ASTRAPÉ CONSULTING
innovation in electric system planning

Planning Reserve Margin and Resource Adequacy Study

Final Report

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PREPARED FOR

Public Service Company of Colorado ("PSCo")

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EXECUTIVE SUMMARY

This study was performed by Astrapé Consulting at the request of Public Service Company of Colorado (PSCo) to identify a target reserve margin[1] and also to comprehensively assess resource adequacy risks that may affect a range of resource planning decisions.

The PSCo electric system is currently in a state of rapid transition. While PSCo has had significant wind resources for many years, additional wind, solar PV, and solar PV with battery resources are expected to be added to the system in the near future. As battery storage costs decline, standalone battery storage could also be added to the system. Efficiently managing resource adequacy in the midst of this transition is challenging because these incipient resources have limited dispatchability, energy constraints, and limited or not yet available operational history. Given the varying penetrations of these energy-limited resources over the next decade and their dynamic interactions, Astrapé was tasked with analyzing the reliability of an evolving resource mix on the PSCo system from 2021 to 2030.

To calculate the necessary reserve margin for the PSCo system, Astrapé Consulting utilized their reliability model, SERVM (Strategic Energy and Risk Valuation Model), to perform over 9,500 yearly simulations with 1-hour granularity at various reserve margin levels. SERVM calculates multiple physical reliability metrics in order to provide a wholistic perspective on PSCo reliability. Each of the 9,500 yearly simulations was developed through stochastic modeling of the uncertainty of load, renewable generation, economic growth, unit availability, and transmission availability. In addition to the Base Case analysis of study years 2021, 2023, 2026, and 2030, sensitivity analyses were performed to understand the importance of varying assumptions.

The standard for resource adequacy planning in the United States is to procure sufficient resources to expect to shed firm load less than once every 10 years. This is commonly referred to as the 1-day-in-10 standard. This standard has historically been interpreted one of two ways: 1) A single firm load shed event over a 10-year period calculated with the Loss of Load Expectation (LOLE) metric or 2) 24 hours of firm load shed over a 10-year period calculated with the Loss of Load Hours (LOLH) metric. The first interpretation of resource adequacy is referred to in shorthand as 0.1 LOLE, and the second interpretation is referred to as 2.4 LOLH. These two interpretations of the 1-day-in-10 standard result in materially different levels of reliability since a single load shed event might only last 2-3 hours. Thus, the 2.4 LOLH interpretation generally has about 10 more days with firm load shed than the 0.1 LOLE interpretation. As documented in numerous reliability reports[2], nearly all planning entities, including all independent system operators (ISOs), now use the 0.1 LOLE interpretation to plan for resource adequacy. All other assumptions held constant, a 0.1 LOLE based reserve margin is typically 5 percentage points higher than a 2.4 LOLH based reserve margin[3]. To normalize for the difference in reliability, studies using the 2.4 LOLH interpretation often involve modeling the electric market purchases and sales with either a simple representation with limited availability or no representation at all. These conservative assumptions of electric market access applied in 2.4 LOLH-based studies often result in reserve margins of similar magnitude as those from studies which use the 0.1 LOLE

[1]Throughout this report, reserve margin is defined by the formula: reserve margin = (resources – firm peak demand) / (firm peak demand).

[2]https://cdn.misoenergy.org/20200610%20RASC%20Item%2005a%20RAN%20Reliability%20Requirements%20Presentation%20(RASC010%20RASC011%20RASC012)451665.pdf

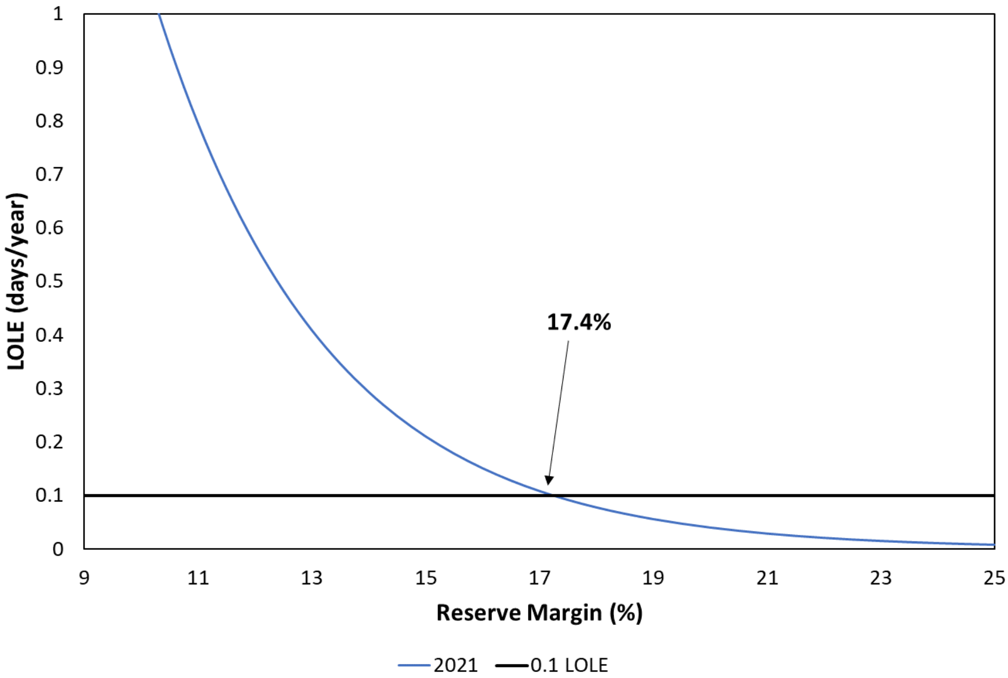
[3] https://www.astrape.com/?ddownload=637 p.iii

interpretation, plus a more realistic representation of support that can be provided from the electric market.

In PSCo's reserve margin study performed in 2008, the target reserve margin of 16.3% was based on the 2.4 LOLH interpretation and an electric market assumption of access to imports of 200 MW[4]. For this current study, Astrapé is using the industry standard interpretation of 0.1 LOLE but has also included a more detailed consideration of the reliability benefit of the electric market in its determination of the target reserve margin[5]. The shift to the industry standard 0.1 LOLE reliability metric increased the target reserve margin while the more detailed electric market assessment put downward pressure on the target reserve margin.

The results of the SERVM simulations for the Base Case for study year 2021 demonstrate that as the target reserve margin increases, system LOLE declines, meeting the 0.1 LOLE standard at a 17.4% reserve margin, as illustrated in Figure ES1.

Figure ES1. 2021 LOLE



Theoretically, if the reliability contribution of energy-limited resources and the electric market were to be known with certainty, the target reserve margin could remain static across the study years of 2021, 2023, 2026, and 2030. However, the changing resource mix in PSCo brings added uncertainty because the reliability contributions of new resources, the correlations between the generation output at different renewable sites, and the correlations amongst different resource technologies are not known with precision. And there are external neighbor sources of resource adequacy uncertainty as well. Within the PSCo Balancing Authority Area (PSCo BAA) and the surrounding regions, announcements of fossil fuel unit closures are significant over the coming decade without complete certainty what the replacement resources will be. These external neighbor changes create added uncertainty to the

[4] The transmission import capability was modeled as 200 MW plus or minus 50 MW on a Monte Carlo basis. The non-firm energy was assumed to be always available.

[5] Non-firm electric market energy in the simulations provides reliability benefits to PSCo but is not included as a resource in the reserve margin calculation.

reliability support PSCo's neighbors can provide PSCo as well as the general level of reliability of the neighboring systems. These variations are reflected in the target reserve margin results that meet the 0.1 LOLE standard, shown in Table ES1, for the Base Cases. Astrapé recommends a target reserve margin range of 18% to 20% to adequately reflect the uncertainties and reliability implications of PSCo's system.

Table ES1. 0.1 LOLE Results

Year	**2021**	**2023**	**2026**	**2030**
0.1 LOLE Reserve Margin	17.4%	19.3%	19.1%	18.0%

Ultimately, Astrapé believes that further work in the coming years is warranted on assessing the reliability contributions of different resource technologies as their penetrations on the PSCo system increase and as PSCo's neighbors transition their systems toward more energy-limited resources. This will require future renewable output data collection, operational history of battery storage, and more electric market transaction history. This additional effort could tighten the future range of reserve margins that should be targeted. In the meantime, a target reserve margin range of 18% to 20%, applied to the 50th percentile probability demand forecast, adequately reflects the reliability risk of the changing system.

PSCo plans to implement the results of this study in its next ERP cycle by acquiring longer term generation resources as necessary to achieve an 18.0% reserve margin plus carrying 1) an additional 45 MW of planning reserve in accordance with PSCo's wholesale contract with Intermountain Rural Electric Association and Holy Cross Energy, and 2) additional resources in certain years to achieve the reserve margin levels reflected in Table ES1, through shorter term power purchases.

INPUT ASSUMPTIONS

STUDY YEARS

The selected study years are 2021, 2023, 2026, and 2030. The results of the SERVM simulations should be used as an input into procurement decisions made in the Company's next ERP cycle. Given the uncertainty associated with the reliability contribution offered to power supply systems from energy-limited storage, renewable resources, and the electric market, Astrapé recommends analyzing reserve margin needs relatively frequently. Recent generation reliability events in California highlight the need for careful attention to reliability in systems with increasing penetrations of renewable resources and reliance on non-firm energy imports.

