2022
SUMMER LOADS AND RESOURCES ASSESSMENT

California ISO

May 18, 2022

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I. EXECUTIVE SUMMARY

The *2022 Summer Loads and Resources Assessment* is an assessment of the expected supply and demand conditions this coming summer for the California Independent System Operator (ISO) balancing authority area (BAA), providing a comparative statistical analysis to the prior year for the purpose of ensuring operational preparedness. The Assessment considers supply and demand conditions across the entire ISO balancing authority area and, to a more limited extent, the entire Western Electricity Coordinating Council (WECC).

Extreme drought, increased demand and the continued potential for widespread heating events and other disruptions continue to leave the ISO grid with a high degree of vulnerability for reliability during the summer months.

Although we continue to move in the right direction relative to long-term reliability with the addition of more than 4,000 megawatts (MW) of net qualifying capacity since last summer, 2,751 MW of which is available at 8 pm, the grid continues to fall short of meeting the industry's traditional reliability risk target of less than one resource shortfall-related outage event every 10 years.

In addition to this Summer Loads and Resources Assessment for summer 2022, the ISO, as part of a collaborative effort with the California Public Utilities Commission (CPUC) and the California Energy Commission (CEC), has determined there is currently an estimated 1,700 megawatt (MW) capacity shortfall from meeting the "1 event in 10-years" planning target.

That conclusion is based on comparison of the CPUC's 2022 Preferred System Plan, which was determined to be adequate to meet the traditional "1 event in 10 year" planning metric, with the expected resource capacity based on authorized procurement and planned retirements given the CEC's latest load forecast.

Existing contingency measures will be used to close this gap in 2022, but they are unlikely to be sufficient to preserve reliability in the face of extreme regional heat waves across the West or other contingencies which are beyond those captured by a purely statistical analysis.

In addition to a third consecutive year of lower-than-normal hydro capacity, and the projected increased possibility of extreme weather events in the West[1], these challenges could be exacerbated if imports of electricity into California were limited by conditions just when they are most needed, as happened in July 2021 when the state lost about 4,000 MW of imports from the Pacific Northwest due to the Bootleg Fire in Southern Oregon. The conclusions about summer reliability were supported by both the ISO's probabilistic analysis of the summer season based on the ISO load projection of summer loads, as well

[1] https://www.noaa.gov/news/new-us-climate-normals-are-here-what-do-they-tell-us-about-climate-change

as a deterministic “stack” analysis based on a September forecast of resource adequacy capacity and the most recent California Energy Commission (CEC) load forecast[2].

It should not be overlooked in this discussion that a number of significant steps have been taken by the ISO and by the State designed to mitigate the risk of having to implement rotating outages to balance supply and demand as happened in August 2020, but those actions and added resources have not been enough to completely eliminate summer reliability risks.

Preparation for Summer Operation

Preparing and publishing the Assessment report and sharing the results with industry participants and stakeholders is one of many activities the ISO undertakes each year to prepare for summer system operations. Since the widespread heat wave events of 2020, the ISO, State entities, and others have put in place a number of measures to strengthen system preparedness and performance. These included pursuing and approving procurement of additional resources, ensuring existing resources are retained in service, and improving operational readiness and measures to access resources or load reductions that can be implemented when faced with the risk of shortfalls.

This Assessment evaluates the effectiveness of expected supply including established demand response programs to meet system load and reserve requirements. The report is not designed to evaluate the effectiveness of various voluntary or extraordinary measures[3], including more effective Flex Alert and conservation actions that may be deployed when the system is experiencing extreme or emergency conditions. Nonetheless, these additional measures can be – and have been in the past – effective mitigation tools to avoid having to rely on firm load shedding during extreme events.

Other routine preparatory activities include coordinating meetings on summer preparedness with the WECC, California Department of Forestry and Fire Protection (Cal Fire), natural gas providers, transmission operators and neighboring balancing areas. For 2022, the ISO engaged most of these entities in a tabletop exercise where participants walked through the ISO’s Emergency Procedure 4420C[4]. The exercise covered the change from the ISO’s Alerts, Warnings and Emergencies notifications to the North American Electric Reliability Corporation’s (NERC) Energy Emergency Alerts; communications protocols; recent policy changes; and contingency reserve management procedures. The ISO’s ongoing coordination activities with these entities helps ensure that everyone is prepared for the upcoming summer operational season.

[2] The latest CEC forecast for 2022 shows an increase of 1005 MW above last year’s forecast for 2021.
[3] Example is the Emergency Load Reduction Program developed by the CPUC.
[4] http://www.caiso.com/Documents/4420C.pdf#search=4420C

II. 2022 SUMMER ASSESSMENT

The *2022 Summer Loads and Resources Assessment* provides a probabilistic assessment of the expected supply and demand conditions this coming summer for the California Independent System Operator (ISO) balancing authority area. The Assessment forecasts this summer's supply and demand and identifies potential operational issues using information held by the ISO, third-party modeling tools, and public information from various state agencies, generation and transmission owners, load-serving entities, and other balancing authorities (BAs). The Assessment considers the supply and demand conditions across the entire ISO balancing authority area and, to a more limited extent, the entire WECC.

The Assessment is based on the availability of resources accessible through normal market operations. It does not take into account extraordinary measures employed under the extreme loss of load conditions to mitigate the risk of actually having to shed or curtail firm load. Therefore, capacity shortfalls identified in this report are more indicative of the likelihood of needing to rely on those extraordinary measures, rather than the actual risk of loss of firm load.

In addition to the probabilistic study, the ISO performed a deterministic stack[5] analysis of the resource procurement targets and minimum resource needs under the California Public Utilities Commission (CPUC) Resource Adequacy program based on the most recent forecast from the California Energy Commission, and provided those results in this Assessment to complement the probabilistic analysis. This stack analysis focuses on resources and demand available in September at the 8 p.m. period during high-load days that is emerging as the period of highest risk as daily solar output drops off. The stack analysis provides an additional perspective on the amount of capacity the ISO is expecting to be available for summer 2022 and the level of reliability anticipated under various load levels and import conditions.

The body of this report consists of a discussion of the key input parameters such as demand and supply projections, a probabilistic study, and deterministic analysis that drive to the ISO's conclusion. Each of these topics is discussed in turn.

Probabilistic Study Key Parameters

Peak Demand Forecast

The ISO's load forecast for 2022 used a revised methodology from prior years. The historical weather period used to develop the forecast was shortened from the 26 years of

[5] A stack analysis focuses on a particular point in time, adding up or "stacking" the resources expected to be available at the point in time and comparing the total to the demand side expectation at that time of day including a planning margin for reserves, variations from forecast load levels, and unanticipated, unplanned forced outages to the resource fleet.

weather history used in 2021 to the use of the most recent 20-years in 2022. This gives more weight in the load forecast to more recent weather experiences related to climate change.

The ISO's 1-in-2 peak demand forecast[6] is 45,866 MW for summer 2022, which is 0.1 percent above the 2021 peak demand forecast. A comparison of the ISO 2022 weather driven peak demand forecasts to those for 2021 is shown in *Table 1*. The 1-in-2, 1-in-5 forecasts are close to 2021 forecast levels. The 1-in-10 forecast level is 1 percent higher than that for 2021, which is the result of greater percentage of high load scenarios in 2022 due to 2022 load forecast use of the 20-year historical weather data set.

Table 1

ISO 2022 Peak Demand Forecast Compared to 2021

	1-in-2	1-in-5	1-in-10
CAISO 2022 Forecast	**45,866**	**47,850**	**51,469**
CAISO 2021 Forecast	**45,837**	**47,747**	**50,968**
Difference (MW)	**29**	**103**	**501**
Difference (%)	**0.1%**	**0.2%**	**1.0%**

Hydro Conditions

For the third consecutive year, California's hydro energy supply will be significantly lower than normal in 2022. The statewide snow water content peaked in January at approximately 60 percent of the April 1 average. Snowmelt was significant early in the season and by April 1 snowpack had decreased to 38 percent of the April 1 average, and continued to decline through April 11. The entire Sierras saw significant snow over the second half of April with the majority in the Northern Sierras. That recent precipitation added almost three inches back to the statewide snowpack. Since April 23, the statewide snowpack has again steadily declined, and on May 9 was 21 percent of the May 9 average. In comparison, statewide snow water content in 2021 peaked at 60 percent of normal in late March, 2021.

On April 11, 2022, California's major reservoir storage levels were at 70 percent of average, slightly below the 74 percent of average in 2021. Storage levels in California's major reservoirs provides a better indication of water supply conditions than of hydro

[6] A 1-in-2 peak demand forecast is the forecast of peak demand that is statistically expected to be reached once every two years. Similarly, a 1-in-5 and 1-in-10 peak demand forecasts are statistically expected to be reached once every five years and once very ten years, respectively.

potential because the majority of hydro generation in California is located on smaller reservoirs, not tracked by the California Department of Water Resources.

The ISO uses the Northwest River Forecast Center's water supply forecast at The Dalles Dam on the Columbia River[7] as an indication of potential surplus energy for imports into California from the Northwest. The current April to September reservoir storage projection at The Dalles Dam Columbia River is 95 percent of average.

System Capacity

The ISO projected for this Assessment system capacity[8] of 51,556 MW for June, 52,654 MW in July, 50,885 MW in August, and 47,892 MW in September for summer 2022. The decline of available capacity from July to September is the result of the declining effective load carrying capability, or Net Qualifying Capacity (NQC), of solar and the decline of hydro generation across the summer. The declining NQC for grid-connected solar and hydro is primarily due to the shifting of peak loads to later in the day due to behind-the-meter solar generation, and declining hydro energy expectations, respectively.

The ISO also projected approximately 7,621 MW[9] of installed capacity to reach commercial operation from June 1, 2021 to June 1, 2022: 3,271 MW is dispatchable and 4,350 MW is non-dispatchable.[10] During the same period, 65 MW of dispatchable generation capacity has been retired. The net of additions and retirements represents an increase of 7,556 MW, with a net increase of dispatchable capacity of 3,206 MW. Additional new resources could come online across the summer, but due to the tentative nature of scheduled commercial operation dates, resources that do not have a high likelihood of achieving commercial operation by June 1 were not included in the analysis.

Of the new resource capacity expected to be operational by June 1, 3,124 MW is from battery energy storage systems (BESS). While not providing new energy generation, BESS enable surplus energy generated during periods of high solar production and energy generated during periods of lower energy prices to be stored and provided to meet system needs during the net peak period when solar production ramps down and is no

[7] https://www.nwrfc.noaa.gov/water_supply/ws_forecasts.php?id=TDAO3

[8] Based on the Final Net Qualifying Capacity Report for Compliance Year 2022, http://www.ISO.com/planning/Pages/ReliabilityRequirements/Default.aspx, plus the projected Net Qualifying Capacity for new resources expected by June 1, 2022; projected as of early April, 2022, the date the ISO needed to establish its study assumptions for the probabilistic analysis.

[9] New resource capacity was developed from the ISO Master File and the New Resource Implementation process to determine the anticipated commercial operation date of new resources expected to come online within the 2022 Assessment study period. The amounts were based on known information as of 4/21/2022.

[10] Non-dispatchable resources are technologies that are dependent on a variable fuel source and are modeled in PLEXOS as energy production profiles based on historical generation patterns. Non-dispatchable technologies include biofuels, geothermal, wind, solar, run-of-river hydro, and non-dispatchable natural gas.

longer available. BESS are able to provide system capacity, ancillary service and flexible capacity.

In addition to the total ISO system capacity described above, 1,221 MW of demand response resource capability is projected to be available to the market in 2022. Demand response is utilized when the simulation depletes all other available resources before meeting the load and contingency reserve requirements.

Probabilistic Simulation Study

The ISO developed a stochastic[11] production simulation model employing the PLEXOS market simulation software to assess hourly operating conditions given the changing resource mix of higher penetration of variable renewable resources and fewer dispatchable conventional resources. The model assesses 2,000 unique randomly generated summer scenarios of forecasted hourly load and renewable generation to assess the ISO's resource adequacy of system capacity, ancillary service, and flexible capacity on an hourly basis.

In determining the capacity adequacy for each hour of the 2,000 scenarios, the Assessment considers the capacity serving load and any remaining available capacity that can be obtained within 20 minutes. This capacity is referred to as unloaded capacity[12], and it consists of any portion of online generation capacity that has not been dispatched to serve load or offline generation capacity that can come online in 20 minutes or less to serve load. It also includes curtailable demands such as demand response, interruptible pumping load, and aggregated participating load that can provide non-spinning reserve or demand reduction. The unloaded capacity includes system operating reserves. The ISO has further defined the Unloaded Capacity Margin (UCM) as the excess of the resources, available within 20 minutes or less, over the projected load expressed as a percentage on an hourly basis. Levels of UCM above the operating reserve requirement for any given hour (typically around 6 percent) signify that capacity is available beyond the requirement for operating reserves, which to the extent available, can be used during system contingencies.

The ISO performed the stochastic production simulation analysis incorporating an import nomogram[13] to net limit imports into the ISO based on historical and anticipated levels during on-peak hours, as load levels increase from near peak load conditions through the highest load forecasted. Despite the addition of new capacity since summer, 2021, the ISO system will still face significant challenges during more extreme load conditions, specifically at load levels associated with 1-in-10 year weather events and higher and

[11] "Stochastic" is a description that refers to outcomes based upon random probability. A modeling approach that uses a random variable, based on the property of being well described by a random probability distribution.

[12] Generation capacity that is serving load is referred to as "loaded capacity".

[13] A nomogram, is a graphical calculating device, a two-dimensional diagram designed to allow the approximate graphical computation of a mathematical function.

particularly when availability of non-firm imports diminishes due to high-heat events that encompass areas beyond California's borders. Extreme heat waves that spread over a broader area than the ISO can lead to diminished availability of surplus energy for imports into the ISO. Extreme conditions could lead to requests for more aggressive voluntary load reductions and even firm load shedding to maintain sufficient operating reserves.

<u>NERC Energy Emergency Alert Designations</u>

Historically the ISO has used AWE notifications (Alerts, Warnings, and Emergencies) to signal activation of system emergency procedures. Effective May 1, 2022, the ISO changed its messaging system to align with NERC's Energy Emergency Alert[14] (EEA) designations. The ISO is making this change to align its emergency levels with the NERC standards, align our emergency levels with Reliability Coordinators and neighboring Balancing Authority procedures, and to ensure that everyone is using consistent terminology during supply shortages. Table 2 provides a comparison of the historical emergency levels with the NERC emergency levels the ISO will be using from this point forward.

Table 2

ISO Balancing Authority Emergency Notifications

1998 to Present Day Emergency Levels	Emergency Levels as of 5/1/2022
Flex Alert	Flex Alert
Restricted Maintenance Operations	Restricted Maintenance Operations
Transmission Emergency	Transmission Emergency
Alert	EEA Watch
Warning	EEA 1
Warning – triggering DR programs	EEA 2
Stage 1	
Stage 2	EEA 3/EEA 3 – Firm Load Interruption
Stage 3	

EEA Watch: Analysis shows all available resources are committed or forecasted to be in use, and energy deficiencies are expected. Market participants are encouraged to

[14] See System Alerts, Warnings and Emergencies Fact Sheet on the ISO webpage – http://www.ISO.com/informed/Pages/Notifications/NoticeLog.aspx

offer supplemental energy. This notice can be issued the day before the projected shortfall or if a sudden event occurs.

EEA 1: Real-time analysis shows all resources are in use or committed for use, and energy deficiencies are expected. Market participants are encouraged to offer supplemental energy and ancillary service bids. Consumers are encouraged to conserve energy.

EEA 2: ISO requests emergency energy from all resources and has activated its emergency demand response program. Consumers are urged to conserve energy to help preserve grid reliability.

EEA 3: ISO is unable to meet minimum contingency reserve requirements and controlled power curtailments are imminent or in progress according to each utility's emergency plan. Maximum conservation by consumers requested

Simulation Results

The lowest UCM from each scenario modeled is termed the Minimum Unloaded Capacity Margin (MUCM). The MUCMs of all 2,000 scenarios simulated are used to determine the probability of various capacity shortfall events occurring. In other words, by looking at the worst, lowest margin hour of each scenario, a single scenario showing a capacity shortfall event would result in a probability of shortfall of one in 2,000, regardless of how many hours or how many events within that scenario that the shortfall occurred. *Table 3* shows scenarios with low operating reserves where the MUCM is at these points that fall within EEA 3:

- EEA 3 Threshold : The point of transitioning from EEA 2 to EEA 3, where reserves are just beginning to be depleted and start to fall below the reserve requirement.
  - 15.1 percent probability based on 301 scenarios having at least one hour that met that condition.
- EEA 3 – 50 percent of contingency reserves from firm load[15]: At this point 50 percent of the contingency reserves are met by firm load. (i.e. Reserves are below required levels and we are having to dispatch our contingency reserves to meet the load and firm load is armed for load shedding to replace the dispatched contingency reserves. This is not a defined point in the EEA 3 definition.)
  - 7.7 percent probability based on 154 scenarios having one hour or more that meet that condition.
- Unserved energy: The point in EEA 3 where firm load interruption is required to maintain contingency reserves.
  - 4.0 percent probability based on 80 scenarios showing one hour or more of unserved energy.

[15] The point where 50 percent of contingency reserves are served by arming firm load for interruptions is roughly equivalent to the prior stage 3 emergency condition.

System capacity shortfall probabilities for the first two of these three conditions in 2022 are higher than those in 2021, primarily the result of a greater percentage of high load scenarios in 2022 due to the forecast methodology change to using a 20-year historical weather data set. The 2022 system supply includes a net increase of dispatchable capacity of 3,206 MW over 2021; as a result, the number of unserved energy hours in each scenario with unserved energy in 2022 is less than 2021.

These seasonal shortfall probabilities, developed as comparative operational metrics and based on the maximum depth of shortfall in cases that had shortfalls, do not translate directly into an annual loss of load expectation used in assessing annual performance against a "1 event in 10 years" target.

Table 3

Probability of system capacity shortfall

2022		
System Capacity Shortfall	Shortfall Probability	Number of Shortfall Cases (out of 2,000)
EEA 3 Threshold (Stage 2)	15.1%	301
EEA 3 – 50% of contingency reserves from firm load (Stage 3)	7.7%	154
Unserved energy EEA 3 - firm load interruption	4.0%	80
2021		
System Capacity Shortfall	Shortfall Probability	Number of Shortfall Cases (out of 2,000)
EEA 3 Threshold (Stage 2)	6.4%	128
EEA 3 – 50% of contingency reserves from firm load (Stage 3)	4.8%	96
Unserved energy EEA 3 - firm load interruption	4.6%	91

Demand response programs were utilized as needed to maintain contingency reserves. Should ISO system operating conditions go into the EEA stages, the ISO will issue a notice of potential load interruptions to utilities and implement the mitigation operating plan to minimize loss of load in the ISO balancing authority area described in the *Preparation for Summer Operation* section at the end of Section II of this report. Whether actual interruptions would occur depends on the specific circumstances and effectiveness of the extraordinary measures.

Figure 1 shows the amount of unserved energy – not accounting for the impact of mitigations – for each hour of unserved energy and the ISO load levels they occurred at. The maximum unserved energy was 4,716 MW in September. The ISO loads when unserved energy occurs ranged from 44,986 MW to 53,016 MW.

Figure 1

ISO loads versus unserved energy

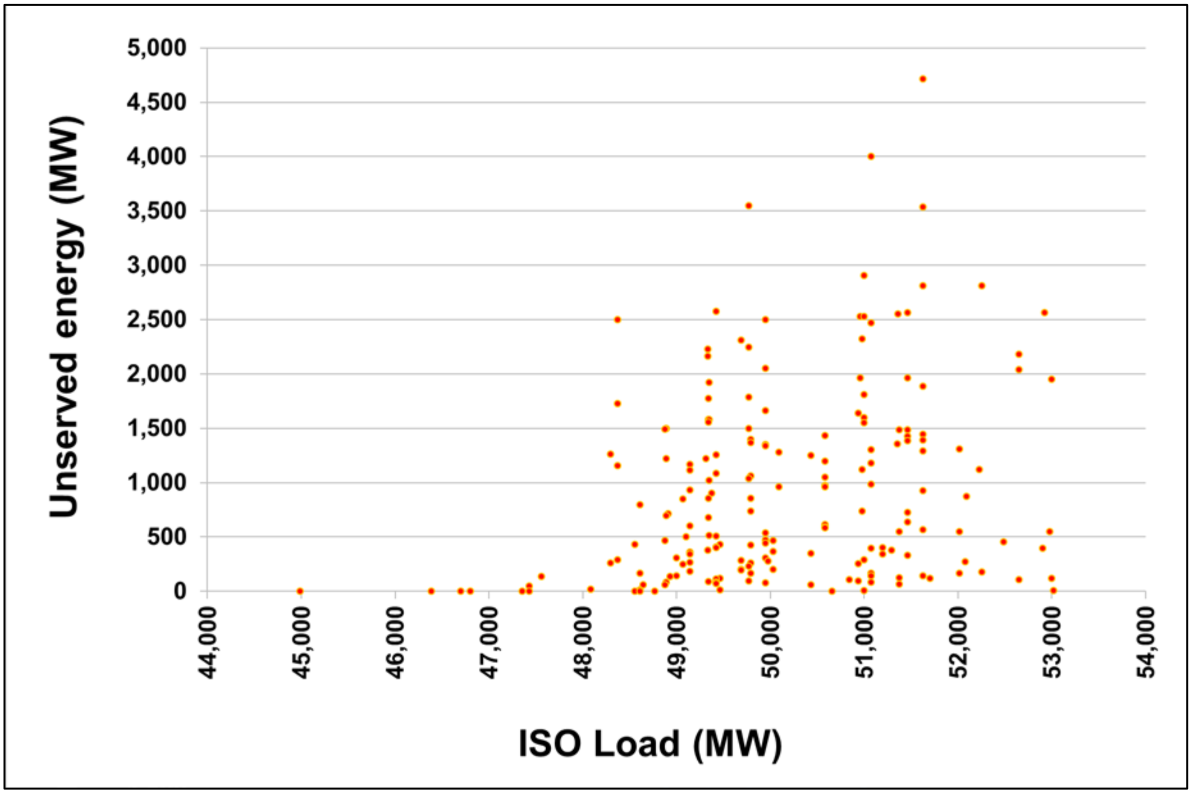


Figure 1 shows ISO load level versus unserved energy

To further assess resource adequacy for the summer period, the MUCM from each of the 2,000 scenarios are shown in *Figure 2*. The zero results are hours where the supply was less than demand, and represent the most extreme hours within the 2,000 scenarios considered.

