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APPENDIX A

California Public Utilities Commission

June 1, 2022

Energy Division Study for Proceeding R.21-10-002

Regional Wind Effective Load Carrying Capability Study Results for 2024

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List of Acronyms

AAEE – Additional Achievable Energy Efficiency	LOLH – Loss of Load Hours
BAA – Balancing Authority Area	MW – Megawatt
BTM PV – Behind the Meter Photovoltaic	NQC – Net Qualifying Capacity
CAISO – California ISO	PRM – Planning Reserve Margin
CEC – California Energy Commission	PU Code – Public Utilities Code
ELCC – Effective Load Carrying Capability	RA – Resource Adequacy
EUE – Expected Unserved Energy	RPS – Renewables Portfolio Standard
IEPR – Integrated Energy Policy Report	SERVM – Strategic Energy Risk Valuation Model
LCR – Local Capacity Requirements	TAC – Transmission Access Control
LOLE – Loss of Load Expectation	UCAP – Unforced Capacity
LSE – Load Serving Entity	WECC – Western Electric Coordinating Council

1. Introduction

Consistent with CPUC Decisions D.20-06-031 and D.21-06-029, this report discusses the assumptions and results of Energy Division's 2024 Regional Wind Effective Load Carrying Capability (ELCC) studies for party comment and CPUC consideration. This report intends to comply with Ordering Paragraph 15 of D.21-06-029: "Energy Division is directed to develop regional effective load carrying capability (ELCC) values for wind resources for the ELCC update in 2022 for the 2023 Resource Adequacy compliance year." Energy Division studied the 2024 Resource Adequacy (RA) compliance year rather than 2023 to leverage and build upon the work contained in the February 18, 2022 report, entitled "Loss of Load Expectation (LOLE) and Effective Load Carrying Capability Study Results for 2024," issued for party comment in the Resource Adequacy Proceeding, R.21-10-002.[1]

In this report, Staff presents results consistent with Portfolio D from the March LOLE report, which is also consistent with the Proposed Decision in the RA proceeding. These results are intended to inform parties and their procurement efforts, and allow additional time to thoroughly consider the results, to determine whether this approach can work in conjunction with RA reform. These results may allow for load serving entities (LSEs) to modify their portfolio positions considering the relative reliability value of wind resources located in different regions of the WECC and/or inform Integrated Resource Planning (IRP) and RA procurement more broadly. This report presents assumptions and results specific to the regional wind ELCC analysis. For broader, comprehensive descriptions of modeling assumptions, refer to the February 18, 2022 report referenced above.

2. Summary of Study Results

This section provides average regional wind ELCC results at a monthly level to mirror the current monthly RA construct. This is different than the annual marginal ELCC results presented for use in the IRP process. This average monthly regional wind ELCC analysis builds upon and is consistent with the model assumptions and portfolio ELCC results included in the February 18, 2022 report. The same methodologies were employed to create average monthly ELCC values for six wind regions listed below.

1. Northern California (CAISO)
2. Southern California (CAISO)
3. Northeast Out of State (OOS) Wind (Wyoming/Idaho)
4. Northwest OOS Wind (Washington/Oregon)
5. Southwest OOS Wind (Arizona/New Mexico)
6. Offshore Wind

The table below summarizes the average monthly regional wind ELCC results.

[1] Link to February 18, 2022 LOLE and ELCC report for 2024 study year: https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M452/K750/452750851.PDF

Table 1: 2024 Average Monthly Regional Wind ELCC

Month	WY/ID	WA/OR	AZ/NM	Offshore	SoCal	NorCal
Jan	38%	21%	34%	35%	33%	18%
Feb	38%	25%	36%	39%	35%	19%
Mar	42%	30%	40%	36%	31%	17%
Apr	38%	25%	35%	29%	33%	16%
May	28%	19%	26%	31%	34%	17%
Jun	23%	20%	22%	44%	25%	15%
Jul	24%	22%	21%	56%	23%	14%
Aug	26%	19%	23%	53%	21%	11%
Sep	31%	19%	28%	43%	22%	11%
Oct	40%	23%	33%	37%	18%	10%
Nov	44%	25%	34%	39%	23%	14%
Dec	41%	22%	34%	38%	29%	17%

3. Analysis Scope and Inputs

This analysis leverages and builds upon the ELCC studies described in the February 18, 2022 Energy Division report "Loss of Load Expectation and Effective Load Carrying Capability Study Results for 2024." Staff used:

- The Strategic Energy and Risk Valuation Model (SERVM),
- All the input assumptions and model settings described in the February 18, 2022 report, and
- The "Scenario D" portfolio of existing and new variable and use-limited resources present in this report's regional wind ELCC studies.

