Report on Cost-Effectiveness and Other Analyses for Proposed Solar Ordinance

Prepared for the Department of the Environment of the City and County of San Francisco

by

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1 Executive Summary

The San Francisco Department of the Environment is exploring the possibility of an ordinance that would require installation of photovoltaic systems on newly constructed residential and commercial buildings. The Department commissioned this study to inform its work and to provide supporting documentation to the California Energy Commission for approval of the ordinance.

This study examined several main outcomes:

1. The cost-effectiveness of rooftop photovoltaic systems installed on newly constructed residential and commercial buildings in the City and County of San Francisco.
2. The effects of different input values on the outcome were studied using a sensitivity analysis.
3. The potential impact on carbon emissions.
4. Aggregate city-wide effects.

This executive summary will give an overview of the study's framework and will then summarize the results of the above analyses.

1.1 Framework

This study analyzed outcomes in two future years: 2015 and 2017. The year 2015 was selected because it is the earliest year in which the ordinance could come into effect. The second year, 2017, was selected due to the expected reduction in the federal investment tax credit, which is a significant factor affecting the cost of photovoltaic systems. The credit will be 30% through 2016, but in 2017 the credit is expected to be reduced to 10% for commercial systems and eliminated for residential systems.

A few main assumptions guided this study:

- The roof area available for a photovoltaic system would correspond to the solar ready area required by California's building energy code, which is 250 ft^2 for single-family residential buildings or 15% of roof area for most commercial buildings.
- A single owner would derive the full benefits, and pay the full costs, associated with a photovoltaic system.
- The only incentive available would be the federal investment tax credit.

Further assumptions are described in this report as appropriate.

This study modeled projects in several prototypical building models. Different building models were used to represent types of buildings that may be encountered in San Francisco. The building models specify physical features of the buildings and the end uses of the occupied space, for instance, hotel or office. This information was used to estimate energy usage in the buildings and to provide a constraint on the size of the photovoltaic systems that could be installed on each building.

A variety of additional parameters were needed to specify the modeled projects, including:

- general parameters specifying the location and analysis period;

- parameters affecting initial purchase cost and ongoing maintenance costs of the photovoltaic systems;
- parameters specifying the performance of the photovoltaic systems;
- financial parameters, including debt terms, taxes, insurance, inflation, discount rate, incentives, and depreciation;
- utility rates and annual escalation rates.

Appropriate values for the parameters were researched and were used to specify a reference scenario. These parameters are discussed in further detail in this report.

This report is divided into several main sections, described briefly below.

Section 2, **Introduction**, discusses the basis for the study, the cost-effectiveness evaluation framework, considerations due to uncertainty in input parameter values and simulation results, main assumptions associated with the study, and the general modeling framework and tools used for the study.

Section 3, **Building Models and Projects**, discusses the various building models and photovoltaic systems associated with each building model. This section includes information on the energy consumption of the building models and the photovoltaic systems' sizes.

Section 4, **Input Parameters**, discusses in detail the input parameters used in the study. This section includes the methodology used to forecast future photovoltaic system costs, and discusses the values used for photovoltaic system performance, financial parameters, and utility rates.

Section 5, **Results**, presents the results of the analyses. The results section includes the results of the cost-effectiveness analysis, discussion of a sample cash flow, results of the sensitivity analysis, estimated per-project carbon emissions impacts, and estimated additional building costs for installation of a photovoltaic system. Section 5.6, **Aggregate Results**, presents an analysis of the potential effects had the proposed systems been installed in all relevant buildings currently in San Francisco's building pipeline.

1.2 Cost Effectiveness

A project is considered to be cost-effective if its benefits are greater than its costs. This study used a participant cost test, which considers the benefits and costs to a participant in a project. The participants considered were the owners of newly constructed buildings with rooftop solar photovoltaic systems that provide electric energy which is consumed on-site.

The figure below shows the main results of the cost-effectiveness analysis.

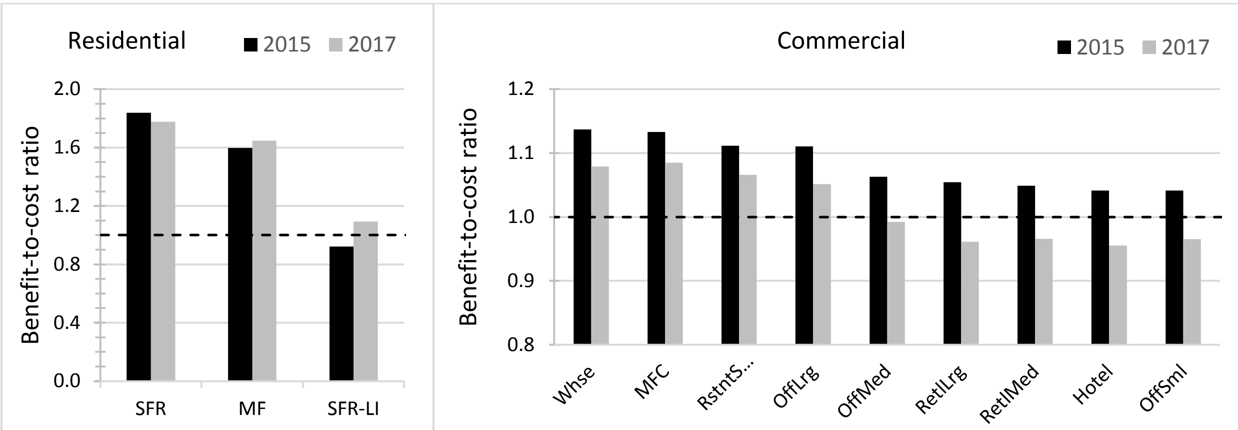


Figure 1 Results of cost-effectiveness analysis. The vertical axis shows the ratio of benefits to costs. The results shown are for the reference scenario; additional scenarios were also analyzed. (SFR=single-family residential, MF=multifamily, SFR-LI=single-family low income, Whse=warehouse, MFC=multifamily common area, RstntSmall=small restaurant, OffLrg=large office, OffMed=medium office, RetlLrg=large retail, RetlMed=medium retail, Hotel=small hotel, OffSml=small office.)

The benefit-to-cost ratios, shown in the figure above, could be interpreted as precise single values. When interpreted in this manner, a ratio greater than 1.0 would indicate that the outcome is cost-effective, while a ratio less than 1.0 would indicate that the outcome is not cost-effective. With this interpretation, the proposed solar requirement is cost-effective for nearly all projects installed in 2015, except for single-family low income households. The requirement, however, is cost-effective for only some projects installed in 2017; it is not cost-effective for the medium office, large retail, medium retail, small hotel, and small office building models.

Alternatively, the benefit-to-cost ratios could be interpreted as point estimates drawn from a population of possible values having some probability distribution. This interpretation is more representative of the uncertainty inherent in forecasting future conditions. However, interpretation of the results when considering uncertainty is less clear cut, since the results could take on a range values, depending on the possible input values and modeling assumptions. It is possible, though, to make some inferences about the likelihood of a result indicating cost-effectiveness. The greater the difference of a result from the cost-effectiveness threshold, the more likely it is that the result represents a true outcome (cost-effective or not cost-effective). The results in Figure 1 above are ordered from left to right in decreasing benefit-to-cost ratio for the year 2015. Thus, the results that are closer to the left end of the charts represent a higher likelihood of a cost-effective outcome than the results that are closer to the right end of the charts. The single-family and multifamily building models, with benefit-to-cost ratios above 1.6, are most likely to be cost-effective. For the commercial building models, the order of likelihood of cost-effectiveness for projects installed in 2015 is: warehouse, multifamily common, small restaurant, large office, medium office, large retail, medium retail, small hotel, and small office. The results for 2017 have essentially the same order of decreasing cost-effectiveness, except that all of the commercial projects are less cost effective than in 2015, and the small hotel is less cost-effective than the small office.

1.3 Sensitivity Analysis

A sensitivity analysis was done to gauge the effect of varying the values of several input parameters. Performing simulations while varying input parameters over reasonable expected ranges helps explore the sensitivity of the outcomes to particular choices of values. This also provides insight into the range of outcomes that could be encountered in real-world projects. The effects of variation of individual parameters are summarized below. Additional analysis was done by constructing scenarios in which the values of multiple input parameters were varied together; these results can be found in the detailed results in section 5.1, Cost Effectiveness, on page 35.

Overall results of the sensitivity analysis are shown in Figure 2 below. This figure shows the average decrease or increase in the benefit-to-cost ratio relative to the reference scenario, as well as the minimum and maximum change. The simulation results for all buildings in both modeled years (2015 and 2017) were combined to calculate these summary values. The results were then sorted in decreasing order of average range of effect.

Debt fraction had the largest average impact on the ratio, followed by the cost per watt, and then debt rate. The cost per watt and debt rate both have a significant impact on the cost of owning a photovoltaic system. Azimuth (compass orientation) and availability resulted in decreased ratios, which was expected given that 100% availability and a near-optimal azimuth were assumed in the reference scenario, so that any change in those values could only reduce the benefits of the system. The ratio varied the least due to changes in federal tax rate, discount rate, and system size. The small change in the ratio due to varying system size suggests that systems could be sized to occupy more or less of the roof area, not just the 250 ft^2 or 15% of roof area that were assumed for this study, without too great an effect on cost-effectiveness.

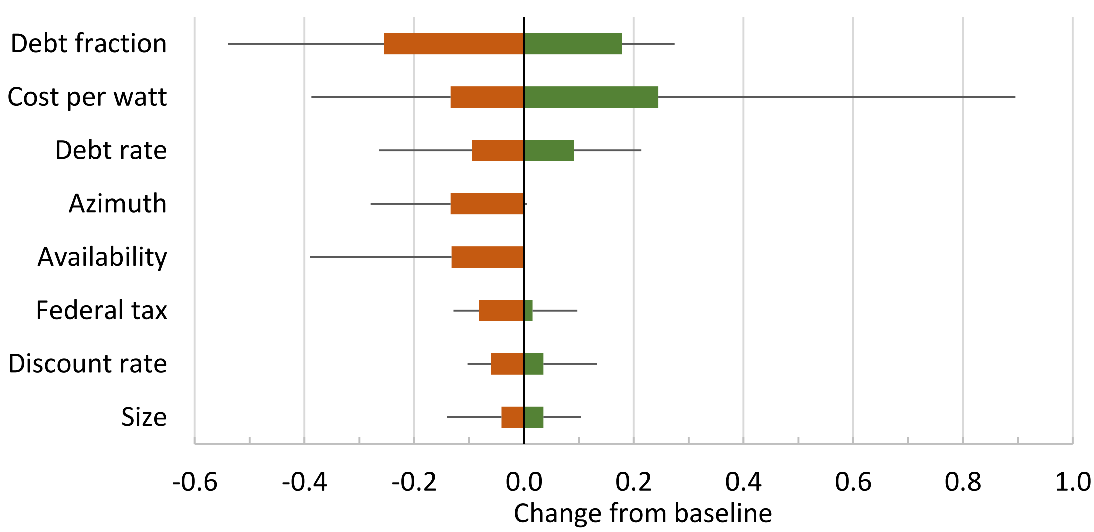


Figure 2 Sensitivity analysis results showing the average decrease or increase in the benefit-to-cost ratio relative to the reference scenario as well as the minimum and maximum change.

1.4 Carbon Emissions Impact

An analysis was done of the potential carbon emission reductions for each individual project (see figure below). Lifetime avoided emissions ranged from 5.7 to 2,150 metric tons CO_2 (MT CO_2) for projects installed in 2015. Avoided emissions depended on year of installation and were proportional to system size. Each 1 kW of photovoltaic capacity installed in 2015 could avoid emissions of 3.6 MT CO_2. A larger system offsetting a small portion of a building's electric energy consumption could have a greater impact on carbon emissions than a smaller system offsetting a large portion of consumption. This can be seen in the results for the warehouse (Whse) versus the large retail building models (RetlLrg) in the figure below. A 95 kW photovoltaic system on the warehouse building model could offset 94% of electric energy consumption in the building over the typical 25 year lifetime of the photovoltaic system. This would result in an estimated 306 MT CO_2 in avoided emissions. In contrast, a 600+ kW photovoltaic system on the large retail building model could offset just 44% of the building's electric energy consumption, but would avoid 7 times more emissions, or 2,153 MT CO_2.

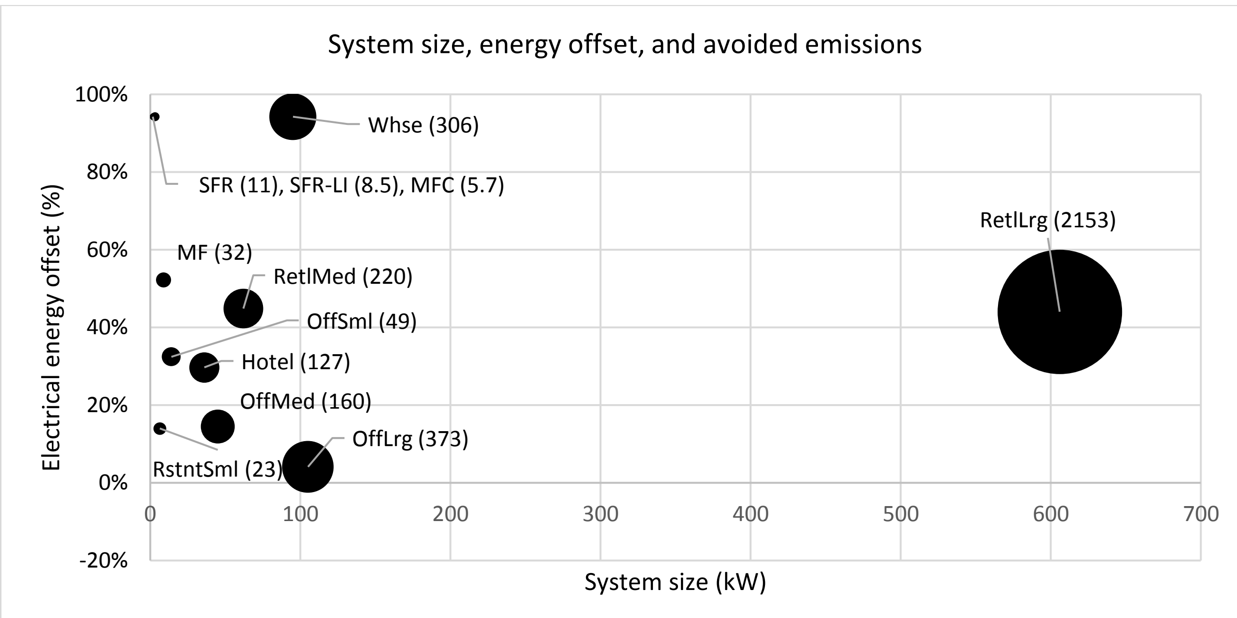


Figure 3 System size, electrical energy offset, and avoided emissions of projects installed in 2015. The sizes of the circles are proportional to the amount of avoided carbon emissions over the lifetime of the projects, while the numbers in parentheses give the estimated amounts of avoided emissions.

