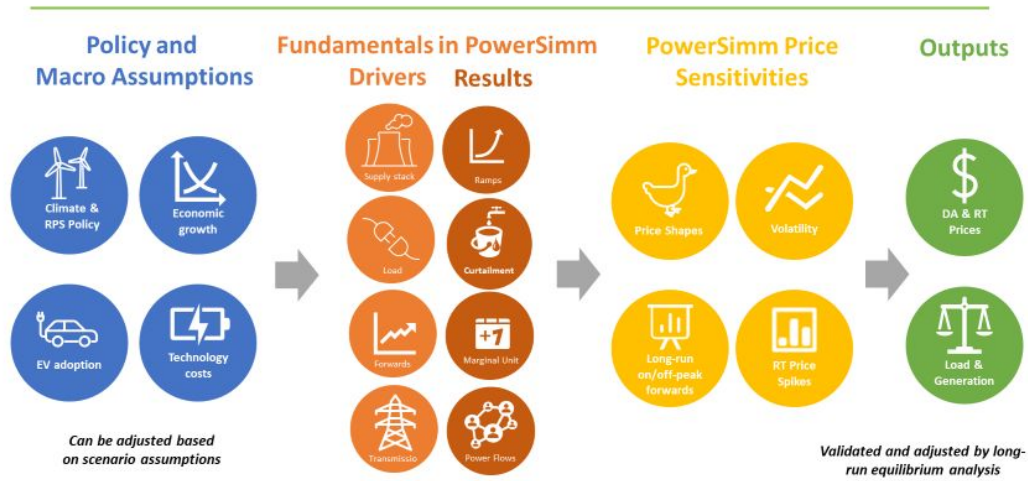


Figure 1: Ascend’s Fundamental Framework

Ascend’s analysis starts with defining macro-level assumptions regarding climate and RPS policy, economic growth, EV adoption, and technology costs. These can be adjusted to generate different future outlooks. For this analysis, climate and RPS policy assumes SB 100 targets and the 46 and 38 MMT carbon scenarios to generate two future views of power prices. Load was assumed to follow the IEPR mid-demand mid-AAEE projections as used in the RESOLVE modeling as were the technology costs for renewables and batteries. Economic growth was not adjusted for COVID-19 effects due to forecast vintage and uncertainty regarding economic recovery in 2020 and beyond. These drivers directly affect the evolution of the supply stack serving the CAISO footprint. **Figure 2** below shows Ascend’s forecast of the CAISO generation mix.

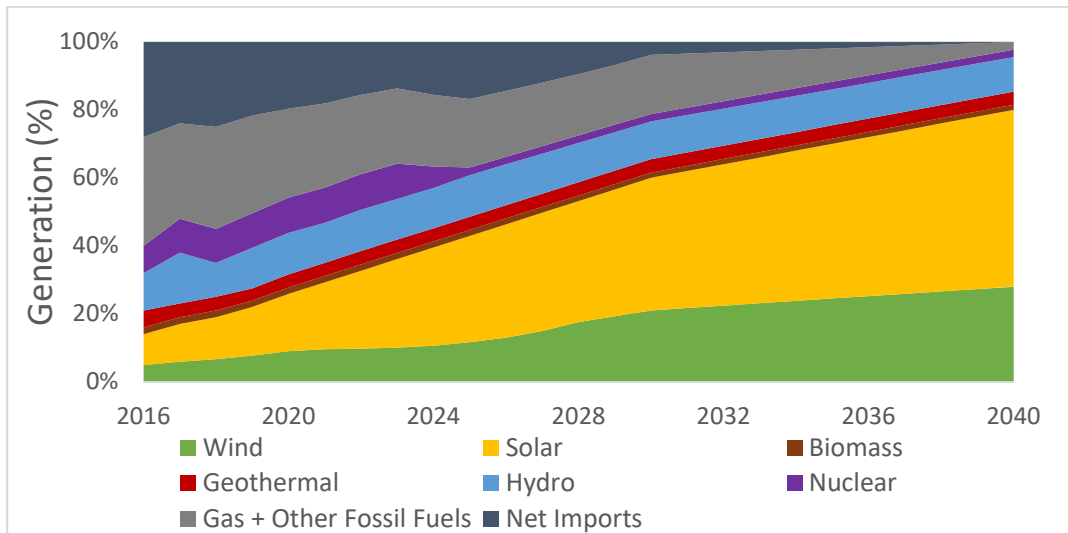


Figure 2: Ascend core projection of the CAISO generation mix

Figure 2 shows a rapid transition from a grid dominated by natural gas to one where solar is the primary energy generator. Wind, geothermal, and hydro provide important complementary energy, especially during nighttime and winter periods. The implications of this transition on prices is shown below.

Changing Market Dynamics

Price Depression and Renewable Penetration Growth

Growth in renewable penetration depresses prices in both the real-time and day-ahead prices, which is caused by two mechanisms:

1. A shifting of the supply stack to the right, pushing lower marginal cost units onto the margin.
2. Renewable curtailment during times of surplus generation, resulting in zero or negative prices.

As renewable penetration rises, the first mechanism results in price depression in line with the slope of the supply stack, as **Figure 3** shows. In addition to the shifting supply stack, the non-dispatchability of intermittent renewables (primarily wind and solar) creates challenges in accommodating forecast uncertainty for both load and renewable generation, as well as maintaining sufficient dispatchable power online at minimum output levels to manage evening ramps as the sun goes down on the solar-heavy CAISO grid. This need to keep dispatchable resources online results in periods of oversupply, causing negative price formation and curtailment of surplus renewable generation. **Figure 4** shows the acceleration of negative price formation at high renewable penetrations. While storage can help manage some of the intermittency of renewable output, Ascend forecasts that the buildout of storage capacity will be insufficient to keep up with the continued growth in renewable deployment and mitigate the net load ramps expected at high renewable penetrations. Curtailment and negative price formation will persist.

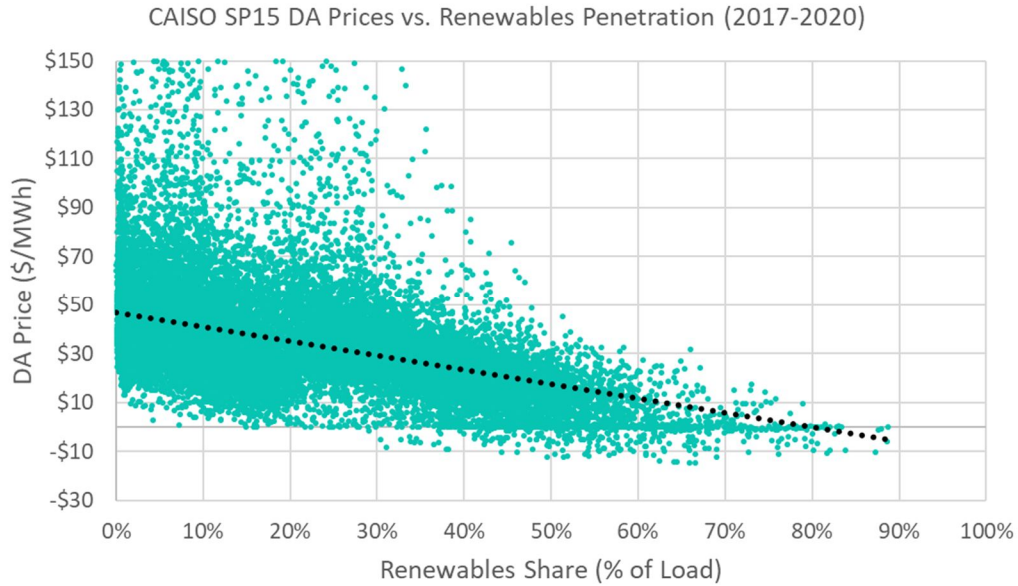


Figure 3. Price depression as a function of renewable penetration.

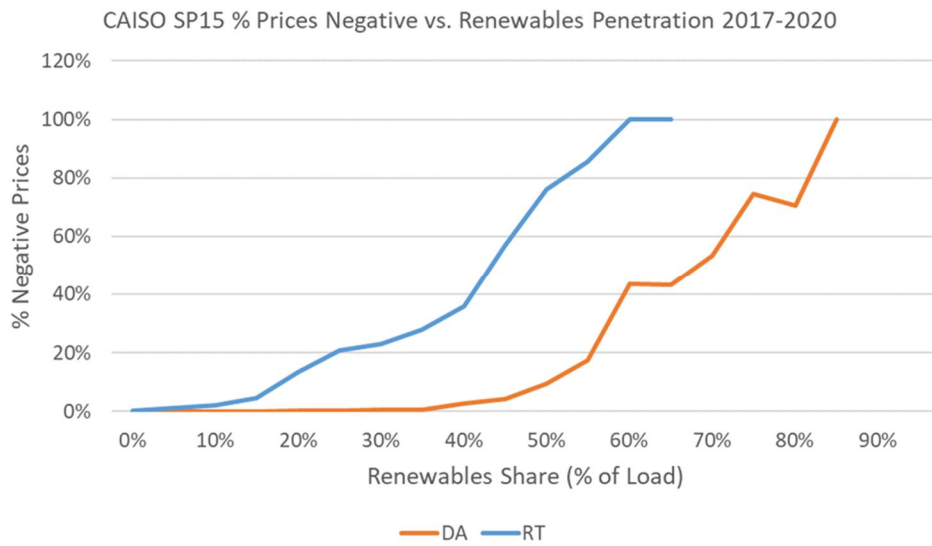


Figure 4. Negative price formation as a function of renewable penetration

Price volatility and Renewable Penetration Growth

While renewables reduce the average price of energy, the intermittency of renewable output drives increased price volatility due to uncertain supply levels. **Figure 5** shows how market price volatility has grown with renewable penetration over time.

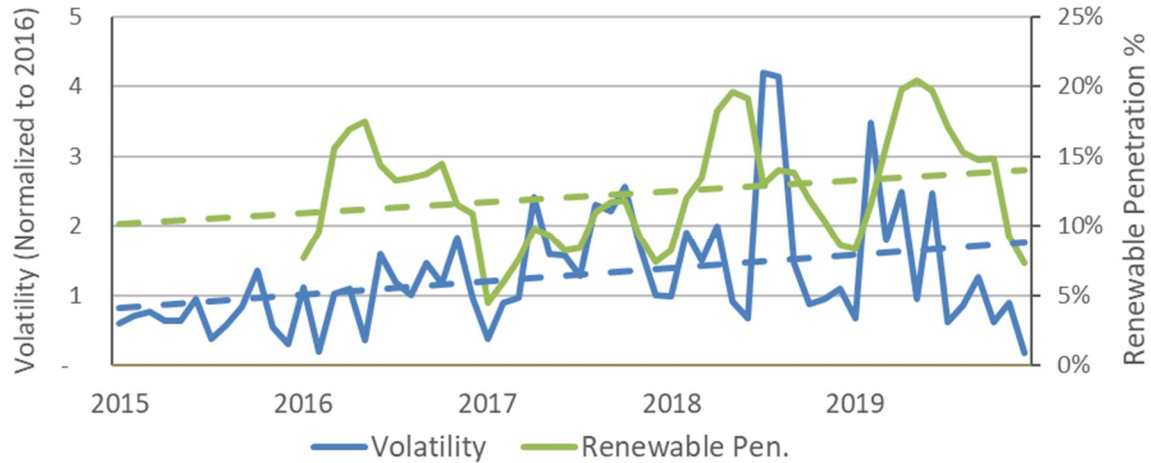


Figure 5. Real-Time (RT) LMP Volatility vs. Renewable Penetration

In general, growing volatility is observed with growing penetration both in the real-time and day-ahead markets year-over-year (**Figure 5**). Volatility fell in 2019 as an outlier year due to historically low demand, with peak load dropping lower than any year before 2004. Volatility in the real-time energy market increased 50% between 2014 and 2018, while the share of energy generated from renewables doubled. The high correlation between renewables and LMP volatility is more striking in the real-time market as RT pricing reflects the supply discrepancies between the day-ahead and real-time markets.

Ascend’s Forecasting Approach

Average monthly Day-Ahead Power Prices

Ascend forecasts begin with market forwards for fuel and power prices over the duration for which they are liquid. Ascend then blends the end of the liquidity period with a long-run forecasting approach that explicitly accounts for the new market dynamics as discussed previously.

The approach for forecasting monthly on/off-peak forwards explicitly accounts for each of the two mechanisms of price depression: shifting of the supply stack and negative price formation during surplus renewable generation. Ascend uses empirical relationships derived from market fundamental modeling for these price depression mechanisms to evolve the modeled implied heat rates, which allows separating the power price impacts of renewable penetration from the impacts of fuel prices. The modeling also incorporates the impact of storage by calculating an adjusted renewable penetration that accounts for the ability of storage to absorb surplus renewable generation. Hourly, monthly, and seasonal variation in renewable generation and load shapes provide a more granular basis for forecasting the renewable curtailment by peak period, month, and year. To account for a variety of structural market characteristics, the implied heat rate forecasts are calibrated and anchored to the end of the market forward period.

The forecasted implied heat rates are then multiplied by the natural gas price forecast to generate an initial power forecast. The natural gas price forecast uses the Pindyck approach,¹ which takes market forward data and then indexes by inflation after the liquidity period. Pindyck’s analysis showed that using this method for natural gas forecasting is more reliable than a fundamentals-based approach, as price changes can drive a variety of unforeseen developments, including efficiency gains, alternative

¹ Pindyck, “The Dynamics of Commodity Spot and Futures Markets: A Primer,” *The Energy Journal*, August 2001

sources, and fuel switching. Ascend’s forecast then calculates a carbon price adder, which is the product of the forecasted carbon price and the monthly carbon intensity forecast, which co-evolves with the implied heat rate forecast.

Day-ahead Shapes and Volatilities

As renewable penetrations rise, the up/down movement in prices becomes important to forecast alongside the monthly averages. Ascend forecasts day-ahead price volatilities, defined as standard deviation in price divided by the mean, at the monthly level. Price shapes are also forecasted at the monthly level, providing 24-hour price shapes. Ascend’s shape forecast evolves historical price shapes forward to track with changes in net load that are caused by evolution in load shape (due to forecasted electric vehicle adoption, building electrification, energy efficiency, and behind-the-meter solar and storage deployment) and changes to renewable generation deployment.

Price Basis

Figure 6 shows that the price bases from load centers to renewable generation pockets can both be significant and change over time. To model price differences from a given node to a market hub, Ascend begins with a structural model of the price basis between the node and hub. This structural model incorporates historical correlations with weather, renewable generation, and load characteristics.

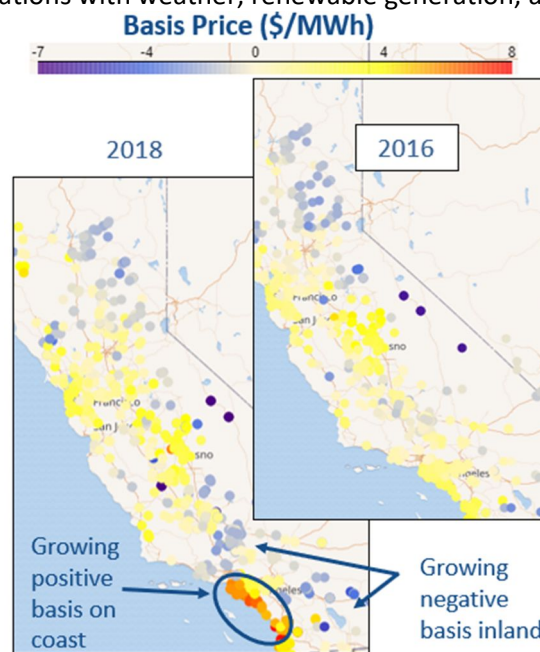


Figure 6. Changing basis in CAISO

In addition to the structural basis model that is determined from historical patterns, Ascend forecasts long-term trajectories for this nodal basis and the nodal volatility, considering regional patterns in interconnection queues, planned transmission, population growth, and geographic constraints.

Day-ahead Ancillary Service Prices

Ascend’s ancillary service price forecasts explicitly consider that storage is so well-suited to providing ancillary services that they will begin to set prices as their deployment grows. In the long-run, Ascend expects ancillary service prices to reflect the opportunity cost of not providing real-time energy

arbitrage within a given time interval. Thus, regulation prices will be highest during periods of high expected real-time price volatility, and low during periods of low expected real-time price volatility. Because providing spin does not preclude providing real-time energy under current rules, Ascend forecasts that spin prices will be very low to reflect their lack of opportunity cost. Ascend forecasts the time period over which prices decline from their current levels to these long-run equilibrium levels by considering the depth of the ancillary services markets and the forecasted deployment of storage.

Average Annual Capacity Prices

Ascend’s capacity price forecast assumes that the marginal new capacity unit will be a storage resource. This assumption is based on renewable policy mandates, stakeholder opposition to the construction of new thermal resources, low capacity values for wind and solar generation, and limited resource availability for new carbon-free generation with high capacity values (hydro, geothermal). In the near-term, Ascend also considers the impact of expected retirements of thermal capacity due to age and OTC policies. In the medium- and long-term, Ascend evolves capacity prices forward in-line with the forecasted cost trajectory for storage. Ascend also accounts for the declining ELCC of storage as storage deployment increases, which increases the storage duration required for full capacity credit.

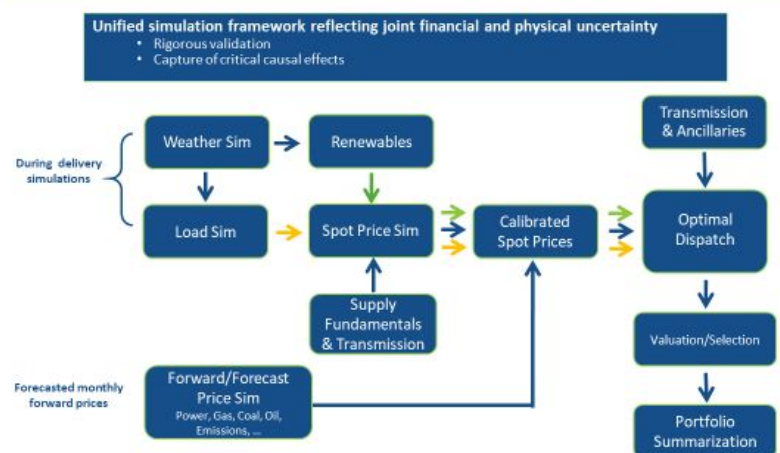
Ascend’s Price Simulations

While the forecasting approach described above focuses on monthly trajectories for market forecasts, Ascend’s simulation infrastructure generates sets of stochastic simulations of hourly and sub-hourly prices that are calibrated to these monthly forecasts.

Ascend blends the long-term fundamental driven view with the liquid portion of the forward market, as we take the position that fundamental modeling cannot improve upon the wisdom of market interactions. PowerSIMM is considered a ‘hybrid’ model because it combines market data with structured modeling and intuitive reasoning about the future evolution of the market undergoing dramatic and rapid changes.