SERVM is a probabilistic system reliability planning and production cost model developed by Astrapé Consulting. SERVM was configured to analyze a target study year (2024) under a range of uncertainty including weather conditions (20 historical weather years), economic output (5 weighted levels of load forecast error), and unit performance (400 stochastic unit outage draws) for a total of 40,000 unique simulations per study. SERVM simulates hourly economic unit commitment including reserves and dispatch for individual generating units over all 8,760 hours of the study year. The probability weighted average of the reliability metrics output by SERVM such as loss of load expectation (LOLE) represent the expected system reliability value.

Scenario D approximates a realistic assumption regarding new resources that will be online in 2023, but all other model assumptions, e.g., electric demand and fuel prices, use 2024 projections. The table below summarizes this report's "Base Portfolio," i.e., Scenario D.

Table 2: Base Portfolio (Scenario D) of variable and use-limited resources in installed capacity MW

Portfolio Technology Group	Unit Category	Potential 2023 Portfolio
Solar	Solar	14,805
Wind	Wind	7,946
Storage	Battery Storage	4,161
	PSH	2,099
Hybrid	Hybrid Combined	6,687
	Hybrid Solar Portion	4,540
	Hybrid Storage Portion	2,108
	Total	35,698

4. Regional Wind Assumptions

In total, six aggregated regional wind groups were developed including both in-state and out-of-state (OOS) resources, each modeled with 20 unique synthetic wind output profiles for the 1998-2017 weather years. The analyzed regional groups are listed below.

1. Northern California (CAISO)
2. Southern California (CAISO)
3. Northeast OOS Wind (Wyoming/Idaho)
4. Northwest OOS Wind (Washington/Oregon)
5. Southwest OOS Wind (Arizona/New Mexico)
6. Offshore Wind

The figures below summarize the monthly capacity factors of all six regional wind groups, averaged across all 20 weather years.

Figure 1: Average Monthly Capacity Factors (CAISO Wind)

