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STAFF REPORT

Midterm Reliability Analysis

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California Energy Commission

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ABSTRACT

This report provides the results of analyses conducted by CEC staff to inform decisions about the need for future resource procurement to support reliability for the midterm (2023 – 2026). The report addresses multiple questions associated with reliability over this period, including loss of load expectation modeling, assessment of risks to reliability from a growing amount of battery energy storage system resources on the grid, and an evaluation of additional thermal generation sources that could support reliability. The report is prepared for the California Public Utilities Commission to consider as part of their Integrated Resource Planning Proceeding (R.20-05-003) as they decide whether to adopt the preferred system plan by the end of 2021.

Keywords: System reliability, clean energy resources, loss of load expectation, battery energy storage system, natural gas fleet, thermal resources

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EXECUTIVE SUMMARY

Recent California and west-wide extreme heat events attributed to the impacts of climate change in 2020 and 2021 have resulted in the need for a closer look at the need for additional generation resources for the state to bolster reliability. In addition to potential climate change impacts, the state will have a critical transition period over the next five years as nearly 6,000 MW of older firm and dispatchable resources are expected to be retired. At the same time, the state continues to expand deployment of renewable resources to support SB 100 targets and plan for increased electrification.

In response to the rotating outages the state experienced in August 2020, the California Energy Commission (CEC), California Public Utilities Commission (CPUC), and California Independent System Operator (CAISO) developed the Final Root Cause Analysis (RCA) for Governor Gavin Newsom.[1] The RCA highlighted the importance of adequately planning for a changing generation mix, accounting for climate change impacts, and making sure that sufficient resources are available to serve load during the net peak period, to ensure reliability.

Over the past two years, the CPUC has issued two decisions for additional procurement in the Integrated Resource Planning proceeding. In their June 30, 2021 decision, the CPUC ordered the procurement of 11,500 MW of net qualifying capacity (NQC) to come online from 2023 to 2026.[2] While the proposed decision included authorization to procure up to 1,500 MW NQC of incremental thermal capacity, the final decision removed consideration of fossil-fueled capacity, but noted that additional procurement of fossil-fueled capacity would be evaluated based on additional analysis from the CPUC and CEC, including the analysis in this report, for the decision adopting the CPUC's preferred system plan by the end of 2021.

This report addresses three analytical tracks to inform the CPUC's decision. The first track is the CEC's reliability modeling for the years 2023 – 2026. The second track addresses questions associated with the growth of battery energy storage (BESS) on the grid and the implications for reliability. The third track addresses options for additional thermal resources, if needed.

2023 – 2026 Reliability Modeling

This track of the report includes results of the CEC's first California Reliability Outlook (CRO). The CRO was developed in response to the RCA to help provide situational awareness and support reliability planning in the near-, mid-, and long-term. The scope for this first version was primarily informed by the immediate needs of the CPUC's midterm reliability decision and was developed in close collaboration with CPUC staff and stakeholder input. The analysis addressed the following questions:

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1 *Final Root Cause Analysis Mid-August 2020 Extreme Heat Wave*. 2021. California Independent System Operator. Available at http://www.caiso.com/Documents/Final-Root-Cause-Analysis-Mid-August-2020-Extreme-Heat-Wave.pdf.

2 Decision Requiring Procurement to Address Mid-term Reliability (2023-2026). D.21-06-035. June 30, 2021. Available at https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M389/K603/389603637.PDF.

- Whether additional capacity beyond current procurement orders is needed to maintain system reliability.
- Whether incremental thermal resources provide an additional system reliability benefit compared to a portfolio of zero-emitting resources.

The analysis reached the following conclusions:

- The ordered resource procurement for 2023 through 2026 appears to be sufficient to meet a 1 day in 10-year loss of load expectation (LOLE) target, indicating system reliability.
- The reliance on zero-emitting resources does not appear to diminish reliability compared to procuring thermal resources.

Further considerations include:

- This study did not include resource retirements beyond those assumed in the CPUC's mid-term reliability decision. Additional retirements would increase the likelihood of system reliability challenges.
- Additionally, the CEC demand forecast is being further enhanced to capture the frequency and dispersion of extreme climate impacts. This new climate analysis or increased electrification could necessitate planning for a higher demand and characteristics that are not captured in current analysis.

Battery Energy Storage Systems on the Grid

This track includes an assessment of potential risks associated with increasing deployment of battery energy storage systems (BESS) on the California grid. BESS resources have substantially increased in recent years and are expected to continue to grow as the BESS market matures. However, as would be expected of any new application of a technology, there are concerns to be addressed, such as whether the systems are performing as needed, particularly during net peak, whether supply chain issues will affect deployment and grid reliability, and whether safety risks of systems, particularly lithium-ion batteries, can be mitigated.

The analysis reached the following conclusions:

- The current procurement orders could result in adding in excess of 10 GW of new BESS to the CAISO system in order to support peak and net peak loads.
- Modeling indicates BESS performance does not appear to be a limiting factor to system reliability in the midterm timeframe. In 2021, CAISO dispatch data indicates that in aggregate, BESS supported meeting the net peak load.
- Modeling indicates that a one-year delay of 20% of new BESS resources, potentially resulting from supply chain issues, would not, by itself, jeopardize system reliability. However, further procurement delays due to either supply chain constraints or permitting or interconnection timelines, beyond those modeled in this analysis, could contribute to system reliability challenges. It is essential that state agencies and CAISO develop solutions to ensure timely interconnection of resources.

- Modeling suggests that there is sufficient energy on the system to adequately charge BESS resources to support system reliability, even under energy constrained conditions, owing to limited imports, hydro generation and reductions in solar output.
- BESS performance and safety should continue to be monitored by CEC and other relevant state agencies and safety frameworks continued to be improved to ensure both public safety and reliability. Higher levels of outage rates, lengths of an outage etc., than assumed in the modeling could have significant effect on the modeling results and need to be carefully considered as more data becomes available. It would be prudent to retain current levels of capacity supporting peak and net peak demands until BESS performance has been further demonstrated.

Role of the Natural Gas Fleet

This track provides information on the incremental capacity options at existing natural gas facilities and the permitting timelines should there be a need for incremental thermal capacity to maintain system reliability over the coming decade.

CHAPTER 1: Introduction

The next five years represent a critical transition period for California's electric grid. Nearly 6,000 MW of firm and dispatchable resources are expected to be retired, including the remaining once-through-cooling (OTC) plants and Diablo Canyon Nuclear Power Plant. At the same time, the state continues to expand deployment of renewable resources to support SB 100 (De León, Chapter 312, Statutes of 2018) targets,[3] plan for increased electrification, and plan for climate induced demand and supply uncertainties. As the state continues its transition toward clean resources, it is vital to ensure that the transition is reliable and equitable, both of which have been brought into focus following the rotating outages in August 2020.

The Final Root Cause Analysis (RCA) — prepared for Governor Gavin Newsom jointly by the California Energy Commission (CEC), California Public Utilities Commission (CPUC), and California Independent System Operator (CAISO) following the rotating outages - highlighted the importance of adequately planning for a changing generation mix, accounting for climate change impacts, and making sure that sufficient resources are available to serve load during the net peak period, to ensure system reliability.[4]

Thermal resources that have been relied upon primarily to support the reliability and ramping needs, especially during the net peak hours, must be augmented with zero-emitting resources, battery energy storage systems (BESS) and other zero-carbon dispatchable resources. This transition to a more diversified portfolio of resources provides additional challenges to planning for grid reliability and needs to be carefully considered.

In response to the projected capacity needs over the next five years, the CPUC issued Decision D.19-11-016 in the Integrated Resource Planning (IRP) Proceeding (R.20-05-003) ordering procurement of 3,300 MW Net Qualifying Capacity (NQC) by August 1, 2023.[5] Additionally, on June 30, 2021, the CPUC issued midterm reliability decision D.21-06-035 ordering the procurement of 11,500 MW NQC from resources that are zero-emission or Renewables Portfolio Standard (RPS) eligible to come online from 2023 to 2026.[6] While the proposed decision included authorization to procure up to 1,500 MW NQC of incremental thermal

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3 SB 100, also known as the 100 Percent Clean Energy Act of 2018, is landmark legislation that established the state policy that renewable and zero-carbon resources supply 100 percent of retail sales and electricity procured to serve all state agencies by 2045

4 *Final Root Cause Analysis Mid-August 2020 Extreme Heat Wave*. 2021. California Independent System Operator. Available at http://www.caiso.com/Documents/Final-Root-Cause-Analysis-Mid-August-2020-Extreme-Heat-Wave.pdf.

5 Decision Requiring Electric System Reliability Procurement for 2021-2023. D.19-11-016. November 7, 2019. Available at https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M319/K825/319825388.PDF.

6 Decision Requiring Procurement to Address Mid-term Reliability (2023-2026). D.21-06-035. June 30, 2021. Available at https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M389/K603/389603637.PDF.

capacity, the final decision removed consideration of fossil-fueled capacity, but noted that additional procurement of fossil-fueled capacity would be evaluated based on additional analysis from the CPUC and CEC, including the analysis in this report, for the decision adopting the CPUC's preferred system plan by the end of 2021.

The decision called out the need for procurement, requiring that half of the 2026 resources be provided by long-duration storage (eight hours or greater). Further the 2,500 MW of replacement for Diablo Canyon Nuclear Power Plant are required to be from zero-emitting generation paired with storage, which is likely to be met by a significant amount of BESS procurement. Storage is an increasing part of the resource mix and anticipated to provide critical support to the net peak. Because of its growth and potential for reliability, it is prudent to continue to monitor its performance to support net peak, as well as monitor the supply chain and operational safety of the systems.

This report provides the results of three tracks of analysis by the CEC to support grid reliability, focusing on the next five years. These tracks respond to critical analytical recommendations of the RCA and designed to address questions that have been raised in the CPUC IRP proceeding. The report leverages the results of the CEC's first California Reliability Outlook, included in its entirety in Appendix A, as Track 1 of this report to assess reliability for 2023 – 2026, an assessment of the performance and risks of utility scale BESS for the grid, which is Track 2, and ongoing efforts to provide incremental thermal resources, which is Track 3.

Reliability Analysis and Considerations

Reliability analysis is an essential component of electric sector planning. For the purposes of long-term planning and procurement, reliability need is typically assessed through loss of load expectation (LOLE) studies, which are stochastic analyses. They draw on a distribution of future demand profiles, historic wind and solar profiles, and randomized forced outages to determine a probability for a supply shortfall, for a given mix of resources expected to be connected to the grid. The typical standard of reliability for this analysis is to meet a loss of load event of no more than one day of unserved energy every 10 years. A day with unserved energy means a single day with any length of outage. This report relies on LOLE studies where possible. The LOLE modeling incorporated reasonable simplifications in assumptions with the goal to reduce computation time and increase the number of scenarios modeled. This analysis studied system reliability and did not separately study local reliability.

Other factors that are typically not considered in LOLE analysis can impact and inform the state's efforts to ensure reliability. For example, delayed resource deployment, due to any reason, reduces the assumed resource portfolio, increasing the risk of supply shortfalls. The state experienced supply chain issues with BESS deployments in 2021 and those issues may continue throughout the midterm.

To mitigate risks in the planning process from unforeseen issues, such as global supply chain constraints, project development delays owing to permitting or interconnection, the state may need to consider additional actions to bolster proposed plans. This could include identifying opportunities to make the most effective use of existing resources, and where necessary and possible, increasing their performance to provide additional system reliability.

Midterm Reliability Assessment

The goal of this report is to provide insights into potential additional needs and considerations necessary to maintain grid reliability in the midterm timeframe. To achieve this stated goal, the report includes three tracks:

- Track 1: Technical analysis evaluating midterm electricity capacity needs and thermal capacity need.
- Track 2: Assessing potential risks with dependence on battery deployment and performance.
- Track 3: Information on potential thermal capacity additions.

Track 1 can be further broken into two questions:

- The first question is whether additional capacity beyond current procurement orders is needed to maintain system reliability. This is approached through a LOLE analysis on the CPUC ordered procurement.
- The second question is whether incremental thermal resources provide an additional system reliability benefit compared to a portfolio of zero-emitting resources. This is again approached through an LOLE analysis and by replacing a portion of the zero-emitting resources with thermal resources.

Reaching the state's SB 100 targets requires a shift to reliance on zero-emitting resources in maintaining grid reliability and meeting the capacity needs during the net peak hours. The midterm timeframe represents the beginning of that fundamental shift as new zero-emitting resources augment and replace retiring conventional resources to meet the future electric demands on the system. As with the deployment of any new technology, there are market maturity risks as the market adapts and operators continue to develop operational and safety best practices. It is important to consider these risks when planning for reliability and is addressed in Track 2.

Track 2 explores the potential risks of relying on BESS deployment for midterm reliability. This is approached through 1) evaluating whether BESS is performing currently as desired on the grid, particularly to support net peak; 2) exploring whether near-term supply chain issues, if sustained, will impact reliability; 3) evaluating whether there are risks to the ability of BESS to perform as desired as the proportion of zero-emitting resources grow on the grid; and 4) learning from past BESS safety issues and developing strategies to reduce risks to the grid and workers.

Track 3 provides information on the incremental capacity options at existing natural gas facilities and the permitting timelines, should there be a need for incremental thermal capacity additions to maintain system reliability over the coming decade.

CHAPTER 2:
2023 - 2026 Reliability Modeling

The CEC developed its first California Reliability Outlook (CRO), provided in its entirety in Appendix A, in response to the recommendations in the RCA for the CEC to provide situational awareness and support reliability planning in the near, mid, and long term. The scope for this first version of the CRO is primarily informed by the immediate needs of the CPUC's midterm reliability decision and was developed in close collaboration with CPUC staff and with stakeholder input. The CRO included the five-year period of 2022 – 2026; however, given the period of focus for the CPUC proceeding, only the results for the period 2023 – 2026 are discussed in this chapter and the main body of this report.

This chapter addresses Track 1 of the scope of this report, answering the following key questions:

1. Whether additional capacity beyond current procurement orders is needed to maintain system reliability. This is approached through a LOLE analysis on the CPUC ordered procurement.
2. Whether incremental thermal resources provide an additional system reliability benefit compared to a portfolio of zero-emitting resources and BESS. This is again approached through a LOLE analysis with thermal resources replacing the planned zero-emitting resources.

Approach

The CEC's analysis relied on the well-established LOLE analytical framework used widely in the industry to evaluate reliability. The LOLE target used in this study is 1 day with unserved energy every 10 years or a LOLE of 0.1 days/year. A day with unserved energy means a single day with any length of outage. The LOLE approach considers the probability of a wide range of distributions of key variables and relies on thousands of simulations drawing randomly from different combinations of demand, solar, and wind profiles as well as unexpected plant outages to arrive at the LOLE metrics. However, like any other modeling effort, the modeling used in this analysis approximates conditions and includes many reasonable simplifying assumptions to reduce computation time and increase the number of scenarios modeled.

This study includes resources eligible to participate in the CPUC's resource adequacy (RA) program. These are resources that have been assigned a qualifying capacity (QC) by the CPUC, and a subsequent net qualifying capacity (NQC) value, which captures the ability of the resource to deliver capacity to the system for the purposes of meeting RA requirements. Scenarios based on three different resource builds were included in the broader CRO, but only the two relevant ones were included here:

1. **No Build Scenario** – No new resources beyond the baseline in the CPUC's Reliability Need Assessment and the summer 2021 procurement (D.21-02-028) that will be online

for the modeled years. This scenario identifies the baseline need if no new procurement had occurred.

2. **Procurement Order Scenarios** – Resource build based on the procurement orders for 2021 – 2023 (D.19-11-016) and 2023 – 2026 (D.21-06-035). See Table 1.

Table 1: Cumulative Procurement Order Requirements

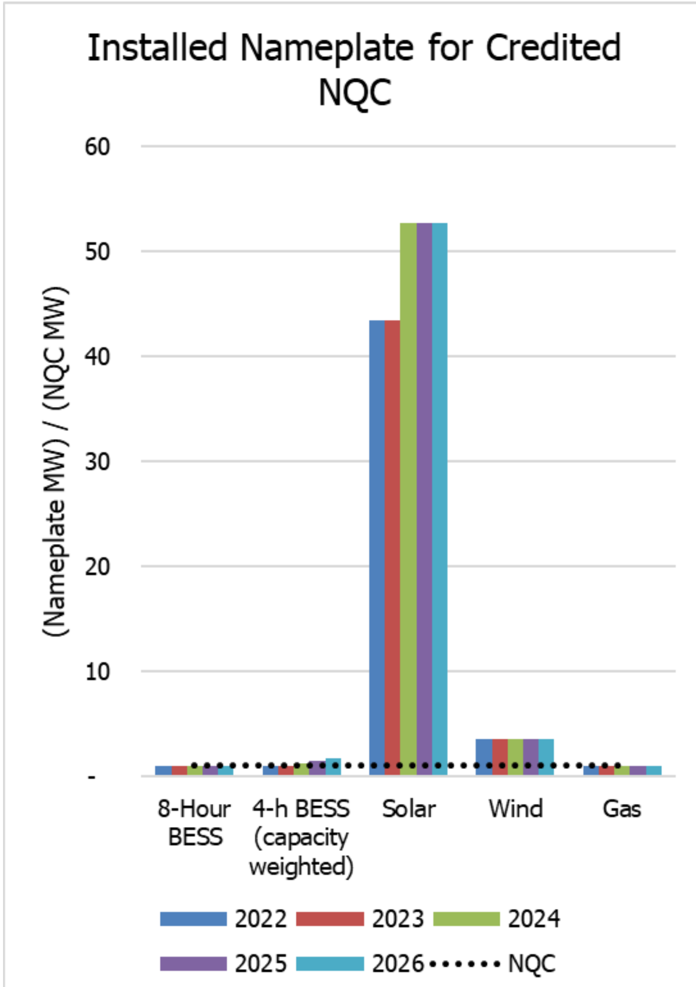
Resource (MW NQC)	**2022**	**2023**	**2024**	**2025**	**2026**	**2026+**
D.19-11-016 NQC Remaining	1,070	1,505	-	-	-	-
D.21-06-035 NQC Remaining	-	2,000	8,000	9,500	-	11,500
Total	**1,070**	**3,505**	**9,505**	**11,005**	**11,005**	**13,005**

Source: CEC Staff Analysis of D.19-11-016 and D.21-06-035

When estimating the nameplate capacity build required to meet the procurement orders, CPUC's published technology factors and effective load carrying capability (ELCC) values were applied to the mix of resources selected. The new capacity build in the model was then adjusted until the NQC equaled the procurement orders. For scenarios that analyzed the reliability of the system with gas capacity in place of the zero-emitting resources, the total NQC of the portfolio was replaced with gas capacity at a one-for-one basis using the NQC values.

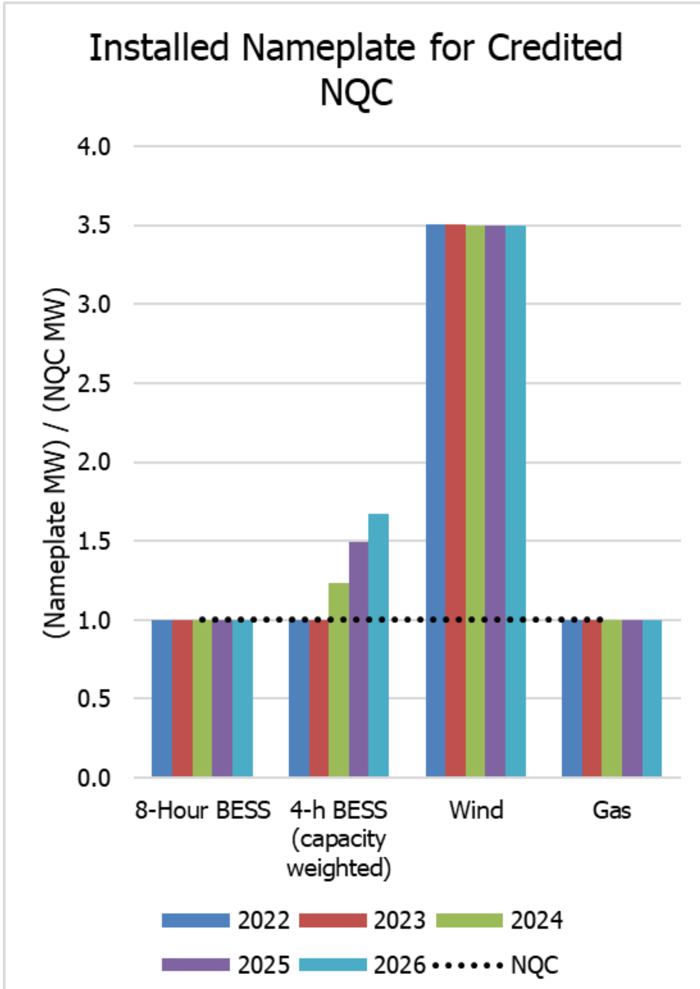
Figure 1 and **Figure 2** illustrate how nameplate capacity is converted to NQC values. Gas resources and long duration storage, modeled as 8-hour BESS, were assumed to have an NQC equal to nameplate capacity. In 2022 and 2023, 4-hour BESS is also assumed to require 1 MW nameplate to provide 1 MW NQC, but due to a declining ELCC, by 2026 is assumed to require 1.7 MW nameplate to provide 1 MW NQC. Solar requires approximately 43 MW nameplate capacity to provide 1 MW NQC in 2022, growing to 53 MW nameplate by 2026. Wind consistently requires approximately 3.5 MW nameplate capacity to provide 1 MW NQC across all years.

Figure 1: Comparison of the Nameplate Capacity Necessary to Provide 1 MW NQC



Source: California Energy Commission staff

Figure 2: Comparison of the Nameplate Capacity Necessary to Provide 1 MW NQC of BESS, Wind and Gas



Source: California Energy Commission staff

Using these capacity values, a model was created in PLEXOS, a commercial production cost model software utilized by the CEC. This model represented all of the CAISO footprint, along with specified and unspecified imports, within a single zone with no transmission constraints that hinder the delivery of electricity supply to demand. Generation capacity was modeled by resource type with a simple characterization, focused on what power capacity could be delivered in each hour. The model included four variables that were randomly selected for each of the over 10,000 samples simulated for each scenario. These variables include 7 solar profiles, 7 wind profiles, 140 demand distributions, and randomized unplanned outages. A detailed description of the model can be found in APPENDIX A:
2021 California Reliability Outlook.

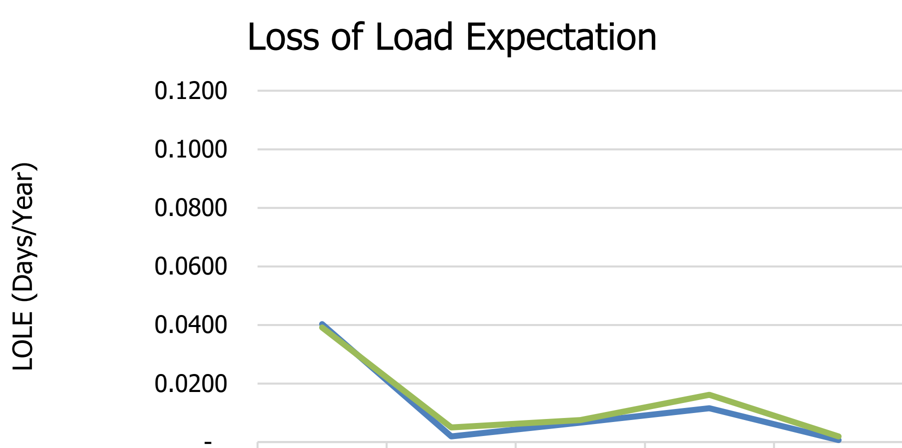
Results from these scenarios were then processed to determine the LOLE and the shortfall capacity, if any. The unserved demand for each event is defined as the hour with the highest unserved energy in a day. The LOLE is the number of unserved demand events divided by the number of samples. To determine the shortfall, the events were ordered from highest to lowest unserved demand. The scenario shortfall capacity is the capacity that would need to be fully available in all hours of the year (perfect capacity) to reduce the LOLE to below 1 day in 10 years. The shortfall capacity for a simulation with 100 samples would be the 11th highest unserved demand event.

