Cost-Benefit Analysis of Additional Energy Storage Procurement

Authors
Tarroja, Brian
Samuelsen, Scott

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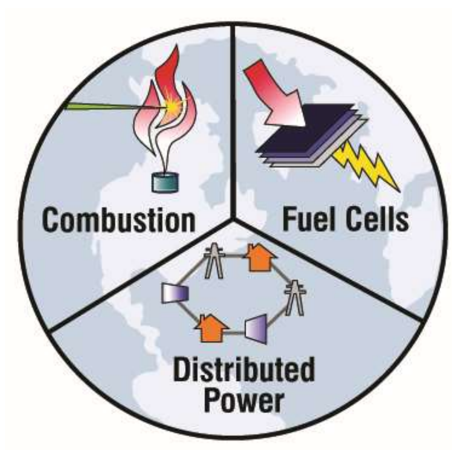

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PREPARED BY:

Primary Author(s):
Brian Tarroja
Scott Samuelsen

Advanced Power and Energy Program
221 Engineering Lab Facility, Bldg. 323
Irvine, CA 92697-3550
(949) 824-7302
www.apep.uci.edu

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Terry Surles (CIEE PM)

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Executive Summary

California has ambitious goals for reducing and eliminating greenhouse gas emissions from the State's electricity system as a cornerstone of efforts to decarbonize the State's economy more broadly. Electricity decarbonization efforts are codified by Senate Bill (SB) 100 which seeks to have 100% of retail sales of electricity by the year 2045 provided by eligible zero-carbon resources with an interim target of 60% of retail sales of electricity provided by eligible renewable resources by the year 2030. This policy contributes to a broader goal of achieving economy-wide carbon neutrality in the State by 2045, codified by Executive Order B-55-18.

Planning studies were undertaken to determine how California should proceed in terms of electricity generation and storage resource rollout to meet these goals, such as the Senate Bill 100 Joint Agency Report [1], which highlights the need for rapid renewable resource and energy storage buildout. Energy storage is typically selected as utility-scale lithium-ion batteries for short-duration storage and pumped hydropower energy storage for long-duration energy storage functions, primarily due to their relatively low cost for the former and technological maturity for the latter. Since the capacity expansion models used for such planning studies focus on minimizing cost, the recommended course from these studies focuses on lithium-ion and pumped hydropower energy storage connected as utility energy storage.

In practice, however, energy storage deployment will not be dictated by a central plan. Energy storage is being deployed to serve different priorities. Behind-the-meter energy storage may be deployed by individual residential, commercial, and industrial customers to serve their specific needs, provide electricity savings, and enable higher uptake of local renewable resources. Energy storage may also be installed at wind or solar farms to enable these to act as more dispatchable resources for the electric grid and enable them to provide electricity to the grid when they would otherwise not be generating. Additionally, other energy storage technologies such as flow batteries and hydrogen energy storage are emerging as potential alternatives to lithium-ion batteries and pumped hydropower, each with its own advantages and disadvantages in terms of technical, economic, and practical (i.e. safety, recyclability, etc…) characteristics.

Energy storage is a critical enabler of plans for complying with Senate Bill 100 and broader economy-wide decarbonization goals. Therefore, it is critical to understand the effect of alternative configurations for energy storage deployment on the broader electricity system's ability to rely on zero-carbon electricity for meeting load, how well it can use available renewable electricity generation, and the system-wide cost of electricity.

Therefore, the goal of this project is to provide information on the preferred configuration of energy storage technologies for supporting a decarbonized California electric grid by investigating alternative configurations for the buildout of energy storage to meet California's electricity decarbonization goals and comparing them to the configuration suggested by Senate Bill 100 planning studies. This will be accomplished by meeting the following objectives:

- Determine the costs associated with deploying different energy storage technology portfolios to facilitate an electricity system that complies with SB 100 goals.

- Compare the costs and benefits associated with the use of different energy storage technology portfolios in terms of expenditures and system-wide electricity system operations.
- Determine the energy storage characteristics that are better suited for providing different grid services at a minimal cost.

These objectives were met by carrying out the following procedures:

1. We developed cost parameter datasets for near-term (year 2030) and long-term (year 2045) for energy storage technologies at different unit sizes, including lithium-ion batteries, vanadium redox flow batteries, pumped hydropower, and hydrogen energy storage, based on recent literature reviews and technology-specific cost projections.
2. We then developed scenarios for energy storage deployment configurations that differ from common results in electricity decarbonization planning studies consisting of lithium-ion batteries and pumped hydropower energy storage deployed as utility-scale energy storage. These alternative configurations include the substituting of utility energy storage capacity for behind-the-meter energy storage, adding behind-the-meter energy storage to utility energy storage, co-locating energy storage at wind or solar farms instead of directly to the broader electric grid, substituting lithium-ion batteries for flow batteries, and adding long-duration hydrogen energy storage to the electricity system.
3. We then simulated these different energy storage configurations in the Holistic Grid Resource Integration and Deployment (HiGRID) electricity system dispatch model in electricity system resource mixes compliant with California's Senate Bill 100 goal. These simulations model the dispatch of electricity system resources to satisfy time-varying electric load demand and provide sufficient ancillary services with an hourly resolution for 1 year. From the electricity system dispatch modeling, the system-wide zero-carbon electricity penetration, curtailed renewable energy, and the system-wide average cost of electricity were determined for each energy storage scenario.

A summary of the key results and their driving factors are as follows:

- All of the alternative energy storage deployment configurations act to increase the cost of electricity relative to the base scenario consisting solely of utility-scale lithium-ion and pumped hydropower energy storage.
    - This is expected since the energy storage deployments in the base scenario are derived from capacity expansion modeling that selects resources based on minimizing electricity cost.
- Substituting utility energy storage for behind-the-meter (BTM) energy storage provides benefits for individual customers, but reduces the zero-carbon electricity penetration and increases the curtailed energy and cost of electricity for the broader electricity system.
    - This occurs due to conflicts in the priority for how energy storage operates. BTM energy storage charges and discharges to serve the needs of individual customers to which it is connected, which may differ from and conflict with how energy storage would operate to serve the needs of the broader electricity system.

- The system-wide electricity cost increases brought about by deploying BTM energy storage do not mean BTM energy storage should not be pursued, as many of the practical benefits of BTM energy storage were not accounted for (i.e. value of backup power).
    - Additionally, the savings that BTM energy storage deployment incurs from avoiding grid integration costs are highly uncertain, and narrowing down the expected range of avoided grid integration costs should be a priority in future research.
- Adding energy storage capacity, whether as BTM energy storage or as additional utility-scale energy storage capacity, expectedly improves zero-carbon electricity penetration and reduces curtailed renewable energy. This comes at the cost of increased electricity costs for the resource mixes considered here.
    - Here, added energy storage capacity was modeled in the form of additional BTM storage or relatively expensive utility-scale hydrogen energy storage, contributing to increased costs.
    - However, even if the added storage was utility-scale lithium-ion batteries, the marginal benefit of adding that capacity in terms of enabling the electricity system to reduce the use of expensive peaking resources needs to exceed its capital cost. This depends on the availability of excess renewable generation: if significant excess renewable generation is present, adding energy storage can provide significant marginal value. But if excess renewable generation is limited, adding more energy storage has a marginal effect.
- For short-duration energy storage, the benefits of the higher energy-to-power ratio of vanadium redox flow batteries do not outweigh their increased capital costs relative to lithium-ion batteries when it comes to effects on the system average cost of electricity.
    - However, vanadium redox flow batteries are relatively high cost due to the price of vanadium pentoxide. Other flow battery chemistries may be capable of exhibiting lower capital costs while providing the same technical benefit and may compete better with lithium-ion batteries.
- Co-locating energy storage capacity at wind or solar farms limits their ability to respond to the needs of the broader electricity system relative to installing the same capacity as utility energy storage.
    - While energy storage co-located at wind or solar farms enables them to be more predictable as a generation resource for balancing authorities, these energy storage units can only charge with electricity generation from the wind or solar farm that they are connected to. This limits their effectiveness in improving grid operations or excess renewable energy uptake since energy storage co-located at a wind farm cannot manage solar variability and energy storage co-located at a solar farm cannot manage wind variability unless the wind or solar farm is allowed to act as a grid load during certain hours.

Regarding recommendations for energy storage procurement to meet SB100 goals, the result of this analysis shows that the planned course in California electricity system decarbonization studies of expanding utility lithium-ion battery energy storage capacity and complimenting it with pumped hydropower energy storage yields the lowest costs of electricity. This result is consistent with the outputs of cost-minimizing capacity expansion studies and is perhaps unsurprising.

However, this result also has significant uncertainty since many of the benefits of BTM energy storage (i.e. providing backup power, avoiding grid integration costs, avoiding the need for entirely new transmission buildout, etc…) were not accounted for comprehensively or at all due to uncertainty in their monetary value. Other benefits, such as improved predictability from solar or wind farms from co-located energy storage, were also not accounted for in a monetized way.

To provide more comprehensive insight into the advantages and disadvantages of different energy storage deployment configurations, key uncertainties such as more accurately accounting for grid integration costs, disruptive changes in energy storage costs for emerging technologies, conflicts in dispatch priorities, and the effect of flexible loads must be addressed.

1. Project Overview

California has ambitious goals for reducing and eliminating greenhouse gas emissions from the State's electricity system as a cornerstone of efforts to decarbonize the State's economy more broadly. Electricity decarbonization efforts are codified by Senate Bill (SB) 100 which seeks to have 100% of retail sales of electricity by the year 2045 provided by eligible zero-carbon resources with an interim target of 60% of retail sales of electricity provided by eligible renewable resources by the year 2030. This policy contributes to a broader goal of achieving economy-wide carbon neutrality in the State by 2045, codified by Executive Order B-55-18. Planning studies were undertaken to determine how California should proceed in terms of electricity generation and storage resource rollout to meet these goals, such as the Senate Bill 100 Joint Agency Report [1], which highlights the need for rapid renewable resource and energy storage buildout. Energy storage is typically selected as utility-scale lithium-ion batteries for short-duration storage and pumped hydropower energy storage for long-duration energy storage functions, primarily due to their relatively low cost for the former and technological maturity for the latter. Since the capacity expansion models used for such planning studies focus on minimizing cost, the recommended course from these studies focuses on lithium-ion and pumped hydropower energy storage connected as utility energy storage.

In practice, however, energy storage deployment will not be dictated by a central plan. Energy storage is being deployed to serve different priorities and many alternative technologies are currently emerging. Since energy storage is a critical enabler of plans for complying with Senate Bill 100 and broader economy-wide decarbonization goals. It is critical to understand the effect of alternative configurations for energy storage deployment on the broader electricity system's ability to rely on zero-carbon electricity for meeting load, how well it can use available renewable electricity generation, and the system-wide cost of electricity.

In this study, alternative configurations for the deployment of energy storage for California's electricity system in the year 2030 and year 2045 were developed and simulated using the Holistic Grid Resource Integration and Deployment (HiGRID) [2,3] electricity system dispatch model. Each of the alternative configurations was evaluated on the bases of how their implementation affected system-wide zero-carbon electricity penetration (defined as the percentage of total electricity generation that is not curtailed), curtailed renewable energy, and the system-wide average cost of electricity. These alternative scenarios were compared against the reference scenario consisting of the energy storage portfolio produced from capacity expansion modeling for Senate Bill 100. To achieve the goals of the study, the following tasks were completed:

Task 2: Energy Storage Parameter Characterization

In this task, we developed cost parameter datasets for near-term (year 2030) and long-term (year 2045) for energy storage technologies at different unit sizes, including lithium-ion batteries, vanadium redox flow batteries, pumped hydropower, and hydrogen energy storage, based on recent literature reviews and technology-specific cost projections.

Task 3: Electric Grid Resource and Energy Storage Portfolio Scenario Development

In this task, we developed scenarios for energy storage deployment configurations that differ from common results in electricity decarbonization planning studies consisting of lithium-ion batteries and pumped hydropower energy storage deployed as utility-scale energy storage. These alternative configurations include the substituting of utility energy storage capacity for behind-the-meter energy storage, adding behind-the-meter energy storage to utility energy storage, co-locating energy storage at wind or solar farms instead of directly to the broader electric grid, substituting lithium-ion batteries for flow batteries, and adding long-duration hydrogen energy storage to the electricity system. We also drew upon electricity system decarbonization studies for meeting California's Senate Bill 100 goal [1] and from the NREL Standard Scenarios [4] to characterize the electricity system for the State in the years 2030 and 2045.

Task 4: Energy Storage Scenario Simulation and Characterization

In this task, we then simulated these different energy storage configurations in the Holistic Grid Resource Integration and Deployment (HiGRID) electricity system dispatch model in electricity system resource mixes compliant with California's Senate Bill 100 goal. These simulations model the dispatch of electricity system resources to satisfy time-varying electric load demand and provide sufficient ancillary services with an hourly resolution for 1 year. From the electricity system dispatch modeling, the system-wide zero-carbon electricity penetration, curtailed renewable energy, and the system-wide average cost of electricity were determined for each energy storage scenario.

2. Approach, Methodology, and Data Sources

Here we present the approach used to carry out the present study. A description of the relevant data sources is provided within the descriptions of each methodological step.

2.1. Energy Storage Parameter Characterization

The first step in carrying out this analysis is to gather and compile the relevant data needed to represent the costs, and capabilities of different energy storage technologies in simulations of the electric grid, as well as develop scenarios for the sensitivities and ranges in these parameters. Here, we present the parameters for energy storage technologies that will be used in the subsequent analysis of the project and their justification.

To support the present project, we gather parameters that are necessary for characterizing a) the costs associated with deploying and operating different energy storage systems in different applications and b) the technical performance of these energy storage systems with respect to costs and degradation. Specifically, we gathered data for the following parameters:

- **<u>Capital Cost</u> [$/kW]:** The capital cost accounts for the cost of materials, construction, and labor associated with producing and installing a given energy storage system. For this analysis, we adopt the definition of Energy Storage System Installed Cost from Mongird et al. [5], which accounts for the storage block, balance of system, power equipment, controls and communication equipment, system integrator costs, engineering, procurement, and construction costs, project development, and grid integration costs as applicable. Capital costs can be defined on a per-unit power or per-unit energy basis. Here, we opt to represent capital costs on a per-unit power basis for a given duration of storage.
- **<u>Fixed Operation and Maintenance</u> [$/kW-yr]:** This refers to the costs incurred to keep a given energy storage system operating over its lifetime that are not dependent on the extent to which the system is used. Examples include planned maintenance costs and labor. This metric is represented by an annual cost that scales with per-unit of power capacity.
- **<u>Variable Operation and Maintenance</u> [$/MWh]:** This refers to costs incurred to keep an energy storage system operating over its lifetime that are dependent on the extent to which the system is used. Examples include consumables and unplanned maintenance associated with degradation.
- **<u>Round Trip Efficiency (RTE)</u> [%]:** This refers to the ratio of energy discharged to the electric grid by the energy storage system to the total energy required to charge the energy storage system, after conversion and parasitic losses have been accounted for. This metric is typically defined for a given charging and discharging duty cycle.
- **<u>Cycle Life</u> [# Cycles]:** This refers to the number of equivalent full charge and discharge cycles that an energy storage system can endure before degrading to the point where it is no longer suited to perform its intended function. The end-of-function criteria depend on the energy storage system, for example, a battery may be considered no longer useful when its energy capacity degrades to a set percentage of its original energy capacity, whereas a thermal system may be considered no longer useful when one of its major components is likely to suffer failure from fatigue.

- **<u>Calendar Life</u> [Years]:** This refers to the maximum number of years after which an energy storage system will be considered non-functional for its intended purpose.
- **<u>Annual Round Trip Efficiency Degradation</u> [% of Initial RTE]:** This refers to an estimate of how much the round-trip efficiency of an energy storage system degrades over time due to aging effects. This factor applies an annual factor to account for degradation.

There are other technical characteristics of energy storage systems that are important to consider, depending on the application, such as response time. For the intended analysis, however, all of the considered energy storage technologies have response times on the order of seconds to minutes, which are more highly resolved than the applications being considered.

Cost and technical parameters of energy storage systems as well as different projections for how these will change over time are documented in much of the academic literature [6], government-sponsored research studies [5,7–9], and industry market reports [10]. A summary table of the studies and reports reviewed is presented in

Table 1:

Table 1 - Summary of Reviewed Studies for Technical and Cost Parameters

Reference	Sector	Year	Technologies Included	Projections Included	Notes
NREL Annual Technology Baseline 2021 [8]	Government	2021	Lithium-ion Battery (Utility, Commercial, and Residential) Pumped Hydropower	Cost parameters from 2021 to 2050 in 1-year increments Advanced, Moderate, and Conservative Scenarios	No capital cost included for pumped hydropower
Mongird et al. [5]	Government	2020	Lithium-ion Battery (Utility and Commercial) Lead-Acid Battery Redox Flow Battery Compressed Air Pumped Hydropower Hydrogen	Projections for 2030 for all parameters	Used for U.S DOE Energy Storage Grand Challenge
Mongird et al. [7]	Government	2019	Lithium-ion Battery (Utility and Commercial) Lead-Acid Battery Redox Flow Battery Sodium-Sulfur Battery Sodium Metal Battery Zinc-hybrid Battery Compressed Air Pumped Hydropower Hydrogen Flywheels	Projections for 2025 for all parameters	Used for U.S. DOE HydroWIRES Initiative. Very comprehensive, but limited projection horizon. Some data was also updated and used for later Mongird et al. study.
Lazard Levelized Cost of Storage v7.0 [10]	Industry	2021	Lithium-ion Battery (Utility, Commercial, and Residential) Redox Flow Battery (Vanadium and Zinc Bromide)	None, only characterizes the present day. Also does not provide technical parameters	Only publishes LCOS, does not provide data on individual components
Schmidt et al. [6]	Academic	2019	Lithium-ion Battery (Utility) Lead-Acid Battery Redox Flow Battery Sodium-Sulfur Battery Compressed Air Pumped Hydropower Hydrogen Flywheels Supercapacitor	Projects from 2015 to 2050 in 5-year increments	Focused on LCOS for different applications, but component data and detail on projections for each technology are available
NREL Storage Futures Study [9]	Government	2020	Lithium-ion Battery (Utility, Commercial, and Residential) Pumped Hydropower		Used as input to NREL ATB 2021

Underlying the parameter values in each of these studies and reports are differences in what elements are included in cost parameters, the vintage of the cost and technical data, the set of technologies included, and optimism and pessimism in projected future changes in these parameters. Therefore, we applied the following considerations to ensure that we draw upon these studies to compose the energy storage parameters and their sensitivities for this study in a consistent and defensible manner:

- **Consistent boundary of analysis and complete inclusion of the desired energy storage technologies.** We found that it was critical to base the reference values for the energy storage parameters on studies that applied a consistent boundary and framework to different energy storage technologies and also endogenously included all of the energy storage technologies considered in this project. Many studies in the literature use different boundaries for what factors are included in cost parameters and also may omit some of the technologies to be considered in this project. In selecting the reference values, mixing and matching parameters from different studies introduces inconsistency and uncertainty in the values. Since this project focuses on lithium-ion batteries, redox flow batteries, pumped hydropower, compressed air, and hydrogen energy storage, we select our reference values from studies that include all of these endogenously.
- **Recency of the study.** Energy storage parameters, particularly cost parameters, can change significantly over time. The most prominent example is the significant drops in the capital costs of lithium-ion battery storage over the past decade. Therefore, we found that it is critical to rely on studies that use recent data and reflect recent trends in the progression of these parameters. For selecting parameter values, we only consider studies that have been performed within the past three years (2019 or later).
- **Forward projections.** Many studies characterize present-day parameters for energy storage systems and additionally include some form of projection for how these parameters change over time. The present project focuses on the years 2030 and 2045, consistent with California's Senate Bill 100 policy goals. We selected studies that contain at least a projection towards 2030 for the technologies of interest.
- **Sensitivity to size or scale.** Since some of the energy storage technologies considered can be applied at different scales (i.e. residential vs utility-scale, etc…), we also found it important to focus on studies that differentiated energy storage parameters by their scale of installation for use in developing sensitivities to our reference parameters.
- **Availability of cost component breakdowns.** Certain studies such as the annual Levelized Cost of Storage report by Lazard [10] characterize the levelized cost of storage (LCOS) that is used to characterize the cost of storage but do not provide the input data on the components that went into calculating the LCOS results. We found it important to consider studies that provide the breakdown of their input data.

Based on these considerations, we develop the energy storage cost and technical parameters as follows.

Reference values: The reference values for the cost and technical parameters for energy storage systems are selected from the 2020 Grid Energy Storage Technology Cost and Performance Assessment by Mongird et al. [5], performed for the U.S. Department of Energy – Energy Storage Grand Challenge. This study was selected since it presents parameters for each of the energy storage technologies of interest in this project (lithium-ion, vanadium redox, pumped hydropower, compressed air, and hydrogen) using recent data for 2020 and applies a comprehensive and consistent approach to each technology. This study also contains a projection to 2030, as well as a sensitivity to different sizes of each energy storage technology.

The Mongird et al. [5] study, while comprehensive and recent, still does not contain data for all of the scenarios needed for this project. Specifically, the Mongird et al. study a) contains data for commercial and utility-scale systems only and omits data on residential-scale systems, b) projects technology costs out to 2030 and does not include any projections for 2045, and c) does not contain data for annual round-trip efficiency degradation. To develop parameters for these sensitivities, we rely on other studies as follows:

Projection of costs to 2045 and optimistic and pessimistic scenarios: To project the cost parameters for each energy storage technology to 2045, we rely on the levelized cost of storage projections from Schmidt et al. [6]. This study contains projections for how the investment costs of different energy storage technologies will change in 5-year increments from 2020 to 2050 relative to their values in the year 2015, for each of the energy storage technologies considered in this project. In addition to the projections themselves, the Schmidt et al. study also includes the forecast uncertainty associated with each future projection. We apply the projected percentage change in investment costs for the year 2045 relative to the year 2030 from the Schmidt et al. study [6] to the year 2030 capital cost values from the Mongird et al. study [5] to obtain capital cost values for the year 2045. We then develop optimistic scenarios by reducing the capital cost values in each year by the appropriate forecast uncertainty percentage for each technology and conversely develop pessimistic scenarios by increasing the capital cost values in each year by the corresponding forecast uncertainty.

Residential-scale battery storage parameters: Cost parameters for residential scale lithium-ion batteries were developed from calculating the percentage difference between residential and commercial lithium-ion batteries in the National Renewable Energy Laboratory Annual Technology Baseline (NREL ATB) 2021 dataset [8]. The NREL ATB 2021 dataset contains cost projections from 2020 to 2050 for residential, commercial, and utility-scale lithium-ion batteries. We calculate the percentage difference between residential and commercial-scale lithium-ion batteries from the NREL ATB 2021 and apply this to the commercial-scale lithium-ion capital cost values from the Mongird et al. study [5] to develop residential lithium-ion battery cost parameters.

Projecting technical parameters: For this project, we hold the values of technical parameters as constant at their year 2030 value. While improvements in round-trip efficiency and cycle life can occur beyond 2045, there is significant uncertainty in projecting these parameters. Different energy storage technologies will be defined by different fundamental limits and are also currently at different levels of technological maturity. Without a specific understanding of scientifically-sound improvements in the technical parameters for these technologies, we consider the arbitrary projection of these parameters based on factors such as learning rates to not be defensible.

Lithium-ion battery chemistry: The dataset from Mongird et al [5] contains separate cost and technical parameters for Nickel-Manganese-Cobalt (NMC) and Lithium-Iron-Phosphate (LFP) lithium-ion battery chemistries. To represent future procurement, we base our values for the cost and technical parameters on the LFP chemistry, owing to the efforts to move away from dependence on cobalt-based chemistries to avoid exacerbating human rights and labor issues in cobalt-producing countries such as the Democratic Republic of Congo [11].

Based on the aforementioned considerations, the developed cost and technical parameters for each of the energy storage technologies considered are presented as follows for Lithium-ion Batteries (

Table 2), Redox Flow Batteries (

Table 3), Pumped Hydropower Energy Storage (

Table 4), Compressed Air Energy Storage (

Table 5), and Hydrogen Energy Storage (

Table 6):

Table 2 - Cost and Technical Parameters for Lithium-Ion Batteries

Lithium-ion Battery							
Parameter	Units	Utility Scale		Commercial Scale		Residential Scale	
Representative Size		10 MW/4 hr		1 MW/4 hr		5 kW/4 hr	
Year		**2030**	**2045**	**2030**	**2045**	**2030**	**2045**
Capital Cost	$/kW (2020 $)	1156.00	753.91	1266.00	825.65	3136.65	2045.64
Capital Cost - Optimistic	$/kW (2020 $)	1005.72	655.90	1101.42	718.32	2728.89	1779.71
Capital Cost - Pessimistic	$/kW (2020 $)	1306.28	851.92	1430.58	932.99	3544.41	2311.57
Fixed O&M	$/kW-yr (2020 $)	3.30	3.30	3.61	3.61	8.94	8.94
Variable O&M	$/MWh (2020 $)	0.51	0.51	0.51	0.51	0.51	0.51
Round-Trip Efficiency	%	88.00	88.00	88.00	88.00	88.00	88.00
Cycle Life	# Cycles	2100.00	2100.00	2100.00	2100.00	2100.00	2100.00
Calendar Life	Years	10.00	10.00	10.00	10.00	10.00	10.00
Annual RTE Degradation	% of Initial RTE	0.50	0.50	0.50	0.50	0.50	0.50
Grid Integration Costs	$/kW (2020 $)	20	20	25 (Front) 0 (BTM)	25 (Front) 0 (BTM)	0 (BTM)	0 (BTM)

Projections for lithium-ion batteries include aggressive reductions in capital cost for the battery blocks themselves, but smaller-scale systems are still expected to be more expensive. Modest technical improvements in efficiency are expected by 2030 relative to the present day.

Table 3 - Cost and Technical Parameters for Redox Flow Batteries

Redox Flow Battery									
Parameter	Units	Utility Scale		Utility Scale LD		Commercial Scale		Commercial Scale LD	
Representative Size		10 MW / 4 hr		10 MW / 10 hr		1 MW / 4 hr		1 MW / 10 hr	
Year		**2030**	**2045**	**2030**	**2045**	**2030**	**2045**	**2030**	**2045**
Capital Cost	\$/kW (2020 \$)	1773.00	1227.46	3399.00	2353.15	1922.00	1330.62	3645	2523.46
Capital Cost - Optimistic	\$/kW (2020 \$)	1524.78	1104.72	2923.14	2117.84	1652.92	1197.55	3134.70	2271.12
Capital Cost - Pessimistic	\$/kW (2020 \$)	2021.22	1350.21	3874.86	2588.47	2191.08	1463.68	4155.30	2775.81
Fixed O&M	\$/kW-yr (2020 \$)	5.15	5.15	9.82	9.82	5.57	5.57	10.47	10.47
Variable O&M	\$/MWh (2020 \$)	0.5125	0.5125	0.5125	0.5125	0.5125	0.5125	0.5125	0.5125
Round-Trip Efficiency	%	70.00	70.00	70.00	70.00	70.00	70.00	70.00	70.00
Cycle Life	# Cycles	5201.00	5201.00	5201.00	5201.00	5201.00	5201.00	5201.00	5201.00
Calendar Life	Years	15.00	15.00	15.00	15.00	15.00	15.00	15.00	15.00
Annual RTE Degradation	% of Initial RTE	0.40	0.40	0.40	0.40	0.40	0.40	0.40	0.40
Grid Integration Costs	\$/kW (2020 \$)	21	21	21	21	25 (FTM) 0 (BTM)	25 (FTM) 0 (BTM)	25 (FTM) 0 (BTM)	25 (FTM) 0 (BTM)

Redox flow battery parameters are largely based on the Vanadium redox flow battery chemistry, due to its relative maturity compared to other flow battery chemistries. Other flow battery chemistries, particularly iron-based chemistries, can potentially introduce significant cost reductions, but not enough data exists to reliably base a projection on these newer chemistries.

Table 4 - Cost and Technical Parameters for Pumped Hydropower Energy Storage

Pumped Hydropower			
Parameter	Units	Utility Scale	
Representative Size		100 MW / 10 hr	
Year		**2030**	**2045**
Capital Cost	$/kW (2020 $)	1651.00	1684.02
Capital Cost - Optimistic	$/kW (2020 $)	1601.47	1633.50
Capital Cost - Pessimistic	$/kW (2020 $)	1700.53	1734.54
Fixed O&M	$/kW-yr (2020 $)	30.40	30.40
Variable O&M	$/MWh (2020 $)	0.5125	0.5125
Round-Trip Efficiency	%	80.00	80.00
Cycle Life	# Cycles	13870.00	13870.00
Calendar Life	Years	40.00	40.00
Annual RTE Degradation	% of Initial RTE	0.00	0.00
Grid Integration Costs	$/kW (2020 $)	20	20

Pumped hydropower energy storage parameters are not projected to change significantly between present-day, 2030, and 2045 owing to the relatively high maturity of this technology.

Table 5 - Cost and Technical Parameters for Compressed Air Energy Storage

Compressed Air Energy Storage			
Parameter	Units	Utility Scale	
Representative Size		100 MW / 10 hr	
Year		**2030**	**2045**
Capital Cost	$/kW (2020 $)	1184.00	1207.68
Capital Cost - Optimistic	$/kW (2020 $)	1148.48	1171.45
Capital Cost - Pessimistic	$/kW (2020 $)	1219.52	1243.91
Fixed O&M	$/kW-yr (2020 $)	16.12	16.12
Variable O&M	$/MWh (2020 $)	0.5125	0.5125
Round-Trip Efficiency	%	52.00	52.00
Cycle Life	# Cycles	10403.00	10403.00
Calendar Life	Years	30.00	30.00
Annual RTE Degradation	% of Initial RTE	0.52	0.52
Grid Integration Costs	$/kW (2020 $)	20	20

Similar to pumped hydropower, compressed air energy storage parameters are also not projected to change significantly between present-day, 2030, and 2045 due to the relative maturity of its technological components. Cost reductions can still potentially occur from system optimization, however.

Table 6 - Cost and Technical Parameters for Hydrogen Energy Storage

Hydrogen Energy Storage			
Parameter	Units	Utility Scale	
Representative Size		100 MW / 10 hr	
Year		**2030**	**2045**
Capital Cost	$/kW (2020 $)	1612.00	1094.94
Capital Cost - Optimistic	$/kW (2020 $)	1483.04	985.45
Capital Cost - Pessimistic	$/kW (2020 $)	1740.96	1204.44
Fixed O&M	$/kW-yr (2020 $)	28.51	28.51
Variable O&M	$/MWh (2020 $)	0.5125	0.5125
Round-Trip Efficiency	%	35.00	35.00
Cycle Life	# Cycles	10403.00	10403.00
Calendar Life	Years	30.00	30.00
Annual RTE Degradation	% of Initial RTE	0.00	0.00
Grid Integration Costs	$/kW (2020 $)	20	20

The parameters for hydrogen energy storage are based on the proton-exchange membrane (PEM) electrolyzer and fuel cell technologies. Higher-efficiency solid-oxide fuel cell and electrolyzer technologies may also play a significant role, but harmonized cost parameters and projections that meet our criteria for inclusion in this project are relatively sparse.

2.2. Year 2030 and Year 2045 Electricity Resource Mix

To support the present project, we establish the parameters for the electricity supply resource mix in California in 2030 and 2045. Specifically, these parameters entail the installed capacities of zero-carbon electricity resources, defined here as solar, wind, geothermal, biomass, nuclear, and hydropower resources, consistent with specifications in California's SB 100 policy goal. Here, we use installed capacity as the input for our modeling, since the HiGRID model to be used for the simulations takes in the installed capacity of each resource as input, with energy delivered being an output of the simulations. There are two datasets that we drew upon for the zero-carbon electricity supply projections, each with two scenarios that we propose to use for comparison. Specifically, we will simulate the different approaches for energy storage deployment described later in this report on electricity systems comprised of these different resource mixes.

The first dataset is the California SB 100 Joint Agency Report [1]. This report contains projections from Energy Environmental Economics (E3) using their RESOLVE capacity expansion model, developed with regular input from California State agencies and represents the first official planning effort supported by California state agencies for planning the deployment of resources to comply with the SB 100 goal. The SB 100 Joint Agency Report investigated multiple scenarios and sensitivities such as different interpretations of SB 100 compliance, the costs associated with certain technologies, and differences in the compliance timeline. Of these scenarios, we propose to use two for the present study:

- **SB 100 Core:** This is the core scenario based on the literal interpretation of the criteria required to comply with SB 100: that 100% of retail sales of electricity are satisfied with eligible zero-carbon resources by 2045. This means that all electricity generation sold to consumers must be zero-carbon, however, additional electricity production that is needed to overcome losses (i.e., due to transmission, distribution, or energy storage round-trip efficiencies) does not need to come from zero-carbon resources. Since this is the legal interpretation of SB 100 as it is written currently, this is an important scenario to include.
- **SB 100 Study – Expanded Load Coverage:** This is a scenario where SB 100 is interpreted to specify that electricity production required to overcome system losses must also be sourced from eligible zero-carbon resources. From a practical standpoint, this will require a higher capacity of zero-carbon resources to be installed to comply with this interpretation of SB 100.

The second dataset is the NREL 2021 Standard Scenarios Report [4]. The NREL Standard Scenarios are a set of electricity sector resource projections for the entire U.S. that is updated yearly to incorporate the latest data on technology performance and cost, as well as to develop electricity sector resource scenarios that account for recent research or policy trends of interest. The electricity sector projections are developed under specific scenarios using the NREL Regional Energy Deployment System (ReEDS) model, the NREL Distributed Generation Market Demand Model (dGen), and incorporates technology costs from the NREL Annual Technology Baseline (NREL ATB) [8] from the same year.

In contrast to the SB 100 Joint Agency Report, the NREL Standard Scenarios develops scenarios for the entire U.S. and assumes more dynamic connections between California and surrounding regions by modeling the entire WECC. These scenarios also capture state, regional, and federal policy related to electricity sector decarbonization in place as of June 2021 as a reference scenario, then presents two more aggressive scenarios for power sector decarbonization. This means that California's SB 100 is accounted for in all of the report scenarios. Of the report scenarios, we propose to use the following scenarios to contrast with those specified by the California SB 100 Joint Agency Report:

- **Mid-Case**: This refers to the reference scenario of the NREL Standard Scenarios report. This accounts for all state, regional, and federal policies in place as of June 2021, including California's SB 100. This scenario presents a contrast to the SB 100 Core scenario from the California SB 100 Joint Agency Report where California is modeled as a component of the WECC instead of the main focus.
- **Mid-Case 95 by 2035:** This represents a more aggressive power sector decarbonization trajectory for the U.S., projecting the rollout of electricity resources needed to have the U.S. power sector reach net-zero greenhouse gas emissions by the year 2035. This scenario requires states to more aggressively install zero-carbon electricity capacity and potentially rely more on direct air capture to reach and maintain net-zero emissions.

Collectively, these two datasets present differences in projections for the evolution of the electricity supply mix in California to comply with or even exceed the State's SB 100 goals. Simulating the scenarios for energy storage deployment in systems with these different electricity mixes enables the study to investigate the sensitivity of energy storage benefits to the electricity mix. The installed capacities of electricity resources serving California for the considered scenarios in each dataset are presented for the year 2030 in Table 7 and the year 2045 in Table 8:

Table 7 - Installed capacities of electricity resource capacities in California in 2030 for each proposed scenario and dataset.

Year 2030	SB 100 Joint Agency Report		2021 NREL Standard Scenarios*	
	SB 100 Core	SB 100 Study	Mid-Case	Mid-Case 95 by 2035
	[MW]	[MW]	[MW]	[MW]
Nuclear	1042	1042	0	0
Coal	0	0	0	0
CHP	2296	2296	0	0
Gas	32959	32959	29564	29564
Hydrogen Fuel Cell	0	0	0	0
Geothermal	2644	2644	2957	3153
Biomass	995	995	886	886
Hydropower In-State	11548	11548	10906	10906
Hydropower Scheduled Imports	3478	3478	3478*	3478*
Wind Onshore	15623	16799	6466	6415
Offshore Wind	0	0	0	0
Utility-Scale Solar	34949	34655	27170	26504
Customer Solar	23296	23296	15180	15180
Battery Storage	13058	12640	3833	3959
Pumped Storage	3194	3086	5512	5847
Concentrating Solar Thermal	0	0	966	966
BECCS	0	0	0	0
DAC	0	0	0	0

***The NREL Standard Scenarios does not explicitly specify hydropower imports to California as a resource, since it models the entire WECC simultaneously, so we assume the effective capacity for hydropower imports is the same as that in the SB 100 Joint Agency Report.**

Table 8 - Installed capacities of electricity resource capacities in California in 2045 for each proposed scenario and dataset.

Year 2045	SB 100 Joint Agency Report		2021 NREL Standard Scenarios*	
	SB 100 Core	SB 100 Study	Mid-Case	Mid-Case 95 by 2035
	[MW]	[MW]	[MW]	[MW]
Nuclear	1042	1042	0	0
Coal	0	0	0	0
CHP	0	0	0	0
Gas	29580	27270	27798	27798
Hydrogen Fuel Cell	0	0	0	0
Geothermal	2779	4944	6682	6724
Biomass	995	995	285	285
Hydropower In-State	11548	11548	10956	11030
Hydropower Scheduled Imports	3478	3478	3478*	3478*
Wind Onshore	20432	23866	25829	18981
Offshore Wind	10000	10000	0	0
Utility-Scale Solar	86956	103383	45752	41985
Customer Solar	39063	39063	21292	21292
Battery Storage	53191	58748	10320	6695
Pumped Storage	5599	5599	14319	14911
Concentrating Solar Thermal	0	0	0	0
BECCS	0	0	0	348
DAC	0	0	0	8263

***The NREL Standard Scenarios does not explicitly specify hydropower imports to California as a resource, since it models the entire WECC simultaneously, so we assume the effective capacity for hydropower imports is the same as that in the SB 100 Joint Agency Report.**

For both of the datasets, battery storage refers to 4-hour Lithium-ion battery energy storage operating in response to price signals of the broader transmission grid.

2.3. Projections for Electric Load Demands in California

To further support the present project, we also draw upon projections for the electric load demand in California for the years 2030 and 2045 to complete defining the parameters of the electricity system on which the energy storage deployment scenarios will be simulated.

For electric load demands, we draw only on a single source: the E3 PATHWAYS study update from 2018 [12], which corresponds to the electric load demands used for the California SB 100 Joint Agency Report. We select this source since it contains the most detailed breakdown of electric loads by sector for California that is consistent with the State's policies and trajectories regarding energy efficiency and electrification of energy end-uses, ranging from transportation to building heating. A contrasting source that was considered was the NREL Standard Scenarios Report, however, this source only provided total electric load and not a breakdown by subsector since it was primarily focused on developing electricity supply scenarios.

The projected annual electric load demands for the years 2030 and 2045 are presented for the commercial sector in Table 9, the agriculture sector in Table 10, the industrial sector in Table 11, the residential sector in Table 12, the transportation sector in Table 13, and for electrofuel production in Table 14.

Table 9 - Commercial sector electric load projections for 2030 and 2045 in California

Commercial Subsector	**Year 2030**	**Year 2045**
	[GWh]	[GWh]
Commercial Air Conditioning	26731	32721
Commercial Cooking	2103	7560
Commercial Lighting	17931	15096
Commercial Other	27187	34739
Commercial Refrigeration	8004	8835
Commercial Space Heating	1368	4582
Commercial Ventilation	10450	10525
Commercial Water Heating	2044	8899

Table 10 - Agriculture sector electric load projections for 2030 and 2045 in California

Agriculture Subsector	**Year 2030**	**Year 2045**
	[GWh]	[GWh]
Agricultural Unspecified	23869	24728

Table 11 - Industrial sector electric load projections for 2030 and 2045 in California

Industrial Subsector	**Year 2030**	**Year 2045**
	[GWh]	[GWh]
Apparel & Leather	122	84
Cement	3181	2462
Chemical Manufacturing	2121	1614
Computer and Electronic	1571	1202
Construction	863	712
Electrical Equipment & Appliance	308	333
Fabricated Metal	1414	1224
Food & Beverage	2884	2058
Food Processing	773	567
Furniture	106	61
Glass	3499	3276
Logging & Wood	276	190
Machinery	574	396
Mining	224	124
Miscellaneous	2581	1980
Nonmetallic Mineral	306	229
OGE Unspecified	4547	1790
Paper	332	195
Petroleum Refining Unspecified	4503	1698
Plastics and Rubber	2040	2060
Primary Metal	491	406
Printing	277	165
Publishing	404	331
Pulp & Paperboard Mills	299	179
Semiconductor	1094	823
Streetlighting	889	437
TCU Unspecified	20001	24451
Textile Mills	78	54
Textile Product Mills	27	15
Transportation Equipment	827	568

Table 12 - Residential sector electric load projections for 2030 and 2045 in California

Residential Subsector	Year 2030	Year 2045
	[GWh]	[GWh]
Residential Central Air Conditioning	6888	5461
Residential Clothes Drying	5317	7240
Residential Clothes Washing	509	485
Residential Cooking	4371	7056
Residential Dishwashing	1582	1443
Residential Freezers	2099	1943
Residential Lighting	7270	5613
Residential Other	42889	43368
Residential Refrigerators	12629	12346
Residential Room Air Conditioning	599	679
Residential Space Heating	3909	11429
Residential Water Heating	3557	15026

Table 13 - Transportation sector electric load projections for 2030 and 2045 in California

Transportation Subsector	Year 2030	Year 2045
	[GWh]	[GWh]
Aviation	0	0
Buses	1230	2345
Freight Rail	728	7852
Harborcraft	905	2260
Heavy Duty Trucking	2062	9503
Light Duty Vehicles	13954	46863
Medium Duty Trucking	633	6614
Ocean Going Vessels	2467	5378
Passenger Rail	45	449

Table 14 - Electrofuel production electric load projections for 2030 and 2045 in California

Electrofuel Production	Year 2030	Year 2045
	[GWh]	[GWh]
Hydrogen	5129	38048
Compressed Pipeline Gas (CNG)	330	870
Power to Gas	0	0

2.4. Energy Storage Deployment Scenarios

The primary aim of this project is to investigate how various configurations of energy storage technology deployment on the California grid affect the performance of the electricity system from a cost perspective while complying with California's economy-wide decarbonization goals. Planning studies for complying with State policies such as SB 100 exist [1] and present specific deployment trajectories for energy storage capacity, but to develop a more robust understanding of the preferred energy storage deployment strategy, multiple configurations of energy storage deployment must be investigated and compared.

Here we describe the methods for how each of these energy storage scenarios was implemented in modeling the year 2030 and 2045 electricity systems in the Holistic Grid Resource Integration and Deployment (HiGRID) model.

2.4.1. Scenario 1: Effect of increased focus on behind-the-meter storage deployments.

Behind-the-meter (BTM) energy storage refers to energy storage capacity that is installed and connected to the customer side of the utility electricity meter. This contrasts with utility energy storage, which is connected to the utility-side of the distribution system or directly to the transmission system as a centralized grid resource. Capacity expansion studies that inform the planning of the future electricity system, including those conducted for compliance with California's SB 100 goal [1], project significant deployments of energy storage capacity installed and operated as utility energy storage being dispatched in response to the time-varying conditions of the broader electricity system.

