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BUILDING ENERGY EFFICIENCY MEASURE PROPOSAL TO THE

CALIFORNIA ENERGY COMMISSION

FOR THE 2022 UPDATE TO THE

CALIFORNIA ENERGY CODE, TITLE 24, PART 6

BUILDING ENERGY EFFICIENCY STANDARDS

NONRESIDENTIAL PV AND BATTERY STORAGE

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Document Information

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EXECUTIVE SUMMARY

Introduction

The California Energy Commission (Energy Commission) sponsored this effort to investigate the cost-effectiveness of PV and battery systems in nonresidential and high-rise multifamily (> 3 stories) buildings. The measure would move nonresidential buildings closer to the 2030 ZNE target for nonresidential buildings and towards the state's greenhouse gas (GHG) reduction goals.

Scope of Code Change Proposal

This PV and battery system measure will affect the following code documents listed in Table 1.

Table 1: Scope of Code Change Proposal

Standards Requirements (see note below)	Compliance Option	Appendix	Modeling Algorithms	Simulation Engine	Forms
M, Ps, Pm	Yes	JA12	ACM	CBECC-Com	NRCC-SRA-E NRCC-PRF-01-E NRCI-SPV-01-E NRCI-SPV-02-E

Note: An (M) indicates mandatory requirements, (Ps) Prescriptive, (Pm) Performance.

Measure Description

This measure proposes PV and battery system requirements for nonresidential and high-rise multifamily buildings and is analogous to the PV measure for residential buildings currently in the 2019 Title 24 Standard. The PV and battery system is proposed to be sized to minimize site energy consumption and electricity exports to the grid. The requirement would apply to the following building types:

- office,
- retail and grocery,
- schools,
- high-rise multifamily (> 3 stories),
- warehouse, and
- other commercial buildings, including auditorium, convention center, hotel/motel, library, medical/clinic, restaurant, and theater.

The measure requires a minimum amount of PV based on building type and the available roof and carport area. When PV systems are required, a battery storage system is also required, and it is sized based on the PV system with the goal of limiting exports back to the grid. Exceptions are provided for cases where there is insufficient roof or carport area, the required PV system is too small, or for locations where high snow loads or other conditions prevent the installation of PV systems.

Market Analysis and Regulatory Impact Assessment

The PV market in California is quite mature and the battery market has been growing at its fastest pace in the last few years. A study of the market and supply chain capability indicates that by the time this measure goes into effect in 2023, there will be sufficient capacity to enable the installation of PV and battery systems on nonresidential and high-rise multifamily buildings as required by this measure.

The measure was found to be cost-effective over the period of analysis. Overall, this proposal increases the wealth of the State of California. California consumers and businesses save more money on energy than they do for financing the efficiency measure.

Statewide Energy Impacts

Table 2 shows the estimated energy savings over the first twelve months of implementation of this measure.

Table 2: Statewide Estimated First Year Energy Savings

	First Year Statewide Savings			First Year Statewide TDV Savings	
	Electricity Savings (GWh)	Power Demand Reduction (MW)	Natural Gas Savings (MMtherms)	TDV Electricity Savings (Million kBTU)	TDV Natural Gas Savings (Million kBTU)
PV and Battery Systems	453	42	0	923	0

Section 4.2 discusses the methodology and Section 4.3 shows the results for the per unit energy impact analysis.

Compliance and Enforcement

The proposed compliance and enforcement process to ensure the success of the measure is described in Section 2.5. The impacts the proposed measure will have on various market actors is described in Section 2.5.

Cost-effectiveness

Results per unit Cost-effectiveness Analyses are presented in Table 3. The TDV Energy Costs Savings are the present valued energy cost savings over the 30-year period of analysis using Energy Commission's TDV methodology. The Total Incremental Cost represents the incremental initial construction and maintenance costs of the proposed measure relative to existing conditions (current minimally compliant construction practice when there are existing Title 24 Standards). Costs incurred in the future (such as periodic maintenance costs or replacement costs) are discounted by a 3 percent real discount rate, per Energy Commission's LCC Methodology. The Benefit to Cost (B/C) Ratio is the incremental TDV Energy Costs Savings divided by the Total Incremental Costs. When the B/C ratio is greater than 1.0, the added cost of the measure is more than offset by the discounted energy cost savings and the measure is deemed to be cost effective. For a detailed description of the Cost-effectiveness Methodology see Section 5.1of this report. The PV and battery size requirement was calculated such that it is cost-effective in every building type and climate zone that was analyzed.

Table 3: Cost-effectiveness Summary

Climate Zone	Benefit: TDV Energy Cost Savings (2023 PV$/ft²)	Cost: Total Incremental First Cost and Maintenance Cost (2023 PV$/ ft²)	Change in Lifecycle Cost (2023 PV$/ ft²)	Planned Benefit to Cost (B/C) Ratio
Climate Zone 1	20.74	19.37	(1.37)	1.07
Climate Zone 2	32.74	22.66	(10.07)	1.44
Climate Zone 3	26.94	19.37	(7.57)	1.39
Climate Zone 4	33.53	22.66	(10.87)	1.48
Climate Zone 5	27.31	19.37	(7.94)	1.41
Climate Zone 6	34.40	22.66	(11.74)	1.52
Climate Zone 7	31.68	22.66	(9.01)	1.40
Climate Zone 8	35.91	22.66	(13.25)	1.58
Climate Zone 9	36.23	22.66	(13.57)	1.60
Climate Zone 10	35.44	22.66	(12.77)	1.56
Climate Zone 11	32.06	22.66	(9.40)	1.41
Climate Zone 12	32.31	22.66	(9.65)	1.43
Climate Zone 13	33.67	22.66	(11.00)	1.49
Climate Zone 14	37.64	22.66	(14.97)	1.66
Climate Zone 15	43.35	27.17	(16.18)	1.60
Climate Zone 16	25.96	19.37	(6.59)	1.34

Section 5.1discusses the methodology and Section 5.2 shows the results of the Cost Effectiveness Analysis

Greenhouse Gas and Water Related Impacts

For more a detailed and extensive analysis of the possible environmental impacts from the implementation of the proposed measure, please refer to Section 6.2 through 6.5 and Appendix B and C of this report.

Greenhouse Gas Impacts

Table 4 presents the estimated avoided greenhouse gas (GHG) emissions of the proposed code change for the first year the standards are in effect. Assumptions used in developing the GHG savings are provided in Section 6.2 and Appendix C of this report.

The monetary value of avoided GHG emissions is included in TDV cost factors (TDV $) and is thus included in the Cost-effectiveness Analysis prepared for this report.

Table 4: Estimated Statewide Greenhouse Gas Emissions Impacts

	First Year Statewide	
	Avoided GHG Emissions (tCO_2e/yr)	Monetary Value of Avoided GHG Emissions ($2023)
TOTAL	36,000	3,819,000

Section 6.2 discusses the methodology and Table 12 shows the results of the greenhouse gas emission impacts analysis.

Water Use and Water Quality Impacts

The proposed measure is not expected to have any impacts on water use or water quality, excluding impacts that occur at power plants.

Acceptance Testing

The proposed photovoltaic and battery storage system requirements will not require acceptance testing. See section Section 3 Market Analysis for a detailed report on how the proposed requirements may impact the installation process.

1. INTRODUCTION

1.1 Background

The California Public Utilities Commission (CPUC) developed the Energy Efficiency Strategic Plan (CPUC 2008) in 2008. The plan set goals for newly constructed residential and nonresidential buildings to be zero net energy (ZNE) by 2020 and 2030, respectively. The CPUC's adoption of the plan in a 2008 rulemaking required state agencies to begin taking actions to meet the goals. The California Energy Commission (Energy Commission) adopted photovoltaic (PV) requirements for newly constructed residential buildings (single-family and low-rise multifamily) in the 2019 edition of Title 24. This measure allowed the Energy Commission to achieve the state's ZNE goal for new residential buildings by 2020. Credit for installing battery storage system was also allowed under the 2019 Title 24 edition.

Even prior to the adoption of the PV requirements in the 2019 Title 24 code, the PV market in California had matured with over 1,000 MW installed[1] in 2016 in the residential sector alone. The adoption of the residential PV requirements into the minimum statewide code was a logical choice because of wide market adoption and because the measure was cost-effective. PV and battery storage costs have since reduced even further and many new and existing buildings install these systems either voluntarily or because of the prevalence of local laws required on-site renewable generation.

The California Energy Commission (Energy Commission) sponsored this effort to investigate the cost-effectiveness of PV and battery systems in nonresidential (and high-rise multifamily) buildings. The measure would move nonresidential buildings closer to the 2030 ZNE target for nonresidential buildings and towards the state's greenhouse gas (GHG) reduction goals[2].

1.2 Report Structure

The goal is to prepare and submit proposals that will result in cost-effective enhancements to energy efficiency in buildings. This report and the code change proposal presented herein is a part of the effort to develop technical and cost-effectiveness information for proposed regulations on building energy efficiency design practices and technologies.

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[1] California annual solar installations published on the SEIA website.

[2] Assembly Bill 32 (2006), the California Global Warming Solutions Act of 2006, required California to return GHG emissions to 1990 levels by 2020, and Senate Bill 32 (2015) extended this requirement to a 40% below 1990 levels by 2030.

The overall goal of this Report is to propose a code change proposal for requiring photovoltaic (PV) systems and battery storage systems. The report contains pertinent information that justifies the code change.

Section 2 of this Report provides a description of the measure, how the measure came about, and how the measure helps achieve the state's zero net energy (ZNE) goals. This section presents how the proposed code change would be enforced and the expected compliance rates.

Section 3 presents the market analysis, including a review of the current market structure, a discussion of product availability, and the useful life and persistence of the proposed measure. This section offers an overview of how the proposed standard will impact various stakeholders including builders, building designers, building occupants, equipment retailers (including manufacturers and distributors), energy consultants, and building inspectors. Finally, this section presents estimates of how the proposed change will impact statewide employment.

Section 4 describes the key assumptions used in the energy savings analysis, the energy savings methodology and provides the per-unit energy impacts and energy savings results.

Results from the energy, demand, costs, and environmental impacts analysis are presented in Sections 5 and 6. The authors calculated energy, demand, and environmental impacts using three metrics: (1) per unit, (2) statewide impacts during the first year buildings complying with the 2016 Title 24 Standards are in operation, and (3) the cumulative statewide impacts for all buildings built during the 30-year period of analysis. Time Dependent Valuation (TDV) energy impacts, which accounts for the higher value of peak savings, are presented per unit, first year statewide and cumulative statewide. The incremental costs, relative to existing conditions are presented as are present value of year TDV energy cost savings and the overall cost impacts over the year period of analysis.

Section 7 of the report concludes with specific recommendations for language for the Standards, Appendices, Alternate Calculation Manual (ACM) Reference Manual and Compliance Forms.

2. Measure Description

2.1 Measure Overview

The proposed measure is a new prescriptive and performance path requirement for PV and battery storage systems in newly constructed nonresidential and high-rise multifamily (>3 stories) buildings. The requirement would apply to the following building types:

- office,
- retail and grocery,
- schools,
- high-rise multifamily (> 3 stories),
- warehouse, and
- other commercial buildings, including auditorium, convention center, hotel/motel, library, medical/clinic, restaurant, and theater.

While PV and battery systems can be modeled in the current compliance software, they cannot be used in trade-offs towards compliance. The proposed measure would create a renewable energy budget for PV and battery systems, and allow trade-offs within that budget, separate from efficiency, similar to how the residential PV and battery requirements are structured in the 2019 Title 24 edition. The measure would add a new subsection to Section 140 (prescriptive requirements) of the Standards.

The measure requires a minimum amount of PV to be sized based on building type when sufficient roof and carport area is available. The PV system size is allowed to be reduced when less than the minimum required surface area is available. When PV systems are required, a battery storage system is also required, and it is sized based on the PV system with the goal of limiting exported energy back to the grid. Exceptions are provided for cases where there is insufficient roof or carport area, the required PV system is too small, or for locations where high snow loads or other conditions prevent the installation of PV systems.

In addition to the PV and battery requirements, the measure proposes a compliance credit for electric vehicle (EV) chargers when exceeding the EV charger requirement under the CALGreen Standard (CBSC 2019). This compliance credit would be available only in the performance path. EV charging during the daytime coincides with the period of highest renewable generation and has the potential to reduce the load on the grid during peak hours.

2.2 Measure History

This measure would be a major step towards the state's 2030 ZNE goal for newly constructed nonresidential buildings (CPUC 2008). A similar PV and battery storage (credit only) requirement has been adopted in the 2019 Title 24 Standard for residential buildings. The proposed measure for nonresidential buildings is similar in nature, with requirements for minimum PV size and battery size; although, the costs, savings, impact, and cost-effectiveness were independently evaluated for nonresidential buildings. A recent change to ASHRAE Standard 90.1-2019 (ASHRAE 2019), which has been approved for publication, requires a minimum amount of PV be installed (Watts per square foot of roof area) for nonresidential buildings. Additional examples of PV requirements exist in other Standards and jurisdictions. There are no minimum Standards for PV or batteries at the federal level and therefore, this measure does not preempt federal standards.

PV and battery storage systems can be modeled in the nonresidential compliance software. However, there is no credit towards compliance that can be claimed by these systems. By introducing PV and battery requirements in the prescriptive path, this measure will enable projects to claim credit in the compliance software when going beyond the minimum PV and battery requirements.

2.3 Summary of Proposed Changes to Code Documents

The sections below provide a summary of how each Title 24 document will be modified by the proposed change. See *Section 4* of this report for detailed proposed revisions to code language.

2.3.1 Standards Change Summary

This proposal would modify the following sections of the Building Energy Efficiency standards as shown below. See *Section 4* of this report for the detailed proposed revisions to the standards language.

SECTION 110.10 – Mandatory Requirements for Solar Ready Buildings

Subsection 110.10 (a) through (e): The solar ready requirements will be exempted for nonresidential and high-rise multifamily buildings when PV systems are required and are installed.

SECTION 140.10 – Photovoltaic Requirements

The proposed regulations creates a new section, Section 140.10, and adds PV and battery requirements to that section.

Subsection 140.10(a): Section 140.10(a) specifies how a minimum PV size shall be calculated for nonresidential buildings. It provides several exceptions to PV requirements.

Subsection 140.10(b): Section 140.10(b) specifies how a minimum battery system size shall be calculated for nonresidential buildings. It provides several exceptions to the battery requirements.

2.3.2 Reference Appendices Change Summary

This proposal would modify the following sections of the Standards Appendices as shown below. See Section 7.2 Reference Appendices of this report for the detailed proposed revisions to the text of the reference appendices.

JOINT APPENDICIES

JA11 – Qualification Requirements for PV Systems: A reference to new section, 140.10 is added to JA11 to identify the new nonresidential and high-rise multifamily requirements proposed in this measure.

JA12 – Qualification Requirements for Battery Storage System: The proposed regulations modify JA12 with respect to the new battery storage requirements. New performance compliance requirements have been specified as part of this measure. In addition, controls for uncoupled battery storage systems have also been specified.

2.3.3 Alternative Calculation Method (ACM) Reference Manual Change Summary

This proposal would modify the following sections of the Nonresidential Alternative Calculation Method (ACM) Reference Manual as shown below. See *Section 7.3 ACM Reference Manual* of this report for the detailed proposed revisions to the text of the Alternative Calculation Method (ACM) Reference Manual.

Section 1.0 – Overview

New sections are added to discuss how buildings would comply with dual energy design ratings and dual metrics. The new sections also describe how PV and battery systems and the EV charging credit are to be credited towards compliance.

The proposed prescriptive PV and battery requirements specify minimum sizes by building types. The building type definitions and how they would be mapped based on the proposed design inputs has been described.

Section 3.5 – Software Sensitivity Tests

New tests are being proposed to be added for PV and battery systems.

Section 5.0 – Building Descriptors Reference

Details about the PV and battery systems inputs, how they must be derived, and how they are used have been added. Input restrictions on the proposed design, as well as baseline rules have been added. These have been marked clearly for new construction.

2.3.4 Compliance Manual Change Summary

The proposed code change will modify the following sections of the Title 24 Compliance Manual:

- 1.0: Introduction
- 2.0: Compliance and Enforcement
- 8.0 Electrical Power Distribution
- 11.0: Performance Approach

2.3.5 Compliance Forms Change Summary

This proposal would modify the Nonresidential Certificates of Compliance (NRCC) listed below. See Section 7 of this report for the detailed proposed revisions to the 2022 NRCC forms.

- NRCC-SRA-E
- NRCC-PRF-E
- NRCI-SPV-01-E
- NRCI-SPV-02-E

2.4 Regulatory Context

2.4.1 Existing Standards

Requirements for onsite PV systems exist in both national model energy codes, ASHRAE Standard 90.1 (ASHRAE 2019) and the International Energy Conservation Code (IECC) (ICC 2018).

- ASHRAE Standard 90.1-2019: An addendum to ASHRAE Standard 90.1-2019 incorporated minimum PV requirements in the prescriptive path. The addendum has been approved for publication, meaning it is part of the Standard and will be published with the 2022 edition of the Standard.
- 2018 IECC: An optional efficiency package for renewables (C406.5) is in the current edition of the IECC. Multiple efficiency packages are available and the building must comply with at least one of them. The renewables requirement includes a minimum PV size based either on the roof area or certain building end-uses.
- International Green Conservation Code (IgCC) (ICC 2018): The IgCC 2018, which supersedes past ASHRAE Standard 189.1 (ASHRAE 2014)code editions, also includes prescriptive requirements for onsite renewable systems.

2.4.2 Relationship to Other Title 24 Requirements

The 2019 CALGreen Standard (CBSC 2019), Title 24, Part 11, requires additions, alterations, and new construction buildings to include "EV-capable" parking spaces. These spaces must include all essential features so that they may easily be converted into EV charging stations in the future, including a dedicated 208/240-Volt branch circuit and a raceway to the parking space to protect the circuit from damage. CALGreen specifies a minimum number of EV-capable parking spaces based on the number of parking spaces associated with a building. However, there are no requirements for EV chargers to be installed in the spaces. A requirement for EV chargers is being considered for the 2022 CALGreen edition.

Parts 2, 2.5, and 9 of Title 24 include fire code provisions for the installation of rooftop solar photovoltaic systems. These regulations cover required testing, marking, location of components, and access and pathways restrictions. The access and pathway requirements limit the total area available for solar arrays on any roof face. Therefore, care must be taken during design to ensure there is adequate roof space for PV in all proposed orientations.

Part 3 of Title 24 includes provisions for electrical safety of photovoltaic systems. These regulations cover circuit requirements, disconnection means, wiring methods, grounding, marking, and storage batteries. Battery storage installations must meet National Fire Protection Agency (NFPA) regulations for fire safety.

2.4.3 Relationship to Federal Laws

The National Fire Protection Act (NFPA) was recently updated to include measures to mitigate fire risk from battery storage in commercial buildings. As a result of these changes, batteries in commercial buildings are typically installed outside, near the building exterior. There are no other major relationships to federal laws.

2.4.4 Relationship to Industry Standards

The net energy metering (NEM) tariff developed by the California Public Utilities Commission (CPUC) impacts the amount of reimbursement received for electricity exported to the grid. This tariff directly affects the energy and cost savings from the measure being proposed as well as the measure cost-effectiveness. Starting in November 2020, the CPUC began a 15-month NEM proceeding, beginning with a prehearing conference to determine what a successor NEM tariff might look like compared to the current tariff. CPUC's major goal with new tariff is to develop a "mechanism for providing customer-generators with credit or compensation for electricity generated by their renewable facilities that a) balances the costs and benefits of the renewable electrical generation facility, and b) allows customer-sited renewable generation to grow sustainably among different types of customers and throughout California's diverse communities."[3]

As of October 2, 2020, each of the four major investor-owned utilities in the state are offering incentive levels of $0.35/Wh, or $0.25/Wh for energy storage projects claiming the Investment Tax Credit (ITC)[4]. Projects over 10 kW in capacity must receive half of their incentive as a performance-based incentive (PBI). The projects must meet a modest number of discharge cycles per year (corresponding to a minimum capacity factor of 10%) and must be capable of reducing greenhouse gas emissions by the specified target amounts. The $0.25/Wh represents an approximate 30% to 40% reduction in installed cost; this rebate is not incorporated into cost-effectiveness calculations.

2.5 Compliance and Enforcement

The PV market in California is mature due to the presence of local mandates for renewable generation, favorable economics, and the steep reduction in the price of PVs. Solar ready requirements are already present in the 2019 Title 24 edition, requiring the identification of areas where PV could be installed and a provision for interconnection pathways and panel capacity for future PV systems. Battery systems are allowed to provide credit and enable a reduction in the minimum size of PV system required to comply for single family and low-rise multifamily buildings since the 2019 Title 24 edition. Thus, compliance with PV and battery systems and their enforcement is no longer a novel topic in California.

The proposed requirements apply to nonresidential buildings, where previously there have been no minimum requirements for PV or battery systems. Therefore, additional checks and verification will be required on the part of the building official. In order for permit applicants to accurately determine the effective annual solar access, solar assessment tools will need to be developed privately and approved by the CEC for use on nonresidential projects as specified in Joint Appendix JA11.4 Inspection and verification are expected to be straightforward with the main verification and enforcement activities as follows:

1. Verify the Nonresidential Certificates of Installation (NRCI) form is valid.
2. Verify the battery storage system is programmed and operational with one of the control strategies listed in JA12.2.3.1-3 and matches the control strategy on the Certificate of Compliance.

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[3] CPUC's NEM 3.0 Rulemaking: https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M346/K286/346286700.PDF

[4] CPUC self-generation incentive program revisions pursuant to senate bill 700 and other program changes, Rulemaking 12-11-005, January 27, 2020. https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M325/K979/325979689.PDF

The plans examiner will verify the compliant specifications listed on the Nonresidential Certificates of Compliance (NRCC) match the design documents. Then the installer will document the installed PV and battery equipment on the NRCI. The building inspector will verify the NRCI is valid by confirming the NRCI matches what has been physically installed and that it meets operational requirements, including controls. The main aspects of inspection and verification are as follows:

3. Check that the designed and installed PV size complies with the code. Check if any roof area reduction has been applied by the project and if the reduction is appropriate.
4. Check that the battery size complies with the code.
5. Check that the installed PV, battery, and inverter efficiency match the specifications used for compliance.
6. Check that interconnection requirements have been met.