Results

Figure 3 shows the LOLE results for the procurement order with ELCC values used in the CPUC's Reliability Need Determination Model[7] and those published in September 2021.[8] The 2026 year is for modeling results without the 2,000 MW NQC of long lead time resources, while the 2026+ year includes that additional capacity.[9]

Modelling suggests that the current CPUC procurement orders result in a reliable system, with a loss of load expectation at, or below, one outage event in every ten years, over the procurement period of 2023 through 2026. This is true using both the ELCC values used in the CPUC's Reliability Need Determination Model and those published in September 2021.

Figure 3: LOLE Results for the Procurement Orders



	2023	2024	2025	2026	2026+
Order	0.0403	0.0019	0.0066	0.0115	0.0007
Order_(R.ELCC)	0.0391	0.0050	0.0075	0.0162	0.0019

Source: California Energy Commission staff

7 The February 22, 2021 version of the CPUC's Reliability Determination Model can be found online at: https://www.cpuc.ca.gov/industries-and-topics/electrical-energy/electric-power-procurement/long-term-procurement-planning/more-information-on-authorizing-procurement/irp-procurement-track. A later version of this model was provided to the CEC that made minor modifications to the total NQC values.

8 Carden, Kevin, Alex Krasny Dombrowsky, Arne Olson, Aaron Burdick, Louis Linden. 2021. *Incremental ELCC Study for Mid-Term Reliability Procurement*. Prepared for California Public Utilities Commission. Available at https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/energy-division/documents/integrated-resource-plan-and-long-term-procurement-plan-irp-ltpp/20210831_irp_e3_astrape_incremental_elcc_study.pdf.

9 D.21-06-035 allows for the long lead-time resources to be delayed up to two years to 2028.

Furthermore, the low LOLE found in 2026, even without the additional 2,000 MW of long lead time resources, suggest that delayed procurement of these resources would not prevent the CAISO footprint from maintaining an LOLE under 0.1 day per year in 2026.

The results of the No Build scenario also indicate the procurement ordered through D.21-06-035 was appropriate to fill the need determined by the Reliability Need Determination Model. The modeling showed capacity shortfalls in similar quantities if no additional capacity is procured. Table 2 shows the capacity shortfall found in the No Build scenario, which did not include any capacity additions outside of those included in the CPUC's Reliability Need Determination Model and approximately 120 MW from the Summer 2021 procurement decision, D.21-02-028.

Table 2: No Build Shortfall Capacity Compared to NQC Additions

(MW)	**2023**	**2024**	**2025**	**2026**	**2026+**
No Build Shortfall	2,391	6,711	11,540	12,022	12,022
Cumulative Ordered NQC	3,505	9,505	11,005	11,005	13,005

Source: California Energy Commission staff

It should be noted that a capacity shortfall is the need for perfect operating capacity and cannot be directly translated into NQC need. However, it does provide valuable information on the magnitude of the need and can be used to facilitate the analysis to identify NQC need.

Incremental Thermal Capacity

To determine if incremental thermal capacity provides additional system reliability compared to zero-emitting resources of equivalent NQC, staff replaced the entire incremental resource build with gas capacity, one megawatt of gas for each megawatt of NQC added by the resource build. This methodology to compare portfolios was selected to align with CPUC's Resource Adequacy Qualifying Capacity methodology, which is currently utilized to assign system reliability value to resources. The total nameplate capacity for new zero-emitting resources is approximately 24,000 MW, compared to approximately 11,000 MW for thermal capacity to provide equivalent NQC in 2026.

Figure 4: Comparison of the Procurement Order Scenario and Thermal Replacement Portfolio

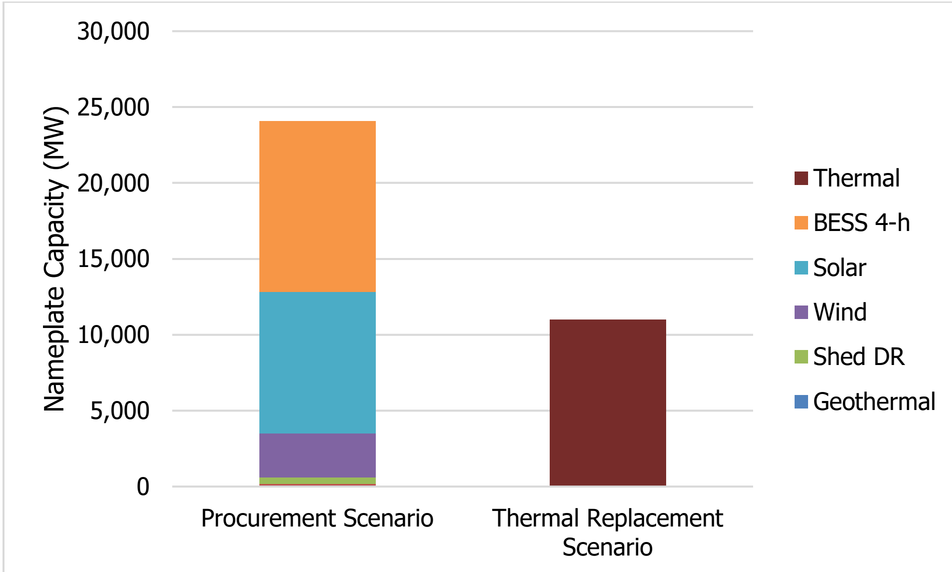
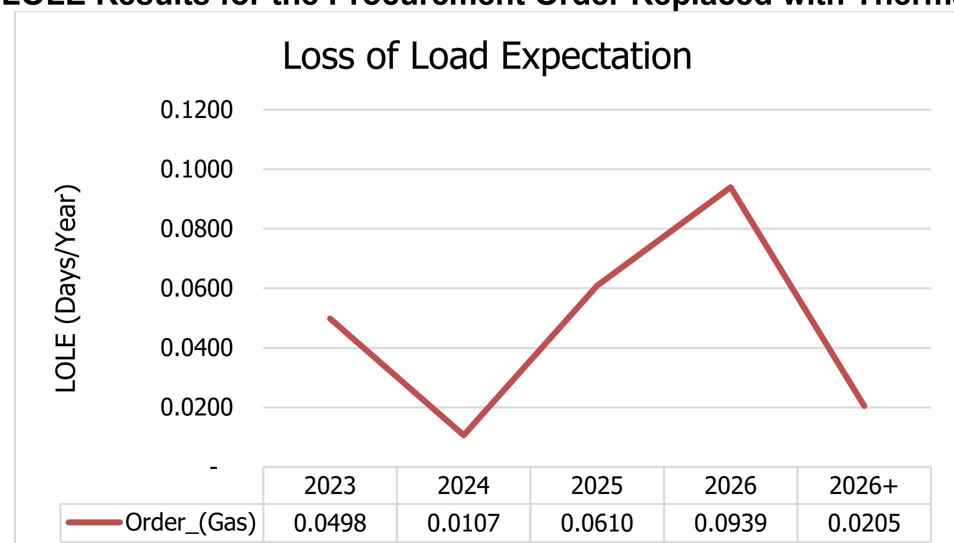


Figure 4 shows the LOLE does not increase above an LOLE of 0.1 day per year.

Figure 5: LOLE Results for the Procurement Order Replaced with Thermal Capacity



Source: California Energy Commission staff

Thermal capacity was also determined to meet system reliability, as the zero-emitting resource portfolio did. While both portfolios meet reliability standards, it is important to recognize the accounting methodology differences for determining the NQC of different resource technologies. The scenarios with a thermal capacity NQC equivalent to replace the new zero-emitting resources, resulted in a slightly higher LOLE. Additional work is needed to determine if this performance difference is attributable to the specific technologies, the qualifying capacity methodology used to compare the resources on an NQC basis, or if adjustments to the model are necessary to better compare the resources in an equivalent manner. These scenarios illuminate that many technology types can support system reliability, should there be enough capacity procured. These scenarios do not indicate that a portfolio consisting of zero-emitting or thermal resources are in and of themselves inherently less reliable.

Track 1 Conclusions

The analysis reached the following conclusions:

- The ordered resource procurement for 2023 through 2026 appears to be sufficient to meet a 1 day in 10-year loss of load expectation (LOLE) target, indicating system reliability.
- The reliance on zero-emitting resources does not appear to diminish reliability compared to procuring thermal resources.

Further considerations include:

- This study did not include resource retirements beyond those assumed in the CPUC's mid-term reliability decision. Additional retirements would increase the likelihood of system reliability challenges.
- Additionally, the CEC demand forecast is being further enhanced to capture the frequency and dispersion of extreme climate impacts. This new climate analysis or increased electrification could necessitate planning for a higher demand and characteristics that are not captured in current analysis.

Additional information on this analysis can be found in APPENDIX A:
2021 California Reliability Outlook.

CHAPTER 3: Battery Energy Storage Systems on the Grid

Deployment of BESS on the California grid has substantially increased in recent years, including 2021, which has seen an unprecedented growth. CAISO reports that BESS capacity on the system was approximately 550 MW at the end of 2020, 1500 MW as of September 2021, and is expected to grow to 3,000 MW by the end of 2021.[10] BESS offers the opportunity to take advantage of excess clean energy during the day by storing it for use during resource-limited conditions, such as the net peak. The CPUC has begun to call for more storage in procurements to provide greater grid reliability during net peak. The CPUC's recent 11,500 MW of NQC procurement order will likely result in over 10,000 MW of new BESS nameplate capacity by end of 2026.

Reliability in the mid-term and beyond will be highly dependent on BESS deployment at a sustained rate and BESS operational performance. While the modeling results presented in Chapter 2 indicate that the portfolio of zero-emitting resources can adequately meet the system reliability requirements of the system, it is dependent on unprecedented procurement levels of BESS and current assumptions around BESS performance. Due to the relative inexperience in deployment and operation of the technology, there is still an incomplete picture of their reliability and long-term safety. There is limited availability of historic data on performance, especially at the scale envisioned in the CPUC procurement, as well as anticipated to meet SB 100 targets. Higher levels of outage rates, lengths of an outage etc., than assumed in the modeling could have significant effect on the modeling results and need to be carefully considered as more data becomes available.

In addition to performance, there are other market maturity issues to be addressed, such as whether there is a robust supply chain and whether the systems can operate safely over their life. Recent experiences with supply chain delays and an incident[11] at Vistra's Moss Landing Energy Storage Facility, the world's largest BESS installation, located in Monterey County, raised concerns about the scale of deployment and safety of the systems. As we learn more about these systems, and operational best practices continue to evolve, it is important to consider these risks when planning for reliability.

This chapter addresses Track 2 of the scope of this report and attempts to provide information regarding some of the potential risks of reliance on BESS deployment for midterm reliability by exploring sensitivities to modeling presented in chapter 2. This is approached through 1)

10 Murtaugh, Gabe. 2021. *Storage: An intersection between reliability today and climate goals of tomorrow*. California Independent System Operator. Available at http://www.caiso.com/about/Pages/Blog/Posts/Storage-An-intersection-between-reliability-today-and-climate-goals-of-tomorrow.aspx.

11 Phase I of the installation brought 300 MW online December 2020, and Phase II brought the remaining 100 MW online in August 2021. On September 4, 2021, Phase I was forced offline when the batteries overheated resulting in battery racks being scorched and wiring melted. A root cause analysis is underway, but this incident highlights the possible risks associated with BESS.

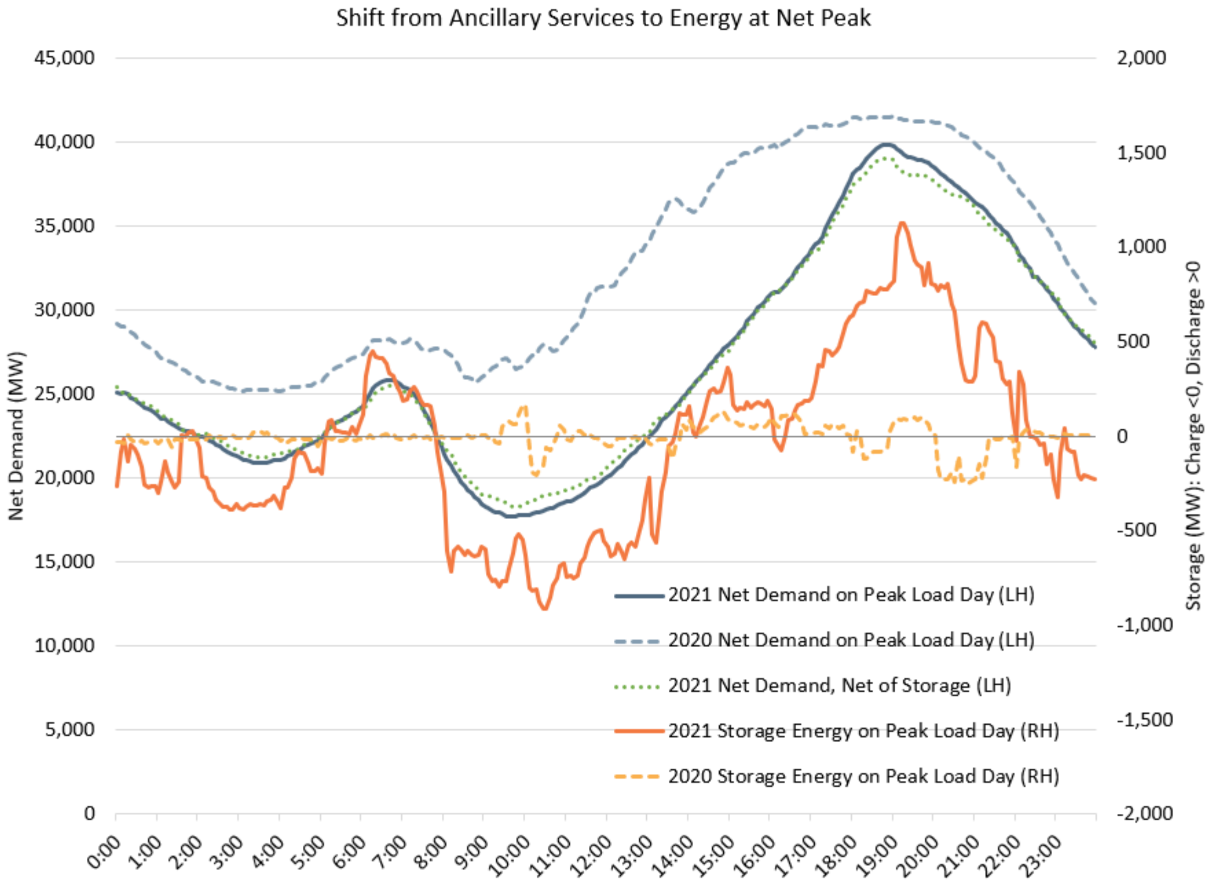
evaluating whether BESS are preforming currently as desired on the grid, particularly to support net peak; 2) exploring whether near term supply chain issues, if sustained, would impact reliability; 3) evaluating whether there are energy sufficiency risks that may affect the ability of BESS to perform as desired as the proportion of zero-emitting resources grow on the grid; and 4) learning from past BESS safety issues and developing strategies to reduce risks to the grid and workers.

BESS Performance on the Grid: 2021 vs Previous Years

In 2021, the role of BESS resources in California's electric system continued to increase as each month passed. The monthly incremental additions of the BESS, at times ahead of schedule, provided CAISO with critical support during tight conditions in 2021.

BESS operational behavior for the grid, in the aggregate, has begun to reflect the growth in capacity. Prior to 2021, when installed capacity only totaled in the hundreds of megawatts, the BESS charging and discharging profiles depicted a resource dedicated to providing ancillary services, especially regulating reserves. But, by the summer of 2021, the BESS resources on the grid grew to nearly 1,500 MW and the operating profiles began to demonstrate the shift from ancillary services to a resource consistently supporting reliability during the net peak period. **Figure 6** plots the net peak demand curve and BESS operations curve for the annual peak days in both 2021 and 2020. Notably, the 2020 Storage Energy on Peak Load Day remains within 250 MW of the x-axis and does not exhibit strong correlation with the 2020 Net Demand on Peak Load Day. This data represents an operating profile more consistent with provision of regulation reserves. The 2021 Storage Energy on Peak Load Day and 2021 Net Demand on Peak Load Day exhibit a more pronounced relationship consistent with charging in low net demand periods and discharging in higher net demand periods, acting as a critical grid resource during net peak. This marks a clear transition in the operating mode of BESS resources from an early history of ancillary services provision to an expected future of energy shifting across operating hours. This is shown by the 2021 Net Demand, Net of Storage, which shows how energy storage might create a trend that moves toward flattening the duck curve.

Figure 6: BESS Grid Performance for 2020 and 2021



Source: California Energy Commission staff

Further, as of August 2021, there were 30 BESS resources actively participating in the CAISO markets. Of these 30 resources, 28 BESS resources participated in both the energy and ancillary service markets. The remaining two resources participated only in the regulation market.

As BESS resources grow to represent a greater proportion of the operational resource fleet, the increase in interconnected BESS capacity, combined with the small and relatively fixed market sizes for ancillary services, especially for regulation service, drive the apparent shift to delivering energy across the net peak period. With saturated markets for ancillary services, BESS is well suited to time shift energy from periods with significant solar production and corresponding low energy prices to the net peak period and attendant higher energy prices.

The CAISO resource interconnection queue has seen a tremendous growth in BESS resource capacity; approximately 60 percent of the nearly 250 GW in the queue are BESS projects. Of these, half of the proposed capacity would interconnect as stand-alone resources and the other half as an element of a hybrid or co-located resource. Over 100 GW of this BESS queue capacity represents new requests in the latest cluster, Cluster 14, also known as the "Super Cluster." The sheer size of the commercial interest in BESS projects has forced significant changes to the CAISO interconnection processes.

Reliability Impacts of Potential Procurement Delays

Recent discussions with storage developers have highlighted changing dynamics in both the current and future BESS supply chain. At the August 30, 2021, CEC Lead Commissioner Workshop on Reliability, developers and industry leaders remarked on widespread global shipping bottlenecks as having immediate impacts, some of which can be moderated by larger developers exercising certain flexibilities embedded within project portfolios. The impact of this situation for resources with online dates in 2021 has been difficult to quantify and is reliant on commercially sensitive information. The trade press and indications from regulatory agency staff appear to indicate that a few hundred megawatts of resources may have been delayed by up to three months. Despite strained conditions with global shipping, the most recent updates from the CAISO still project about 3 GW of BESS projects online by the end of 2021.

The more concerning observation from the discussion with storage developers may hold significant consequences over the coming two to five years. While BESS production has enjoyed a declining cost curve in recent years, record demand for these systems and component materials appears to likely alter expectations around continued cost declines and could threaten to flatten or even reverse this trend. Flat to increasing costs, paired with lengthy permitting and interconnection processes loom as growing deployment risks for storage developers.

To evaluate the impact of potential delays in deployment of BESS, either due to supply chain constraints or interconnection delays, an LOLE analysis was conducted with a one-year delay of 20% of all new 4-hour BESS for each year, beginning in 2022. This is an approximate representation of the delays observed in 2021. See **Table 3** for capacity delays modeled.

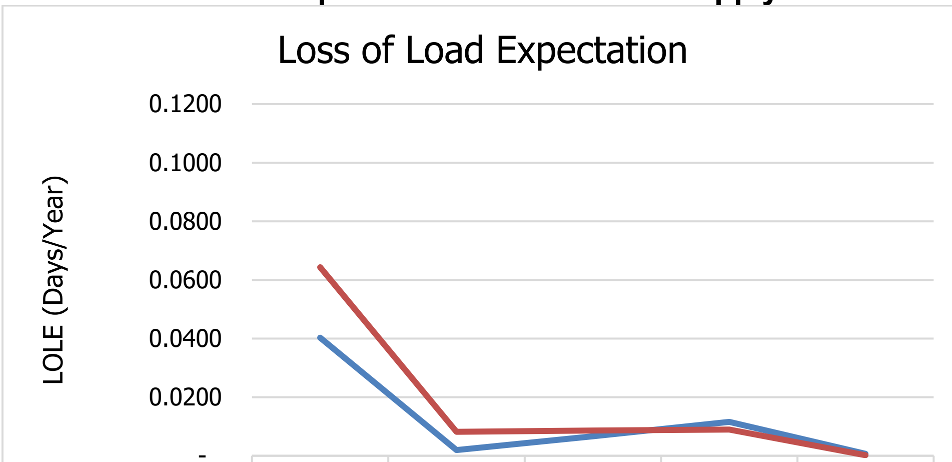
Table 3: Reduction in the Total Installed Capacity for 4-Hour Energy Storage

(MW)	**2022**	**2023**	**2024**	**2025**	**2026**
Order_(B20)	326	482	1,269	383	8
Order_(R.ELCC, B20)	331	493	1,143	343	8

Source: California Energy Commission staff

A one-year delay of 20 percent of new 4-hour BESS resources did not have a material effect on the reliability of the system, as shown in Figure 7.

Figure 7: Loss of Load Expectation for the BESS Supply Chain Scenarios



	2023	2024	2025	2026	2026+
Order	0.0403	0.0019	0.0066	0.0115	0.0007
Order_(B20)	0.0643	0.0082	0.0087	0.0089	0.0002

Source: California Energy Commission staff

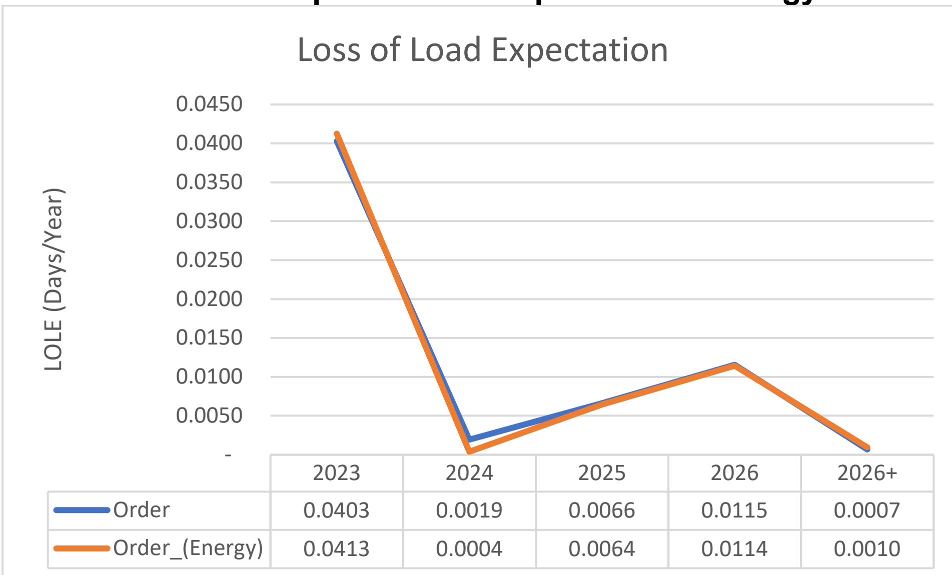
Additional information on this analysis can be found in APPENDIX A: 2021 California Reliability Outlook.

Ability to Sufficiently Charge BESS

Given the unprecedented scale at which BESS is anticipated to be deployed over the next five years, concerns have been raised over the ability to sufficiently charge BESS to meet the peak and net peak demands. While procurement for reliability has typically focused on meeting capacity needs, utilizing BESS to meet capacity needs requires that the system can sufficiently charge the resource to meet demand when needed. As part of the CRO, the CEC analyzed a scenario created to test whether there would be sufficient resources on the grid ahead of the net peak to charge BESS sufficiently to provide services during the net peak under increasingly constrained conditions. The scenario restricted the maximum imports to the CPUC-assumed specified and unspecified imports in all hours of the day and confined hydroelectric generation to a minimum generation level outside the hours ending 17-22. This reduced the total energy available in the model by approximately 100,000 MWh daily to test the ability of the system to charge BESS if significant economic energy is unavailable throughout the day.

The results for these energy-limited cases, shown in **Figure 8**, are very similar to the non-energy limited cases, suggesting that the resource builds expected based on the CPUC procurement would result in sufficient energy generation during lower demand periods to adequately charge energy storage for use during net peak periods.

