PROGRESS REPORT for EPC-19-060

May, 2021

Recipient Project Manager: Sarah Kurtz

Commission Agreement Manager: Jeffrey Sunquist

What we planned to accomplish this period

1. We expect to complete paper #3, described above, and to have a second paper well along by the end of May.
2. We will continue to meet with stakeholders and community representatives to gather inputs and request feedback
3. We hope to complete the "Issues in Science and Technology" piece by the end of May, but we cannot move forward on it until we hear from the editor, so the date of completion is uncertain
4. We will provide an update on the multiple deliverables that will be due in July
5. We will update our status of completing the Knowledge Transfer plan

What we actually accomplished this period

1. Paper #3: Seasonal challenges: We completed paper #3 below and submitted it to the IEEE Journal of PV. It is attached as a supplement to this Monthly report. This paper shows that in all probable scenarios California will shift its focus from analyzing resource adequacy in the late summer around sunset to analyzing times during the winter around sunrise. This conclusion arises from an assumption that most of the electricity generation in California will be from solar, which generates more during the summer than during the winter. Adding on-shore wind with its current profile results in an even more difficult challenge during the winter. Adding mostly off-shore wind would change the conclusion, but adding off-shore wind in such a quantity is unlikely. Paper 5 will consider the effects of winter-dominant on-shore wind, but the economic viability has not been well established. Similarly, geothermal could change when the resource adequacy challenges would arise, but has not been demonstrated to be economically viable.

We also provide updates on the other papers planned in Table 1:

Paper #1: We received the editorial review, made the revisions, and resubmitted the draft. We are awaiting reply from the editor, but we believe that it will proceed to publication in June.

Paper #2: *Seasonal challenges*: This paper was submitted for presentation at the conference in June. An oral presentation is being prepared that describes both papers 2 and 3.

Paper #4: *Storage review*: We are reconnecting with companies to ensure that we have captured the latest information. We plan to complete a rough draft in June. The information in this paper will comprise a substantial part of one of the July 2 deliverables.

Table 1. Papers that are in progress.

Topic of paper	Targeted journal	Status	Lead author	Primary conclusion/impact
1. Defining long-duration storage	Issues in Science and Technology	Resubmitted in response to editor's comments	Sarah Kurtz, plus other team leads	Defining long-duration storage broadly will stimulate innovation
2. Seasonal challenges	PVSC conference proceedings	Submitted in May	Mahmoud Abido	Seasonal storage in a solar-driven grid will show minimum energy storage during the winter
3. Seasonal challenges	IEEE JPV	Submitted in May	Mahmoud Abido	Biggest challenges to resource adequacy will occur during the winter unless off-shore wind or a flat or dispatchable generator is added
4. Review of currently available storage technologies	TBD	A rough draft is nearing completion	Rui Shan and Jeremiah Reagan	There are many storage options, some of which have the potential to replace existing fossil fuel plants
5a. Analysis of winter-dominant on-shore wind resource in California	Applied Energy	Met with researcher at LBL to review simulation methodology. Writing rough draft	Zabir Mahmud	A small number of wind generators in California generate more electricity in the winter than in the summer. We are assembling data to assess how consistently this is seen and to assess what fraction of California could show winter-dominant wind generators.
5b. Analysis of storage applications and effect of off-shore wind	Applied Energy(?)	Data being organized for rough draft	Zabir Mahmud	The amount of diurnal storage needed is about a quarter of a TWh. If the grid is solar dominated, the diurnal storage is used > 350 times/y. If wind is added, we still need the same amount of diurnal storage, but it will be used much less frequently…
6. Time sampling in modeling of storage	TBD	Data being collected	Pedro Sanchez	How do we choose the time periods for accurately modeling different applications of long-duration storage?
7. Impact of load shifting	PVSC conference proceedings	Submitted in May	Ashling Leilaeioun	Impact on revenue when load shifting is used to move load from the head of the duck to the belly of the duck

Papers #5: Storage analysis as a function of wind. As we analyzed the relative amount of diurnal, cross-day, and seasonal storage that would be needed for different generation scenarios, we found that a key question was whether we included a generator that generates more electricity in the winter than in the summer. On-shore wind is currently documented to generate about twice as much electricity in the summer as in the winter, with the winter generation sometimes dipping very low for a month or so. However, we found that a small set of generators reported different behavior. We found the monthly data from EIA to be unreliable. Figure 1 characterizes how the EIA monthly data are mostly simulated data.

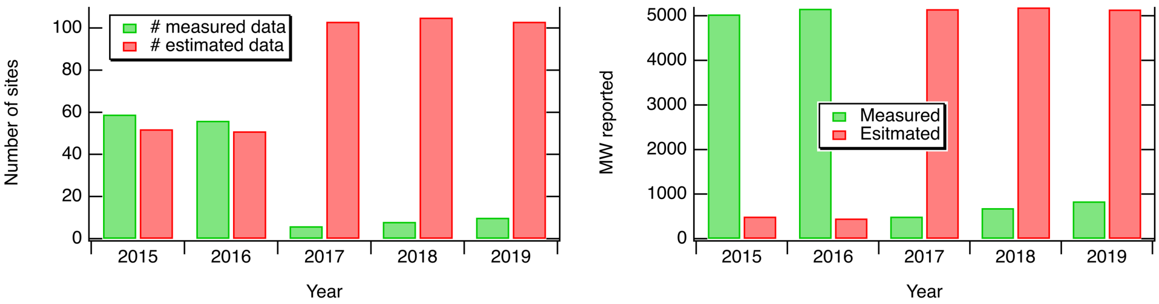

Fig. 1. Statistics for EIA data that report monthly measured data for wind generators in California. The simulated monthly data use measured annual data and simulate monthly generation based on the sampled data.

Fortunately, Jeff Sunquist identified a good set of monthly wind data for California generators from a CEC data base.[1] This has enabled us to move forward with the analysis in a much more confident way. The conclusions of the analysis are clear: there are a few wind sites in northern California and southern California that generate more electricity during the winter than during the summer consistently. Data for 2015 - 2020 are shown in Fig. 2. The median capacity factors of the two groups are similar with clear differentiation of seasonal behavior.

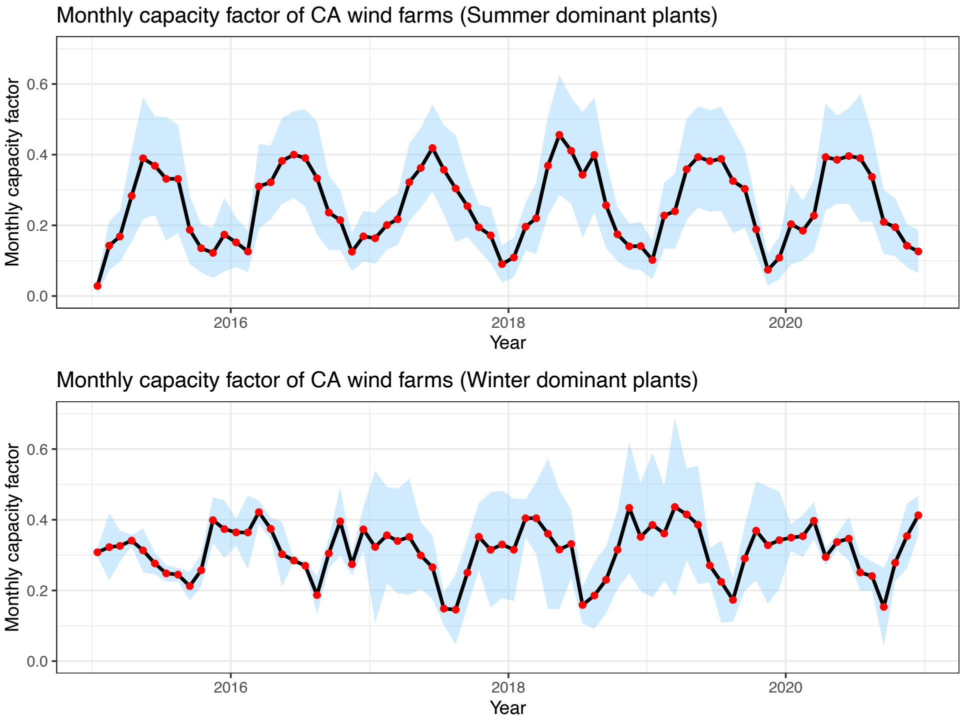

Fig. 2. Monthly wind generation for CA wind farms using data from CEC and EIA. The red points show median data; the blue shaded region shows one standard deviation.

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[1] https://ww2.energy.ca.gov/almanac/electricity_data/web_qfer/Power_Plant_Statistical_Information_cms.php

A meeting with Dev Millstein, of Lawrence Berkeley National Lab, guided us in the selection of power curves for simulating wind generation data. We will report wind generation data statistics in the June monthly report. Preliminary data show that there are many locations in California that have strong winds in winter, but it remains to be seen as to whether these could be practical.

Paper #6: Time sampling This project is using SWITCH to compare results depending on the number of days that are used for sampling. The sampling methodology has been developed and initial runs have been completed.

Paper #7: Impact of load shifting: This paper considers the variability of the price as a function of the net load, then calculates the ramifications of shifting load from the head of the duck (highest priced times) to the belly of the duck (times when there is maximum solar generation). The results demonstrated the value in terms of reduced curtailment and increased income for the solar plants. Income for the gas plants is reduced. For small amounts of load shifting, the reduced price of the electricity more than paid for the cost of implementing the demand management. This paper will be published in this year's PVSC proceedings and will be presented as a half-hour recorded talk at the conference itself.

2. Stakeholder meetings: During the month of May, we met with:

- Bao Truong of Malta
- Dev Millstein of Lawrence Berkeley National Lab
- Roderick Go and others at E3
- Priya Sreedharan of Gridlab
- Julia Prochnik of Long Duration Energy Storage Association of California
- Ron Sinton of Sinton Instruments
- Clark Crawford of GKN

3. Talking about Long-duration storage: The editors of "Issues in Science and Technology" provided detailed feedback on our draft. We have made revisions and resubmitted the draft – we hope to hear back soon about publication.

We are interested in publishing a second version to reach a wider audience and are formulating a strategy on that.