Figure 2

ISO Minimum Unloaded Capacity Margin Distribution

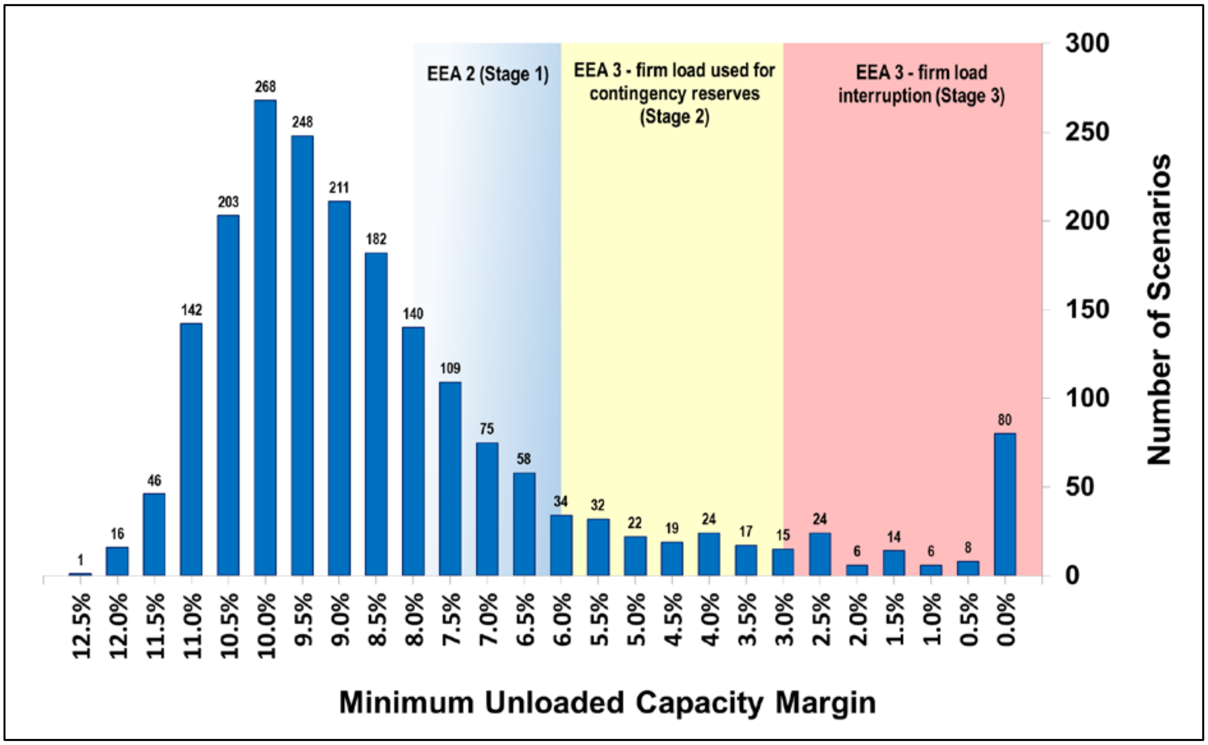


Figure 2 shows distribution of summer ISO MUCM.

While the additional capacity positively impacts the results, the revised forecast methodology results in increasing probability of low operating reserve levels even with the added capacity. However, to understand these results more fully, *Table 4* shows the levels of unserved energy from the 2021 and 2022 assessments. Unserved energy is the amount of customer load that is unable to be served due to a lack of resources that are able to serve load at that time. The results in *Table 4* show a reduction in unserved energy in 2022 versus 2021, with the amount of unserved energy reduced by 84 percent and the hours of unserved energy reduced by 71 percent.

Table 4

Comparison of Unserved Energy Results

<table>
<tr><th></th><th>2021</th><th>2022</th><th>Percent Reduction (2021-2022)/2021</th></tr>
<tr><td>Total unserved energy MWH of all hours in 2,000 scenarios</td><td>1,085,168</td><td>177,394</td><td>84%</td></tr>
<tr><td>Number of hours of unserved energy in all 2,000 scenarios</td><td>645</td><td>190</td><td rowspan="2">71%</td></tr>
<tr><td>Percent of hours of unserved energy in all 2,000 scenarios</td><td>0.011%</td><td>0.003%</td></tr>
</table>

To put these two sets of data in context, *Table 3* shows that the higher loads in the load forecast range result in higher probabilities for experiencing conditions leading to reserve margins in the EEA 3 range. However, the *Table 3* probabilities are based on the number of scenarios, but as shown in *Table 4* the 2022 simulation results show the number of hours at risk of actual load shedding is significantly reduced. This is demonstrated in the unserved energy results. When reserves decline to the point that firm load needs to be shed, the actual amounts of simulated load shed is reduced from 2021 to 2022.

These results do not take into account growing risks of more extreme events stemming from more disruptive climate change events and supply chain disruptions. These risks include:

- More extreme weather events beyond those projected from the most recent 20 years of historical data;
- Wildfires that could limit key transfer paths or resources and other potential transmission outages;
- The unexpected confluence of extreme heat and drought affecting fire risk;
- Smoke impacting solar production, and;
- Project development delays such as those triggered by the recent Department of Commerce investigation of solar panel tariff issues and other supply chain delays.

The timeframe of greatest operational risk is during the late summer if the ISO and the West experience a widespread heat wave that results in low net imports into the ISO due to high peak demands in its neighboring balancing authority areas, concurrent with the diminishing effective load carrying capability of solar resources and diminished of hydro generation.

The probabilities for operating in conditions that lead to an EEA 3 are based on the minimum reserve margins within each of the model's 2,000 scenarios. The minimum reserve margin is used to show the likelihood of reaching various levels of low operating reserves for at least one hour over the summer period. *Figure 3* shows the 2022 model results distribution for scenarios with a minimum reserve margin of 6 percent or less and the hours of the day that they occurred. The hours of solar generation anticipated during the 2022 summer peak day are shown to demonstrate that 81 percent of these low minimum reserve margins occurred during the hours ending 19:00 to 21:00 – hours of little to no production from solar resources. *Figure 3* demonstrates that resource adequacy levels are most challenged in the post-solar window, as reductions in the gas fleet have not yet been offset by sufficient new energy storage resources to compensate for the loss of capacity available in that window.

Figure 3

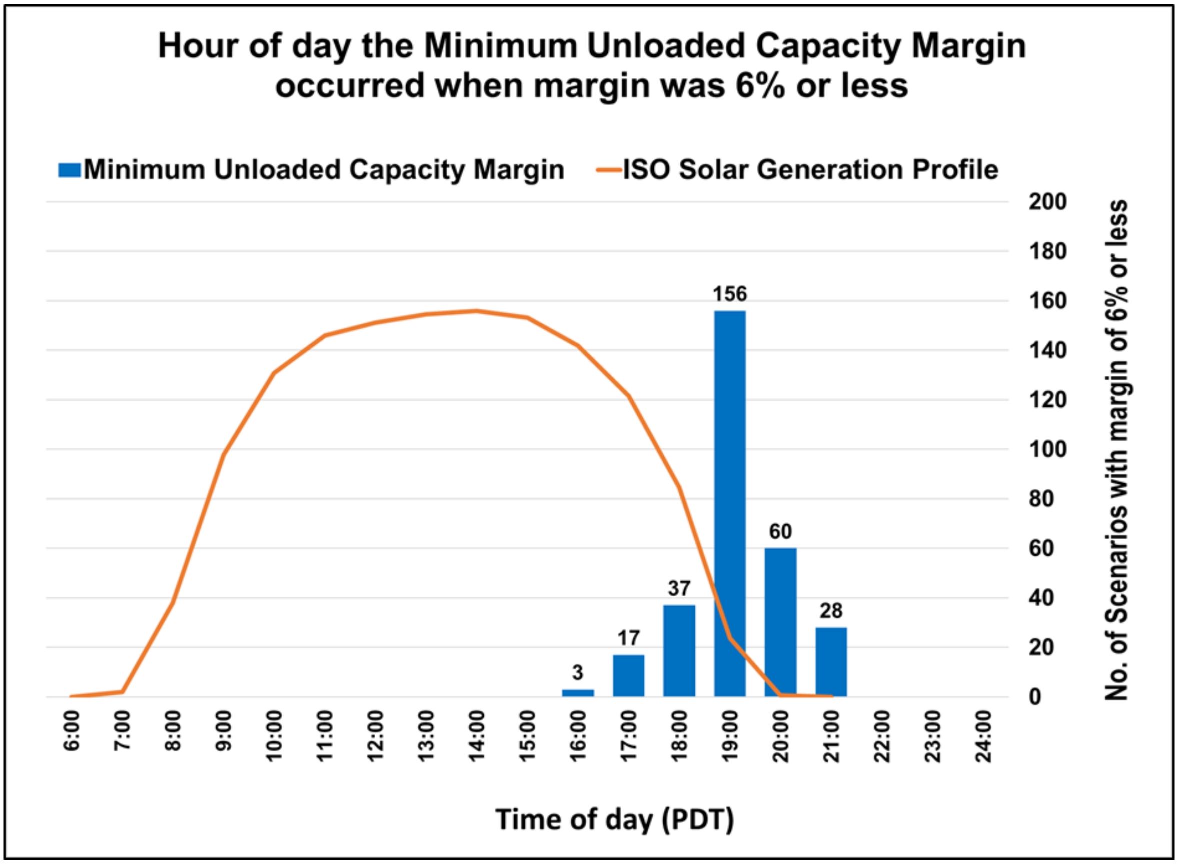


Figure 3 shows the hour of occurrence where the MUCM is of 6 percent or less

Deterministic Stack Analysis

In a process of assessing adequate resource procurement targets and minimum resource needs under the California Public Utilities Commission (CPUC) Resource Adequacy program, the ISO performed a deterministic stack analysis. In addition to the stochastic modeling described above, the ISO deterministic stack analysis is included to provide an additional perspective on the amount of capacity the ISO is expecting to be available for summer 2022 and the level of reliability that is anticipated under various load levels and import conditions.

To maintain reliability, the ISO must comply with several NERC and WECC standards in real-time. BAL-002-WECC-2a requires the ISO to carry approximately 6 percent of expected load as contingency reserves. The contingency reserves required under BAL-002-WECC-2a cannot be used for other types of operational needs other than contingencies unless the ISO is in an EEA 3. In addition, the ISO also requires unloaded capacity to meet operational needs like frequency response and regulation pursuant to BAL-003-2 and BAL-001-2. To assess the ISO's ability to maintain those reserve margins necessary for reliable service in real-time operation, the ISO considered the capacity needs taking into account the overall outage rate of the existing fleet, which is currently about 7.5 percent. The ISO also based the deterministic assessment on meeting at least a 1-in-5 load forecast level. The 1-in-5 level is 4 percent above the 1-in-2 forecast used as a baseline, providing an allowance for loads up to 1-in-5. The combined effect of these requirements established a threshold need for a 17.5 percent margin above a 1-in-2 load forecast level.

The ISO's analysis consisted of two steps; first assessing the need for capacity required to meet the contingency provisions of BAL-002-WECC-2a, and then assessing the ability of existing and forecast resources to meet those needs in the summer of 2022. As set out above, the ISO considers that a 17.5 percent margin applied to a 1-in-2 load level is necessary to provide a minimum level of reliable service pursuant to the contingency reserve provisions[16].

Figure 4 shows the result of the deterministic stack analysis for the month of September, 2022, at 8 pm, which is the month and hour of the greatest supply risk. Approximately 4,000 MW of NQC has reached commercial operation or is expected to from June 1 2021 to June 1, 2022. The NQC of the existing and new resources were reduced by 1,984 MW to account for solar generation not being available at 8 pm. As a result, the total capacity amount shown in *Figure 4* is less than the September capacity amount listed earlier in the *System Capacity* section of this report that included the NQC amount for solar. The amount of demand response is also different because the two methods account for different types of demand response differently.

The three bars of stacked resources portray three scenarios of progressively increasing resource amounts. Moving from left to right, the first bar represents resources similar to the stochastic sensitivity case, where imports are limited to the average of the last six-years of RA imports[17] procured by the load serving entities to meet their collective RA

[16] The ISO's detailed analysis conducted in support of the CPUC's integrated resource planning process identified that the CPUC's preferred system plan meets a 1-in-10 loss of load expectation, and the ISO notes that the preferred system plan reflects a planning reserve margin higher than a 17.5 percent planning reserve margin at 8 pm, demonstrating that a 17.5 percent planning reserve margin may provide a minimum level of reliability but does not achieve a target loss of load expectation of 1 event in 10 years. http://www.caiso.com/Documents/Sep27-2021-OpeningComments-ProposedPreferredSystemPlan-IntegratedResourcePlanning-R20-05-003.pdf

[17] The 2015 – 2021 average of the total import capacity procured by all load serving entities to meet their RA program obligations is 5,990 MW for the month of September.

obligations. The middle bar represents an increase in the RA import level to 8,500 MW, the highest amount procured for the month of September over the last 6 years. The bar on the right further increases the level of imports from the middle bar by assuming an additional 1,000 MW of non-RA economic imports during the peak period. *Figure 4* demonstrates the importance of imports above typical RA import levels for meeting 1-in-2 and higher peak demand conditions during late summer.

- The bar on the left shows that if the system is limited to imports of 5,990 MW the 15 percent planning reserve margin (PRM) associated with 1-in-2 load is able to be met in September with a narrow margin.
- The middle bar shows that if system imports reach 8,500 MW, approximately 2,500 MW greater than the typical RA procurement levels, the 17.5 percent PRM, reflecting 1-in-5 loads, can be met; however a 22.5 percent PRM would not be met.
- The bar on the right demonstrates that loads equivalent to the day-ahead forecast for August 18, 2020, the day of the ISO 2020 summer peak, would meet a 22.5 percent PRM if imports reach the maximum over the last six years, a level of approximately 3,500 MW greater than the typical RA procurement levels.

Figure 4

ISO stack analysis for September 2022
(PRM levels based on CEC 1-in-2 load forecast plus planning reserve margin)

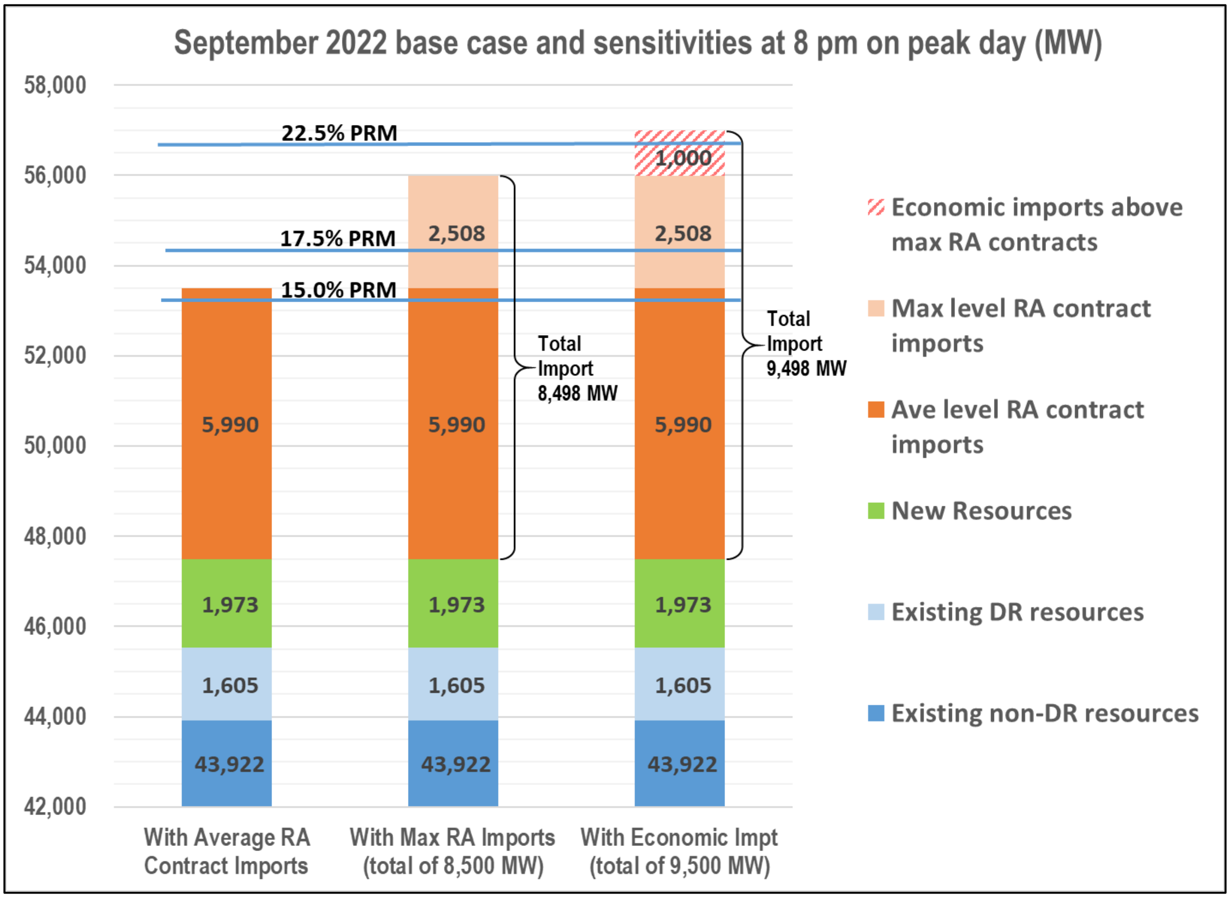
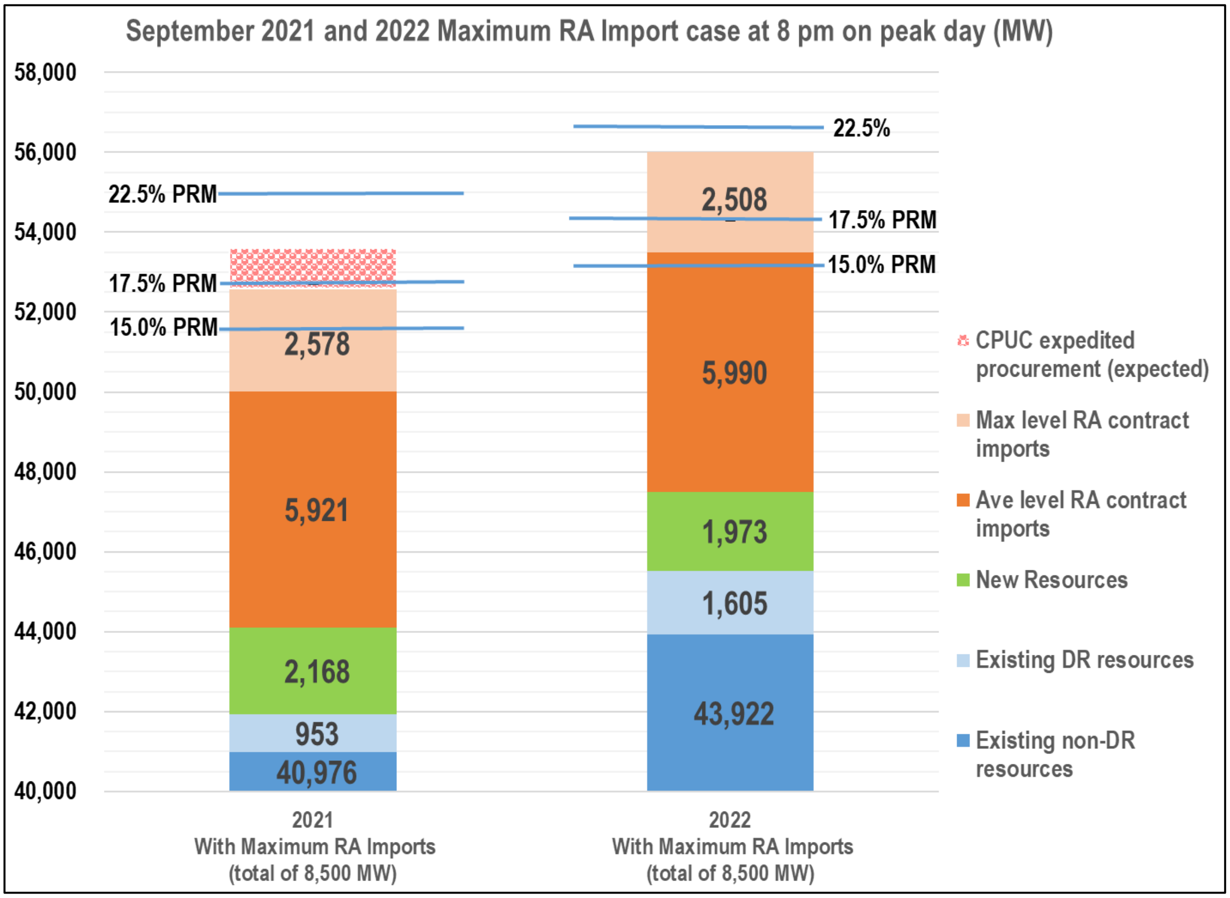


Figure 5 provides a reference to the results from 2021, comparing the maximum import scenario, which shows marginally better supply in 2022 than 2021. The approximate gain of 4,000 MW of new resources is partially offset by a 1,005 MW higher load forecast for 2022 based on the latest CEC 1-in-2 forecast. The higher load forecast is illustrated in *Figure 5* by the higher planning reserve margins for the bar on the left that represents 2022.

Figure 5

ISO stack analysis comparison of September 2022 to September 2021
(PRM levels based on CEC 1-in-2 load forecast plus planning reserve margin)



Status of the Aliso Canyon Gas Storage Operating Restrictions

Natural gas needs in Southern California are met by a combination of major gas pipelines, distribution gas infrastructure and gas storage facilities. Four major gas storage facilities are located in the Southern California Gas system, the largest of which is the Aliso Canyon facility located in Los Angeles County. Aliso Canyon and other gas storage facilities are used year-round to support the delivery of gas to core and non-core users. Among the non-core users are electric generators, which help meet electric demands throughout the region.

Aliso Canyon directly supplies 17 gas-fired power plants with a combined total 8,225 MW of ISO electric generation in the Los Angeles basin as well as generation in the Los Angeles Department of Water and Power balancing authority. Aliso Canyon storage indirectly impacts three other Southern California Gas storage facilities that support 48 additional plants in the ISO with a combined total 20,120 MW of electric generation across

Southern California. There are limitations in attempting to shift power supply from resources affected by Aliso Canyon to resources that are not affected because of certain factors, such as local generation requirements, transmission constraints and other resource availability issues.

The ISO and the CPUC have taken separate but complementary actions to manage the ongoing situation. Between 2016 and 2019 the ISO put in place a number of operational tools and market mechanisms to mitigate the electric system reliability and market risks posed by restricted operations at Aliso Canyon.