Figure 8: Loss of Load Expectation Comparison for Energy Limited Cases



Source: California Energy Commission staff

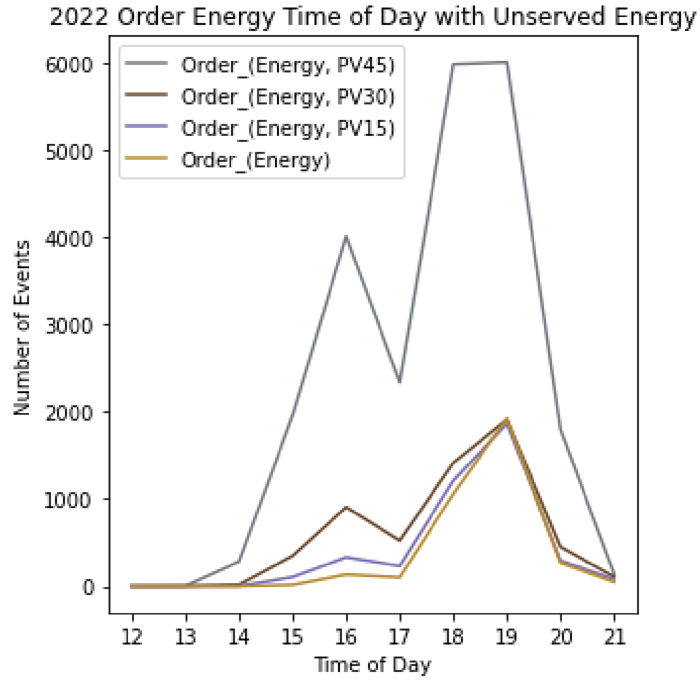
The analysis also evaluated different levels of solar reduction (e.g., from cloud cover or smoke) to evaluate whether there could be risks to BESS charging. Staff evaluated 15 percent, 30 percent, and 45 percent solar reduction levels. When further reductions in the total available energy were introduced through reduction in solar output in 2026 there was not a significant impact to the LOLE for the 15 percent and 30 percent reduction cases. However, with between a 30 percent reduction and a 45 percent reduction, the impact becomes significant and drives an unacceptably high LOLE of 0.17 day per year.

In these extremely energy constrained scenarios, some unserved energy was observed outside of the Hour Ending (HE) 17-22. The decreased output from solar facilities results in outage events as early as noon, but with a local peak at HE 16 (3-4 pm PST), see Figure 9 **Source:** California Energy Commission staff

. The relative decrease in the number of unserved energy events at HE 17 is attributable to increased hydroelectric output between the HE 17 and 22 for these scenarios.

These scenarios indicate that energy sufficiency is unlikely to be a constraint for BESS performance with the assumed resource portfolio. However, this analysis does not account for potential constraints associated with co-located or hybrid BESS with solar projects that may have limitations on charging from the grid to, for example, qualify for federal or local tax credits or exemptions.

Figure 9: Number of Unserved Energy Events by Time of Day, 2022



Source: California Energy Commission staff

Additional information on this analysis can be found in APPENDIX A:
2021 California Reliability Outlook.

Growing but Limited Experience with BESS Operations and Safety

BESS safety, particularly for lithium-ion systems, presents an ongoing challenge as best practices continue to be developed. Fires have broken out at multiple grid-connected systems in the US, Europe, Asia, and Australia. In 2019, a 2 MW system in Arizona caught fire and exploded, and this summer overheating of a BESS at Moss Landing forced the 300 MW system offline. As deployment of these systems increases, development of best practices is necessary to protect workers and the public and ensure grid reliability and public confidence.

The licensing of BESS systems that are either built on the property of a CEC-licensed facility or are a CAISO-designated "Black Start Battery Energy Storage System," or black start BESS, has required CEC's Siting, Transmission and Environmental Protection Division's staff to evaluate the safety of BESS resources. To date, CEC has licensed two black start BESS and the third is attached to natural gas turbines where the batteries enable the gas turbines to supply spinning reserve by providing approximately 10 minutes of ramping profile for the natural gas turbines.

The CEC's safety evaluations have been specific to lithium-ion batteries. One of the principal hazards associated with lithium-ion BESS is fire. A fire could occur from a battery casing being opened, punctured, or if a battery cell is short-circuited or overheats. If a fire ensues after such an event, it may burn rapidly with a flare burning effect and may ignite other batteries in proximity. The fire could produce corrosive or toxic gases including hydrogen chloride, hydrogen fluoride, and carbon monoxide similar to a fire involving a like amount of plastics, requiring first responders to wear a self-contained breathing apparatus to suppress the fire safely. Such fires also produce flammable gases that could, under certain circumstances, lead to an explosion within the BESS container.

The CEC has reviewed the current regulatory framework regarding fire and life safety as related to a lithium-ion BESS, which is rapidly evolving to address the risks involved with lithium-ion BESS installations. Guidelines have been developed by several industry standards groups. These organizations include Underwriters Laboratories (UL) and the National Fire Protection Association (NFPA). One of the newest guidelines, issued in 2019, is NFPA 855: Standard for the Installation of Stationary Energy Storage Systems; and another is UL 9540-2020: Energy Storage Systems and Equipment, which lists safety requirements for BESS connected to the electric grid. A guideline specific to testing is UL 9540A-2019: Test Method for Evaluating Thermal Runaway Fire Propagation, which provides the standard test methodology for determining fire and explosion hazards presented by a given BESS design when undergoing an overheating failure, such as thermal runaway which is when the heat generated within the battery exceeds the amount of heat that is dissipated to its surroundings. The most recent edition of the California Fire Code also provides fire safety requirements for stationary lithium-ion BESS. These recent standards and codes provide evidence that the regulatory environment is quickly evolving to deal with the new lithium-ion BESS installations.

Though the regulatory environment is evolving for BESS installations, the application of the available regulatory tools requires technical expertise for this emerging technology. As indicated, the CEC has overseen the construction of BESS installations, with another currently under construction, and another about to start. Outreach to the local fire departments is paramount since they are the first to respond to a system fire and is part of the CEC's inspection process. Through these collaborative efforts, the CEC has observed that the local fire department personnel's technical expertise for BESS installations varies greatly. The local fire departments engaged are aware of the hazards associated with lithium-ion BESS, but the technical expertise to ensure that the fire and explosion hazards are mitigated remains uneven. Urban local fire departments have had a greater level of expertise in using the current codes to ensure proper mitigations are put in place for potential hazards. However, rural local fire departments have not had the same level of expertise and staff has directed them to reach out to the California State Fire Marshal's office for additional resources.

As the state of lithium-ion BESS from the placement and construction of these systems evolves, the regulatory framework is addressing these hazards and providing tools to mitigate them; however, there remains a technical expertise gap that should be addressed in a state-wide mandate and permitting process to ensure that every jurisdiction that sites BESS does it consistently to mitigate the potential hazards present.

Ongoing CEC work tracking BESS Deployment and Safety

To support further tracking and evaluation of BESS resources, the CEC has begun identifying and mapping California's large-scale BESS that are not designated for use in black start. Since there is no centralized database, the CEC is compiling data by filtering through several different datasets, including the United States Energy Information Administration's EIA-860 database and the United State Department of Energy's Global Energy Storage database. For cross-referencing, the CEC also refers to the CAISO Storage Resources database, which is limited to only CAISO balancing authority territories and lacks location. The CEC will be engaging with stakeholders to supplement these resources to build a better accounting of location, size, type, and use of grid-scale BESS.

Track 2 Conclusions:

- The current procurement orders could result in adding in excess of 10 GW of new BESS to the CAISO system in order to support peak and net peak loads.
- Modeling indicates BESS performance does not appear to be a limiting factor to system reliability in the midterm timeframe. In 2021, CAISO dispatch data indicates that in aggregate, BESS supported meeting the net peak load.
- Modeling indicates that a one-year delay of 20% of new BESS resources, potentially resulting from supply chain issues, would not, by itself, jeopardize system reliability. However, further procurement delays due to either supply chain constraints or permitting or interconnection timelines, beyond those modeled in this analysis, could contribute to system reliability challenges. It is essential that state agencies and CAISO develop solutions to ensure timely interconnection of resources.
- Modeling suggests that there is sufficient energy on the system to adequately charge BESS resources to support system reliability, even under energy constrained conditions, owing to limited imports, hydro generation and reductions in solar output.
- BESS performance and safety should continue to be monitored by CEC and other relevant state agencies and safety frameworks continued to be improved to ensure both public safety and reliability. Higher levels of outage rates, lengths of an outage etc., than assumed in the modeling could have significant effect on the modeling results and need to be carefully considered as more data becomes available. It would be prudent to retain current levels of capacity supporting peak and net peak demands until BESS performance has been further demonstrated.

CHAPTER 4: Role of the Natural Gas Fleet

Track 3 provides information on the incremental capacity options at existing natural gas facilities and the permitting timelines, should there be a need for incremental thermal capacity additions to maintain system reliability over the coming decade. As decision-makers determine whether there is a need for additional incremental thermal capacity, new thermal capacity additions approved by the CEC to support grid reliability in 2021 offer a template for the types of upgrades that may increase thermal capacity on the system with shorter payback periods and permitting timelines than those associated with contracting and building a new natural gas facility.

The CEC has been responsible for the state's power plant program for facilities generating 50 MW or higher since 1975. A key part of the CEC's role is creating a safe and reliable electric system and ensuring that the review of thermal power plants includes an assessment of the project's design, an analysis of its potential adverse environmental impacts, and a process for public input.

Currently, there are 76 operational power plants generating more than 26,600 MW of electricity under CEC jurisdiction. This includes 63 natural gas, 5 solar thermal and photovoltaic, and 8 geothermal power plants. Once the CEC approves a power plant, the project must comply with all provisions of their license. Per California Code of Regulations section 1769, if there are any proposed changes to the design, operation, or performance of a licensed project then the CEC must approve that project change. These are known as post-certification project change petitions.

At any given time, the CEC is addressing project change petitions for one-third of its jurisdictional power plant fleet. Of these, more than 34 percent are changes to the power plant's design, operation, or performance, a process that can take up to six months for formal approval. Another 58 percent of proposed changes are processed as staff-approved project changes. These can be processed within three months unless there is opposition during the 14-day public comment period, then the petition must go to a CEC business meeting for approval. The remaining projects are either jointly initiated project changes, such as separating a large power plant into two individual facilities, which can take up to a year for an approval, or a compliance advice letter, which is generated within 30 days.

Additional Incremental Capacity for Summer 2021

In anticipation of the CPUC's Rulemaking Order 20-11-003 directing California's three large electric investor-owned utilities to seek contracts for additional power in 2021, CEC-jurisdictional power plant owners and operators filed petitions between December 2020 and February 2021 to amend their licenses' conditions of certification to increase generation capacity. CEC staff reviewed and approved these petitions between March to June 2021.

These incremental efficiency improvements were for 8 projects across the state, providing nearly 136 additional MW for 2021 summer reliability. These projects included six staff-approved project change petitions consisting of three software technology upgrades, two advanced gas path systems upgrades for their combustion turbines, a local control system upgrade, and a BESS expansion project. The remaining two project change petitions were for air quality permit modifications to increase fuel input and ammonia flow output and were approved at the CEC's June 25, 2021 business meeting.

The *Electric System Reliability and the Recent Role of California's Fossil Fleet: Actions Taken for Incremental Capacity to Prepare for Summer 2021*[12] report details the CEC's coordination with power plant owners and operators and actions taken to address imminent supply shortages for summer 2021 and beyond. These CEC actions included:

1. Hosting a December 2020 workshop titled *Incremental Efficiency Improvements to the Natural Gas Fleet Power Plant Fleet for Electric System Reliability and Resiliency,* that highlighted to stakeholders a range of options for incremental upgrades at existing geothermal, solar thermal, and natural gas-fired facilities to increase their capacities.
2. Reviewing and approving efficiency and post-certification project change petition improvements between March and June 2021 to increase output totaling an additional 136 MW.
3. Communicating with all 76 jurisdictional power plant owners and operators the importance of their voluntary reporting should one of their facilities experience an unplanned incident that limited their generating capacity, or their operations are impaired and cannot meet their commitment to CAISO. Throughout summer 2021, jurisdictional facilities that experienced operational impairments or shutdowns immediately contacted STEP staff.
4. Conducting a July 2021 survey of the CEC-jurisdictional fleet to identify multiple types of projects that could be expedited, including efficiency upgrades, BESS expansions, and opportunities to locate temporary power generator units at existing natural gas-fired facilities.
5. Identifying reasons for power plant owners withdrawing project change petitions that could have provided additional generation potential in support of the grid during summer 2021 extreme heat events.
6. Summarizing reliability issues and providing an update on steps taken to address these issues for CEC-jurisdictional plants at an August 30, 2021 CEC Lead Commissioner Reliability workshop.
7. Developing procedures to expedite post-certification petitions at existing facilities, to license temporary power generators of 10 MW or more, and to license BESS of 20 MW or more that can discharge for at least two hours.

12 California Energy Commission staff. 2021. *Electric System Reliability and Recent Role of California's Fossil Fleet: Actions Taken to Prepare for Summer 2021.* California Energy Commission. Publication Number: CEC-XXX-2021-XXX.

The report also addresses next steps to ensure electricity reliability and the potential role that the existing thermal fleet will play in the mid-term.

Prior to the Governor's July 30, 2021, emergency proclamation, project change petitions were filed with the CEC on behalf of an additional four power plants. These petitions were eventually withdrawn after not securing procurement contracts. As a result, 75 MW of additional incremental capacity was not initially realized for summer 2021. After the emergency proclamation was issued, some of these facilities were able to secure procurement contracts immediately through the state's emergency proclamation waiver. A federal 202(c) waiver could make available another 148 MW of incremental capacity in an emergency.

As shown in **Figure 10**, CEC staff were able to identify and implement near-term physical improvements totaling nearly 300 MWs of NQC at jurisdictional facilities, and another 120 MW in proposed temporary power generators to support summer reliability in 2021 and beyond.

Figure 10: Net Qualifying Capacity Resulting from CEC Actions Since November 2020

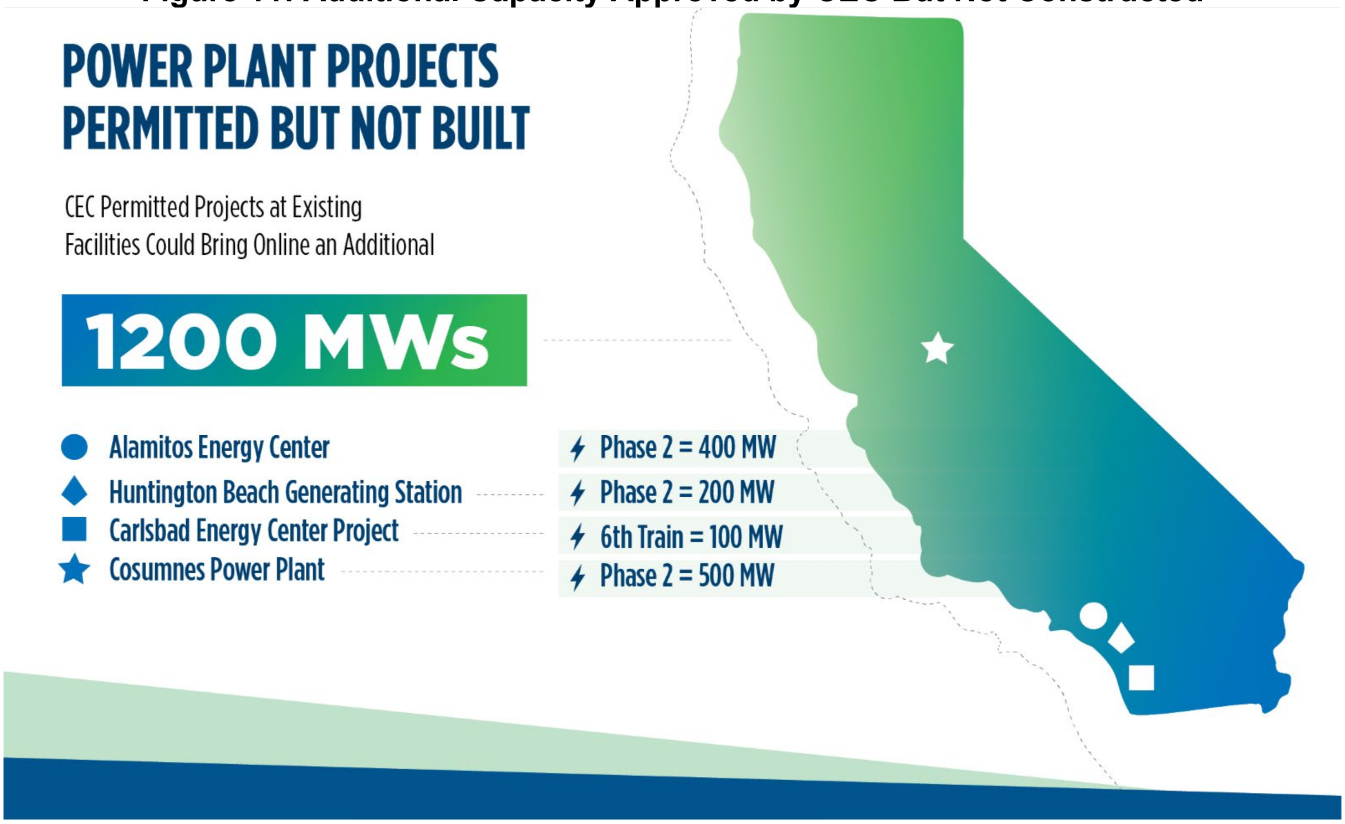
TYPE OF PROJECTS	ACTION TAKEN	APPROVAL TIMELINE	ADDITIONAL GENERATION CAPACITY
Efficiency Upgrades	Staff-level Project Change Petition Process	March – June 2021 (45-90-day process)	89 MW
Equipment Upgrades	Business Meeting Petition Process	March – June 2021 (45-90-day process)	47 MW
Temporary Power Generator	Temporary Power Generator Licensing Process	August - September 2021 (10-day process)	120 MW
Governor's Emergency Proclamation and DOE 202 (c) Waiver	Expedited Facility Changes Petition Process	August – October 2021 (10-day process)	100-150 MW

Source: California Energy Commission staff

Additional Capacity Approved by CEC But Not Yet Built

The CEC has approved additional units that could be built at several existing jurisdictional facilities. These additional units have not been constructed, as the owners of the facilities do not have contracts for the additional capacity. **Figure 11** shows these facilities and their locations.

Figure 11: Additional Capacity Approved by CEC But Not Constructed



Source: California Energy Commission staff

Cradle-to-Cradle Opportunities

Finally, there are cradle-to-cradle opportunities at existing power plants that are or will be in the decommissioning and closure process. One example is the April 2021 CEC license termination at Inland Empire Energy Center. The closure of this natural gas power plant illustrates a cradle-to-cradle opportunity in which a former power plant site is being repurposed as a 680 MW BESS facility that will help meet peak power needs and support midterm reliability. Another example is at the Alamitos Energy Center, which has a 20-year procurement contract with Southern California Edison for 300 MW of BESS of which 100 MW came online in January 2021 at its adjacent existing natural gas power plant. These BESS facilities can immediately act as peaking capacity as well as serve as ancillary services in the market with fast response times and spinning reserves.

CHAPTER 5: Conclusions & Limitations

This report is divided into three tracks to inform midterm reliability and considerations.

Track one addressed the following questions:

- Whether additional capacity beyond current procurement orders is needed to maintain system reliability.
- Whether incremental thermal resources provide an additional system reliability benefit compared to a portfolio of zero-emitting resources.

Track one reached the following conclusions:

- The ordered resource procurement for 2023 through 2026 appears to be sufficient to meet a 1 day in 10-year loss of load expectation (LOLE) target, indicating system reliability.
- The reliance on zero-emitting resources does not appear to diminish reliability compared to procuring thermal resources.

Further considerations for track one include:

- This study did not include resource retirements beyond those assumed in the CPUC's mid-term reliability decision. Additional retirements would increase the likelihood of system reliability challenges.
- Additionally, the CEC demand forecast is being further enhanced to capture the frequency and dispersion of extreme climate impacts. This new climate analysis or increased electrification could necessitate planning for a higher demand and characteristics that are not captured in current analysis.
- The analysis reached the following conclusions:

Track two addresses the potential risks associated with increasing deployment of battery energy storage systems and reached the following conclusions:

- The current procurement orders could result in adding in excess of 10 GW of new BESS to the CAISO system in order to support peak and net peak loads.
- Modeling indicates BESS performance does not appear to be a limiting factor to system reliability in the midterm timeframe. In 2021, CAISO dispatch data indicates that in aggregate, BESS supported meeting the net peak load.
- Modeling indicates that a one-year delay of 20% of new BESS resources, potentially resulting from supply chain issues, would not, by itself, jeopardize system reliability. However, further procurement delays due to either supply chain constraints or permitting or interconnection timelines, beyond those modeled in this analysis, could contribute to system reliability challenges. It is essential that state agencies and CAISO develop solutions to ensure timely interconnection of resources.

- Modeling suggests that there is sufficient energy on the system to adequately charge BESS resources to support system reliability, even under energy constrained conditions, owing to limited imports, hydro generation and reductions in solar output.
- BESS performance and safety should continue to be monitored by CEC and other relevant state agencies and safety frameworks continued to be improved to ensure both public safety and reliability. Higher levels of outage rates, lengths of an outage etc., than assumed in the modeling could have significant effect on the modeling results and need to be carefully considered as more data becomes available. It would be prudent to retain current levels of capacity supporting peak and net peak demands until BESS performance has been further demonstrated.

Track three provides information on the incremental capacity options at existing natural gas facilities and the permitting timelines should there be a need for incremental thermal capacity to maintain system reliability over the coming decade.

GLOSSARY

APPLICATION — Any request for certification of any site and related facility filed in accordance with the procedures established under this division.

BASE LOAD — The lowest level of power production needs during a season or year.

BATTERY — A device that stores energy and produces electric current by chemical action.

CAPACITY — The amount of electric power for which a generating unit, generating station, or other electrical apparatus is rated either by the user or manufacturer. The term is also used for the total volume of natural gas that can flow through a pipeline over a given amount of time, considering such factors as compression and pipeline size.

COMBINED-CYCLE PLANT — An electric generating station that uses waste heat from its gas turbines to produce steam for conventional steam turbines.

ENERGY RESOURCES — Everything that could be used by society as a source of energy.

FOSSIL FUEL(S) — Oil, coal, natural gas, or associated by-products. Fuel that was formed in the earth in prehistoric times from remains of living-cell organisms.

GENERATING STATION — A power plant.

GRID — The electric utility companies' transmission and distribution system that links power plants to customers through high-power transmission lines.

MARKET FORCES — Entities that participate in the energy marketplace through the buying, selling, transmission, or distribution of energy or ancillary services into, out of, or through the California ISO-controlled grid.

MEGAWATT (MW) — One thousand kilowatts (1,000 kW) or 1 million (1,000,000) watts. One megawatt is enough electrical capacity to power 1,000 average California homes.

NATURAL GAS — Hydrocarbon gas found in the earth, composed of methane, ethane, butane, propane, and other gases.

OUTAGE (Electric utility) — An interruption of electric service that is temporary (minutes or hours) and affects a relatively small area (buildings or city blocks).

PEAK LOAD — The highest electrical demand within a particular period. Daily electric peaks on weekdays occur in late afternoon and early evening. Annual peaks occur on hot summer days.

PERMIT — Written authorization from a government agency (for example, an air quality management district) that allows the construction or operation or both of an emission generating facility or related equipment within certain specified limits.

POWER PLANT — A central station generating facility that produces energy.

RELIABILITY — Electric system reliability has two components: adequacy and security. Adequacy is the ability of the electric system to always supply the aggregate electrical demand and energy requirements of the customers, considering scheduled and unscheduled outages of system facilities. Security is the ability of the electric system to withstand sudden disturbances such as electric short circuits or unanticipated loss of system facilities.

THERMAL POWER PLANT — Any stationary or floating electrical generating facility using any source of thermal energy.