4. Update on deliverables due July 2: The following deliverables are due July 2:

3.1	Evaluate and document future energy storage technology alternatives	Draft storage Technology summary	7/2/21
3.3	Evaluate and document future energy electricity generation technology alternatives	Draft electricity generation technology summary	7/2/21
4.1	Multi-day model optimization	Summary of multi-day baseline model results	7/2/21

The following deliverables were flagged to be rescheduled:

4.2	Grid scenario selection	Draft grid scenario summary	6/11/21
6.2	Public workshop for grid scenario selection	Agenda	7/2/21
		Presentation materials	7/2/21
	Public workshop with CEC and TAC to present proposed scenarios		7/16/21

We will first discuss the deliverables for 3.1, 3.3, and 4.1, and then make a recommendation about the rescheduling of the deliverables for 4.2 and 6.2.

Deliverable 3.1 “Draft storage technology summary”:

This work has been led by the University of North Carolina, Chapel Hill, with support from the University of California Merced. Data have been gathered and organized. The draft of a manuscript is not yet completed. The July 2 deliverable will include both the draft of the paper for publication and a summary written specifically for the CEC. Here we present a graph (Fig. 3) and two tables (Tables 2 and 3) as preliminary examples of the data being collected.

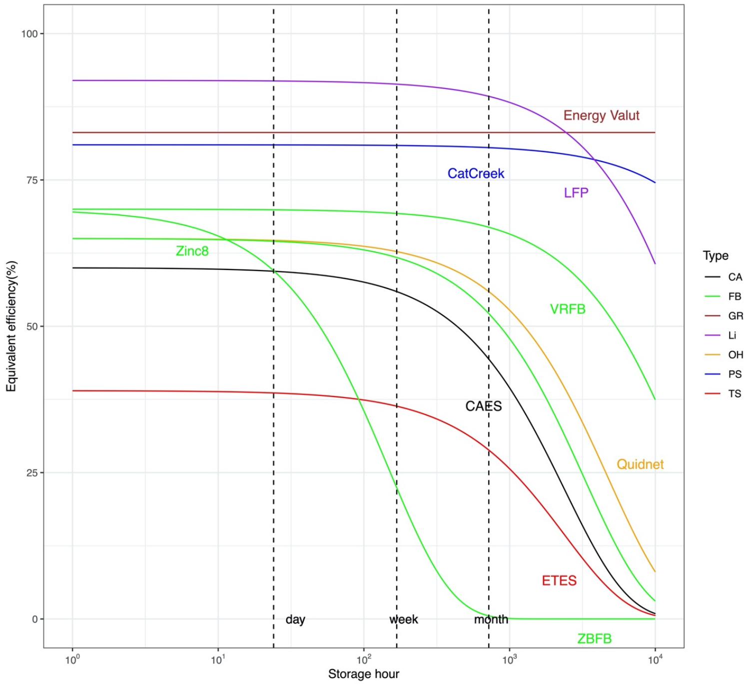

Fig. 3. Equivalent efficiency of storage technologies

Table 2. Company-specific information for long-duration storage

Company	Type	Discharge duration (hr)	Energy Density (kWh/m3)	Land Usage (m2/MW)	Land Usage (m2/MWh)	Energy capacity (MWh)	Discharging power capacity (MW)	Lifetime (years)	Self-discharge rate (%/day)	Roundtrip efficiency (%)	Response time(s)	Marginal Energy Capital cost ($/kWh)	Average capital cost ($/kW)	Average capital cost ($/kWh)	Fixed O&M ($/kW-yr)
Zinc8	Flow Battery	8~100+	8-13	150-200	20-25	0.16~240	0.02~10	20	0.5~0.7	65	~1	45	3800	475	20-50
Renewell*	Gravity			900	900	25~100	25~100	25	0	74	~1		8000	8000	50
Energy Vault	Gravity	4~10		90	175	4~10000	1~1000	25	0	83	~5	85	1130	280	20
Quidnet	Other Hydro power	~10				5~3000	0.5~300	40	0.5	65~75	~300	15~30	1500~1800	150~180	60~70
Cat Creek	Pumped Hydro power	121~726		10600	90	500~3300000	120~750	100		81	~30	7	2200	0.05	9
ETES	Thermal				7	30~4608	1.6-100	25	1	39	~300	2	2700	150	
Antora*	Thermal	50		50.00	10.00	>5	>0.05	30	1	43		7	800	10	10

*These companies have not built a demonstration project yet

Table 3: Long duration storage technologies being explored commercially

Type	Subtype	Discharge Duration (h)	Response time	Energy density	Land Usage (kW/m2)	Land Usage (kWh/m2)	Energy capacity (MWh)	Discharging power capacity (MW)	Lifetime (years)	Daily self-discharge rate (%/day)	Roundtrip efficiency (%)	Average capital cost ($/kW).	Average capital cost ($/kWh)
Compressed air	Adiabatic	10-100	3-10 min	0.5~20	~0.6*	3~4*	10~10000	1~300	20~30	0.5~1	55~75	700~1000	40~80
	Diabatic	10-100	3-10 min	2~15	~0.8*	13~14*	10~10000	1~300	20~40	0.003~0.03	40~60	400~2300	2~50
Liquid air	Liquid air**	4-24	5-10 min	8~24			10~1000	5~100	20~40		50~85	900~4000	260~530
Flow battery	Vanadium-based	4~24	msecs	15~70			0.1~100	0.01-10	5~20	0~1	65~85	600~1500	150~1050
	Zinc-based flow battery	4~24	msecs	20~70			0.1~100	0.01-10	5~20	0.24~33	65~75	700~2500	150~1680
Gravity Storage	Rail-based	4-24	secs		0.20	0.05	100~20000	10~3000	40		75~80	1200	
	Block-based	4-24	secs			~6	4~10000	1-1000	40		80~85		
Innovative pumped hydro	Ground level	4-24	Sec-3 min	0.3~2.5			4~2000	1~300			75~85		250~5100
	Underwater	4-24	~min	1.5	8	30	20~4000	5~1000	5~20		70-75	1650~2200	470~600
Pumped storage hydro	Pumped storage hydropower	10-100	Sec-5 min	<2			100-20000	10~3000	25~100	0~0.02	60-85	1700~3200	5~200
Thermal	CSP^*	4~24			0.4~8*	0.8~30*	0.1~2000	1~300					40~6250
Li	LFP^***	0-4	msec										

*These data are estimated based on Google Earth

**only one company developing,

^* CSP is generational technology and includes a storage component, but different from other long duration storage technologies shown in the table.

^***Li-ion is not a long duration energy storage technology

Deliverable 3.3 “Draft electricity generation technology summary”:

The analysis presented in papers 2, 3, 5a, and 5b will be the basis for this analysis. Paper 3 is attached, and Fig. 2 shows example data being used to develop the input for this analysis.

Deliverable 4.1 “Summary of multi-day baseline model results”:

Papers 5b and 6 will form the basis of this deliverable. Some of the results that will be presented in 5b were shown in a previous monthly report.

The July 2 dates for Deliverables 3.1, 3.3, and 4.1 were not revised to reflect the initial delay in the start of the work. We have focused on these while waiting for the revision of RESOLVE. We expect to deliver these on time, though we may be a little late with one of them.

Deliverables 4.2 and 4.6 “Grid scenario selection” and “Public workshop”:

While we worked hard so as to not delay Deliverables 3.1, 3.3 and 4.1, we ask for four months delay of Deliverables 4.2 & 6.2. We feel this delay is reasonable to reflect the late start from the budget renegotiation, the delay of receiving the revised version of RESOLVE from E3 and finding missing changes. Our work to date positions us to do well with 4.2 & 6.2, but the work quality would be compromised if we tried to complete 4.2 & 6.2 on the original schedule.

5. Update on Knowledge Transfer plan:

As noted in items #1 and #3 above, the “Defining how we talk about long-duration storage” publication is accepted for publication and is undergoing final editing before publication. We do not yet have a publication date, but anticipate that it will be sometime in June.

The publication associated with developing intuition about when resource adequacy will be most problematic in a zero-carbon world was addressed by publications #2 and #3, as described in Table 1. We mark this as complete in the table based on the submission of both the conference and the journal paper, though we note that the journal version has not yet been reviewed and accepted.

Communication element	**Planned completion date**	**Status**
Public workshop #1 – Introduction to project	Dec. 3, 2020	Completed
Public workshop #2 – Grid scenario selection	Fall 2021	
Public workshop #3 – Preliminary scenario analysis	Summer 2022	
Public workshop #4 – Final scenario analysis	Fall 2022	
LinkedIn site set up	Spring 2021	Completed
Website @ UCMerced live	Spring 2021	Completed
Publication – Defining how we talk about long-duration storage	Spring 2021	Accepted
Publication – Developing intuition about when resource adequacy will be most problematic in a zero-carbon world	Summer 2021	Completed

How we are doing compared to our plan

The work is progressing commensurate with the expenditures and following the new plan. Some of the dates will still need to be revisited.

Significant problems or changes

UC Merced changed its financial system in December 2020. It was discovered that the new system and old system were misaligned, and priority was given during the month of May to realign the records, so I was unable to get traction on preparing the next set of invoices. I'm told that things should be better as we move into June.

The discussions with E3 have identified that they have been improving the RESOLVE code, but do not currently plan to implement the changes that we were looking forward to. We are investigating the possibility of implementing those changes ourselves. Primary decisions to be made include whether to implement those changes on the previous version or new version of RESOLVE and whether to create our own isolated branch, or try to work directly with E3 to implement the desired changes, in which case, they might also be able to benefit from them.

What we expect to accomplish during the next period

- We will focus on completion of the three deliverables due on July 2
- We will continue work on the multiple papers.
- We will continue to meet with stakeholders and community representatives to gather inputs and request feedback
- We will develop a plan for making modifications to RESOLVE

Status of Milestones and Products.