Deploying energy storage as BTM installations are likely to be pursued by individual industrial, commercial, or residential customers rather than by a centralized entity such as a utility or balancing authority. BTM energy storage installations can provide many benefits for these individual consumers, including but not limited to:

- Reducing costs of electricity for the individual consumer by avoiding the import of grid electricity during high electricity price hours.
- Enhancing the availability and use of rooftop solar photovoltaic resources for both reducing customer electricity costs and emissions
- Ability to provide backup power in the event of broader electricity system blackouts, either as a standalone resource or in combination with rooftop or otherwise on-site solar.

This means, however, that the operating priorities of BTM energy storage installations will be different than utility energy storage. While utility energy storage systems will charge and discharge in response to the conditions of the broader electricity system (i.e. responding to balancing authority net load profiles or electricity price signals), BTM energy storage installations will respond to the energy use profiles of the customers to which they are connected. This has the potential to cause conflicts: for example, a BTM energy storage system can choose to charge when it is beneficial for a local customer but detrimental to the broader electricity system, and vice versa for discharge.

However, installing BTM energy storage can also have overall system cost benefits. While capital cost numbers for BTM energy storage are typically higher than their utility-scale counterparts [5,13], these systems also avoid certain costs relating to grid integration that utility energy storage systems are subject to. Specifically, the costs of interconnection to the transmission system and the hardware necessary to establish this connection (transformers, busbars, etc…).

This scenario seeks to understand the effect of substituting increasing fractions of planned utility energy storage capacity for BTM energy storage capacity, as well as the effect of adding BTM energy storage capacity on top of planned utility energy storage capacity, on the zero-carbon penetration, average cost of electricity, and curtailed renewable energy from the system-wide perspective, not the local customer perspective. Therefore, we will focus on modeling the components of BTM energy storage that affect system-wide performance parameters. We are not quantifying the value of the benefits provided to the consumer here – such as resilience and backup power – or how those consumer benefits translate to system-wide benefits. Valuation of these factors is a subject of extensive ongoing research and will be included in future work.

With these considerations, we make the following assumptions for the costs and dispatch of BTM energy storage:

- **General assumptions:**
    - BTM energy storage is modeled as 4-hour lithium-ion battery energy storage at the commercial scale, with a nominal power capacity of 1 MW per installation.
        - While not all BTM energy storage will be installed by commercial customers, this assumption is made since although residential systems are smaller, previous research has found that it is more cost-effective to deploy energy storage as a community resource for entire residential neighborhoods rather than as independently operating installations at individual residences [14]. This is reflected in the cost parameters for lithium-ion battery energy storage at different scales presented in Section 2.1.
    - Utility energy storage is modeled as 4-hour lithium-ion battery energy storage with a nominal power capacity of 10 MW per installation.
    - Cost, efficiency, and lifetime parameters are further described in Section 2.1.
- **Scenario-specific cost assumptions:**
    - The costs of grid integration as specified by Mongird et al [5] are subtracted from the capital cost parameters for BTM energy storage. These range from \$25-\$31/kW for the year 2030 and \$20-25/kW for the year 2045.
        - These costs include the "*direct cost associated with connecting the energy storage system to the grid, including transformer cost, metering, and isolation breakers*."
        - It is important to note that grid interconnection costs vary between different reports, depending on what factors are taken into account. Here we use the figures from Mongird et al [5,7] since that report formed the basis for calculating and projecting the cost parameters used in this study. Narrowing down a more accurate number to account for the costs of grid interconnection is a subject of future work.
- **Scenario-specific dispatch assumptions:**

- The capacity of energy storage installed as BTM will be dispatched to maximize the absorption of distributed (rooftop) solar PV by residential or commercial loads as appropriate.
    - In this mode, BTM energy storage will operate to charge with distributed solar PV as much as possible and discharge stored energy to reduce or eliminate residential or commercial load peaks. If sufficient excess stored energy remains, the energy storage will act to reduce the overall net load.
- Utility energy storage will be dispatched to flatten and reduce the net load profile of the broader electricity system, accounting for the effect of all loads, renewable generation, and committed baseload generation.

The specific scenarios modeled in HiGRID are as follows. Each of these is simulated under the 4 different projected resource mixes (SB100 Core, SB100 Study, NREL Mid, NREL Mid95 by 2030) described in detail in Section 2.2.

- Total energy storage capacity set constant at the value specified by the resource mix:
    - 0%, 20%, 40%, 60%, 80%, and 100% of projected energy storage capacity installed as BTM
- BTM storage capacity added on top of projected utility energy storage capacity:
    - +20% and +40% of projected energy storage capacity operating as BTM added to the overall resource mix

2.4.2. Scenario 2: Effect of co-locating energy storage at wind and solar farms

Energy storage capacity can also be deployed co-located at wind and solar farms instead of directly tied to the transmission grid. Since the rapid buildout of large-scale wind and solar farms are a cornerstone of strategies to decarbonize California's electricity system and comply with Senate Bill 100 goals [15], this scenario will investigate whether there is any system-wide for co-locating increasing fractions of projected energy storage capacity at wind and solar farms instead of being directly tied to the transmission grid.

Similar to the scenario for BTM storage, energy storage capacity co-located at wind and solar farms is likely to operate differently than that connected directly to the transmission grid. Co-located energy storage is likely to be installed by the developer of the wind or solar farm and will be dispatched to benefit the operation of these installations. Such storage will operate to shift wind and solar generation to be stored and exported to the grid during hours when these resources aren't inherently available and add a degree of predictability for grid operators. This can be particularly important for wind generation, which is more difficult to predict accurately on hourly and sub-hourly timescales compared to solar generation. Co-located energy storage also allows wind and solar farms to provide

From a system-wide perspective, however, substituting utility energy storage for co-located energy storage can have certain disadvantages. Specifically, co-located energy storage will only charge with electricity produced by the wind or solar farm to which they are connected instead of being able to draw on combined wind and solar generation in the case of utility energy storage. This consequently limits the extent to which co-located energy storage capacity can affect the system-wide net load profile compared to the same amount of capacity installed as utility energy storage.

The co-location of energy storage at wind and solar farms, however, does allow such systems to take advantage of the existing interconnection infrastructure of the wind or solar farm that it is located at. From a practical perspective, this reduces procedural barriers for siting and permitting, since separate siting and permitting considerations for the energy storage system can be avoided.

Similar to the BTM energy storage scenario, this scenario seeks to understand the effect of substituting increasing fractions of planned utility energy storage capacity for energy storage capacity co-located at large-scale wind and solar farms on the zero-carbon penetration, average cost of electricity, and curtailed renewable energy from the system-wide perspective, not the wind and solar farm owner/operator perspective.

With these considerations, we make the following assumptions for the costs and dispatch of co-located energy storage at wind and solar farms:

- **General assumptions:**
    - Energy storage co-located at wind or solar farms is modeled as 4-hour lithium-ion battery energy storage at utility scale capacities.
    - Utility energy storage is modeled as 4-hour lithium-ion battery energy storage with a nominal power capacity of 10 MW per installation.
    - Cost, efficiency, and lifetime parameters are further described in Section 2.1.
- **Scenario-specific cost assumptions:**
    - Similar to the BTM scenario, the costs of grid integration as specified by Mongird et al [5] are subtracted from the capital cost parameters for co-located energy storage at wind and solar farms. These range from $25-$31/kW for the year 2030 and $20-25/kW for the year 2045. This accounts for the ability of co-located energy storage at wind and solar farms
- **Scenario-specific dispatch assumptions:**
    - The capacity of energy storage co-located at wind or solar farms will be dispatched to charge with wind or solar generation from their specific installation that would otherwise be curtailed to prevent overproduction on the grid and discharge when wind or solar generation is low or zero.
    - Utility energy storage will be dispatched to flatten and reduce the net load profile of the broader electricity system, accounting for the effect of all loads, renewable generation, and committed baseload generation.

The specific scenarios modeled in HiGRID are as follows. Each of these is simulated under the 4 different projected resource mixes (SB100 Core, SB100 Study, NREL Mid, NREL Mid95 by 2030) described in detail in Section 2.2.

- Total energy storage capacity set constant at value specified by the resource mix:

- 0%, 20%, 40%, 60%, 80%, and 100% of projected energy storage capacity installed as co-located at utility-scale solar farms.
- 0%, 20%, 40%, 60%, 80%, and 100% of projected energy storage capacity installed as co-located at utility-scale wind farms.

2.4.3. Scenario 3: Effect of technology substitution for grid-connected energy storage

Planning studies for meeting regional electricity decarbonization goals specify the rollout of energy storage as a critical part of the required resource portfolios to comply with such goals. These studies, such as that for California's SB 100 goal, represent energy storage using leading incumbent technologies. For short-duration storage (less than or equal to 10 hours of storage at rated discharge), this functionality is typically represented by lithium-ion battery technology due to its relatively low cost (current and projected), high round-trip efficiency, and its large market share due to co-development from electric vehicles. For long-duration storage, pumped hydropower energy storage is typically used to represent this functionality due to its relative maturity compared to other long-duration energy storage types (i.e. hydrogen, compressed air, etc…).

Other energy storage technologies (non-lithium-ion) are emerging for short-duration energy storage that can provide other benefits. For example, flow battery energy storage can potentially 1) be safer in operation compared to lithium-ion batteries due to reduced risk of fires 2) are expected to experience relatively lower capacity degradation for an equivalent number of cycles, and 3) can be more easily sized for power-centric or energy-centric applications as needed compared to conventional batteries. Flow batteries, however, currently come with the disadvantages of higher upfront costs and lower energy efficiency. Therefore, here we will conduct simulations that will increase the share of flow battery energy storage in the short-duration energy storage portfolio and track the effects on the electricity costs associated with achieving a given zero-carbon electricity penetration.

Since the long-duration energy storage is represented as pumped hydropower in the reference planning studies, which is largely already existing capacity that is not expected to be retired. The study carried out for SB 100 Joint Agency Report places limits on pumped hydropower expansion in California, likely due to concerns regarding the expansion of hydropower capacity on ecological conditions in the State's rivers. Therefore, for long-duration storage, we will investigate how the addition of capacity consisting of alternative long-duration energy storage technologies on top of the specified pumped hydropower capacities will affect electricity costs associated with achieving a given zero-carbon electricity penetration level. This differs from the approach for short-duration energy storage in that alternative technologies will not substitute for existing technologies, but rather add to them.

The dispatch priority of the alternative short- and long-duration energy storage technologies will be similar to that of the technologies specified in the corresponding electricity resource mix. These alternative technologies may produce different charge/discharge profiles due to differences in their technical characteristics, but they will respond to the same objective function as the reference technologies since both will be installed as utility energy storage.

With these considerations, we make the following assumptions for the costs and dispatch of alternative technologies for short- and long-duration energy storage:

- **General assumptions:**
  - Utility lithium-ion energy storage is modeled as 4-hour duration storage with a nominal power capacity of 10 MW per installation.
  - Flow batteries will be represented by vanadium redox flow battery technology with a 10-hour storage duration. Vanadium redox flow batteries are currently the most mature flow battery technology for which the largest amount of data on costs and performance exists.
  - Alternative long-duration energy storage will be represented by hydrogen energy storage consisting of proton exchange membrane (PEM) electrolyzers, underground storage, and a PEM fuel cell.
  - Cost, efficiency, and lifetime parameters are further described in Section 2.1.
- **Scenario-specific cost assumptions:**
  - No scenario-specific cost assumptions differ between the technologies other than their input cost parameters, since all of the considered technologies will be installed as utility energy storage.
- **Scenario-specific dispatch assumptions:**
  - All energy storage technologies will be dispatched to flatten and reduce the net load profile of the broader electricity system, accounting for the effect of all loads, renewable generation, and committed baseload generation.

The specific scenarios modeled in HiGRID are as follows. Each of these is simulated under the 4 different projected resource mixes (SB100 Core, SB100 Study, NREL Mid, NREL Mid95 by 2030) described in detail in Section 2.2.

- Short-duration energy storage
  - 0%, 20%, 40%, 60%, 80%, and 100% of projected utility-scale lithium-ion battery power capacity substituted for vanadium redox flow batteries.
- Long-duration energy storage
  - 0%, 10%, 20%, 30%, 40%, and 50% of projected pumped hydropower energy storage power capacity added to the system as hydrogen energy storage.

3. Scenario Results

This section presents the effect of the different energy storage scenarios on the system-wide zero-carbon electricity penetration, cost of electricity per-unit delivered, and renewable curtailment for California's electricity system. Here, results are presented for the projected resource mix in the SB100 Core scenario, described in Section 2.2, then the effects of using different resource mixes are presented as a sensitivity.

3.1. Year 2030 Results

3.1.1. Behind-the-meter (BTM) energy storage

The effect of substituting projected utility-scale energy storage in 2030 for BTM energy storage or adding BTM energy storage to projected utility-scale energy storage is presented in Figure 1 for zero-carbon electricity penetration, Figure 2 for renewable curtailment, and Figure 3 for the cost of electricity.

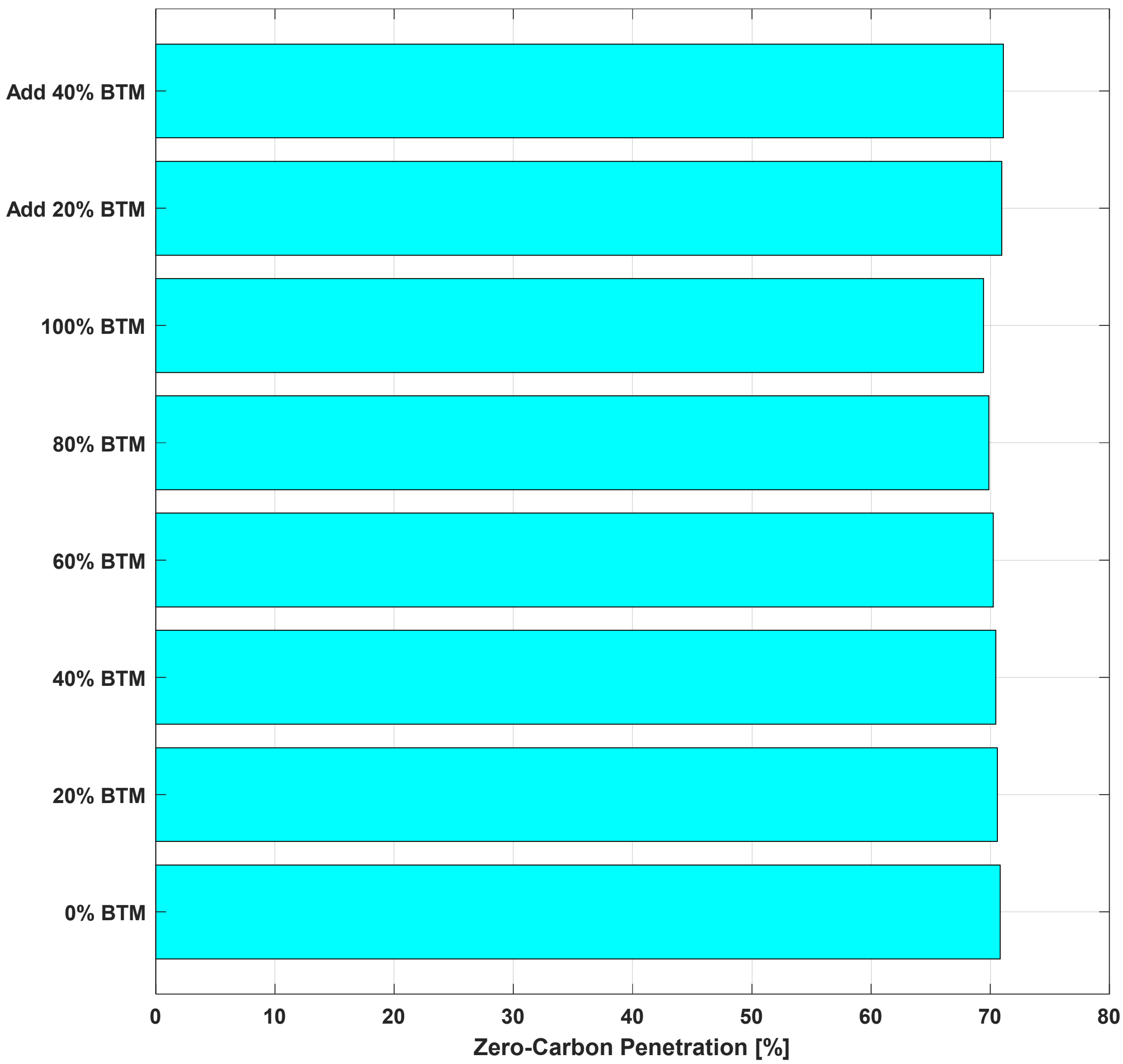

Figure 1 - System-wide zero-carbon electricity penetration for BTM energy storage cases [% of total annual electricity generation] in 2030

Substituting utility energy storage with BTM energy storage of equivalent capacity acts to decrease the system-wide zero-carbon electricity penetration. When all energy storage is installed as utility energy storage (0% BTM), the zero-carbon electricity penetration is 70.8%. This drops to 69.4% when all utility energy storage capacity is substituted for BTM energy storage capacity (100% BTM). This occurs due to differences in the priorities of how energy storage is dispatched causing conflict. Utility energy storage receives full information on generation and loads on the whole system and can charge or discharge accordingly, meaning it can operate to shape the system-wide net load. BTM energy storage operates to serve the interests of the individual residential, commercial, and industrial customers to which it is connected. Therefore, BTM energy storage can end up charging or discharging when it would be detrimental to the broader electricity system. This causes the system-wide zero-carbon electricity penetration to decrease when BTM energy storage replaces utility energy storage, even though BTM energy storage provides the benefit of reduced losses from energy storage charge or discharge not being placed onto the transmission system.

Adding BTM energy storage to projected utility energy storage capacity increases the system-wide zero-carbon electricity penetration by up to 0.27 percentage points. The added energy storage capacity enables the system to shift excess renewable generation over longer timescales.

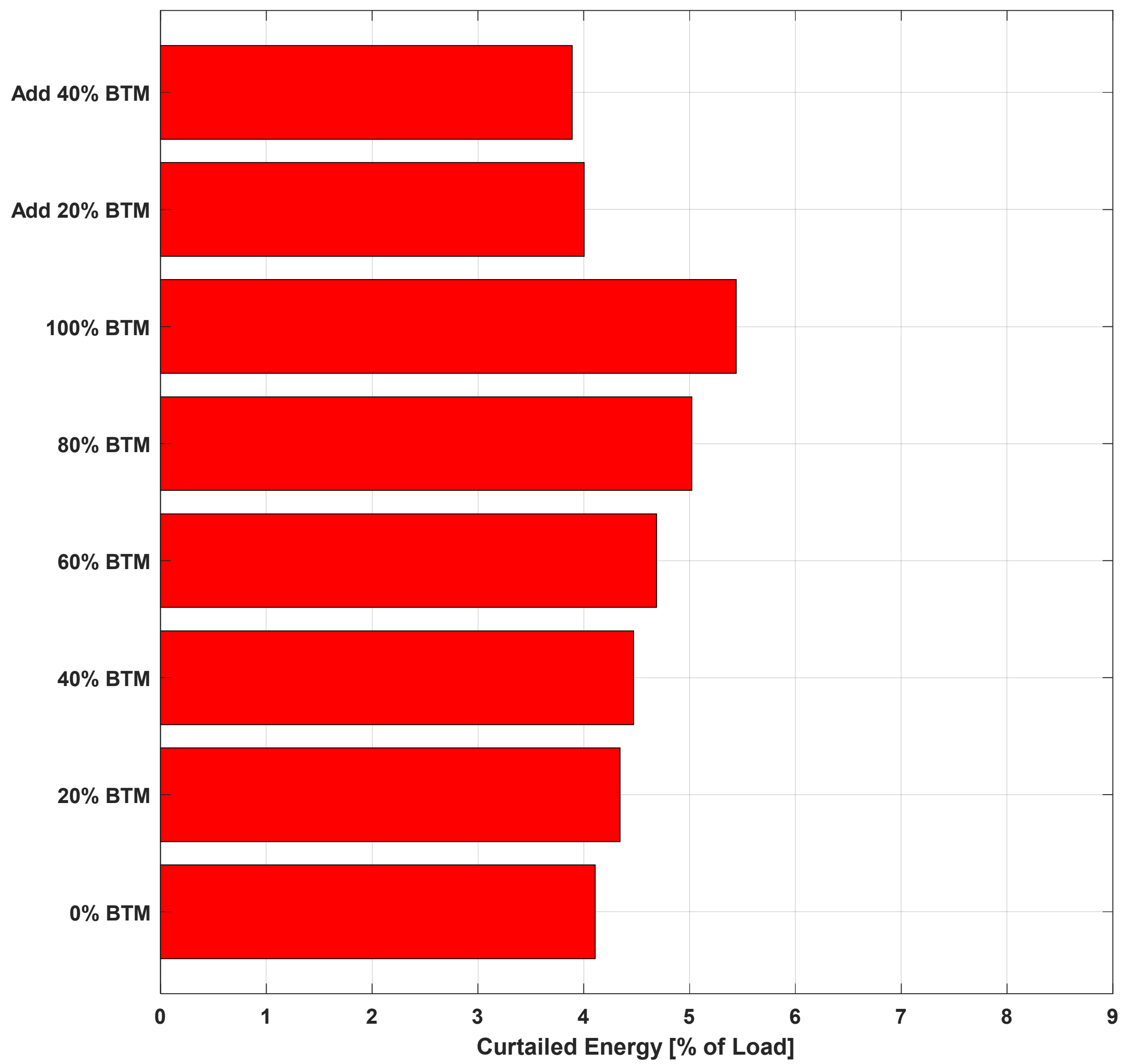

Figure 2 - System-wide renewable curtailment for BTM energy storage cases (% of annual load) in 2030

The results for the zero-carbon electricity penetration effects are reflected in the trends for curtailed renewable energy. Substituting utility energy storage for BTM energy storage increases curtailed renewable energy due to the conflict in dispatch priorities of energy storage. Adding BTM energy storage on top of utility energy storage reduces curtailed renewable energy by a small amount.

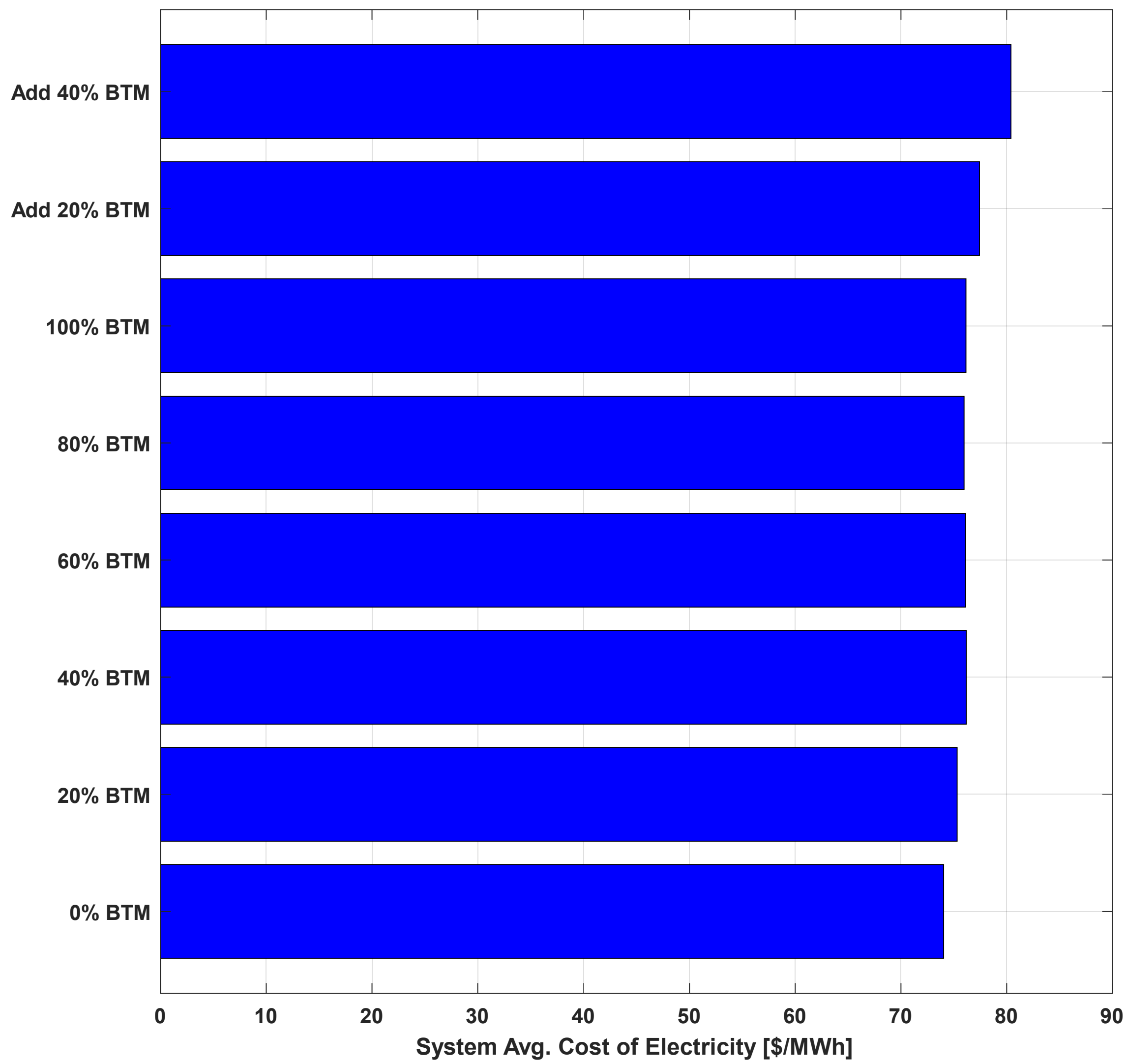

Figure 3 - System-wide average cost of electricity for BTM energy storage cases in 2030 [$/MWh]

Both substituting utility energy storage for BTM energy storage and adding BTM energy storage on top of utility energy storage increase electricity costs. For the substitution cases, the capital costs of BTM energy storage are higher than that for utility energy storage even with the assumed subtraction of grid integration costs, but other resources need to be used (i.e. natural gas) to ensure the broader electric load is satisfied when BTM energy storage dispatches in ways that do not directly address the needs of the broader system. For the addition cases, the added capital cost of additional energy storage capacity increases costs since the added energy storage has minimal effect on enabling the system to operate more efficiently or have a greater reliance on cheaper electricity generation sources.

These results are strongly dependent on assumed grid integration costs. We use the grid integration costs from the study by Mongird et al [5], consistent with other cost parameters. The specified grid integration costs from this source are less than 5% of the total installed cost for a given technology. In practice, grid integration costs can be higher, in which case increasing BTM energy storage can potentially provide a system-wide cost benefit. For example, grid integration costs specified by the California Energy Commission for lithium-ion batteries [16] are roughly one order of magnitude higher than that specified by Mongird et al [5]. However, grid integration costs from different sources account for different factors, and these need to be harmonized to narrow down more accurate values.

The sensitivity of the BTM energy storage cases to different projected resource mixes is presented in Figure 4 for zero-carbon penetration, Figure 5 for renewable curtailment, and Figure 6 for system cost of electricity. Note that these values are presented as percentage deviations from the base (0% BTM) value achieved in each resource mix.

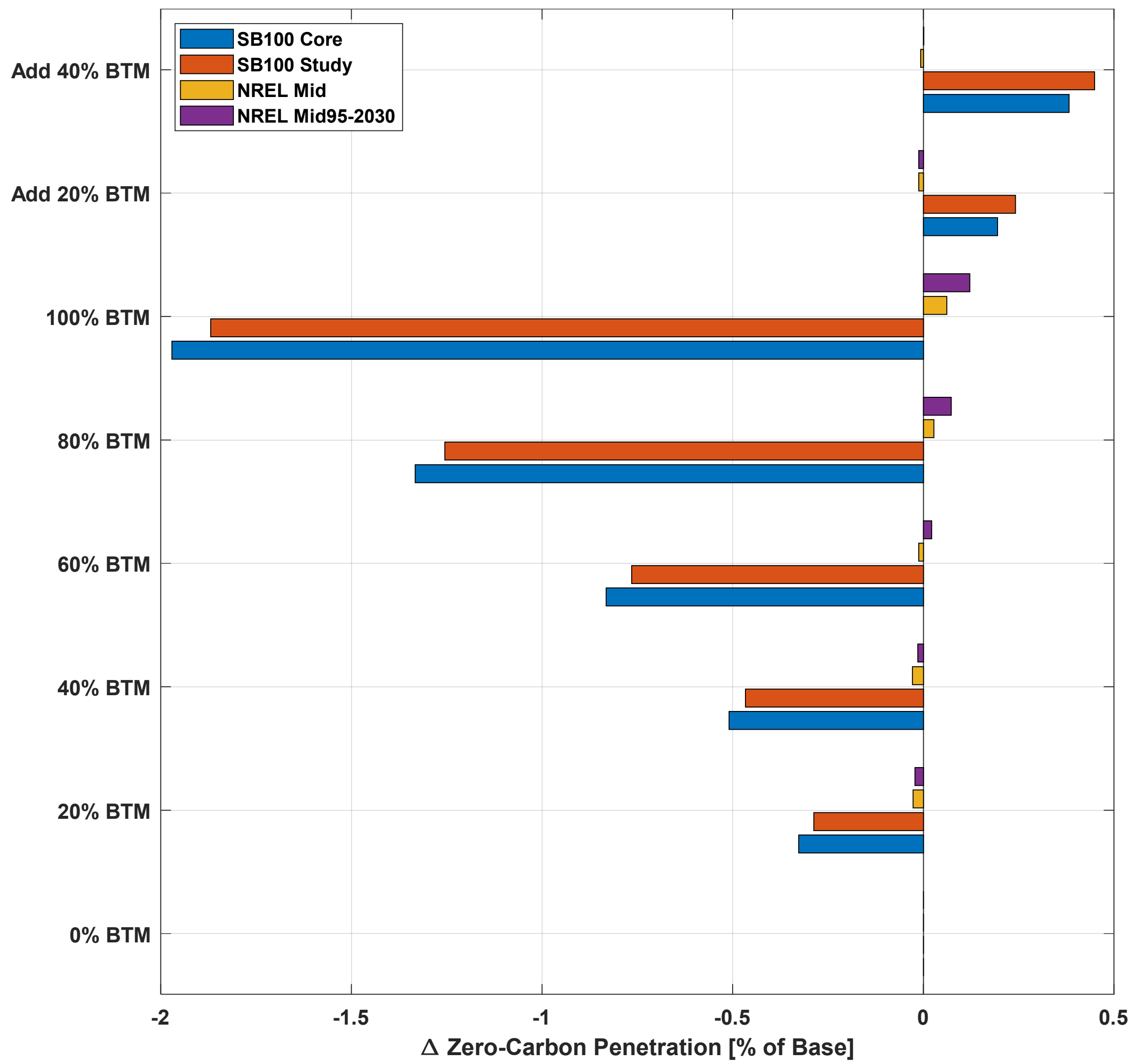

Figure 4 - Sensitivity of system-wide zero-carbon electricity penetration to different projected electricity resource mixes in 2030 for BTM energy storage cases [% of base value for each resource mix]

The SB100 Study resource mix represents increased zero-carbon generation and storage capacity relative to the SB100 Core mix, to ensure that additional components of total electric load are met by zero-carbon generation. When BTM energy storage is substituted in the SB 100 Study mix, the effects on zero-carbon penetration follow similar trends to that of the SB100 Core results by decreasing zero-carbon penetration. Adding energy storage increases zero-carbon penetration very slightly by enabling additional excess renewable energy uptake.

The two resource mixes from the 2021 NREL Standard Scenarios show little to no change from the 0% BTM value as BTM energy storage is substituted or added. This occurs since these resource mixes specify lower zero-carbon electricity generation and storage capacity compared to the SB 100 mixes and subsequently, do not have significant renewable curtailment to start with, especially in 2030. Therefore, adding or substituting energy storage capacity does not have much renewable curtailment to handle.

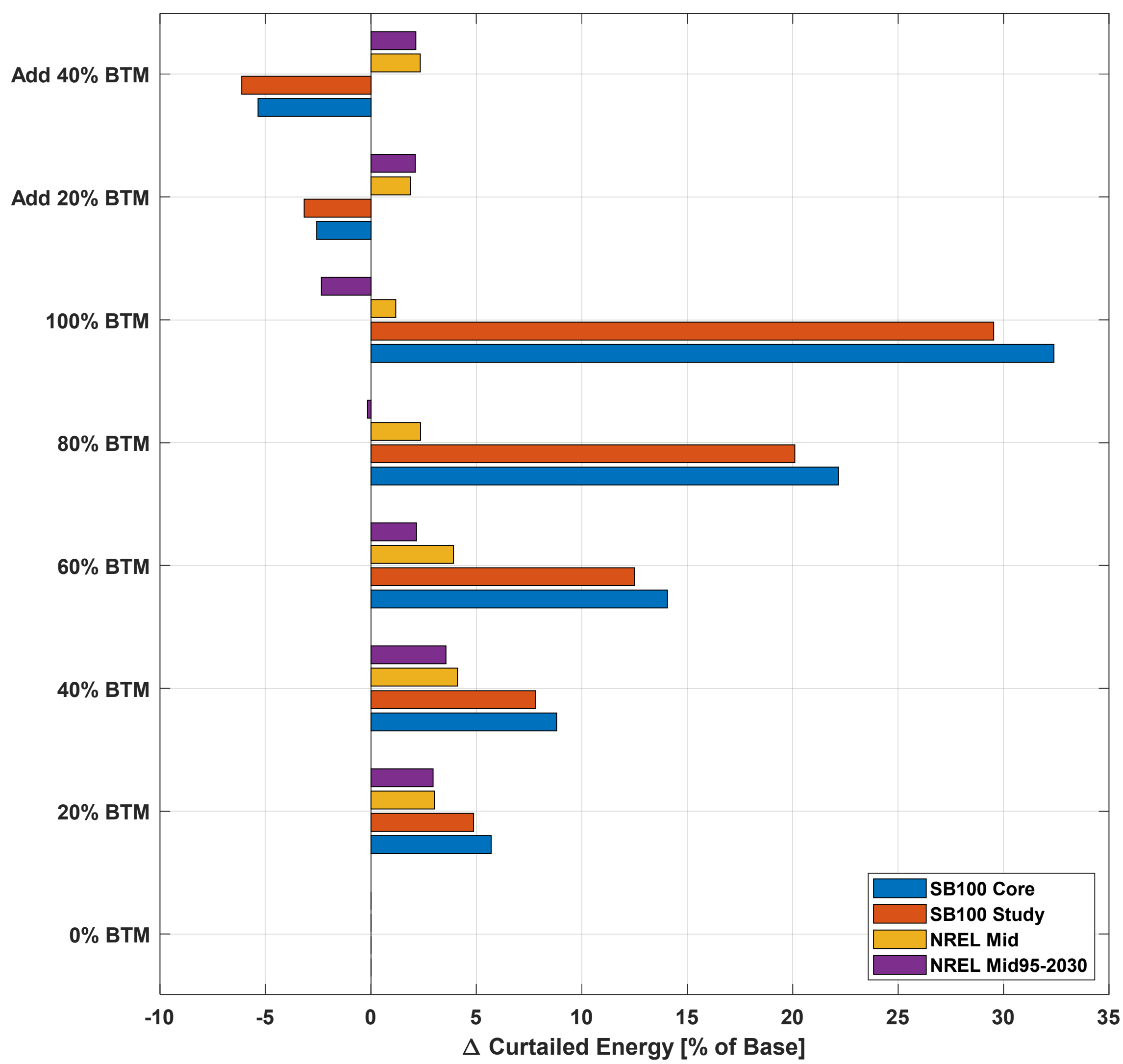

Figure 5 - Sensitivity of curtailed renewable energy electricity to different projected electricity resource mixes in 2030 for BTM energy storage cases [% of base value for each resource mix]

For all of the considered resource mixes, substituting utility energy storage for BTM energy storage increases curtailed renewable energy, consistent with the effects on zero-carbon electricity penetration. For the addition of BTM energy storage, the SB100 resource show reduced curtailed renewable energy while the resource mixes from the NREL Standard Scenarios show slight increases.

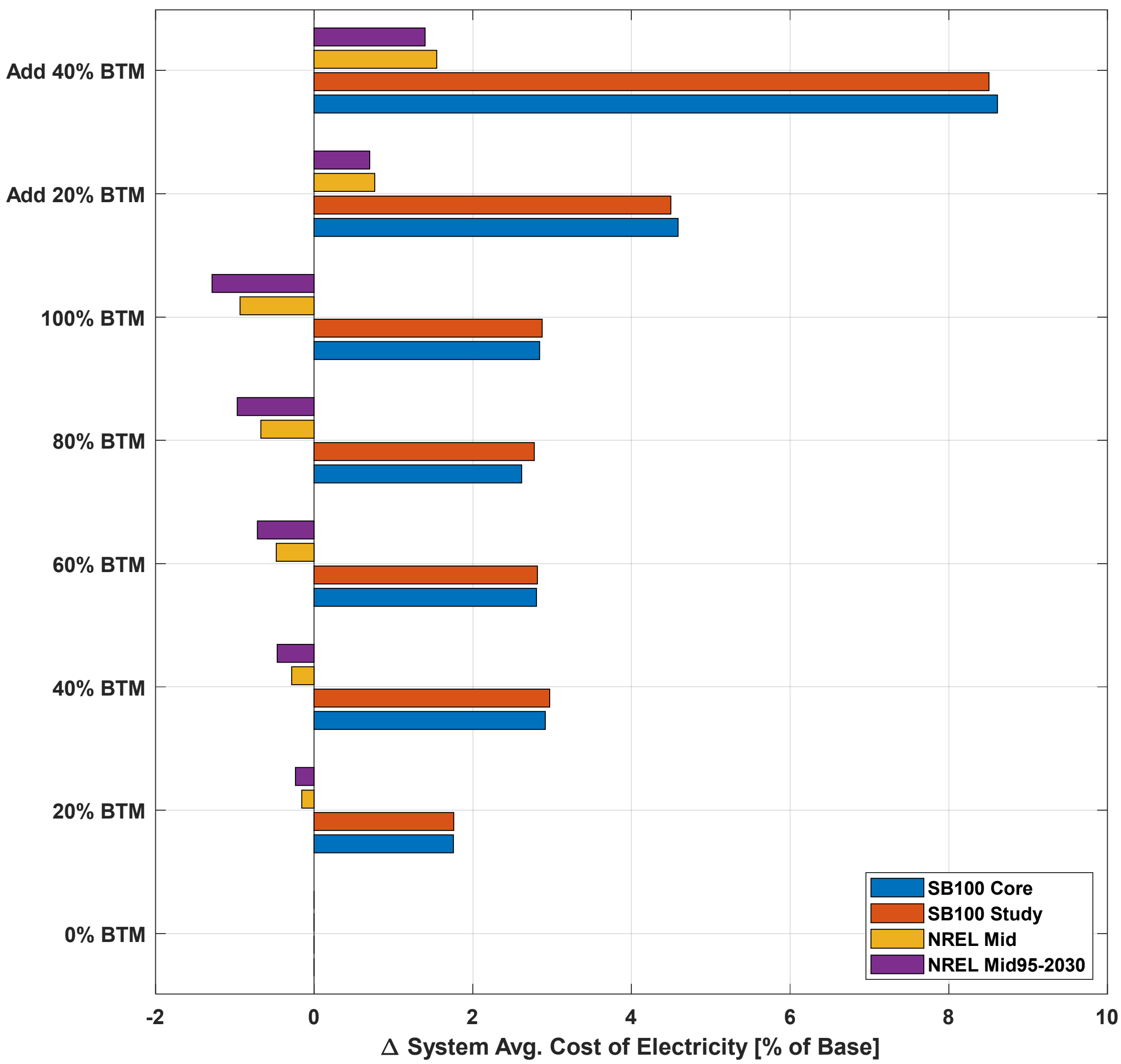

Figure 6 - Sensitivity of system-wide average cost of electricity to different projected electricity resource mixes in 2030 for BTM energy storage cases [% of base value for each resource mix]

For the system-wide average cost of electricity, the SB100 Study resource mix shows similar increases in costs compared to the SB100 Core results. The resource mixes from the NREL standard scenarios show very slightly decreased costs compared to their base values for the substitution cases. This occurs since these scenarios have low renewable curtailment to being with, therefore energy storage just acts to enable other electricity resources to operate more steadily and with higher capacity factors, reducing costs slightly. For the addition cases, the NREL mixes show slightly increased costs due to the additional cost of more energy storage capacity.

3.1.2. Co-located energy storage at wind farms

The effect of substituting projected utility-scale energy storage in 2030 with energy storage co-located at large-scale wind farms is presented in Figure 4 for zero-carbon electricity penetration, Figure 5 for renewable curtailment, and Figure 6 for the cost of electricity.