1.5 Aggregate Results

An analysis of aggregate results was done to estimate overall potential effects of the proposed ordinance. San Francisco's development pipeline, which tracks buildings for which permits have been applied for and for which construction has not been completed, was analyzed for the years 2008-2014. If all 200 of the analyzed projects were to install solar photovoltaic systems on 15% of their roof area, they would generate 10.5 GWh/yr of electricity, offsetting 16% of the projects' energy consumption over the lifetime of the photovoltaic panels. Assuming installation in 2015, they would also avoid 26.3 MT of CO_2 emissions over the projects' lifetimes. Stated another way, 15% of the rooftops of the relevant buildings in the city's building pipeline represent 434,000 square feet of potential solar area, or nearly 10 acres. This is sufficient area to install a total of almost 7.4 MW of solar generating capacity, providing 10.5 GWh of electric energy per year.

2 Introduction

The Commission on the Environment of the City and County of San Francisco passed resolution 009-14-COE in July 2014 supporting development of policies by the Department of the Environment "that would require the inclusion of solar energy systems on newly constructed buildings" (COE 2014). As part of its policy work, the Department has explored the possibility of an ordinance that would require photovoltaic systems on newly constructed residential and commercial buildings.

The Department sought to study the cost-effectiveness and other aspects of requiring photovoltaic systems in all new residential and commercial construction in the city. An ordinance that would require photovoltaic systems on buildings would require approval by the California Energy Commission (CEC). The CEC requires, as part of the approval process, that the city provide "findings and supporting analyses on the energy savings and cost effectiveness of the proposed energy standards" (CEC 2014). The Department commissioned this study to inform its work and to provide supporting documentation to the California Energy Commission for approval of the ordinance.

This study examined the cost-effectiveness of rooftop photovoltaic systems installed on newly constructed buildings in the City and County of San Francisco (CCSF). In addition, this study performed sensitivity analyses to assess alternative system sizes and the effects of different input values, evaluated the potential impact on carbon emissions, and estimated aggregate city-wide effects.

2.1 Cost Effectiveness

A project is considered to be cost-effective if its benefits are greater than its costs. This study used a participant cost test (PCT), which considers the benefits and costs to a participant in a project. The participants considered were the owners of newly constructed buildings with rooftop solar photovoltaic systems that provide electric energy which is consumed on-site. The components of the benefits and costs used in this study were consistent with those specified in California's Standard Practice Manual (OPR 2002).

The benefits to the participants were defined as the sum of:

- the value of the electricity generated by a photovoltaic system
- federal tax savings
- state tax savings

For residential systems, the federal tax savings consist of the Investment Tax Credit (ITC) and home mortgage deduction. For commercial systems, federal and state tax savings include accelerated depreciation and tax deductions due to expenses related to paying for and operating the system. Federal tax savings for commercial systems also include the value of the ITC. The cost of electricity to a commercial entity is normally deductible from its taxes. A photovoltaic system, however, reduces expenditure on electricity, and thus also reduces the tax deduction. Therefore, for commercial entities, the value of the generated electricity is reduced by the lost tax deduction.

The costs were defined as the sum of:

- purchase cost
- debt repayment (principal and interest)
- operation and maintenance expenditures
- insurance costs

All costs and benefits were discounted back to the initial project year using a nominal discount rate before the benefit-to-cost ratios were calculated.

Equation 1 shows the calculation of the benefit-to-cost ratio (BCR):

$$BCR = B/C$$

$$B = EV_{after\ tax} + TS_{federal} + TS_{state}$$

$$C = C_{O+M} + C_{insurance} + C_{debt}$$

$$EV_{after\ tax} = \begin{cases} EV \quad if\ residential \\ EV_{energy} \times (1 - TR_{effective})\ if\ commercial \end{cases}$$

BCR	Benefit-to-cost ratio
B	Sum of benefits to participant
$EV_{after\ tax}$	After-tax value of generated energy
EV	Before-tax value of generated energy
$TS_{federal}$	Federal tax savings
TS_{state}	State tax savings
$TR_{effective}$	Effective tax rate
C	Sum of costs to participant
C_{O+M}	Operations and maintenance costs
$C_{insurance}$	Insurance costs
C_{debt}	Debt repayment costs (principal and interest)

Equation 1 Calculation of benefit-to-cost ratio.

2.2 Uncertainty

The results of this study depend on a variety of inputs and modeling assumptions with a range of possible values and approaches. No single benefit-to-cost ratio can represent all potential scenarios. There is uncertainty and variability in the value of all of the input parameters. This uncertainty is magnified when dealing with projections of future conditions. For instance, the cost of purchasing a photovoltaic system depends on a variety of factors, including overall price trends and project and installer characteristics. Some of these factors depend on project characteristics, such as size, shading, and orientation of roof, which would affect the performance of a photovoltaic system. Other factors depend on global and local economic trends, such as debt-finance rates and solar panel costs.

Several approaches were taken in this study to address these limitations[1]. First, the values of the input parameters were chosen to reasonably reflect expected real-world conditions. Second, a variety of building models were used to represent some of the variability that is due to different energy consumption patterns and physical constraints. Third, approved and widely used software was used to generate the results. Fourth, sensitivity analyses were performed by varying the values of several parameters that were considered likely to affect the benefit-to-cost ratio. Fifth, the presentation of the results is meant to convey some of the range of uncertainty in this study.

2.3 Primary Assumptions

It was assumed that a single entity derives the full benefits, and pays the full costs, associated with owning and operating the modeled photovoltaic systems. This assumption is correct only for some situations. For instance, this assumption is accurate for a photovoltaic system installed on a single-family residence that is owner occupied, and where the system was purchased by the owner of the home. This assumption is not accurate when describing buildings with separately metered tenants who are not the owners of the photovoltaic system. In this situation, the owner of the photovoltaic system pays the cost of owning and operating the system. The owner should also benefit from tax deductions associated with paying for the system and from tax credits for installing the system. However, the owner would only benefit from the portion of energy used for common areas and owner-occupied areas. Excess generation would receive, at best, only relatively low net surplus compensation rates.

The analysis under the single-owner assumption could show whether it is cost-effective to install a photovoltaic system. Whether it is cost-effective for other cost/benefit allocation arrangements would depend on how those arrangements function and the extent to which any added overhead can be covered by the overall benefits of the system. There are some mechanisms, such as virtual net metering, that would allow tenants to benefit from reduced energy costs on their electric bills as a result of renewable generation. These alternative mechanisms, however, would not necessarily benefit the system's owner. It is possible that a third-party owned system could address these limitations, though such systems generally have higher costs (Barbour et al 2013).

This study is limited to exploring building models and photovoltaic systems. No actual project is modeled. Instead, this study examined a variety of prototypical buildings that were representative of some buildings in San Francisco, and which could therefore provide information to support work on the proposed ordinance. In addition, the building models were treated as single-use structures. Thus, for instance, the multifamily building model is treated as containing residential units only. Similarly, the large office building model is treated as if it were used only for typical office activities. In contrast, mixed-use buildings in San Francisco are not uncommon. These buildings could have a variety of uses, such as retail, residential, and office. Mixed-use buildings would have a different electric load profile compared to single use buildings, and this would affect the amount and timing of energy consumed as well as the value of that energy.

[1] Additional approaches, which were outside the scope of this study, could use statistical methods, such as Monte Carlo simulations, to model system and financial performance.

It was assumed that the only incentive available would be the federal ITC. Several state and local incentive programs were assumed to not be applicable for systems installed under the proposed ordinance. The California Solar Initiative (CSI) has provided incentives in past years for photovoltaic system installations (CSI 2014a). The CSI program, however, is not accepting new applications, and therefore would not apply to projects built in the future. CSI's Multifamily Affordable Solar Housing (MASH) program is also closed to new applications (MASH 2014). The California New Solar Homes Partnership (NSHP) program was assumed to be unavailable (NSHP 2014). Finally, following initial stakeholder feedback, it was assumed that San Francisco's GoSolarSF incentive program would also not be extended to include projects that would be required under the proposed ordinance (SFPUC 2014).

2.4 Modeling Framework

Analyses were performed for two future years in which photovoltaic systems might be required under the proposed ordinance. The first year selected was 2015, which was the earliest year in which it could be expected that the ordinance would come into effect. The second year was 2017, which was selected due to the expected change in the ITC. The ITC is a significant factor affecting the cost of photovoltaic systems. The ITC will be 30% through 2016, but in 2017 the ITC is expected to be reduced to 10% for commercial systems, and to be eliminated entirely for residential systems (NCSC 201a, NCSC 2014b).

Several data sets, sources, and components were used to perform the cost-effectiveness analysis, including:

- Prototypical building models
- Electric energy consumption profiles for each building
- Input parameters specifying model assumptions
- Simulation software
- Analysis process

Figure 4 shows an overview of the modeling framework.

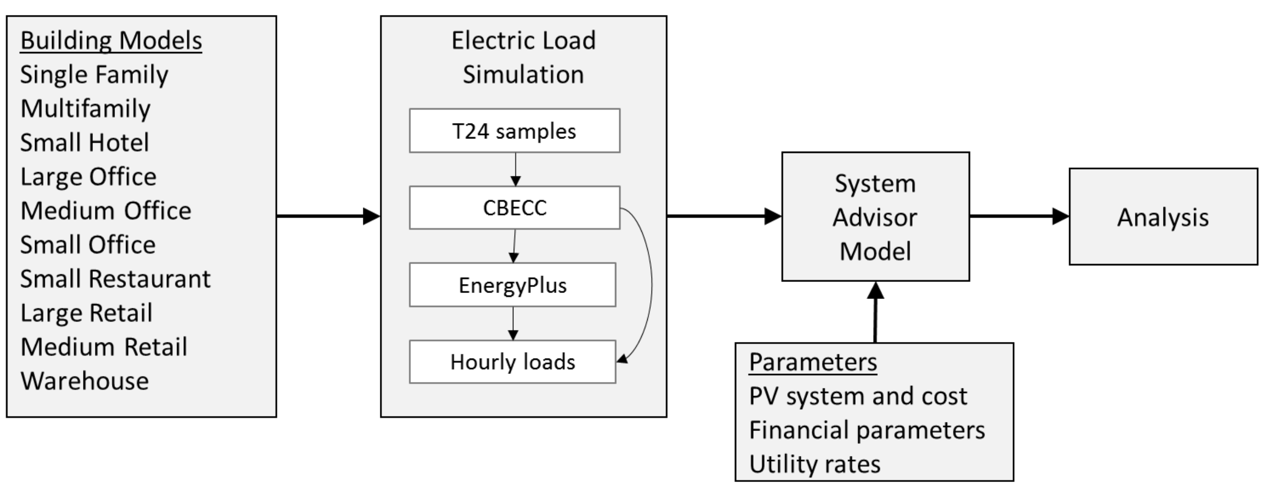


Figure 4 Overview of modeling framework.

A set of prototypical building models was selected to evaluate the cost-effectiveness of systems installed in future construction. These buildings were intended to be representative of a range of new construction that meets the current energy code standards in California, though they do not represent actual buildings or projects. Electric energy consumption profiles for each building were generated using building energy simulation software. In addition, a variety of other parameters affect the cost-effectiveness of photovoltaic systems. These parameters include first-costs, electric utility rate forecasts, and financial and tax parameters. Research was conducted to determine reasonable values for these parameters.

The energy consumption profiles and parameter values were input into the National Renewable Energy Laboratory's (NREL) System Advisor Model (SAM) software (NREL 2014 SAM). SAM "is a performance and financial model designed to facilitate decision making for people involved in the renewable energy industry". Version 2014.1.14 of SAM was used for this study. SAM performs simulations based on input parameters and its internal models to calculate output values associated with renewable energy projects. SAM generates a cash flow prediction for the specified analysis period, which includes the values needed to calculate the benefits and costs of a solar photovoltaic system. The output from SAM was summarized and analyzed in Excel.

3 Building Models and Projects

3.1 Buildings Models

This study models energy use in prototypical buildings. Several building types were selected to represent a range of uses and sizes of buildings that may be encountered in San Francisco. The building models specify physical features of the buildings and the end use of the occupied space, for instance, hotel or office. This information was used to estimate hourly energy usage in the buildings. The models also provide a constraint on the roof area relative to the building's total energy consumption, which is then used to set a limit on the size of the photovoltaic systems that could be installed on each building. The hourly energy usage is used in calculations of the amount of energy consumed and the value of the generated energy.

California's building energy codes specify requirements for energy use in buildings. The CEC has certified software to model compliance of buildings with its standards. Two software packages are freely available. CBECC-Res models compliance of residential buildings, while CBECC-Com models compliance of commercial buildings with the 2013 building energy standards (Wilcox B 2013, AEC 2013). Each program is provided with several sample input files that describe buildings that are compliant with the building energy standards. These sample files were used for the building models and to produce the electricity consumption models for this study.

Table 1 summarizes the physical characteristics of the modeled buildings, based on the sample files included with CBECC Com and Res.

Building	**Abbr.**	**Type**	**Floor area (ft^2)**	**Floors**	**Roof area (ft^2)**
Single Family	SFR	Residential	2,100	1	2,100
Single Family Low Income	SFR-LI	Residential	2,100	1	2,100
Multifamily	MF	Hybrid	6,960	2	3,480
Multifamily Common	MFC	Commercial	6,960	2	3,480
Small Hotel	Hotel	Commercial	42,554	3	14,185
Large Office	OffLrg	Commercial	498,589	12	41,549
Medium Office	OffMed	Commercial	53,628	3	17,876
Small Office	OffSml	Commercial	5,502	1	5,502
Small Restaurant	RstntSml	Commercial	2,501	1	2,501
Large Retail	RetlLrg	Commercial	240,000	1	240,000
Medium Retail	RetlMed	Commercial	24,563	1	24,563
Warehouse	Whse	Commercial	49,495	1	49,495

Table 1 Model buildings analyzed in this study.

Both commercial and residential buildings were modeled. Residential building models used residential electric rates (E1, EL1), residential Title 24 solar area requirements, and input parameters and tax considerations appropriate to residential owners. Commercial building models used commercial electric rates (A1, A10, E19), commercial Title 24 solar area requirements, and input parameters and tax considerations (including depreciation) appropriate to commercial owners.

Multifamily buildings were modeled as a hybrid of residential and commercial buildings. In multifamily buildings, rates are residential, but the ownership structure is commercial. The tenants in multifamily buildings are billed using residential rates. The financing and ownership of a multifamily building, however, are structured as commercial enterprises. Therefore, for this study, the residential electric utility rate was used for multifamily buildings, but all other simulation parameters (taxes, depreciation, etc.) used commercial values. In addition, the Multifamily Common building model broke out just the common area load of a multifamily building, which was then treated as a pure commercial model.

Table 2 summarizes the energy consumption characteristics of the building models. This table shows estimated annual total electric energy consumption for each building, as well as consumption normalized to the conditioned space and total roof area. It was assumed that electric load and hourly consumption patterns remained constant from year-to-year. In practice, electric load may be expected to vary over time as changes occur in the building, occupants, equipment, weather, etc.

