PUBLIC UTILITIES COMMISSION
505 Van Ness Avenue
San Francisco CA 94102-3298

Pacific Gas & Electric Company
ELC (Corp ID 39)
Status of Advice Letter 6214E
As of July 8, 2021

Subject: San Diego Gas & Electric Company, Southern California Edison Company, And Pacific Gas And Electric Company's ELCC Study Update Submission

Division Assigned: Energy

Date Filed: 06-01-2021

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Effective Date:	**07-14-2021**

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Resolution Number: None

Commission Meeting Date: None

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STATE OF CALIFORNIA **GAVIN NEWSOM,** *Governor*

PUBLIC UTILITIES COMMISSION
505 Van Ness Avenue
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To: Energy Company Filing Advice Letter

From: Energy Division PAL Coordinator

Subject: Your Advice Letter Filing

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Energy Division's Tariff Unit by e-mail to
edtariffunit@cpuc.ca.gov

Clay Faber - Director
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June 1, 2021

ADVICE LETTER 6214-E
(Pacific Gas and Electric Company – U39 M)

ADVICE LETTER 3775-E
(San Diego Gas & Electric Company - U902 M)

ADVICE LETTER 4512-E
(Southern California Edison Company – U338 E)

PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA

SUBJECT: SAN DIEGO GAS & ELECTRIC COMPANY, SOUTHERN CALIFORNIA EDISON COMPANY, AND PACIFIC GAS AND ELECTRIC COMPANY'S ELCC STUDY UPDATE SUBMISSION

I. PURPOSE

Pursuant to Ordering Paragraph (OP) 2 of Decision (D.) 19-09-043, San Diego Gas & Electric Company (SDG&E), Southern California Edison Company (SCE), Pacific Gas and Electric Company (PG&E) – collectively, the Joint IOUs – submit their updated Effective Load Carrying Capability (ELCC) study results.

II. BACKGROUND

As ordered in D.19-09-043, the Joint IOUs performed a study to assess the ELCC values used in RPS evaluations. The Decision required using a specific dataset, software, and methodology including the following:

- The joint IOU study shall use the Strategic Energy and Risk Valuation Model (SERVM).
- BTM PV must be treated as a supply-side resource.
- An annual loss of load expectation (LOLE) study must be conducted using a 0.1 LOLE metric.
- Annual, marginal ELCC values must be determined.
- The most recently updated base portfolio from the IRP proceeding must be used with study years of subsequent four-year increments.
- The following years 2022, 2026, and 2030 must be studied.

- The study shall analyze the following resources: fixed axis PV, tracking PV, tracking PV paired with storage, distributed PV, wind, and wind paired with storage.
- The study shall be performed across seven regions, four in CAISO and three outside of CAISO.
- The investor-owned utilities must continue to update the joint ELCC study annually until directed otherwise.

To fulfill the joint study and its associated requirements, the Joint IOUs hired Astrapé Consulting to perform the analysis.

III. DISCUSSION

A. ELCC Study Results

While the 2020 ELCC report showed very low marginal ELCCs for solar, two key differences result in higher values in the current study. The first is solar output during net load peaks is higher in the current baseline dataset's solar profiles, and the second is reliability interactions between storage resources and marginal solar resources were observed. Utility scale PV ELCC in CAISO drops from 9-11% in 2022 to 5-6% in 2030. The ELCCs of non-dispatchable resources are also dependent on the modeled load profiles. As gross loads peak later in the day, solar contributes less to the aggregate reliability of the system. The CAISO load shapes in the RSP dataset reflect a higher risk of late day gross load peaks than is present in other synthetic shapes such as the 2018 IEPR hourly load forecast. This characteristic has the potential to suppress solar ELCCs, although the effect is expected to be modest. The joint IOUs are not suggesting either one is more correct, but instead simply noting differences in the load profiles from different sources.

Wind resources also interact with other resource classes and while the average wind contribution to net load peaks remains constant at 14-15%, the CAISO wind output in the 8 hours preceding the net load peak tends to be low, preventing wind from reliably delaying the start of storage discharging. This causes storage energy to be exhausted during net load peak periods, depressing wind ELCCs in 2026 and 2030.

Hybrid facility ELCCs largely mimic the ELCC of equal capacity standalone batteries in the penetrations and hybrid configurations studied. At higher system battery penetrations with a flatter net load shape, the limited renewable energy used to charge the battery portion of a hybrid facility could limit the ELCC below what a standalone battery charging from the grid could provide. At the penetrations studied in 2030, the storage duration required by the batteries to provide reliability was able to be met by the associated renewable energy generator.

D.19-09-043 ordered the IOUs to determine the ELCC of several renewable and renewable with battery storage technologies. Determination of battery ELCCs was not ordered in the decision, however in the study, standalone battery ELCCs were also calculated. They are included in the report results only as a reference and to provide context when evaluating results of other technology ELCC values.

Battery ELCCs remain above 75% at penetrations projected through 2030, contingent on nearly all battery capacity having 4-hour duration or longer. If the projected mix of batteries skews towards shorter duration, marginal batteries will have reduced ELCCs. Marginal 1-hour and 2-hour batteries are used to serve ancillary services are assumed to not be exhausted after providing those services, while 4-hour batteries that were previously serving ancillary services shift to serve energy. Thus, the reliability contribution of 1-hour batteries is similar to that of 4-hour batteries.

Battery and hybrid battery plus renewable project ELCCs are noticeably lower than those in the 2020 joint IOU ELCC study report. In this study, batteries and hybrids do not achieve close to 100% ELCC in 2022 and 2026 even though they are nearly always sufficiently charged to serve either ancillary service requirements or net load peaks. While some reduction is due to the much higher penetrations of batteries studied this year - 7,551 MW more battery capacity is available by 2026 - the primary reason for the reduction is the interaction that storage resources have with other dispatchable resources that have forced outage rates.

Tables ES1 – ES4 provide the ELCC values by technology and region for the study years 2022, 2026, and 2030[1,2,3]. A detailed discussion of study results is included in the Simulation Results section of the ELCC study report.

Table ES1. 2022 Study Results (expressed as a percentage of assumed interconnection capability)

Technology	BTM PV	Fixed PV	Tracking PV	Wind
PGE Valley	5.9%	8.6%	11.0%	17.2%
PGE Bay	5.5%	8.5%	10.9%	24.4%
SCE	6.4%	8.9%	11.2%	11.8%
SDGE	5.9%	8.7%	11.0%	11.8%
AZ APS	N/A	5.0%	6.8%	16.1%
NM EPE	N/A	5.0%	6.8%	14.8%
BPA	N/A	N/A	N/A	16.0%
CAISO	5.9%	8.7%	11.0%	16.3%

[1] For purposes of the ELCC Study, ELCC is calculated as a percentage of interconnection capability, where interconnection capability is assumed equal to (i) the installed capacity of non-hybrid resources, or (ii) in the case of hybrid resources, the installed capacity of the renewable resource or storage device, which are equally sized for all hybrids analyzed.
[2] Values for all three study years reflect post-processing to reduce statistical noise.
[3] The CAISO marginal ELCC values are calculated by averaging the values for PGE Valley, PGE Bay, SCE, and SDGE for each technology.

Table ES2. 2026 Study Results (expressed as a percentage of assumed interconnection capability)

Technology	BTM PV	Fixed PV	Tracking PV	Wind
PGE Valley	3.6%	6.0%	7.2%	15.6%
PGE Bay	3.4%	5.8%	7.1%	19.2%
SCE	5.1%	6.1%	7.8%	10.8%
SDGE	4.2%	6.0%	7.4%	10.8%
AZ APS	N/A	3.8%	5.9%	8.6%
NM EPE	N/A	3.8%	5.9%	8.6%
BPA	N/A	N/A	N/A	12.6%
CAISO	4.1%	5.9%	7.4%	14.1%

Table ES3. 2030 Study Results (expressed as a percentage of assumed interconnection capability)

Technology	BTM PV	Fixed PV	Tracking PV	Wind
PGE Valley	2.1%	4.3%	5.9%	12.1%
PGE Bay	2.1%	4.2%	5.7%	15.5%
SCE	2.3%	4.8%	6.5%	6.3%
SDGE	2.1%	4.6%	6.5%	6.3%
AZ APS	N/A	1.2%	3.0%	3.3%
NM EPE	N/A	1.2%	3.0%	3.3%
BPA	N/A	N/A	N/A	8.8%
CAISO	2.2%	4.5%	6.2%	10.1%

Table ES4. Battery and Hybrid Study Results[4]

Technology	2022	2026	2030
1-Hour Hybrid or Standalone Battery	87.1%	85.4%	78.6%
2-Hour Hybrid or Standalone Battery	88.3%	86.7%	80.4%
4-Hour Hybrid or Standalone Battery	90.6%	88.1%	82.2%

Standalone batteries, PV hybrids, and wind hybrid facilities were simulated independently but the results demonstrated ELCCs for all three technologies and all locations to be within statistical error bounds and are thus averaged for this report. When battery penetration reaches a level after 2030 where energy sufficiency is a significant concern, the ELCCs of hybrid facilities will be sensitive to the charging

[4] Simulations were performed with standalone battery in addition to PV hybrids and wind hybrids for calibration purposes.

capability of the associated renewable energy and locational differences between hybrid facilities may surface.

B. Joint IOU Recommendations

The ELCC results for non-dispatchable resources are highly contingent on accurate modeling of their energy production profiles. The development of synthetic solar production profiles is simpler and more accurate than the development of wind profiles since robust historical solar data is readily available. Wind profile development is inherently more challenging as historical wind observations do not reliably translate to site specific production profiles. Astrapé's recommendation is to use an aggregated wind ELCC for all projects until more rigorous synthetic wind profiles can be developed and consideration of factors such as wind regime and technology can be considered rather than exclusively the zonal definitions inherent in the current results.

While the ELCC study was performed across the seven regions, the Joint IOUs recommend, that for any CAISO-located resource, the CAISO ELCC values for the respective technologies be used for any RPS evaluation purposes. The geographic differences remain difficult to capture without significant time and effort.

The IOUs recommend that the CPUC begin a process to consider aligning resource reliability contribution counting in the various proceedings such as RPS, Resource Adequacy, and Integrated Resource Plan.

IV. APPENDICES

This advice letter contains appendices as listed below.

Appendix A: ELCC Study Report

V. EFFECTIVE DATE

SDG&E believes this submittal is subject to Energy Division disposition and should be classified as Tier 2 (effective after staff approval) pursuant to GO 96-B. SDG&E respectfully requests that the Commission approve this advice letter no later than July 17, 2021, which is 30 days from the date of this filing.

VI. PROTEST

Anyone may protest this Advice Letter to the Commission. The protest must state the grounds upon which it is based, including such items as financial and service impact, and should be submitted expeditiously. The protest must be made in writing and must be received no later than July 7, 2021, which is 20 days after the date this Advice Letter was submitted with the Commission. There is no restriction on who may submit a protest. The address for mailing or delivering a protest to the Commission is:

CPUC Energy Division
Attention: Tariff Unit
505 Van Ness Avenue
San Francisco, CA 94102

Copies of the protest should also be sent via e-mail to the attention of the Energy Division at EDTariffUnit@cpuc.ca.gov. A copy of the protest should also be sent via e-mail to the address shown below on the same date it is mailed or delivered to the Commission.

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NOTICE

A copy of this filing has been served on the utilities and interested parties shown on the attached list, including interested parties in A.14-11-007 et. al. and R.18-07-003 service lists, by providing them a copy hereof either electronically or via the U.S. mail, properly stamped and addressed. Direct address changes to SDG&E Tariffs by email to SDG&ETariffs@sdge.com.

/s/ Clay Faber

CLAY FABER
Director – Regulatory Affairs

ADVICE LETTER SUMMARY

ENERGY UTILITY

MUST BE COMPLETED BY UTILITY (Attach additional pages as needed)

Company name/CPUC Utility No.:

Utility type:

- ELC
- GAS
- WATER
- PLC
- HEAT

Contact Person:
Phone #:
E-mail:
E-mail Disposition Notice to:

EXPLANATION OF UTILITY TYPE

ELC = Electric
GAS = Gas
PLC = Pipeline
HEAT = Heat
WATER = Water

(Date Submitted / Received Stamp by CPUC)

Advice Letter (AL) #:

Tier Designation:

Subject of AL:

Keywords (choose from CPUC listing):

AL Type: Monthly Quarterly Annual One-Time Other:

If AL submitted in compliance with a Commission order, indicate relevant Decision/Resolution #:

Does AL replace a withdrawn or rejected AL? If so, identify the prior AL:

Summarize differences between the AL and the prior withdrawn or rejected AL:

Confidential treatment requested? Yes No

If yes, specification of confidential information:
Confidential information will be made available to appropriate parties who execute a nondisclosure agreement. Name and contact information to request nondisclosure agreement/access to confidential information:

Resolution required? Yes No

Requested effective date:July 17,2021

No. of tariff sheets:

Estimated system annual revenue effect (%):

Estimated system average rate effect (%):

When rates are affected by AL, include attachment in AL showing average rate effects on customer classes (residential, small commercial, large C/I, agricultural, lighting).

Tariff schedules affected:

Service affected and changes proposed[1]:

Pending advice letters that revise the same tariff sheets:

[1]Discuss in AL if more space is needed.

Protests and all other correspondence regarding this AL are due no later than 20 days after the date of this submittal, unless otherwise authorized by the Commission, and shall be sent to:

CPUC, Energy Division Attention: Tariff Unit 505 Van Ness Avenue San Francisco, CA 94102 Email: EDTariffUnit@cpuc.ca.gov	Name: Title: Utility Name: Address: City: State: Zip: Telephone (xxx) xxx-xxxx: Facsimile (xxx) xxx-xxxx: Email:
	Name: Title: Utility Name: Address: City: State: Zip: Telephone (xxx) xxx-xxxx: Facsimile (xxx) xxx-xxxx: Email:

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General Order No. 96-B
ADVICE LETTER SUBMITTAL MAILING LIST

cc: (w/enclosures)

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Service List(s)
A.14-11-007
R.18-07-003

APPENDIX A

2021 Joint IOU ELCC Study

Final Report

5/28/2021

PREPARED FOR

California Investor Owned Utilities
Southern California Edison Company
Pacific Gas & Electric Company
San Diego Gas & Electric Company

PREPARED BY

Kevin Carden
Alex Krasny Dombrowsky
Cole Benson
Chase Winkler
Astrapé Consulting

Disclaimer: This report was prepared by the authors for the California Investor Owned Utilities (CA IOUs) which include San Diego Gas & Electric Company, Southern California Edison Company, and Pacific Gas & Electric Company. It is provided as is, and Astrapé Consulting and CA IOUs disclaim any and all express or implied representations or warranties of any kind relating to the accuracy, reliability, completeness, or currency of the data, conclusions, forecasts or any other information in this report. Readers of this report should independently verify the accuracy, reliability, completeness, currency, and suitability for any particular purpose of any information in this report.

Furthermore, this report is not intended nor should it be read as either comprehensive or fully applicable to any specific opportunity in the CAISO market, as all opportunities have idiosyncratic features that will be impacted by actual market conditions. Readers of this report should seek independent expert advice regarding any information in this report and any conclusions that could be drawn from this report. The report itself in no way offers to serve as a substitute for such independent expert advice.

To the fullest extent permitted by law, Astrapé Consulting and CA IOUs, along with their respective directors, officers, and employees, shall not be liable for any errors, omissions, defects, or misrepresentations in the information contained in this report, whether intentional or unintentional, or for any loss or damage suffered by persons who use or rely on such information or any conclusions that could be drawn from the report that turn out to be inaccurate (including by reason of negligence, negligent misstatement, or otherwise).

By reviewing this report, the reader agrees to accept the terms of this disclaimer.

Acknowledgement: We acknowledge the valuable contributions of many individuals to this report and to the underlying analysis, including peer review and input offered by the CA IOUs staff. We especially would like to acknowledge the analytical, technical, and conceptual contributions of Matt O'Connell, Maurice Ahyow, Matthew Kawatani, Daniel Hopper, Ben Montoya, Effat Moussa, Habibou Maiga, Jan Strack, Anupama Pandey, Grace Li, Joseph Yan, Alan Soe, Amy Li, and Maren Wenzel.

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AZ APS	Arizona Public Service
BANC	Balancing Authority of Northern California
BCHA	British Columbia Hydro Authority
BPA	Bonneville Power Administration
BTM PV	Behind the Meter PV
CAISO	California Independent System Operator
CA-N	Northern California (PGE Valley and PGE Bay)
CA-S	Southern California (SDGE and SCE)
CFE	Comisión Federal de Electricidad
CPUC	California Public Utilities Commission
Decision	Decision Adopting Modeling Requirements to Calculate Effective Load Carrying Capability Values for Renewables Portfolio Standard Procurement
EE	Energy Efficiency
EFOR	Equivalent Forced Outage Rate
EIA	Energy Information Administration
ELCC	Effective Load Carrying Capability
EV	Electric Vehicle
GW	Gigawatts
IEPR	Integrated Energy Policy Report
IID	Imperial Irrigation District
ILR	Inverter Loading Ratio
IOUs	California Investor Owned Utilities
IPCO	Idaho Power Company
IRP	Integrated Resource Plan
LADWP	Los Angeles Department of Water and Power
LOLE	Loss of Load Expectation
MW	Megawatts
NEVP	Nevada Power Company
NM EPE	New Mexico Area and El Paso Electric
NWMT	NorthWestern Energy
NREL	National Renewable Energy Laboratory
PACE	PacifiCorp East

PACW	PacifiCorp West
PGE Bay	Pacific Gas & Electric Bay
PGE Valley	Pacific Gas & Electric Valley
PSCO	Public Service Company of Colorado
PV	Photovoltaic
RSP	Reference System Plan
SAM	System Advisor Model
SCE	Southern California Edison
SDGE	San Diego Gas & Electric
SERVM	Strategic Energy and Risk Valuation Model
SRP	Salt River Project
TEPC	Tucson Electric Power Company
TIDC	Turlock Irrigation District
TOU	Time-of-Use
WACM	Western Area Power Administration – Colorado/Missouri Region
WALC	Western Area Power Administration – Lower Colorado Region

EXECUTIVE SUMMARY

As directed in the "Decision Adopting Modeling Requirements to Calculate Effective Load Carrying Capability Values for Renewables Portfolio Standard Procurement" ("Decision") on October 3rd, 2019 in California Public Utilities Commission's ("CPUC" or "Commission") Renewable Portfolio Standard ("RPS") Proceeding Rulemaking. 18-07-003, the Commission ordered the California Investor Owned Utilities ("IOUs"), which comprise Pacific Gas & Electric Company, San Diego Gas & Electric Company, and Southern California Edison Company, to perform an Effective Load Carrying Capability ("ELCC") study. [1]

In accordance with the Decision, Astrapé Consulting, acting as contractor, provided to the IOUs one report that updates the ELCC values for the resource classes and class subtypes located in seven geographical regions (PGE Bay, PGE Valley, SCE, SDGE, AZ APS, NM EPE, and BPA), details the input assumptions (e.g., load, installed capacity), explains the methodology used to calculate the ELCC values, and compares the impact of the different locations on the same technology types.[2] As directed in the Decision, the 2019-2020 IRP's Reference System Plan ("RSP") was used for the baseline resource list for the analysis presented here. ELCC values are reflective of the system studied and are not applicable to a system with a substantially different load and resource mix. The marginal ELCC values in this report represent the annual contribution towards reliability of a given increment of generation capacity. These ELCC values do not specifically represent, but do incorporate, the reliability contribution of this incremental generation capacity, during critical hours (HE 19-21) in August and September.