Task #	Task	Deliverable	Due date	Status
1.2	Kick-off meeting	Updated budget	9/18/2020	Complete
1.3	CPR Meeting #1	CPR Report	TBD	
	CPR Meeting #1	CPR Meeting #1	TBD	
1.4	Final meeting	Final Meeting	11/11/22	
		Schedule for closeout	11/18/22	
		Draft and Final Written Products	11/18/22	
1.5	Progress Reports & Invoices	Progress Reports	Monthly	Ongoing
		Invoices	Monthly	Ongoing
1.6	Final Report	Draft Outline	6/30/22	
		Final Outline	TBD	
		Draft Report	8/30/22	
		Final Report	10/31/22	

		Written Responses to Comments on Draft Report	9/15/22	
1.7	Match funds	Status letter	9/9/20	Revision submitted
1.9	Subcontracts	Final subcontracts	TBD	Awaiting CEC approval of revised budget
1.10	TAC	List of potential members	9/9/20	Completed
		List of TAC members	TBD	Completed
		Documentation of TAC member commitment	TBD	Completed
1.11	TAC Meetings	Draft TAC meeting schedule	10/1/20	Completed
		Final TAC meeting schedule	TBD	Tentative dates completed
		Draft TAC meeting agenda	TBD	First one completed
		Backup materials	TBD	First one completed
		Final TAC Meeting agenda	TBD	First one completed
		TAC meeting summaries	TBD	First one completed
2.1	Data assembly	Draft baseline description	2/4/21	Completed
		Final baseline description	2/25/21	Completed
2.2	Confirmation of baseline data and approach	Draft modeling approach description	2/4/21	Completed
		Final modeling approach description	2/25/21	Completed
2.3	Implementation of baseline data into models to create initial baseline scenario	Summary of baseline model results	3/23/21	Completed
		CPR Report #1	15 days prior	Completed
3.1	Evaluate and document future energy storage technology alternatives	Draft storage Technology summary	7/2/21	
		Final storage technology summary	8/12/22	

3.2	Define representative future energy storage technology alternatives	Draft proposed storage scenarios summary	4/1/22	
		Final	8/12/22	
3.3	Evaluate and document future energy electricity generation technology alternatives	Draft electricity generation technology summary	7/2/21	
		Final	8/12/22	
3.4	Define representative future electricity generation technology alternatives	Draft proposed electricity generation scenarios summary	4/1/22	
		Final	8/12/22	
4.1	Multi-day model optimization	Summary of multi-day baseline model results	7/2/21	
		CPR #2	**Summer**	
4.2	Grid scenario selection	Draft grid scenario summary	6/11/21	Request 10/11/21
		Final	8/13/21	Request 12/13/21
5.1	Preliminary Scenario Analysis	Draft preliminary analysis summary	2/11/22	
		Final	4/15/22	
5.2	Final scenario analysis	Draft final analysis summary	6/10/22	
		Final	8/12/22	
6.1	Initial public meetings	Opening workshop presentation materials	11/17/20	Completed
		Northern CA workshop	12/3/20	Completed
		Southern CA workshop	12/3/20	Completed
		Opening workshop summary	1/8/21	Completed
6.2	Public workshop for grid scenario selection	Agenda	7/2/21	Request 11/2/21
		Presentation materials	7/2/21	Request 11/2/21
	Public workshop with CEC and TAC to present proposed scenarios		7/16/21	Request 11/16/21
		Workshop summary	7/23/21	Request 11/23/21
6.3	Public workshop for preliminary scenario analysis	Agenda	3/3/22	

		Presentation materials	3/3/22	
	Public Workshop with CEC and TAC to present preliminary analysis		3/18/22	
		Workshop summary	3/25/22	
6.4	Public Workshop for Final Scenario Analysis	Agenda	7/1/22	
		Presentation materials	7/1/22	
	Public workshop with CEC and TAC to present final analysis		7/15/22	
		Workshop summary	7/22/22	
7	Evaluation of Project Benefits	Kick-off meeting benefits questionnaire	9/18/20	Completed
		Final meeting benefits questionnaire	10/14/22	
8	Knowledge transfer activities	Draft initial fact sheet	7/23/20	Completed
		Final initial fact sheet	7/30/20	Completed
		Draft final project fact sheet	7/21/22	
		Final project fact sheet	7/28/22	
		Draft knowledge transfer plan	12/31/20	Completed
		Final knowledge transfer plan	2/26/21	Completed
		Draft knowledge transfer report	8/30/22	
		Final knowledge transfer report	10/31/22	

Seasonal Challenges for a California Renewable-Energy-Driven Grid

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Abstract—**Currently, the most difficult time of year for California to supply the demanded electricity is around sunset in late summer. As California uses more renewable electricity that challenge may shift to other seasons. We apply an energy-balance approach to various renewable-electricity scenarios to gain an understanding of the storage needed to enable adequate electricity supply at all times of year and to identify the times of year that may be most challenging. We find that the greatest challenge shifts from summer to winter and that the month of greatest risk may change by two or more months depending on the amount of solar generation that will be built.**

Keywords—storage, renewable-energy grid, resource adequacy

I. INTRODUCTION

Adequate supply of electricity to maintain reliable grid function will be a key element of successful implementation of a renewable-energy driven grid. During the wide-spread heat wave in August 2020, resource inadequacy around the time of sunset forced California Independent System Operator (CAISO) to cut electricity supply to customers [1]. Such events raise questions about the practical penetration level of variable electricity sources (solar and wind) and have motivated much discussion [2, 3] about CAISO's ability to meet demand in the coming years, especially when the Diablo Canyon nuclear plant is scheduled to decommission by 2025 and the availability of imports may be reduced during critical hours as nearby states rely more on renewable electricity. Planning for resource adequacy is a routine process, but the methods typically used to meet resource adequacy in a fossil-fuel powered grid differ substantially from those relevant to a grid supplied mainly by solar and wind generation backed up by storage.

Resource adequacy for a fossil-fuel powered grid may be met by installing relatively inexpensive peaker plants that are anticipated to sit idle for much of the year and then operated only during times of high demand. In California, during times of acute shortages, prices may increase to \$1000/MWh [3], enabling the investors in the peaker plants to receive substantial income during those short times. Resource adequacy for a renewable-energy driven grid requires resources to deliver the peak power that is demanded and, to the extent that those resources use stored energy,[1] adequate stored energy must also be available. The dual focus on both power and energy for a renewable-energy-driven grid represents a change in the discussion of resource adequacy.[2]

We previously [4] demonstrated that building many solar plants could easily supply the needed electricity during the summer, but that stored energy might run low during the winter without an adequate storage reservoir.

This paper expands on the previous study and focuses specifically on the seasonal storage challenges that California may anticipate if a renewables-plus-storage approach is used to reach a zero-carbon-emissions grid. In section II we review the resource mix that California may be able to access and why it may experience a seasonal challenge that is not found in many locations. In section III we describe our energy-balance approach which assumes that practical (i.e., low-cost and efficient) storage is available and perfectly connected within the state of California. In section IV we present results showing how energy balance of energy into and out of storage is affected by the selected scenario. Finally, in section V, we conclude that the time to be most concerned about resource adequacy in California will change from what it is today for all plausible renewable-energy-driven scenarios and summarize our conclusions.

II. BACKGROUND – RESOURCE AVAILABILITY

When using energy storage to balance supply and demand of electricity, we may divide the needed applications into categories, such as described in Table I. While all are important, here we focus on seasonal storage to answer the question "what times during the year will we be most concerned about resource adequacy?" We seek to answer this question in the context of a renewable-electricity-driven grid in sunny locations like California.

TABLE I. STORAGE APPLICATIONS RELEVANT FOR RENEWABLES-DRIVEN GRID

Storage application	***Description***
Short duration	Address transients and congestion
Diurnal	From sunset to sunrise, approximately
Cross-day	Cloudy and/or windless days
Seasonal	Variations between the seasons

The need for seasonal storage in a renewables-driven grid may be avoided in many locations by adjusting the relative installation of solar and wind power plants [5], [6], [7]. Figure 2

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[1] Inclusion of nuclear power and fossil generation with carbon capture and sequestration are possible approaches and largely avoid the need to consider the stored energy, but are outside of our scope, which focuses on a renewables-driven grid.

[2] The February 2021 massive black-outs in Texas are relevant to this discussion, but fall into a somewhat different category since both power and energy resources had been installed, but became inoperable during the cold weather.

compares historical monthly solar electricity generation in California with wind electricity generation in California and Colorado. As expected, the solar electricity generation is at a minimum around January each year. Less expected, the historical California wind-generated electricity also shows a minimum in January or during winter months. In contrast, wind in Colorado tends to increase during the winter. In both locations, the wind tends to blow more at night, allowing it to complement the daytime solar electricity very well, but the Colorado wind is much better than the California wind in complementing the seasonal performance.

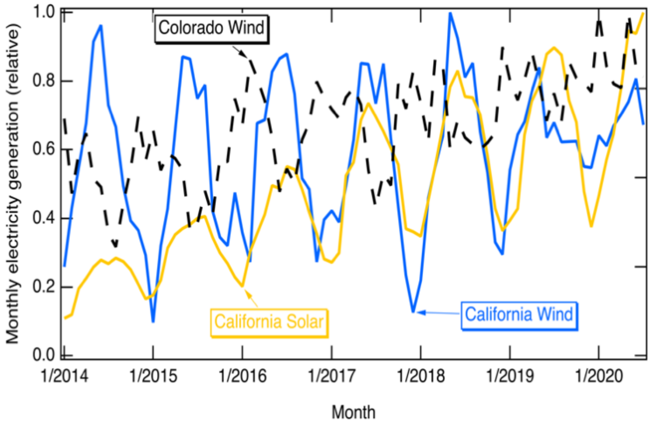

Fig. 1. Monthly electricity generation from solar in California and wind in both California and Colorado [8].

Thus, a renewables-driven grid in Colorado may select an optimal ratio of solar and wind to meet the year-round demand in a consistent way. In contrast, balancing solar with wind doesn't decrease seasonal storage needs when the generation profiles look like those shown in Fig. 1 for California. California may benefit from importing wind from locations like Colorado. Additionally, there may be locations within California that could provide stronger wind resource during the winter, for example, using offshore wind locations.

Offshore wind speeds in California also decrease during the winter, but the offshore wind speeds are higher than onshore wind speeds, resulting in more consistent generation throughout the year [9]. California is discussing installation of offshore wind starting in 2026 [10]. California's coast has very little opportunity for wind in shallow areas, so floating platforms will be needed, increasing the cost and the risk, but there is substantial potential as well as substantial interest [11]. Nevertheless, the available resource for both onshore and offshore wind is estimated to be limited [12] suggesting that it will be difficult to find economically attractive sites for large wind farms.

Today, geothermal and biomass plants are typically operated in California with a constant output, though it may also be possible to operate these as flexible generators [13]. These could be helpful in meeting winter load, but in 2020, the electricity generated by geothermal and biomass were 3.7% and 1.2%, respectively, out of the total generation reported by CAISO [14], [15]. The use of biomass is not anticipated to grow substantially because of the low availability of low-cost feedstocks and because of the high cost of collecting materials. However, there is a possibility that the need for reducing fuel in forests to reduce the severity of wildfires will motivate investment in collecting forest waste, allowing electricity generation from those materials to become cost effective. A possible estimate for that potential may assume the availability of about 50 Million tons of biomass per year, as estimated by reference [16]. If this biomass can generate electricity with a higher heating value of 15 MJ/kg with 25% conversion efficiency, about 50 TWh can be generated from California's biomass each year. Use of biogas from landfills and installations of digesters at waste-water treatment plants is increasing under incentives such as the Low Carbon Fuel Standard [17], supporting the possibility of reaching the 50 TWh/year generation potential, but biogas is not increasing fast enough to motivate inclusion of these levels [12].