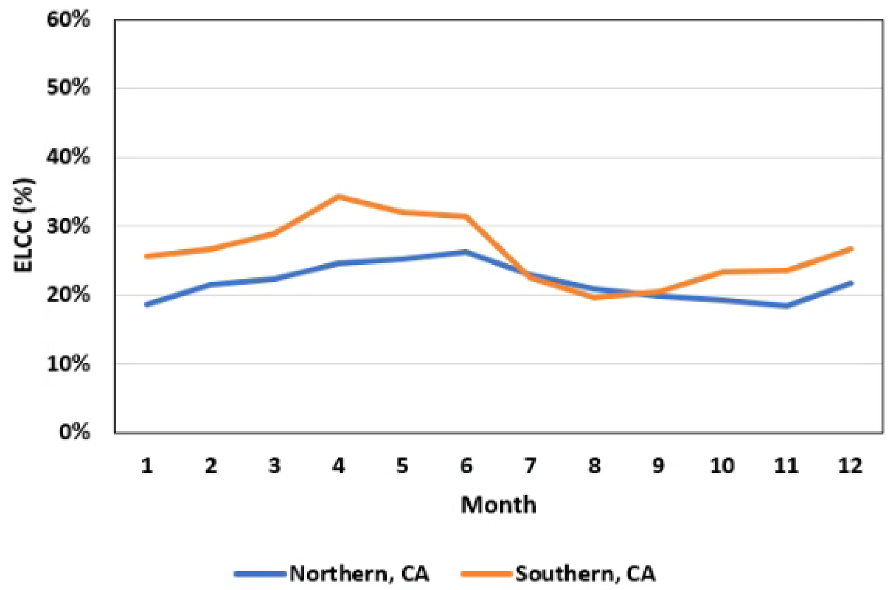
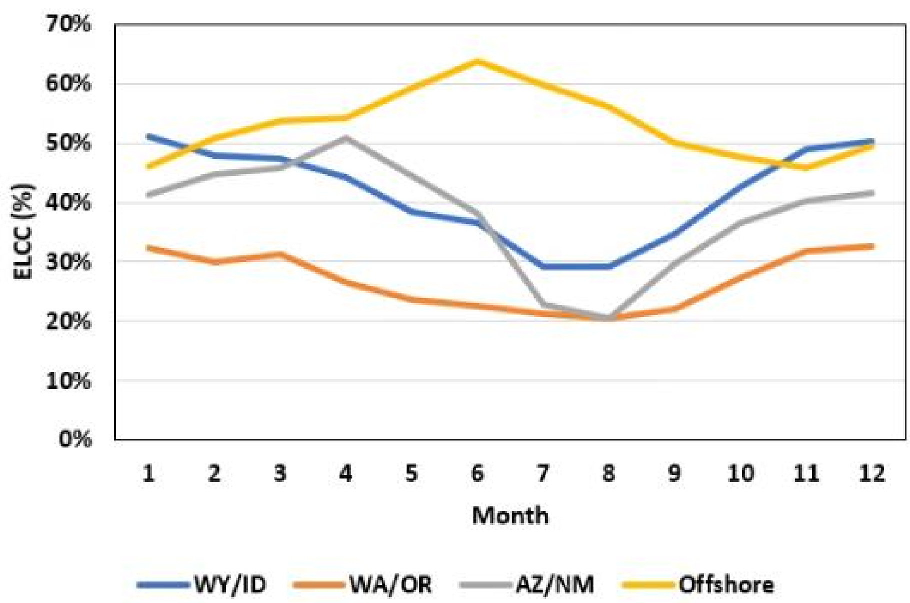


Figure 2: Average Monthly Capacity Factors (Non-CAISO Wind)



On average, Southern California wind resources produce more energy than Northern California resources, and thus have a higher capacity factor. Offshore wind has the highest average capacity factor, with steady energy production throughout the summer months while other resources decline in total energy output.

5. ELCC Calculation Methodology

The average monthly ELCC values for each of the six aggregated regional wind groups were calculated using the steps below:

1. Calculate First-In Marginal ELCC
    a. Begin with the CAISO system with the Base Portfolio removed (all existing variable and use-limited resources, i.e., solar, storage, wind, and hybrids) and calibrated to 0.1 days/year LOLE for the summer months of June – September. Perfect capacity was added to calibrate.
        i. Available capacity in other months was adjusted to surface a minimal amount of reliability events, such that the impact of wind could still be determined by the model (approximately 0.005-0.009 days/year LOLE). Oldest fossil thermal capacity was removed for non-summer months.
    b. Add an incremental 1,000 MW of wind capacity associated with the regional wind profile being analyzed, reducing the system LOLE in each month.
    c. Add varying monthly amounts of negative output units (i.e., increased load) such that the LOLE is increased to the calibrated values in steps 1a and 1a-i in all months.
    d. The MW amount of load added divided by 1,000 MW is equal to the monthly First-In Marginal ELCC of the regional wind resource.
2. Calculate Last-In Marginal ELCC
    a. Begin with the CAISO system with the Base Portfolio included (all existing renewable and use-limited resources, i.e., solar, storage, wind, and hybrids) and calibrated to 0.1 days/year LOLE for the summer months of June – September. Perfect capacity was added, or oldest fossil thermal capacity was removed to calibrate.
        i. Available capacity in other months was adjusted to surface a minimal amount of reliability events, such that the impact of wind could still be determined by the model (approximately 0.005-0.009 days/yr LOLE). Oldest fossil thermal capacity was removed for non-summer months.
    b. Repeat steps 1b through 1d to calculate the Last-In Marginal ELCC of the regional wind resource.
3. Calculate Average ELCC
    a. Calculate the average ELCC for each regional wind resource by averaging the First-In and Last-In ELCC values for each month.
    b. For regional specific CAISO wind values (Southern/Northern CA), the average ELCC was used to allocate the total CAISO wind ELCC values developed in Scenario D of the February 18, 2022 report.