The RSP includes significant changes to synthetic wind, solar, and load profiles and reflects significant changes in the resource mix in the California Independent System Operator Corporation ("CAISO") system. Other relevant changes include the assumptions on import capability during peak periods and forced outage rates of conventional generation. These changes result in meaningful shifts in the ELCCs for nearly all technology classes and surface significant reliability-related interactions among those technology classes.

The major findings of this study are:

- While the intent of this study was to exclusively analyze renewable and hybrid resource ELCCs, the increasing penetration of batteries expected over the next decade introduced significant reliability-related interactions across resource classes. To understand these interactions, the ELCCs of batteries were also calculated, but are presented here for context only.
- The ELCCs of battery resources remain high (>75%) at penetrations projected through 2030 (~12 gigawatts or "GW"). These results are contingent on nearly all battery capacity having 4-hour duration or longer. If the projected mix of batteries are weighted toward shorter duration, marginal batteries of any duration will have lower ELCCs. However, the slope of the decline in ELCCs is modest and differences between durations are minor, largely because Strategic Energy and Risk Valuation Model ("SERVM") optimizes the utilization of batteries by duration. Marginal 1- and 2-hour batteries are used to serve ancillary services and are assumed to be not exhausted after providing ancillary services, while 4-hour batteries that were

[1] Decision at Ordering Paragraph 1. The Decision is available at http://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M316/K882/316882092.PDF

[2] Pacific Gas & Electric Bay, Pacific Gas & Electric Valley, Southern California Edison, San Diego Gas & Electric, Arizona Public Service, New Mexico Area and El Paso Electric, and Bonneville Power Administration, respectively

previously serving ancillary services shift to serve energy. Thus, the reliability contribution of 1-hour batteries nearly mimics that of 4-hour batteries.

  - Battery and hybrid ELCCs are contingent on being able to serve ancillary services with only 30 minutes of energy duration. The hourly simulations are able to avoid discharging, but in actual practice, net load volatility and generator contingencies may require discharging batteries which could reduce battery and hybrid reliability contributions. Differences between modeled and actual performance of batteries should be monitored.

- Battery and hybrid battery plus renewable project ELCCs are noticeably lower than those in our 2020 ELCC report. In this study, batteries and hybrids do not achieve close to 100% ELCC in 2022 and 2026 even though they are nearly always sufficiently charged to serve either ancillary service requirements or net load peaks. While some reduction is due to the much higher penetrations of batteries studied this year – 7,551 megawatts ("MW") more battery capacity is available by 2026 – the primary reason for the reduction is the interaction that storage resources have with other dispatchable resources that have forced outage rates. Adding a 500 MW battery and raising load by 500 MW results in the need to run more than 500 MW of dispatchable resources on average across the year.[3] That generation will primarily come from dispatchable units that have a forced outage rate which in turn results in more MW offline on average.[4] This impact on system outages translates to a reduction in ELCC for the storage resource approximately equal to the equivalent forced outage rate ("EFOR") of marginal generation. In the 2020 ELCC study, marginal generation was not significantly affecting system forced outages as the EFOR of the marginal generation was 1.9%, but with the new RSP dataset, there is a significant impact with the EFOR of marginal generation at 3.9%. In the 2020 study, the introduction of battery and hybrid capacity did not materially affect conventional generation as the batteries provided ancillary services that were previously served by conventional units. Fewer operating hours for the conventional units meant fewer system outages in that study. However, in this study, as penetrations reached levels where marginal batteries began serving load rather than ancillary services, the effects described above began to have a material impact on ELCC. A test was performed with the RSP dataset where base battery capacity was 1 GW and the resulting ELCCs of marginal batteries exceeded 95%. This confirmed our intuition that system interactions are primarily responsible for the declines in the reliability contributions of marginal energy limited capacity.
- It is well understood that as solar penetration increases, net load shifts to later in the day, reducing the ELCC for marginal solar resources. This finding was shown in our 2020 ELCC report with solar ELCCs dropping to 0-3% in 2030. However, two data changes in the RSP ameliorated this effect.
  - First, the net load profiles from the 2020 study demonstrated lower solar output during net load peaks than the current RSP shapes. Analysis of the current RSP load and renewable shapes demonstrates that in the top 50 net load hours across all 20 synthetic weather shapes for study year 2022, the marginal solar resources reduced the net load peaks by approximately 4% of nameplate for behind the meter photovoltaic ("BTM PV") and fixed photovoltaic ("PV") and by approximately 8% for

[3] A 4-hour battery with one daily cycle and a round trip cycle efficiency of 85% would require an additional 2.5% net generation due to losses (365 * 4 * 0.15 / 8760 = 2.5%). The load adder corresponds to the loss of a 500 MW perfect generation resource at 100% capacity factor, so the total impact on system generation is a 102.5% capacity factor 500 MW unit.

[4] While the additional load would be served by renewable resources during shoulder seasons, it would be served by conventional resources during peak seasons, thus increasing the likelihood of an outage that would carry over into the peak hours. See detailed discussion in the results section below.

single axis tracking PV. The same calculations for the profiles used in the 2020 study only showed 1% and 5% respectively for the same 2022 study year. The higher values from the net load analysis correspond to the higher solar ELCCs shown in this report.
    - Second, with the higher storage penetration in the current RSP, some reliability interactions between storage resources and marginal solar resources were surfaced. With much higher storage penetration, the timing of storage discharge becomes critical. Solar energy narrows the peak, pushing the start of battery discharge to later in the day. Even though reliability events still mostly occur after sunset, the ability of solar resources to support batteries by keeping them charged until later in the day results in continued, albeit small, reliability benefits from solar. This is evidenced by ELCCs for solar resources that only fall modestly from 2026 to 2030. The average solar ELCC in CAISO drops from 5.8% in 2026 to 4.3% in 2030.[5]
- Interactions between wind resources and other resource classes also surfaced in this study. The average wind contribution to net load peaks remains relatively constant at 14-15%. However, with the increasing storage penetration over time, the effect wind has on the timing of storage discharge becomes more impactful. During high net load days in the 2030 study year, the CAISO wind output in the 8 hours preceding the net load peak is typically low, meaning wind generation is not able to delay the start of storage discharging, making storage energy more likely to be exhausted during net load peak periods. This effect depresses the wind ELCCs in 2026 and 2030.
- The ELCC results for non-dispatchable resources are highly contingent on accurate modeling of their energy production profiles. The development of synthetic solar production profiles is simpler and more accurate than the development of wind profiles since robust historical solar data is readily available. Wind profile development is inherently more challenging as historical wind observations do not reliably translate to site specific production profiles. This challenge was present in the 2020 study for all regions but most acutely for out of state wind resources. The challenge persists in the 2021 study but is now acute in CAISO regional wind profiles. Astrapé's recommendation is to use an aggregated wind ELCC for all projects until more rigorous synthetic wind profiles can be developed and consideration of factors such as wind regime and technology can be considered rather than exclusively the zonal definitions inherent in the current results.
- The ELCCs of non-dispatchable resources are also dependent on the modeled load profiles. As gross loads peak later in the day, solar contributes less to the aggregate reliability of the system. The CAISO load shapes in the RSP dataset reflect a higher risk of late day gross load peaks than is present in other synthetic shapes such as the 2018 IEPR hourly load forecast.[6] This characteristic has the potential to suppress solar ELCCs, although the effect is expected to be modest. Since Astrapé was not involved in the development of either set of synthetic load shapes, and is not aware of the details of the respective development processes, we are not in a position to offer an opinion as to which set of load shapes is more realistic.
- Hybrid facility ELCCs largely mimic the ELCC of an equal capacity standalone battery. Variations are likely random fluctuations rather than products of different physical characteristics. At higher system battery penetrations, the renewable charging constraints of the battery portion of hybrid facilities could limit the ELCC below what would be provided by a standalone battery but at the penetrations analyzed through 2030, the storage duration needed for a marginal

[5] The average solar ELCC in CAISO is calculated as the average of the ELCC values of BTM PV, fixed PV, and tracking PV in PGE Valley, PGE Bay, SCE, and SDGE

[6] https://efiling.energy.ca.gov/Lists/DocketLog.aspx?docketnumber=18-IEPR-04

battery to supply reliability is shorter than the charging potential of the associated renewable energy.

Tables ES1 – ES4 provide the ELCC values by technology and region for the study years 2022, 2026, and 2030. [7,8,9] A detailed discussion of study results is included in the Simulation Results section of this report.

Table ES1. 2022 Study Results (expressed as a percentage of assumed interconnection capability)

Technology	BTM PV	Fixed PV	Tracking PV	Wind
PGE Valley	5.9%	8.6%	11.0%	17.2%
PGE Bay	5.5%	8.5%	10.9%	24.4%
SCE	6.4%	8.9%	11.2%	11.8%
SDGE	5.9%	8.7%	11.0%	11.8%
AZ APS	N/A	5.0%	6.8%	16.1%
NM EPE	N/A	5.0%	6.8%	14.8%
BPA	N/A	N/A	N/A	16.0%
CAISO	5.9%	8.7%	11.0%	16.3%

Table ES2. 2026 Study Results (expressed as a percentage of assumed interconnection capability)

Technology	BTM PV	Fixed PV	Tracking PV	Wind
PGE Valley	3.6%	6.0%	7.2%	15.6%
PGE Bay	3.4%	5.8%	7.1%	19.2%
SCE	5.1%	6.1%	7.8%	10.8%
SDGE	4.2%	6.0%	7.4%	10.8%
AZ APS	N/A	3.8%	5.9%	8.6%
NM EPE	N/A	3.8%	5.9%	8.6%
BPA	N/A	N/A	N/A	12.6%
CAISO	4.1%	5.9%	7.4%	14.1%

Table ES3. 2030 Study Results (expressed as a percentage of assumed interconnection capability)

Technology	BTM PV	Fixed PV	Tracking PV	Wind
PGE Valley	2.1%	4.3%	5.9%	12.1%
PGE Bay	2.1%	4.2%	5.7%	15.5%
SCE	2.3%	4.8%	6.5%	6.3%
SDGE	2.1%	4.6%	6.5%	6.3%
AZ APS	N/A	1.2%	3.0%	3.3%
NM EPE	N/A	1.2%	3.0%	3.3%
BPA	N/A	N/A	N/A	8.8%
CAISO	2.2%	4.5%	6.2%	10.1%

[7] For purposes of the ELCC Study, ELCC is calculated as a percentage of interconnection capability, where interconnection capability is assumed equal to (i) the installed capacity of non-hybrid resources, or (ii) in the case of hybrid resources, the installed capacity of the renewable resource or storage device, which are equally sized for all hybrids analyzed.

[8] Values for all three study years reflect post-processing to reduce statistical noise.

[9] The CAISO marginal ELCC values are calculated by averaging the values for PGE Valley, PGE Bay, SCE, and SDGE for each technology.

Table ES4. Battery and Hybrid Study Results[10]

Technology	2022	2026	2030
1-Hour Hybrid or Standalone Battery	87.1%	85.4%	78.6%
2-Hour Hybrid or Standalone Battery	88.3%	86.7%	80.4%
4-Hour Hybrid or Standalone Battery	90.6%	88.1%	82.2%

Standalone batteries, PV hybrids, and wind hybrid facilities were simulated independently but the results demonstrated ELCCs for all three technologies and all locations to be within statistical error bounds and are thus averaged for this report. When battery penetration reaches a level after 2030 where energy sufficiency is a significant concern, the ELCCs of hybrid facilities will be sensitive to the charging capability of the associated renewable energy and locational differences between hybrid facilities may surface.

[10] Simulations were performed with standalone battery in addition to PV hybrids and wind hybrids for calibration purposes.

INPUT ASSUMPTIONS

STUDY REQUIREMENTS

Astrapé Consulting was contracted by the California Investor Owned Utilities to examine the annual marginal ELCC values for the resource classes and locations found in Table 1 for 3 study years (2022, 2026, and 2030).

Table 1. Resource Class and Location Combinations Calculated

Technology	PGE Bay	PGE Valley	SCE	SDGE	AZ APS	NM EPE	BPA
BTM PV	X	X	X	X			
Fixed PV	X	X	X	X	X	X	
Tracking PV	X	X	X	X	X	X	
1-Hour Tracking PV Hybrid	X	X	X	X	X	X	
2-Hour Tracking PV Hybrid	X	X	X	X	X	X	
4-Hour Tracking PV Hybrid	X	X	X	X	X	X	
Wind	X	X	X	X	X	X	X
1-Hour Wind Hybrid	X	X	X	X	X	X	X
2-Hour Wind Hybrid	X	X	X	X	X	X	X
4-Hour Wind Hybrid	X	X	X	X	X	X	X
1-Hour Standalone Storage	X	X	X	X	X	X	X
2-Hour Standalone Storage	X	X	X	X	X	X	X
4-Hour Standalone Storage	X	X	X	X	X	X	X

Astrapé performed simulations to determine the ELCC values using the Strategic Energy and Risk Valuation Model (SERVM). The base database was constructed using the 2019-2020 Reference System Plan ("RSP") as directed in the "Decision Adopting Modeling Requirements to Calculate Effective Load Carrying Capability Values for Renewables Portfolio Standard Procurement' ("Decision") on October 3rd, 2019 in California Public Utilities Commission's ("CPUC's") RPS Proceeding Rulemaking. 18-07-003.[11,12] Limited input changes were made from the 2019-2020 RSP to correct errors or to assist in producing convergent results. These changes are discussed in Appendix 1. A base case of the system was first established by calibrating the CAISO region to a reliability level of 0.1 Loss of Load Expectation (LOLE) for each of the three study years (2022, 2026, and 2030) by adding load uniformly across each hour of the year. LOLE was determined as the expected number of days per year where load and ancillary service requirements exceeded available generation, as measured over thousands of hourly chronological simulations. Using the base case from each respective study year, multiple technology and locational ELCC values were studied. Table 2 contains the resource mix from the 2019-2020 RSP.

[11] https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M331/K772/331772681.PDF

[12] The decision is available at http://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M316/K882/316882092.PDF

Table 2. Study Year Resource Mix

Unit Category	Total Capacity by Year (MW)		
	2022	2026	2030
Battery Storage	**4,716**	**9,065**	**12,138**
1-Hour	68	68	68
2-Hour	692	1,019	1,345
4-Hour	3,956	7,979	10,725
Thermal	**27,897**	**27,417**	**27,381**
Nuclear	**2,935**	**635**	**635**
DR/EE	**6,122**	**8,990**	**11,690**
EV	**-1,136**	**-2,188**	**-2,944**
Hydro	**6,870**	**6,870**	**6,870**
PSH	**1,599**	**2,572**	**2,572**
Other Renewable*	**2,749**	**2,749**	**2,748**
Wind	**9,401**	**10,188**	**10,894**
BTM PV	**12,284**	**16,156**	**20,058**
Solar Thermal	**1,237**	**1,237**	**1,237**
Solar Fixed	**12,556**	**13,249**	**14,003**
Solar Tracking	**7,046**	**8,399**	**10,662**
Total	**94,276**	**105,339**	**117,944**

** Other Renewable includes biogas, biomass, and geothermal units*

Table 3 shows the differences for battery, wind, and solar capacities between the 2020 and 2021 studies for each study year.[13] The RSP reflects significant additions of capacity across several technologies.

Table 3. Study Year Battery, Wind, and Solar Capacity Differences Between 2020 and 2021 Study

Unit Category	Total Capacity Delta by Year (MW)*		
	2022	2026	2030
Battery Storage	**3,601**	**7,551**	**8,707**
1-Hour	28	-168	-2,076
2-Hour	692	1,019	1,345
4-Hour	2,881	6,692	9,438
Wind	**835**	**1,194**	**1,773**
BTM PV	**-17**	**-571**	**-701**
Solar Thermal	**-11**	**-11**	**-11**
Solar Fixed	**4,623**	**5,062**	**5,770**
Solar Tracking	**-8,176**	**-8,170**	**-6,114**
Total	**855**	**5,055**	**9,424**

** Positive indicates higher values in 2021 study*

[13] The 2020 study used the 2017-2018 Preferred System Plan for the resource portfolios, and the 2021 study used the 2019-2020 RSP for the resource portfolios.

Since ELCCs are calculated with the system calibrated to 0.1 LOLE, and the increased capacity in the 2021 study compared to the 2020 study resulted in much better reliability, load was added in the 2021 study each year to achieve 0.1 LOLE. The load adjustments are shown in Table 4. While the reliability in the base case improved, this study required more overall capacity than the last study to achieve 0.1 LOLE due to two key assumption changes in the 2019-2020 RSP. First, available on-peak imports were reduced from 11,665 MW to 5,000 MW. Second, ELCCs of energy limited and non-dispatchable resource additions are less than 100%.

Table 4. Load Added to Achieve 0.1 LOLE

Study Year	Load Adjustment (MW)
2022	2,850
2026	4,000
2030	5,250

MARGINAL ELCC METHODOLOGY

After calibrating the system, the study technology resource was added to the system. The load was then artificially increased uniformly across all hours until LOLE returned to 0.1 days per year. The following equation was used to calculate the marginal ELCC value:

$$ELCC = \frac{Load\ \ Increase\ (MW)}{Study\ Technology\ Resource\ Added^{14}\ (MW)} * 100\%$$

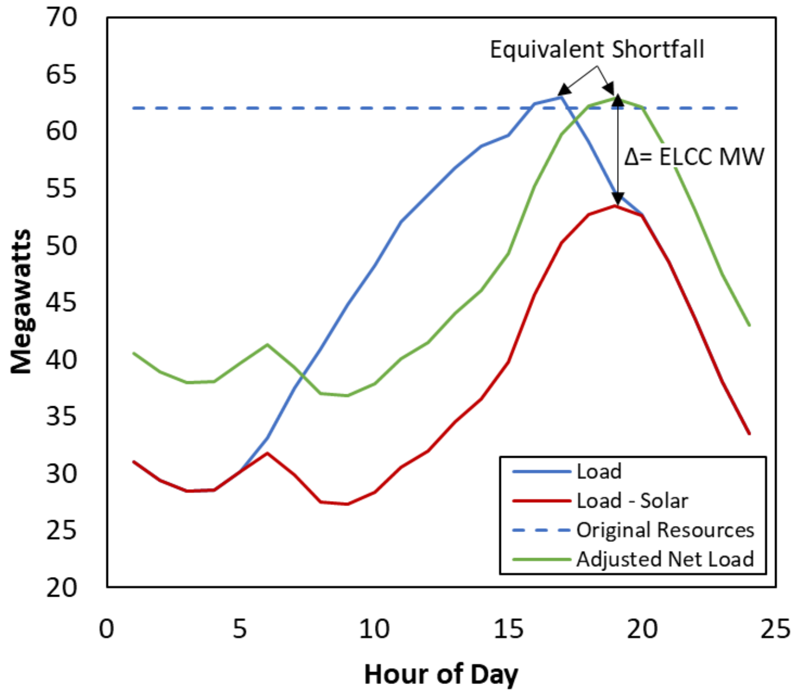
The process is as follows, using illustrative values and a solar resource:

1. Add a 30 MW solar resource to system calibrated to 0.1 LOLE
    a. LOLE decreases to 0.08, indicating an improvement in reliability
2. Add 10 MW of load every hour
    a. LOLE increases to 0.1, indicating a return to original reliability
3. The ELCC is calculated as the ratio of step 2 and step 1
    a. 10 MW / 30 MW = 33.3% ELCC

Figure 1 contains a graphic example of the process described above. Marginal resource ELCC is typically analyzed assuming small increments of resources relative to system size. Figure 1 shows an exaggerated visualization for clarity.