Building	**Electric energy (kWh/yr)**	**Electric energy per unit floor area (kWh/ft^2/yr)**	**Electric energy per unit roof area (kWh/ft^2/yr)**
Single Family	4,560	2.2	2.2
Single Family Low Income	3,420	1.6	1.6
Multifamily	22,844	3.3	6.6
Multifamily Common	2,284	0.3	0.7
Small Hotel	161,971	3.8	11.4
Large Office	3,435,150	6.9	82.7
Medium Office	417,967	7.8	23.4
Small Office	57,479	10.4	10.4
Small Restaurant	61,427	24.6	24.6
Large Retail	1,847,380	7.7	7.7
Medium Retail	185,647	7.6	7.6
Warehouse	134,926	2.7	2.7

Table 2 Estimated annual electric energy consumption in modeled buildings.

Low income households were expected to have lower energy consumption than moderate and higher income households. Statewide household annual electricity consumption for moderate-income households ($25-$75K/yr) was reported as 5,887 kWh/yr, while for low-income households (<$25K) it was 4,313 kWh/yr, or 73% of moderate-income household consumption (KEMA 2010, Table ES-7, p33). To approximate the difference between low-income and moderate-income households, annual electricity consumption for the Single Family Low Income building model was scaled to 75% of the Single Family building model. For the Multifamily Common building model, which includes only estimated common area load, electricity consumption was scaled to 10% of the multifamily base case.

3.2 Hourly Energy Consumption

Electric energy costs and benefits depend on the time of generation and consumption of the energy due to a variety of factors, including:

- tiered and time of use rate structures, which depend on time of day and day of year;
- variable energy use in buildings, which vary by time, weather, and occupant behavior;
- photovoltaic energy output, which depends on insolation and weather.

To model costs and benefits, hourly resolution of energy consumption and generation was needed. This resolution provided a standard level of analysis, approximately matching utility rate structures and solar energy generation.

The programs CBECC-Res, CBECC-Com, and EnergyPlus were used to model total facility electric energy consumption at hourly resolution for the sample input files. EnergyPlus is an "energy analysis and thermal load simulation program" which, given a building's description, can model hourly facility electric energy usage (EERE 2014). CBECC-Res version 2013-3 (650), CBECC-Com version 2013-3 (653), and EnergyPlus version 8.1 were used in this study. To model total electricity consumption, software must make assumptions about installed equipment and occupant behavior that go beyond the loads and equipment regulated under California's energy codes. CBECC-Res provides as output total facility electric energy use. CBECC-Com does not provide total hourly electric energy consumption as an output. It does, however, generate data files that can be read by EnergyPlus ("IDF" files), which can then generate the needed consumption data.

The programs calculate energy consumption based on a model of the building and the location of the building. The location input is based on a typical meteorological year. For the residential buildings, which were analyzed with CBECC-Res, the CEC's climate data files for the San Francisco climate zone were used (CZ3). For commercial buildings, for which energy consumption data were generated with EnergyPlus, the closest typical meteorological year station was San Francisco International Airport (NREL 2014c). The sample files included with CBECC-Com were modified to refer to the San Francisco climate zone and to use ZIP code 94103. The orientation of buildings also affects their energy profile. It was assumed that the buildings were all south facing for purposes of this study.

3.3 Modeled Projects

Each building was modeled using a corresponding reference case. For the reference case, it was assumed that the roof area available for a solar photovoltaic system matches the area specified in the Title 24 2013 Solar Ready regulations (CEC 2013). The Solar Ready zone is a roof area that must meet certain requirements to facilitate installation of solar energy systems. These include size, orientation, and freedom from penetration and shading by equipment. For single-family residential buildings the solar ready zone is 250 ft^2, while for multifamily and commercial buildings it is 15% of total roof area. Title 24 allows for exemptions from the solar ready requirements, for instance, some commercial buildings over three stories are exempt. For purposes of this study, the basic Solar Ready area guidelines were applied to all buildings, without regard for possible exemptions. In addition, the area available for solar photovoltaic installation in commercial buildings was assumed to be 15% of total roof area, notwithstanding adjustments in the solar ready regulations (such as exclusion of skylights from the total area).

Table 3 summarizes the system sizes for each modeled building. The amount of energy offset by the systems over the course of a year ranges from 4% for the Large Office building model to 100% for the Single-Family Residential and Warehouse building models. The area of the systems in square feet and as a percentage of total roof area are also shown. For each system, the azimuth (orientation) of the system is shown, as well as total generation per year and generation per square foot of floor space per year.

The azimuth of a photovoltaic system has a significant impact on its energy generation. In addition, the azimuth affects the benefits from the energy because of the time-dependent nature of energy generation, consumption, and pricing. Depending on the building type, the optimal azimuth was either (approximately) 180^o or 210^o. The best value was determined empirically by running the simulation over several orientations and selecting the one with the greatest benefit-to-cost ratio. In practice, the Title 24 solar ready regulations allow a wider range of orientations, so that systems installed in the solar ready area may not be optimally oriented and therefore could have reduced cost-effectiveness.

Building	**Size (kW)**	**Electric energy offset**	**Area (ft^2)**	**Area (% roof)**	**Azimuth (^{o})**	**Tilt (^{o})**	**Per floor space (W/ft^2)**	**Generation (kWh/yr)**	**Generation per floor space ($kWh/ft^2/yr$)**
Single Family	3.2	100%	192	9.1%	180	20	1.5	4,560	2.2
Single Family Low Income	2.4	100%	144	6.9%	180	20	1.1	3,420	1.6
Multifamily	8.9	55%	522	15.0%	180	33	1.3	12,651	1.8
Multifamily Common	1.6	100%	94	2.7%	180	33	0.2	2,284	0.3
Small Hotel	36	31%	2128	15.0%	210	33	0.8	51,000	1.2
Large Office	105	4%	6232	15.0%	210	33	0.2	149,386	0.3
Medium Office	45	15%	2681	15.0%	210	33	0.8	64,271	1.2
Small Office	14	34%	825	15.0%	210	33	2.5	19,782	3.6
Small Restaurant	6.4	15%	375	15.0%	180	33	2.6	9,092	3.6
Large Retail	606	47%	36000	15.0%	210	33	2.5	862,896	3.6
Medium Retail	62	48%	3684	15.0%	210	33	2.5	88,314	3.6
Warehouse	95	100%	5567	11.2%	180	33	1.9	134,926	2.7

Table 3 Photovoltaic system sizes and related parameters for the modeled projects.

3.3.1 System Sizing

For each building model, a photovoltaic system size was specified based on the available roof space, the energy density of the photovoltaic system (see 4.2 Photovoltaic System Performance on page 26), and the modeled electric energy consumption of the building. The system size was limited to the lesser of the available space and the total electric energy consumption of the building, as shown in Equation 2.

$$S = A_{system} \times D_{DC}$$

$$A_{system} = \min(C/D_{AC}, A_{available})$$

$$A_{available} = \begin{cases} 250 ft^2 \ if\ single\text{-}family\ residential \\ 15\%\ roof\ area\ if\ commercial \end{cases}$$

S	Rated (DC) system size (kW)
A_{system}	Area of system (ft^2)
$A_{available}$	Available roof area (ft^2)
C	Building energy consumption (kWh/yr)
D_{DC}	DC power density of photovoltaic system (kW/ft^2)
D_{AC}	AC power density of photovoltaic system (kWh/ft^2/yr)

Equation 2 Calculation of photovoltaic system size.

4 Input Parameters

A variety of parameters were needed to specify the modeled projects, in addition to the building models described previously. The building models provided constraints on roof area and, through simulations, hourly electric energy consumption data. The additional parameters included:

- general parameters specifying the location and analysis period;
- parameters affecting initial purchase cost and ongoing maintenance costs of the photovoltaic systems;
- parameters specifying the performance of the photovoltaic systems;
- financial parameters, including debt terms, taxes, insurance, inflation, discount rate, incentives, and depreciation;
- utility rates and annual escalation rates.

Table 4 summarizes the input parameters used in this study for the reference scenario. Several parameters, such as azimuth and discount rate, were specific to individual building models. The following sections describe these parameters in more detail and the derivation of their values.

Category	Parameter	Residential (single-family)	Residential (low income)	Commercial	Sources and notes
General	Location and weather	SF Intl. Airport, CEC CZ3	SF Intl. Airport, CEC CZ3	SF Intl. Airport	NREL TMY3, CEC CZ3
	Analysis period	25	25	25	Various
PV Cost	$/W in 2015	$5.20 (<10 kW) $4.50 (≥10 kW)	$5.20 (<10 kW) $4.50 (≥10 kW)	$4.58 (<10 kW) $4.64 (≥10 kW)	CSI, forecast
	$/W in 2017	$4.53 (<10 kW) $3.85 (≥10 kW)	$4.53 (<10 kW) $3.85 (≥10 kW)	$3.90 (<10 kW) $4.01 (≥10 kW)	CSI, forecast
	Inverter replacement	10%	10%	10%	10% of initial cost at 10 and 20 years, inflation adjusted
PV System	DC→AC derate	0.77	0.77	0.77	PV Watts
	Module efficiency	17%	17%	17%	Estimate
	Annual degradation	0.50%	0.50%	0.50%	SAM
	Sun hours per year	1850	1850	1850	PV Watts
	Sun hours per day	5.07	5.07	5.07	PV Watts
	Tilt	20°	20°	33°	SAM
	Azimuth	180°	180°	180° or 210°	Most cost-effective azimuth depends on building
	Availability	100%	100%	100%	
PV Output	AC power (W/ft^2)	12.8	12.8	13.1	At 180°
	AC energy (kWh/ft^2/yr)	23.7	23.7	24.2	At 180°
Financial	Debt proportion	80%	80%	70%	Realty Rates
	Debt term	25	25	25	Same as analysis period
	Debt rate	5.00%	5.00%	5.00-6.72%	Realty Rates
	Federal tax rate	25%	15%	35%	Tax tables, median income
	State tax rate	8%	4%	8.84%	Tax tables, median income
	Sales tax rate	8.75%	8.75%	8.75%	SF tax
	Insurance rate	0.50%	0.50%	0.50%	SAM
	Inflation rate	2.50%	2.50%	2.50%	SAM
	Real discount rate	8.00%	8.00%	6.5-7.9% (2015) 6.9-8.2% (2017)	IRR survey
	ITC in 2015	30%	0%	30%	
	ITC in 2017	0%	0%	10%	
	Depreciation	N/A	N/A	5 yr MACRS	
Utility rates	Schedule	E1 Region T	EL1	A1, A10, E19 TOU primary	PG&E
	Escalation	2.11% real through 2020, 1.42% thereafter			E3
	NSC at end of 2015	0.06278			PG&E, forecast
	NSC at end of 2017	0.08341			PG&E, forecast

Table 4 Summary of input parameters.

4.1 Photovoltaic System Cost

The cost of the photovoltaic systems has a significant impact on cost effectiveness. There is a first cost to purchase and install a system, which is represented as a normalized cost per watt. This is then multiplied by the nameplate (DC) rating of the modeled systems to arrive at a purchase cost. In addition, periodic maintenance costs due to inverter replacement were also modeled.

4.1.1 Cost Per Watt

This study uses forecasted costs of solar systems to estimate the cost of installing solar systems in new construction. Price forecasts were estimated for the residential and commercial sectors for small (<10 kW) and medium-size (10 - 100 kW) photovoltaic systems. The forecasted prices for 2015 and 2017 are shown in the table below.

Year	Residential		Commercial	
	< 10 kW	10-100 kW	< 10 kW	10-100 kW
2015	$5.20	$4.50	$4.58	$4.64
2017	$4.53	$3.85	$3.90	$4.01

Table 5 Forecasted cost per watt for the initial study years.

Past system prices from the California Solar Initiative (CSI) were analyzed for the residential and commercial sectors. The historic price changes were used to forecast prices in subsequent years by fitting an exponential growth curve to the historic data. Data for commercial and medium-sized systems in San Francisco were lacking, so an adjustment factor was derived to account for differences between statewide costs and the cost of solar in San Francisco. A new construction adjustment factor was also added to each forecasted price, to account for the expected reduced cost of installation in new construction.

4.1.1.1 Analysis of statewide cost per watt

Data from the CSI were analyzed to determine the average cost per watt of solar systems (CSI 2014b). The September 30, 2014 CSI working data set was used in this study. Average costs per watt were calculated for small residential systems in San Francisco and for small and midsize residential and commercial systems throughout California for the years 2007 through 2014. Data for completed systems ranging in size from 0-10 kW and 10-100 kW were used. Outliers, defined as costs per watt more than three standard deviations from the annual mean of the statewide commercial or residential data, were also excluded. Data for third-party systems were excluded due to reported irregularities in these data and reporting of third-party prices based on appraised value (E3 2011, Barbose et al 2013). In addition, this study examined single-owner photovoltaic systems, so that third-party pricing models were less applicable. The average statewide costs per watt for each year are shown in Table 6 below.

	Year	Residential (<10 kW)	Residential (10-100 kW)	Commercial (<10 kW)	Commercial (10-100 kW)
Average cost	2007	$8.03	$7.81	$7.70	$8.13
	2008	$8.11	$7.66	$8.29	$7.53
	2009	$7.93	$7.40	$7.86	$7.45
	2010	$7.39	$6.40	$6.83	$6.24
	2011	$6.89	$5.99	$5.77	$5.71
	2012	$6.13	$5.07	$5.26	$5.15
	2013	$5.03	$4.53	$4.62	$4.43
	2014	$4.78	$4.33	$4.44	$4.85
Forecast	2015	$4.61	$3.92	$4.00	$4.06
	2016	$4.25	$3.57	$3.63	$3.71
	2017	$3.92	$3.25	$3.29	$3.40

Table 6 Average statewide costs per watt and forecasted costs for 2015-2017.

Only small sample sizes were available for commercial and midsize residential systems in San Francisco. In addition, the data for commercial systems in San Francisco were much less consistent than the data for the other sectors and geographic regions. Data for only a few commercial systems were available for San Francisco, and there were years for which data were available for only one system. In addition, the commercial data exhibited erratic rises and falls that were not consistent with overall solar market behavior. Therefore, the data for commercial and midsize residential systems in San Francisco were not used for forecasting.

4.1.1.2 Calculation of statewide to San Francisco adjustment factor

To derive a cost for the commercial and for midsize residential systems in San Francisco, the assumption was made that the difference between the average statewide small residential costs to San Francisco small residential costs in each year would be representative of the difference in costs for installations in San Francisco overall. The difference in each year was then added to the forecasted costs for the four categories (small/midsize commercial and small/midsize residential) to derive a value for San Francisco. The calculation of these adjustment factors for each year is shown in Table 7 below.

	Year	San Francisco residential (<10 kW)	California residential (<10 kW)	CA to SF adjustment
Average cost	2007	$9.08	$8.03	$1.05
	2008	$8.89	$8.11	$0.78
	2009	$8.53	$7.93	$0.60
	2010	$8.25	$7.39	$0.86
	2011	$7.85	$6.89	$0.96
	2012	$8.07	$6.13	$1.94
	2013	$6.34	$5.03	$1.31
	2014	$5.83	$4.78	$1.05
Forecast	2015	$5.95	$4.61	$1.33
	2016	$5.60	$4.25	$1.35
	2017	$5.28	$3.92	$1.36

Table 7 Calculation of California to San Francisco adjustment factor.