APPENDIX A: 2021 California Reliability Outlook

Introduction

This Appendix marks the preliminary launch of a new CEC analytical report, the California Reliability Outlook (CRO). The CRO was developed in response to the recommendations in the Final Root Cause Analysis (RCA)[13] — prepared for Governor Gavin Newsom jointly by the CEC, California Public Utilities Commission (CPUC), and California Independent System Operator (CAISO) and published January 13, 2021. The goal of the CRO is to provide situational awareness and support reliability planning in the near, mid, and long term. The scope for this first version is primarily informed by the immediate needs of the CPUC's midterm reliability decision in the Integrated Resource Planning proceeding (R.20-05-003) and was developed in close collaboration with the CPUC staff and with stakeholder input. As the CEC continues to further this analytical work and a public process informing it, the CEC will continue to gather stakeholder input in developing the scope for these outlook assessments and attempt to consolidate various reliability related studies into a coherent unified report. CEC will attempt to incorporate relevant procurement, market, and policy considerations in future versions of this report. CEC also intends to publish future CRO reports to coincide with the adoption of IEPRs.

Background

Extreme heat events in 2020 impacted the western United States and strained electric system operations in California, resulting in rotating outages on August 14 and 15, 2020. The RCA detailed three root causes behind the outages and identified actions to be taken by the three entities to reduce the potential for grid outages, like those that occurred in August 2020. The RCA required the CEC to develop and publish a multiyear statewide summer assessment to provide information to support reliability planning and maintain situational awareness of potential impacts to grid reliability under extreme conditions.

In response, the CEC began development of two classes of reliability assessments: 1) Hourly Stack Analyses to help inform contingency planning in the year-of and year-ahead timeframe and 2) Loss-of-Load-Expectation (LOLE) analyses to help inform long-term policy studies and procurement planning over a 5-to-10-year time horizon. The LOLE analysis of the CAISO system over the next five years is the focus of this appendix.

Hourly Stack Analysis

The Hourly Stack Analysis is aimed at informing near term contingency planning and assessing the potential for a near-term system shortfall, considering supply and demand conditions under average and extreme weather conditions. The Hourly Stack Analysis supplements

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13 *Final Root Cause Analysis Mid-August 2020 Extreme Heat Wave*. 2021. California Independent System Operator. Available at http://www.caiso.com/Documents/Final-Root-Cause-Analysis-Mid-August-2020-Extreme-Heat-Wave.pdf.

traditional planning methods and provides a first-order directional estimate of system reliability. However, it offers the advantage of simplicity and therefore the ability to be revised regularly as new information becomes available. It is primarily intended to provide a snapshot of a potential worst-case scenario to inform the level of contingencies that the state should plan for. As such, the extreme scenario is developed to capture extreme demand and supply conditions that might represent a very low likelihood. While portions of an identified shortfall using the Hourly Stack Analysis in an extreme weather scenario might be deemed necessary to be addressed by additional procurement, the intention of an Hourly Stack Analysis is not to determine whether traditional procurement is needed. CEC published 2021 and 2022 hourly stack analyses[14] and will continue to revise them as new information of new supply and demand conditions become available.

Loss of Load Expectation Analyses

Traditional electric system planning tools, such as LOLE analyses, attempt to establish the procurement and market conditions needed to secure reliability to a specified target. A standard target is no more than 1 day of unserved energy every 10 years. These analyses do not attempt to capture a single worst-case scenario, but a statistical chance of having an outage based on inputs relating to procurement, distributions of demand, and generation profiles to name a few. LOLE analyses in combination with Hourly Stack Analyses provide a more robust picture to determine the appropriate balance between traditional procurement and the need for contingency resources. The rest of this appendix presents the analysis developed using the LOLE approach to assess reliability over the next five years – 2022 through 2026 – for the CAISO footprint. Appropriate portions of the analysis presented in this appendix are used to inform this "Midterm Reliability Analysis" report and thereby midterm reliability considerations in the CPUC's Integrated Resource Planning proceeding.

Purpose and Scope of 2021 California Reliability Outlook

The primary purpose of this first CRO is to help assess reliability of the CAISO footprint over the next five-year period based on current procurement targets. The outlook attempts to achieve this by modeling specific scenarios and sensitivities relating to projected procurement and supply conditions as ordered or proposed by the CPUC. The high-level scope for this first outlook is summarized in the following four questions of interest:

1. Is additional capacity needed beyond the current procurement orders by CPUC to meet the system planning reliability standards for CAISO footprint?
2. Does incremental thermal capacity provide additional system reliability compared to the portfolio of zero-emitting resources of equivalent NQC?
3. Is there sufficient energy to charge battery energy storage systems (BESS) under the expected resource build?

14 Tanghetti, Angela, Liz Gill, and Lana Wong. 2021. *2022 Summer Stack Analysis*. California Energy Commission. Publication Number: CEC-200-2021-006.

4. What is the potential reliability impacts of potential supply chain delays that impact BESS?

While the focus of this first report is to inform midterm reliability procurement in the CPUC's Integrated Resource Planning proceeding, CEC modeled CPUC's recently published proposed preferred system plan (PSP) as it also informs procurement over the period of interest.

Analytical Approach

This reliability outlook relies on the well-established LOLE analytical framework used widely in the industry to answer the questions of interest stated in the scope. The LOLE target used in this study is 1 day with unserved energy every 10 years or a loss of load expectation (LOLE) of 0.1 days per year. A day with unserved energy means any length of outage in a single day. While the 1-in-10 LOLE metric was used to assess reliability of the system, 1-in-20 and 1-in-100 LOLE results were included for informational purposes. The LOLE approach considers the probability for a wide range of distributions of key variables, including demand, solar, wind, and forced outages (or unplanned outages). These probability distributions are randomly sampled thousands of times for each scenario. Each sample is then run to produce results for each sample. These results are then compiled into a collection for each scenario. This compilation of results is analyzed to arrive at the LOLE metrics. Like any other modeling effort, modeling used in this outlook is an approximation of conditions and includes many simplifying but reasonable assumptions to reduce computation time and increase the number of scenarios modeled.

To establish the baseline of generation capacity and resources available on the system prior to new additions from the procurement orders, this study included all resources eligible to participate in the resource adequacy (RA) program. These are resources that have been assigned a qualifying capacity (QC) by the CPUC, and a subsequent net qualifying capacity (NQC) value which captures the deliverability of the QC to the system.

The generation capacity is divided into several resource types, such as solar, wind, 4-hour BESS, and combined cycle plants. Capacity for each resource type is then modeled as a single plant compared to modeling hundreds of individual plants to reduce computational time required to complete each simulation. Each resource type is characterized to approximate the resource's operations (e.g., generation profile, BESS capacity, force outage rate). These properties are described in the assumptions section.

Staff developed the CRO model in PLEXOS production cost modeling software currently licensed by the CEC. The outlook model was used to analyze the ability of the resources to meet demand, plus minimum operating reserves under a variety of scenarios. Every individual scenario in the study was analyzed for a unique resource mix with four key variables randomly selected for each simulation run within a particular scenario analysis. The randomized variables include 7 solar profiles, 7 wind profiles, 140 demand distributions, and randomized forced outages (or unplanned outages). This results in 6,860 possible combinations of solar, wind, and demand.

All scenarios were run with 10,400 simulations, each representing a random combination of solar, wind, demand, and forced outages. Some scenario results included fewer results due to unexpected interruptions during the simulation runs. However, all scenario results include over 10,000 samples, and all statistical calculations were adjusted accordingly to account for any decrease in the number of simulations.

The model was used to solve for the hourly system dispatch for each day with a 24-hour look ahead. This approach allows the system dispatch to account for future, expected situations similar to a day ahead market. Months May through October were modeled for each year under consideration.

Results from these scenarios were then processed to determine the LOLE and the shortfall capacity, if any. The unserved demand for each event is defined as the hour with the highest unserved energy in a day. To determine the shortfall, the events were ordered from highest to least unserved demand. The shortfall capacity is the capacity that would need to be fully available in all hours of the year (perfect capacity) to reduce the LOLE to below 1 day in 10 years. The shortfall capacity for a simulation with 100 samples would be the 11th highest unserved demand event. The LOLE is the number of unserved demand events divided by the number of simulations.

If any shortfall capacity is determined, additional capacity was added to the years with an LOLE exceeding 0.1 day per year. Capacity additions were repeated until the LOLE was less than 0.1 day per year.

For scenarios that explored the value of gas capacity compared to a combination of zero-emitting resources, the zero-emitting resource additions, in NQC, were directly replaced by gas capacity. These results were then compared.

Inputs and Assumptions

The inputs and assumptions section is organized into three broad categories:

1. System Input and Assumptions pertaining to transmission constraints, CAISO system demand and reserves requirements
2. Resource Inputs and Assumptions pertaining to the characterization of various resource types and facilities modeled (e.g., generation profiles, outage rates)
3. New Resource Build Assumptions pertaining to translation of the NQC ordered in procurement or identified in the PSP to nameplate capacities of relevant resources

System Inputs and Assumptions

This section describes the inputs and assumptions included in the model pertaining to transmission, system demand, and reserves requirements.

Transmission Constraints

The model used for the analysis groups all the CAISO footprint into a single region, with no transmission constraints represented. As a result, the model assumes that transmission is sufficient to handle all existing and new capacity that would be added within the CAISO footprint without any limitations or additional losses. Modeling transmission constraints could increase the loss of load expectation and total unserved energy, depending on the location of the demand and the supply resources.

Import resources were modeled as being within the CAISO footprint, and were not subject to any transmission constraints beyond the import limits set in the model, see the Imports section below.

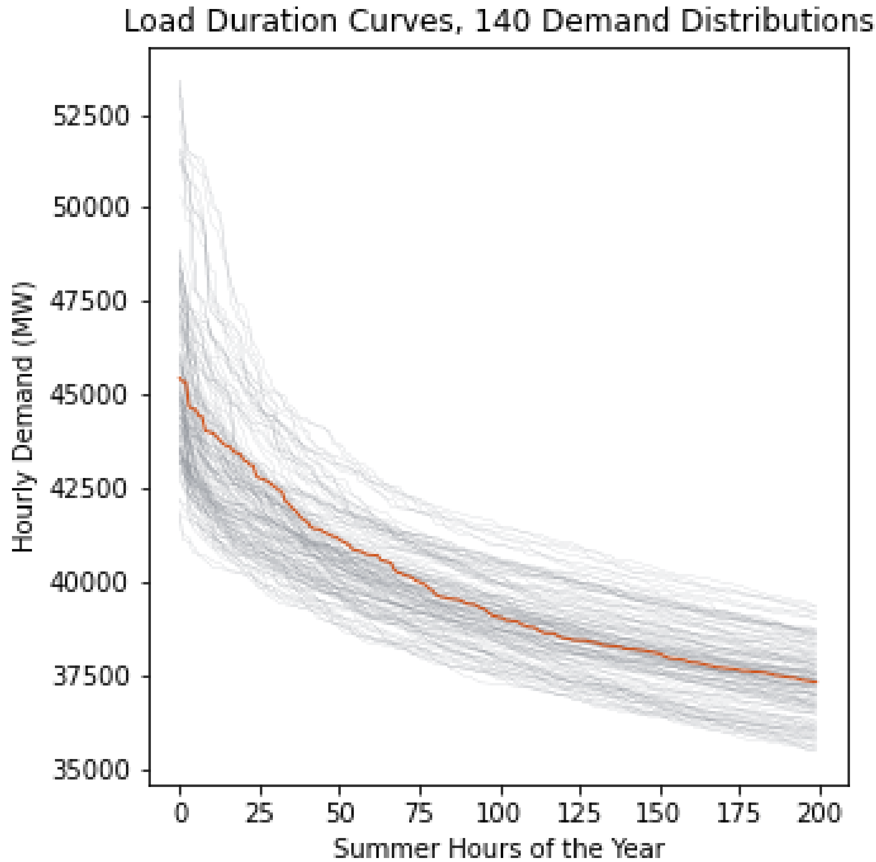
CAISO System Demand Profiles

The analysis used a distribution of hourly demand profiles developed as part of the 2020 California Energy Demand (CED) Forecast. The CED uses historical information to construct 140 demand profiles capturing 20 weather years and seven different starting days of the week for each weather year. The load modifiers, such as electric vehicles charging, and behind-the-meter solar photovoltaic, were not varied among the cases. However, load modifiers that are dependent on the day of the week (e.g., electric vehicle charging) were aligned with the days of the week for each demand profile. The resulting demand distributions have a median value within 0.5 percent of the adopted 1-in-2 peak demand from the 2020 CED.

Distributions were developed for the PG&E, SCE, and SDG&E regions and aggregated to create the demand distributions for the CAISO footprint. A demand distribution was not available for Valley Electric Association (VEA). Staff included the adopted 2020 CED mid-mid load for VEA into the distributions to capture its contribution to the CAISO system demand. The peak demand for VEA is approximately 150 MW, or less than one-third of one percent of the total CAISO wide peak demand and this approximation was deemed reasonable.

Figure A-1, shows the top 200 demand hours for each individual profile in the demand distribution with the 2020 CED mid demand case highlighted in red.

Figure A-1: 2022 Load Duration Curves for the Demand Distribution Compared to the 2020 CED for 2022.



Source: California Energy Commission staff

Reserves

The operating reserves were set to six percent of the load in each hour to meet North American Electric Reliability Corporation (NERC) standards. These reserves could be met by a combination of resources, see **Table A-1** for the capacity that can contribute to the reserve by year and technology.

Table A-1: Generating Capacity Capable of Providing Reserves

Technology (MW)	2022	2023	2024	2025	2026
Combined Cycle	2,500	2,500	2,500	2,500	2,500
Gas Turbine	2,500	2,500	2,500	2,500	2,500
Hydro	1,000	1,000	1,000	1,000	1,000
BESS 4-h	1,000	1,250	1,500	1,750	1,750
BESS 8-h	-	-	-	-	250

Source: California Energy Commission staff

Energy limited resources, 4-hour and 8-hour BESS, are constrained to have 0.5 MWh of energy stored for every 1 MW of capacity contributing to the reserves, or 30 minutes of full discharge for each megawatt contributing to the reserves. The 8-hour BESS is available only in 2026 as a result of the CPUC procurement order, which requires longer duration BESS in 2026.

While recognizing that various approaches are used to model reserves, this study assumes that six percent minimum reserves must be maintained even while energy goes unserved, to ensure consistency with the approach taken in CPUC's loss-of-load studies.

Resource Inputs and Assumptions

This section describes the model inputs assumptions for the supply resources included in the model.

Wind and Solar

Wind and solar shapes used in this analysis were produced from confidential data filings submitted by the CAISO to the CEC under a subpoena. The following steps were taken to address confidentiality limitations. First, individual plant generation from 2014 through 2020 was summed into seven statewide profiles for each resource. Each profile representing a calendar year. These statewide profiles were then normalized by the installed capacity. All wind and solar capacity, existing and new, made use of these statewide profiles. The generation from wind in each hour was determined by multiplying the total installed wind capacity by the normalized profile selected for that sample. Solar generation was determined in the same manner.

There is no correlation among the profiles selected for solar generators, wind generators, or demand. This is due to a data availability limitation and is flagged as a priority for future work.

The model did not assign any specific forced outage rates for wind or solar plants. Since the wind and solar profiles were taken from observed generation at actual plants, the profiles capture actual forced outages and other reductions in plant output for any reason. As with the desire to use weather correlated data for wind, solar, and demand in the future, staff has identified as a priority for future work to move the forced outages and other reductions in generation of wind and solar plants from the input profiles to a function of the model, like other resources.

Hydroelectric Generators

Hydroelectric generators, excluding pumped hydro, are modeled as able to deliver energy up to the total net qualifying capacity in all hours of the day. Staff explored limiting hydro generation with a monthly energy budget, capping the total energy output of hydro facilities to observed output levels. However, for the primary scenarios studied in the model including an energy budget did not impact results when import limits were increased to the maximum import capacity outside of the peak period.

In select scenarios a hydro budget was simulated. This was done by limiting the output of hydroelectric facilities were to the NQC values during the hours ending 17-22 Pacific Standard Time (PST), and to the median observed minimum hourly generation for each month between 2014 and 2020. See **Table A-2** for specific values used in the model.

Table A-2: Minimum Generation Values Used for Select Scenarios

Month	**Min Generation Percent of the NQC Values**	**Min Gen (MW)**	**Monthly NQC Value (MW)**
May	44.4%	2,007	4,520
June	35.6%	1,654	4,649
July	34.2%	1,745	5,101
August	25.9%	1,205	4,649
September	24.7%	1,166	4,714
October	19.2%	844	4,391

Source: California Energy Commission staff

Forced outages were not applied to hydro facilities. It was assumed that capacity above the individual plant NQC would be used in the short term to compensate for a forced outage in another plant.

Hydroelectric facilities could contribute to reserve requirements up to 1,000 MW of the NQC for the plants. As with other resources, hydro could not provide energy with that 1,000 MW while simultaneously contributing to the reserve requirements.

Demand Response

Demand response (DR) was modeled as a supply side generator. The maximum dispatch of the DR capacity was limited on an energy basis to fully dispatch at most 4 hours' worth of energy in a single day, and no more than 80 hours a year (which for this model is from May through October). This was accomplished with a daily and annual capacity factor limit. Thus, the DR in the model can be dispatched for more than 4 hours a day and 80 hours a year. This was done to account for the ability to separately dispatch various DR programs to best serve reliability. Staff acknowledges that this approach does not account for "DR fatigue" or any restrictions on when DR can dispatch due to the type of demand.

Within the model the identified DR capacity was increased by six percent of the identified capacity, the quantity of reserves that must be maintained for load. This was done to acknowledge that DR reduces load, which also reduces the reserves that must be maintained on the system. The scaled-up capacity is not incorporated into the capacity values for the resource builds.

Scaling up the DR capacity results in a shift of six percent of the DR capacity dispatched from demand to reserves, see **Table A- 3**. Reserves can be met by energy storage without discharging energy. This effectively makes reserves supplied by energy storage resources less costly to meet than actual demand from a reliability perspective, while the reliability cost of serving reserves of demand with gas capacity or hydro capacity is equivalent in this model. Thus, this approach will only impact results for situations where the total reserves are met entirely by energy storage resources (loads less than 17,000 MW in 2022, up to 34,000 MW in 2026) and DR is needed to maintain reliability.

Table A-3: Shifting of Capacity Need from Demand to Reserves

(MW)	**Supply Side DR**	**Demand Side DR**	**Notes**
DR Capacity	100	100	
Demand	1,000	1,000	
Scaled up DR	106	N/A	DR Capacity x 1.06
Reserves	60	N/A	Demand x 0.06
Demand Plus Reserves	1,060	N/A	Demand x 1.06
Total Capacity Need	954	N/A	(Demand x 1.06) - (DR x 1.06)
Demand Less DR	N/A	900	Demand - DR
Reserves	N/A	54	(Demand - DR) x 1.06
Total Capacity Need	N/A	954	(Demand - DR) x 1.06
Total Reserves Carried	60	54	
Total Demand, Less DR	894	900	
Total Capacity Need	954	954	

Source: California Energy Commission staff

Thermal Plants

Thermal plants, including gas technologies, nuclear, geothermal, and biomass plants were modeled with largely the same properties, except for the forced outage rate. Solar thermal plants are included in the solar category with photovoltaic plants. All these plants were modeled as able to deliver up to their NQC value in all hours of the day, except when on a forced or unplanned outage. These plants were not modeled with limits on ramping, operational hours, or minimum down times. It was assumed that given dispatch assignments in the day ahead market, these resources would be operated as necessary to meet the assigned obligation.

Table A-4: Forced Outage and Unit Size Assumptions

Technology	Forced Outage Rate (%)	Mean Time to Repair (h)	Standard Unit Size (MW)	Test Unit Size (MW)	CAISO Median Unit Size (MW)	CAISO Mean Unit Size (MW)
Combined Cycle	3.69	24	100	600	583	619.0
Gas Turbine	11.66	24	100	125	49.8	125.4
Cogen	13.84	24	100	50	49.8	125.4
Gas-Other	13.84	24	100	40	9.9	40.1
Nuclear	1.92	24	1140	1140	N/A	N/A
Geothermal	7.2	24	25	25	N/A	N/A
Biomass	8	24	10	10	N/A	N/A

Source: California Energy Commission staff analysis, California Independent System Operator analysis of NERC GADS 2019 data[15]

Forced outage rates for gas plants and nuclear plants were taken from a presentation to WECC by Yi Zhang of the CAISO and are based on data from the NERC Generating Availability Data System (GADS) for 2019. Rates for other plants were taken from the CEC's production cost model database used for the IEPR. See **Table A-4** for technology specific assumptions. Since power plants were not individually modeled, but rather the total capacity was modeled as an individual plant made up of many different units, a standard unit size had to be assumed.

Staff tested two different unit size assumptions, the "Standard Unit Size (MW)" and the "Test Unit Size (MW)" in Thermal plants, including gas technologies, nuclear, geothermal, and biomass plants were modeled with largely the same properties, except for the forced outage rate. Solar thermal plants are included in the solar category with photovoltaic plants. All these plants were modeled as able to deliver up to their NQC value in all hours of the day, except when on a forced or unplanned outage. These plants were not modeled with limits on ramping, operational hours, or minimum down times. It was assumed that given dispatch assignments in the day ahead market, these resources would be operated as necessary to meet the assigned obligation.

15 Zhang, Yi. 2021. Forced Outage Rates. Presentation to WECC. California Independent System Operator. Available at https://www.wecc.org/_layouts/15/WopiFrame.aspx?sourcedoc=/Administrative/Zhang%20-%20FOR%20PCMS.pdf&action=default&DefaultItemOpen=1.

Table A-5, in three different scenarios. The results of these scenarios showed only a minor impact in the LOLE and did not represent a consistent increase or decrease in unserved energy events or magnitude. Further study of how the assumed unit size impacts results will be pursued if this approach is used in the future.

BESS

BESS technologies, include pumped hydroelectric resources, are simply modeled with the parameters in **Table A-5**. Forced outage rates for pumped hydro are taken from a presentation to WECC by Yi Zhang of the CAISO and are based on NERC GADS data for 2019, while the forced outage rates for BESS were from California Energy Storage Alliance estimates provided in comments to a preliminary presentation of this approach at a July 8 Integrated Energy Policy Report Reliability workshop.

Table A-5: BESS Properties

Technology	Forced Outage Rate (%)	Standard Unit Size (MW)	Charge Efficiency (%)	Storage Duration (h)
Energy Storage 4 h	5	10	89.94	4
Energy Storage 8 h	5	10	89.94	8
Pumped Hydro Storage	5.77	100	70.56	12

Source: California Energy Commission staff, California Independent System Operator,[16] California Energy Storage Alliance comments[17]

Charge efficiencies for BESS devices were taken from the CEC's PLEXOS database used for the IEPR and represent the roundtrip efficiency for the resources. The efficiencies were applied this way to simplify and standardize the BESS duration calculation so that a fully charged 4-hour BESS device can discharge at full capacity for a full 4 hours.

Imports

Imports are split into two categories, specified and unspecified imports. Specified imports represent specific electricity generators outside of California that are contracted to or expected to provide capacity for resource adequacy. Unspecified imports represent possible capacity that will be contracted for resource adequacy.

Specified imports are modeled with forced outages identical to combined cycle forced outage rates. The specified imports are a combination of nuclear, hydro, and gas plants.

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16 Zhang, Yi. 2021. Forced Outage Rates. Presentation to WECC, using NERC GADs data. California Independent System Operator. Available at https://www.wecc.org/_layouts/15/WopiFrame.aspx?sourcedoc=/Administrative/Zhang%20-%20FOR%20PCMS.pdf&action=default&DefaultItemOpen=1.

17 California Energy Storage Alliance staff. 2021. CESA's Comments on the Multi-Year Reliability Assessment Scope, Inputs, and Assumptions. California Energy Commission. TN Number: 238987.

Unspecified imports are modeled as perfect capacity, able to deliver to the identified capacity in each year without restrictions.

For most scenarios the specified and unspecified imports only limit import during the hours ending 17 through 23 (4 pm through 11 pm PST). In all other hours, imports are constrained only to the maximum import capability of the system, which is set at 10,800 MW. In specified scenarios, imports are limited to the specified and unspecified imports in all hours.

Paired and Hybrid Resources

Paired and hybrid resources are not directly included in this analytical work. Existing or planned paired and hybrid plants are separated into generation resources and BESS resources (assuming a 4-hour BESS capacity). Staff had insufficient information on the capacity ratios or operational constraints for these resources. The data limitation paired with the simplified modeling approach necessitated modeling these resources as separate generation and BESS plants. The Energy Commission plans to develop a model for paired and hybrid plants in PLEXOS for future work.