On March 30, 2022, SoCalGas published its Summer 2022 Technical Assessment[18], which concluded that SoCalGas has sufficient capacity to serve the forecasted summer peak demand of 3.307 billion cubic feet per day (BCFD) under the "best case" supply scenario, with or without the use of Aliso Canyon, and under the "worst case" supply scenario with the use of Aliso Canyon. SoCalGas has insufficient capacity to serve the forecasted summer peak demand under the "worst case" supply scenario without the use of Aliso Canyon. Under the "worst case" supply scenario without the use of Aliso Canyon, the system capacity is 2.88 BCFD resulting in a partial curtailment of electric generating (EG) customers. Core and non-EG noncore customers are not impacted, however, as consistent with the Commission's July 23, 2019 Aliso Canyon Withdrawal Protocol, SoCalGas may use Aliso Canyon to maintain service to core and critical noncore customers.

Conclusions

The ISO continues to see challenges in meeting demand, especially during extreme heat waves, given the challenges of climate induced supply and demand variability on the system and especially in light of recent demand growth and the unpredictability of external risks. While we are moving in the right direction for the longer term with the addition of new resources to the grid, a third year of significantly lower-than-normal hydro conditions and the projected increased possibility of extreme weather events in the West leaves the ISO grid in an elevated state of risk during extreme events this summer. Moreover, if these conditions were to affect a substantial portion of the Western Interconnection, the situation would be exacerbated because imports into the ISO balancing authority area would also be reduced precisely when they are needed the most.

These conclusions were supported by both the ISO's probabilistic analysis of the summer season based on the ISO load projection of summer loads, as well as a deterministic "stack" analysis based on a September forecast of resource adequacy capacity and the most recent California Energy Commission load forecast. The stack analysis demonstrates that capacity has been added since last summer, but that the system is still not yet

[18] https://efiling.energy.ca.gov/GetDocument.aspx?tn=242505&DocumentContentId=76010

achieving planning targets for supply adequacy, e.g. the common industry target of 1-in-10 loss of load expectation.[19]

Potential capacity shortfalls this summer may be mitigated by additional extraordinary measures accessed under extreme or emergency conditions to limit the risk of actual firm load shedding (rotating outages). Since September 2020, the ISO enhanced its operational procedures to increase operational reliability, including the ability to access these extraordinary measures. ISO coordination with the State and regional entities and utilization of conservation through the Flex Alert campaign to conserve energy during extreme events could again be needed to avoid shedding load. The ISO and State entities have taken significant measures to inform consumers in a timely manner through the Flex Alert campaign to conserve energy when requested to avoid outages. Additionally, the CPUC's Emergency Load Reduction Program has been expanded to include residential customers as well as commercial customers.

This Assessment is a zonal level assessment and does not provide results on local area resource adequacy issues. Supply disruptions due to public safety power shutoff procedures are also not addressed in this report. Additionally, conventional planning techniques referred to in this analysis also do not take into account growing risks of more extreme events stemming from more disruptive climate change events and supply chain disruptions, for example. These pose additional risks not included in this analysis. These additional risks include:

- More extreme weather events beyond those projected from the most recent 20 years of historical data
- Wildfire events that could limit key transfer paths or resources, and other potential transmission outages
- The unexpected confluence of extreme heat, drought affecting fire risk, and smoke impacting solar production
- Project development delays such as those triggered by the recent Department of Commerce investigation of solar panel tariff issues.

These types of events tend to be managed in part by additional reliability measures beyond normal resource planning and market operation.

While progress has been made in overcoming past supply shortfall conditions, additional resources are needed to ultimately achieve long-term reliability margins.

[19] As part of a collaborative effort by ISO, CPUC and CEC to evaluate capacity sufficiency in the near to mid-term timeframe, the ISO determined there was an estimated 1,700 MW capacity shortfall in 2022 based on comparison of 2022 Preferred System Plan, which was determined to be adequate to meet a 1-in-10 year shortage event traditional planning metric, with the expected resource capacity based on authorized procurement and planned retirements considering the latest CEC forecast load forecasts. The summer assessment report attempts to assess system performance at a more operational granularity specific to this summer's conditions.

Preparation for Summer Operation

Preparing and publishing the Assessment report and sharing the results with industry participants and stakeholders is one of many activities the ISO undertakes each year to prepare for summer system operations. Since the widespread heat wave events of 2020, the ISO, state entities, and others have put in place a number of contingency measures to improve system preparedness and performance. These included pursuing and approving procurement of additional resources, with a significant amount going into operation over the past year; ensuring existing resources are retained in service; and improving operational readiness and measures to access resources or load reductions that can be implemented when faced with the risk of shortfalls. However, these contingency measures are not sufficient to cover more extreme regional heat events or a serious wildfire that affects transmission similar to the July 2021 Bootleg Fire in Southern Oregon. The grid still falls short of the industry's traditional reliability risk target of one resource shortfall-related outage event every 10 years. Other activities include coordinating meetings on summer preparedness with the WECC, California Department of Forestry and Fire Protection (Cal Fire), natural gas providers, Transmission Operators and neighboring balancing areas. For 2022, the ISO engaged most of these entities in a tabletop exercise where participates walked through the ISO's Emergency Procedure 4420C[20]. The exercise covered the change from the ISO's Alerts, Warnings and Emergencies to the NERC EEAs, communications protocols, recent policy changes, and contingency reserve management procedures. The ISO's ongoing coordination with these entities helps ensure that everyone is prepared for the upcoming summer operational season.

Should the ISO system operating conditions go into the emergency stages—such as operating reserve shortfalls where non-spinning reserve requirements cannot be maintained or spinning reserves are depleted and operating reserves fall below the minimum requirement—the ISO will implement the following mitigation operating plan to limit loss of load in its balancing authority area:

- Activation of the Summer 2022 Joint Readiness Plan (ISO, CPUC, & CEC). This triggers communication 4-7 days in advance of an anticipated tight supply day or days to California water agencies, Utility Distribution Company (UDC) & Metered Subsystem (MSS), neighboring BAs;
- Activation of ISO Operating Procedure 4420
- Utilization of the Flex Alert program, signaling that the ISO expects high peak load conditions. This program has proven to reduce peak load in the ISO balancing authority area;
- Utilization of the ISO Restricted Maintenance program, which is intended to reduce potential forced outages during the high peak load conditions;
- Manual post-day-ahead unit commitment and exceptional dispatch of resources under Resource Adequacy contract to ensure ability to serve load and meet flexible ramping

[20] http://www.caiso.com/Documents/4420C.pdf#search=4420C

capability requirements;

- Manual exceptional dispatch of intertie resources that have Resource Adequacy obligation to serve ISO load;
- Utilization of NERC EEAs;
- Activation of the CPUC pilot Emergency Load Reduction Program upon declaration of an ISO Alert in the day-ahead timeframe;
- Utilization of Demand Response program including the Reliability Demand Response Resources (RDRR) under the EEA 2 (formerly known as “Warning”) notice;
- Manual exceptional dispatch and utilization of backstop Capacity Procurement Mechanism for physically available resources that have un-contracted RA capacity;
- Coordinate with the ISO UDC/MSS to use firm load that can be dropped within 10 minutes of notification as contingency reserves. The market procured contingency reserves will then be dispatched to serve firm load;
- Assess curtailment of export or wheel schedules when preparing for firm load shed.

III. APPENDIX A: TECHNICAL REVIEW AND ASSESSMENT

This section consists of a more comprehensive review of input parameters, modeling approach and discussion of the Assessment probabilistic results.

Summer 2021 REVIEW

Demand

Figure 6 shows actual monthly peak demands from 2011 to 2021 for the ISO. The fluctuation of the annual peak demand is primarily due to weather conditions unique to each year, with changing economic conditions and demographics impacting longer-term trends. The ISO peak demand has been significantly offset by the behind-the-meter solar installations, reducing the system peak and shifting the peak hour to later in the evening when solar energy production is low or zero. To a lesser extent, increasing energy efficiency and the use of demand side management impacted peak demand as well.

Figure 6

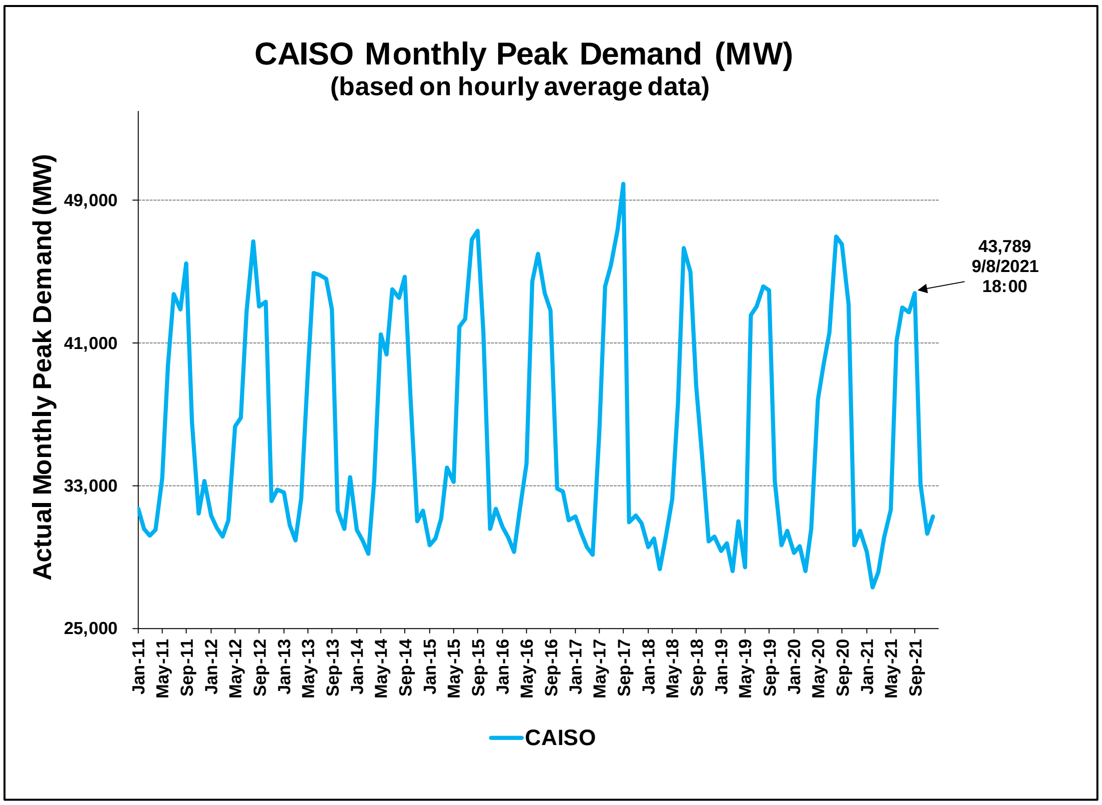


Figure 6 shows the system peak and peaks for ISO (2011-2021).

The recorded 2021 summer hourly average peak demand reached 43,789 MW[21] on 9/8/2021 at 18:00. The 2021 peak demand, normalized to 1-in-2 weather conditions, is 45,612 MW.

Load impacts due to COVID-19 were monitored from the beginning of the California stay-at-home orders through July 2020[22]. While reduction in energy consumption was observed, minimal to no load reductions to daily peak demand levels were observed during the month of July when compared to pre-COVID-19 conditions.

Table 5 shows the ISO 2021 actual peak demand, the estimated reduction in the peak due to demand response, various forms of load management, and load curtailments, and an assessment of the 2021 weather ranking at the time of its peak. Weather conditions in the ISO Balancing Authority area were mild, ranked as a 1-in-1.1 weather event. The weather rankings shown in *Table 5* will differ from the weather rankings performed using longer term weather data sets than the 20-year historical data set used here.

Table 5

2021 Summer Peak Load and Peak Day Weather Ranking Across the ISO

Zone	Date & Time	Actual Peak (MW)	Peak Reduction (MW)	Actual Peak plus Reduction (MW)	Area Weather Index (deg. F)	Percentile	Weather Event
ISO	9/8/21 18:00	43,789	132	43,921	89	0.08	1-in-1.1

Table 6 shows the 2021 actual peaks, 2021 weather normalized peaks, and the 2021 1-in-2 peak demand forecasts. The weather during the 2021 peak demand resulted in the ISO actual peak demand plus the peak reduction from demand response being 3.7 percent lower than the normalized peak demand of 45,612 MW.

Table 6

2021 ISO actual, normalized and forecast peak (MW)

Zone	Actual	Peak Reduction	Actual + Peak Reduction	Normalized	1-in-2 Forecast	Actual + Peak Reduction vs. Normalized	Forecast vs. Normalized	Time
ISO	43,789	132	43,921	45,612	45,837	-3.7%	0.5%	9/8/21 18:00

[21] All demand data represented in this report is hourly average demand.
[22] http://www.ISO.com/Documents/COVID-19-Impacts-ISOLoadForecast-Presentation.pdf#search=covid%2019%20impacts

Supply

Actual daily supply and demand from June through September 2021 for the ISO system is shown in *Appendix B: 2021 Summer Supply and Demand Summary Graphs.*

Interchange

Figure 7 shows the 2021 ISO daily peak demand and the net imports at the time of the peak across the summer period. The highlighted data points in the daily peak line and the net import line in *Figure 7* are those days when the ISO daily system peak was 90 percent or more than the 2021 summer peak. There are numerous factors that determine the level of interchange between the ISO and other balancing authorities at any given time. These factors include market dynamics, the availability of generation internal and external to the ISO, resource adequacy contracting, transmission congestion, hydro conditions, forecasted renewable generation, demands within various areas, and day-ahead forecasts accuracy. On any given day, the degree to which any one of these interrelated factors influence import levels can vary greatly. Additional information on daily net import from June through September 2021 for the ISO system are shown in *Appendix B: 2021 Summer Supply and Demand Summary Graphs.*

Figure 7

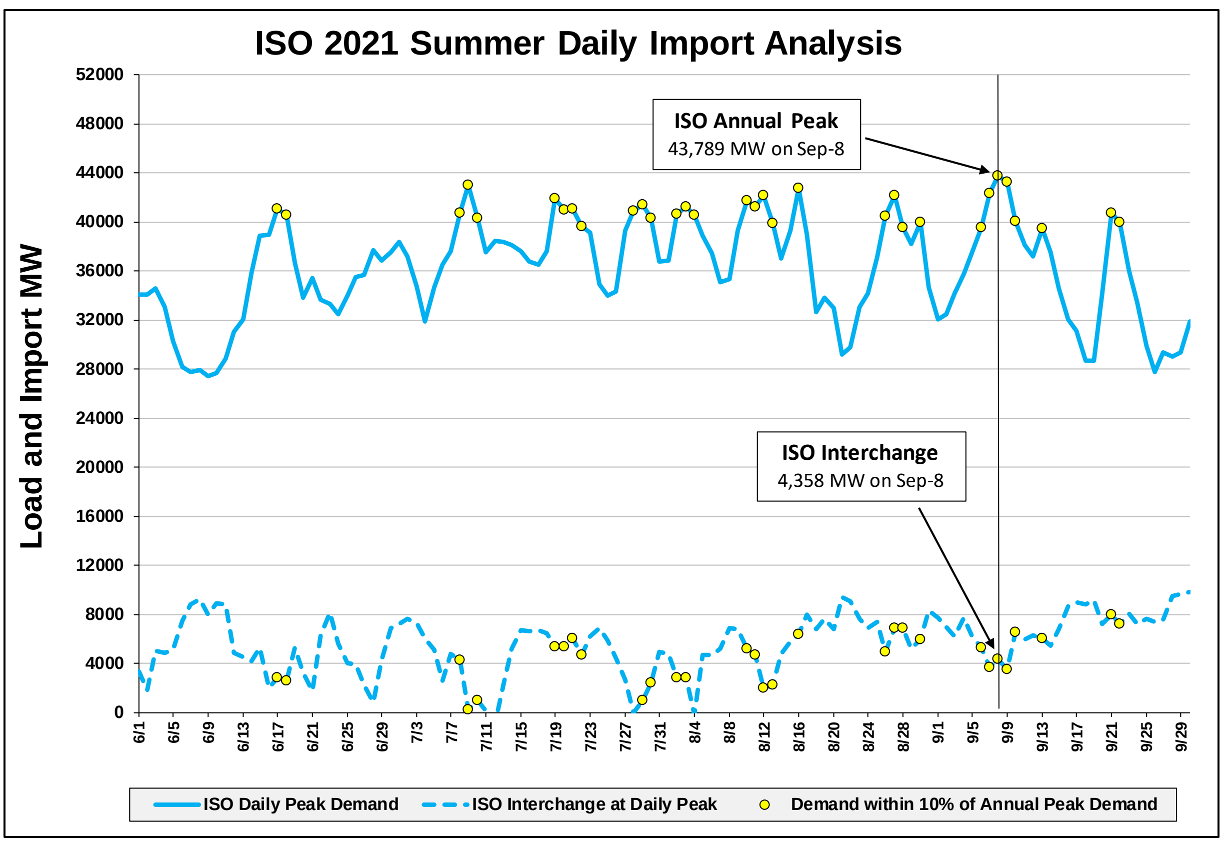


Figure 7 shows the amount of net imports at ISO 2021 daily system peaks.

Summer 2022 Assessment

ISO Loads

Annual Peak and Energy Forecast

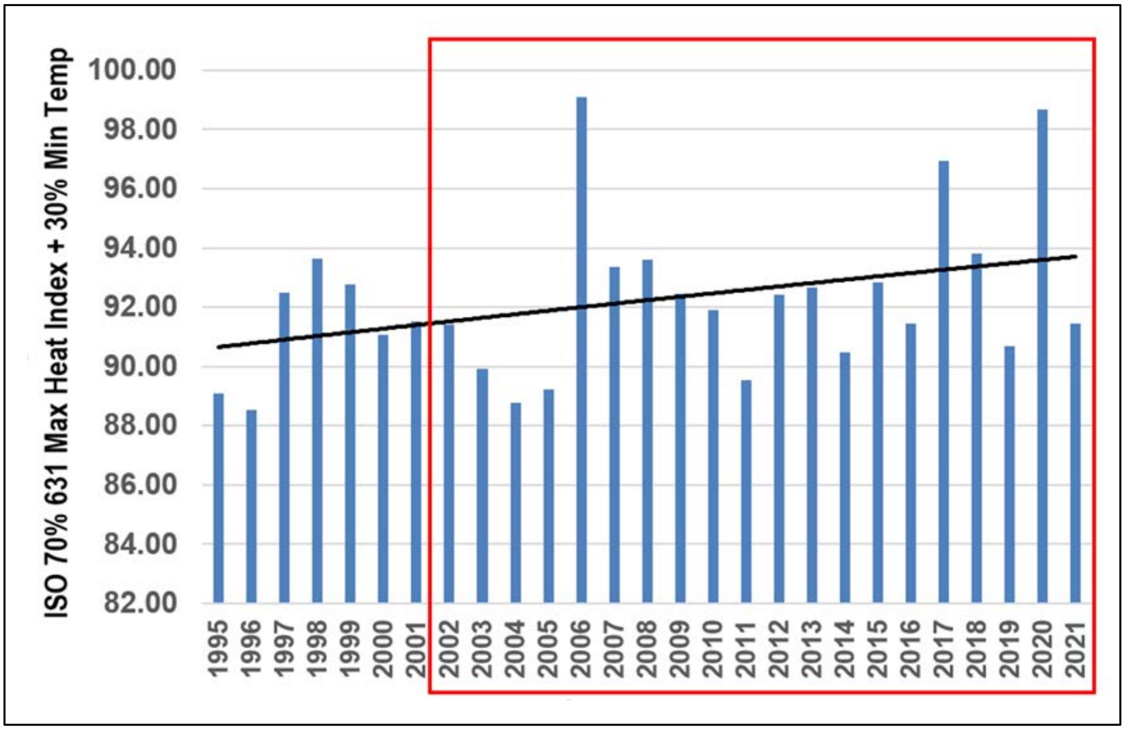
The ISO's annual peak and energy forecast process has five steps. The first step is to develop daily peak and energy models for PG&E, SCE, and SDGE and the ISO using MetrixND®. The inputs are weather data, economic and demographic data, and historical loads (adding demand response back in and excluding water delivery pumping loads). The second step employs a weather simulation program to generate 140 weather scenarios using 20-years of historical weather data from 2002 through 2021. Seven different weather scenarios are developed for each historical year to simulate calendar effects across the weekdays. The third step uses a peak and energy simulation process to generate 140 annual peak and energy amounts through the MetrixND® models based on the 140 weather scenarios. The fourth step randomly generates 5,000 samples from each area's range of 140 annual peak and energy amounts. Finally, a range of typical pump loads during summer peak conditions are added back into the loads to arrive at 5,000 annual peak loads. The 1-in-2 peak load is calculated at the 50^{th} percentile of the 5,000 annual peak loads, the 1-in-5 peak load is calculated at the 80^{th} percentile and the 1-in-10 peak load is calculated at the 90th percentile.

The weather data comes from 24 weather stations located throughout large population centers within the ISO balancing authority area. Weather data used in the model include maximum, minimum and average temperatures, cooling degree days, heat index, relative humidity, solar radiation indices, as well as various temperature weighting indices.

In the 2022 forecast development process, the ISO modified from previous years the historical weather period used in the second step of the load forecast process described above. In prior years' forecasts the ISO utilized a historical weather data period beginning with 1995, the first year that humidity data was available for all 24 weather stations used in the forecast. This resulted in 26 years of historical weather data used in the 2021 load forecast process. For this year's forecast the ISO reduced the historical weather data period to 20-years, *e.g.* 2002 – 2021. This gives more weight in the load forecast to more recent weather experiences related to climate change. Figure 8 shows the historical weather that occurred on the peak day from 1995 – 2021, using the temperature/heat index shown. The black line is the trend line of the data. For the 2022 forecast, only 20-years of historical data, 2002 – 2021, was used to develop the 2022 load forecast of the distribution of loads input into the simulation model. This results in a larger population of the higher loads within the 140 weather scenarios described above, and in the 2,000 scenarios run in the 2022 simulation model, described in the *Stochastic Simulation Approach* section later in this report.

Figure 8

Historical Weather Data Period Used for the 2022 Load Forecast



The historical loads are hourly average demand values sourced from the ISO energy management system (EMS). Water delivery pump loads were not included in the historical demand that is input to the forecast model as they do not react to weather conditions in a similar fashion and are subject to interruption. Pump loads are added back into the forecast demand based on a range of typical pump loads during summer peak conditions.

The ISO uses gross domestic product and population values developed by Moody's Analytics for the metropolitan statistical areas within the ISO as the economic and demographic indicators to the models. *Figure 9* shows a baseline economic scenario forecast developed by Moody's Analytics that represents how the economy is projected to perform based on Moody's baseline assumptions.