Additional requirements in JA11 and JA12 must also be verified.

3. Market Analysis

The authors performed a market analysis with the goals of identifying current technology availability, current product availability, and market trends. The authors considered how the proposed standard may impact the market in general and individual market players. The authors gathered information about the incremental cost of complying with the proposed measure. Estimates of market size and measure applicability were identified through research and outreach with key stakeholders and wide range of industry players who were invited to participate in stakeholder meetings held in 2020.

3.1 Market Structure

3.1.1 PV Systems

The PV market in California is highly developed. Figure 1 shows manufacturers, installers, distributers, and other companies involved with PV and battery systems in California. California ranks first in the country for installed solar generation with more than 19% of the state's electricity coming from large- and small-scale solar PV and solar thermal installations[5].

Figure 1: PV manufacturers, suppliers, installers, and other companies in California (source: SEIA.org)

[5] Energy Information Administration (EIA) California Energy Profile: https://www.eia.gov/state/?sid=CA

Photovoltaic (PV) panels are available from a number of manufacturers. The top three panel producers in 2019[6] are:

1. First Solar, 1,900 MW
2. Hanwha Q Cells,1,700 MW
3. Tesla/Panasonic, 1,000 MW

First Solar has multiple plants in the United States and is well-known for thin-film modules that are popular with utility-scale projects. Hanwha has a large plant in Georgia, with the company headquarters in South Korea. Sunpower is another U.S. based company that produces panels with high-efficiency modules that are used on many California projects.

There are three major types of PV panels: monocrystalline solar panels, polycrystalline panels, and thin film panels. Monocrystalline solar panels are the most common on commercial buildings, with rated efficiency levels of approximately 20%. For this measure, the module efficiency is not a factor in the prescriptive requirement, because the capacity requirement is based on the rated power production.

PV systems have a steadily rising market penetration in California. Commercial PV systems have an estimated market penetration of 2.5% statewide (Hoen, Rand and Elmallah 2019), with the greatest penetration in the school building type. Owner-occupied buildings and higher property market valuations per square foot are correlated with higher PV penetration rates.

3.1.2 Battery Storage Systems

Battery storage installations in commercial buildings have increased in recent years, both, in the United States and in California. More than 90 percent of large-scale battery storage in the United States is provided by lithium-ion batteries (EIA 2020). Installations for the California Independent System Operator (CAISO) constitute 21% of existing large-scale battery storage capacity in the United States (EIA 2020). This is fueled in part by state Assembly Bill 2514[7], which established 2020 storage targets for state investor-owned utilities. As a consequence of this growth and advances in technology and product delivery, there has been a large reduction in installed battery system costs over the last five to seven years. Projections by the National Renewable Energy Laboratory (NREL) estimate that by 2030 system costs will reduce from 2018 levels by 11% in the low scenario and 67% in the high scenario (Cole and Frazier 2019).

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[6] Largest US Solar Panel Manufacturers by Capacity: https://cleantechnica.com/2019/12/18/largest-us-solar-panel-manufacturers-by-capacity/

[7] Assembly bill 2514, Energy Storage Systems: https://leginfo.legislature.ca.gov/faces/billNavClient.xhtml?bill_id=200920100AB2514

In 2020, quarter 3 alone saw 39 MWh of battery storage being deployed in the nonresidential sector, 69 MWh in the residential sector, and 510 MWh in front of the meter (utility-scale) installations (Wood Mackenzie 2020). The total distributed storage installed in 2018 (smaller than 1 MW each) was 234 MW, with about half installed in the commercial sector. California is in line to meet its energy storage mandate (AB 2514) of 1,325 MW by 2024 (including utility-scale installations) (EIA 2020).

Commercial battery systems today that have a minimum capacity factor are eligible for state incentives through the Self-Generation Incentive Program (SGIP). Commercial battery storage is provided by a small number of providers; some of these providers offer management of the battery storage system as a turnkey solution. For small commercial storage, Tesla, Sunpower, and LG offer products on the market. Sunpower and LG offer small storage AC-based products that can be coupled directly with the PV system.

3.1.3 EV Charging

California Governor Newsom, through executive order N-79-20[8] has introduced a ban on the sale of gas vehicles by 2035. With an increased number of EVs on the road, there is more attention on the availability of public (and private) EV charging stations to deliver power while away from home. These EV chargers work best when located in areas where vehicles are likely to be parked for extended periods of time, ideally 30-60 minutes for fast charging stations, and several hours for lower intensity charging.

There are three major types of EV chargers, each offering different charging speeds, at vastly different costs (New West Technologies 2015):

- Level 1: Costs between $300 – $1,500, drawing 1.44 kW for a slower, less expensive charge.
- Level 2: Costs between $400 – $6,500, drawing 7kW for a faster, more expensive charge.
- DC Fast Chargers: Cost between $10,000, and $40,000, generally drawing 50-60kW.

Credit for installing EV chargers is being proposed as an option and is therefore expected to be less demanding from a market supply and installed cost point of view.

[8] Governor Newsom's Executive Order N-79-20 prohibits the sale of gasoline vehicles beginning 2035: https://www.gov.ca.gov/wp-content/uploads/2020/09/9.23.20-EO-N-79-20-text.pdf

3.2 Technical Feasibility, Market Availability and Current Practices

3.2.1 PV Systems

As described previously, California has a mature PV and a robust battery market. Photovoltaic (PV) systems have been successfully installed on commercial buildings for many years in California. They are available from a number of suppliers and manufacturers, and the market has resulted in a steadily decreasing cost for both the PV modules and the installed costs of battery systems. As such, there are no technical or market availability hurdles expected from the adoption of this measure.

The NEM Interconnected Database shows (CPUC 2020) that the most prevalent type of PV installation is racks on the roof facing south and at a slight tilt (10 degrees). Racks can be either fastened to the roof or secured via ballast. Ballasted systems can be installed more quickly and therefore with lower labor cost, but they require sufficient structural support at the roof. Ballasted systems are seen on retail and other commercial buildings. Applications with higher expected wind loads or where the roof structure may not support the weight of the ballast, positive attachment systems are used. An additional step in the design process for projects will be to accommodate space for rooftop PV panels, clear from any rooftop HVAC and rooftop refrigeration equipment.

Buildings that are core and shell buildouts and buildings with multiple tenants require a way of apportioning the benefits of the solar PV system to multiple tenants. The building owner can either facilitate a virtual net energy metering (VNEM) arrangement, or incorporate utility costs into tenant leases, and share PV benefits in an agreed-upon manner. Under a virtual net energy metering structure, a unitary PV system generates electricity behind a building-level meter, and, based on a pre-determined apportionment, the utility assigns energy credits to bills of individually metered, participating tenants. These VNEM credits provide the same bill impacts to tenants as if their share of the system was behind their individual meter. Virtual net energy metering is offered by California's three investor-owned utilities—PG&E, SCE, and SDG&E—however, is not offered by some of the publicly-owned utilities, including LADWP and SMUD.

3.2.2 Battery Systems

Commercial battery systems are typically installed in enclosures just outside the building[9]. Batteries have either a two-hour or four-hour duration with the two-

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[9] Author's email and phone correspondence with battery installers in California.

hour battery being more common, which aligns with the state's SGIP incentives. A 100 kW battery system typically occupies a footprint that is slightly smaller than a car parking space. Smaller battery storage systems such as the Tesla Powerwall are used in residential and light commercial applications. These can be mounted indoors, where there is sufficient ventilation.

Battery storage systems have become a more popular complement to PV systems in commercial buildings (EIA 2020). The fraction of buildings with PV systems that also have battery storage has increased from just over 1 percent a few years ago to nearly 5 percent in 2019 (Barbose and Darghouth 2019).

Storage systems can also provide resilience by providing backup power during an outage. Battery system size in this measure varies by building type, with some buildings requiring enough storage to sustain multiple building end-uses for a few hours. This is an important potential benefit that is not directly factored into the cost-effectiveness analysis. These battery systems have the potential to continue operating several building systems, such as building exterior and interior lighting and ventilation, especially during planned power outages such as the Public Safety Power Shutoffs (PSPS) instituted during wildfire season in California.

The primary benefit of the proposed battery requirement is the ability to limit exports to the grid from PV generation, and reducing peak demand and energy use during peak periods. Several battery storage providers include either adaptive or managed control systems as part of their packages. These control systems use not only information on building loads and generation, but also retail and wholesale price signals to know when to use and when to store onsite generated energy. The proposed measure does not restrict the battery operation to a specific control strategy.

The two primary control strategies are the reduction of exported electricity that is subject to NEM guidelines, and energy arbitrage, i.e., storing energy when electricity rates are low and using the stored energy during peak periods when rates are higher. The effectiveness of energy storage for either of these strategies depends upon rate policies offered by the utility. The objective of the energy storage measure is to provide buildings with systems and tools for better managing their energy use and energy production in coordination with the grid.

Commercial battery storage systems have been used in California since 2010, where 7 large-scale storage systems accounted for 59 MW of capacity (EIA 2020). According to the California Solar and Storage Association (CALSSA)[10], more than 10,000 California customers installed battery storage system for a combined 138 MW of installed energy storage in 2019, a 27% increase from

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[10] CALSSA advocates for the solar and storage industry in California: https://calssa.org/

2018 and approximately triple from 2017 levels. Several companies offer battery storage products, including Tesla, SunPower, LG, Panasonic, and SimpliPhi.

While the primary market for battery storage products is residential, some of the products can be linked together to provide storage for small commercial buildings. For 100 kW (200 kWh) or larger system, there are several providers of battery storage products. Some large providers offer storage solutions that include turnkey installation and remote management of the system and its operation.

This Title 24 measure predicts that 100 MW of batteries would be installed in new nonresidential buildings in 2023 (when the measure goes into effect). With the steady increase in nonresidential storage systems throughout the country and in California, it is expected that there will be sufficient supply of systems to meet market needs. The adoption of this measure in July 2021, with the adoption of the 2022 Title 24, will give the already expanding supply chain enough time to ramp up supply by 2023 when the measure goes into effect. In addition, the increased installation of battery storage systems is likely to continue the decreasing trend in battery costs (see Section 5.3 on incremental first cost).

3.3 Market Impacts and Economic Assessments

3.3.1 Impact on Builders

This change will impact builders in the following ways:

1) Builders will need to make an allowance for additional first cost of PV systems.
2) Coordination with trades for allowance of roof space for HVAC equipment. Analysis of representative roof plans shows that for some building types up to 30% or more of roof space is taken up by rooftop HVAC equipment, exhaust fans, refrigeration equipment, etc. Designers will have to designate available roof space with sufficient clearance and solar access from the south and west.
3) Builders will need to allocate sufficient time in the construction process for permitting, inspection, and interconnection to occur, which can take a period of several weeks in some jurisdictions.
4) The PV panels can be installed on roofs or carports. In some cases, the panels must be secured to the roof with positive attachment, which necessitate additional roof penetrations. However, panel installations can avoid roof penetrations if secured to the roof with ballast. Ballast is a common installation method for commercial buildings, because it avoids the need for additional roof penetrations, and because the panels can be set more quickly than with other methods, reducing labor cost.

3.3.2 Impact on Building Designers and Energy Consultants

The primary change for building designers is to coordinate with trades for allowing available roof space and clearance. For energy consultants, the additional requirement for PV systems, with or without storage, places greater emphasis on aligning both energy efficiency and PV and storage systems with the building's load profile.

3.3.3 Impact on Occupational Safety and Health

The proposed code change to require commercial batteries onsite places a responsibility on the building owner to locate and secure the storage in a location that mitigates fire risk. For commercial installations, this often steers designers to locate the batteries outside, away from the building.

3.3.4 Impact on Building Owners and Occupants

PV and battery systems will require periodic maintenance. Special attention must be given when entering into NEM agreements and rate structures with the utilities. Occupants are unlikely to see a significant change in normal operations, except the potential benefit of fewer interruptions to regular operations during a power outage.

3.3.5 Impact on Building Component Retailers (including manufacturers and distributors)

Distributors and installing contractors are likely to experience a significant increase in business volume due to this measure.

3.3.6 Impact on Building Inspectors

This measure will require building inspectors to verify that the specified PV system and battery storage system meets the proposed prescriptive requirements for capacity and performance.

3.3.7 Impact on Statewide Employment

This measure will likely result in an increase in jobs in the state of California. A significant number of new jobs will be created to meet the increased demand for nonresidential PV and battery system installations. Details are provided in the section Creation or Elimination of Jobs.

3.4 Economic Impacts

The estimated impacts that the proposed code change will have on California's economy are discussed below.

3.4.1 Creation or Elimination of Jobs

In 2019, California had 74,255 jobs in the industry according to the Solar Foundation[11], with a mean annual wage of $47,640 (Bureau of Labor Statistics 2019). With 3000 MW of PV capacity being added in 2020 (SEIA.org), this corresponds to approximately 25 jobs per MW of added generation. In comparison, the National Renewable Energy Laboratory's (NREL) Jobs and Economic Development Impact (JEDI) model predicted 5,400 jobs for 218 MW of added PV in the residential sector (Energy and Environmental Economics 2017), which also translates to approximately 25 jobs per MW of added generation. Therefore, assuming 25 jobs are added per MW of added PV generation, the proposed measure for nonresidential buildings will add approximately 7,000 new jobs in 2023 given 280 MW of added generation.

The California Energy Storage Association (CESA) found that new energy storage investments and project development may support more than 98,000 jobs over the next ten years. (CESA 2020). In addition, there were 18,571 workers in the California energy storage industry in 2019, with the majority employed in battery storage manufacturing, procurement, and installation. CESA estimates approximately 10 jobs per MW of added energy storage. Through this measure, 100 MW of battery storage is projected to be added in 2023. Therefore, at a rate of 10 jobs per MW, there would be an addition of 1,000 jobs from this measure in 2023.

This measure does not reduce the efficiency of the building and is therefore not expected to displace jobs within the energy efficiency industry. The measure applies to only new construction and thus represents new demand. However, the measure drastically reduces the building's energy consumption and therefore could result in fewer jobs in other energy sectors. E3 found net reduction in jobs from the adoption of the residential PV measure in the 2019 Title 24 Standard when including both the addition and loss of jobs from all economic sectors (Energy and Environmental Economics 2017). It should be noted that these reductions are very small compared to the overall size of the generation and battery storage industry in California.

3.4.2 Creation or Elimination of Businesses within California

This measure is expected to spur new business to open to support the demand of new PV and battery system procurement, design, and installation. The measure does not compete with other building measures and is thus unlikely to result in the elimination of businesses related to building energy efficiency.

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[11] Solar jobs census 2019: http://www.solarstates.org/#state/california/counties/solar-jobs/2019

3.4.3 Competitive Advantages or Disadvantages for Businesses within California

This measure will result in an increased first cost in the design and construction of nonresidential and high-rise multifamily buildings (> 3 stories). Retail, office, and other businesses that operate in California and other states will see an increase in the cost of constructing new buildings or renting newly constructed buildings. However, this is likely to be more than offset by the steep reduction in annual electricity costs. A study of net-zero commercial properties in the United States showed a 17% sale value premium and a 19% increase in profits over ten years (Carmichael and Petersen 2018). Thus, California properties that have significant renewable generation capability and greatly reduced utility bills are likely to garner higher rents and have a competitive advantage against similar properties that do not have these features.

3.4.4 Increase or Decrease of Investments in the State of California

The proposed changes to the building code are expected to positively impact investments in California on a macroeconomic scale and are expected to affect investments by individual firms. Transitioning from the current market, where there is no PV or battery requirement for newly constructed nonresidential and multifamily buildings, to a minimum code PV and battery requirement will create a significant increase in the amount of goods produced and jobs created to meet new demand. The proposed changes will sustain widespread adoption of PV and battery systems and will increase the number of distributed energy sources available to the State of California. The new requirement will also lead to an increase in direct investment in California manufacturers, distributors, and installers of PV systems and supporting products (see section 3.1). It is too early to gauge the impact on the market from the residential PV requirement than went into effect with the adoption of the 2019 Title 24 Standard.

3.4.5 Effects on Innovation in Products, Materials, or Processes

The production and installation of PV modules and systems has mature products and markets in the United States and abroad. The California PV market is a small fraction of the global market, and an increase in demand from the proposed changes is not expected to significantly alter the trajectory of PV system development and related processes in California.

In contrast, the commercial battery storage market is comprised of a small number of companies for large (100 kW and greater) and small commercial storage. The proposed requirement for battery systems will result in market growth and may accelerate the already prevalent downward trend in system costs, both through competition and through technological advancement. The proposed change provides flexibility for designers to specify the type of system and controls that best serves their needs. The battery control scheme is left entirely to the designer and will most likely be guided by the utility rate structure available to the building. Therefore, while the battery requirement will drive demand and reduce costs, it is not likely to stifle innovation in the fields of battery and control technologies.

Finally, a review of the 2019 Energy Standards Update (CEC 2018) showed that the residential PV requirement did not affect the "existing regulations governing the production, processing, handling, transportation, storage, use, and disposal" of materials.

3.4.6 Effects on the State General Fund, State Special Funds and Local Governments

The proposed will result in a significant reduction in ratepayer utility bills in newly constructed nonresidential and multifamily buildings, which means that there will slower growth in the utility tax that funds special-funded agencies, including the Energy Commission. The proposed requirement for PV and battery storage is not expected to negatively impact the General Fund. Due to the additional cost of PV and battery systems, local and state government buildings will cost more to construct. In addition, the leasing cost of newly constructed buildings to state and local governments may increase.

3.4.6.1 Cost of Enforcement

Cost to the State

The California state government already has budget for code development, education, and compliance enforcement. While state government will be allocating resources to update the Title 24, Part 6 Standards, including updating education and compliance materials and responding to questions about the revised requirements, these activities are already covered by existing state budgets. The costs to state government are small when compared to the overall costs savings and policy benefits associated with this proposal.

This measure is expected to have a modest positive effect on the state General Fund through expected increases in employment in the PV, battery, and construction industry. This effect would be seen through income tax and sales tax revenue associated with the newly created jobs. Reductions in energy expenditures are expected to increase corporate discretionary income. This can lead to reinvestment in increasing the workforce, with subsequent tax increases. These indirect positive impacts have not been quantified.

The additional first cost of PV and battery systems is not expected to impact the property tax revenue that contributes to the General Fund. Revenue generated from property taxes is directly linked to the value of the property, which is usually linked to the purchase price of the property. The proposed changes may result in an increase in property valuation. However, the value of an onsite PV generation system is specifically excluded from property tax valuation (BOE 2021). There will also likely be a significant cost savings to the state of California, through reduction or elimination of self-generation incentives for commercial buildings.

Cost to Local Governments

Any revision to the Title 24, Part 6 Standard will result in changes to compliance determinations. Local governments will need to train building department staff on the revised Title 24, Part 6 Standard. While this retraining is an expense to local governments, it is not a new cost associated with the 2022 code cycle. The building code is updated on a triennial basis, and local governments plan and budget for retraining every time the code is updated. There are numerous resources available to local governments to support code compliance.

Local building code officials have a large number of requirements to check and are often constrained by time and department budgets. The new requirement for commercial PV system requires an additional plan check, but no field verification testing. Battery storage systems involve a modest amount of checks and may also require coordination with NFPA guidance on siting the system considering fire safety. While additional requirements are not new, for effective enforcement, the new requirements could provide justification for a modest increase to department budgets for code enforcement. Even so, this does not pose a significant additional cost for the state.

Local governments are often more amenable to longer payback periods than industry, and an array of third-party financing mechanisms are available to absorb first costs of PV systems and battery storage. Therefore, this measure is not expected to impact municipal construction within the state.

3.4.6.2 Impacts on Specific Persons

The PV system requirement could benefit renters in affordable housing by dramatically reducing utility energy costs. However, the developer would bear the burden of the increased first cost. Currently there are large incentives in place for both PV and battery systems for affordable housing. Developers and program administrators may need to develop an equitable solution for both the developer and tenants.

4. Energy Savings

4.1 Key Assumptions for Energy Savings Analysis

This study assumes building load profiles from CBECC-Com for 11 key Nonresidential building typologies, all based on 2019 prescriptive requirements, in each of the 16 climate zones.

The following prototype buildings were simulated, using CBECC-Com prototypes, with both mixed fuel and all-electric configurations

- High-Rise Residential
- Mid-Rise Residential
- Large Office
- Medium Office
- Small Office
- Large Retail
- Medium Retail
- Small Retail
- Large School
- Small School
- Warehouse

Based on these prototype buildings, this analysis adds on-site solar, with generation profiles modeled using the NREL System Advisor Model (SAM) (Blair 2018). PV generation profiles were modeled for each climate zone, using the CTZ22 weather year. PV systems were modeled with the following characteristics. These inputs were selected to either follow the most standard configuration (such as orientation), or to create a conservative estimate of generation (such as an inverter loading ratio).

- 180° south facing orientation
- Flat on roof, fixed open rack, zero-tilt
- 96% inverter efficiency
- Standard module type
- Inverter loading ratio of 1.0
- No shading

Building on the prototype buildings and PV systems, battery storage systems were modeled with the following system characteristics. These input characteristics were selected to err on the side of a conservative estimate for the cost-benefit of the system.

- Round trip efficiency 85%
- Minimum State of Charge 0%
- Parasitic loss - 0% SOC/hr
- Only charge from solar
- No cycling limits
- 10-year battery cell lifetime
- Inverter loading ratio of 1.0
- Duration sized so battery can discharge at full capacity for four hours, after accounting for discharge efficiency losses

The battery storage system was dispatched assuming a "Time-of-Use Control" dispatch scheme, consistent with JA12. The Time-of-Use Control scheme follows these rules, and provides a conservative estimate of battery dispatch relative to commercially available battery controls:

- Storage can only charge from on-site PV generation, during solar hours
- Storage can only discharge from 4pm to 9pm, each day of the year
- Storage can only offset customer load, may not export to the grid

4.2 Energy Savings Methodology

To assess the energy, demand, and energy cost impacts, E3 compared current design practices to design practices that would comply with the proposed requirements. There are no existing Title 24 requirements that cover the proposed on-site solar system in question. E3 used current design practices as the existing conditions.