[14] Limited by interconnection capability for combined hybrid projects

Figure 1. Marginal ELCC Calculation Methodology Illustration



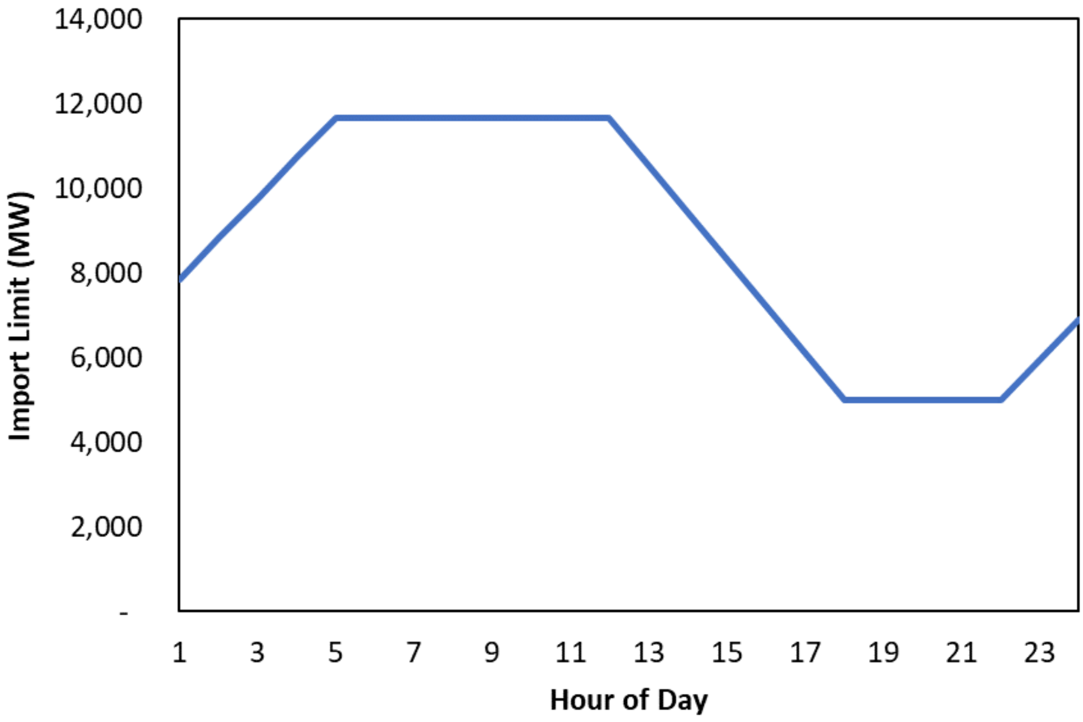
REGIONS

CAISO is separated into 4 distinct regions in SERVM: PGE Bay, PGE Valley, SCE, and SDGE. The following external regions were included in the study:

- Arizona Public Service Company (AZ APS)
- Balancing Authority of Northern California (BANC)
- British Columbia Hydro Authority (BCHA)
- Bonneville Power Administration (BPA)
- Comisión Federal de Electricidad (CFE)
- Imperial Irrigation District (IID)
- Idaho Power Company (IPCO)
- Los Angeles Department of Water and Power (LADWP)
- Nevada Power Company (NEVP)
- NorthWestern Energy (NWMT)
- New Mexico Area and El Paso Electric (NM EPE)
- PacifiCorp East (PACE)
- PacifiCorp West (PACW)
- Portland General
- Public Service Company of Colorado (PSCO)
- Salt River Project (SRP)
- Tucson Electric Power Company (TEPC)
- Turlock Irrigation District (TIDC)
- Western Area Power Administration – Colorado/Missouri Region (WACM)
- Western Area Power Administration – Lower Colorado Region (WALC)

The neighboring resources were assumed to be fully deliverable to CAISO subject to an 11,665 MW (hours 5 to 12) and a 5,000 MW (hours 18 to 22) aggregated import limit with a linear ramp between the two limiting periods, as shown in Figure 2.[15]

Figure 2. Modeled Maximum Import Limit



All external regions described above were not explicitly modeled, instead North and South neighbor assistance was modeled as a proxy. Table 5 defines which Tier 1 (one tie away) neighboring entities were classified as North and which neighbors were classified as South.

Table 5. Region Definitions for Proxy Neighbor Assistance

Region	Tier 1 Entity
North	BANC
	BPA
	PACW
	TIDC
South	AZ APS
	CFE
	IID
	LADWP
	NEVP
	SRP
	WALC

[15] All references to hours in a day use the hour-ending convention.

A time series of imports into CAISO was developed for North and South Tier 1 neighboring entities separately and was based on historic interchange as a function of CAISO net load by season, where net load is calculated as load minus the sum of wind, utility scale solar PV, and behind the meter PV ("BTM PV").[16] Supporting information for CAISO was retrieved from the Energy Information Administration ("EIA") website based on January 2020 to February 2021 actual data. [17] The relationship between net load and net imports was applied to all 20 weather years studied (1998 to 2017) so that each weather year included a unique profile of assistance from neighboring areas reflective of each year's renewable output and weather conditions.[18] While historical imports often showed more than 5 GW during peak net load hours, total imports were capped as shown in Figure 2 to match the expected future transmission and generation availability constraints of 5 GW between hours 18 and 22. The average hourly imports as a function of net load during hours 18 to 22 are provided in Figure 3. In most net load conditions, the 5GW import capability is fully utilized.

Figure 3. Average Hourly Imports by Zone

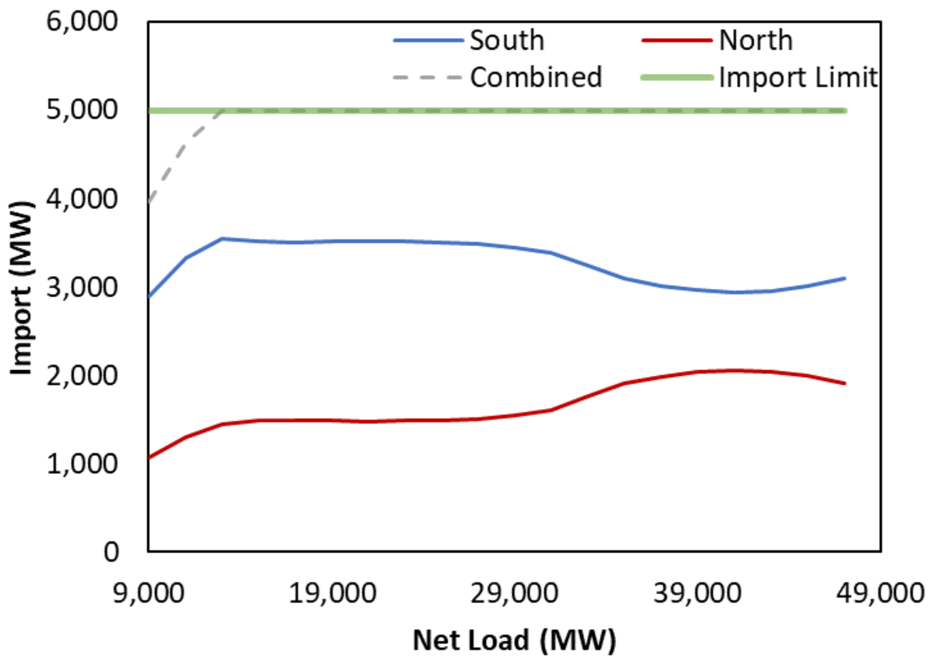


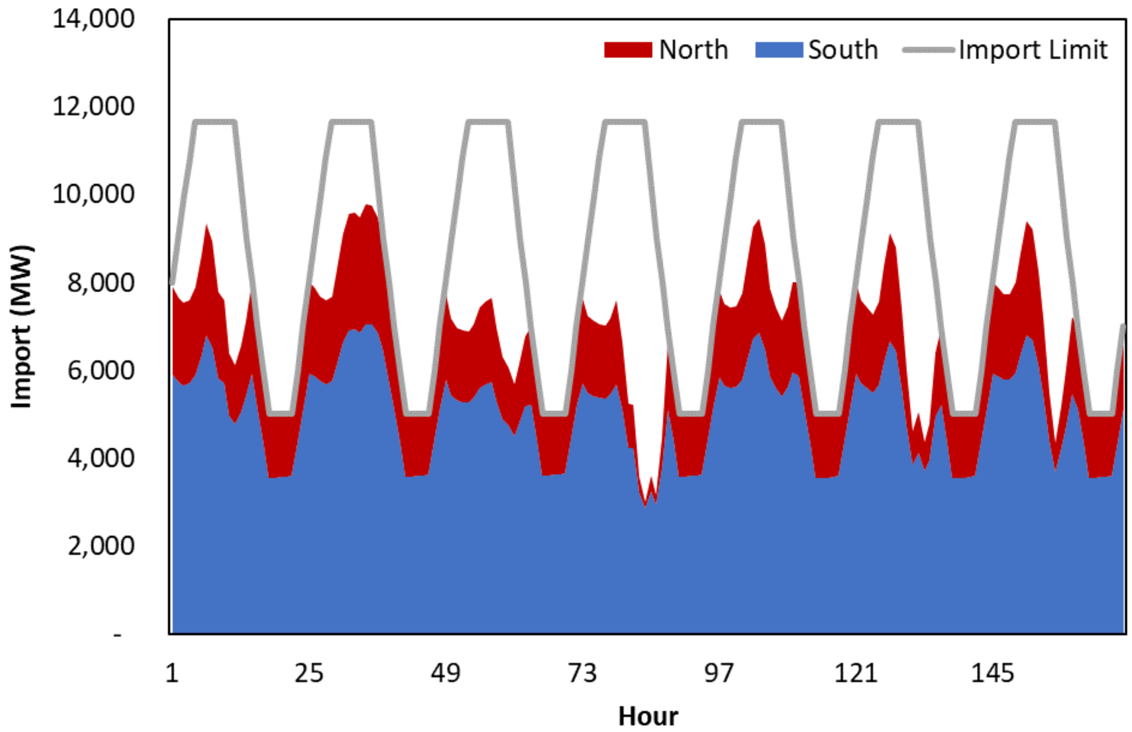
Figure 4 provides an illustrative example of a week of imports for both the North and South zones.

[16]Unless noted otherwise, net load will be defined as gross load less BTM PV, utility scale solar PV, and wind generation.

[17] Data is available at https://www.eia.gov/beta/electricity/gridmonitor/dashboard/electric_overview/balancing_authority/CISO

[18] Net imports are exports minus imports. The study simulations do not capture periods of net export, but as a resource adequacy study, those periods are not relevant for ELCC calculations.

Figure 4. Imports – 1 Week Illustrative Example



LOAD SHAPES

To capture the effects of weather uncertainty, synthetic load shapes were originally developed by CPUC for twenty historical weather years (1998 – 2017) to reflect the impact of weather on load for all four CAISO regions.[19] The synthetic load profiles represent expected load given customer electric use patterns in the study year if historic weather conditions were to occur. The synthetic shapes are scaled such that the median peak of all shapes matches the zonal 2018 IEPR load forecast.[20] The forecast peak load by study year for each CAISO region is displayed in Table 6.

Table 6. Gross Peak Load by Weather Year and Region

Region	Peak Load (MW)		
	2022	2026	2030
PGE Bay	9,829	10,363	10,778
PGE Valley	13,735	14,393	14,982
SCE	26,173	27,635	28,753
SDGE	5,004	5,307	5,517
Non-Coincident CAISO	54,741	57,698	60,030
Coincident CAISO	52,661	55,637	58,439

[19] https://www.cpuc.ca.gov/General.aspx?id=6442461894

[20] California Energy Demand Update Forecast 2018 - 2030, Mid Demand Baseline Case, Mid AAEE and AAPV Savings. Because of load gross-up methodology differences and shape differences, the reported values do not correspond exactly to 2018 IEPR forecasts.

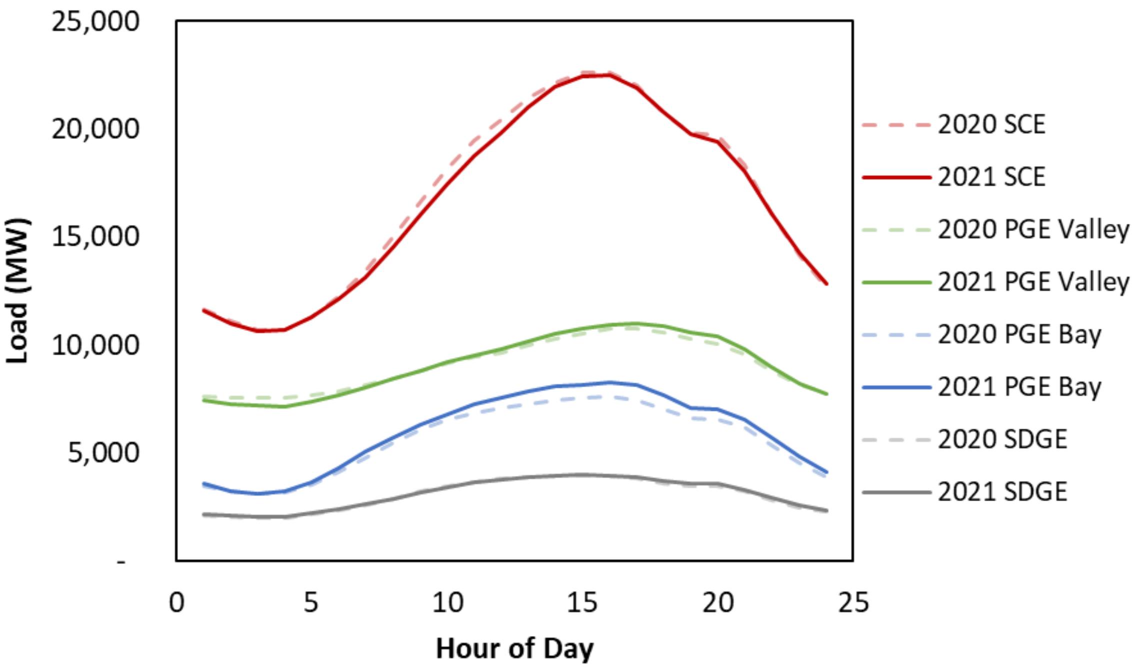
Table 7 summarizes the differences in the peak load assumptions between the 2020 and 2021 studies.

Table 7. Peak Load Delta between 2020 and 2021 Studies by Weather Year and Region

Region	Peak Load Delta (MW)[21]		
	2022	2026	2030
PGE Bay	540	664	749
PGE Valley	642	665	748
SCE	179	211	242
SDGE	-5	10	27
CAISO	1,356	1,550	1,766

A comparison of the average August daily load shape for all study regions for the 2022, 2026, and 2030 study year for the 2020 and 2021 studies are provided in Figures Figure 5, Figure 6, and Figure 7, respectively.

Figure 5. August Average Daily Shape Comparison for 2022 Study Year



[21] Positive indicates higher values in 2021 study and negative indicates higher values in the 2020 study