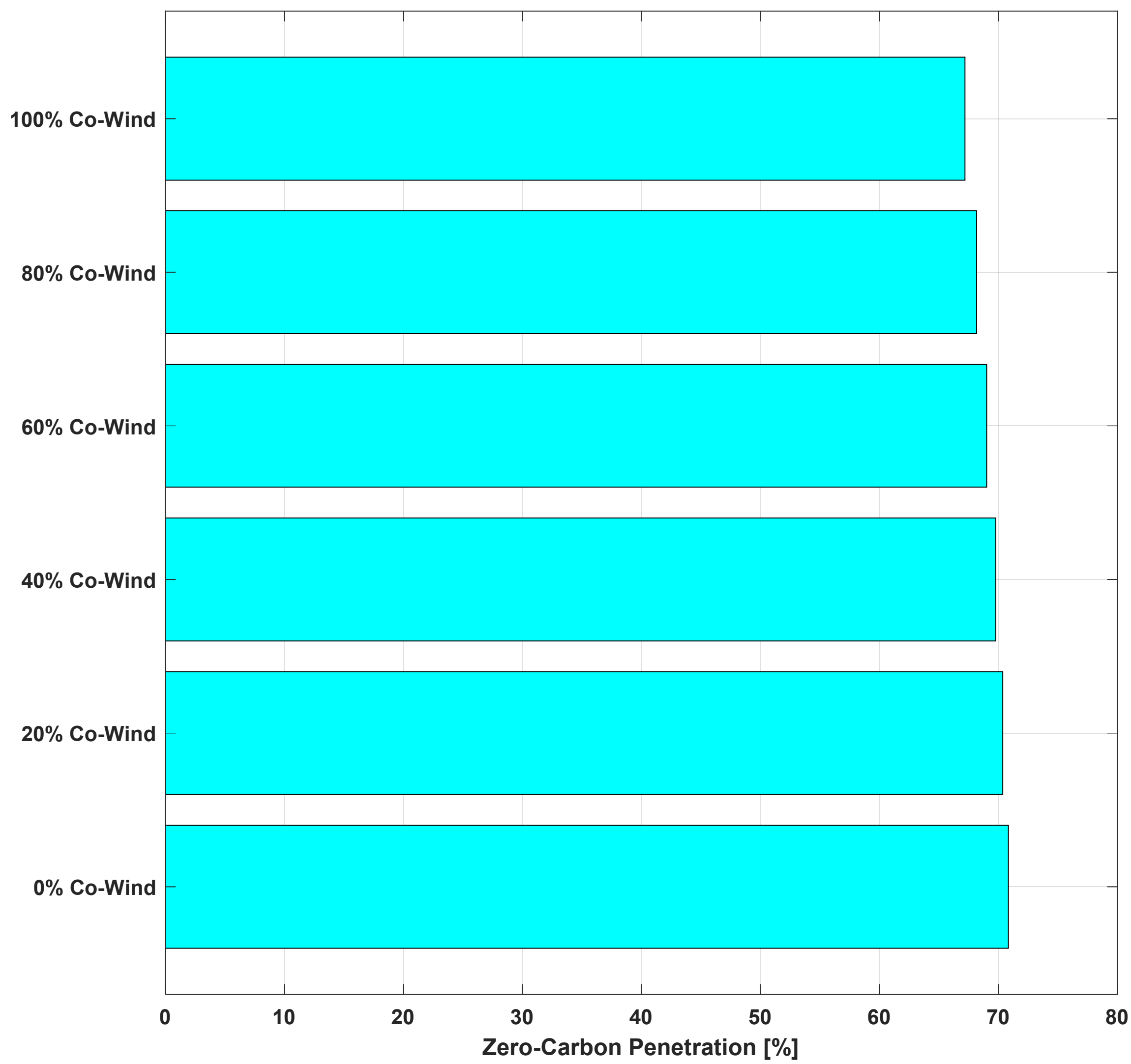

Figure 7 - System-wide zero-carbon electricity penetration for wind farm co-location energy storage cases [% of total annual electricity generation] in 2030

Replacing utility energy storage capacity for an equivalent capacity of energy storage co-located at wind farms acts to decrease the system-wide zero-carbon electricity penetration from 70.8% (all utility energy storage) to 67.1% (all wind co-located energy storage). This occurs since energy storage co-located at wind farms can only charge with wind generation and cannot aid the broader grid in managing excess solar generation. In the SB100 Core resource mix, both large-scale and distributed solar PV capacity comprise most of the renewable resource capacity. The generation profile of these resources concentrates their excess generation during the middle of the day. Removing utility energy storage that can charge with wind and/or solar and aid in managing their combined behavior and replacing it with the equivalent energy storage capacity that can only manage wind variability, will expectedly cause a decrease in system-wide zero-carbon electricity penetration.

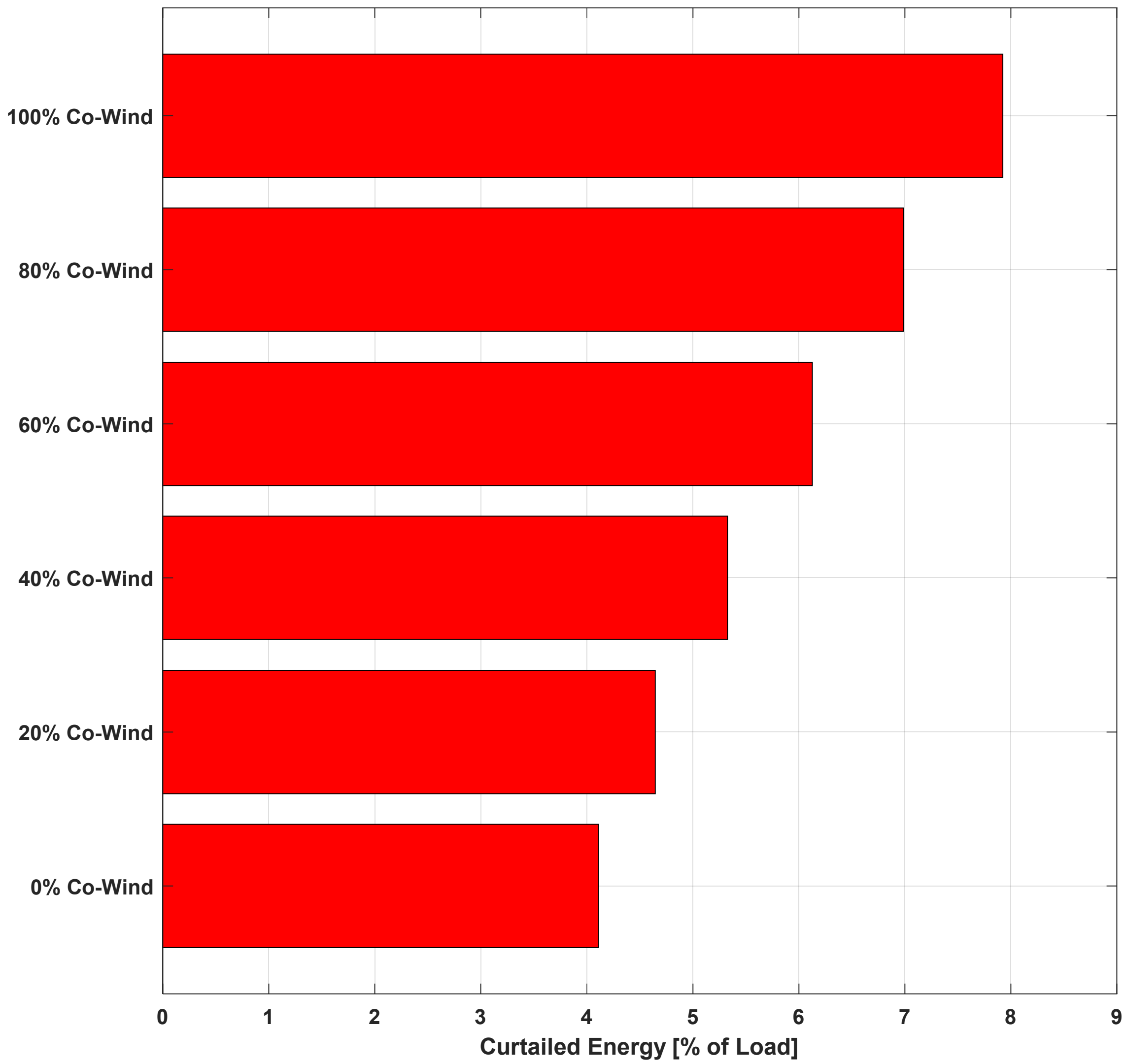

Figure 8 - System-wide renewable curtailment for wind farm co-location energy storage cases (% of annual load) in 2030

The limitations on energy storage co-located at wind farms to respond to the combined dynamics of wind and solar on the broader electricity system result in increased renewable energy curtailment, from 4.1% of annual load equivalent (all utility energy storage) to 7.9% of annual load equivalent (all co-located energy storage at wind farms).

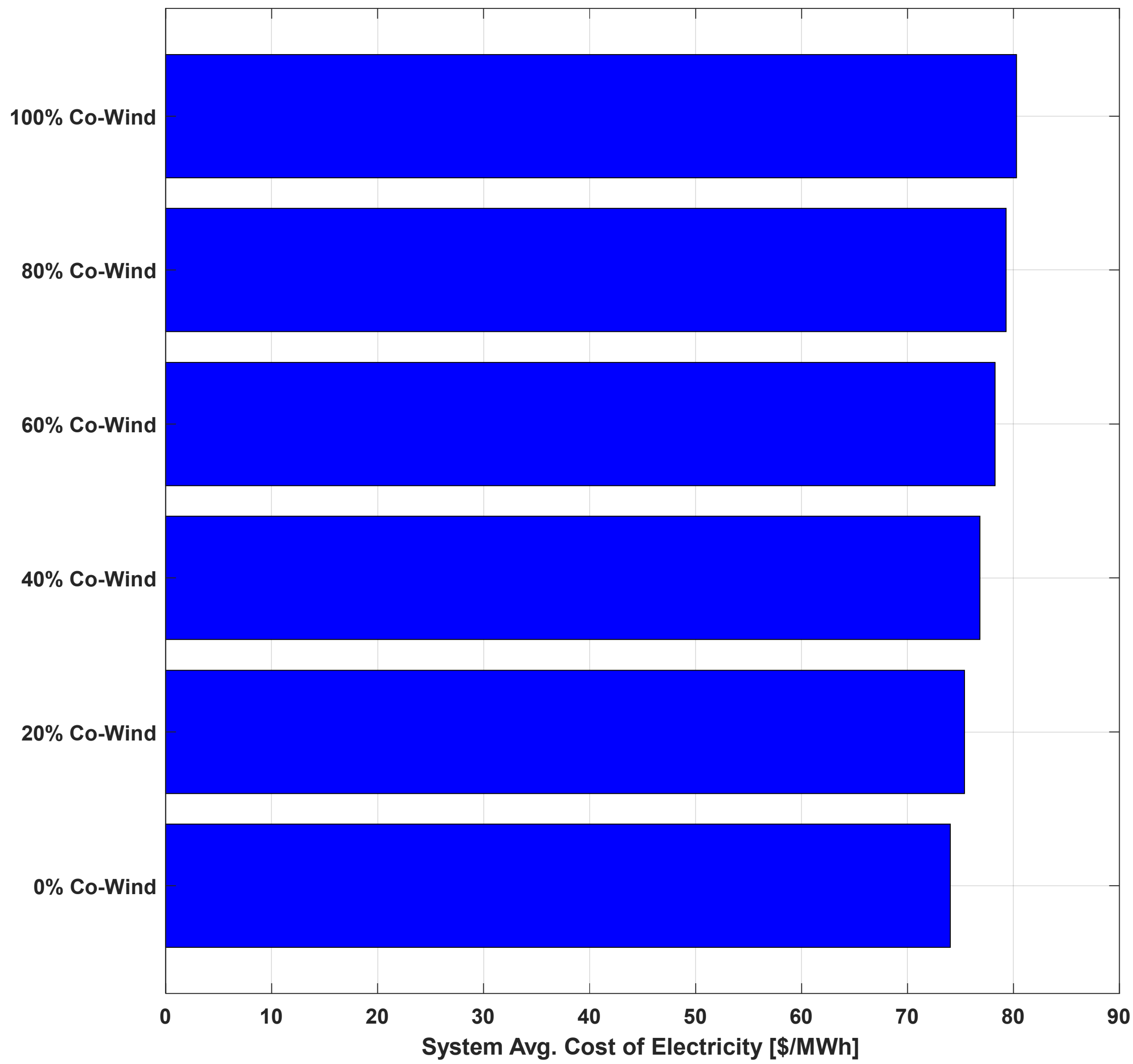

Figure 9 - System-wide average cost of electricity for wind farm co-location energy storage cases in 2030 [$/MWh]

The reduction in the system's ability to capture excess solar generation when more energy storage is co-located at wind farms means that other resources such as expensive natural gas peaking power plants are called upon to ensure that the system-wide electric load profile is satisfied. This results in increases in the system-wide average cost of electricity.

The sensitivity of the wind farm co-location energy storage cases to different projected resource mixes is presented in Figure 7 for zero-carbon penetration, Figure 8 for renewable curtailment, and Figure 9 for system cost of electricity. Note that these values are presented as percentage deviations from the base (0% Co-location) value achieved in each resource mix.

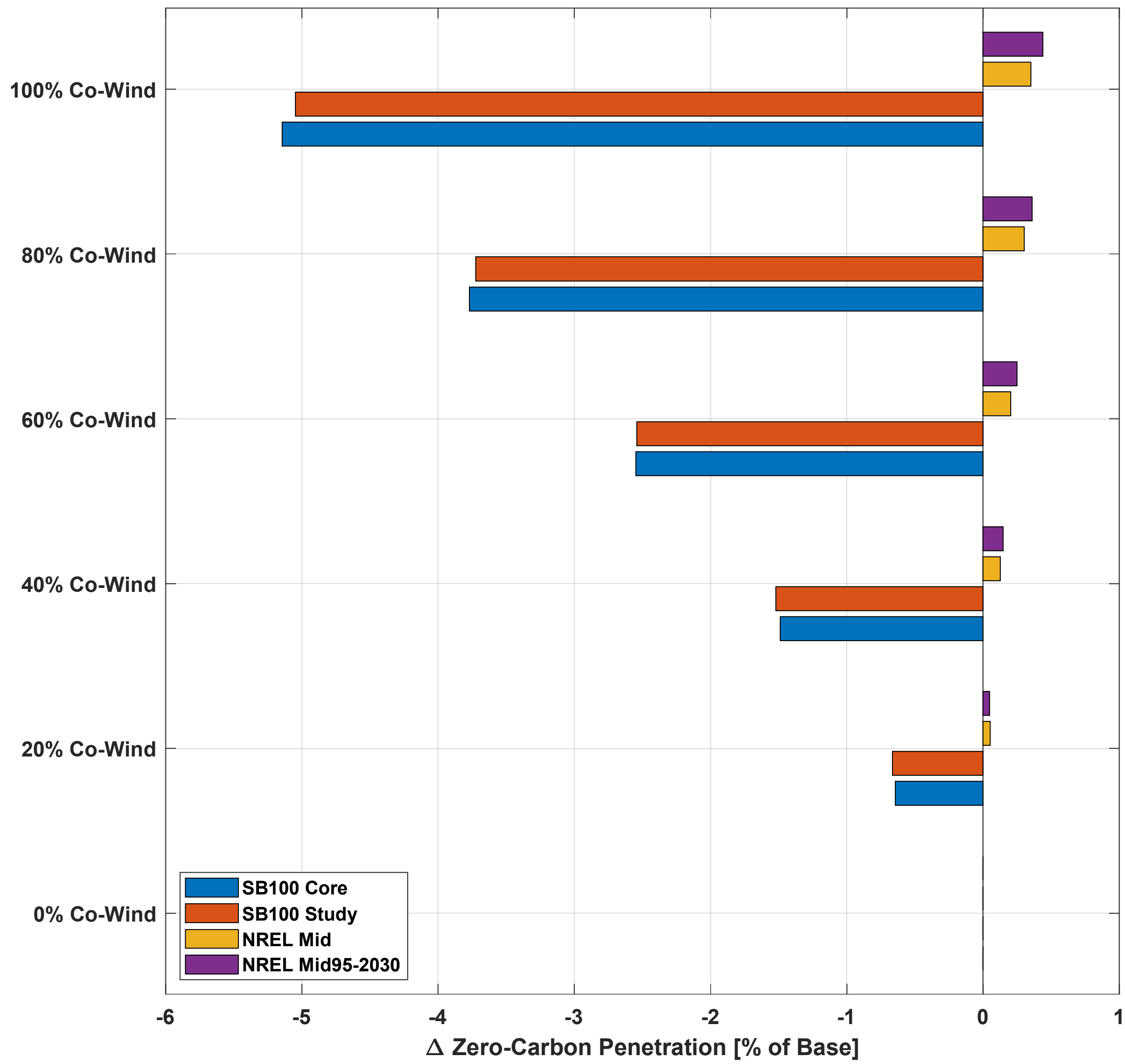

Figure 10 - Sensitivity of system-wide zero-carbon electricity penetration to different projected electricity resource mixes in 2030 for wind farm co-location energy storage cases [% of base value for each resource mix]

The SB100 resource mixes behave similarly when utility energy storage is replaced by energy storage co-located at wind farms in that the zero-carbon electricity penetration decreases. The mixes from the NREL Standard Scenarios by contrast show small increases in zero-carbon electricity penetration since wind resource capacity is larger in these mixes than in the SB100 mixes and solar resource capacity is lower. The reduced ability of the system to manage solar variability is not as detrimental since these mixes are more wind-reliant, meaning that co-locating energy storage at wind farms can still provide a benefit. The reduced losses from co-locating energy storage at wind farms due to avoiding separate transformer and transmission losses from the wind farm and energy storage systems enable the zero-carbon penetration to increase very slightly.

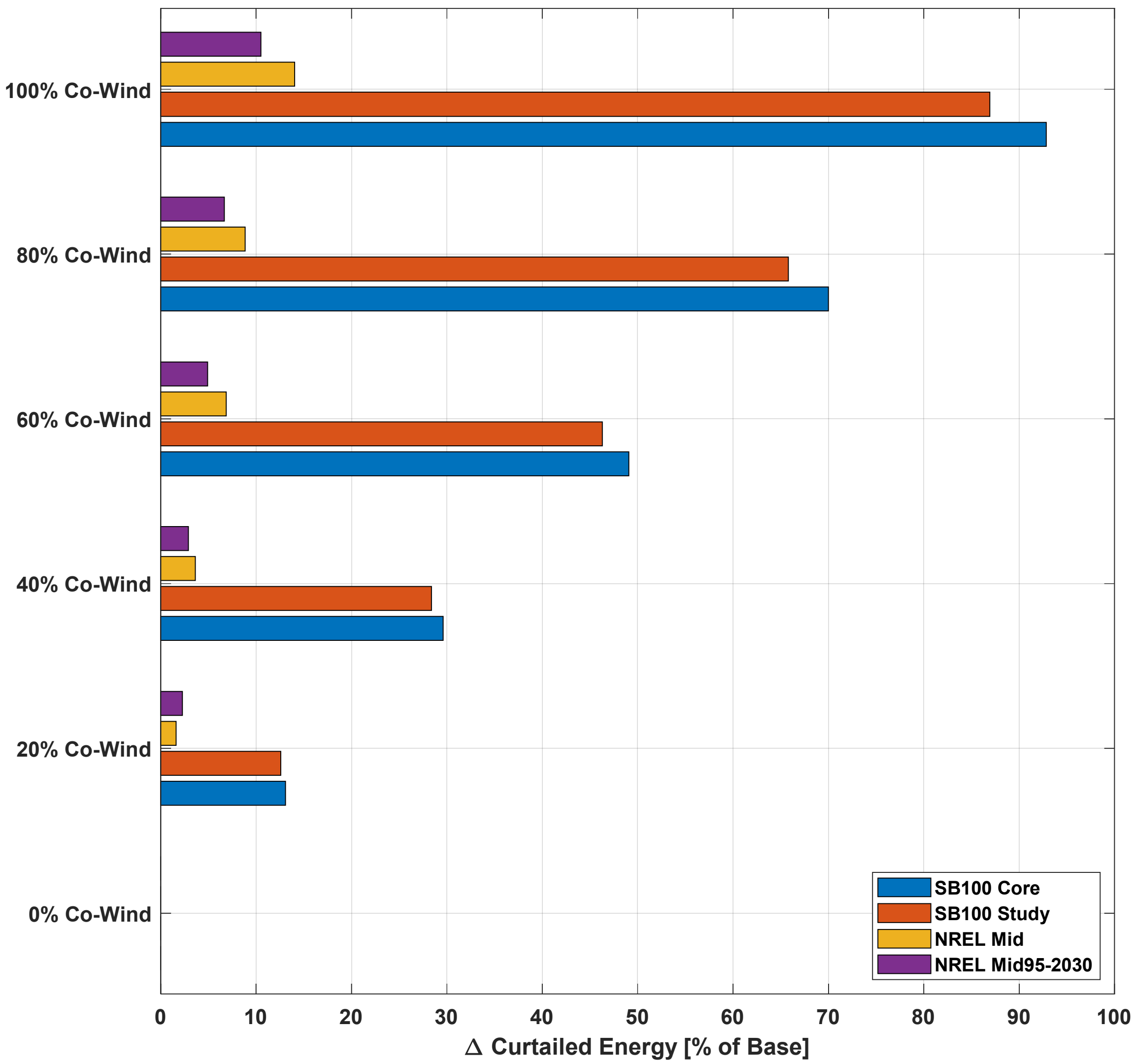

Figure 11 - Sensitivity of curtailed renewable energy electricity to different projected electricity resource mixes in 2030 for wind farm co-location energy storage cases [% of base value for each resource mix]

All four resource mixes exhibit increased renewable energy curtailment when utility energy storage is replaced with energy storage co-located at wind farms. The relative effect is larger for the SB100 mixes than the NREL mixes, due to the larger presence of solar resources in the former exacerbating the extent to which losing the ability to manage solar generation affects the overall system.

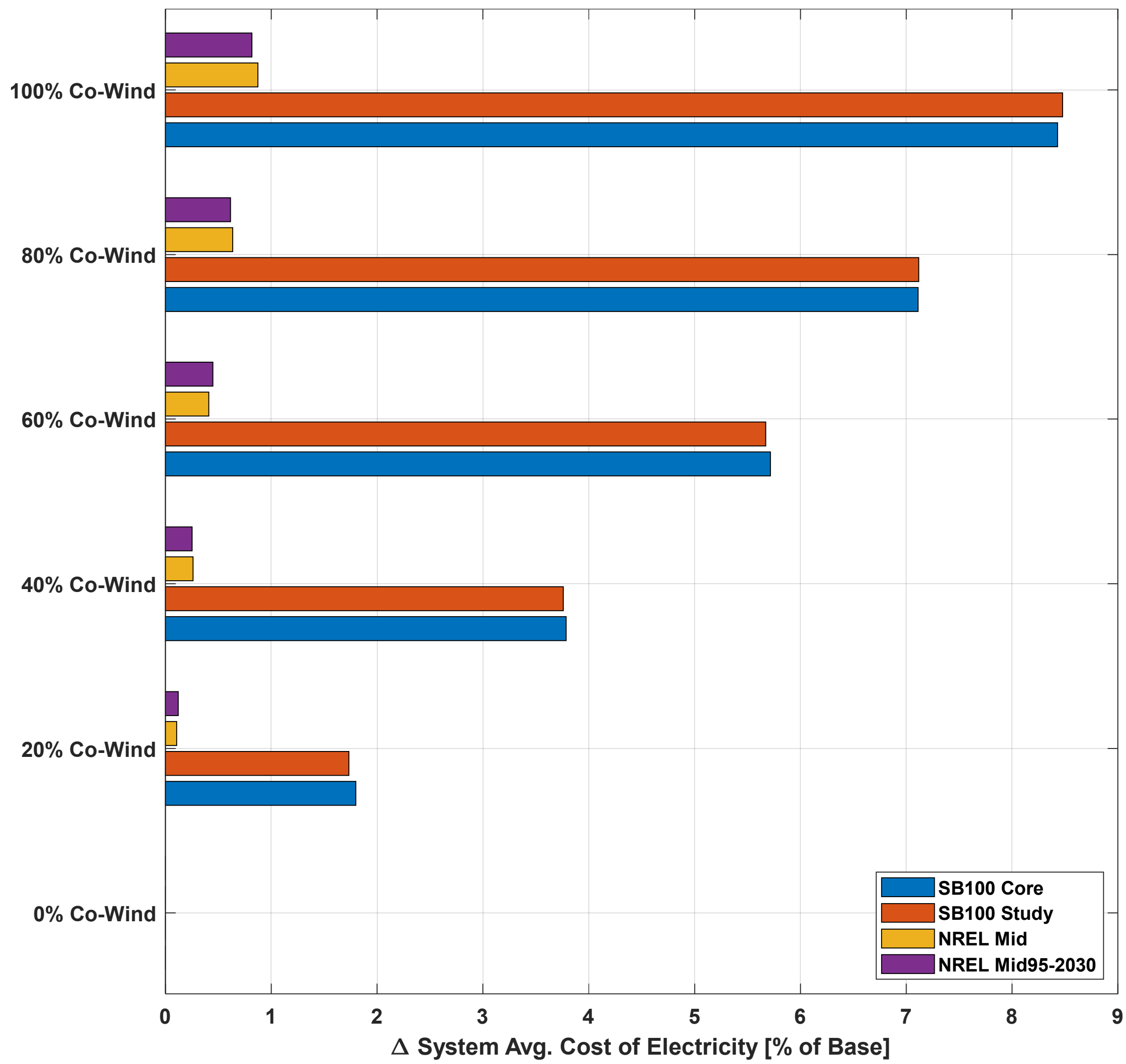

Figure 12 - Sensitivity of system-wide average cost of electricity to different projected electricity resource mixes in 2030 for wind farm co-location energy storage cases [% of base value for each resource mix]

All four of the considered resource mixes show the cost of electricity increases as more utility energy storage is replaced with energy storage co-located at wind farms. The SB100 resource mixes show a larger relative increase since the reduced ability to manage excess solar generation requires more other resources to be used to balance system-wide generation and load.

3.1.3. Co-located energy storage at solar farms

The effect of substituting projected utility-scale energy storage in 2045 with energy storage co-located at large-scale solar farms is presented in Figure 13 for zero-carbon electricity penetration, Figure 14 for renewable curtailment, and Figure 15 for the cost of electricity.

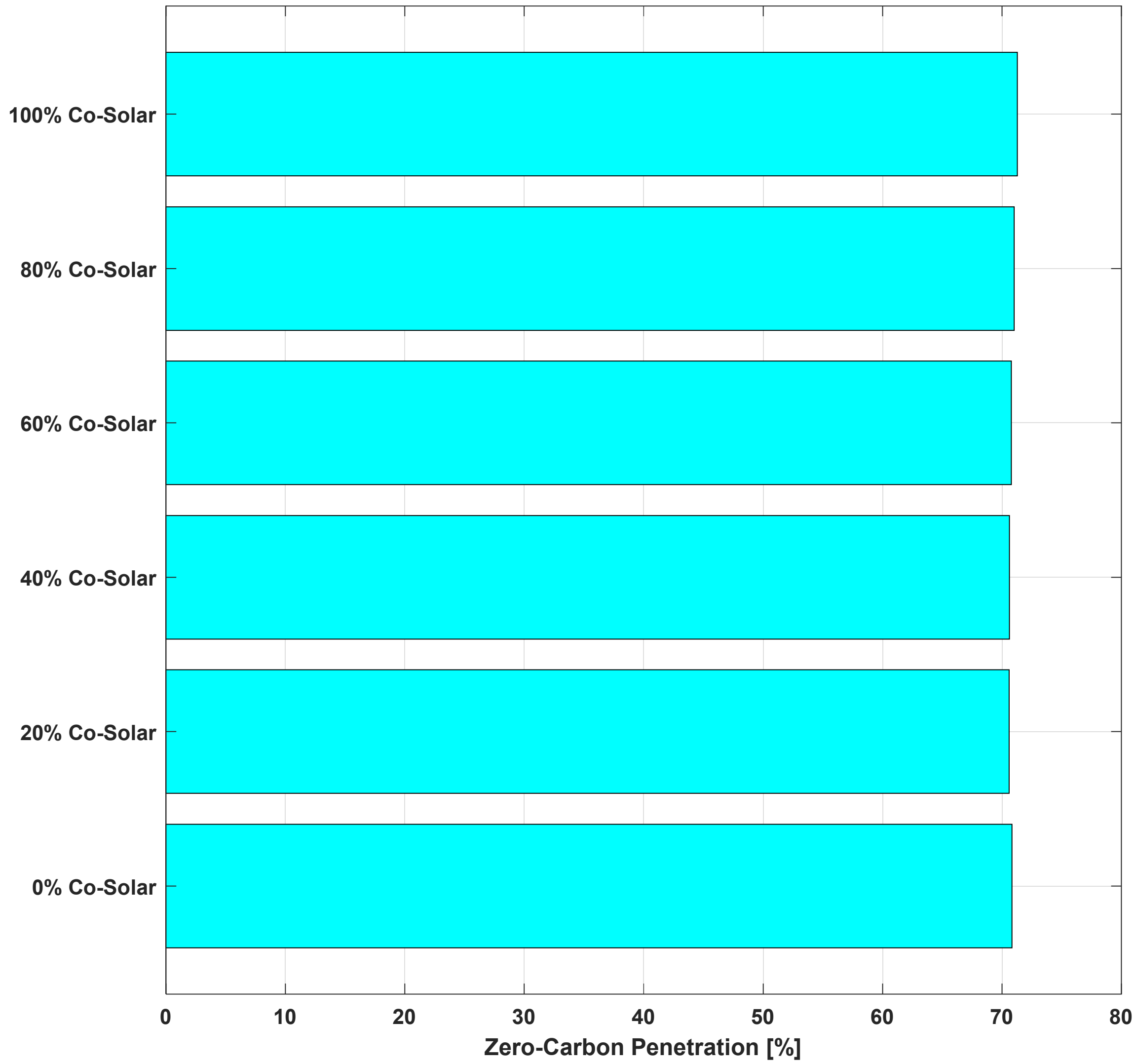

Figure 13 - System-wide zero-carbon electricity penetration for solar farm co-location energy storage cases [% of total annual electricity generation] in 2030

The effect of replacing utility energy storage with energy storage co-located at large-scale solar farms on system-wide zero-carbon electricity penetration is small and varied. Two factors are at play. First, energy storage capacity co-located at solar farms is only capable of managing excess solar generation from the facilities that they are sited at, whereas utility energy storage can manage excess solar and wind generation. This factor would cause the zero-carbon electricity penetration to decrease. Second, energy storage co-located at solar farms enables the energy storage system to avoid losses from separate conversion to high voltage AC to connect to the transmission system and can manage solar generation more directly. This factor causes the zero-carbon electricity penetration to increase.

As some utility energy storage capacity is initially replaced by energy storage co-located at solar farms, the system-wide zero-carbon electricity penetration decreases slightly, with the lowest value (70.5%) occurring at the 20% capacity replacement level. As more utility energy storage capacity is replaced by energy storage co-located at solar farms, the system-wide zero-carbon electricity penetration starts to increase until 100% of utility energy storage capacity is replaced.

When 100% of utility energy storage capacity is replaced with energy storage capacity co-located at solar farms, the system-wide zero carbon penetration (71.3%) is slightly higher than the case with no co-located energy storage (70.8%).

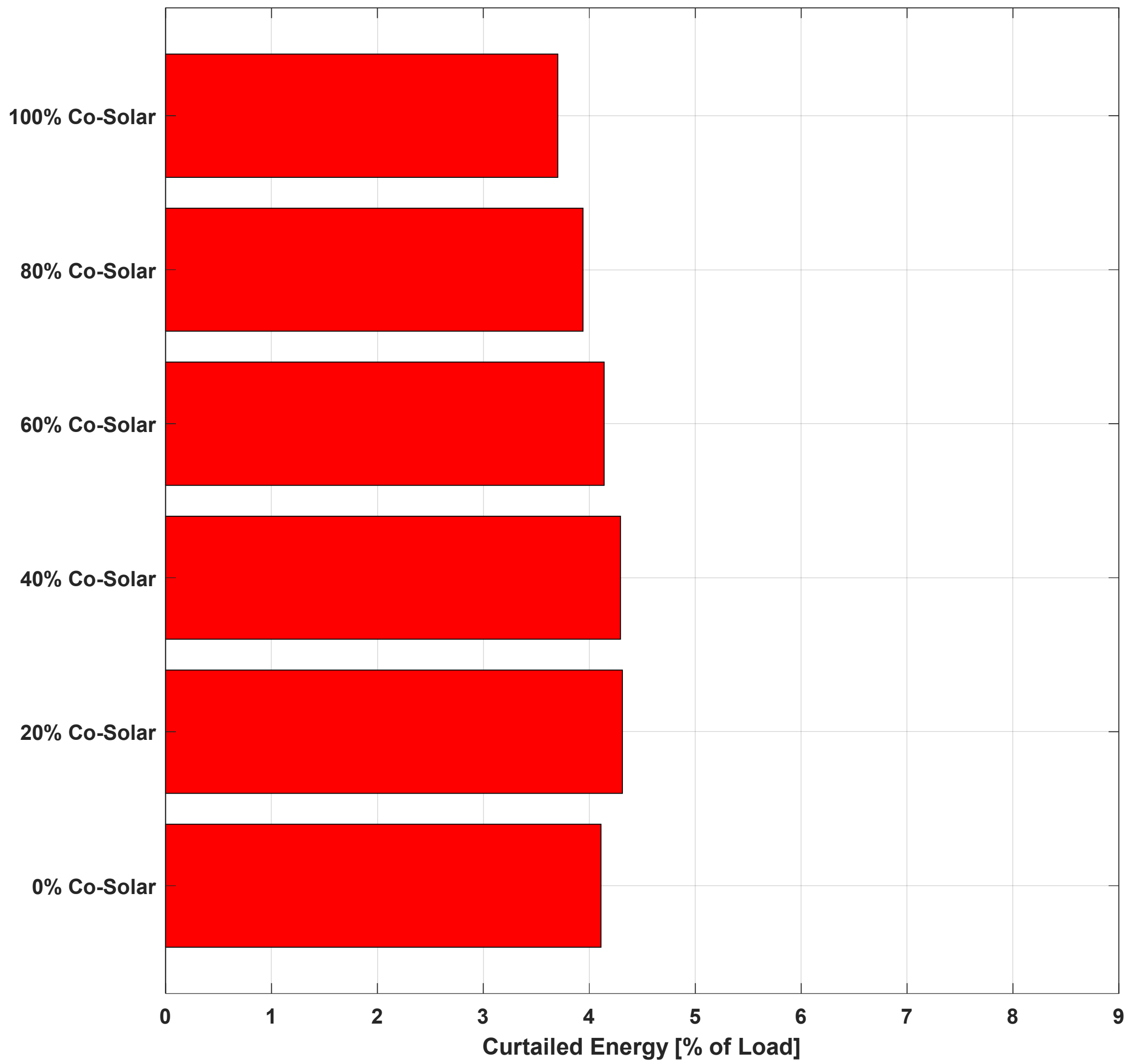

Figure 14 - System-wide renewable curtailment for solar farm co-location energy storage cases (% of annual load) in 2030

As some utility energy storage is replaced with solar farm co-located energy storage, renewable curtailment initially increases. As this process continues, the reduced losses enable more solar PV generation to be available to serve electric load, reducing system-wide curtailed renewable energy. Curtailed renewable energy in the 100% energy storage co-located at solar farm case (3.7%) slightly improves on the performance of the case where no energy storage was co-located at solar farms (4.1%).

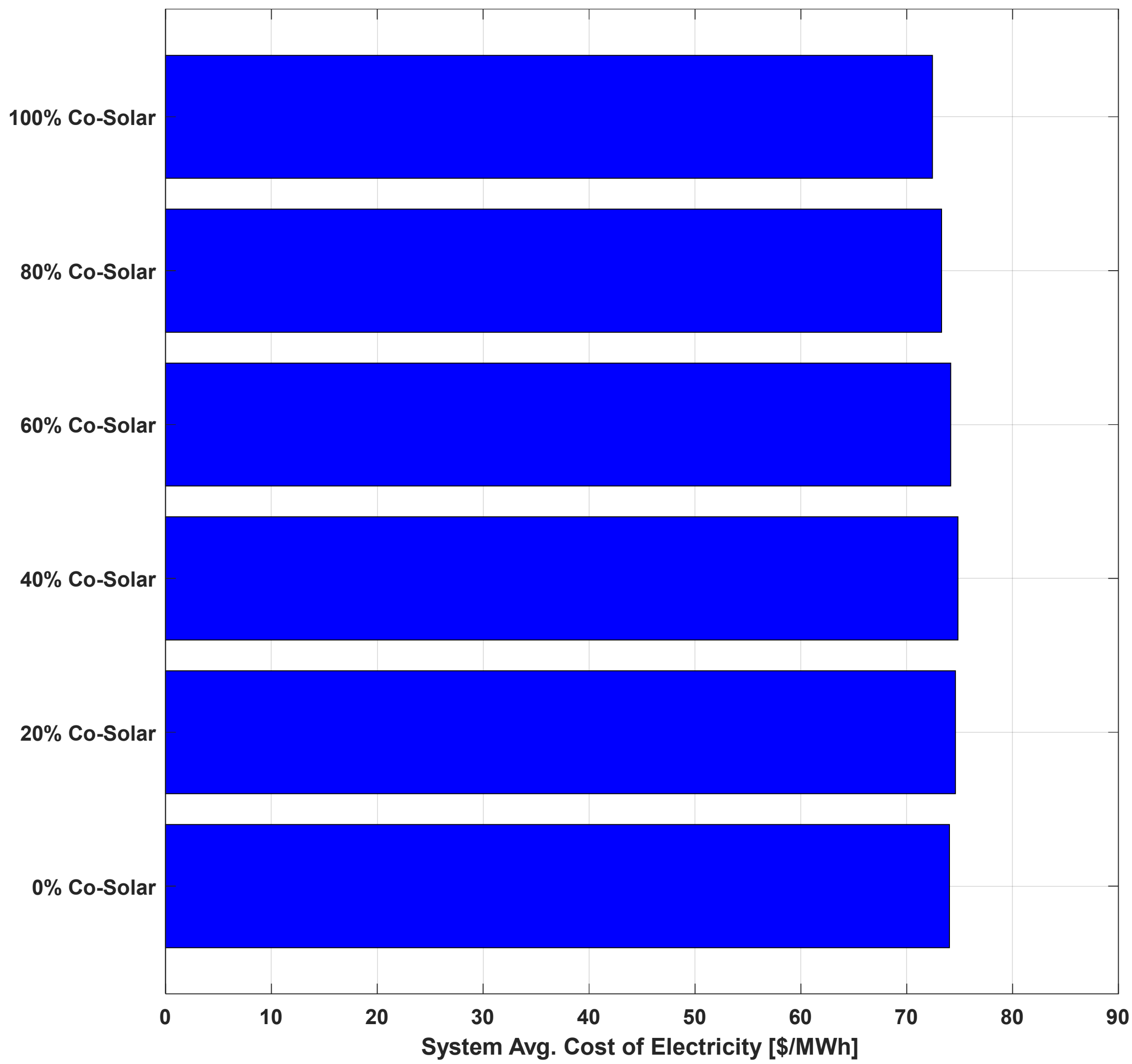

Figure 15 - System-wide average cost of electricity for solar farm co-location energy storage cases in 2030 [$/MWh]

The trends for zero-carbon electricity penetration and curtailed renewable energy are reflected in the system-wide average cost of electricity. The cost of electricity increases until between 20-40% of energy storage capacity is co-located at solar farms, after which it begins to decrease when the effect of reduced losses on a dominant generation resource in the SB100 Core resource mix results outcompetes the limitation of co-located energy storage only being able to manage excess solar generation. The case where 100% of energy storage capacity is co-located at solar farms shows reduced electricity costs ($72.4/MWh) compared to the case where no energy storage capacity is co-located at solar farms ($74.0/MWh).

The sensitivity of the solar farm co-location energy storage cases to different projected resource mixes is presented in Figure 16 for zero-carbon penetration, Figure 17 for renewable curtailment, and Figure 18 for the system cost of electricity. Note that these values are presented as percentage deviations from the base (0% Co-location) value achieved in each resource mix.

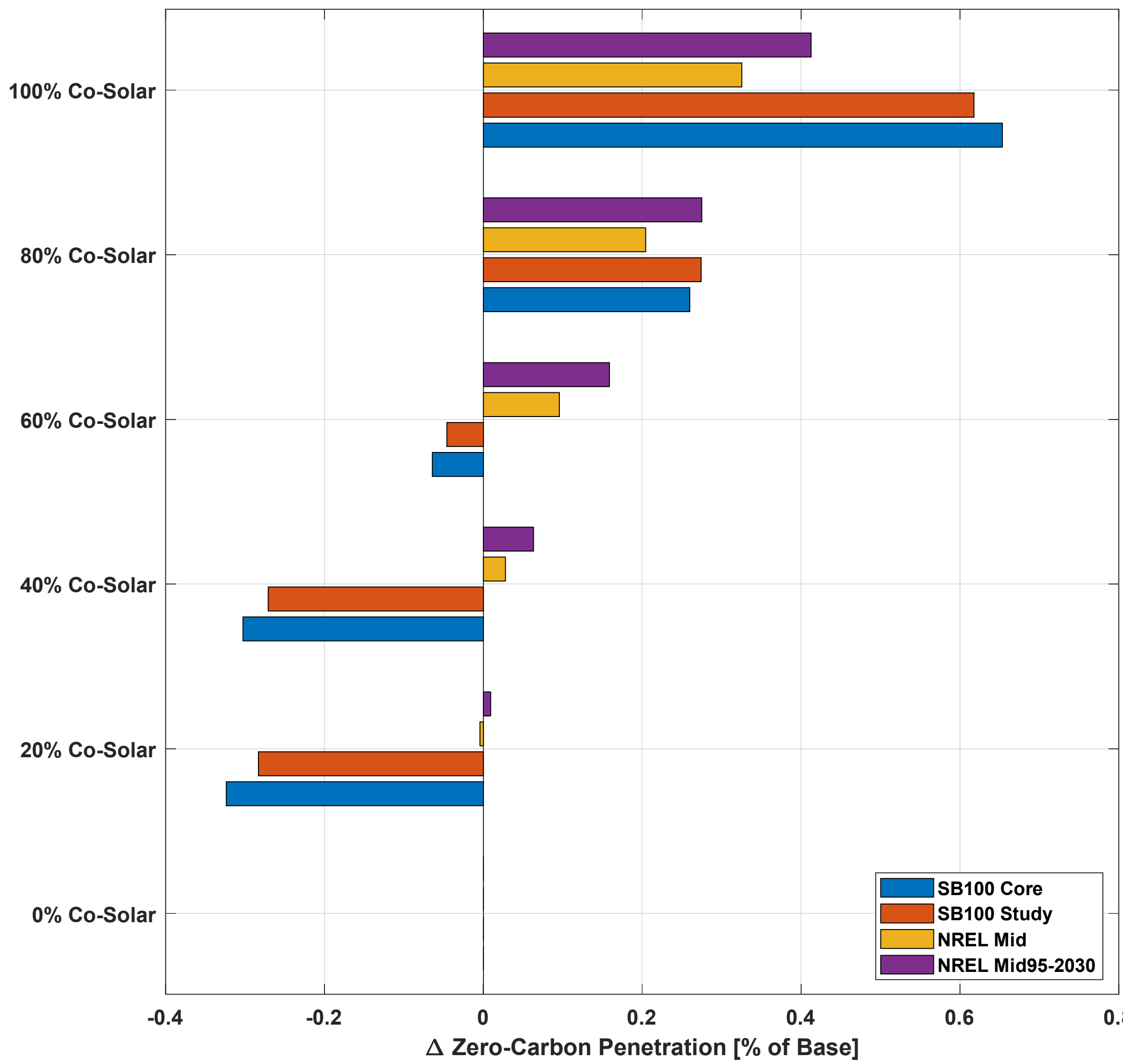

Figure 16 - Sensitivity of system-wide zero-carbon electricity penetration to different projected electricity resource mixes in 2030 for solar farm co-location energy storage cases [% of base value for each resource mix]

The SB100 resource mixes follow similar trends regarding the effect of co-locating energy storage at solar farms. System-wide zero-carbon electricity penetration decreases until 40% of energy storage capacity is co-located at solar farms, after which the trend reverses, due to the same driving factors. For the resource mixes from the NREL Standard Scenarios, zero-carbon electricity penetration increases as more energy storage is co-located at solar farms due to reduced losses.