The diagram to the right shows Ascend’s price formation modeling framework in the PowerSimm platform. PowerSimm first simulates weather, which drives both load and renewable generation. Together, these factors drive spot price simulations, which are simulated at the hourly and sub-hourly time scales. The simulated spot prices are scaled so that the average of all simulated spot prices equal the input on-peak/off-peak monthly forward price. In addition to average on-peak and off-peak power prices, Ascend ensures that simulated prices are calibrated to the inputs described previously, which are critical for appropriate asset valuation:

PowerSimm Modeling Framework



- **Average 24-hour price shapes (by month and weekday/end):** Price shapes are critical for reflecting the changing value of renewable generation resources at high penetrations and for capturing the value of flexible resources that can alter their output in response to changes in price.
- **Average on-peak and off-peak power price volatilities:** Similar to price shapes, volatilities determine how much up/down movement is expected in prices rather than considering only the average value.
- **Sub-hourly (real-time) price volatility:** Real-time price spikes can be significant sources of revenue for flexible resources, with storage able to benefit from both negative and positive price spikes, and positive price spikes often being much larger in magnitude than day-ahead prices. As renewable penetrations increase, real-time price volatility also increases.
- **Ancillary service prices:** Ancillary service prices can be a significant revenue stream, particularly for storage, and are sensitive both to renewable penetration and storage deployment.
- **Basis:** Price differences between market hubs and project locations can be particularly stark in areas saturated with renewables, and these price differences strongly correlate with the generation profile of the resources. Ascend builds structural models that correlate the basis price with weather and renewable generation to avoid overvaluing renewable resources in saturated markets.

Price Forecast Outputs

Monthly Forwards

Ascend forecasts that the combination of decreasing implied heat rates from growing renewable penetration, inflation in fuel prices (**Figure 7**), and growing carbon prices, will cause power prices at SP-15 to stay relatively flat in nominal terms, as **Figure 8** shows. To align the IRP analysis with CPUC default assumptions, Ascend used the mid gas prices listed in the CPUC inputs assumptions, while maintaining a monthly variation consistent with market forwards. These higher gas prices resulted in a power price forecast that was similarly elevated relative to the default Ascend forecast.

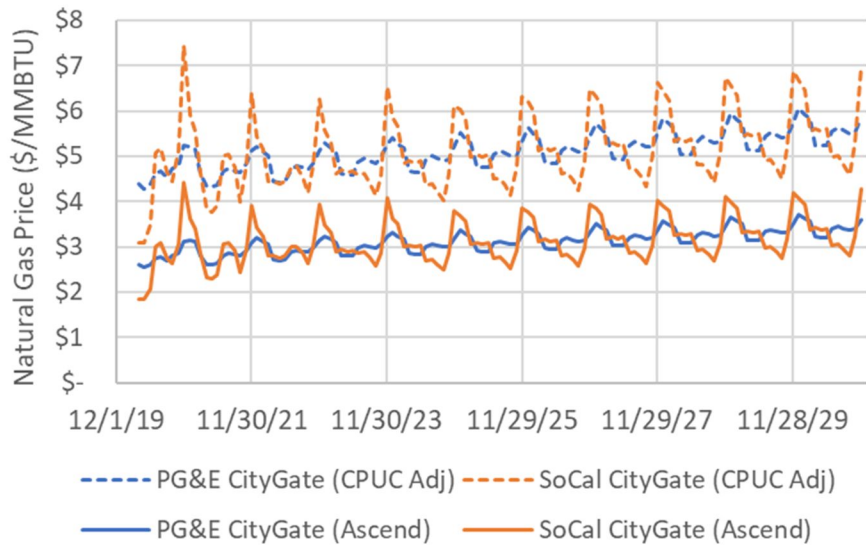


Figure 7. Ascend forecast for north and south CAISO natural gas prices compared to CPUC assumptions



Figure 8. Default and CPUC-adjusted Ascend monthly forward forecast for SP-15 and NP-15

Monthly Volatilities and Shapes

Ascend’s forecasted monthly volatilities are shown in **Figure 9**. The forecasted volatility reflects historical patterns, with volatility highest in the spring and fall months where net load is lowest. Ascend projects that the volatility will grow in the early 2020s with rising renewable penetrations, before declining in the late 2020s with storage deployment. In the 2030s, Ascend expects the volatility to remain stable with balanced growth in both renewables and storage.

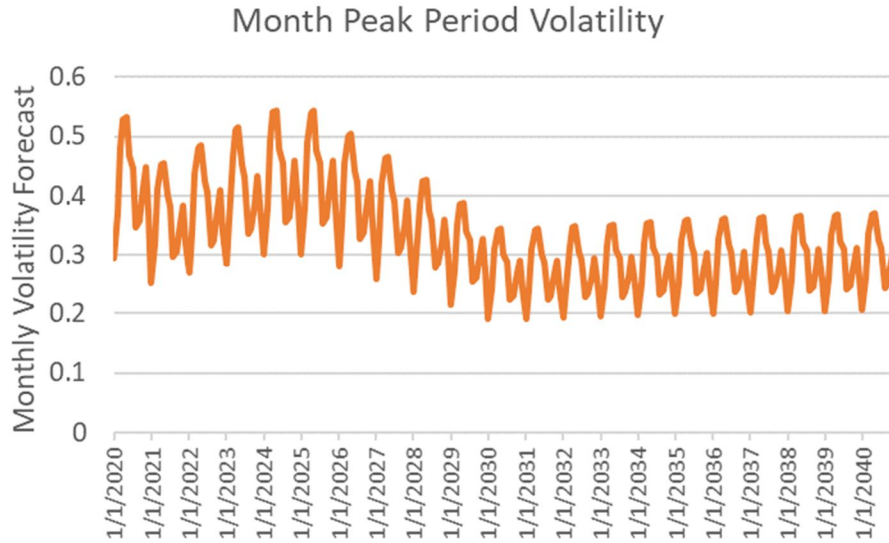


Figure 9. Ascend monthly volatility forecast

Ascend’s forecasted monthly shapes are shown in **Figure 10**. Ascend forecasts price shapes to become increasingly ‘ducky’ throughout the 2020s, with low prices particularly pronounced during the daylight hours in the spring and fall shoulder seasons.

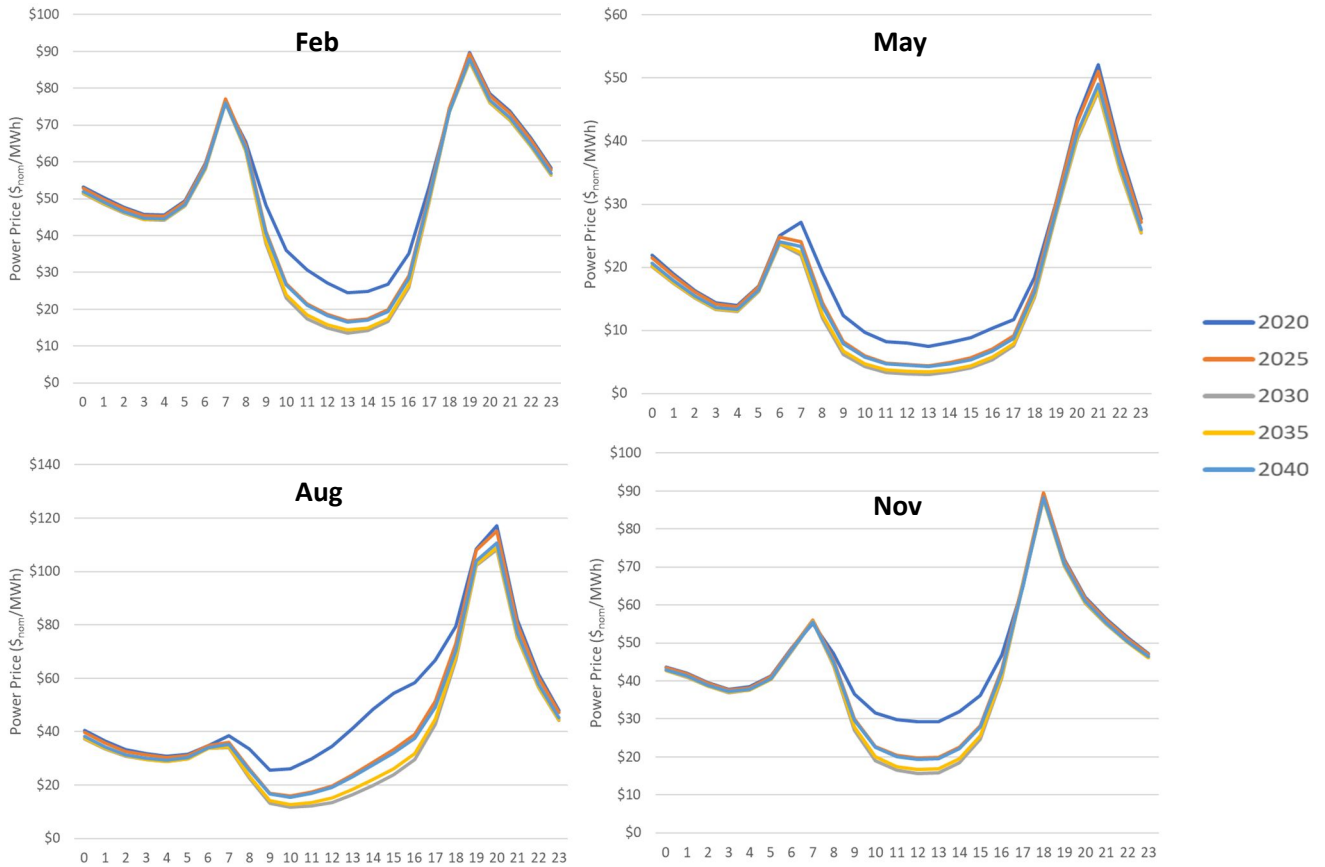


Figure 10. Hourly price shape forecast for select months and years

Ancillary Services Price Forecast

Figure 11 shows that regulation and spinning reserve prices are anticipated to decline from historical levels. Retiring thermal plants and entering flexible generation saturates the ancillary services market, putting downward pressure on mean prices.

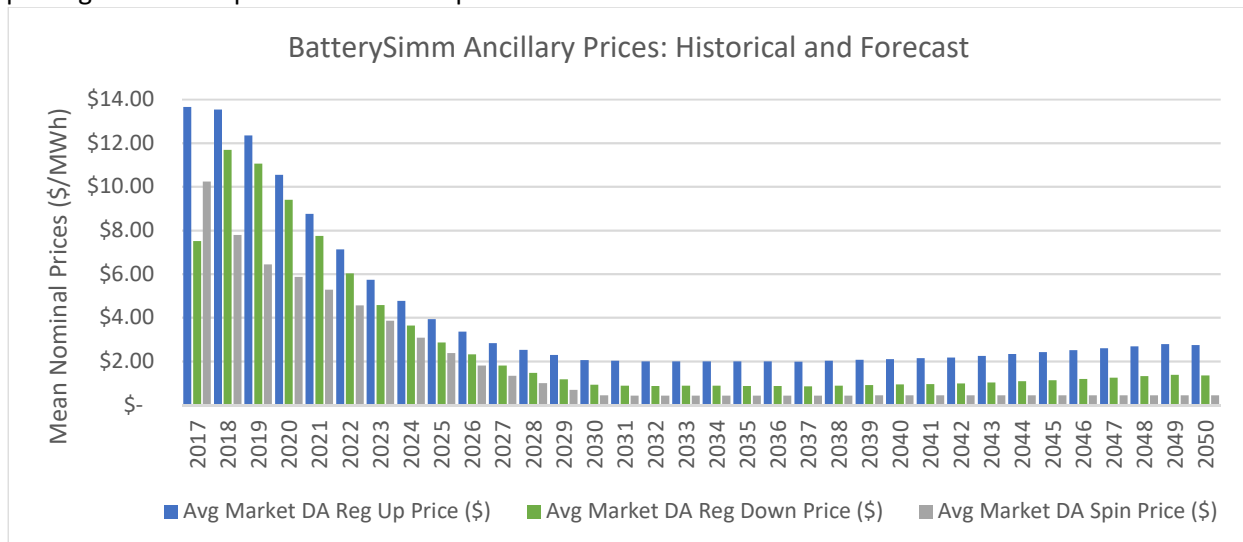


Figure 11. Ascend DA regulation and DA spinning reserves price forecast

Over time, ancillary markets are going to reflect the opportunity cost of providing energy. Ascend forecasts spin prices to decline to current non-spin levels because it carries no opportunity costs and batteries can perform spin obligations at zero marginal costs. Given the shallowness of the regulation market, Ascend forecasts that the market will quickly saturate with storage, causing rapid declines in value. Providing regulation precludes providing energy, so regulation prices can either decline to the marginal costs or the opportunity cost of energy arbitrage, rather than declining to zero, as **Figure 12** shows.

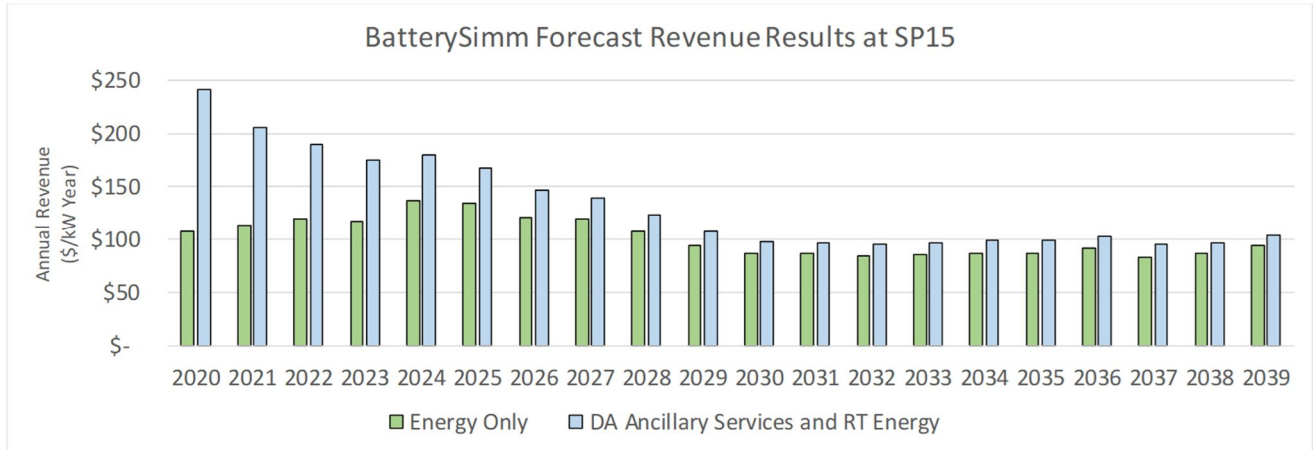


Figure 12. Ascend ancillary services price forecast

Super-peak regulation is the most resistant to price movements as it carries the largest opportunity costs with the high value of energy arbitrage during these hours. In contrast, off-peak and solar-peak regulation prices are more heavily exposed to BESS saturation of the ancillary market since the opportunity cost of lost arbitrage opportunities is minimal during these periods.

Resource Adequacy Price Forecast

Historical resource adequacy (RA) prices increased in recent years due to retirements of baseload thermal generation and diminishing effective load carrying capacity (ELCC) of solar generation. As described above, Ascend forecasts that future resource adequacy prices will be driven by BESS capital costs, with near-term RA price declines due to reductions in BESS capital costs.

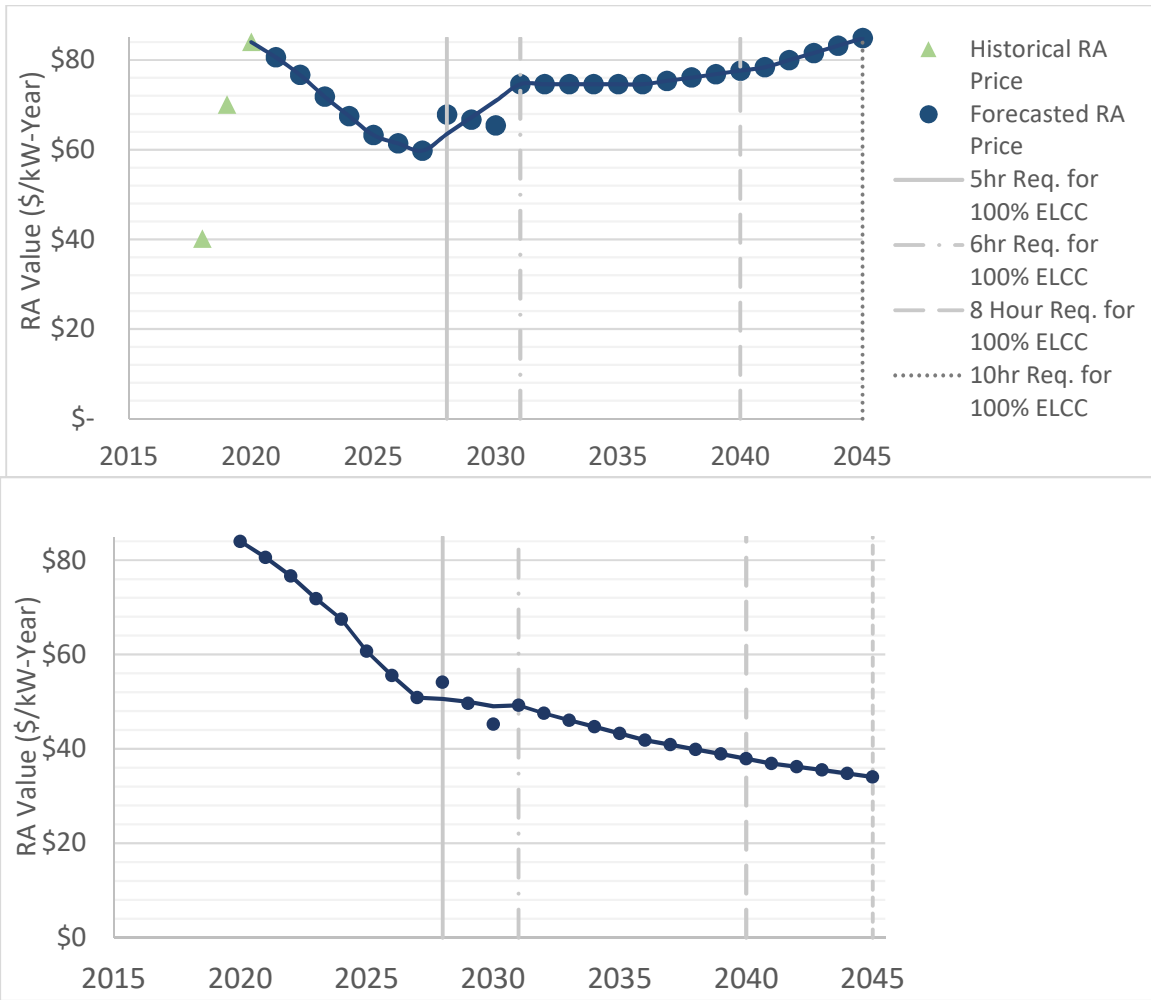


Figure 13. 100% ELCC Resource Adequacy Historical and Forecasted Capacity Value (top) and RA value for a 4h storage resource (bottom)

Shown in **Figure 13**, as battery penetration increases, the effective capacity value decreases, increasing the duration required to get full RA value. Therefore, Ascend expects the RA price to rise as more battery duration is required for full RA value, offsetting the cost reductions for the batteries. **Figure 13** also shows the RA value that would be realized by a four-hour storage resource.

Appendix B

Clean System Power Calculators - 38 MMT and 46 MMT

Accessible here:

https://ebce.org/uploads/csp_46mmt_june_2020_ebce.xlsx

https://ebce.org/uploads/csp_38mmt_june_2020_ebce.xlsx

Please see concurrently filed Notice of Availability for further information.

**BEFORE THE PUBLIC UTILITIES COMMISSION OF THE
STATE OF CALIFORNIA**

Order Instituting Rulemaking to Continue
Electric Integrated Resource Planning and
Related Procurement Processes.