Similarly, geothermal power generation is found to be relatively expensive and unlikely to expand by even a factor of two [12]. However, investment from the oil and gas industries [18] could rapidly reduce the cost. If cost reduction were achieved, the resulting geothermal resource could provide ample power [19].

Hydropower can play the dual roles of generation and storage. It may directly (as pumped hydro) or indirectly (by controlling output) act as storage. However, in a dry year, it may not contribute much and in a wet year it may need to be used in a continuous manner to provide stable flow in the rivers or may need to be used when the reservoirs fill, limiting its ability to match supply and demand, especially in a reliable way.

In the rest of the paper, we explore the impact of a range of renewables-driven scenarios on the time of year when the energy resource adequacy may be most challenged. The scenarios were chosen to explore the effects of the various possibilities, even those that are unlikely. We then discuss the implications in the context of which of the scenarios are most plausible.

III. METHODOLOGY

Our energy-balance approach was described earlier [4], with additional specifics provided here. It provides a straightforward way of quantifying seasonal challenges to supplying energy when it is needed. In the end, cost will be a primary factor in determining the technology mix, but being able to generate (and store, if needed) enough electricity to meet the load in real time is foundational to every solution. All selected scenarios use historical renewable electricity generated in California to meet California's electrical load. Importing and exporting of electricity is neglected as we focus on the worst-case situation of needing to meet all demand with local resources.

The generation profiles for solar, wind, and hydropower electricity were taken using historical CAISO data [14, 4] for years 2015 - 2020. To ensure that air conditioning and other weather-dependent loads realistically align with the solar and wind generation profiles, we used California load profiles from the same data sets. Fig. 2 shows solar, wind, and load profiles for 2018 (a year that is representative of the typical trends). These 5-min data sets were first screened for missing and anomalous data. About 0.16% of the data were found to be missing. Some of them were short intervals (5 – 20 minutes) and others were long intervals (up to 7 hours). The short intervals were treated by linear interpolation using the previous and the next data points, while the long intervals were treated by linear interpolation using the previous and the next day's data points in the same time intervals. The reported electricity from thermal, nuclear, and imported resources were replaced with scaled-up solar or wind using equation 1.

$$Total\ Generation = Added\ Power + Hydro + Renewables \tag{1}$$

where *Added Power* is historical generation multiplied by a variable factor and the other terms in equation 1 are taken directly from the historical data [15], as shown for 2018 in Fig. 2. A flat generation profile was also included to simulate the consistent output that might be obtained from a geothermal plant or other constant output generator. For some of the calculations, offshore wind data were simulated using wind-speed data [20] at height of 120 m for a location with a latitude of 35.03 and a longitude of -121.52. This location provides data that contrast the historical generation profiles reported for California, but does not attempt to represent all of the potential generation profiles, which is outside of the scope of this paper. The power curve for aerodyn SCD 8.0/168 was used to determine the expected power generation if this wind turbine were used in this location [21]. Data for 2018 are shown in Fig. 2; data from 2015 - 2020 were used for the calculations.

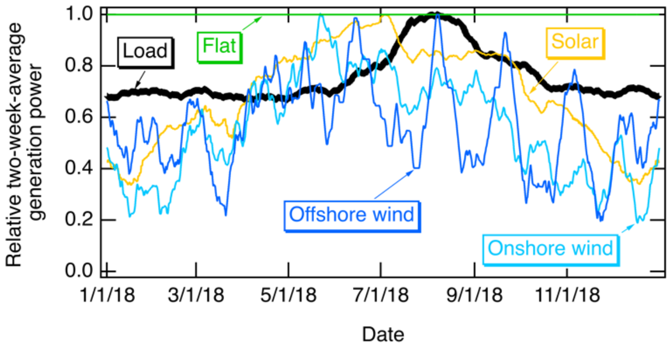

Fig. *2*. Generation and load profiles taken from CAISO data base [15] for 2018 with simulated offshore wind data.

When generation exceeded the load, the excess was placed in a single storage reservoir until the reservoir was full, with the overflow counted as "surplus" electricity. When the generation was less than the load, energy was taken from storage to meet the remaining demand. The size of the reservoir was adjusted so that the state of charge of the reservoir at the end of the year matched that at the beginning of the year.

To simplify the analysis, storage charging and discharging efficiencies are assumed to be 100% with no self-discharge loss. We explored the effect of losses and found that inefficiencies caused the need for more generation, but did not significantly affect the time when the resource adequacy was challenged, so do not report those results here. The minimum state of charge was set to zero as a reference point. For a subset of the calculations, the charging rate was limited to 40 GW (the common maximum discharging rate) and the extra power beyond this limit was added to the electricity counted as surplus.

This approach gives realistic results in that the generation and load profiles are based on observed data. However, this approach does not 1) consider transmission constraints (we balance the supply and demand globally not locally), 2) adjust hydro generation to better meet the supply/demand imbalances, 3) attempt to identify the nature of the storage reservoir, nor 4) adjust the load profile, which may be driven by electric vehicle (EV) adoption, demand management, and many other things as discussed below.

We calculate the state of charge of the central storage reservoir as a function of time of year to demonstrate the effects of 1) the amount of solar electricity generation, 2) limiting the charge rate, and 3) the use of other types of renewable electricity. We focus on how these choices affect the time of the year when resource adequacy may be most challenged. We also explore how the size of the needed storage reservoir and the amount of surplus electricity generated are interrelated.

IV. RESULTS AND DISCUSSION

The effect of the size of the solar buildout on the calculated state of charge is shown in Fig. 3. This calculation used data for 2020 [15], replacing the thermal generation, nuclear generation, and imports with additional solar generation according to equation 1. The resulting annual generation mix to exactly meet 2020's load included 79.6% solar, 7.4% wind, 6.5% hydropower, and 6.5% other renewables (geothermal, biomass, biogas, and small hydropower). The reservoir is found to reach its minimum state of charge between Jan 24 for large solar build out (annual generation = 135% × annual load) and March 21 for small solar build out (annual generation = 105% × annual load). The systematic shift in the time of minimum energy in storage is a direct result of how quickly the storage can be filled during daytime hours from the solar electricity. Greater solar build out enables the storage reservoir to begin to refill in January, while minimal solar build out requires March's longer days.

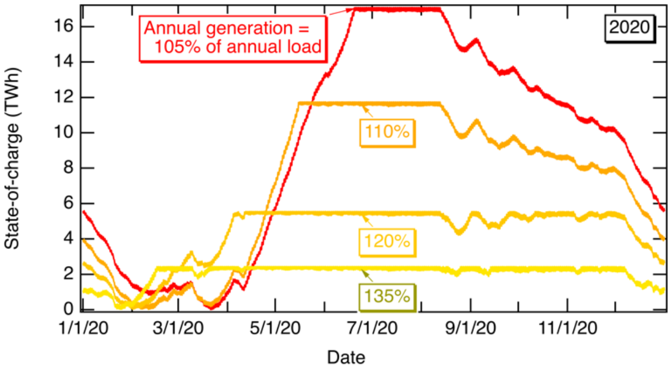

Fig. 3. Calculated state of charge for stored energy using 2020 generation and load data adjusted to reflect renewables-only grid scenarios with solar electricity added to result in total generation being more than 100% of annual load according to the labels. The charging rate is unconstrained.

While the California August 2020 emergency occurred around sunset, the storage reservoir in Fig. 3 reaches a minimum charge state just after sunrise, as shown in Fig. 4, which expands the data from Fig. 3 to view days in January and July for two levels of generation. The times for sunrise and sunset were taken for the centrally located California City. On most days, the minimum and maximum in the state of charge are observed approximately an hour after sunrise and before sunset, respectively, reflecting that the sun needs to be away from the horizon before the solar electricity generation increases enough to supply much of the load. These observations pertain to the energy balance of California's entire grid with generation dominated by solar generation. The times of day for the minima and maxima are expected to vary with the weather, location, and the technology mix used for the generation.

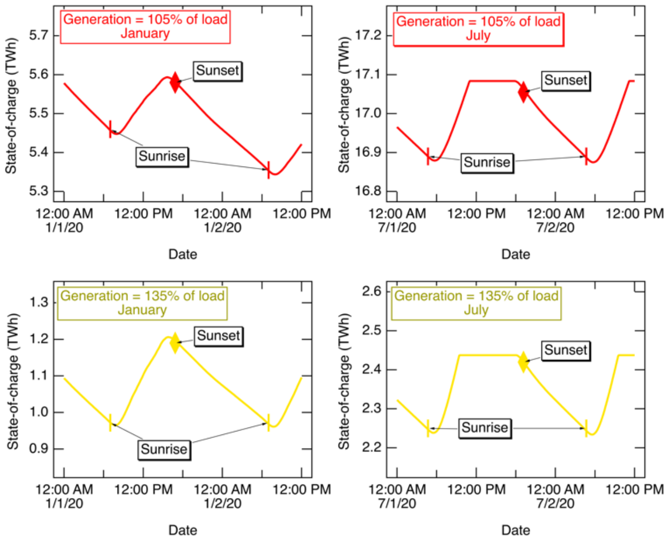

Fig. 4. Magnifying a day of January and another day of July from Fig. 3 to show the daily charging and discharging details.

Similar calculations for 2015-2020 (Fig. 5) showed that the minimum state-of-charge in the reservoir is always observed during the winter or early spring, even in 2020 which experienced lower than usual solar generation because of wildfires. Although the exact date of the minimum state-of-charge varies each year, for a given level of build out, the date of the minimum varies by less than one month, suggesting that once the build out is defined for a solar-dominated grid, the time of highest risk for resource inadequacy can be well predicted.

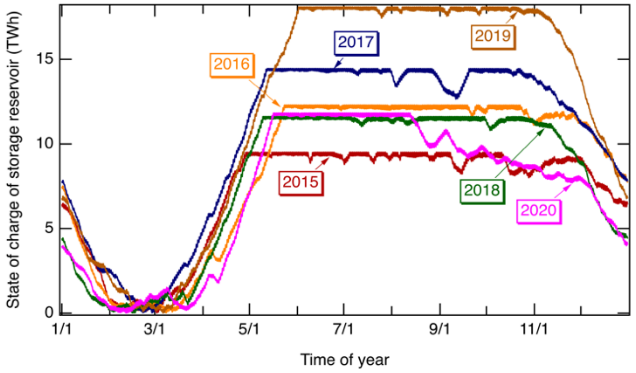

Fig. 5. Calculated state of charge for stored energy using data from 2015-2020, as described for Fig. 3, but showing only the total annual generation = 110% of annual load case for each year.