STUDY TOPOLOGY

Figure 1 shows the study topology that was used for this study. To thoroughly quantify resource adequacy, it is important to capture the load, renewable generation, and generator outage diversity that a system has with its neighbors. For this study, the PSCo system was modeled along with its Joint Dispatch Agreement (JDA) neighbors within the PSCo Balancing Authority Area (BAA) and external neighbors. The surrounding systems and regions captured in the modeling include:

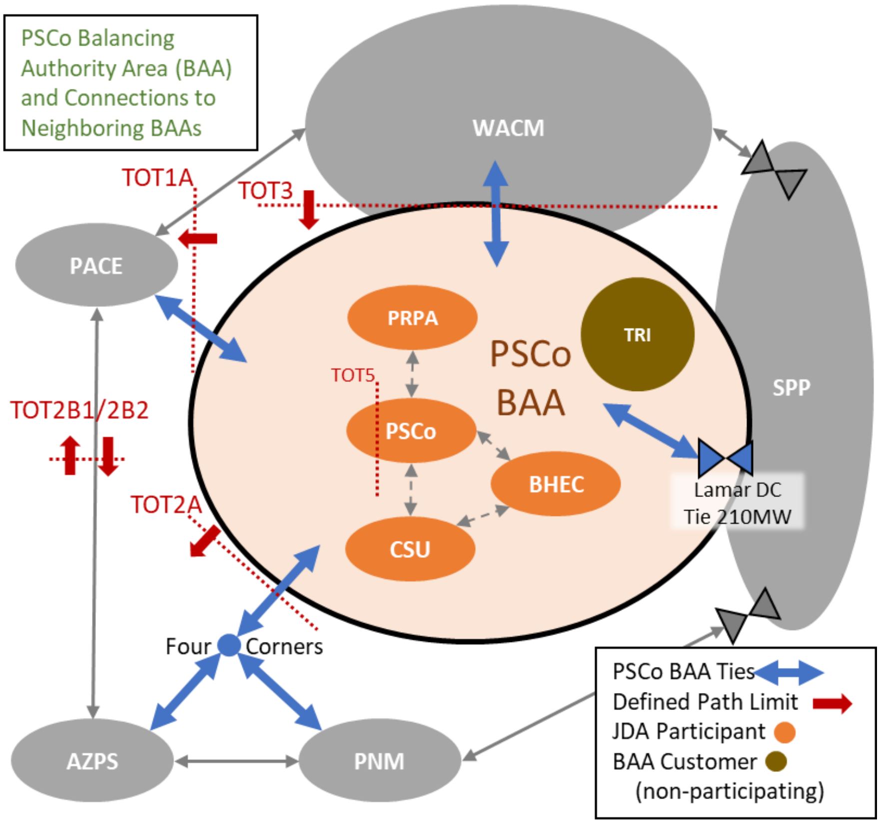
- JDA Neighbors
  - Platte River Power Authority (PRPA)
  - Colorado Springs Utilities (CSU)
  - Black Hills Energy Colorado (BHEC)
- External Neighbors
  - Tri-State (TRI)
  - Western Area Power Administration-Colorado Missouri (WACM)
  - PacifiCorp East (PACE)
  - Southwest Power Pool (SPP)[6]
  - Public Service Company of New Mexico (PNM)
  - Arizona Public Service (AZPS)

Sometime during the year 2022, PSCo, PRPA, CSU, and BHEC are projected to join the Western Energy Imbalance Market (WEIM). PACE and AZPS are already WEIM members, and PNM is projected to join in 2021. The reliability contributions of these JDA neighbors and external neighbors are captured within the study topology.

SERVM uses a pipe and bubble representation where non-firm energy can be shared based on economics but subject to transmission constraints. The modeled regions and transmission connecting them are shown in Figure 1. The transmission import and export limits are discussed in the External Assistance section of the report.

[6] SPP was modeled with only the load and resources of Southwestern Public Service (SPS).

Figure 1. Study Topology



LOAD MODELING

Table 1 displays PSCo seasonal peak demand forecast for 2021, 2023, 2026, and 2030 under normal weather conditions. PSCo's wholesale customers' loads were modeled as a part of PSCo load. The wholesale customers included were Intermountain Rural Electric Association (IREA), Holy Cross Energy, Grand Valley Power, Yampa Valley Electric Association, and City of Burlington.

Table 1. PSCo Aggregate Load Forecasts

PSCo	Summer	Winter
2021	7,309	5,678
2023	7,404	5,720
2026	7,622	5,877
2030	8,063	6,183

39 historical weather years (1980-2018) were developed to reflect the influence of weather on load, wind, solar, and hydro generation and the associated uncertainty. For developing the synthetic load profiles used in the study, a neural network program was used to develop relationships between weather observations and hourly load from historical data provided by PSCo. The historical load data was from June 2013 through December 2019. The historical weather consisted of hourly temperature

from Denver supplemented by a station in Aurora for days with insufficient data. Other weather stations were considered but ultimately were excluded due to the lack of a statistical significance.

Before being input into the neural network software, the temperature data for weather years 1980-2010 was adjusted to create the same baseline expectation for hot weather for the entire 1980-2018 weather year period. This translates to a flat slope over time on the expected frequency of hot weather. The adjustment does not increase the maximum temperature seen in each weather year. Figure 2 below shows the number of days with temperatures above 90°F in each PSCo weather year before and after the adjustment and Figure 3 shows the degrees added to each year.

Figure 2. Temperature Adjustment

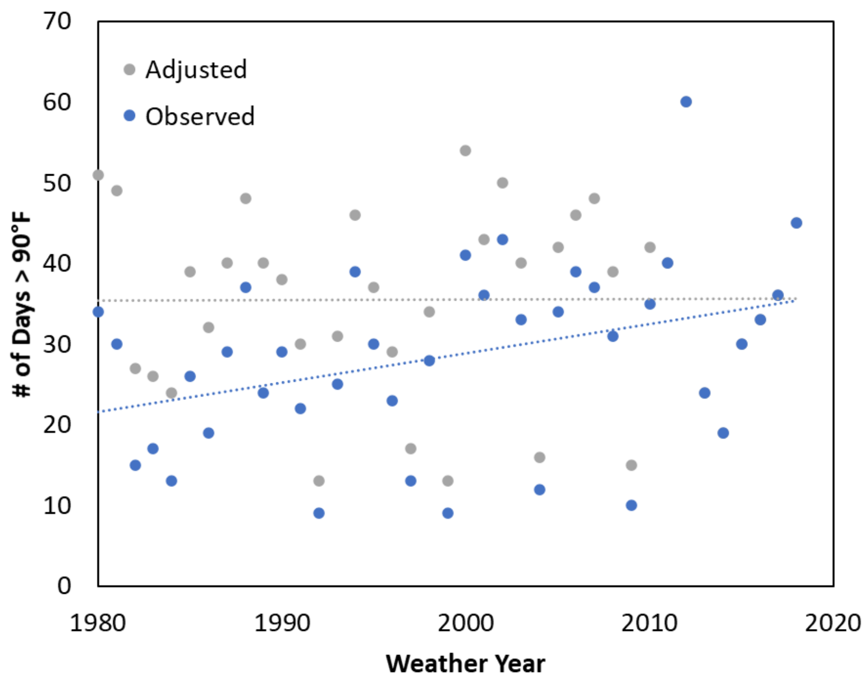
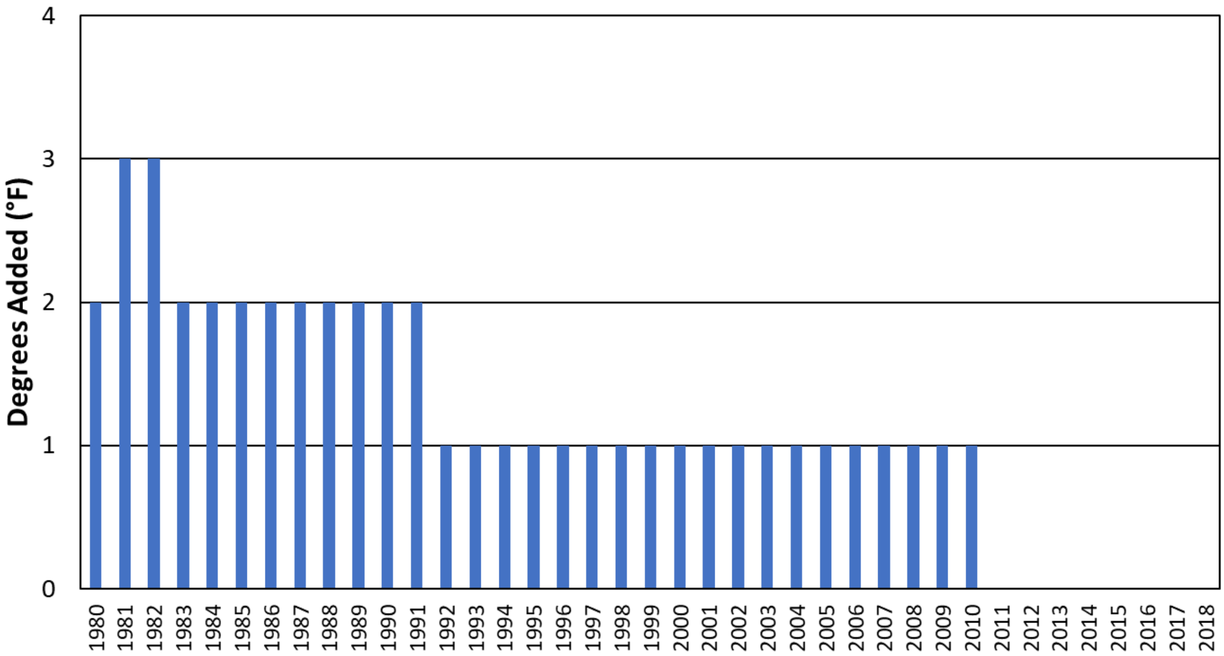


Figure 3. Degrees Added



Other inputs into the neural network model consisted of an hour of week factor and an average temperature from the past 8, 24, and 48 hours. Different weather and load relationships were built for each of the three defined seasons (winter, summer, and shoulder).

These relationships were then applied to the 39 years of weather to develop 39 synthetic load shapes. Equal probabilities were given to each of the 39 load shapes in the simulation. Table 2 below shows the results of the load modeling by displaying the peak load and the peak load variance for both the winter and summer seasons. The load variance is calculated by dividing the difference between each year's peak load and the mean by the mean.