The proposed conditions are defined as the design conditions that will comply with the proposed code change. Specifically, the proposed code change will add on-site solar and battery storage at the prescribed amount, as detailed in Table 5 and Table 6. The on-site solar in this proposal is sized such that, over the course of a year, a mixed-fuel building would self-utilize approximately 80% of annual generation without battery storage. In addition to this on-site solar, the battery storage system is sized such that, when operated with the Time-of-Use control scheme, annual self-utilization of PV generation increases from approximately 80% to approximately 90%. To achieve this, a different size solar system (measured in kW) and was added to each prototype building in the 16 different climate zones, as shown in Table 5. Additionally, a different battery storage system (measured in kW and kWh) was added to each prototype building in the 16 different climate zones, as shown in Table 6. Note that the warehouse prototype does not include a battery storage requirement; the analysis team found that battery storage is not cost effective in this application, and therefore does not propose a requirement for that building classification.

Table 5: PV System Capacities (W_{DC}/ft^2) sized for mixed-fuel prototype building to self-utilize approximately 80% of annual PV generation

Prototype ID	Occupancy Type	Climate Zones 1, 3, 5,16	Climate Zones 2, 4, 6-14	Climate Zone 15
Prototype 1	High-Rise Residential	1.82	2.21	2.77
Prototype 2	Mid-Rise Residential	1.59	1.89	2.29
Prototype 3	Large Office	2.16	2.64	3.00
Prototype 4	Medium Office	2.59	3.13	3.80
Prototype 5	Small Office	4.04	4.44	5.02
Prototype 6	Large Retail	2.58	2.87	3.39
Prototype 7	Medium Retail	2.62	2.91	3.53
Prototype 8	Small Retail	4.35	4.62	5.17
Prototype 9	Large School	1.10	1.47	2.00
Prototype 10	Small School	1.44	1.78	2.93
Prototype 11	Warehouse	0.39	0.44	0.58

Table 6: Storage System Capacities ($W_{Battery,DC}/W_{PV,DC}$) and ($Wh_{Battery}/W_{PV,DC}$) sized for mixed-fuel prototype building to increase self-utilization of annual PV generation to be approximately 90%

Prototype ID	Occupancy Type	Battery Power Capacity ($W_{Battery,DC}/W_{PV,DC}$)	Battery Energy Capacity ($Wh_{Battery}/W_{PV,DC}$)
Prototype 1	High-Rise Residential	0.26	1.03
Prototype 2	Mid-Rise Residential	0.25	1.02
Prototype 3	Large Office	0.43	1.73
Prototype 4	Medium Office	0.42	1.68
Prototype 5	Small Office	0.37	1.48
Prototype 6	Large Retail	0.27	1.07
Prototype 7	Medium Retail	0.26	1.03
Prototype 8	Small Retail	0.23	0.93
Prototype 9	Large School	0.45	1.81
Prototype 10	Small School	0.48	1.93
Prototype 11	Warehouse	0.23	0.93

Energy Commission provided guidance on the type of prototype buildings that must be modeled. Nonresidential energy saving estimates are calculated using the prototype models of representative nonresidential and multifamily buildings available in CBECC-Com. Those weights are based on newly constructed square footage. Table 7 presents the details of the prototype building(s) used in the analysis.

Table 7: Prototype Buildings used for Energy, Demand, Cost, and Environmental Impacts Analysis

#	Occupancy Type (Residential, Retail, Office, etc.)	Area (Square Feet)	Number of Stories	Statewide Area (square feet)
1	High-Rise Residential	94,097	10	2,228,566
2	Mid-Rise Residential	113,100	4	27,206,395
3	Large Office	498,589	12	14,725,389
4	Medium Office	52,628	3	14,735,389
5	Small Office	5,502	1	8,380,572
6	Large Retail	240,000	1	21,462,424
7	Medium Retail	24,700	1	2,861,657
8	Small Retail	9,375	1	1,430,828
9	Large School	210,886	1	4,002,496
10	Small School	24,413	1	6,003,743
11	Warehouse	52,045	1	24,237,822

The energy savings from this measure varies by climate zone because 1) the electric loads that the solar system is sized to vary by climate zone and 2) the solar insolation is climate zone specific. As a result, the energy impacts and cost-effectiveness were evaluated by climate zone.

Energy savings, energy cost savings and peak demand savings were calculated on an hourly basis using a Time Dependent Valuation methodology.

4.3 Per Unit Energy Impacts and Energy Savings Results

Energy savings, peak demand savings and per unit energy and demand impacts of the proposed measure are presented in Table 8 through Table 18.

Table 8: First Year Energy Impacts per square foot for the High-Rise Residential prototype

Climate Zone	Electricity Savings (kWh/yr/sq ft)	Peak Electricity Demand Savings (kW/sq ft)	Natural Gas Savings (Therms/yr/ Sq ft)	Source Energy Savings (kBtu/sq ft)	TDV Energy Savings (TDVkBTU/yr/ sq ft)
1	2.3	3.01E-04	0.0	3.1	49.7
2	3.4	3.54E-04	0.0	4.1	79.0
3	2.9	2.91E-04	0.0	3.5	64.1
4	3.6	3.54E-04	0.0	4.3	84.6
5	3.1	2.92E-04	0.0	3.9	66.5
6	3.7	3.54E-04	0.0	4.8	85.4
7	3.4	3.51E-04	0.0	4.8	78.3
8	3.6	3.53E-04	0.0	4.7	90.3
9	3.8	3.57E-04	0.0	4.8	90.4
10	3.8	3.46E-04	0.0	4.8	88.0
11	3.4	3.52E-04	0.0	4.0	79.1
12	3.5	3.51E-04	0.0	4.0	80.0
13	3.5	3.51E-04	0.0	4.0	82.3
14	4.1	3.54E-04	0.0	5.1	92.9
15	4.8	4.40E-04	0.0	6.2	110.6
16	3.0	2.87E-04	0.0	3.6	65.4

Table 9: First Year Energy Impacts per square foot for the Mid-Rise Residential prototype

Climate Zone	Electricity Savings (kWh/yr/sq ft)	Peak Electricity Demand Savings (kW/sq ft)	Natural Gas Savings (Therms/yr/ Sq ft)	Source Energy Savings (kBtu/sq ft)	TDV Energy Savings (TDVkBTU/yr/ sq ft)
1	2.0	2.47E-04	0.0	2.6	42.8
2	2.9	2.91E-04	0.0	3.4	66.8
3	2.5	2.45E-04	0.0	3.0	55.3
4	3.0	2.92E-04	0.0	3.5	71.4
5	2.7	2.45E-04	0.0	3.3	57.3
6	3.2	2.91E-04	0.0	4.0	71.9
7	3.0	2.89E-04	0.0	4.0	65.7
8	3.1	2.90E-04	0.0	3.9	76.0
9	3.2	2.93E-04	0.0	4.0	75.8
10	3.2	2.85E-04	0.0	4.1	73.9
11	2.9	2.89E-04	0.0	3.3	66.7
12	3.0	2.88E-04	0.0	3.3	67.4
13	3.0	2.89E-04	0.0	3.4	69.3
14	3.5	2.91E-04	0.0	4.3	78.0
15	3.9	3.51E-04	0.0	5.0	89.8
16	2.6	2.41E-04	0.0	3.1	55.9

Table 10: First Year Energy Impacts per square foot for the Large Office prototype

Climate Zone	Electricity Savings (kWh/yr/sq ft)	Peak Electricity Demand Savings (kW/sq ft)	Natural Gas Savings (Therms/yr/ Sq ft)	Source Energy Savings (kBtu/sq ft)	TDV Energy Savings (TDVkBTU/yr/ sq ft)
1	2.8	3.36E-04	0.0	3.9	60.7
2	3.9	4.13E-04	0.0	5.2	97.2
3	3.4	3.53E-04	0.0	4.7	79.5
4	4.1	4.15E-04	0.0	5.5	97.1
5	3.7	3.47E-04	0.0	5.1	79.6
6	4.4	4.09E-04	0.0	6.2	101.3
7	4.0	4.20E-04	0.0	6.2	93.6
8	4.2	4.35E-04	0.0	6.2	105.2
9	4.4	4.32E-04	0.0	6.3	106.3
10	4.4	4.15E-04	0.0	6.3	104.1
11	4.0	4.26E-04	0.0	5.3	93.9
12	4.1	4.17E-04	0.0	5.2	94.9
13	4.1	4.27E-04	0.0	5.3	99.4
14	4.8	4.32E-04	0.0	6.6	110.4
15	5.1	4.93E-04	0.0	7.4	122.5
16	3.6	3.63E-04	0.0	4.8	74.1

Table 11: First Year Energy Impacts per square foot for the Medium Office prototype

Climate Zone	Electricity Savings (kWh/yr/sq ft)	Peak Electricity Demand Savings (kW/sq ft)	Natural Gas Savings (Therms/yr/ Sq ft)	Source Energy Savings (kBtu/sq ft)	TDV Energy Savings (TDVkBTU/yr/ sq ft)
1	3.4	3.86E-04	0.0	4.7	73.0
2	4.8	4.94E-04	0.0	6.2	117.8
3	4.1	4.11E-04	0.0	5.5	95.2
4	5.0	4.99E-04	0.0	6.5	118.5
5	4.4	4.00E-04	0.0	6.1	95.4
6	5.3	4.83E-04	0.0	7.4	122.3
7	4.9	4.80E-04	0.0	7.4	112.5
8	5.1	5.01E-04	0.0	7.3	126.6
9	5.4	5.21E-04	0.0	7.5	129.4
10	5.4	5.06E-04	0.0	7.6	127.0
11	4.8	5.23E-04	0.0	6.3	115.8
12	4.9	5.09E-04	0.0	6.2	116.3
13	5.0	5.25E-04	0.0	6.4	123.0
14	5.8	5.25E-04	0.0	7.9	135.1
15	6.6	6.44E-04	0.0	9.4	159.4
16	4.3	4.25E-04	0.0	5.7	89.0

Table 12: First Year Energy Impacts per square foot for the Small Office prototype

Climate Zone	Electricity Savings (kWh/yr/sq ft)	Peak Electricity Demand Savings (kW/sq ft)	Natural Gas Savings (Therms/yr/ Sq ft)	Source Energy Savings (kBtu/sq ft)	TDV Energy Savings (TDVkBTU/yr/ sq ft)
1	5.1	5.77E-04	0.0	6.9	111.8
2	6.7	6.40E-04	0.0	8.5	162.0
3	6.3	5.84E-04	0.0	8.0	142.5
4	7.0	6.51E-04	0.0	8.9	165.0
5	6.7	5.81E-04	0.0	8.9	144.0
6	7.4	6.46E-04	0.0	10.0	169.8
7	6.8	6.45E-04	0.0	10.0	156.7
8	7.2	6.53E-04	0.0	9.9	176.1
9	7.5	6.63E-04	0.0	10.1	179.3
10	7.5	6.41E-04	0.0	10.2	175.2
11	6.7	6.71E-04	0.0	8.5	159.0
12	6.9	6.48E-04	0.0	8.4	159.7
13	6.9	6.67E-04	0.0	8.6	168.6
14	8.1	6.66E-04	0.0	10.8	186.9
15	8.5	7.82E-04	0.0	12.0	203.8
16	6.5	5.88E-04	0.0	8.4	139.3

Table 13: First Year Energy Impacts per square foot for the Large Retail prototype

Climate Zone	Electricity Savings (kWh/yr/sq ft)	Peak Electricity Demand Savings (kW/sq ft)	Natural Gas Savings (Therms/yr/ Sq ft)	Source Energy Savings (kBtu/sq ft)	TDV Energy Savings (TDVkBTU/yr/ sq ft)
1	3.3	3.80E-04	0.0	4.2	69.3
2	4.4	4.18E-04	0.0	5.1	101.6
3	4.1	3.77E-04	0.0	4.8	88.8
4	4.6	4.26E-04	0.0	5.4	107.4
5	4.3	3.79E-04	0.0	5.3	91.4
6	4.9	4.23E-04	0.0	6.2	107.6
7	4.5	4.23E-04	0.0	6.1	98.7
8	4.7	4.27E-04	0.0	6.1	113.7
9	4.9	4.33E-04	0.0	6.2	114.2
10	4.9	4.19E-04	0.0	6.2	110.9
11	4.4	4.27E-04	0.0	5.2	100.9
12	4.5	4.23E-04	0.0	5.1	101.3
13	4.5	4.27E-04	0.0	5.2	104.7
14	5.3	4.29E-04	0.0	6.6	118.8
15	5.8	4.98E-04	0.0	7.5	132.8
16	4.2	3.76E-04	0.0	5.0	87.6

Table 14: First Year Energy Impacts per square foot for the Medium Retail prototype

Climate Zone	Electricity Savings (kWh/yr/sq ft)	Peak Electricity Demand Savings (kW/sq ft)	Natural Gas Savings (Therms/yr/ Sq ft)	Source Energy Savings (kBtu/sq ft)	TDV Energy Savings (TDVkBTU/yr/ sq ft)
1	3.4	3.84E-04	0.0	4.2	70.5
2	4.4	4.17E-04	0.0	5.2	102.5
3	4.1	3.78E-04	0.0	4.8	89.8
4	4.7	4.20E-04	0.0	5.4	108.3
5	4.4	3.80E-04	0.0	5.4	92.7
6	4.9	4.20E-04	0.0	6.2	108.6
7	4.5	4.18E-04	0.0	6.1	99.6
8	4.8	4.19E-04	0.0	6.1	115.0
9	5.0	4.25E-04	0.0	6.2	115.5
10	5.0	4.12E-04	0.0	6.2	112.2
11	4.5	4.19E-04	0.0	5.2	101.9
12	4.6	4.16E-04	0.0	5.1	102.2
13	4.6	4.19E-04	0.0	5.2	105.6
14	5.4	4.21E-04	0.0	6.6	120.4
15	6.1	5.01E-04	0.0	7.8	137.6
16	4.3	3.74E-04	0.0	5.1	90.1

Table 15: First Year Energy Impacts per square foot for the Small Retail prototype

Climate Zone	Electricity Savings (kWh/yr/sq ft)	Peak Electricity Demand Savings (kW/sq ft)	Natural Gas Savings (Therms/yr/ Sq ft)	Source Energy Savings (kBtu/sq ft)	TDV Energy Savings (TDVkBTU/yr/ sq ft)
1	5.6	5.61E-04	0.0	6.6	115.6
2	7.1	5.88E-04	0.0	7.7	159.8
3	6.9	5.54E-04	0.0	7.6	146.5
4	7.5	5.90E-04	0.0	8.1	170.0
5	7.3	5.54E-04	0.0	8.5	151.5
6	7.9	5.88E-04	0.0	9.3	170.9
7	7.2	5.86E-04	0.0	9.3	156.5
8	7.6	5.87E-04	0.0	9.1	180.7
9	8.0	5.94E-04	0.0	9.3	181.1
10	7.9	5.77E-04	0.0	9.4	175.9
11	7.1	5.86E-04	0.0	7.7	158.2
12	7.3	5.82E-04	0.0	7.6	159.5
13	7.3	5.87E-04	0.0	7.8	164.2
14	8.6	5.89E-04	0.0	10.0	187.6
15	8.9	6.50E-04	0.0	10.8	198.6
16	7.1	5.48E-04	0.0	8.0	146.7

Table 16: First Year Energy Impacts per square foot for the Large School prototype

Climate Zone	Electricity Savings (kWh/yr/sq ft)	Peak Electricity Demand Savings (kW/sq ft)	Natural Gas Savings (Therms/yr/ Sq ft)	Source Energy Savings (kBtu/sq ft)	TDV Energy Savings (TDVkBTU/yr/ sq ft)
1	1.4	1.95E-04	0.0	2.1	30.8
2	2.2	2.56E-04	0.0	3.1	56.0
3	1.7	2.00E-04	0.0	2.4	40.6
4	2.3	2.62E-04	0.0	3.2	56.2
5	1.8	2.01E-04	0.0	2.7	40.5
6	2.5	2.61E-04	0.0	3.6	58.2
7	2.3	2.60E-04	0.0	3.6	53.6
8	2.4	2.61E-04	0.0	3.6	59.4
9	2.5	2.65E-04	0.0	3.7	60.6
10	2.5	2.56E-04	0.0	3.7	59.7
11	2.2	2.66E-04	0.0	3.1	54.5
12	2.3	2.60E-04	0.0	3.1	54.8
13	2.3	2.71E-04	0.0	3.1	57.6
14	2.7	2.63E-04	0.0	3.9	63.2
15	3.4	3.65E-04	0.0	5.1	82.8
16	1.8	1.98E-04	0.0	2.5	39.3

Table 17: First Year Energy Impacts per square foot for the Small School prototype

Climate Zone	Electricity Savings (kWh/yr/sq ft)	Peak Electricity Demand Savings (kW/sq ft)	Natural Gas Savings (Therms/yr/ Sq ft)	Source Energy Savings (kBtu/sq ft)	TDV Energy Savings (TDVkBTU/yr/ sq ft)
1	1.8	2.66E-04	0.0	2.8	41.5
2	2.7	3.15E-04	0.0	3.8	68.9
3	2.2	2.62E-04	0.0	3.2	53.7
4	2.8	3.17E-04	0.0	4.0	68.0
5	2.4	2.64E-04	0.0	3.6	53.4
6	3.0	3.16E-04	0.0	4.5	71.0
7	2.7	3.17E-04	0.0	4.5	65.6
8	2.9	3.16E-04	0.0	4.4	71.6
9	3.0	3.21E-04	0.0	4.5	73.7
10	3.0	3.09E-04	0.0	4.5	72.5
11	2.7	3.20E-04	0.0	3.9	66.3
12	2.8	3.11E-04	0.0	3.8	66.6
13	2.8	3.18E-04	0.0	3.9	69.9
14	3.3	3.18E-04	0.0	4.8	77.4
15	5.0	5.33E-04	0.0	7.9	123.6
16	2.3	2.61E-04	0.0	3.4	53.3

Table 18: First Year Energy Impacts per square foot for the Warehouse prototype

Climate Zone	Electricity Savings (kWh/yr/sq ft)	Peak Electricity Demand Savings (kW/sq ft)	Natural Gas Savings (Therms/yr/ Sq ft)	Source Energy Savings (kBtu/sq ft)	TDV Energy Savings (TDVkBTU/yr/ sq ft)
1	0.5	3.03E-05	0	0.5	8.2
2	0.7	3.07E-05	0	0.6	11.9
3	0.6	3.06E-05	0	0.6	10.4
4	0.7	3.06E-05	0	0.6	12.7
5	0.7	3.05E-05	0	0.7	10.8
6	0.8	3.07E-05	0	0.8	13.4
7	0.7	3.11E-05	0	0.8	12.9
8	0.7	3.07E-05	0	0.8	14.4
9	0.8	3.05E-05	0	0.8	14.5
10	0.8	3.02E-05	0	0.8	14.9
11	0.7	3.49E-05	0	0.6	11.9
12	0.7	3.52E-05	0	0.6	12.1
13	0.7	3.51E-05	0	0.6	12.3
14	0.8	3.40E-05	0	0.9	15.3
15	1.0	4.68E-05	0	1.1	18.5
16	0.6	3.01E-05	0	0.6	11.2

5. Life Cycle Cost and Cost-Effectiveness

5.1 Energy Cost Savings Methodology

Time Dependent Value (TDV) energy is a normalized format for comparing electricity and natural gas savings that takes into account the cost of electricity and natural gas consumed during each hour of the year. The TDV values are based on long term discounted costs (30 years for all residential measures and nonresidential envelope measures and 15 years for all other nonresidential measures). In this case, the period of analysis used is 30 years. The TDV cost impacts are presented in 2023 present valued dollars. The TDV energy estimates are based on present-valued cost savings but are normalized in terms of "TDVkBTUs". Peak demand savings are presented in peak power reductions (kW). Energy Commission derived the 2023 TDV values that were used in the analyses for this report (Energy Commission 2019).

This study investigated the cost-effectiveness of packaged solar PV and battery storage systems for 11 prototype buildings with mixed-fuel and all-electric configurations. Results are presented for each climate zone and mixed-fuel prototype building. All-electric configurations were tested in this study as a sensitivity and were found to be uniformly more cost-effective than their mixed-fuel counterparts due to higher self-utilization of on-site PV generation.

To simulate hourly PV generation, normalized generation profiles were created using standard 1 kW_{DC} PV generation systems and modeled using NREL's System Advisor Model (SAM). Normalized profiles were scaled up to a level for each combination of prototype building and climate zone, where, given a scenario with no on-site battery storage, the prototype building would self-utilize 80% of annual PV generation and export 20% of annual generation to the grid. This PV generation modeling is consistent with available features in CBECC-Com.

With PV size set for each prototype building, energy storage was sized to reduce grid exports of the PV system to 10% of annual on-site PV generation, or 90% self-utilization of annual generation. The calculated battery size to accomplish this assumed an 85% round trip efficiency, and the capability to discharge at full capacity for 4 hours.

With PV and battery storage system sizing in place, battery dispatch was modeled using the CEC Solar + Storage Tool[12], assuming a "Time-of-Use" control scheme. Under this control scheme, batteries fully charge to the extent

[12] See CEC Modeling Tool to Maximize Solar + Storage for additional details, model documentation and model download: https://www.energy.ca.gov/programs-and-topics/programs/electric-program-investment-charge-epic-program/modeling-tool-maximize

possible, exclusively from on-site PV-generation, then fully discharge during the 4pm-9pm evening time-of-use period, each day of the year. Under this scheme, battery storage only offsets building consumption, and does not export electricity to the grid. No additional optimization is performed for demand charge reductions or load flattening. This is a simple and conservative dispatch algorithm achievable with basic battery controls and providing less participant benefit than most commercially available battery storage control algorithms. Currently CBECC-Com does not have the capability to model battery storage systems with a Time-of-Use control scheme, but the software package is intended to be updated with this feature.