4.1.1.3 Calculation of new construction adjustment factor

An additional adjustment factor was used to account for installation in new construction. The analyzed cost per watt based on the CSI data reflects the cost of installation in existing buildings. The proposed ordinance under study, however, was for new construction. Installation of solar systems on new residential construction is expected to be less costly than retrofit installation (Barbose et al 2013). Data on solar system costs in new construction are not readily available. Therefore, an estimate was derived of the difference in costs between retrofit and new construction, and this estimate was used to adjust all forecasted retrofit prices to forecasted new construction prices.

Tracking the Sun VI provides cost data for new versus retrofit construction based on California's New Solar Home Partnership (Barbose et al 2013, figure 28, p35). The table below shows the costs per watt for new construction and retrofit construction in new homes, along with their differences. The average difference of the cost per watt for new versus retrofit installation from 2008-2012 was -$0.75. This average was added to the forecasted cost per watt in existing construction to determine the cost in new construction. In addition, since data for installation on new commercial systems was not available, the same value was used for both residential and commercial costs.

Year	New	Retrofit	Difference
2008	$8.00	$8.70	-$0.70
2009	$7.40	$8.50	-$1.10
2010	$7.00	$7.50	-$0.50
2011	$6.10	$6.80	-$0.70
2012	$5.30	$6.00	-$0.70
		Average	-$0.75

Table 8 Difference of average cost per watt for residential new construction and retrofit installation for the years 2008-2012.

The Title 24 2013 Solar Ready requirements reduce the cost of retrofit installation of solar systems on solar ready buildings. These solar ready requirements were estimated to reduce the costs of solar installations in new single-family residential construction from $2,687 to $182, a savings of $2,505 (CASE 2011, figure 45, p90). The NSHP data, which were available through 2012, apply to structures that were not solar ready. Therefore, the difference in cost may be less significant, reducing the cost advantage of installation in new construction. This adjustment was not factored into the adjustment used for this study.

4.1.2 Maintenance Costs

SAM's default annual maintenance costs of $20/kW/yr were retained for this study. SAM does not, however, include the cost of inverter replacement. Inverters were assumed to require replacement 10 years after being placed in service. For the 25 year analysis period, inverter replacement was expected to occur in years 10 and 20 and it was assumed that new inverters represent 10% of a total PV project's cost (see, e.g., Borenstein S 2011). As an estimate of the maintenance cost due to inverter replacement, 10% of the projects' initial cost were inflated to current dollars at years 10 and 20, and applied as a cost in the simulations in SAM for those years.

For instance, assuming a $20,000 total initial system cost in year 0, the cost of the inverter would be 10% x $20,000 = $2,000. At an inflation rate of 2.50%, after 10 years inverter replacement would cost 28% more in current dollars (1.28x) or $2,560 and after 20 years it would cost 64% more (1.64x) or $3,280.

While it is entirely possible that the future price of inverters will be lower given improvements in inverter technology, no attempt was made to derive a value based on future market changes. A reduction in price in real terms of 2%/yr may be reasonable (Borenstein S 2011). In addition, inverter replacement should result in an increase in efficiency. The model in SAM assumes a constant percent degradation in system output year-to-year. This study does not include an offset to increase system production following inverter replacement.

4.2 Photovoltaic System Performance

Generic photovoltaic systems were modeled using NREL's PV Watts model and System Advisor Model (SAM) software (NREL 2014a,b). PV Watts provides information on solar power and energy based on location, system tilt, azimuth, and system performance characteristics. Values for San Francisco were calculated for the tilt and azimuth combinations that were modeled for this study. As a simplifying assumption, it was also assumed that all of the roof area allocated for the systems was covered in panels. Table 9 below summarizes the system performance parameters.

Parameter	Values
Tilt (^{o})	20, 33
Azimuth (^{o})	180, 210
Panel efficiency	0.17
AC to DC derate	0.77
Annual degradation	0.5%

Table 9 Summary of parameters for the modeled photovoltaic systems' tilt, azimuth, and efficiency.

SAM's defaults for tilt were used, with 20^o assumed for residential systems and 33^o for commercial systems. The azimuth was either 180^o or 210^o. An azimuth of 180^o results in more cost-effective systems for some buildings, while an azimuth of 210^o is more cost-effective for other buildings. The choice of azimuth was initially set at 180^o, and then changed to 210^o for those buildings where sensitivity analysis showed a more cost-effective outcome at 210^o.

Panels vary in the efficiency with which they convert solar radiation to electricity. Higher efficiencies yield greater power density, such that a smaller area covered with solar panels can generate the same amount of energy as a system using lower efficiency panels. A panel efficiency of 17%, which is within the range of systems currently available on the market, was used for this study.

Solar systems also vary in the efficiency with which they convert the DC electricity produced by the panels into AC electricity, known as the DC to AC derate factor. This factor depends on a variety of system characteristics. A default value of 0.77 was used for this study, which is the default value in both PV Watts and SAM.

Photovoltaic systems degrade over time, producing less energy with each passing year. The SAM-default system degradation rate of 0.5%/yr was used for the model.

Table 10 shows the insolation, power, and energy densities for the modeled generic systems, which were calculated using PV Watts and the above parameters. The power and energy densities determine the amount of generation that can be installed in a given area of a roof.

Azimuth (^{o})	Tilt (^{o})	Insolation (W/ft^2)	DC power (W/ft^2)	AC power (W/ft^2)	DC energy (kWh/ft^2/yr)	AC energy (kWh/ft^2/yr)
180	37.6	99.9	17.0	13.1	31.4	24.2
180	33	100.1	17.0	13.1	31.5	24.2
180	20	98.1	16.7	12.8	30.8	23.7
210	37.6	98.6	16.8	12.9	31.0	23.9
210	33	99.0	16.8	13.0	31.1	24.0
210	20	97.3	16.5	12.7	30.6	23.6

Table 10 Power and energy densities for the modeled systems' azimuths and tilts.

4.3 Financial Parameters

A variety of financial parameters affect the analysis results and are required as inputs to SAM. The financial parameters specific to the individual model buildings used in this study are summarized in Table 11 below.

Building	Discount rate in 2014 (real)	Discount rate change per year (%/yr)	Loan interest rate	Debt proportion	Federal tax rate	State tax rate	ITC (2015)	ITC (2017)
Single Family	8%	0%	5.00	80%	25%	8%	30%	0%
Single Family Low Income	8%	0%	5.00	80%	15%	4%	0%	0%
Multifamily	6.3%	0.21%	5.00	70%	35%	8.84%	30%	10%
Multifamily Common	6.3%	0.21%	5.00	70%	35%	8.84%	30%	10%
Hotel Small	7.5%	0.12%	5.80	70%	35%	8.84%	30%	10%
Office Large	6.5%	0.21%	5.38	70%	35%	8.84%	30%	10%
Office Medium	6.5%	0.21%	5.38	70%	35%	8.84%	30%	10%
Office Small	6.5%	0.21%	5.38	70%	35%	8.84%	30%	10%
Restaurant Small	7.0%	0.12%	6.72	70%	35%	8.84%	30%	10%
Retail Large	7.8%	0.12%	5.25	70%	35%	8.84%	30%	10%
Retail Medium	7.0%	0.12%	5.25	70%	35%	8.84%	30%	10%
Warehouse	6.8%	0.12%	5.25	70%	35%	8.84%	30%	10%

Table 11 Summary of financial parameters used for each building model type.

Additional financial parameters common to all modeled projects are summarized in Table 12.

Parameter	Value
Inflation rate	2.50%
Insurance rate	0.5%
Property tax rate	0%
Debt term	25 years
Depreciation schedule (commercial only)	5 year MACRS

Table 12 Summary of financial parameters applicable to all buildings.

4.3.1 Financial Parameter Alternatives

Individual parameter values can have a range of plausible values. Several parameters in particular may have significant impact on the cost-effectiveness outcome. These include the:

- debt fraction, which is the proportion of a project funded by debt
- debt rate, which is the interest rate charged on the debt

- discount rate

Table 13 lists five groups of options for these parameters for commercial buildings. These options are described below.

- **Reference scenario**: For the reference scenario the intent was to use values for the parameters that represent typical real world conditions. Therefore, the reference scenario uses recent market-specific industry survey data as a basis for these parameters. Industry surveys provided values for the debt rate and discount rate for different property types. For the debt fraction, an approximate average of surveyed values was used.
- **Industry surveys**: Integra Realty Resources (IRR) and Realty Rates (RR) each publish industry surveys on financing of commercial properties (Integra Realty Resources 2014a-e, Realty Rates 2014). IRR's data are further specified for particular property types in San Francisco. These data were used in the reference scenario.
- **E3 study**: Energy and Environmental Economics (E3) performed a study on the cost-effectiveness of rooftop photovoltaic systems in California (E3 2013).
- **NREL (System Advisor Model):** NREL based the default financial parameters in SAM on a variety of sources, with a focus on national long-term averages (NREL 2014a). The values listed in Table 13 were the defaults in SAM.
- **SF Environment staff proposal**: The San Francisco Department of the Environment proposed values that staff believes are appropriate for evaluating the cost-effectiveness of the proposed ordinance.

	Reference scenario	**Industry surveys**	**E3 study**	**NREL (System Advisor Model)**	**SF Environment staff proposal**
Source focus	New construction	Commercial real estate financing	Rooftop PV in new construction	Analysis software	New construction
Debt fraction	70%	70%	40 - 55%	100%	100%
Debt rate	5.0-6.7%	5.0-6.7%	6.80%	7.5%	5%
Discount rate	6.5-7.9% (2015) 6.9-8.2% (2017)	6.3-7.8% (2014) +0.12-0.21%/yr	6.13%	5.2%	4%
Inflation rate	2.5%			2.5%	2%

Table 13 Alternatives for several financial parameters. Industry surveys from Realty Rates and Integra Realty Resources. E3 study specified equity fraction of 45 to 60%, depending on year. NREL SAM values are defaults for new commercial model files. Discount rates are real rates.

4.3.2 Discount Rates

The discount rate is "used to calculate the present value of a future payment" (Short et al 1995). The specific discount rate used in an analysis can have a significant impact on the cost effectiveness of financial decisions. There is no single discount rate used by all individuals, and there are a variety of methods for calculating or selecting a discount rate. Ultimately, the choice of discount rate is highly dependent on individual circumstances and decisions. This study uses different discount rates for the residential and commercial models. The residential discount rate used in this study was 8%, which was the default value in SAM. For the commercial models, the discount rates were based on industry surveys and depended on the type of building being modeled.

The commercial discount rates used in this study were based on a survey of firms involved in the real estate industry. Integra Realty Resources (IRR) publishes industry surveys for the San Francisco commercial real estate market (Integra Realty Resources 2014a-e). Surveys for the industrial, lodging, multifamily, office, and retail real estate sectors are published annually and mid-year. The survey data include real discount rates for several property classes and types. The discount rates for the highest-class (i.e., class A) property types that most closely matched the types of buildings modeled in this study were used. In addition, the surveys included a range of forecasted changes in the discount rate over a 36 month period. The midpoint of the forecasted change was used to forecast discount rates in the modeled years 2015 and 2017. Table 14 summarizes the discount rates used in this study to model commercial systems.

Building name	**IRR property type**	**Discount rate (real, mid-2014)**	**Change per year (%/yr)**
Multifamily	Multifamily Urban Class A	6.3%	0.21%
Multifamily Common	Multifamily Urban Class A	6.3%	0.21%
Hotel Small	Lodging Full service	7.5%	0.12%
Office Large	Office CBD Class A	6.5%	0.21%
Office Medium	Office CBD Class A	6.5%	0.21%
Office Small	Office CBD Class A	6.5%	0.21%
Restaurant Small	Retail Community	7.0%	0.12%
Retail Large	Retail Mall	7.8%	0.12%
Retail Medium	Retail Community	7.0%	0.12%
Warehouse	Industrial Class A	6.8%	0.12%

Table 14 Real discount rates and forecasted change per year used for each commercial building model. Rates are based on those reported in Integra Realty Resources (IRRs) midyear viewpoints for the San Francisco market for several commercial real estate types.

4.3.3 Debt Parameters

A debt term of 25 years was used for both residential and commercial systems, the same as the analysis period, which corresponds to the typical expected lifetime of a photovoltaic system. The residential debt rate used was 5%, corresponding to typical long-term mortgage rates. This was also the default rate in SAM. The residential debt proportion was 80%, which corresponds to standard mortgage practices.

For commercial properties, published survey data were used for debt parameters. Realty Rates' publishes an Investor Survey (RRIS, Realty Rates 2014) with data on permanent financing for several commercial real estate property types. The data include interest rates and loan-to-value ratios. The property types in the RRIS were assigned to the most closely matching building models used in this study, along with the corresponding loan-to-value ratio and interest rate. The proportion of debt to system cost for commercial properties is based on an average loan to value ratio from the RRIS. An approximate average loan to value ratio of 70% was used as the debt proportion.

Building name	**RRIS property type**	**Loan interest rate**	**RRIS Loan to value ratio**
Multifamily	Apt	5.00	0.73
Multifamily Common	Apt	5.00	0.73
Hotel Small	Lodging	5.80	0.67
Office Large	Office	5.38	0.73
Office Medium	Office	5.38	0.73
Office Small	Office	5.38	0.73
Restaurant Small	Restaurant	6.72	0.64
Retail Large	Retail	5.25	0.70
Retail Medium	Retail	5.25	0.70
Warehouse	Self storage	5.25	0.69

Table 15 Debt parameters for each building model. The rates are based on survey data from the Realty Rates Investor Survey (RRIS). A debt fraction of 70% was used for all buildings, which is close to the average RRIS loan-to-value ratio.

4.3.4 Tax Parameters

Marginal tax rates have a significant impact on cost-effectiveness, as they affect the tax deductions available to individuals and companies. Commercial entities can deduct expenses for purchasing and operating a system. Residential owners pay for a system that is included in new construction as part of their home mortgage, and interest payments on home mortgages are tax deductible (IRS 2014).

For residential customers who are not low income, the federal and state tax rates were based on the tax rate for the median family income in San Francisco. The median family income in San Francisco for 2008-2012 was $73,802 (U.S. Census Bureau 2014). The marginal federal tax rate for couples filing jointly and earning the median income was 25% (Bankrate 2014). The marginal state tax rate for couples filing jointly was 6% for taxable income between $57,990 and $80,500 (FTB 2014).

For low income residential customers, tax rates were based on the tax rate for families qualifying for CARE electric rates in PG&E's service territory. For a four person household, the maximum gross annual income to qualify for CARE rates is $47,700 (PGE 2014a). At this income level, the marginal federal tax rate was 15% in 2014. The marginal state tax rate for couples filing jointly was 4% for taxable income between $36,742 and $57,900 (FTB 2014).

For commercial customers, a marginal federal tax rate of 35% was used. This is also the default value in SAM. The California state tax for corporations other than banks and financials was 8.84% (FTB 2014).

The sales tax rate for San Francisco was 8.75%, and applies to residential and commercial owners (BOE 2014).