New Resource Build Assumptions

This section describes how the NQC capacities in the CPUC's Mid-Term Reliability Need Determination Model were translated to monthly NQC values and nameplate capacities.

The CPUC's Mid-Term Reliability Need Determination Model[18] was developed to help determine the procurement need to maintain system reliability through 2026. The original version of the model was published in February 2021, and subsequently updated with two corrections as well as adjustments to update to the 2020 IEPR.[19] The updated version was provided by CPUC staff and used in this analysis.

Technology Factors

This analysis used the technology factors in the CPUC's 2021 Net Qualifying Capacity list. This analysis made use of the average technology factors for cogeneration, geothermal, biomass, and hydro plants. Except for wind and solar, a technology factor of 1 was assumed for technologies not listed. Wind and solar nameplate capacities were taken directly from the CPUC's Mid-term Reliability Need Determination Model, which is discussed in the Base Resource Assumptions section below.

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18 The February 22, 2021 version of the CPUC's Reliability Determination Model can be found online at: https://www.cpuc.ca.gov/industries-and-topics/electrical-energy/electric-power-procurement/long-term-procurement-planning/more-information-on-authorizing-procurement/irp-procurement-track. A later version of this model was provided to the CEC that made minor modifications to the total NQC values.

19 These are described in the CPUC's Final Decision Requiring Procurement to Address Mid-Term Reliability, 6/24/2021, section 3.2. Available at: https://www.cpuc.ca.gov/industries-and-topics/electrical-energy/electric-power-procurement/long-term-procurement-planning/more-information-on-authorizing-procurement/irp-procurement-track.

Table A-6: Technology Factors by Month

Technology	**May**	**June**	**July**	**August**	**September**	**October**
Cogen	80%	88%	84%	87%	83%	75%
Geothermal	82%	78%	90%	88%	87%	87%
Biomass	90%	93%	92%	94%	94%	87%
Hydro	70%	72%	79%	72%	73%	68%

Source: California Public Utilities Commission's Net Qualifying Capacity list for 2021.[20]

Technology factors were used to convert the CPUC-identified NQC values into a nameplate capacity associated with the NQC for that resource type. This was done by dividing the NQC values by the September technology factor. Using this nameplate capacity associated with the NQC values, the NQC values for each month, May through October, were created by multiplying nameplate capacity by the technology factor.

Gas nameplate capacity was assumed to have a one-to-one relationship with NQC, except for cogeneration. Thus, a one-to-one relationship with NQC is reasonable for new gas capacity consistent with the current Qualifying Capacity method if no reductions in deliverability are expected.

Effective Load Carrying Capability

Two different effective load carrying capabilities (ELCC) were used in this analysis for different scenarios, the marginal ELCC used in the CPUC's Reliability Need Determination Model and the ELCC values published by the CPUC on September 10, 2021. The ELCC values were only used to produce resource builds for compliance with the outstanding procurement orders or to quantify the NQC capacity included in the CPUC's preferred system plan (PSP).

Marginal ELCC Values from the Reliability Need Determination Model

The marginal ELCC values from the CPUC's Reliability Need Determination Model are provided in **Table A-7**. To calculate the NQC for resources in a resource build, staff multiplied the wind and solar marginal ELCC values by the nameplate capacity. For example, the 2022 ELCC value for solar is 2.3 percent, thus 100 MW of installed solar capacity would contribute 2.3 MW to the NQC of the resource mix. For 4-hour BESS resources, the total installed capacity between the minimum capacity and maximum capacity in **Table A-7** was multiplied by the associated marginal ELCC value in that year. For example, adding 100 MW of 4-hour BESS in 2024 with 6,000 MW would only increase the NQC of the build by 89.5 MW, since the total installed capacity for 4-hour batteries is between 5,265 MW and 7,675 MW. This process was used to determine the capacity additions in each year.

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20 CPUC's Final Net Qualifying Capacity Report for Compliance Year 2021. Available at https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/energy-division/documents/resource-adequacy-compliance-materials/cpuc-netqualifyingcapacitylist-2021-19aug21.xlsx, accessed on September 9, 2021.

Table A-7: Marginal ELCC Values in the CPUC's Reliability Need Determination Model

Technology	2022	2023	2024	2025	2026	Capacity Min (MW)	Capacity Max (MW)
Wind	28.5%	28.5%	28.6%	28.6%	28.6%	N/A	N/A
Solar	2.3%	2.3%	1.9%	1.9%	1.9%	N/A	N/A
4 h BESS	100.0%	100.0%	100.0%	100.0%	100.0%	-	5,265
4 h BESS	88.8%	89.1%	89.5%	89.8%	90.1%	5,265	7,674
4 h BESS	76.2%	76.7%	77.1%	77.6%	78.0%	7,674	10,530
4 h BESS	66.4%	67.1%	67.8%	68.5%	69.3%	10,530	13,034
4 h BESS	54.2%	55.6%	57.0%	58.4%	59.9%	13,034	15,795

Source: California Public Utilities Commission’s Reliability Need Determination Model

For scenarios where nameplate capacity needed to reach a specific NQC value, a similar process was used, but in reverse. Specifically, a set of ratios of nameplate capacity resource additions would be identified (for this study the 2026 cumulative capacity additions in the proposed PSP) comparing each resource to the BESS build. Then nameplate capacity for BESS would be added, the proportional capacity additions of other resources would be added, and the new NQC values would be calculated as described above. The process would then be repeated until the NQC total matched the target NQC values.

Long duration BESS (those with durations longer than 8 hours), were given a marginal ELCC value of 1.

CPUC Released ELCC Values for the D.21-06-035

On September 10, 2021, the CPUC published the ELCC values that will be used for 2023 and 2024 procurement under D.21-06-035, as well as indicative values for resources coming online in 2025 and 2026. The values used in this study are provided in **Table A-8**. Please note that no ELCC values were provided for 2022, staff used the 2023 values for ELCC calculations of 2022 capacity.

Table A-8: Annual 2021 ELCC Values for D.21-06-035

-	2023	2024	2025	2026
Wind CA	13.90%	16.50%	22.60%	21.60%
Solar - Utility Scale and BTM PV	7.80%	6.60%	6.70%	5.70%
4-Hour BESS	96.30%	90.70%	74.20%	69.00%
8-Hour BESS	98.20%	94.30%	82.20%	78.20%

Source: Astrapé Consulting and Energy + Environmental Economics[21]

These ELCC Values were used in several scenarios to estimate the NQC capacity or to build nameplate capacity required to meet an NQC value ordered. When estimating the NQC of a PSP build, the NQC values are determined by multiplying the ELCC value for the specific resource in a given year by the nameplate capacity to estimate the NQC values. When producing nameplate capacity to meet an NQC target, a similar approach is used. However, nameplate capacity was added until the product of the ELCC values and the nameplate capacity equaled the ordered procurement.

Base Resource Assumptions

The base resources for the study originate from the CPUC's Reliability Need Determination Model. The CEC was provided with an updated version of the Reliability Need Determination Model in July 2021. This version includes several small corrections and updates compare to the version of the model currently available to the public. Below is the method used to create nameplate capacity values for resource adequacy purposes for the IRP baseline resources.

1. The NQC values for resources were taken from the "RESLVE/SERVM (Updated) Gen List Based" in the "Inputs + Analysis" sheet and grouped by resource type used in this study.
2. The NQC capacity for these resources was converted to a nameplate capacity associated with the NQC values by dividing by the applicable September Technology Factors, see the Technology Factors section above.
3. The wind and solar values were then replaced with the "RESOLVE/SERVM (Updated) Gen List Based – Wind and Solar Nameplate for ELCC Calculation" table, which excludes energy only resources. This table is also found in the "Inputs + Analysis" sheet.

The resulting baseline capacity values are presented in **Table A-9**.

21 Incremental ELCC study for Mid-Term Reliability Procurement, prepared for the CPUC by Astrapé Consulting and Energy + Environmental Economics.

Table A-9: IRP Baseline Resources

Nameplate (MW)	**2022**	**2023**	**2024**	**2025**	**2026**
Combined Cycle	15,781	15,781	15,781	15,781	15,781
Gas Turbine	7,907	7,907	7,907	7,686	7,591
Gas-Other	3,109	3,109	255	255	255
Cogen	1,659	1,640	1,633	1,502	1,428
Nuclear	2,280	2,280	2,280	-	-
Geothermal	1,348	1,348	1,348	1,348	1,348
Biomass	610	610	610	610	610
Hydro	6,457	6,457	6,457	6,457	6,457
Wind	5,801	5,801	5,801	5,801	5,801
Solar	12,139	11,952	11,952	11,952	11,952
Energy Storage 4 h	512	512	512	512	512
Pumped Hydro Storage	1,579	1,579	1,579	1,579	1,579
Demand Response	2,195	2,195	2,195	2,195	2,195
Unspecified Imports	5,000	5,000	4,000	4,000	4,000
Specified Imports	1,981	1,981	1,981	1,502	1,502
Total	**68,358**	**68,152**	**64,291**	**61,180**	**61,011**

Source: California Energy Commission staff

Next, the nameplate additions to the IRP baseline are taken from the "Additions to IRP Baseline per LSE filings (After project viability weighting)" table in the "Inputs + Analysis" sheet. See **Table A-10**. Hybrid resources were split into the separate solar and 4-hour BESS technologies groupings, as described in Paired and Hybrid Resources.

Table A-10: IRP Baseline Additions per LSE Filings

Nameplate (MW)	**2022**	**2023**	**2024**	**2025**	**2026**
Combined Cycle	-	-	-	-	-
Gas Turbine	-	-	-	-	-
Gas-Other	-	-	-	-	-
Cogen	-	-	-	-	-
Nuclear	-	-	-	-	-
Geothermal	11	12	13	13	13
Biomass	10	12	14	15	17
Hydro	-	-	-	-	-
Wind	747	790	820	842	856
Solar	1,763	2,637	2,727	2,884	3,003
Energy Storage 4 h	1,235	1,513	1,544	1,604	1,644
Pumped Hydro Storage	-	-	-	-	-
Demand Response	-	-	-	-	-
Imports - Unspecified	-	-	-	-	-
Imports - Specified	-	-	-	90	98
Total	**3,765**	**4,964**	**5,117**	**5,450**	**5,632**

Source: California Energy Commission staff

The summer 2021 procurement, D.21-02-028, is based on the IOU advice letters.[22] With the exception of the gas turbine in SCE's advice letter 4415-E, all resources are assumed to not impact the total resource available outside of the year and months in the analysis. SCE's gas turbine resource is incremental capacity and is assumed to be available in future years for reliability, thus it remains in the model after the contract term. The CEC is aware that additional procurement pursuant to the summer 2021 order has occurred that is not captured in this study. The 2021 procurement totals in **Table A-11** are included for reference, but 2021 was not modeled for this analysis.

22 Advice letters 3689-E (SDG&E), 6088-E (PG&E), and 4415-E (SCE).

Table A-11: Summer 2021 Procurement

Total Capacity (MW)	2021	2022	2023	2024	2025	2026	Advice Letter
Imports – Unspecified (SDG&E)	62	-	-	-	-	-	3689-E
Gas Turbine (SDG&E)	47	47	47	47	47	47	3689-E
Biomass (PG&E)	63	-	-	-	-	-	6088-E
Gas Turbine (PG&E)	70	-	-	-	-	-	6088-E
Cogen (PG&E)	2	-	-	-	-	-	6088-E
Gas Turbine (SCE)	69	69	69	69	69	69	4415-E
Total	**314**	**116**	**116**	**116**	**116**	**116**	

Source: Advice letters 3689-E (SDG&E), 6088-E (PG&E), and 4415-E (SCE), with CEC Staff adjustments.

The capacity from **Table A-11** through **Table A-** are combined to create the total baseline capacity.

Table A-12: Total Baseline Nameplate Capacity for Resource Adequacy

Nameplate (MW)	2022	2023	2024	2025	2026
Combined Cycle	15,781	15,781	15,781	15,781	15,781
Gas Turbine	8,023	8,023	8,023	7,802	7,707
Gas-Other	3,109	3,109	255	255	255
Cogen	1,659	1,640	1,633	1,502	1,428
Nuclear	2,280	2,280	2,280	-	-
Geothermal	1,359	1,360	1,361	1,361	1,362
Biomass	620	622	624	626	627
Hydro	6,457	6,457	6,457	6,457	6,457
Wind	6,548	6,591	6,622	6,644	6,658
Solar	13,902	14,589	14,679	14,836	14,955
Energy Storage 4 h	1,747	2,024	2,055	2,116	2,156
Pumped Hydro Storage	1,579	1,579	1,579	1,579	1,579
Demand Response	2,195	2,195	2,195	2,195	2,195
Imports - Unspecified	5,000	5,000	4,000	4,000	4,000
Imports - Specified	1,981	1,981	1,981	1,592	1,600
Total	**72,240**	**73,232**	**69,524**	**66,746**	**66,759**

Source: California Energy Commission staff

Table A-13 shows the baseline resources used in all scenarios. Any changes to this baseline are documented with a description of each scenario in the Scenarios section below

Modeling Scenarios

As part of this analysis, staff analyzed three groups of scenarios.

1. No Build scenarios: These scenarios do not add any capacity beyond the total baseline nameplate capacity for resource adequacy displayed in **Table A-**. This scenario helps to inform the initial need, before ordered procurement, for resources for 2022 – 2026.
2. PSP scenarios: These scenarios use the proposed preferred system plan (PSP) resource additions published in on August 17, 2021 under Rulemaking 20-05-003. These scenarios assess the impact of the PSP on reliability for each year and evaluates the impact of prioritizing zero-emitting resources or including gas resources.
3. Procurement scenarios: These scenarios use the outstanding procurement associated with D.19-11-016 and D.21-06-035 as the target NQC capacity for resource builds. The

ratio of resources is matched to the 2026 cumulative resource additions in the PSP, except for the long duration BESS. These scenarios assess whether additional capacity beyond ordered procurements is needed to maintain system reliability. They also evaluate the impact of several conditions that may affect reliability, including approaches to further support reliability in 2022 and to understand how supply chain issues with BESS could affect reliability as the state increases BESS procurement across the study period.

For each scenario capacity shortfalls under 1 day in 20 years, and 1 day in 100 years in addition to a 1 day in 10 years LOLE were evaluated for informational purposes.

A complete list of scenarios analyzed for this study, and the primary attributes, can be found in Error! Reference source not found.. The remainder of this section provides information on the content of the scenarios.

Table A-13: Scenario Summary

Scenario	Capacity Additions	Include 2026+	Import and Hydro Limits	Gas in Place of Zero-emitting	New ELCC Values	BESS Supply Chain Impact	Solar Output Reduction
No Build	No Build	-	-	-	-	-	-
PSP	PSP	Yes	-	-	-	-	-
PSP_(Energy)	PSP	Yes	Yes	-	-	-	-
PSP_(Gas)	PSP	Yes	-	Yes	-	-	-
PSP_(Gas, R.ELCC)	PSP	Yes	-	Yes	Yes	-	-
Order	Order	Yes	-	-	-	-	-
Order_(Energy)	Order	Yes	Yes	-	-	-	-
Order_(R.ELCC)	Order	Yes	-	-	Yes	-	-
Order_(Gas)	Order	Yes	-	Yes	-	-	-
Order_(1200 Shift)	Order	-	-	-	-	-	-
Order_(1300 Shift)	Order	-	-	-	-	-	-
Order_(1400 Shift)	Order	-	-	-	-	-	-
Order_(1600 Shift)	Order	-	-	-	-	-	-
Order_(1800 Shift)	Order	-	-	-	-	-	-
Order_(2000 Shift)	Order	-	-	-	-	-	-
Order_(B20)	Order	Yes	-	-	-	20%	-
Order_(R.ELCC, B20)	Order	Yes	-	-	Yes	20%	-

Scenario	Capacity Additions	Include 2026+	Import and Hydro Limits	Gas in Place of Zero-emitting	New ELCC Values	BESS Supply Chain Impact	Solar Output Reduction
Order_(Energy, PV15)	Order	-	Yes	-	-	-	15%
Order_(Energy, PV30)	Order	-	Yes	-	-	-	30%
Order_(Energy, PV45)	Order	-	Yes	-	-	-	45%

Source: California Energy Commission staff

Capacity Additions

The No Build scenarios do not add any capacity beyond the total baseline nameplate capacity for resource adequacy displayed in **Table A-12**.

Resource builds for PSP Scenarios

The PSP scenarios are based on the proposed PSP published on August 17, 2021 for the resource additions.[23] The published proposed PSP was changed in two ways for this study.

First, the 120 MW of offshore wind capacity scheduled to come online in 2026 was converted to onshore wind capacity. There is not any historic generation for offshore wind near California, thus no historic-based profiles exist that can be used alongside the other wind and solar profiles.

Second, the incremental additions in the PSP includes several facilities that are also included in the baseline for the CPUC's Reliability Need Determination Model. Information on this capacity was provided by the CPUC and contained confidential information. A summary of the capacity removed from the PSP for this analysis is contained in **Table A-14**. All overlapping capacity was removed in 2022. The capacity in **Table A-14** includes the total resource capacity for hybrid and paired generation facilities, and thus it is approximately 200 MW larger than the specific nameplate capacity identified by CPUC staff. This approach was taken to be consistent with the accounting method used for the hybrid resources identified in the Reliability Need Determination Model.

Table A-14: Capacity Removed from the PSP Due to Overlap with the Base Resources

Nameplate (MW)	**2022**
Energy Storage 4 h	406
Biomass	15
Geothermal	14
Solar	883
Wind	409

Source: California Energy Commission staff

Once these adjustments have been made, the incremental nameplate capacity added is shown in **Table A-15**. The NQC values for this build calculated by the methods described above, are found in **Table A-16**.

23 Administrative Law Judge's Ruling Seeking Comments on Proposed Preferred System Plan, August 17, 2021. https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/energy-division/documents/integrated-resource-plan-and-long-term-procurement-plan-irp-ltpp/2019-2020-irp-events-and-materials/ruling_proposed-psp.pdf, accessed on September 10, 2021

Table A-15: PSP Incremental Resource Additions

Nameplate (MW)	2022	2023	2024	2025	2026	2026+
Geothermal	-	100	100	100	170	1,319
Biomass	19	50	68	92	92	92
Shed DR	151	151	353	441	441	441
Wind	1,310	1,332	1,662	3,144	3,264	3,264
Solar	2,211	5,666	6,867	10,117	10,117	10,117
BESS 4-h	2,159	4,198	10,211	12,147	12,147	12,147
BESS 8-h	-	-	-	-	196	1,196
Total	**5,850**	**11,497**	**19,261**	**26,041**	**26,427**	**1,852**

Source: California Energy Commission staff

Table A-16: NQC Values for the PSP

NQC (MW)	2022	2023	2024	2025	2026	2026+
Reliability Need Determination Model NQC	*2,753*	*4,916*	*9,907*	*11,712*	*12,012*	*14,012*
September 2021 NQC	*2,603*	*4,970*	*10,778*	*12,879*	*13,128*	*15,128*

Source: California Energy Commission staff

Resource Builds for Procurement Scenarios

Resource builds based on the procurement orders are created by adding nameplate capacity from zero-emitting resources until the specified NQC value is reached. The NQC capacity required in each year is identified in **Table A-17**. Please note that hybrid resources were modeled as separate solar and 4-hour BESS facilities, see Paired and Hybrid Resources above.

Table A-17: Cumulative Procurement Order Requirements and Estimates of the Resource Types and Amounts to Comply

Resource (MW NQC)	**2022**	**2023**	**2024**	**2025**	**2026**	**2026+**
D.19-11-016 NQC Remaining	1,070	1,505	-	-	-	-
D.21-06-035 NQC Remaining	-	2,000	8,000	9,500	-	11,500
Solar Hybrid with 4-h BESS	-	-	1,000	2,500	2,500	2,500
Geothermal	-	-	-	-	-	1,000
8-H BESS	-	-	-	-	-	1,000
Other Capacity	1,070	3,505	8,505	8,505	8,505	8,505
Total	**1,070**	**3,505**	**9,505**	**11,005**	**11,005**	**13,005**

Source: California Energy Commission staff analysis of D.19-11-016 and D.21-06-035

The NQC values for D.19-11-016 include all remaining capacity not already procured are procured on time by 2023.

For the procurement scenarios, necessary nameplate capacity was added until the procurement order's NQC capacity for each year was met, using a mix of resources consistent with the ratio for 2026 in the PSP, except for the 8-hour BESS. See New Resource Build Assumptions above for more information. The resource build based on the marginal ELCC values from the Reliability Need Determination Model can be found in **Table A-18**, the resource build using the ELCC values released in September 2021 are presented in **Table A-19**.

Table A-18: Order Resource Build Additions using the Reliability Need Determination Model Marginal ELCC Values

Nameplate (MW)	**2022**	**2023**	**2024**	**2025**	**2026**	**2026+**
Geothermal	8	25	77	92	92	1,241
Biomass	7	23	71	85	85	85
Shed DR	34	111	340	408	408	408
Wind	242	794	2,427	2,908	2,908	2,908
Solar	780	2,554	7,811	9,356	9,356	9,356
BESS 4-h	936	3,066	9,378	11,233	11,233	11,233
BESS 8-h	-	-	-	-	-	1,000
Total	**2,007**	**6,573**	**20,105**	**24,082**	**24,082**	**26,231**

Source: California Energy Commission staff

Table A-19: Order Resource Build Additions using the ELCC Values for D.21-06-035

Nameplate (MW)	2022	2023	2024	2025	2026	2026+
Geothermal	8	26	73	86	86	1,231
Biomass	7	24	67	79	79	79
Shed DR	35	114	321	381	381	381
Wind	248	814	2,286	2,714	2,714	2,714
Solar	800	2,619	7,355	8,733	8,733	8,733
BESS 4-h	960	3,145	8,831	10,485	10,485	10,485
BESS 8-h	-	-	-	-	-	1,279
Total	**2,058**	**6,742**	**18,932**	**22,478**	**22,478**	**24,902**

Source: California Energy Commission staff

Include 2026+

The "2026+" label refers to the addition of 2,000 MW of NQC in 2026. Most scenarios were run with and without this capacity.

Import and Hydro Limits

Scenarios with import and hydro limits are used to test the sensitivity of the model to limited energy availability. Specifically, the Imports are restricted to the CPUC-identified specified and unspecified imports for all hours of the day. Rather than being allowed to increase to 10,800 MW outside of hours ending 17 through 23. See the Imports section above for additional information.

Hydro in these scenarios is still allowed to generate at the NQC levels during hours ending 17 through 22 but is restricted to a lower output in the remaining hours. These lower limits are discussed further in the Hydroelectric Generators section above.

Gas in Place of Zero-emitting Resources

These scenarios replace the new capacity, on an NQC basis, with natural gas capacity, specifically, with a ratio of one-part combined cycle plants and two parts gas turbine plants. The operations for both types of gas plants are effectively identical in this model, except for the forced outage rate. The forced outage rate for gas turbines is substantially greater than the forced outage rate for combined cycle plants.

New ELCC Values

These scenarios that make use of the ELCC values published on September 10, 2021, for use with D.21-06-035. See the Effective Load Carrying section above for additional details.

BESS Supply Chain Impact

BESS supply chain impact scenarios incorporate delays in 4-hour BESS procurement to study the potential impacts of global supply chain issues persisting into future years. Specifically, 20 percent of the incremental 4-hour BESS for each year is delayed to the following year. **Table A-20** summarizes the reduction in total installed 4-hour BESS capacity in each year. No delays were applied to 8-hour BESS that is part of the long lead time resources, as a delay in procurement from those resources is captured in the 2026+ scenarios. No other changes are made to the resource builds.

Table A-20: Reduction in the Total Installed Capacity for 4-Hour BESS

(MW)	2022	2023	2024	2025	2026
Order_(B20)	326	482	1,269	383	8
Order_(R.ELCC, B20)	331	493	1,143	343	8

Source: California Energy Commission staff

Solar Output Reductions

The solar output reduction scenarios reduce the total output of solar plants by 15 percent, 30 percent, or 45 percent to study the potential impacts of smoke and monsoonal cloud cover as experienced in August 2020. These scenarios also include the additional limits on imports and hydro, with the goal of better understanding how energy scarcity in hours without reliability concerns can impact reliability during peak periods.