Table 2. Peak Load Variability

Weather Year	Summer Peak (MW)	Winter Peak (MW)	Summer Variability (%)	Winter Variability (%)
1980	6,784	5,499	-1.13%	-4.68%
1981	6,928	5,554	0.96%	-3.73%
1982	6,779	5,949	-1.21%	3.12%
1983	6,734	6,230	-1.86%	7.99%
1984	6,725	6,149	-1.99%	6.59%
1985	6,717	5,927	-2.11%	2.74%
1986	6,768	5,508	-1.37%	-4.52%
1987	6,778	5,635	-1.22%	-2.32%
1988	6,751	5,625	-1.62%	-2.50%
1989	7,202	6,038	4.96%	4.66%
1990	7,120	6,123	3.76%	6.14%
1991	7,028	5,390	2.42%	-6.57%

1992	6,844	5,429	-0.26%	-5.89%
1993	6,971	5,741	1.59%	-0.49%
1994	6,878	5,433	0.24%	-5.82%
1995	6,752	5,524	-1.60%	-4.25%
1996	6,857	5,961	-0.07%	3.33%
1997	6,802	5,974	-0.87%	3.55%
1998	6,735	5866	-1.85%	1.68%
1999	6,585	5,407	-4.03%	-6.27%
2000	6,938	5,581	1.11%	-3.26%
2001	6,751	5,925	-1.62%	2.70%
2002	6,838	5,612	-0.35%	-2.72%
2003	6,942	5,710	1.17%	-1.02%
2004	6,762	5,917	-1.46%	2.57%
2005	7,194	5,723	4.84%	-0.80%
2006	6,993	5,802	1.91%	0.57%
2007	6,883	5,687	0.31%	-1.42%
2008	7,179	6,071	4.62%	5.23%
2009	6,499	5,791	-5.29%	0.38%
2010	6,675	6,029	-2.72%	4.51%
2011	6,876	5,922	0.21%	2.65%
2012	7,158	5,575	4.32%	-3.36%
2013	6,809	5,845	-0.77%	1.32%
2014	7,027	6,008	2.41%	4.14%
2015	6,750	5,685	-1.63%	-1.46%
2016	6,711	5,618	-2.20%	-2.62%
2017	6,782	5,856	-1.16%	1.51%
2018	7,107	5,672	3.57%	-1.68%
Mean	6,862	5,769	-	-
Minimum	6,499	5,390	-5.29%	-6.57%
Maximum	7,202	6,230	4.96%	7.99%

Loads for each external region were developed in a similar manner as the PSCo loads. A relationship between hourly weather and publicly available hourly load was developed based on recent history, and then this relationship was applied to 39 years of weather data to develop 39 synthetic load shapes[7]. The same temperature adjustment applied to create the synthetic PSCo load shapes was also applied to each neighbor shape. Tables 3 and 4 show the resulting seasonal weather diversity between PSCo and the external neighbors. When the PSCo system is peaking in summer, the aggregate of the neighboring regions is only 3.97% below the system coincident peak load on average over the 39-year period and 2.97% below in winter suggesting the market is likely to be relatively tight during PSCo's peak conditions. However, since hourly load and renewable profiles were constructed for each region, the unique pattern of diversity benefit is fully captured in the modeling. The same approach used for constructing neighboring loads is used by Astrapé's other clients including MISO, SPP, and ERCOT, and

[7] FERC 714 Forms were accessed to pull hourly historical load for all neighboring regions.

the magnitude of diversity found in this study is similar to that of studies performed by or on behalf of the other entities mentioned.

Table 3. External Region Diversity – Summer

	Non-Coincident Peak (MW)	System Coincident Peak (MW)	PSCo Peak (MW)	Load Diversity (% below system coincident peak)	Load Diversity (% below non-coincident peak)	
				At PSCo Peak	At System Coincident Peak	At PSCo Peak
PSCo	6,862	6,525	6,862	-5.17%	4.92%	0.00%
AZPS	17,979	17,320	15,573	10.08%	3.67%	13.38%
TRI	2,636	2,515	2,491	0.99%	4.58%	5.52%
PACE	9,135	8,621	8,201	4.87%	5.63%	10.22%
PNM	2,034	1,837	1,798	2.14%	9.67%	11.61%
WACM	4,373	4,141	4,139	0.05%	5.30%	5.35%
BHEC	637	592	597	-0.93%	7.06%	6.19%
CSU	909	839	852	-1.47%	7.68%	6.32%
PRPA	677	612	620	-1.28%	9.61%	8.44%
SPP	5,979	5,563	5,505	1.04%	6.95%	7.92%
System	51,220	48,564	46,636	3.97%	5.18%	8.95%

Table 4. External Region Diversity – Winter

	Non-Coincident Peak (MW)	System Coincident Peak (MW)	PSCo Peak (MW)	Load Diversity (% below system coincident peak)	Load Diversity (% below non-coincident peak)	
				At PSCo Peak	At System Coincident Peak	At PSCo Peak
PSCo	5,769	5,420	5,769	-6.45%	6.06%	0.00%
AZPS	10,734	9,622	8,556	11.09%	10.36%	20.30%
TRI	2,185	2,072	2,046	1.26%	5.20%	6.39%
PACE	7,587	7,212	7,019	2.68%	4.94%	7.49%
PNM	1,540	1,403	1,366	2.62%	8.95%	11.34%
WACM	3,943	3,667	3,664	0.08%	7.00%	7.07%
BHEC	624	571	570	0.21%	8.57%	8.76%
CSU	791	722	737	-2.11%	8.68%	6.76%
PRPA	510	466	472	-1.23%	8.65%	7.53%
SPP	4,290	4,039	3,951	2.18%	5.86%	7.91%
System	37,975	35,194	34,149	2.97%	7.32%	10.07%

ECONOMIC LOAD FORECAST ERROR

Economic load forecast error estimates were developed to isolate the economic uncertainty that PSCo has in its three-year-ahead load forecasts. The three-year-ahead load forecasts were selected for this study because three years is a reasonable lower bound on the amount of time required to place new resources in service to meet future resource needs, given the time required to identify the need, solicit projects, receive PUC approval, and acquire resources. The difference between Congressional Budget Office (CBO)[8] GDP forecasts three years ahead and actual data was fit to a normal distribution, which was then used as economic load forecast error in the model. Because electric load grows at a slower rate than GDP, a 40% multiplier was applied to the raw CBO forecast error distribution. Table 5 shows the economic load forecast errors and associated probabilities. As an illustration, 24.10% of the time, it is expected that load will be under forecasted by 2% three years out. Within the simulations, when PSCo under forecasts load, the external neighbors also under forecast load. The SERVM model utilized each of the 39 weather years and applied each of the five load forecast error multipliers to each hour to create 195 different load scenarios. Each weather year was given equal probability of occurrence.

Table 5. Economic Load Forecast Error

Load Forecast Errors	Associated Probabilities	Economic Load Forecast Error Multiplier
-4%	7.26%	0.96
-2%	24.10%	0.98
0%	37.28%	1
2%	24.10%	1.02
4%	7.26%	1.04

[8] Astrapé uses CBO data primarily because client-generated, weather-normalized forecast error data generally suggests larger magnitude economic forecast error impacts. Also, CBO data is available for more than two decades which demonstrates periods of both under forecast and over forecast. Client-generated data is often one-sided because it does not cover long enough time periods.

PSCO GENERATION RESOURCES

The PSCO generation resources included in this study are outlined below in Tables 6 and 7. All thermal resources were committed and dispatched to load economically.

Table 6. PSCo Owned Thermal Resources

Unit Name	Unit Category	Summer Capacity (MW)	Winter Capacity (MW)
Cherokee CT5	PSC CC	168	176
Cherokee CT6	PSC CC	168	176
Cherokee ST7	PSC CC	240	248
FSV CT2	PSC CC	123	134
FSV CT3	PSC CC	128	139
FSV CT4	PSC CC	128	139
FSV ST1	PSC CC	301	304
RMEC CT1	PSC CC	145	157
RMEC CT2	PSC CC	145	157
RMEC ST3	PSC CC	290	301
Comanche 1	PSC Coal	325	325
Comanche 2	PSC Coal	335	335
Comanche 3	PSC Coal	500	511
Craig 1	PSC Coal	42	42
Craig 2	PSC Coal	40	40
Hayden 1	PSC Coal	135	135
Hayden 2	PSC Coal	98	98
Pawnee 1	PSC Coal	505	505
Cherokee 4G	PSC Gas	310	310
Alamosa CT1	PSC SC	13	17
Alamosa CT2	PSC SC	14	18
Blue Spruce CT1	PSC SC	130	144
Blue Spruce CT2	PSC SC	134	148
Fort Lupton CT1	PSC SC	44	50
Fort Lupton CT2	PSC SC	44	50
Fruita CT1	PSC SC	14	18
FSV CT5	PSC SC	144	159
FSV CT6	PSC SC	144	159
Manchief CT1	PSC SC	128	151
Manchief CT2	PSC SC	128	151
Valmont CT6	PSC SC	43	51
Valmont CT78	PSC SC	82	86

Table 7. PSCo Contract Thermal Resources

Unit Name	Unit Category	Summer Capacity (MW)	Winter Capacity (MW)
WM.Landfill.Gas	PPA Biomass	3	3
Brush 13 CC1x1	PPA CC	77	89
Brush 4 CC2x1	PPA CC	132	146
SWG Arapahoe CC2x1	PPA CC	118	129
Plains End	PPA SC	112	114
Plains End II	PPA SC	110	117
Spindle CT1&2	PPA SC	274	321
SWG Fountain Valley	PPA SC	238	253
PacifiCorp	Delivered Energy	150	150

Tables 8, 9, 10, and 11 show the PSCo renewable, battery storage, pumped storage, and demand response resources captured in the study.

Table 8. PSCo Solar and Battery Storage Resources

		Capacity (MW)			
Unit Name	**Unit Category**	**2021**	**2023**	**2026**	**2030**
Bighorn	PPA Solar	-	240	240	240
Cogentrix	PPA Solar	30	30	30	30
Community Energy	PPA Solar	120	120	120	120
Hartsel	PPA Solar	-	72	72	72
Hooper	PPA Solar	50	50	50	50
Iberdrola	PPA Solar	30	30	30	30
Neptune	PPA Solar	-	250	250	250
Storage Neptune	PPA Battery	-	125	125	125
Sandhill	PPA Solar	19	19	19	19
Sun Edison	PPA Solar	7	7	7	-
Thunder Wolf	PPA Solar	-	200	200	200
Storage Thunder Wolf	PPA Battery	-	100	100	100
2019 Solar RFP	PPA Solar	-	113	113	113
2019 Solar RFP	PPA Solar	-	100	100	100
Storage 2019 Solar RFP	PPA Battery	-	50	50	50
San Luis Valley	Generic Solar	-	-	150	300
Western Slope	Generic Solar	-	-	100	200
Northern Front Range	Generic Solar	-	-	200	400
Southern Front Range	Generic Solar	-	-	200	400
Solar Connect	PPA Solar	50	50	50	50
Solar Gardens	Distributed Solar	138	196	310	463
Solar On-Site	Distributed Solar	464	592	784	1,041

Table 9. PSCo Wind Resources

		Capacity (MW)			
Unit Name	**Unit Category**	**2021**	**2023**	**2026**	**2030**
Bronco Plains	PPA Wind	300	300	300	300
Cedar Creek	PPA Wind	301	301	301	301
Cedar Creek II	PPA Wind	251	251	251	251
Cedar Point	PPA Wind	252	252	252	252
Cheyenne Ridge	PSC Wind	500	500	500	500
Golden West	PPA Wind	249	249	249	249
Limon	PPA Wind	200	200	200	200
Limon II	PPA Wind	200	200	200	200
Limon III	PPA Wind	201	201	201	201
Logan	PPA Wind	201	201	201	201
Mountain Breeze	PPA Wind	169	169	169	169
Northern Colorado	PPA Wind	152	152	152	152
Northern Colorado II	PPA Wind	23	23	23	23
Peetz Table	PPA Wind	199.5	199.5	199.5	199.5
Ridgecrest	PPA Wind	29.7	29.7	29.7	29.7
Rush Creek	PSC Wind	600	600	600	600
Spring Canyon	PPA Wind	60	60	60	60
Colorado Green[9]	PSC Wind	162	162	162	162
Twin Buttes[10]	PSC Wind	75	75	75	75
ERZ 1	Generic Wind	-	-	125	250
ERZ 2	Generic Wind	-	-	125	250
ERZ 3	Generic Wind	-	-	250	500

[9] The volume of non-firm energy that can be imported across the Lamar DC Tie is affected by the output of Colorado Green and Twin Buttes.
[10] Same as footnote 9.