When defining a storage asset, we may consider the energy rating and the power ratings for both charging and discharging. In figures 3-5 we have described the energy in the reservoir. The power rating for discharge of the storage should be set to meet the maximum relevant load. The maximum load during the 2015-2020 period studied was 50 GW [22]. Of the 50 GW, we anticipate that storage should be available to provide discharge rate of at least 40 GW. In the future, the demand for electricity may increase suggesting that even higher numbers will be relevant. The power ratings for the charging and discharging may be the same or may differ. There may be benefit from a larger charging power rating when electricity is supplied at a rate that can both meet the current load and charge the battery faster than the battery is ever discharged. Some types of storage reservoirs use different converters for the charging and discharging, enabling differing power ratings, so the charging rate was not constrained for the calculations of Fig. 3-5. However, we recognize that some storage types may use the same power ratings for the charging and discharging cycles. In Fig. 6 we show that limiting the charging rate to 40 GW has very little effect when the build out is small (105% curves), but delays the recharging of the reservoir and increases the storage needed when the build out is greater (135%).

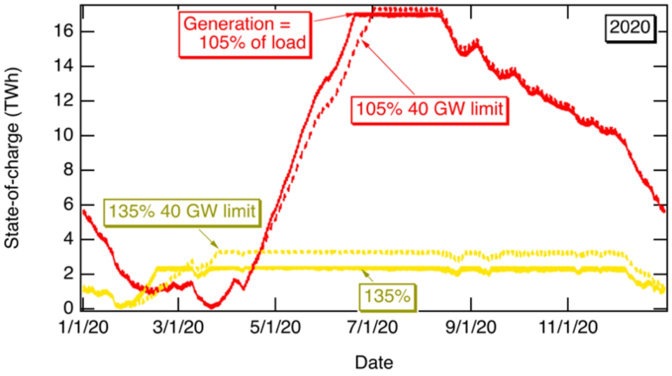

Fig. 6. Calculated state of charge for stored energy using data from 2020, as described for Fig. 3, but comparing calculations when the charge rate was limited to 40 GW and unlimited, using two build out levels, as indicated in the figure.

It is fairly unlikely that an all-renewables grid in California will be constructed by building only solar. We repeated the calculation of Fig. 3, expanding the generation using the generation profiles shown in Fig. 2 for onshore wind (from the historical data), offshore wind (simulated), and a constant ("flat") value. The results are shown in Fig. 7. For each of these cases, the reported 2018 generation from solar, hydropower, wind, and other renewables was retained while scaling up one of the generation profiles to replace the thermal and nuclear generation with that resource. As shown in Fig. 1, the California onshore wind tends to be greater in the summer compared with winter, so an even larger storage reservoir is needed. Offshore wind and flat renewables come closer to matching the load seasonally, so a much smaller storage reservoir is needed. While adding onshore wind, solar, or offshore generation results in the minimum storage level in March, a similar build out with a flat generation profile results in the minimum shifting to October and extending for a couple of months after the high load in July and August depleted the storage.

If the resources are built out in a bigger way as shown in Fig. 8, only the solar build out results in a minimum state of charge in winter. Again, build out of onshore wind results in the need for the largest energy reservoir. Adding a flat generation profile to annually meet 135% of the load resulted in adequate electricity generation at all times. In the case of the offshore wind build out, the reservoir reaches near zero at times ranging from July to November, or throughout the year for other years.

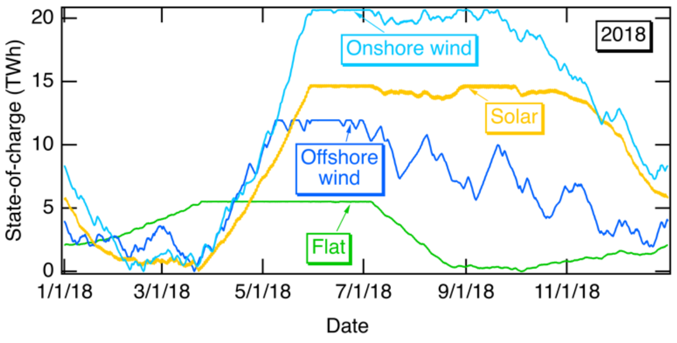

Fig. 7. Calculated state of charge for stored energy using 2018 generation and load data with thermal, nuclear, and imports replaced with electricity generation from a single technology (as indicated) to deliver 105% of load.

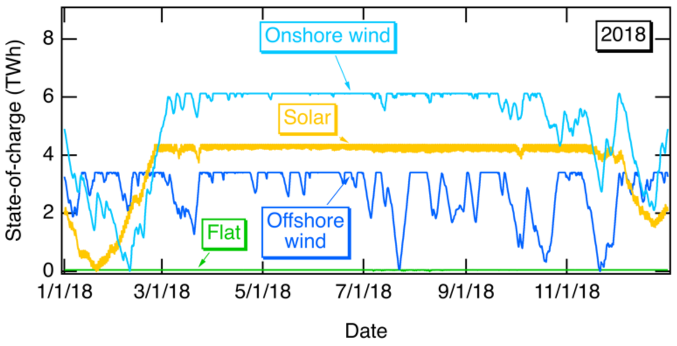

Fig. 8. Calculated state of charge for stored energy as in Fig. 7, but with generation added to deliver 135% of annual load.

In addition to a shift in time for when the minimum state of charge is observed, Fig. 3 shows that the needed storage reservoir decreases as the solar generation is increased, as would be expected and as shown in Fig. 9 for years 2015-2020.

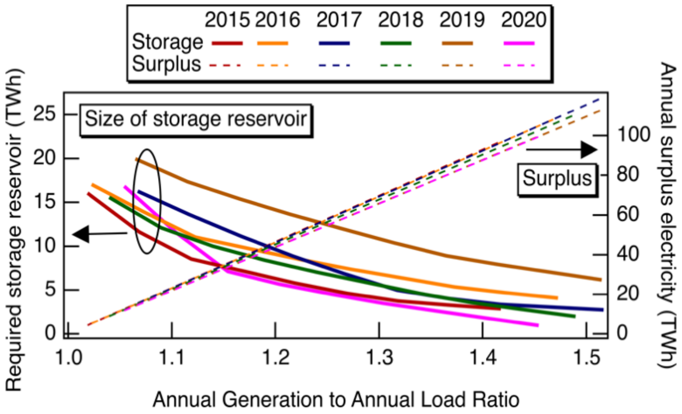

Fig. 9. Decrease of storage needed to meet minimal resource adequacy (left axis) and associated surplus electricity (right axis) as a function of solar build out.

While it is generally assumed that it is preferable to size the generation to meet the load to avoid curtailment, in the future there is a desire for renewable electricity to supply all energy, not just energy for the power sector. Thus, the electricity we have counted as "surplus" may turn out to be essential for providing energy for the transportation sector, chemical sector, and others. If, for example, the "surplus" electricity was used to make hydrogen for production of fertilizer and to fuel trucks, steel making, and furnaces, the demand for the "surplus" electricity might be substantially greater than what we have described. In that case, resource adequacy concerns could be met by providing low electricity prices to the companies using the "surplus" electricity in return for their promise to stop using the electricity whenever the generation is challenged to meet the current load. Inspection of Fig. 3 suggests that scenarios with solar generation much larger than the load will require a smaller seasonal storage reservoir and will risk depleting that reservoir only in January in the typical year.

A future renewable-energy driven grid in California is likely to include a mixture of technologies, rather than expanding a single technology, as shown in Figs. 7 and 8. The effect of adding wind alongside of solar is shown in Fig. 10, comparing the addition of 1) equal amounts of solar and onshore wind, 2) only solar (as for Fig. 3 and 5), and 3) equal amounts of solar and offshore wind. In general, adding the mixture of onshore wind and solar required a larger reservoir while a mixture of offshore wind and solar required a smaller reservoir compared with all-solar additions. Of the years studied for build out to 105% of load, the year 2019 required the largest storage reservoirs, with a reservoir size of about 22 TWh for the solar/onshore wind, 20 TWh for 100% solar, and 15 TWh for solar/offshore wind scenarios. In every case for the 105% ratio of annual generation to annual load, the minimum state of charge was observed in February or March.

If the build out is increased to supply 135% of annual load, the needed reservoir size decreases, with 2019 again being the year to require the most. For these wind-containing scenarios, the storage reservoir approaches a zero state of charge not only during January, but sometimes in December (2017) or November (2018). In 2020, when there were wide-spread wildfires, the wind-plus-solar scenario showed < 20% in storage as early as September. Although one might have anticipated a problem with inadequate solar generation in 2020 because of the smoke, the 135% scenario with added wind came closer to the minimum than the only-added-solar scenario.

Based on our analysis in Section II, we anticipate that, as more renewable electricity generators are installed, California will use more solar than wind and little more geothermal or biomass (which are currently about 4% of total generation).

We anticipate that load profiles will change as electrification is increased. Electrification of heating applications will increase demand during the winter, just when a solar-driven system is already under the most stress. Electrification of the transportation sector will have much less effect on the seasonal challenges. If capabilities are developed for geothermal, biomass, and/or hydropower to be able to be dispatchable the need for storage will be greatly reduced. Alternatively, California may choose to add nuclear, natural gas coupled with carbon sequestration, hydrogen-powered generation, or a number of other technologies to the renewable-driven scenarios studied here. These fully dispatchable technologies may play the role of the storage reservoir studied here, or may be used more like dispatchable thermal plants are used today.