It should be noted that the reduction in solar output decreases both the total daily energy availability and the capacity available during peak periods. No attempt was made to separate the impacts from the reduced energy from the reduced power capacity.

Additionally, these scenarios do not consider any other limitations on the operations of other power plants, such as maximum operating hours. Thus, actual energy availability from the resources included in the model may be even more restrictive.

Results

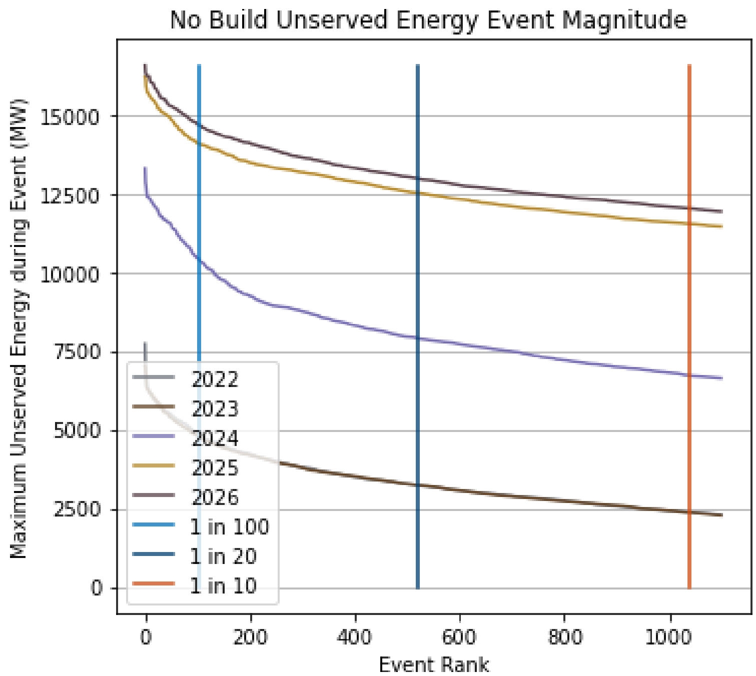
The following section summarizes the results from the LOLE analysis of the three different categories of scenarios studied: No build scenario, PSP scenarios, and new procurement scenarios. In addition to reporting the potential capacity shortfall and other LOLE metrics for the standard 1-in-10 case, results for 1-in-20 and 1-in-100 were also included for informational purposes. Given the unprecedented climate change impacts and the extreme weather events that are currently being observed, the state might consider making planning modifications on how climate change impacts are considered in both demand- and supply-side modeling, and the 1-in-20 and 1-in-100 could inform those considerations.

No Build Scenario

Results from the No Build Scenario establish the need for a substantial new resource build through 2026, and strongly support the need for the procurement decisions taken by CPUC.

Figure A-2 shows the quantity of unserved energy progressively increasing from 2022 through 2026 under the No Build Scenario. The LOLEs and shortfall capacities for the No Build scenario can be found in **Table A-21**. The LOLE for each year significantly exceeds the 0.1 day per year target with unserved demand level reaching 12,022 MW by 2026. These shortfall capacities are comparable to the procurement ordered by CPUC through decisions, D.19-11-016 and D.21-06-35. Though, due to forced outages and other limitations, it is possible the NQC need may be higher than the shortfall value to ensure reliability.

Figure A-2: Unserved Energy Event Magnitude, No Build Scenario



Source: California Energy Commission staff

Table A-21: Reliability Statistics Summary, No Build Scenario

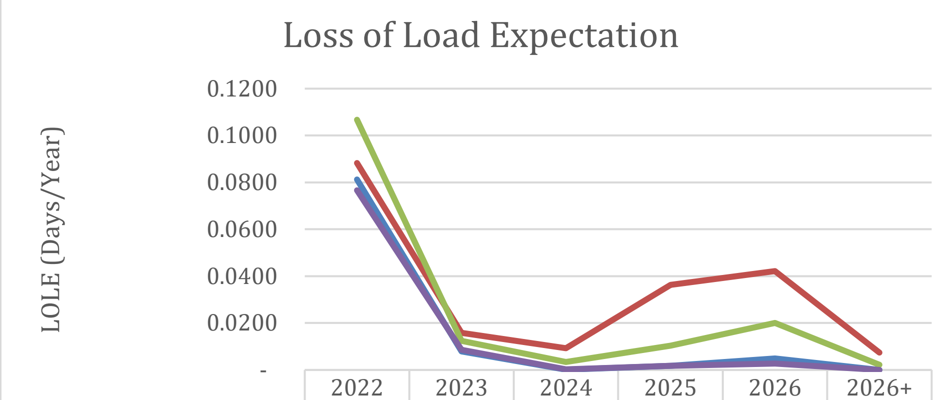
No Build	**2022**	**2023**	**2024**	**2025**	**2026**
LOLE	0.311	0.303	2.369	14.639	17.839
1 in 10 Shortfall (MW)	2,372	2,391	6,711	11,540	12,022
1 in 20 Shortfall (MW)	3,215	3,246	7,893	12,525	12,968
1 in 100 Shortfall (MW)	4,817	4,774	10,351	14,065	14,662

Source: California Energy Commission staff

PSP Scenarios

The PSP based scenarios generally resulted in an LOLE below the 0.1 target, as seen in **Figure A-3**. This is an expected result, with the quantity of NQC added exceeding the shortfall capacity identified in the No Build scenario in every year. However, for the scenario with gas in place of the PSP resources using the new ELCC values, the LOLE exceeds 0.1 and has a shortfall capacity of 90 MW. This is despite building 200 MW NQC more than the shortfall identified in the No Build scenario, meaning the capacity shortfall cannot be directly translated into an NQC need. The reduction in 150 MW NQC from the PSP_(Gas) to the PSP_(Gas, R. ELCC) scenario is the only difference between the two scenarios.

Figure A-3:Loss of Load Expectation, PSP-Based Scenarios



	2022	2023	2024	2025	2026	2026+
PSP	0.0813	0.0079	0.0001	0.0018	0.0049	-
PSP_(Gas)	0.0883	0.0158	0.0093	0.0363	0.0421	0.0074
PSP_(Gas, R.ELCC)	0.1067	0.0124	0.0034	0.0104	0.0200	0.0022
PSP_(Energy)	0.0766	0.0086	0.0003	0.0018	0.0027	-

Source: California Energy Commission staff

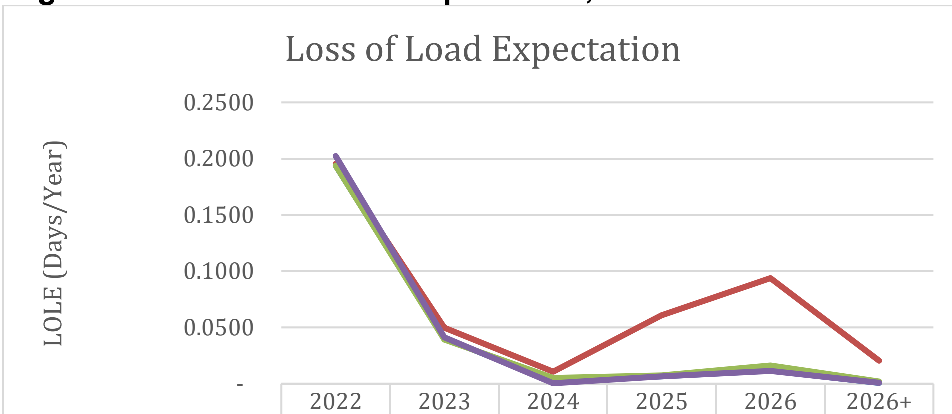
The scenarios that replace a portion of zero-emitting resources with gas resources consistently resulted in a higher LOLE, although still under the 0.1 event/year target. It is not clear if this difference is attributable to the specific technologies, the qualifying capacity methodology used to compare the resources on an NQC basis, or if adjustments to the model are necessary to better compare the resources in an equivalent manner. It is clear from these results that additions of zero-emitting resources can provide similar reliability to incremental gas additions with the same NQC values.

Additional work is needed to establish the appropriate method of modeling gas and zero-emitting resources in an equivalent manner consistent with the qualifying capacity methodology, as a truly equivalent installation of resources for reliability should provide the same LOLE. Though the shortfall capacity, duration of events, and timing of the unserved energy may differ.

Procurement Order Scenarios

Like the PSP scenarios, the LOLE for each of the Procurement Order scenarios is largely below the 0.1 day per year target. However, 2022 consistently exceeds this target as shown in **Figure A-4**. The Order_(Gas) scenarios shows a much higher LOLE in 2025 and 2026, similar to the gas-based scenarios for the PSP cases.

Figure A- 4: Loss of Load Expectation, Order Based Scenarios



	2022	2023	2024	2025	2026	2026+
Order	0.1938	0.0403	0.0019	0.0066	0.0115	0.0007
Order_(Gas)	0.1955	0.0498	0.0107	0.0610	0.0939	0.0205
Order_(R.ELCC)	0.1938	0.0391	0.0050	0.0075	0.0162	0.0019
Order_(Energy)	0.2023	0.0413	0.0004	0.0064	0.0114	0.0010

Source: California Energy Commission staff

The revised ELCC values published in September 2021 did not cause any significant increase in the LOLE, despite resulting in a resource build that is more than 1,000 MW of total nameplate less than the build for zero-emitting resources in the later years. This is because the installed capacity is sufficient that only increasingly rare combinations of demand, wind, solar, and forced outages can drive unserved energy events. While the capacity shortfall difference between events that would occur for scenarios with an LOLE near 0.1 is relatively small (1-10 MW), when the LOLE is driven closer to zero, the relative difference begins to grow by an order of magnitude. Thus, reducing the LOLE from 0.05 to 0.01 day per year requires significantly more generation capacity than reducing the LOLE from 0.1 to 0.05 day per year.

The shortfall for 2022 in the base Order scenario is 1,300 MW. This shortfall is almost exactly equal to the shortfall seen in the No Build case (2,372 MW), less the procurement ordered for 2022 (1,070 MW NQC). The capacity required to make up the shortfall was studied in more depth through a series of procurement acceleration scenarios that accelerated the deployment of resources from 2023 to 2022.

Identifying the Capacity Need to Address the 2022 Shortfall

This set of scenarios incrementally added capacity to determine the approximate NQC that would result in decreasing the LOLE to 0.1 day per year or less in 2022. The additional capacity was accelerated from the target in 2023, with the result that the total NQC for 2023 and beyond was not changed. Thus, these scenarios were only run for 2022.

Net qualifying capacity additions were increased from the baseline of 1,070 MW by a value between 1,200 MW and 2,000 MW. These additions in 2022 resulted in significant reductions in the shortfall capacity in the year, see **Table A-22**. The results for the first three capacity shift scenarios (1,200 MW to 1,400 MW) show very little difference in reliability and capacity shortfall. This suggests a larger sample size is needed to pinpoint the needed capacity additions, but these number provide a reference point.

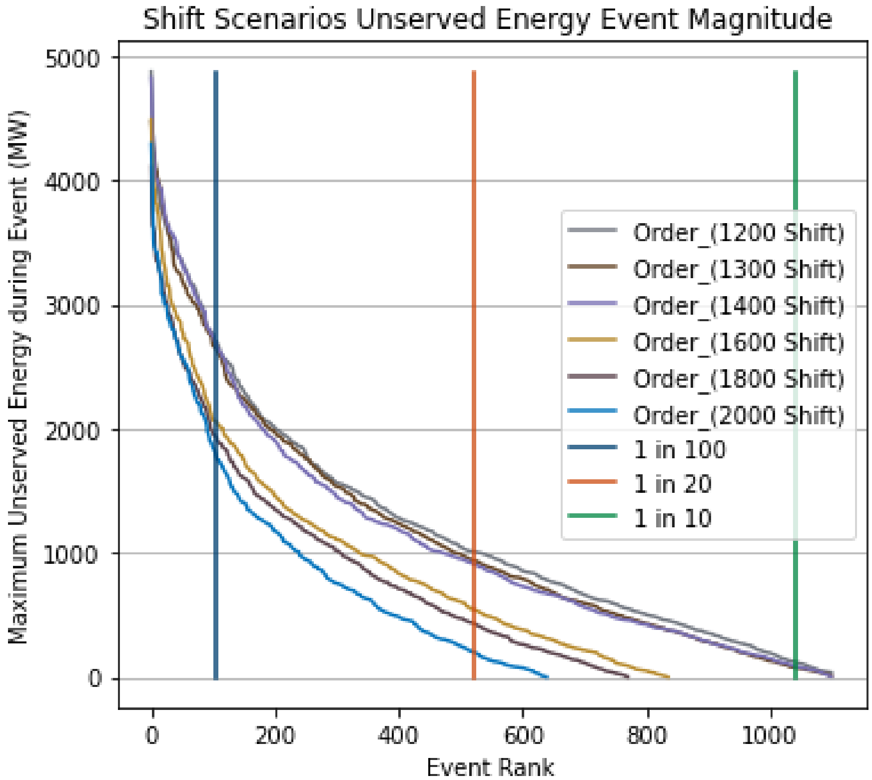
Table A-22: Results for the Capacity Shift Scenarios

-	Total Addition (MW NQC)	LOLE	1-in-10 Shortfall, 2022 (MW)
Order	1,070	0.194	1,296
Order_(1200 Shift)	2,266	0.109	122
Order_(1300 Shift)	2,366	0.106	74
Order_(1400 Shift)	2,466	0.106	89
Order_(1600 Shift)	2,666	0.082	-
Order_(1800 Shift)	2,866	0.076	-
Order_(2000 Shift)	3,066	0.063	-

Source: California Energy Commission staff

Based on the results of the six additional capacity shift runs, between 1,400 MW NQC and 1,600 MW NQC would need to be accelerated to 2022 to reduce the LOLE to below 0.1 day per year. This is similar to the additional capacity in the PSP scenarios compared to the Order scenarios for 2022.

Figure A-5: Unserved Energy Event for the Order_(Shift) Scenarios



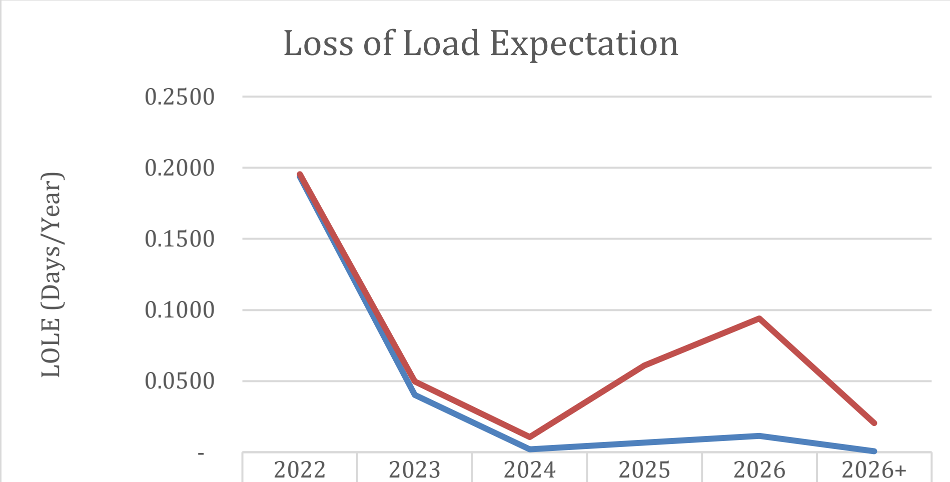
Source: California Energy Commission staff

Energy Limited Cases

The energy limited cases restricted the maximum imports to the CPUC-assumed specified and unspecified imports in all hours of the day and confined hydroelectric generation to a minimum generation level outside the hours ending 17-22. These adjustments are discussed further in the Imports section and Hydroelectric Generators section, respectively.

The results for these scenarios are very similar to the non-energy limited cases, suggesting the resource builds have sufficient energy generation during lower demand periods to sufficiently charge BESS for use during peak periods. See **Figure A-6**.

Figure A- 6: Loss of Load Expectation Comparison for Energy Limited Cases



	2022	2023	2024	2025	2026	2026+
Order	0.1938	0.0403	0.0019	0.0066	0.0115	0.0007
Order_(Gas)	0.1955	0.0498	0.0107	0.0610	0.0939	0.0205

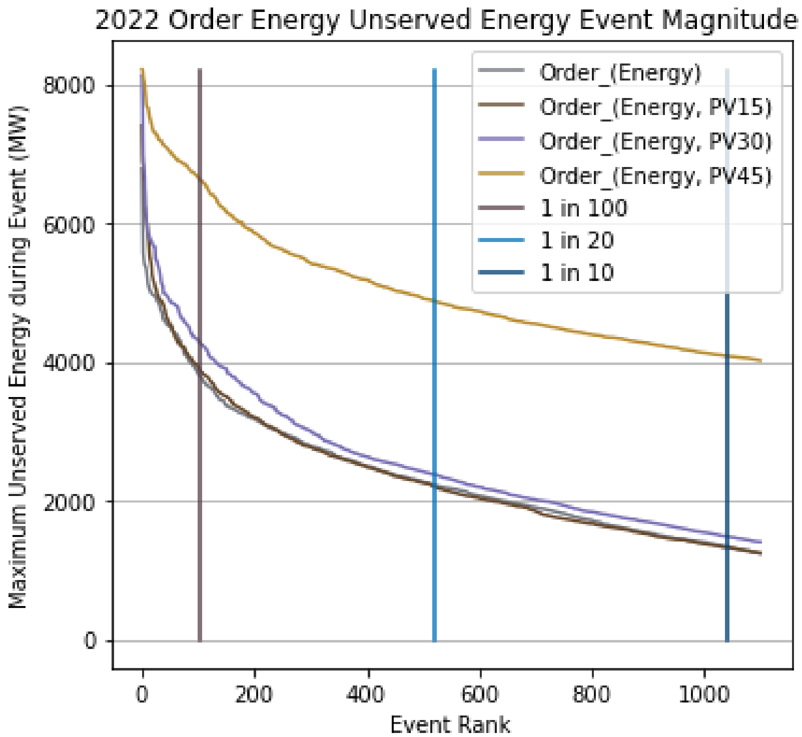
Source: California Energy Commission staff

The 1 day in 10 year capacity shortfalls for the Order_(Energy) scenario in 2022 exceeded the shortfall for the Order scenario by 40 MW. A similar increase in the capacity shortfall was observed for the 1 day in 20 year and 1 day in 100 year shortfalls in 2022, and in 2023 and 2026 for the 1 in 100 shortfalls. All other years did not have LOLEs high enough to produce even a 1 in 100 shortfall.

Solar Output Reductions

Applying further energy limitations beyond the import and hydro limitations, by reducing the total output of solar facilities by 15 percent had a negligible effect in 2022, shown in **Figure A-7**. Reducing the solar output by 30 percent is noticeable, but not a significant increase in the LOLE or shortfall capacity. However, reducing solar output by 45 percent increases the LOLE by 2.5 times and nearly triples the 1 in 10 shortfall capacity compared to the base case.

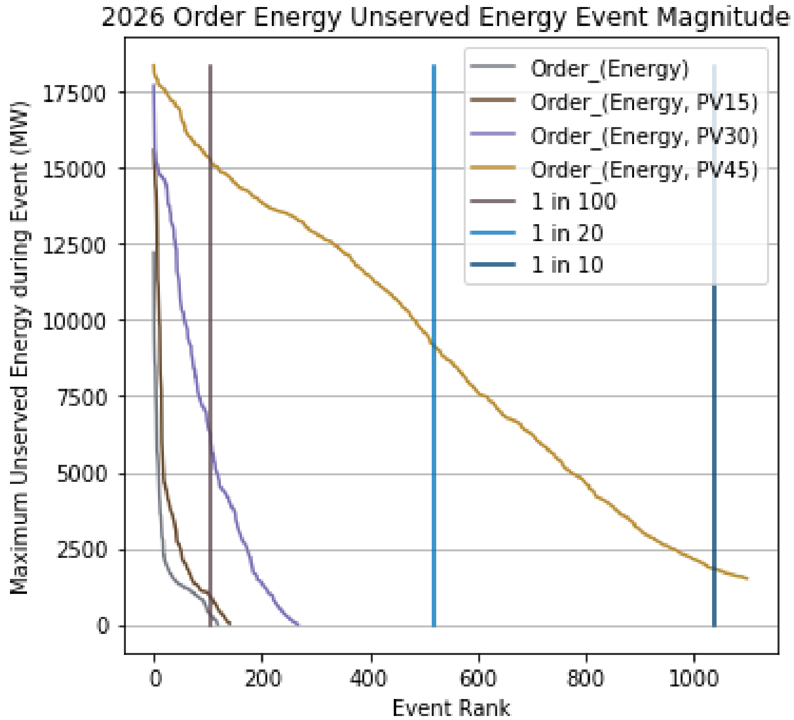
Figure A-7: 2022 Unserved Energy Event for the Order_(Energy) Scenarios with Decreasing Solar Production



Source: California Energy Commission staff

The impacts become more pronounced in 2026, shown in **Figure A-8**.The 15 percent solar reduction case shows a minor, but noticeable, increase in LOLE. The 30 percent reduction case more than doubles the LOLE compared to the base case, though it is still well below the 0.1 day per year LOLE target. Finally, the 45 percent solar reduction case represents an increase in the LOLE in excess of 14 times the case without a reduction in solar, Order_(Energy), for 2026.

Figure A- 8: 2026 Unserved Energy Event for the Order_(Energy) Scenarios with Decreasing Solar Production

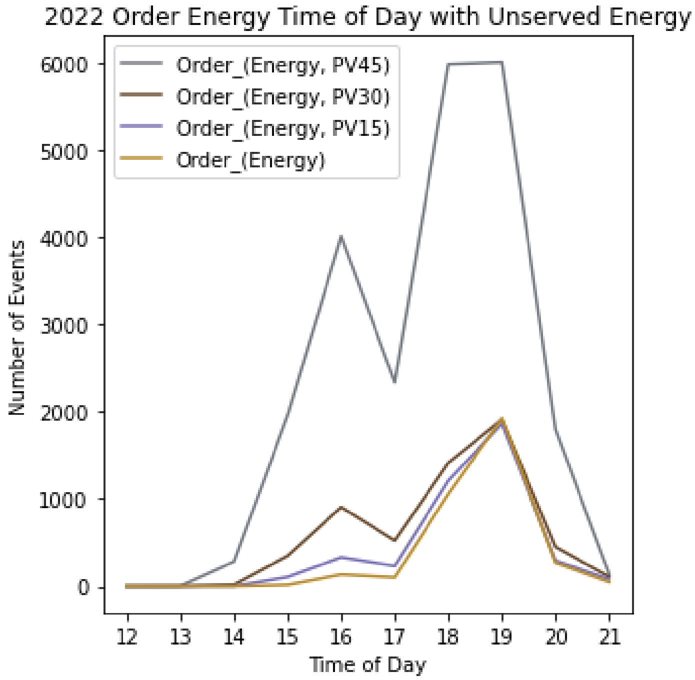


Source: California Energy Commission staff

These solar scenarios show the exponential relationship that reliability has with energy sufficiency, at least for when energy production is reduced from solar resources. Reliability starts off as being relatively unchanged by reductions in total energy availability. However, once energy limits begin to impact reliability, small reductions in energy available to the system can have significant impacts on reliability.

Some of the increases in unserved energy occur outside of the traditional peak period of HE 17-22 in these scenarios. The decreased output from solar facilities results in outage events as early as noon, but with a local peak at HE 16 (3-4 pm PST), see **Figure A-** 9. The abrupt decrease in the number of unserved energy events at HE 17 is attributable to increased hydroelectric output for these scenarios between the HE 17 and 22. See subsections Hydroelectric Generators and Import and Hydro Limits in the section above.

