ECONOMIC ANALYSIS OF RESIDENTIAL SOLAR PHOTOVOLTAICS IN THE
CONTINENTAL UNITED STATES BY CLIMATE REGION

A Thesis
by
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ABSTRACT

Solar energy is a growing and largely untapped market for residential renewable energy. Solar photovoltaic (PV) systems can have the potential to offer homeowners reduced electricity bills and a chance to lower their personal greenhouse gas emissions; however, there are several factors that impede PV adoption by homeowners. Capital costs, installation costs and incentives, local net metering rules, unknown resale value added to the home are some examples but another is aesthetics. Building integrated photovoltaics (BIPV) have the opportunity to address the aesthetic value by appearing to be a seamless part of a residential roof. However, it is unknown whether or not BIPV is economically competitive with the more conventional building applied photovoltaics (BAPV) or with a traditional shingle roof with grid supplied electricity for that matter. To address these economic questions, research was performed by using the National Renewable Energy Laboratory’s (NREL) System Advisor Model (SAM) software to simulate BAPV (applied) and BIPV (integrated) solar roofing to generate two economic indicators, namely net present value (NPV) and levelized cost of energy (LCOE). These economic indicators were compared for the applied (BAPV) and integrated (BIPV) roofing PV systems to a traditional shingle roof. This analysis was done for BAPV and the BIPV system across the seven climate regions in the continental United States represented by seven cities for three system sizes along with three inverter types for BAPV and for one inverter type for BIPV.
BAPV systems were economically favorable by both NPV and LCOE over a traditional shingle roof in cities where there was both strong net metering policy and incentives. Cities where both of these conditions were not met had at least one economic indicator that suggested a BAPV system did not make economic sense. Inverter type and system size did not significantly change the result. No BIPV system had competitive NPV or LCOE that is mainly due to the higher cost of BIPV compared to BAPV.
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Contributors

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All work for the thesis was completed by the student, under the advisement of Dr. Michael Pate of the Department of Mechanical Engineering and Dr. James F. Sweeney of the Texas A&M Engineering Experiment Station.

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<td>BIPV</td>
<td>Building Integrated Photovoltaic(s)</td>
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<td>BOS</td>
<td>Balance of System</td>
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<td>CEC</td>
<td>California Energy Commission</td>
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<tr>
<td>DC</td>
<td>Direct Current</td>
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<td>EER</td>
<td>Effective Electricity Rate</td>
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<td>IECC</td>
<td>International Energy Conservation Code</td>
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<tr>
<td>kW</td>
<td>Kilowatt</td>
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<td>kWh</td>
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<td>LCOE</td>
<td>Levelized Cost of Electricity</td>
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<td>NPV</td>
<td>Net Present Value</td>
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<td>NREL</td>
<td>National Renewable Energy Lab</td>
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<td>PV</td>
<td>Photovoltaic(s)</td>
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<td>SAM</td>
<td>System Advisor Model</td>
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1. INTRODUCTION

Solar energy is a growing and largely untapped market for residential renewable energy. Currently, solar photovoltaic only accounts for about 1% of electricity generation according to the U.S. Energy Information Administration [1]. Solar photovoltaic (PV) systems offer homeowners reduced electricity bills and a chance to lower their personal greenhouse gas emissions. There are several factors that impede PV adoption by homeowners. Capital costs, installation cost and incentives, local net metering rules, unknown resale value added to the home are some examples but another, not as frequently discussed, is aesthetics [2], [3]. There are newer forms of residential solar roofing, including some where the solar panels do double duty and act as the roof, that will help minimize the aesthetic disturbance on a solar roof. The market for new roofing or roof replacement is also strong, with projections of over 270 million squares of demand in the residential market by 2021 [4]. Combined, there is a strong opportunity for growth of solar roofing in the United States.