Table 10. PSCo Hydro and Pumped Storage Resources

		Capacity (MW)			
Unit Name	**Unit Category**	**2021**	**2023**	**2026**	**2030**
COB-Betasso Lakewood	Municipal Water Hydro	6.0	6.0	6.0	6.0
COB- Silver Lake	Municipal Water Hydro	3.0	3.0	3.0	3.0
DWB-Foothills	Municipal Water Hydro	2.3	2.3	2.3	2.3
DWB Strontia	Municipal Water Hydro	1.2	1.2	1.2	1.2
DWB-Dillon	Municipal Water Hydro	1.9	1.9	1.9	1.9
DWB-Roberts Tunnel	Municipal Water Hydro	6.1	6.1	6.1	6.1
DWB-Hillcrest	Municipal Water Hydro	2.3	2.3	2.3	2.3
DWB-Gross Reservoir	Municipal Water Hydro	8.1	8.1	8.1	8.1
Redlands Water & Power	Municipal Water Hydro	1.4	1.4	1.4	1.4
STS (Mt. Elbert)	Municipal Water Hydro	2.5	2.5	2.5	2.5
Shoshone 1	PSCo-Owned Run of River	7.5	7.5	7.5	7.5
Shoshone 2	PSCo-Owned Run of River	7.5	7.5	7.5	7.5
Georgetown 1	PSCo-Owned Run of River	0.8	0.8	0.8	0.8
Georgetown 2	PSCo-Owned Run of River	0.8	0.8	0.8	0.8
Ames	PSCo-Owned Run of River	3.8	3.8	3.8	3.8
Tacoma	PSCo-Owned Run of River	4.6	4.6	4.6	4.6
Cabin Creek 1	PSCo Pumped Storage	150	150	150	150
Cabin Creek 2	PSCo Pumped Storage	150	150	150	150

Table 11. PSCo Demand Response Resources

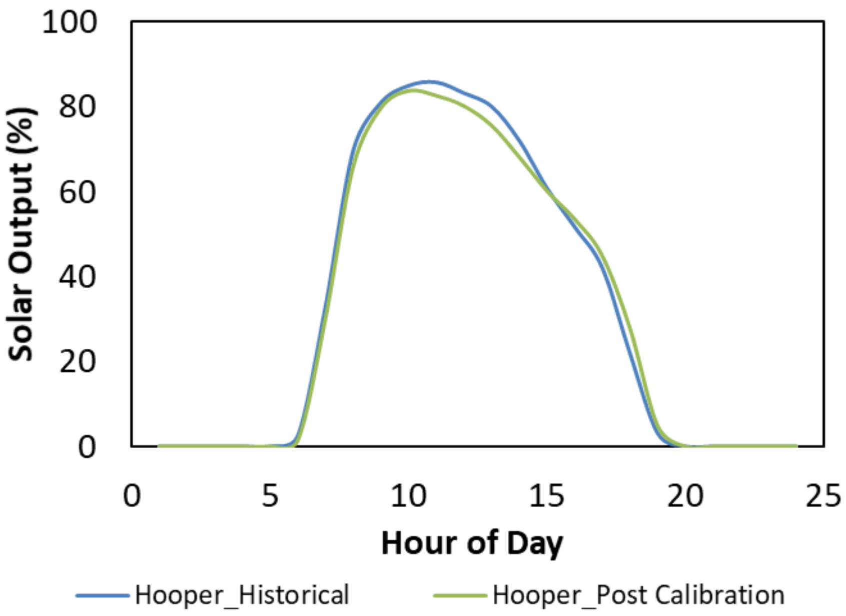
		Capacity (MW)			
Unit Name	**Unit Category**	**2021**	**2023**	**2026**	**2030**
AC Rewards	DR	33	45	57	68
Critical Peak Pricing	DR	38	46	48	50
ISOC160 Hour Customers	DR	116	117	118	116
ISOC40 Hour Customers	DR	12	12	12	12
ISOC80 Hour Customers	DR	60	61	62	61
Peak Day Partners	DR	5	8	8	10
Peak Partner Rewards	DR	47	51	55	58
Savers Switch Residential	DR	216	221	226	231

The changing resource mix in PSCo brings added uncertainty because the reliability contributions of new renewable and battery storage resources with little or no operational history are not known with precision. Actual generation data for solar, storage, wind, and hydro resources for the 1980-2018 weather year period would be the best source for determining the resource adequacy contribution of these resources. However, none of these resources existed for the entire weather year period and many have yet to be constructed. Using historical weather observations, recent-history generation data, and simulation methods, Astrapé created renewable generation profiles for solar, wind, and hydro resources for the 1980-2018 weather years as if the solar, wind, and hydro resources existed throughout the period. The correlations between the generation output at different renewable sites and amongst different resource technologies are not known with precision;

however, Astrapé used best-in-industry practices to create the synthetic profiles. The techniques preserve the correlations between load and renewable generation.

The solar units were simulated with 39 shapes representing 39 years of weather. The solar shapes were developed by Astrapé from data downloaded from the National Renewable Energy Laboratory (NREL) National Solar Radiation Database Data Viewer. The data was then input into NREL's System Advisor Model (SAM) for each year and county to generate hourly profiles. The configuration of the solar projects in SAM were carefully calibrated with actual PSCo historical solar profiles. Figure 4 shows the average August solar shape at the Hooper site.

Figure 4. Hooper Average August Solar Shape



The wind units were simulated with 39 shapes representing 39 years of weather. The hourly wind shapes used in this study were developed using historical wind generation data provided by PSCo. Calculations were performed to reflect historical correlation between wind projects as well as projected correlations between future wind projects.

Wind generation profiles were also adjusted to account for historical wind lull trends. The frequency of having very low wind output for an extended period is an important driver of the reliability contribution of wind and correspondingly to the required reserve margin of the system. Construction of the synthetic wind profiles were done on a daily basis, so it was important to look at longer trends to ensure that extended lull periods in the historical wind data were replicated in the synthetic profiles. Figures 5 and 6 below reflect the modeled frequency of each lull period for <5%, <2.5%, and <1% of system wind output as a percentage of all hours and demonstrate that the synthetic profiles accurately reflect the expected frequency of each category of lull period.

Wind profiles were manually set to zero output when the temperature dropped below -20°F in recognition of how wind turbine electronic controls will shut the wind turbines down at extreme cold temperatures. While some of PSCo's wind projects had cold temperature cut outs above -20°F, given that reliability issues were primarily in the summer even in 2030 scenarios, the additional effort to create more discrete cold temperature cut out profiles was deemed unnecessary.

Figure 5. Historical Wind Lull Data

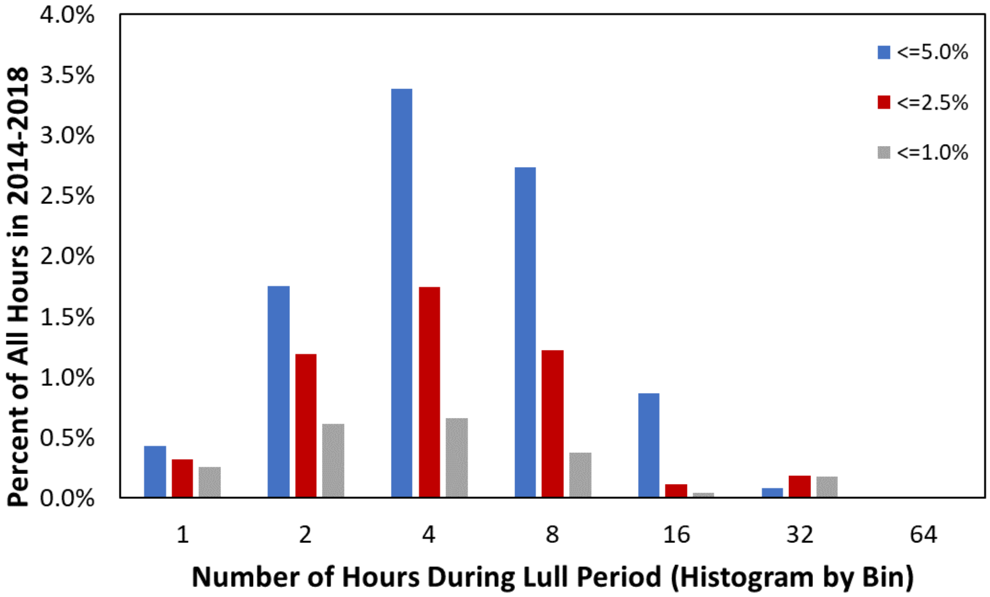


Figure 6. Synthetic Wind Lull Data

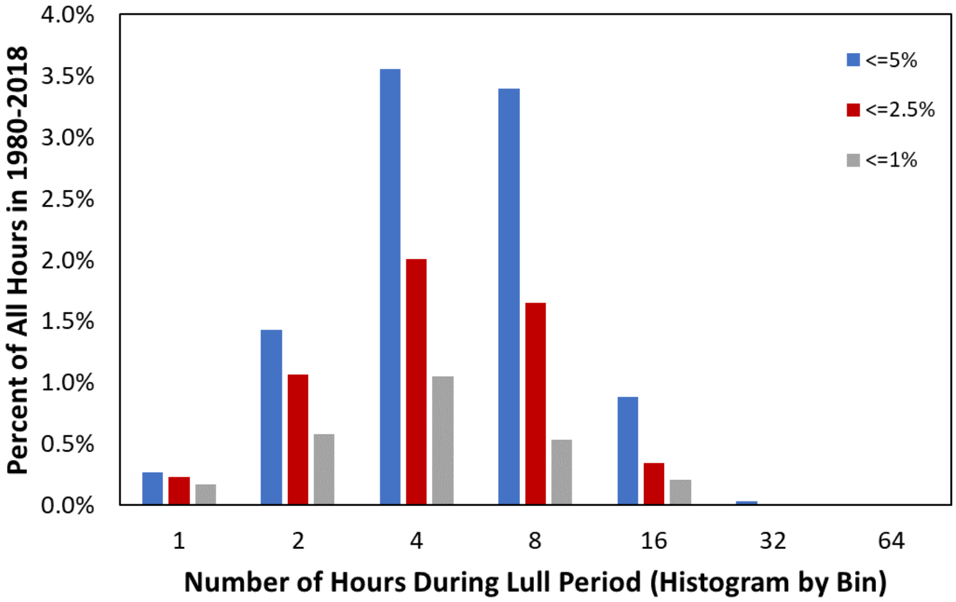


Table 13 shows the wholesale customer resources modeled.