Figure 6. August Average Daily Shape Comparison for 2026 Study Year

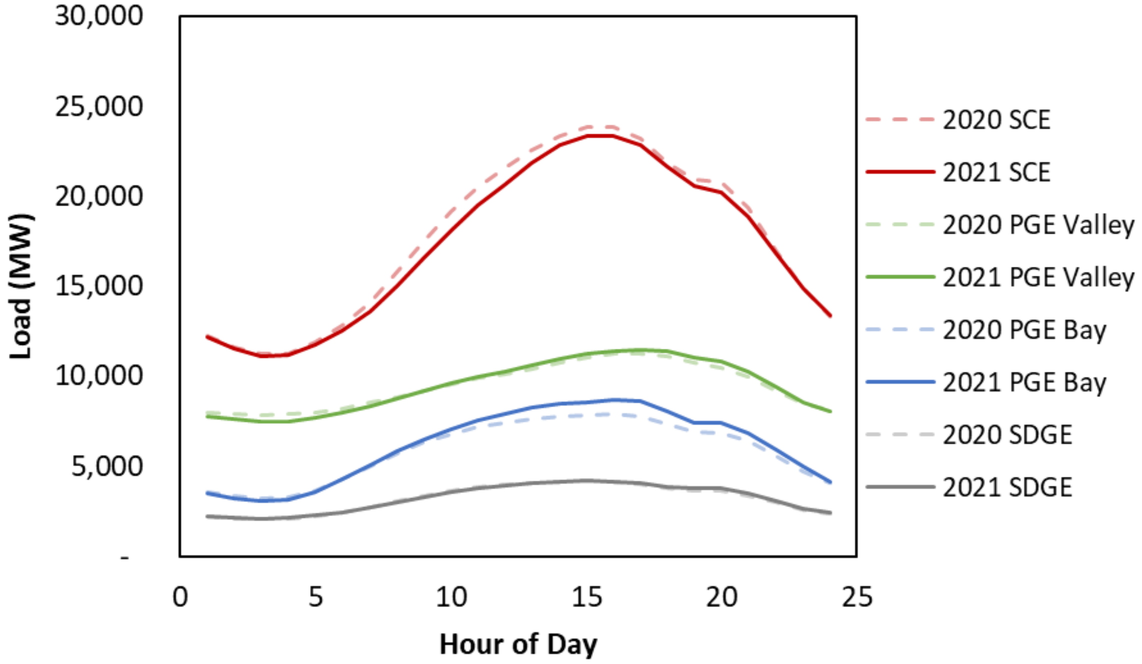
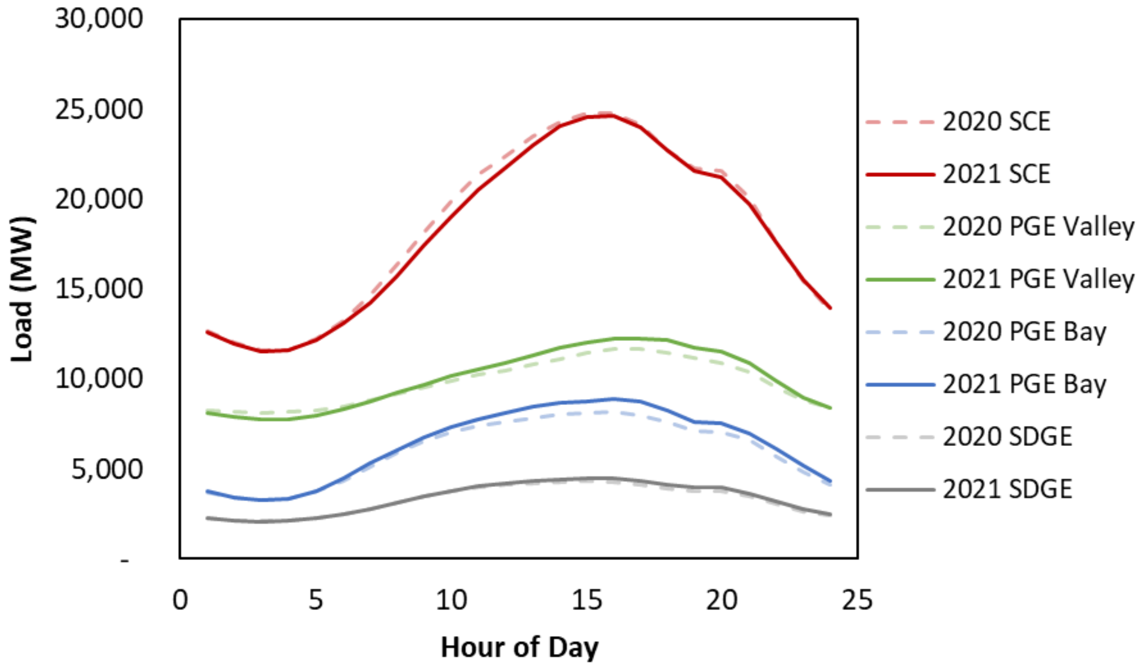
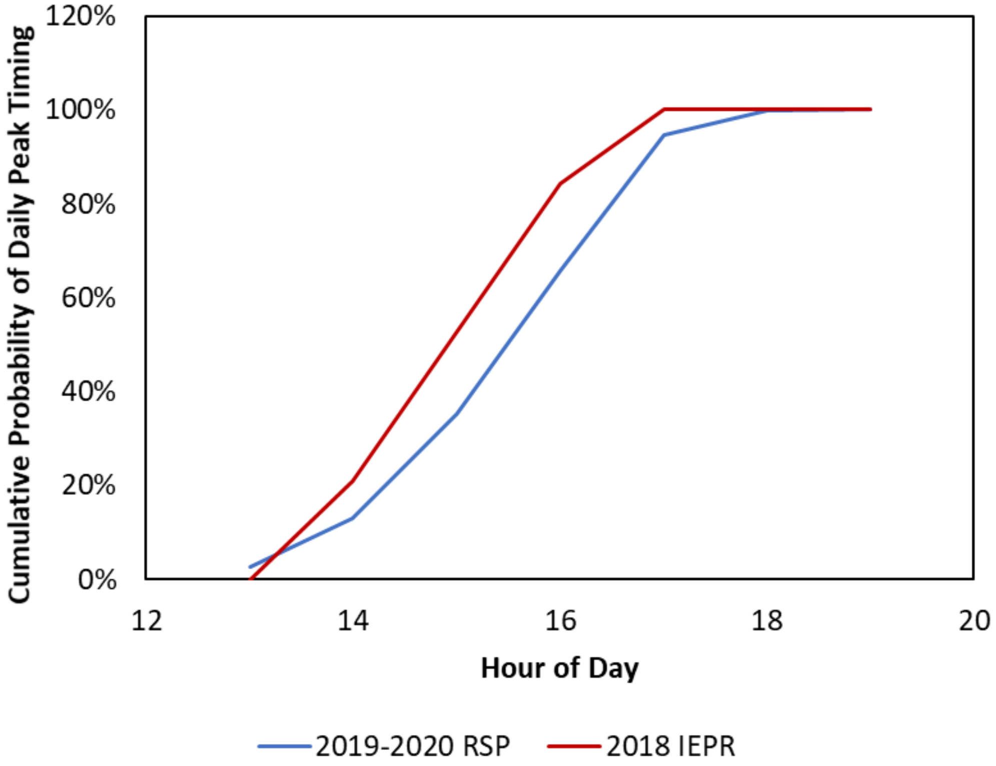


Figure 7. August Average Daily Shape Comparison for 2030 Study Year



In addition to the typical shape comparisons, we also reviewed the timing of gross load peaks which can affect the reliability contributions of all non-dispatchable resource classes. The gross load peaks in the RSP tend to occur late in the day. However, other synthetic load profiles publicly available show most peak load days with earlier peaks. As shown in Figure 8, the RSP data set shows only 65% of the top 5% of gross load days with peaks at or before hour 16. The 2018 IEPR hourly load shape shows 85% of the top 5% of gross load days with peaks at or before hour 16. It is possible that the distribution of late gross load peaks in the RSP suppresses the reliability contributions of solar resources.

Figure 8. Gross Load Peak Timing Distribution



RENEWABLE PROFILES

The wind and solar shapes for all study locations are from the RSP and were developed by CPUC staff.

A representative set of renewable profiles was selected for each of the four California study regions (PGE Bay, PGE Valley, SCE, and SDGE). For the four CAISO regions, marginal ELCC values were calculated for each of the following technologies: BTM PV, fixed PV, tracking PV, tracking PV hybrid, wind, wind hybrid, and standalone battery. AZ APS and NM EPE marginal ELCC values were calculated for the following technologies: fixed PV, tracking PV, tracking PV hybrid, wind, wind hybrid, and standalone battery. Marginal ELCC values were calculated for the following technology types in BPA: wind, wind hybrid, and standalone battery. For each case, 500 MW increments for each respective technology and location were added. The average annual capacity factor for the set of profiles used for each technology and region is provided in Table 8.

Table 8. Average Capacity Factor for Renewable Profiles Used

Region	BTM PV	Solar Fixed	Solar Tracking Single Axis	Wind
PGE Bay	18.26%	23.61%	30.77%	28.57%
PGE Valley	19.08%	23.90%	31.23%	30.14%
SCE	20.68%	24.39%	33.32%	26.62%
SDGE	19.67%	25.07%	33.70%	26.62%
AZ APS	N/A	25.33%	33.00%	25.32%
NME PE	N/A	24.81%	32.70%	29.09%
BPA	N/A	N/A	N/A	37.45%
Average	**19.42%**	**24.65%**	**32.55%**	**29.57%**

The average annual capacity factor for the profiles used for each technology and region in the 2020 study and the delta from the 2020 study are presented in Table 9. In the 2020 study, PGE Valley and PGE Bay regions were aggregated into Northern California (CA-N), and SDGE and SCE results were aggregated into Southern California results (CA-S).

Table 9. Average Capacity Factor and Capacity Factor Differences from 2020 and 2021 Studies

	2020 Study				Delta[22]			
Region	**BTM PV**	**Solar Fixed**	**Solar Tracking Single Axis**	**Wind**	**BTM PV**	**Solar Fixed**	**Solar Tracking Single Axis**	**Wind**
CA-N	20.70%	25.90%	31.20%	27.50%	-2.03%	-2.15%	-0.20%	1.85%
CA-S	21.00%	26.80%	33.30%	24.80%	-0.83%	-2.07%	0.21%	1.82%
AZ APS	N/A	27.60%	32.10%	30.20%	N/A	-2.27%	0.90%	-4.88%
NME PE	N/A	27.10%	31.10%	30.20%	N/A	-2.29%	1.60%	-1.11%
BPA	N/A	N/A	N/A	30.90%	N/A	N/A	N/A	6.55%
Average	**21.20%**	**25.90%**	**30.80%**	**28.20%**	**-1.78%**	**-1.25%**	**1.75%**	**1.37%**

TECHNOLOGY ASSUMPTIONS

SOLAR TECHNOLOGIES

For each region, the PV units total 500 MW and used the corresponding technology weather stations and inverter loading ratios (ILR). The capacity was divided evenly across all corresponding weather stations for each region. As a result, multiple profiles were used for some regions and technologies. The weather shape, capacity, ILR, and capacity factor breakdowns for each region and technology are defined in Table 10.

[22] Positive indicates higher values in 2021 study and negative indicates higher values in the 2020 study.

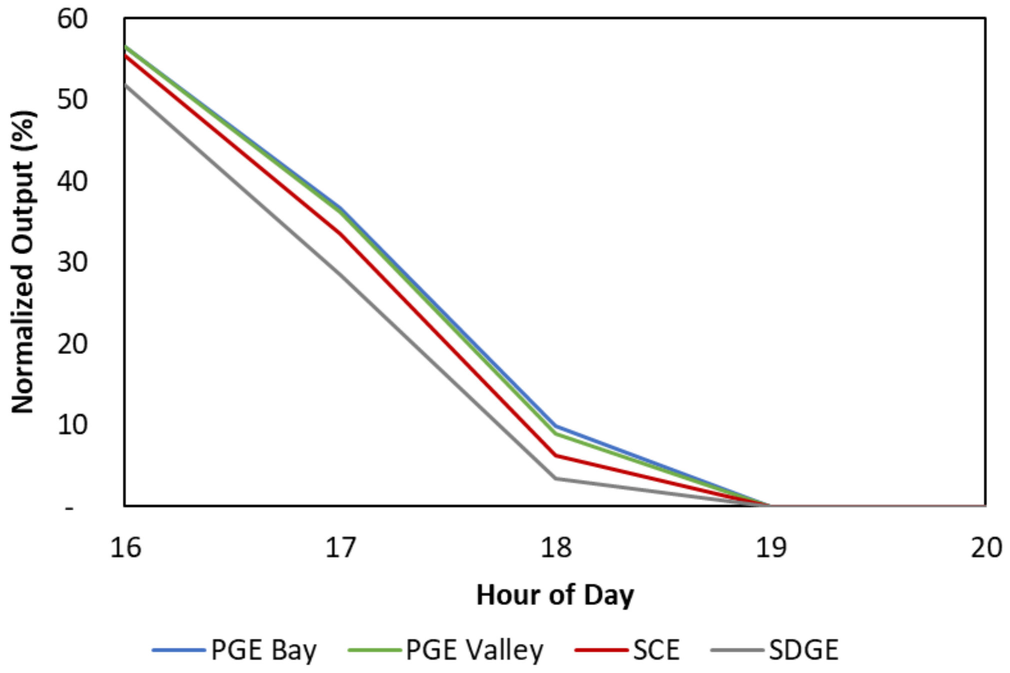
Table 10. Solar Technology Assumptions

Region	Technology	Solar Shape	Capacity (MW)	Inverter Loading Ratio (ILR)	Capacity Factor (%)
PGE Bay	BTM PV	Solar_Fixed_CA__Monterey	250	1.1	18.0%
	BTM PV	Solar_Fixed_CA__Oakland	250	1.1	18.6%
PGE Valley	BTM PV	Solar_Fixed_CA__Chico	71	1.1	18.4%
	BTM PV	Solar_Fixed_CA__Fresno	71	1.1	19.7%
	BTM PV	Solar_Fixed_CA__Monterey	71	1.1	18.0%
	BTM PV	Solar_Fixed_CA__Sacramento	71	1.1	19.1%
	BTM PV	Solar_Fixed_CA__SantaRosa	71	1.1	18.3%
	BTM PV	Solar_Fixed_CA_Kern_Bakersfield	71	1.1	20.3%
	BTM PV	Solar_Fixed_CA_Madera_Madera	71	1.1	19.8%
SCE	BTM PV	Solar_Fixed_CA__LosAngeles	125	1.1	20.1%
	BTM PV	Solar_Fixed_CA_Kings_Stratford	125	1.1	20.0%
	BTM PV	Solar_Fixed_CA_LosAngeles_Lancaster	125	1.1	22.1%
	BTM PV	Solar_Fixed_CA_Riverside_Riverside	125	1.1	20.6%
SDGE	BTM PV	Solar_Fixed_CA__LosAngeles	250	1.1	20.1%
	BTM PV	Solar_Fixed_CA__SanDiego	250	1.1	19.2%
PGE Bay	Solar Fixed	Solar_Fixed_CA__Oakland	125	1.3	21.9%
	Solar Fixed	Solar_Fixed_CA_Kern_LostHills	125	1.3	24.1%
	Solar Fixed	Solar_Fixed_CA_Kern_Rosamond	125	1.3	26.1%
	Solar Fixed	Solar_Fixed_CA_Placer_Roseville	125	1.3	22.3%
PGE Valley	Solar Fixed	Solar_Fixed_CA_Kern_Bakersfield	83	1.3	23.9%
	Solar Fixed	Solar_Fixed_CA_Kern_LostHills	83	1.3	24.1%
	Solar Fixed	Solar_Fixed_CA_Kern_Rosamond	83	1.3	26.1%
	Solar Fixed	Solar_Fixed_CA_Kings_Stratford	83	1.3	23.6%
	Solar Fixed	Solar_Fixed_CA_Madera_Madera	83	1.3	23.3%
	Solar Fixed	Solar_Fixed_CA_Placer_Roseville	83	1.3	22.3%
SCE	Solar Fixed	Solar_Fixed_CA__LosAngeles	45	1.3	23.7%
	Solar Fixed	Solar_Fixed_CA_Riverside_Riverside	45	1.3	24.2%
	Solar Fixed	Solar_Fixed_CA_SanBernardino_AppleValley	45	1.3	26.0%
	Solar Fixed	Solar_Fixed_CA_Imperial_Calipatria	45	1.3	24.9%
	Solar Fixed	Solar_Fixed_CA_Kern_Bakersfield	45	1.3	23.9%
	Solar Fixed	Solar_Fixed_CA_Kern_LostHills	45	1.3	24.1%
	Solar Fixed	Solar_Fixed_CA_Kern_Rosamond	45	1.3	26.1%
	Solar Fixed	Solar_Fixed_CA_Kings_Stratford	45	1.3	23.6%
	Solar Fixed	Solar_Fixed_CA_LosAngeles_Lancaster	45	1.3	26.0%
	Solar Fixed	Solar_Fixed_CA_Madera_Madera	45	1.3	23.3%
	Solar Fixed	Solar_Fixed_CA_Placer_Roseville	45	1.3	22.3%
SDGE	Solar Fixed	Solar_Fixed_CA_Imperial_Calipatria	167	1.3	24.9%
	Solar Fixed	Solar_Fixed_CA_Imperial_Ocotillo	167	1.3	26.1%
	Solar Fixed	Solar_Fixed_CA_Riverside_Riverside	167	1.3	24.2%
AZ APS	Solar Fixed	Solar_Fixed_AZ__Phoenix	167	1.3	25.0%
	Solar Fixed	Solar_Fixed_AZ__Tucson	167	1.3	25.3%

	Solar Fixed	Solar_Fixed_AZ_LaPaz_None	167	1.3	25.6%
NM EPE	Solar Fixed	Solar_Fixed_NM__Albuquerque	167	1.3	24.8%
	Solar Fixed	Solar_Fixed_NM_LosAlamos_LosAlamos	167	1.3	23.5%
	Solar Fixed	Solar_Fixed_NM_Luna_Deming	167	1.3	26.1%
PGE Bay	Solar 1Axis	Solar_1Axis_CA_Madera_Madera	500	1.3	30.8%
PGE Valley	Solar 1Axis	Solar_1Axis_CA_Kern_Bakersfield	167	1.3	31.7%
	Solar 1Axis	Solar_1Axis_CA_Kings_Stratford	167	1.3	31.3%
	Solar 1Axis	Solar_1Axis_CA_Madera_Madera	167	1.3	30.8%
SCE	Solar 1Axis	Solar_1Axis_CA_LosAngeles	83	1.3	31.0%
	Solar 1Axis	Solar_1Axis_CA_Imperial_Calipatria	83	1.3	32.8%
	Solar 1Axis	Solar_1Axis_CA_Kern_Bakersfield	83	1.3	31.7%
	Solar 1Axis	Solar_1Axis_CA_Kern_Rosamond	83	1.3	35.0%
	Solar 1Axis	Solar_1Axis_CA_LosAngeles_Lancaster	83	1.3	34.6%
	Solar 1Axis	Solar_1Axis_CA_SanBernardino_AppleValley	83	1.3	34.8%
SDGE	Solar 1Axis	Solar_1Axis_CA_Imperial_Calipatria	250	1.3	32.8%
	Solar 1Axis	Solar_1Axis_CA_Imperial_Ocotillo	250	1.3	34.6%
AZ APS	Solar 1Axis	Solar_1Axis_AZ_Phoenix	500	1.3	33.0%
NM EPE	Solar 1Axis	Solar_1Axis_NM_Albuquerque	167	1.3	32.6%
	Solar 1Axis	Solar_1Axis_NM_LosAlamos_LosAlamos	167	1.3	31.1%
	Solar 1Axis	Solar_1Axis_NM_Luna_Deming	167	1.3	34.4%

Figure 9 illustrates the average September shape for hours 16 to 20 for all PV technologies (average of fixed, 1-axis, and BTM PV) between the four different CA study regions. The higher outputs late in the day in Northern California are primarily a function of longitude as the PG&E service territory is largely further west than the SCE and SDG&E territories. In past studies, this difference translated to slightly higher ELCCs for projects in Northern California than in Southern California. In the current study, solar ELCCs are slightly higher in Southern California than in Northern California. One explanation for this effect is that Southern California peak load profiles are more strongly correlated with system peak load conditions than are Northern California load conditions. In the top 25 peak net load days for all of CAISO, peak load in Southern California averages 94% of its all-time peak, and in Northern California, peak load averages only 89% of its all-time peak. Since solar output is correlated with load, this translates to slightly higher ELCCs for resources in Southern California in this study despite their more eastern locations than those in Northern California.

Figure 9. Average September PV Shape for Hours 16 to 20 for Four Different CA Study Regions



A comparison of the average August daily shapes for all PV technologies between the 2020 and 2021 studies is shown in Figure 10. The 2021 solar 1-axis shapes have a higher output in mid-day due to different configuration assumptions from the 2020 study. The current shapes reflect more up to date assumptions on the 1-axis tracking facilities.