Rulemaking 20-05-003
(Filed May 7, 2020)

**NOTICE OF AVAILABILITY OF EAST BAY
COMMUNITY ENERGY
APPENDIX B OF 2020 INTEGRATED RESOURCE PLAN
(PUBLIC VERSION)**

Pursuant to California Public Utilities Commission (“Commission”) Rules of Practice and Procedure 1.9(d), East Bay Community Energy (“EBCE”) hereby provides this Notice of Availability of Appendix B that supports its 2020 Integrated Resource Plan (“EBCE IRP”), which is being filed concurrently with this Notice. Appendix B includes the Clean System Power (CSP) Calculators for both the 46 MMT and 38 MMT portfolios.

To access Appendix B from EBCE’s website, utilize the following URLs:

- https://ebce.org/uploads/csp_46mmt_june_2020_ebce.xlsx
- https://ebce.org/uploads/csp_38mmt_june_2020_ebce.xlsx

EBCE’s Appendix B may be accessed through EBCE’s website electronically within one day of this e-mail service. If you have any questions about the above documents please contact Dan Lieberman (dlieberman@ebce.org).

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Respectfully submitted,

/s/

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September 1, 2020

Attorneys for East Bay Community Energy

Appendix C

Resource Data Template - 38 MMT

(Public Version)

38 <--- Select your MMT here using the dropdown.
Do not change other cells in this tab.

38 MMT Portfolio
46 MMT Portfolio

Form 1.5b - STATEWIDE
 California Energy Demand 2019-2030 Managed Forecast - Mid Demand / Mid AEE Case
 1-in-2 Net Electricity Peak Demand by Agency and Balancing Authority (MW)

Balancing Authority	Agency	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	Average Annual Growth (2019-2030)	CAISO area Non-IOU,CCA,ESP demand flag
	PG&E Service Area - Greater Bay Area	7,223	7,113	6,970	6,926	6,902	6,898	6,922	6,951	6,977	7,032	7,025	7,062	-0.20%	
	NCPA - Greater Bay Area	198	194	190	188	186	186	186	186	186	187	186	188	-0.49%	1
	Power Enterprise of the San Francisco PUC	125	123	120	118	117	117	117	117	117	118	118	118	-0.49%	1
	Silicon Valley Power	530	542	540	546	553	562	569	570	570	573	571	575	0.75%	1
	Other NP15 LSEs - Bay Area	5	5	5	5	5	5	5	5	5	5	5	5	-0.69%	1
	CDWR - Greater Bay Area	55	55	57	57	57	57	56	56	56	56	56	60	0.92%	1
	WAPA - Greater Bay Area	52	52	52	52	52	52	52	52	52	52	52	52	0.00%	1
	Greater Bay Area Subtotal	8,188	8,083	7,933	7,892	7,873	7,876	7,907	7,937	7,964	8,023	8,013	8,061	-0.14%	
	PG&E Service Area - Non Bay Area	9,955	9,803	9,606	9,545	9,513	9,507	9,540	9,580	9,616	9,691	9,682	9,734	-0.20%	
	NCPA - Non Bay Area	211	207	202	200	199	198	198	198	199	200	199	200	-0.49%	1
	Other NP15 LSEs - Non Bay Area	7	7	7	7	7	7	7	7	7	7	7	7	-0.49%	1
	CDWR - Non Bay Area	55	55	57	57	57	57	56	56	56	56	56	60	0.92%	1
	WAPA - Non Bay Area	185	185	185	185	185	185	185	185	185	185	185	185	0.00%	1
	Total North of Path 15	18,602	18,341	17,991	17,886	17,832	17,829	17,893	17,964	18,026	18,161	18,142	18,247	-0.17%	
	PG&E Service Area - ZP26	2,047	2,016	1,975	1,963	1,956	1,956	1,962	1,970	1,977	1,993	1,991	2,002	-0.20%	
	CDWR - ZP26	115	115	120	120	120	120	119	118	118	118	118	127	0.92%	1
	WAPA - ZP26	15	15	15	15	15	15	15	15	15	15	15	15	0.00%	1
	Total Zone Path 26	2,177	2,146	2,110	2,097	2,091	2,090	2,095	2,103	2,111	2,126	2,124	2,144	-0.14%	
	Total Valley	12,591	12,403	12,167	12,091	12,050	12,043	12,081	12,130	12,173	12,265	12,253	12,330	-0.19%	
	Total North of Path 26 (Total PG&E TAC Area)	20,779	20,486	20,100	19,983	19,923	19,919	19,988	20,067	20,137	20,287	20,266	20,391	-0.17%	
	Turlock Irrigation District	543	535	531	530	528	528	524	524	524	524	524	524	-0.27%	
	Merced	109	108	107	107	106	106	106	106	106	106	106	106	-0.27%	
	Total Turlock Irrigation District Control Area	652	643	638	637	634	633	630	630	629	630	631	633	-0.27%	
	SMUD	2,959	2,916	2,899	2,897	2,890	2,881	2,870	2,861	2,861	2,869	2,862	2,895	-0.20%	
	Modesto Irrigation District	674	664	659	658	656	654	652	651	650	651	652	654	-0.27%	
	Roseville	325	321	318	318	316	316	315	314	314	314	315	316	-0.27%	
	Redding	221	217	216	215	215	214	213	213	213	213	213	214	-0.27%	
	City of Shasta Lake	35	34	34	34	34	34	33	33	33	33	33	34	-0.27%	
	WAPA (BANC)	90	90	90	90	90	90	90	90	90	90	90	90	0.00%	
	Total Balancing Authority of Northern California Control Area	4,304	4,242	4,215	4,211	4,200	4,188	4,174	4,163	4,161	4,171	4,186	4,202	-0.22%	
	SCE Service Area - LA Basin	16,297	16,109	15,975	15,861	15,850	15,796	15,753	15,749	15,769	15,789	15,883	16,027	-0.15%	
	Anaheim	526	520	515	512	511	509	508	508	509	509	511	509	-0.15%	1
	Pasadena Water and Power	273	270	267	265	265	264	264	264	264	264	264	266	-0.15%	1
	Riverside	594	587	582	578	577	575	574	574	574	575	579	584	-0.15%	1
	Vernon	149	147	147	147	149	149	149	149	149	149	149	171	1.26%	1
	Other SP15 LSEs - LA Basin	246	243	241	240	239	239	238	238	238	239	240	242	-0.15%	1
	MWD - LA Basin	20	20	20	20	20	20	20	20	20	20	20	20	0.00%	1
	LA Basin Subtotal	18,104	17,895	17,771	17,645	17,633	17,572	17,525	17,521	17,542	17,565	17,669	17,829	-0.14%	
	SCE Service Area - Big Creek/Ventura	3,996	3,950	3,917	3,889	3,886	3,873	3,862	3,861	3,866	3,871	3,894	3,929	-0.15%	
	CDWR - Big Creek/Ventura	290	275	275	275	275	275	275	276	276	303	303	303	0.40%	1
	Big Creek/Ventura Subtotal	4,286	4,224	4,192	4,164	4,161	4,148	4,137	4,142	4,142	4,174	4,197	4,233	-0.11%	
	SCE Service Area - Other	1,010	999	990	983	983	979	977	976	977	979	985	993	-0.15%	
	Other SP15 LSEs - Other	26	26	25	25	25	25	25	25	25	25	25	25	-0.15%	1
	CDWR - Other	47	45	45	45	45	45	45	45	45	50	50	50	0.40%	1
	MWD - Other	163	154	154	154	154	154	154	154	154	171	171	172	0.45%	1
	Total SCE TAC Area	23,637	23,343	23,177	23,015	23,000	22,923	22,862	22,859	22,886	22,964	23,097	23,301	-0.13%	
	SDG&E TAC Area	4,194	4,138	4,158	4,194	4,224	4,250	4,273	4,292	4,313	4,334	4,354	4,373	0.38%	
	Valley Electric Association (CA + NV Territory)	133	145	153	156	159	161	164	166	169	171	173	176	2.53%	
	Total South of Path 26	27,964	27,625	27,488	27,366	27,383	27,334	27,299	27,317	27,368	27,469	27,625	27,850	-0.04%	
	LADWP	5,787	5,696	5,608	5,555	5,450	5,368	5,246	5,160	5,059	4,992	4,940	4,872	-1.55%	
	Burbank	286	284	284	285	283	282	281	279	279	279	281	283	-0.11%	
	Glendale	297	295	294	294	292	291	290	289	289	291	291	293	-0.11%	
	Total LADWP Control Area	6,370	6,275	6,186	6,135	6,028	5,942	5,818	5,729	5,627	5,561	5,512	5,448	-1.41%	
	Imperial Irrigation District Control Area	1,071	1,056	1,045	1,037	1,030	1,024	1,019	1,017	1,017	1,020	1,026	1,033	-0.33%	
	Total California ISO Noncoincident Peak	48,743	48,112	47,589	47,349	47,306	47,253	47,287	47,384	47,505	47,757	47,891	48,241	-0.09%	
	Total California ISO Coincident Peak	46,117	45,647	45,184	45,280	45,447	45,610	45,827	46,011	46,227	46,493	46,702	47,016	0.18%	
	Total STATEWIDE Noncoincident Peak	61,141	60,327	59,673	59,369	59,198	59,040	58,299	58,293	58,940	59,138	59,246	59,558	-0.24%	
	Total STATEWIDE Coincident Peak	57,848	57,236	56,658	56,775	56,872	56,987	57,109	57,216	57,354	57,572	57,776	58,045	0.03%	

119 net peak demand values for each BA area. Includes the impact of IOU load-modifying demand response programs. within a BA area is adjusted to be coincident with the respective BA area net peak demand total.

Your LSE's 2021 System RA allocation, NQC MW here. This will be kept **REDACTED**

	2,020	2,021	2,022	2,023	2,024	2,025	2,026	2,027	2,028	2,029	2,030
CAISO area Non-IOU,CCA,ESP non-coincident demand	3,985	3,997	3,988	3,992	3,995	3,999	4,004	4,009	4,068	4,077	4,120
CAISO area IOU,CCA,ESP non-coincident demand	44,127	43,592	43,361	43,314	43,259	43,288	43,380	43,496	43,689	43,813	44,121
coincident adjustment	95%	95%	96%	96%	97%	97%	97%	97%	97%	98%	97%
CAISO area IOU,CCA,ESP coincident demand	41,866	41,389	41,466	41,612	41,754	41,951	42,123	42,326	42,533	42,726	43,000

Your LSE's estimated percent of CAISO area IOU,CCA,ESP coincident demand **REDACTED**

Your LSE's estimated system RA requirement, NQC MW

REDACTED

EBCE	new_generic_wind	2027	4	10	1	planned_new	none	42	CAISO_Wind	0	wind_low_cf	wind_low_cf_2027_4	36%	1	15.2421066	15.2421066	ok	new_generic	1	1	new_generic_wind_name	0	0
EBCE	new_generic_wind	2027	5	11	1	planned_new	none	42	CAISO_Wind	0	wind_low_cf	wind_low_cf_2027_5	36%	1	15.2421066	15.2421066	ok	new_generic	1	1	new_generic_wind_name	0	0
EBCE	new_generic_wind	2027	6	12	1	planned_new	none	42	CAISO_Wind	0	wind_low_cf	wind_low_cf_2027_6	33%	1	20.11558071	20.11558071	ok	new_generic	1	1	new_generic_wind_name	0	0
EBCE	new_generic_wind	2027	7	9	1	planned_new	none	42	CAISO_Wind	0	wind_low_cf	wind_low_cf_2027_7	33%	1	14.02273807	14.02273807	ok	new_generic	1	1	new_generic_wind_name	0	0
EBCE	new_generic_wind	2027	8	8	1	planned_new	none	42	CAISO_Wind	0	wind_low_cf	wind_low_cf_2027_8	30%	1	12.80336954	12.80336954	ok	new_generic	1	1	new_generic_wind_name	0	0
EBCE	new_generic_wind	2027	9	8	1	planned_new	none	42	CAISO_Wind	0	wind_low_cf	wind_low_cf_2027_9	22%	1	9.14532956	9.14532956	ok	new_generic	1	1	new_generic_wind_name	0	0
EBCE	new_generic_wind	2027	10	9	1	planned_new	none	42	CAISO_Wind	0	wind_low_cf	wind_low_cf_2027_10	12%	1	4.877474112	4.877474112	ok	new_generic	1	1	new_generic_wind_name	0	0
EBCE	new_generic_wind	2027	11	7	1	planned_new	none	42	CAISO_Wind	0	wind_low_cf	wind_low_cf_2027_11	17%	1	7.316211168	7.316211168	ok	new_generic	1	1	new_generic_wind_name	0	0
EBCE	new_generic_wind	2027	12	11	1	planned_new	none	42	CAISO_Wind	0	wind_low_cf	wind_low_cf_2027_12	19%	1	7.325895442	7.325895442	ok	new_generic	1	1	new_generic_wind_name	0	0
EBCE	new_generic_wind	2028	1	20	1	planned_new	none	84	CAISO_Wind	0	wind_low_cf	wind_low_cf_2028_1	17%	1	17.0468485	17.0468485	ok	new_generic	1	1	new_generic_wind_name	0	0
EBCE	new_generic_wind	2028	2	20	1	planned_new	none	84	CAISO_Wind	0	wind_low_cf	wind_low_cf_2028_2	17%	1	14.61401558	14.61401558	ok	new_generic	1	1	new_generic_wind_name	0	0
EBCE	new_generic_wind	2028	3	18	1	planned_new	none	84	CAISO_Wind	0	wind_low_cf	wind_low_cf_2028_3	41%	1	34.0993697	34.0993697	ok	new_generic	1	1	new_generic_wind_name	0	0
EBCE	new_generic_wind	2028	4	20	1	planned_new	none	84	CAISO_Wind	0	wind_low_cf	wind_low_cf_2028_4	44%	1	38.1592498	38.1592498	ok	new_generic	1	1	new_generic_wind_name	0	0
EBCE	new_generic_wind	2028	5	22	1	planned_new	none	84	CAISO_Wind	0	wind_low_cf	wind_low_cf_2028_5	36%	1	30.4458658	30.4458658	ok	new_generic	1	1	new_generic_wind_name	0	0
EBCE	new_generic_wind	2028	6	20	1	planned_new	none	84	CAISO_Wind	0	wind_low_cf	wind_low_cf_2028_6	48%	1	40.18854286	40.18854286	ok	new_generic	1	1	new_generic_wind_name	0	0
EBCE	new_generic_wind	2028	7	18	1	planned_new	none	84	CAISO_Wind	0	wind_low_cf	wind_low_cf_2028_7	33%	1	28.01019654	28.01019654	ok	new_generic	1	1	new_generic_wind_name	0	0
EBCE	new_generic_wind	2028	8	16	1	planned_new	none	84	CAISO_Wind	0	wind_low_cf	wind_low_cf_2028_8	30%	1	25.57452727	25.57452727	ok	new_generic	1	1	new_generic_wind_name	0	0
EBCE	new_generic_wind	2028	9	16	1	planned_new	none	84	CAISO_Wind	0	wind_low_cf	wind_low_cf_2028_9	22%	1	18.26751948	18.26751948	ok	new_generic	1	1	new_generic_wind_name	0	0
EBCE	new_generic_wind	2028	10	18	1	planned_new	none	84	CAISO_Wind	0	wind_low_cf	wind_low_cf_2028_10	12%	1	9.742677056	9.742677056	ok	new_generic	1	1	new_generic_wind_name	0	0
EBCE	new_generic_wind	2028	11	14	1	planned_new	none	84	CAISO_Wind	0	wind_low_cf	wind_low_cf_2028_11	17%	1	14.61401558	14.61401558	ok	new_generic	1	1	new_generic_wind_name	0	0
EBCE	new_generic_wind	2028	12	12	1	planned_new	none	84	CAISO_Wind	0	wind_low_cf	wind_low_cf_2028_12	19%	1	15.8185022	15.8185022	ok	new_generic	1	1	new_generic_wind_name	0	0
EBCE	new_generic_wind	2029	1	30	1	planned_new	none	126	CAISO_Wind	0	wind_low_cf	wind_low_cf_2029_1	20%	1	25.54231438	25.54231438	ok	new_generic	1	1	new_generic_wind_name	0	0
EBCE	new_generic_wind	2029	2	30	1	planned_new	none	126	CAISO_Wind	0	wind_low_cf	wind_low_cf_2029_2	17%	1	21.89341224	21.89341224	ok	new_generic	1	1	new_generic_wind_name	0	0
EBCE	new_generic_wind	2029	3	17	1	planned_new	none	126	CAISO_Wind	0	wind_low_cf	wind_low_cf_2029_3	41%	1	51.0682856	51.0682856	ok	new_generic	1	1	new_generic_wind_name	0	0
EBCE	new_generic_wind	2029	4	30	1	planned_new	none	126	CAISO_Wind	0	wind_low_cf	wind_low_cf_2029_4	36%	1	45.6112755	45.6112755	ok	new_generic	1	1	new_generic_wind_name	0	0
EBCE	new_generic_wind	2029	5	33	1	planned_new	none	126	CAISO_Wind	0	wind_low_cf	wind_low_cf_2029_5	36%	1	45.6112755	45.6112755	ok	new_generic	1	1	new_generic_wind_name	0	0
EBCE	new_generic_wind	2029	6	30	1	planned_new	none	126	CAISO_Wind	0	wind_low_cf	wind_low_cf_2029_6	48%	1	60.2068856	60.2068856	ok	new_generic	1	1	new_generic_wind_name	0	0
EBCE	new_generic_wind	2029	7	27	1	planned_new	none	126	CAISO_Wind	0	wind_low_cf	wind_low_cf_2029_7	23%	1	41.9623746	41.9623746	ok	new_generic	1	1	new_generic_wind_name	0	0
EBCE	new_generic_wind	2029	8	24	1	planned_new	none	126	CAISO_Wind	0	wind_low_cf	wind_low_cf_2029_8	30%	1	38.31347142	38.31347142	ok	new_generic	1	1	new_generic_wind_name	0	0
EBCE	new_generic_wind	2029	9	24	1	planned_new	none	126	CAISO_Wind	0	wind_low_cf	wind_low_cf_2029_9	22%	1	27.3667653	27.3667653	ok	new_generic	1	1	new_generic_wind_name	0	0
EBCE	new_generic_wind	2029	10	21	1	planned_new	none	126	CAISO_Wind	0	wind_low_cf	wind_low_cf_2029_10	12%	1	14.59284616	14.59284616	ok	new_generic	1	1	new_generic_wind_name	0	0
EBCE	new_generic_wind	2029	11	21	1	planned_new	none	126	CAISO_Wind	0	wind_low_cf	wind_low_cf_2029_11	17%	1	21.89341224	21.89341224	ok	new_generic	1	1	new_generic_wind_name	0	0
EBCE	new_generic_wind	2029	12	13	1	planned_new	none	126	CAISO_Wind	0	wind_low_cf	wind_low_cf_2029_12	19%	1	23.71786326	23.71786326	ok	new_generic	1	1	new_generic_wind_name	0	0
EBCE	new_generic_wind	2030	1	40	1	planned_new	none	170	CAISO_Wind	0	wind_low_cf	wind_low_cf_2030_1	20%	1	34.418921	34.418921	ok	new_generic	1	1	new_generic_wind_name	0	0
EBCE	new_generic_wind	2030	2	17	1	planned_new	none	170	CAISO_Wind	0	wind_low_cf	wind_low_cf_2030_2	17%	1	29.5014792	29.5014792	ok	new_generic	1	1	new_generic_wind_name	0	0
EBCE	new_generic_wind	2030	3	36	1	planned_new	none	170	CAISO_Wind	0	wind_low_cf	wind_low_cf_2030_3	40%	1	68.83678443	68.83678443	ok	new_generic	1	1	new_generic_wind_name	0	0
EBCE	new_generic_wind	2030	4	40	1	planned_new	none	170	CAISO_Wind	0	wind_low_cf	wind_low_cf_2030_4	36%	1	61.46141467	61.46141467	ok	new_generic	1	1	new_generic_wind_name	0	0
EBCE	new_generic_wind	2030	5	36	1	planned_new	none	170	CAISO_Wind	0	wind_low_cf	wind_low_cf_2030_5	41%	1	61.46141467	61.46141467	ok	new_generic	1	1	new_generic_wind_name	0	0
EBCE	new_generic_wind	2030	6	40	1	planned_new	none	170	CAISO_Wind	0	wind_low_cf	wind_low_cf_2030_6	48%	1	81.1290736	81.1290736	ok	new_generic	1	1	new_generic_wind_name	0	0
EBCE	new_generic_wind	2030	7	36	1	planned_new	none	170	CAISO_Wind	0	wind_low_cf	wind_low_cf_2030_7	33%	1	56.54450149	56.54450149	ok	new_generic	1	1	new_generic_wind_name	0	0
EBCE	new_generic_wind	2030	8	32	1	planned_new	none	170	CAISO_Wind	0	wind_low_cf	wind_low_cf_2030_8	30%	1	51.6758832	51.6758832	ok	new_generic	1	1	new_generic_wind_name	0	0
EBCE	new_generic_wind	2030	9	36	1	planned_new	none	170	CAISO_Wind	0	wind_low_cf	wind_low_cf_2030_9	12%	1	36.8748668	36.8748668	ok	new_generic	1	1	new_generic_wind_name	0	0
EBCE	new_generic_wind	2030	10	36	1	planned_new	none	170	CAISO_Wind	0	wind_low_cf	wind_low_cf_2030_10	12%	1	19.66765269	19.66765269	ok	new_generic	1	1	new_generic_wind_name	0	0
EBCE	new_generic_wind	2030	11	28	1	planned_new	none	170	CAISO_Wind	0	wind_low_cf	wind_low_cf_2030_11	17%	1	29.50147924	29.50147924	ok	new_generic	1	1	new_generic_wind_name	0	0
EBCE	new_generic_wind	2030	12	30	1	planned_new	none	170	CAISO_Wind	0	wind_low_cf	wind_low_cf_2030_12	19%	1	31.90593563	31.90593563	ok	new_generic	1	1	new_generic_wind_name	0	0
EBCE	themr_CA_Desert_Southern_NV_Solar	2022	1	33	1	planned_new	Desert Solar Project	205	CAISO_Solar	0	solar_2022_1	4%	1	8.2	8.2	ok	new_resolve	1	1	"_CA_Desert_Southern_NV_Solar_Desert Solar	1	15	
EBCE	themr_CA_Desert_Southern_NV_Solar	2022	2	36	1	planned_new	Desert Solar Project	205	CAISO_Solar	0	solar_2022_2	3%	1	6.15	6.15	ok	new_resolve	1	1	"_CA_Desert_Southern_NV_Solar_Desert Solar	0	0	
EBCE	themr_CA_Desert_Southern_NV_Solar	2022	3	49	1	planned_new	Desert Solar Project	205	CAISO_Solar	0	solar_2022_3	18%	1	36.9	36.9	ok	new_resolve	1	1	"_CA_Desert_Southern_NV_Solar_Desert Solar	0	0	
EBCE	themr_CA_Desert_Southern_NV_Solar	2022	4	30	1	planned_new	Desert Solar Project	205	CAISO_Solar	0	solar_2022_4	15%	1	30.75	30.75	ok	new_resolve	1	1	"_CA_Desert_Southern_NV_Solar_Desert Solar	0	0	
EBCE	themr_CA_Desert_Southern_NV_Solar	2022	5	14	1	planned_new	Desert Solar Project	205	CAISO_Solar	0	solar_2022_5	16%	1	32.8	32.8	ok	new_resolve	1	1	"_CA_Desert_Southern_NV_Solar_Desert Solar	0	0	
EBCE	themr_CA_Desert_Southern_NV_Solar	2022	6	63	1	planned_new	Desert Solar Project	205	CAISO_Solar	0	solar_2022_6	31%	1	63.55	63.55	ok	new_resolve	1	1	"_CA_Desert_Southern_NV_Solar_Desert Solar	0	0	
EBCE	themr_CA_Desert_Southern_NV_Solar	2022	7	17	1	planned_new	Desert Solar Project	205	CAISO_Solar	0	solar_2022_7	39%	1	79.95	79.95	ok	new_resolve	1	1	"_CA_Desert_Southern_NV_Solar_Desert Solar	0	0	
EBCE	themr_CA_Desert_Southern_NV_Solar	2022	8	54	1	planned_new	Desert Solar Project	205	CAISO_Solar	0	solar_2022_8	27%	1	55.35	55.35	ok	new_resolve	1	1	"_CA_Desert_Southern_NV_Solar_Desert Solar	0	0	
EBCE	themr_CA_Desert_Southern_NV_Solar	2022	9	47	1	planned_new	Desert Solar Project	205	CAISO_Solar	0	solar_2022_9	14%	1	28.7	28.7	ok	new_resolve	1	1	"_CA_Desert_Southern_NV_Solar_Desert Solar	0	0	
EBCE	themr_CA_Desert_Southern_NV_Solar	2022	10	43	1	planned_new	Desert Solar Project	205	CAISO_Solar	0	solar_2022_10	2%	1	4.1	4.1	ok	new_resolve	1	1	"_CA_Desert_Southern_NV_Solar_Desert Solar	0	0	
EBCE	themr_CA_Desert_Southern_NV_Solar	2022	11	30	1	planned_new	Desert Solar Project	205	CAISO_Solar	0	solar_2022_11	0%	1	0	0	ok	new_resolve	1	1	"_CA_Desert_Southern_NV_Solar_Desert Solar	0	0	
EBCE	themr_CA_Desert_Southern_NV_Solar	2022	12	30	1	planned_new	Desert Solar Project	205	CAISO_Solar	0	solar_2022_12	0%	1	0	0	ok	new_resolve	1	1	"_CA_Desert_Southern_NV_Solar_Desert Solar	0	0	
EBCE	themr_CA_Desert_Southern_NV_Solar	2023	1	33	1	planned_new	Desert Solar Project	205	CAISO_Solar	0	solar_2023_1	4%	1	8.2	8.2	ok	new_resolve	1	1	"_CA_Desert_Southern_NV_Solar_Desert Solar	0	0	
EBCE	themr_CA_Desert_Southern_NV_Solar	2023	2	36	1	planned_new	Desert Solar Project	205	CAISO_Solar	0	solar_2023_2	3%	1	6.15	6.15	ok	new_resolve	1	1	"_CA_Desert_Southern_NV_Solar_Desert Solar	0	0	
EBCE	themr_CA_Desert_Southern_NV_Solar	2023	3	49	1	planned_new	Desert Solar Project	205	CAISO_Solar	0	solar_2023_3	18%	1	36.9	36.9	ok	new_resolve	1	1	"_CA_Desert_Southern_NV_Solar_Desert Solar	0	0	
EBCE	themr_CA_Desert_Southern_NV_Solar	2023	4	30	1	planned_new	Desert Solar Project	205	CAISO_Solar	0	solar_2023_4	15%	1	30.75	30.75	ok	new_resolve	1	1	"_CA_Desert_Southern_NV_Solar_Desert Solar	0	0	
EBCE	themr_CA_Desert_Southern_NV_Solar	2023	5	14	1	planned_new	Desert Solar Project	205	CAISO_Solar	0	solar_2023_5	16%	1	32.8	32.8	ok	new_resolve	1	1	"_CA_Desert_Southern_NV_Solar_Desert Solar	0	0	
EBCE	themr_CA_Desert_Southern_NV_Solar	2023	6	63	1	planned_new	Desert Solar Project	205	CAISO_Solar	0	solar_2023_6	31%	1	63.55									