Figure A- 9: Number of Unserved Energy Events by Time of Day, 2022

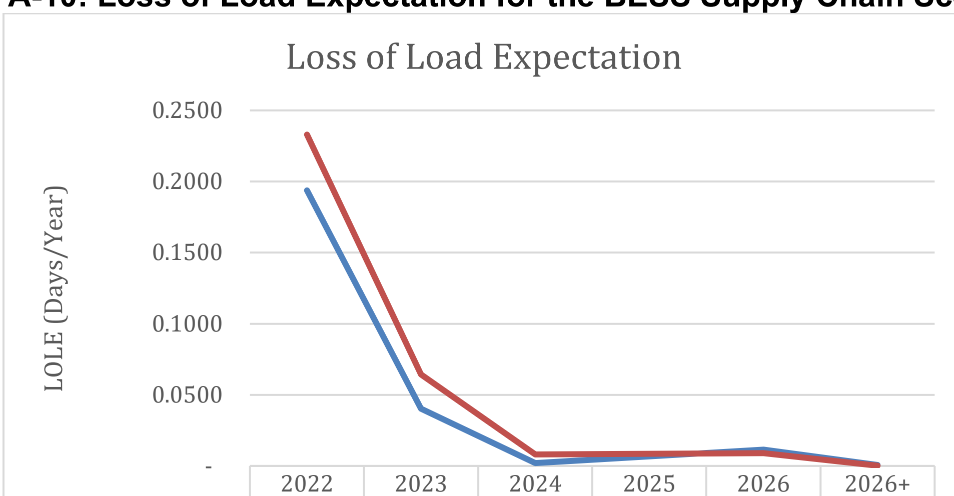


Source: California Energy Commission staff

BESS Supply Chain Delays

A one-year delay of 20 percent of new 4-hour energy storage resources did not have a material effect on the reliability of the system, as shown in **Figure A-10**. Basing the resource build on either the marginal ELCC values from the Reliability Need Determination Model or the ELCC Values released in September 2021 for D.21-06-035 had little effect on the results.

Figure A-10: Loss of Load Expectation for the BESS Supply Chain Scenarios



	2022	2023	2024	2025	2026	2026+
Order	0.1938	0.0403	0.0019	0.0066	0.0115	0.0007
Order_(B20)	0.2330	0.0643	0.0082	0.0087	0.0089	0.0002

Source: California Energy Commission staff

In 2022, the only year with an LOLE exceeding 0.1 day per year, the approximately 330 MW of delayed energy storage results in an increase in the 1 day in 10 year shortfall by 389 MW in the Order_(B20). This increase in the shortfall capacity corresponding with a similar reduction in energy storage capacity is consistent with expectations. However, this pattern is not consistently maintained for the 1 day in 20 year and 1 day in 100 year shortfalls, likely due the more sensitive nature of those values to random draws in the model.

Conclusions

This CRO outlook of CAISO footprint was designed to answer the following four questions and the section is organized accordingly:

1. Is additional capacity needed beyond the current procurement orders by CPUC to meet the system planning reliability standards for CAISO footprint?
2. Does incremental thermal capacity provide additional system reliability compared to the portfolio of zero-emitting resources of equivalent NQC?
3. Is there sufficient energy to charge battery energy storage systems (BESS) under the expected resource build?
4. What are the potential reliability impacts of potential supply chain delays that impact BESS?

On Need for Additional Capacity:

Modeling suggests that the current CPUC's procurement orders result in a reliable system, with a loss of load expectation at, or below, one outage event in every ten years, over the CPUC's MTR procurement period - beginning 2023 through 2026. However, the LOLE for 2022 exceeds the desired one event in ten years reliability metric. For 2022, the ordered procurement results in a capacity shortfall of about 1,300 MW. Modeling suggests that an estimated 1,400-1,600 MW NQC of additional capacity is needed to reduce the LOLE to 0.1 day per year and eliminate the shortfall. **Table A-23** illustrates the anticipated shortfall, had no procurement been ordered, compared to anticipated procurement and the proposed PSP.

Table A-23: No Build Shortfall Capacity Compared to NQC Additions

(MW)	2022	2023	2024	2025	2026	2026+
No Build Shortfall	2,372	2,391	6,711	11,540	12,022	12,022
Cumulative Ordered NQC	1,070	3,505	9,505	11,005	11,005	13,005
PSP NQC	2,753	4,916	9,907	11,712	12,012	14,012
PSP NQC, with September 2021 ELCC Values	2,603	4,970	10,778	12,879	13,128	15,128

Source: California Energy Commission staff

On Reliability Impacts of Incremental Thermal Capacity

Thermal capacity was also determined to meet system reliability, as the zero-emitting resource portfolio did. While both portfolios meet reliability standards, it is important to recognize the accounting methodology differences for determining the NQC of different resource technologies. The scenarios with an equivalent NQC replacement of the new zero-emitting resources with thermal capacity, while meeting the desired LOLE target of less than 0.1 day per year, resulted in a slightly higher LOLE compared to those with zero-emitting resources assumed to meet the procurement order. Additional work is needed determine if this performance difference is attributable to the specific technologies, the qualifying capacity methodology used to compare the resources on an NQC basis, or if adjustments to the model are necessary to better compare the resources in an equivalent manner. These scenarios illuminate that many technology types can support system reliability, should there be enough capacity procured. These scenarios do not indicate that a portfolio consisting of zero-emitting or thermal resources are in and of themselves inherently less reliable. Additional analysis may also be required to determine if additional operational constraints should be considered when comparing technologies.

On Energy Sufficiency Relating to BESS Charging Needs:

Modeling indicates that the anticipated resource additions can be reasonably expected to supply sufficient energy to meet the needs for the system. This study showed that limiting imports to the CPUC-assumed specified and unspecified imports in all hours of the day, along with restricting hydroelectric generation to the NQC values between the hours of 4 pm and 10 pm (PST) and to minimum generation levels outside of these hours does not meaningfully impact the reliability of the system.

Further limiting energy available by reducing the total output of all the installed solar by up to 30 percent in all hours of the period had only minor impacts on reliability. This reduction increased the shortfall in 2022 by less than 200 MW, but not resulting in even a 1 day in 100 year shortfall in 2026.

On BESS Supply Chain Concerns for Reliability:

The study results suggest that the reliability impacts of supply chain delays for BESS will impact reliability, but not move any scenarios from an LOLE below 0.1 day per year to an LOLE above 0.1 day per year. An annual supply chain delay that shifts 20% of the installed BESS in each year to the following year results in increased shortfalls of between 300 and 400 MW in 2022. This would be a 20-30 percent increase in the 1 day in 10 year shortfall capacity. After 2022, these delays do not result in the LOLE exceeding 0.1 day per year for the scenarios studied.

As noted above, the current resource procurement path for the state appears to be sufficient to support a 1 day in 10-year LOLE target, with the exception of 2022, which requires additional resources. The reliance of non-emitting resources does not appear to adversely impact reliability compared to procuring thermal resources. As a result, the clean energy path for the state should not affect system reliability over the period of this study. Lastly, it appears that increasing reliance on energy storage at levels proposed does not appear to have an impact on system reliability. Staff completed only a limited analysis of supply chain impacts and while modest supply chain impacts do not appear to substantially impact reliability, the state needs to continue to monitor and evaluate energy storage deployment and its impact on reliability.

This analysis is the result of the development of a new approach to informing procurement decisions. The CEC created the model in 2021, improved it with input from the CPUC and public stakeholders and will continue to improve the model and to generate analyses like this one each year for a reliability outlook. CEC looks forward to additional input to improve this analysis to inform decision making.

APPENDIX B: Electric System Reliability and the Recent Role of California's Fossil Fleet

In 2020, two extreme heat events, or heat waves, impacted the western United States. During the first heat wave on August 14 and 15, 2020, the California Independent System Operator (California ISO) was forced to institute rotating electricity outages in California. After this, state agencies implemented emergency measures that avoided further electric system outages in the California ISO system as experienced during the second heat wave beginning on September 3, 2020, Governor Gavin Newsom then directed the CEC, CPUC, and the California ISO, to report on the root causes of the events leading to the outages. The three agencies were further directed to take actions to identify potential additional generation supplies that could be available in summer 2021 to help avoid future rotating electricity outages.

The Final Root Cause Analysis report (final analysis) was published on January 13, 2021. The final analysis identified three major causal factors that contributed to the summer 2020 outages: (1) extreme weather conditions, (2) inadequate resource adequacy and planning processes, and (3) market practices.

As a result of the Governor's directive and the subsequent release of the final analysis, the CEC's Siting, Transmission and Environmental Protection Division took several actions to address the performance of resources credited to resource adequacy requirements by the CEC-jurisdictional power plant fleet, identify potential additional generation in preparation for 2021 summer heat waves, and avoid rotating electricity outages. These actions include the following:

1. Hosted a December 2020 Lead Commission workshop titled "Incremental Efficiency Improvements to the Natural Gas Powerplant Fleet for Electric System Reliability and Resiliency" (Docket 20-SIT-01) that included stakeholder presentations and discussion on a range of options for incremental upgrades at existing geothermal, solar thermal, and natural gas-fired facilities to increase capacities.
2. Reviewed and approved efficiency and post certification project change petition improvements between March and June 2021 to increase capacity totaling an additional 136 megawatts (MW). These petitions were filed by project owners and operators in response to the CPUC's Rulemaking Order 20-11-003, which directed California's three large electric investor-owned utilities to seek contracts for additional power.
3. Requested all 76 CEC-jurisdictional power plant owners and operators to report to the CEC any unplanned incident that limits generating capacity, or the operations are impaired and cannot meet their commitment to the California ISO. Throughout summer 2021, jurisdictional facilities that experienced operational impairments or shutdowns immediately emailed CEC staff.

4. Conducted a July 2021 survey of the CEC-jurisdictional fleet to identify types of projects that could be expedited, including efficiency upgrades, battery energy storage system expansions, and opportunities to locate temporary power generator units at existing natural gas-fired facilities.
5. Identified reasons for power plant owners withdrawing project change petitions that could have provided additional generation potential in support of the grid during summer 2021 heat waves.
6. Participated in an August 30, 2021, workshop to summarize the reliability issues and provide an update on steps taken to address these issues.
7. Developed procedures to expedite post certification petitions at existing facilities, license temporary power generators of 10 MW or more, and license battery storage systems of 20 MW or more that can discharge for at least two hours in response to the Governor's July 30, 2021 Emergency Proclamation.

As shown in Figure B-1, CEC staff was able to work with power plant owners and operators to identify and implement near-term physical improvements to add between 236 and 286 MWs of net qualifying capacity at existing jurisdictional facilities, and another 120 MW in proposed temporary power generators to support summer reliability in 2021 and beyond. The CEC staff also provided consultation with California ISO and the California Air Resources Board (CARB) to inform the Department of Energy (DOE) which facilities would require a Title V waiver under their Emergency Order pursuant to section 202(c) of the Federal Power Act.

Figure B-1: Net Qualifying Capacity Resulting from CEC Actions Since November 2020

NET QUALIFYING CAPACITY SINCE NOVEMBER 2020

TYPE OF PROJECTS	ACTION TAKEN	APPROVAL TIMELINE	ADDITIONAL GENERATION CAPACITY
Efficiency Upgrades	Staff-level Project Change Petition Process	March – June 2021 (45-90-day process)	89 MW
Equipment Upgrades	Business Meeting Petition Process	March – June 2021 (45-90-day process)	47 MW
Temporary Power Generator	Temporary Power Generator Licensing Process	August - September 2021 (10-day process)	120 MW
Governor's Emergency Proclamation and DOE 202 (c) Waiver	Expedited Facility Changes Petition Process	August – October 2021 (10-day process)	100-150 MW

Source: California Energy Commission staff

This report details the CEC's coordination with power plant owners and operators and actions taken to address imminent supply shortages for summer 2021. The report also addresses next steps to ensure electricity reliability and the potential role that the existing thermal fleet will play in the midterm to long term.

Recent Heat Events and System Reliability Problems in California

A significant portion of California's in-state electricity generation comes from combustion turbine-based capacity, or otherwise known as thermal capacity. Thermal capacity is operated at less than its rated maximum capability or derated, during hot, dry conditions associated with extreme heat waves. The multistate drought conditions have also reduced hydropower availability throughout the West. Together, the drought and extreme heat conditions increase the threat and severity of wildfires in California and the western United States. Wildfires can also impact system reliability — smoke from fires decreases solar output, and energy imports are reduced when transmission lines are threatened, derated, or even shutdown because of wildfire.

During August and September 2020, California and the western United States experienced unprecedented heat waves and storms. At the same time, several wildfires raged across California and the western United States, and electricity demand exceeded supply. The heat and wildfires significantly impacted electrical energy generation and transmission. The extensive heat stressed several natural gas power plant subsystems, resulting in power loss in combustion turbines, inlet air and cooling system stresses, steam tube leaks, and condenser pump failures. Smoke from wildfires also decreased solar facility output.

On August 14, 2020, California ISO issued a Stage 3 emergency notice[24] because of a lack of sufficient operating reserves due to several factors. The lack of operating reserves triggered rotating outages to maintain grid stability and avoid a more widespread electrical grid shutdown. As a result, investor-owned utilities (Pacific Gas and Electric Company [PG&E], Southern California Edison [SCE], and San Diego Gas & Electric Company [SDG&E]) in the California ISO-controlled grid experienced their first rotating outages in 20 years. On August 15, 2020, California ISO issued another Stage 3 emergency notice. Ambient temperatures were 10 to 25 degrees Fahrenheit above normal. This situation was described as a "1-in-35-year event," which far exceeded the 1-in-10-year planning horizon used for power plant system reliability studies.

As a direct result of these two events, on August 16, 2020, Governor Newsom issued an emergency proclamation[25] to free up additional capacity and allow use of backup energy sources. This proclamation led to energy conservation measures and support from power plant operators and balancing authorities other than California ISO, which helped avoid additional outages on the following days.

24 California ISO Stage 3 Emergency Notice, August 14, 2020,

http://www.caiso.com/Documents/Stage-3-Emergency-Declared-Rotating-Power-Outages-Initiated-Maintain-Grid-Stability.pdf.

25 August 16, 2020, Proclamation of a State of Emergency

https://www.gov.ca.gov/wp-content/uploads/2020/08/8.16.20-Extreme-Heat-Event-proclamation.pdf.

On August 17, 2020, because of the intensifying heat wave, Governor Newsom issued Executive Order N-74-20[26] and ordered the suspension of permitting requirements or conditions adopted by CEC and local air quality management districts that restricted the amount of power a facility may generate or dule that a facility may use, or impose air quality requirements that prevent the facility from generating additional power during peak demand hours. The order required any facility that operated under this emergency order to report to the CEC, CARB, and the local air district.

On September 3, 2020, Governor Newsom extended the emergency proclamation through midnight September 8. In addition, the California ISO issued a statewide Flex Alert beginning September 5 through September 7 for voluntary load reductions each day from 3 p.m. to 9 p.m. warning that consumers should "be prepared for potential power outages, both planned and unplanned during extreme heat events."[27]

On September 5, 2020, California ISO directed all generating facilities in its balancing authority area to produce the maximum capability during certain times of the day, because the electric grid lost nearly 1,600 MW of generation as a result of wildfires forcing transmission lines out of service. In response to California ISO's directive, some generators indicated that they could not produce maximum generation capability without exceeding federal air quality or other permit limitations.

On September 6, 2020, California ISO requested the Secretary of Energy concur and declare that the State of California is in the middle of an electric reliability emergency pursuant to section 202(c) of the Federal Power Act.[28] In response, DOE issued Order N. 202-20-2 "to preserve the reliability of bulk electric power system."[29]

Dispatchable Generation Is Integral to a Reliable System

During normal operations, electricity system balancing authorities must maintain an instantaneous balance between supply and demand. Dispatchable power plants can start up quickly, oftentimes in as short an amount of time as 10 minutes, and they can also ramp up and down quickly to balance supply and demand. Natural gas and hydroelectric power plants provide the bulk of the dispatchable power generation for California. By late summer or during drought conditions, hydroelectric power plant capacities are significantly diminished, leaving natural gas power plants as the primary dispatchable resource. For example, on August 5, 2021, the Edward Hyatt Hydroelectric Power Plant at Lake Oroville experienced its first unplanned outage since the facility began operating in 1967.

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26 August 17, 2020, Executive Order N-74-20

https://www.gov.ca.gov/wp-content/uploads/2020/08/8.17.20-EO-N-74-20.pdf.

27 September 3, 2020 State-wide Flex Alert

http://www.caiso.com/Documents/FlexAlertIssued-WeekendCalling-EnergyConservation.pdf.

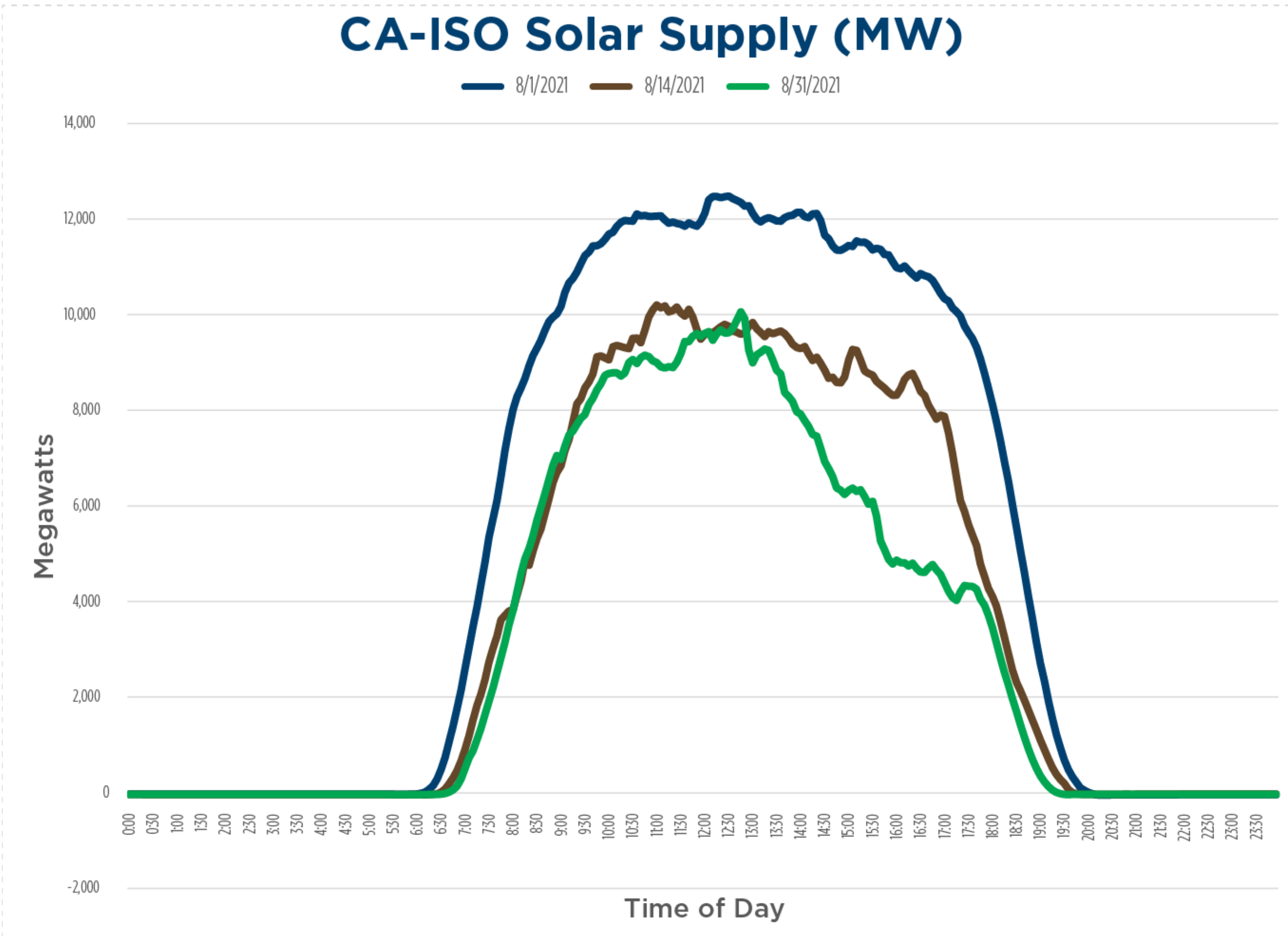
28 September 6, 2020 California ISO emergency request to DOE

http://www.caiso.com/documents/Order-202-20-2-9-6-5p.pdf.

29 September 6, 2020 DOE Order 202-20-2
https://www.energy.gov/sites/prod/files/2020/09/f78/CAISO%20202c%20Request%20Letter.PDF.

Stored renewable energy, while desirable and capable of providing some amount of dispatchable power, currently is not available in significant quantities or for long-enough duration to meet the need. For example, at 8 p.m. August 1, 2021, in the California ISO, natural gas power plants provided 18,230 MW of power, while battery storage provided only 947 MW. Furthermore, new mechanisms developed by the CPUC are available to encourage or require certain loads to leave the grid, thereby reducing immediate demand.

Figure B-2: Solar Output in California ISO on August 1, 14, and 31, 2021

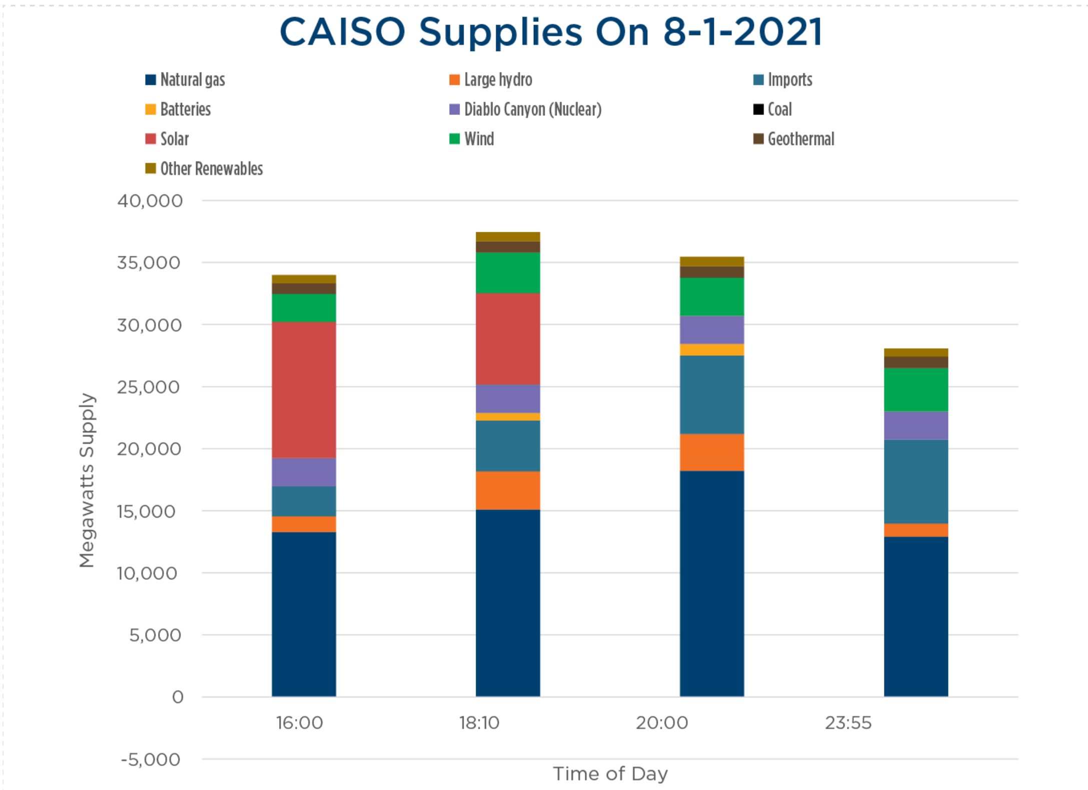


Source: California Independent System Operator staff

During energy shortfalls, dispatchable generation and load shedding are used to help provide this balance and firming the electricity system. During any typical late afternoon, even without heat waves or smoke from forest fires, solar power is not fully available because the sun is not as high in the sky as midday. Figure B-2 shows solar production in California ISO supplies on August 1 (blue line), August 14 (brown line), and August 31 (green line) of 2021. Facility operators have confirmed that cloudy or smoky skies reduce solar production as shown in Figure B-2 for August 14 and 31.

Next, in Figure B-3, an example of how the resource mix on the California ISO system changed as the solar component of supply declined on August 1, 2021. As the solar supply (yellow bar) diminished between 4 p.m. (16:00) and 8 p.m. (20:00), natural gas (darker blue), large hydro (red orange) and imports (grey) all increased to offset the reduction in solar power. Note the minor contribution from batteries (lighter orange) bar. Furthermore, the nuclear supply (lighter blue bar) will be lost as the Diablo Canyon Nuclear Power plant is retired in 2023 (1,100 MW) and 2024 (another 1,100 MW).