According to Moody's baseline economic forecast, COVID-19 remains a significant headwind to the U.S. economy with the worst of the economic fallout from the virus likely over. Travel, tourism and trade will remain hindered and the economy will continue to encounter difficulty until effective vaccines are widely adopted. With a high degree of uncertainty, the Moody's baseline forecast anticipates that the U.S. population will effectively achieve herd immunity from the virus this summer. The real GDP will grow stronger in 2022 than in 2021 and unemployment is moving sideways because of government economic stimulus. The baseline forecast is the median scenario where there is a 50 percent probability that the economy will perform better and a 50 percent probability that the economy will perform worse.

The ISO load forecast is based on the Moody's baseline gross domestic product forecast released in December 2021, the most current data available at the time it was developed. The gross domestic product data reflect actual historical data through Dec 31, 2020 (January 2021 and later historical data are estimates of actual GDP). *Figure 10* shows historical ISO annual peak demands and their associated weather normalized peak demands. The 1-in-2, 1-in-5, and 1-in-10 peak forecasts are also provided, which are based on the base case economic scenarios from Moody's Analytics (*Figure 9*). In monitoring the impact to July 2020 peak demands due to COVID-19 minimal to no load reductions to daily peak demand levels were observed. With the significant unknowns in how the COVID-19 pandemic will continue to impact society and how the various electric sectors use energy, no attempt was made in ISO load forecasting process to predict potential ongoing impacts to loads due to COVID-19 through the 2022 summer period beyond the impacts to the economy projected by Moody's.

Figure 9

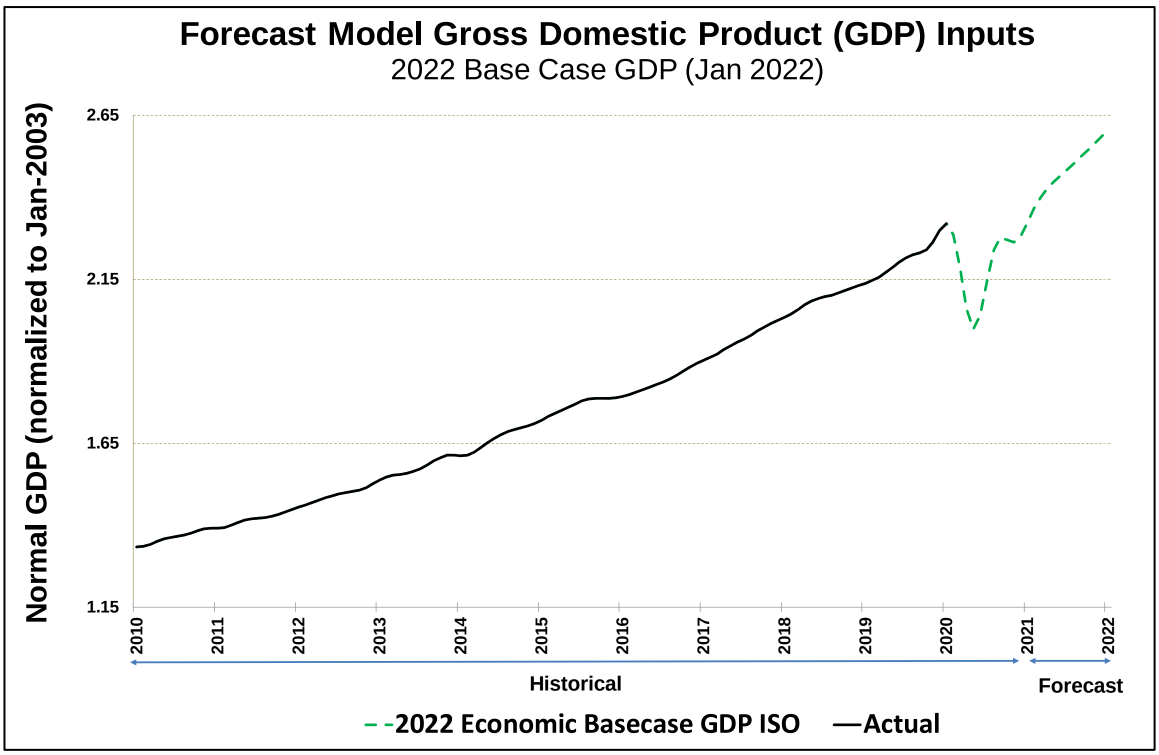


Figure 9 shows 2022 base case Gross Domestic Product for the metropolitan statistical areas within the ISO.

Figure 10

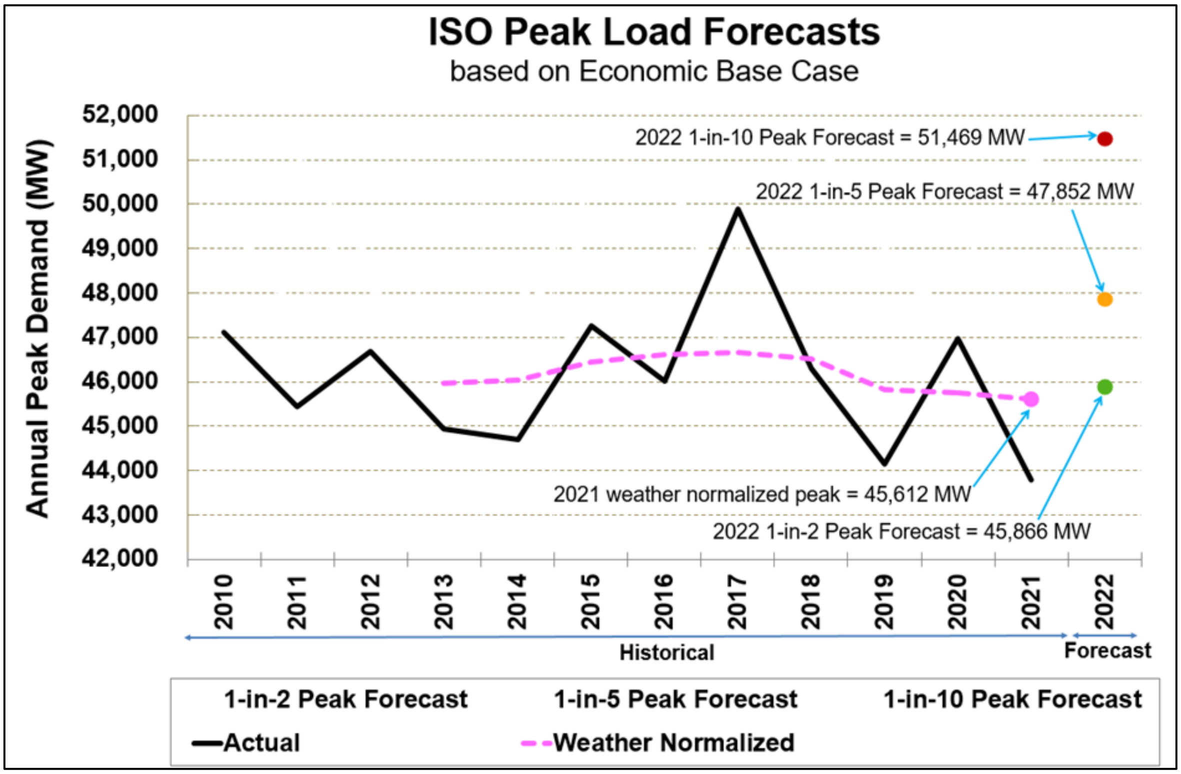


Figure 10 shows the ISO 2021 1-in-2, 1-in-5 and 1-in-10 peak forecasts.

The 2022 1-in-2 peak forecast of 45,866 MW[23] is only a 0.1 percent increase from the ISO 2021 peak demand forecast. The relatively unchanged demand projection is primarily a result of Moody's Analytics baseline forecast of gross domestic product, as shown in *Figure 9*, and continuing load reductions from ongoing behind-the-meter solar installations, and energy efficiency program impacts on peak demand. The 1-in-2, 1-in-5 and 1-in-10 peak load forecasts for 2022 are shown in *Table 7* and compares the 2022 peak demand forecast to the 2021 forecast. The 2022 1-in-2 and 1-in-5 forecasts are virtually unchanged from 2021. The 1-in-10 peak demand forecast in 2022 is 51,469 MW is 1 percent higher than that in 2021. This higher 1-in-10 peak demand forecast is the result of the forecast methodology change to using a 20-year historical weather data set.

[23] The ISO developed 1-in-2 peak demand forecast of 45,866 MW is within 1 percent of the California Energy Commission's 1-in-2 Baseline Forecast Mid Demand Case of 46,319 from its 2021 Integrated Energy Policy Report. As the ISO's projection for 2021 was higher than last year's California Energy Commission forecast for 2021, the year-over-year increase reflected in the ISO forecast from 2021 to 2022 was smaller than the increase in the year-over-year forecasts of the California Energy Commission.

Table 7

2022 Peak Demand Forecast Compared to 2021

	1-in-2	1-in-5	1-in-10
CAISO 2022 Forecast	45,866	47,850	51,469
CAISO 2021 Forecast	45,837	47,747	50,968
Difference (MW)	29	103	501
Difference (%)	0.1%	0.2%	1.0%

Net load is defined as hourly load minus grid-connected wind and solar production. In other words, net load is the remaining load after the gross load has been reduced by the amount of energy production from renewable resources, which the ISO serves by dispatching non-renewable resources. Renewable resources have an energy profile based on the availability of the resource they utilize to produce energy, such as solar and wind. The net load is served by the resources that the ISO is able to dispatch. *Table 8* shows the forecasted net peak load for 2022.

Table 8

2022 Net Peak Load Forecast (MW)

2022	CAISO Net Peak Load Forecast
1-in-2	40,011
1-in-5	43,072
1-in-10	45,391

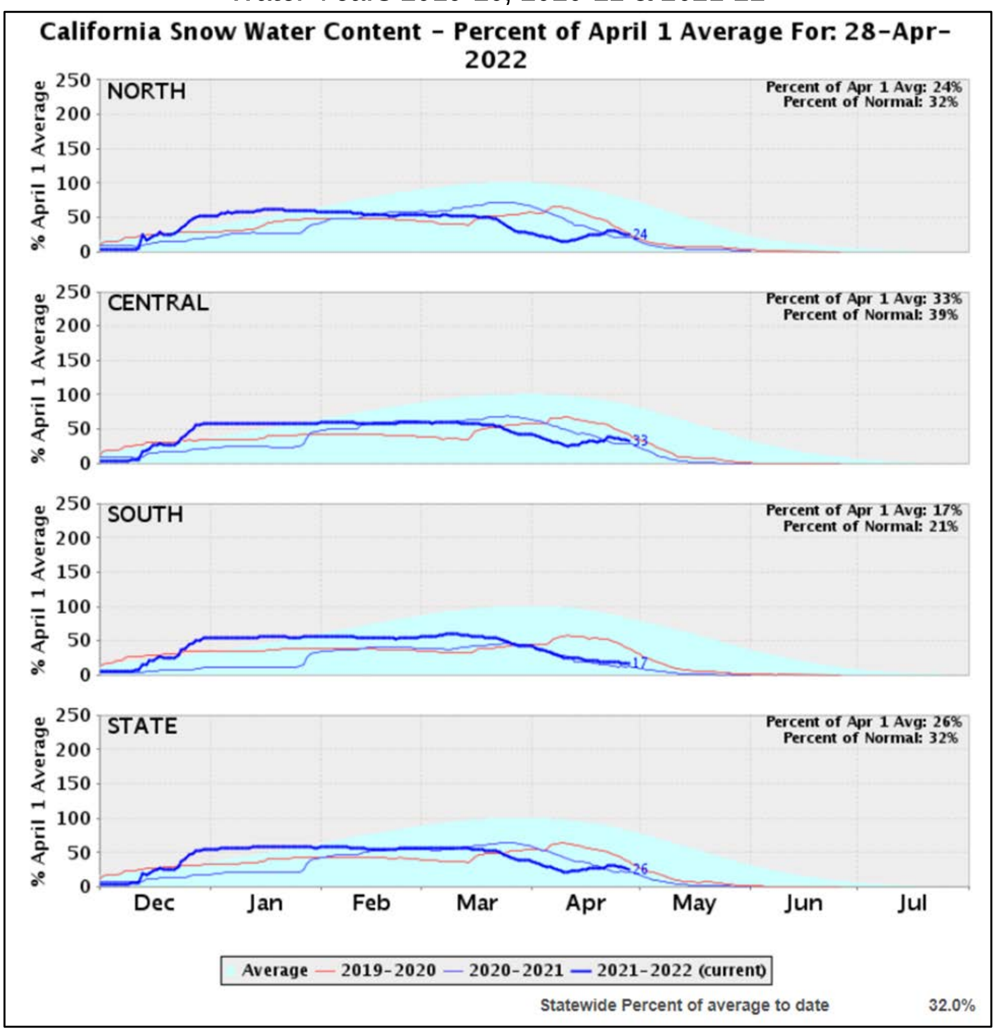
Hydro Generation

For the third consecutive year, California's hydro energy supply will be significantly lower than normal in 2022. The statewide snow water content peaked in January at approximately 60 percent of the April 1 average. Snowmelt was significant early in the season and by April 1 snowpack had decreased to 38 percent of the April 1 average, and continued to decline through April 11. The entire Sierras saw significant snow over the second half of April with the majority in the Northern Sierras. That recent precipitation added almost three inches back to the statewide snowpack. Since April 23, the statewide snowpack has again steadily declined, and on May 9 was 21 percent of the May 9 average. In comparison, statewide snow water content in 2021 peaked at 60 percent of normal in late March, 2021.

Hydro generation is modeled on an aggregated basis as two types: non-dispatchable run-of-river and dispatchable hydro generation. Run-of-river hydro generation is modeled as a fixed generation profile across the summer. The dispatchable hydro generation is optimized subject to the daily energy limits and daily maximum and minimum values. These are derived from historical generation data, for each zone modeled, using the historical hydro year with snowpack and reservoir conditions that most closely resemble the current year. Dispatchable hydro generation can provide system capacity, ancillary service and flexible capacity. Pump storage generators are modeled individually and are optimized subject to storage capacity, inflow and target limits, and cycling efficiency.

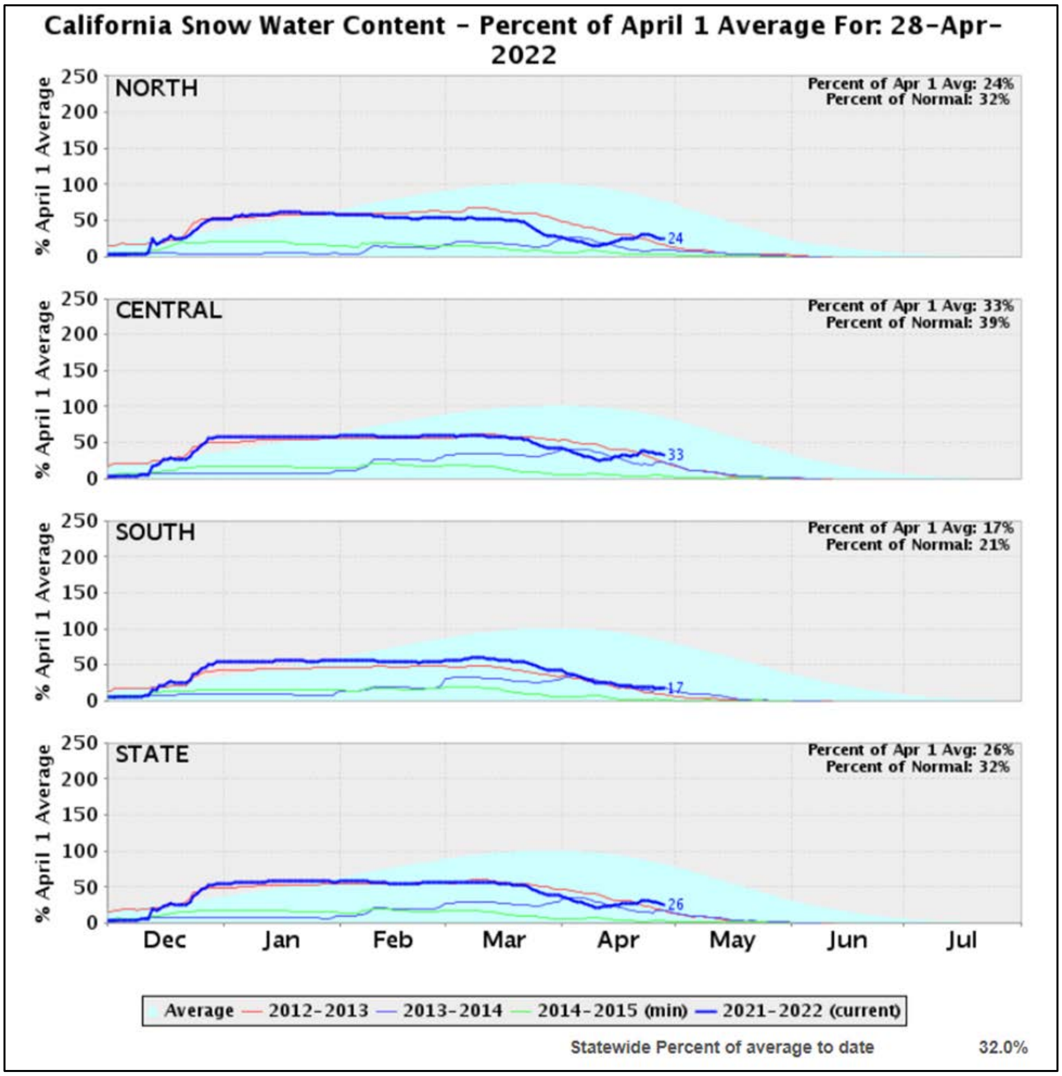
Figure 11 is a chart of the daily snow water content for the last three years. All three years are below normal. The three-year period for water years 2012-13, 2013-14 and 2014-15, shown in *Figure 12*, is the most similar three year historical trend to the three year period ending with 2022, and the 2022 hydro production is anticipated to be most similar to the 2015 historical hydro production.

Figure 11
California Snow Water Content for
Water Years 2019-20, 2020-21 & 2021-22



Source: California Department of Water Resources

Figure 12
California Snow Water Content for
Water Years 2012-13, 2013-14, 2014-15 & 2021-22



Source: California Department of Water Resources

On April 11, 2022, California's major reservoir storage levels were at 70 percent of average, slightly below the 74 percent of average in 2021. Storage levels in California's major reservoirs provides a better indication of water supply conditions than for hydro potential because the majority of hydro generation in California is located on smaller reservoirs, not tracked by the California Department of Water Resources. Flexibility of the hydro fleet can be impacted by the scheduling of water releases from reservoirs to meet water supply needs, which typically has a higher priority than the needs of the electric system, resulting in less than optimal timing of generation from hydro facilities.

Table 9 shows the historical reservoir storage levels as of the end of March. This shows that the three year period ending in 2015 is most comparable to the three-year period ending 2021, on a three-year average basis and on a single-year basis. Based on the historical snow water content history and the reservoir storage history, the 2015 hydro generation profile was used for the 2022 modeling process as a proxy of 2022 hydro production across the summer 2022.

Table 9

Historical California Reservoir Water Storage

End of March

Report generated: April 11, 2022 10:20

End-of-month Storage in Calendar Year:

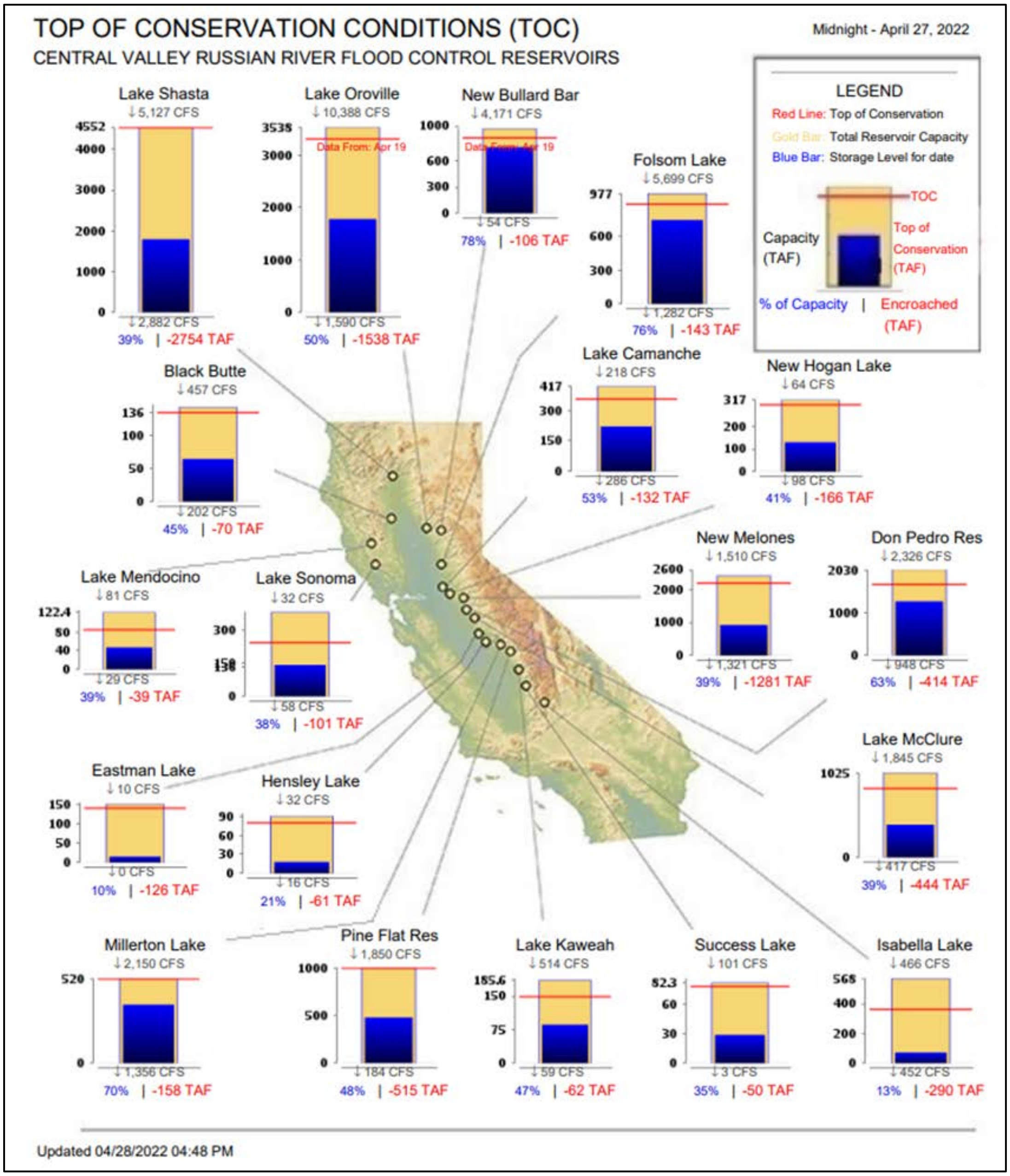
REGION	NUM of RES	CAP	Hist Avg	1977	1983	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
STATE															
NORTH COAST	6	3,096	2,229	1,165	2,421	2,475	1,626	1,565	1,718	2,644	2,234	2,376	2,345	1,549	1,071
SAN FRANCISCO BAY	17	715	525	318	656	441	436	443	527	553	441	539	469	394	451
CENTRAL COAST	6	982	637	435	929	527	210	204	202	668	460	673	519	388	281
SOUTH COAST	29	2,122	1,433	921	1,920	1,242	1,143	864	1,036	1,422	1,270	1,458	1,355	1,243	1,082
SACRAMENTO RIVER	43	16,151	12,012	6,233	13,208	12,746	8,813	9,681	13,076	13,525	12,518	13,398	11,457	8,333	8,458
SAN JOAQUIN RIVER	34	11,483	7,640	2,918	9,045	7,150	5,009	4,641	5,394	8,960	9,075	8,881	7,970	6,378	5,705
TULARE LAKE	6	2,088	884	468	1,462	609	406	377	658	1,018	1,067	919	865	490	640
NORTH LAHONTAN	5	1,073	505	221	826	577	282	74	107	753	969	844	795	419	290
SOUTH LAHONTAN	8	412	264	168	293	249	245	226	240	245	287	272	291	265	236
STATE TOTAL	154	38,122	26,129	12,846	30,761	26,016	18,169	18,076	22,957	29,787	28,321	29,360	26,067	19,459	18,213
PCT OF AVG				**49**	**118**	**99**	**69**	**68**	**87**	**114**	**108**	**112**	**100**	**74**	**70**
						2-Year Ave	84	68.5	77.5	100.5	111	110	106	87	72.0
						3-Year Ave		78.7	74.7	89.7	103.0	111.3	106.7	95.3	81.3

Source: California Department of Water Resources

Figure 13 shows the storage levels of individual major reservoirs across the state.