Agency	City	Year	Month	Day	Category	Priority	Project Name	Area	System	Model	Capacity	Status	Notes	Agency	City	Year	Month	Day	Category	Priority	Project Name	Area	System	Model	Capacity	Status	Notes
EBCE	Sonoma	2030	5	33	34	development	4	CA Solar Park VI	100	CAISO_Solar	0	solar	solar_2030_5	5%	1	#N/A	34,13927549	ok	physical	1	1	Sonoma_CA Solar Park VI	0	0			
EBCE	Sonoma	2030	6	36	35	development	4	CA Solar Park VI	100	CAISO_Solar	0	solar	solar_2030_6	10%	1	#N/A	35,190165	ok	physical	1	1	Sonoma_CA Solar Park VI	0	0			
EBCE	Sonoma	2030	8	37	40	development	4	CA Solar Park VI	100	CAISO_Solar	0	solar	solar_2030_8	10%	1	#N/A	40,14349341	ok	physical	1	1	Sonoma_CA Solar Park VI	0	0			
EBCE	Sonoma	2030	8	36	43	development	4	CA Solar Park VI	100	CAISO_Solar	0	solar	solar_2030_8	9%	1	#N/A	42,66798866	ok	physical	1	1	Sonoma_CA Solar Park VI	0	0			
EBCE	Sonoma	2030	9	39	39	development	4	CA Solar Park VI	100	CAISO_Solar	0	solar	solar_2030_9	5%	1	#N/A	38,78095122	ok	physical	1	1	Sonoma_CA Solar Park VI	0	0			
EBCE	Sonoma	2030	11	34	34	development	4	CA Solar Park VI	100	CAISO_Solar	0	solar	solar_2030_11	3%	1	#N/A	34,24338827	ok	physical	1	1	Sonoma_CA Solar Park VI	0	0			
EBCE	Sonoma	2030	11	20	34	development	4	CA Solar Park VI	100	CAISO_Solar	0	solar	solar_2030_11	1%	1	#N/A	30,48868072	ok	physical	1	1	Sonoma_CA Solar Park VI	0	0			
EBCE	Sonoma	2030	12	15	30	development	4	CA Solar Park VI	100	CAISO_Solar	0	solar	solar_2030_12	0%	1	#N/A	30,33105004	ok	physical	1	1	Sonoma_CA Solar Park VI	0	0			
EBCE	Luciana	2021	1	0	26	1	development	0	0	CAISO_Solar	56	solar	solar_2021_1	4%	1	2,232	26,25	ok	physical	0	2	Luciana_Tulane Solar Center	1	78			
EBCE	Luciana	2021	9	0	0	1	development	0	0	CAISO_Solar	56	solar	solar_2021_9	2%	1	1,674	16,74	ok	physical	0	1	Luciana_Tulane Solar Center	0	0			
EBCE	Luciana	2021	3	0	0	1	development	0	0	CAISO_Solar	56	solar	solar_2021_3	18%	1	10,044	10,044	ok	physical	0	1	Luciana_Tulane Solar Center	0	0			
EBCE	Luciana	2021	4	0	0	1	development	0	0	CAISO_Solar	56	solar	solar_2021_4	15%	1	8,37	8,37	ok	physical	0	1	Luciana_Tulane Solar Center	0	0			
EBCE	Luciana	2021	6	0	0	1	development	0	0	CAISO_Solar	56	solar	solar_2021_6	16%	1	8,928	8,928	ok	physical	0	1	Luciana_Tulane Solar Center	0	0			
EBCE	Luciana	2021	6	0	0	1	development	0	0	CAISO_Solar	56	solar	solar_2021_6	31%	1	17,298	17,298	ok	physical	0	1	Luciana_Tulane Solar Center	0	0			
EBCE	Luciana	2021	7	0	0	1	development	0	0	CAISO_Solar	56	solar	solar_2021_7	39%	1	21,762	21,762	ok	physical	0	1	Luciana_Tulane Solar Center	0	0			
EBCE	Luciana	2021	8	0	0	1	development	0	0	CAISO_Solar	56	solar	solar_2021_8	27%	1	15,066	15,066	ok	physical	0	1	Luciana_Tulane Solar Center	0	0			
EBCE	Luciana	2021	9	0	0	1	development	0	0	CAISO_Solar	56	solar	solar_2021_9	14%	1	7,812	7,812	ok	physical	0	1	Luciana_Tulane Solar Center	0	0			
EBCE	Luciana	2021	10	0	0	1	development	0	0	CAISO_Solar	56	solar	solar_2021_10	2%	1	1,116	1,116	ok	physical	0	1	Luciana_Tulane Solar Center	0	0			
EBCE	Luciana	2021	11	0	0	1	development	0	0	CAISO_Solar	56	solar	solar_2021_11	2%	1	1,116	1,116	ok	physical	0	1	Luciana_Tulane Solar Center	0	0			
EBCE	Luciana	2021	12	0	0	1	development	0	0	CAISO_Solar	56	solar	solar_2021_12	0%	1	0	0	ok	physical	0	1	Luciana_Tulane Solar Center	0	0			
EBCE	Luciana	2022	1	7	0	1	development	0	0	CAISO_Solar	56	solar	solar_2022_1	4%	1	2,232	2,232	ok	physical	1	1	Luciana_Tulane Solar Center	0	0			
EBCE	Luciana	2022	2	8	0	1	development	0	0	CAISO_Solar	56	solar	solar_2022_2	3%	1	1,674	1,674	ok	physical	1	1	Luciana_Tulane Solar Center	0	0			
EBCE	Luciana	2022	3	14	0	1	development	0	0	CAISO_Solar	56	solar	solar_2022_3	18%	1	10,044	10,044	ok	physical	1	1	Luciana_Tulane Solar Center	0	0			
EBCE	Luciana	2022	4	15	0	1	development	0	0	CAISO_Solar	56	solar	solar_2022_4	15%	1	8,37	8,37	ok	physical	1	1	Luciana_Tulane Solar Center	0	0			
EBCE	Luciana	2022	5	17	0	1	development	0	0	CAISO_Solar	56	solar	solar_2022_5	16%	1	8,928	8,928	ok	physical	1	1	Luciana_Tulane Solar Center	0	0			
EBCE	Luciana	2022	6	18	0	1	development	0	0	CAISO_Solar	56	solar	solar_2022_6	31%	1	17,298	17,298	ok	physical	1	1	Luciana_Tulane Solar Center	0	0			
EBCE	Luciana	2022	7	19	0	1	development	0	0	CAISO_Solar	56	solar	solar_2022_7	39%	1	21,762	21,762	ok	physical	1	1	Luciana_Tulane Solar Center	0	0			
EBCE	Luciana	2022	8	19	0	1	development	0	0	CAISO_Solar	56	solar	solar_2022_8	27%	1	15,066	15,066	ok	physical	1	1	Luciana_Tulane Solar Center	0	0			
EBCE	Luciana	2022	9	15	0	1	development	0	0	CAISO_Solar	56	solar	solar_2022_9	14%	1	7,812	7,812	ok	physical	1	1	Luciana_Tulane Solar Center	0	0			
EBCE	Luciana	2022	10	14	0	1	development	0	0	CAISO_Solar	56	solar	solar_2022_10	2%	1	1,116	1,116	ok	physical	1	1	Luciana_Tulane Solar Center	0	0			
EBCE	Luciana	2022	11	9	0	1	development	0	0	CAISO_Solar	56	solar	solar_2022_11	0%	1	0	0	ok	physical	1	1	Luciana_Tulane Solar Center	0	0			
EBCE	Luciana	2022	12	8	0	1	development	0	0	CAISO_Solar	56	solar	solar_2022_12	0%	1	0	0	ok	physical	1	1	Luciana_Tulane Solar Center	0	0			
EBCE	Luciana	2023	1	8	0	1	development	0	0	CAISO_Solar	56	solar	solar_2023_1	4%	1	2,232	2,232	ok	physical	1	1	Luciana_Tulane Solar Center	0	0			
EBCE	Luciana	2023	2	8	0	1	development	0	0	CAISO_Solar	56	solar	solar_2023_2	3%	1	1,674	1,674	ok	physical	1	1	Luciana_Tulane Solar Center	0	0			
EBCE	Luciana	2023	3	12	0	1	development	0	0	CAISO_Solar	56	solar	solar_2023_3	18%	1	10,044	10,044	ok	physical	1	1	Luciana_Tulane Solar Center	0	0			
EBCE	Luciana	2023	4	14	0	1	development	0	0	CAISO_Solar	56	solar	solar_2023_4	15%	1	8,37	8,37	ok	physical	1	1	Luciana_Tulane Solar Center	0	0			
EBCE	Luciana	2023	5	17	0	1	development	0	0	CAISO_Solar	56	solar	solar_2023_5	16%	1	8,928	8,928	ok	physical	1	1	Luciana_Tulane Solar Center	0	0			
EBCE	Luciana	2023	6	18	0	1	development	0	0	CAISO_Solar	56	solar	solar_2023_6	31%	1	17,298	17,298	ok	physical	1	1	Luciana_Tulane Solar Center	0	0			
EBCE	Luciana	2023	7	19	0	1	development	0	0	CAISO_Solar	56	solar	solar_2023_7	39%	1	21,762	21,762	ok	physical	1	1	Luciana_Tulane Solar Center	0	0			
EBCE	Luciana	2023	8	18	0	1	development	0	0	CAISO_Solar	56	solar	solar_2023_8	27%	1	15,066	15,066	ok	physical	1	1	Luciana_Tulane Solar Center	0	0			
EBCE	Luciana	2023	9	15	0	1	development	0	0	CAISO_Solar	56	solar	solar_2023_9	14%	1	7,812	7,812	ok	physical	1	1	Luciana_Tulane Solar Center	0	0			
EBCE	Luciana	2023	10	12	0	1	development	0	0	CAISO_Solar	56	solar	solar_2023_10	2%	1	1,116	1,116	ok	physical	1	1	Luciana_Tulane Solar Center	0	0			
EBCE	Luciana	2023	11	10	0	1	development	0	0	CAISO_Solar	56	solar	solar_2023_11	2%	1	1,116	1,116	ok	physical	1	1	Luciana_Tulane Solar Center	0	0			
EBCE	Luciana	2023	12	7	0	1	development	0	0	CAISO_Solar	56	solar	solar_2023_12	0%	1	0	0	ok	physical	1	1	Luciana_Tulane Solar Center	0	0			
EBCE	Luciana	2024	1	8	0	1	development	0	0	CAISO_Solar	56	solar	solar_2024_1	4%	1	2,232	2,232	ok	physical	1	1	Luciana_Tulane Solar Center	0	0			
EBCE	Luciana	2024	2	11	0	1	development	0	0	CAISO_Solar	56	solar	solar_2024_2	3%	1	1,674	1,674	ok	physical	1	1	Luciana_Tulane Solar Center	0	0			
EBCE	Luciana	2024	3	14	0	1	development	0	0	CAISO_Solar	56	solar	solar_2024_3	16%	1	8,72515057	8,72515057	ok	physical	1	1	Luciana_Tulane Solar Center	0	0			
EBCE	Luciana	2024	4	14	0	1	development	0	0	CAISO_Solar	56	solar	solar_2024_4	13%	1	7,27099214	7,27099214	ok	physical	1	1	Luciana_Tulane Solar Center	0	0			
EBCE	Luciana	2024	5	18	0	1	development	0	0	CAISO_Solar	56	solar	solar_2024_5	14%	1	7,75569829	7,75569829	ok	physical	1	1	Luciana_Tulane Solar Center	0	0			
EBCE	Luciana	2024	6	19	0	1	development	0	0	CAISO_Solar	56	solar	solar_2024_6	27%	1	15,0264904	15,0264904	ok	physical	1	1	Luciana_Tulane Solar Center	0	0			
EBCE	Luciana	2024	7	20	0	1	development	0	0	CAISO_Solar	56	solar	solar_2024_7	34%	1	18,9049396	18,9049396	ok	physical	1	1	Luciana_Tulane Solar Center	0	0			
EBCE	Luciana	2024	8	19	0	1	development	0	0	CAISO_Solar	56	solar	solar_2024_8	23%	1	13,0877659	13,0877659	ok	physical	1	1	Luciana_Tulane Solar Center	0	0			
EBCE	Luciana	2024	9	15	0	1	development	0	0	CAISO_Solar	56	solar	solar_2024_9	2%	1	6,786286	6,786286	ok	physical	1	1	Luciana_Tulane Solar Center	0	0			
EBCE	Luciana	2024	10	13	0	1	development	0	0	CAISO_Solar	56	solar	solar_2024_10	2%	1	0,969461229	0,969461229	ok	physical	1	1	Luciana_Tulane Solar Center	0	0			
EBCE	Luciana	2024	11	9	0	1	development	0	0	CAISO_Solar	56	solar	solar_2024_11	2%	1	0,969461229	0,969461229	ok	physical	1	1	Luciana_Tulane Solar Center	0	0			
EBCE	Luciana	2024	12	7	0	1	development	0	0	CAISO_Solar	56	solar	solar_2024_12	0%	1	0	0	ok	physical	1	1	Luciana_Tulane Solar Center	0	0			
EBCE	Luciana	2025	1	8	0	1	development	0	0	CAISO_Solar	56	solar	solar_2025_1	3%	1	1,645828971	1,645828971	ok	physical	1	1	Luciana_Tulane Solar Center	0	0			
EBCE	Luciana	2025	2	8	0	1	development	0	0	CAISO_Solar	56	solar	solar_2025_2	2%	1	1,23437379	1,23437379	ok	physical	1	1	Luciana_Tulane Solar Center	0	0			
EBCE	Luciana	2025	3	13	0	1	development	0	0	CAISO_Solar	56	solar	solar_2025_3	13%	1	7,46620371	7,46620371	ok	physical	1	1	Luciana_Tulane Solar Center	0	0			
EBCE	Luciana	2025	4	15	0	1	development	0	0	CAISO_Solar	56	solar	solar_2025_4	4%	1	6,17458643	6,17458643	ok	physical	1	1	Luciana_Tulane Solar Center	0	0			
EBCE	Luciana	2025	5	15	0	1	development	0	0	CAISO_Solar	56	solar	solar_2025_5	12%	1	6,58315886	6,58315886	ok	physical	1	1	Luciana_Tulane Solar Center	0	0			
EBCE	Luciana	2025	6	19	0	1	development	0	0	CAISO_Solar	56	solar	solar_2025_6	23%	1	12,75517453	12,75517453	ok	physical	1	1	Luciana_Tulane Solar Center	0				