To calculate energy cost savings, energy costs were first calculated for baseline prototype buildings with no on-site PV generation or batteries, and then calculated for the same prototype buildings with the proposed on-site PV and batteries. Hourly net building consumption in each case was multiplied by hourly TDV, and the two results were compared to determine savings. While CASE studies typically only consider TDV as the energy cost metric, this study used a lower bound of potential customer benefit for the following reasons:

1) TDV is meant to be an approximation for state retail rate forecast,

2) Participant cost-effectiveness for PV and battery storage systems is heavily dependent on retail rate structures with Net Energy Metering, and

3) Through its NEM 3.0 proceeding, the California Public Utilities Commission is actively considering potential reforms to Net Energy Metering policy and retail rate structures for customers with on-site PV generation. There is presently no indication what changes to Net Energy Metering will follow this proceeding.

To create a robust cost-effectiveness test in the face of uncertainty around future NEM policy, the analysis team, with guidance from the CEC, defined a TDV-base rate scenario that would be consistent with significant Net Energy Metering retail rate reform. This rate scenario is created by assuming that self-utilized electricity for a building (solar energy that is both generated and consumed behind the meter) is compensated at the full TDV $/kWh rate. To represent potential reform, grid exports (solar energy that is generated behind the meter but exceeds hourly on-site load and is exported to the grid) are compensated at TDV hourly avoided costs. TDV hourly avoided costs are defined as the sum of all of the cost components of TDV with the exception of the retail rate adder. This is designed to be a conservative compensation scenario with the intention that it will yield lower participant benefits than any near-term NEM reform. Under these assumptions, if the combined PV and storage system is cost-effective in this scenario, it would be cost-effective after any near-term NEM reform is enacted.

By modeling a retail rate that is different for self-utilization vs grid exports, there is an added economic incentive for battery storage to charge with solar generation that would have otherwise been exported, and discharge when there is sufficient electric load to be offset by the stored energy.

5.2 Energy Cost Savings Results

The TDV methodology allows peak electricity savings to be valued more than electricity savings during non-peak periods. Table 19 through Table 29 show 30-yr lifetime TDV energy cost savings in Nominal $. Each prototype building in all climate zones show energy costs savings over the 30-yr lifetime.

Table 19: Annual TDV Energy Cost Savings Over 30 Year Period of Analysis – per square foot. High-Rise Residential Prototype

Climate Zone	Annual 30 Year TDV Electricity Cost Savings (Nominal $)	Annual 30 Year TDV Natural Gas Cost Savings (Nominal $)	Total Annual 30 Year TDV Energy Cost Savings (Nominal $)
1	15.7	0.0	15.7
2	24.9	0.0	24.9
3	20.2	0.0	20.2
4	26.7	0.0	26.7
5	21.0	0.0	21.0
6	27.0	0.0	27.0
7	24.7	0.0	24.7
8	28.5	0.0	28.5
9	28.5	0.0	28.5
10	27.8	0.0	27.8
11	25.0	0.0	25.0
12	25.3	0.0	25.3
13	26.0	0.0	26.0
14	29.3	0.0	29.3
15	34.9	0.0	34.9
16	20.6	0.0	20.6

Table 20: Annual TDV Energy Cost Savings Over 30 Year Period of Analysis – per square foot. Mid-Rise Residential Prototype

Climate Zone	Annual 30 Year TDV Electricity Cost Savings (Nominal $)	Annual 30 Year TDV Natural Gas Cost Savings (Nominal $)	Total Annual 30 Year TDV Energy Cost Savings (Nominal $)
1	13.5	0.0	13.5
2	21.1	0.0	21.1
3	17.5	0.0	17.5
4	22.5	0.0	22.5
5	18.1	0.0	18.1
6	22.7	0.0	22.7
7	20.7	0.0	20.7
8	24.0	0.0	24.0
9	23.9	0.0	23.9
10	23.3	0.0	23.3
11	21.1	0.0	21.1
12	21.3	0.0	21.3
13	21.9	0.0	21.9
14	24.6	0.0	24.6
15	28.4	0.0	28.4
16	17.6	0.0	17.6

Table 21: Annual TDV Energy Cost Savings Over 30 Year Period of Analysis – per square foot. Large Office Prototype

Climate Zone	Annual 30 Year TDV Electricity Cost Savings (Nominal $)	Annual 30 Year TDV Natural Gas Cost Savings (Nominal $)	Total Annual 30 Year TDV Energy Cost Savings (Nominal $)
1	19.2	0.0	19.2
2	30.7	0.0	30.7
3	25.1	0.0	25.1
4	30.7	0.0	30.7
5	25.1	0.0	25.1
6	32.0	0.0	32.0
7	29.5	0.0	29.5
8	33.2	0.0	33.2
9	33.5	0.0	33.5
10	32.9	0.0	32.9
11	29.7	0.0	29.7
12	30.0	0.0	30.0
13	31.4	0.0	31.4
14	34.8	0.0	34.8
15	38.7	0.0	38.7
16	23.4	0.0	23.4

Table 22: Annual TDV Energy Cost Savings Over 30 Year Period of Analysis – per square foot. Medium Office Prototype

Climate Zone	Annual 30 Year TDV Electricity Cost Savings (Nominal $)	Annual 30 Year TDV Natural Gas Cost Savings (Nominal $)	Total Annual 30 Year TDV Energy Cost Savings (Nominal $)
1	23.0	0.0	23.0
2	37.2	0.0	37.2
3	30.1	0.0	30.1
4	37.4	0.0	37.4
5	30.1	0.0	30.1
6	38.6	0.0	38.6
7	35.5	0.0	35.5
8	40.0	0.0	40.0
9	40.9	0.0	40.9
10	40.1	0.0	40.1
11	36.6	0.0	36.6
12	36.7	0.0	36.7
13	38.8	0.0	38.8
14	42.6	0.0	42.6
15	50.3	0.0	50.3
16	28.1	0.0	28.1

Table 23: Annual TDV Energy Cost Savings Over 30 Year Period of Analysis – per square foot. Small Office Prototype

Climate Zone	Annual 30 Year TDV Electricity Cost Savings (Nominal $)	Annual 30 Year TDV Natural Gas Cost Savings (Nominal $)	Total Annual 30 Year TDV Energy Cost Savings (Nominal $)
1	35.3	0.0	35.3
2	51.1	0.0	51.1
3	45.0	0.0	45.0
4	52.1	0.0	52.1
5	45.5	0.0	45.5
6	53.6	0.0	53.6
7	49.5	0.0	49.5
8	55.6	0.0	55.6
9	56.6	0.0	56.6
10	55.3	0.0	55.3
11	50.2	0.0	50.2
12	50.4	0.0	50.4
13	53.2	0.0	53.2
14	59.0	0.0	59.0
15	64.3	0.0	64.3
16	44.0	0.0	44.0

Table 24: Annual TDV Energy Cost Savings Over 30 Year Period of Analysis – per square foot. Large Retail Prototype

Climate Zone	Annual 30 Year TDV Electricity Cost Savings (Nominal $)	Annual 30 Year TDV Natural Gas Cost Savings (Nominal $)	Total Annual 30 Year TDV Energy Cost Savings (Nominal $)
1	21.9	0.0	21.9
2	32.1	0.0	32.1
3	28.0	0.0	28.0
4	33.9	0.0	33.9
5	28.9	0.0	28.9
6	34.0	0.0	34.0
7	31.2	0.0	31.2
8	35.9	0.0	35.9
9	36.1	0.0	36.1
10	35.0	0.0	35.0
11	31.8	0.0	31.8
12	32.0	0.0	32.0
13	33.0	0.0	33.0
14	37.5	0.0	37.5
15	41.9	0.0	41.9
16	27.7	0.0	27.7

Table 25: Annual TDV Energy Cost Savings Over 30 Year Period of Analysis – per square foot. Medium Retail Prototype

Climate Zone	Annual 30 Year TDV Electricity Cost Savings (Nominal $)	Annual 30 Year TDV Natural Gas Cost Savings (Nominal $)	Total Annual 30 Year TDV Energy Cost Savings (Nominal $)
1	22.3	0.0	22.3
2	32.4	0.0	32.4
3	28.4	0.0	28.4
4	34.2	0.0	34.2
5	29.3	0.0	29.3
6	34.3	0.0	34.3
7	31.4	0.0	31.4
8	36.3	0.0	36.3
9	36.5	0.0	36.5
10	35.4	0.0	35.4
11	32.2	0.0	32.2
12	32.3	0.0	32.3
13	33.3	0.0	33.3
14	38.0	0.0	38.0
15	43.4	0.0	43.4
16	28.4	0.0	28.4

Table 26: Annual TDV Energy Cost Savings Over 30 Year Period of Analysis – per square foot. Small Retail Prototype

Climate Zone	Annual 30 Year TDV Electricity Cost Savings (Nominal $)	Annual 30 Year TDV Natural Gas Cost Savings (Nominal $)	Total Annual 30 Year TDV Energy Cost Savings (Nominal $)
1	36.5	0.0	36.5
2	50.5	0.0	50.5
3	46.2	0.0	46.2
4	53.7	0.0	53.7
5	47.8	0.0	47.8
6	53.9	0.0	53.9
7	49.4	0.0	49.4
8	57.0	0.0	57.0
9	57.2	0.0	57.2
10	55.5	0.0	55.5
11	49.9	0.0	49.9
12	50.3	0.0	50.3
13	51.9	0.0	51.9
14	59.2	0.0	59.2
15	62.7	0.0	62.7
16	46.3	0.0	46.3

Table 27: Annual TDV Energy Cost Savings Over 30 Year Period of Analysis – per square foot. Large School Prototype

Climate Zone	Annual 30 Year TDV Electricity Cost Savings (Nominal $)	Annual 30 Year TDV Natural Gas Cost Savings (Nominal $)	Total Annual 30 Year TDV Energy Cost Savings (Nominal $)
1	9.7	0.0	9.7
2	17.7	0.0	17.7
3	12.8	0.0	12.8
4	17.8	0.0	17.8
5	12.8	0.0	12.8
6	18.4	0.0	18.4
7	16.9	0.0	16.9
8	18.8	0.0	18.8
9	19.1	0.0	19.1
10	18.8	0.0	18.8
11	17.2	0.0	17.2
12	17.3	0.0	17.3
13	18.2	0.0	18.2
14	20.0	0.0	20.0
15	26.1	0.0	26.1
16	12.4	0.0	12.4

Table 28: Annual TDV Energy Cost Savings Over 30 Year Period of Analysis – per square foot. Small School Prototype

Climate Zone	Annual 30 Year TDV Electricity Cost Savings (Nominal $)	Annual 30 Year TDV Natural Gas Cost Savings (Nominal $)	Total Annual 30 Year TDV Energy Cost Savings (Nominal $)
1	13.1	0.0	13.1
2	21.8	0.0	21.8
3	17.0	0.0	17.0
4	21.5	0.0	21.5
5	16.8	0.0	16.8
6	22.4	0.0	22.4
7	20.7	0.0	20.7
8	22.6	0.0	22.6
9	23.3	0.0	23.3
10	22.9	0.0	22.9
11	20.9	0.0	20.9
12	21.0	0.0	21.0
13	22.1	0.0	22.1
14	24.4	0.0	24.4
15	39.0	0.0	39.0
16	16.8	0.0	16.8

Table 29: Annual TDV Energy Cost Savings Over 30 Year Period of Analysis – per square foot. Warehouse Prototype

Climate Zone	Annual 30 Year TDV Electricity Cost Savings (Nominal $)	Annual 30 Year TDV Natural Gas Cost Savings (Nominal $)	Total Annual 30 Year TDV Energy Cost Savings (Nominal $)
1	2.6	0	2.6
2	3.8	0	3.8
3	3.3	0	3.3
4	4.0	0	4.0
5	3.4	0	3.4
6	4.2	0	4.2
7	4.1	0	4.1
8	4.6	0	4.6
9	4.6	0	4.6
10	4.7	0	4.7
11	3.8	0	3.8
12	3.8	0	3.8
13	3.9	0	3.9
14	4.8	0	4.8
15	5.8	0	5.8
16	3.5	0	3.5

The per unit TDV energy cost savings over the 30-year period of analysis are presented in Table 30 through Table 40 These are presented as the discounted present value of the energy cost savings over the analysis period. The proposed measure results in energy cost savings for all tested prototype buildings, in all climate zones. As seen in the tables below, climate zone 1 has the lowest cost savings due to limited capacity factor for rooftop PV, while climate zone 15 has the largest cost savings and the largest solar capacity factor. Cost savings per square foot is different for each prototype building, depending on how large the proposed combined PV and battery sized are, along with the energy consumption patterns of the prototype building. As PV and Battery storage systems only impact electricity consumption, there are no TDV natural gas cost savings.

Table 30: TDV Energy Cost Savings Over 30 Year Period of Analysis -per square foot. High-Rise Residential Prototype

Climate Zone	30 Year TDV Electricity Cost Savings (2023 PV $)	30 Year TDV Natural Gas Cost Savings (2023 PV $)	Total 30 Year TDV Energy Cost Savings (2023 PV $)
1	7.7	0.0	7.7
2	12.2	0.0	12.2
3	9.9	0.0	9.9
4	13.0	0.0	13.0
5	10.2	0.0	10.2
6	13.2	0.0	13.2
7	12.1	0.0	12.1
8	13.9	0.0	13.9
9	13.9	0.0	13.9
10	13.6	0.0	13.6
11	12.2	0.0	12.2
12	12.3	0.0	12.3
13	12.7	0.0	12.7
14	14.3	0.0	14.3
15	17.0	0.0	17.0
16	10.1	0.0	10.1

Table 31: TDV Energy Cost Savings Over 30 Year Period of Analysis -per square foot. Mid-Rise Residential Prototype

Climate Zone	30 Year TDV Electricity Cost Savings (2023 PV $)	30 Year TDV Natural Gas Cost Savings (2023 PV $)	Total 30 Year TDV Energy Cost Savings (2023 PV $)
1	6.6	0.0	6.6
2	10.3	0.0	10.3
3	8.5	0.0	8.5
4	11.0	0.0	11.0
5	8.8	0.0	8.8
6	11.1	0.0	11.1
7	10.1	0.0	10.1
8	11.7	0.0	11.7
9	11.7	0.0	11.7
10	11.4	0.0	11.4
11	10.3	0.0	10.3
12	10.4	0.0	10.4
13	10.7	0.0	10.7
14	12.0	0.0	12.0
15	13.8	0.0	13.8
16	8.6	0.0	8.6

Table 32: TDV Energy Cost Savings Over 30 Year Period of Analysis -per square foot. Large Office Prototype

Climate Zone	30 Year TDV Electricity Cost Savings (2023 PV $)	30 Year TDV Natural Gas Cost Savings (2023 PV $)	Total 30 Year TDV Energy Cost Savings (2023 PV $)
1	9.3	0.0	9.3
2	15.0	0.0	15.0
3	12.2	0.0	12.2
4	15.0	0.0	15.0
5	12.3	0.0	12.3
6	15.6	0.0	15.6
7	14.4	0.0	14.4
8	16.2	0.0	16.2
9	16.4	0.0	16.4
10	16.0	0.0	16.0
11	14.5	0.0	14.5
12	14.6	0.0	14.6
13	15.3	0.0	15.3
14	17.0	0.0	17.0
15	18.9	0.0	18.9
16	11.4	0.0	11.4

Table 33: TDV Energy Cost Savings Over 30 Year Period of Analysis -per square foot. Medium Office Prototype

Climate Zone	30 Year TDV Electricity Cost Savings (2023 PV $)	30 Year TDV Natural Gas Cost Savings (2023 PV $)	Total 30 Year TDV Energy Cost Savings (2023 PV $)
1	11.2	0.0	11.2
2	18.1	0.0	18.1
3	14.7	0.0	14.7
4	18.3	0.0	18.3
5	14.7	0.0	14.7
6	18.8	0.0	18.8
7	17.3	0.0	17.3
8	19.5	0.0	19.5
9	19.9	0.0	19.9
10	19.6	0.0	19.6
11	17.8	0.0	17.8
12	17.9	0.0	17.9
13	18.9	0.0	18.9
14	20.8	0.0	20.8
15	24.6	0.0	24.6
16	13.7	0.0	13.7

Table 34: TDV Energy Cost Savings Over 30 Year Period of Analysis -per square foot. Small Office Prototype

Climate Zone	30 Year TDV Electricity Cost Savings (2023 PV $)	30 Year TDV Natural Gas Cost Savings (2023 PV $)	Total 30 Year TDV Energy Cost Savings (2023 PV $)
1	17.2	0.0	17.2
2	24.9	0.0	24.9
3	21.9	0.0	21.9
4	25.4	0.0	25.4
5	22.2	0.0	22.2
6	26.2	0.0	26.2
7	24.1	0.0	24.1
8	27.1	0.0	27.1
9	27.6	0.0	27.6
10	27.0	0.0	27.0
11	24.5	0.0	24.5
12	24.6	0.0	24.6
13	26.0	0.0	26.0
14	28.8	0.0	28.8
15	31.4	0.0	31.4
16	21.4	0.0	21.4

Table 35: TDV Energy Cost Savings Over 30 Year Period of Analysis -per square foot. Large Retail I Prototype

Climate Zone	30 Year TDV Electricity Cost Savings (2023 PV $)	30 Year TDV Natural Gas Cost Savings (2023 PV $)	Total 30 Year TDV Energy Cost Savings (2023 PV $)
1	10.7	0.0	10.7
2	15.6	0.0	15.6
3	13.7	0.0	13.7
4	16.5	0.0	16.5
5	14.1	0.0	14.1
6	16.6	0.0	16.6
7	15.2	0.0	15.2
8	17.5	0.0	17.5
9	17.6	0.0	17.6
10	17.1	0.0	17.1
11	15.5	0.0	15.5
12	15.6	0.0	15.6
13	16.1	0.0	16.1
14	18.3	0.0	18.3
15	20.5	0.0	20.5
16	13.5	0.0	13.5

Table 36: TDV Energy Cost Savings Over 30 Year Period of Analysis -per square foot. Medium Retail Prototype

Climate Zone	30 Year TDV Electricity Cost Savings (2023 PV $)	30 Year TDV Natural Gas Cost Savings (2023 PV $)	Total 30 Year TDV Energy Cost Savings (2023 PV $)
1	10.9	0.0	10.9
2	15.8	0.0	15.8
3	13.8	0.0	13.8
4	16.7	0.0	16.7
5	14.3	0.0	14.3
6	16.7	0.0	16.7
7	15.3	0.0	15.3
8	17.7	0.0	17.7
9	17.8	0.0	17.8
10	17.3	0.0	17.3
11	15.7	0.0	15.7
12	15.7	0.0	15.7
13	16.3	0.0	16.3
14	18.5	0.0	18.5
15	21.2	0.0	21.2
16	13.9	0.0	13.9

Table 37: TDV Energy Cost Savings Over 30 Year Period of Analysis -per square foot. Small Retail Prototype

Climate Zone	30 Year TDV Electricity Cost Savings (2023 PV $)	30 Year TDV Natural Gas Cost Savings (2023 PV $)	Total 30 Year TDV Energy Cost Savings (2023 PV $)
1	17.8	0.0	17.8
2	24.6	0.0	24.6
3	22.6	0.0	22.6
4	26.2	0.0	26.2
5	23.3	0.0	23.3
6	26.3	0.0	26.3
7	24.1	0.0	24.1
8	27.8	0.0	27.8
9	27.9	0.0	27.9
10	27.1	0.0	27.1
11	24.4	0.0	24.4
12	24.6	0.0	24.6
13	25.3	0.0	25.3
14	28.9	0.0	28.9
15	30.6	0.0	30.6
16	22.6	0.0	22.6

Table 38: TDV Energy Cost Savings Over 30 Year Period of Analysis -per square foot. Large School Prototype

Climate Zone	30 Year TDV Electricity Cost Savings (2023 PV $)	30 Year TDV Natural Gas Cost Savings (2023 PV $)	Total 30 Year TDV Energy Cost Savings (2023 PV $)
1	4.7	0.0	4.7
2	8.6	0.0	8.6
3	6.3	0.0	6.3
4	8.7	0.0	8.7
5	6.2	0.0	6.2
6	9.0	0.0	9.0
7	8.3	0.0	8.3
8	9.1	0.0	9.1
9	9.3	0.0	9.3
10	9.2	0.0	9.2
11	8.4	0.0	8.4
12	8.4	0.0	8.4
13	8.9	0.0	8.9
14	9.7	0.0	9.7
15	12.8	0.0	12.8
16	6.1	0.0	6.1

Table 39: TDV Energy Cost Savings Over 30 Year Period of Analysis -per square foot. Small School Prototype

Climate Zone	30 Year TDV Electricity Cost Savings (2023 PV $)	30 Year TDV Natural Gas Cost Savings (2023 PV $)	Total 30 Year TDV Energy Cost Savings (2023 PV $)
1	6.4	0.0	6.4
2	10.6	0.0	10.6
3	8.3	0.0	8.3
4	10.5	0.0	10.5
5	8.2	0.0	8.2
6	10.9	0.0	10.9
7	10.1	0.0	10.1
8	11.0	0.0	11.0
9	11.3	0.0	11.3
10	11.2	0.0	11.2
11	10.2	0.0	10.2
12	10.3	0.0	10.3
13	10.8	0.0	10.8
14	11.9	0.0	11.9
15	19.0	0.0	19.0
16	8.2	0.0	8.2

Table 40: TDV Energy Cost Savings Over 30 Year Period of Analysis -per square foot. Warehouse Prototype

Climate Zone	30 Year TDV Electricity Cost Savings (2023 PV $)	30 Year TDV Natural Gas Cost Savings (2023 PV $)	Total 30 Year TDV Energy Cost Savings (2023 PV $)
1	1.3	0	1.3
2	1.8	0	1.8
3	1.6	0	1.6
4	2.0	0	2.0
5	1.7	0	1.7
6	2.1	0	2.1
7	2.0	0	2.0
8	2.2	0	2.2
9	2.2	0	2.2
10	2.3	0	2.3
11	1.8	0	1.8
12	1.9	0	1.9
13	1.9	0	1.9
14	2.4	0	2.4
15	2.8	0	2.8
16	1.7	0	1.7

5.3 Incremental First Cost

For PV systems, incremental costs were determined by gathering system cost data from several sources, including NEM interconnection databases, and a survey of industry professionals including 2 installing solar contracting firms, 1 MEP engineering firm, and 1 facility manager. For contractors and MEP firms, surveys were administered to provide a uniform "ask" of PV system prices. Cost databases included in the installed cost survey include

- EnergySage – commercial PV cost estimates (EnergySage 2020)
- LBNL – Tracking the Sun Database (G. N. Barbose October 2019)
- NREL – U.S. Solar Photovoltaic System Cost Benchmark: Q1 2018 (Fu 2018)
- Elshurfa, Amro, et al – Estimating the learning curve of solar PV balance-of-system for over 20 countries: Implications and policy recommendations (Elshurfa 2018)

- CPUC – California NEM Interconnected Data Set (CPUC 2020)
- NREL – Comparing Photovoltaic Costs and Deployment Drivers in the Japanese and U.S. Residential and Commercial Markets (Friedman 2016)

The projects list from 2018 through 2020 in the NEM database of interconnected self-generation projects was filtered to remove projects not aligned with the study, including:

- Projects identified as "self-install"
- Projects that were not roof-mounted
- All projects that included tracking
- Projects with unusually high (> $10/W) and unusually low ($1/W) costs
- Entries with third-party financing (PPA and similar) were removed
- Projects prior to January 1, 2018

The median costs for projects of different size bins for 2018, 2019 and 2020 were taken from the filtered results and used in the cost data analysis. Costs are reduced by $0.18/W_{DC}$ (2020$) to reflect lower customer acquisition costs in new construction (Friedman 2016). Additionally, cost data was adjusted for expected cost declines between 2019 and 2023. Over this time period, NREL's Forecast Scenarios project cost declines to be 3% in a conservative scenario and 15% in a moderate scenario (Cole and Frazier 2019). Averaging the conservative and moderate scenario, this analysis uses an estimated 9% reduction in installed cost by 2023. Per Energy Commission's guidance, design costs are not included in the incremental first cost.