Table 13. Wholesale Customer Resources

Unit Name	Capacity (MW)
WAPA_Allocation[11]	45
IREA_Victory Solar	12.8
IREA_Pioneer Solar	80
IREA_Hunter Solar	45
IREA_Kiowa Solar	54.5
Holy Cross_Arriba Wind	100
Holy Cross_Hunter Solar	30
Comanche 3	250

STORAGE DISPATCH

For the PSCo study, SERVM modeled the storage resources to be dispatched for economic arbitrage. In economic arbitrage operation, storage resources are scheduled using day-ahead forecasts of wind generation, solar generation, and load to be charged during low net load hours and dispatched during high net load hours. While the storage is dispatched in a manner to maximize economic arbitrage, that strategy is almost perfectly correlated with one that also preserves reliability. Additionally, SERVM allowed energy storage resources to provide ancillary services during emergency conditions without discharging which maximizes its reliability contributions.

The storage resources were modeled to be dispatched late in the dispatch stack only ahead of demand response resources. If generators fail unexpectedly or the actual renewable generation and load deviated significantly from the forecast, SERVM can dispatch the storage resources outside of the day-ahead schedule to preserve reliability, but it may affect the unit's availability in a later hour.

The modeled differences between batteries and pumped storage units were pumped storage units were modeled with a minimum discharge level instead of being able to operate at a baseline of 0 MW output like batteries. Similarly, charging pumped storage units was only allowed at a uniform charging level. The modeling respected the annual cycle limitations of the batteries and a 2-hour rest period between either fully charging or discharging the batteries.

DEMAND RESPONSE DISPATCH

The demand response resources listed in Table 11 above were given the dispatch constraints listed in Table 12 below. It was assumed that demand response could not serve ancillary services, and they were dispatched last in the dispatch stack.

[11] Based on historical data provided from PSCo for 2019-2020, daily average energy, total monthly energy, maximum dispatch, and schedule flow range entries were created for the WAPA hydro allocations of PSCo's Wholesale Customers. SERVM then optimally schedules hourly hydro energy while respecting these constraints. The total energy is the total amount of hydro that will be produced in a given month. This value cannot be greater than the total maximum hydro capacity multiplied by the number of hours in the month.

Table 12. PSCo Demand Response Dispatch Constraints

Interruption Action Window								
Program	Start Date	End Date	Start Hour (hr ending)	End Hour (hr ending)	Duration Single Event (Min)	Duration Single Event (Max)	Call Limits (Annual hours)	Call Limits (Annual Events)
AC Rewards	1-Jun	31-Aug	15	20	1	4	50	12
Critical Peak Pricing	1-Jan	31-Dec	13	20	4	4	60	15
ISOC160 Hour Customers	1-Jan	31-Dec	1	24	4	4	160	N/A
ISOC40 Hour Customers	1-Jan	31-Dec	1	24	4	4	40	N/A
ISOC80 Hour Customers	1-Jan	31-Dec	1	24	4	4	80	N/A
Peak Day Partners	1-Jan	31-Dec	1	24	1	6	None	None
Peak Partner Rewards	1-Jan	31-Dec	15	18	1	4	60	15
Savers Switch Residential	1-Jun	30-Sep	15	20	1	None	50	12

FUEL PRICES

Table 14 shows the fuel prices used in the study for PSCo and its neighboring power systems. The prices are based on data provided by PSCo. Since this study is focused on reliability, fuel prices are not a primary driver of the study results. Fuel prices are however necessary to create reasonable dispatch order in the simulations which can affect the reliability contribution of each generation resource.

Table 14. 2021 Fuel Prices

Fuel	2021 Price ($/mmBtu)
Coal	2.14
Oil	14.85
Natural Gas	3.36
Landfill Gas	2.10

UNIT OUTAGE DATA

Unlike typical production cost models, SERVM does not use an Equivalent Forced Outage Rate (EFOR) for each unit as an input. Instead, historical Generating Availability Data System (GADS) data events are entered in for each unit and SERVM randomly draws from these events to simulate the unit outages. The events are entered using the following variables:

Full Outage Modeling

Time-to-Repair Hours

Time-to-Fail-Hours

Partial Outage Modeling

Partial Outage Time-to-Repair Hours

Partial Outage Derate Percentage

Partial Outage Time-to-Fail Hours

Maintenance Outages

Maintenance Outage Rate entered as a % of time in a month that the unit will be on maintenance outage. SERVM uses this percentage and schedules the maintenance outages during off peak periods.

Planned Outages

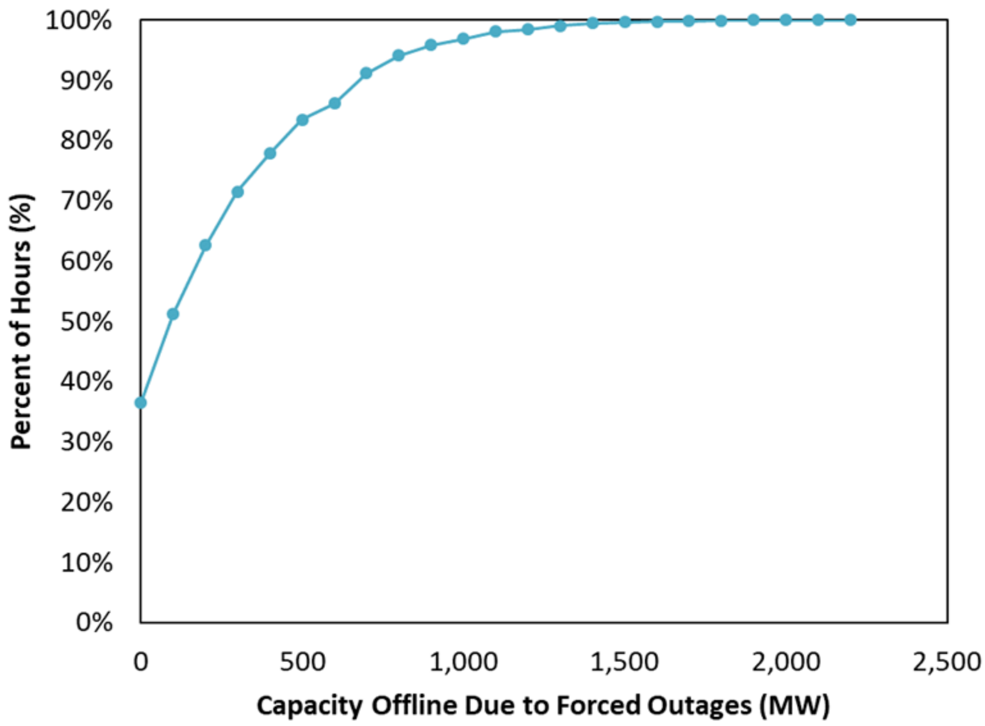
Specific time periods are entered for planned outages. Typically, these are performed during shoulder months.

As an example, assume that from 2014 to 2018 Cherokee CT5 had 13 full outages reported in the GADS data. The time-to-repair and time-to-fail between each event is calculated from the GADS data. These multiple time-to-repair and time-to-fail inputs are the distributions used by SERVM. Further, assume Cherokee CT5 is online in hour 1 of the simulation, SERVM will randomly draw a time-to-fail value from the distribution provided for full outages. The unit will run for that amount of time before failing. Next, the model will draw a time-to-repair value from the distribution and be on outage for that number of hours. When the repair is complete it will draw a new time-to-fail value. The process repeats until the end of the iteration when it will begin again for the subsequent iteration. This more detailed modeling is important to capture the tails of the distribution that a simple convolution method would not capture.

Table A.1.1. in the Highly Confidential Appendix document shows each unit with its Modeled Equivalent Forced Outage Rate (EFOR). These reported values do not include maintenance outages which are also captured in the modeling. For neighboring regions, Astrapé used some of its in-house distributions to capture a reasonable EFOR in each external region. The average EFOR represented for external regions was 8.78%.

The most important aspect of unit performance modeling in resource adequacy studies is the cumulative MW offline distribution. Most service reliability problems are due to significant coincident outages. Figure 7 below shows the distribution of system outages as a percentage of time. The totals in this figure do not include maintenance outages or planned outages which are listed in Table A.2.1 in the Highly Confidential Appendix.

Figure 7. Cumulative Outages



EXTERNAL MARKET ASSISTANCE MODELING

The non-firm electric market plays a significant role in planning for resource adequacy. If multiple PSCo resources experience an outage and PSCo did not have access to surrounding non-firm energy, there is a high likelihood of firm load shed even during non-peak conditions. To capture a reasonable amount of non-firm energy assistance from surrounding neighbors, each neighbor was modeled at a target reliability of approximately 0.1 LOLE. Because only one tie away was modeled, neighboring systems do not have access to purchases from their neighbors not modeled in the study topology, so it was necessary to add additional capacity above the target reserve margin to get the external neighbors to the reliability standard. The 0.1 LOLE standard was chosen for neighbors even though other systems may not explicitly plan to it because it is the most common standard in the industry and because it results in a reasonable level of external assistance to PSCo. If neighbors were modeled at a standard less stringent than 0.1 LOLE, they may not frequently have excess energy to sell to neighbors and would rely on PSCo resources for reliability. Conversely, short-term excess resources in neighboring systems was not reflected because for planning decisions, only weather diversity and generator outage diversity benefit should be captured. Otherwise, PSCo may plan its future system to be reliant on neighboring generation resources that may be retired or otherwise unavailable. All study years assumed neighbors achieve approximately 0.1 LOLE despite rapidly changing resource mixes. However, the recent reliability events in California highlight the challenge of maintaining reliability when undergoing such a significant transition. While no conservatism was applied to market support within the SERVM modeling to consider the potential impact of increasing renewable penetration, changes in the market that may affect resource adequacy should be carefully monitored. This uncertainty is also part of the reason that Astrapé often recommends using a reserve margin range for a planning target because it recognizes that resources above the bare minimum required to meet 0.1 LOLE can obviate risks not taken into account in the Base Cases.