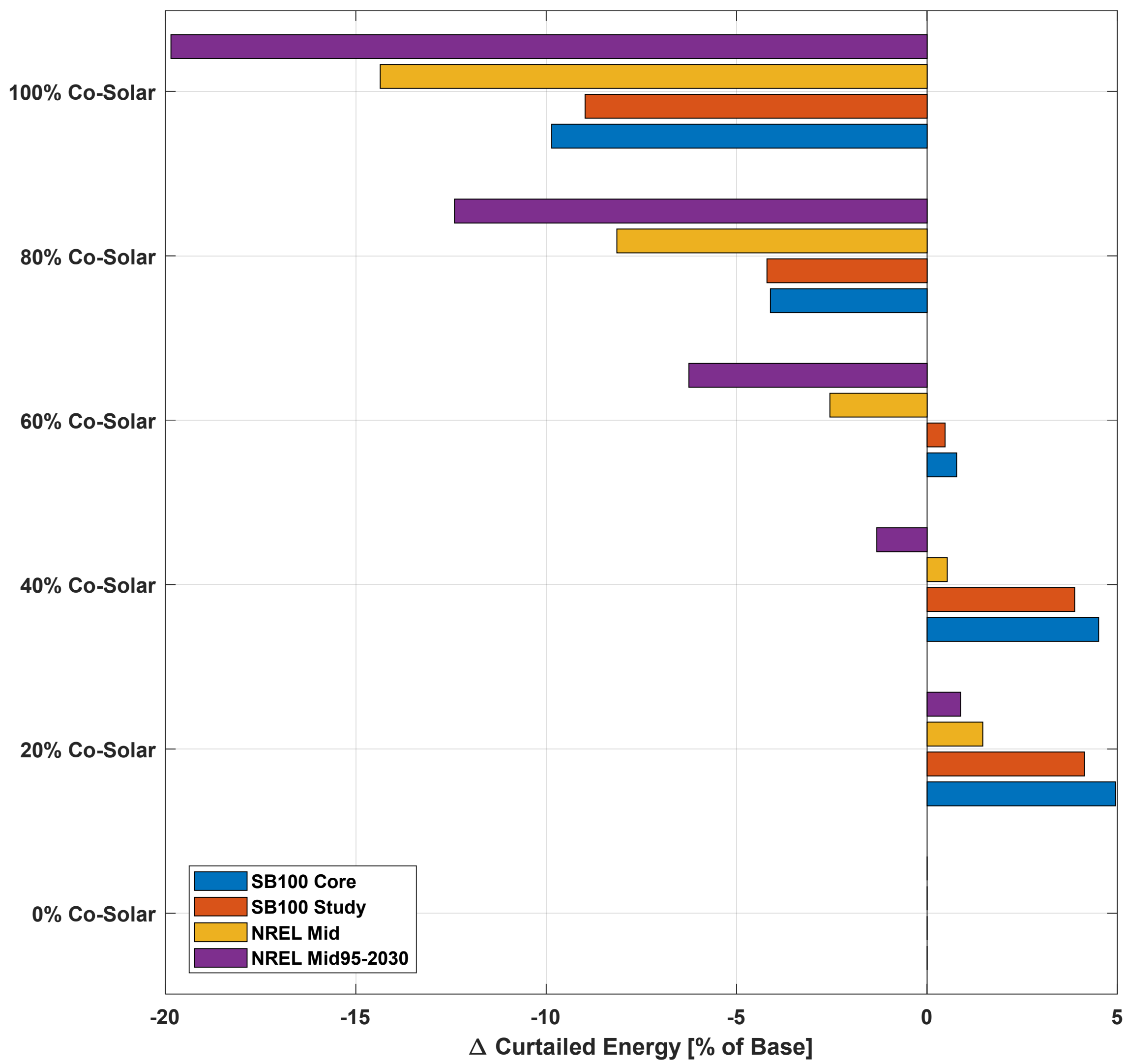

Figure 17 - Sensitivity of curtailed renewable energy electricity to different projected electricity resource mixes in 2030 for solar farm co-location energy storage cases [% of base value for each resource mix]

The trends for zero-carbon electricity penetration are also reflected in those for system-wide curtailed renewable energy and are due to the same drivers. Increases in curtailed energy reflect decreases in zero-carbon penetration and vice versa.

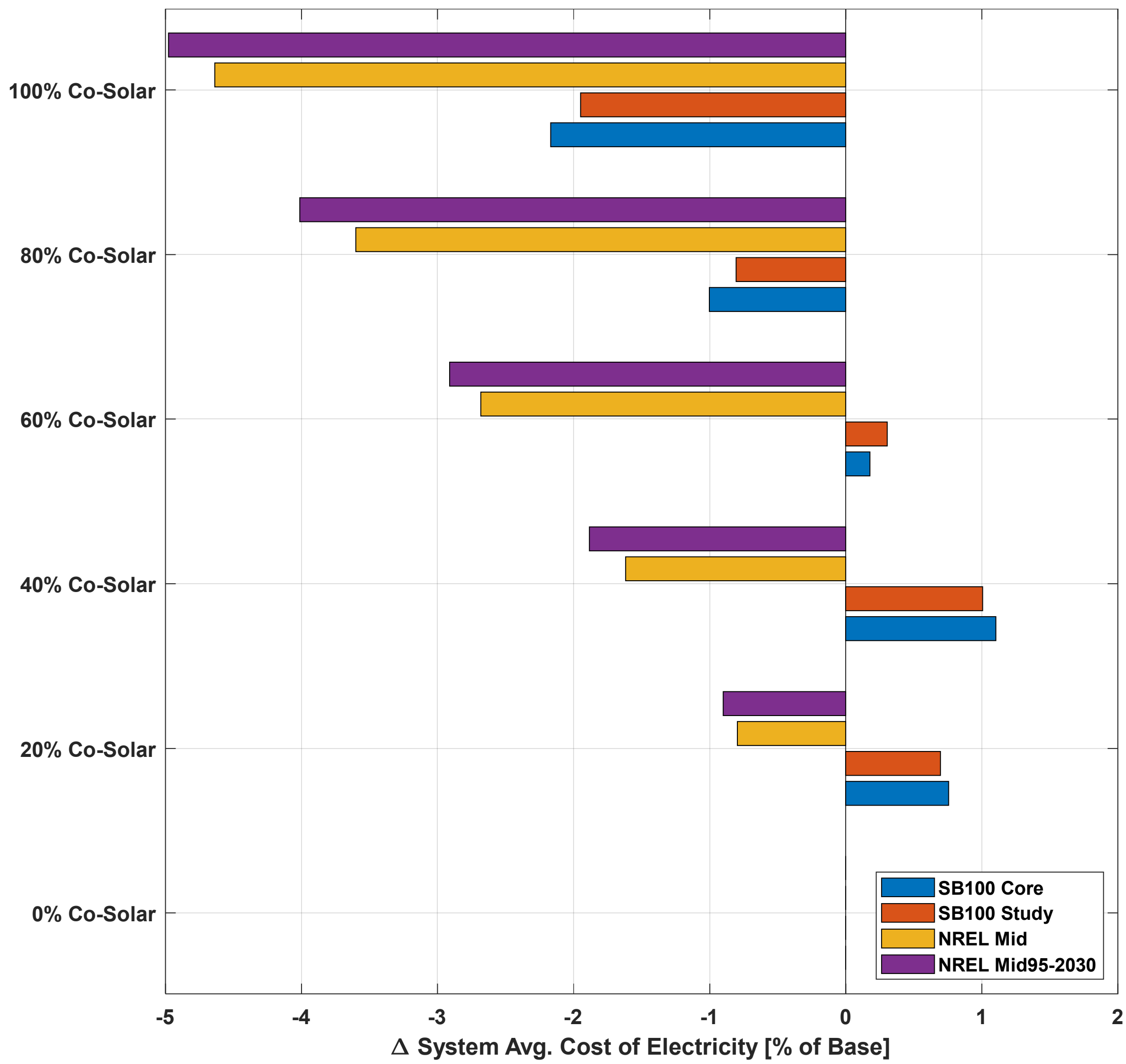

Figure 18 - Sensitivity of system-wide average cost of electricity to different projected electricity resource mixes in 2030 for solar farm co-location energy storage cases [% of base value for each resource mix]

The trends for the effect on zero-carbon electricity penetration from co-locating energy storage at solar farms also drive the trends in the cost of electricity. When the effect of the limited ability to manage combined solar and wind generation is stronger, electricity costs increase for the SB100 resource mixes, until the benefit of reduced losses becomes more valuable after which electricity costs decrease. For the NREL Standard Scenarios resource mixes, electricity costs decrease as more energy storage is co-located at solar farms.

3.1.4. Short-duration energy storage technology substitution

The effect of substituting projected lithium-ion utility-scale energy storage in 2030 with vanadium redox flow batteries is presented in Figure 19 for zero-carbon electricity penetration, Figure 20 for renewable curtailment, and Figure 21 for the cost of electricity.

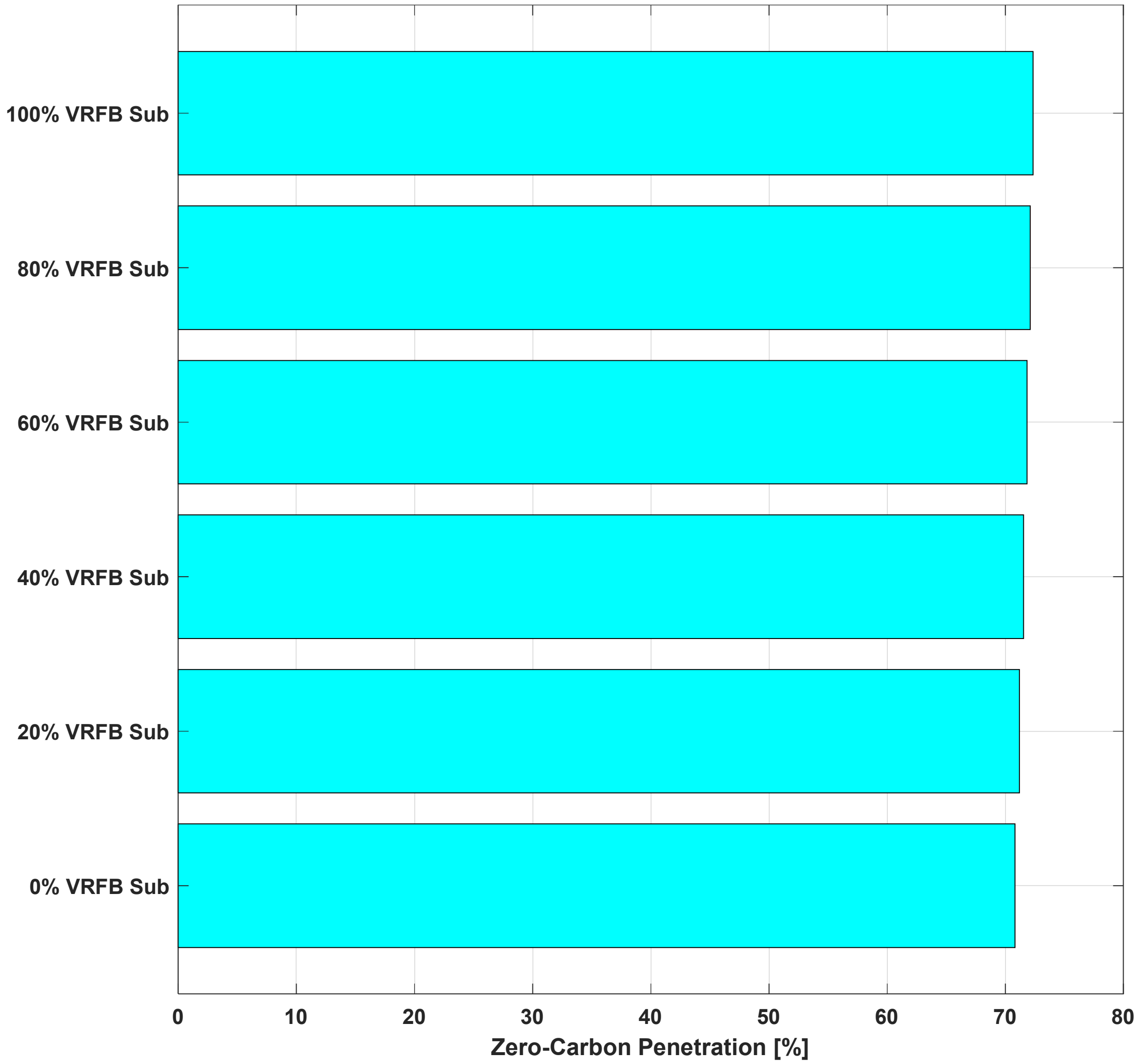

Figure 19 - System-wide zero-carbon electricity penetration for VRFB energy storage substitution cases [% of total annual electricity generation] in 2030

Substituting increasing capacities of lithium-ion battery capacity for vanadium redox flow battery capacity increases the system-wide zero-carbon electricity penetration from 70.8% (all lithium-ion) to 72.3% (all flow battery). The vanadium redox flow batteries are modeled as 10-hour energy storage, therefore when substituting lithium-ion battery capacity on a power capacity basis, this results in a higher energy capacity of energy storage installed in the system. Larger total energy capacities for the energy storage fleet allow it to shift excess renewable generation over longer timescales, enabling higher uptake of otherwise curtailed renewable energy even though the flow batteries have a lower round-trip efficiency.

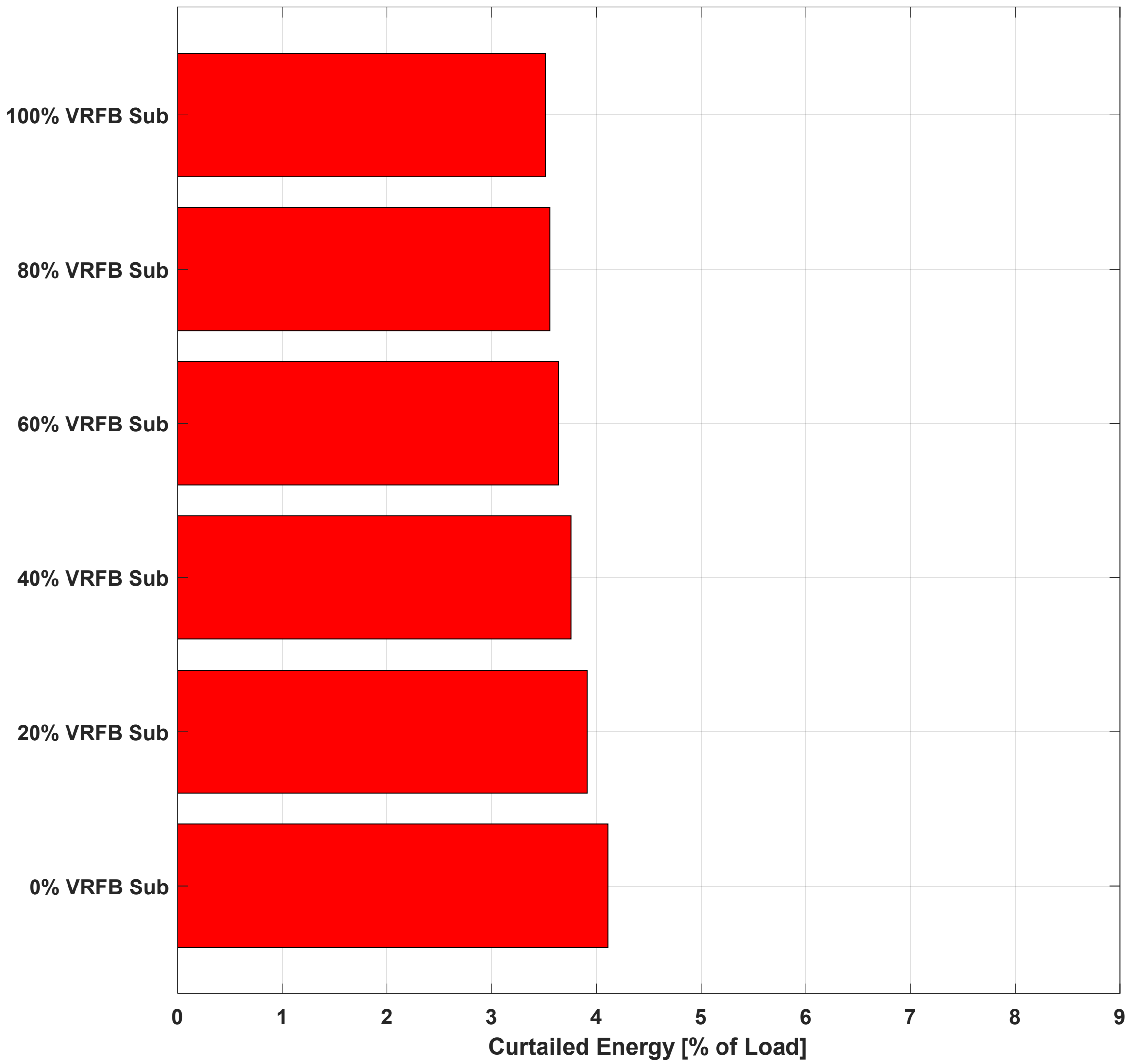

Figure 20 - System-wide renewable curtailment for VRFB energy storage substitution cases (% of annual load) in 2030

The larger energy capacity in the energy storage fleet resulting from substituting lithium-ion batteries capacity for vanadium redox flow batteries on a power capacity basis results in reduced curtailed renewable energy, from 4.1% of annual load equivalent (all lithium-ion) to 3.5% of annual load equivalent (all flow battery).

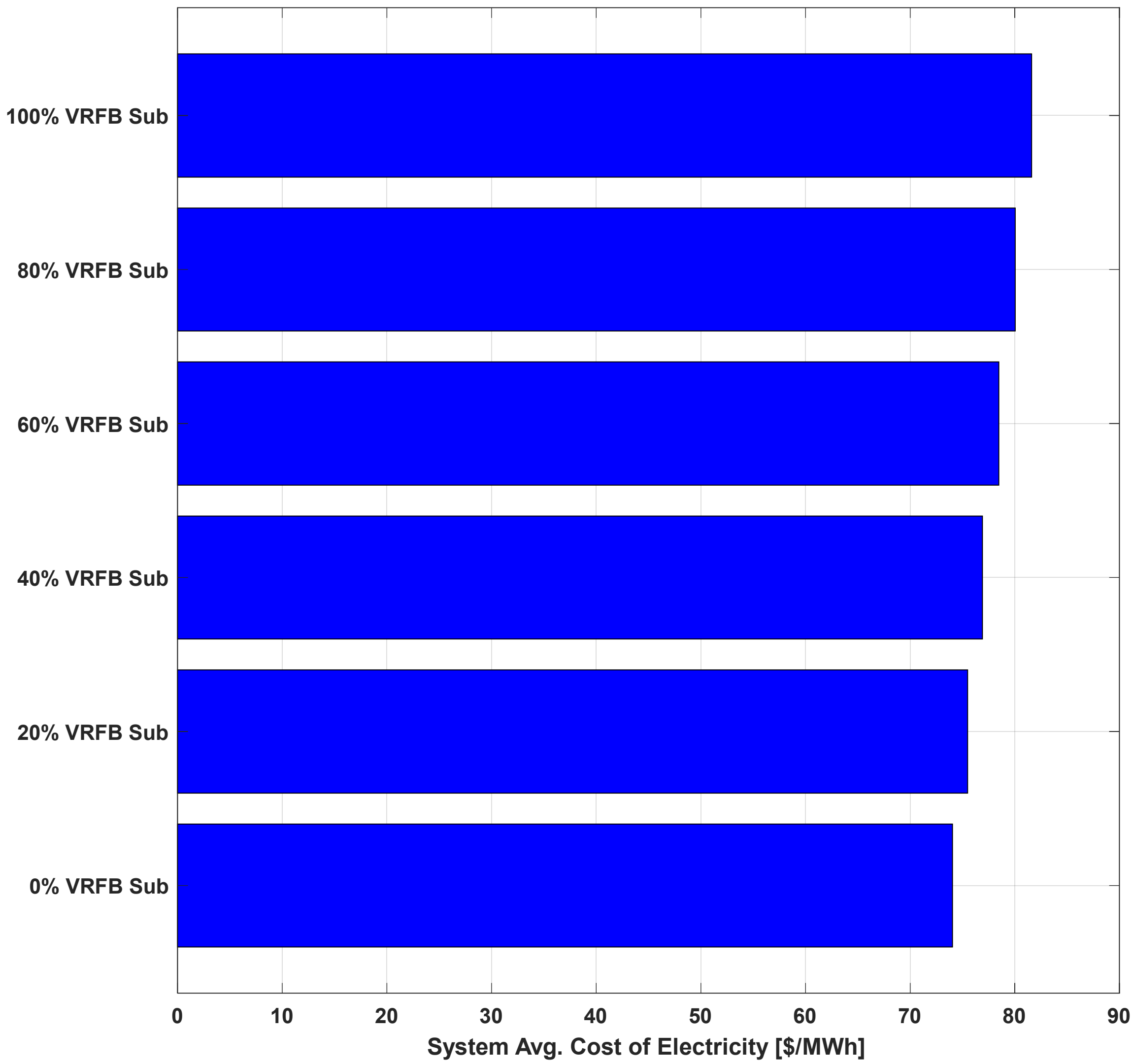

Figure 21 - System-wide average cost of electricity for VRFB energy storage substitution cases in 2030 [$/MWh]

Substituting lithium-ion batteries for flow batteries increases electricity costs despite the improvement in zero-carbon electricity penetration and reduced renewable energy curtailment, due to the much higher capital costs of vanadium redox flow batteries compared to lithium-ion batteries in the cost projections used for this study.

The sensitivity of the short-duration energy storage substitution cases to different projected resource mixes is presented in Figure 22 for zero-carbon penetration, Figure 23 for renewable curtailment, and Figure 24 for the system cost of electricity. Note that these values are presented as percentage deviations from the base (0% VRFB = 100% lithium-ion) value achieved in each resource mix.

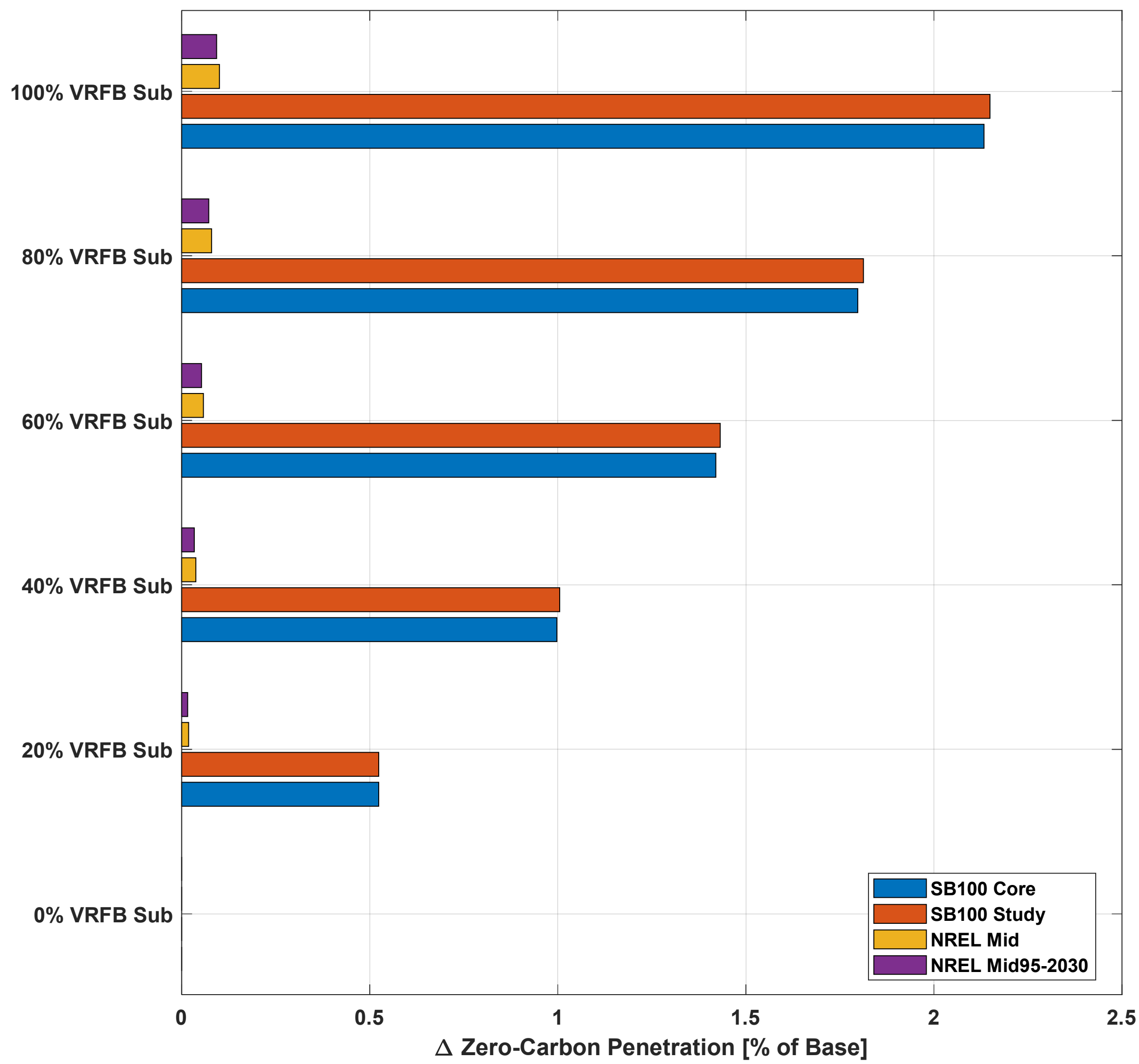

Figure 22 - Sensitivity of system-wide zero-carbon electricity penetration to different projected electricity resource mixes in 2030 for VRFB energy storage substitution cases [% of base value for each resource mix]

All four of the different projected resource mixes show increases in system-wide zero-carbon electricity penetration when lithium-ion batteries are substituted for vanadium redox flow batteries. The SB100 resource mixes show a larger relative benefit than the mixes from the NREL Standard Scenarios, due to the larger availability of excess renewable generation. However, the improvement in zero-carbon penetration is small relative to each mixes' base value, due to low levels of excess renewable generation being present by the year 2030.

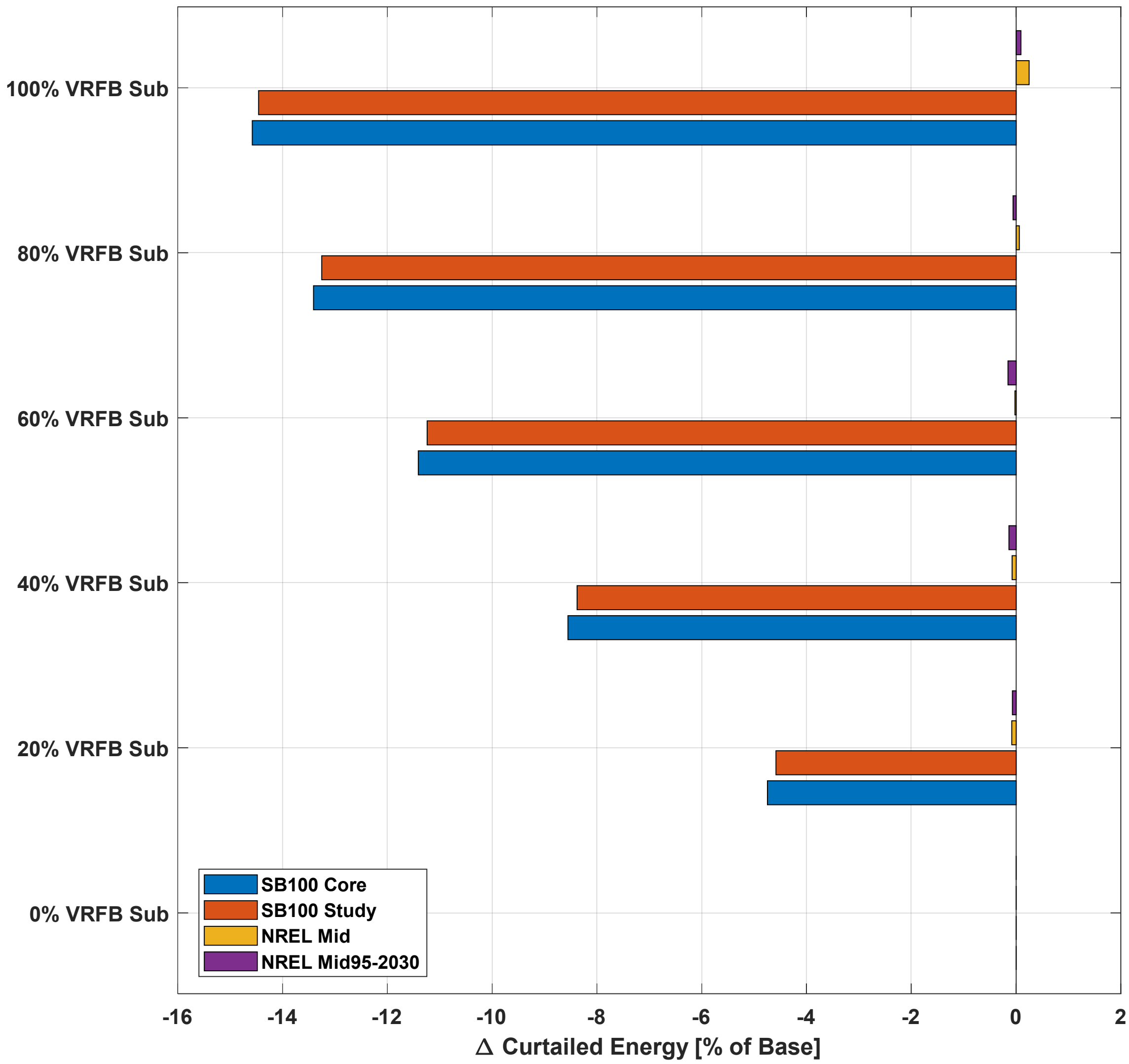

Figure 23 - Sensitivity of curtailed renewable energy electricity to different projected electricity resource mixes in 2030 for VRFB energy storage substitution cases [% of base value for each resource mix]

Reflective of the trends for effects on zero-carbon electricity penetration, the SB100 resource mixes show clear reductions in curtailed renewable energy. The resource mixes from the NREL Standard Scenarios show negligible change due to already low curtailed renewable energy availability. These values are likely an artifact of the modeling framework resolution.

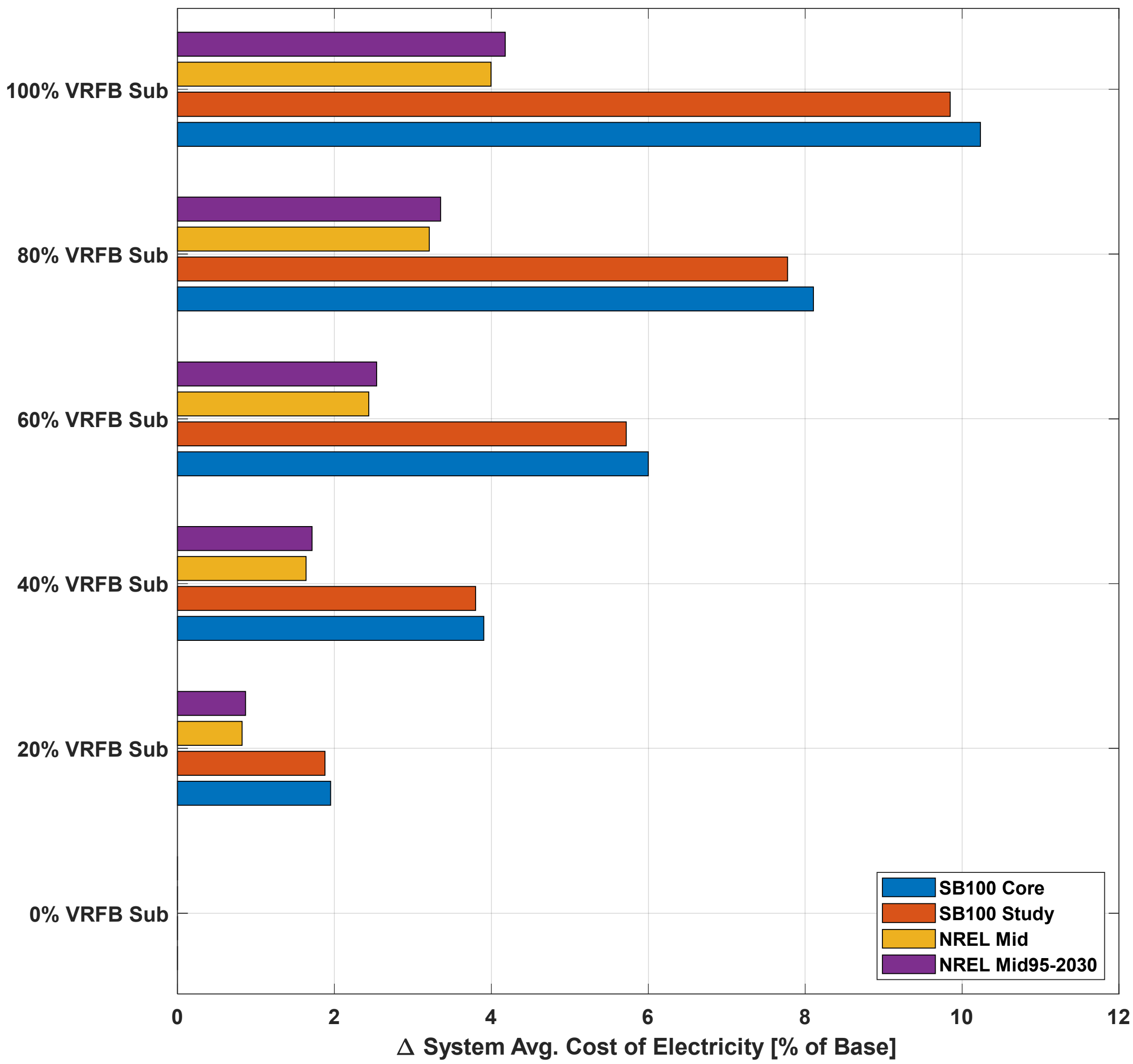

Figure 24 - Sensitivity of system-wide average cost of electricity to different projected electricity resource mixes in 2030 for VRFB energy storage substitution cases [% of base value for each resource mix]

In all four of the resource mixes considered, substituting lithium-ion batteries for vanadium redox flow batteries increases the system-wide cost of electricity due to the increased capital cost of the flow batteries relative to lithium-ion batteries for the cost parameter inputs used in this study.

3.1.5. Long-duration energy storage technology addition

The effect of adding long-duration hydrogen energy storage to the SB100 Core resource mix in 2030 is presented in Figure 25 for zero-carbon electricity penetration, Figure 26 for renewable curtailment, and Figure 27 for the cost of electricity.

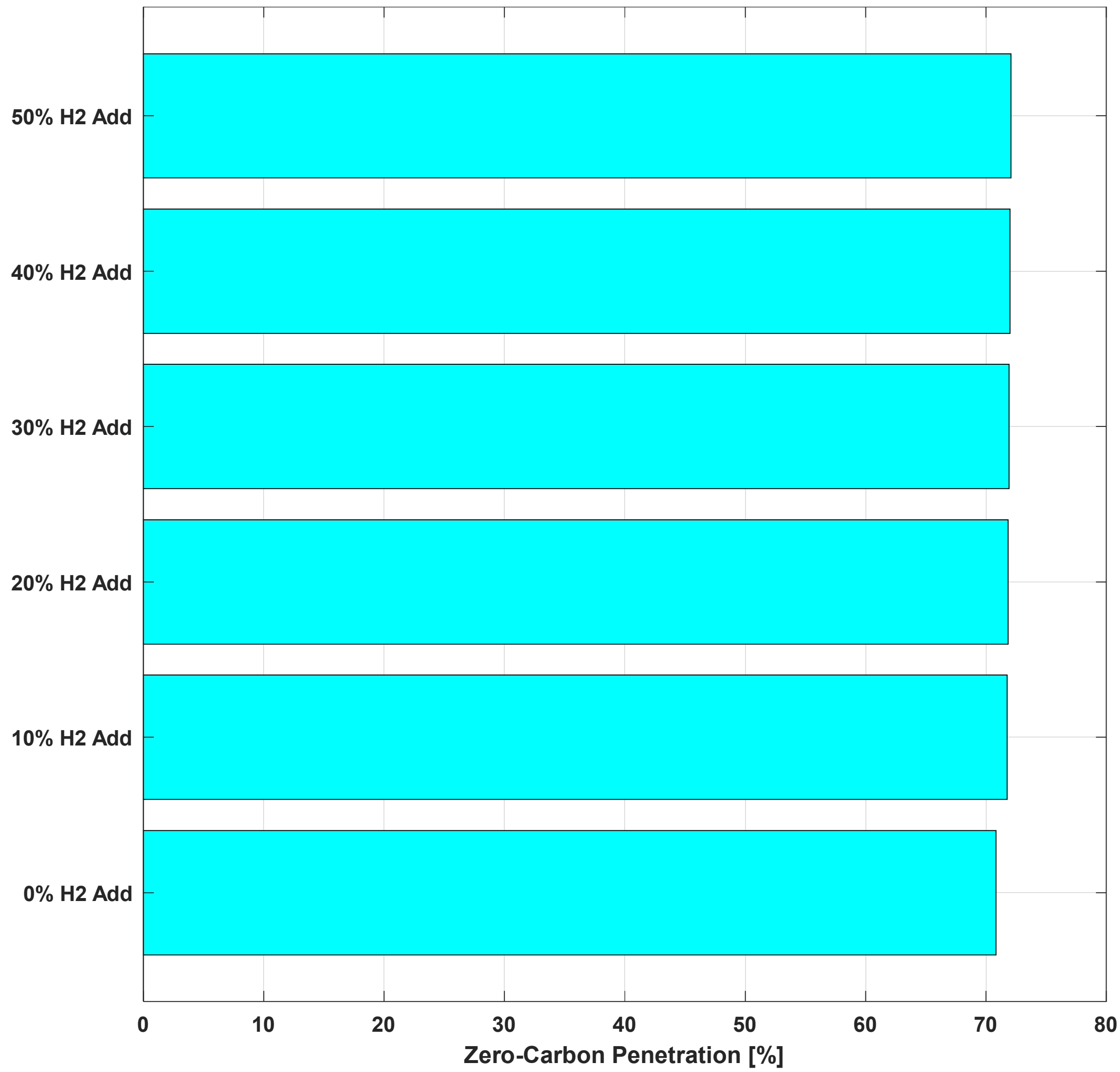

Figure 25 - System-wide zero-carbon electricity penetration for hydrogen energy storage addition cases [% of total annual electricity generation] in 2030

Adding hydrogen energy storage to the SB100 Core resource mix increases system-wide zero-carbon electricity penetration, from 70.8% (no added storage) to 72.0% (hydrogen energy storage added equivalent to 50% of pumped hydropower energy storage capacity). Increased long-duration energy storage enables the system to capture more excess renewable energy. The increase in zero-carbon penetration, however, is relatively small since the absolute power capacity of energy storage added is a small part of the total mix of resources and the round-trip efficiency of hydrogen energy storage (~35%) is lower than pumped hydropower energy storage (~80%). While more excess renewable energy is absorbed, the low round-trip efficiency means that much of it is not delivered as usable electricity supply.

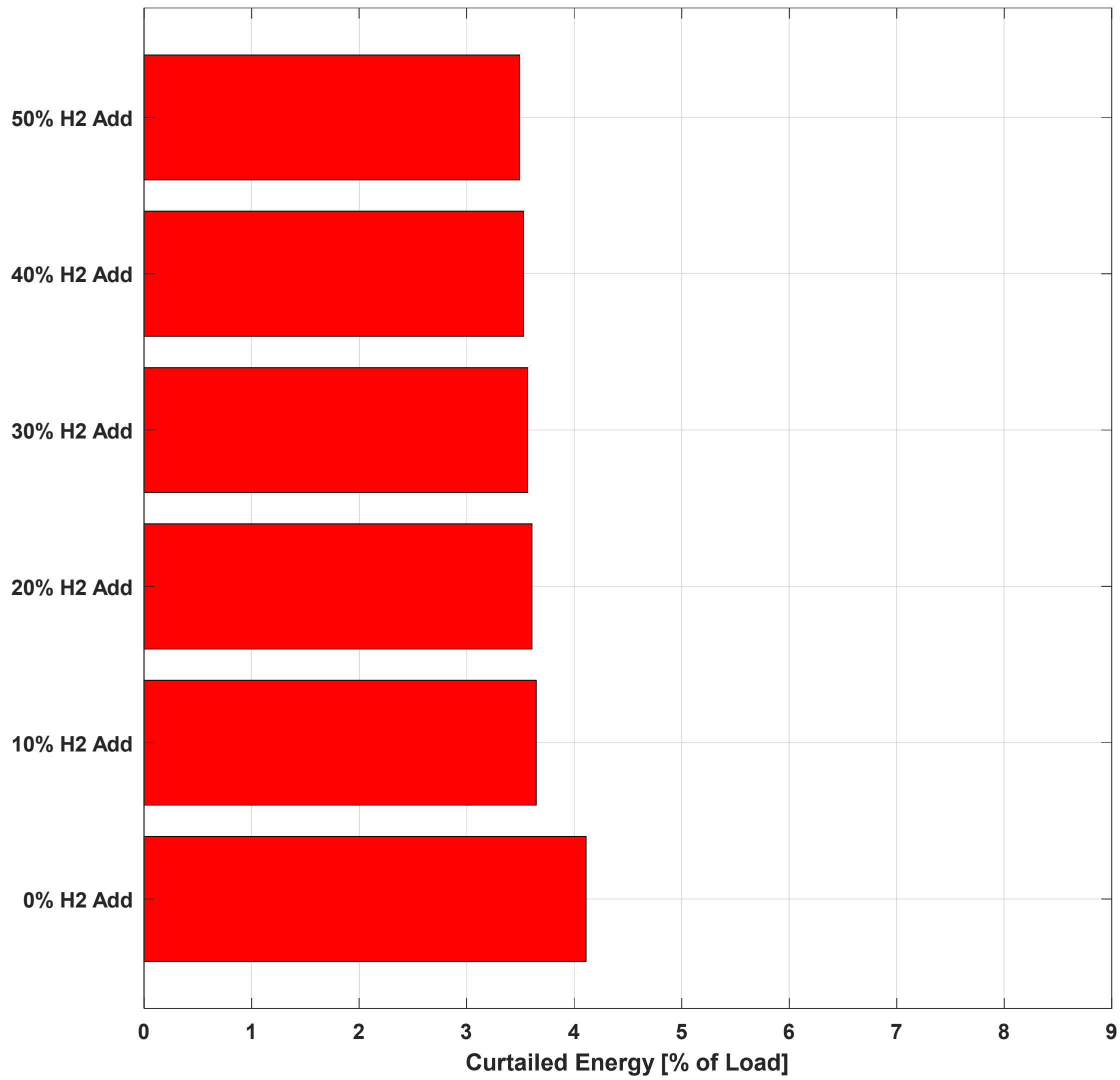

Figure 26 - System-wide renewable curtailment for hydrogen energy storage addition cases (% of annual load) in 2030

The addition of hydrogen energy storage to the system reduces curtailed renewable energy from 4.1% of annual load equivalent to 3.5% of annual load equivalent due to enabling additional uptake of excess renewable energy. The relatively small total capacity of storage added limits the extent to which curtailed renewable energy is decreased.