EBCE	Altamont Winds	2029	11	10	1	development	Summit Wind	58	CAISO_Wind	0	wind_low_cf	wind_low_cf_2029_11	17%	1	9.9910413	9.9910413	ok	physical	1	1	Altamont_Winds_Summit Wind	0	0
EBCE	Altamont Winds	2029	12	14	1	development	Summit Wind	58	CAISO_Wind	0	wind_low_cf	wind_low_cf_2029_12	19%	1	10.8232828	10.8232828	ok	physical	1	1	Altamont_Winds_Summit Wind	0	0
EBCE	Altamont Winds	2030	2	9	1	development	Summit Wind	58	CAISO_Wind	0	wind_low_cf	wind_low_cf_2030_2	17%	1	11.6415101	11.6415101	ok	physical	1	1	Altamont_Winds_Summit Wind	0	0
EBCE	Altamont Winds	2030	2	9	1	development	Summit Wind	58	CAISO_Wind	0	wind_low_cf	wind_low_cf_2030_2	17%	1	9.9784444	9.9784444	ok	physical	1	1	Altamont_Winds_Summit Wind	0	0
EBCE	Altamont Winds	2030	3	15	1	development	Summit Wind	58	CAISO_Wind	0	wind_low_cf	wind_low_cf_2030_3	40%	1	23.2830303	23.2830303	ok	physical	1	1	Altamont_Winds_Summit Wind	0	0
EBCE	Altamont Winds	2030	4	21	1	development	Summit Wind	58	CAISO_Wind	0	wind_low_cf	wind_low_cf_2030_4	30%	1	20.7884167	20.7884167	ok	physical	1	1	Altamont_Winds_Summit Wind	0	0
EBCE	Altamont Winds	2030	5	22	1	development	Summit Wind	58	CAISO_Wind	0	wind_low_cf	wind_low_cf_2030_5	36%	1	20.7884167	20.7884167	ok	physical	1	1	Altamont_Winds_Summit Wind	0	0
EBCE	Altamont Winds	2030	6	22	1	development	Summit Wind	58	CAISO_Wind	0	wind_low_cf	wind_low_cf_2030_6	48%	1	27.4407136	27.4407136	ok	physical	1	1	Altamont_Winds_Summit Wind	0	0
EBCE	Altamont Winds	2030	7	22	1	development	Summit Wind	58	CAISO_Wind	0	wind_low_cf	wind_low_cf_2030_7	33%	1	19.1253469	19.1253469	ok	physical	1	1	Altamont_Winds_Summit Wind	0	0
EBCE	Altamont Winds	2030	9	19	1	development	Summit Wind	58	CAISO_Wind	0	wind_low_cf	wind_low_cf_2030_9	20%	1	17.4627252	17.4627252	ok	physical	1	1	Altamont_Winds_Summit Wind	0	0
EBCE	Altamont Winds	2030	9	19	1	development	Summit Wind	58	CAISO_Wind	0	wind_low_cf	wind_low_cf_2030_9	22%	1	12.4730518	12.4730518	ok	physical	1	1	Altamont_Winds_Summit Wind	0	0
EBCE	Altamont Winds	2030	10	15	1	development	Summit Wind	58	CAISO_Wind	0	wind_low_cf	wind_low_cf_2030_10	12%	1	6.65229423	6.65229423	ok	physical	1	1	Altamont_Winds_Summit Wind	0	0
EBCE	Altamont Winds	2030	11	11	1	development	Summit Wind	58	CAISO_Wind	0	wind_low_cf	wind_low_cf_2030_11	17%	1	9.9784444	9.9784444	ok	physical	1	1	Altamont_Winds_Summit Wind	0	0
EBCE	Altamont Winds	2030	12	12	1	development	Summit Wind	58	CAISO_Wind	0	wind_low_cf	wind_low_cf_2030_12	9%	1	10.8097823	10.8097823	ok	physical	1	1	Altamont_Winds_Summit Wind	0	0
EBCE	existing_generic_unknown	2030	9	0	82	online	TEMU01RA2020	82	CAISO_Unknown	1	unknown	unknown_2020_9	0%	1	0	0	ok	existing_generic	0	1	existing_generic_unknown_TEMU01RA2020	1	80
EBCE	existing_generic_unknown	2020	10	0	71	online	SC08BRA2020	71	CAISO_Unknown	1	unknown	unknown_2020_10	0%	1	0	0	ok	existing_generic	0	1	existing_generic_unknown_SC08BRA2020	1	81
PGE	BOKRICK_1_UNIT	2021	9	0	2	online	CAM	2	CAISO_Peaker1	1	thermal	thermal_2021_9	100%	1	0	0	ok	physical	0	1	BOKRICK_1_UNIT_CAM	0	82
PGE	BEARMT_1_UNIT	2021	9	0	3	online	CAM	3	CAISO_Peaker1	1	thermal	thermal_2021_9	100%	1	0	0	ok	physical	0	1	BEARMT_1_UNIT_CAM	0	83
PGE	CAPRN_1_AGRNEW	2021	9	0	2	online	CAM	2	CAISO_CGT1	1	thermal	thermal_2021_9	100%	1	0	0	ok	physical	0	1	CAPRN_1_AGRNEW_CAM	0	84
PGE	CHALE_1_UNIT	2021	9	0	3	online	CAM	3	CAISO_Peaker1	1	thermal	thermal_2021_9	100%	1	0	0	ok	physical	0	1	CHALE_1_UNIT_CAM	0	85
PGE	COCOP_2_CT61	2021	9	0	12	online	CAM	12	CAISO_Peaker1	1	thermal	thermal_2021_9	100%	1	0	0	ok	physical	0	1	COCOP_2_CT61_CAM	0	86
PGE	COCOP_2_CT62	2021	9	0	12	online	CAM	12	CAISO_Peaker1	1	thermal	thermal_2021_9	100%	1	0	0	ok	physical	0	1	COCOP_2_CT62_CAM	0	87
PGE	COCOP_2_CT63	2021	9	0	12	online	CAM	12	CAISO_Peaker1	1	thermal	thermal_2021_9	100%	1	0	0	ok	physical	0	1	COCOP_2_CT63_CAM	0	88
PGE	COCOP_2_CT64	2021	9	0	12	online	CAM	12	CAISO_Peaker1	1	thermal	thermal_2021_9	100%	1	0	0	ok	physical	0	1	COCOP_2_CT64_CAM	0	89
PGE	DEKEL_1_UNIT	2021	9	0	1	online	CAM	1	CAISO_CHP	1	cogen	cogen_2021_9	80%	1	0	0	ok	physical	0	1	DEKEL_1_UNIT_CAM	0	90
PGE	DOUBL_1_UNITS	2021	9	0	3	online	CAM	3	CAISO_Peaker2	1	thermal	thermal_2021_9	100%	1	0	0	ok	physical	0	1	DOUBL_1_UNITS_CAM	0	91
PGE	GRDZY_1_BRNRY	2021	9	0	1	online	CAM	1	CAISO_CHP	1	cogen	cogen_2021_9	80%	1	0	0	ok	physical	0	1	GRDZY_1_BRNRY_CAM	0	92
PGE	KRNMT_1_UNITS	2021	9	0	3	online	CAM	3	CAISO_CHP	1	cogen	cogen_2021_9	80%	1	0	0	ok	physical	0	1	KRNMT_1_UNITS_CAM	0	93
PGE	LIVDAK_1_UNIT1	2021	9	0	3	online	CAM	3	CAISO_Peaker2	1	thermal	thermal_2021_9	100%	1	0	0	ok	physical	0	1	LIVDAK_1_UNIT1_CAM	0	94
PGE	MTRCKA_1_UNIT1	2021	9	0	3	online	CAM	3	CAISO_Peaker2	1	thermal	thermal_2021_9	100%	1	0	0	ok	physical	0	1	MTRCKA_1_UNIT1_CAM	0	95
PGE	OMAR_2_UNIT1	2021	9	0	4	online	CAM	4	CAISO_Peaker1	1	thermal	thermal_2021_9	100%	1	0	0	ok	physical	0	1	OMAR_2_UNIT1_CAM	0	96
PGE	OMAR_2_UNIT2	2021	9	0	4	online	CAM	4	CAISO_Peaker1	1	thermal	thermal_2021_9	100%	1	0	0	ok	physical	0	1	OMAR_2_UNIT2_CAM	0	97
PGE	OMAR_2_UNIT3	2021	9	0	5	online	CAM	5	CAISO_Peaker1	1	thermal	thermal_2021_9	100%	1	0	0	ok	physical	0	1	OMAR_2_UNIT3_CAM	0	98
PGE	OMAR_2_UNIT4	2021	9	0	5	online	CAM	5	CAISO_Peaker1	1	thermal	thermal_2021_9	100%	1	0	0	ok	physical	0	1	OMAR_2_UNIT4_CAM	0	99
PGE	OROV_6_UNIT	2021	9	0	0	online	CAM	5	CAISO_Peaker1	1	thermal	thermal_2021_9	100%	1	0	0	ok	physical	0	1	OROV_6_UNIT_CAM	0	100
PGE	SERRA_1_UNITS	2021	9	0	3	online	CAM	3	CAISO_Peaker2	1	thermal	thermal_2021_9	100%	1	0	0	ok	physical	0	1	SERRA_1_UNITS_CAM	0	101
PGE	STOES_1_UNITS	2021	9	0	0	online	CAM	0	CAISO_CHP	1	cogen	cogen_2021_9	80%	1	0	0	ok	physical	0	1	STOES_1_UNITS_CAM	0	102
PGE	SUBET_1_UNITS	2021	9	0	13	online	CAM	13	CAISO_Peaker1	1	thermal	thermal_2021_9	100%	1	0	0	ok	physical	0	1	SUBET_1_UNITS_CAM	0	103
PGE	TOWHTA_1_UNITS	2021	9	0	0	online	CAM	0	CAISO_CHP	1	cogen	cogen_2021_9	80%	1	0	0	ok	physical	0	1	TOWHTA_1_UNITS_CAM	0	104
PGE	KERNIN_1_UNITS	2021	9	0	0	online	CAM	0	CAISO_CHP	1	cogen	cogen_2021_9	80%	1	0	0	ok	physical	0	1	KERNIN_1_UNITS_CAM	0	105
PGE	TANH_6_SOLART	2021	9	0	1	online	CAM	1	CAISO_CHP	1	cogen	cogen_2021_9	80%	1	0	0	ok	physical	0	1	TANH_6_SOLART_CAM	0	106
PGE	BOKRICK_1_UNITS	2022	9	0	2	online	CAM	2	CAISO_Peaker1	1	thermal	thermal_2022_9	100%	1	0	0	ok	physical	0	1	BOKRICK_1_UNITS_CAM	0	107
PGE	BEARMT_1_UNIT	2022	9	0	3	online	CAM	3	CAISO_Peaker1	1	thermal	thermal_2022_9	100%	1	0	0	ok	physical	0	1	BEARMT_1_UNIT_CAM	0	108
PGE	CAPRN_1_AGRNEW	2022	9	0	2	online	CAM	2	CAISO_CGT1	1	thermal	thermal_2022_9	100%	1	0	0	ok	physical	0	1	CAPRN_1_AGRNEW_CAM	0	109
PGE	CHALE_1_UNIT	2022	9	0	3	online	CAM	3	CAISO_Peaker1	1	thermal	thermal_2022_9	100%	1	0	0	ok	physical	0	1	CHALE_1_UNIT_CAM	0	110
PGE	COCOP_2_CT61	2022	9	0	12	online	CAM	12	CAISO_Peaker1	1	thermal	thermal_2022_9	100%	1	0	0	ok	physical	0	1	COCOP_2_CT61_CAM	0	111
PGE	COCOP_2_CT62	2022	9	0	12	online	CAM	12	CAISO_Peaker1	1	thermal	thermal_2022_9	100%	1	0	0	ok	physical	0	1	COCOP_2_CT62_CAM	0	112
PGE	COCOP_2_CT63	2022	9	0	12	online	CAM	12	CAISO_Peaker1	1	thermal	thermal_2022_9	100%	1	0	0	ok	physical	0	1	COCOP_2_CT63_CAM	0	113
PGE	COCOP_2_CT64	2022	9	0	12	online	CAM	12	CAISO_Peaker1	1	thermal	thermal_2022_9	100%	1	0	0	ok	physical	0	1	COCOP_2_CT64_CAM	0	114
PGE	DEKEL_1_UNIT	2022	9	0	1	online	CAM	1	CAISO_CHP	1	cogen	cogen_2022_9	80%	1	0	0	ok	physical	0	1	DEKEL_1_UNIT_CAM	0	115
PGE	DOUBL_1_UNITS	2022	9	0	3	online	CAM	3	CAISO_Peaker2	1	thermal	thermal_2022_9	100%	1	0	0	ok	physical	0	1	DOUBL_1_UNITS_CAM	0	116
PGE	GRDZY_1_BRNRY	2022	9	0	1	online	CAM	1	CAISO_CHP	1	cogen	cogen_2022_9	80%	1	0	0	ok	physical	0	1	GRDZY_1_BRNRY_CAM	0	117
PGE	KRNMT_1_UNITS	2022	9	0	3	online	CAM	3	CAISO_CHP	1	cogen	cogen_2022_9	80%	1	0	0	ok	physical	0	1	KRNMT_1_UNITS_CAM	0	118
PGE	LIVDAK_1_UNIT1	2022	9	0	3	online	CAM	3	CAISO_Peaker2	1	thermal	thermal_2022_9	100%	1	0	0	ok	physical	0	1	LIVDAK_1_UNIT1_CAM	0	119
PGE	MTRCKA_1_UNIT1	2022	9	0	3	online	CAM	3	CAISO_Peaker2	1	thermal	thermal_2022_9	100%	1	0	0	ok	physical	0	1	MTRCKA_1_UNIT1_CAM	0	120
PGE	OMAR_2_UNIT1	2022	9	0	4	online	CAM	4	CAISO_Peaker1	1	thermal	thermal_2022_9	100%	1	0	0	ok	physical	0	1	OMAR_2_UNIT1_CAM	0	121
PGE	OMAR_2_UNIT2	2022	9	0	4	online	CAM	4	CAISO_Peaker1	1	thermal	thermal_2022_9	100%	1	0	0	ok	physical	0	1	OMAR_2_UNIT2_CAM	0	122
PGE	OMAR_2_UNIT3	2022	9	0	5	online	CAM	5	CAISO_Peaker1	1	thermal	thermal_2022_9	100%	1	0	0	ok	physical	0	1	OMAR_2_UNIT3_CAM	0	123
PGE	OMAR_2_UNIT4	2022	9	0	5	online	CAM	5	CAISO_Peaker1	1	thermal	thermal_2022_9	100%	1	0	0							

PGE	Oakland Energy Storage	2030	2	0	20	development	Visira - Oakland Energy	20	CAISO_Li_Battery	0	battery	battery_2030_2	93%	0	#N/A	20	ok	physical	0	1	and Energy Storage_Visira - Oakland Energy Sto	0	0
PGE	Oakland Energy Storage	2030	3	0	20	development	Visira - Oakland Energy	20	CAISO_Li_Battery	0	battery	battery_2030_3	93%	0	#N/A	20	ok	physical	0	1	and Energy Storage_Visira - Oakland Energy Sto	0	0
PGE	Oakland Energy Storage	2030	4	0	20	development	Visira - Oakland Energy	20	CAISO_Li_Battery	0	battery	battery_2030_4	93%	0	#N/A	20	ok	physical	0	1	and Energy Storage_Visira - Oakland Energy Sto	0	0
PGE	Oakland Energy Storage	2030	5	0	20	development	Visira - Oakland Energy	20	CAISO_Li_Battery	0	battery	battery_2030_5	93%	0	#N/A	20	ok	physical	0	1	and Energy Storage_Visira - Oakland Energy Sto	0	0
PGE	Oakland Energy Storage	2030	6	0	20	development	Visira - Oakland Energy	20	CAISO_Li_Battery	0	battery	battery_2030_6	93%	0	#N/A	20	ok	physical	0	1	and Energy Storage_Visira - Oakland Energy Sto	0	0
PGE	Oakland Energy Storage	2030	7	0	20	development	Visira - Oakland Energy	20	CAISO_Li_Battery	0	battery	battery_2030_7	93%	0	#N/A	20	ok	physical	0	1	and Energy Storage_Visira - Oakland Energy Sto	0	0
PGE	Oakland Energy Storage	2030	8	0	20	development	Visira - Oakland Energy	20	CAISO_Li_Battery	0	battery	battery_2030_8	93%	0	#N/A	20	ok	physical	0	1	and Energy Storage_Visira - Oakland Energy Sto	0	0
PGE	Oakland Energy Storage	2030	9	0	20	development	Visira - Oakland Energy	20	CAISO_Li_Battery	0	battery	battery_2030_9	93%	0	#N/A	20	ok	physical	0	1	and Energy Storage_Visira - Oakland Energy Sto	0	0
PGE	Oakland Energy Storage	2030	10	0	20	development	Visira - Oakland Energy	20	CAISO_Li_Battery	0	battery	battery_2030_10	93%	0	#N/A	20	ok	physical	0	1	and Energy Storage_Visira - Oakland Energy Sto	0	0
PGE	Oakland Energy Storage	2030	11	0	20	development	Visira - Oakland Energy	20	CAISO_Li_Battery	0	battery	battery_2030_11	93%	0	#N/A	20	ok	physical	0	1	and Energy Storage_Visira - Oakland Energy Sto	0	0
PGE	Oakland Energy Storage	2030	12	0	20	development	Visira - Oakland Energy	20	CAISO_Li_Battery	0	battery	battery_2030_12	93%	0	#N/A	20	ok	physical	0	1	and Energy Storage_Visira - Oakland Energy Sto	0	0