Figure 10. Average August PV Daily Shape Comparison

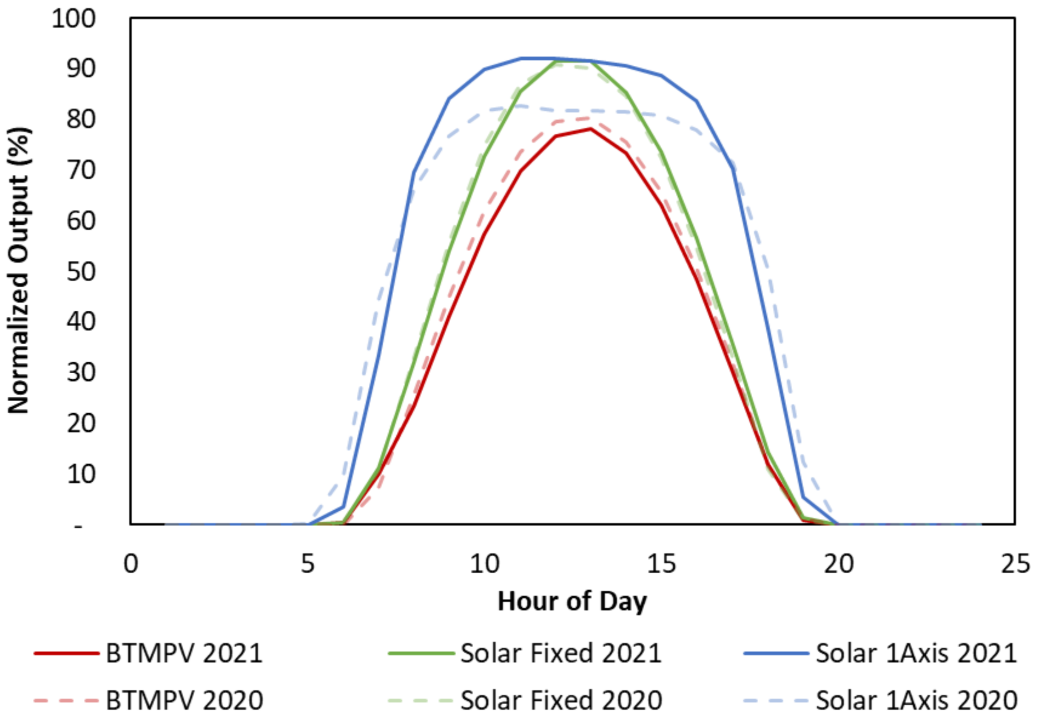


Figure 11 illustrates the average September shape for PV technologies (average of fixed and 1-axis) between the four CA study regions, NM EPE, and AZ APS. Figure 12Figure 9 shows only hours 16 to 20 from Figure 11.

Figure 11. Average September Shape Comparison for CAISO, NM EPE, and AZ APS

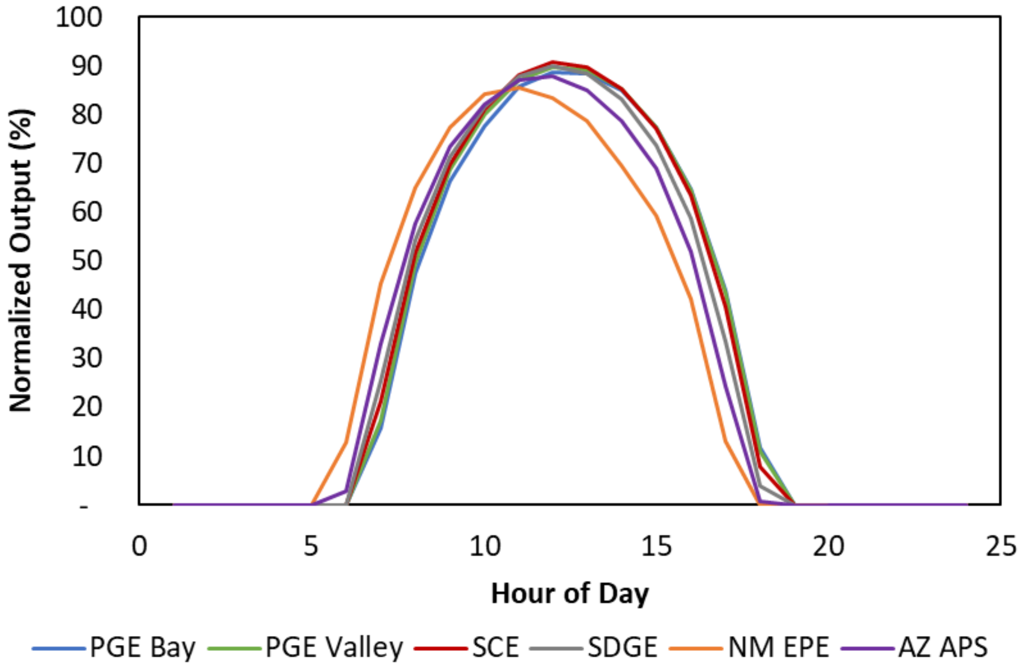
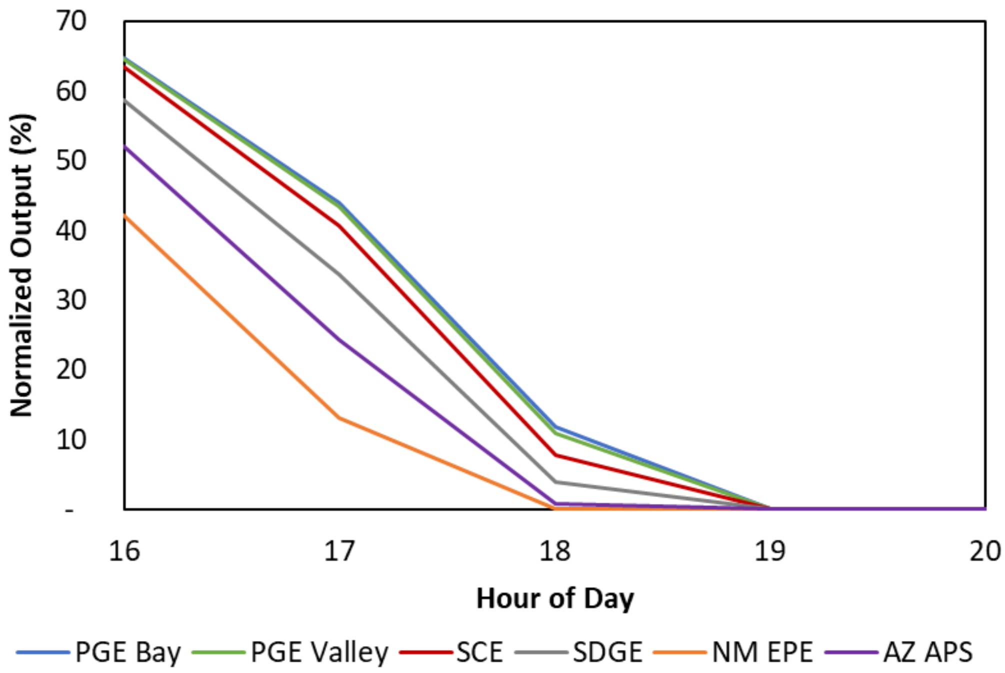


Figure 12. Average September Shape Comparison for Hours 16 to 20 for CAISO, NM EPE, and AZ APS



TRACKING PV HYBRID

The tracking PV hybrid units used the tracking PV solar shapes and capacities defined in Table 11 below.

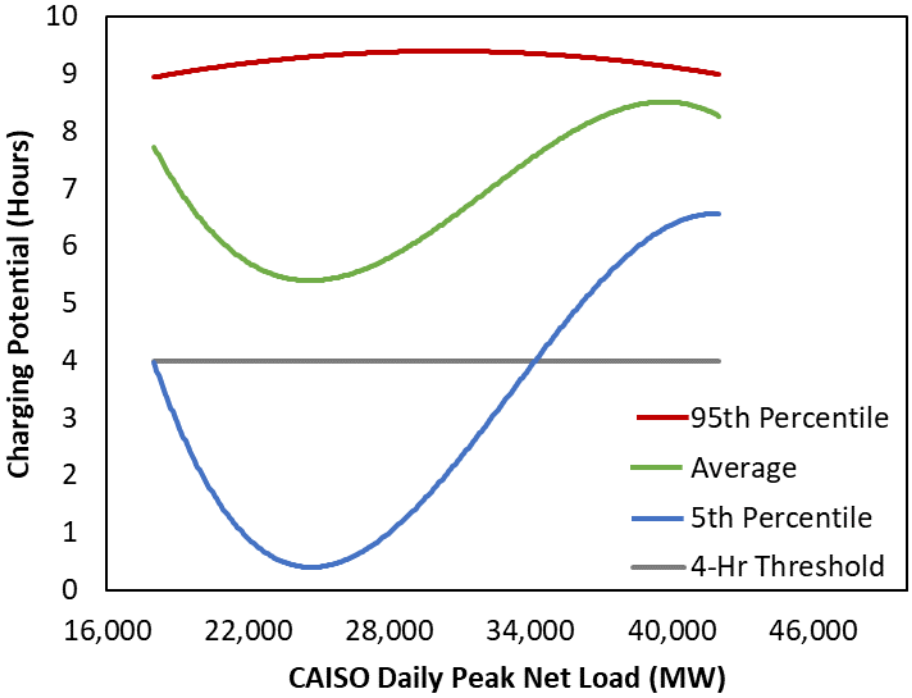
Table 11. Tracking PV Technology Assumptions

Region	Solar Shape	Capacity (MW)	Inverter Loading Ratio (ILR)	Capacity Factor (%)
PGE Bay	Solar_1Axis_CA_Madera_Madera	500	1.3	30.8%
PGE Valley	Solar_1Axis_CA_Kern_Bakersfield	167	1.3	31.7%
	Solar_1Axis_CA_Kings_Stratford	167	1.3	31.3%
	Solar_1Axis_CA_Madera_Madera	167	1.3	30.8%
SCE	Solar_1Axis_CA_LosAngeles	83	1.3	31.0%
	Solar_1Axis_CA_Imperial_Calipatria	83	1.3	32.8%
	Solar_1Axis_CA_Kern_Bakersfield	83	1.3	31.7%
	Solar_1Axis_CA_Kern_Rosamond	83	1.3	35.0%
	Solar_1Axis_CA_LosAngeles_Lancaster	83	1.3	34.6%
	Solar_1Axis_CA_SanBernardino_AppleValley	83	1.3	34.8%
SDGE	Solar_1Axis_CA_Imperial_Calipatria	250	1.3	32.8%
	Solar_1Axis_CA_Imperial_Ocotillo	250	1.3	34.6%
AZ APS	Solar_1Axis_AZ_Phoenix	500	1.3	33.0%
NM EPE	Solar_1Axis_NM_Albuquerque	167	1.3	32.6%
	Solar_1Axis_NM_LosAlamos_LosAlamos	167	1.3	31.1%
	Solar_1Axis_NM_Luna_Deming	167	1.3	34.4%

Though solar shape allocation differed between hybrids, the tracking PV units and battery units totaled 500 MW each, yielding 1,000 MW of nameplate capacity with 500 MW maximum combined output based on an assumed 500 MW interconnection capability. The battery units were modeled with 1-, 2-, or 4-hour storage capability, 85% round trip efficiency, and used economic commitment and dispatch subject to the constraint that the battery could only charge from the corresponding tracking PV unit. As DC coupled would be expected to result in higher ELCC than AC coupled when renewable energy charging constraints are binding, the tracking PV and battery units were assumed to be AC coupled to serve as a conservative estimate of hybrid configuration ELCC.

Figure 13 below was developed to determine if the solar profiles would provide adequate energy to consistently charge the paired energy storage resource. The charging potential of the PGE Bay solar shape describes the amount of energy produced prior to hour 18 by the solar plant, expressed in terms of hours of energy which could be stored within a 500 MW storage device. Hybrid ELCCs are highly dependent on the ability to fully charge prior to the highest net load peak periods. Figure 13 shows that during the highest CAISO net daily load peaks across the year 2022, the coupled solar PV tracking component should be able to consistently charge the studied storage devices (1-, 2-, or 4-hours) with a 90% confidence interval, with an average charging potential of roughly 8 hours. The 90% confidence interval is shown as the difference in the 95th percentile and 5th percentile curves. Because the PGE Bay solar shape exhibits the lowest annual capacity factor of hybrid resources studied, other configurations are assumed to also have enough energy to achieve a full charge.

Figure 13. Charging Potential of PGE Bay Tracking PV Hybrid



WIND

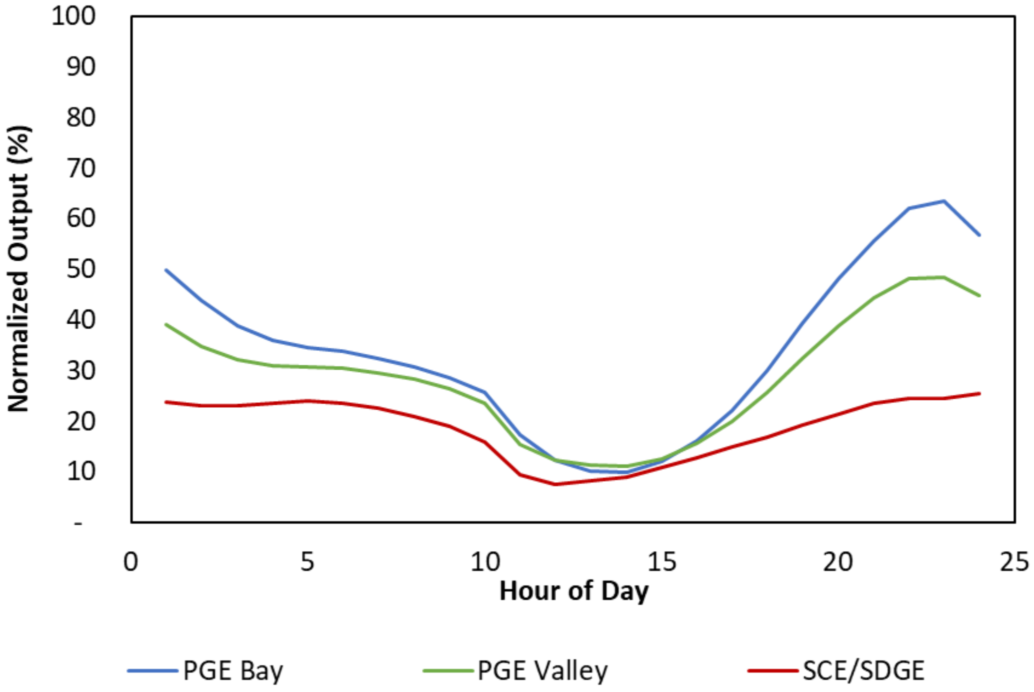
The wind units being studied totaled 500 MW for each region and used the wind weather stations in SERVM for each region. Table 12 displays the wind shape and capacity breakdown for each region being tested.

Table 12. Wind Technology Assumptions

Region	Solar Shape	Capacity (MW)	Capacity Factor (%)	Capacity Factor on CAISO Net Peak (%)
PGE Bay	Wind_CA_Solano_RioVista	500	28.6%	34.6%
PGE Valley	Wind_CA_Kern_Mojave	250	31.7%	18.5%
	Wind_CA_Solano_RioVista	250	28.6%	34.6%
SCE	Wind_CA_Kern_Mojave	250	31.7%	18.5%
	Wind_CA_Riverside_ThousandPalms	250	21.5%	8.4%
SDGE	Wind_CA_Kern_Mojave	250	31.7%	18.5%
	Wind_CA_Riverside_ThousandPalms	250	21.5%	8.4%
AZ APS	Wind_CA_Riverside_ThousandPalms	250	21.5%	8.4%
	Wind_NM_Socorro_Alamo	250	29.1%	10.0%
NM EPE	Wind_NM_Socorro_Alamo	500	29.1%	10.0%
BPA	Wind_WA_Benton_Paterson	500	37.5%	24.6%

Figure 14 illustrates the average August daily wind shape for the four California study regions.

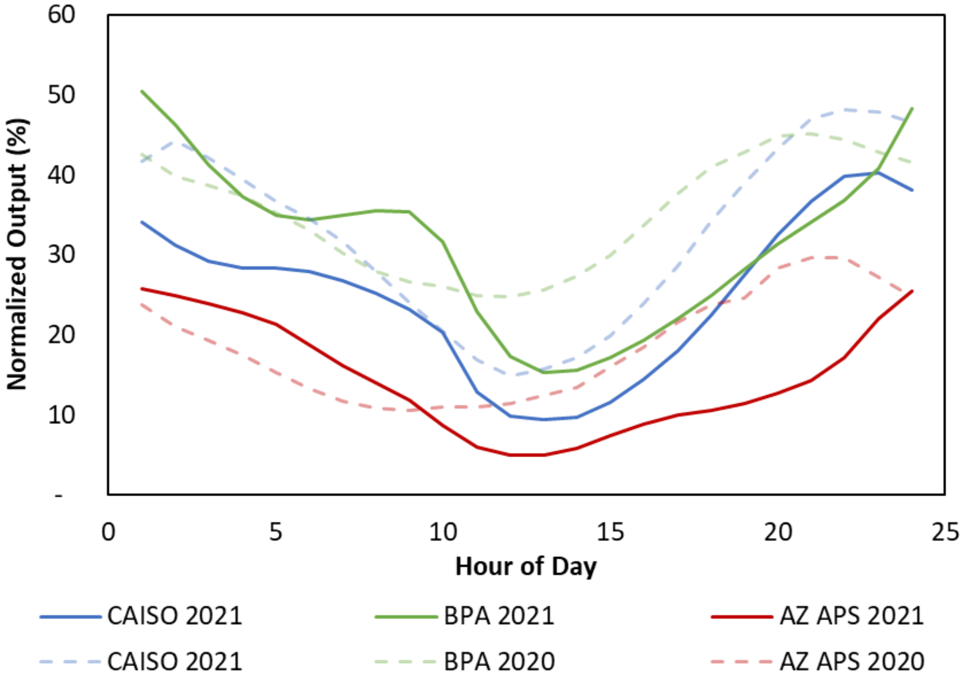
Figure 14. Average August Daily Wind Shape for PGE Bay, PGE Valley, SCE, and SDGE



A comparison of the average August daily wind shapes between the 2020 and 2021 studies for California, AZ APS, and BPA is shown in Figure 15. The methodology for developing wind profiles has changed significantly from that used for the 2020 study. The methodology used for the 2020 load shapes primarily relied on project level wind data. The wind profiles used in this study are heavily reliant on modeled data from the MERRA wind dataset.[23] However, neither methodology likely reflects location-specific resource adequacy contributions of actual and future wind projects accurately and thus further development work on wind shapes is warranted.