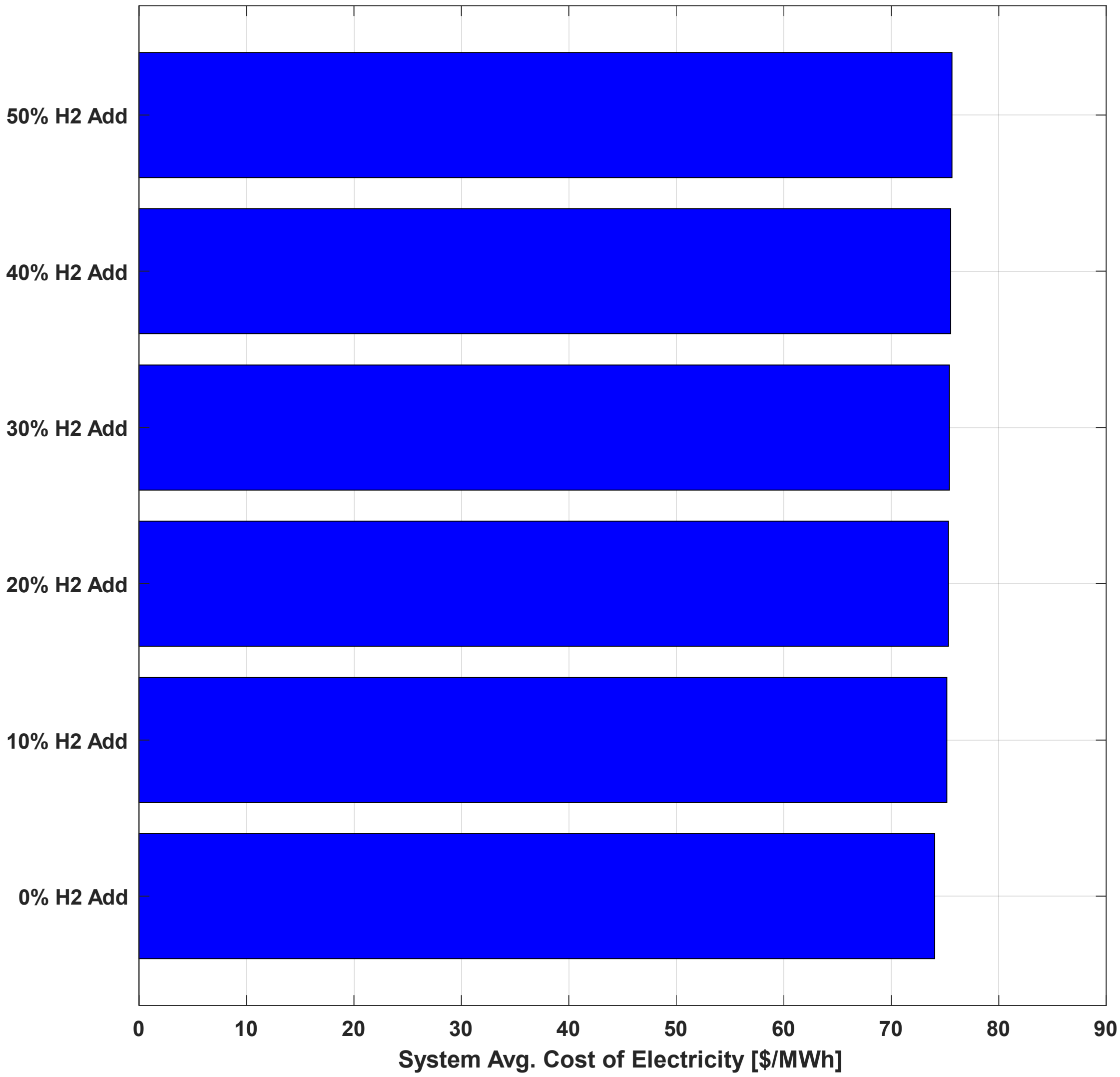

Figure 27 - System-wide average cost of electricity for hydrogen energy storage addition cases in 2030 [$/MWh]

Adding hydrogen energy storage to the system increases system-wide costs of electricity, from $74.0/MWh (no storage addition) to $75.6/MWh (added hydrogen storage equivalent to 50% of pumped hydropower capacity). This occurs due to the high capital cost of the hydrogen energy storage systems and somewhat limited benefit due to its low round-trip efficiency.

The sensitivity of the hydrogen energy storage addition cases to different projected resource mixes is presented in Figure 28 for zero-carbon penetration, Figure 29 for renewable curtailment, and Figure 30 for system cost of electricity. Note that these values are presented as percentage deviations from the base (No added storage – 0% H2 Add) value achieved in each resource mix.

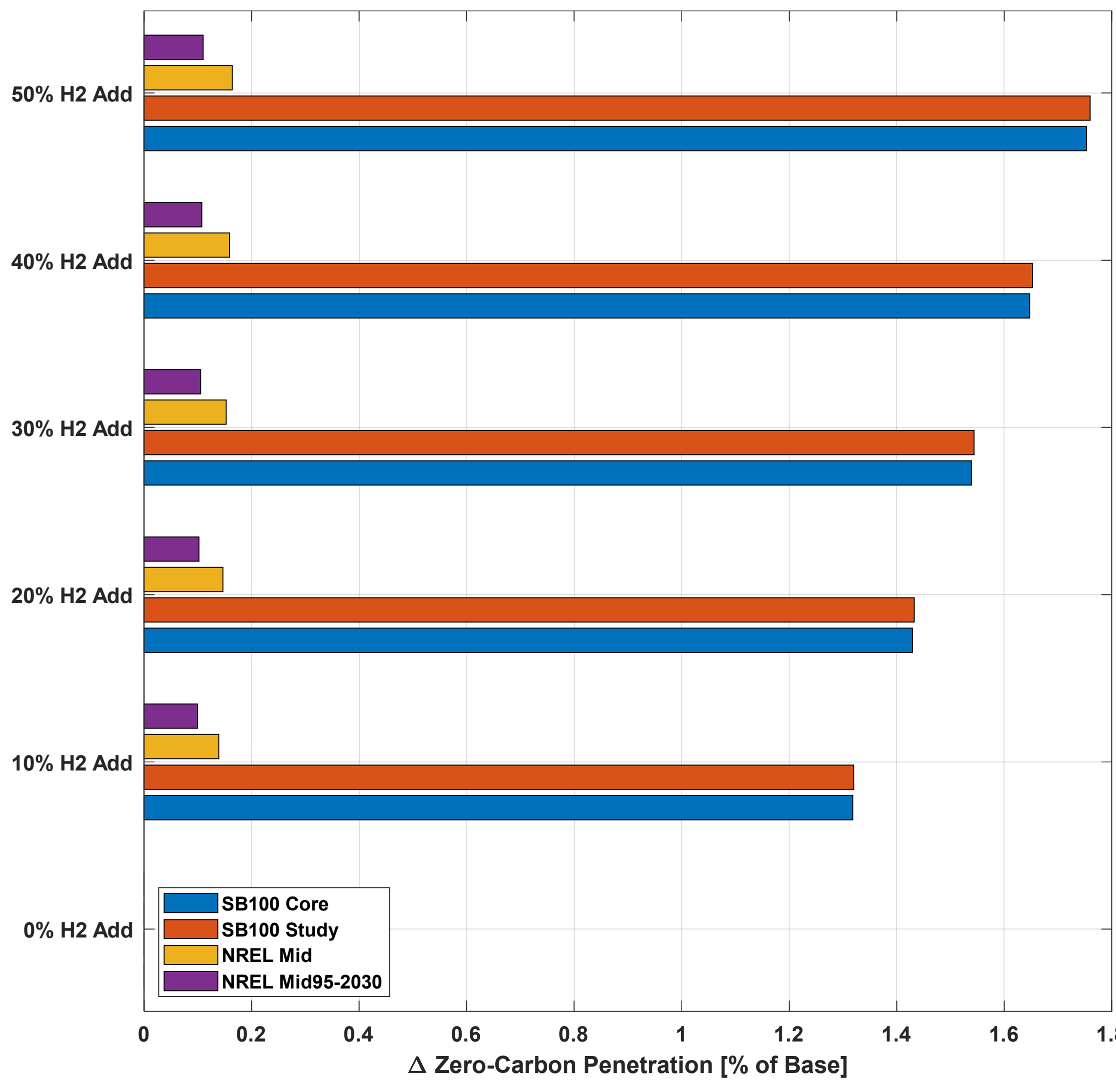

Figure 28 - Sensitivity of system-wide zero-carbon electricity penetration to different projected electricity resource mixes in 2030 for hydrogen energy storage addition cases [% of base value for each resource mix]

All four resource mixes show increases in system-wide zero-carbon electricity penetration when hydrogen energy storage is added due to enabling increased uptake of excess renewable generation. The SB100 resource mixes show larger relative benefits due to their higher availability of excess renewable generation.

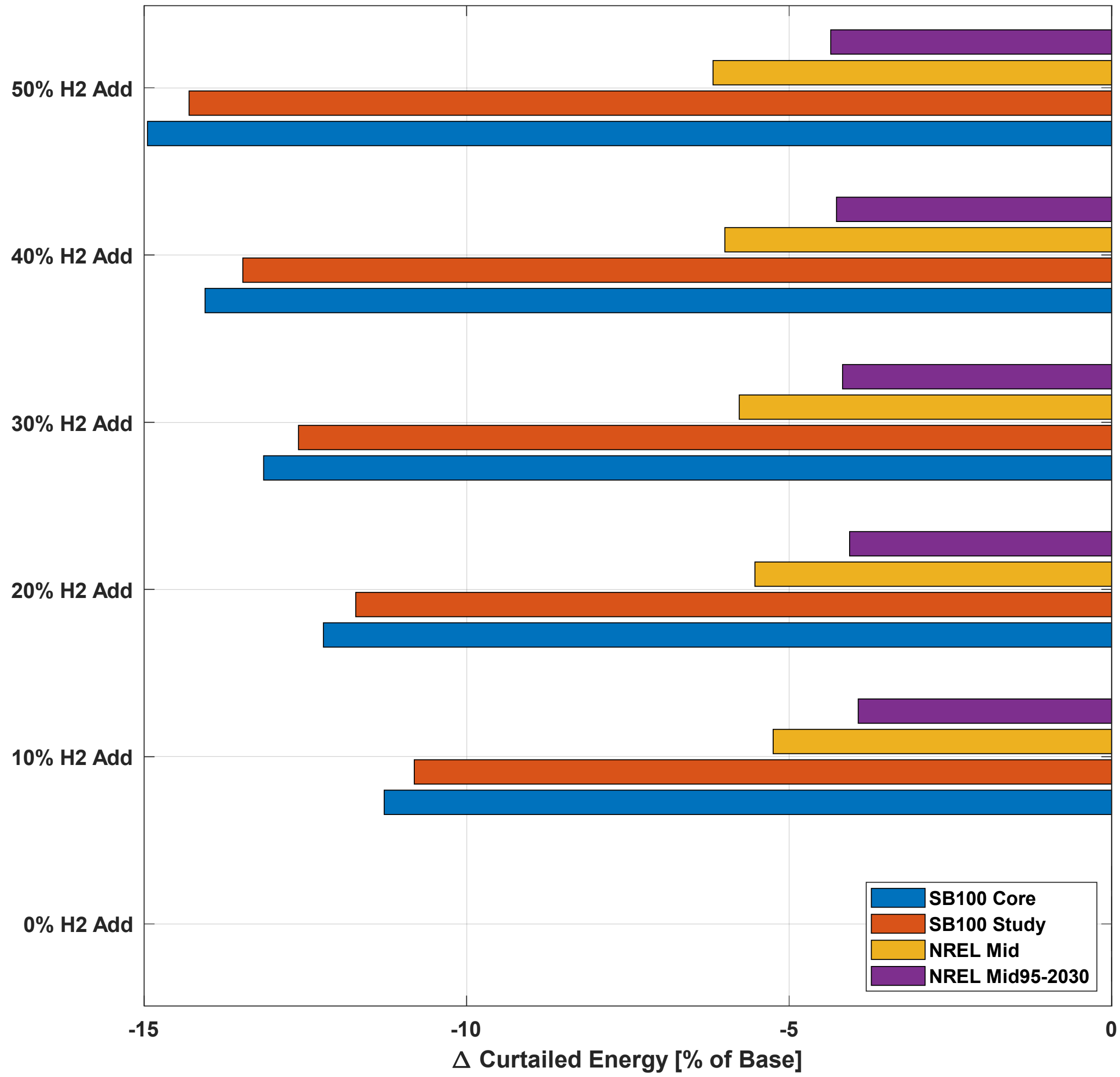

Figure 29 - Sensitivity of curtailed renewable energy electricity to different projected electricity resource mixes in 2030 for hydrogen energy storage addition cases [% of base value for each resource mix]

The addition of hydrogen energy storage reduces curtailed renewable energy in the electricity system due to enabling the additional uptake of excess renewable generation for all projected resource mixes, consistent with the trends for zero-carbon electricity penetration.

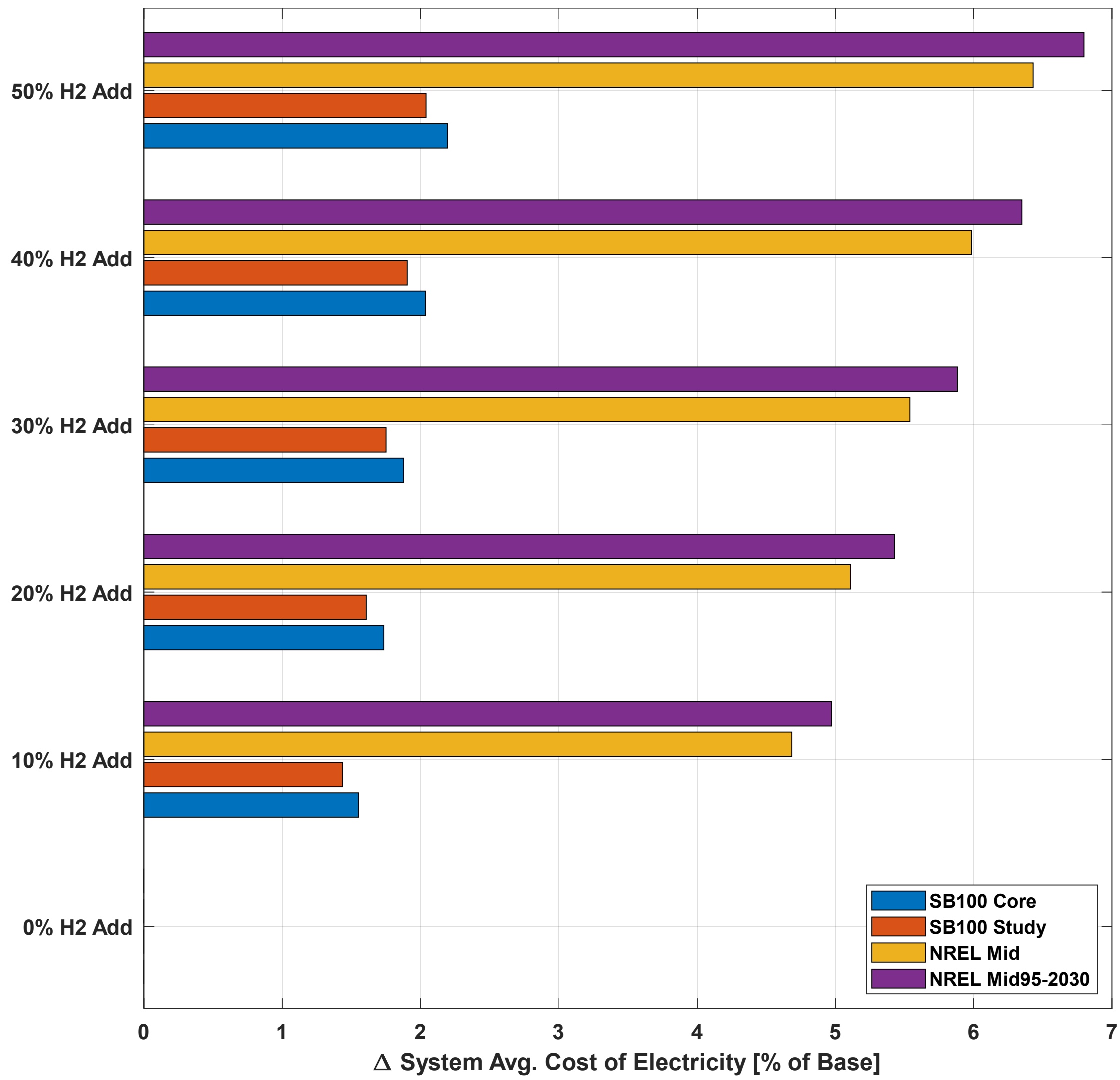

Figure 30 - Sensitivity of system-wide average cost of electricity to different projected electricity resource mixes in 2030 for hydrogen energy storage addition cases [% of base value for each resource mix]

All four resource mixes follow similar trends for the cost of electricity when hydrogen energy storage is added, namely that the cost of electricity increases due to the high capital cost of hydrogen energy storage technology.

3.2. Year 2045 Results

The results for the effect of different energy storage scenarios on system-wide zero-carbon electricity penetration, curtailed renewable energy, and system average cost of electricity in the year 2045 is presented here. Many of the described trends are similar to those described for the year 2030 results but larger in extent. The description of the results, however, is written such that a reader can understand them without having read the subchapter on the year 2030 results.

3.2.1. Behind-the-meter (BTM) energy storage

The effect of substituting projected utility-scale energy storage in 2045 for BTM energy storage or adding BTM energy storage to projected utility-scale energy storage is presented in Figure 31 for zero-carbon electricity penetration, Figure 32 for renewable curtailment, and Figure 33 for the cost of electricity.

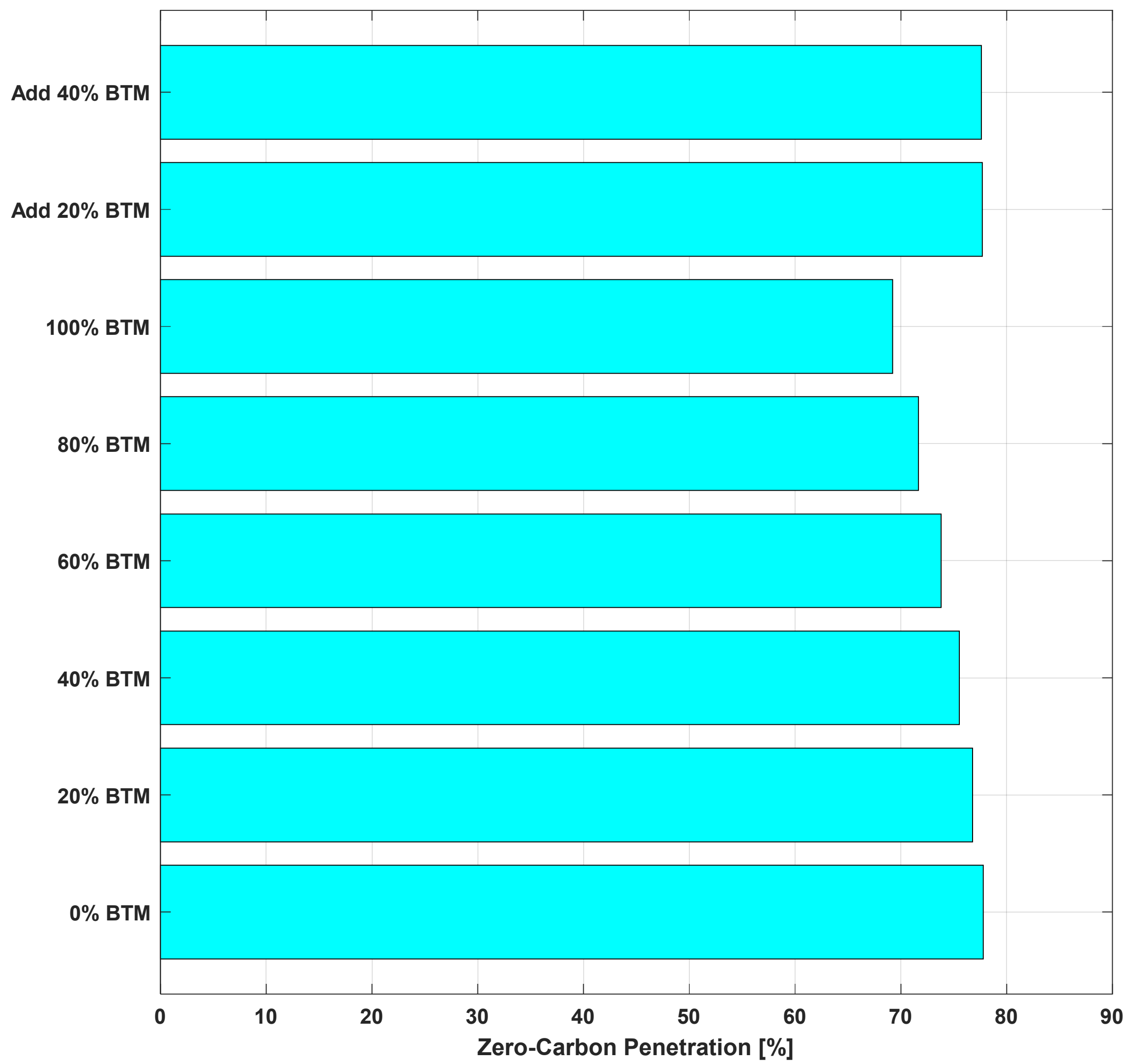

Figure 31 - System-wide zero-carbon electricity penetration for BTM energy storage cases [% of total annual electricity generation] in 2045

When utility energy storage capacity is substituted for BTM energy storage capacity, the system-wide zero-carbon electricity penetration decreases. The base case for this scenario (0% BTM) achieves a zero-carbon electricity penetration of 77.8%. This decreases to 69.2% when utility energy storage is fully substituted for BTM energy storage (100% BTM). This primarily occurs due to conflicts between the priorities of energy storage operations. When energy storage is installed as utility energy storage, it receives full information on generation and loads on the whole system and can charge or discharge accordingly, meaning it can operate to shape the system-wide net load. When energy storage is installed as BTM energy storage under the assumption that it will operate to maximize the renewable uptake or cost of electricity benefits for the residential, commercial, or industrial customer to which it is connected, it can inadvertently charge (add load) during times of high grid stress or discharge when excess renewables are present on the broader system. The result is a decrease in system-wide zero-carbon electricity penetration, despite the reduced losses from energy storage charge or discharge not being placed onto the transmission system.

When BTM energy storage is added to the projected utility energy storage capacity, the zero-carbon electricity penetration remains relatively unchanged from the base case for this scenario. The addition of BTM storage does not enable additional uptake of otherwise curtailed renewable energy since it is still short-duration energy storage as shown in Figure 32. With the amount of energy storage capacity installed in the SB100 Core resource mix, the mismatches between electricity production and load occur over longer timescales, and since the added energy storage capacity is not operating to benefit the system as a whole, no improvement is made.

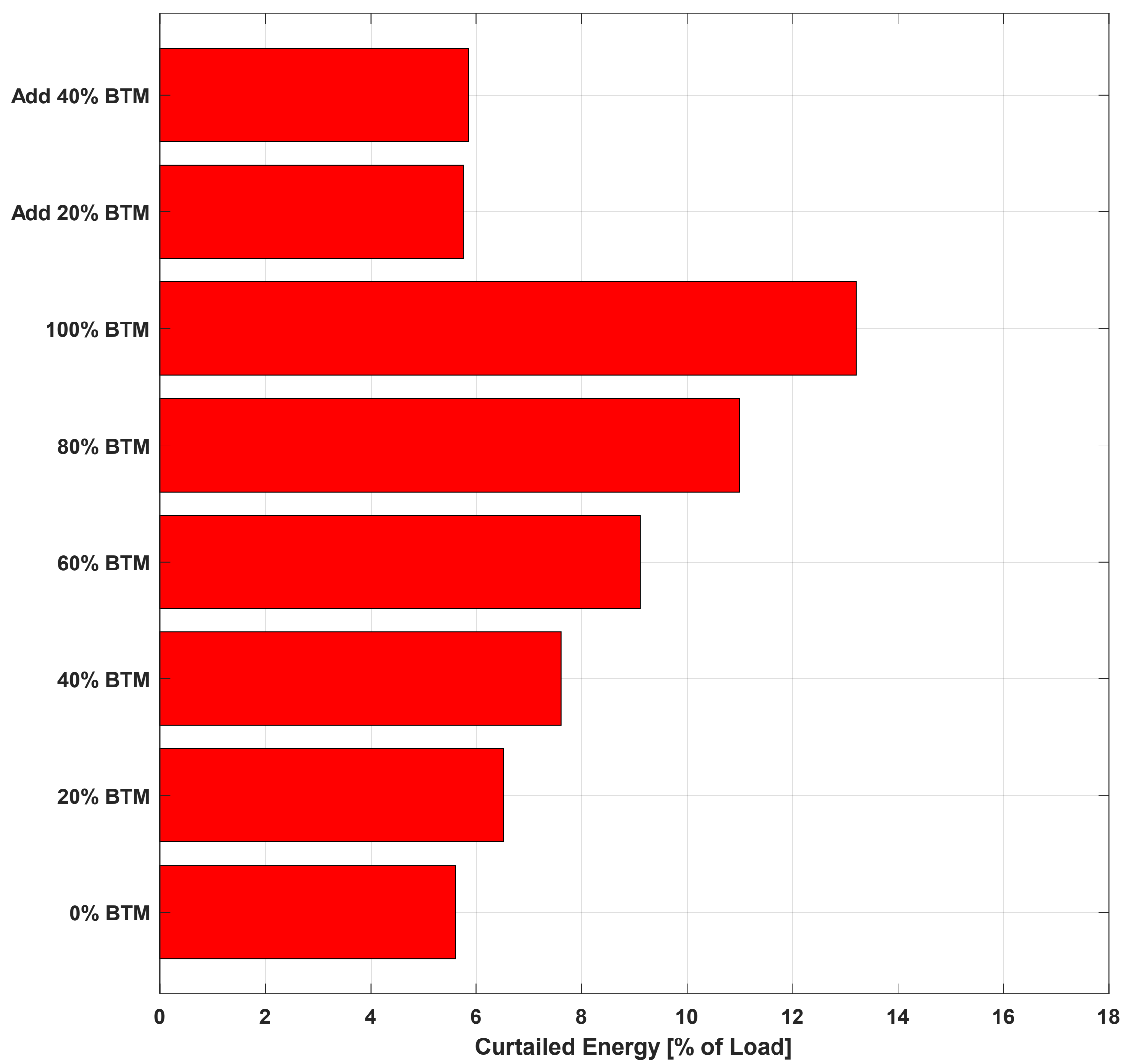

Figure 32 - System-wide renewable curtailment for BTM energy storage cases (% of annual load) in 2045

As expected from the zero-carbon electricity penetration results, substituting utility energy storage for BTM energy storage increases renewable curtailment for the entire system even though it decreases it for individual customers. This is due to the conflict in dispatch priorities for a fixed total capacity of energy storage.

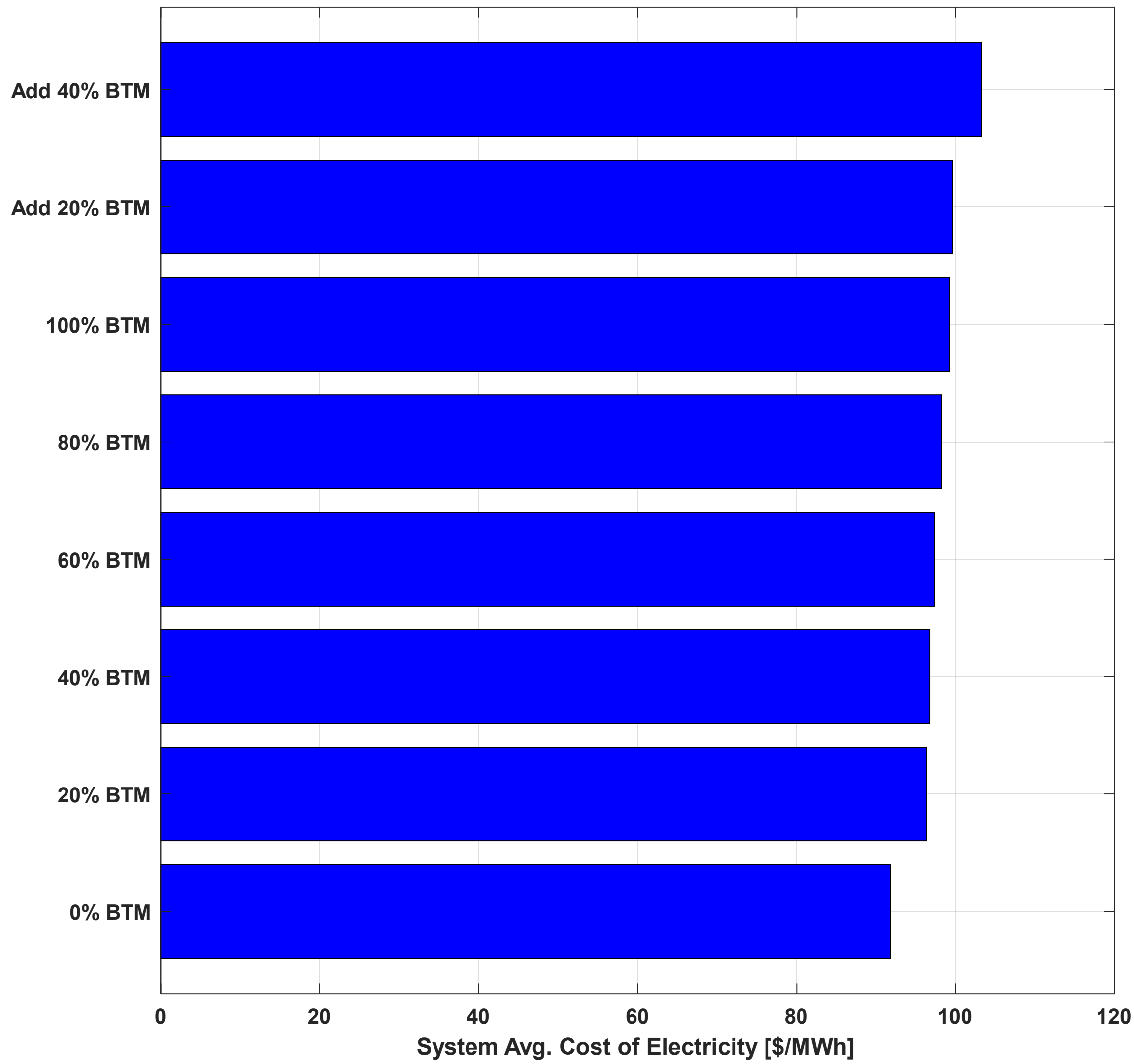

Figure 33 - System-wide average cost of electricity for BTM energy storage cases in 2045 [$/MWh]

When translating BTM energy storage effects on system-wide electricity costs, generally substituting utility-scale energy storage for BTM energy storage or adding BTM energy storage to the former increases costs. For the substitution cases, system-wide electricity costs increase since 1) the capital costs of BTM energy storage are higher than that for utility energy storage even with the assumed subtraction of grid integration costs and 2) other resources need to be used (i.e. natural gas) to ensure the broader electric load is satisfied when BTM energy storage dispatches in ways that do not directly address the needs of the broader system. For the addition cases, system-wide electricity costs still increase due to the capital cost of additional energy storage capacity with no additional system-wide benefit for these metrics.

It is important to discuss, however, the effect of assumed grid integration costs. Here we use the grid integration costs from the study by Mongird et al [5] since the cost parameters used in this study are also based on that source. The specified grid integration costs from this source are generally small (i.e. less than 5% of total installed cost) compared to the capital cost of the corresponding energy storage technology. Grid integration costs in practice can be higher, in which case increasing BTM energy storage can potentially provide a system-wide cost benefit. For example, grid integration costs specified by the California Energy Commission for lithium-ion batteries [16] are roughly one order of magnitude higher than that specified by Mongird et al [5]. However, grid integration costs from different sources account for different factors, and these need to be harmonized to narrow down more accurate values.

It is also possible for BTM energy storage to be dispatched in response to broader grid conditions and therefore have a more positive effect on system-wide zero-carbon penetration, renewable curtailment, and electricity costs. Since these systems are paid for by individual residential, commercial, or industrial customers, however, these customers will need a better incentive to operate these assets for the system-wide benefit instead of local benefits under their current rate structures. These results show that while BTM energy storage can have significant benefits for individual customers, the conflict in dispatch priority between serving local customers versus the needs of the broader grid means that balancing authorities need to use other resources to compensate for BTM energy storage sometimes dispatching in ways that exacerbate undesirable grid conditions.

The sensitivity of the BTM energy storage cases to different projected resource mixes is presented in Figure 34 for zero-carbon penetration, Figure 35 for renewable curtailment, and Figure 36 for system cost of electricity. Note that these values are presented as percentage deviations from the base (0% BTM) value achieved in each resource mix.

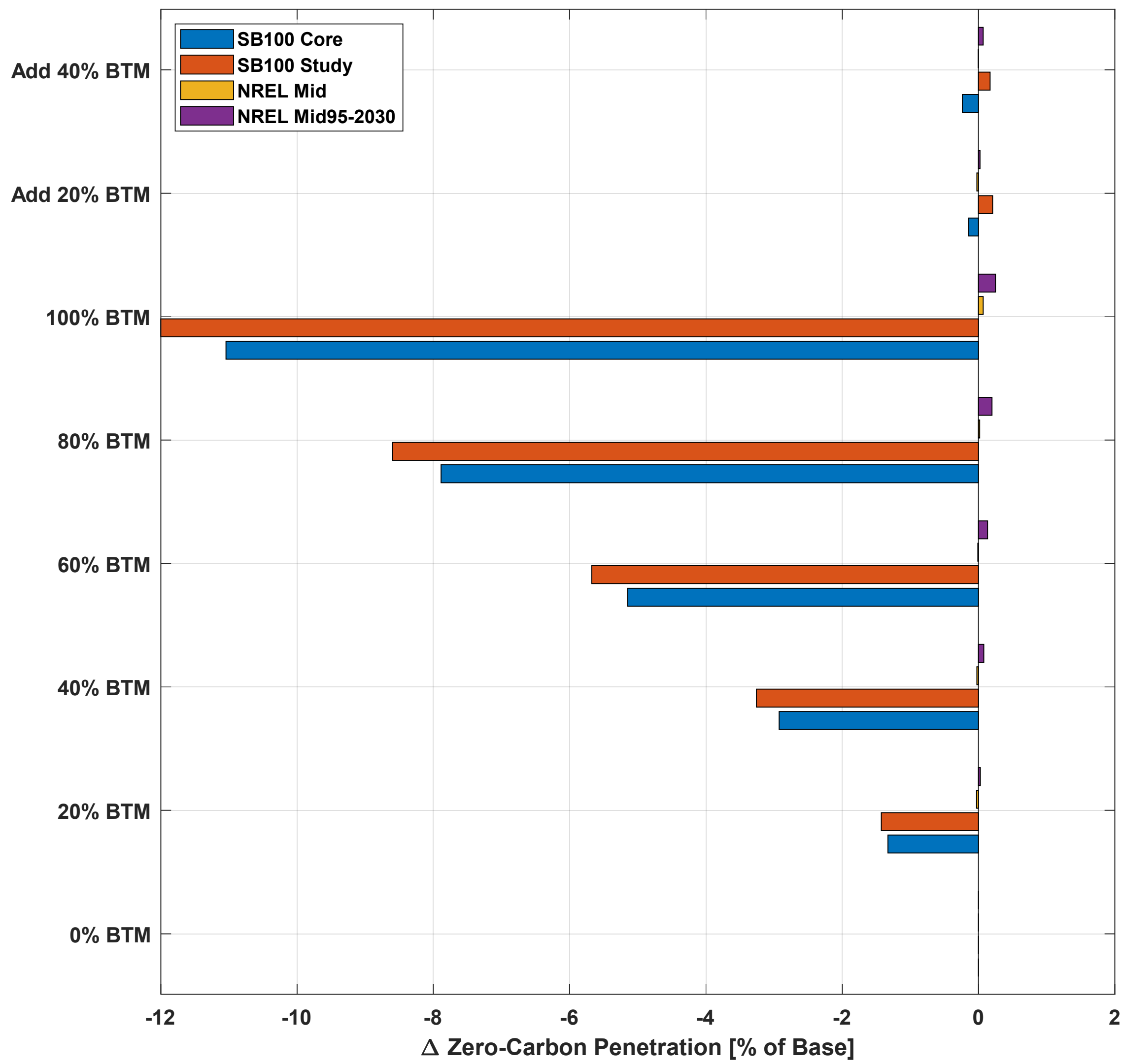

Figure 34 - Sensitivity of system-wide zero-carbon electricity penetration to different projected electricity resource mixes in 2045 for BTM energy storage cases [% of base value for each resource mix]

The SB100 Study resource mix represents increased zero-carbon generation and storage capacity relative to the SB100 Core mix, to ensure that additional components of total electric load are met by zero-carbon generation. When BTM energy storage is substituted or added to the SB 100 Study mix, the effects on zero-carbon penetration follow similar trends to that of the SB100 Core results by decreasing zero-carbon penetration, but to slightly larger extents. When a higher fraction of the zero-carbon electricity generation portfolio is based on variable renewable resources, the effect of energy storage capacity not being dispatched to respond to the needs of the broader grid is more pronounced.

The two resource mixes from the 2021 NREL Standard Scenarios show little to no change from the 0% BTM value as BTM energy storage is substituted or added. This occurs since these resource mixes specify lower zero-carbon electricity generation and storage capacity compared to the SB 100 mixes and subsequently, do not have significant renewable curtailment to start with. Therefore, adding or substituting energy storage capacity does not have much renewable curtailment to handle.

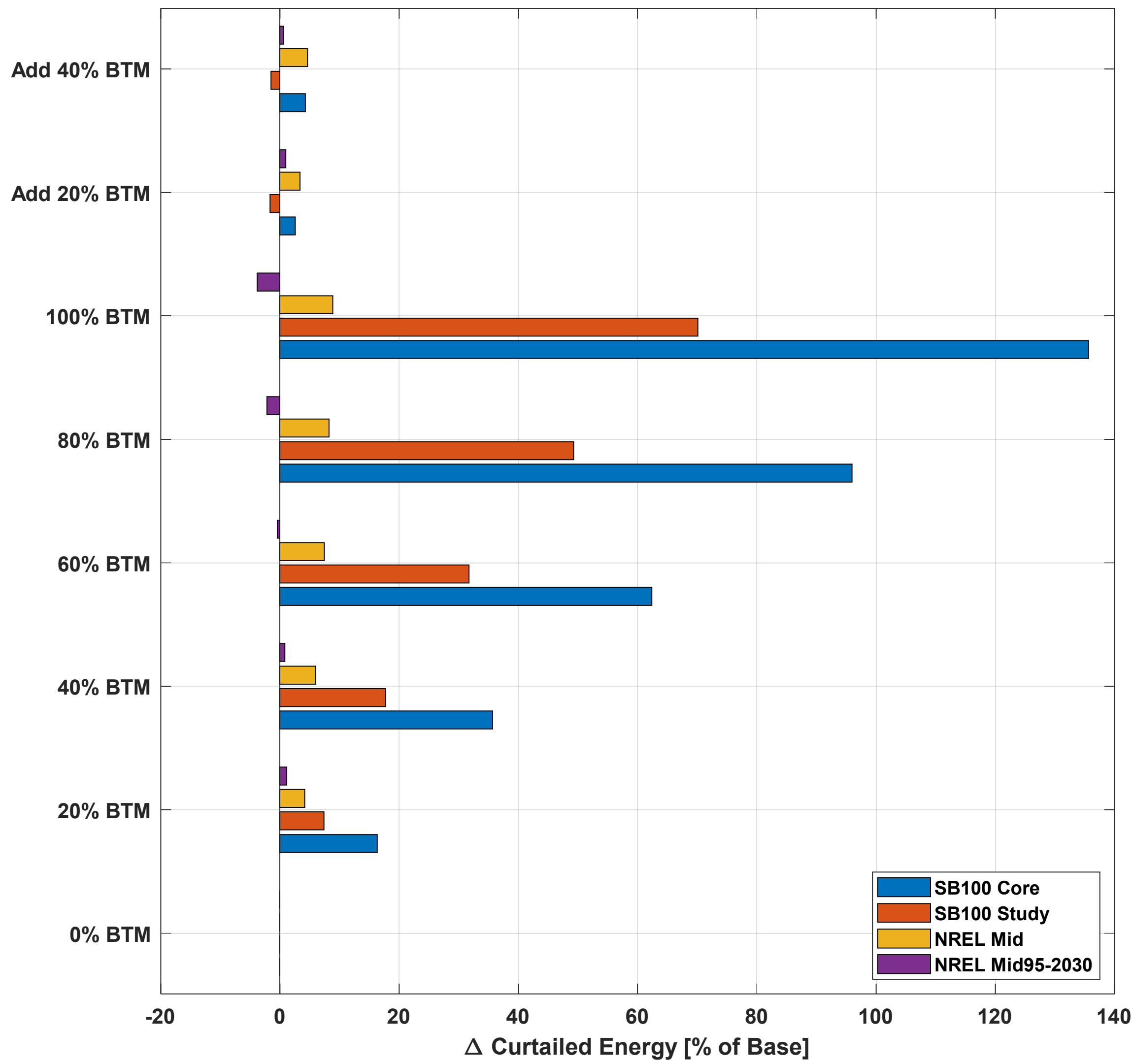

Figure 35 - Sensitivity of curtailed renewable energy electricity to different projected electricity resource mixes in 2045 for BTM energy storage cases [% of base value for each resource mix]

For curtailed renewable energy, the SB100 Study (higher zero-carbon electricity generation) shows higher values than the SB100 Core mix. The NREL Mid-case shows small increases from the base value achieved by that mix, while the NREL Mid95-2030 case does not show a consistent trend.