Data from all sources was used to form a regression between installed cost and system capacity:

$$y = 4.5015 * x^{-0.154}$$

where *x* is the PV system size in kW_{DC} and *y* is system cost in 2020$/$W_{DC}$.

Figure 2 shows the PV installed capacity versus cost curve for newly constructed buildings. Results of the above equation and corresponding cost adjustments for a range of example PV system sizes are displayed in Table 41. Results for capital expenditures (CAPEX) from the above regression equation are assumed to in 2020$. CAPEX was converted to 2023$ using a 2% inflation rate.

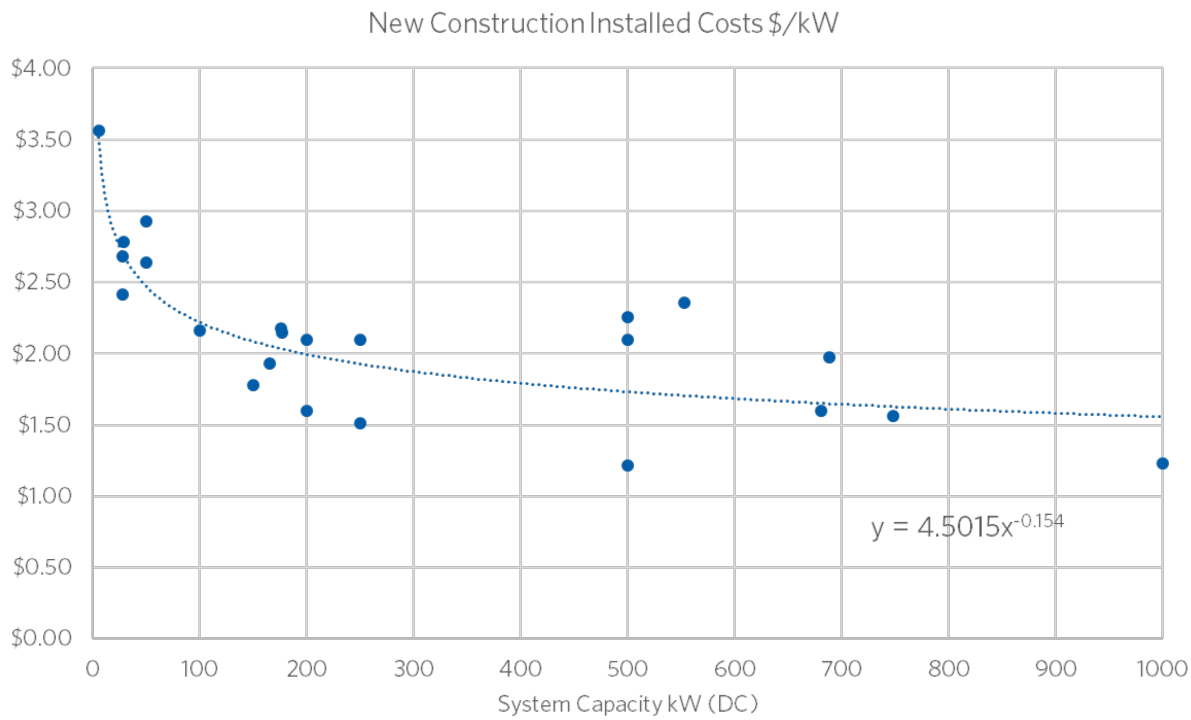

Figure 2: PV system installed capacity versus cost for newly constructed nonresidential buildings.

Table 41: Incremental First Cost for Photovoltaic System

PV Size (kW_{DC})	CAPEX (2020$/$W_{DC}$)	CAPEX (2023$/$W_{DC}$)
10	$3.16	$3.35
20	$2.84	$3.01
50	$2.46	$2.61
100	$2.21	$2.35
200	$1.99	$2.11
500	$1.73	$1.84
1000	$1.55	$1.64

Battery storage costs were estimated based on the following data sources:

- NREL Cost Projections for Utility-Scale Battery Storage (W. a. Cole 2019)
- Lazard Levelized Cost of Storage, Version 5.0 (Lazard 2019)
- Survey estimate and interview from manufacturer/turnkey provider

Based on these sources, a linear regression formula to determine volumetric cost dependent on system size was developed both for 2-hour batteries and 4-

hour batteries. As the proposed code change considers a 4-hour battery, this analysis uses the linear regression equation for the cost of a 4-hour battery:

$$y = -0.1044x + 765.09$$

where x is the battery's usable energy capacity in kWh, and y is the cost of a battery in $/kWh (in 2020$).

It is assumed that the size of the battery used in this equation is the energy that can be discharged to offset a behind the meter load, accounting for any discharge efficiency losses. A 4-hour battery in the context of this regression formula is defined as a battery that is can discharge at full power capacity (kW) for four hours. Figure 3 shows the battery storage capacity versus cost curve for newly constructed buildings. Table 42 below displays example calculated costs for a range of example battery sizes based on the above regression equation.

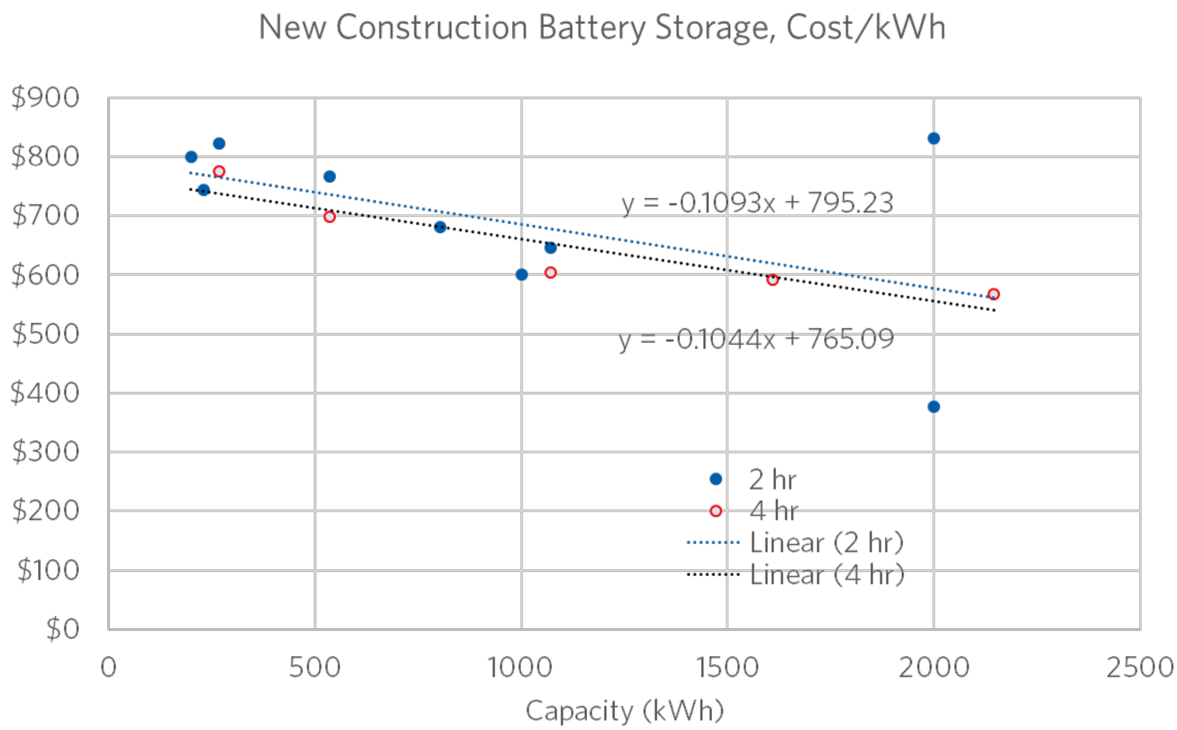

Figure 3: Battery Storage installed capacity versus cost for newly constructed nonresidential buildings.

Table 42: Incremental First Costs for Battery Storage System

Battery Size (kW, kWh)	CAPEX (2020$/kWh)	CAPEX (2023$/kWh)
10 kW, 40 kWh	$760	$807
25 kW, 100 kWh	$754	$800
50 kW, 200 kWh	$743	$789
75 kW, 300 kWh	$733	$778
100 kW, 400 kWh	$723	$767
500 kW, 2000 kWh	$599	$636

While installed first costs reported in Table 41 and Table 42 do not account for the federal Investment Tax Credit (ITC), lifetime present value costs do assume that both PV and storage costs are eligible for the 10% commercial ITC. To qualify for the 10% ITC, storage must be charged by a renewable energy system more than 75 percent of the time. Under the Time-of-Use control scheme, the charge-on-solar requirement is fulfilled, and storage is eligible for the ITC. It is also assumed that participants are able to monetize the ITC. While tax-exempt entities, such as schools, are not able to monetize the ITC benefit with full ownership of a PV and Storage system, these entities can sign Power Purchase Agreements (PPAs) with rooftop solar providers, who can monetize the ITC benefit.

5.4 Lifetime Incremental Maintenance Costs

Incremental maintenance cost is the incremental cost of replacing the equipment or parts of the equipment, as well as periodic maintenance required to keep the equipment operating relative to current practices over the period of analysis. The present value of equipment and maintenance costs (savings) was calculated using a three percent discount rate (d), which is consistent with the discount rate used when developing the 2022 TDV. The present value of maintenance costs that occurs in the nth year is calculated as follows (where d is the discount rate of 3 percent):

$$\text{Present Value of Maintenance Cost} = \text{Maintenance Cost} \times \left\lfloor \frac{1}{1+\text{d}} \right\rfloor^{\text{n}}$$

The expected useful life of a rooftop PV system and paired storage system was assumed to be 30 years. Fixed Operation and Maintenance (O&M) were taken from NREL’s 2020 Annual Technology Baseline (NREL (National Renewable Energy Laboratory) 2020) and are included at:

a) $11/kW$_{DC}$-yr for PV systems (2018$), which includes component replacement costs (PV Inverter replacement, etc) over the system's technical lifetime

b) $29.61/kW$_{DC}$-yr for battery storage systems (2018$)

Fixed O&M costs were assumed to be held constant in real dollars.

In addition to fixed O&M, battery storage is assumed to have an expected useful life 30 years, with cell replacements needed in 10-year intervals (Year 0, Year 10, and Year 20). Replacement costs are modeled in with the following assumptions:

c) Battery cells are assumed to have an expected life of 10 years; cell replacement costs were modeled year 10 and year 20 to achieve a 30-year lifetime. Due to avoiding soft costs of first installation, along with technology cost declines, year-10 cell replacement costs are assumed to be 70% of incremental first costs in real dollars. Year-20 cell replacements are assumed to be 62% of incremental first cost in real dollars. These costs were brought to present value using a 3% discount rate.

Combining incremental first cost with the lifetime incremental maintenance costs yields present values show in Table 43 and Table 44. These cost tables include cost reductions from the Investment Tax Credit (ITC)

Table 43: Lifetime Present Value Costs for Photovoltaic System

PV Size (kW$_{DC}$)	Lifetime Present Value of Costs (2023$/W$_{DC}$)
10	$3.26
20	$2.96
50	$2.59
100	$2.36
200	$2.15
500	$1.90
1000	$1.73

Table 44: Lifetime Present Value Costs for Battery Storage System

Battery Size (kW, kWh)	Lifetime Present Value of Costs (2023$/kWh)
10 kW, 40 kWh	$1610
25 kW,100 Wh	$1599
50 kW, 200 kWh	$1579
75 kW,300 kWh	$1559
100 kW, 400 kWh	$1539
500 kW, 2000 kWh	$1305

5.5 Lifecycle Cost-Effectiveness

This measure proposes a prescriptive requirement. As such, a lifecycle cost analysis is required to demonstrate that the measure is cost-effective over the 30-year period of analysis.

Energy Commission's procedures for calculating lifecycle cost-effectiveness are documented in LCC Methodology (Energy and Environmental Economics 2020). E3 followed these guidelines when developing the cost-effectiveness analysis for this measure. Energy Commission's guidance dictated which costs were included in the analysis. Incremental first cost and incremental maintenance costs over the 30-year period of analysis were included. The TDV energy cost savings from electricity savings were also considered. Design costs were not included nor was the incremental cost of code compliance verification.

According to Energy Commission's definitions, a measure is cost-effective if the Benefit-to-Cost (B/C) Ratio is greater than 1.0. The B/C Ratio is calculated by dividing the total present lifecycle cost benefits by the present value of the total incremental costs.

Results per unit lifecycle Cost-effectiveness Analyses are presented in Table 45 through Table 55. As seen below, the proposed measure saves money over the 30-year period of analysis relative to the existing conditions. The proposed code change is cost effective for all prototype buildings in climate zone 2-16. In climate zone 1, the proposed code change is cost effective for High-Rise Residential, Mid-Rise Residential, Large Office, Large Retail, Medium Retail, and Small Retail. Benefit-to-Cost Ratios from these tables for each combination of prototype building and climate zone are summarized in Figure 4.

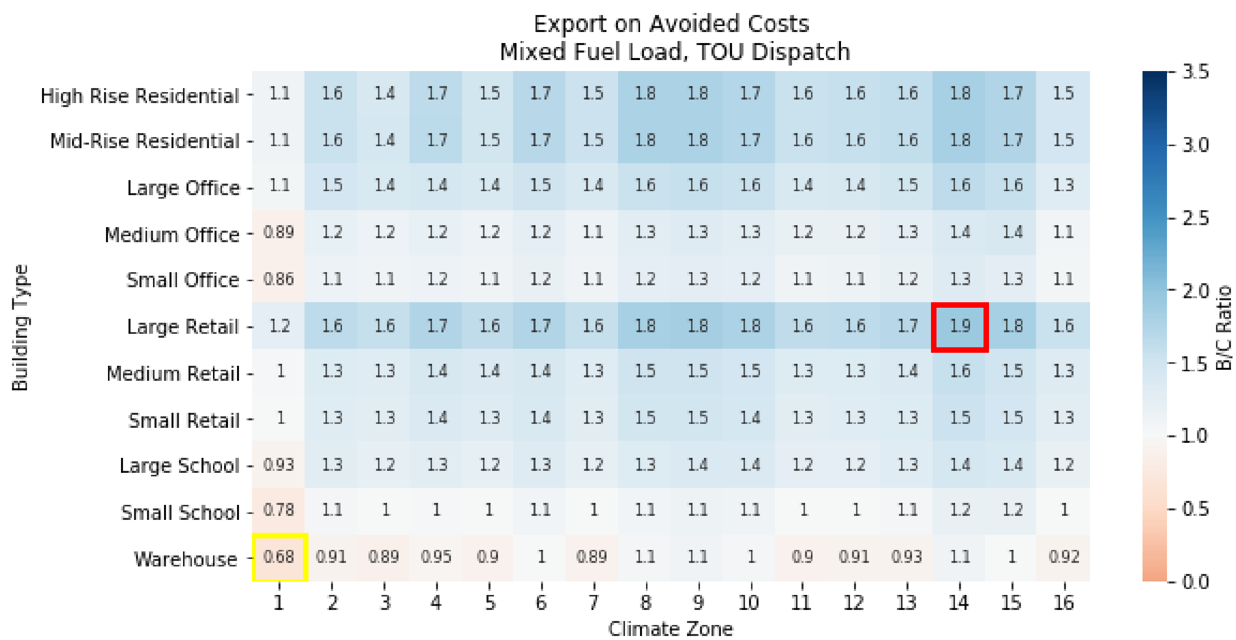

Figure 4. Benefit-to-Cost (B/C) Ratio for each prototype building and climate zone, summarizing results from tables below.

Table 45: Life Cycle Cost-effectiveness Summary per square foot. High-Rise Residential Prototype

Climate Zone	Benefits TDV Energy Cost Savings + Other PV Savings[1] (2023 PV $)	Costs Total Incremental Present Valued (PV) Costs[2] (2023 PV $)	Benefit-to-Cost Ratio
1	$7.7	$6.9	1.1
2	$12.2	$7.8	1.6
3	$9.9	$6.9	1.4
4	$13.0	$7.8	1.7
5	$10.2	$6.9	1.5
6	$13.2	$7.8	1.7
7	$12.1	$7.8	1.5
8	$13.9	$7.8	1.8
9	$13.9	$7.8	1.8
10	$13.6	$7.8	1.7
11	$12.2	$7.8	1.6
12	$12.3	$7.8	1.6
13	$12.7	$7.8	1.6
14	$14.3	$7.8	1.8
15	$17.0	$9.8	1.7
16	$10.1	$6.9	1.5

1. **TDV Energy Cost Savings + Other PV Savings:** Benefits include TDV energy cost savings over the period of analysis (see http://docketpublic.energy.ca.gov/PublicDocuments/16-BSTD-06/TN212524_20160801T120224_2019_TDV_Methodology_Report_7222016.pdf, Chapter 5 pages 51-53). Other savings are discounted at a real 3% rate. Includes incremental first cost savings if proposed first cost is less than current first cost. Includes present value maintenance cost savings if PV of proposed maintenance costs is less than the PV of current maintenance costs.
2. **Total Incremental Present Valued Costs:** Costs include incremental equipment, replacement and maintenance costs over the period of analysis. Present value cost = Current cost x (1/(1.03)^n. Costs are discounted by 3% real rate. Includes incremental first cost if proposed first cost is greater than current first cost. Includes present value of maintenance incremental cost if PV of proposed maintenance costs is greater than the PV of current maintenance costs. If incremental maintenance cost is negative it is treated as a positive benefit. If there are no Total Incremental Present Valued Costs, the Benefit/Cost Ratio is Infinite.

Table 46: Life Cycle Cost-effectiveness Summary per square foot. Mid-Rise Residential Prototype

Climate Zone	Benefits TDV Energy Cost Savings + Other PV Savings[1] (2023 PV $)	Costs Total Incremental Present Valued (PV) Costs[2] (2023 PV $)	Benefit-to-Cost Ratio
1	$6.6	$5.9	1.1
2	$10.3	$6.6	1.6
3	$8.5	$5.9	1.4
4	$11.0	$6.6	1.7
5	$8.8	$5.9	1.5
6	$11.1	$6.6	1.7
7	$10.1	$6.6	1.5
8	$11.7	$6.6	1.8
9	$11.7	$6.6	1.8
10	$11.4	$6.6	1.7
11	$10.3	$6.6	1.6
12	$10.4	$6.6	1.6
13	$10.7	$6.6	1.6
14	$12.0	$6.6	1.8
15	$13.8	$7.9	1.7
16	$8.6	$5.9	1.5

1. **TDV Energy Cost Savings + Other PV Savings:** Benefits include TDV energy cost savings over the period of analysis (see http://docketpublic.energy.ca.gov/PublicDocuments/16-BSTD-06/TN212524_20160801T120224_2019_TDV_Methodology_Report_7222016.pdf, Chapter 5 pages 51-53). Other savings are discounted at a real 3% rate. Includes incremental first cost savings if proposed first cost is less than current first cost. Includes present value maintenance cost savings if PV of proposed maintenance costs is less than the PV of current maintenance costs.
2. **Total Incremental Present Valued Costs:** Costs include incremental equipment, replacement and maintenance costs over the period of analysis. Present value cost = Current cost x (1/(1.03)^n. Costs are discounted by 3% real rate. Includes incremental first cost if proposed first cost is greater than current first cost. Includes present value of maintenance incremental cost if PV of proposed maintenance costs is greater than the PV of current maintenance costs. If incremental maintenance cost is negative it is treated as a positive benefit. If there are no Total Incremental Present Valued Costs, the Benefit/Cost Ratio is Infinite.