Figure 13

California Major Reservoir Storage Levels



Source: California Department of Water Resources

The ISO uses the Northwest River Forecast Center's water supply forecast at The Dalles Dam on the Columbia River[24] as an indication of potential imports into California from the Northwest. The current April to September reservoir storage projection at The Dalles Dam Columbia River is 95 percent of average.

[24] https://www.nwrfc.noaa.gov/water_supply/ws_forecasts.php?id=TDAO3

System Capacity

The ISO projected system capacity of 51,556 MW in June, 52,654 MW in July, 50,885 MW in August, and 47,892 MW in September for summer 2022. The decline of available capacity from July to September stems from the diminishing effective load-carrying capability of solar and wind generation in the calculation of Net Qualifying Capacity (NQC) for wind and solar resources, and the waning of hydro generation from June through September. The final NQC list for compliance year 2022[25] and the ISO Master Control Area Generating Capability List[26], posted on the ISO website, provide access to information the ISO used in developing the list of online resources that were modeled.

Each year, monthly qualifying capacity (QC) values are developed for generators eligible to participate in the CPUC's Resource Adequacy program. The ISO uses the QC values to develop the NQC for each eligible generator and publishes the NQC list. The NQC values for each resource describes the amount of generation that has been deemed deliverable and can be utilized to meet Resource Adequacy requirements, which endeavor to ensure adequate capacity is available to meet the forecast peak demand for each month. The NQC value for dispatchable resources depends on its demonstrated capacity and deliverability — the ability of the grid to deliver the generation to load centers. The ISO determines the NQC by testing and verifying as outlined in the ISO tariff and the applicable business practice manual. The NQC values for solar have been declining because the ISO system peak has shifted to later in the day when solar production is diminished to levels at or near zero.

The largest generation resource fuel type is natural gas, accounting for 55.8 percent of the ISO summer maximum on-peak available capacity; the second largest generation type is hydro, which accounts for 13.3 percent. Solar accounts for 10.9 percent, based on its effective load-carrying capability, battery is 6.0 percent, nuclear generation is 4.5 percent, wind is 2.7, demand response 2.2 percent, geothermal 2.2 percent, biofuel 1.2 percent, and oil generation provides 0.2 percent. The overall resource percentages by fuel type are shown in a chart in *Appendix D: 2022 ISO Summer Maximum On-Peak Available Capacity by Fuel Type.*

System Capacity Additions

Table 10 shows the total new installed generation capacity of 7,621 MW[27] is expected to reach commercial operation between June 1, 2021 and June 1, 2022: 3,271 MW is

[25] Final Net Qualifying Capacity Report for Compliance Year 2022: http://www.ISO.com/planning/Pages/ReliabilityRequirements/Default.aspx

[26] Master Control Area Generating Capability List: http://www.ISO.com/planning/Pages/GeneratorInterconnection/Default.aspx (under Atlas Reference)

[27] New resource capacity was developed from the ISO Master File and the New Resource Implementation process to determine the anticipated commercial operation date of new resources expected to come online within the 2022 Assessment study period. The amounts were based on known information as of

dispatchable and 4,350 MW is non-dispatchable[28]. During the same period, 65 MW of dispatchable generation capacity was retired. The net of additions and retirements is an increase of 7,556 MW, with a net increase of dispatchable capacity of 3,206 MW. Additional new resources could come online across the summer, but due to the tentative nature of scheduled commercial operation dates, resources that do not have a high likelihood of achieving commercial operation by June 1 are not included in the analysis.

Table 10

Internal resource additions from 6/2/2021 to 6/1/2022

Fuel Type	PG&E	SCE	SDGE	CAISO
BATTERY	711	1,820	593	3,124
BIO	6	22	0	28
GAS	87	0	38	124
HYDRO	12	0	0	12
SOLAR	590	1,987	375	2,952
WIND	171	1,105	105	1,381
Total	1,577	4,933	1,111	7,621

Of the new resource capacity coming online, 3,124 MW is from battery energy storage systems (BESS) coming online by 6/1/2022. While not providing new energy generation, BESS enable surplus energy generated during periods of high solar production and energy generated during periods of lower energy prices to be stored and provided to meet system needs during the net peak period when solar production ramps down and is no longer available. BESS are able to provide system capacity, ancillary service and flexible capacity.

System Capacity Retirement and Unavailability

Forced outages are generated for individual units on a random basis by PLEXOS using each unit's historical forced outage rate with a uniform distribution function based on 2015 through 2017 individual historical summer forced outages. Planned outages are sourced from the ISO outage management system.

4/12/2022. New resources from this process were cross checked against resources known by the CPUC to be sure all resources the CPUC is expecting were accounted for.

[28] Non-dispatchable resources are technologies that are dependent on a variable fuel source and are modeled in PLEXOS as energy production profiles based on historical generation patterns. Non-dispatchable technologies include biofuels, geothermal, wind, solar, run-of-river hydro, and non-dispatchable natural gas.

Table 11 shows the resources that have retired or mothballed since June 2, 2021. To date, there are no other known additional retirements that will take place by June 1, 2022. All 65 MW of retired capacity was dispatchable.

Table 11

Recently Retired or Mothballed Generation (6/1/2021 to 6/1/2022)

RESOURCE ID	Current Status	MW	Actual offline Date	Fuel Type	PTO	Dispatchable
OAK C_7_UNIT 2	Retired	55	1/1/2021	OIL	PG&E	Y
CASTVL_2_FCELL	Retired	1	5/31/2021	GAS	PG&E	Y
DALYCT_1_FCELL	Retired	2	5/31/2021	GAS	PG&E	Y
VACADX_1_NAS	Retired	2	7/31/2021	BATTERY	PG&E	Y
SWIFT_1_NAS	Retired	5	7/31/2021	BATTERY	PG&E	Y
Non-Dispatchable		0				
Dispatchable		65				
Total		65				

Unit Commitment

The PLEXOS production simulation applies unit commitment constraints for generator startups and shutdowns. While the generator is starting up, it cannot provide ancillary or load following services while ramping from initial synchronization to its minimum allowed operating capacity. Similarly, when a generator is in the process of shutting down, it cannot provide ancillary or load following services once it has ramped down past its minimum capacity threshold. Once a generator is committed, it must remain in operation for its minimum run time before it can be shut down. After a generator has been shut down, it is not available for commitment again until it has been off for its specified minimum down time.

Once a generator is operating within its operating range (between its minimum and maximum capacity) it must meet the criteria set out below.

If a generator is ramping up:

- Regulation up, spinning, and non-spinning provided by a generator cannot exceed its 10-minute ramping up capability and unused capacity;
- Energy, regulation up, spinning, and non-spinning provided by a generator cannot exceed its 60-minute ramping capability and its available unused capacity.

During ramping down:

- The difference between a generator’s minimum capacity and its current operating point determines the amount of regulation-down and load following-down that can be provided by a generator.

Therefore, the model sets 60 minutes ramping time for energy and 10 minutes for ancillary services in each hour's simulation.[29] Each dispatchable generator can run at its maximum ramp rate between its minimum and maximum capacity.

Curtailable Demand and Demand Response

Curtailable Demand includes demand response, pumping load, and aggregated participating load that can provide non-spinning reserve or demand reduction. Curtailable demand reduces end-user loads in response to high prices, financial incentives, environmental conditions or reliability issues. It can play an important role to offset the need for more generation and provide grid operators with additional flexibility in operating the system during periods of limited supply.

Demand response programs are modeled as supply side resources that have triggering conditions in the stochastic simulation model. They include base interruptible programs, aggregator managed portfolios, capacity bidding programs, demand bidding programs, smart AC, summer discount plans, and demand response contracts.

Whenever the model depletes all available resources before meeting the load and ancillary service requirements, the model will utilize demand response programs. The total amount of demand response resources modeled for 2022 was 1,221 MW.

The Flex Alert program is a voluntary energy conservation program that alerts and advises consumers about how and when to conserve energy when supply is running low. The Flex Alert program continues to be a vital tool for the ISO during periods of high peak demand or other stressed grid conditions to maintain system reliability. The alerts also serve as a signal that both non-event and event-based demand response are needed.

Interchange

The model simulates 35 WECC zones and 91 WECC interchange paths between zones, as shown in *Figure 14*. The zonal interchange path limits were set based on the WECC Path Rating Catalog. Transmission limits within the zones were not modeled and the model cannot provide results related to local capacity requirements. The transfer capabilities between any two adjacent zones reflect the maximum simultaneous transfer capabilities. In addition, a total ISO maximum net import limit was set based on historical net import patterns. Path 15 and Southern California Import Transmission (SCIT) nomogram constraint were enforced in the model.

[29] The maximum ancillary service (regulation or spinning) a generator can provide (the maximum ramp up rate × 10 minutes) is calculated by PLEXOS on an hourly basis.

Figure 14

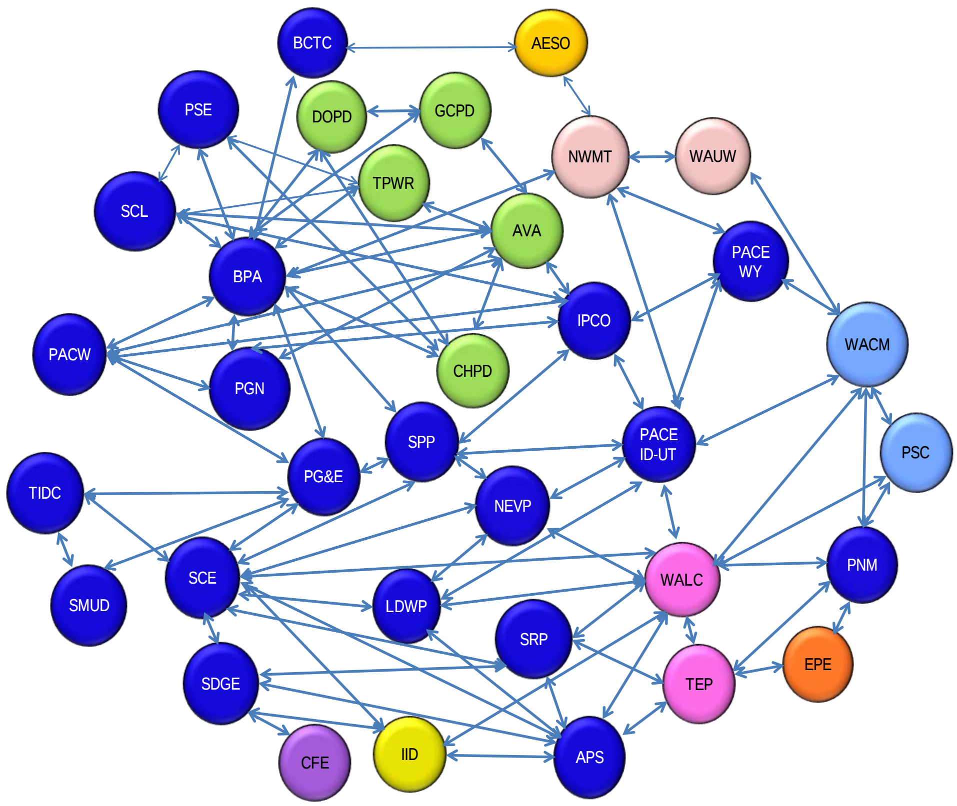


Figure 14: Simulation covers 35 WECC zones and 91 paths.

Net Import Constraints

Table 12 shows historical ISO net imports during any hour of the day when the ISO load is equal to or greater than 41,000 MW[30] during 2019 to 2021. ISO system reliability depends on a various levels of net imports from neighboring balancing authorities, particularly during higher system demands. This indicates that the availability of net imports at historical levels could be at risk at times when the ISO may need higher levels of imports to meet high ISO loads if surplus energy in neighboring balancing authorities is diminished due to high loads in their areas.

[30] 41,000 MW is approximately 90 of the 1-in-2 peak demand forecasts for 2019 - 2021.

Table 12

ISO net imports when ISO load is equal to or greater than 41,000 MW during all 2019 to 2021 summer hours

Year	2021	2020	2019
Min	521	2,392	4,436
First Quartile	3,473	4,710	6,313
Median	5,022	6,165	7,004
Third Quartile	6,461	7,692	8,063
Max	8,552	10,352	9,682

When seasonal high temperatures increase electric energy consumption in California, neighboring Balancing Authorities' electric energy consumption are often high as well. Under these conditions, imports from neighboring Balancing Authorities will frequently be reduced when the ISO's demand ramps up to its peak. To reflect this system operation situation in the ISO's production simulation model, a net import nomogram was developed based on historical EMS net import data from 2019 to 2021. *Figure 15* shows the net imports during the hours of hour-ending 16 – 21 when demand is at or above 41,000 MW[31] for all summer months during 2019 – 2021. Analyses of the monthly trends of net imports demonstrate a declining nature of net imports as demand increases. The red line in *Figure 15* represents the net import limit of the nomogram as a function of load during the hour-ending 16 – 21 peak period. During non-peak hours the net imports are capped at 10,996 MW, the highest net import experienced during all hours of 2021. The chart in Appendix C provides additional information on net imports at time of daily peak demand.

- Off peak net imports (HE 1 - 15, 22 - 24): capped at 10,996 MW (the maximum net imports during 2021)
- On peak nomogram (HE 16 - 21):
  - 2022 model nomogram: Net imports capped at 9,700 MW when the ISO peak is 41,000 MW, declining to 6,000 MW (the approximate 5-year average of the August RA import showings), at the ISO peak of 51,000 MW (the approximate 1-in-10 demand forecast)

[31] 41,000 MW is approximately 90 of the 1-in-2 peak demand forecasts for 2019 - 2021.

Figure 15

On-peak net import nomogram used in the 2022 model

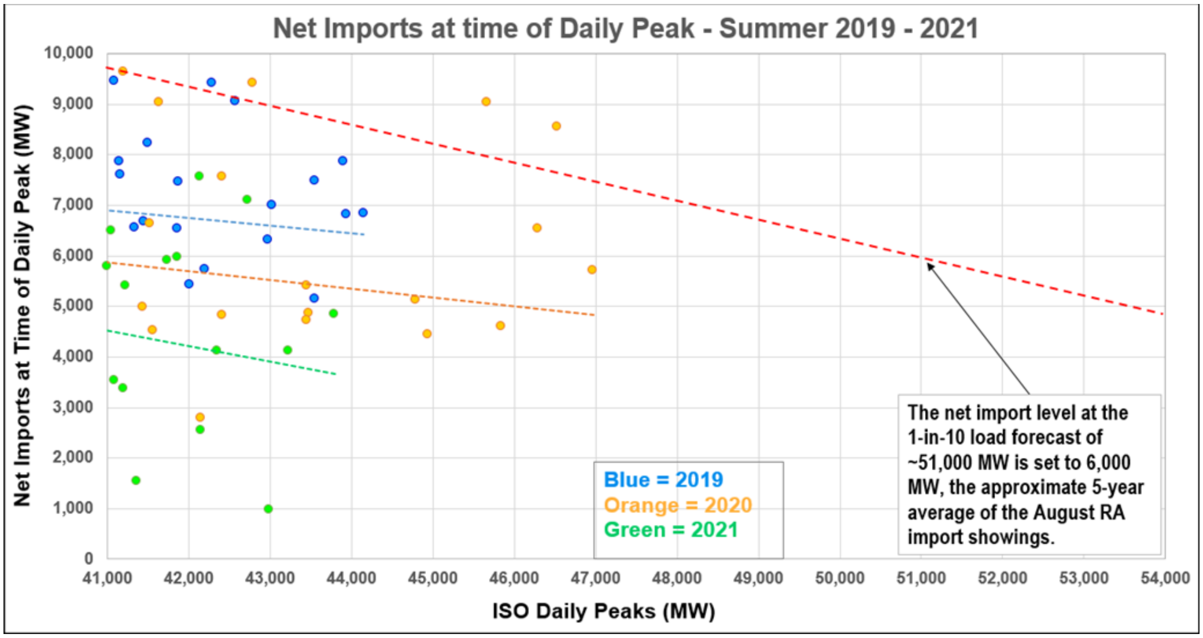


Figure 15 shows ISO net imports vs. ISO load during the hours of hour-ending 16 – 21 when the demand is at or above 41,000 MW for the years 2019 to 2021.

Stochastic Simulation Approach

To evaluate resource adequacy and to understand how the system will respond under a broad range of operating conditions, the modeling methodology uses all active market participant capacities available within the ISO balancing authority regardless of contractual arrangements. While some resources may not receive contracts under the Resource Adequacy program, and may possibly contract with entities outside the ISO for scheduled short-term exports, these resources are still considered available to the ISO for the purposes of this Assessment. Resources not procured for the Resource Adequacy program do not have must-offer obligation to the ISO Day-Ahead and Real-Time Market. The ISO may be able to utilize these non-RA resources, if physically available, via the backstop Capacity Procurement Mechanism.

Conventional generation units such as gas and nuclear are modeled as individual dispatchable units, while non-dispatchable resources, such as qualifying facilities (QFs), biofuel, geothermal, solar and wind, are modeled using fixed hourly generation profiles based on aggregated historical hourly generation profiles, which are adjusted based on the projected capacity additions and retirements.

In recent years, significant amounts of new renewable generation, especially solar, have reached commercial operation to meet the 60 percent requirement by 2030. To successfully meet the state's Renewables Portfolio Standard goals, increasing amounts of flexible and fast responding resources must be available to integrate the growing amounts of variable resources. These increasing amounts of variable resources integrated with the

ISO grid pose unique challenges for ISO operations and for the analytical tools used by the ISO to assess near-term reliability.

As new renewable resources come on the system, the ISO reliability focus has evolved from meeting the gross peak demand to meeting both net peak demand and flexible capacity requirements. The gross peak usually occurs at the hour ending 16:00 to 18:00 while net peak occurs in the hour ending 19:00 to 21:00 timeframe, when solar generation is close to zero. The ISO's evolving net load profile – gross load minus grid-interconnected solar and wind generation – has become known as the duck curve. The growing amount of photovoltaic solar generation that is interconnected to the ISO grid continues to change the ISO's net load profile and creates more challenges and uncertainty for ISO operations.

Photovoltaic solar generation located behind the customer meter is an additional impact, affecting the gross load and further decreasing the net load that the ISO serves. The result is a constantly increasing ramping requirement, significantly more than what has been required from the generation fleet in the past, both upward and downward. Furthermore, solar generation does not provide significant power at the hours ending 19:00 to 21:00, which leads to reliance on gas and other non-solar generation after sunset. The continuing decline in dispatchable generation in the ISO as dispatchable units retire is beginning to challenge the ISO system's ability to meet net peak demand after sunset and flexible capacity requirements.

To assess the changing resource needs from the increasing number of variable resources and declining fleet of dispatchable resources, the ISO started to use the PLEXOS stochastic model in the development of the 2016 Summer Assessment. To mimic the real-time market short-term unit commitment function during the window extending 4.5 hours prior to real-time and the real-time unit dispatch function 1 hour 45 minutes prior to real-time for the intra-hour requirement to cover intra-hour uncertainty and variability, the ISO calculates the intra-hour regulation and load following requirements and converts these intra-hour requirements to hourly requirements using a probabilistic Monte Carlo simulation program developed by Pacific Northwest National Laboratory, inputting them as system requirements in the PLEXOS stochastic model.

The model simulates 35 WECC zones with 91 WECC interchange paths. It uses a mixed-integer linear programing to determine the optimal generation dispatch. The model runs chronologically to dispatch capacity, ancillary services and load following to seek the least cost, co-optimized solution to meet system demand and flexibility requirements simultaneously. Operational constraints include forced and planned outage rates, unit commitment parameters, minimum unit up and down times, unit heat rates, and ramp rates for each generator in the ISO.

The model runs 2,000 scenarios on an hourly interval chronologically. Each scenario has a 2,928-hour profile from June 1 to September 30[32]. The optimization time horizon was set

[32] The study period of June 1 through September 30 in each scenario represents 2,928 hours (24 hours × 122 days).

as 24 hours. The end status of one optimization is used as the initial status of the next optimization. For hours when supply is sufficient, the model calculates the UCM and determines the MUCM for each 2,928-hour profile scenario based on load and available resources including curtailable demand, imports, and exports. Each of the 2,000 scenarios produce one MUCM value over the 2,928 hours from June 1 through September 30. If supply is not sufficient, the model reports the unserved hours and unserved energy where demand exceeds supply.

UCM (t) = $\frac{Unloaded\ Capacity(t)}{Load(t)}$[33]

MUCM = Min ($UCM\ (1), \dots, UCM\ (t), \dots, UCM(2{,}928)$)

Where, *Unloaded Capacity (t)* is any portion of online generation capacity not serving load and offline generation capacity that can come online in 20 minutes or less to serve load as well as curtailable demands such as demand response, interruptible pumping load, and aggregated participating load that can provide non-spinning reserve or demand reduction.