Table 15 outlines the transmission import limits between PSCo and each of its modeled external neighbors. These transmission limits reflect only the level of transmission available from neighboring systems to PSCo while the actual non-firm energy purchases will depend on the weather and generator outage diversity benefit with the neighboring systems. Several of the transmission connections between PSCo and its neighbors were modeled with a dynamic rather than static MW transfer rating based on historical available transfer capability on the transmission paths.

Historical hourly purchase data by counterparty was used to calibrate the modeled import and export amounts. Additionally, based on historical purchases during high load hours from 2015-2018, an aggregated import limit of 950 MW of non-firm energy purchases was imposed. 2019 was excluded from the external assistance calibration because PSCo made several short-term transmission purchases in 2019 for additional import capability.

Table 15. Transmission Capability

Region A	Region B	Import Distribution	Max Import Capability (MW)
PSCo	PACE	Static	0
PSCo	AZPS[1]	Dynamic	150
PSCo	PNM[1]	Dynamic	150
PSCo	SPP[2]	Dynamic	210
PSCo	WACM	Dynamic	60
PSCo	TRI	Dynamic	300
PSCo	PRPA	Static	300
PSCo	CSU	Static	350
PSCo	BHEC	Static	350

1. The Four Corner Transmission Path (AZPS & PNM) is modeled with a 150 MW aggregated limit based on recent historical performance
2. Represents the Lamar DC Tie. The dynamic import distribution reflects the historical outage rate of the Lamar DC Tie.

The Lamar DC Tie connects PSCo to SPP and has a 210 MW limit. The greater the wind generation output of Colorado Green and Twin Buttes the less the amount of non-firm energy PSCo can import from SPP. To capture this relationship, these two wind units were modeled in SPP, but their output was committed to PSCo. This limited the combined output of Colorado Green and Twin Buttes to below their total generation capability (237 MW compared to 210 MW); however, when these wind units are at maximum output there are no resource adequacy concerns for the PSCo system. The dynamic outage rate of the Lamar DC Tie was only applied to SPP generation to avoid impacting the reliability contribution of Colorado Green and Twin Buttes. The non-firm energy purchases made from SPP were capped at 190 MW based on historical purchase history and recognizing that non-firm energy from SPP delivered to PSCo must utilize the transmission rights of Colorado Green and Twin Buttes.

CONTINGENCY RESERVE

Astrapé modeled the contingency reserve required of the PSCo Balancing Authority Area (PSCo BAA) by the Northwest Power Pool. The contingency reserve is calculated in the model on a dynamic basis as a function of load, generation, transmission import paths to PSCo, and the generation output of the most severe single contingency (MSSC) within the PSCo BAA for any simulation hour.

Astrapé also modeled contingency reserve currently purchased from PSCo by Platte River Power Authority (PRPA). Because of this contingency reserve relationship, the model shed PSCo customer load when either the Platte River Power Authority system or the PSCo system were short contingency reserve which aligns with PSCo load shed procedures in this event. While PRPA was modeled at approximately 0.1 LOLE in every study year, PRPA's system is also transitioning to a high renewable system. It would require a complete study of PRPA's transitioning system through the study period to completely equalize its reliability effect on PSCo's System. This additional study was not completed, but its effect is captured in the target reserve margin range recommendation.

In addition to contingency reserves, Astrapé modeled the PSCo BAA ancillary services of regulation and flex reserve. Modeling these ancillary services in this study ensures the unit dispatch simulated within SERVM is reasonable for the amount of solar and wind generation in any simulation hour. Regulation and flex reserve reliably integrate renewable generation, but deficits of regulation or flex reserve did not contribute to load shed in the modeling. Only the deficit of contingency reserve contributed to firm load shed.

SIMULATION METHODOLOGY

Since most reliability events are high impact, low probability events, a large number of simulations must be considered. For PSCo, SERVM utilized 39 years of historical weather to create 39 years of load shapes and renewable profiles, 5 distribution points of economic load forecast error, and 10 iterations of unit outages for each case to represent the full distribution of realistic outcomes. The number of simulations for each case is 39 weather years * 5 economic load forecast errors * 10 unit outage iterations for a total of 1,950 simulations. The cases analyzed include the Base Cases for years 2021, 2023, 2026, and 2030 and several sensitivities of the Base Cases.

CASE PROBABILITIES

An example of probabilities given for each case is shown in Table 16. Each weather year is given equal probability and each weather year is multiplied by the probability of each economic load forecast error to calculate the case probability. Each of the case probabilities in Table 16 would also have 10 representations of unit outages to create the total 1,950 simulations.

Table 16. Case Probability Example

Weather Year	Weather Year Probability	Economic Load Forecast Error Multiplier	Economic Load Forecast Error Probability	Case Probability
1980	2.56%	0.96	7.26%	0.186%
1980	2.56%	0.98	24.10%	0.620%
1980	2.56%	1	37.28%	0.954%
1980	2.56%	1.02	24.10%	0.620%
1980	2.56%	1.04	7.26%	0.186%
1981	2.56%	0.96	7.26%	0.186%
1981	2.56%	0.98	24.10%	0.620%
1981	2.56%	1	37.28%	0.954%
1981	2.56%	1.02	24.10%	0.620%
1981	2.56%	1.04	7.26%	0.186%
1982	2.56%	0.96	7.26%	0.186%
1982	2.56%	0.98	24.10%	0.620%
1982	2.56%	1	37.28%	0.954%
1982	2.56%	1.04	24.10%	0.186%
1982	2.56%	1.04	7.26%	0.186%
…	…	…	…	…
2018	2.56%	1.04	7.26%	0.186%
			Total	1

RESERVE MARGIN DEFINITION

For this study, reserve margin is defined by the formula:

$$Reserve\ margin = \frac{resources - firm\ peak\ demand}{firm\ peak\ demand}$$

RELIABILITY METRIC

Across the industry, the 1 firm load shed event in 10 years is defined as 0.1 LOLE[12]. Loss of Load Expectation (LOLE) is defined in days per year and is calculated for each simulation. As outlined in the executive summary, the 1-day-in-10-year standard can also be interpreted as 24 hours of firm load shed over a 10-year period with the Loss of Load Hours (LOLH) metric. Traditionally, the 2.4 LOLH interpretation was used in studies that modeled systems without taking into account the reliability benefit of an interconnected transmission system. Given that this study modeled PSCo with non-firm energy purchases, the 0.1 LOLE metric will be used to determine the target reserve margin. Other reliability metrics are provided in this study report for informational purposes including LOLH and Expected Unserved Energy (EUE). Any hour that failed to maintain contingency reserve was a firm load shed event.

[12] https://www.ferc.gov/sites/default/files/2020-05/02-07-14-consultant-report.pdf

PHYSICAL RELIABILITY RESULTS

Physical reliability of the electric power system is the measure of frequency, duration, and severity of firm load shed events. A firm load shed event refers to an instance where the utility must reduce load on the system by turning off the power to firm load customers due to the lack of generation resources. The most common resource adequacy standard in the industry today is the 1-day-in-10 standard. This standard allows for 1 firm load shed event every 10 years and is represented as an LOLE of 0.1 days per year. Figure 8 shows Loss of Load Expectation (LOLE) as a function of reserve margin. A 17.4% reserve margin provides PSCo 1-in-10 reliability for the Base Case in 2021.

Figure 8. LOLE Results

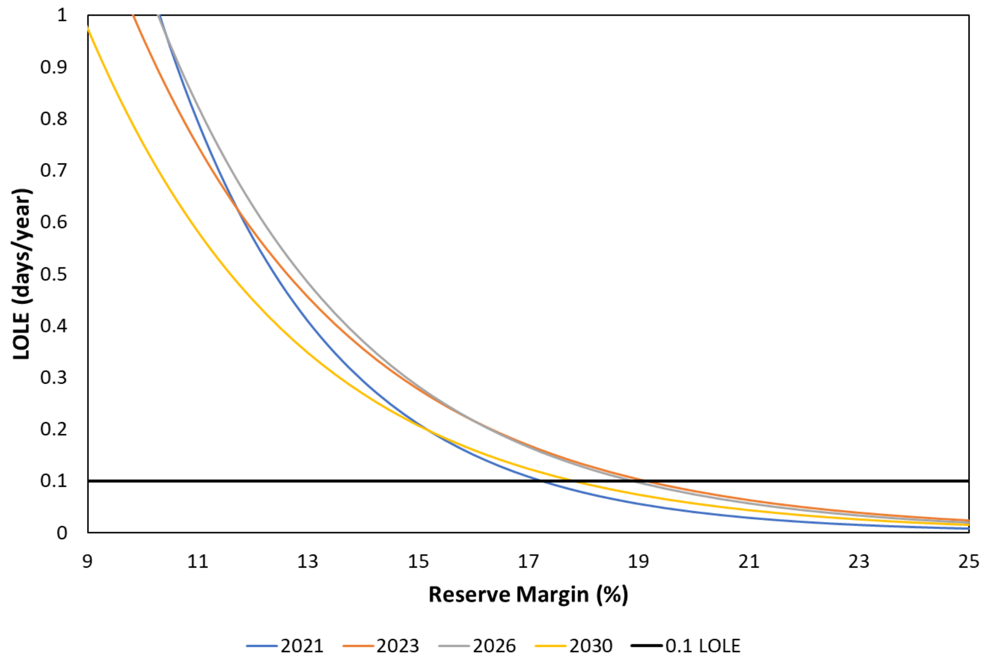


Table 17 shows LOLE and other physical reliability metrics by reserve margin for the 2021 Base Case. Loss of Load Hours (LOLH) is expressed in hours per year and Expected Unserved Energy (EUE) is expressed in MWh. The full table of results for the 2023, 2026, and 2030 Base Cases are located in the appendix.