Resource ID	Resource	Resource Note	Resource Contract Note	Online Date for New Resources	Contract Execution Date	Contract Start	Contract End	Interconnection Queue Position	Is Owned	Can	Is Incremental	Incremental Reason	Viability_Condition	Viability_Tech	Viability_Resource	Viability_Financing	Storage_Capacity (MWh)	Storage_Dead_Weight (MWh)	Hybrid_Generation (MW)	Hybrid_Combined (MW)	Hybrid_Can_Charge (MW)	Execution Year	Execution Month	Start Year	Start Month	End Year	End Month
1	New_U1_Battery	20 Li-Ion Battery	New_U1_Battery_20 Li-Ion Battery	0	1/1/2022			TBD	0	1	3	1	2	4	144	288	0				1900	1	1900	1	1900	1	
2	New_U1_Battery	40 Li-Ion Battery	New_U1_Battery_40 Li-Ion Battery	0	1/1/2022			TBD	0	1	3	1	2	4	288	576	0				1	1900	1	1900	1	1900	1
3	New_U1_Battery	80 Li-Ion Battery	New_U1_Battery_80 Li-Ion Battery	0	1/1/2022			TBD	0	1	3	1	2	4	576	1152	0				1	1900	1	1900	1	1900	1
4	existing_generic_instate_large_hydro	none	existing_generic_instate_large_hydro_none	1	ok			n/a	0	0	0	0	0	0	80	640	0				1900	1	1900	1	1900	1	
5	existing_generic_instate_small_hydro	none	existing_generic_instate_small_hydro_none	1	ok			n/a	0	1	0	0	0	0	0	0	0				1900	1	1900	1	1900	1	
6	existing_generic_geothermal	none	existing_generic_geothermal_none	1	ok			n/a	0	1	0	0	0	0	0	0	0				1900	1	1900	1	1900	1	
7	existing_generic_biomass_landfills	none	existing_generic_biomass_landfills_none	1	ok			n/a	0	1	0	0	0	0	0	0	0				1900	1	1900	1	1900	1	
8	existing_generic_biomass_wood	none	existing_generic_biomass_wood_none	1	ok			n/a	0	1	0	0	0	0	0	0	0				1900	1	1900	1	1900	1	
9	new_generic_dr	none	new_generic_dr_none	0	1/1/2022			n/a	0	1	3	1	2	4							1900	1	1900	1	1900	1	
11	them_Ca_Desert_Southern_WV_U	Desert Wind Project	Southern_CA_Desert_Southern_WV_Wind_Desert Wind Project	0	1/1/2022			TBD	0	1	3	1	2	4							1900	1	1900	1	1900	1	
12	Tehachapi_Wind	Tehachapi Wind Project	Tehachapi_Wind_Tehachapi Wind Project	0	1/1/2022			TBD	0	1	3	1	2	4							1900	1	1900	1	1900	1	
13	New_Mexico_Wind	New Mexico Wind Project	New_Mexico_Wind_New Mexico Wind Project	0	1/1/2022			TBD	0	1	3	1	2	4							1900	1	1900	1	1900	1	
14	new_generic_wind	none	new_generic_wind_none	0	1/1/2022			TBD	0	1	3	1	2	4							1900	1	1900	1	1900	1	
15	them_Ca_Desert_Southern_WV_U_5	Desert Solar Project	Southern_CA_Desert_Southern_WV_Solar_Desert Solar Project	0	1/1/2022			TBD	0	1	3	1	2	4							1900	1	1900	1	1900	1	
16	Tehachapi_Solar	Tehachapi Solar Project	Tehachapi_Solar_Tehachapi Solar Project	0	1/1/2022			TBD	0	1	3	1	2	4							1900	1	1900	1	1900	1	
17	new_generic_solar_isais	none	new_generic_solar_isais_none	0	1/1/2022			TBD	0	1	3	1	2	4							1900	1	1900	1	1900	1	
18	existing_generic_unknown	none	existing_generic_unknown_none	1	ok			n/a	0	0	0	0	0	0	0	0	0				1900	1	1900	1	1900	1	
19	existing_generic_unknown	PG&E8RA2020	existing_generic_unknown_PG&E8RA2020	1	ok	9/30/2019	12/1/2019	12/1/2022	n/a	0	0	0	0	0	0	0	0				2019	9	2019	12	2022	12	
20	existing_generic_unknown	PG&E8RA2020	existing_generic_unknown_PG&E8RA2020	1	ok	9/24/2019	1/1/2020	12/31/2022	n/a	0	0	0	0	0	0	0	0				2019	9	2020	1	2022	12	
21	existing_generic_unknown	CALP01RA2020	existing_generic_unknown_CALP01RA2020	1	ok	10/23/2019	7/1/2020	9/30/2022	n/a	0	0	0	0	0	0	0	0				2019	10	2020	7	2022	9	
22	existing_generic_unknown	CALP01RA2021	existing_generic_unknown_CALP01RA2021	1	ok	10/2/2019	1/1/2020	12/31/2022	n/a	0	0	0	0	0	0	0	0				2019	10	2020	1	2022	12	
23	existing_generic_unknown	CALP01RA2021	existing_generic_unknown_CALP01RA2021	1	ok	11/26/2019	1/1/2021	12/31/2022	n/a	0	0	0	0	0	0	0	0				2019	7	2021	1	2022	12	
24	existing_generic_unknown	TPSO18A2021	existing_generic_unknown_TPSO18A2021	1	ok	11/14/2019	1/1/2021	12/31/2022	n/a	0	0	0	0	0	0	0	0				2019	11	2021	1	2022	12	
25	existing_generic_unknown	WP0318A2021	existing_generic_unknown_WP0318A2021	1	ok	7/1/2019	1/1/2021	12/31/2022	n/a	0	0	0	0	0	0	0	0				2019	7	2021	1	2022	12	
26	existing_generic_unknown	EDF018A2022	existing_generic_unknown_EDF018A2022	1	ok	8/9/2019	5/1/2021	12/31/2022	n/a	0	0	0	0	0	0	0	0				2019	8	2021	8	2022	12	
27	existing_generic_unknown	SEMA02RA2022	existing_generic_unknown_SEMA02RA2022	1	ok	11/20/2019	1/1/2022	12/31/2022	n/a	0	0	0	0	0	0	0	0				2019	11	2021	1	2022	12	
28	existing_generic_unknown	EDF018A2022	existing_generic_unknown_EDF018A2022	1	ok	8/16/2019	1/1/2021	12/31/2021	n/a	0	0	0	0	0	0	0	0				2019	8	2021	1	2021	12	
29	existing_generic_unknown	PG&E18A2020	existing_generic_unknown_PG&E18A2020	1	ok	10/31/2019	1/1/2021	12/31/2022	n/a	0	0	0	0	0	0	0	0				2019	10	2021	1	2022	12	
30	existing_generic_unknown	BM04170201	existing_generic_unknown_BM04170201	1	ok	9/6/2019	5/1/2021	12/31/2021	n/a	0	0	0	0	0	0	0	0				2019	9	2021	1	2021	12	
31	existing_generic_unknown	CHM03RA2022	existing_generic_unknown_CHM03RA2022	1	ok	10/31/2019	1/1/2020	12/31/2022	n/a	0	0	0	0	0	0	0	0				2019	10	2020	1	2022	12	
32	existing_generic_unknown	CHM03RA2022	existing_generic_unknown_CHM03RA2022	1	ok	10/31/2019	1/1/2020	12/31/2022	n/a	0	0	0	0	0	0	0	0				2019	10	2020	1	2022	12	
33	existing_generic_unknown	EDF018A2021	existing_generic_unknown_EDF018A2021	1	ok	10/31/2019	1/1/2021	12/31/2021	n/a	0	0	0	0	0	0	0	0				2019	10	2021	1	2021	12	
34	existing_generic_unknown	SEMA02RA2021	existing_generic_unknown_SEMA02RA2021	1	ok	10/31/2019	1/1/2020	12/31/2021	n/a	0	0	0	0	0	0	0	0				2019	10	2020	1	2021	12	
35	existing_generic_unknown	SEMA02RA2022	existing_generic_unknown_SEMA02RA2022	1	ok	8/16/2019	1/1/2022	12/31/2022	n/a	0	0	0	0	0	0	0	0				2019	8	2022	1	2022	12	
36	existing_generic_unknown	AMPO18A2020	existing_generic_unknown_AMPO18A2020	1	ok	10/25/2019	7/1/2020	9/30/2020	n/a	0	0	0	0	0	0	0	0				2019	10	2020	7	2020	9	
37	existing_generic_unknown	CALP02RA2019	existing_generic_unknown_CALP02RA2019	1	ok	7/23/2018	1/1/2019	12/31/2020	n/a	0	0	0	0	0	0	0	0				2018	7	2019	1	2020	12	
38	existing_generic_unknown	CALP03RA2019	existing_generic_unknown_CALP03RA2019	1	ok	7/23/2018	1/1/2019	12/31/2020	n/a	0	0	0	0	0	0	0	0				2018	7	2019	1	2020	12	
39	existing_generic_unknown	CP&D18A2020	existing_generic_unknown_CP&D18A2020	1	ok	10/31/2019	2/1/2020	3/31/2020	n/a	0	0	0	0	0	0	0	0				2019	10	2020	2	2020	3	
40	existing_generic_unknown	DYN018A2020	existing_generic_unknown_DYN018A2020	1	ok	10/31/2019	1/1/2020	12/31/2020	n/a	0	0	0	0	0	0	0	0				2019	10	2020	1	2020	12	
41	existing_generic_unknown	EDF018A2020	existing_generic_unknown_EDF018A2020	1	ok	10/23/2019	1/1/2020	12/31/2020	n/a	0	0	0	0	0	0	0	0				2019	10	2020	1	2020	12	
42	existing_generic_unknown	MFC018A2020	existing_generic_unknown_MFC018A2020	1	ok	10/31/2019	1/1/2020	12/31/2020	n/a	0	0	0	0	0	0	0	0				2019	10	2020	1	2020	12	
43	existing_generic_unknown	MFC018A2020	existing_generic_unknown_MFC018A2020	1	ok	10/31/2019	1/1/2020	12/31/2021	n/a	0	0	0	0	0	0	0	0				2019	10	2020	1	2021	12	
44	existing_generic_unknown	NEXT018A2020	existing_generic_unknown_NEXT018A2020	1	ok	8/13/2019	1/1/2020	12/31/2020	n/a	0	0	0	0	0	0	0	0				2019	6	2020	1	2020	12	
45	existing_generic_unknown	NEXT02RA2020	existing_generic_unknown_NEXT02RA2020	1	ok	10/31/2019	10/1/2020	10/31/2020	n/a	0	0	0	0	0	0	0	0				2019	10	2020	10	2020	10	
46	existing_generic_unknown	NAGE018A2020	existing_generic_unknown_NAGE018A2020	1	ok	10/9/2019	1/1/2020	12/31/2020	n/a	0	0	0	0	0	0	0	0				2019	10	2020	1	2020	12	
47	existing_generic_unknown	PC0318A2020	existing_generic_unknown_PC0318A2020	1	ok	10/31/2019	1/1/2020	11/30/2020	n/a	0	0	0	0	0	0	0	0				2019	10	2020	1	2020	11	
48	existing_generic_unknown	PC0318A2020	existing_generic_unknown_PC0318A2020	1	ok	10/31/2019	1/1/2020	11/30/2020	n/a	0	0	0	0	0	0	0	0				2019	10	2020	1	2020	11	
49	existing_generic_unknown	PC0318A2020	existing_generic_unknown_PC0318A2020	1	ok	12/16/2019	2/1/2020	2/29/2020	n/a	0	0	0	0	0	0	0	0				2019	12	2020	2	2020	2	
50	existing_generic_unknown	PG&E18RA2019	existing_generic_unknown_PG&E18RA2019	1	ok	8/20/2019	1/1/2019	12/31/2020	n/a	0	0	0	0	0	0	0	0				2019	8	2019	1	2020	12	
51	existing_generic_unknown	PG&E8RA2020	existing_generic_unknown_PG&E8RA2020	1	ok	9/24/2019	1/1/2020	12/31/2020	n/a	0	0	0	0	0	0	0	0				2019	9	2020	1	2020	12	
52	existing_generic_unknown	PG&E8RA2020	existing_generic_unknown_PG&E8RA2020	1	ok	1/29/2020	4/1/2020	9/30/2020	n/a	0	0	0	0	0	0	0	0				2020	1	2020	4	2020	9	
53	existing_generic_unknown	PG&E8RA2020	existing_generic_unknown_PG&E8RA2020	1	ok	10/29/2019	8/1/2020	10/31/2020	n/a	0	0	0	0	0	0	0	0				2019	10	2020	8	2020	10	
54	existing_generic_unknown	PG&E8RA2020	existing_generic_unknown_PG&E8RA2020	1	ok	11/25/2019	8/1/2020	9/30/2020	n/a	0	0	0	0	0	0	0	0				2019	11	2020	9	2020	10	
55	existing_generic_unknown	SC08RA2020	existing_generic_unknown_SC08RA2020	1	ok	9/19/2019	1/1/2020	1/31/2020	n/a	0	0	0	0	0	0	0	0				2019	9	2020	1	2020	1	
56	existing_generic_unknown	SC08RA2020	existing_generic_unknown_SC08RA2020	1	ok	10/23/2019	1/1/2020	6/30/2020	n/a	0	0	0	0	0	0	0	0				2019	10	2020	1	2020	6	
57	existing_generic_unknown	SC08RA2020	existing_generic_unknown_SC08RA2020	1	ok	10/23/2019	3/1/2020	10/31/2020	n/a	0	0	0	0	0	0	0	0				2019	10	2020	3	2020	10	
58	existing_generic_unknown	SC08RA2020	existing_generic_unknown_SC08RA2020	1	ok	7/31/2019	1/1/2020	5/31/2020	n/a	0	0	0	0	0	0	0	0				2019	7	2020	1	2020	5	
59	existing_generic_unknown	SC08RA2020	existing_generic_unknown_SC08RA2020	1	ok	10/23/2019	5/1/2020	9/30/2020	n/a	0	0	0	0	0	0	0	0				2019	10	20				

Show NQC for this month in System Reliability
 Show D.19-11-016 incremental procurement in this
 Display NQC MW or GWh in System Reliability

September
2021
NQC MW

September 2021

System Reliability Progress Tracking Table (NQC MW) for month of September by contract status, 38 MMT portfolio	ELCC type	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
online	wind_low_cf	-	-	-	-	-	-	-	-	-	-	-
online	wind_high_cf	-	-	-	-	-	-	-	-	-	-	-
online	biomass	-	-	-	-	-	-	-	-	-	-	-
online	cogen	-	6	6	6	6	6	6	6	6	6	6
online	geothermal	-	-	-	-	-	-	-	-	-	-	-
online	hydro	-	-	-	-	-	-	-	-	-	-	-
online	thermal	-	99	99	99	99	99	99	99	99	99	99
online	battery	-	-	-	-	-	-	-	-	-	-	-
online	nuclear	-	-	-	-	-	-	-	-	-	-	-
online	solar	-	-	-	-	-	-	-	-	-	-	-
online	psh	-	-	-	-	-	-	-	-	-	-	-
development	unknown	1,277	599	438	-	-	-	-	-	-	-	-
development	wind_low_cf	-	9	9	9	10	11	13	13	13	12	12
development	wind_high_cf	-	-	-	-	-	-	-	-	-	-	-
development	biomass	-	-	-	-	-	-	-	-	-	-	-
development	cogen	-	-	-	-	-	-	-	-	-	-	-
development	geothermal	-	-	-	-	-	-	-	-	-	-	-
development	hydro	-	-	-	-	-	-	-	-	-	-	-
development	thermal	-	-	-	-	-	-	-	-	-	-	-
development	battery	-	-	28	28	28	28	28	28	28	28	28
development	nuclear	-	-	-	-	-	-	-	-	-	-	-
development	solar	-	37	37	137	128	119	110	113	108	102	97
development	psh	-	-	-	-	-	-	-	-	-	-	-
development	unknown	-	-	-	-	-	-	-	-	-	-	-
review	wind_low_cf	-	-	-	-	-	-	-	-	-	-	-
review	wind_high_cf	-	-	-	-	-	-	-	-	-	-	-
review	biomass	-	-	-	-	-	-	-	-	-	-	-
review	cogen	-	-	-	-	-	-	-	-	-	-	-
review	geothermal	-	-	-	-	-	-	-	-	-	-	-
review	hydro	-	-	-	-	-	-	-	-	-	-	-
review	thermal	-	-	-	-	-	-	-	-	-	-	-
review	battery	-	-	-	-	-	-	-	-	-	-	-
review	nuclear	-	-	-	-	-	-	-	-	-	-	-
review	solar	-	-	-	-	-	-	-	-	-	-	-
review	psh	-	-	-	-	-	-	-	-	-	-	-
review	unknown	-	-	-	-	-	-	-	-	-	-	-
planned_existing	wind_low_cf	-	-	-	-	-	-	-	-	-	-	-
planned_existing	wind_high_cf	-	-	-	-	-	-	-	-	-	-	-
planned_existing	biomass	-	-	-	-	-	-	-	3	7	10	14
planned_existing	cogen	-	-	-	-	-	-	-	-	-	-	-
planned_existing	geothermal	-	-	16	32	48	65	65	65	65	65	65
planned_existing	hydro	-	-	136	136	136	136	136	136	136	136	136
planned_existing	thermal	-	-	-	-	-	-	-	-	-	-	-
planned_existing	battery	-	-	-	-	-	-	-	-	-	-	-
planned_existing	nuclear	-	-	-	-	-	-	-	-	-	-	-
planned_existing	solar	-	-	-	-	-	-	-	-	-	-	-
planned_existing	psh	-	-	-	-	-	-	-	-	-	-	-
planned_existing	unknown	-	675	385	725	695	665	605	575	535	495	465
planned_new	wind_low_cf	-	-	38	39	48	57	66	75	84	93	104
planned_new	wind_high_cf	-	-	12	12	15	18	21	21	21	21	21
planned_new	biomass	-	-	-	-	-	-	-	-	-	-	-
planned_new	cogen	-	-	-	-	-	-	-	-	-	-	-
planned_new	geothermal	-	-	-	-	-	-	-	-	-	-	-
planned_new	hydro	-	-	-	-	-	-	-	-	-	-	-
planned_new	thermal	-	-	-	-	-	-	-	-	-	-	-
planned_new	battery	-	-	176	198	220	242	264	303	340	376	410
planned_new	nuclear	-	-	-	-	-	-	-	-	-	-	-
planned_new	solar	-	-	57	57	50	42	35	33	31	28	25
planned_new	psh	-	-	-	-	-	-	-	-	-	-	-
planned_new	unknown	-	-	-	-	-	-	-	-	-	-	-
TOTAL supply, NQC MW		1,277	1,425	1,420	1,461	1,466	1,470	1,447	1,469	1,471	1,470	1,480
Load (MW)												
Load +15% PRM (MW)												
Supply minus load: Shortfall (-) or Surplus (+), in MW												

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Incremental Procurement for D.19-11-016, NQC MW
Supply-side resource is incremental
New resource that is energy only in 2021
Demand-side resource is not in IEPR demand forecast (and therefore incremental)
MW added to existing resource
Total NQC MW

2021
46
-
-
-
46

NQC MW from data	NQC MW displayed in table	difference (absolute)	match?
15,855	15,855	0	TRUE

0

Check mat

TRUE

Appendix D

Resource Data Template - 46 MMT

(Public Version)

46 <--- Select your MMT here using the dropdown.
Do not change other cells in this tab.