Table 47: Life Cycle Cost-effectiveness Summary per square foot. Large Office Prototype

Climate Zone	Benefits TDV Energy Cost Savings + Other PV Savings[1] (2023 PV $)	Costs Total Incremental Present Valued (PV) Costs[2] (2023 PV $)	Benefit-to-Cost Ratio
1	$9.3	$8.7	1.1
2	$15.0	$10.3	1.5
3	$12.2	$8.7	1.4
4	$15.0	$10.3	1.4
5	$12.3	$8.7	1.4
6	$15.6	$10.3	1.5
7	$14.4	$10.3	1.4
8	$16.2	$10.3	1.6
9	$16.4	$10.3	1.6
10	$16.0	$10.3	1.6
11	$14.5	$10.3	1.4
12	$14.6	$10.3	1.4
13	$15.3	$10.3	1.5
14	$17.0	$10.3	1.6
15	$18.9	$11.9	1.6
16	$11.4	$8.7	1.3

1. **TDV Energy Cost Savings + Other PV Savings:** Benefits include TDV energy cost savings over the period of analysis (see http://docketpublic.energy.ca.gov/PublicDocuments/16-BSTD-06/TN212524_20160801T120224_2019_TDV_Methodology_Report_7222016.pdf, Chapter 5 pages 51-53). Other savings are discounted at a real 3% rate. Includes incremental first cost savings if proposed first cost is less than current first cost. Includes present value maintenance cost savings if PV of proposed maintenance costs is less than the PV of current maintenance costs.
2. **Total Incremental Present Valued Costs:** Costs include incremental equipment, replacement and maintenance costs over the period of analysis. Present value cost = Current cost x (1/(1.03)^n. Costs are discounted by 3% real rate. Includes incremental first cost if proposed first cost is greater than current first cost. Includes present value of maintenance incremental cost if PV of proposed maintenance costs is greater than the PV of current maintenance costs. If incremental maintenance cost is negative it is treated as a positive benefit. If there are no Total Incremental Present Valued Costs, the Benefit/Cost Ratio is Infinite.

Table 48: Life Cycle Cost-effectiveness Summary per square foot. Medium Office Prototype

Climate Zone	Benefits TDV Energy Cost Savings + Other PV Savings[1] (2023 PV $)	Costs Total Incremental Present Valued (PV) Costs[2] (2023 PV $)	Benefit-to-Cost Ratio
1	$11.2	$12.7	0.9
2	$18.1	$15.1	1.2
3	$14.7	$12.7	1.2
4	$18.3	$15.1	1.2
5	$14.7	$12.7	1.2
6	$18.8	$15.1	1.2
7	$17.3	$15.1	1.1
8	$19.5	$15.1	1.3
9	$19.9	$15.1	1.3
10	$19.6	$15.1	1.3
11	$17.8	$15.1	1.2
12	$17.9	$15.1	1.2
13	$18.9	$15.1	1.3
14	$20.8	$15.1	1.4
15	$24.6	$17.4	1.4
16	$13.7	$12.7	1.1

1. **TDV Energy Cost Savings + Other PV Savings:** Benefits include TDV energy cost savings over the period of analysis (see http://docketpublic.energy.ca.gov/PublicDocuments/16-BSTD-06/TN212524_20160801T120224_2019_TDV_Methodology_Report_7222016.pdf, Chapter 5 pages 51-53). Other savings are discounted at a real 3% rate. Includes incremental first cost savings if proposed first cost is less than current first cost. Includes present value maintenance cost savings if PV of proposed maintenance costs is less than the PV of current maintenance costs.
2. **Total Incremental Present Valued Costs:** Costs include incremental equipment, replacement and maintenance costs over the period of analysis. Present value cost = Current cost x (1/(1.03)^n. Costs are discounted by 3% real rate. Includes incremental first cost if proposed first cost is greater than current first cost. Includes present value of maintenance incremental cost if PV of proposed maintenance costs is greater than the PV of current maintenance costs. If incremental maintenance cost is negative it is treated as a positive benefit. If there are no Total Incremental Present Valued Costs, the Benefit/Cost Ratio is Infinite.

Table 49: Life Cycle Cost-effectiveness Summary per square foot. Small Office Prototype

Climate Zone	Benefits TDV Energy Cost Savings + Other PV Savings[1] (2023 PV $)	Costs Total Incremental Present Valued (PV) Costs[2] (2023 PV $)	Benefit-to-Cost Ratio
1	$17.2	$19.9	0.9
2	$24.9	$21.9	1.1
3	$21.9	$19.9	1.1
4	$25.4	$21.9	1.2
5	$22.2	$19.9	1.1
6	$26.2	$21.9	1.2
7	$24.1	$21.9	1.1
8	$27.1	$21.9	1.2
9	$27.6	$21.9	1.3
10	$27.0	$21.9	1.2
11	$24.5	$21.9	1.1
12	$24.6	$21.9	1.1
13	$26.0	$21.9	1.2
14	$28.8	$21.9	1.3
15	$31.4	$24.9	1.3
16	$21.4	$19.9	1.1

1. **TDV Energy Cost Savings + Other PV Savings:** Benefits include TDV energy cost savings over the period of analysis (see http://docketpublic.energy.ca.gov/PublicDocuments/16-BSTD-06/TN212524_20160801T120224_2019_TDV_Methodology_Report_7222016.pdf, Chapter 5 pages 51-53). Other savings are discounted at a real 3% rate. Includes incremental first cost savings if proposed first cost is less than current first cost. Includes present value maintenance cost savings if PV of proposed maintenance costs is less than the PV of current maintenance costs.
2. **Total Incremental Present Valued Costs:** Costs include incremental equipment, replacement and maintenance costs over the period of analysis. Present value cost = Current cost x (1/(1.03)^n. Costs are discounted by 3% real rate. Includes incremental first cost if proposed first cost is greater than current first cost. Includes present value of maintenance incremental cost if PV of proposed maintenance costs is greater than the PV of current maintenance costs. If incremental maintenance cost is negative it is treated as a positive benefit. If there are no Total Incremental Present Valued Costs, the Benefit/Cost Ratio is Infinite.

Table 50: Life Cycle Cost-effectiveness Summary per square foot. Large Retail Prototype

Climate Zone	Benefits TDV Energy Cost Savings + Other PV Savings[1] (2023 PV $)	Costs Total Incremental Present Valued (PV) Costs[2] (2023 PV $)	Benefit-to-Cost Ratio
1	$10.7	$8.6	1.2
2	$15.6	$9.5	1.6
3	$13.7	$8.6	1.6
4	$16.5	$9.5	1.7
5	$14.1	$8.6	1.6
6	$16.6	$9.5	1.7
7	$15.2	$9.5	1.6
8	$17.5	$9.5	1.8
9	$17.6	$9.5	1.8
10	$17.1	$9.5	1.8
11	$15.5	$9.5	1.6
12	$15.6	$9.5	1.6
13	$16.1	$9.5	1.7
14	$18.3	$9.5	1.9
15	$20.5	$11.1	1.8
16	$13.5	$8.6	1.6

1. **TDV Energy Cost Savings + Other PV Savings:** Benefits include TDV energy cost savings over the period of analysis (see http://docketpublic.energy.ca.gov/PublicDocuments/16-BSTD-06/TN212524_20160801T120224_2019_TDV_Methodology_Report_7222016.pdf, Chapter 5 pages 51-53). Other savings are discounted at a real 3% rate. Includes incremental first cost savings if proposed first cost is less than current first cost. Includes present value maintenance cost savings if PV of proposed maintenance costs is less than the PV of current maintenance costs.
2. **Total Incremental Present Valued Costs:** Costs include incremental equipment, replacement and maintenance costs over the period of analysis. Present value cost = Current cost x (1/(1.03)^n. Costs are discounted by 3% real rate. Includes incremental first cost if proposed first cost is greater than current first cost. Includes present value of maintenance incremental cost if PV of proposed maintenance costs is greater than the PV of current maintenance costs. If incremental maintenance cost is negative it is treated as a positive benefit. If there are no Total Incremental Present Valued Costs, the Benefit/Cost Ratio is Infinite.

Table 51: Life Cycle Cost-effectiveness Summary per square foot. Medium Retail Prototype

Climate Zone	Benefits TDV Energy Cost Savings + Other PV Savings[1] (2023 PV $)	Costs Total Incremental Present Valued (PV) Costs[2] (2023 PV $)	Benefit-to-Cost Ratio
1	$10.9	$10.5	1.0
2	$15.8	$11.7	1.3
3	$13.8	$10.5	1.3
4	$16.7	$11.7	1.4
5	$14.3	$10.5	1.4
6	$16.7	$11.7	1.4
7	$15.3	$11.7	1.3
8	$17.7	$11.7	1.5
9	$17.8	$11.7	1.5
10	$17.3	$11.7	1.5
11	$15.7	$11.7	1.3
12	$15.7	$11.7	1.3
13	$16.3	$11.7	1.4
14	$18.5	$11.7	1.6
15	$21.2	$14.2	1.5
16	$13.9	$10.5	1.3

1. **TDV Energy Cost Savings + Other PV Savings:** Benefits include TDV energy cost savings over the period of analysis (see http://docketpublic.energy.ca.gov/PublicDocuments/16-BSTD-06/TN212524_20160801T120224_2019_TDV_Methodology_Report_7222016.pdf, Chapter 5 pages 51-53). Other savings are discounted at a real 3% rate. Includes incremental first cost savings if proposed first cost is less than current first cost. Includes present value maintenance cost savings if PV of proposed maintenance costs is less than the PV of current maintenance costs.
2. **Total Incremental Present Valued Costs:** Costs include incremental equipment, replacement and maintenance costs over the period of analysis. Present value cost = Current cost x (1/(1.03)^n. Costs are discounted by 3% real rate. Includes incremental first cost if proposed first cost is greater than current first cost. Includes present value of maintenance incremental cost if PV of proposed maintenance costs is greater than the PV of current maintenance costs. If incremental maintenance cost is negative it is treated as a positive benefit. If there are no Total Incremental Present Valued Costs, the Benefit/Cost Ratio is Infinite.

Table 52: Life Cycle Cost-effectiveness Summary per square foot. Small Retail Prototype

Climate Zone	Benefits TDV Energy Cost Savings + Other PV Savings[1] (2023 PV $)	Costs Total Incremental Present Valued (PV) Costs[2] (2023 PV $)	Benefit-to-Cost Ratio
1	$17.8	$17.7	1.0
2	$24.6	$18.8	1.3
3	$22.6	$17.7	1.3
4	$26.2	$18.8	1.4
5	$23.3	$17.7	1.3
6	$26.3	$18.8	1.4
7	$24.1	$18.8	1.3
8	$27.8	$18.8	1.5
9	$27.9	$18.8	1.5
10	$27.1	$18.8	1.4
11	$24.4	$18.8	1.3
12	$24.6	$18.8	1.3
13	$25.3	$18.8	1.3
14	$28.9	$18.8	1.5
15	$30.6	$21.1	1.5
16	$22.6	$17.7	1.3

1. **TDV Energy Cost Savings + Other PV Savings:** Benefits include TDV energy cost savings over the period of analysis (see http://docketpublic.energy.ca.gov/PublicDocuments/16-BSTD-06/TN212524_20160801T120224_2019_TDV_Methodology_Report_7222016.pdf, Chapter 5 pages 51-53). Other savings are discounted at a real 3% rate. Includes incremental first cost savings if proposed first cost is less than current first cost. Includes present value maintenance cost savings if PV of proposed maintenance costs is less than the PV of current maintenance costs.
2. **Total Incremental Present Valued Costs:** Costs include incremental equipment, replacement and maintenance costs over the period of analysis. Present value cost = Current cost x (1/(1.03)^n. Costs are discounted by 3% real rate. Includes incremental first cost if proposed first cost is greater than current first cost. Includes present value of maintenance incremental cost if PV of proposed maintenance costs is greater than the PV of current maintenance costs. If incremental maintenance cost is negative it is treated as a positive benefit. If there are no Total Incremental Present Valued Costs, the Benefit/Cost Ratio is Infinite.

Table 53: Life Cycle Cost-effectiveness Summary per square foot. Large School Prototype

Climate Zone	Benefits TDV Energy Cost Savings + Other PV Savings[1] (2023 PV $)	Costs Total Incremental Present Valued (PV) Costs[2] (2023 PV $)	Benefit-to-Cost Ratio
1	$4.7	$5.1	0.9
2	$8.6	$6.8	1.3
3	$6.3	$5.1	1.2
4	$8.7	$6.8	1.3
5	$6.2	$5.1	1.2
6	$9.0	$6.8	1.3
7	$8.3	$6.8	1.2
8	$9.1	$6.8	1.3
9	$9.3	$6.8	1.4
10	$9.2	$6.8	1.4
11	$8.4	$6.8	1.2
12	$8.4	$6.8	1.2
13	$8.9	$6.8	1.3
14	$9.7	$6.8	1.4
15	$12.8	$9.1	1.4
16	$6.1	$5.1	1.2

1. **TDV Energy Cost Savings + Other PV Savings:** Benefits include TDV energy cost savings over the period of analysis (see http://docketpublic.energy.ca.gov/PublicDocuments/16-BSTD-06/TN212524_20160801T120224_2019_TDV_Methodology_Report_7222016.pdf, Chapter 5 pages 51-53). Other savings are discounted at a real 3% rate. Includes incremental first cost savings if proposed first cost is less than current first cost. Includes present value maintenance cost savings if PV of proposed maintenance costs is less than the PV of current maintenance costs.
2. **Total Incremental Present Valued Costs:** Costs include incremental equipment, replacement and maintenance costs over the period of analysis. Present value cost = Current cost x (1/(1.03)^n. Costs are discounted by 3% real rate. Includes incremental first cost if proposed first cost is greater than current first cost. Includes present value of maintenance incremental cost if PV of proposed maintenance costs is greater than the PV of current maintenance costs. If incremental maintenance cost is negative it is treated as a positive benefit. If there are no Total Incremental Present Valued Costs, the Benefit/Cost Ratio is Infinite.

Table 54: Life Cycle Cost-effectiveness Summary per square foot. Small School Prototype

Climate Zone	Benefits TDV Energy Cost Savings + Other PV Savings[1] (2023 PV $)	Costs Total Incremental Present Valued (PV) Costs[2] (2023 PV $)	Benefit-to-Cost Ratio
1	$6.4	$8.2	0.8
2	$10.6	$10.1	1.1
3	$8.3	$8.2	1.0
4	$10.5	$10.1	1.0
5	$8.2	$8.2	1.0
6	$10.9	$10.1	1.1
7	$10.1	$10.1	1.0
8	$11.0	$10.1	1.1
9	$11.3	$10.1	1.1
10	$11.2	$10.1	1.1
11	$10.2	$10.1	1.0
12	$10.3	$10.1	1.0
13	$10.8	$10.1	1.1
14	$11.9	$10.1	1.2
15	$19.0	$15.9	1.2
16	$8.2	$8.2	1.0

1. **TDV Energy Cost Savings + Other PV Savings:** Benefits include TDV energy cost savings over the period of analysis (see http://docketpublic.energy.ca.gov/PublicDocuments/16-BSTD-06/TN212524_20160801T120224_2019_TDV_Methodology_Report_7222016.pdf, Chapter 5 pages 51-53). Other savings are discounted at a real 3% rate. Includes incremental first cost savings if proposed first cost is less than current first cost. Includes present value maintenance cost savings if PV of proposed maintenance costs is less than the PV of current maintenance costs.
2. **Total Incremental Present Valued Costs:** Costs include incremental equipment, replacement and maintenance costs over the period of analysis. Present value cost = Current cost x (1/(1.03)^n. Costs are discounted by 3% real rate. Includes incremental first cost if proposed first cost is greater than current first cost. Includes present value of maintenance incremental cost if PV of proposed maintenance costs is greater than the PV of current maintenance costs. If incremental maintenance cost is negative it is treated as a positive benefit. If there are no Total Incremental Present Valued Costs, the Benefit/Cost Ratio is Infinite.

Table 55: Life Cycle Cost-effectiveness Summary per square foot. Warehouse Prototype

Climate Zone	Benefits TDV Energy Cost Savings + Other PV Savings[1] (2023 PV $)	Costs Total Incremental Present Valued (PV) Costs[2] (2023 PV $)	Benefit-to-Cost Ratio
1	1.3	1.6	0.8
2	1.8	1.8	1.0
3	1.6	1.6	1.0
4	2.0	1.8	1.1
5	1.7	1.6	1.0
6	2.1	1.8	1.1
7	2.0	1.8	1.1
8	2.2	1.8	1.2
9	2.2	1.8	1.2
10	2.3	1.8	1.3
11	1.8	1.8	1.0
12	1.9	1.8	1.0
13	1.9	1.8	1.0
14	2.4	1.8	1.3
15	2.8	2.4	1.2
16	1.7	1.6	1.1

1. **TDV Energy Cost Savings + Other PV Savings:** Benefits include TDV energy cost savings over the period of analysis (see http://docketpublic.energy.ca.gov/PublicDocuments/16-BSTD-06/TN212524_20160801T120224_2019_TDV_Methodology_Report_7222016.pdf, Chapter 5 pages 51-53). Other savings are discounted at a real 3% rate. Includes incremental first cost savings if proposed first cost is less than current first cost. Includes present value maintenance cost savings if PV of proposed maintenance costs is less than the PV of current maintenance costs.
2. **Total Incremental Present Valued Costs:** Costs include incremental equipment, replacement and maintenance costs over the period of analysis. Present value cost = Current cost x (1/(1.03)^n. Costs are discounted by 3% real rate. Includes incremental first cost if proposed first cost is greater than current first cost. Includes present value of maintenance incremental cost if PV of proposed maintenance costs is greater than the PV of current maintenance costs. If incremental maintenance cost is negative it is treated as a positive benefit. If there are no Total Incremental Present Valued Costs, the Benefit/Cost Ratio is Infinite.

6. First Year Statewide Impacts

6.1 Statewide Energy Savings and Lifecycle Energy Cost Savings

E3 calculated the first year statewide savings by multiplying the per unit savings, which are presented in Section 4.3 Per Unit Energy Impacts and Energy Savings Results, by the statewide new construction forecast for 2023, which is presented in more detail in Appendix A: Statewide Savings Methodology. The first year energy impacts represent the first year annual savings from all buildings that were completed in 2023. The lifecycle energy cost savings represents the energy cost savings over the entire 30-year period of analysis. Results are presented in Table 11.

Given data regarding the new construction forecast for 2023, E3 estimates that the proposed code change will reduce annual statewide electricity use by 481 GWh with an associated demand reduction of 39 MW. Natural gas use is not expected to be impacted, so there are no estimated natural gas savings. The energy savings for buildings constructed in 2023 are associated with a present valued energy cost savings of approximately PV$9,895 million in (discounted) energy costs over the 30- year period of analysis.

Table 56: Statewide Energy and Energy Cost Impacts

Climate Zone	Statewide Construction in 2023 (million sf)	First Year[1] Electricity Savings (GWh)	First Year[1] Peak Electrical Demand Reduction (MW)	First Year[1] Natural Gas Savings (million therms)	First Year[1] Source Energy Savings (kBtu/sq ft)	Lifecycle[2] Present Valued Energy Cost Savings (PV$ million)
1	0.5	1.3	0.2	0	41	28
2	3.2	10.9	1.1	0	53	257
3	15.3	46.3	4.4	0	48	1,031
4	7.9	28.3	2.7	0	55	659
5	1.5	4.8	0.4	0	53	103
6	9.9	37.6	3.3	0	63	845
7	7.7	27.8	2.7	0	63	626
8	14.2	52.0	4.9	0	62	1,268
9	25.4	98.0	8.9	0	63	2,304
10	12.2	42.5	3.6	0	64	973
11	2.8	9.0	0.9	0	53	208
12	16.0	55.7	5.3	0	52	1,267
13	5.1	17.8	1.7	0	54	418
14	2.9	11.1	0.9	0	67	249
15	1.8	7.4	0.7	0	80	171
16	0.9	2.8	0.3	0	50	59
TOTAL	127.3	453	42	0	923	10,467

1. First year savings from all buildings completed statewide in 2023.
2. Energy cost savings from all buildings completed statewide in 2023 accrued during 30-year period of analysis.

6.2 Statewide Greenhouse Gas Emissions Reductions

E3 calculated avoided greenhouse gas (GHG) emissions assuming the emissions factors specified in the USEPA Emissions & Generation Resource Integrated Database (eGRID) for the WECC California (CAMX) subregion. The electricity emission factor represents savings from avoided electricity generation and accounts for the GHG impacts if the state meets the Renewable Portfolio Standard (RPS) goal of 33 percent renewable electricity generation by 2020. [13] Avoided GHG emissions from natural gas savings attributable to sources other than utility-scale electrical power generation are calculated using emissions factors specified in USEPA's Compilation of Air Pollutant Emissions Factors (AP-42).

Table 12 presents the estimated first year avoided GHG emissions of the proposed code change. During the first year, greenhouse gas emissions of 36,000 metric tons of carbon dioxide equivalents (tCO_2e) will be saved.

Table 57: First Year1 Statewide Greenhouse Gas Emissions Impacts

Electricity Savings (GWH/yr)	Reduced GHG Emissions from Electricity Savings (tCO_2e)	Natural Gas Savings (Million Therm/yr)	Reduced GHG Emissions form Natural Gas Savings (tCO_2e)	Total Reduced CO2e Emissions[2] (tCO_2e)
453	36,000	0	0	**36,000**

1. First year savings from all buildings completed statewide in 2023.
2. Assumes the hourly emission factors associated with TDV Model

6.3 Statewide Water Use Impacts

The proposed code change will not result in direct water savings within the scope of this Proposal. Potential water savings may result from the substitution of water-intensive thermal generation with solar PV generation.

6.4 Statewide Material Impacts

Impacts on statewide materials are limited.

6.5 Other Non-Energy Impacts

Non-energy benefits of the proposed measures for the occupant include 1) increased property valuation, 2) independence from utility rate escalation, and 3) reliability.