4.3.5 Investment Tax Credit (ITC)

The investment tax credit (ITC) has a significant impact on the cost-effectiveness of systems, as it represents a large reduction in the cost of the system. The ITC is received as a credit against taxes in the first year that a system is installed. The ITC is 30% of system cost through 2016, and is expected to be reduced in 2017: to 10% for commercial systems and eliminated entirely for residential systems (NCSC 2014a, NCSC 2014b). To fully realize the value of the ITC requires that the beneficiary have sufficient tax liability. For this study, for both residential and commercial customers, the ITC rate used was 30% for systems installed in 2015. For systems installed in 2017, the commercial rate was 10% and the residential rate was 0%. It was also assumed that low income residential customers would not benefit from the ITC since they would not have sufficient tax liability, so an ITC rate of 0% was used for those customers in both 2015 and 2017.

4.3.6 Other Financial Parameters

Several additional financial parameters were used (see Table 12 on page 28 for a summary of these values):

- An inflation rate of 2.50% per year is assumed for the analysis (SAM default). A long-term average is used for the inflation rate since it applies to the full analysis period. For comparison, the average inflation rate for 2010-2012 was 2.29% (Inflation Data 2014).
- For commercial customers, a 5 year Modified Accelerated Cost Recovery System (MACRS) tax depreciation schedule was used for both federal and state tax purposes.
- An insurance rate of 0.5% per year was used (SAM default).
- Photovoltaic systems are exempt from property taxes in California (NCSC 2014c), so a rate of 0% was used for property taxes.

4.4 Utility Rates

4.4.1 Utility Rate Schedules

Table 16 above summarizes the rate schedules and options used for each building for PG&E electrical service (PGE 2014b). The rates used were based on those current as of October 1, 2014. Annual building electricity consumption is shown for reference, since the applicability of commercial schedules depends on annual consumption. For purposes of this study, it was assumed that utility rate structures would remain unchanged for the analysis period, but that utility rates would escalate annually at a rate greater than inflation.

Building	Consumption (kWh/yr)	Rate schedule	Rate options
Single Family	4560	E1	Baseline region T
Single Family Low Income	3420	EL1	
Multifamily	22844	E1	Baseline region T
Multifamily Common	2284	A1	Time of use
Hotel Small	161971	A10	Time of use, primary voltage
Office Large	3435150	E19	Time of use, primary voltage
Office Medium	417967	A10	Time of use, primary voltage
Office Small	57479	A10	Time of use, primary voltage
Restaurant Small	61427	A1	Time of use
Retail Large	1847380	E19	Time of use, primary voltage
Retail Medium	185647	A10	Time of use, primary voltage
Warehouse	134926	A1	Time of use

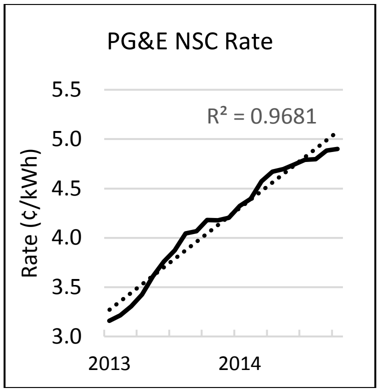
Table 16 Utility rates and options for each building model.

Electric rates were escalated annually at a real rate of 2.11%/yr from 2012-2020, and at a real rate of 1.42%/yr thereafter (E3 2013). These escalation rates were based on an analysis using the E3 RES Calculator by Energy and Environmental Economics (E3) for the California Air Resources Board. The October 2014 utility rates were then inflated to the modeled years (2015 and 2017) using the nominal escalation rate, before being imported into SAM.

4.4.2 Net Energy Metering Rates

Net Energy Metering (NEM) provides a monthly bill credit, at retail rates, for power generation in excess of consumption. In addition, there is an annual payment at the Net Surplus Compensation rate (NSC) for excess generation. The NSC rate is set by the utility for all customers. NEM rules currently limit participation based on capacity. For purposes of this study, it was assumed that all customers would be able to participate in NEM. In addition, it was assumed that the NEM and NSC structure would remain unchanged. The NEM rate schedule used was the same as the customers' regular rate schedule.

NSC payments are modeled by SAM using a calendar year; therefore, forecasts of the NSC rate were done for December of the first year of the simulations. PG&E provides past NSC rates for January 2012 through October 2014 (PGE 2014c). For the period January 2012 through December 2012 the NSC rates declined. From January 2013 through October 2014 the rates increased at a near linear rate. A linear trend line was fitted to the data from January 2013 through October 2014 (R^2 0.9681), and used to forecast the NSC rate in December of the modeled years. These data were plotted in Figure 5 below, which also shows the NSC rate forecasts. In this study, it is unlikely that there would be excess generation at the end of the simulated years since the modeled systems are sized up to maximum annual consumption.



Year	NSC (¢/kWh)
2015	6.278
2017	8.341

Figure 5 The graph on the left shows the Net Surplus Compensation (NSC) rates for the period January 2013 through October 2014. A linear trendline (dotted) was fitted to the data. The table on the right shows the forecasted NSC rates for December of each of the initial simulation years. The forecast was extrapolated using the linear regression line.

5 Results

5.1 Cost Effectiveness

Several scenarios were analyzed for cost-effectiveness, as summarized in Table 17 below. The scenarios were selected to represent different potential conditions as well as perceptions of market conditions. The scenarios cover only a small subset of all possible values, and are not presented as exhaustive of all foreseeable conditions.

Scenario	Description
Reference	Parameter values were as described previously.
All Debt	The entire project was funded with debt.
< Cost	Lower cost scenario. The debt rate and cost per watt were decreased by 10%.
> Cost	Higher cost scenario. The debt rate and cost per watt were increased by 10%, while system availability was decreased by 10%.
SFE	Values for debt fraction (100%), debt rate (5%), and discount rate (4%) were specified by the San Francisco Department of the Environment.

Table 17 Scenarios analyzed for cost-effectiveness.

Simulations were run using SAM for each building, scenario, and year, and the resulting benefit-to-cost ratios (BCRs) were calculated. The results of the simulations are presented in the tables below for the simulation years 2015 and 2017, respectively. The BCRs are color-coded to indicate some of the uncertainty in the results. Values that are more cost-effective (>1.0) are colored in deeper shades of green, values that are close to 1.0 (breakeven) are yellow, and values that are less cost-effective (<1.0) are colored in deeper shades of red. The results were sorted in decreasing BCR order for the 2015 reference case.

Building (2015)	Reference	All Debt	< Cost	> Cost	SFE
Single Family	1.84	2.11	2.03	1.56	1.95
Multifamily	1.60	1.81	1.72	1.43	1.69
Single Family Low Income	0.92	1.06	1.04	0.75	1.03
Warehouse	1.14	1.31	1.19	1.06	1.20
Multifamily Common	1.13	1.30	1.19	1.06	1.19
Small Restaurant	1.11	1.25	1.17	1.03	1.21
Large Office	1.11	1.27	1.16	1.03	1.17
Medium Office	1.06	1.22	1.11	1.00	1.12
Large Retail	1.05	1.25	1.10	1.00	1.09
Medium Retail	1.05	1.22	1.09	0.99	1.09
Small Hotel	1.04	1.21	1.09	0.98	1.09
Small Office	1.04	1.19	1.09	0.98	1.10

Table 18 Benefit-to-cost ratios (BCRs) for each building and scenario for the year 2015. Color coding indicates approximate degree of cost-effectiveness. Values sorted by BCR of reference scenario in 2015.

Building (2017)	Reference	All Debt	< Cost	> Cost	SFE
Single Family	1.78	2.04	2.00	1.44	1.98
Multifamily	1.65	1.88	1.79	1.44	1.77
Single Family Low Income	1.09	1.26	1.23	0.89	1.22
Warehouse	1.08	1.25	1.14	0.99	1.16
Multifamily Common	1.08	1.26	1.15	1.00	1.16
Small Restaurant	1.07	1.21	1.13	0.97	1.19
Large Office	1.05	1.22	1.11	0.96	1.14
Medium Office	0.99	1.15	1.05	0.91	1.07
Large Retail	0.96	1.15	1.01	0.90	1.03
Medium Retail	0.97	1.13	1.02	0.89	1.04
Small Hotel	0.96	1.12	1.00	0.89	1.03
Small Office	0.97	1.12	1.02	0.89	1.04

Table 19 Benefit-to-cost ratios (BCRs) for each building and scenario for the year 2017. Values sorted by BCR of reference scenario in 2015.

The ranking of the BCRs remained fairly consistent across the scenarios and the two modeled years, even as the BCRs varied. Thus, the residential buildings (single- and multifamily) have the highest BCRs, driven mainly by the higher retail rates residential customers pay for electricity. The commercial buildings varied in their energy consumption patterns, utility rates, financial parameters, and system sizes, all of which drove the variation in their BCRs. The Warehouse building model consistently had the highest BCR of the commercial buildings, while the Small Office and Small Hotel building models had the lowest BCRs, and thus present the greatest challenge to ensuring cost-effectiveness.

Figure 6 shows the BCR ratios for the residential (left) and commercial (right) building models for the reference scenario in 2015 and 2017, showing the BCRs for the individual building models.

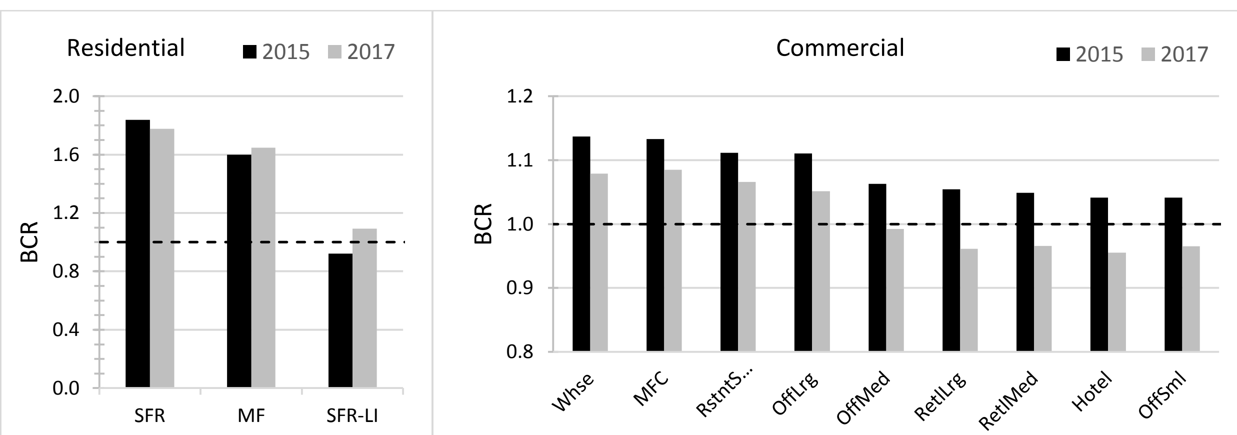


Figure 6 Benefit-to-cost ratios for the residential (left) and commercial (right) building models for the reference scenario in 2015 and 2017.

5.1.1 Interpretation of cost-effectiveness results

The results presented above do not provide a clear-cut answer to the question of cost-effectiveness for all building models. The cost-effectiveness threshold and BCRs could be interpreted as precise single values. Alternatively, they could be interpreted as point estimates drawn from a population of possible values having some probability distribution. The latter interpretation is more representative of the uncertainty inherent in forecasting future conditions.

When interpreted as precise single values, any BCR that is greater than 1.0 would be interpreted as indicating that the outcome is cost-effective, while any BCR less than 1.0 would be interpreted as indicating that the outcome is not cost-effective. Using this interpretation, the results for some of the model buildings are cost-effective while others are not, when evaluated using the reference scenario for 2017. Specifically, all of the residential building models–Single Family, Single Family Low Income, and Multifamily–would be cost-effective. In addition, the Warehouse, Multifamily Common, Small Restaurant, and Large Office commercial building models would be cost-effective. The Medium Office, Large Retail, Medium Retail, Hotel, and Small Office commercial building models would not be cost-effective.

Interpretation of the results when considering uncertainty is less clear cut. While the results are shown as single BCR values, they could take on a range of possible values, depending on the range of possible input values and modeling assumptions. The input values, which depend on a large number of factors and assumptions, could be significantly different from the values selected for this study. Different values for inputs including the cost per watt, interest rate on debt, and building energy use are quite possible. The results of the sensitivity analysis and alternate scenarios suggest some of the range of variability that is possible. For instance, the BCRs of the commercial building models in the reference scenario in 2017 ranged from 0.96 to 1.08. In the higher-cost scenario in 2017 they dropped to 0.89 to 1.00. Without further analysis, it is not clear whether a difference of -0.04, +0.08, or even -0.11 relative to the threshold is statistically significant. Does a result of 0.97 indicate that a project is not cost-effective, while a result of 1.05 indicates cost-effectiveness? To interpret the BCRs as being associated with a probability distribution would require information about that distribution.

However, even without a more detailed level of analysis, it is possible to make some inferences about the likelihood of a result indicating cost-effectiveness. The greater the difference of a result from the cost-effectiveness threshold, the more likely it is that the result represents a true outcome (cost-effective or not cost-effective). The BCRs for the single- and multifamily residential building models in the reference scenario in 2017 were significantly above the cost-effectiveness threshold, at 1.78 and 1.65, respectively. These results are therefore more likely to represent a true cost-effective result for these building models, compared to the other building models that have lower BCRs. For the commercial building models, the Warehouse building model had a BCR of 1.08 in the 2017 reference scenario. This represents an outcome that is more likely to be cost-effective than the results for the Small Hotel building model, which had a BCR 0.97 in the 2017 reference scenario.

The single-family low income (SFR-LI) model is somewhat unique, due to a combination of low utility rates and limited tax benefits. The SFR-LI model for the reference scenario had a BCR of just 0.92 in

2015, which increased to 1.09 in 2017 due to the forecasted decrease in the cost per watt. In the low income model, it was assumed that the residents do not benefit from the federal investment tax credit. At the same time, they pay lower electric rates under the CARE program, so that their cost of grid electricity is lower, while their net energy metering benefit is also reduced. The SFR-LI model also fared poorly in the higher cost scenario in 2015, with a BCR of just 0.75, and 0.89 in 2017. It should be noted that very few single-family residences are built in San Francisco. In contrast, there are many more low-income residences in multifamily buildings. Therefore, issues of low-income affordability in single-family residences should be less prevalent than those in multifamily buildings. The Multifamily building model, however, does not consider issues of low-income ratepayers, such as those paying CARE rates. The Multifamily building model is represented as one large aggregate system paying standard residential rates. Therefore, these building models provide limited insight into issues associated with low-income residents.

5.2 Cash Flow

The net lifetime benefits and costs for each project were used to calculate the projects' overall benefit-to-cost ratio. Individual project cash flows, showing the annual benefits and costs, provide additional detail that can assist in understanding the calculation of the ratio. For instance, one of the results of the sensitivity analysis (see 5.3 Sensitivity Analysis on page 41) was that an increase in discount rate can result in a higher benefit-to-cost ratio. Examining a representative cash flow in more detail will provide insight into this outcome.