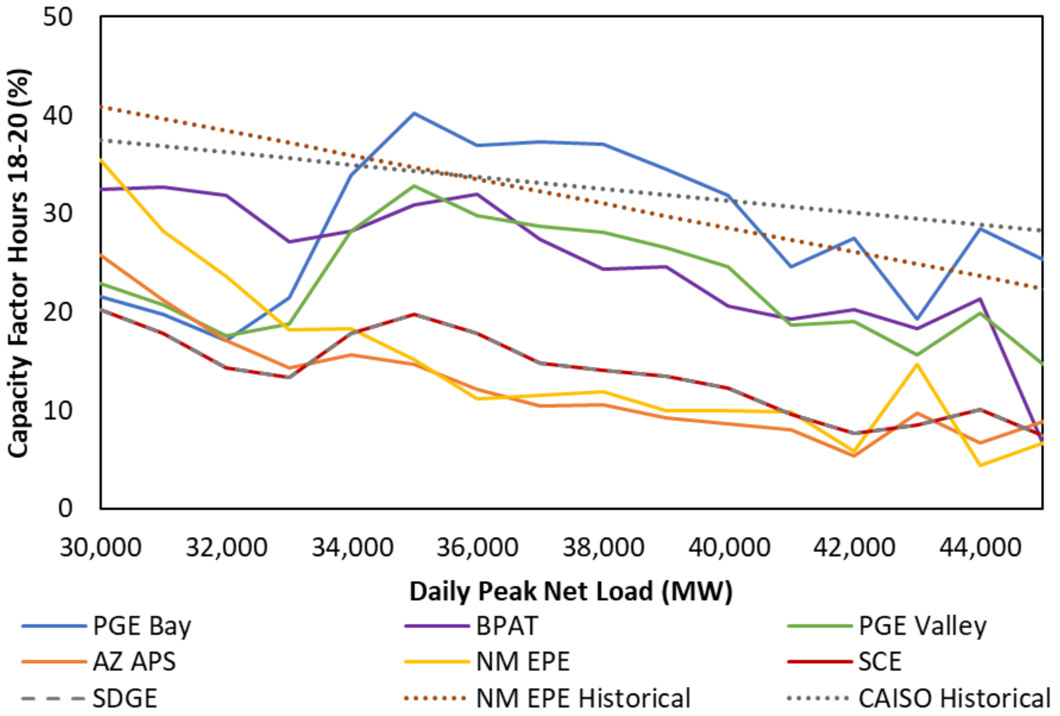
[23] https://gmao.gsfc.nasa.gov/reanalysis/MERRA/

Figure 15. Average August Daily Shape Comparison



To understand the characteristics of each wind shape and to validate ELCC results, the capacity factor during the expected CAISO net peak demand was calculated.[24] Figure 16 below illustrates each wind shape's generation during hours 18 to 20 for high demand periods across all weather years for both synthetic profiles and historical profiles.

Figure 16. Average Wind Output Hours 18 to 20 on Peak Net Load Days[25]



[24] Considering all solar, wind, EE, and EV.

[25] NM EPE and CAISO were the only publicly available historical datasets. Their lines use a linear curve fit.

As illustrated in the chart above, there is significant variation in the synthetic wind output as a function of location. Unfortunately, these locational differences could not be validated from publicly available historical data. Aggregated CAISO and New Mexico wind output was available historically for 2020 but suggested a different relationship than what is inherent in the RSP profiles. Both sets of historical wind data suggest declining wind output as a function of net load, but the average values are quite similar. The synthetic profiles in the RSP data set show significantly lower wind output during high net load conditions in SCE and SDGE compared to those of the PG&E wind locations and contribute to their lower ELCCs. However, the discrepancy in wind production in the synthetic profiles is suspect. The limited historical data available suggests the average ELCCs across all zones could be reasonable for each zone rather than use the location specific ELCCs. Absent development of new wind profiles that reflect technology differences and specific wind regimes, Astrapé's recommendation is to use a single wind ELCC for all locations for each year based on the average of all locations.

WIND HYBRID

The wind hybrid units used the wind shapes and capacities defined in Table 13 below.

Table 13. Wind Technology Assumptions

Region	Solar Shape	Capacity (MW)	Capacity Factor (%)	Capacity Factor on CAISO Net Peak (%)
PGE_Bay	Wind_CA_Solano_RioVista	500	28.6%	34.6%
PGE_Valley	Wind_CA_Kern_Mojave	250	31.7%	18.5%
	Wind_CA_Solano_RioVista	250	28.6%	34.6%
SCE	Wind_CA_Kern_Mojave	250	31.7%	18.5%
	Wind_CA_Riverside_ThousandPalms	250	21.5%	8.4%
SDGE	Wind_CA_Kern_Mojave	250	31.7%	18.5%
	Wind_CA_Riverside_ThousandPalms	250	21.5%	8.4%
AZPS	Wind_CA_Riverside_ThousandPalms	250	21.5%	8.4%
	Wind_NM_Socorro_Alamo	250	29.1%	10.0%
PNM	Wind_NM_Socorro_Alamo	500	29.1%	10.0%
BPAT	Wind_WA_Benton_Paterson	500	37.5%	24.6%

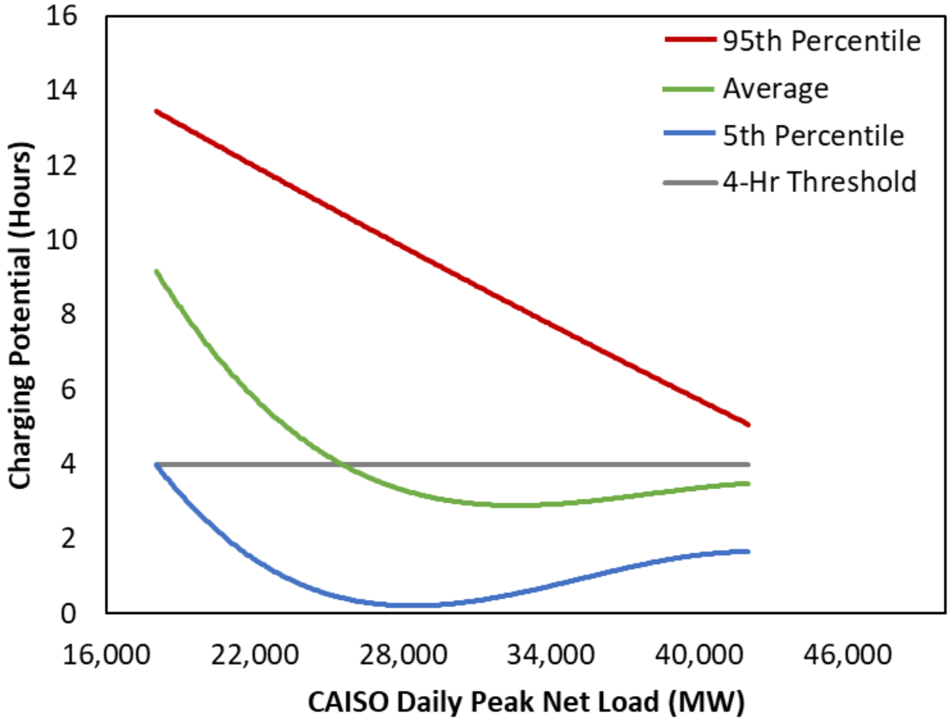
Though wind shape allocations differed between hybrids, the wind units and battery units totaled 500 MW each, yielding 1,000 MW of nameplate capacity with 500 MW maximum combined output based on the assumed interconnection capability. The battery units were modeled with 1-, 2-, or 4-hour storage capability, 85% round trip efficiency, used economic commitment and dispatch subject to the constraint that the battery could only charge from the corresponding wind unit.

Figure 17 was developed to determine if the wind profiles would provide adequate energy to consistently charge the coupled energy storage resource. The charging potential of the PGE Bay wind shape describes the daily amount of energy produced prior to hour 18 by the wind plant, expressed in terms of hours of energy which could be stored within a 500 MW storage device.[26] The figure shows

[26] These hours represent the peak net load hours, considering all solar, wind, EE, and EV and serves as a proxy for timing of expected reliability events.

during the highest net daily peaks, the coupled wind would not be able to consistently charge a 500 MW storage device to 4 hours of energy in a 90% confidence interval. The coupled wind is even insufficient for 1- and 2-hour storage devices to consistently provide full charge, considering the 5th percentile is below 1 hour. The expected charging capability at the highest net load periods is expected to be less than 2 hours, with some days as low as a fraction of 1 hour. However, since this product is assumed to be capable of providing AS, and the system does not reach storage exhaustion in any study year, its ELCC remains elevated throughout the analysis. If battery ELCCs become constrained by energy duration because of system battery penetration in the future, the wind hybrid project ELCCs would begin to reflect the charging constraint effect. Wind hybrids exhibit characteristics of 1- and 2-hour battery storage resources which is consistent with the available charging energy distribution modeled. If penetration of 1- and 2-hour batteries in CAISO increased significantly, 1- and 2-hour standalone battery ELCCs would decline, and it is expected that wind hybrids would also see a commensurate decline in ELCCs due to the limited wind energy available for charging.

Figure 17. Charging Potential of PGE Bay Wind Hybrid



STANDALONE BATTERY

The battery units were modeled with 500 MW of capacity, 1-, 2-, or 4-hour storage capability, 85% round trip efficiency, used economic commitment and dispatch and were allowed to charge from the grid. The batteries were modeled with forced outage rates of 0% so the effect of duration on the ELCC values could be isolated from any influence of forced outages.

SIMULATION RESULTS

Astrapé performed simulations to determine the annual, marginal ELCC values for the defined resource classes and class subtype locations. Table 14 defines the results for the 2022 study year.

Table 14. 2022 Study Results[27] (expressed as a percentage of the interconnection capability)

Technology	BTM PV	Fixed PV	Tracking PV	Wind
PGE Valley	5.9%	8.6%	11.0%	17.2%
PGE Bay	5.5%	8.5%	10.9%	24.4%
SCE	6.4%	8.9%	11.2%	11.8%
SDGE	5.9%	8.7%	11.0%	11.8%
AZ APS	N/A	5.0%	6.8%	16.1%
NM EPE	N/A	5.0%	6.8%	14.8%
BPA	N/A	N/A	N/A	16.0%
CAISO	5.9%	8.7%	11.0%	16.3%

The results for the 2026 study year are provided in Table 15.

Table 15. 2026 Study Results (expressed as a percentage of the interconnection capability)

Technology	BTM PV	Fixed PV	Tracking PV	Wind
PGE Valley	3.6%	6.0%	7.2%	15.6%
PGE Bay	3.4%	5.8%	7.1%	19.2%
SCE	5.1%	6.1%	7.8%	10.8%
SDGE	4.2%	6.0%	7.4%	10.8%
AZ APS	N/A	3.8%	5.9%	8.6%
NM EPE	N/A	3.8%	5.9%	8.6%
BPA	N/A	N/A	N/A	12.6%
CAISO	4.1%	5.9%	7.4%	14.1%

The results for the 2030 study year are shown in Table 16.

Table 16. 2030 Study Results (expressed as a percentage of the interconnection capability)

Technology	BTM PV	Fixed PV	Tracking PV	Wind
PGE Valley	2.1%	4.3%	5.9%	12.1%
PGE Bay	2.1%	4.2%	5.7%	15.5%
SCE	2.3%	4.8%	6.5%	6.3%
SDGE	2.1%	4.6%	6.5%	6.3%
AZ APS	N/A	1.2%	3.0%	3.3%
NM EPE	N/A	1.2%	3.0%	3.3%
BPA	N/A	N/A	N/A	8.8%
CAISO	2.2%	4.5%	6.2%	10.1%

[27] Values for all three study years reflect post-processing to reduce statistical noise.

The battery and hybrid study results are presented in Table 17. The hybrid projects have total nameplate capacity of 1,000 MW (500 MW renewable and 500 MW battery), but the marginal ELCC is calculated as a percentage of the maximum possible simultaneous output from the facility, which is 500 MW based on the assumed interconnection capacity.[28,29] Additionally, the storage component cannot charge from the grid.

Table 17. Battery and Hybrid Study Results[30]

Technology	2022	2026	2030
1-Hour Hybrid or Standalone Battery	87.1%	85.4%	78.6%
2-Hour Hybrid or Standalone Battery	88.3%	86.7%	80.4%
4-Hour Hybrid or Standalone Battery	90.6%	88.1%	82.2%

Standalone batteries, PV hybrids, and wind hybrid facilities were simulated independently but the results demonstrated ELCCs for all three technologies and all locations to be within statistical error bounds and are thus averaged for this report. When battery penetration reaches a level after 2030 where energy sufficiency is a significant concern, the ELCCs of hybrid facilities will be sensitive to the charging capability of the associated renewable energy and locational differences between hybrid facilities may surface.

[28] These hours represent the peak net load hours, considering all solar, wind, EE, and EV and serves as a proxy for timing of expected reliability events.
[29] Given the wide range of possible configurations for hybrid facilities, multiple methods of accounting for their ELCC may need to be employed, but for simplicity and comparability, using maximum possible simultaneous output as the denominator was most appropriate for this report.
[30] Simulations were performed with standalone battery in addition to PV hybrids and wind hybrids for calibration purposes.

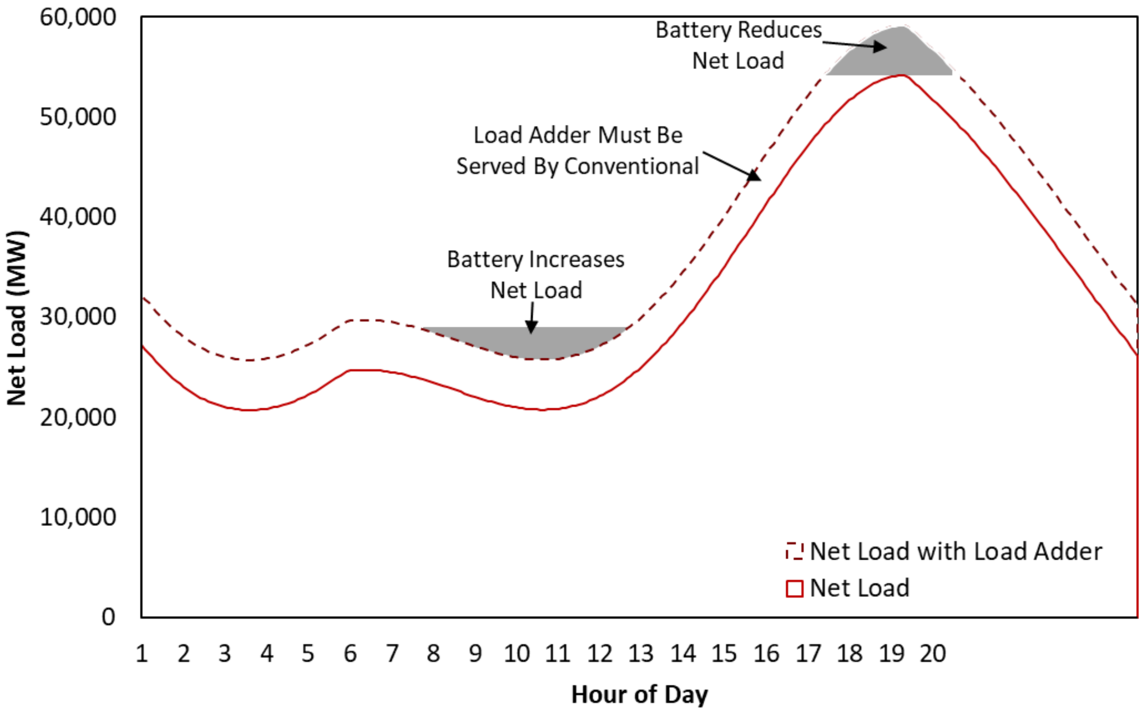
RESULTS DISCUSSION

EFFECTS OF RESOURCE INTERACTIONS ON ELCC RESULTS

As California embarks on significant deployment of battery storage resources, the reliability contributions of these resources will be progressively more important. The ELCCs of battery resources are directly related to two aspects of their integration into a system: their interactions with other classes of resources and the net load shape of the system in which they are installed.

The interactions with other classes of resources can affect the ELCCs of batteries even when battery penetration is relatively low. In a scenario where four-hour batteries are only needed to serve a net load peak that is two hours in duration, the energy in the batteries will not be exhausted. However, the effects of the comparison resource or load in an ELCC analysis will be present in all hours of the day. Further, the need to charge the battery will also affect the reliability of the underlying system. An illustration of the effect on conventional operation is shown in Figure 18. Across the balance of the day, the load adder associated with ELCC analysis plus the charging requirements of the battery result in significant increases in operation of the conventional fleet. Only in a few hours near net load peak does the ELCC analysis show the conventional dispatch to be the same as in the base case. This extra conventional generation will result in additional outages which will be present on peak, reducing battery ELCCs.

Figure 18. Effect on Conventional Operation



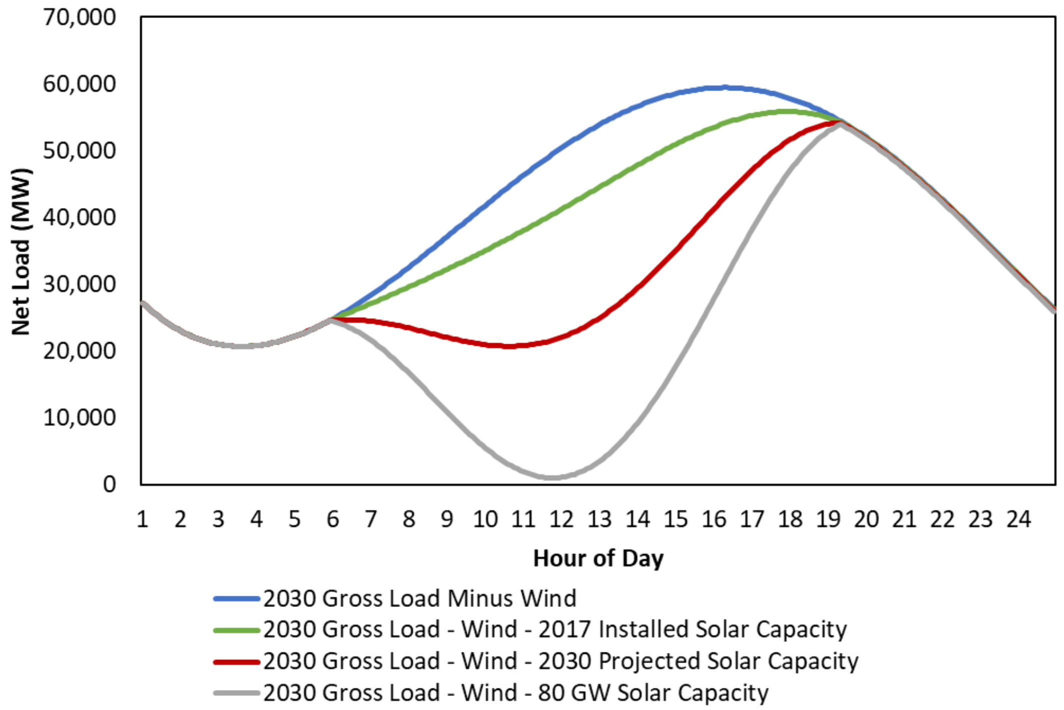
Since the first batteries that are added are used to serve ancillary services around the clock, replacing conventional generators that previously provided this service, this effect is muted. This is partially the reason the hybrid resources in our 2020 study demonstrated much higher ELCCs; the battery penetrations analyzed were much lower resulting in fewer interactions with the system. As the penetration increases, the interactions become more pronounced in the ELCC results as indicated by the trend in Table 18.