Table 17. Physical Reliability Metrics: Base Case 2021

Reserve Margin (%)	Summer Resources (MW)	LOLE (days per year)	LOLH (hours per year)	EUE (MWh)
8%	7,197	0.86	2.55	542
9%	7,261	0.67	1.95	407
10%	7,324	0.53	1.50	306
11%	7,389	0.41	1.15	229
12%	7,454	0.32	0.88	172
13%	7519	0.25	0.67	129
14%	7,585	0.20	0.52	97
15%	7,652	0.15	0.40	73

16%	7,719	0.12	0.30	55
17%	7,787	0.11	0.27	47
18%	7,856	0.08	0.19	33
19%	7,925	0.06	0.13	23
20%	7,994	0.04	0.09	16
21%	8,064	0.03	0.07	11
22%	8,135	0.02	0.05	8
23%	8,207	0.01	0.03	5
24%	8,279	0.01	0.02	4
25%	8,352	0.01	0.02	3

Table 17 demonstrates the relationship between the level of reliability provided by the 0.1 LOLE standard compared to the 2.4 LOLH metric. The 0.1 LOLE level of reliability is met with a reserve margin of 17.4%, and the 2.4 LOLH level of reliability is met with a reserve margin of 8.2%. However, a reserve margin of 8.2% has a 0.74 LOLE. This means that the 2.4 LOLH interpretation of the reliability standard would expect firm load shed approximately 7 times in 10 years.

Table 18 shows the monthly LOLE distribution for each of the Base Case study years.

Table 18. Monthly LOLE Distribution

	Percentage of LOLE			
Month	**2021**	**2023**	**2026**	**2030**
1	0%	1%	3%	3%
2	0%	5%	4%	5%
3	0%	2%	0%	2%
4	0%	2%	0%	0%
5	0%	2%	0%	1%
6	21%	17%	20%	14%
7	49%	44%	36%	44%
8	21%	16%	21%	18%
9	7%	5%	5%	4%
10	0%	0%	2%	1%
11	0%	3%	4%	2%
12	1%	4%	4%	7%

As the results in the Table 18 demonstrate, there is a small but noticeable increase in winter and shoulder period reliability events. This is mainly caused by the shift of the PSCo portfolio to higher amounts of solar and wind resources. They provide more reliability value during the summer months than in the winter months and as the size of the renewable portfolio increases, PSCo will experience more reliability risk in the winter. The change between winter and summer reliability risk can be seen in Figures 9 and 10 below which displays the seasonal net load peak for each weather year in the 2021 and 2030 study year. By 2030, winter peaks make up a noticeable share of the overall highest net load peaks.

Figure 9. 2021 Seasonal Net Load Peaks

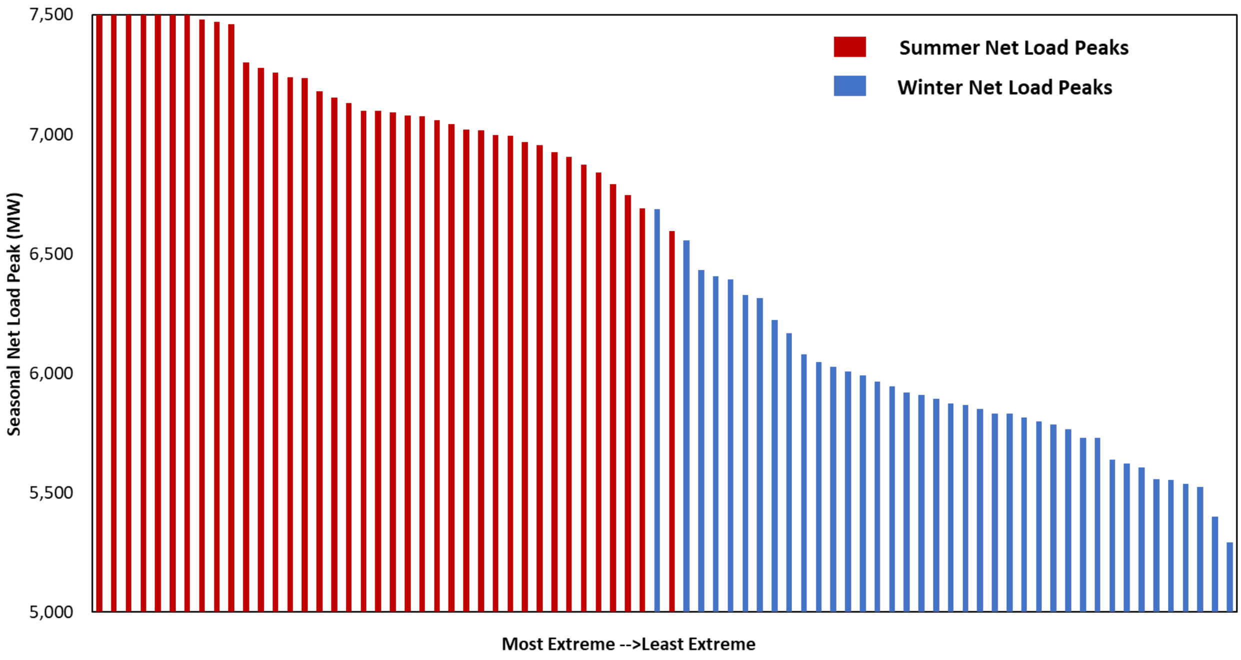
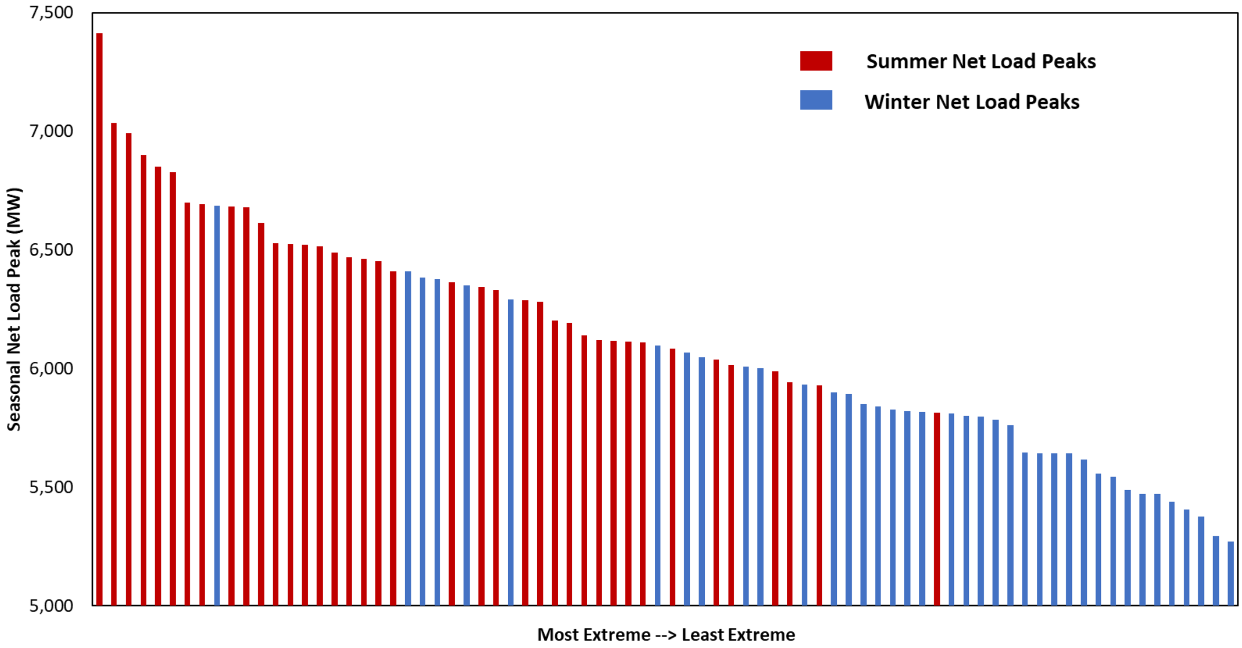


Figure 10. 2030 Seasonal Net Load Peaks



ADDITIONAL SENSITIVITY PHYSICAL RELIABILITY RESULTS

ISLAND SENSITIVITY

This sensitivity modeled PSCo as an island and assumed no external assistance from its neighbors. Table 19 shows LOLE and other physical reliability metrics by reserve margin for this sensitivity in 2021. The full table of results for the 2023, 2026, and 2030 study years are located in the appendix. As the table indicates, the target reserve margin increases by nearly 10% to 26.99%. This does not mean that PSCo can count on 10% of its peak load to be served by non-firm energy purchases, but rather from a wholistic perspective, the contribution of the electric market in off-peak and on-peak period allows PSCo to carry 10% lower planning reserve than it would need as an island. During both extreme hot and cold periods, the simulations indicated the ability to purchase less than 10% of its total load. When generator outages were high but weather conditions were mild, the non-firm electric market could provide more support.

Table 19. 2021 Island Sensitivity Physical Reliability Metrics

Reserve Margin (%)	Summer Resources (MW)	LOLE (days per year)	LOLH (hours per year)	EUE (MWh)
14%	7,598	2.50	8.24	2943
15%	7,661	1.94	6.16	2131
16%	7,725	1.50	4.61	1542
17%	7,789	1.16	3.45	1117
18%	7,854	0.90	2.58	808
19%	7,919	0.70	1.93	585
20%	7,985	0.54	1.44	424
21%	8,051	0.42	1.08	307
22%	8,118	0.33	0.81	222
23%	8,186	0.25	0.60	161
24%	8,254	0.20	0.45	116
25%	8,322	0.15	0.34	84
26%	8,391	0.12	0.25	61
27%	8,461	0.09	0.19	44
28%	8,531	0.07	0.14	32
29%	8,602	0.06	0.11	23
30%	8,674	0.04	0.08	17
31%	8,746	0.03	0.06	12

NO ECONOMIC LOAD FORECAST ERROR SENSITIVITY

The economic load forecast error distribution was removed in this sensitivity for the 2030 study year. The impact of the economic load forecast error is 0.55% as shown in Table 20 below.

Table 20. 2030 No Load Forecast Error Sensitivity Results

	0.1 LOLE Reserve Margin (%)
2030 Base Case	18.03%
2030 No LFE	17.48%

NO SPP IMPORT

In this sensitivity, the SPP import across the Lamar DC tie was removed for the 2030 study year. The maximum import capability of this DC tie is 210 MW and the difference in target reserve margin translated to MW is 119 MW as shown below in Table 21. A combination of SPP generation unavailability and transmission unavailability make the reliability contribution of SPP import less than the nominal rating of the DC tie. A portion of the transmission unavailability is associated with the PSCo wind resources which can affect the ability to import across the Lamar DC tie.