The undiscounted (current-dollar) cashflow for the Medium Office building model for the reference scenario in 2015 is shown in Figure 7 below, while the corresponding discounted cash flow is shown in Figure 8 on page 41. This sample cashflow shows the breakdown of the components of the benefits and costs, as well as how a change in discount rate can affect the benefit-to-cost ratio.

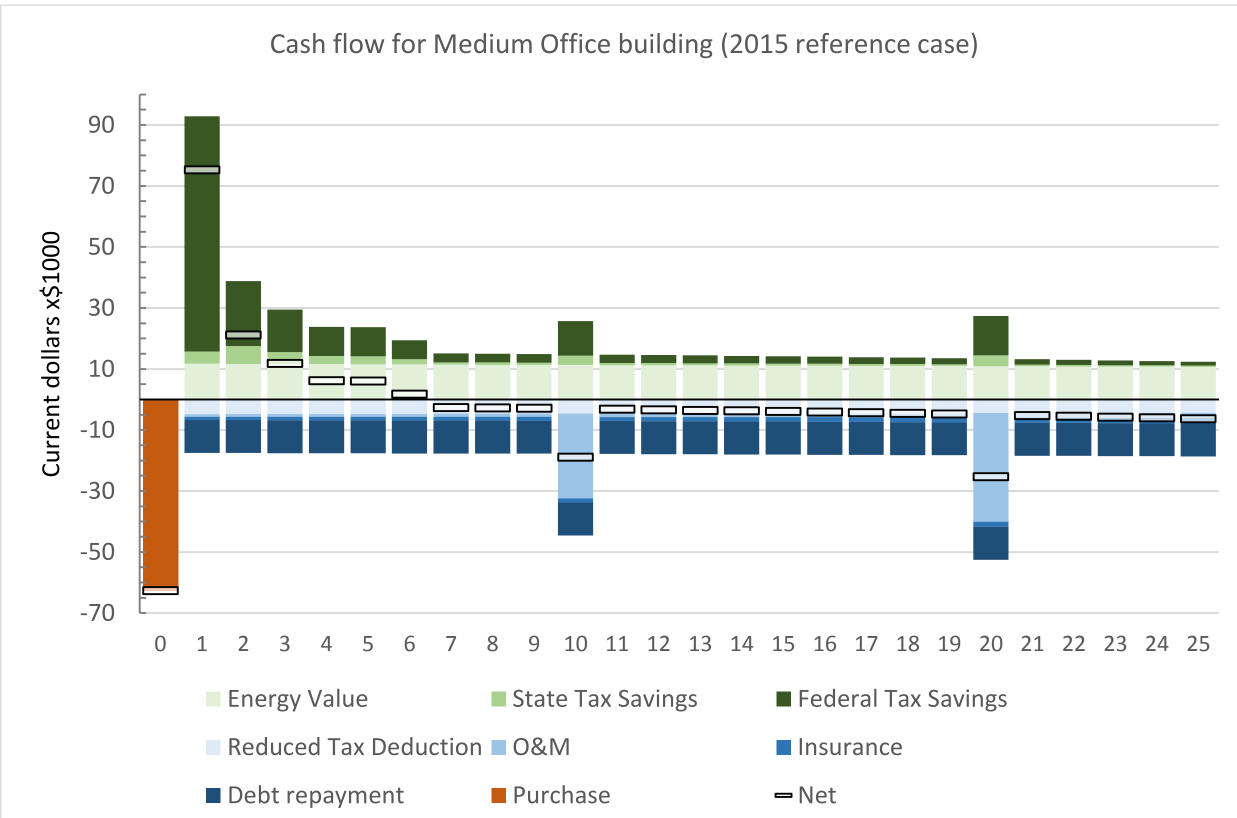


Figure 7 Current-dollar annual cash flow for the Medium Office building model for the 2015 reference case. This shows the net after-tax cash flow, as well as the individual benefits and costs that contribute to the net value. The horizontal axis shows years flow is negative in year zero due to the purchase of the photovoltaic system, then turns positive as a result of tax credits and deductions, before going negative after year 6 due to debt repayment, maintenance costs, and the reduced tax deductibility of energy costs. The large costs in years 10 and 20 are due to inverter replacement.

In the initial project year, the cost is dominated by the purchase costs of the system for the portion not financed with debt. Then, in the first few years of the project the federal tax benefits are significant, composed primarily of the investment tax credit (in year 1) and the value of the accelerated depreciation (years 1-5). State tax benefits, comprised mainly of the value of the accelerated depreciation, also contribute to overall benefits. Throughout the analysis period the value of the energy generated remains relatively constant, affected mainly by system degradation and utility rate escalation. In years 10 and 20 there are large maintenance costs due to inverter replacement. In the remaining years costs are composed mainly of debt repayment and the reduction in the tax deduction due to lower spending on energy. While the reduced tax deduction is shown in the figure as a cost, in the cost benefit calculation it is treated as a reduction in the energy value, and thus a reduction in benefits (not an increase in costs).

An apparently unusual result of the sensitivity analysis is an increase in net present value (NPV) and of the benefit-to-cost ratio with increasing discount rate. Yet, a higher discount rate results in a lower (absolute) value of future payments. An examination of the cash flow helps explain these results. In Figure 7 above, which shows cash flows in current dollars, there is a large positive balance in year 1 of the project due to a combination of the investment tax credit and accelerated depreciation. The net after-tax cash flow is positive in years 1-6. From year 7 onward, however, the net cash flow remains negative. Thus, after year 7, the annual costs are greater than the annual benefits of the project. A higher discount rate will discount these future costs more than a lower discount rate. When calculating the NPV, the large positive cash flows in the first few years of the project will therefore be more significant than the discounted future negative cash flows. The corresponding discounted cash flow is shown in Figure 8 below. Comparing Figure 7 with Figure 8, it is apparent that the future cash flows are discounted, with the negative cash flows becoming less significant over time.

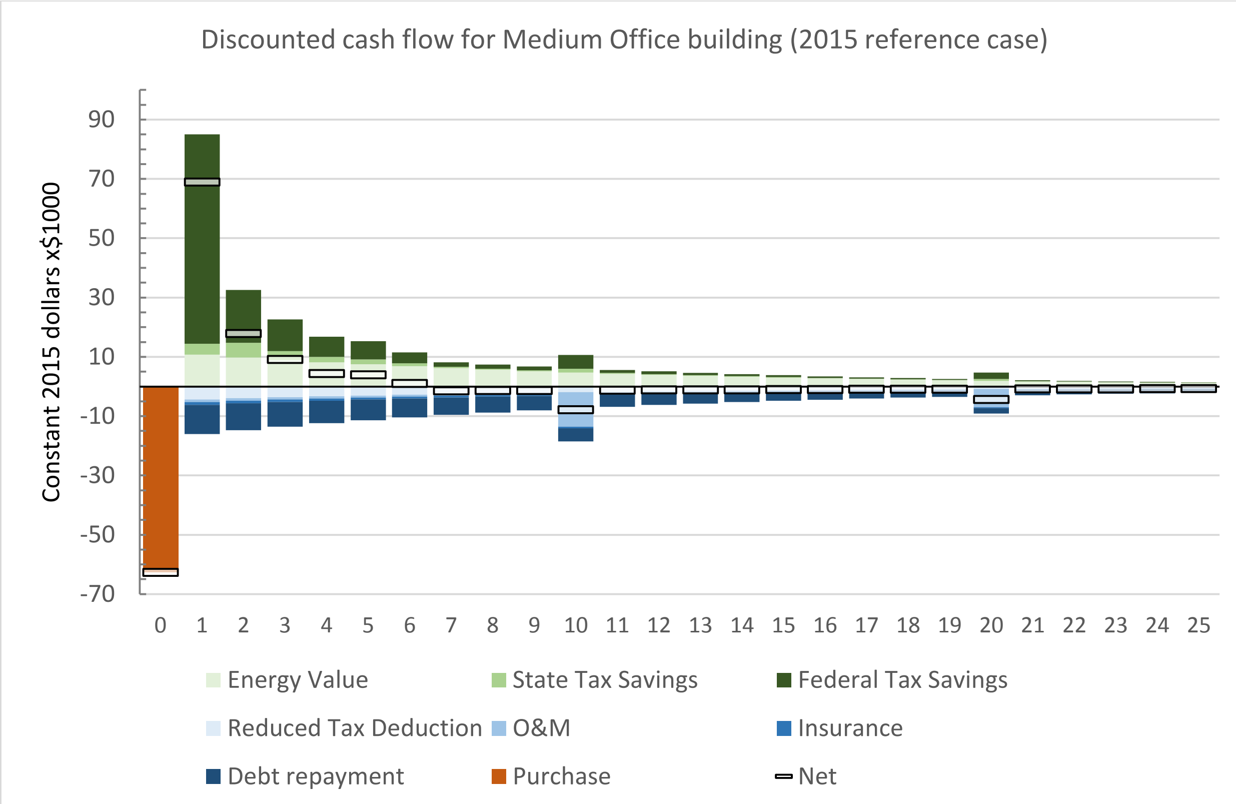


Figure 8 Discounted annual cash flow for the Medium Office building model for the 2015 reference scenario.

5.3 Sensitivity Analysis

A sensitivity analysis was done to gauge the effect of varying the values of several input parameters. Performing analyses while varying input parameters over reasonable expected ranges helps explore the sensitivity of the outcomes to particular choices of values. This also provides insight into the range of uncertainty that could be encountered in real-world projects. Table 20 shows the input parameters for which sensitivity analysis was done, along with the range of values tested and the amount by which the values were varied.

Parameter	Range	Increment	Notes
Debt fraction	20% - 100%	20%	The amount borrowed to finance projects depends on particular project circumstances and access to financing.
Cost per watt	\$3.00 - \$6.00	\$0.50	The range covers reasonable possible forecasts for the cost per watt.
Debt rate	3% - 8%	1%	The interest rate depends on a variety of uncertain factors, including borrower credit risk and macro economic conditions.
Azimuth	90^{o} - 270^{o}	30^{o}	Varied from due east to due west.
Availability	75% - 100%	5%	Lower availability means reduced energy output. May be affected by weather, shading, soiling, equipment failure, etc.
Federal tax rate	15% - 35%	5%	Varied over range of plausible federal income tax rates.
Discount rate	2% - 12%	2%	Discount rate variability was discussed previously. The chosen range covers a wide range of plausible values. Values are real discount rates.
Size	1 kW - 100% kW	1/10 of maximum size	Maximum size was limited to 100% energy offset.

Table 20 Inputs for individual parameter sensitivity analysis.

Overall results of the sensitivity analysis are shown in Figure 9 below. This figure shows the average decrease or increase in the BCR relative to the reference scenario, as well as the minimum and maximum ranges. The simulation results for all buildings in both modeled years (2015 and 2017) were combined to calculate these summary values. The results were then sorted in decreasing order of average range of effect. Debt fraction had the largest impact on the BCR, followed by the cost per watt, and then debt rate. Both availability and azimuth resulted in decreased BCRs, which is expected given that 100% availability and the optimal azimuth were assumed in the reference scenario, so that any change in those values could only reduce the benefits of the system. The BCR varied the least due to changes in federal tax rate, discount rate, and system size.

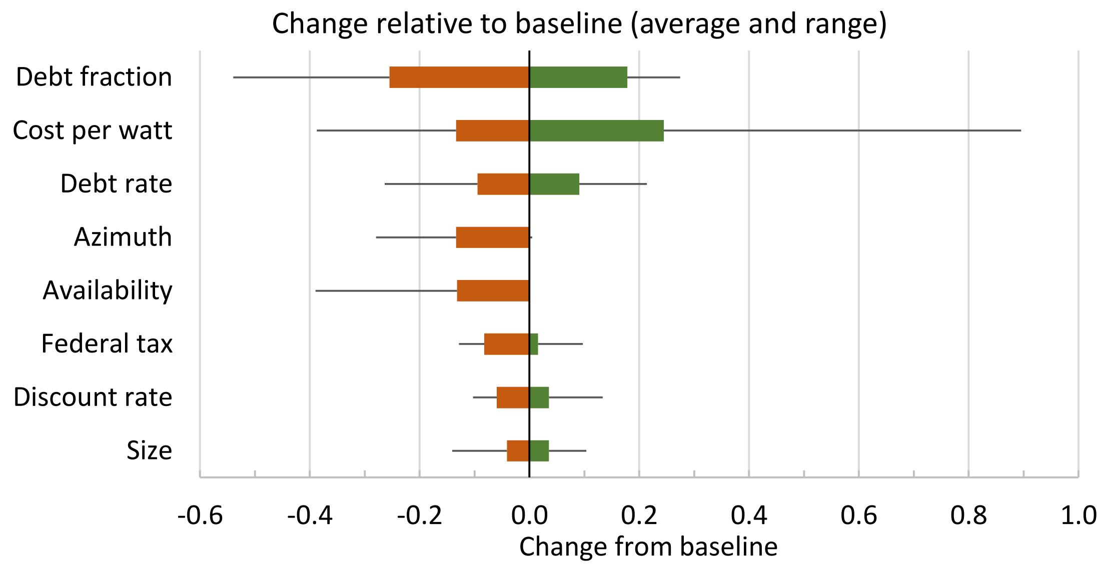
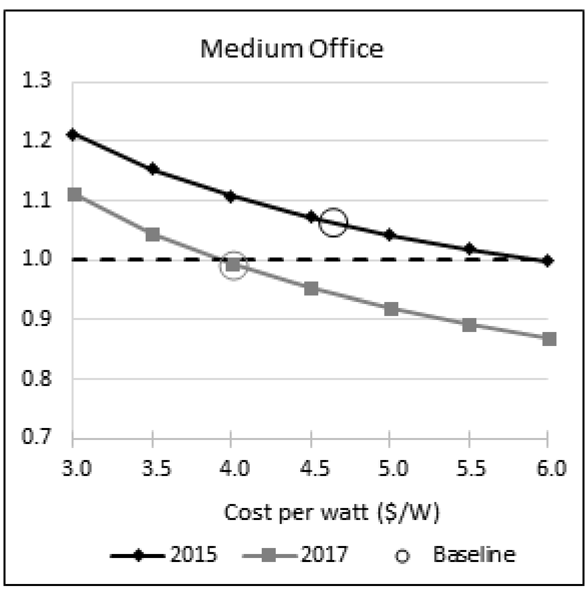


Figure 9 Sensitivity analysis results showing the average decrease or increase in the BCR relative to the reference scenario as well as the minimum and maximum ranges.

Individual plots of the sensitivity analysis results were also generated. Two examples are shown in Figure 10 below. The cost per watt, shown in the figure on the left, was varied over a range of $3 to $6. System availability, shown in the figure on the right, was varied from 75% to 100%. The reference scenario's value is marked with a circle in each figure. From the effect of varying the cost per watt it is apparent that the change in BCR is not necessarily linear across the full range, a result that can be seen more clearly in the plots of the BCR against varying azimuth (see Table 22 on page 45).