Table 18. Relationship Between Battery Penetration and Battery ELCC Results[31]

Technology	1 GW	4.7 GW	9 GW	12 GW
4-Hour Hybrid or Standalone Battery	96.0%	90.6%	88.1%	82.2%

Energy sufficiency is the second driver of reliability contributions of batteries. Energy sufficiency is a function of the system's net load shape. Flatter net load shapes (i.e., higher number of hours with net load that is close to the daily net load peak) require longer battery duration for batteries to support reliability. In contrast, steep net load shapes (i.e., fewer hours with net load close to the daily net load peak) require shorter battery duration. Non-dispatchable renewable resources can either flatten or steepen the net load shape. If the output of the non-dispatchable resource is higher during net load peak hours than its annual average output, it will flatten the net load shape. At most of the feasible renewable penetrations over the planning horizon, solar resources have a steepening effect on net load shapes, as shown in Figure 19. The steepening effect can allow for either shorter duration storage resources to provide high ELCCs or more capacity with the same duration to provide high ELCCs.

Figure 19. Net Load Shape Impact of Solar – Example Summer Peak Day in 2030[32]



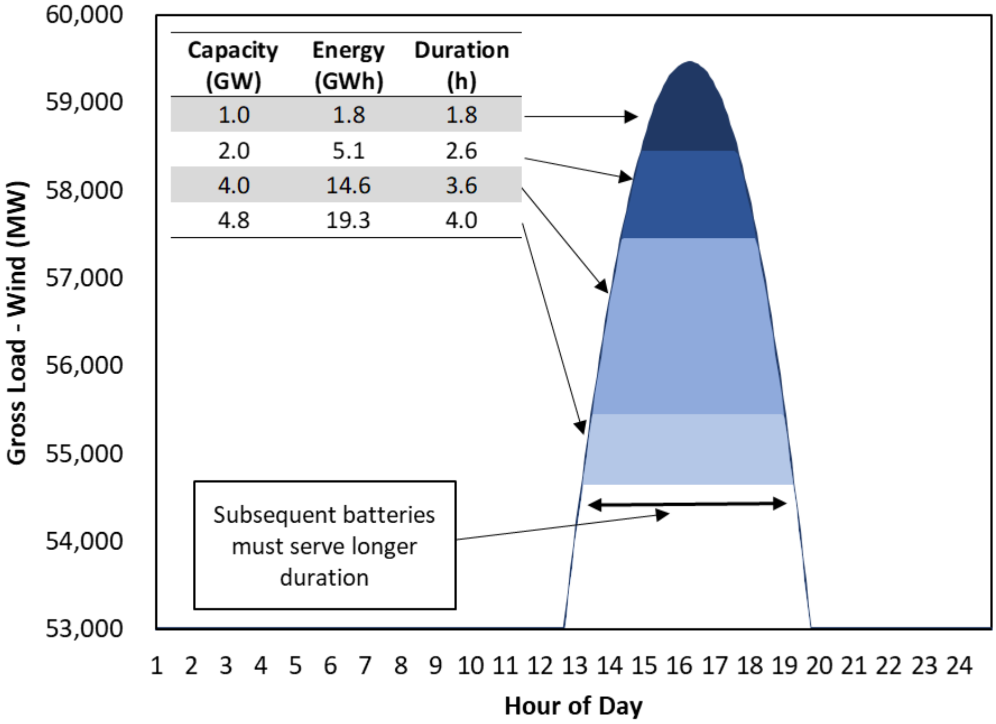
For the CAISO load shape, initial solar penetrations only modestly steepen the net load, resulting in modest declines in battery duration requirements or modest increases in battery capacity potential to serve peak net load needs. However, as penetrations increase into the future, the net load shape steepens significantly as shown in Figure 19.

The first step to understanding the energy sufficiency of batteries is analyzing the energy under the net load peak, as shown in Figure 20. The following analysis was performed for a typical peak day load shape. Since the actual results are produced from simulations that consider 20 years of synthetic

[31] Results for all penetrations are from the study results. A separate sensitivity was run at 1 GW battery penetration to understand the ELCC trend.
[32] Solar is defined as the sum of utility scale solar and BTM PV capacity. Wind output removed corresponds to the expected wind production for 2030 based on the RSP.

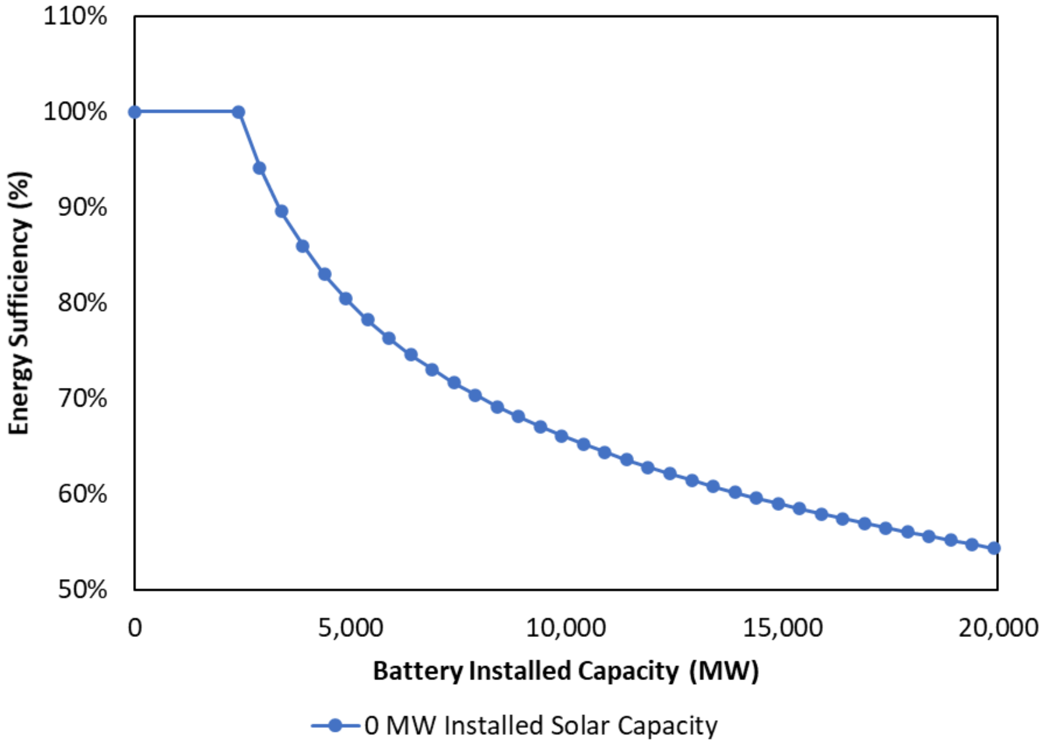
profiles and other factors influence batteries' potential, the analytical results are not a perfect estimate of energy sufficiency of batteries but do provide a meaningful illustration. Taking the '2030 Gross Load Minus Wind' scenario from Figure 19, we calculate the capacity of energy limited resources that can serve 4 hours of energy. Figure 20 illustrates the build up to the 4-hour calculation. The first GW of capacity will serve the last 1.8 GWh during net load peak hours. Two GW of capacity can serve 5.1 GWh. The capacity that corresponds to 4-hour duration is 4.8 GW. Any 4-hour duration energy limited resources added to this scenario after this level will not supply perfect energy sufficiency.

Figure 20. Energy Limited Duration Analysis Example



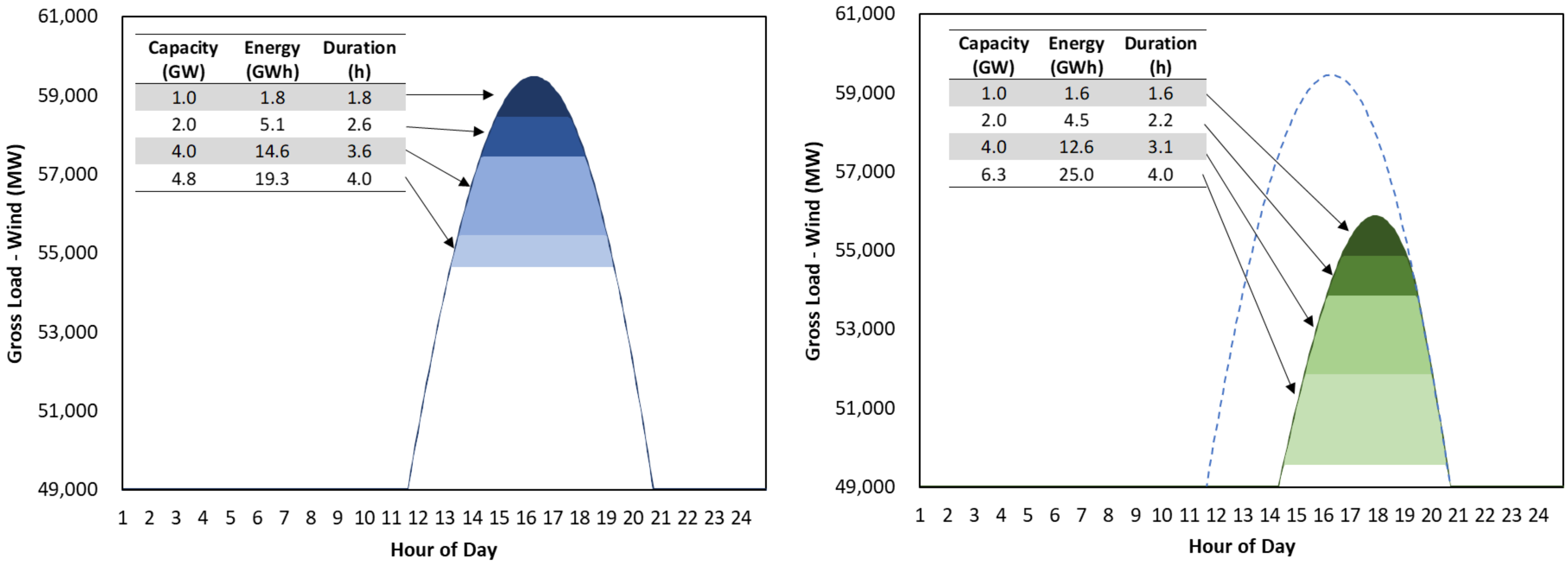
Again, 4.8 GW of energy-limited capacity can provide energy sufficiency. However, batteries are not the only energy-limited resource in the California electric system. These considerations must reflect pumped storage resources and limited duration demand response products. Pumped storage resources are typically dispatched earlier and have longer duration limits, so they generally would not reduce the potential for 4-hour batteries. Demand response resources though, are reserved for emergency conditions and are assumed to be dispatched after batteries. Since CAISO has 2.4 GW of energy-limited demand response capacity, the energy sufficiency potential for batteries is only 2.4 GW. In this system, subsequent battery capacity would either need to be a longer duration than 4 hours or would provide less than 100% energy sufficiency. The magnitude of the decline can be explicitly calculated by dividing the total energy below the net load by the battery capacity serving that energy. A plot of the decline in energy sufficiency is shown in Figure 21.

Figure 21. Decline in Energy Sufficiency as a Function of Battery Installed Capacity



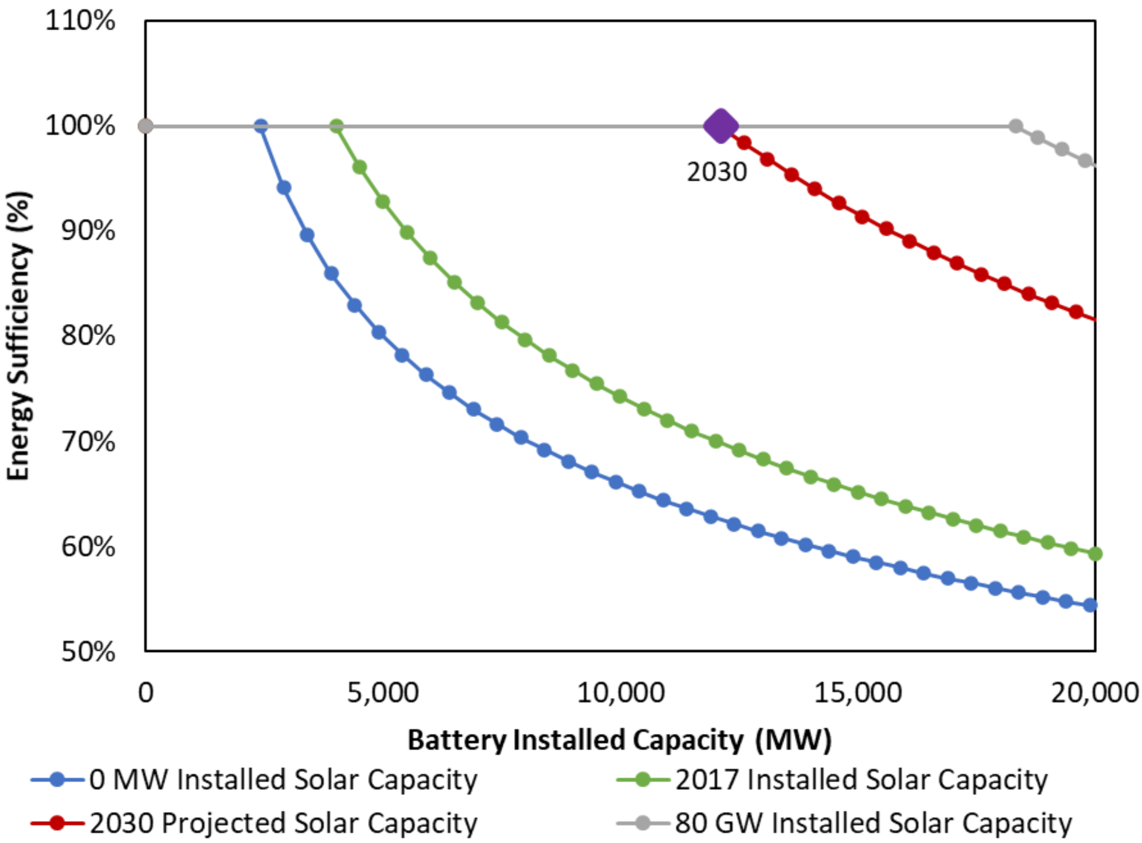
The impact of solar penetration changes is more apparent as performing battery energy sufficiency calculations for different solar penetrations shows significant impacts on the energy sufficiency curve. Figure 22 compares the 100% energy sufficiency level in the '2030 Load Minus Wind' portfolio to the '2030 Load Minus Wind Minus 2017 Solar' portfolio. The potential for batteries to provide 100% energy sufficiency has increased substantially simply due to the steepening effect of the solar on the net load.

Figure 22. 100% Energy Sufficiency Level in the '2030 Load Minus Wind' and '2030 Load Minus Wind Minus 2017 Solar' Portfolios



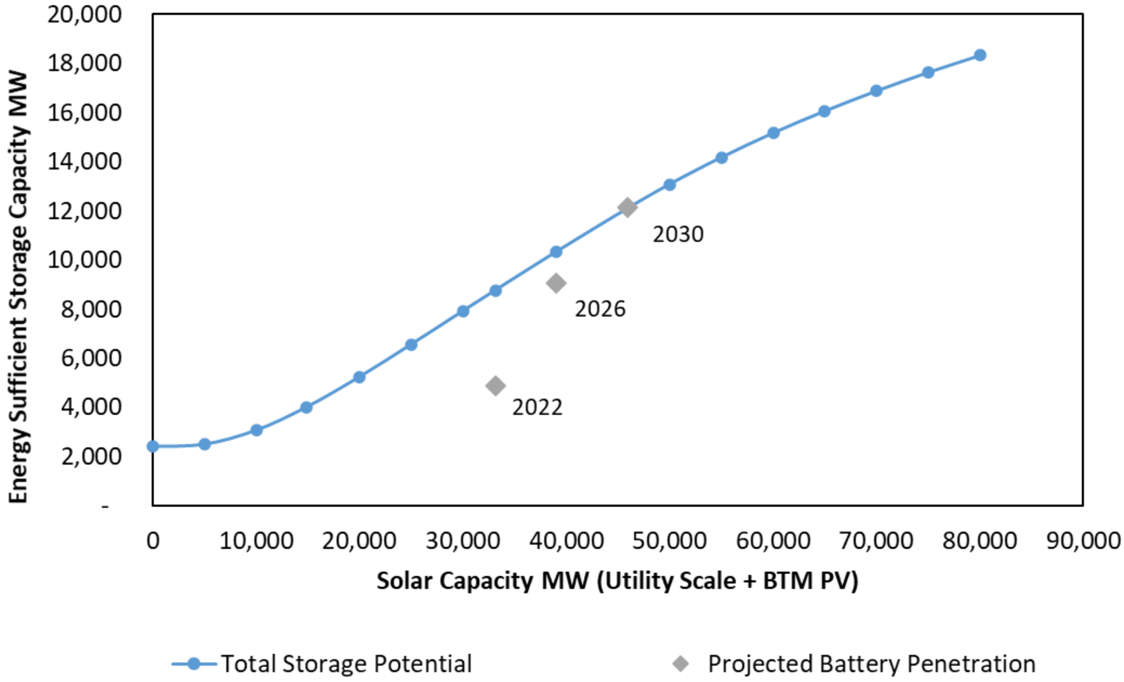
The battery energy sufficiency curves for the four portfolios from Figure 19 are shown in Figure 23.

Figure 23. Battery Energy Sufficiency Curves of Four Varying Solar Penetration Portfolios



With an 80 GW solar portfolio, over 20 GW of 4-hour batteries are energy sufficient, but with no solar, less than 3 GW of 4-hour batteries are energy sufficient. The full development of this sufficiency potential is shown in Figure 24. The 2022, 2026, and 2030 projected battery penetrations are also shown on this chart indicating that by 2030 the energy sufficiency of projected installed battery capacity is expected to approach the threshold that supplies 100% and incremental batteries would need to be of longer duration to provide energy sufficiency. Again, this analysis uses a typical shape and does not capture the variation in load and solar shapes included in the simulations, so there are likely days when the batteries are not energy sufficient. The analytical estimates then only apply to the day's shape that is being used, and the inclusion of the full range of simulated days would show a reduction in potential to provide full energy sufficiency. This decline due to approaching the energy efficiency threshold is apparent in the ELCCs in 2030 since the decline by that point cannot be explained by system interactions exclusively.