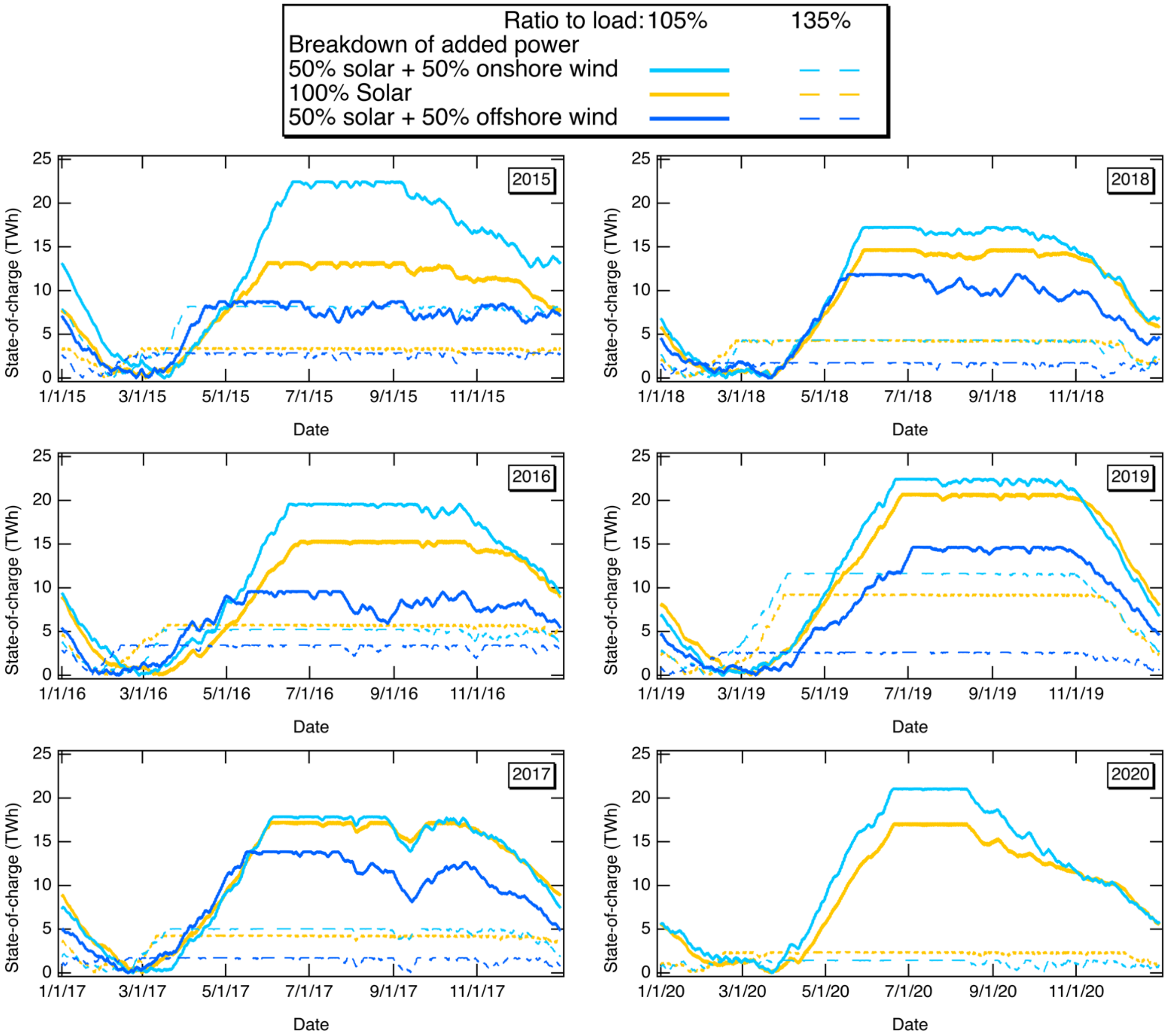

Fig. 10. Calculated state of charge for stored energy using renewables generation and load data for years 2015-2020 adding additional solar and wind generation as indicated in the legend to replace thermal, nuclear and imports. Offshore wind data were not available for 2020.

Each of these will contribute to provide the needed resource adequacy, probably in ways that are more similar to how resource adequacy is handled today. We have omitted these from our study because of our desire to understand what would be needed by a renewables-driven grid.

V. CONCLUSIONS

Exploring the question "When during the year will resource adequacy be most challenged for a renewable-electricity-driven grid in sunny locations like California?" we find the highest risk times to be around sunrise during January, February, or March, depending on the amount of solar generation that is built. The range of renewable-energy-driven scenarios we explored show that the technology mix can have a large effect on the times of year when there is risk of resource inadequacy. However, the most plausible scenarios use large amounts of solar energy. As more solar electricity is available, the time of the seasonal challenge shifts from March to January. None of the plausible scenarios calculated the storage to reach < 10% of full charge during spring or summer. On the other hand, addition of substantial wind generation which appears to be unlikely (as discussed in Section II) may result in risk of the reservoir running too low at almost any time of year.

The seasonal storage needed to balance supply and demand may be cut in half by building 30% more electricity generating capacity as shown by our comparison of building generation to provide 135% vs 105% of load over a year. The surplus from the added electricity generation is anticipated to be useful for generating hydrogen for transportation, heating, chemical, or other applications.

The effects of electrification on load profiles were not included in this study, but the addition of heat pumps to the load profiles is likely to further exacerbate the resource adequacy challenge during winter, suggesting even stronger confidence in our assertion that resource inadequacy challenges of a renewable-driven grid in California will occur in winter around sunrise. This conclusion would be changed for locations with stronger wind generation during the winter and for zero-carbon grids that are not primarily driven by solar electricity. The benefits and requirements of transmission and distribution and the cost of delivering the system were not considered, but will be critical in identifying the electricity-generating resources that will be used in the future.

VI. ACKNOWLEDGEMENTS

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Demand Shifting as a Profitable Strategy for Solar Plant Operators

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***Abstract*— As solar electricity generation increases, the daytime net load (total load less solar generation) decreases, reducing prices in the middle of the day. These low prices reduce motivation to invest in more solar electricity. In this study, the correlation between net load and price is quantified on a seasonal average basis, and used to predict resulting hourly price changes if demand can be shifted from evening peak hours to mid-day when solar generation is greatest. The results suggest such a strategy will be of economic benefit to solar generators by increasing the price at mid-day for all electricity delivered, while reducing the price and thus total expenditures for energy during evening peak hours, with a net overall savings for energy consumers. These financial benefits motivate solar plant owners and developers to promote load-shifting, both to increase the revenue from current solar plants and to create demand for more solar plants.**

Keywords—demand management, electricity markets, duck curve

I. INTRODUCTION AND MOTIVATION

The portion of energy in California generated by solar energy increased by 52x from 2010 to 2019, and in 2020 solar energy accounted for 22.7% of all generation[1]. Each morning, as the sun rises, thermal generation sources ramp down and a large fraction of the total load during the mid-day is served by solar generators. Then in the afternoon, as the sun sets and solar generation fades, thermal generation sources (primarily gas) must ramp up to satisfy the total load through the evening peak demand and overnight. The California independent system operator (CAISO) gave the resulting net load daily cycle the moniker "the duck curve"[2], which is illustrated in Fig. 1.

CAISO provides the central management of electricity operations in California, including operation of the electricity trading market. At the system (wholesale) level, most of the electricity purchased from generators and delivered to consumers is bought and sold in the day-ahead market, in which bids to purchase electricity and bids to sell electricity are organized with a "bid stack" for each: bids to purchase electricity are stacked from highest price to lowest, whereas bids to sell electricity are stacked from lowest to highest, and the price at which these two stacks meet is the "clearing price", which changes hour-to-hour throughout the day[3]. In each operating hour, all of the generators delivering energy in that hour are remunerated at the clearing price. Because solar energy plants have virtually no marginal cost of generating power, their energy is generally offered at the lowest price, and the availability of large amounts of solar energy suppresses mid-day prices, whereas prices rise as the amount of thermal generation rises to meet afternoon and early evening demand. Indeed, it is observed that the day-ahead price (red line) is highly correlated with the net load (green line), as depicted in Fig. 1.

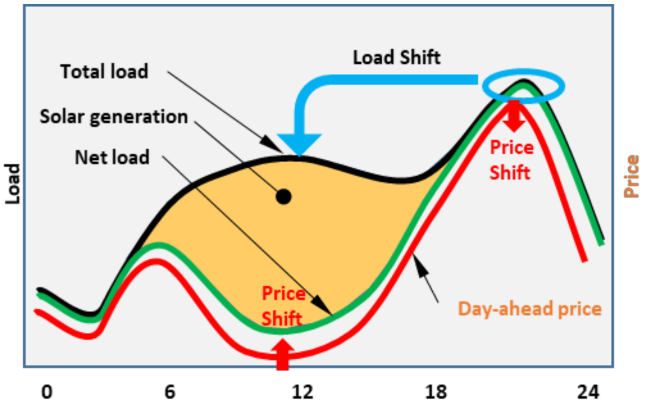


Fig. 1. The "duck curve" and notional objective of the study.

California has established (through the SB100 state law)[4] ambitious targets for decarbonizing electricity generation in the state, aiming for 100% carbon-free electricity by 2045. Recently, even more ambitious timelines have been introduced at the federal level[5]. It is expected that solar energy will play a leading role in achieving the goal of 100% carbon-free electricity; however, solar energy has the obvious drawback of being available only during daylight hours. For solar energy to play a larger role, energy storage must be employed to serve nighttime loads — or nighttime demand can be shifted into daylight hours.

Load shifting has an important distinction from traditional demand response services, which have been primarily in the form of load shedding of large industrial loads under command of the utility, remunerated by capacity payments and/or very high peak pricing for the load reduction, treated equivalently to peak generation by the market. Load shifting by contrast is not a reduction in demand, but rather a shift in the timing of demand, whether through use of storage in some form or by taking advantage of inherent flexibility in the timing of loads. A well-known example of load shifting is through the use of chilled water or ice storage to meet building cooling loads, which until now has generally been used to shift load into nighttime because electricity tariffs until now are lowest at night, but may in the future shift load to mid-day as solar energy makes mid-day power the lowest cost. More widespread adoption of chilled water storage (including in the residential sector) could enable much more load shifting in the carbon-free grid, and there are many other potential load uses amenable to shifting in the industrial, commercial, and residential sectors. Other prominent examples include space heating, industrial process heat, water pumping, refrigeration, and electric vehicle charging. Finally, of course, load can be shifted for any type of load by charging and discharging batteries.

Load shifting is, however, not free. Some opportunities, such as EV charging, may be nearly free and involve changing consumer behavior; others require installation or modification of consumer premise equipment at varying cost points. A recent comprehensive study by Gerke et.al.[6] has explored the potential for many load-shifting use cases and quantified their estimated cost of implementation using the cost of batteries as a benchmark. The study showed that non-battery load shifting of ~6 GWh per day can be accomplished at lower cost than batteries in California, mainly with industrial process loads, agricultural pumping, and commercial HVAC.

This paper is focused on price rather than cost, and explores how load shifting may impact the day-ahead market prices as suggested in Fig. 1. We quantify how shifting load from the peak hour to mid-day is expected to impact the price at both times based on historical data. Because all generators supplying energy during a given trading hour are compensated at the clearing price, the price shift expected in response to a load shift will be leveraged to amplify the benefits and costs to all generators selected in the bid stack at market clearing. As a final step, the changes in overall market expenditures and revenue for the mid-day solar generators are compared to the estimated costs from the Gerke study.