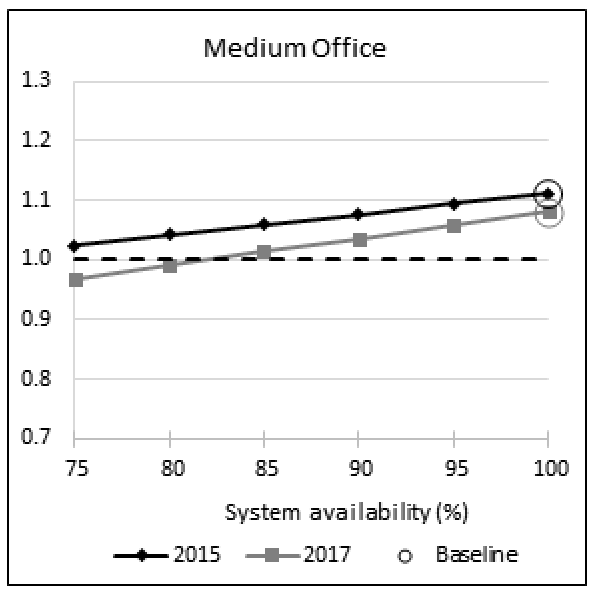


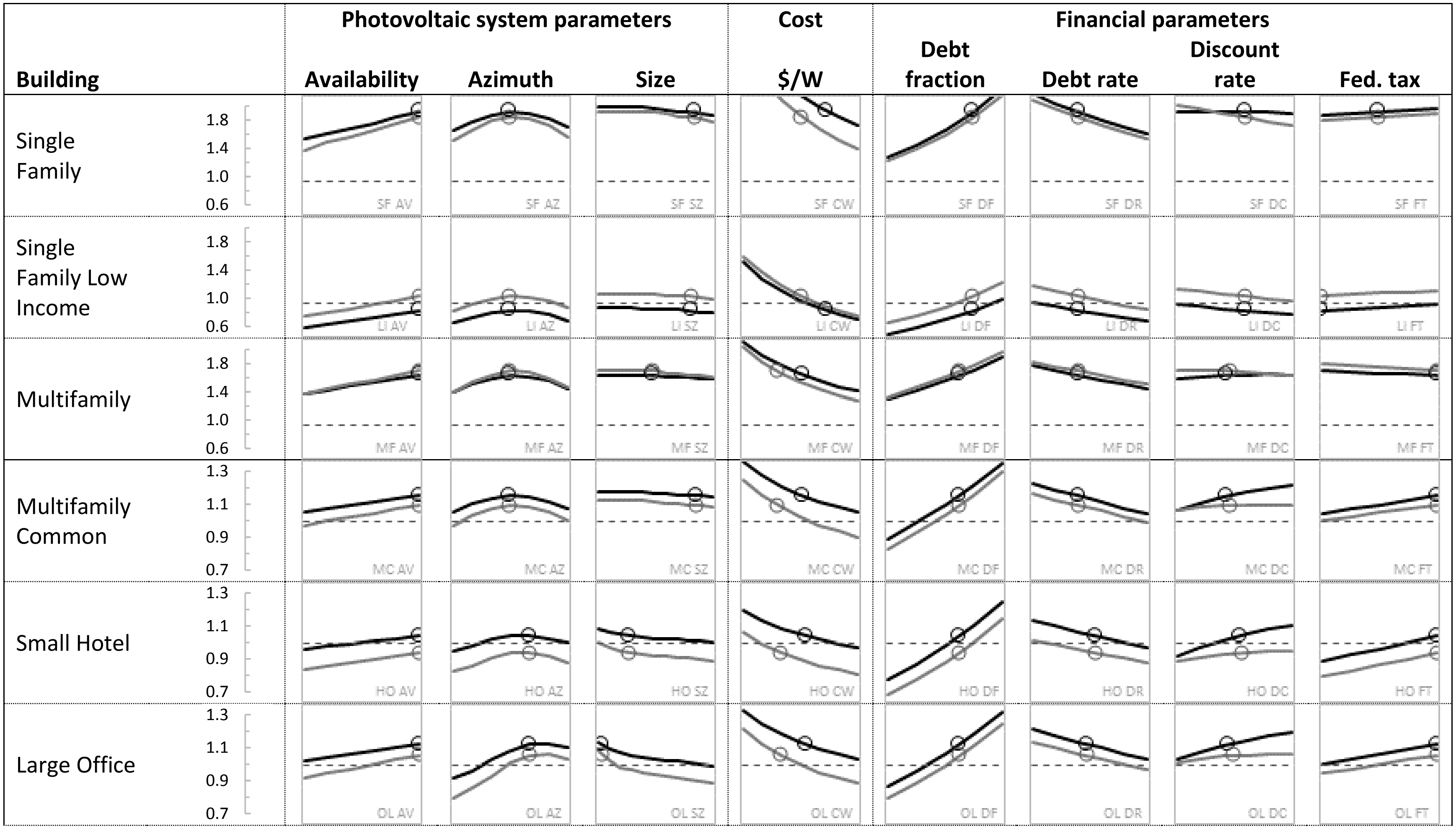
Figure 10 Sensitivity plots of cost per watt and system availability for the Medium Office building model. The circles mark the value of the reference scenario.

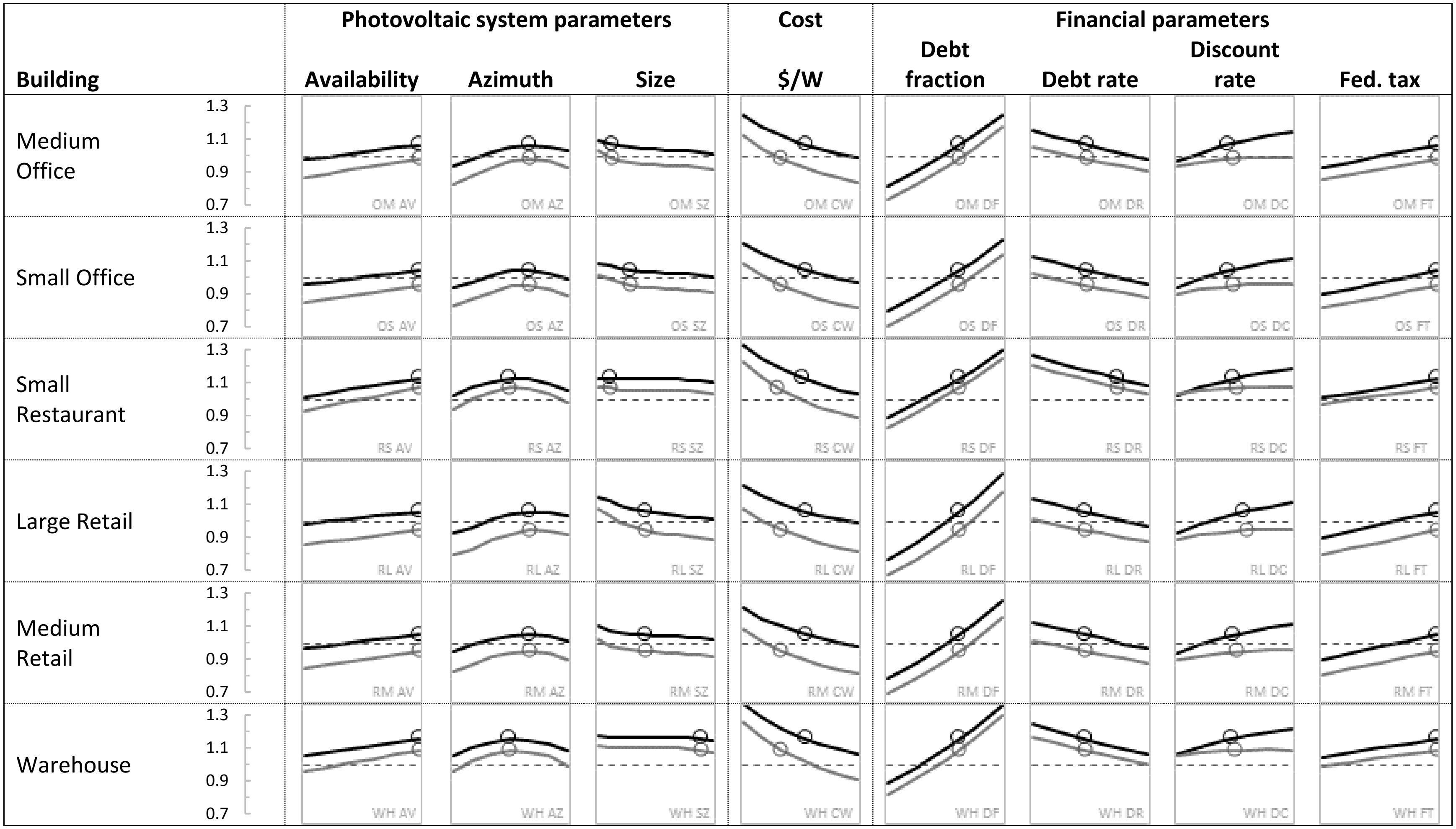
A qualitative summary of the sensitivity analysis results is presented in Table 21. The correlation, positive (+), negative (-), or mixed (+/-), between the input variables and the BCRs is shown, along with a brief interpretation of the overall results for each input variable. Table 22 on page 45 shows the individual plots of the sensitivity analysis results.

Parameter	**Correlation**	**Discussion**
Debt fraction	+	Higher debt fractions resulted in more cost-effective outcomes.
Cost per watt	-	Cost per watt had a significant negative correlation: the more expensive the system, the lower its cost-effectiveness.
Debt rate	-	Lower-cost debt resulted in more cost-effective outcomes.
Azimuth		The output varied by the orientation of the solar panels. Cost-effectiveness decreased as the azimuth was varied in either direction from the optimal midpoint.
Availability	+	Higher availability resulted in higher cost-effectiveness. Reduced availability resulted in reduced energy output, making the systems less cost-effective.
Federal tax rate	+	The federal tax rate had a slight positive correlation with the BCR, so that higher marginal federal tax rates resulted in more cost-effective outcomes. (Except for the Multifamily building model, where a slight negative correlation is seen.)
Discount rate	+/-	Varying the discount rate had variable effects on the outcome, including positive, negative, or no correlation, depending on the building model.
Size	-	Increasing size typically resulted in slightly decreasing cost-effectiveness.

Table 21 Qualitative summary of sensitivity analysis.

Table 22 Graphs of all individual sensitivity analyses. Input values, plotted on the X axis, were varied as described in Table 20 on page 42. The vertical axis shows the benefit to cost ratio. The black line shows the results for the year 2015, while the gray line shows the results for 2017. The circles indicate the values for the reference scenario. The X axis scale varies with each parameter and building model. The Y axis scale has two ranges, one for the residential buildings (single- and multifamily), and another for the commercial buildings.




Photovoltaic system parameters
Cost
Financial parameters
Building
Availability
Azimuth
Size
$/W
Debt fraction
Debt rate
Discount rate
Fed. tax
Medium Office
Small Office
Small Restaurant
Large Retail
Medium Retail
Warehouse
1.3
1.1
0.9
0.7
OM AV
OM AZ
OM SZ
OM CW
OM DF
OM DR
OM DC
OM FT
OS AV
OS AZ
OS SZ
OS CW
OS DF
OS DR
OS DC
OS FT
RS AV
RS AZ
RS SZ
RS CW
RS DF
RS DR
RS DC
RS FT
RL AV
RL AZ
RL SZ
RL CW
RL DF
RL DR
RL DC
RL FT
RM AV
RM AZ
RM SZ
RM CW
RM DF
RM DR
RM DC
RM FT
WH AV
WH AZ
WH SZ
WH CW
WH DF
WH DR
WH DC
WH FT

5.4 Carbon Emissions

A reduction in the emissions of greenhouse gases (GHGs) is a goal of the proposed ordinance. Photovoltaic systems are a clean energy source that does not produce emissions once installed. In addition, lifecycle emissions are low (Hertwich et al 2014). In contrast, grid power is provided through a combination of sources, including fossil fuels that result in emission of greenhouse gases. Each unit of energy produced by a photovoltaic system displaces energy that would otherwise be provided by grid power, thus reducing greenhouse gas emissions. Lifetime avoided CO_2 emissions were estimated for the modeled projects to assess their possible contribution to the goal of reducing emissions of greenhouse gases.

PG&E publishes estimated CO_2 emissions per MWh of electric energy consumed for the period 2003 to 2020 (PGE 2013). The CO_2 emissions due to PG&E's electric generation mix have been declining over this period. The average rate of decline was used to forecast estimated emissions for the full period of the study. Total avoided emissions were then calculated as the sum of the forecasted emissions in each year multiplied by the expected annual energy generation from the modeled systems in each year; see Equation 3 below for details of the calculation. These results are intended to provide a general sense of the expected CO_2 emission reductions. The calculations do not account for all sources of variability, for instance they do not take into account hourly variability in emissions.

$C_{avoided} = \sum_{i=1}^{n} C_i \times E_i$	Total avoided CO_2 emissions in metric tons (MT).
C_i	Metric tons of CO_2 emissions per megawatt hour (MT/MWh) in year i. Forecast for 2015 to 2020 is based on PG&E's published forecast, after 2020 emissions are reduced by forecasted decline.
$E_i = \frac{E_0}{(1 + R_E)^{i-1}}$	Energy output in year 0 is scaled by compounded annual degradation rate (MWh).
$R_E = 0.005$	Annual degradation rate of photovoltaic system.

Equation 3 Calculation of lifetime avoided CO_2 emissions.

Figure 11 below shows lifetime avoided CO_2 emissions for systems installed in 2015. Avoided emissions range from 5.7 MT for the Multifamily Common building model and up to 2150 MT for the Large Retail building model. Avoided emissions depend on year of installation and are proportional to system size, not percent of energy offset. For systems installed in 2015, each 1 kW of capacity avoids 3.6 MT CO_2, while for systems installed in 2017 each 1 kW avoids 3.2 MT CO_2. For instance, considering systems installed in 2015, the system for the Warehouse building model can offset 94% of the electric energy consumption, while the system for the Large Office building model can offset just 4%. Despite these differences in percent of energy offset, the Warehouse system can avoid emission of 306 MT CO_2 while the Large Office system can avoid emission of 373 MT CO_2.