6. Results

The average monthly regional wind ELCC values are shown in the figures and table below.

Figure 3: Average Monthly Wind ELCC (CAISO)

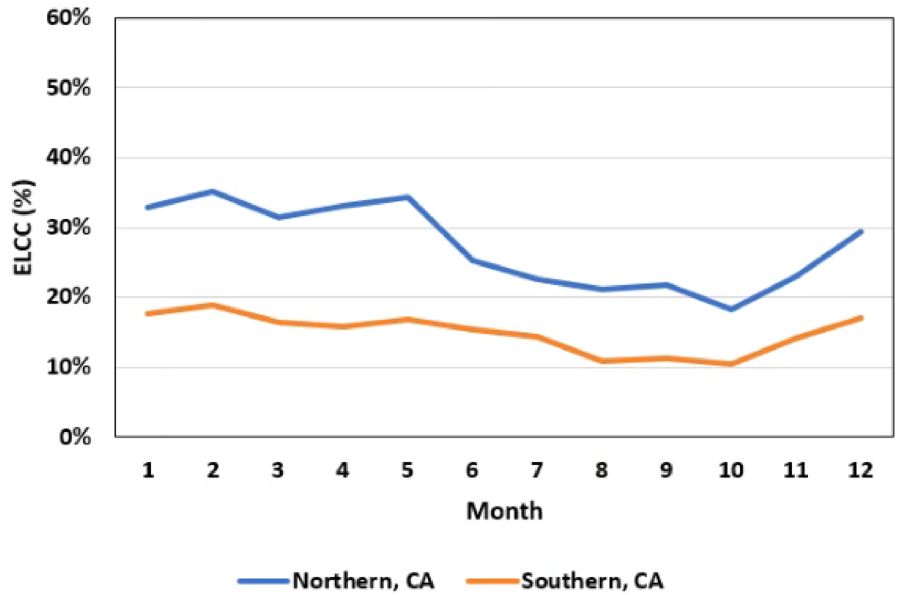


Figure 4: Average Monthly Wind ELCC (Non-CAISO)

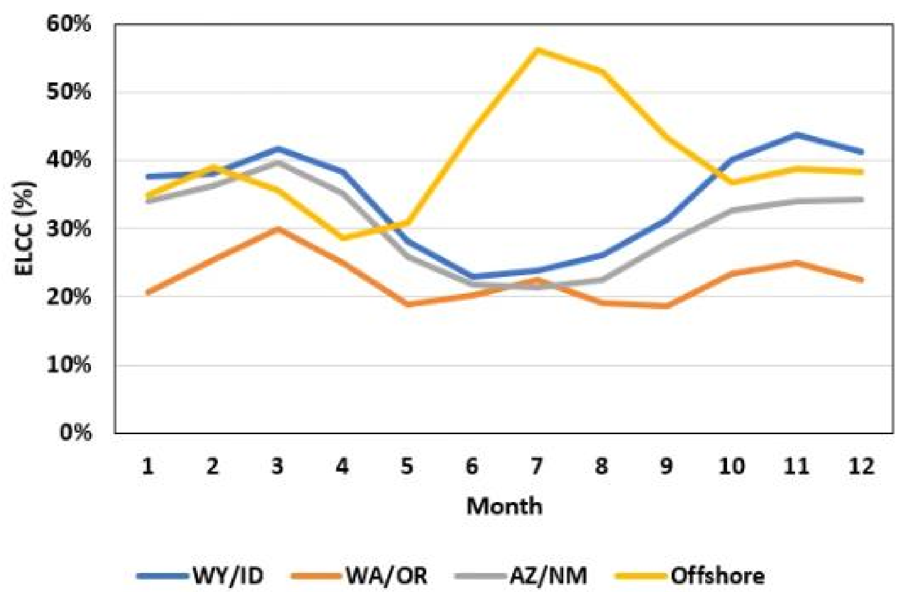


Table 3: Average Monthly Wind ELCC (All Regions)