II. METHODOLOGY

The data used in this study were accessed through publicly available historical datasets published by CAISO for load and generation sources[7] and, separately, for day-ahead price[8].

As a preliminary step, Fig. 2 shows daily peak prices in the day-ahead market over several years and reveals that there is considerable volatility in the peak prices (indeed the plot for 2018 does not show the true peak, which reached $976.39 on 25 July[8]). Such volatility can result from a variety of influences, such as outages in generation plants or transmission lines, but generally simply follows gas prices. The price spikes in July-August and February 2019 were attributed by CAISO to volatility in gas prices[9].

To establish the functional relationship between net load and day-ahead prices during the majority of days, we seasonally averaged both net load and price at each hour for the spring, summer, fall, and winter seasons. The resulting curves in Fig. 3 show the high degree of correlation that exists. In Fig. 4 the data of Fig. 3 have been re-cast as price versus net load, from which the price sensitivity to changes in net load is taken as the slope of a linear fit found by least squares regression.

Armed with these price sensitivities, the anticipated price impact of load shifting was calculated for various load shifting scenarios. In Fig. 5 the price changes are calculated for the case of a shift of 6 GWh total over a period of 3 hours (2 GWh per hour). On the top row of the figure, the load, solar generation delivered, and curtailment are shown before and after load

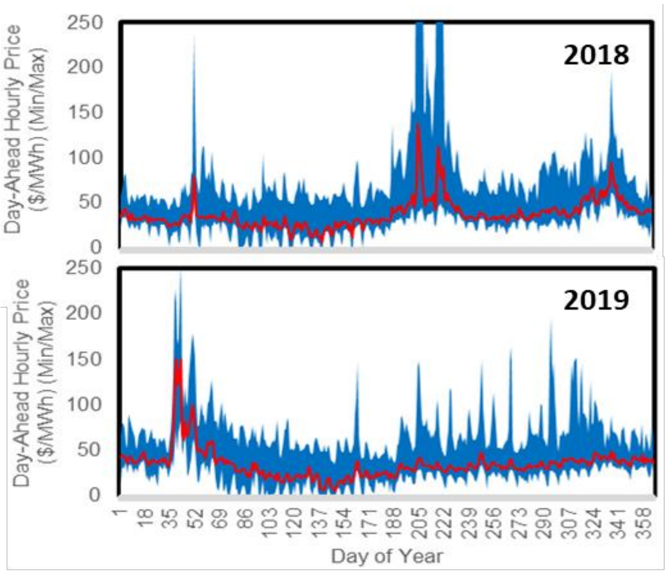


Fig. 2. Range of day-ahead electricity price values. The red curve is the median daily price.

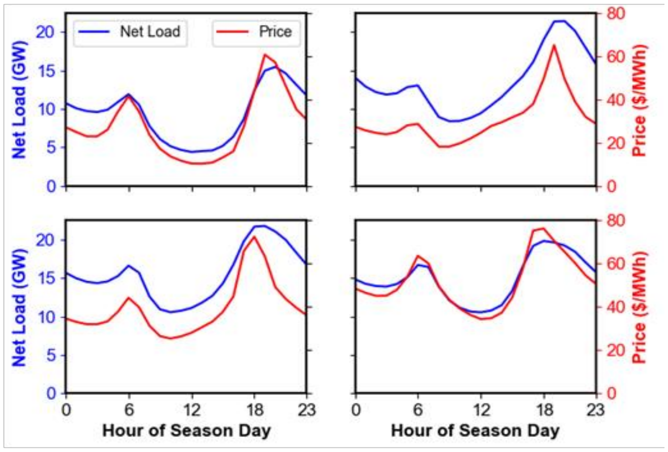


Fig. 3. Correlation of the net load and day-ahead price. These curves are seasonally averaged over spring (days 59–150), summer (days 151–242), fall (days 243–333), and winter (days 334–365 and 1–58), capping prices greater than $150/MWh.

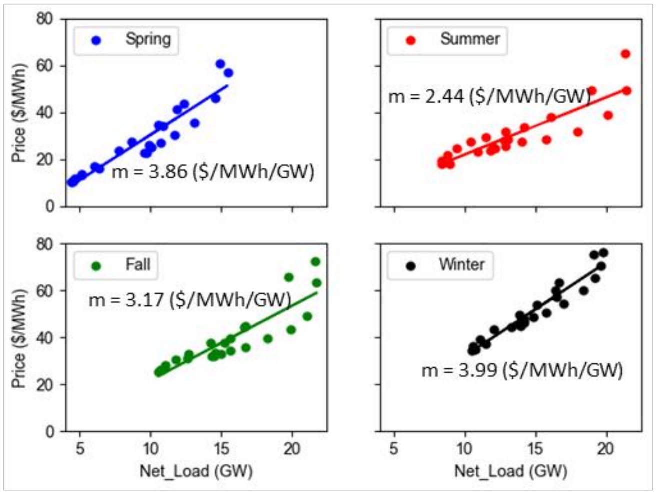


Fig. 4. Price sensitivity to net load, based on seasonal averages of net load and day-ahead price.

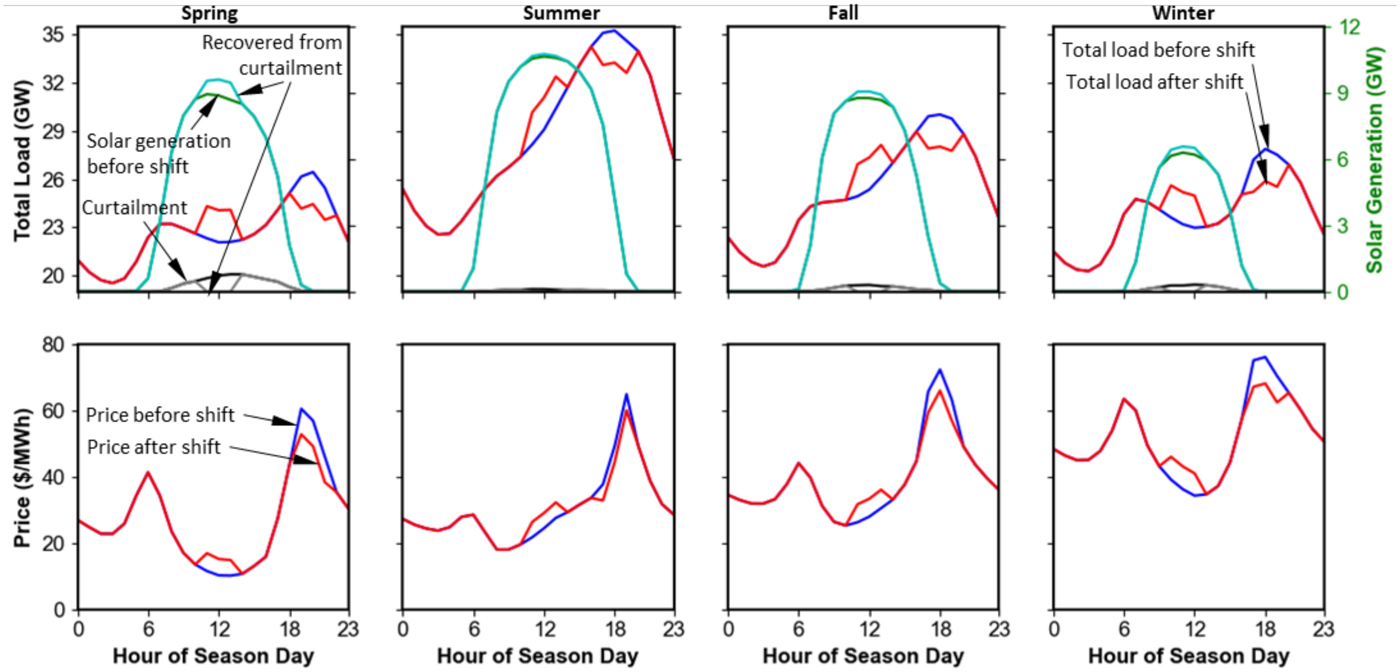


Fig. 5. Total load, solar generation, and solar curtailment (top) and price (bottom) before and after shift of 6 GWh load over 3 hours (2 GWh in each hour). The solar generation is modified by delivering energy that would otherwise be curtailed. The curtailed energy is used first in each hour, and any remaining shifted load increases net load.

shifting, and on the bottom the resulting modified price curve is shown before and after shifting. Note the range of the y-axis for total load; the variation between minimum and maximum is about 25–35% of the peak, depending on season. The load shifting strategy employed is to move energy from the highest load hour to the highest solar generation hour, then from the second highest load hour to the second-highest solar generation hour, and so on, for as many hours as specified (in this case 3 hours).

Although there is almost no curtailment in the summer, some curtailment is present in the other seasons (particularly for spring). When curtailment is present in the historical data (again seasonally averaged in this analysis), the shifted load is first satisfied by reducing the curtailment, and if the shifted load exceeds the amount that can be supplied from the curtailed energy, it increases the net load to be met by thermal generators.

III. RESULTS AND DISCUSSION

A complete numerical example is provided in Table I, showing how the load shift and resulting price change impacts the solar and thermal generators and the system as a whole. In this scenario, 2 GWh was shifted in a single hour. Again, the strategy employed is to shift from the highest load hour to the highest solar generation hour.

Following the same logic, and returning to the scenario of Fig. 5, Fig. 6 shows the revenue gains and losses for each generator class ("other" includes biomass and geothermal). It is evident that while solar generators gain revenue, all other generator classes lose revenue.

Fig. 6 shows that the benefit of this load shifting to solar generators is substantial (~ 7% revenue boost), whereas thermal generators suffer the biggest losses because it is they who have the greatest share of the generation mix at the evening peak. The capacity factor of the solar plants is increased slightly because previously curtailed energy is delivered to load after the shift; the capacity factor of thermal generators is somewhat reduced by the same amount (some thermal generation is substituted with otherwise curtailed energy). The net result is to increase the value of solar plants while decreasing the viability of thermal generation plants.