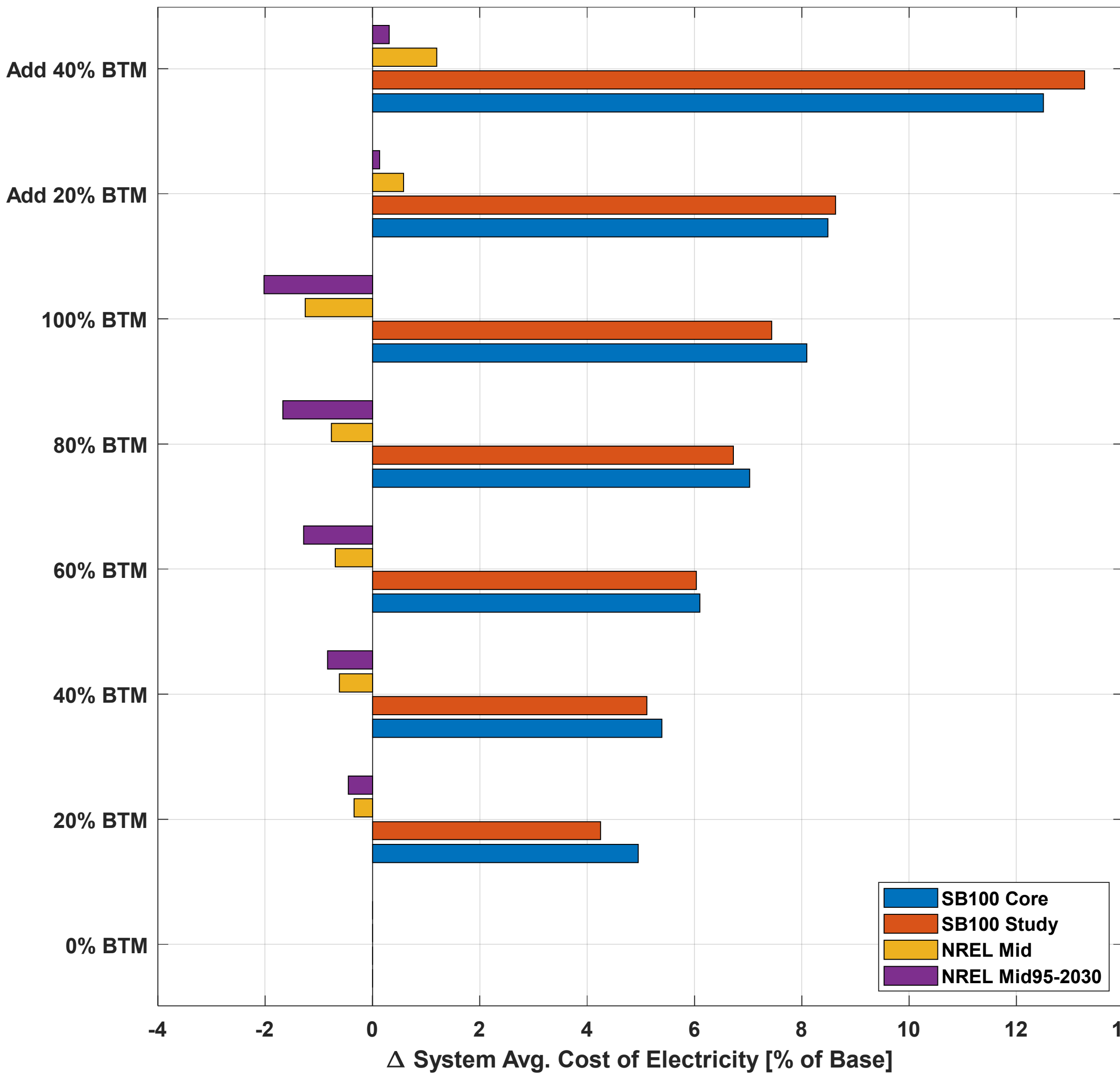

Figure 36 - Sensitivity of system-wide average cost of electricity to different projected electricity resource mixes in 2045 for BTM energy storage cases [% of base value for each resource mix]

For the system-wide average cost of electricity, the SB100 Study resource mix shows similar increases in costs compared to the SB100 Core results. The two NREL mixes show very slightly decreased costs compared to their base values for the substitution cases. This occurs since these scenarios have low renewable curtailment to being with, therefore energy storage just acts to enable other electricity resources to operate more steadily and with higher capacity factors, reducing costs slightly. For the BTM storage addition cases, the NREL mixes show slightly increased costs due to the additional cost of more energy storage capacity.

3.2.2. Co-located energy storage at wind farms

The effect of substituting projected utility-scale energy storage in 2045 with energy storage co-located at large-scale wind farms is presented in Figure 37 for zero-carbon electricity penetration, Figure 38 for renewable curtailment, and Figure 39 for the cost of electricity.

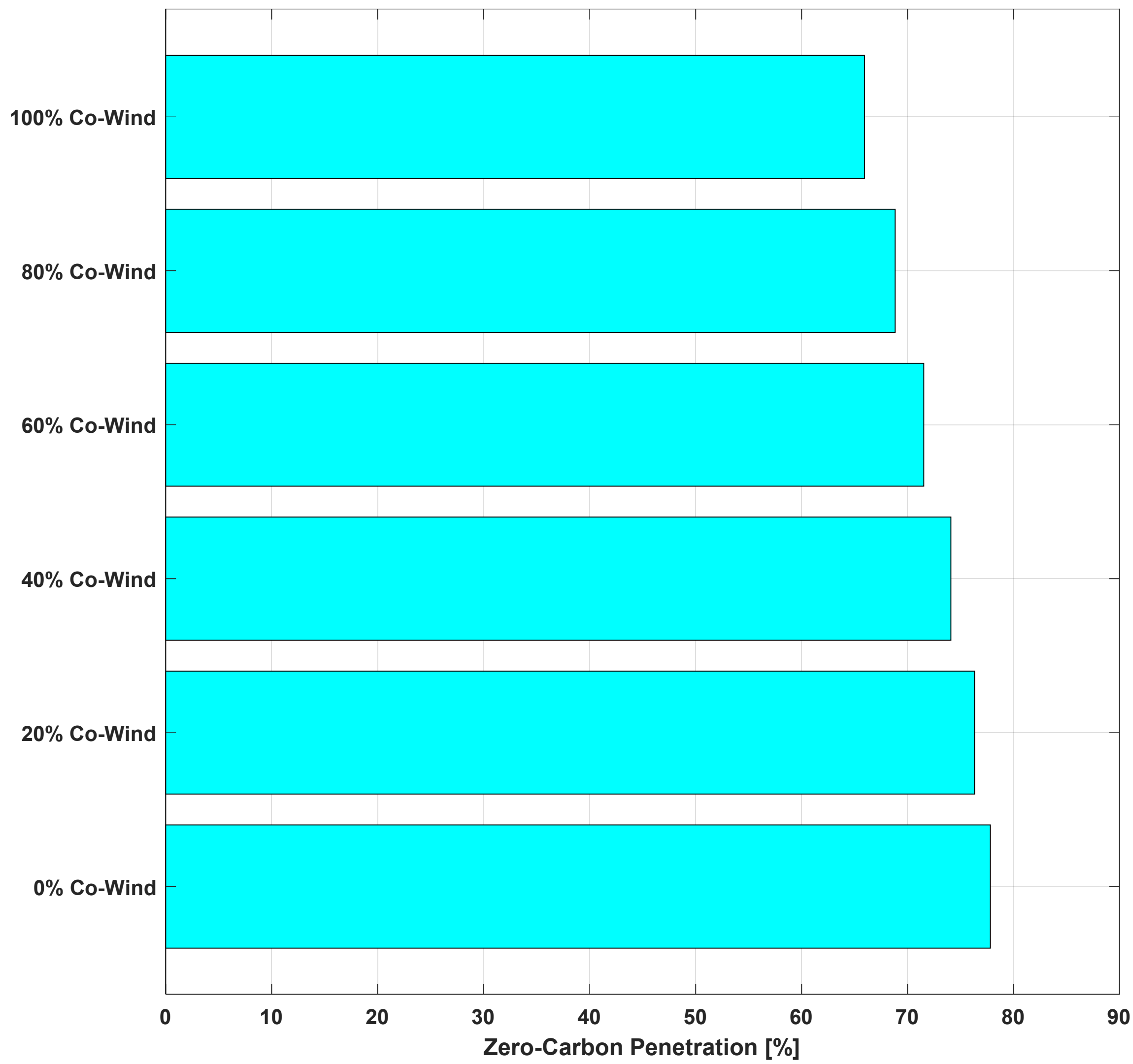

Figure 37 - System-wide zero-carbon electricity penetration for wind farm co-location energy storage cases [% of total annual electricity generation] in 2045

Substituting utility energy storage capacity for energy storage capacity co-located at wind farms decreases the system-wide zero-carbon electricity penetration from 77.8% with no co-location to 65.9% when 100% of energy storage capacity is co-located at wind farms. This is expected since energy storage co-located at wind farms is only able to charge with wind generation that would otherwise be curtailed and therefore does not aid the broader grid in managing excess solar generation. In the SB100 Core resource mix, both large-scale and distributed solar PV capacity comprise the majority of renewable resource capacity and the generation profile of these resources concentrates their excess generation during the middle of the day. Therefore, removing utility energy storage that can charge with wind and/or solar and aid in managing the combined behavior of each resource and replacing it with the equivalent energy storage capacity that can only manage wind variability, will expectedly cause a decrease in system-wide zero-carbon electricity penetration.

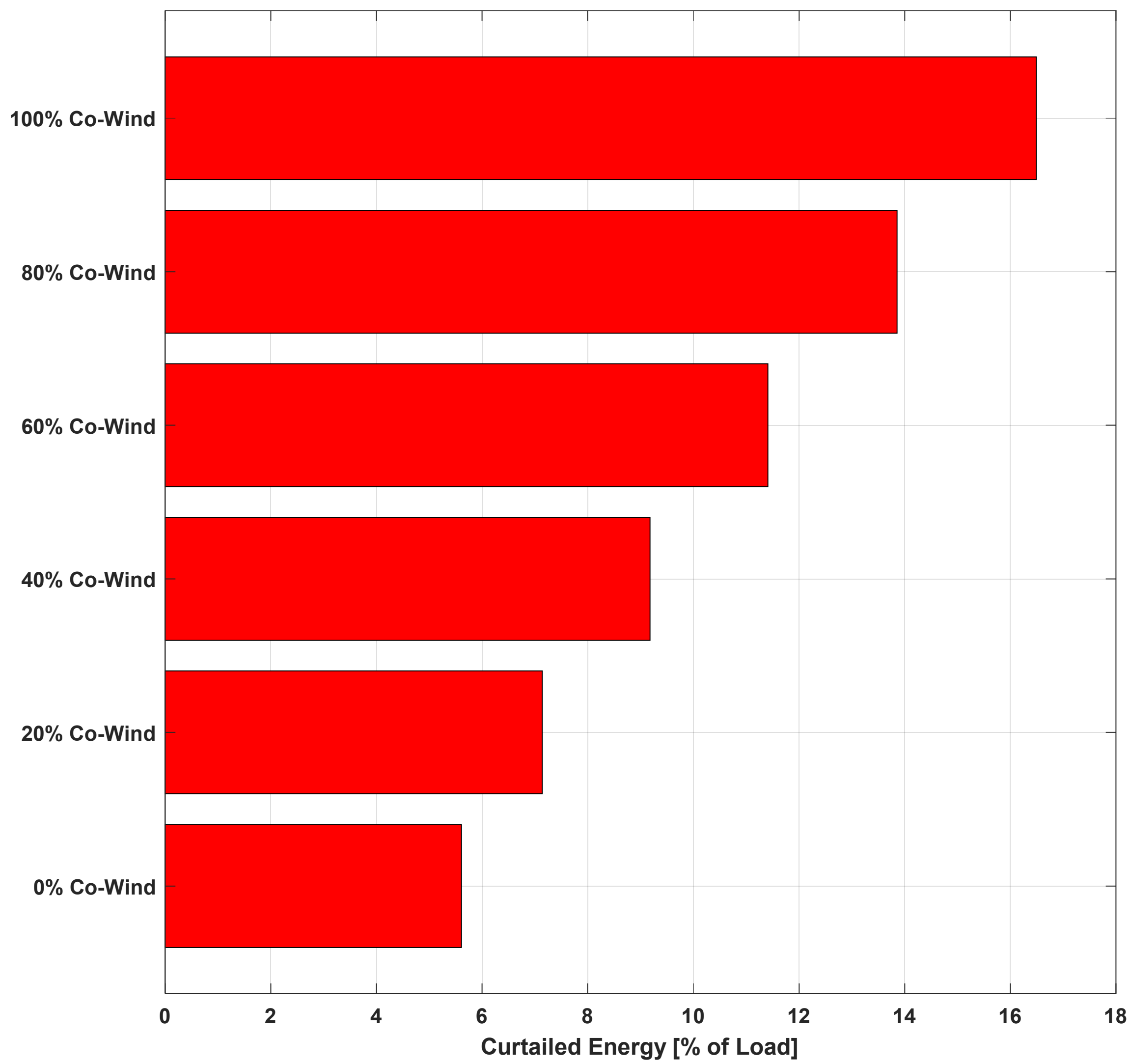

Figure 38 - System-wide renewable curtailment for wind farm co-location energy storage cases (% of annual load) in 2045

The limited ability of energy storage co-located at wind farms to aid in managing excess generation from solar and other needs of the broader grid is reflected in increased renewable curtailment. Utility energy storage can manage both wind and solar variability, but energy storage co-located at wind farms only manages wind variability. Replacing the former with the latter results in increased solar energy curtailment and therefore increased overall renewable energy curtailment, from 5.6% of annual load equivalent with no co-location up to 16.5% of annual load equivalent when all energy storage is co-located at wind farms.

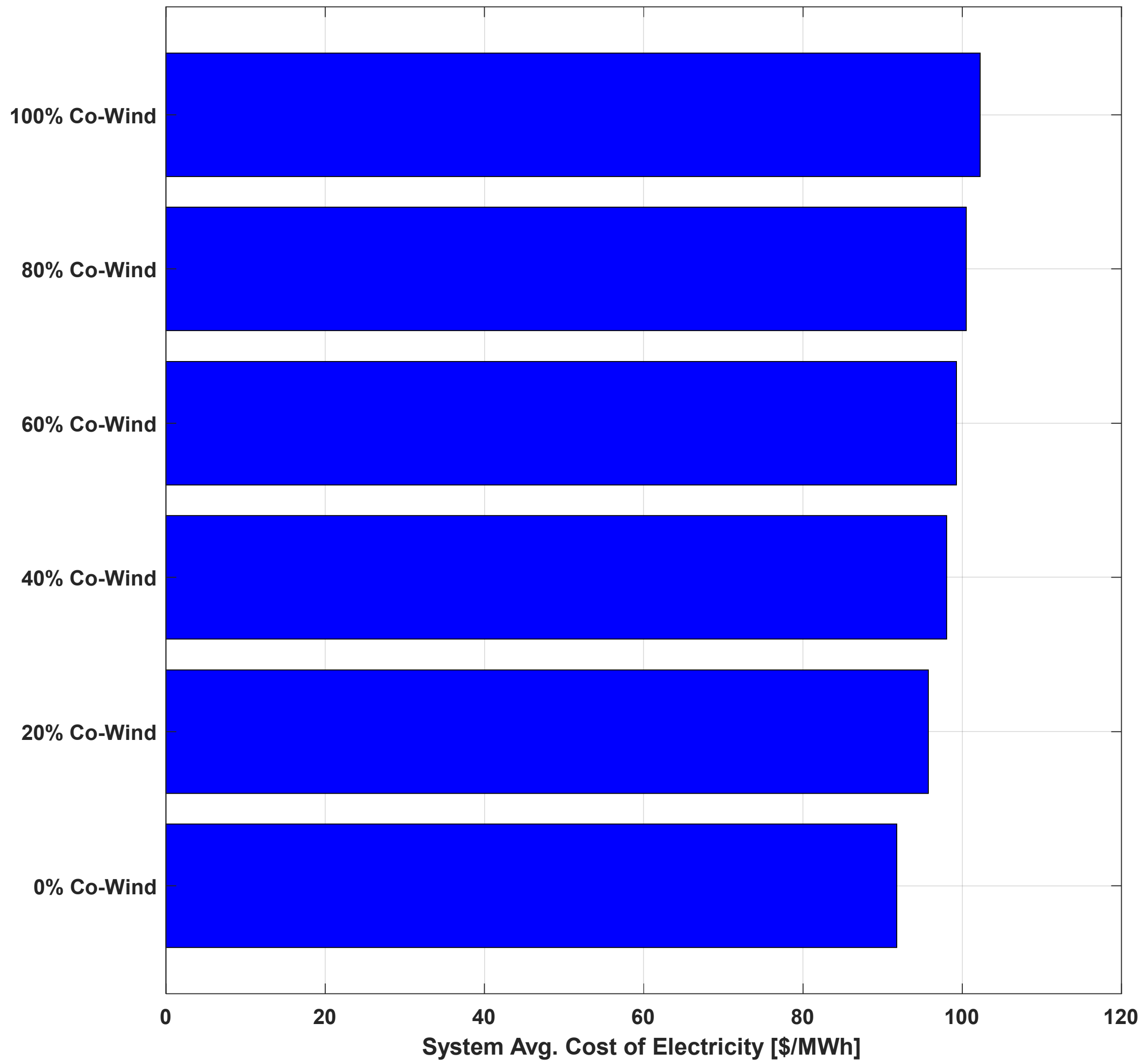

Figure 39 - System-wide average cost of electricity for wind farm co-location energy storage cases in 2045 [$/MWh]

The increased renewable energy curtailment resulting from the limited ability of energy storage co-located at wind farms to manage system-wide net load variability is also reflected in increased costs. The reduction in the system's ability to capture excess solar generation when more energy storage is co-located at wind farms means that other resources – in particular, expensive natural gas peaking resources in this case – are called upon to ensure that the system-wide electric load profile is satisfied. This results in increases in the system-wide average cost of electricity.

The sensitivity of the wind farm co-location energy storage cases to different projected resource mixes is presented in Figure 40 for zero-carbon penetration, Figure 41 for renewable curtailment, and Figure 42 for the system cost of electricity. Note that these values are presented as percentage deviations from the base (0% Co-location) value achieved in each resource mix.

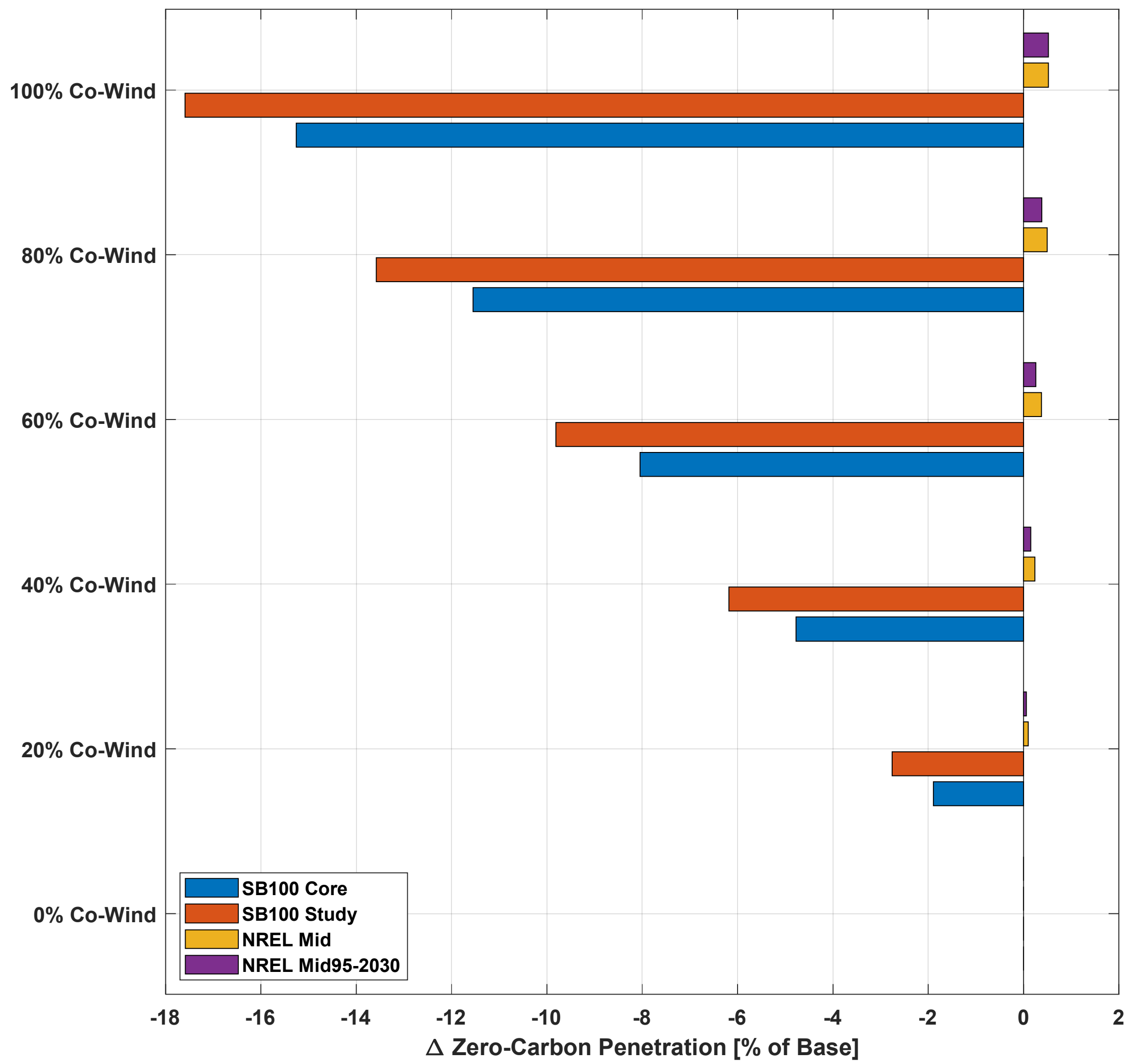

Figure 40 - Sensitivity of system-wide zero-carbon electricity penetration to different projected electricity resource mixes in 2045 for wind farm co-location energy storage cases [% of base value for each resource mix]

The SB100 Study mix behaves similarly to the SB100 Core mix in how co-location of energy storage at wind farms affects zero-carbon penetration – namely that substituting larger fractions of utility energy storage with wind farm co-located energy storage reduces system-wide zero carbon penetration. The drivers are the same as that explained for the SB100 Core mix but have larger detrimental effects as the SB100 Study resource mix is comprised of even more solar generation capacity. The two resource mixes from the NREL Standard Scenarios show tiny increases in zero-carbon penetration. In the NREL resource mixes, wind is a larger fraction of total resource capacity than in the SB100 resource mixes, but overall curtailment levels are lower since solar capacity is roughly half of that in the SB100 resource mixes. This means that the reduced ability to manage excess solar generation is not as much of a detriment since, for these resource mixes, most of the solar generation is absorbed directly. Consequently, the reduced losses from co-locating energy storage at wind farms due to avoiding separate transformer and transmission losses from the wind farm and energy storage systems enable the zero-carbon penetration to increase very slightly.

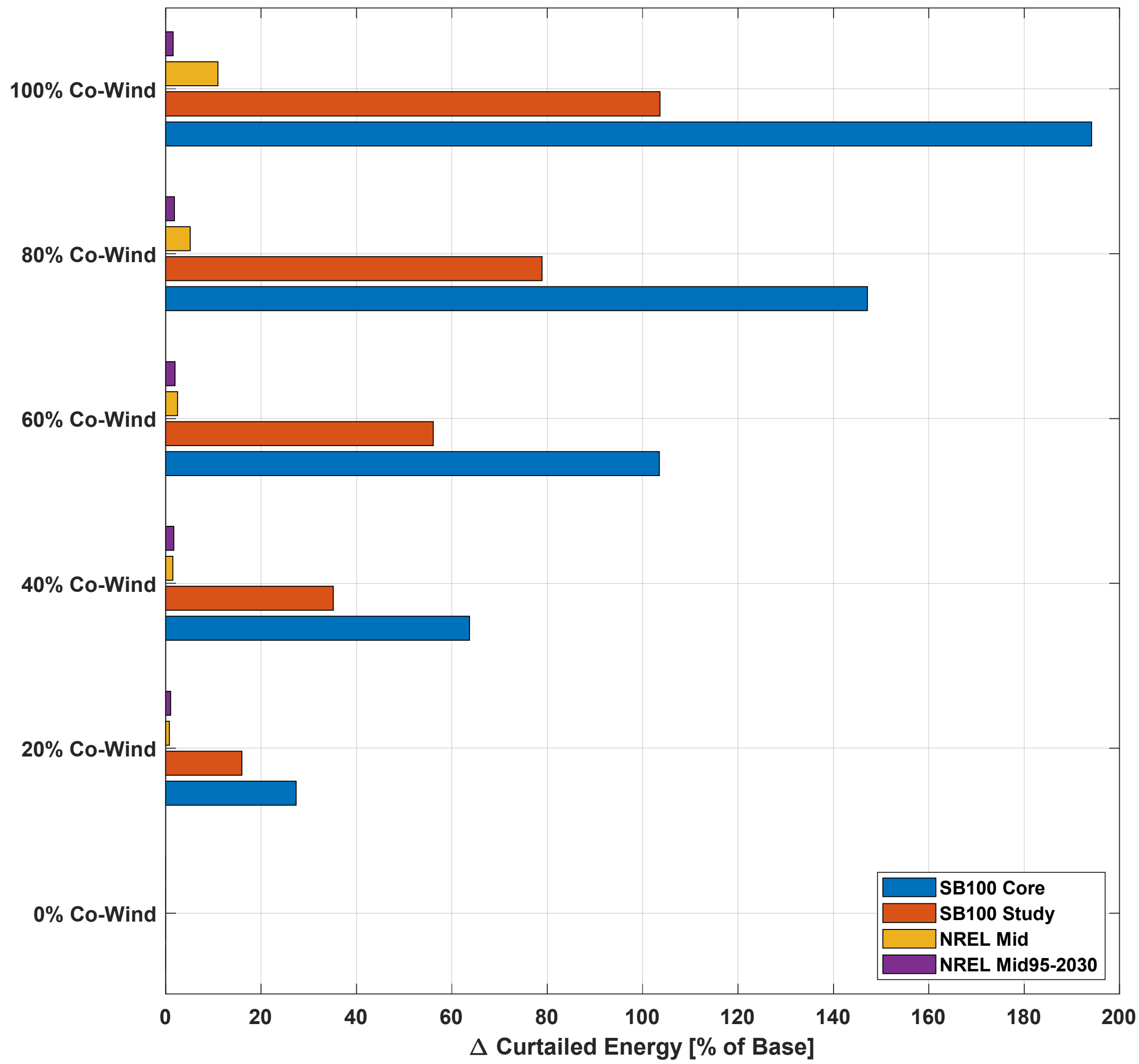

Figure 41 - Sensitivity of curtailed renewable energy electricity to different projected electricity resource mixes in 2045 for wind farm co-location energy storage cases [% of base value for each resource mix]

All four resource mixes show increased renewable energy curtailment as more utility energy storage is replaced by energy storage co-located at wind farms, with the SB100 mixes showing significant increases due to the reduced ability of the system to manage excess solar generation. This effect is still present for the NREL resource mixes but to a much smaller extent.

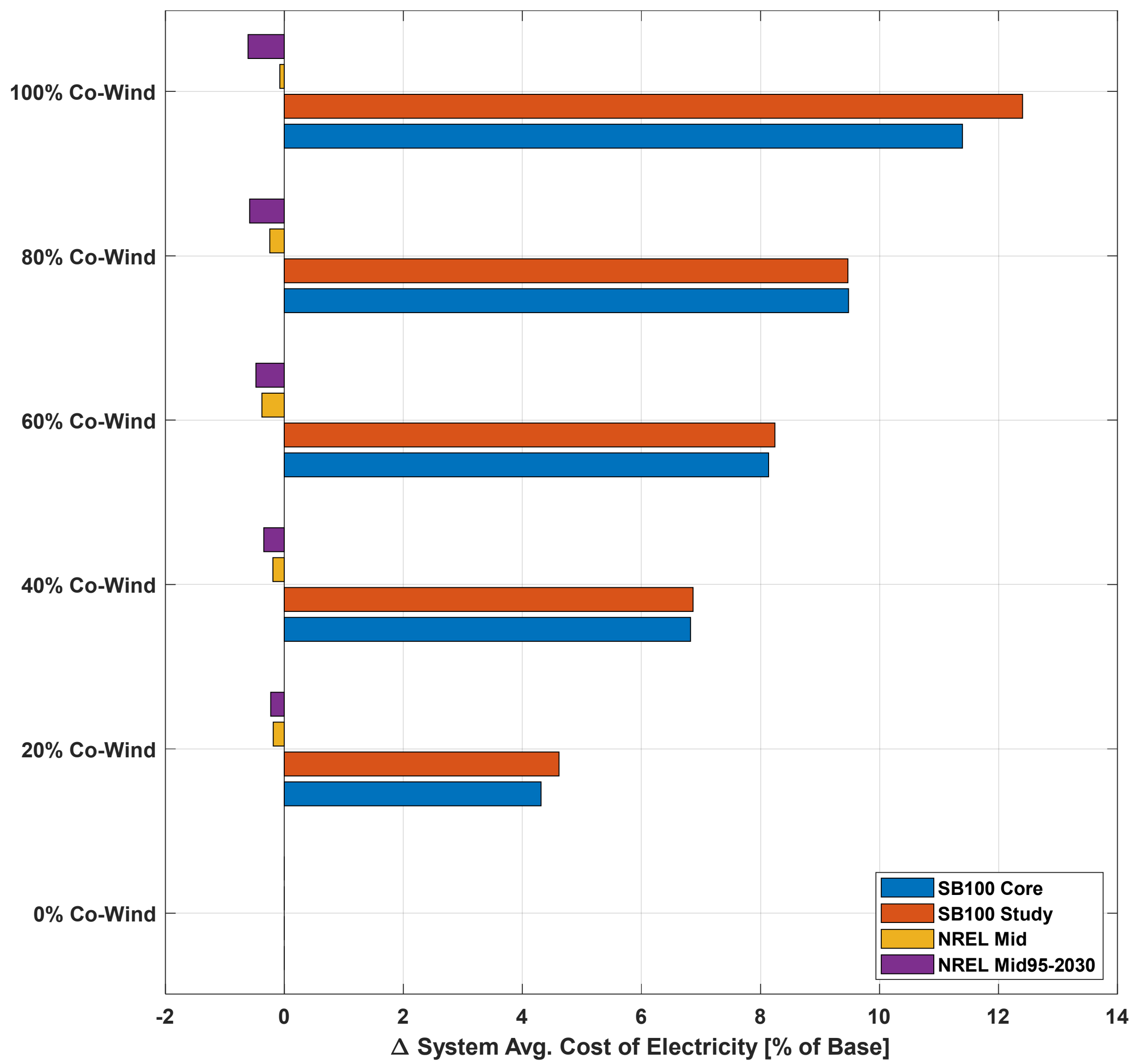

Figure 42 - Sensitivity of system-wide average cost of electricity to different projected electricity resource mixes in 2045 for wind farm co-location energy storage cases [% of base value for each resource mix]

The drivers for the trends in zero-carbon electricity penetration and curtailed renewable energy are reflected in the effects on the system-wide cost of electricity. For the SB100 resource mixes, the ability to manage excess solar generation is critical since solar PV comprises the majority of the generation capacity. Replacing energy storage that can manage combined wind and solar generation with energy storage that can only manage wind generation increases solar energy curtailment, requiring expensive peaking resources to be used to satisfy parts of the electric load profile, increasing costs. For the mixes from the NREL Standard Scenarios, the limited ability to manage excess solar is not as significant and the reduced losses from co-locating energy storage at wind farms slightly reduce reliance on fossil fuel generation, slightly reducing costs.

3.2.3. Co-located energy storage at solar farms

The effect of substituting projected utility-scale energy storage in 2045 with energy storage co-located at large-scale solar farms is presented in Figure 43 for zero-carbon electricity penetration, Figure 44 for renewable curtailment, and Figure 45 for the cost of electricity.

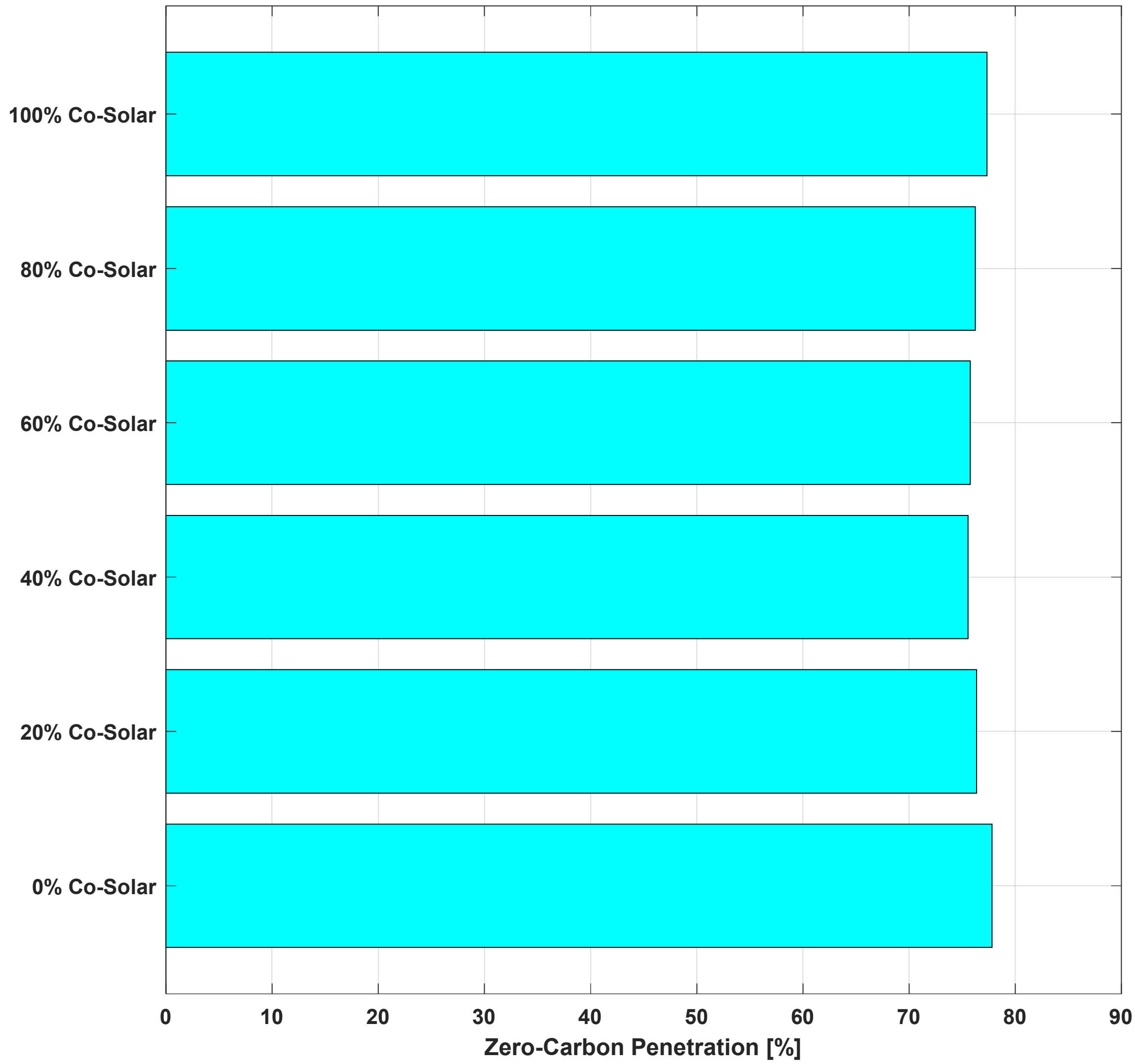

Figure 43 - System-wide zero-carbon electricity penetration for solar farm co-location energy storage cases [% of total annual electricity generation] in 2045

Replacing utility energy storage capacity with energy storage located at large-scale solar farms has a varied effect on system-wide zero-carbon electricity penetration as a result of two competing effects. On one hand, energy storage capacity co-located at solar farms can only respond to manage excess solar generation, as opposed to utility energy storage that can respond to manage combined wind and solar generation. This causes zero-carbon electricity penetration to decrease with more solar farm co-located energy storage since this energy storage capacity cannot manage excess renewable generation from wind or rooftop solar. On the other hand, co-locating energy storage at solar farms reduces losses, since co-located energy storage can augment solar generation without separately having to incur losses from conversion to high voltage AC to connect to the transmission system. Since in the SB100 Core mix that underpins these results, large-scale solar PV resources are the single largest zero-carbon resource by capacity and generation, reducing losses for this resource enables much more solar generation to be available to satisfy the electric load. This causes zero-carbon electricity penetration to increase with more solar farm co-located energy storage.

The result is that as some utility energy storage capacity is replaced by energy storage co-located at solar farms, the system-wide zero-carbon electricity penetration decreases, with the lowest value (75.5%) occurring at the 40% capacity replacement level. As more utility energy storage capacity is replaced by energy storage co-located at solar farms, the system-wide zero-carbon electricity penetration starts to increase until 100% of utility energy storage capacity is replaced.

However, it is important to note that when 100% of utility energy storage capacity is replaced with energy storage capacity co-located at solar farms, the system-wide zero carbon penetration (77.3%) is still slightly lower than the case with no co-located energy storage (77.8%).

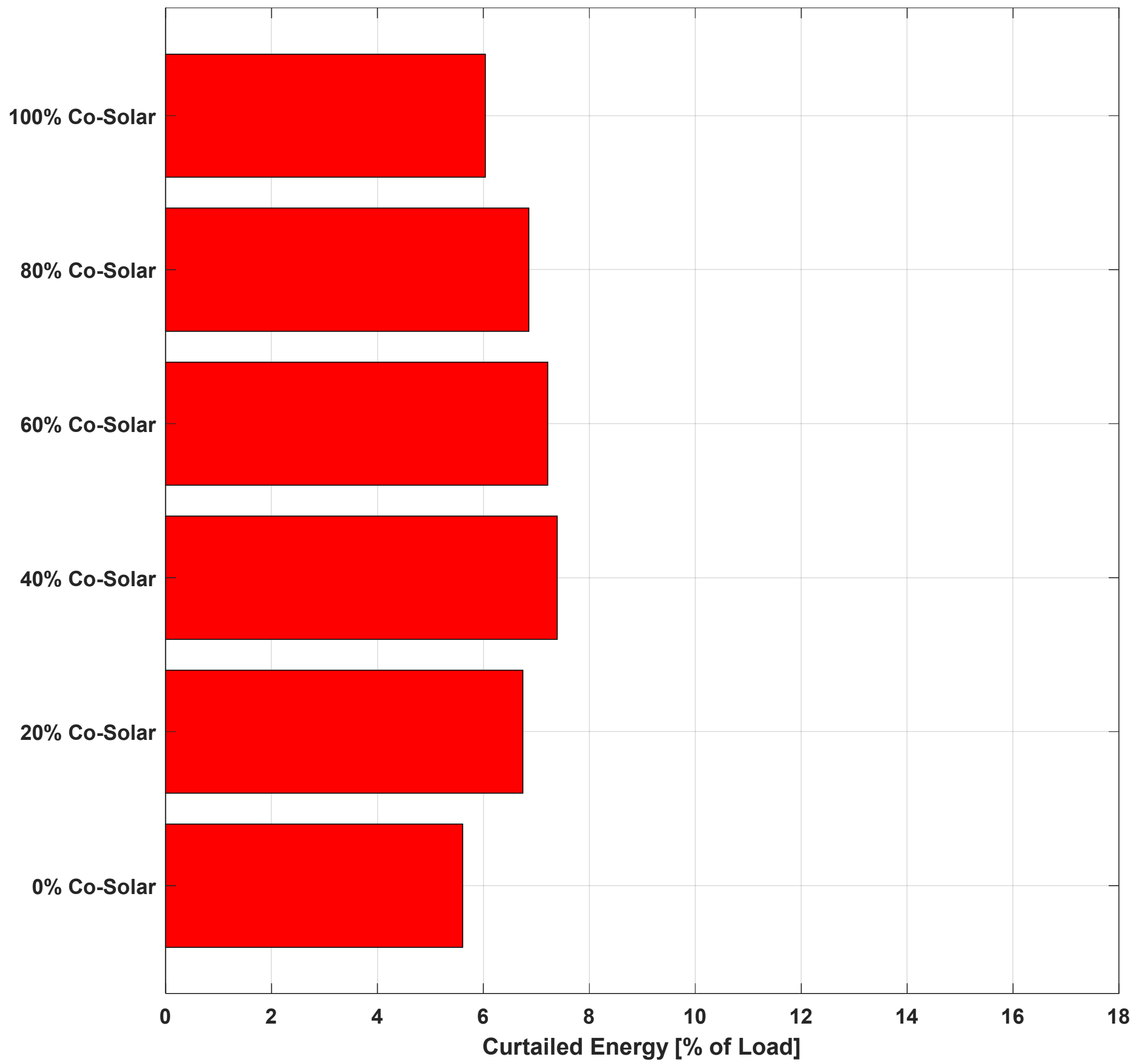

Figure 44 - System-wide renewable curtailment for solar farm co-location energy storage cases (% of annual load) in 2045

The trends in system-wide zero-carbon electricity penetration are reflected in those for curtailed renewable energy. As some utility energy storage is replaced with solar farm co-located energy storage, renewable curtailment initially increases since the latter can only respond to manage large-scale solar PV generation to which it is connected. As this process continues, the reduced losses enable more solar PV generation to be available to serve the electric load, reducing system-wide curtailed renewable energy. Similar to the zero-carbon electricity penetration results, the curtailed renewable energy in the 100% energy storage co-located at solar farm case (6.0%) doesn't quite achieve the performance of the case where no energy storage was co-located at solar farms (5.6%), but it is close.