38 MMT Portfolio
46 MMT Portfolio

Form 1.5b - STATEWIDE
 California Energy Demand 2019-2030 Managed Forecast - Mid Demand / Mid AAE Case
 1-in-2 Net Electricity Peak Demand by Agency and Balancing Authority (MW)

Balancing Authority	Agency	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	Average Annual Growth (2019-2030)	CAISO area Non-IOU,CCA,ESP demand flag	
	PG&E Service Area - Greater Bay Area	7,223	7,113	6,970	6,926	6,902	6,898	6,922	6,951	6,977	7,032	7,025	7,062	-0.20%		
	NCPA - Greater Bay Area	198	194	190	188	186	185	186	186	186	187	186	188	-0.49%	1	
	Power Enterprises of the San Francisco PUC	25	23	20	18	17	17	17	17	17	17	17	18	-0.49%	1	
	Sierra Valley Power	530	542	540	546	553	562	569	570	570	573	571	575	0.75%	1	
	Other NP15 LSEs - Bay Area	5	5	5	5	5	5	5	5	5	5	5	5	-0.69%	1	
	CDWR - Greater Bay Area	55	55	57	57	57	57	57	56	56	56	56	56	60	0.92%	1
	WAPA - Greater Bay Area	52	52	52	52	52	52	52	52	52	52	52	52	0.00%	1	
	Greater Bay Area Subtotal	8,188	8,083	7,933	7,892	7,873	7,876	7,907	7,937	7,964	8,023	8,013	8,061	-0.14%		
	PG&E Service Area - Non Bay Area	9,955	9,803	9,606	9,545	9,513	9,507	9,540	9,580	9,616	9,691	9,682	9,734	-0.20%		
	NCPA - Non Bay Area	211	207	202	200	199	198	198	198	199	200	199	200	-0.49%	1	
	Other NP15 LSEs - Non Bay Area	7	7	7	7	7	7	7	7	7	7	7	7	-0.49%	1	
	CDWR - Non Bay Area	55	55	57	57	57	57	57	56	56	56	56	56	60	0.92%	1
		WAPA - Non Bay Area	185	185	185	185	185	185	185	185	185	185	185	185	0.00%	1
		Total North of Path 15	18,602	18,341	17,991	17,886	17,832	17,829	17,893	17,964	18,026	18,161	18,142	18,247	-0.17%	
	PG&E Service Area - ZP26	2,047	2,016	1,975	1,963	1,956	1,955	1,962	1,970	1,977	1,993	1,991	2,002	-0.20%		
	CDWR - ZP26	115	115	120	120	120	120	119	118	118	118	118	118	127	0.92%	1
	WAPA - ZP26	15	15	15	15	15	15	15	15	15	15	15	15	0.00%	1	
	Total Zone Path 26	2,177	2,146	2,110	2,097	2,091	2,090	2,095	2,103	2,111	2,126	2,124	2,144	-0.14%		
	Total Valley	12,591	12,403	12,167	12,091	12,050	12,043	12,081	12,130	12,173	12,265	12,253	12,330	-0.19%		
	Total North of Path 26 (Total PG&E TAC Area)	20,779	20,486	20,100	19,983	19,923	19,919	19,988	20,067	20,137	20,287	20,266	20,391	-0.17%		
	Turlock Irrigation District	543	535	531	530	528	527	525	524	524	524	524	524	-0.27%		
	Merced	109	108	107	107	106	106	106	106	106	106	106	106	-0.27%		
	Total Turlock Irrigation District Control Area	652	643	638	637	634	633	631	630	629	630	631	630	-0.27%		
	SMUD	2,959	2,916	2,899	2,897	2,890	2,881	2,870	2,861	2,861	2,869	2,882	2,895	-0.20%		
	Modesto Irrigation District	674	664	659	658	656	654	652	651	650	651	652	654	-0.27%		
	Roseville	325	321	318	318	316	316	315	314	314	314	314	315	-0.27%		
	Redding	221	217	216	215	215	214	213	213	213	213	213	214	-0.27%		
	City of Shasta Lake	35	34	34	34	34	34	34	33	33	33	33	34	-0.27%		
	WAPA (BANC)	90	90	90	90	90	90	90	90	90	90	90	90	0.00%		
	Total Balancing Authority of Northern California Control Area	4,304	4,242	4,215	4,211	4,200	4,188	4,174	4,163	4,161	4,171	4,186	4,202	-0.22%		
	SCE Service Area - LA Basin	16,297	16,109	15,975	15,861	15,850	15,796	15,753	15,749	15,769	15,789	15,883	16,027	-0.15%		
	Anaheim	526	520	515	512	511	509	508	508	509	512	517	522	-0.15%	1	
	Pasadena Water and Power	273	270	267	265	265	264	264	264	264	264	266	268	-0.15%	1	
	Riverside	594	587	582	578	577	575	574	574	574	575	579	584	-0.15%	1	
	Vernon	149	147	147	147	147	147	147	147	147	147	147	147	147	0.00%	1
	Other SP15 LSEs - LA Basin	246	243	241	240	239	239	238	238	238	238	239	240	242	-0.15%	1
	MWD - LA Basin	20	20	20	20	20	20	20	20	20	20	20	20	0.00%	1	
	LA Basin Subtotal	18,104	17,895	17,771	17,645	17,633	17,572	17,525	17,521	17,542	17,565	17,669	17,829	-0.14%		
	SCE Service Area - Big Creek/Ventura	3,996	3,950	3,917	3,889	3,886	3,873	3,862	3,861	3,866	3,871	3,884	3,929	-0.15%		
	CDWR - Big Creek/Ventura	290	275	275	275	275	275	275	276	276	303	303	303	0.40%	1	
		Big Creek/Ventura Subtotal	4,286	4,224	4,192	4,164	4,161	4,148	4,137	4,137	4,142	4,174	4,197	4,233	-0.11%	
	SCE Service Area - Other	1,010	999	990	983	983	977	976	977	979	985	993	993	-0.15%		
	Other SP15 LSEs - Other	26	26	25	25	25	25	25	25	25	25	25	25	-0.15%	1	
	CDWR - Other	47	45	45	45	45	45	45	45	45	50	50	50	0.40%	1	
	Total SCE TAC Area	163	154	154	154	154	154	154	154	154	171	172	172	0.45%	1	
	Total SDG&E TAC Area	23,637	23,343	23,177	23,015	23,000	22,923	22,862	22,859	22,886	22,964	23,097	23,301	-0.13%		
	Valley Electric Association (CA + NV Territory)	133	145	153	156	159	161	164	166	169	171	173	176	2.53%	1	
	Total South of Path 26	27,964	27,625	27,488	27,366	27,383	27,334	27,299	27,317	27,368	27,469	27,625	27,850	-0.04%		
	LADWP	5,787	5,696	5,608	5,555	5,450	5,368	5,246	5,160	5,059	4,992	4,940	4,872	-1.55%		
	Burbank	286	284	284	283	283	282	281	279	279	281	281	283	-0.11%		
	Glendale	297	295	294	295	294	292	291	290	289	290	291	293	-0.11%		
	Total LADWP Control Area	6,370	6,275	6,186	6,135	6,028	5,942	5,818	5,729	5,627	5,561	5,512	5,448	-1.01%		
	Imperial Irrigation District Control Area	1,971	1,956	1,945	1,937	1,930	1,924	1,919	1,917	1,917	1,920	1,926	1,933	-0.33%		
	Total California ISO Noncoincident Peak	48,743	48,112	47,589	47,348	47,306	47,253	47,287	47,384	47,505	47,757	47,891	48,241	-0.09%		
	Total California ISO Noncoincident Peak	46,117	45,647	45,184	45,280	45,447	45,610	45,827	46,011	46,227	46,493	46,702	47,016	0.18%		
	Total STATEWIDE Noncoincident Peak	61,141	60,327	59,673	59,369	59,198	59,040	58,929	58,923	58,940	59,138	59,246	59,558	-0.24%		
	Total STATEWIDE Coincident Peak	57,848	57,236	56,658	56,775	56,872	56,987	57,109	57,216	57,354	57,572	57,776	58,045	0.03%		

2019 net peak demand values for each BA area. Includes the impact of IOU load-modifying demand response programs.

1 within a BA area is adjusted to be coincident with the respective BA area net peak demand total.

Your LSE's 2021 System RA allocation, NQC MW here. This will be kept

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	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
CAISO area Non-IOU,CCA,ESP non-coincident demand	3,985	3,997	3,988	3,992	3,995	3,999	4,004	4,009	4,068	4,077	4,120
CAISO area IOU,CCA,ESP non-coincident demand	44,127	43,592	43,361	43,314	43,259	43,288	43,380	43,496	43,689	43,813	44,121
coincident adjustment	95%	95%	95%	96%	97%	97%	97%	97%	97%	98%	97%
CAISO area IOU,CCA,ESP coincident demand	41,866	41,389	41,466	41,612	41,754	41,951	42,123	42,326	42,533	42,726	43,000

Your LSE's estimated percent of CAISO area IOU,CCA,ESP coincident demand

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Your LSE's estimated system RA requirement, NQC MW

REDACTED

Test TRUE

resource_id	resource	note	resource_contract_note	online_date_for_new_resources	contract_execution_start	contract_start	contract_end	reconnection_queue_position	is_new	is_cancelled	is_incremental	is_incremental_expansion	viability_code_reasons	viability_technical_feasibility	viability_resource_sufficiency	viability_financing	storage_max_discharge_mwh	storage_discharge_cycles	hybrid_generator_mw	hybrid_combined_mw	hybrid_capacity_from_grid	execution_year	execution_month	start_year	start_month	end_year	end_month	
1	New_U_Battery	2b Lion Battery	New_U_Battery_2b Li-Ion Battery	0	1/1/2022	10/29/2030	10/29/2030	TBD	0	1	3	1	3	1	2	4	200	400	0	200	1	2012	4	2019	10	2030	10	
2	New_U_Battery	4b Lion Battery	New_U_Battery_4b Li-Ion Battery	0	1/1/2022	TBD	TBD	TBD	0	1	3	1	3	1	2	4	196	784	1	490	64	1	1900	1	1900	1	1900	1
3	New_U_Battery	8b Lion Battery	New_U_Battery_8b Li-Ion Battery	0	1/1/2022	TBD	TBD	TBD	0	1	3	1	3	1	2	4	64	512	0	64	1	1900	1	1900	1	1900	1	
4	existing_generic_instat_large_hydro	none	existing_generic_instat_large_hydro_none	1	ok	n/a	n/a	n/a	0	0	1	ok	ok	ok	ok	ok	ok	ok	ok	ok	ok	ok	ok	ok	ok	ok	ok	ok
5	existing_generic_instat_small_hydro	none	existing_generic_instat_small_hydro_none	1	ok	n/a	n/a	n/a	0	0	1	ok	ok	ok	ok	ok	ok	ok	ok	ok	ok	ok	ok	ok	ok	ok	ok	ok
6	existing_generic_instat_small_hydro	none	existing_generic_instat_small_hydro_none	1	ok	n/a	n/a	n/a	0	0	1	ok	ok	ok	ok	ok	ok	ok	ok	ok	ok	ok	ok	ok	ok	ok	ok	ok
7	existing_generic_geothermal	none	existing_generic_geothermal_none	1	ok	n/a	n/a	n/a	0	0	1	ok	ok	ok	ok	ok	ok	ok	ok	ok	ok	ok	ok	ok	ok	ok	ok	ok
8	existing_generic_biomass_wpdgs	none	existing_generic_biomass_wpdgs_none	1	ok	n/a	n/a	n/a	0	0	1	ok	ok	ok	ok	ok	ok	ok	ok	ok	ok	ok	ok	ok	ok	ok	ok	ok
9	existing_generic_biomass_wood	none	existing_generic_biomass_wood_none	1	ok	n/a	n/a	n/a	0	0	1	ok	ok	ok	ok	ok	ok	ok	ok	ok	ok	ok	ok	ok	ok	ok	ok	ok
10	new_generic_0	none	new_generic_0_none	0	1/1/2022	n/a	n/a	n/a	0	0	1	3	1	2	4	4	1	1	0	0	0	1900	1	1900	1	1900	1	
11	Southern_CA_Desert_Southern_Wind	Desert Wind Project	Southern_CA_Desert_Southern_Wind_Desert Wind Project	0	1/1/2022	TBD	TBD	TBD	0	0	1	3	1	2	4	4	1	1	0	0	0	1900	1	1900	1	1900	1	
12	Tehachapi_Wind	Tehachapi Wind Project	Tehachapi_Wind_Tehachapi Wind Project	0	1/1/2022	TBD	TBD	TBD	0	0	1	3	1	2	4	4	1	1	0	0	0	1900	1	1900	1	1900	1	
13	New_Mexico_Wind	New Mexico Wind Project	New_Mexico_Wind_New Mexico Wind Project	0	1/1/2022	TBD	TBD	TBD	0	0	1	3	1	2	4	4	1	1	0	0	0	1900	1	1900	1	1900	1	
14	new_generic_wind	none	new_generic_wind_none	0	1/1/2022	TBD	TBD	TBD	0	0	1	3	1	2	4	4	1	1	0	0	0	1900	1	1900	1	1900	1	
15	Southern_CA_Desert_Southern_Wind_Solar	Desert Solar Project	Southern_CA_Desert_Southern_Wind_Solar_Desert Solar Project	0	1/1/2022	TBD	TBD	TBD	0	0	1	3	1	2	4	4	1	1	0	0	0	1900	1	1900	1	1900	1	
16	Tehachapi_Solar	Tehachapi Solar Project	Tehachapi_Solar_Tehachapi Solar Project	0	1/1/2022	TBD	TBD	TBD	0	0	1	3	1	2	4	4	1	1	0	0	0	1900	1	1900	1	1900	1	
17	new_generic_solar_taxis	none	new_generic_solar_taxis_none	0	1/1/2022	TBD	TBD	TBD	0	0	1	3	1	2	4	4	1	1	0	0	0	1900	1	1900	1	1900	1	
18	existing_generic_unknown	none	existing_generic_unknown_none	1	ok	n/a	n/a	n/a	0	0	0	ok	ok	ok	ok	ok	ok	ok	ok	ok	ok	ok	ok	ok	ok	ok	ok	ok
19	existing_generic_unknown	PG&E9A2020	existing_generic_unknown_PG&E9A2020	1	ok	8/30/2019	12/1/2020	12/31/2022	n/a	0	0	0	ok	ok	ok	ok	ok	ok	ok	ok	ok	ok	ok	ok	ok	ok	ok	ok
20	existing_generic_unknown	PG&E29A2020	existing_generic_unknown_PG&E29A2020	1	ok	9/24/2019	1/1/2020	12/31/2022	n/a	0	0	0	ok	ok	ok	ok	ok	ok	ok	ok	ok	ok	ok	ok	ok	ok	ok	ok
21	existing_generic_unknown	PG&E48A2020	existing_generic_unknown_PG&E48A2020	1	ok	10/23/2019	7/1/2020	9/30/2022	n/a	0	0	0	ok	ok	ok	ok	ok	ok	ok	ok	ok	ok	ok	ok	ok	ok	ok	ok
22	existing_generic_unknown	CALP&E2020	existing_generic_unknown_CALP&E2020	1	ok	10/27/2019	1/1/2020	12/31/2022	n/a	0	0	0	ok	ok	ok	ok	ok	ok	ok	ok	ok	ok	ok	ok	ok	ok	ok	ok
23	existing_generic_unknown	CALP&E19A21	existing_generic_unknown_CALP&E19A21	1	ok	7/26/2019	1/1/2021	12/31/2022	n/a	0	0	0	ok	ok	ok	ok	ok	ok	ok	ok	ok	ok	ok	ok	ok	ok	ok	ok
24	existing_generic_unknown	CALP&E19A22	existing_generic_unknown_CALP&E19A22	1	ok	11/14/2019	1/1/2021	12/31/2022	n/a	0	0	0	ok	ok	ok	ok	ok	ok	ok	ok	ok	ok	ok	ok	ok	ok	ok	ok
25	existing_generic_unknown	TPSO19A2021	existing_generic_unknown_TPSO19A2021	1	ok	7/1/2019	1/1/2021	12/31/2022	n/a	0	0	0	ok	ok	ok	ok	ok	ok	ok	ok	ok	ok	ok	ok	ok	ok	ok	ok
26	existing_generic_unknown	WP&E19A2021	existing_generic_unknown_WP&E19A2021	1	ok	8/19/2019	5/1/2021	12/31/2022	n/a	0	0	0	ok	ok	ok	ok	ok	ok	ok	ok	ok	ok	ok	ok	ok	ok	ok	ok
27	existing_generic_unknown	EDF&E20A2022	existing_generic_unknown_EDF&E20A2022	1	ok	11/20/2019	1/1/2022	12/31/2022	n/a	0	0	0	ok	ok	ok	ok	ok	ok	ok	ok	ok	ok	ok	ok	ok	ok	ok	ok
28	existing_generic_unknown	SENA&E20A2022	existing_generic_unknown_SENA&E20A2022	1	ok	8/16/2019	1/1/2021	12/31/2021	n/a	0	0	0	ok	ok	ok	ok	ok	ok	ok	ok	ok	ok	ok	ok	ok	ok	ok	ok
29	existing_generic_unknown	EDF&E19A2022	existing_generic_unknown_EDF&E19A2022	1	ok	10/31/2019	1/1/2021	12/31/2022	n/a	0	0	0	ok	ok	ok	ok	ok	ok	ok	ok	ok	ok	ok	ok	ok	ok	ok	ok
30	existing_generic_unknown	OHM&E19A2021	existing_generic_unknown_OHM&E19A2021	1	ok	9/10/2019	1/1/2021	12/31/2022	n/a	0	0	0	ok	ok	ok	ok	ok	ok	ok	ok	ok	ok	ok	ok	ok	ok	ok	ok
31	existing_generic_unknown	OHM&E19A2022	existing_generic_unknown_OHM&E19A2022	1	ok	10/31/2019	1/1/2020	12/31/2022	n/a	0	0	0	ok	ok	ok	ok	ok	ok	ok	ok	ok	ok	ok	ok	ok	ok	ok	ok
32	existing_generic_unknown	OHM&E20A2022	existing_generic_unknown_OHM&E20A2022	1	ok	10/31/2019	1/1/2020	12/31/2022	n/a	0	0	0	ok	ok	ok	ok	ok	ok	ok	ok	ok	ok	ok	ok	ok	ok	ok	ok
33	existing_generic_unknown	EDF&E19A2021	existing_generic_unknown_EDF&E19A2021	1	ok	10/31/2019	1/1/2021	12/31/2021	n/a	0	0	0	ok	ok	ok	ok	ok	ok	ok	ok	ok	ok	ok	ok	ok	ok	ok	ok
34	existing_generic_unknown	MBCF&E19A2021	existing_generic_unknown_MBCF&E19A2021	1	ok	10/31/2019	1/1/2020	12/31/2022	n/a	0	0	0	ok	ok	ok	ok	ok	ok	ok	ok	ok	ok	ok	ok	ok	ok	ok	ok
35	existing_generic_unknown	SENA&E19A2022	existing_generic_unknown_SENA&E19A2022	1	ok	8/16/2019	1/1/2022	12/31/2022	n/a	0	0	0	ok	ok	ok	ok	ok	ok	ok	ok	ok	ok	ok	ok	ok	ok	ok	ok
36	existing_generic_unknown	AMP&E19A2020	existing_generic_unknown_AMP&E19A2020	1	ok	10/25/2019	7/1/2020	9/30/2020	n/a	0	0	0	ok	ok	ok	ok	ok	ok	ok	ok	ok	ok	ok	ok	ok	ok	ok	ok
37	existing_generic_unknown	CALP&E20A2019	existing_generic_unknown_CALP&E20A2019	1	ok	7/23/2018	1/1/2019	12/31/2020	n/a	0	0	0	ok	ok	ok	ok	ok	ok	ok	ok	ok	ok	ok	ok	ok	ok	ok	ok
38	existing_generic_unknown	CALP&E20A2019	existing_generic_unknown_CALP&E20A2019	1	ok	7/23/2018	1/1/2019	12/31/2020	n/a	0	0	0	ok	ok	ok	ok	ok	ok	ok	ok	ok	ok	ok	ok	ok	ok	ok	ok
39	existing_generic_unknown	CP&E19A2020	existing_generic_unknown_CP&E19A2020	1	ok	10/31/2019	2/1/2020	3/31/2020	n/a	0	0	0	ok	ok	ok	ok	ok	ok	ok	ok	ok	ok	ok	ok	ok	ok	ok	ok
40	existing_generic_unknown	DYNG&E20A20	existing_generic_unknown_DYNG&E20A20	1	ok	10/31/2019	1/1/2020	12/31/2020	n/a	0	0	0	ok	ok	ok	ok	ok	ok	ok	ok	ok	ok	ok	ok	ok	ok	ok	ok
41	existing_generic_unknown	EDF&E19A2020	existing_generic_unknown_EDF&E19A2020	1	ok	10/23/2019	1/1/2020	12/31/2020	n/a	0	0	0	ok	ok	ok	ok	ok	ok	ok	ok	ok	ok	ok	ok	ok	ok	ok	ok
42	existing_generic_unknown	EDF&E19A2020	existing_generic_unknown_EDF&E19A2020	1	ok	10/23/2019	1/1/2020	12/31/2020	n/a	0	0	0	ok	ok	ok	ok	ok	ok	ok	ok	ok	ok	ok	ok	ok	ok	ok	ok
43	existing_generic_unknown	MBCF&E19A2020	existing_generic_unknown_MBCF&E19A2020	1	ok	10/31/2019	1/1/2020	12/31/2021	n/a	0	0	0	ok	ok	ok	ok	ok	ok	ok	ok	ok	ok	ok	ok	ok	ok	ok	ok
44	existing_generic_unknown	NEXT&E19A2020	existing_generic_unknown_NEXT&E19A2020	1	ok	6/13/2019	1/1/2020	12/31/2020	n/a	0	0	0	ok	ok	ok	ok	ok	ok	ok	ok	ok	ok	ok	ok	ok	ok	ok	ok
45	existing_generic_unknown	NEXT&E20A2020	existing_generic_unknown_NEXT&E20A2020	1	ok	10/31/2019	10/1/2020	10/31/2020	n/a	0	0	0	ok	ok	ok	ok	ok	ok	ok	ok	ok	ok	ok	ok	ok	ok	ok	ok
46	existing_generic_unknown	NEXT&E20A2020	existing_generic_unknown_NEXT&E20A2020	1	ok	10/31/2019	10/1/2020	10/31/2020	n/a	0	0	0	ok	ok	ok	ok	ok	ok	ok	ok	ok	ok	ok	ok	ok	ok	ok	ok
47	existing_generic_unknown	PC&E19A2020	existing_generic_unknown_PC&E19A2020	1	ok	10/31/2019	1/1/2020	11/30/2020	n/a	0	0	0	ok	ok	ok	ok	ok	ok	ok	ok	ok	ok	ok	ok	ok	ok	ok	ok
48	existing_generic_unknown	PC&E20A2020	existing_generic_unknown_PC&E20A2020	1	ok	10/31/2019	1/1/2020	11/30/2020	n/a	0	0	0	ok	ok	ok	ok	ok	ok	ok	ok	ok	ok	ok	ok	ok	ok	ok	ok
49	existing_generic_unknown	PC&E19A2020	existing_generic_unknown_PC&E19																									