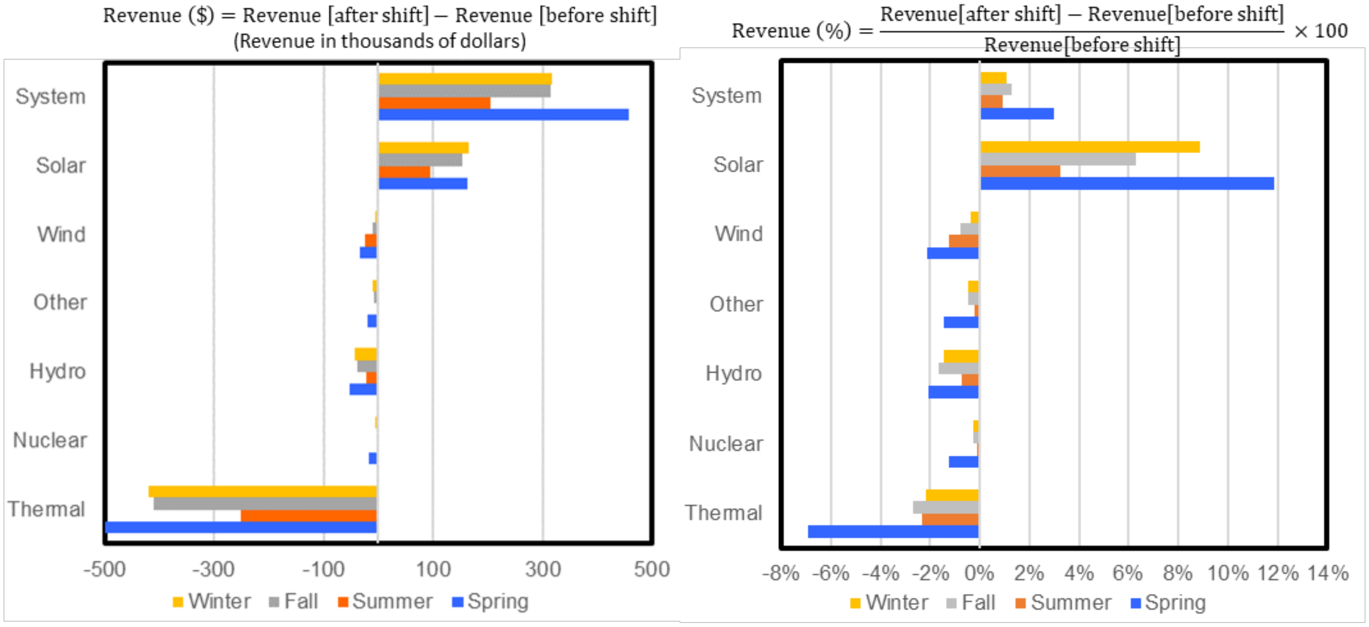
The strategy that has been employed subtracts load from the hours with the highest price and adds to the load when the greatest solar generation occurs. This strategy is non-optimal for the system, because in the summer, the lowest daily prices occur in the early morning when there is not much solar generation, and a greater system benefit could be gained by adding to the load at that hour than by adding to the mid-day load. The strategy is also non-optimal for the solar generators, because in every season there is some solar generation remaining at the peak load hour (indeed, in the example shown in Table I the remaining solar generation exceeds the amount shifted). The strategy is thus "cannibalizing" the revenue for the solar generators at the highest price hour. Even so, the solar generators still realize a net gain in the summer example due to the higher amount of energy being delivered at mid-day and the leveraging effect of the higher mid-day clearing price on that large amount of generation. The solar generators would benefit in this case by a strategy that shifts load from an hour later when there is no resulting solar revenue loss.

The analysis assumes that all curtailed energy is available to satisfy shifted load. Curtailment is primarily due to

TABLE I. NUMERICAL EXAMPLE OF SYSTEM SAVINGS AND SOLAR AND THERMAL GENERATOR GAINS AND LOSSES (2 GWH SHIFTED IN A SINGLE HOUR)

Parameter	Spring				Summer				Fall				Winter			
	Before shift		After shift		Before shift		After shift		Before shift		After shift		Before shift		After shift	
	12:00	20:00	12:00	20:00	12:00	18:00	12:00	18:00	12:00	18:00	12:00	18:00	11:00	18:00	11:00	18:00
System Load (MW)	22,068	26,447	24,068	24,447	29,090	35,262	31,090	33,262	25,352	30,030	27,352	28,030	23,194	27,887	25,194	25,887
Solar generation[1] (MW)	8,885	19	9,489	19	10,653	4,178	10,764	4,178	8,766	374	9,052	374	6,297	3	6,571	3
Thermal generation (MW)	4,391	15,454	5,787	13,454	9,424	18,995	11,313	16,995	10,888	21,674	12,602	19,674	10,636	19,815	12,361	17,815
Price ($/MWh)	$10.27	$56.99	$15.65	$49.28	$24.48	$49.41	$29.10	$44.53	$28.00	$72.42	$33.43	$66.08	$36.28	$76.21	$43.17	$68.23
Total price (affected hours)																
System ($/day)	$1,733,859		$1,581,376		$2,454,444		$2,385,583		$2,884,657		$2,766,716		$2,966,859		$2,853,860	
Solar generators ($/day)	$92,319		$149,473		$467,245		$499,200		$272,488		$327,308		$228,707		$283,929	
Thermal generators ($/day)	$925,855		$753,549		$1,169,245		$1,085,886		$1,874,515		$1,721,399		$1,896,033		$1,749,111	
Gain (Loss) (affected hours)																
System[2] ($/day)	$152,483				$68,861				$117,941				$112,999			
Solar generators ($/day)	$57,154				$31,955				$54,820				$55,222			
Thermal generators ($/day)	($172,307)				($83,360)				($153,115)				($146,922)			
Change in affected hours																
System	8.8%				2.8%				4.1%				3.8%			
Solar generators	61.9%				6.8%				20.1%				24.1%			
Thermal generators	-18.6%				-7.1%				-8.2%				-7.7%			

Notes: 1. Solar generation increase after shift is transferred from curtailment.
2. System gain is net reduction in total expenditure to procure electricity.


$$\text{Revenue (\$)} = \text{Revenue [after shift]} - \text{Revenue [before shift]}$$

(Revenue in thousands of dollars)

$$\text{Revenue (\%)} = \frac{\text{Revenue[after shift]} - \text{Revenue[before shift]}}{\text{Revenue[before shift]}} \times 100$$

Fig. 6. Net revenue gains and losses for the participating generation sources. Calculated for the scenario of 6 GWh total load shifted over 3 hours (2GHw shifted in each hour)..

congestion[10], so the load shifting should be accomplished near the solar plant to facilitate delivery of the otherwise curtailed electricity to the shifted load.

This analysis has been premised on the assumption that the price is responsive to load shifts in proportion to the observed relationship between day-ahead price and net load. This assumption needs further exploration and validation.

Returning now to the study of cost potential for load shifting presented by Gerke et.al. in Ref. 6, it is worth considering how these forecasted revenue shifts compare with the forecasted cost to implement various measures. Fig. 7 shows a comparison. The gains to solar generators alone are insufficient to offset the implementation costs, but the system savings are of greater magnitude and can profitably cover up to 2 GWh/day of load shifting by 2025. With declining costs forecasted by the Gerke study, this figure grows to perhaps 2.5 GWh/day by 2030. The gains can offset the implementation cost of any type of load shift, whether battery or other approaches. A caveat, however, is that the gains have been calculated based on 2019 data and may be modified by changes in the energy mix, primarily as a result of solar capacity growth. A further caveat is that we have combined the price effects over the year, and they are greatest in the spring (when heating and cooling loads are low, and solar generation is comparatively high) but the non-battery load shift

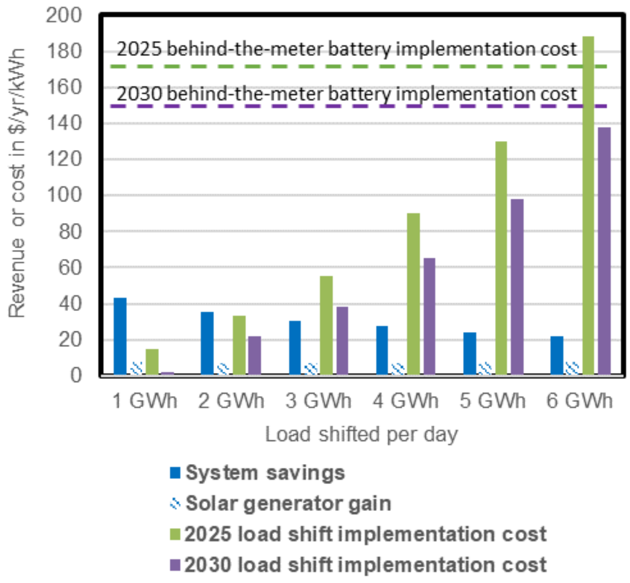


Fig. 7. A comparison of the forecasted financial benefits of load shifting with their implementation costs. The gain in revenue for solar generators, shown for reference, is a portion of the systems savings. The implementation costs (bars) are for non-battery load shift technologies, and the lines are for battery implementation costs, from Ref. 6.

opportunities are generally seasonal in nature (such as HVAC loads) and are lowest in the spring and fall.

A plausible strategy to motivate load shifting is to adjust time-of-use (TOU) rates that reduce a consumer's bill when load-shifting is implemented. Solar advocates have typically lobbied against TOU rates because these tend to reduce the apparent value of solar electricity. Ironically, solar advocates may consider that, while the TOU rates appear to reduce the value of solar electricity, the load shifting that they motivate can increase revenue for solar plant owners and empower solar to grow further. Thus, the time has come for solar advocates to reconsider their strategic approach to policy changes and support policies that incentivize load shifting.

IV. CONCLUSION

For PV penetration to grow much beyond about 20%, some form of load shifting will be essential, via batteries or other avenues. The effect of price response to shifting loads may be rightly viewed as a sweetener to encourage the implementation of load shifting, by improving the return on investment from the system point of view. The benefits to the demand-shifting consumers (by getting a lower price for their consumed energy) and to all consumers (by getting a lower price at the highest price hours) are aligned to those of the solar generators. Thus, it may behoove solar operators and consumer stakeholders to work together advocating policies and incentives to facilitate load shifting technology enablers and pricing schemes. Such policy advocacy should also be supported by public interest stakeholders more generally since the strategy leads to overall lower electricity cost and reduced emissions from fossil fuel generators.

V. ACKNOWLEDGEMENTS

This document was prepared in connection with work sponsored by the California Energy Commission. It does not necessarily represent the views of the Energy Commission, its employees, or the State of California. The Energy Commission, the State of California, its employees, contractors, and subcontractors make no warranty, express or implied, and assume no legal liability for the information in this document; nor does any party represent that the use of this information will not infringe upon privately owned rights. This report has not been approved or disapproved by the Energy Commission nor has the Energy Commission passed upon the accuracy of the information in this report.

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