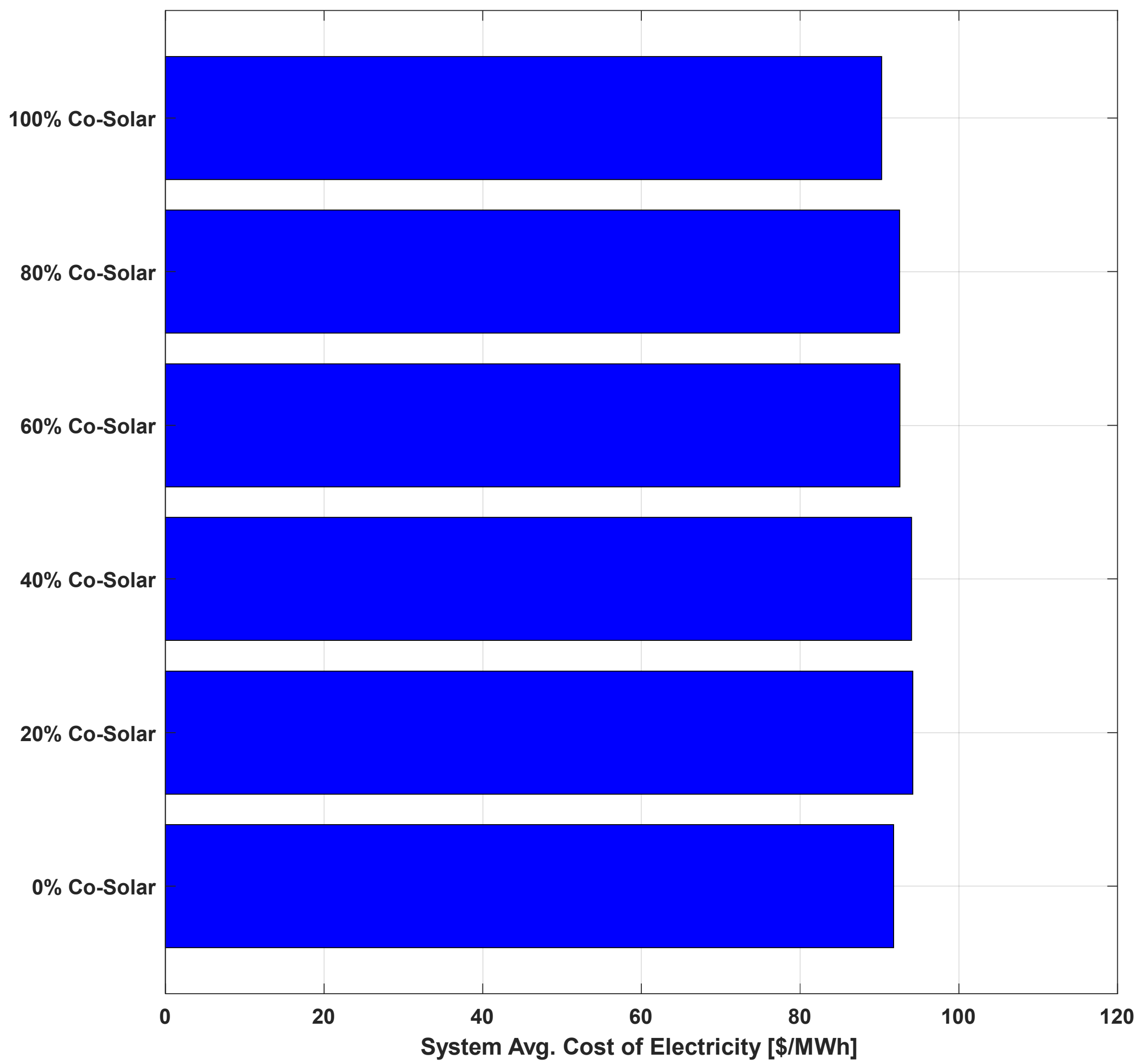

Figure 45 - System-wide average cost of electricity for solar farm co-location energy storage cases in 2045 [$/MWh]

The trends for zero-carbon electricity penetration are also reflected in the system-wide average cost of electricity, but with the exception that the case where 100% of energy storage capacity is co-located at solar farms does outperform the case when no energy storage capacity is co-located at solar farms: $90.2/MWh versus $91.7/MWh, respectively. The reduced losses in the former's case improve the economics of large-scale solar and due to the large presence of this resource in the overall generation mix, this results in slight improvements in the system-wide cost of electricity.

The sensitivity of the solar farm co-location energy storage cases to different projected resource mixes is presented in Figure 46 for zero-carbon penetration, Figure 47 for renewable curtailment, and Figure 48 for system cost of electricity. Note that these values are presented as percentage deviations from the base (0% Co-location) value achieved in each resource mix.

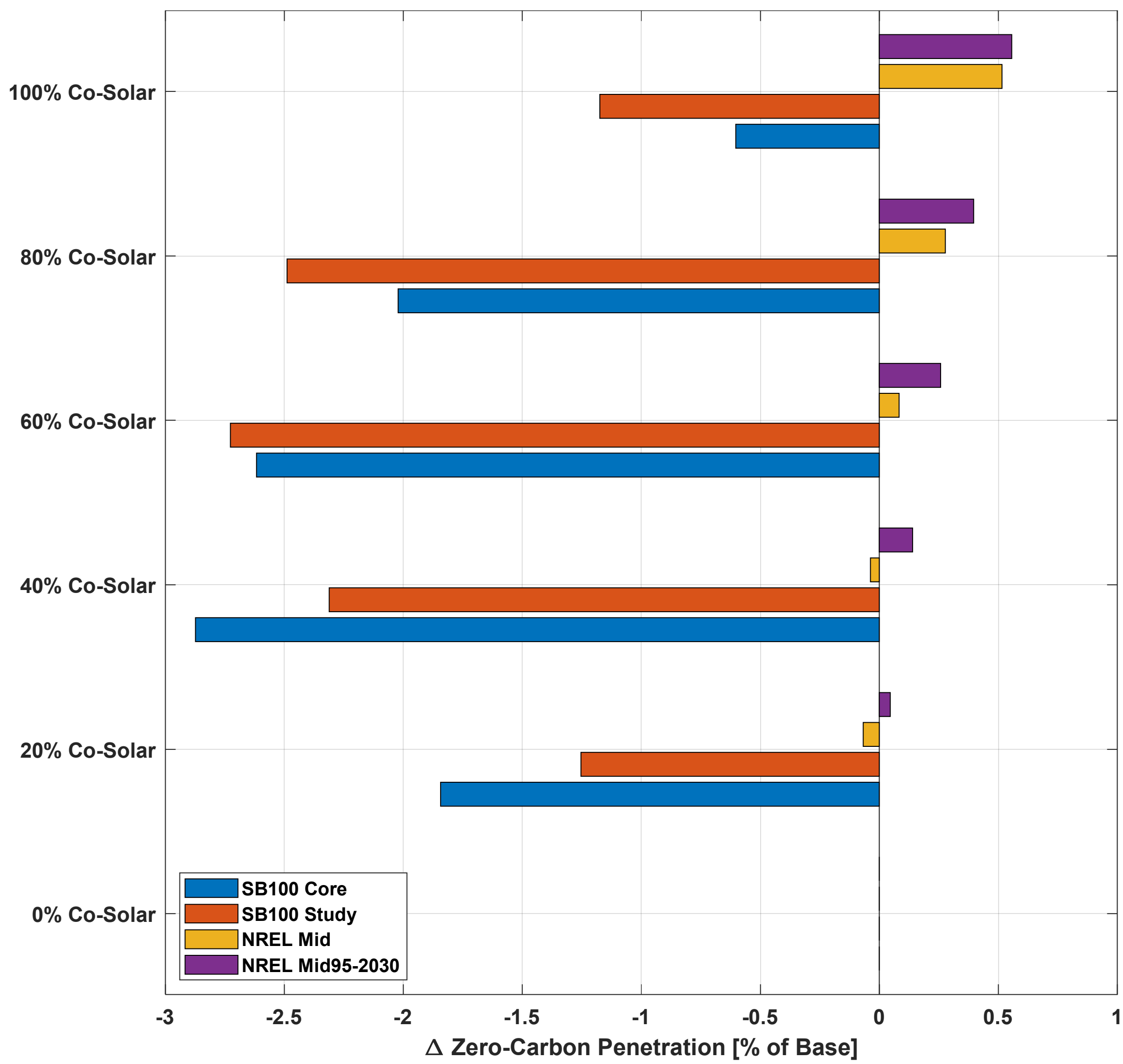

Figure 46 - Sensitivity of system-wide zero-carbon electricity penetration to different projected electricity resource mixes in 2045 for solar farm co-location energy storage cases [% of base value for each resource mix]

The SB100 Study mix follows similar trends regarding the effects of substituting utility energy storage for energy storage co-located at solar farms, but with some key exceptions. First, the largest decrease occurs at 60% co-located energy storage capacity instead of 40% for the SB100 Core mix, and the result for the case where 100% of energy storage is co-located at solar farms has a larger gap from the no co-located energy storage case than the SB100 Core mix. This may be due to the larger capacity of solar PV in the SB100 Study mix requiring more energy storage capacity for the benefit of reduced losses to overcome the detriment of limitations in the information that co-located energy storage can respond to. The two mixes from the NREL Standard Scenarios show small changes, with the Mid95-2030 mix showing increases in zero-carbon penetration for all cases and the Mid mix showing small increases starting at the 60% co-located energy storage capacity case.

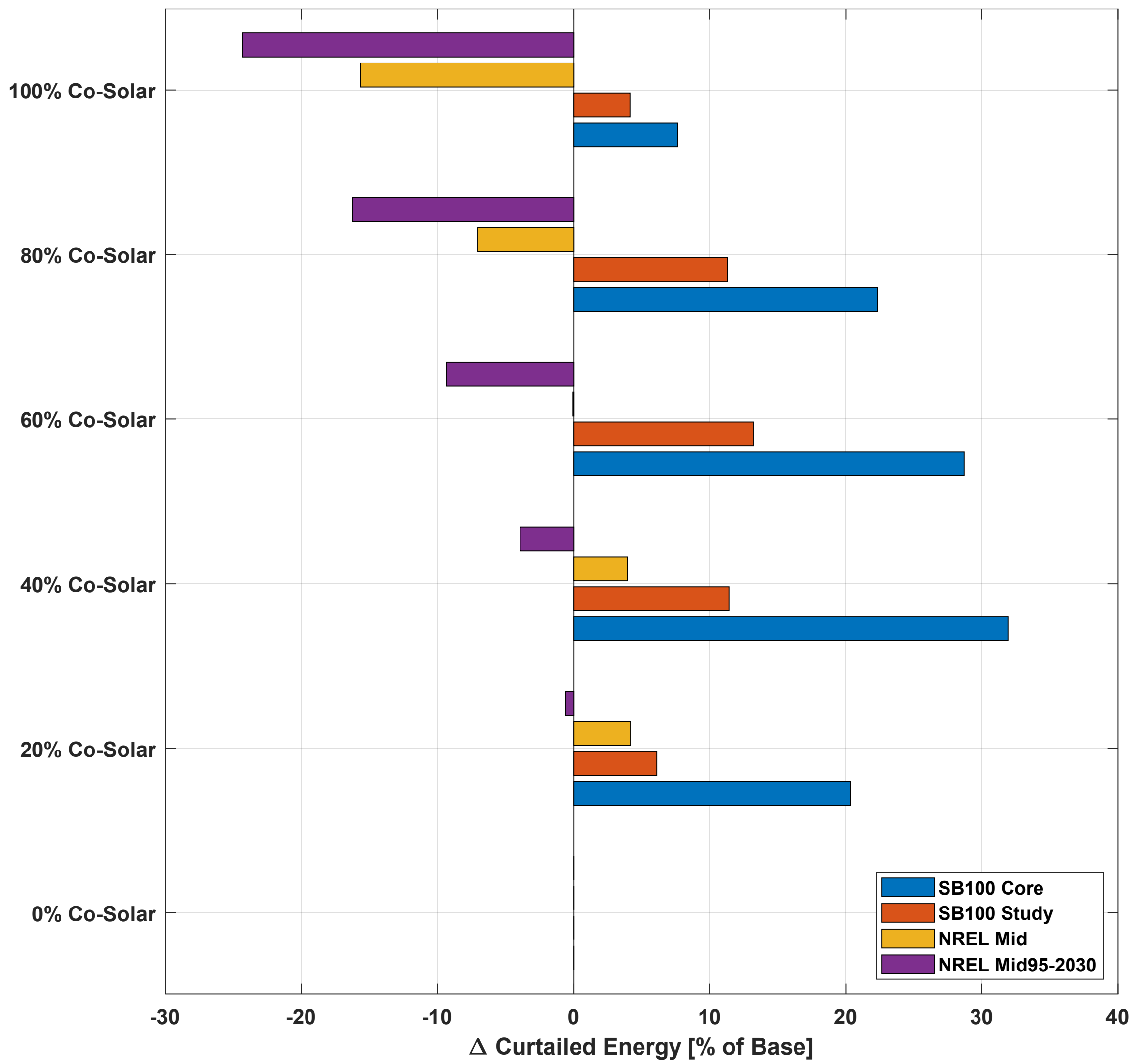

Figure 47 - Sensitivity of curtailed renewable energy electricity to different projected electricity resource mixes in 2045 for solar farm co-location energy storage cases [% of base value for each resource mix]

The trends for zero-carbon electricity penetration are also reflected in those for system-wide curtailed renewable energy and are due to the same drivers. Increases in curtailed energy reflect decreases in zero-carbon penetration and vice versa.

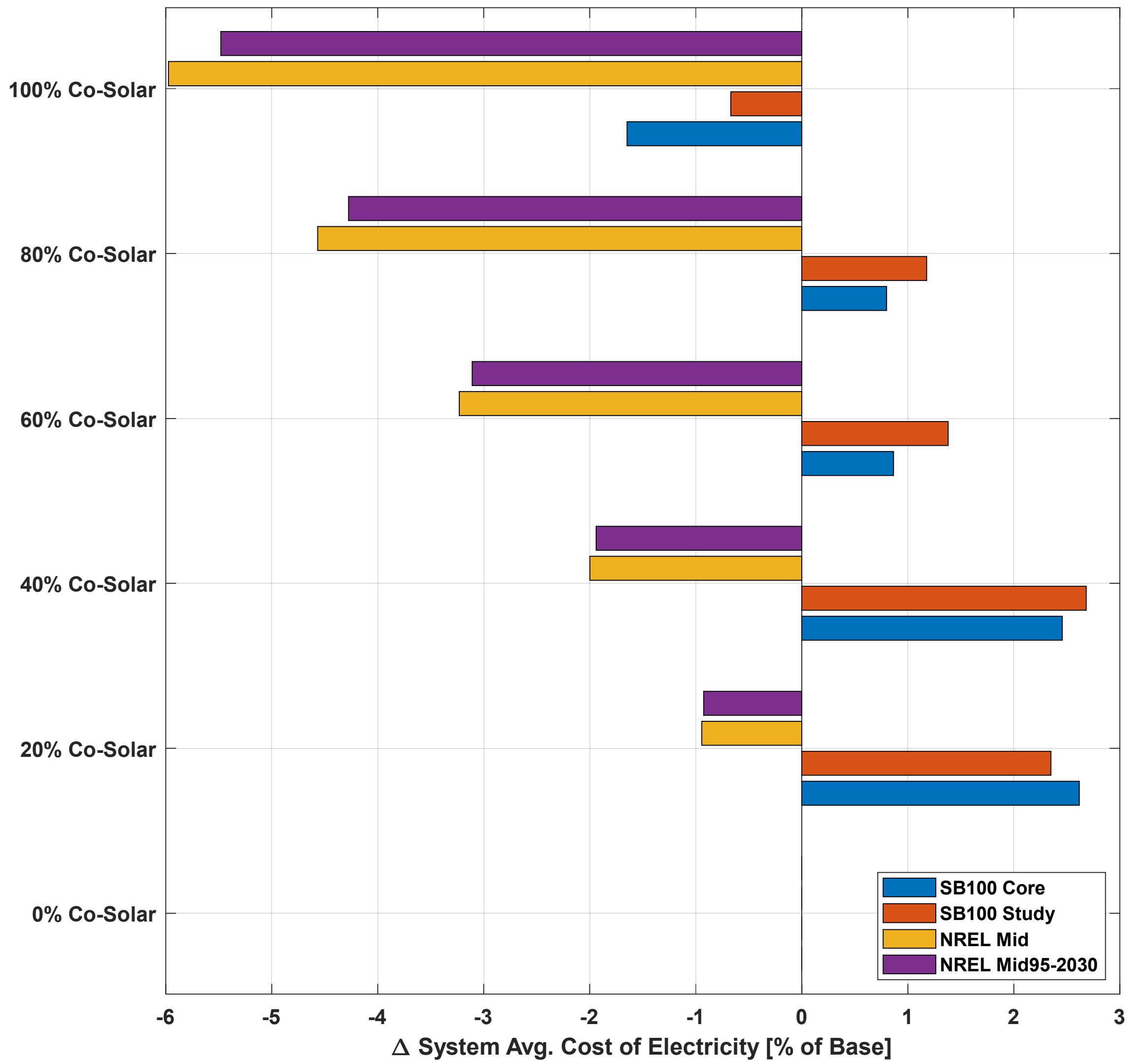

Figure 48 - Sensitivity of system-wide average cost of electricity to different projected electricity resource mixes in 2045 for solar farm co-location energy storage cases [% of base value for each resource mix]

Regarding the cost of electricity, the SB100 resource mixes show initial increases as utility energy storage is substituted for energy storage co-located at solar farms due to limitations in the ability of co-located energy storage to respond to broader grid needs, but the trend reverses with further co-location of energy storage at solar farms due to reduced losses. The mixes from the NREL Standard Scenarios show cost of electricity decreases since the effect of reduced losses dominates the impact of cost for these resource mixes.

3.2.4. Short-duration energy storage technology substitution

The effect of substituting projected lithium-ion utility-scale energy storage in 2045 with vanadium redox flow batteries is presented in Figure 49 for zero-carbon electricity penetration, Figure 50 for renewable curtailment, and Figure 51 for the cost of electricity.

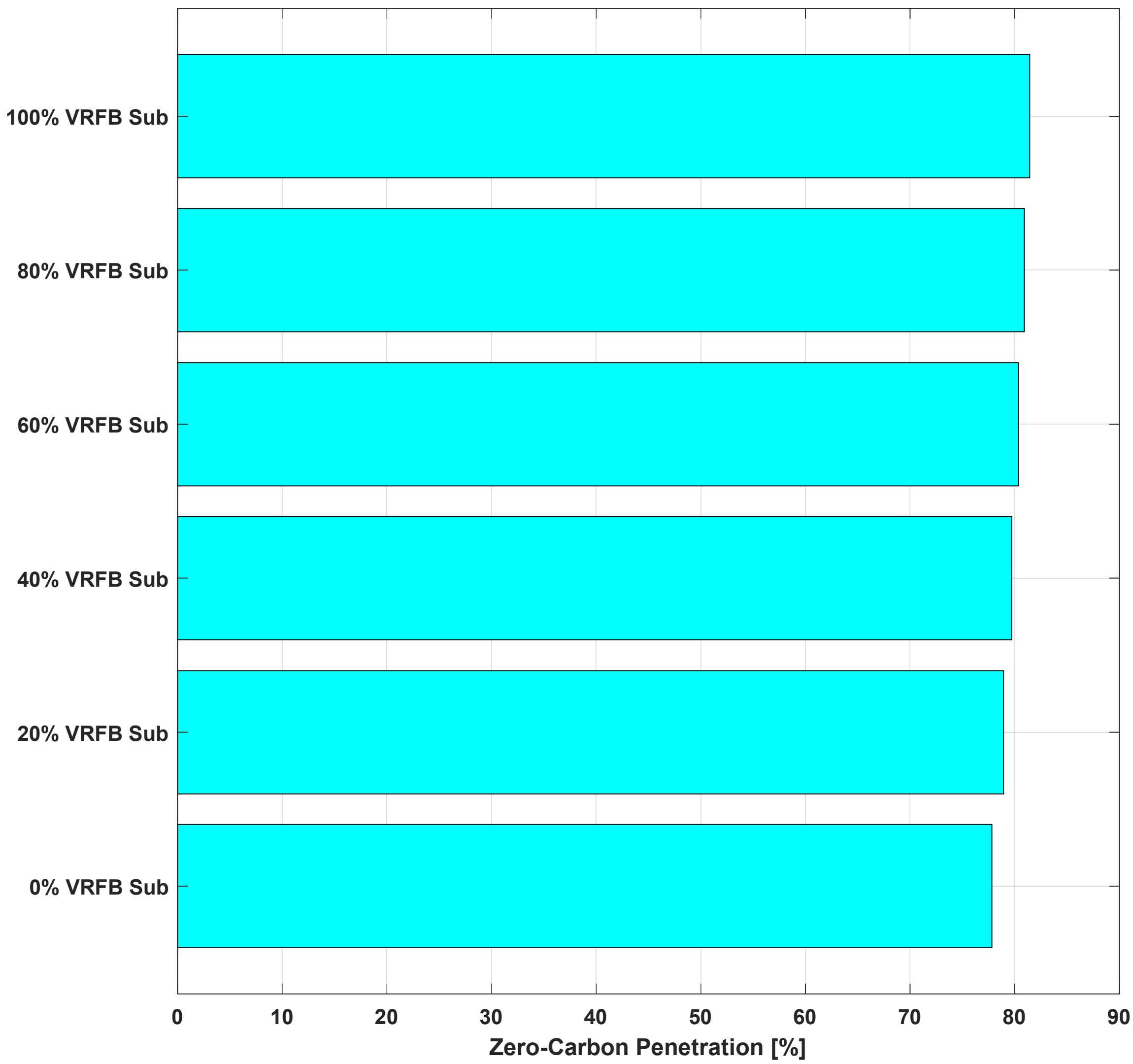

Figure 49 - System-wide zero-carbon electricity penetration for VRFB energy storage substitution cases [% of total annual electricity generation] in 2045

Replacing increasing fractions of lithium-ion-based utility energy storage with vanadium redox flow batteries increases the system-wide zero carbon penetration from 77.8% (lithium-ion only) to 81.4% (fully replaced by vanadium redox flow batteries). This is entirely due to the larger energy-to-power capacity ratio of the vanadium redox flow batteries (10:1) as modeled here compared to the lithium-ion batteries (4:1) and that the substitution is conducted on a per-power capacity basis. Therefore, when flow batteries are installed at the same power capacity as that of the lithium-ion batteries, this results in more energy capacity. A larger total energy capacity of energy storage installed in the system allows the energy storage to mitigate mismatches between zero-carbon electricity generation and load demand over longer timescales, enabling the uptake of more otherwise curtailed renewable energy despite the slightly lower round-trip efficiency of the flow batteries compared to the lithium-ion batteries.

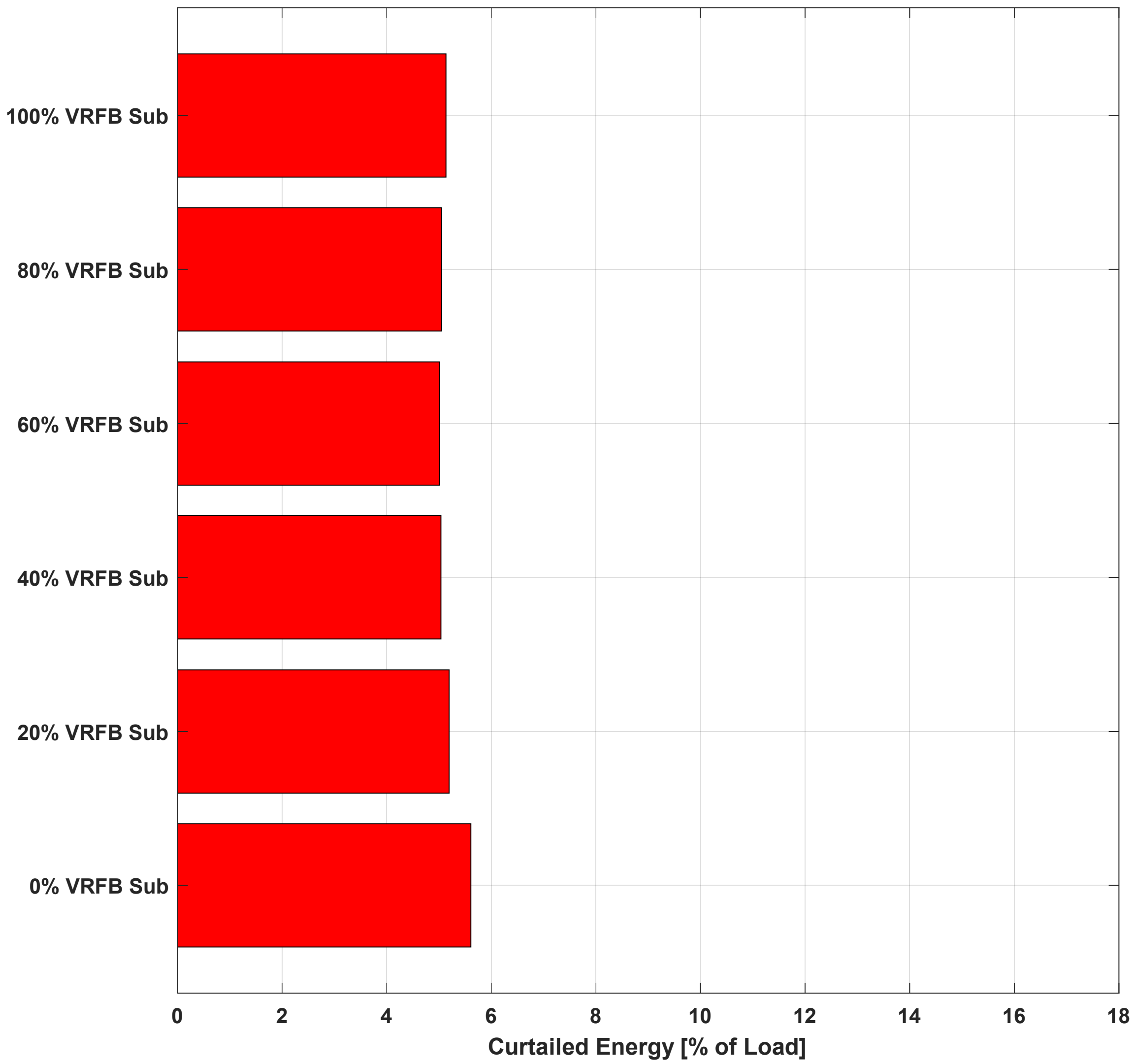

Figure 50 - System-wide renewable curtailment for VRFB energy storage substitution cases (% of annual load) in 2045

Expectedly, substituting lithium-ion batteries for vanadium redox flow batteries resulting in a larger total energy capacity of energy storage installed in the system results in reduced curtailed renewable energy, from 5.6% of annual load equivalent (all lithium-ion) to 5.1% of annual load equivalent (all flow battery). Larger total energy capacity enables uptake of excess renewable generation that otherwise would have been unused since 4-hour lithium-ion batteries would not be able to store energy long enough to level mismatches between zero-carbon electricity generation and load over longer timescales.

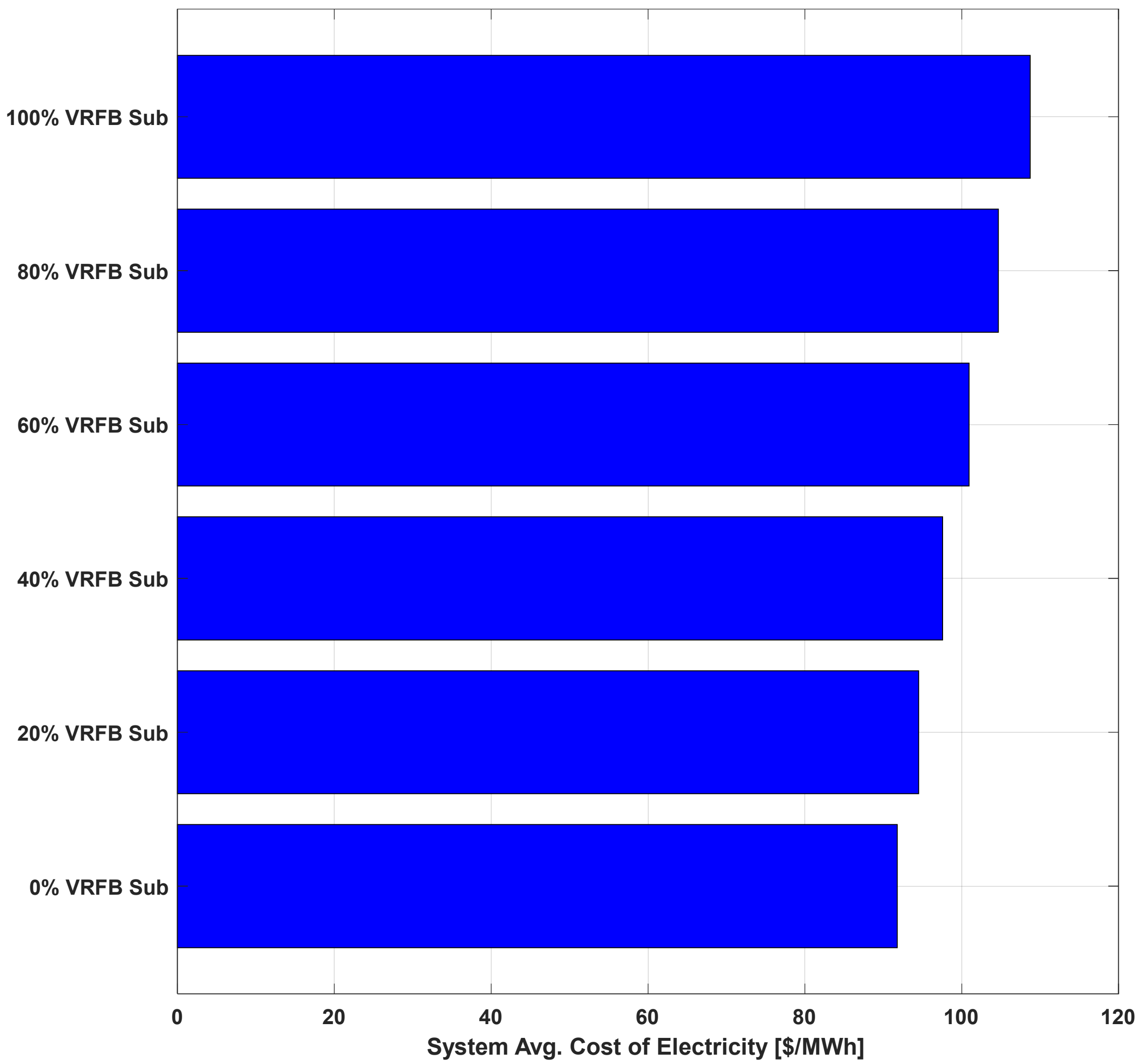

Figure 51 - System-wide average cost of electricity for VRFB energy storage substitution cases in 2045 [$/MWh]

Although substituting lithium-ion batteries for flow batteries improves zero-carbon electricity penetration and reduces curtailed renewable energy, this process does increase electricity costs. This is solely due to the much higher capital costs of vanadium redox flow batteries relative to lithium-ion batteries, currently and projected into the future.

The sensitivity of the short-duration energy storage substitution cases to different projected resource mixes is presented in Figure 52 for zero-carbon penetration, Figure 53 for renewable curtailment, and Figure 54 for system cost of electricity. Note that these values are presented as percentage deviations from the base (0% VRFB = 100% lithium-ion) value achieved in each resource mix.

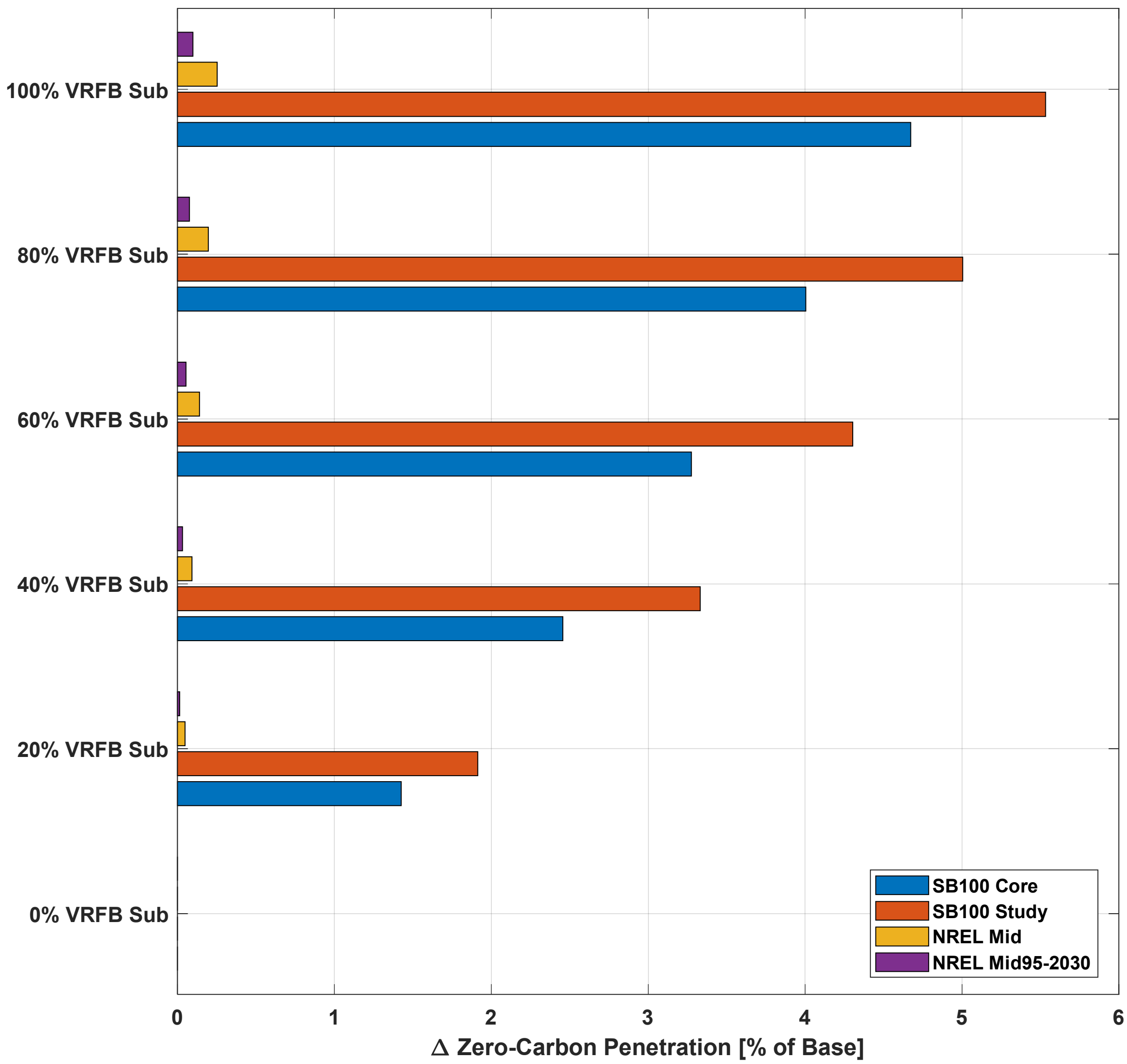

Figure 52 - Sensitivity of system-wide zero-carbon electricity penetration to different projected electricity resource mixes in 2045 for VRFB energy storage substitution cases [% of base value for each resource mix]

All four of the different projected resource mixes show increases in the system-wide zero-carbon electricity penetration when utility-scale lithium-ion batteries are substituted for utility-scale vanadium redox flow batteries. The SB100 mixes show the largest percentage increases over their respective base values since these resource mixes. These mixes exhibit large excess renewable generation availability due to their high renewable resource capacities (particularly from large-scale solar), which the added energy capacity from using 10-hr vanadium redox flow batteries can more fully capture. The resource mixes from the NREL Standard Scenarios also show improvements, but since these mixes have little to no excess renewable generation as modeled here to begin with, the improvements to zero carbon electricity penetration from added energy capacity are small.

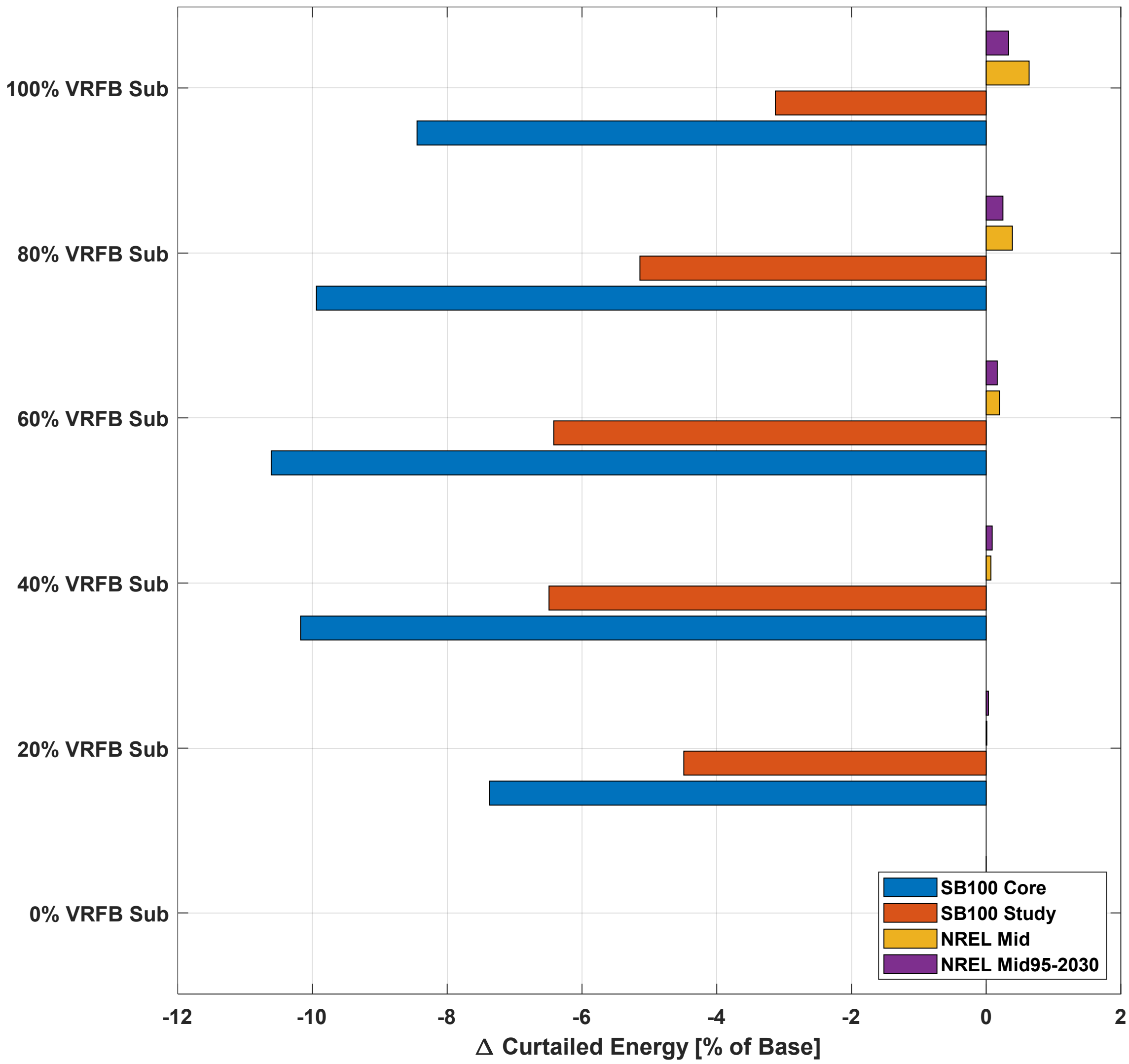

Figure 53 - Sensitivity of curtailed renewable energy electricity to different projected electricity resource mixes in 2045 for VRFB energy storage substitution cases [% of base value for each resource mix]

The increased energy capacity of installed energy storage from substituting lithium-ion batteries with vanadium redox flow batteries expectedly results in reduced curtailed renewable energy in the SB100 resource mixes, since the energy storage system can capture and manage more of the available excess renewable energy. For the NREL resource mixes, very small increases in curtailed renewable energy are observed. Since these resource mixes have very small excess renewable generation to begin with, these effects may primarily be due to the resolution of the modeling framework and not an interpretable result.

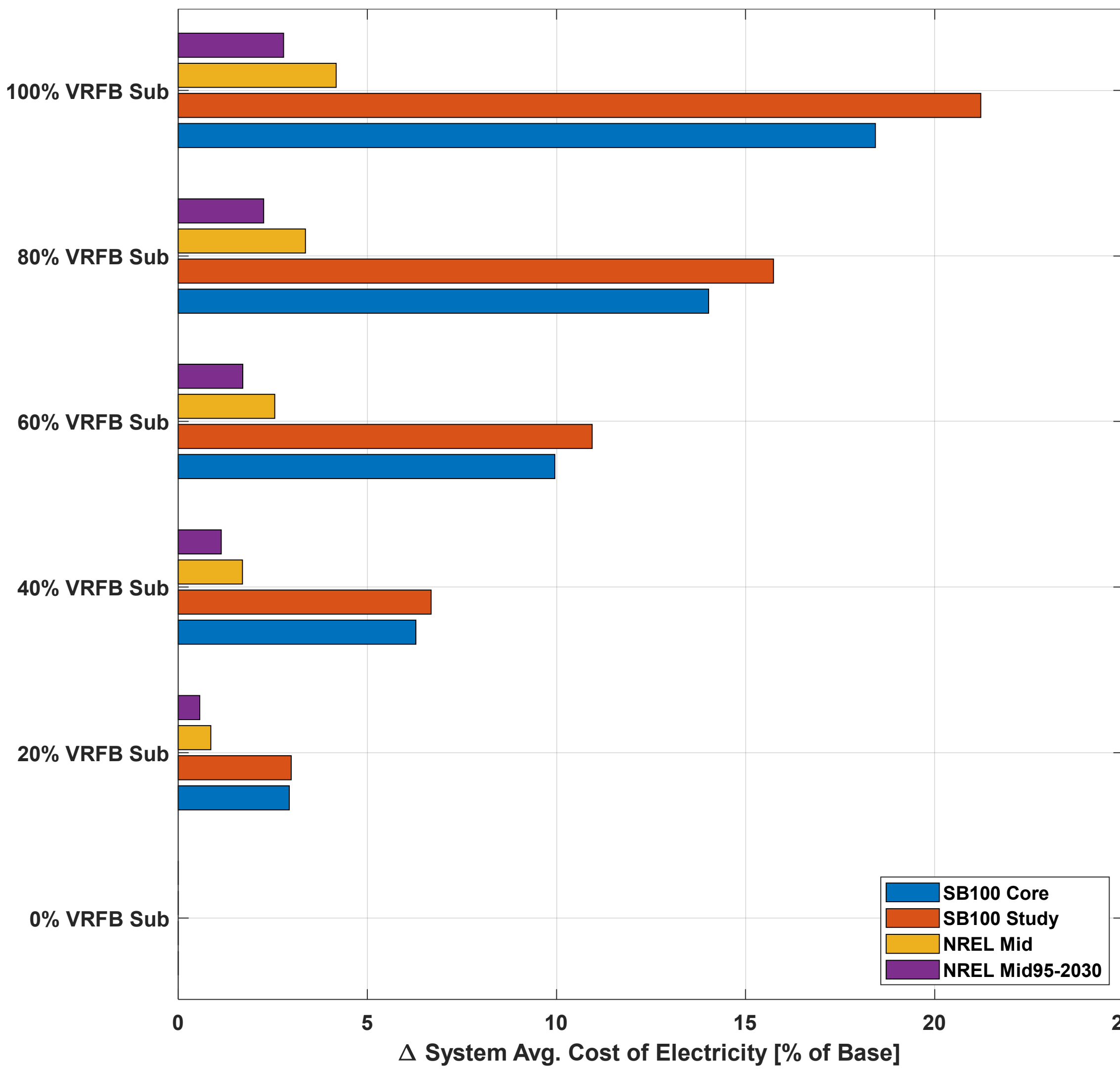

Figure 54 - Sensitivity of system-wide average cost of electricity to different projected electricity resource mixes in 2045 for VRFB energy storage substitution cases [% of base value for each resource mix]

In all four of the resource mixes considered, substituting lithium-ion batteries for vanadium redox flow batteries increases the system-wide cost of electricity due to the increased capital cost of the flow batteries relative to lithium-ion batteries for the cost parameter inputs used in this study.