If battery storage systems are configured appropriately, and capable of islanding from the grid, buildings will gain substantial reliability value. In the right conditions, this could allow buildings to provide interim power to the building during a power outage, relying on the solar PV system to generate electricity, and using the battery to store electricity and power the building. The analysis team used estimated costs of power interruptions from Lawrence Berkeley National Lab's (LBNL) Interruption Cost Estimator Calculator to quantify the

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[13] When evaluating the impact of increasing the Renewable Portfolio Standard (RPS) from 20 percent renewables by 2020 to 33 percent renewables by 2020, California Air Resources Board (CARB) published data on expected air pollution emissions for various future electricity generation scenarios (CARB 2010). The incremental emissions were calculated by dividing the difference between California emissions in the CARB high and low generation forecasts by the difference between total electricity generated in those two scenarios.

potential reliability benefits for participants (Lawrence Berkeley National Lab, Nexant Inc. n.d.). Performing a lifecycle cost analysis with the same economic inputs as the analysis in Section 5, a PV and storage system sized to the proposed code requirement could generate large enough monetary benefits to improve a participant's Benefit-to-Cost Ratio by 0.5 or greater, as seen in Figure 5. Note that this added benefit is not considered in the lifecycle cost effectiveness results shown in Section 5. Due to the building-specific nature of this benefit, the analysis team found that it may not be realized in all applications, therefore potentially including this benefit in the formal cost-effectiveness results would be speculative.

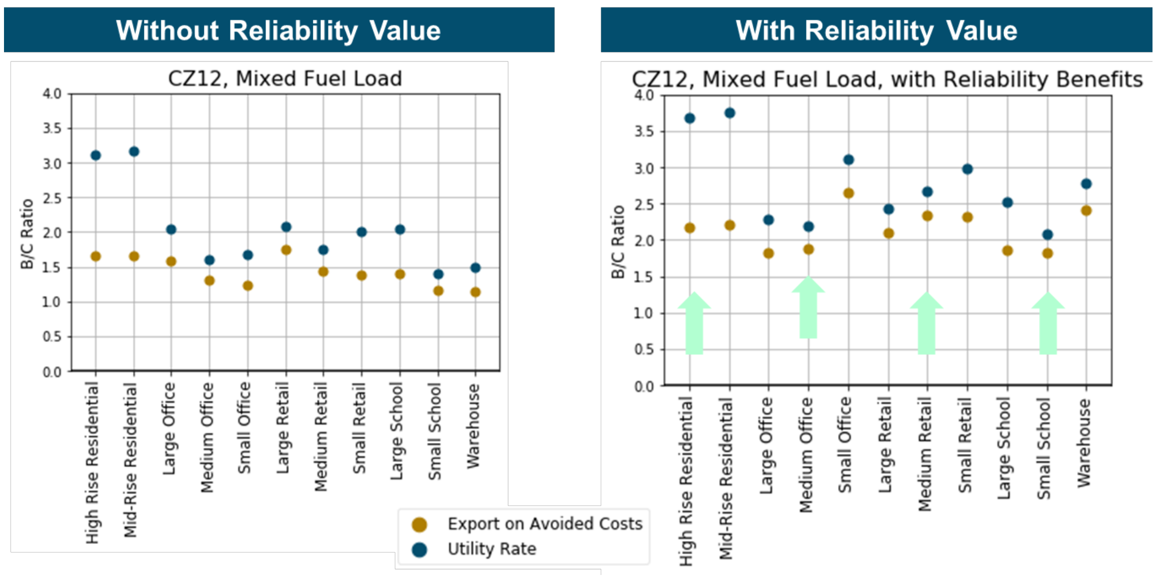

Figure 5. Participant Benefit-to-Cost increases when including reliability benefits of PV and Storage. This chart shows B/C Ratio for prototype buildings in Climate Zone 12. "Export on Avoided Costs" is the TDV metric used in Section 5 of this analysis

7. Proposed Revisions to Code Language

The proposed changes to the Standards, Reference Appendices, and the ACM Reference Manuals are provided below. Changes to the 2019 documents are marked with red underlining indicating new language and strikethroughs indicating deletions.

7.1 Standards

SECTION 110.10 – MANDATORY REQUIREMENTS FOR SOLAR READY BUILDINGS

(b) Solar Zone.

EXCEPTION 1 to Section 110.10(b)1B. High-rise Multifamily Buildings, Hotel/Motel Occupancies, and Nonresidential Buildings ~~with a permanently installed solar electric system having a nameplate DC power rating, measured under Standard Test Conditions, of no less than one watt per square foot of roof area.~~ where a PV system is required per Section 140.10.

SECTION 140.10 – PV AND BATTERY REQUIREMENTS

A. **Photovoltaic Requirements.** All newly constructed building types specified in Table 140.10-A, or mixed occupancy buildings where one or more of these building types constitute at least 80 percent of the floor area of the building, shall have a photovoltaic (PV) system meeting the minimum qualification requirements of Reference Joint Appendix JA11. The PV size in kWdc shall be not less than the smaller of the PV system size determined by Equation 140.10-A, or the total of all available Solar Access Roof Areas (SARA) multiplied by 14 W/ft².
   1. SARA includes the area of the building's roof space capable of structurally supporting a PV system, and the area of all roof space on covered parking areas, carports, and all other newly constructed structures on the site that are compatible with supporting a PV system per Title 24, Part 2, Section 1511.2.
   2. SARA does NOT include:
      A. Any area that has less than 70 percent annual solar access. Annual solar access is determined by dividing the total annual solar insolation (accounting for shading obstructions) by the total annual solar insolation if the same areas were unshaded by those obstructions. For all roofs, all obstructions including those that are external to the building, and obstructions that are part of the building design and elevation features may be considered for the annual solar access calculations.
      B. Occupied roofs as specified by CBC Section 503.1.4.
      C. Roof space that is otherwise not available due to compliance with other building code requirements if confirmed by the Executive Director.

EQUATION 140.10-A PHOTOVOLTAIC DIRECT CURRENT SIZE

$$kW_{PVdc} = (CFA \times A)/1000$$

WHERE:

kW_{PVdc} = Size of the PV system in kW

CFA = Conditioned floor area in square feet

A = PV capacity factor specified in Table 140.10-A for the building type

Where the building includes more than one of the space types listed in Table 140.10-A, the total PV system capacity for the building shall be determined by applying Equation 140.10-A to each of the listed space types and summing the capacities determined for each.

EXCEPTION 1 to Section 140.10(a). No PV system is required where the total of all available SARA is less than five percent of the conditioned floor area.

EXCEPTION 2 to Section 140.10(a). No PV system is required where the required PV system size is less than 4 kWdc.

EXCEPTION 3 to Section 140.10(a). No PV system is required if the SARA contains less than 80 contiguous square feet.

EXCEPTION 4 to Section 140.10(a). Buildings with enforcement-authority-approved roof designs, where the enforcement authority determines it is not possible for the PV system, including panels, modules, components, supports, and attachments to the roof structure, to meet ASCE 7-16, Chapter 7, Snow Loads.

EXCEPTION 5 to Section 140.10(a). Multi-tenant buildings in areas where a load serving entity does not provide either a Virtual Net Metering (VNEM) or community solar program.

B. **Battery Storage System Requirements.** All buildings that are required by Section 140.10(a) to have a PV system shall also have a battery storage system meeting the minimum qualification requirements of Reference Joint Appendix JA12. The rated energy capacity and the rated power capacity shall be not less than the values determined by Equation 140.10-B and Equation 140.10-C. Where the building includes more than one of the space types listed in Table 140.10-B, the total battery system capacity for the building shall be determined by applying Equations 140.10-B and 140.10-C to each of the listed space types and summing the capacities determined for each space type and equation.

EXCEPTION 1 to Section 140.10(b). No battery storage system is required if the installed PV system size is less than 15 percent of the size determined by Equation 140.10-A.

EXCEPTION 2 to Section 140.10(b). No battery storage system is required in buildings with battery storage system requirements with less than 10 kWh rated capacity.

EXCEPTION 3 to Section 140.10(b). No battery storage system is required in buildings with 5,000 square feet of floor area or less in either tenant spaces in multi-tenant buildings or in single-tenant buildings.

EXCEPTION 4 to Section 140.10(b). No battery storage system is required for offices, schools, and warehouses in climate zone 1.

EQUATION 140.10-B - BATTERY STORAGE RATED ENERGY CAPACITY

$kWh_{batt} = kW_{PVdc} \times B / D^{0.5}$

WHERE:

kWh_{batt} = Rated Useable Energy Capacity of the battery storage system in kWh

kW_{PVdc} = PV system capacity required by section 140.10(a) in kWdc

B = Battery energy capacity factor specified in Table 140.10-B for the building type

D = Rated single charge-discharge cycle AC to AC (round-trip) efficiency of the battery storage system

EQUATION 140.10-C - BATTERY STORAGE RATED POWER CAPACITY

$kW_{batt} = kW_{PVdc} \times C$

WHERE:

kW_{batt} = Power capacity of the battery storage system in kWdc

kW_{PVdc} = PV system capacity required by section 140.10(a) in kWdc

C = Battery power capacity factor specified in Table 140.10-B for the building type

Table 140.10-A – PV Capacity Factors

Building Type	**Factor A – Minimum PV Capacity (W/ft² of conditioned floor area)**		
Climate Zone	**1, 3, 5, 16**	**2, 4, 6-14**	**15**
Grocery	2.62	2.91	3.53
Highrise Multifamily	1.82	2.21	2.77
Office, Financial Institutions, Unleased Tenant Space			
< 25,000 ft²	4.04	4.44	5.02
25,000 ft² - 150,000 ft²	2.59	3.13	3.80
> 150,000 ft²	2.16	2.64	3.00
Retail			
< 25,000 ft²	4.35	4.62	5.17
25,000 ft² - 150,000 ft²	2.62	2.91	3.53
> 150,000 ft²	2.58	2.87	3.39
School			
< 25,000 ft²	1.44	1.78	2.93
25,000 ft² - 150,000 ft²	1.27	1.63	2.46
> 150,000 ft²	1.10	1.47	2.00
Warehouse	0.39	0.44	0.58
Auditorium, Convention Center, Hotel/Motel, Library, Medical/Clinic, Restaurant, Theater	0.39	0.44	0.58

Table 140.10-B – Battery Storage Capacity Factors

-	**Factor B – Energy Capacity**	**Factor C – Power Capacity**
Storage to PV Ratio	**Wh/W**	**W/W**
Grocery	1.03	0.26
Highrise Multifamily	1.03	0.26
Office, Financial Institutions, Unleased Tenant Space		
< 25,000 ft²	1.48	0.37
25,000 ft² - 150,000 ft²	1.68	0.42
> 150,000 ft²	1.73	0.43
Retail		
< 25,000 ft²	0.93	0.23
25,000 ft² - 150,000 ft²	1.03	0.26
> 150,000 ft²	1.07	0.27
School		
< 25,000 ft²	1.93	0.48
25,000 ft² - 150,000 ft²	1.87	0.46
> 150,000 ft²	1.81	0.45
Warehouse	0.93	0.23
Auditorium, Convention Center, Hotel/Motel, Library, Medical/Clinic, Restaurant, Theater	0.93	0.23

NOTE: Authority: Sections 25213, 25218, 25218.5, 25402 and 25402.1, Public Resources Code. Reference: Sections 25007, 25008, 25218.5, 25310, 25402, 25402.1, 25402.4, 25402.8, and 25943, P

7.2 Reference Appendices

Appendix JA11 – Qualification Requirements for Photovoltaic System

JA11.1 Purpose and Scope

Joint Appendix JA11 provides the qualification requirements for photovoltaic (PV) system to meet the prescriptive or performance standards set forth in Title 24, Part 6, Sections 140.10(a), 150.1(b) and 150.1(c).

JA11.4 Solar Access Verification

The installer shall provide documentation that demonstrates the shading condition of the actual installation of the PV module is consistent with compliance with either JA11.3.1 or JA11.3.2 by one of the following methods:

a) Solar Assessment Tool. Use a solar assessment tool approved by the Executive Director to ascertain the extent of the shading conditions on the PV system from existing obstructions. At each measurement point, the tool placed on the PV array, leveled, and oriented consistent with the manufacturer's instructions.

   Measurements shall be made at all the major corners of the array with no adjacent measurement being more than 40 feet apart. (See example in Figure JA12-2.) The points of measurement shall be distributed evenly between two major corners if they are more than 40 feet apart such that the linear distance between any sequential points is no more than 40 feet. However, if any linear edge of the array has no obstructions that are closer than two times the height they project above the closest point on the array, then the intermediate measurements along that edge do not need to be made. Measurements made at each major corner and intermediate point shall be documented in the ~~CF-2R~~ Certificate of Installation.

Appendix JA12 – Qualification Requirements for Battery Storage System

JA12.1 Purpose and Scope

Joint Appendix JA12 provides the qualification requirements for battery storage system to meet the prescriptive or performance standards ~~requirements for battery storage compliance credit(s) available in the performance standards~~ set forth in Title 24, Part 6, Sections 150.1(b) and 140.10 in combination with an on-site or a community solar photovoltaic system, or as an uncoupled battery storage system. The primary function of the battery storage system is daily cycling for the purpose of load shifting, maximized solar self-utilization, and grid-harmonization.

JA12.2 Qualification Requirements

JA12.2.2 Minimum System Performance Requirements

JA12.2.2.1 Prescriptive Compliance

The installed battery storage system ~~should~~ shall meet or exceed the following ~~performance~~ specifications:

(a) Usable capacity of at least 5 kWh.

(b) Single Charge-discharge cycle AC to AC (round-trip) efficiency of at least 80 percent.

(c) Energy capacity retention of 70 percent of nameplate capacity after 4,000 cycles covered by a warranty, or 70 percent of nameplate capacity under a 10-year warranty.

JA12.2.2.2 Performance Compliance

The installed battery storage system shall meet or exceed the following specifications:

a. Usable capacity of at least 5 kWh.

~~d.~~b. Energy capacity retention of 70 percent of nameplate capacity after 4,000 cycles covered by a warranty, or 70 percent of nameplate capacity under a 10-year warranty.

JA12.2.3 Control Requirements for Prescriptive and Performance Compliance Paths

The requirements below are applicable to all control strategies.

(a) The battery storage system shall have the capability of being remotely programmed to change the charge and discharge periods.

(b) During discharge, the battery storage system shall be programmed to first meet the electrical load of the dwelling unit(s). If during the discharge period the electrical load of the dwelling unit(s) is less than the maximum discharge rate, the battery storage system shall have the capability to discharge electricity into the grid upon receipt of a demand response signal from the local utility or a third-party aggregator.

(c) The battery storage system shall operate in one of the control strategies listed in JA12.2.3.1, JA12.2.3.2, ~~and~~ JA12.2.3.3, and JA12.2.3.4 except during a power interruption, when it may switch to backup mode. If the battery system switches to backup power mode during a power interruption, upon restoration of power the battery system shall immediately revert to the previously programmed JA12 control strategy.

(d) The battery storage system shall perform a system check on the following dates, to ensure the battery is operating in one of the control strategies listed in JA12.2.3.1, JA12.2.3.2, and JA12.2.3.3:

1) Within 10 calendar days before the onset of summer TOU schedule, and

2) Within 10 calendar days before the onset of winter TOU schedule.

At the time of inspection, the battery storage system shall be installed to meet one of the following control strategies. The battery storage system also shall have the capability to remotely switch to the other control strategies.

JA12.2.3.1 Basic Control

When coupled with an on-site or community solar PV system, ~~T~~to qualify for the Basic Control, the battery storage system shall be installed in the default operation mode to allow charging only from an on-site photovoltaic system when the photovoltaic system production is greater than the on-site electrical load. The battery storage system shall discharge only when the photovoltaic system production is less than the on-site electrical load.

JA12.2.3.2 Time-of-Use (TOU) Control

When coupled with an on-site or community solar PV system, ~~T~~to qualify for the TOU Control, the battery storage system shall be installed in the default operation mode to allow charging from an on-site photovoltaic system. The battery storage system shall begin discharging during the highest priced TOU hours of the day. The operation schedule shall be preprogrammed from factory, updated remotely, or programmed during the installation/commissioning of the system. At a minimum, the system shall be capable of programming three separate seasonal TOU schedules, such as spring, summer, and winter.

JA12.2.3.3 Advanced Demand Response Control

When coupled with an on-site or community solar PV system, ~~T~~to qualify for the Advanced Demand Response Control, the battery storage system shall be programmed by default as Basic Control as described in JA12.2.3.1 or TOU control as described in JA12.2.3.2. The battery storage control shall meet the demand responsive control requirements specified in Section 110.12(a). Additionally, the battery storage system shall have the capability to change the charging and discharging periods in response to signals from the local utility or a third-party aggregator.

JA12.2.3.4 Controls for Uncoupled Battery Storage Systems

When uncoupled with an on-site or community solar PV system, to qualify for the compliance credit, the battery storage system shall be programmed by default to:

1. Start Charging from the grid during at the onset of lowest price TOU hours of the day and start discharging to the grid at the onset of highest priced TOU hours of the day, or

2. Meet the demand responsive control requirements specified in Section 110.12(a), and shall have the capability to change the charging and discharging periods in response to signals from the local utility or a third-party aggregator.

~~JA12.2.3.4~~JA12.2.3.5 Alternative Control Approved by the Executive Director

The Executive Director may approve alternative control strategies that demonstrate equal or greater benefits to one of the JA12 control strategies. To qualify for Alternative Control, the battery storage system shall be operated in a manner that increases self-utilization of the PV array output, responds to utility rates, responds to demand response signals, and/or other strategies that achieve equal or greater. This alternative control option shall be accompanied with clear and easy to implement algorithms for incorporation into the compliance software for compliance credit calculations.

7.3 ACM Reference Manual

Appendix D of this report provides detailed specifications of the changes needed to the compliance software to incorporate this measure. The precise text of the ACM reference manual will be developed when the measure is fully developed within the compliance software. The text below provides a brief outline of how the measure would be specified in the ACM.

The standard design would include a PV system sized to the minimum prescriptive requirements. The system would be faced at an orientation of 180 degrees, with a 10-degree tilt. The battery storage system would be sized according to the proposed prescriptive requirements and operated based on the TDV signal for the given climate zone.

The proposed design would include a model of the PV system with user inputs for orientation, tilt, and rated capacity. The PV module would be selected from a drop-down list, which determines the module efficiency and other performance characteristics. If a commercial battery system is specified, the design capacity and charge duration (2 hours or 4 hours) would be specified. The control sequence of the battery storage would be prescribed and fixed by the compliance software.

7.4 Compliance Manuals

Requirements for commercial PV systems and battery storage systems will be described. Any required inspection procedures will also be included in the Manual.

7.5 Compliance Forms

The proposed code change will modify the following compliance forms listed below.

- **NRCC-SRA-E** – The NRCC-SRA-E will be modified to document compliance for the proposed prescriptive PV and Battery Requirements of 140.10. Specifically, Table G of the NRCC-SRA-E will need to incorporate the PV adjustment factors of Table 140.10-A and Equation 140.10 – Photovoltaic Direct Current Size. Table G will also document roof availability to determine eligibility for exceptions to the proposed prescriptive PV requirements of 140.10(a). A new table (J) will be developed to document the proposed prescriptive battery storage requirements of 140.10(b). Table J will incorporate power and energy adjustment factors of Table 140.10-B and Equation 140.10-B and 140.10-C. Table J will also document eligibility for exceptions to 140.10(b).
- **NRCC-PRF-01-E** – The NRCC-PRF-01-E will be modified to document compliance for the proposed PV and battery requirements following the proposed Alternative Calculation Method (ACM) Reference Manual ruleset. See *Section 7.3 ACM Reference Manual* of this report for the detailed proposed revisions to the text of the ACM. A new table (O1) will be developed to document the proposed photovoltaic system size (kWdc). Table O1 will also document the power capacity of the proposed battery storage system (kWdc), roundtrip efficiency of the battery storage system, and rated energy capacity (kWh).
- **NRCI-SPV-01-E** – The purpose of the NRCI-SPV-01-E will be modified to document the installed solar photovoltaic system when demonstrating

compliance with Section 140.10(a) as well as when the PV system is being used to claim Exception 1 to Section 110.10(b)1B.

- **NRCI-SPV-02-E** – The NRCI-SPV-02-E will be created to document the installed battery storage system when demonstrating compliance with the proposed battery storage requirements of Section 140.10(b). NRCI-SPV-02-E will include the battery's rated energy capacity, rated power capacity, roundtrip efficiency and control capabilities.

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APPENDICES

Appendix A: Statewide Savings Methodology

The Energy Commission Demand Analysis Office provided the authors with the residential and nonresidential new construction forecast for 2023, broken out by building type and forecast climate zones (FCZ). The authors translated this data to building climate zones (BCZ) using the weighting provided by the Energy Commission as presented in Table 58. The projected nonresidential new construction impacted by the measure is presented in Table 61. Table 59 provides a mapping of the prototype models to the construction forecast building types. Table 60 presents the assumed percent of new construction that would be impacted by the proposed code change.

The authors used the mid-scenario of forecasted residential new construction for statewide savings estimates. This measure only applies to high-rise residential buildings (> 3 stories). It was assumed that 50% of the multi-family buildings indicated in the Residential New Construction Forecast, are high-rise residential.

Table 58: Translation from FCZ to BCZ.

Forecast zones along X-axis, climate zones along Y-axis

	0	1	2	3	4	5	6	7	8	9	10
1	17.90%	0.00%	13.51%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
2	0.00%	0.00%	80.20%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
3	0.00%	52.43%	6.28%	0.00%	3.64%	0.00%	52.26%	0.00%	0.00%	0.00%	0.00%
4	0.00%	30.39%	0.00%	0.00%	0.00%	0.00%	15.39%	0.00%	0.00%	0.00%	0.00%
5	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	32.33%	0.00%	0.18%	0.00%	0.00%
6	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.01%	18.89%	61.19%	0.00%	0.00%
7	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
8	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	43.99%	0.00%	0.00%	0.00%
9	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	32.29%	37.22%	0.00%	0.00%
10	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	71.19%
11	0.42%	0.00%	0.00%	84.77%	22.07%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
12	0.00%	17.18%	0.00%	0.00%	72.61%	4.55%	0.00%	0.00%	0.00%	0.00%	0.00%
13	0.00%	0.00%	0.00%	0.00%	0.00%	94.81%	0.00%	0.00%	0.00%	78.49%	0.00%
14	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	4.51%	0.00%	12.10%	24.17%
15	3.18%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.10%
16	78.50%	0.00%	0.01%	15.23%	1.68%	0.64%	0.00%	0.33%	1.41%	9.41%	4.55%
Total	**100.00%**	**100.00%**	**100.00%**	**100.00%**	**100.00%**	**100.00%**	**100.00%**	**100.00%**	**100.00%**	**100.00%**	**100.00%**

Table 59 (cont.)