Show NQC for this month in System Reliability Progress Tracking Table->
 Show D.19-11-016 incremental procurement in this year -->
 Display NQC MW or GWh in System Reliability Progress Tracking Table?

September
2021
NQC MW

September 2021

System Reliability Progress Tracking Table (NQC MW) for month of September by contract status, 46 MMT portfolio		ELCC type	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
online	wind_low_cf	-	-	-	-	-	-	-	-	-	-	-	-
online	wind_high_cf	-	-	-	-	-	-	-	-	-	-	-	-
online	biomass	-	-	-	-	-	-	-	-	-	-	-	-
online	cogen	-	6	6	6	6	6	6	6	6	6	6	6
online	geothermal	-	-	-	-	-	-	-	-	-	-	-	-
online	hydro	-	-	-	-	-	-	-	-	-	-	-	-
online	thermal	-	99	99	99	99	99	99	99	99	99	99	99
online	battery	-	-	-	-	-	-	-	-	-	-	-	-
online	nuclear	-	-	-	-	-	-	-	-	-	-	-	-
online	solar	-	-	-	-	-	-	-	-	-	-	-	-
online	psh	-	-	-	-	-	-	-	-	-	-	-	-
online	unknown	1,277	599	438	-	-	-	-	-	-	-	-	-
development	wind_low_cf	-	9	9	9	10	11	13	13	13	13	13	13
development	wind_high_cf	-	-	-	-	-	-	-	-	-	-	-	-
development	biomass	-	-	-	-	-	-	-	-	-	-	-	-
development	cogen	-	-	-	-	-	-	-	-	-	-	-	-
development	geothermal	-	-	-	-	-	-	-	-	-	-	-	-
development	hydro	-	-	-	-	-	-	-	-	-	-	-	-
development	thermal	-	-	-	-	-	-	-	-	-	-	-	-
development	battery	-	-	28	28	28	28	28	28	28	28	28	28
development	nuclear	-	-	-	-	-	-	-	-	-	-	-	-
development	solar	-	37	37	137	128	120	112	131	131	131	131	131
development	psh	-	-	-	-	-	-	-	-	-	-	-	-
development	unknown	-	-	-	-	-	-	-	-	-	-	-	-
review	wind_low_cf	-	-	-	-	-	-	-	-	-	-	-	-
review	wind_high_cf	-	-	-	-	-	-	-	-	-	-	-	-
review	biomass	-	-	-	-	-	-	-	-	-	-	-	-
review	cogen	-	-	-	-	-	-	-	-	-	-	-	-
review	geothermal	-	-	-	-	-	-	-	-	-	-	-	-
review	hydro	-	-	-	-	-	-	-	-	-	-	-	-
review	thermal	-	-	-	-	-	-	-	-	-	-	-	-
review	battery	-	-	-	-	-	-	-	-	-	-	-	-
review	nuclear	-	-	-	-	-	-	-	-	-	-	-	-
review	solar	-	-	-	-	-	-	-	-	-	-	-	-
review	psh	-	-	-	-	-	-	-	-	-	-	-	-
review	unknown	-	-	-	-	-	-	-	-	-	-	-	-
planned_existing	wind_low_cf	-	-	-	-	-	-	-	-	-	-	-	-
planned_existing	wind_high_cf	-	-	-	-	-	-	-	-	-	-	-	-
planned_existing	biomass	-	-	-	-	-	-	-	-	3	7	10	14
planned_existing	cogen	-	-	-	-	-	-	-	-	-	-	-	-
planned_existing	geothermal	-	-	10	23	37	49	62	62	62	62	62	-
planned_existing	hydro	-	-	133	133	133	133	133	133	133	133	133	133
planned_existing	thermal	-	-	-	-	-	-	-	-	-	-	-	-
planned_existing	battery	-	-	-	-	-	-	-	-	-	-	-	-
planned_existing	nuclear	-	-	-	-	-	-	-	-	-	-	-	-
planned_existing	solar	-	-	-	-	-	-	-	-	-	-	-	-
planned_existing	psh	-	-	-	-	-	-	-	-	-	-	-	-
planned_existing	unknown	-	-	-	-	-	-	-	-	-	-	-	-
planned_new	wind_low_cf	-	675	385	745	735	735	695	665	645	615	595	-
planned_new	wind_high_cf	-	-	36	37	43	50	58	59	60	61	64	-
planned_new	biomass	-	-	11	12	14	16	18	18	18	18	19	-
planned_new	cogen	-	-	-	-	-	-	-	-	-	-	-	-
planned_new	geothermal	-	-	-	-	-	-	-	-	-	-	-	-
planned_new	hydro	-	-	-	-	-	-	-	-	-	-	-	-
planned_new	thermal	-	-	-	-	-	-	-	-	-	-	-	-
planned_new	battery	-	-	176	181	186	188	189	229	269	308	348	-
planned_new	nuclear	-	-	-	-	-	-	-	-	-	-	-	-
planned_new	solar	-	-	52	52	46	39	33	35	38	40	43	-
planned_new	psh	-	-	-	-	-	-	-	-	-	-	-	-
planned_new	unknown	-	-	-	-	-	-	-	-	-	-	-	-
TOTAL supply, NQC MW			1,277	1,425	1,421	1,461	1,464	1,474	1,445	1,481	1,508	1,524	1,491
Load (MW)			REDACTED										
Load +15% PRM (MW)			REDACTED										
Supply minus load: Shortfall (-) or Surplus (+), in MW			REDACTED										

NQC MW from data	NQC MW displayed in table	difference (absolute)	match?
15,972	15,972	0	TRUE

0 <--N

Incremental Procurement for D.19-11-016, NQC MW
Supply-side resource is incremental
New resource that is energy only in 2021
Demand-side resource is not in IEP demand forecast (and therefore incremental)
MW added to existing resource
Total NQC MW

2021
46
-
-
-
46

Check match of TRUE

Appendix E

Senior Executive Attestation (D.19-11-016)

Senior Executive Attestation

Compliance Filing for LSEs Electing to **Self-Provide** the Integrated Resource Planning Procurement Required by D. 19-11-016

September 1, 2020

CA Public Utilities Commission (CPUC)
505 Van Ness Avenue, 4th Floor
San Francisco, CA 94102-3298

Re: September 1, 2020, Individual Integrated Resource Plan Senior Executive Attestation Pursuant to Decision (D). 19-11-016 adopted in R. 16-02-007

Pursuant to Ordering Paragraph (O.P.) 12 of Decision (D.) 19-11-016, adopted in R.16-02-007 on November 5, 2019, East Bay community Energy (EBCE) submits this attestation.

Background

D.19-11-016 requires that all Load Serving Entities (LSEs) file their individual integrated resource (IRP) plans by May 1, 2020 [*revised to September 1, 2020*]¹. The decision also requires that all LSEs directed in the Decision shall present in their IRP plans an attestation from a senior executive in the company that the necessary capacity required in this Decision shall be provided if the LSE is electing to self-provide the capacity required.² This Decision states that the attestation shall be accompanied by a detailed list of projects, capacities, and dates by which the LSE expects the projects to be providing service to the LSE, as well as a demonstration that the projects are incremental, to meet the 2021, 2022, and 2023 requirements of the decision.

Resource Data Template

The Resource Data Template to be used for the September 1, 2020, IRP filing has been developed to identify the required information in O.P. 12 D.19-11-016; consequently, this attestation refers to the template contents to obviate the need for a separate compliance document. The “Certification of Information” section at the bottom of this attestation refers to the specific data fields in the Resource Data Template referenced in Table 1 below, which map to the requirements in O.P. 12 of D.19-11-016.

Table 1

Resource Data Template Reliability Procurement Fields Related to O.P. 12, D.19-11-016

O.P. 12 Requirement	Corresponding Field in Resource Data Template
Detailed List of Projects	“Monthly_GWH_MW” tab; Columns B, C, & K
Capacities	“Monthly_GWH_MW” tab; Columns F, G, & H
Dates by which LSE expects projects to be providing service to LSE	“Unique Contracts” tab; Columns G, H, & I
Demonstration projects are incremental	“Unique Contracts” tab; Columns M & N

¹ Decision (D.)20-03-028 modified the filing date from May 1, 2020 to September 1, 2020 at page 67.

² The LSEs directed in the Decision are named in OP 3 and by CPUC staff as discussed in OP 4.

Attestation Requirements

To satisfy the requirements in O.P. 12 of D. 19-11-016, a senior executive shall sign the “Certification of Information” section below and submit this attestation as part of their compliance filing in the IRP Proceeding by September 1, 2020. No additional documentation is required at this time.

Certification of Information


Consistent with Rules 1 and 2.4 of the CPUC’s Rules of Practice and Procedure, the individual IRP compliance filing has been verified by a senior executive who shall expressly certify, under penalty of perjury, the following:

- (1) The necessary incremental Resource Adequacy capacity required of EBCE in Decision (D.) 19-11-016 shall be provided in compliance with the terms established in D.19-11-016 and January 3, 2020, ruling finalizing baseline resources.
- (2) I have reviewed the Resource Data Template data fields referenced in Table 1 above (and any information provided to meet Milestone 1 of the backstop mechanism proposed in the June 5, 2020, Backstop Procurement and Cost Allocation Mechanisms Ruling) submitted in my company’s individual IRP compliance filing in the IRP Proceeding.
- (3) Based on my knowledge, information or belief, the compliance filing information referenced in (2) above is an accurate reflection of the LSE’s plans to self-provide its obligation of the incremental Resource Adequacy capacity and the terms identified in D.19-11-016, and does not contain any untrue statement of a material fact or data or omit to state a material fact or data necessary to make the statements true.
- (4) Based on my knowledge, information, or belief, the compliance filing information referenced in (2) above contains all of the information required to be provided by CPUC orders, rules, and regulations.

Senior Executive Signature:

Nicolas Chaset
[Name]

Chief Executive Officer
[Title]

DocuSigned by:

9DF8BA3222CE44F...
[Signature] 8/28/2020
[Date]



Integrated Resource Plan Update

PRESENTED BY: Stefanie Tanenhaus

DATE: September 16, 2020



Deliverables



Phase 1: CPUC IRP Compliance Filing

- Analysis based on prescriptive assumptions
- Narrative – analysis, process, results, lessons learned
- Resource Data – conforming & “preferred” portfolios, if applicable
- Clean System Power Calculator
- Attestation electing self-procurement

Phase 2: Analysis on EBCE Organizational Goals

- Additional analysis on lower GHG target (30 MMT)
- Identify reliability needs
- Define trade-offs between organizational objectives
- Inform procurement recommendations
- Develop path to expedited GHG reduction

CPUC Requirements

- 46 MMT *and* 38 MMT scenarios

LSE	2030 Load (GWh)	Share of 2030 load in <u>IOU territory</u>	2030 GHG emissions benchmark – 46 MMT scenario	2030 GHG emissions benchmark – 38 MMT scenario
PG&E Bundled	26,777	35.2%	5.479	4.526
EBCE	6,910 ¹	9.08%	1.222 ²	0.977 ²
SCE Bundled	54,393	63.49%	9.687	8.003
SDG&E Bundled	5,366	29.46	1.198	0.990

¹ Load represents CPUC approved load forecast as of 5/20/20.

² Reflects requirement *after* behind the meter Combined Heat & Power emissions are removed from target. Note: Revised slightly downwards by CPUC.

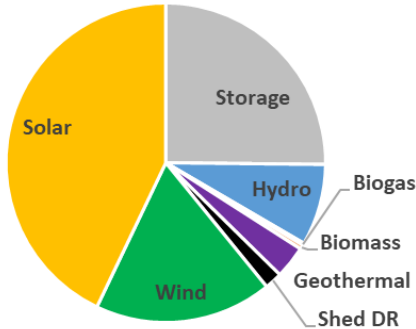
- Specific Input Requirements
- Filing date: September 1, 2020

Final Conforming Portfolios – Capacity

46 MMT Scenario → EBCE = 1.222 MMT in 2030

38 MMT Scenario → EBCE = 0.977 MMT in 2030

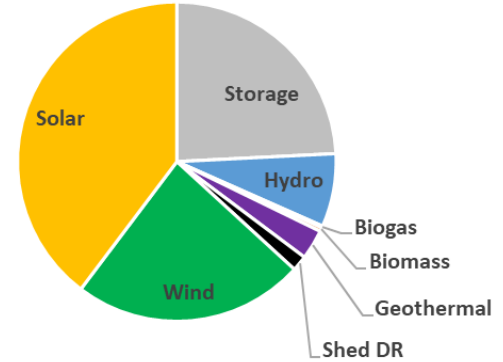
46 MMT Nameplate Capacity (2030)



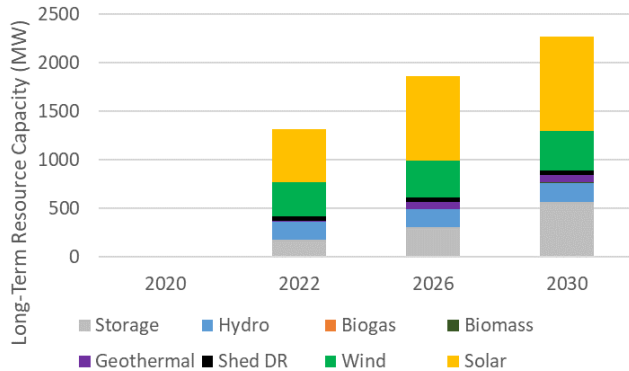
Total Costs
(Levelized 10 yr, \$M)
\$507 | \$516

Total Costs per
MWh Load
(Levelized 10 yr)
\$73.7 | \$75.0

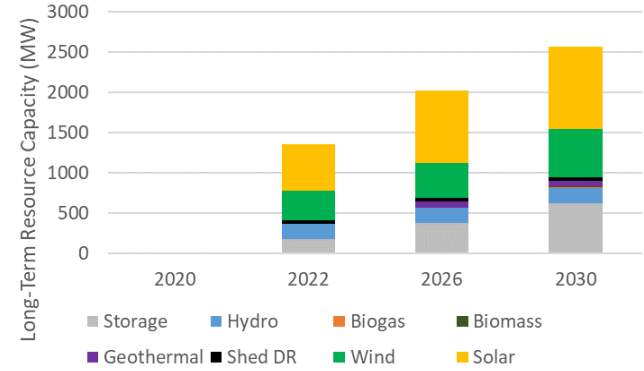
38 MMT Nameplate Capacity



46 MMT



38 MMT



Note: scales on
Y-axes are
different btw
graphs



Next Steps

- EBCE staff to complete analysis of a deeper decarbonization pathway and engage Board and Community in discussion of costs and benefits of more aggressive pathway
- Board to review and approve EBCE's next round of clean energy procurement based on a review of range of decarbonization pathways