3.2.5. Long-duration energy storage technology addition

The effect of adding long-duration hydrogen energy storage to the SB100 Core resource mix in 2045 is presented in Figure 55 for zero-carbon electricity penetration, Figure 56 for renewable curtailment, and Figure 57 for the cost of electricity.

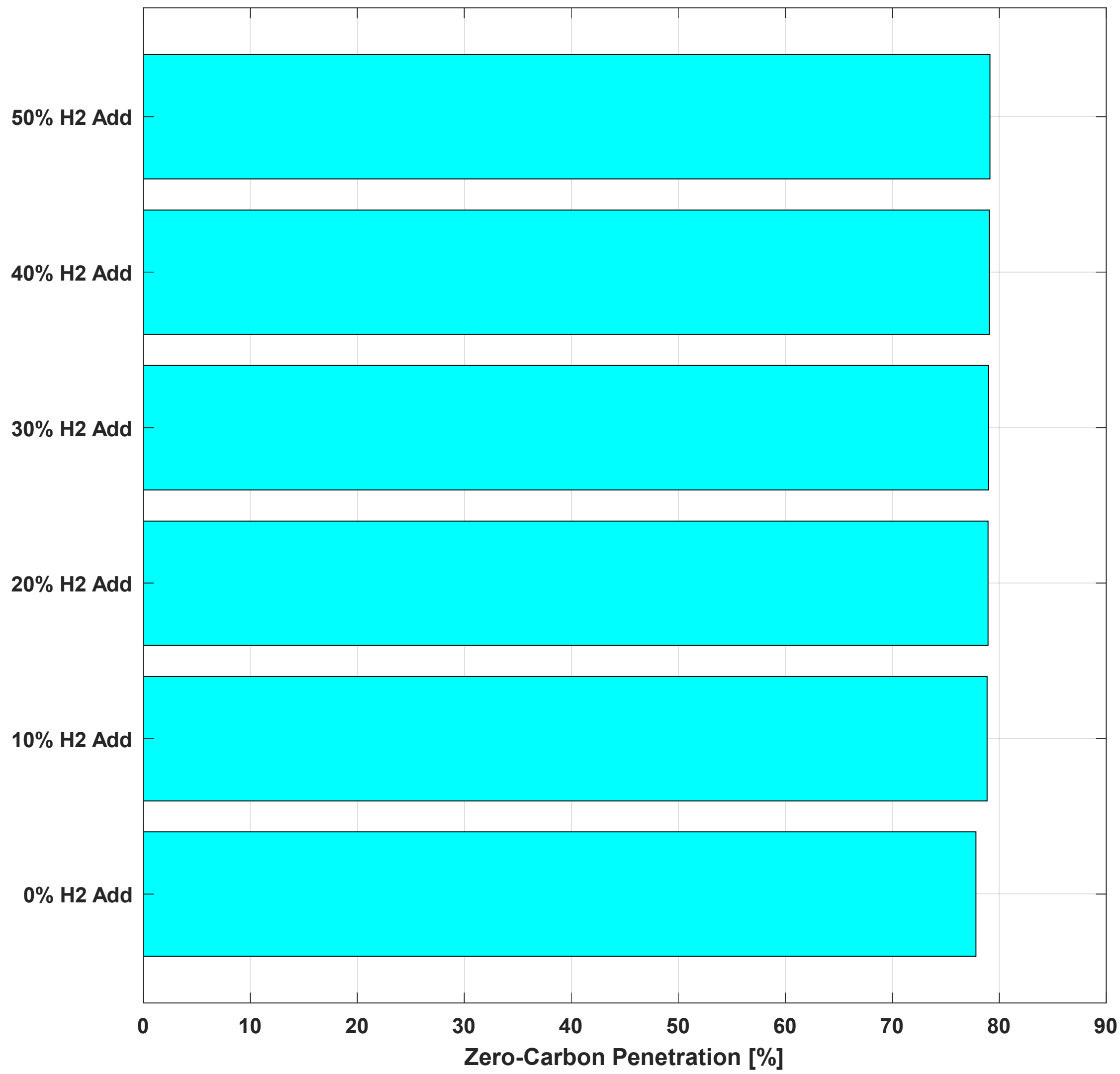

Figure 55 - System-wide zero-carbon electricity penetration for hydrogen energy storage addition cases [% of total annual electricity generation] in 2045

Adding hydrogen energy storage to the SB100 Core resource mix increases system-wide zero-carbon electricity penetration. In the case where hydrogen energy storage is added equivalent to 50% of the projected pumped hydropower energy storage capacity, zero-carbon electricity penetration increases to 79.1% from 77.8% with no hydrogen energy storage addition. This occurs since more long-duration energy storage capacity installed in the system enables larger uptake of excess renewable energy. This increase is relatively small due to two factors. First, the total capacity of energy storage (power-capacity basis) added is relatively small, since pumped hydropower energy storage is a small part of the total energy storage portfolio in the SB100 Core resource mix. Second, the round-trip efficiency of the hydrogen energy storage system is low (~35%) compared to pumped hydropower (~80%), so much of the excess renewable energy captured by the hydrogen energy storage system is not delivered as usable electricity supply.

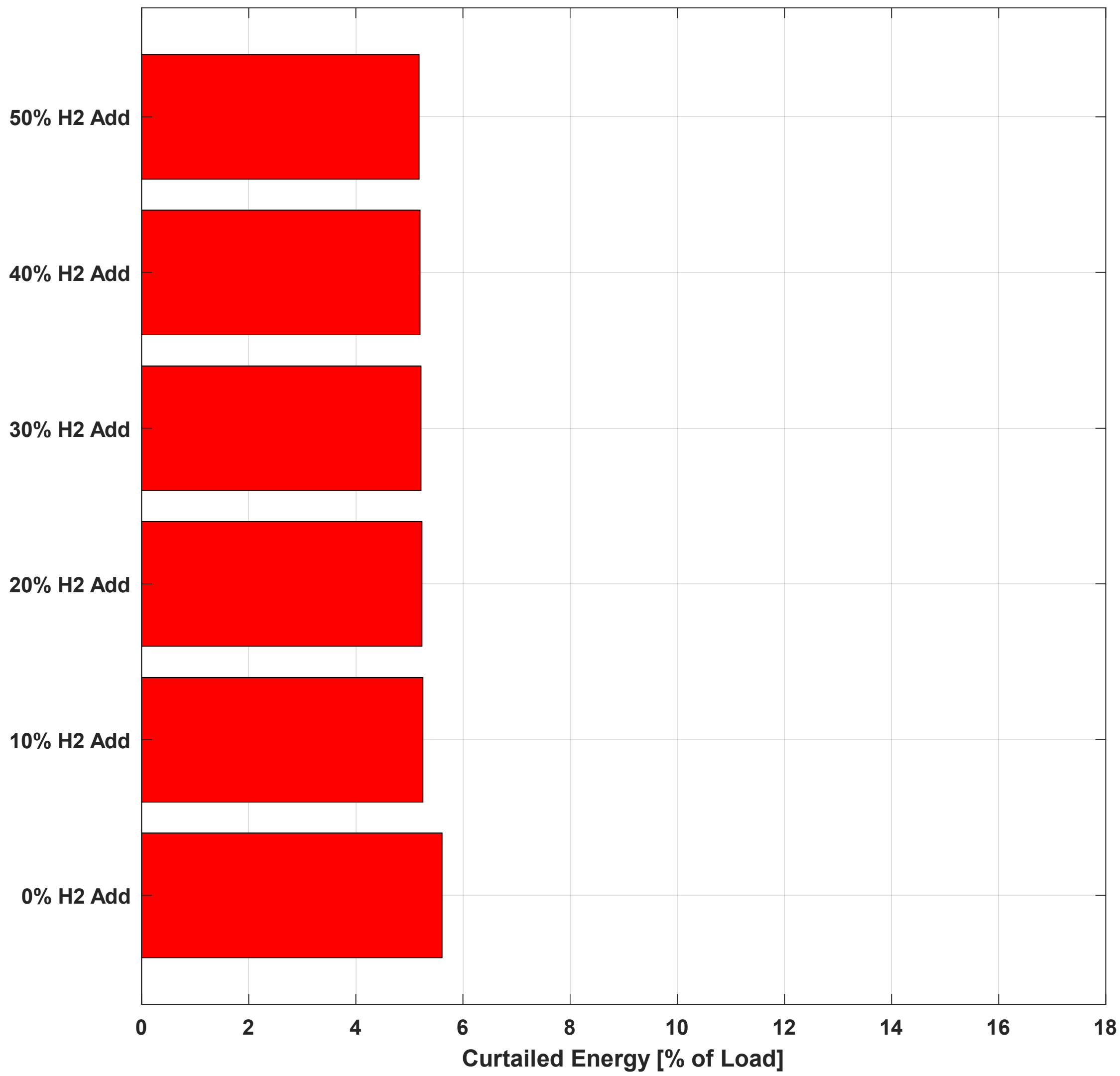

Figure 56 - System-wide renewable curtailment for hydrogen energy storage addition cases (% of annual load) in 2045

The addition of hydrogen energy storage to the system reduces curtailed renewable energy from 5.6% of annual load equivalent to 5.1% of annual load equivalent due to enabling additional uptake of excess renewable energy. The relatively small total capacity of storage added limits the extent to which curtailed renewable energy is decreased.

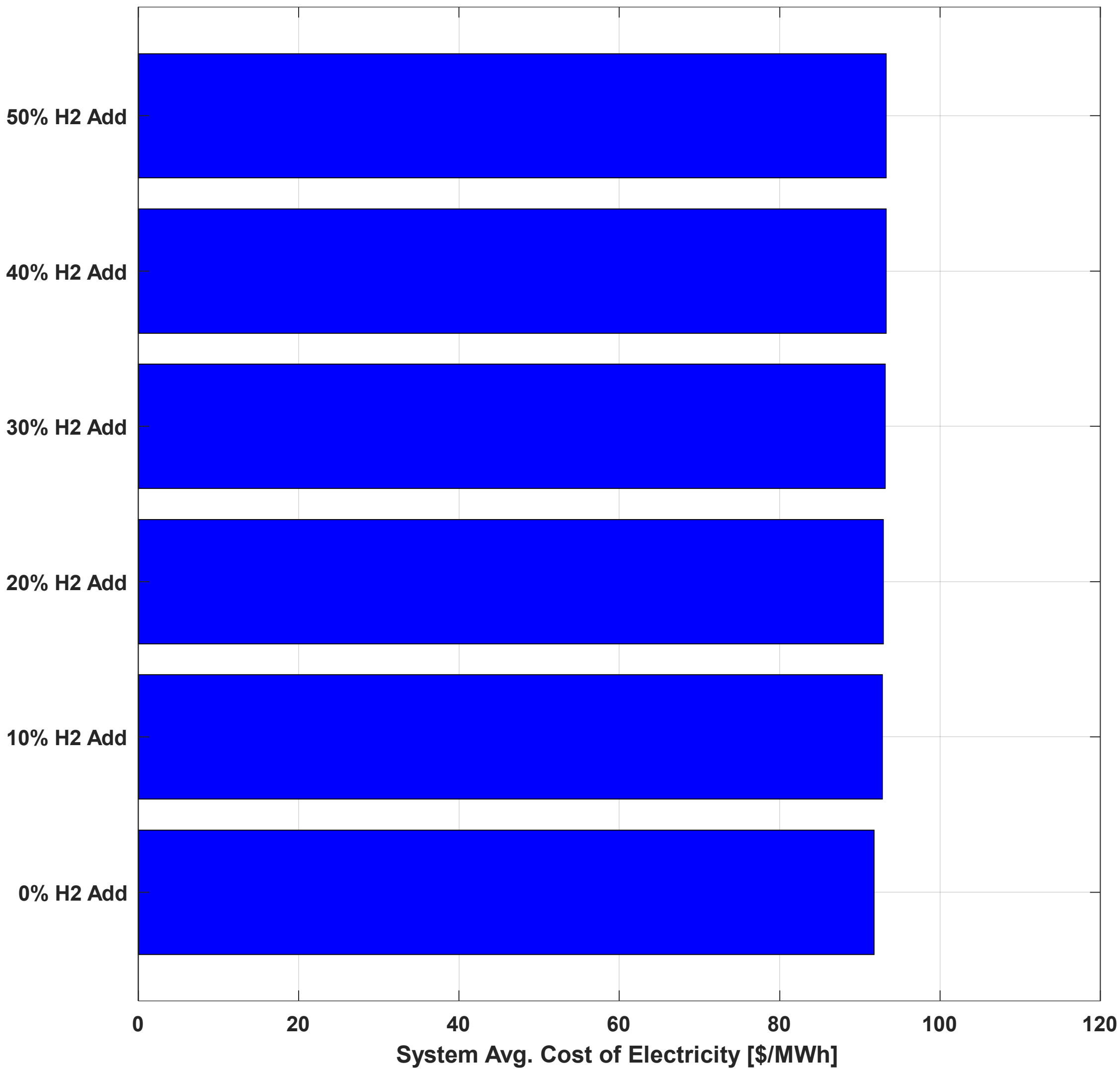

Figure 57 - System-wide average cost of electricity for hydrogen energy storage addition cases in 2045 [$/MWh]

Adding hydrogen energy storage to the system increases system-wide costs of electricity, from $91.7/MWh (no storage addition) to $93.3/MWh (added hydrogen storage equivalent to 50% of pumped hydropower capacity). This primarily occurs due to the high capital cost of the hydrogen energy storage systems and somewhat limited benefit for reducing the need for natural gas resources due to its low round-trip efficiency.

The sensitivity of the hydrogen energy storage addition cases to different projected resource mixes is presented in Figure 58 for zero-carbon penetration, Figure 59 for renewable curtailment, and Figure 60 for system cost of electricity. Note that these values are presented as percentage deviations from the base (No added storage – 0% H2 Add) value achieved in each resource mix.

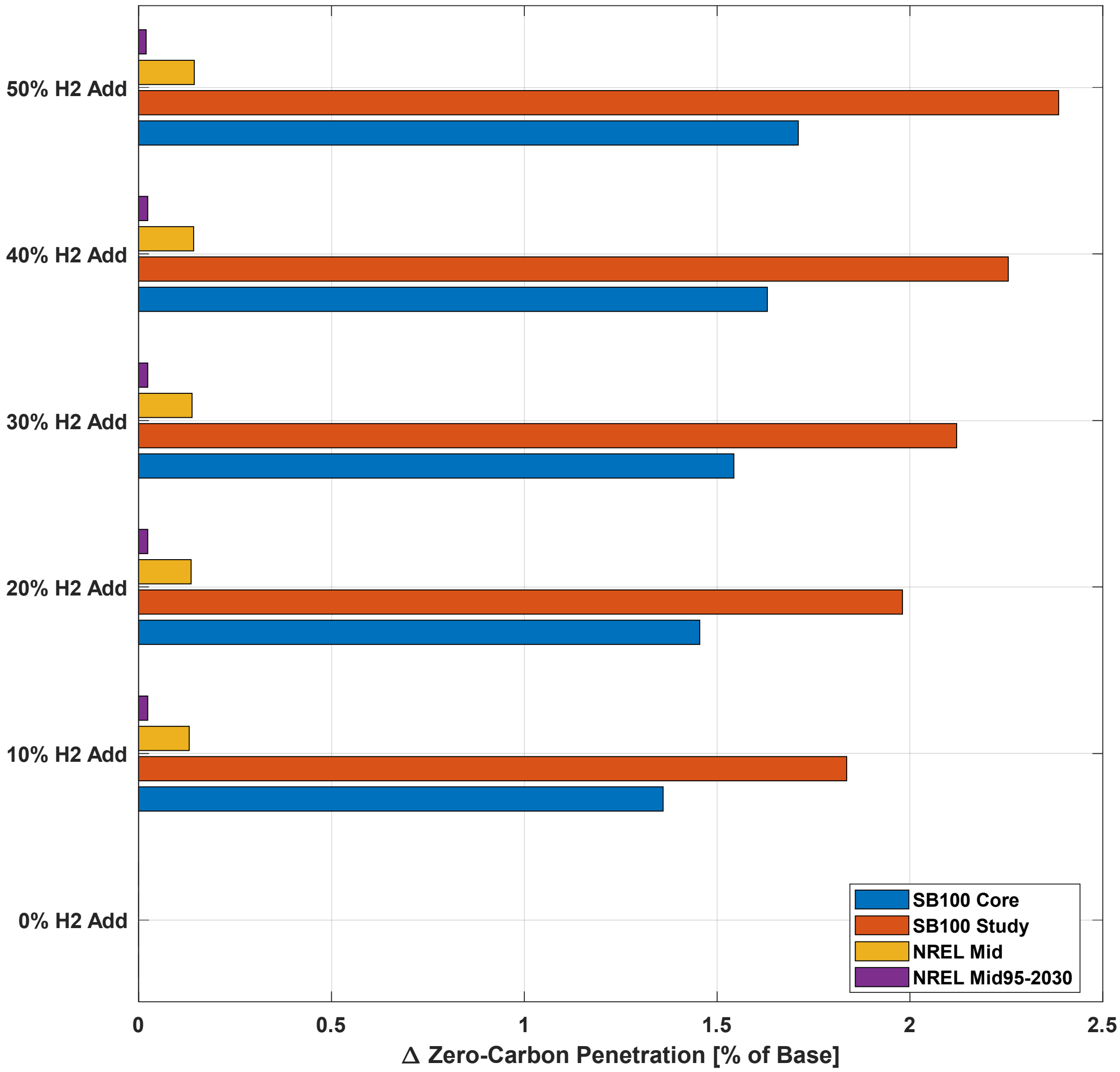

Figure 58 - Sensitivity of system-wide zero-carbon electricity penetration to different projected electricity resource mixes in 2045 for hydrogen energy storage addition cases [% of base value for each resource mix]

For all four resource mixes, the addition of hydrogen energy storage increases the system-wide zero-carbon electricity penetration due to enabling additional uptake of excess renewable generation. The SB100 mixes which exhibit higher availability of excess renewable generation show higher benefits. Overall, however, the low round-trip efficiency and relatively small total power capacity of added storage limit the extent to which zero-carbon electricity penetration is improved.

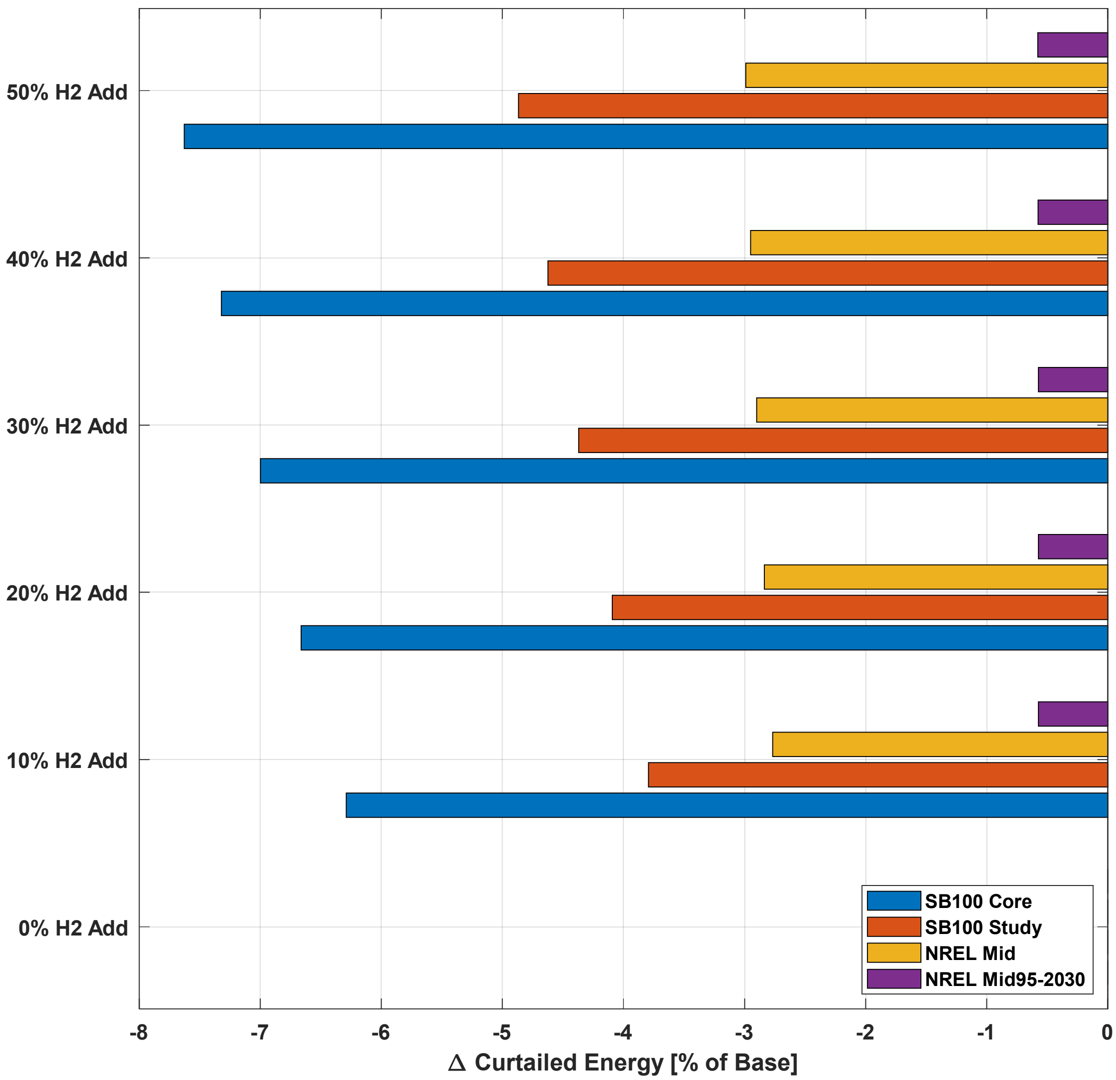

Figure 59 - Sensitivity of curtailed renewable energy electricity to different projected electricity resource mixes in 2045 for hydrogen energy storage addition cases [% of base value for each resource mix]

Consistent with the results for zero-carbon electricity penetration, the addition of hydrogen energy storage reduces curtailed renewable energy in the electricity system due to enabling the additional uptake of excess renewable generation for all projected resource mixes.

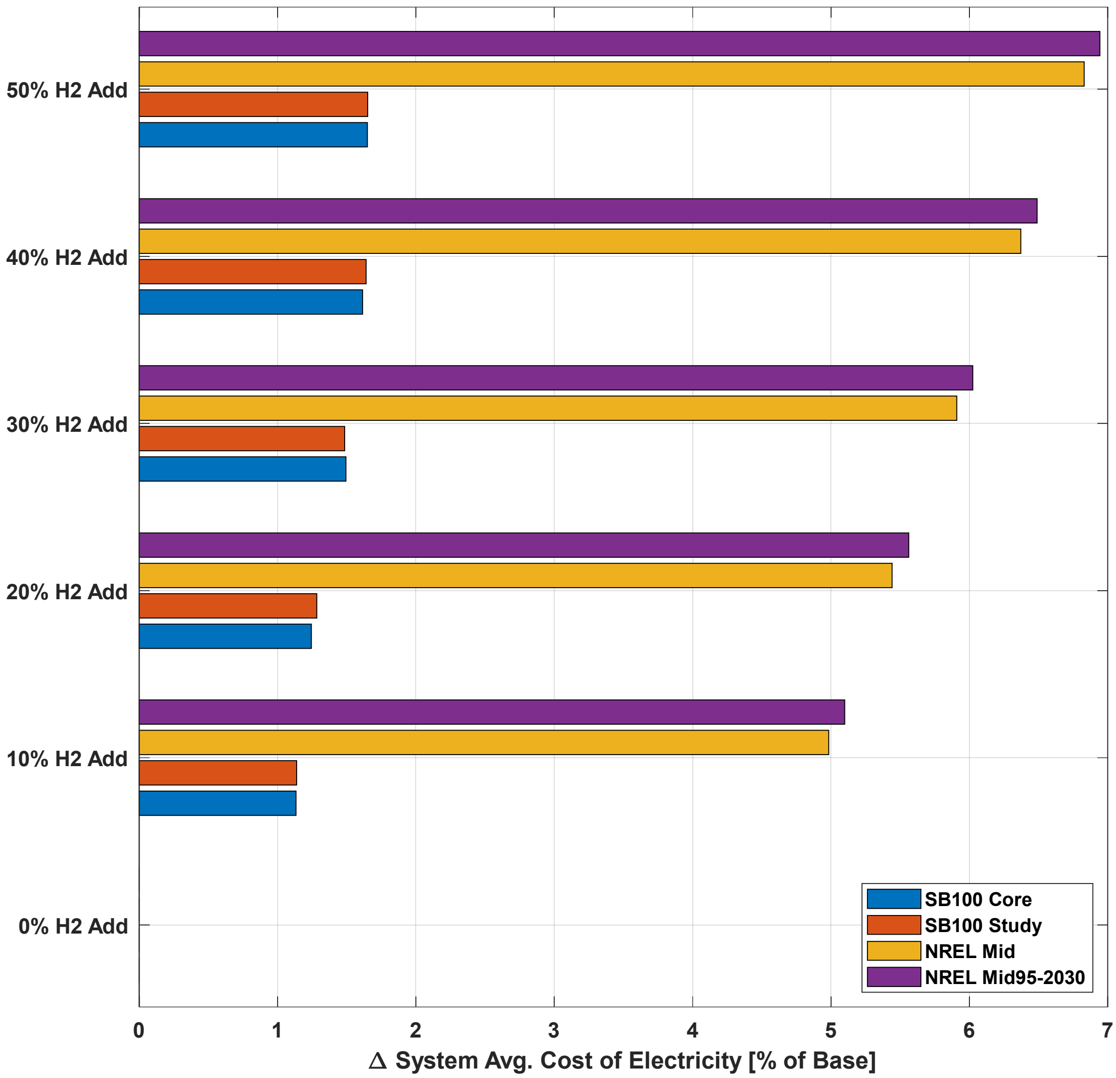

Figure 60 - Sensitivity of system-wide average cost of electricity to different projected electricity resource mixes in 2045 for hydrogen energy storage addition cases [% of base value for each resource mix]

Also consistent with the results for the SB100 Core resource mix, the three other resource mixes exhibited increased electricity costs when hydrogen energy storage was added to the system due to the high capital cost of hydrogen energy storage technology.

4. Discussion

4.1. Key uncertainties and recommendations for future work

This study investigated the effect of different alternative arrangements for the deployment of energy storage capacity in California's electricity system on the achieved zero-carbon electricity penetration, curtailed renewable energy, and system average cost of electricity. This involved relying on many different data sources for cost and performance characterization of energy storage technologies, as well as making various assumptions about the behavior of these technologies on the electricity system. Here, we will discuss how changes in these parameters or assumptions may affect the results, as well as discuss how factors that were not included in the modeling may also change the results. These will also be accompanied by suggestions for future work.

4.1.1. Grid Integration Costs

One of the key potential benefits of some of the alternative energy storage configurations – behind-the-meter (BTM), co-location at wind farms, and co-location at solar farms – is the potential to avoid separate grid integration costs. BTM energy storage can be connected directly to individual residential, commercial, or industrial customer facilities. This avoids the costs associated with connecting to the transmission system that utility energy storage may need to incur and, depending on the specific configuration, can avoid the costs associated with connecting to the utility distribution network. Energy storage co-located at wind and solar farms can use the existing electrical infrastructure of the generation facility and avoid the costs of separate interconnection to the transmission system and associated hardware.

The parameters for grid integration costs used here range between \$25-\$31/kW for the year 2030 and \$20-25/kW for the year 2045 as specified by Mongird et al. [5], accounting for "*direct cost associated with connecting the energy storage system to the grid, including transformer cost, metering, and isolation breakers*.". Comparatively, the capital cost of lithium-ion batteries which are the cheapest among the energy storage technologies considered here, range from \$1156/kW to \$1266/kW in 2030 and \$753/kW to \$825/kW in 2045. The assumed grid integration costs are less than 2% of the capital cost for the cheapest energy storage technology. Therefore, accounting for the benefit of avoiding grid integration costs in the BTM and co-located energy storage cases by subtracting the grid integration costs from Mongird et al [5] provides relatively little benefit. However, these savings in combination with reduced losses from avoiding separate conversion to high voltage AC does limit increases in electricity costs, particularly in 2045.

Grid integration cost parameters can vary between sources since different studies account for different factors in developing these parameters. The California Energy Commission report "Estimated Cost of New Utility-Scale Generation in California: 2018 Update" [16], for example, accounts for "Transmission Interconnection Costs" that are based on real filings by Southern California Edison for substation connection costs and transmission line costs depending on length from the Western Electricity Coordinating Council. This report estimates transmission interconnection costs for a 20 MW lithium-ion battery installed as utility energy storage to range between \$236/kW to \$1015/kW, one to two orders of magnitude higher than that estimated by Mongird et al [5] and translating to 18.6% to 80% of lithium-ion battery capital costs. Since these cost figures are based on actual filings, they may account for more than the cost of hardware and include factors such as utility or balancing authority fees, reviews, etc…, and may be difficult to compare with the costs estimated by Mongird et al [5].

If this study used grid integration cost parameters from the CEC report as the avoided cost associated with deploying BTM or co-located energy storage, the BTM and co-located energy storage scenarios are likely to show significant cost benefits compared to the case where all energy storage is installed and operate as utility energy storage. However, careful consideration must be given to ensuring that the cost parameters used robustly account for real driving factors.

For future work, we recommend:

- Parametric analysis of grid integration costs and their effect on the comparison of electricity cost results between the utility energy storage, BTM, and wind & solar farm co-location energy storage cases. This will help determine how large the savings from avoiding grid integration costs need to be for BTM and co-located energy storage to provide electricity cost improvements over utility energy storage and compensate for the detrimental effects of the conflict in dispatch priority between BTM and co-located energy storage and utility energy storage.
- Perform a systematic review of grid integration cost factors and harmonize results from different sources. This will help determine what the probable range for grid integration costs are expected to be and how these costs may change, improving the accuracy of modeling exercises to determine the effects of BTM and co-located energy storage.

4.1.2. Individual customer vs. system-wide priorities

Another major theme from the results is the conflict in dispatch priority between BTM energy storage, which charges and discharges to serve the needs of the individual customers to which these are connected, and utility energy storage, which charges and discharges to serve the needs of the broader electricity system. BTM energy storage can provide significant benefits for individual customers beyond normal operation for energy arbitrage or peak shaving, these systems also provide a source of backup power for critical functions in the event of a blackout or natural disaster.

Utility energy storage, however, is best suited for responding to the operational needs of the broader electricity system. These units can charge using aggregated electricity generation from wind and solar resources and can discharge directly in response to broader electricity system needs for additional supply. Therefore, it is expected that substituting utility energy storage for BTM energy storage reduces the broader electricity system’s ability to manage renewable generation.

Energy storage units can be connected in a BTM configuration and garner the benefit of avoiding some of the grid integration costs, but in day-to-day operation be dispatched to respond to the needs of the broader electricity system. This effectively provides the benefit of utility energy storage with the advantages of BTM installation. However, given that BTM energy storage will likely be paid for by individual customers, economic incentives for responding to the broader electricity system need to be sufficiently strong for this to occur. In practice, there will likely always be some level of conflict between energy storage dispatch for individual customer needs and that of the broader electricity system.

The result from this analysis that substituting utility energy storage capacity for BTM energy storage capacity, or adding BTM energy storage capacity on top of plans to deploy utility energy storage capacity, increases the cost of electricity does not mean that BTM energy storage should not be pursued. Many of the practical benefits of installing BTM energy storage were not accounted for and monetized in this analysis. Rather, the increase in system-wide electricity cost incurred by substituting in or adding BTM energy storage to the system should be interpreted as the threshold that the value of other BTM energy storage benefits – such as backup power, resilience, etc… - must exceed for BTM energy storage to be beneficial from a system-wide perspective.

4.1.3. Future cost projections for early-stage technologies

The cost results for this study are based on capital and fixed & variable operation and maintenance cost parameters compiled from various sources (academic literature, government reports, real deployments) and harmonized in the year 2020 analysis from Mongird et al [5] and projected forward to 2045 based on the study by Schmidt et al [6]. While these sources represent a robust review of existing literature, projecting these costs forward especially as far as the year 2045 carries significant uncertainty.

Certain energy storage technologies are more mature than others, but all considered energy storage technologies are still constantly evolving in terms of performance and costs. Pumped hydropower and lithium-ion batteries are currently the most mature. Pumped hydropower energy storage has been deployed at scale for the longest amount of time of the energy storage technologies considered. Lithium-ion batteries benefitted from significant public and private investment and co-motivation from the efforts to develop this technology for electric vehicles and consumer electronics as well as stationary energy storage. The other energy storage technologies considered, however, are decidedly less mature in terms of commercialization and cost reduction from large-scale deployment, meaning that their cost parameters can potentially change very quickly for better or worse.

Moving into the future, costs for the different energy storage technologies may follow different paths than that projected by Schmidt et al [6]. Even relatively mature technologies such as lithium-ion batteries are still undergoing improvements and implementation of new chemistries, and pumped hydropower is being evaluated for improvements to allow it to provide benefits for a highly renewable electricity system. Therefore, different cost trajectories, as well as unforeseen disruptions (i.e. supply chain disruptions, etc…), will change the cost results presented in this study.

4.1.4. Effect of considering flexible loads

This study did not model the effect of flexible load capability that enables the timing of electric loads to be shifted to better align with zero-carbon electricity generation or low electricity price periods. Such examples include but are not limited to “smart” electric vehicle charging, thermal energy storage for meeting cooling loads, flexible heat pump operation, shifting water pumping loads, and more.

One of the main purposes of stationary energy storage, regardless of technology, is to shift the availability of renewable or zero-carbon electricity generation to coincide with the timing of electric load. If electric loads are shifted to occur when zero-carbon electricity is plentiful, these loads can be met directly and less energy storage capacity is required to meet a given zero-carbon electricity penetration target.

Previous literature shows this effect especially when "smart" electric vehicle charging and vehicle-to-grid operation are implemented [17]. This implies that the benefits of adding or substituting energy storage technologies to the future electricity system will be reduced if it is assumed that flexible electric load capability is widely implemented and used.

The extent to which flexible electric load capability will be implemented and actually used by residential, commercial, and industrial customers can be uncertain. Literature investigating this topic for the case of grid-responsive electric vehicle charging [18–20] implies that there may be a high participation rate of electric vehicle drivers in utility-controlled charging programs, but in practice, this may or may not be the case. If low participation in flexible load programs occurs, energy storage will be required to compensate.

For future work, we recommend:

- Leverage social science to study the probable range of consumer participation in flexible load programs and how these translate to increased or reduced needs for stationary energy storage and the types of such storage that will be most beneficial for the electricity system

4.2. Year 2030 vs 2045 results

A summary of the results for the effect of each of the energy storage scenarios on the system-wide zero-carbon electricity penetration, system curtailed renewable energy, and the system average cost of electricity is presented in Table 15 for the year 2030 and Table 16 for the year 2045.

Table 15 - Summary results of the energy storage scenarios for the year 2030. Orange = undesirable effect, Blue = desirable effect.

Energy Storage Scenario	**Effect on System-wide Zero-Carbon Electricity Penetration** (Increase = Desirable)	**Effect on System Curtailed Renewable Energy** (Decrease = Desirable)	**Effect on System Average Cost of Electricity** (Decrease = Desirable)
Substitute utility storage for behind-the-meter storage	Decreases	Increases	Increases
Add behind-the-meter storage to utility storage	Increases	Decreases	Increases
Substitute utility storage for storage co-located at wind farms	Decreases	Increases	Increases
Substitute utility storage for storage co-located at solar farms	Neutral	Varied 100% substitution causes a Decrease	Varied 100% substitution causes a Decrease
Substitute utility lithium-ion battery storage for utility flow battery storage	Increases	Decreases	Increases
Add hydrogen energy storage to the portfolio	Increases	Decreases	Increases

Table 16 - Summary results of the energy storage scenarios for the year 2045. Orange = undesirable effect, Blue = desirable effect.

Energy Storage Scenario	**Effect on System-wide Zero-Carbon Electricity Penetration** (Increase = Desirable)	**Effect on System Curtailed Renewable Energy** (Decrease = Desirable)	**Effect on System Average Cost of Electricity** (Decrease = Desirable)
Substitute utility storage for behind-the-meter storage	Decreases	Increases	Increases
Add behind-the-meter storage to utility storage	Neutral	Neutral to Small Increase	Increases
Substitute utility storage for storage co-located at wind farms	Decreases	Increases	Increases
Substitute utility storage for storage co-located at solar farms	Decreases	Increases	Varied 100% substitution causes a Decrease
Substitute utility lithium-ion battery storage for utility flow battery storage	Increases	Decreases	Increases
Add hydrogen energy storage to the portfolio	Increases	Decreases	Increases

The effects of implementing the different energy storage configurations on the broader electricity system are largely similar in both the years 2030 and 2045 from a qualitative perspective. The only difference is the scenario when utility energy storage is substituted for energy storage co-located at large-scale solar farms. For both the years 2030 and 2045, the fundamental drivers are the same:

For BTM energy storage, the operation of BTM energy storage capacity to prioritize individual customer needs rather than system-wide needs decrease the performance of the broader electricity system.

For replacing utility energy storage for energy storage co-located at wind farms, such storage can only charge with and respond to wind electricity and has little to no ability to help manage solar generation variability, decreasing the performance of the broader electricity system.

For replacing utility energy storage for energy storage co-located at solar farms, such storage has limited ability to help manage the effects of wind generation variability but reduces losses for large-scale solar farms.

For replacing lithium-ion batteries with flow batteries, the larger energy-to-power ratio of the flow batteries increases the total energy capacity of the energy storage fleet, enabling larger uptake of excess renewable generation.

For adding hydrogen energy storage to the system, this increases the total energy and power capacity of the energy storage fleet, enabling larger absorption of excess renewable generation. However, the low round-trip efficiency of these systems limits their ability to provide captured excess renewable energy to serve the electric load.

5. Summary and Recommendations

This study investigated how alternative configurations for the deployment of energy storage in future California electricity systems affect their performance regarding zero-carbon electricity penetration, curtailed renewable energy, and system average cost of electricity. This investigation was accomplished by the following steps.

We developed cost parameter datasets for near-term (year 2030) and long-term (year 2045) for energy storage technologies at different unit sizes, including lithium-ion batteries, vanadium redox flow batteries, pumped hydropower, and hydrogen energy storage, based on recent literature reviews and technology-specific cost projections.

We then developed scenarios for energy storage deployment configurations that differ from common results in electricity decarbonization planning studies consisting of lithium-ion batteries and pumped hydropower energy storage deployed as utility-scale energy storage. These alternative configurations include the substituting of utility energy storage capacity for behind-the-meter energy storage, adding behind-the-meter energy storage to utility energy storage, co-locating energy storage at wind or solar farms instead of directly to the broader electric grid, substituting lithium-ion batteries for flow batteries, and adding long-duration hydrogen energy storage to the electricity system.

We then simulated these different energy storage configurations in the Holistic Grid Resource Integration and Deployment (HiGRID) electricity system dispatch model in electricity system resource mixes compliant with California's Senate Bill 100 goal. These simulations model the dispatch of electricity system resources to satisfy time-varying electric load demand and provide sufficient ancillary services with an hourly resolution for 1 year. From the electricity system dispatch modeling, the system-wide zero-carbon electricity penetration, curtailed renewable energy, and the system-wide average cost of electricity were determined for each energy storage scenario.

A summary of the key results and their driving factors are as follows:

- All of the alternative energy storage deployment configurations act to increase the cost of electricity relative to the base scenario consisting solely of utility-scale lithium-ion and pumped hydropower energy storage.
    - This is expected since the energy storage deployments in the base scenario are derived from capacity expansion modeling that selects resources based on minimizing electricity cost.
- Substituting utility energy storage for behind-the-meter (BTM) energy storage provides benefits for individual customers, but reduces the zero-carbon electricity penetration and increases the curtailed energy and cost of electricity for the broader electricity system.
    - This occurs due to conflicts in the priority for how energy storage operates. BTM energy storage charges and discharges to serve the needs of individual customers to which it is connected, which may differ from and conflict with how energy storage would operate to serve the needs of the broader electricity system.

- The system-wide electricity cost increases brought about by deploying BTM energy storage do not mean BTM energy storage should not be pursued, as many of the practical benefits of BTM energy storage were not accounted for (i.e. value of backup power).
    - Additionally, the savings that BTM energy storage deployment incurs from avoiding grid integration costs are highly uncertain, and narrowing down the expected range of avoided grid integration costs should be a priority in future research.
- Adding energy storage capacity, whether as BTM energy storage or as additional utility-scale energy storage capacity, expectedly improves zero-carbon electricity penetration and reduces curtailed renewable energy. This comes at the cost of increased electricity costs for the resource mixes considered here.
    - Here, added energy storage capacity was modeled in the form of additional BTM storage or relatively expensive utility-scale hydrogen energy storage, contributing to increased costs.
    - However, even if the added storage was utility-scale lithium-ion batteries, the marginal benefit of adding that capacity in terms of enabling the electricity system to reduce the use of expensive peaking resources needs to exceed its capital cost. This depends on the availability of excess renewable generation: if significant excess renewable generation is present, adding energy storage can provide significant marginal value. But if excess renewable generation is limited, adding more energy storage has a marginal effect.
- For short-duration energy storage, the benefits of the higher energy-to-power ratio of vanadium redox flow batteries do not outweigh their increased capital costs relative to lithium-ion batteries when it comes to effects on the system average cost of electricity.
    - However, vanadium redox flow batteries are relatively high cost due to the price of vanadium pentoxide. Other flow battery chemistries may be capable of exhibiting lower capital costs while providing the same technical benefit and may compete better with lithium-ion batteries.
- Co-locating energy storage capacity at wind or solar farms limits their ability to respond to the needs of the broader electricity system relative to installing the same capacity as utility energy storage.
    - While energy storage co-located at wind or solar farms enables them to be more predictable as a generation resource for balancing authorities, these energy storage units can only charge with electricity generation from the wind or solar farm that they are connected to. This limits their effectiveness in improving grid operations or excess renewable energy uptake since energy storage co-located at a wind farm cannot manage solar variability and energy storage co-located at a solar farm cannot manage wind variability unless the wind or solar farm is allowed to act as a grid load during certain hours.

Regarding recommendations for energy storage procurement to meet SB100 goals, the result of this analysis shows that the planned course in California electricity system decarbonization studies of expanding utility lithium-ion battery energy storage capacity and complimenting it with pumped hydropower energy storage yields the lowest costs of electricity. This result is consistent with the outputs of cost-minimizing capacity expansion studies and is perhaps unsurprising.

However, this result also has significant uncertainty since many of the benefits of BTM energy storage (i.e. providing backup power, avoiding grid integration costs, avoiding the need for entirely new transmission buildout, etc…) were not accounted for comprehensively or at all due to uncertainty in their monetary value. Other benefits, such as improved predictability from solar or wind farms from co-located energy storage, were also not accounted for in a monetized way.

To provide more comprehensive insight into the advantages and disadvantages of different energy storage deployment configurations, the key uncertainties described in Section 4 must be addressed.

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