The 2,000 unique scenarios are randomly generated, each representing a combination of forecasted 2,928 hourly load profiles and renewable generation levels based on historic annual weather patterns, using a two-step process. The first step is to build three pools of load, wind and solar profiles. In this step, 20-years of historical daily weather profiles were used to forecast 140 daily and annual peak profiles and annual energy loads, which are adjusted to actual historical hourly load profiles to create 140 hourly load profiles. These 140 hourly load profiles were combined with 13 hourly wind and 8 hourly solar profiles to generate 14,560 scenarios[34], among which 2,000 scenarios were randomly selected for the stochastic modeling process, illustrated in *Figure 16*.

[33] Gross or total ISO load as opposed to net load or consumption which includes load served by behind the meter resources.
[34] 140 load profiles × 8 solar profiles × 13 wind profiles equals 14,560 scenarios.

Figure 16

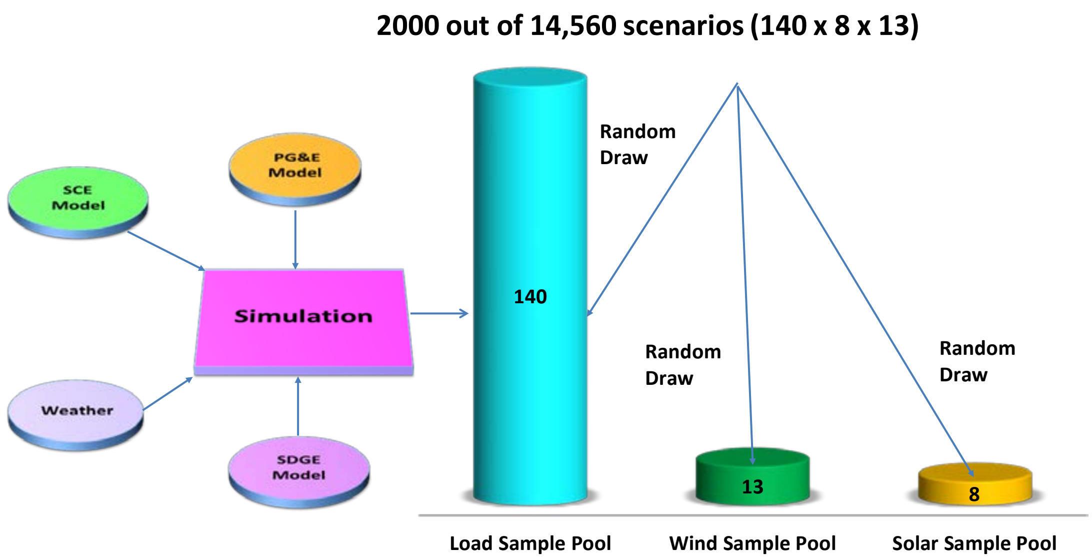


Figure 16: 2,000 scenarios of load, wind and solar are randomly selected from 14,560 scenarios.

Stochastic Simulation Results

The Assessment performed system operation studies to assess resource adequacy based on historical net import levels and under a more conservative net import assumption. The simulation results include the system capacity adequacy, ancillary service and flexible capacity adequacy.

System Capacity Adequacy

The model produces an UCM for each hour modeled. Taking into account the unloaded capacity margin for all of 2,928 hours within each of the 2,000 summer scenarios, the UCM ranges from a high of 95 percent, down to a low of zero, with a very small number of scenarios at both extremes. The median value of all unloaded capacity margin values is 33.8 percent in *Figure 17*.

Figure 17

ISO Unloaded Capacity Margins
June through September 2022

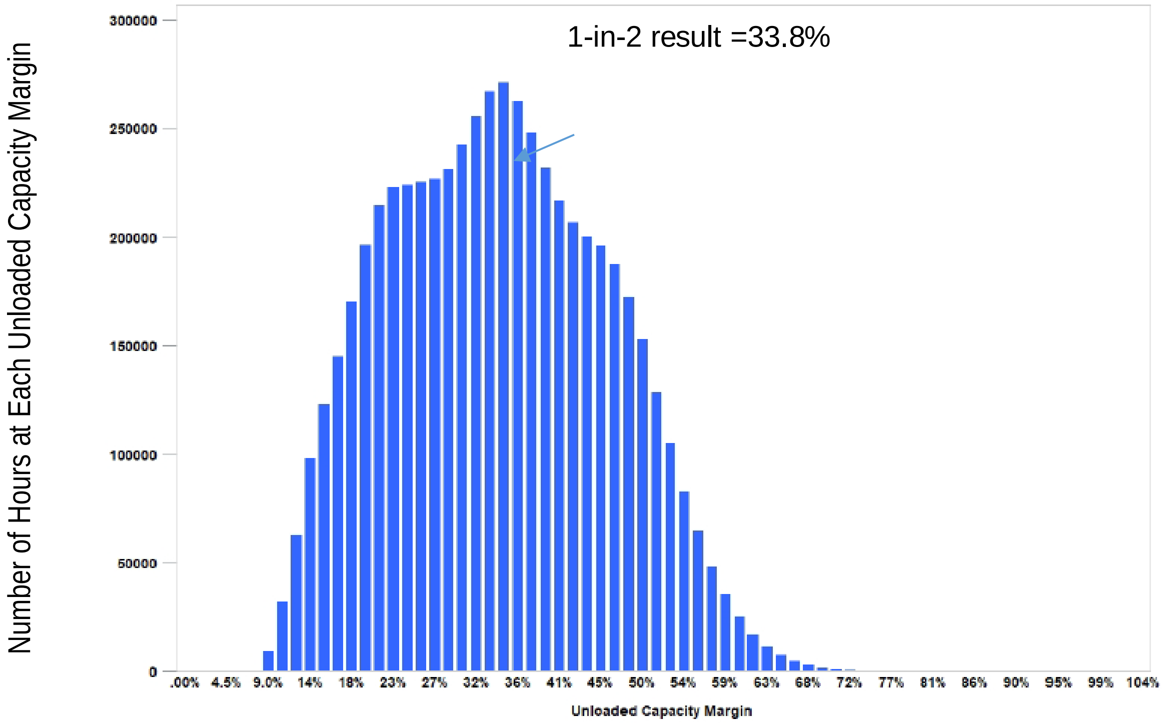


Figure 17 shows the distribution of the UCMs over all 2,928 summer operating hours from all 2,000 scenarios.

The lowest UCM from each scenario modeled is termed the Minimum Unloaded Capacity Margin (MUCM). The MUCMs of all 2,000 scenarios simulated are used to determine the probability of various capacity shortfall events occurring. In other words, by looking at the worst, lowest margin hour of each scenario, a single scenario showing a capacity shortfall event would result in a probability of shortfall of one in 2,000, regardless of how many hours or how many events within that scenario that the shortfall occurred. Table 13 shows scenarios with low operating reserves where the MUCM is at these points that fall within EEA 3:

- EEA 3 Threshold : The point of transitioning from EEA 2 to EEA 3, where reserves are just beginning to be depleted and start to fall below the reserve requirement.
    - o 15.1 percent probability based on 301 scenarios having at least one hour that met that condition.
- EEA 3 – 50 percent of contingency reserves from firm load: At this point 50 percent of the contingency reserves are met by firm load. (i.e. Reserves are below required levels and we are having to dispatch our contingency reserves to meet the load and firm load is armed for load shedding to replace the dispatched contingency reserves. This is not a defined point in the EEA 3 definition.)

  - 7.7 percent probability based on 154 scenarios having one hour or more that meet that condition.

- Unserved energy: The point in EEA 3 where and firm load interruption is required to maintain contingency reserves.
  - 4.0 percent probability based on 80 scenarios showing one hour or more of unserved energy.

System capacity shortfall probabilities for the first two of these three conditions in 2022 are higher than those in 2021, primarily the result of a greater percentage of high load scenarios in 2022 due to the forecast methodology change to using a 20-year historical weather data set. The 2022 system supply includes a net increase of dispatchable capacity of 3,206 MW over 2021; as a result, the number of unserved energy hours in each scenario with unserved energy in 2022 is less than 2021.

These seasonal shortfall probabilities, developed as comparative operational metrics and based on the maximum depth of shortfall in cases that had shortfalls, do not translate directly into an annual loss of load expectation used in assessing annual performance against a “1 event in 10 years” target.

Table 13

Probability of system capacity shortfall

2022		
System Capacity Shortfall	Shortfall Probability	Number of Shortfall Cases (out of 2,000)
EEA 3 Threshold (Stage 2)	15.1%	301
EEA 3 – 50% of contingency reserves from firm load (Stage 3)	7.7%	154
Unserved energy EEA 3 - firm load interruption	4.0%	80
2021		
System Capacity Shortfall	Shortfall Probability	Number of Shortfall Cases (out of 2,000)
EEA 3 Threshold (Stage 2)	6.4%	128
EEA 3 – 50% of contingency reserves from firm load (Stage 3)	4.8%	96
Unserved energy EEA 3 - firm load interruption	4.6%	91

Demand response programs would have been fully utilized to maintain operating reserve margins before reaching the EEA 3 condition. Under this severe operating condition, the ISO will issue a notice of potential load interruptions to utilities and implement the mitigation operating plan to minimize loss of load in the ISO balancing authority area described in the *Preparation for Summer Operation* section at the end of Section II of this report. Whether actual interruptions would occur depends on the specific circumstances and potential for recovering reserves. System capacity shortfall probabilities for EEA 3 in 2022 are higher than those in 2021, primarily the result of a greater percentage of high load scenarios in 2022 due to the forecast methodology change to using a 20-year historical weather data set. The overall supply with additional resources coming online in 2022 will provide more resource capacity in 2022 than what was available in 2021; as a result, the number of unserved energy hours in each scenario with unserved energy in 2022 is less than 2021.

While *Table 13* shows the number of scenarios with at least one hour in the various capacity shortage conditions, *Figure 18* shows the number of hours of shortage within each of the three shortage categories above and the number of scenarios at each hours of occurrence level.

Figure 18

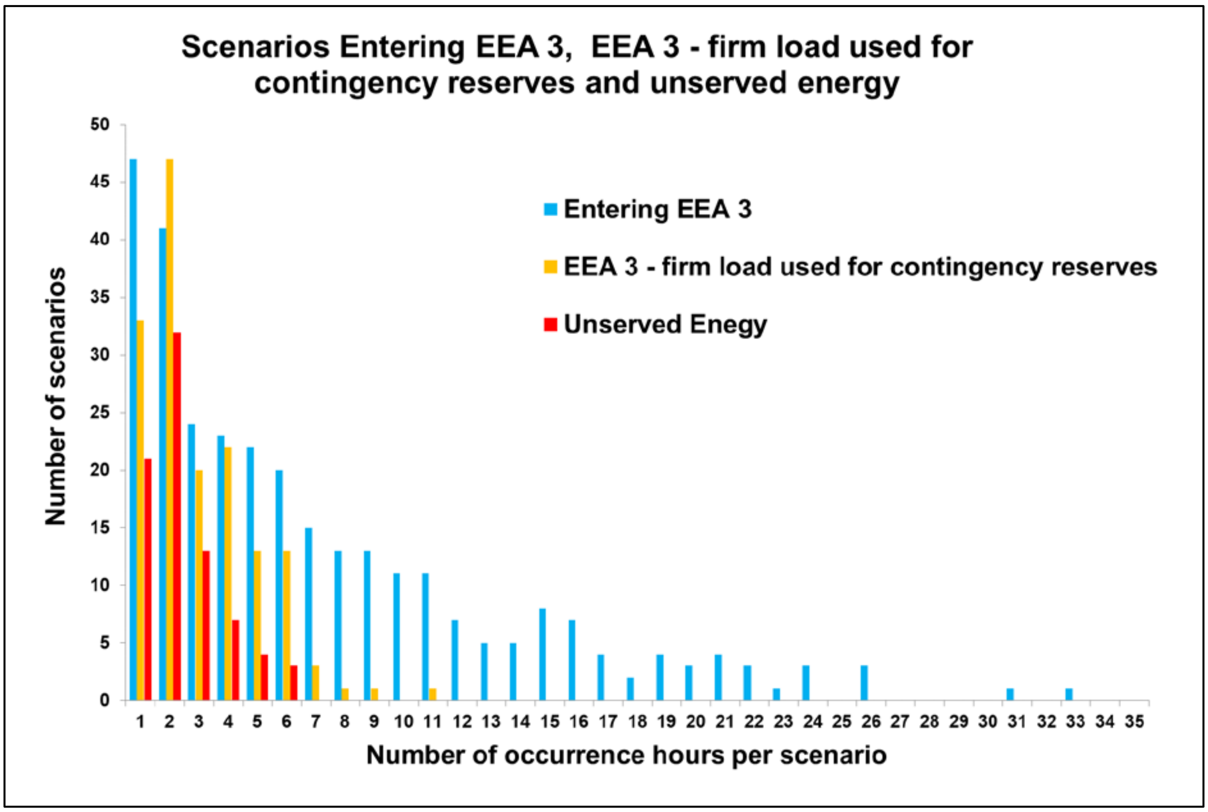


Figure 18 shows the number of hours of shortage within each of the three shortage categories and the number of scenarios at each hours of occurrence level.

Figure 19 shows the occurrences of unserved energy and the corresponding ISO load levels. The maximum unserved energy was 4,717 MW in August. The ISO loads when unserved energy occurs ranged from 44,986 MW to 53,016 MW.

Figure 19

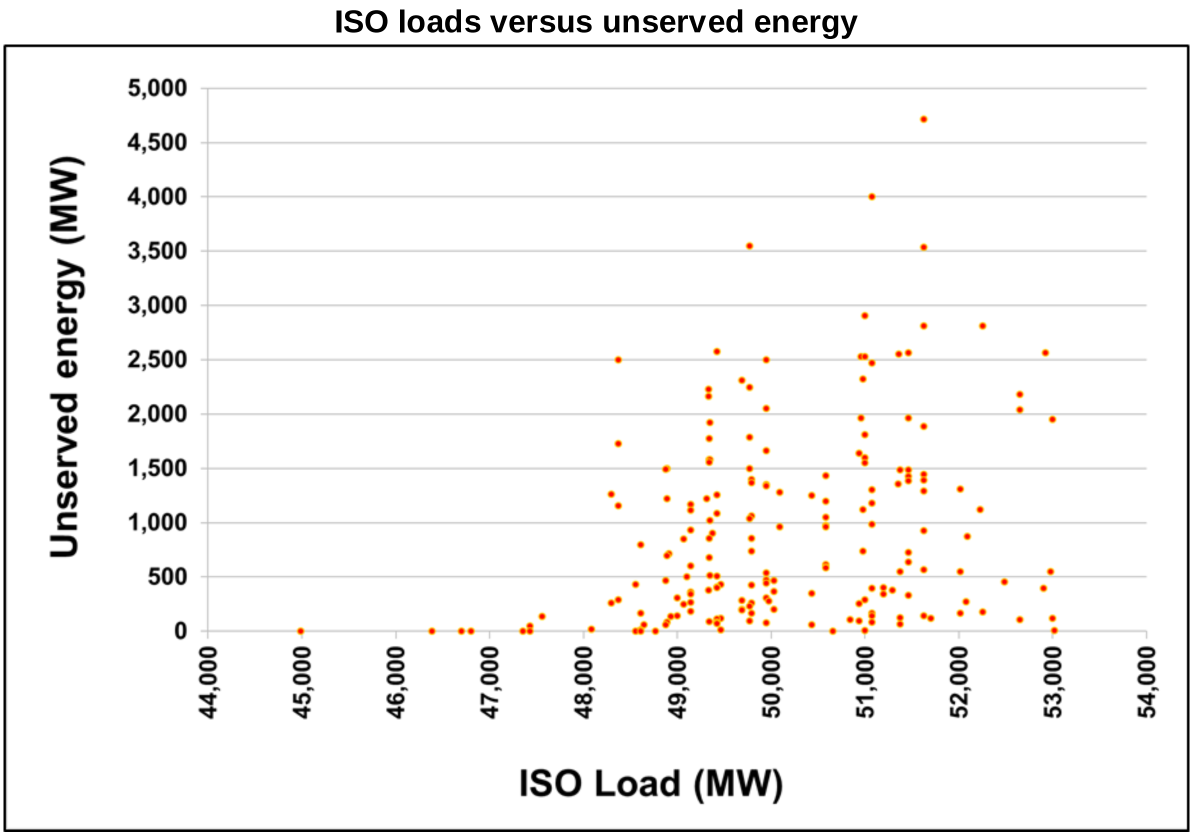


Figure 19 shows ISO unserved energy vs ISO loads.

To further assess resource adequacy for the summer, the MUCM value, equal to the lowest unload capacity margin in all 2,928 hours in each scenario, is determined for each of the 2,000 scenarios. The MUCM values from the 2022 model result range from a high of 12.5 percent down to the lowest result of zero in *Figure 20*. The zero result represents the most extreme hourly supply and demand condition within the 2,000 scenarios considered where in addition to the UCM at zero, there was an amount of energy load that is not served. One or more hours of unserved energy were found in 80 of the 2,000 scenarios.

Figure 20

ISO Minimum Unloaded Capacity Margin Distribution

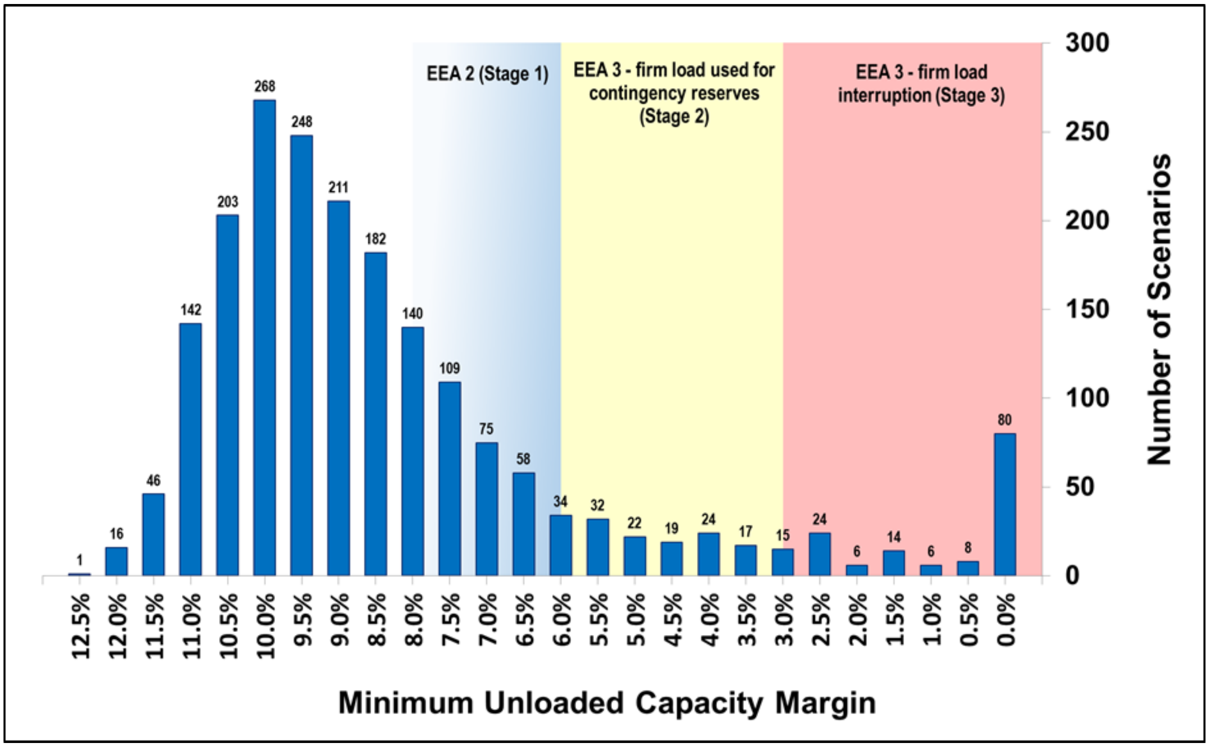


Figure 20 shows distribution of summer ISO MUCM.

While the additional capacity that began operating since last summer positively impacts the results, the revised forecast methodology results in increasing probability of low operating reserve levels even with the added capacity. However, to understand these results more fully, *Table 14* shows the levels of unserved energy from the 2021 and 2022 assessments. Unserved energy is the amount of customer load that is unable to be served due to a lack of resources at that time to serve the load. The results in *Table 14* show a significant reduction in unserved energy in 2022 versus 2021, with the amount of unserved energy reduced by 84 percent and the hours of unserved energy reduced by 71 percent.

Table 14

Comparison of Unserved Energy Results

	2021	2022	Percent Reduction (2021-2022)/2021
Total unserved energy MWH of all hours in 2,000 scenarios	1,085,168	177,394	**84%**
Number of hours of unserved energy in all 2,000 scenarios	645	190	**71%**
Percent of hours of unserved energy in all 2,000 scenarios	0.011%	0.003%	

To put these two sets of data in context, *Table 13* shows that the higher loads in the load forecast range result in higher probabilities for experiencing conditions leading to reserve margins in the EEA 3 range. However, the *Table 13* probabilities are based on the number of scenarios, but as shown in *Table 14* the 2022 simulation results show the number of hours at risk of actual load shedding is significantly reduced. This is demonstrated in the unserved energy results, when reserves decline to the point that firm load needs to be shed, the actual amounts of load shed is significantly reduced from 2021 to 2022.

These results do not take into account growing risks of more extreme events stemming from more disruptive climate change events and supply chain disruptions. These risks include:

- More extreme weather events beyond those projected from the most recent 20 years of historical data;
- Wildfires that could limit key transfer paths or resources and other potential transmission outages;
- The unexpected confluence of extreme heat and drought affecting fire risk;
- Smoke impacting solar production, and;
- Project development delays such as those triggered by the recent Department of Commerce investigation of solar panel tariff issues and other supply chain delays.

The timeframe of greatest operational risk is during the late summer if the ISO and the west experience a widespread heat wave that results in low net imports into the ISO due to high peak demands in its neighboring balancing authority areas, concurrent with the diminishing effective load carrying capability of solar resources and the wane of hydro generation.

The probabilities for operating in conditions that lead to an EEA 3 are based on the minimum reserve margins within each of the model's 2,000 scenarios. The minimum reserve margin is used to show the likelihood of reaching various levels of low operating reserves for at least one hour over the summer period. *Figure 21* shows the 2022 model results distribution for scenarios with a minimum reserve margin of 6 percent or less and the hours of the day that they occurred. The hours of solar generation anticipated during the 2022 summer peak day is shown to demonstrate that 81 percent of these low minimum reserve margins occurred during the hours ending 19:00 to 21:00 – hours of little to no production from solar resources. *Figure 21* demonstrates that resource adequacy levels are most challenged in the post-solar window, as reductions in the gas fleet have not yet been offset by sufficient new energy storage resources to compensate for the loss of capacity available in that window.