	11	12	13	14	15	16	17	18	19	20
1	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
2	0.00%	0.00%	0.00%	0.00%	0.19%	0.00%	0.00%	0.00%	0.00%	0.00%
3	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
4	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
5	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
6	0.00%	6.60%	0.00%	0.00%	0.00%	17.18%	0.00%	0.00%	0.00%	0.00%
7	0.00%	62.81%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
8	0.00%	1.94%	0.00%	0.00%	0.00%	27.90%	0.00%	0.00%	0.00%	0.00%
9	0.00%	0.00%	0.00%	0.00%	0.00%	54.92%	99.35%	100.00%	0.00%	0.00%
10	86.11%	27.88%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
11	0.00%	0.00%	0.42%	0.00%	44.55%	0.00%	0.00%	0.00%	0.00%	0.00%
12	0.00%	0.00%	99.58%	100.00%	52.65%	0.00%	0.00%	0.00%	0.00%	0.00%
13	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
14	0.00%	0.66%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.02%	0.00%
15	13.33%	0.12%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	99.98%	0.00%
16	0.56%	0.00%	0.00%	0.00%	2.61%	0.00%	0.65%	0.00%	0.00%	100.00%
Total	**100.00%**	**100.00%**	**100.00%**	**100.00%**	**100.00%**	**100.00%**	**100.00%**	**100.00%**	**100.00%**	**100.00%**

Table 59: Mapping Factors for Construction Building Types to Nonresidential Prototypes

Building Type *Building sub-type*	**Composition of Building Type by Sub-types**
Small Office	100%
Retail	
Stand-Alone Retail	10%
Large Retail	75%
Strip Mall	5%
Mixed-Use Retail	10%
Non-Refrigerated Warehouse	
Schools	
Small School	60%
Large School	40%
Large Offices	
Medium Office	50%
Large Office	50%

Table 60: Percent of New Construction Impacted by the Proposed Measure

Type of Nonresidential Space	Proposed Measure
Office-Small	100%
Retail	100%
Non-refrigerated Warehouse	100%
School	100%
Office-Large	100%
High-rise Residential Buildings	100%

Table 61: Estimated New Nonresidential Construction in 2023 by Climate Zone and Building Type (Million Square Feet)

Source: Energy Commission Demand Analysis Office

Climate Zone	Small Office	Large Office	Retail	Grocery Store	Non-Refrigerated Warehouse	Schools
1	0.035175679	0.114797092	0.105887256	0.028460539	0.077259841	0.04870007
2	0.209022613	0.681621566	0.628999777	0.169099564	0.459149381	0.289356793
3	0.744038483	3.84212879	2.874726862	0.707800043	2.381855334	1.18067699
4	0.371969234	2.016253088	1.473399101	0.35899845	1.223486071	0.599111674
5	0.081298635	0.352725792	0.298227991	0.075593021	0.227281805	0.123822888
6	0.558138383	2.756426756	2.101335062	0.530878465	1.879997722	0.664616851
7	0.772988876	1.550141896	1.482067296	0.445073286	1.1082226	0.712507276
8	0.732204995	4.126620956	3.016191618	0.749164113	2.70201865	0.912297864
9	1.177502719	7.6788254	4.715759812	1.152329445	4.322036636	1.229060799
10	0.985711895	1.508027947	2.823354783	0.779888816	3.441195004	1.24915386
11	0.269042391	0.322487964	0.582022642	0.192766995	0.636824843	0.332905257
12	1.409103395	3.215716027	3.170179704	0.824079044	3.186690674	1.399892443
13	0.574557079	0.494845784	1.218458015	0.409627114	1.087092988	0.7254288
14	0.192726772	0.519041463	0.668169197	0.176125064	0.739574393	0.258330693
15	0.188980329	0.157913275	0.384238626	0.129441391	0.540421347	0.180968942
16	0.078110511	0.133203774	0.211890727	0.061880138	0.224714437	0.099407927
Total	8.380571988	29.47077757	25.75490847	6.79120549	24.23782173	10.00623913

Table 62: Projected New Residential Construction in 2023 by Climate Zone

Source: Energy Commission Demand Analysis Office

Building Climate Zone	Multifamily Starts[2]
1	265
2	1,573
3	7,630
4	3,975
5	706
6	3,370
7	3,623
8	4,738
9	11,124
10	3,930
11	1,122
12	6,335
13	1,849
14	840
15	547
16	339
Total	**51,966**

1. Energy Commission provided a low, middle, and high forecast. The (Name of Organization) used the middle forecast for the statewide savings estimates. Statewide savings estimates do not include savings from mobile homes.
2. Includes high-rise and low-rise multi-family construction.

Appendix B: Embedded Electricity in Water Methodology

There are no on-site water savings associated with the proposed code change.

Appendix C: Environmental Impacts Methodology

Section 6.2 of this report presents the detailed GHG impact methodology and results.

Appendix D: California Building Energy Code Compliance (CBECC) Software Specification

Introduction

The purpose of this appendix is to present compliance software modifications needed to enable the user to model PV and battery systems. Based on proposed code changes detailed in Section 140.10, many commercial buildings will be required to have PV and battery systems. The compliance software would be required to model the PV and battery requirements and provide appropriate user inputs to allow trade-off against the prescriptive minimum requirements. Standalone PV systems can be modeled in the current version of the software, but they do not receive credit towards compliance. In certain projects, where neither PV nor batteries would be required, but batteries are specified in the proposed design, the software must be able to account for the impact of a standalone battery system.

This appendix summarizes the changes needed to the compliance software (CBECC-Com):

1. Use of existing PV functionality for standalone PV systems.
2. Additional PV functionality needed in combination with batteries.
3. Ability to model standalone battery storage systems as well as PV and battery combination storage systems.
4. Operation of the PV and battery system based on TDV signals.

Existing PV and Battery Modeling Capabilities

Currently, CBECC-Com can model a standalone PV system based on the PVWatts[14] module (housed within CBECC-Res and handled automatically within CBECC-Com). Below is a simplified presentation of PV and Battery system modeling in CBECC-Com.

[14] NREL's PVWatts is a web application that estimates the electricity production of a PV system. The PVWatts module is available through CBECC-Com and through EnergyPlus. It will be used in implementing the PV system.

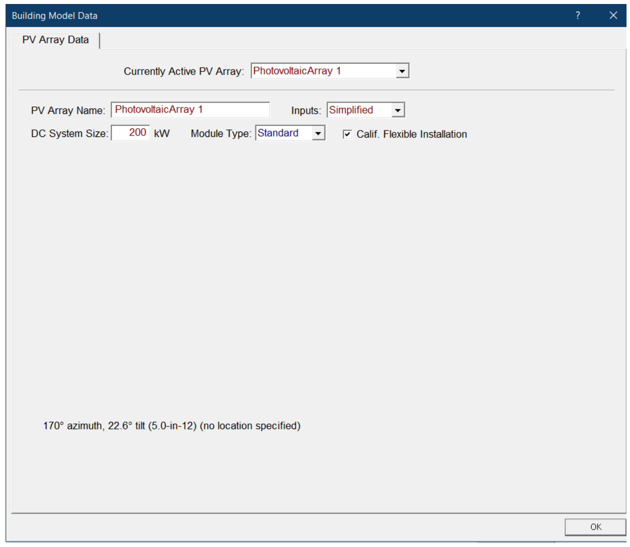

Figure 6: Example of CBECC-Com user inputs for PV Array Data.

Table 63 describes the user inputs currently available in CBECC-Com for modeling a PV system.

Table 63: PV system user inputs currently available in CBECC-Com (Screen: PV Array Data)

Variable Name	Data Type	Units	Default	Restrictions
Inputs	Dropdown Menu	None	Simplified	2 options: Simplified, Detailed
DC System Size	Float	kW	0	None
Module Type	Dropdown Menu	None	Standard	3 options: Standard, Premium, Thin Film
Calif. Flexible Installation	Checkbox	None	Checked, with 170degree azimuth, 22.6 degree tilt (5.0-in-12)	
Orientation Input	Dropdown Menu	None	azimuth and tilt	Only option: azimuth and tilt
Azimuth (deg)	Float	degrees	170	90-300
Tilt Input	Dropdown Menu	None	deg	2 options: degree, pitch
Array Angle / Tilt	Float	deg / x in 12	22.619 degrees or 5-in-12 tilt	User can enter on only one based on "Tilt Input" selection
Inverter Eff.	Float	%	96	None

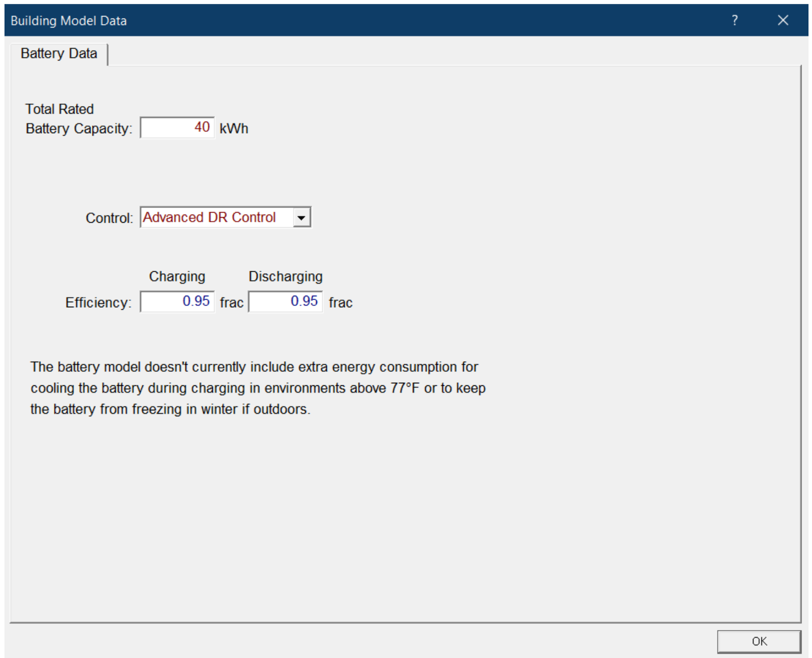

Figure 7: Example of CBECC-Com user inputs for Battery Data

Table 64 lists the above example of CBECC-Com user inputs for the Battery object.

Table 64: Battery system user inputs currently available in CBECC-Com (Screen: PV Array Data)

Variable Name	Data Type	Units	Default	Restrictions
Total Rated Battery Capacity	Float	kWh	5	None
Control	Dropdown Menu	None	Basic	Options are: Basic, Time of Use, Ranked Day DR Control, Advanced DR Control
Efficiency: Charging, Discharging	Fraction	None	0.95	None

Proposed Architecture for Modeling PV and Battery Systems

Much of the existing PV and battery capability will be reused for this measure. Table 65 lists the user inputs required and whether they are new for this measure or they exist in the current software. Using these inputs, the proposed and baseline PV and battery systems will be modeled. The sections that follow describe the full EnergyPlus object inputs and how they should be configured for implementing the modeling.

Table 65: Required PV and Battery User Inputs

Input	New or Existing
DC System Size	Existing

Module Type	Existing
Tilt Input & Array Angle / Tilt	Existing
Azimuth (deg)	Existing
Rated Capacity	Existing
Maximum Power for Discharging	New
Maximum Power for Charging	New

Based on the following generic CBECC-Com project inputs and the criteria in section 140.10, the software will determine whether PV and battery systems are required in the baseline model.

- Climate zone
- Building type, or space type
- Conditioned floor area
- Effective Annual Solar Access Area (EASAA).

EASAA is not an input currently but will be requested from the user. When EASAA is smaller than five percent of the conditioned floor area (CFA) then the project is exempted from both the PV and battery requirement.

Other exceptions, based on PV size (< 4 kW) and battery size (PV size < 15% of minimum required per equation 140.10-A), will be calculated during the compliance run to determine if the baseline model should include PV and battery systems.

Detailed EnergyPlus Configuration For PV and Battery Modeling

The following tables list the details for EnergyPlus objects and their fields. Object inputs are either user inputs taken from the CBECC-Com interface or they are defaults based on data presented in the table. Object fields that cannot be directly determined using manufacturer data or the PV and battery specification are not exposed to the user.

Below are the objects are needed to model a PVWatts PV system in EnergyPlus 9.0:

- Generator:PVWatts
- ElectricLoadCenter:Inverter:PVWatts
- ElectricLoadCenter:Distribution
- ElectricLoadCenter:Generators

To add a battery object in EnergyPlus 9.0:

- ElectricLoadCenter:Storage:Simple
- ElectricLoadCenter:Distribution
- ElectricLoadCenter:Inverter:PVWatts

To have both PV and Battery in EnergyPlus 9.0:

- All of the above objects that were used for PV and battery
- ElectricLoadCenter:Distribution merged between PV and battery

The following tables provide translation CBECC-Com user interface and EnergyPlus object inputs. For the ElectricLoadCenter:Generators object, no user entries are required, and thus, no inputs will be exposed to the user interface.

Table 66: Specification for Generator:PVWatts object

EnergyPlus				CBECC-Com					
Field Name	**Range, values, or options**	**Units**	**EnergyPlus Default**	**Exposed to User?**	**Exposed Field Name**	**Range, values, or options**	**Units**	**Proposed Model Value**	**Baseline Model Value**
Name	User assigned			No				Unique name	Unique name
PVWatts Version	5	-		No				5	5
DC System Capacity		W (Watt)		Yes	DC System Size			User input	Calculated based on prescriptive requirements
Module Type	Standard, Premium, Thin Film			Yes	Module Type	Dropdown menu: Standard, Premium, Thin Film		User input	Standard
Array Type	FixedOpenRack, FixedRoofMounted, OneAxis, OneAxisBacktracking, TwoAxis			No				FixedRoofMounted	FixedRoofMounted
System Losses	0-1		0.14	No				0.14	0.14
Array Geometry Type	One of: TiltAzimuth, Surface		TiltAzimuth	No				TiltAzimuth	TiltAzimuth
Tilt Angle	0-90	degrees	20	Yes	Tilt Input (map to existing input fields)	Dropdown menu: degree (0-90), pitch & degree	degree, x in 12	User input	10 degrees
Azimuth Angle	0-360	degrees	180	Yes	Azimuth (deg)	0-300	degrees	User input	180 degrees
Surface Name	can select surface from the model			No				NA	NA

EnergyPlus				CBECC-Com					
Field Name	**Range, values, or options**	**Units**	**EnergyPlus Default**	**Exposed to User?**	**Exposed Field Name**	**Range, values, or options**	**Units**	**Proposed Model Value**	**Baseline Model Value**
Ground Coverage Ratio	0-1		0.4	No				0.4	0.4

Table 67: Specification for ElectricLoadCenter:Inverter:PVWatts object

EnergyPlus				CBECC-Com					
Field Name	**Range, values, or options**	**Units**	**EnergyPlus Default**	**Exposed to User?**	**Exposed Field Name**	**Range, values, or options**	**Units**	**Proposed Model Value**	**Baseline Model Value**
Name	User assigned			No					
DC to AC Size Ratio	No limit		1.1	No		1.0-1.5		1.1	1.1
Inverter Efficiency	0-1	fraction	0.96	No		1-100	%	0.96	0.96

Table 68: Specification for ElectricLoadCenter:Distribution object

EnergyPlus				CBECC-Com					
Field Name	**Range, values, or options**	**Units**	**EnergyPlus Default**	**Exposed to User?**	**Exposed Field Name**	**Range, values, or options**	**Units**	**Proposed Model Value**	**Baseline Model Value**
Name	User assigned			No				Unique name	Unique name
Generator List Name	Dropdown of ElectricLoadCenter: Generators objects.			No				ElectricLoadCenter:Generators object used in the model will be selected.	
Generator Operation Scheme Type	Baseload, DemandLimit, TrackElectrical, TrackSchedule, TrackMeter, FollowThermal, and FollowThermalLimitElectrical		none	No				Baseload	Baseload

EnergyPlus				**CBECC-Com**					
Field Name	**Range, values, or options**	**Units**	**EnergyPlus Default**	**Exposed to User?**	**Exposed Field Name**	**Range, values, or options**	**Units**	**Proposed Model Value**	**Baseline Model Value**
Generator Demand Limit Scheme Purchase Electric Demand Limit	Any number		none	No				0	0
Generator Demand Limit Scheme Schedule Name	Dropdown menu of all schedules		none	No				NA	NA
Generator Track Meter Scheme Meter Name	Dropdown menu of all meters available		none	No					
Electrical Buss Type	AlternatingCurrent, AlternatingCurrentWithStorage, DirectCurrentWithInverter, DirectCurrentWithInverterDCStorage, or DirectCurrentWithInverterACStorage		AlternatingCurrent	No				DirectCurrentWithInverterDCStorage	DirectCurrentWithInverterDCStorage
Inverter Name	Dropdown list of existing inverter objects		none	No				ElectricLoadCenter:Inverter:PVWatts object used in the model will be selected.	
Electrical Storage Object Name	Dropdown list of existing storage objects		none	No				ElectricLoadCenter:Storage:Simple object used in the model will be selected.	

EnergyPlus				CBECC-Com					
Field Name	**Range, values, or options**	**Units**	**EnergyPlus Default**	**Exposed to User?**	**Exposed Field Name**	**Range, values, or options**	**Units**	**Proposed Model Value**	**Baseline Model Value**
Transformer Object Name	Dropdown list of transformer objects		none	No				NA	NA
Storage Operation Scheme	TrackFacilityElectricDemandStoreExcessOnSite; TrackMeterDemandStoreExcessOnSite; TrackChargeDischargeSchedules; FacilityDemandLeveling		TrackFacilityElectricDemandStoreExcessOnSite	No				TrackChargeDischargeSchedules	TrackChargeDischargeSchedules
Storage Control Track Meter Name				No				NA	NA
Storage Converter Object Name	Dropdown		none	No				NA	NA
Maximum Storage State of Charge Fraction	0-1		1	No				1	1
Minimum Storage State of Charge Fraction	0-1		0	No				0	0
Design Storage Control Charge Power	numerical input	Watts	none	No				NA	NA

EnergyPlus				CBECC-Com					
Field Name	**Range, values, or options**	**Units**	**EnergyPlus Default**	**Exposed to User?**	**Exposed Field Name**	**Range, values, or options**	**Units**	**Proposed Model Value**	**Baseline Model Value**
Storage Charge Power Fraction Schedule Name	To be selected from dropdown, defined elsewhere		none	No				Based on TDV and pre-determined monthly charging periods	Based on TDV and pre-determined monthly charging periods
Design Storage Control Discharge Power	Number to be typed in	Watts	none	No					
Storage Discharge Power Fraction Schedule Name	To be selected from dropdown, defined elsewhere		none	No				Based on TDV and pre-determined monthly charging periods	Based on TDV and pre-determined monthly charging periods
Storage Control Utility Demand Target		Watts	none	No				NA	NA
Storage Control Utility Demand Target Fraction Schedule Name	To be selected from dropdown, defined elsewhere		none	No				NA	NA

Table 69: Specification for ElectricLoadCenter:Generators object

EnergyPlus				CBECC-Com					
Field Name	**Range, values, or options**	**Units**	**EnergyPlus Default**	**Exposed to User?**	**Exposed Field Name**	**Range, values, or options**	**Units**	**Proposed Model Value**	**Baseline Model Value**
Name	User assigned			No				Unique value	Unique value
Generator 1 Name	Dropdown list of generators			No				"Generator:PVWatts" object from the model will be selected	
Generator 1 Object Type	Generator:InternalCombustionEngine, Generator:CombustionTurbine, Generator:Photovoltaic, Generator:PVWatts, Generator:FuelCell, Generator:MicroCHP, Generator:MicroTurbine, Generator:WindTurbine		none	No				Generator:PVWatts	Generator:PVWatts
Generator 1 Rated Electric Power Output	Numerical input		none	No				Set to arbitrary high value (this input is not critical to the simulation)	Set to arbitrary high value (this input is not critical to the simulation)
Generator 1 Availability Schedule Name	Dropdown list of schedules		none	No				Always on	Always on
Generator 1 Rated Thermal to Electrical Power Ratio	Not used for this measure		none	No				NA	NA

Table 70: Specification for ElectricLoadCenter:Storage:Simple object

EnergyPlus				CBECC-Com					
Field Name	**Range, values, or options**	**Units**	**EnergyPlus Default**	**Exposed to User?**	**Exposed Field Name**	**Range, values, or options**	**Units**	**Proposed Model Value**	**Baseline Model Value**
Name	User assigned		none	No				Unique name	Unique name
Availability Schedule Name	Dropdown menu of schedules		none	No				Always on	Always on
Zone Name			none	No				Not in zone	Not in zone
Radiative Fraction for Zone Heat Gains	0-1		none					NA	NA
Nominal Energetic Efficiency for Charging	0-1		none	No		0-1		0.922	0.922
Nominal Discharging Energetic Efficiency	0-1		none	No		0-1		0.922	0.922
Maximum Storage Capacity		J	none	Yes	Rated Usable Capacity		kW	User input. EnergyPlus input (Joules) calculated as kW input times battery hour rating (input below)	Sized based on prescriptive requirements
Maximum Power for Discharging		W	none	No	Maximum Power for Discharging		kW	Same as user input for rated usable capacity	Same as maximum storage capacity
Maximum Power for Charging		W	none	No	Maximum Power for Charging		kW	Same as user input for rated usable capacity	Same as maximum storage capacity

EnergyPlus				**CBECC-Com**					
Field Name	**Range, values, or options**	**Units**	**EnergyPlus Default**	**Exposed to User?**	**Exposed Field Name**	**Range, values, or options**	**Units**	**Proposed Model Value**	**Baseline Model Value**
Initial State of Charge		J	none	No			kWh	0	0
NA	NA	NA	NA	Yes	Battery Hour Rating	0.5 - 6 hours	hour	User input	4