Figure 24. 100% Energy Sufficient Battery Capacity on Typical Summer Day

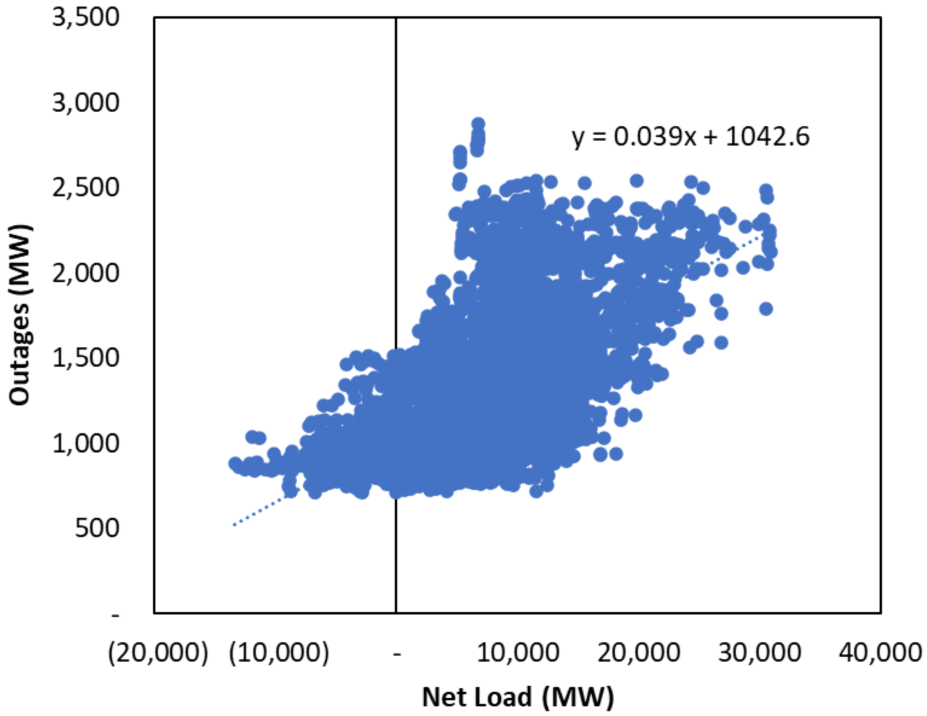


The combination of the system interactive effects and energy sufficiency drive the overall ELCC of batteries. While energy sufficiency can be estimated analytically, the interactive effects can only be captured by performing hourly chronological commitment and dispatch simulations which is why the ELCCs that are quantified in this study are produced directly from SERVM simulations.

SOLAR, WIND, AND CONVENTIONAL RESOURCE INTERACTIONS

Storage resources are not the only technology that have interactive effects with other classes of resources. Solar production can also affect the operation of conventional units, but they have the opposite effect on reliability. Lower net load driven by increasing solar penetration results in fewer conventional units in operation which in turn lowers system outages. This impact on system outages translates to a reliability benefit provided by solar even if it occurs during hours prior to the net load peak. This is because there is a lag effect of forced outages. Since outages typically last for several hours or even several days, avoiding outages during hours prior to the peak also reduces outages during the net load peak. Forced outages as a function of net load are plotted in Figure 25.

Figure 25. Forced Outages as a Function of Net Load



The slope of the line in Figure 25 is 3.9% which implies that for every MW of net load reduced, 0.039 MW of outages would be avoided. With higher forced outage rates in the RSP database, this effect is more pronounced than seen in the 2020 study. The solar output several hours prior to the net load peak is 70-90% of nameplate so it is feasible that 70-90% of the forced outage benefit would translate directly to improvement in solar ELCCs.

Wind resources demonstrate the opposite interaction with conventional generators and with storage resources in that their production profiles are generally lower before the system net load peak. The lack of energy from wind prior to peak contributes to more outages in the comparison case and the need for earlier deployment of storage energy, resulting in a declining ELCC over time for wind.

HYBRID AND STANDALONE BATTERY ELCC VALUES

Existing and proposed hybrid configuration facilities are varied with a wide range of battery to renewable max output, battery durations, and interconnection size. Since constraints on reliability value are expected to occur when batteries are not able to sufficiently charge from the renewable energy, this study analyzed configurations with a 1:1 ratio of battery capacity to renewable capacity. As described in the inputs section, solar facilities were generally able to fully charge 4-hour batteries while wind facilities showed some risk to providing full charge for four-hour batteries. However, since battery penetration did not significantly exceed levels that provide energy sufficiency, hybrid facility ELCCs mostly mimicked the ELCCs of the paired battery. The differences in ELCCs between standalone batteries, PV hybrids, and wind hybrids ranged from 0-1% and were mostly within simulation error, so the results were reported as an average. At higher penetrations of system batteries, distinctions will become more apparent.

ELCCs for hybrid facilities with alternate ratios of battery capacity to renewable capacity were not calculated during this study. As shown in the 2020 ELCC study, the renewable plus battery hybrid ELCCs for projects with alternate configurations can be approximated by using the sum of the solar and standalone battery ELCC subject to a cap of the maximum combined output of the facility.[33]

MODELING PROFILE EFFECTS ON RESULTS

Developing synthetic load and renewable profiles is inherently challenging, and ELCCs are highly dependent on the resulting shapes. While the latest vintage of load, wind, and solar profiles reflect increasing confidence on the projected shape and better available historical data from which to construct the shapes, there are still concerns that the profiles may not fully capture potential outcomes. Synthetic wind profiles are notably challenging to develop, and the location specific profiles in the RSP dataset reflect distinctions that cannot be verified from historical data. Our recommendation is to use average wind ELCCs across all locations until more robust wind data sets can be developed.

[33] https://www.pge.com/tariffs/assets/pdf/adviceletter/ELEC_5868-E.pdf

CONCLUSION AND LESSONS LEARNED

CONCLUSION

The reliability events of the summer of 2020 emphasized the importance of understanding the reliability contributions of all resource classes and their interactions. Energy constraints should be monitored carefully on the California system as the penetration of short duration storage approaches 12 GW over the next decade.[34] This penetration of energy limited capacity results in significant interactions between resource classes. Preserving energy in batteries for system peaks requires marginal generation from conventional units. Additional solar generation allows for lower forced outages from conventional generation. These interactions mean that resource adequacy cannot be accurately measured by simple accounting methods, but rather requires chronological simulations which respect all unit characteristics and constraints. The ELCC values and conclusions are based on the 2019-2020 IRP RSP system studied. As we have described throughout, resource class interactions affect ELCC values, and future systems with significantly different penetrations of resource classes may result in different ELCC values.

LESSONS LEARNED

In reviewing the results and input assumptions, several potential improvements to future ELCC studies were identified:

1. The quality of synthetic wind profiles will directly translate to the quality of their ELCC estimates. Given the variability in the input profiles, Astrapé believes a complete redevelopment of the wind profiles for all zones is merited, and the redevelopment should place a high emphasis on forecasting the wind output distribution during high net load periods.
2. Development of synthetic load profiles is likewise challenging since historical load data must be grossed up for expected behind the meter energy production. Further, demand side categories such as TOU, EV, and EE are inherently difficult to estimate, and those programs are often considered from typical usage patterns rather than from the perspective of their effects on reliability. Rigorous review of consumption patterns and all demand side programs is recommended.

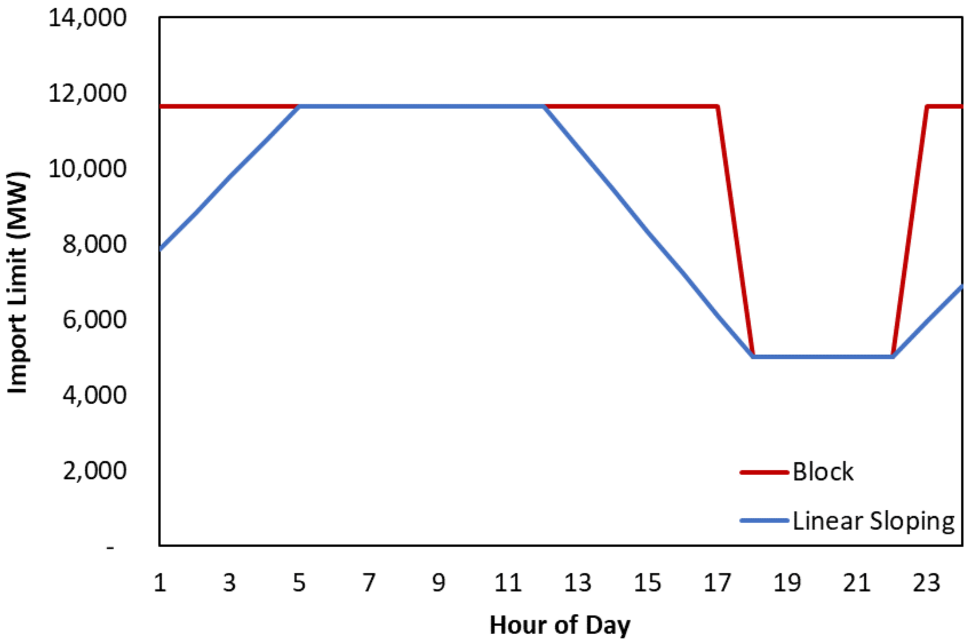
[34] Four-hour duration or less

APPENDIX 1: 2019-2020 RSP BASELINE RESOURCE DEVIATIONS

As directed in the Decision, the 2019-2020 RSP was used for the baseline resource list for the analysis presented in the Report. The RSP includes significant changes to synthetic wind, solar, and load profiles and reflects significant changes in the resource mix in the CAISO system. There were also four additional changes that were made to the original RSP: net import assumption, wind shape time shift, time shift for the profiles for NM EPE and AZ APS, and adjustments to the implicit battery durations in 2030.

In the RSP, available on-peak imports (hours 18 to 22) are constrained from 11,665 MW in the off-peak periods to 5,000 MW. In the original RSP dataset, the change in constraint is applied simply as a one-hour shift. This jump is unwieldy for the SERVM commitment algorithms. Instead of applying the instant shift, our simulations used a linear sloping import profile. Publicly available interchange information for CAISO was retrieved from the EIA website based on January 2020 to February 2021 actual data.[35] While historical imports often showed more than 5GW, total imports were capped as shown in Figure A1 to match the expected future transmission and generation availability constraints of 5 GW between hours 18 and 22. The historical data also showed an average of 1000 MW/h ramping capability, leading to the use of the linear sloping import limit rather than the block shape that abruptly drops and increases 6,665 MW in one hour.

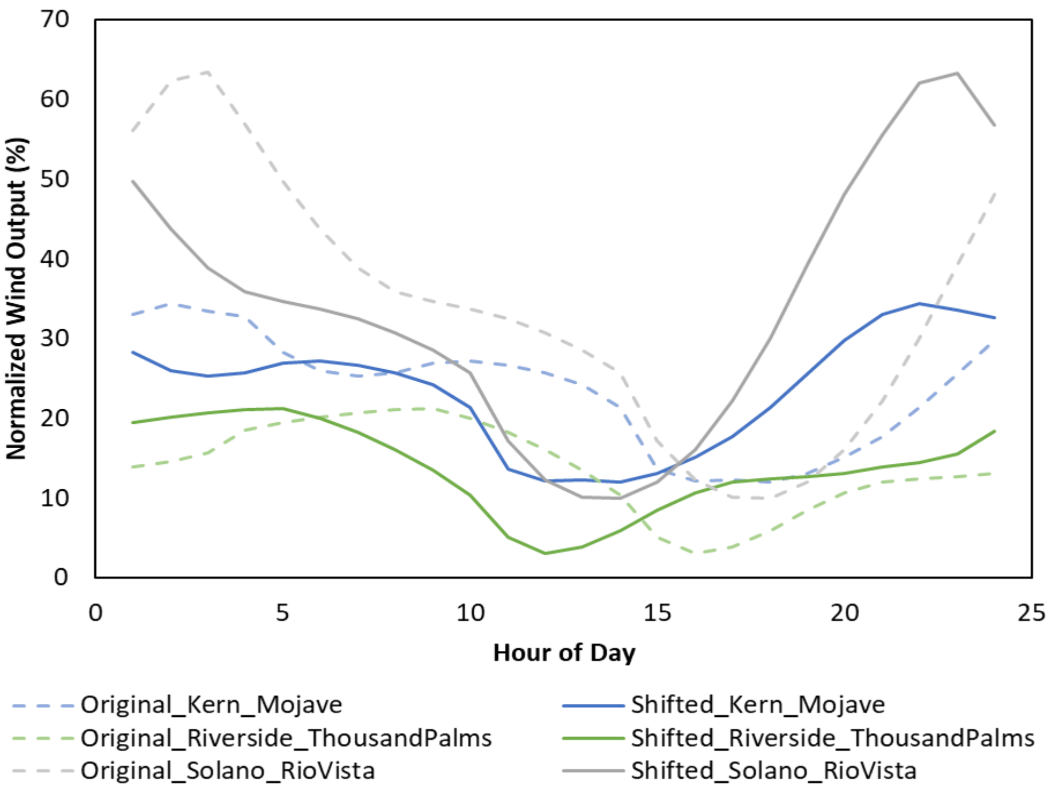
Figure A1. Import Limit Modeling Options



[35] https://www.eia.gov/beta/electricity/gridmonitor/dashboard/electric_overview/balancing_authority/CISO

Wind shapes in the database were all shifted back by 4 hours, as shown in Figure A2, to better align with historical profile shapes.[36]

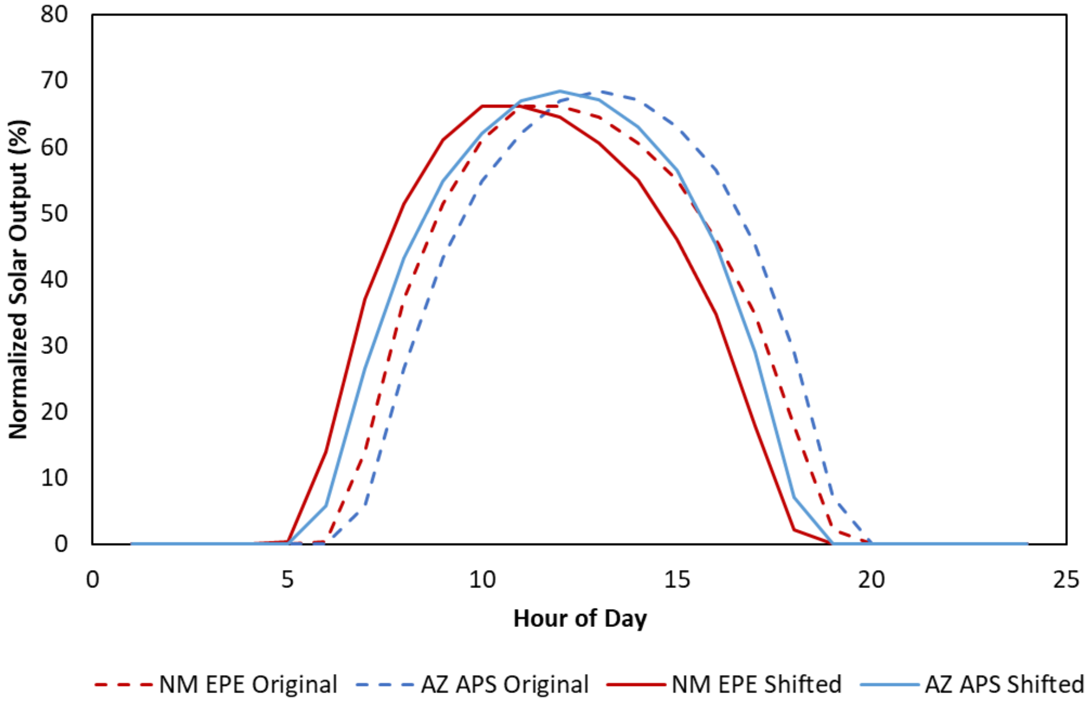
Figure A2. August Average Shape of Original CA Shapes and Shifted CA Shapes



Solar profiles in NM EPE and AZ APS were shifted back one hour, as shown in Figure A3.[37] The shift was performed because the CA shapes' output ended one hour earlier than the AZ and NM shapes which did not comport with the correct effects of longitude.

[36]https://www.cpuc.ca.gov/uploadedFiles/CPUCWebsite/Content/UtilitiesIndustries/Energy/EnergyPrograms/ElectPowerProcurementGeneration/irp/2018/IRP_MAG_20190617_CoreInputs.pdf
https://www.cpuc.ca.gov/uploadedFiles/CPUCWebsite/Content/UtilitiesIndustries/Energy/EnergyPrograms/ElectPowerProcurementGeneration/irp/2018/Unified_RAIRP_IA_Final_20190329.pdf
[35] The shapes provided in the figure are the average of the fixed and the 1-axis shapes.

Figure A3. Average August Daily Solar Shape Comparison for AZ APS and NM EPE



The implicit battery durations in 2030 for the 8,873 MW of battery units named "46MMT_20200121_2045_2PRM_NOOTCEXT…" were updated to match the 4-hour durations assigned to these batteries in 2022 and 2026. Unchanged, the units would have had an assigned 2.76-hour duration.

PG&E Gas and Electric
Advice Submittal List
General Order 96-B, Section IV

AT&T
Albion Power Company

Alta Power Group, LLC
Anderson & Poole

Atlas ReFuel
BART

Barkovich & Yap, Inc.
California Cotton Ginners & Growers Assn
California Energy Commission

California Hub for Energy Efficiency Financing

California Alternative Energy and Advanced Transportation Financing Authority
California Public Utilities Commission
Calpine

Cameron-Daniel, P.C.
Casner, Steve
Cenergy Power
Center for Biological Diversity

Chevron Pipeline and Power
City of Palo Alto

City of San Jose
Clean Power Research
Coast Economic Consulting
Commercial Energy
Crossborder Energy
Crown Road Energy, LLC
Davis Wright Tremaine LLP
Day Carter Murphy

Dept of General Services
Don Pickett & Associates, Inc.
Douglass & Liddell

East Bay Community Energy Ellison Schneider & Harris LLP Energy Management Service
Engineers and Scientists of California

GenOn Energy, Inc.
Goodin, MacBride, Squeri, Schlotz & Ritchie
Green Power Institute
Hanna & Morton
ICF
IGS Energy
International Power Technology
Intestate Gas Services, Inc.
Kelly Group
Ken Bohn Consulting
Keyes & Fox LLP
Leviton Manufacturing Co., Inc.

Los Angeles County Integrated Waste Management Task Force
MRW & Associates
Manatt Phelps Phillips
Marin Energy Authority
McKenzie & Associates

Modesto Irrigation District
NLine Energy, Inc.
NRG Solar

Office of Ratepayer Advocates
OnGrid Solar
Pacific Gas and Electric Company
Peninsula Clean Energy

Pioneer Community Energy

Redwood Coast Energy Authority
Regulatory & Cogeneration Service, Inc.
SCD Energy Solutions
San Diego Gas & Electric Company

SPURR
San Francisco Water Power and Sewer
Sempra Utilities

Sierra Telephone Company, Inc.
Southern California Edison Company
Southern California Gas Company
Spark Energy
Sun Light & Power
Sunshine Design
Tecogen, Inc.
TerraVerde Renewable Partners
Tiger Natural Gas, Inc.

TransCanada
Utility Cost Management
Utility Power Solutions
Water and Energy Consulting Wellhead Electric Company
Western Manufactured Housing Communities Association (WMA)
Yep Energy