Figure 21

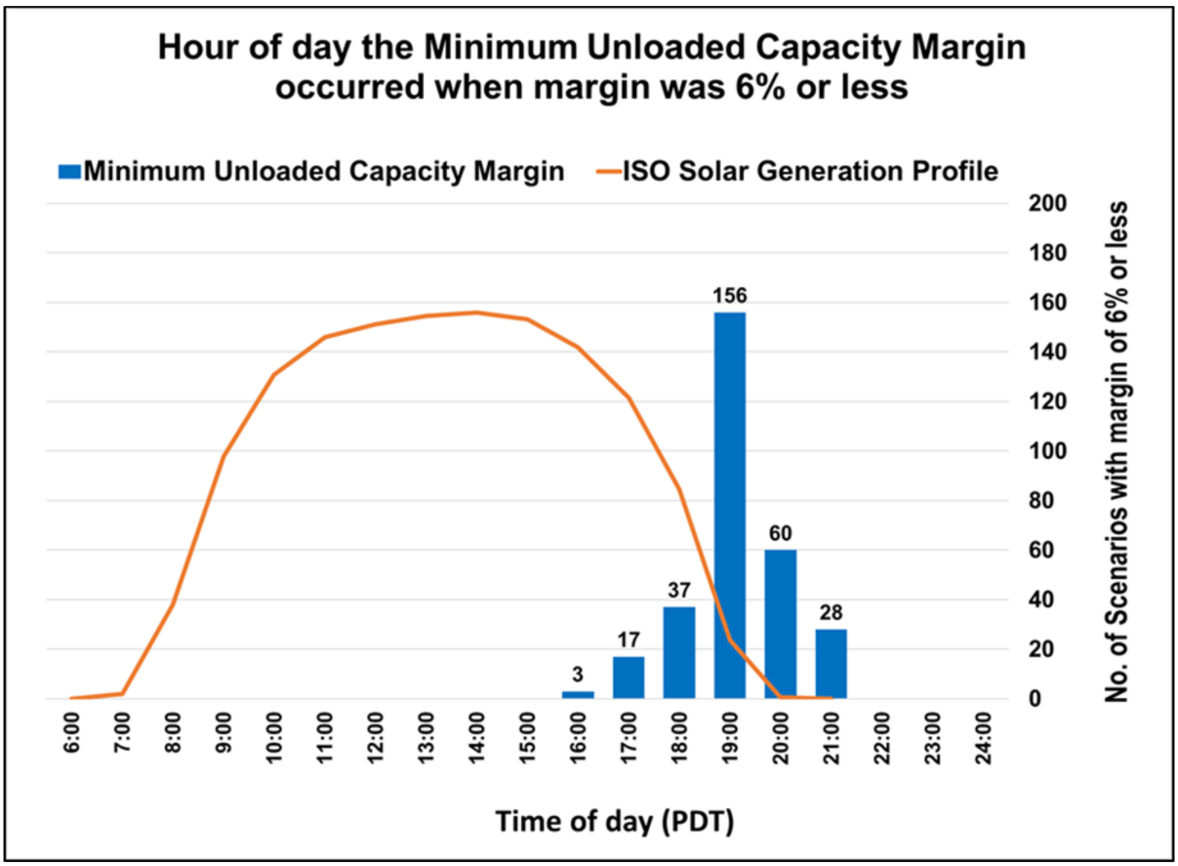


Figure 21 shows the occurrence hour of MUCM and solar generation.

Ancillary Service and Flexible Capacity Adequacy

In addition, to assess system capacity adequacy, the PLEXOS model assesses the ancillary service and flexible capacity adequacy in the ISO market. *Table 15* and *Figure 22* show the 2022 simulation results where the ISO system has a 12.6 percent probability of a load following up shortage, based on 251 scenarios that produced an hour or more of the shortage, a 9.7 percent probability of a spinning shortage, based on 194 scenarios that produced an hour or more of the shortage, and a 5.4 percent probability of a regulation up shortage based on 107 scenarios that produced one hour or more of a potential shortage.

The model's load following shortfall result is an indicator of tightness of dispatch capability. In actual real time operations a load following shortfall occurs and impacts ability to meet demand only when actual intra hour variability and uncertainty needs materialize. A load following shortfall does not have an operational impact when potential intra-hour uncertain and variability do not materialize. Therefore, load following shortfalls observed in hourly production simulations may only have a minimal operational impact. However, if a load following shortfall were to occur when actual intra hour variability and uncertainty needs do materialize, prices may rise and in some cases it may be necessary to rely on regulation or operating reserve to maintain balance between supply and demand. Otherwise, the ISO system may face operational challenges maintaining frequency within required limits. The scarcity of ancillary service and flexible capacity could cause NERC Control Performance Standard 1 (CPS1) violations, frequency deviation, increased area control error, and high scarcity prices.

Table 15

Probability of ancillary service and flexible capacity shortfall

AS and LFU Shortfall	Shortfall Probability	Number of Shortfall Cases
Load following up	12.6%	251
Spinning	9.7%	194
Regulation up	5.4%	107

Figure 22

Scenarios with regulation up, spinning and load following up shortage

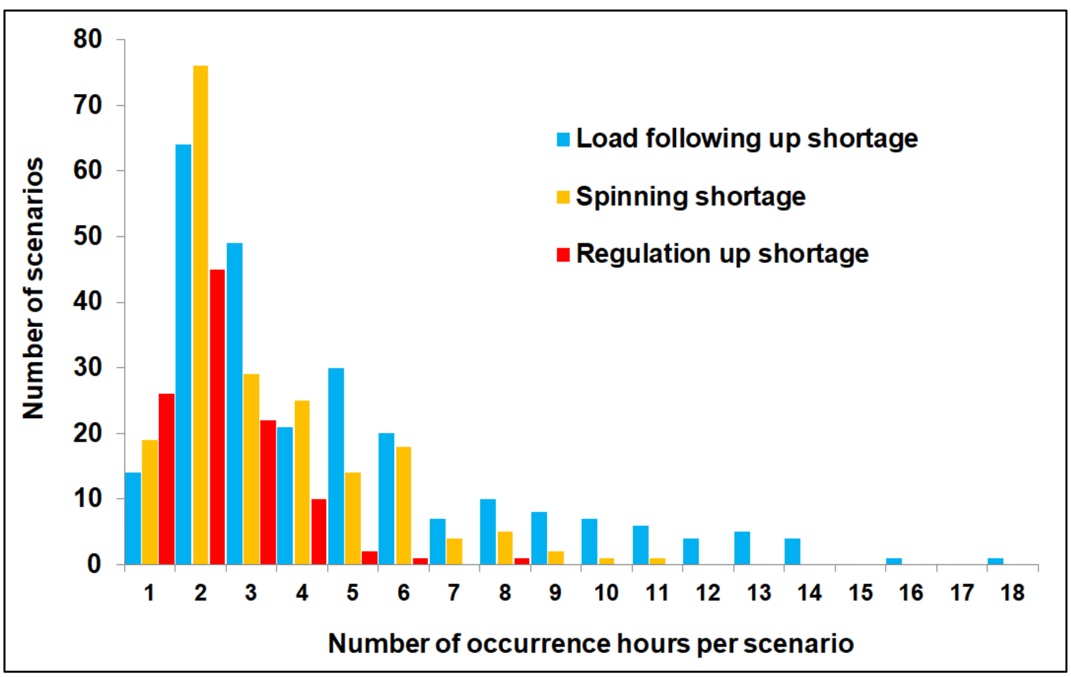


Figure 22 shows scenario occurrences with regulation up, spinning and load following up shortage.

Deterministic Stack Analysis

In the process of assessing adequate resource procurement targets and minimum resource needs under the CPUC Resource Adequacy program, the ISO performed a deterministic stack analysis. In addition to the stochastic modeling described above, the ISO deterministic stack analysis is included to provide an additional perspective on the amount of capacity the ISO is expecting to be available for summer 2022 and the level of reliability that is anticipated under various load levels and import conditions.

To maintain reliability, the ISO must comply with several North American Electric Reliability Corporation (NERC) and Western Electricity Coordinating Council (WECC) standards in real-time. BAL-002-WECC-2a requires the ISO to carry approximately 6 percent of expected load as contingency reserves. The contingency reserves required under BAL-002-WECC-2a cannot be used for other types of operational needs other than contingencies unless the ISO is in an energy emergency alert. In addition, the ISO also requires unloaded capacity to meet operational needs like frequency response and regulation pursuant to BAL-003-2 and BAL-001-2. To assess the ISO's ability to maintain those reserve margins necessary for reliable service in real time operation, the ISO considered the capacity needs taking into account the overall outage rate of the existing fleet, which is currently about 7.5 percent. The ISO also based the deterministic assessment on meeting a 1-in-5 load forecast level. The 1-in-5 level is 4 percent above the 1-in-2 forecast used as a baseline, providing an allowance for loads up to 1-in-5. The combined effect of these requirements established a threshold need for a 17.5 percent margin above a 1-in-2 load forecast level.

The ISO's analysis consisted of two steps; first assessing the need for capacity required to meet the contingency provisions of BAL-002-WECC-2a, and then assessing the ability of existing and forecast resources to meet those needs in the summer of 2022. As set out above, the ISO considers that a 17.5 percent margin applied to a 1-in-2 load level is necessary to provide a minimum level of reliable service pursuant to the contingency reserve provisions[35].

Figure 23 shows the result of the deterministic stack analysis for the month of September, 2022, at 8 pm, which is the month and hour of the greatest supply risk. Approximately 4,000 MW of NQC has reached commercial operation date or is expected to from June 1 2021 to June 1, 2022. The NQC of the existing and new resources were reduced by 1,984 MW to account for solar generation not being available at 8 pm. As a result, the total

[35] The ISO's detailed analysis conducted in support of the CPUC's integrated resource planning process identified that the CPUC's preferred system plan meets a 1-in-10 loss of load expectation, and the ISO notes that the preferred system plan reflects a planning reserve margin higher than a 17.5 percent planning reserve margin at 8 pm, demonstrating that a 17.5 percent planning reserve margin may provide a minimum level of reliability but does not achieve a target loss of load expectation of 1 event in 10 years. http://www.caiso.com/Documents/Sep27-2021-OpeningComments-ProposedPreferredSystemPlan-IntegratedResourcePlanning-R20-05-003.pdf

capacity amount shown in *Figure 23* is less than the September capacity amount listed earlier under System Capacity that included the NQC amount for solar. The amount of demand response is also different because the two methods account for different types of demand response differently.

The three bars of stacked resources portray three scenarios of progressively increasing resource amounts. Moving from left to right, the first bar represents resources similar to the stochastic sensitivity case, where imports are limited to the average of the last six-years of RA imports[36] procured by the load serving entities to meet their collective RA obligations. The middle bar represents an increase in the RA import level to 8,500 MW, the highest amount procured for the month of September over the last 6 years. The bar on the right further increases the level of imports from the middle bar by assuming an additional 1,000 MW of non-RA economic imports during the peak period. As with the stochastic sensitivity results, *Figure 23* demonstrates the importance of imports above typical RA import levels for meeting 1-in-2 and higher peak demand conditions during late summer.

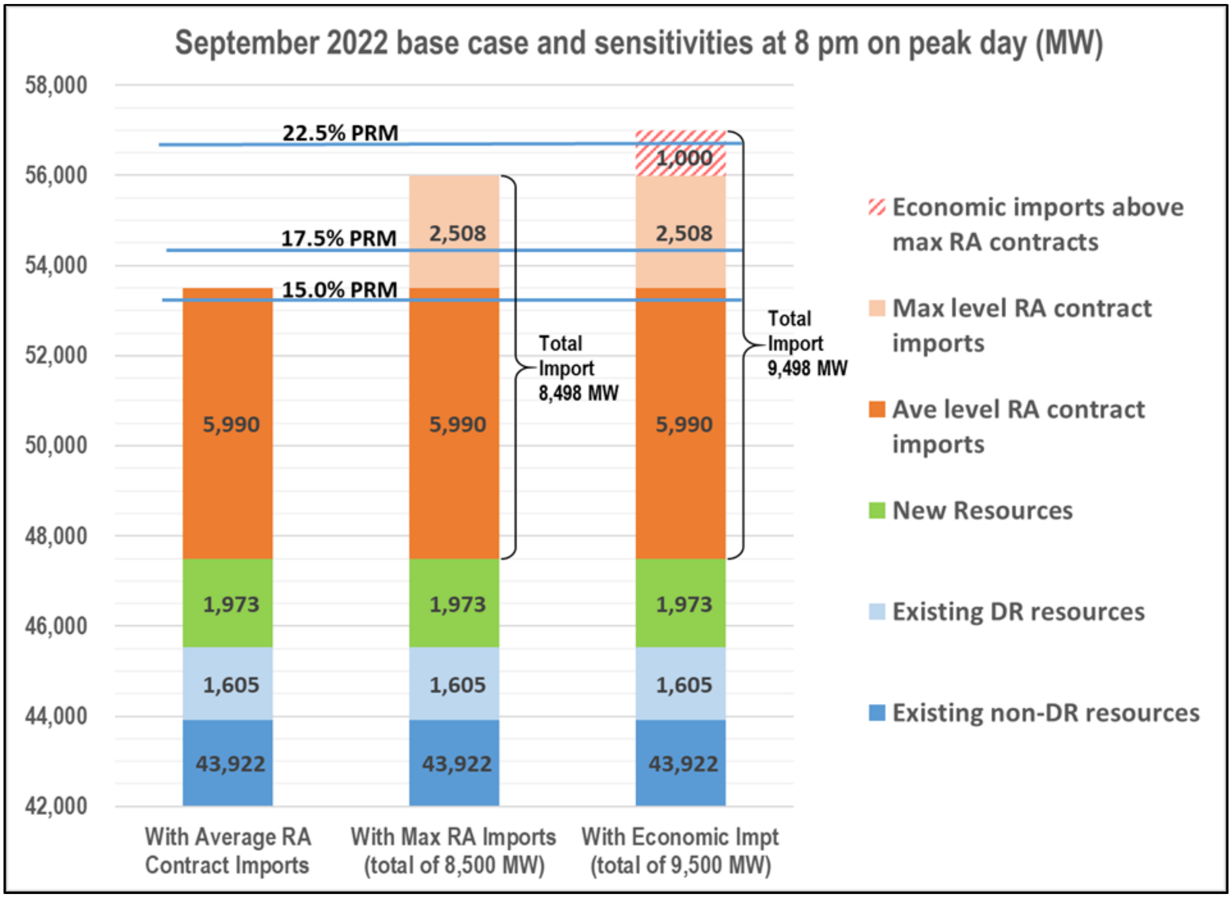
- The bar on the left shows that if the system is limited to imports of 5,990 MW the 15 percent planning reserve margin (PRM) associated with 1-in-2 load is able to be met in September with a narrow margin.
- The middle bar shows that if system imports reach 8,500 MW, approximately 2,500 MW greater than the typical RA procurement levels, the 17.5 percent PRM, reflecting 1-in-5 loads, can be met; however a 22.5 percent PRM would not be met.
- The bar on the right demonstrates that loads equivalent to the day-ahead forecast for August 18, 2020, the day of the ISO 2020 summer peak, would meet a 22.5 percent PRM if imports reach the maximum over the last six years, a level of approximately 3,500 MW greater than the typical RA procurement levels.

[36] The 2015 – 2021 average of the total import capacity procured by all load serving entities to meet their RA program obligations is 5,990 MW for the month of September.

Figure 23

ISO stack analysis for September 2022

(PRM levels based on CEC 1-in-2 load forecast plus planning reserve margin)



Impacts of the Aliso Canyon Gas Storage Operating Restrictions

Natural gas needs in Southern California are met by a combination of major gas pipelines, distribution gas infrastructure and gas storage facilities. Four major gas storage facilities are located in the Southern California Gas system, the largest of which is the Aliso Canyon facility located in Los Angeles County. Aliso Canyon and other gas storage facilities are used year-round to support the delivery of gas to core and non-core users. Among the non-core users are electric generators, which helps meet electric demands throughout the region.

Following a significant natural gas leak in late 2015, the injection and withdrawal capabilities of the Aliso Canyon were severely restricted. These restrictions impacted the ability of pipeline operators to manage real-time natural gas supply and demand deviations, which in turn could have had impacts on the real-time flexibility of natural gas-fired electric generators in Southern California. This primarily impacted resources operated in the Southern California Gas Company (SoCalGas) and San Diego Gas and Electric (SDG&E) service areas, collectively referred to as the SoCalGas system.

Aliso Canyon directly supplies 17 gas-fired power plants[37] with a combined total 8,225 MW of ISO electric generation in the Los Angeles basin as well as generation in the Los Angeles Department of Water and Power balancing authority. Aliso Canyon storage indirectly impacts three other Southern California Gas storage facilities that support 48 additional plants in the ISO with a combined total 20,120 MW of electric generation across Southern California. There are limitations in attempting to shift power supply from resources affected by Aliso Canyon to resources that are not affected because of factors such as local generation requirements, transmission constraints and other resource availability issues.

To address the continued operating restrictions at Aliso Canyon, the ISO and the CPUC have taken separate but complementary actions to manage the current situation while the state considers the long-term need and viability of the storage facility.

Starting in summer 2016, the ISO received approval from the Federal Energy Regulatory Commission (FERC) to temporarily implement three operational tools and market mechanisms to mitigate the electric system reliability and market risks posed by restricted operations at Aliso Canyon. The first was a maximum gas constraint tool to manage generator gas consumption in Southern California within bounds established by SoCal Gas. The second was the ability for the ISO to manually override the competitive path assessment to determine if transmission constraints are uncompetitive. This action allows supply limitations to be reflected in the market power mitigation process. Lastly, the ISO could suspend virtual bidding if the maximum gas constraint was causing market inefficiencies. On December 31, 2019, the ISO received approval from the FERC to make permanent the three main operational tools and market mechanisms.[38] In addition, the ISO worked closely with SoCalGas to develop enhanced coordination procedures where SoCalGas adjusted natural gas balancing rules to provide stronger incentives for natural gas customers, such as electric generators, to align their natural gas schedules and burns.

Following the direction provided by the legislature in California Public Utilities Code Section 715, the CPUC determines the inventory needed "to ensure safety and reliability for the region and just and reasonable rates in California." The CPUC has revised this inventory level several times in response to changing conditions and have continued to do so through Commission decisions since Section 715 expired on January 1, 2021. Most

[37] https://www.cpuc.ca.gov/-/media/cpuc-website/files/uploadedfiles/cpuc_public_website/content/news_room/news_and_updates/aliso-canyon-action-plan-04-4-16-final-clean.pdf

[38] Federal Energy Regulatory Commission, Order Accepting Tariff Revisions, ER20-273-000, December 31, 2019.

recently, the CPUC capped Aliso Canyon inventory at 41.16 billion cubic feet in November 2021.

On March 30, 2022, SoCalGas published its Summer 2022 Technical Assessment[39], which concluded that SoCalGas has sufficient capacity to serve the forecasted summer peak demand of 3.307 billion cubic feet per day (BCFD) under the "best case" supply scenario, with or without the use of Aliso Canyon, and under the "worst case" supply scenario with the use of Aliso Canyon. SoCalGas has insufficient capacity to serve the forecasted summer peak demand under the "worst case" supply scenario without the use of Aliso Canyon. Under the "worst case" supply scenario without the use of Aliso Canyon, the system capacity is 2.88 BCFD resulting in a partial curtailment of electric generating (EG) customers. Core and non-EG noncore customers are not impacted, however, as consistent with the Commission's July 23, 2019 Aliso Canyon Withdrawal Protocol, SoCalGas may use Aliso Canyon to maintain service to core and critical noncore customers.

Once Through Cooled Generation

On May 4, 2010, the State Water Resources Control Board (SWRCB) adopted a policy on the use of coastal and estuarine waters for power plant cooling. The 2010 policy applies to 19 power plants located in both the ISO and LADWP balancing authority areas, some of which have already retired. Together, these plants had the ability to withdraw more than 15 billion gallons per day from the state's coastal and estuarine waters using a single-pass system, also known as once-through cooling (OTC). Table 16 shows the 16 power plants located in the ISO balancing authority that are subject to the policy. Of the OTC units' 17,302 MW of generating capability affected by the policy, 11,304 MW are in compliance. The remaining 3,758 MW of gas-fired generation will be required to repower, retrofit or retire to be in compliance by the end of 2022 and 2023, with Diablo Canyon's 2,240 MW currently scheduled to retire later in 2024 and 2025.