Month	WY/ID	WA/OR	AZ/NM	Offshore	SoCal	NorCal
Jan	38%	21%	34%	35%	33%	18%
Feb	38%	25%	36%	39%	35%	19%
Mar	42%	30%	40%	36%	31%	17%
Apr	38%	25%	35%	29%	33%	16%
May	28%	19%	26%	31%	34%	17%
Jun	23%	20%	22%	44%	25%	15%
Jul	24%	22%	21%	56%	23%	14%
Aug	26%	19%	23%	53%	21%	11%
Sep	31%	19%	28%	43%	22%	11%
Oct	40%	23%	33%	37%	18%	10%
Nov	44%	25%	34%	39%	23%	14%
Dec	41%	22%	34%	38%	29%	17%

Monthly ELCC values in the non-summer months ranged from 20-40 percent, with most regional wind resources seeing a decline in ELCC in summer to around 15-20 percent. Offshore wind was found to be an outlier, with summer ELCC values increasing rather than decreasing to approximately 45-55 percent.

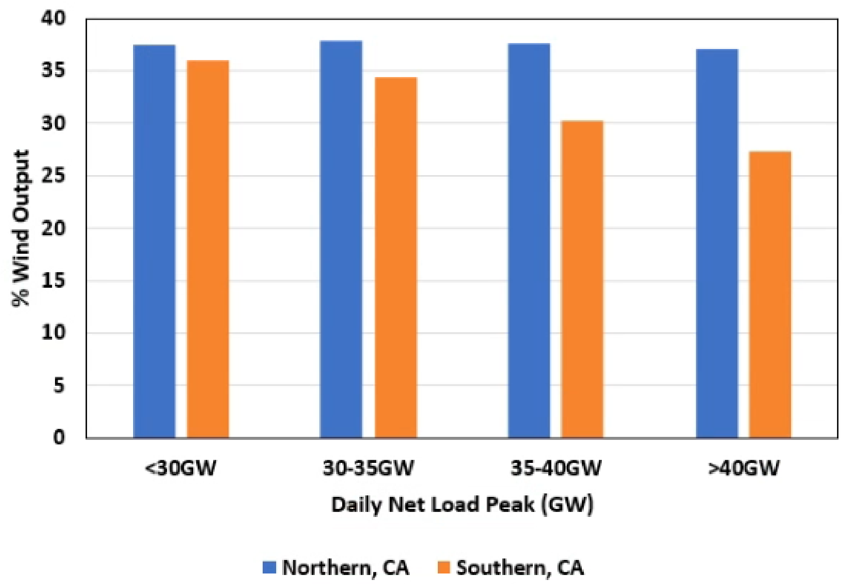
Despite greater annual energy production from Southern CA wind resources (i.e., higher capacity factors), the monthly ELCC values for Southern CA wind were found to be lower on average than Northern CA wind. Further data analysis was performed to compare Southern and Northern CA wind profiles to determine the reason for the lower Southern CA ELCC values. On average, it was found that while Southern CA resources produced more energy during morning and midday hours, the percentage of wind maximum output during the critical net load peak hours when loss of load events are most likely (HE18-22) declined. Figure 5 below shows the average summer daily percentage of wind maximum output for both regions, binned by ranges of CAISO daily net load peak.

Figure 5: Average Summer Daily Percentage of Wind Max Output (June - September)