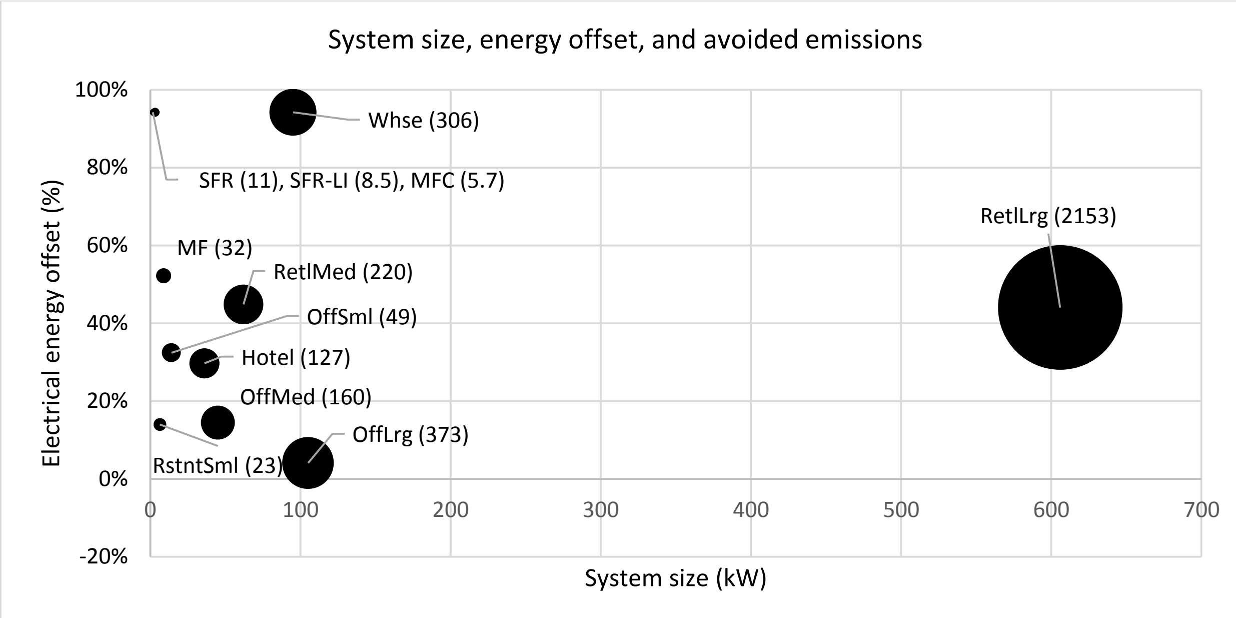


Figure 11 Avoided emissions are proportional to system size, not percent of energy offset. Circle size is proportional to lifetime avoided CO2 emissions. Labels show building name and avoided lifetime CO_2 emissions. Values are for systems installed in 2015.

Converting the avoided emissions per year to a carbon price provides another way to measure the benefits associated with photovoltaic systems. A price forecast for carbon was constructed from several sources and converted to constant 2015 dollars. The CEC has developed a price forecast for carbon in its update of the TDV metric for the 2016 code cycle, which provided a forecast of carbon prices in current dollars from 2017 through 2046 (CEC 2014b). Carbon prices were extracted from the CEC Title 24 TDV Calculator and deflated using a 2% inflation rate to 2015 dollars (CEC 2014c, worksheets "Emissions" and "Base Inputs"). To determine a price for 2015-2016, the current price of carbon (as of November 16, 2014) trading in California was escalated by 5% per year in real terms (State of California 17 CCR § 95911). The two sequences were combined to build an approximate carbon price forecast from 2015 to 2046.

Figure 12 below shows the benefit or cost of avoided CO_2 emissions for the residential and commercial model buildings, respectively. These costs and benefits could be compared to the cost of greenhouse gas mitigation actions undertaken through other measures and policies. The benefit or cost was calculated by dividing the net present value (NPV) of the projects by their lifetime avoided emissions. Where the NPV was positive, customers essentially earned an excess return while reducing emissions. Where the NPV was negative, customers incurred a cost for each unit of avoided emissions. The Single Family Low Income building model incurred a cost of $85 in 2015, but this shifted to a benefit of $100/MT CO_2 in 2017. For the other residential categories–single-family and multifamily–there were significant benefits per avoided ton. The commercial building models had a benefit for each avoided ton in 2015, but in 2017 several commercial building models incurred costs of between $9 and $53/MT CO_2.

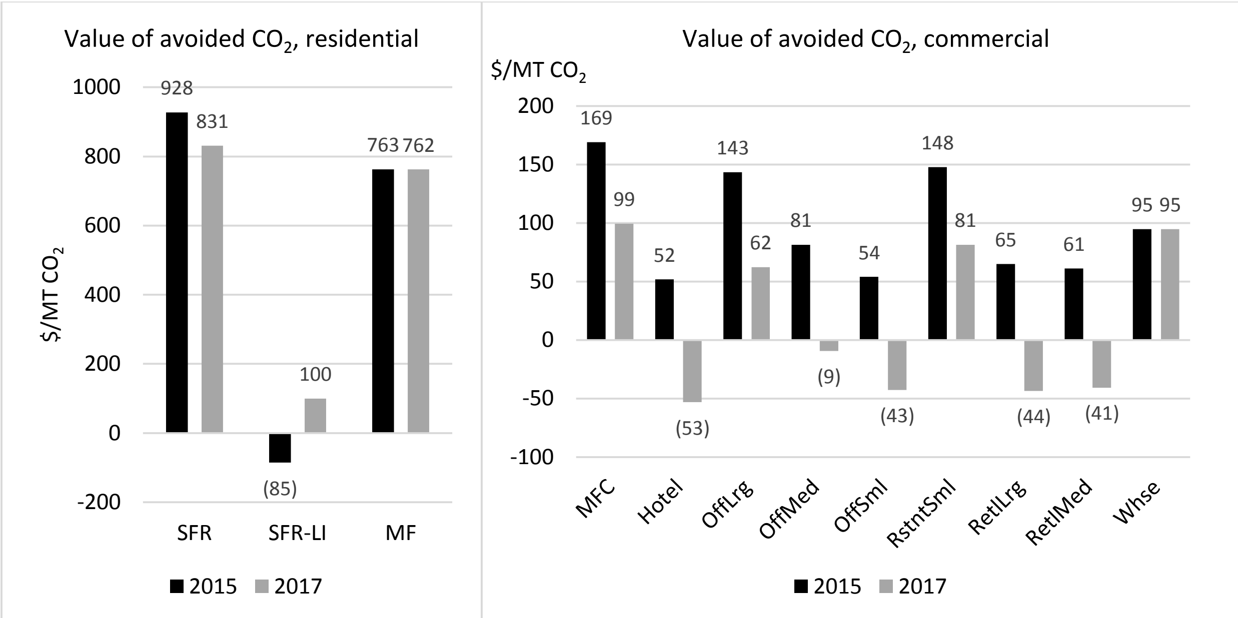


Figure 12 Benefit (or cost) of avoided CO_2 emissions.

For photovoltaic systems installed in 2015, the lifetime value of avoided CO_2 emissions for each 1 kW of generating capacity was estimated at $114, while in 2017 the value was estimated at $125. Figure 13 below shows the relative value of the avoided emissions for the commercial projects compared to the projects' overall net present values for systems installed in 2015. The value of the avoided CO_2 emissions ranged from 7% to 23% of the projects' NPVs.

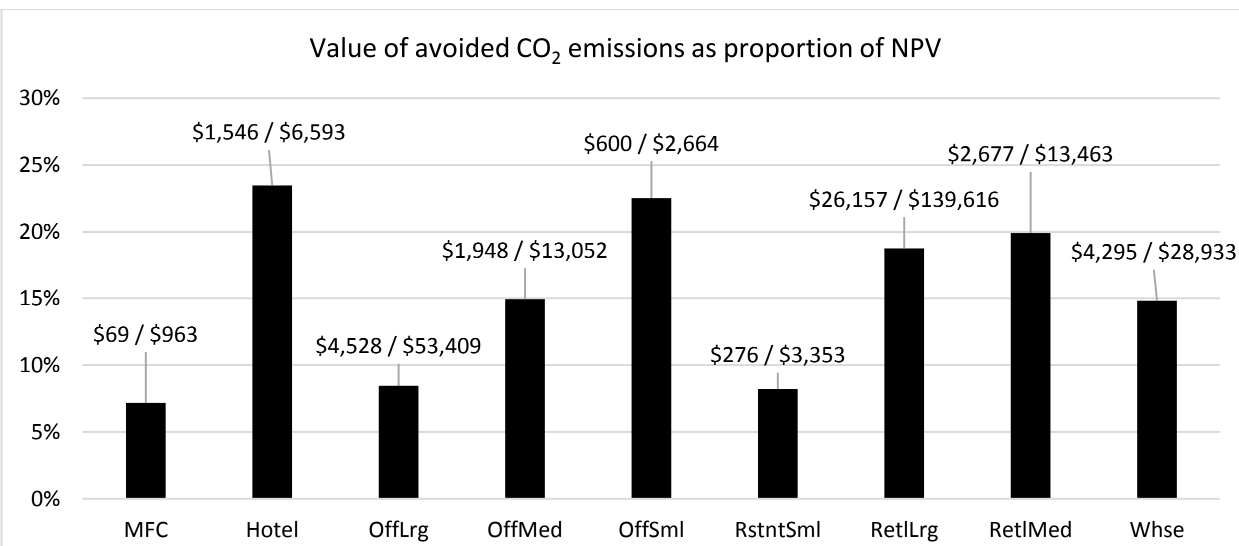


Figure 13 Lifetime value of avoided CO_2 emissions as proportion of overall project net present value (NPV). The labels above each column show the present value of the lifetime avoided carbon emissions along with the project's total NPV.

5.5 Building Costs

Inclusion of photovoltaic systems in new building construction adds an additional upfront cost to existing construction costs. The table below shows estimated added construction costs due to the installation of photovoltaic systems in the commercial building models. Construction costs, in dollars per square foot, were obtained from various sources (CRES 2014, CMD Group 2013). Estimated additional construction costs ranged from 0.4% to 8.4%. These data provide only a rough approximation of actual construction costs; real-world project costs would be expected to differ from these estimates.

Building	Floor Area (ft2)	Construction cost ($/ft2)	Construction cost (x$1000)	System cost (x$1000)	Added cost (%)	Source
Multifamily	6960	263	1829	41	2.2%	CRES
Multifamily Common	6960	263	1829	7	0.4%	CRES
Small Hotel	42554	196	8341	167	2.0%	CRES
Large Office	498589	185	92239	487	0.5%	CRES
Medium Office	53628	196	10511	209	2.0%	Estimated
Small Office	5502	222	1221	65	5.3%	CMD
Small Restaurant	2501	273	683	29	4.3%	CMD
Large Retail	240000	140	33600	2812	8.4%	Estimated
Medium Retail	24563	140	3439	288	8.4%	CMD
Warehouse	49495	140	6929	441	6.4%	Estimated

Table 23 Estimated additional construction costs due to installation of the modeled photovoltaic systems.

5.6 Aggregate Results

An analysis of aggregate results was done to estimate the overall potential energy generation, energy offset, and carbon emission reduction that the proposed installation of photovoltaic systems could have in San Francisco. This was a retrospective analysis, in which solar generation was applied to buildings already in the pipeline, to provide a measure of the effect had these buildings all included the proposed solar generation capability. The analysis was done on buildings in the Planning Department's building pipeline for the years 2008-2014, where the year is based on the year that the first filing was made.

5.6.1 Aggregate Analysis Methods

San Francisco maintains a database of projects in its building pipeline (SF 2014). The "pipeline consists of development projects that would add residential units or commercial space, applications for which have been formally submitted". Completed projects are taken out of the pipeline. For this analysis, the most recent available data set, for the third quarter of 2014, was used. The data included information about construction projects, including descriptive text, filing dates, and other parameters. In addition, the planning department provided a Department of Building Inspection (DBI) data set, which contained data on area allocated by end use category as well as building lot area (Aksel Olsen, Planning Department, private communication). The datasets were cross-referenced using a common case number.

The most recent proposal from the Department of the Environment was to exclude buildings over 10 stories in height from the requirement for solar generation. Therefore, the aggregate analysis excluded any buildings greater than 10 stories. In addition, the relevance of each project to the analysis was determined using several criteria: additions were excluded, since they will be excluded by the proposed ordinance; and complex projects involving many buildings or general redevelopment plans were excluded due to the difficulty in estimating building parameters.

The number of floors and roof area were estimated using several methods. Estimated roof area was calculated by dividing project area by an estimated number of floors, limited to a maximum of 80% of total lot area. Some project entries included the number of floors and building heights in the descriptive text associated with each project. Where they were provided, the number of floors and heights of the buildings were determined based on the text. Where only height information was provided, an average floor height of 11.5 ft for mixed-use buildings was used and the number of floors was estimated by dividing the buildings' heights by this average floor height (CTBUH 2014). The average number of floors for all included projects was then calculated. The average number of floors was used for the remaining projects if both number of floors and height were unavailable.

Electric energy consumption was estimated by assigning end-use intensity (EUI) values in kWh/ft^2/yr to each of the end-use types (see Table 24 below). The EUIs were then multiplied by the area of each end-use. The EUIs were based on the prototypical building models, and thus represent estimates appropriate for buildings compliant with the 2013 energy standards. Where no corresponding category was available, the end-use intensity for the Medium Office building model was used. This end-use intensity is not completely accurate for the projects in the pipeline. Many of those projects predate the 2013 energy standards and would be expected to have higher EUIs.

Code	Description	Building model	kWh/ft^2/yr
CIE	Cultural, institutional, and educational	Medium Office	7.79
MIPS	Office	Medium Office	7.79
PDR	Production, distribution, repair/light industry	Medium Office	7.79
RES	Residential	Multifamily	3.28
RET	Retail or entertainment	Large Retail	7.70
VIS	Hotels and motels	Small Hotel	3.81

Table 24 End use intensities for electric energy consumption.

Energy generation potential was estimated from the available roof area and the solar panel efficiency parameters. The solar ready area was set at 15% of estimated roof area. Generation potential in kW DC and in kWh/yr AC was then calculated using the photovoltaic system energy density parameters developed for the reference scenario (see 4.2 Photovoltaic System Performance on page 26). Lifetime avoided CO_2 emissions potential was estimated by multiplying the generation potential by the lifetime avoided emissions for projects installed in 2015 and having an azimuth of 180^o and a tilt of 33^o (see 5.4 Carbon Emissions on page 47).

5.6.2 Aggregate Analysis Results

Aggregate totals for all projects[2], shown in Table 25 below, were calculated for each year from 2008 to 2014. If all 200 of the analyzed projects in the pipeline were to install solar photovoltaic systems on 15% of their roof area, they would generate 10.5 GWh/yr of electricity, offsetting 16% of the projects' energy consumption over the lifetime of the photovoltaic panels. Assuming installation in 2015, they would also avoid 26.3 MT of CO_2 emissions over the projects' lifetimes. Stated another way, 15% of the rooftops of the relevant buildings in the city's building pipeline represent 434,000 square feet of potential solar area, or nearly 10 acres. This is sufficient area to install a total of almost 7.4 MW of solar generating capacity providing 10.5 GWh per year.

Year	Count	Area (M ft2)	Consumption (GWh/yr)	Roof area (M ft2)	Solar area (M ft2)	Generation potential (MW)	Generation potential (GWh/yr)	Offset potential	Lifetime avoided emissions (MT CO2)
2008	19	0.33	1.12	0.07	0.01	0.17	0.25	22%	612
2009	16	1.50	7.64	0.30	0.05	0.77	1.10	14%	2750
2010	15	2.72	9.98	0.55	0.08	1.41	2.00	20%	4995
2011	8	0.25	0.86	0.05	0.01	0.13	0.18	22%	460
2012	32	1.87	8.17	0.38	0.06	0.97	1.38	17%	3439
2013	66	5.97	30.78	1.21	0.18	3.09	4.40	14%	10966
2014	44	1.65	7.70	0.33	0.05	0.85	1.22	16%	3038
Total	200	14.29	66.24	2.90	0.43	7.39	10.52	16%	26259

Table 25 Aggregate totals for all projects and all years (2008-2014).

[2] The data for 2014 included only the first three quarters, so the final 2014 numbers are expected to be higher.

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