Figure B-3: California ISO Changing Resource Mix as Solar Generation Declined on August 1, 2021



Source: California Independent System Operator staff

Joint Energy Agency Root Cause Analysis

On January 13, 2021, the CEC, CPUC, and California ISO published a Final Root Cause Analysis Report describing the rotating outages that occurred on August 14 and 15, 2020, and a summary of actions each agency planned to undertake to avoid recurrence. The three agencies took responsibility for the outages and stated their joint intent to take actions to minimize or eliminate the probability of recurrence. While the agencies concluded there was no single cause of the August outages, they found that the three major causal factors that contributed to the outages were (1) extreme weather conditions, (2) resource adequacy and planning processes, and (3) market practices. Each agency stated its intent to work cooperatively to address these issues.

The Final Root Cause Analysis report provided recommendations to all three agencies addressing immediate, near-, and longer-term improvements to resource planning, procurement, and market practices, and stated that many of these improvements are already underway. These actions are intended to ensure that California's transition to a reliable, clean, and affordable energy system is sustained and accelerated.

In the Final Root Cause Analysis Report, the CEC stated its intent to work in the near term with the CPUC and California ISO as follows:

1. The California ISO and CEC will coordinate with non-CPUC-jurisdictional entities to encourage additional necessary procurement by such entities.
2. The CEC will conduct probabilistic studies that evaluate the loss of load expectation on the California system to determine the amount of capacity that needs to be installed to meet the desired service reliability targets.
3. The California ISO, CPUC, and CEC will enhance the efficacy of Flex Alerts to maximize consumer conservation and other demand-side efforts during heat waves.
4. Preparations by the California ISO, CPUC, and CEC are underway to improve advance coordination for contingencies, including communication protocols and development of a contingency plan.

In the midterm, the CEC stated its intent to work with the CPUC and California ISO as follows:

1. Developing planning and operational improvements for the performance of different resource types (such as batteries, imports, demand response, and so forth).
2. Making improvements to accelerate the deployment and integration of demand side resources
3. Considering generation and transmission buildouts to evaluate options and constraints under the SB 100 scenarios.

This midterm planning will also account for the pending retirements of some existing natural gas units and the Diablo Canyon nuclear power plant.

For the longer term, 2025 and beyond, the California ISO, CPUC, and CEC expect to work closely together with each other and with other regional stakeholders to establish a modernized, integrated approach to forecasting, resource planning, and resource adequacy targets.

Incremental Efficiency Power Plant Improvements Workshop

On December 2, 2020, the CEC's STEP Division hosted a Lead Commissioner public workshop titled "Incremental Efficiency Improvements to the Natural Gas Powerplant Fleet for Electric System Reliability and Resiliency." The workshop explored technology options to increase the efficiency and flexibility of the existing natural gas power plant fleet to increase California electric system reliability and provide insurance against extreme weather, fire, or climate-related events while helping smooth the transition to Senate Bill (SB) 100 goals.

Workshop participants and attendants represented a broad range of stakeholders, including investor-owned and publicly owned utilities, community choice aggregators, independent energy suppliers, power plant owners and operators, local governments, regional air districts, Disadvantaged Communities Advisory Group members, and CPUC and California ISO staff. The workshop included three expert panel discussions. The first two panels focused on technology improvements and process modifications to increase the efficiency of California's power plant fleet for electric system reliability and resiliency, and the third panel focused on finance and governance, exploring how the incremental improvements identified in earlier panels could be procured.

Vendors and owners identified and presented information on potential incremental changes specific to natural gas power plants. These changes include the potential for increased generation through project change improvements to increase peak output and reduce start times from existing equipment; and, software technology upgrades to improve ramp rate, turndown, and overall efficiency of the combustion turbines. Panelists also explained that coupling energy storage with combustion turbine modifications would also support increased flexibility and potentially reduce the number of natural gas facilities operating during peak demand times. However, panelists indicated that equipment and software lead times were long, and some upgrades would require extensive planning and design, as well as downtime for installation. Thus, timing for plants modifications could also become an issue if not planned appropriately.

The second panel included industry representatives and regulatory agencies. They expressed concerns with the existing regulatory processes and timelines in place. They noted these different local, state, and federal agencies timelines could make it difficult to realize these efficiency improvements ahead of summer 2021. Even if incremental improvements were authorized by the CPUC, reopening, and modifying existing project permits could be more timely than new construction or permitting processes. While the CEC has already implemented process improvements to facilitate project change petitions, several air districts indicated that their regulatory processes and required comment periods can be lengthy. The air districts encouraged project owners to do outreach early, define clear project descriptions, and request expedited review when necessary.

The third panel, which included the CPUC, investor-owned utilities, and the Sierra Club, focused on the feasibility of different procurement options given the near-term time frames under consideration and whether and how this procurement should occur. The CPUC discussed the recent Order Instituting Rulemaking (OIR) 20-11-003, for Summer 2021 Reliability, which is intended to increase energy supply or decrease demand during peak and net peak hours. Panelists discussed the need to address new peak and dispatchable generation, the need for clear procurement communications, and concerns over regulatory uncertainty and the impact to market stability. Panelists also discussed the retirements of once-through-cooling plants, natural gas-fired facilities, and the Diablo Canyon nuclear facility, and the associated initial impact on system reliability as the state's generation resource mix continues to change, including the addition of more renewable generation that is variable. Participants also expressed concerns over ongoing air quality impacts in disadvantaged communities.

Improvements to Energy Commission Licensed Facilities

Energy Commission Jurisdiction

The CEC has jurisdiction and permitting authority for thermal power plants 50 MW and greater in California. This jurisdiction also includes infrastructure associated with thermal power plants, including electric transmission lines, natural gas lines, and water pipelines. The CEC's permitting process ensures that proposed thermal power plants are designed, constructed, and operated in a manner that protects public health and safety, promotes the general welfare, and preserves environmental quality. The process is the functional equivalent of a California Environmental Quality Act review and includes coordination with local, state, and federal agencies to ensure that these agencies' permit requirements are incorporated. Currently, there are 76 power plants under CEC license, totaling roughly 26,600 MW. Of these, 63 are fueled by natural gas, totaling 24,044 MW.

Project Change Improvements Submitted and Withdrawn

In February 2021, in response to the CPUC's Rulemaking Order 20-11-003 directing California's three large electric investor-owned to seek contracts for additional supply-side capacity, the investor-owned utilities filed advice letters with the CPUC seeking contract approvals for 564 MW of additional generation for summer 2021. As a result, owners and operators of more than a dozen CEC-jurisdictional power plants submitted project change petitions to modify their conditions of certification in anticipation of securing procurement contracts.

The CPUC approved these contracts on March 18, 2021. Power plant owners that did not receive contracts withdrew their CEC project change petitions. An additional potential 100 MW of generation could have been available to support summer 2021 reliability; however, power plant owners were reluctant to make new investments without a CPUC procurement contract.

Project Change Improvements

STEP staff reviewed the remaining project change petitions following Title 20, California Code of Regulations, section 1769 regarding post certification amendments and changes to ensure that these project changes were consistent with all applicable laws, ordinances, regulations, and standards and would not result in significant impacts to the environment or to local communities.

STEP staff approved eight projects totaling an additional 136 MW to support electric grid reliability for summer 2021. More than 90 percent of these approved project are outside designated disadvantaged communities. These projects and modifications are discussed below, and Figure B-4 shows the locations.

Figure B-4: Jurisdictional Facility MW Capacity Upgrades for Summer 2021
Jurisdictional Facility MW Capacity Upgrades for Summer 2021

Source: California Energy Commission staff

Each upgrade is summarized as follows:

The Marsh Landing Generating Station is a nominal 760 MW simple-cycle project in Contra Costa County. The project owner, NRG Marsh Landing, LLC, has been approved to install an 11.5 MW Battery Energy Storage System (BESS) capacity through modifying the design, technology, and battery chemistry of the system using a lithium ferrous phosphate battery chemistry for improved reliability and capacity requirements. The BESS is also designed to restart the power plant gas turbines to support California ISO's directed restoration of the electricity grid in response to an emergency condition, also known as a "black start" capability.

The Pastoria Energy Facility is a nominal 750 MW combined-cycle project in southeastern Kern County. The project owner, Calpine, increased output by 10 MW by making a software improvement that will allow the project to increase firing temperatures in order to increase the output efficiency. Firing temperatures will be increased only when additional MWs are needed to meet peak demand. Pastoria was one of the first projects to upgrade hot gas components to improve performance in 2012.

The Palomar Energy Project is a nominal 565 MW combined-cycle project in north San Diego County. The Palomar Energy Project owner, San Diego Gas & Electric, increased output by 22 MW by upgrading with advanced gas path technology.

The Roseville Energy Park is a nominal 160 MW combined-cycle power plant owned by the City of Roseville. It recently increased output by 5 MW by installing a comprehensive combustion turbine upgrade to the natural gas-fired turbines and a control software system upgrade. This reduced the turbine heat rate, which allows for an increase in capacity from the same amount of fuel.

The Otay Mesa Energy Center is a nominal 600 MW combined-cycle project owned by Calpine Corporation. The project increased output by 10 MW by upgrading the control logic systems on the natural gas-fired turbines to allow for increased firing temperatures, if needed.

The Metcalf Energy Center is a nominal 605 MW combined-cycle project in Santa Clara County. The project owner, Calpine, increased output by 30 MW through equipment and software upgrades that reduce the turbine heat rate, which allows the project to generate more power from the same amount of fuel.

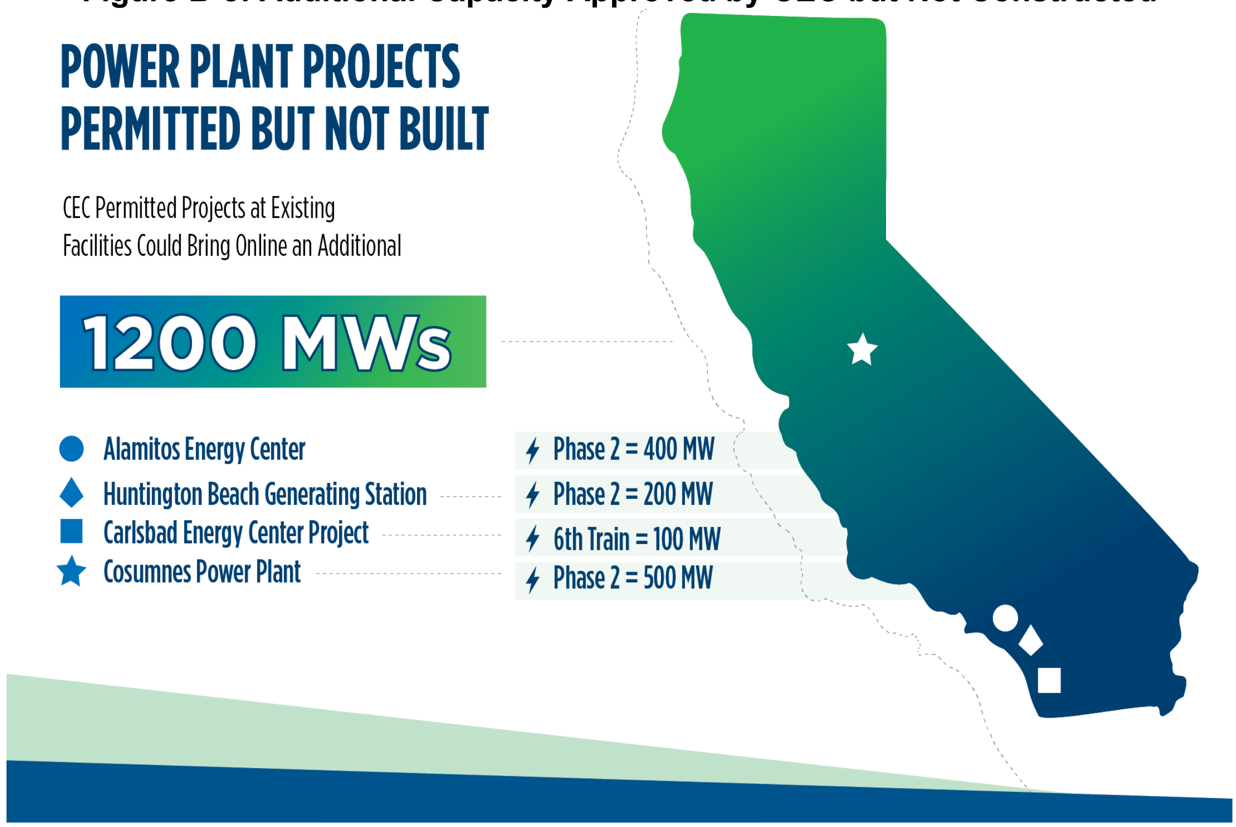
The Walnut Creek Energy Park is a nominal 500 MW simple-cycle (peaking) project. The project owner, Clearway Energy, increased project output by 17.4 MW through dual amendments with CEC and the South Coast AQMD for Units 1–5. The increased output is tied to increased fuel input and ammonia flow rate to the selective catalytic reduction emission control system.

The El Segundo Energy Center is a nominal 560 MW combined-cycle plant using the fast-start, air-cooled Siemens SGT6-5000 F package. The project owner, Clearway, increased output by 30 MW by upgrading combustion turbine logic controls enabling the power plant to increase the fuel input.

Additional Capacity Approved by CEC but Not Yet Built

The CEC has approved additional units that could be built at several existing CEC jurisdictional facilities. The additional units have not been constructed, as the owners of the plants do not have contracts to for the additional capacity. Figure B-5 shows these facilities and locations, and the text below summarizes them.

Figure B-5: Additional Capacity Approved by CEC but Not Constructed



Source: California Energy Commission staff

The Alamitos Energy Center (AES Alamitos Energy Center) was proposed as a nominal 1,040 MW, natural-gas-fired, combined-cycle and simple-cycle, air-cooled electrical generating facility consisting of two power blocks. Both blocks were approved by CEC on April 12, 2017. Block 1 is a two-on-one combined-cycle facility with a total generating capacity of 640 MW, which began commercial operation in February 2021. Block 2 was proposed as four natural gas-fired simple cycle turbines with a generating capacity of 400 MW, but it has not been constructed.

The originally permitted Huntington Beach Energy Project (HBEP) was a natural-gas fired, combined-cycle, air-cooled, 939 MW electrical generating plant to replace the former Huntington Beach Generating Station. As licensed, HBEP would have consisted of two independently operating, three-on-one, combined-cycle gas turbine power blocks. On April 1, 2017, an amendment to the decision was approved that changed the project to an 844 MW power plant to be constructed in two phases. Phase 1, which began commercial operation on June 25, 2020, consists of two natural-gas-fired combustion turbine generators in a combined-cycle configuration to produce a nominal 644 MW. Phase 2, which has not been constructed, would add two GE simple-cycle gas turbines with a nominal capacity of 200 MW.

The Carlsbad Energy Center (NRG Energy, Inc) was proposed as a plant consisting of six simple-cycle turbines totaling 600 MW. The project was approved by the CEC on July 30, 2015, and five of the six turbines entered commercial operation by December 2019. Only five combustion turbine generators (CTGs) with a total net output capacity of about 527 MW have been constructed. The sixth train would add nearly 100 MW, but it has not been constructed.

The Cosumnes Power Plant was licensed September 9, 2003. It was originally proposed as a two-phase, 1,000 MW project with each phase consisting of two combined-cycle combustion turbines, one condensing steam turbine, and two heat recovery steam generators with a capacity of 500 MW. Only one phase was approved for construction and became operational February 24, 2006. In 2018, installation of advanced gas path components was approved to increase the total output by nearly 70 MW. The second 500 MW phase of the project can only be constructed if the project owner files a new Application for Certification with review being limited to Air Quality, Water Resources, and Transmission System Engineering unless any circumstances identified in the CEQA guidelines, section 15162(a)(1)-(3) have changed.

Additional Outreach

Communication with Jurisdictional Power Plants

With the likelihood that California would face possible heat waves in 2021, communication with power plant owners and operators is critical. Unlike California ISO's curtailment and nonoperational balancing authorities' reporting requirements and the CPUC's Power Plant Outage Reporting portal requirements, the CEC does not have the statutory authority to require jurisdictional facilities to report real-time unplanned or forced outages. CEC staff worked with power plant owners and operators to coordinate and implement, as necessary, measures to enable additional generating capacity during high summer demand.

CEC staff developed new protocols to communicate with plant owners and the California ISO in the event of emergencies. The California ISO works directly with power plants to notify them of potential events via a "heat wave bulletin" up to a week ahead of time and more frequently as an event is developing. CEC staff communicated with all 76 jurisdictional power plant owners ahead of and during extreme weather conditions and Flex Alerts to inform them that an energy emergency may be developing, request they coordinate closely with the California ISO, and notify the CEC of any issues or concerns with their facility. If an energy emergency is declared, CEC staff informs project owners, provides information regarding any emergency waivers and emission limit waivers, and requests that they closely coordinate with California ISO and report project issues or outage information to the CEC. This communication between staff and power plant owners allowed staff to identify facilities impacted by unplanned outages and helped identify if and where potential additional capacity could be available to support reliability by operating during periods of high peak demand.

Jurisdictional Fleet Survey

To understand if additional opportunities for additional capacity might be available to support system reliability in 2021 and 2022 during peak demand, CEC staff surveyed CEC-jurisdictional power plants. The objective of the survey was to understand the potential for power plant improvements that could increase electric system reliability, enhance resiliency, and improve the integration of intermittent resources. CEC staff sought to understand what additional efficiency improvements, project upgrades, battery energy storage system expansions, or opportunities to locate temporary power generator units at existing natural gas-fired facilities might be possible. Ninety percent of CEC-jurisdictional projects responded and provided information on potential additional capacity that may be available in summer 2021, as well as for summer 2022 through 2026. Roughly 200 MW additional of capacity may be available by summer of 2022, of which 80 percent would be outside designated disadvantaged communities.

Second Lead Commissioner Public Workshop

On August 30, 2021, the CEC's STEP Division participated in another Lead Commissioner public workshop titled "Midterm Reliability Analysis and Incremental Efficiency Improvements to Natural Gas Power Plants." The STEP portion of this workshop focused on longer-term efficiency improvement options expected to be needed for 2022 and beyond to support electric grid reliability, including a discussion of incremental efficiency improvements potential for natural gas power plants. This ongoing work is being performed in collaboration with the CPUC to help inform a preferred system plan decision expected later this year.

STEP staff discussed actions the CEC has taken to increase the generating capacity of its jurisdictional power plants since last summer and identify the permitted and potential MW that could be available in the near term. STEP staff summarized the facilities in the existing fleet of CEC-licensed facilities, summarized the outreach and jurisdictional fleet survey efforts described above, and the process approval change implemented to speed up the review and approval of capacity upgrades in support of improved system reliability over the next few years. Staff also summarized the December 2, 2020, workshop described earlier, and the staff worked with facility owners to obtain additional capacity for 2021 and beyond. STEP staff also described the Governor's executive order described in Chapter 3. Finally, STEP staff summarized the additional facility upgrades being considered for 2022 and beyond.

On June 17, 2021, Governor Newsom proclaimed a state of emergency[30] because of an extreme heat wave that began June 16, 2021. This order extended through midnight on June 22, 2021. The provisions of this order mirrored the orders of August 16 and 17, 2020.

On July 30, 2021, Governor Newsom proclaimed another state of emergency[31] because of sudden and severe energy shortages in California resulting from extreme drought, wildfires, and record-breaking heat events. The proclamation declared that California faces a projected energy supply shortfall of up to 3,500 MW in 2021, and a shortfall of up to 5,000 MW in summer of 2022.

In the event California ISO declares a state of emergency between August and October 2021, these would be allowed:

1. Utility companies shall pay incentives for large energy users to reduce demand.

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30 Proclamation of a State of Emergency, June 17, 2021

https://www.gov.ca.gov/wp-content/uploads/2021/06/6.17.21-Extreme-Heat-proclamation.pdf.

31 Proclamation of a State of Emergency, July 30, 2021

https://www.gov.ca.gov/wp-content/uploads/2021/07/Energy-Emergency-Proc-7-30-21.pdf.

2. Emergency power equipment may operate.
3. Power Plants needing to exceed permit limits to increase power production may do so.
4. Ocean vessels docked in port may use onboard diesel-fueled power rather than grid power.
5. CARB to develop a plan to reduce emissions that exceed permit limits.
6. Department of Water Resources to enter contracts with entities that are able to add capacity by October 31, 2021.
7. CEC to expedite post-certification petitions for changes in design, operation, or performance requirements of existing facilities to increase MW capacity.
8. CEC to expedite the siting of emergency and temporary power generators of 10 MW or more.
9. CEC to expedite the siting of new battery energy storage systems of 20 MW or more that can discharge for at least two hours.
10. CEC, in consultation with the CARB, the California ISO, and the CPUC, to identify and prioritize action on recommendations in the March 2021 Senate Bill 100 Joint Agency Report, and any additional actions, that would accelerate the state's transition to carbon-free energy.

California Energy Commission Emergency Responsibilities

Governor Newsom's emergency proclamation directed the CEC to work with the state's load-serving entities on accelerating plans for the construction, procurement, and rapid deployment of new clean energy and storage projects. The emergency proclamation addresses the climate-induced energy shortfall and specifically requires the CEC to develop procedures to expedite three directives as follows:

1. Expedite post certification petitions for changes in the design, operation, or performance requirements of existing facilities under the CEC's jurisdiction.
2. License emergency and temporary power generators of 10 MW or more.
3. License battery storage systems of 20 MW or more that can discharge for at least two hours.

Expedited Facility Change Petition Process

The first two directives of the emergency proclamation apply to projects that can reduce the energy shortfall or deliver net peak capacity by the end of October 2021.

The Expedited Facility Change Petition Process suspends Title 20, section 1769 of the California Code of Regulations. The CEC order implementing this provision was approved by the CEC on August 17, 2021. It provides an alternative process for facility change requests. The order specifies required information that the petition must contain, including a detailed description of how the facility change would contribute to near-term reliability needs by October 31, 2021.

The authority to approve these petitions is delegated to the executive director. The executive director's decision must be made within 10 working days of receiving a completed petition, and the decision is final and not subject to appeal.

Temporary Power Generator Licensing

The second directive of the emergency proclamation, known as the Temporary Power Generator Licensing Program, expands CEC's authority under the Public Resources Code sections beginning with section 25500. It provides CEC the authority to establish a streamlined process for approving licenses for temporary power generators of 10 MW or more that the CEC determines will deliver net peak energy before October 31, 2021.

The temporary power generators must meet criteria set forth in the proclamation and specified in the order approved by the CEC on August 17, 2021. For a project to be considered under this program, applicants must complete and submit to the CEC a self-certification template for a license. Within 10 days of receiving an applicant's completed self-certification form and appropriate documentation, the executive director shall file a decision on the self-certification application either granting or denying the license. The decision is final and not subject to appeal. Licenses are valid for up to five years.

Battery Storage System Licensing

The third directive of the emergency proclamation applies to battery storage system projects that can deliver net peak energy by October 31, 2022. Recent feedback from CEC-jurisdictional plants indicates that there is potential for an additional 900–1,100 MW available from new and expanded battery storage between 2022 to 2026 to support midterm reliability.

Known as the Battery Storage System Licensing Program, this directive expands the CEC's authority under the Public Resources Code sections beginning with section 25500. It directs the CEC to establish an expedited process for approving licenses for new or expanded battery storage systems of 20 MW or more. The CEC must determine that eligible projects are capable of discharging for at least two hours and will deliver net peak energy no later than October 2022.

As a result of all the actions taken by the CEC, future mid-term reliability capacity includes efficiency and equipment upgrades, battery energy storage system expansions, and permitted projects constructed totaling more than 1,500 MW of new generation as shown in Figure B-6.

Figure B-6 Permitted and Potential Capacity 2022–2026

Source: California Energy Commission staff

The projects resulting from these orders will help reduce the strain on the state's energy infrastructure, increase energy capacity, and increase the reliability and resiliency of California's energy supply.