	Northern, CA Net Load Daily Peak				Southern, CA Net Load Daily Peak			
	<30GW	30-35GW	35-40GW	>40GW	<30GW	30-35GW	35-40GW	>40GW
1	28	29	29	28	36	33	29	27
2	27	28	28	26	35	32	28	26
3	25	26	26	24	35	32	27	25
4	24	25	24	23	33	30	26	24
5	23	23	23	24	31	28	25	23
6	20	21	21	22	27	25	22	20
7	17	17	15	18	23	20	17	15
8	13	13	11	14	21	18	15	14
9	12	11	9	13	19	17	14	13
10	11	11	9	12	19	16	13	13
11	13	12	11	14	20	17	14	13
12	15	14	13	16	21	18	14	14
13	17	17	15	19	22	19	15	15
14	20	20	19	22	24	21	16	16
15	23	24	22	25	26	23	18	19
16	27	27	25	28	28	25	20	21
17	30	31	29	30	30	27	22	22
18	**33**	**34**	**34**	**34**	**32**	**30**	**25**	**25**
19	**38**	**38**	**38**	**38**	**34**	**33**	**28**	**26**
20	**41**	**41**	**41**	**40**	**38**	**36**	**32**	**29**
21	**40**	**40**	**39**	**38**	**38**	**37**	**33**	**29**
22	**36**	**36**	**35**	**35**	**37**	**36**	**33**	**28**
23	32	33	32	33	36	35	32	27
24	30	31	31	32	36	34	31	27

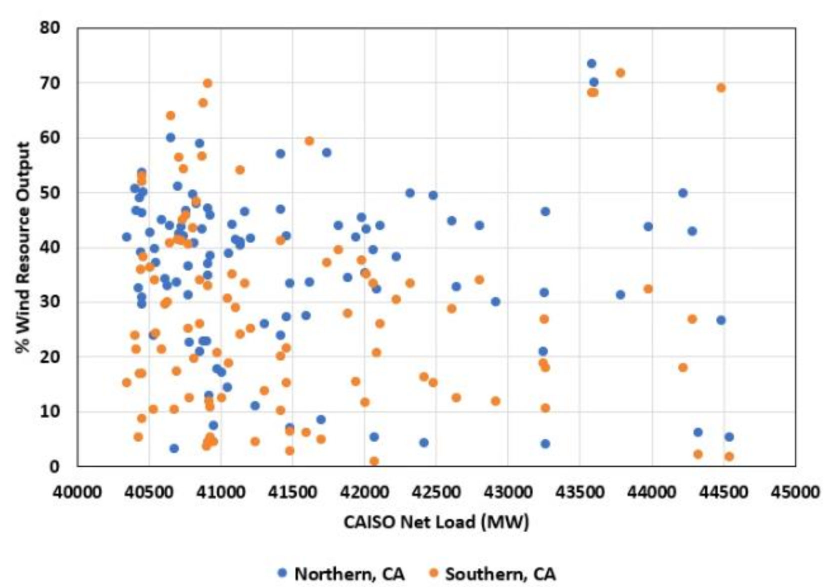
Two additional figures are provided below demonstrating the difference in wind resource performance between Southern and Northern CA. Figure 6 shows the average percentage of wind maximum output during the critical net load peak hours, binned by ranges of CAISO daily net load peak. On days where the daily net load peak is greater than 40 GW, Southern CA resources produced at approximately 27 percent of maximum output while Northern CA resources produced at approximately 37 percent of maximum output.

Figure 6: Average Percentage of Wind Max Output During Net Load Peak Hours (HE18-22)



While average wind output as a percentage of maximum output during the highest net load days is approximately 27-37 percent, the actual average ELCC values are much lower at 10-20 percent. This is because very low wind output hours will have a disproportionate impact on increasing the LOLE of the system that cannot be captured by calculating the average. Figure 7 below shows the correlation between the percentage of wind maximum output and hourly net load, highlighting the range of wind resource output during critical peak conditions. While resource output can be as high as 60 percent, there are several hours below 10 percent which are primary drivers in the resulting system LOLE. Additionally, Figure 7 highlights how the Southern CA resource output is consistently lower than Northern CA across the high net load hours, driving a lower Southern CA ELCC value.

Figure 7: Percentage of Wind Max Output vs. CAISO Net Load (> 42 GW)



7. Conclusion

This report presents completed ELCC modeling consistent with CPUC Decisions D.20-06-031 and D.21-06-029. These Commission decisions required an updated Loss of Load study analyzing a revised PRM, as well as updating the wind and solar ELCC values used for the RA program to include regional wind ELCC factors. This report includes the results of that analysis and data to support these results. These results represent the Portfolio D mix of existing and new resources consistent with the overall portfolio proposed in the RA proceeding. Parties are requested to consider these results and use these results in their comments to the proceeding.

(End of Appendix A)