On November 30, 2020, the SWRCB approved extending the OTC compliance date for Alamitos Units 3, 4, and 5, Ormond Beach Units 1 and 2, and Huntington Beach Unit 2 for three years through December 31, 2023, and Redondo Beach Units 5, 6, and 8 for one year through December 31, 2021 to address local and system-wide grid reliability concerns.[40] Subsequently, the SWRCB amended the OTC policy to extend the compliance date for Redondo Beach Units 5, 6, and 8 to December 31, 2023 to address

[39] https://efiling.energy.ca.gov/GetDocument.aspx?tn=242505&DocumentContentId=76010

[40] State Water Resources Control Board - Approval Letter https://www.waterboards.ca.gov/water_issues/programs/ocean/cwa316/docs/oal_approval_2020/oalapp.pdf and Final Amendment to the Water Quality Control Policy on the Use of Coastal and Estuarine Waters for Power Plant Cooling https://www.waterboards.ca.gov/water_issues/programs/ocean/cwa316/docs/otc_policy_2020/final_amendment.pdf

system-wide grid reliability concerns.[41] These system-wide grid reliability concerns come from the shifting daily peaks to later in the day when solar resources are not available to meet peak demand; the changes in the calculation of NQC for wind and solar resources to be less than previously determined; an increase in reliance on the net imports over historical levels; and earlier-than-expected retirements of non-OTC resources. The necessity of additional power becomes imperative for summer peak during the hot days. On November 7, 2019, Decision D.19-11-016 was approved by commissioners of the CPUC, completing the Integrated Resource Plan process for R.16-02-007. D.19-11-016 directs 3,300 MW of new procurement from load serving entities under the CPUC's jurisdiction to ensure system-wide electric reliability. The decision also recommended that the State Water Board consider revising the OTC policy to extend the compliance dates for Alamitos Units 3, 4, and 5, Huntington Beach Unit 2, Redondo Beach Units 5, 6, and 8, and Ormond Beach Units 1 and 2.[42]

On March 26, 2021, the Statewide Advisory Committee on Cooling Water Intake Structures (SACCWIS) recommended that the State Water Resources Control Board extend the OTC policy compliance date of Redondo Beach Units 5, 6 and 8 for two years through December 31, 2023.[43] The power generated by Redondo Beach will help offset projected system-wide shortfalls during periods of high energy demand. At the SWRCB meeting on October 19, 2021, the State Water Board adopted the resolution to extend Redondo Beach's OTC policy compliance date for two years, from December 31, 2021, to December 31, 2023.[44]

41 https://www.waterboards.ca.gov/water_issues/programs/ocean/cwa316/docs/otc_policy_2021/final_amdmt.pdf

42 https://www.waterboards.ca.gov/water_issues/programs/ocean/cwa316/saccwis/docs/final_report.pdf
https://www.waterboards.ca.gov/water_issues/programs/ocean/cwa316/docs/otc_policy_2020/final_amendment.pdf

43 Draft 2021 Report of the Statewide Advisory Committee on Cooling Water Intake Structures https://www.waterboards.ca.gov/water_issues/programs/ocean/cwa316/saccwis/docs/21draftreport.pdf

44 https://www.waterboards.ca.gov/water_issues/programs/ocean/cwa316/docs/otc_policy_2021/final_amdmt.pdf

Table 16

Generating Units Compliance with California Statewide Policy on the Use of Coastal and Estuarine Waters for Power Plant Cooling					
Plant (Unit)	**Owner**	**State Water Resources Control Board Compliance Date**	**Planned retirement Date by Generating Owners**	**Capacity (MW)**	**PTO Area**
Compliance Plan Yet to be Implemented (Natural Gas Fired)					
Huntington Beach Units 2	AES	12/31/2023		226	SCE
Redondo Beach Units 5,6,8*	AES	12/31/2023		850	SCE
Alamitos Units 3,4,5	AES	12/31/2023		1,166	SCE
Ormond Beach Units 1 and 2	NRG	12/31/2023		1,516	SCE
			Total MW	**3,758**	
Notes*extension to 12/31/2023 is recommended by the SACCWIS at the SWRCB for consideration					
In Compliance**					
Huntington Beach Units 1	AES	1/31/2020		226	SCE
Alamitos Units 1,2,6	AES	1/31/2020		845	SCE
Redondo Beach Units 7	AES	10/1/2019		493	SCE
Encina Power Station Units 2-5	NRG	12/12/2018		840	SDG&E
Mandalay Units 1 and 2	NRG	2/15/2018		430	SCE
Encina Power Station Units 1	NRG	5/8/2017		106	SDG&E
Moss Landing Units 6 and 7	Dynegy	1/1/2017		1,500	PG&E
Pittsburg Units 5, 6 and 7	NRG	12/31/2016		1,159	PG&E
Huntington Beach Units 3-4	AES	12/7/2012		452	SCE
Humboldt	PG&E	Sept. 2010		105	PG&E
Potrero Unit 3	GenOn	2/28/2011		206	PG&E
South Bay	Dynegy	1/1/2011		702	SDG&E
Contra Costa Units 6 and 7	NRG	5/1/2013		674	PG&E
San Onofre Unit 2 & 3	SCE	6/7/2013		2,246	SCE
El Segundo Units 3	NRG	7/1/2014		335	SCE
El Segundo Units 4	NRG	12/31/2015		335	SCE
Morro Bay Units 3 and 4	Dynegy	2/5/2014		650	PG&E
			Total MW	**11,304**	
Notes**: these generating units were retired. Nuclear Plant to be in compliance					
Diablo Canyon unit 1	PG&E	11/2/2024		1,122	PG&E
Diablo Canyon unit 2	PG&E	8/26/2025		1,118	PG&E
			Total MW	**2,240**	
			Total of all OTC Units	**17,302**	

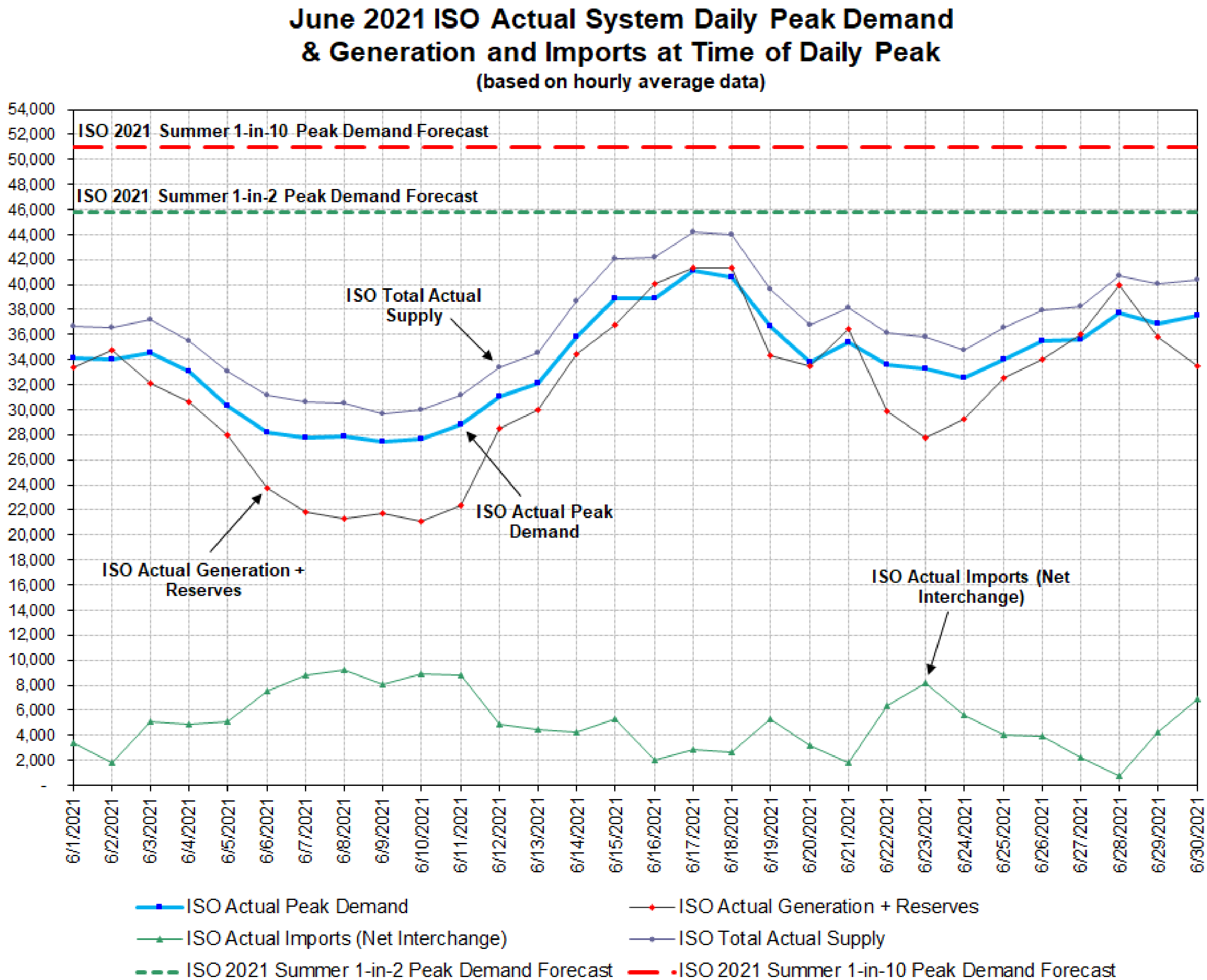
Technical Report Appendices

B. 2021 Summer Supply and Demand Summary Graphs

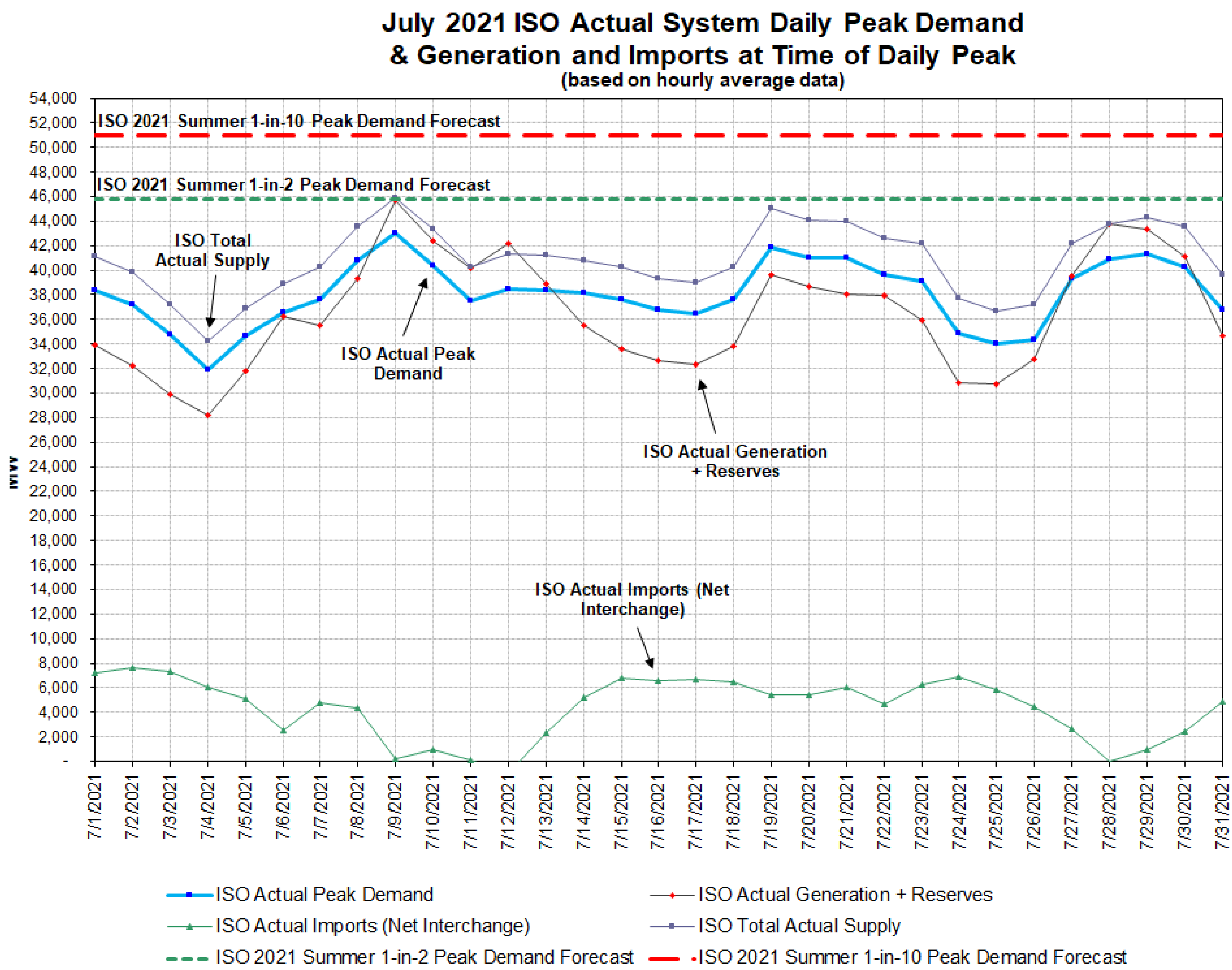
C. 2021 Summer Net Imports Summary Graphs

D. 2021 ISO Summer Maximum On-Peak Available Capacity by Fuel Type

Appendix B: 2021 Summer Supply and Demand Summary Graphs



Appendix B: 2021 Summer Supply and Demand Summary Graphs



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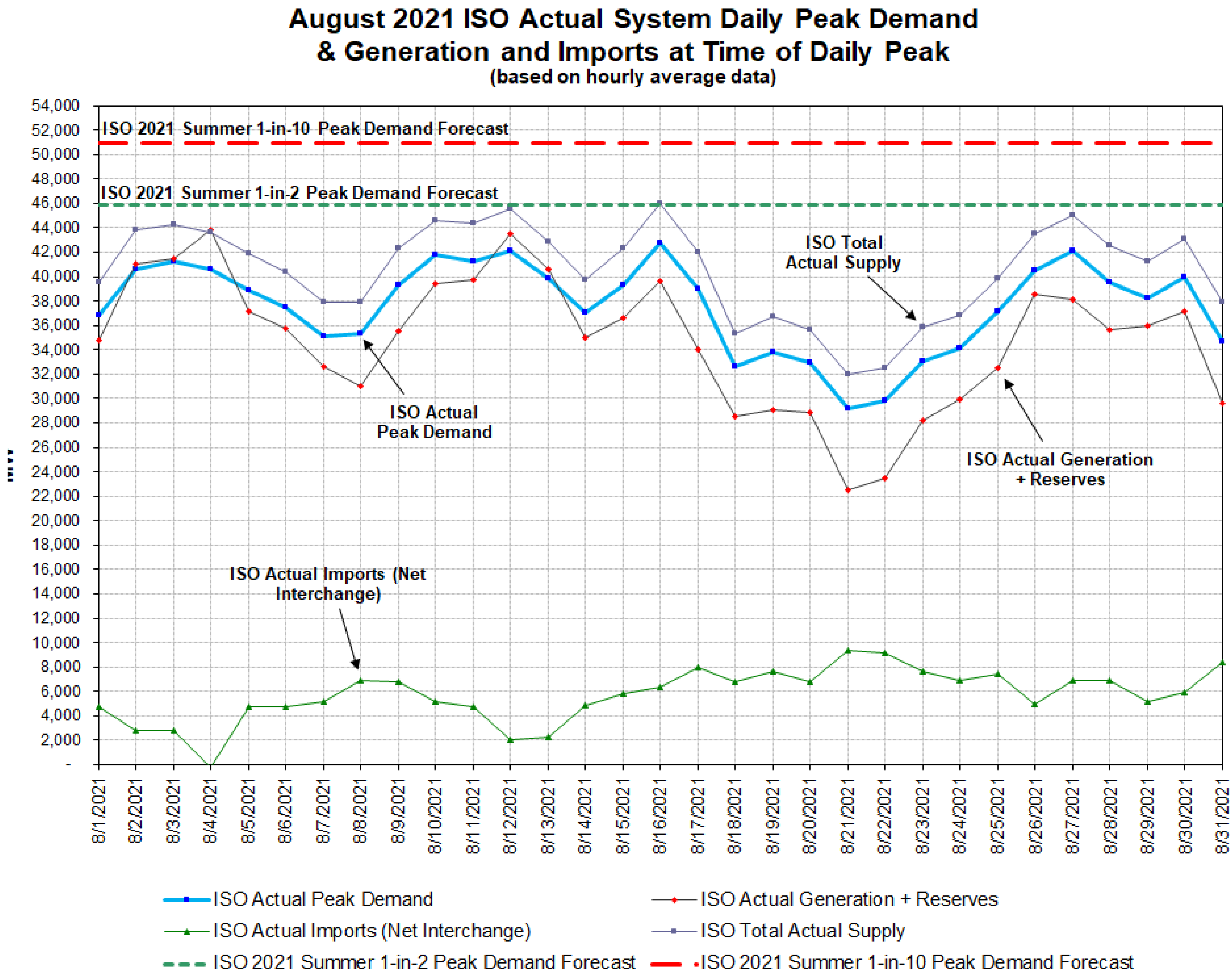

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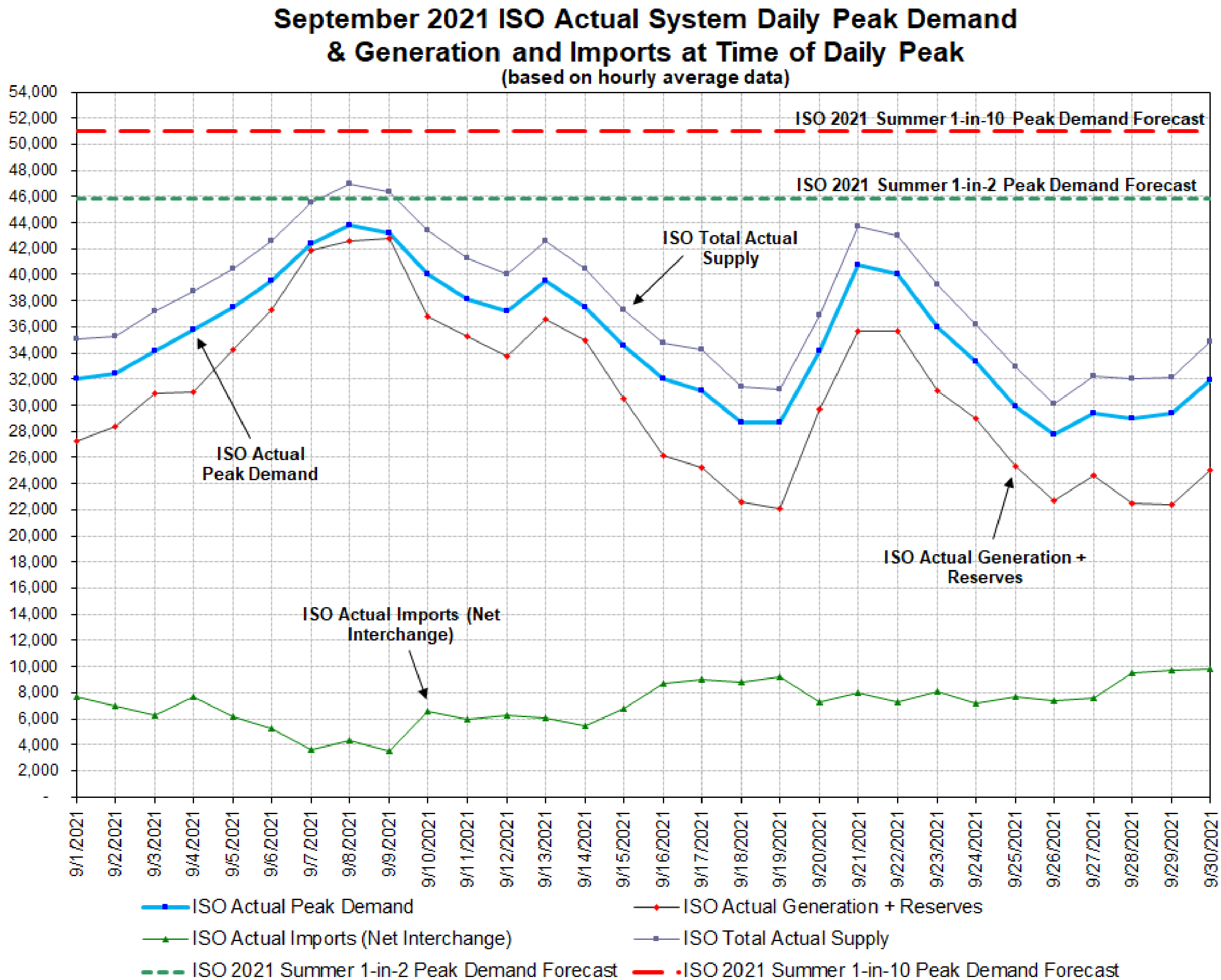
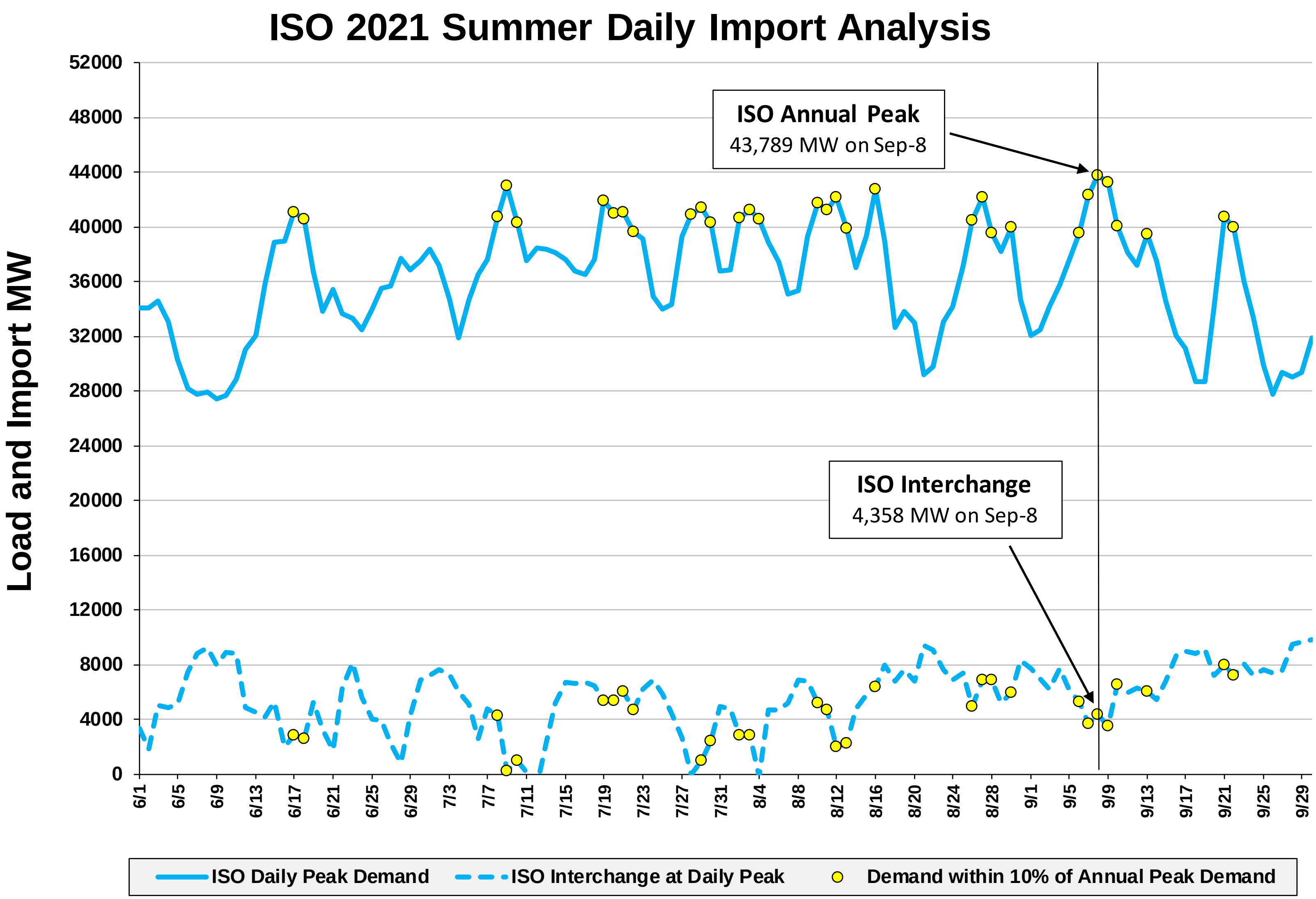


Appendix C: 2021 Summer Imports Summary Graphs



Appendix D: 2022 ISO Summer Maximum On-Peak Available Capacity by Fuel Type