Table 21. 2030 No SPP Import Sensitivity Results

	0.1 LOLE Reserve Margin (%)	Benefit (MW)[13]
2030 Base Case	18.03%	-
2030 No Lamar Tie	19.67%	119

NO FOUR CORNERS TRANSMISSION IMPORT PATH SENSITIVITY

The Four Corners transmission import path was removed for the 2030 study year. PSCo's Four Corners transmission reservation is 188MW; however, the path rating is dynamically impacted by load and generation in the SW Colorado area. The difference in reserve margin target as a result of this sensitivity translated to MW is 97 MW as shown below in Table 22. A combination of generation unavailability and transmission unavailability make the reliability contribution of this import path less than its nominal rating.

Table 22. 2030 No Four Corners Path Sensitivity Results

	0.1 LOLE Reserve Margin (%)	Benefit (MW)[14]
2030 Base Case	18.03%	-
2030 No Four Corners Path	19.33%	97

INCREASED TRANSMISSION SENSITIVITIES

In these transmission sensitivities, the PSCO⇔PACE transmission capability was bi-directionally increased by 200 MW in 2030 in one scenario and 400 MW in another scenario. As the results in Table 23 below show, there is enough system (weather, load, and generator outages) diversity that the first

[13] 1.64% reserve margin multiplied by 7,269 MW of peak load = 119 MW.
[14] 1.33% reserve margin multiplied by 7,269 MW of peak load = 97 MW.

200 MW increase receives almost full credit but the second 200 MW addition receives diminishing credit of 51% [(289 MW – 187 MW)/200 MW].

Table 23. 2030 Increased Transmission Sensitivity Results

	0.1 LOLE Reserve Margin (%)	Benefit (MW)
2030 Base Case	18.03%	-
2030 Increased Transmission by 200 MW	15.46%	187
2030 Increased Transmission by 400 MW	14.06%	289

NON-FIRM FUEL SUPPLY SENSITIVITY

This sensitivity was simulated to examine the effects of potential fuel supply disruptions during cold weather conditions for the 2030 study year. To assess this risk, Plains End I and Plains End II were modeled on forced outage when the temperature was -5°F or below due to an assumed lack of natural gas supply. These units were chosen to assess this risk because they currently have non-firm fuel supply and have had fuel supply disruptions during cold weather in the past. The results are listed in Table 24 below. Since winter reliability risk is expected to become more frequent as solar and wind penetration increases, non-firm fuel supply risk may necessitate further analysis in future reliability studies.

Table 24. 2030 Non-Firm Fuel Supply Sensitivity Results

	0.1 LOLE Reserve Margin (%)
2030 Base Case	18.03%
2030 Non-Firm Gas Supply	18.52%

JDA MARKET RELIANCE SENSITIVITY

This sensitivity was performed to examine the contribution of the non-firm energy purchases from members of PSCo's JDA: BHEC, CSU, and PRPA. These zones were removed, and the 2030 study year was simulated. All other market connections were still included in the simulations. The results in Table 25 below show that PSCo can carry about a 1.3% lower reserve margin due to the market assistance from BHEC, CSU, and PRPA.

Table 25. 2030 JDA Market Reliance Sensitivity Results

	0.1 LOLE Reserve Margin (%)
2030 Base Case	18.03%
No Market Reliance	19.33%

250 MW FIRM ENERGY PURCHASE SENSITIVITY

This sensitivity was performed to examine the reliability contribution of 250 MW of firm energy purchases during the summer of 2023. Since no new capacity was added to the aggregated modeled area, the 250 MW firm energy purchase represents only a re-allocation of capacity. This re-allocation improves PSCo reliability, but some of the capacity purchased may have previously been available as a non-firm energy purchase in the modeled electric market. Thus, the benefit of the purchase is less than the nominal amount of capacity purchased. The results of the simulation demonstrate that a 250 MW firm energy purchase during the summer provides the equivalent reliability of 197 MW of new, fully dispatchable, year-round capacity.

SUMMARY

This study represents the culmination of efforts from PSCo and Astrapé staff to carefully analyze resource adequacy risks as PSCo anticipates continued evolution of its electric system. This study recommends changing the basis of the reserve margin target to the industry standard 0.1 LOLE from the 2.4 LOLH that was used in the prior study. While this standard is markedly more stringent, this study more rigorously assessed the ability of the market to provide support to PSCo. Astrapé applied this philosophy of modeling the distribution of expected conditions throughout all aspects of the study in order to give a true picture of the reliability needs of the PSCo system rather than applying conservatism to any of the inputs to the study. Therefore, the target reserve margin range of 18-20% represents a recommendation that is expected to efficiently produce reliability consistent with industry standards.

APPENDIX

APPENDIX A: PHYSICAL RELIABILITY RESULTS FOR ADDITIONAL STUDY YEARS

APPENDIX A.1: 2023 STUDY YEAR

Table A.1.1. Physical Reliability Metrics for 2023

Reserve Margin (%)	Summer Resources (MW)	LOLE (days per year)	LOLH (hours per year)	EUE (MWh)
8%	7,195	1.57	4.07	928
9%	7,257	1.23	3.13	703
10%	7,319	0.96	2.41	533
11%	7,382	0.75	1.86	404
12%	7,445	0.58	1.43	306
13%	7,509	0.45	1.10	232
14%	7,574	0.36	0.85	176
15%	7,639	0.28	0.65	133
16%	7,704	0.22	0.50	101
17%	7,770	0.17	0.39	77
18%	7,837	0.13	0.30	58
19%	7,904	0.10	0.23	44
20%	7,972	0.08	0.18	33
21%	8,040	0.06	0.14	25
22%	8,109	0.05	0.11	19
23%	8,179	0.04	0.08	15
24%	8,249	0.03	0.06	11
25%	8,320	0.02	0.05	8

Table A.1.2. Physical Reliability Metrics for 2023 Island

Reserve Margin (%)	Summer Resources (MW)	LOLE (days per year)	LOLH (hours per year)	EUE (MWh)
14%	7,574	3.11	9.01	3,264
15%	7,639	2.36	6.66	2,367
16%	7,704	1.78	4.92	1,716
17%	7,770	1.35	3.64	1,244
18%	7,837	1.02	2.69	902
19%	7,904	0.77	1.99	654
20%	7,972	0.59	1.47	474
21%	8,040	0.44	1.08	344
22%	8,109	0.34	0.80	249
23%	8,179	0.25	0.59	181
24%	8,249	0.19	0.44	131
25%	8,320	0.15	0.32	95
26%	8,391	0.11	0.24	69
27%	8,463	0.08	0.18	50

28%	8,536	0.06	0.13	36
29%	8,609	0.05	0.10	26
30%	8,683	0.04	0.07	19
31%	8,758	0.03	0.05	14

APPENDIX A.2: 2026 STUDY YEAR

Table A.2.1. Physical Reliability Metrics for 2026

Reserve Margin (%)	Summer Resources (MW)	LOLE (days per year)	LOLH (hours per year)	EUE (MWh)
8%	7,390	1.84	4.54	1,033
9%	7,455	1.41	3.39	754
10%	7,521	1.08	2.53	550
11%	7,588	0.83	1.89	401
12%	7,655	0.63	1.41	292
13%	7,723	0.48	1.05	213
14%	7,791	0.37	0.79	155
15%	7,860	0.28	0.59	113
16%	7,929	0.22	0.44	83
17%	7,999	0.17	0.33	60
18%	8,070	0.13	0.24	44
19%	8,141	0.10	0.18	32
20%	8,213	0.07	0.14	23
21%	8,286	0.06	0.10	17
22%	8,359	0.04	0.08	12
23%	8,433	0.03	0.06	9
24%	8,507	0.03	0.04	7
25%	8,583	0.02	0.03	5

Table A.2.2. Physical Reliability Metrics for 2026 Island

Reserve Margin (%)	Summer Resources (MW)	LOLE (days per year)	LOLH (hours per year)	EUE (MWh)
14%	7,814	3.83	9.91	3,419
15%	7,879	2.82	7.17	2,443
16%	7,944	2.08	5.19	1,746
17%	8,009	1.53	3.75	1,248
18%	8,076	1.13	2.72	892
19%	8,142	0.83	1.96	638
20%	8,210	0.61	1.42	456
21%	8,278	0.45	1.03	326
22%	8,346	0.33	0.74	233
23%	8,415	0.24	0.54	166

24%	8,485	0.18	0.39	119
25%	8,555	0.13	0.28	85
26%	8,626	0.10	0.20	61
27%	8,697	0.07	0.15	43
28%	8,769	0.05	0.11	31
29%	8,841	0.04	0.08	22
30%	8,915	0.03	0.06	16
31%	8,988	0.02	0.04	11

APPENDIX A.3: 2030 STUDY YEAR

Table A.3.1. Physical Reliability Metrics for 2030

Reserve Margin (%)	Summer Resources (MW)	LOLE (days per year)	LOLH (hours per year)	EUE (MWh)
8%	7,840	1.26	2.80	590
9%	7,912	0.98	2.13	437
10%	7,984	0.75	1.62	324
11%	8,056	0.58	1.23	240
12%	8,129	0.45	0.94	178
13%	8,203	0.35	0.71	132
14%	8,278	0.27	0.54	98
15%	8,353	0.21	0.41	72
16%	8,429	0.16	0.31	54
17%	8,506	0.12	0.24	40
18%	8,583	0.10	0.18	30
19%	8,661	0.07	0.14	22
20%	8,740	0.06	0.11	16
21%	8,819	0.04	0.08	12
22%	8,899	0.03	0.06	9
23%	8,980	0.03	0.05	7
24%	9,062	0.02	0.04	5
25%	9,144	0.02	0.03	4

Table A.3.2. Physical Reliability Metrics for 2030 Island

Reserve Margin (%)	Summer Resources (MW)	LOLE (days per year)	LOLH (hours per year)	EUE (MWh)
14%	8,281	1.40	3.26	1,124
15%	8,351	1.03	2.34	791
16%	8,422	0.76	1.68	557
17%	8,494	0.56	1.20	392
18%	8,566	0.41	0.86	276
19%	8,638	0.30	0.62	194
20%	8,711	0.22	0.45	137
21%	8,785	0.16	0.32	96

22%	8,859	0.12	0.23	68
23%	8,935	0.09	0.16	48
24%	9,010	0.07	0.12	34
25%	9,087	0.05	0.08	24
26%	9,164	0.04	0.06	17
27%	9,241	0.03	0.04	12
28%	9,319	0.02	0.03	8
29%	9,398	0.01	0.02	6
30%	9,478	0.01	0.02	4
31%	9,558	0.01	0.01	3