1.1 Overview of Photovoltaic Technology

The next section will be an overview of how photovoltaic cells work. Solar panels are sold as modules which contain within them many smaller solar cells that are comprised of two layers of semiconducting silicon dioxide. A diagram of solar cells and a stylized cross section can be seen in Figure 1. One side of the two layers of silicon has a minute amount of additive, or has been “doped,” to make it such that there is an excess
of electrons in the silicon, the N-silicon. The other side has been doped with a small amount of additive that accepts electrons, leaving that region with an excess of positive “holes,” the P-silicon. When these two layers are next to each other the concentration of electrons on one side and positive holes on the other creates an electric field. When sunlight strikes the silicon and has the right energy to liberate an electron from a silicon atom, the electric field drives the electron toward the N-silicon side. There are metallic fingers and backing on the front and back surfaces of the silicon wafer respectively. Electrons flow through the wire doing work along the way to fill the holes on the P-silicon side when the sides are connected. The movement of electrons provides electric current and the electric field in the cell provides the voltage. The individual solar cells are wired in series to increase the voltage. About 60 cells are packaged together in a metal casing with glass or plastic front to form a typical solar module [5].

Figure 1: Picture of a Solar Cell (a) & Diagram of How a Solar Cell Works (b) [5]

The two solar technologies being investigated in this research are not new photovoltaic technology per se, but rather they are two different and emerging ways of
packaging and mounting solar panels. Building applied photovoltaics (BAPV) are solar panels mounted on a building after the roofing material (shingles, tiles, etc.) is applied, and in such a way that the solar panels conform to the shape of the roof or façade. This can done simply by having a close rack mount or something like thin solar panels with an adhesive backing with the latter conforming to the shape of the building, so as to minimize visual disruptions to the building [2]. To further minimize or hide their visual impact, building integrated photovoltaics (BIPV) takes it a step further by being a structural part of the roof or façade. In fact, the solar cells are packaged in such a way that they are strong enough to constitute the roof of a building. Building integrated photovoltaics do not usually constitute the entire roof in residential installations because the PV area required is in most cases less than the roof area available, which means that BIPVs must integrate seamlessly with traditional roofing. Visual examples of building applied and building integrated photovoltaics can be seen in Figure 2.

![Building Applied PV and Building Integrated PV](image)

**Figure 2**: Building Applied PV (left) and Building Integrated PV (right) [6]
A grid tied system is arguably the simplest type of PV system a homeowner can install, primarily, because there is not a need for an electrical storage system, such as batteries. A simplified graphic depiction of all the necessary parts of a grid tied photovoltaic system is shown in Figure 3 [5]. At the top of the diagram is a row of solar modules in a PV array connected in parallel. The DC power from the PV array is sent to the inverter where it is inverted into AC power, which is a necessary step for integrating with the grid and for supplying power to homes. In fact, after leaving the inverter, the AC power is then fed to the main service panel where it can enter the electrical grid or home. There are disconnects, or breakers, for both the DC lines and the AC lines so that the PV array can be disconnected from the inverter or the from the grid, respectively. As their name suggests, grid tied systems are tied to, or are dependent, on the electrical grid to function properly even to the point that if a power outage occurs in the wider electrical grid, then the grid tied system must also shut down for safety reasons. As noted previously, grid tied systems do not have battery backup or any other type of energy storage.
There are many benefits to a more decentralized electricity grid that residential solar roofing helps accomplish. For example, solar tends to produce more power during the sunniest and hottest part of the day when electrical demand, especially for air conditioning, is the highest, thus helping ease the pressure on utilities during this time [3]. If enough solar capacity is installed, it can defer investment on new conventional power plants or delay expansions or the adding of additional capacity to older conventional power plants [3], [7]. Generating electricity at the same site where it will be used also helps cut down on the transmission and distribution losses experienced in the electrical grid due to resistance in wires and other equipment, thus improving energy
efficiency [7]. A decentralized electricity grid helps with energy security and reliability. Traditional power plants rely on a limited number of fuel sources that have fluctuations in price and availability whereas once renewables are installed and operating like solar, they do not have much variation in the price to produce electricity [7]. Finally, decentralization helps make the grid less vulnerable during events like natural disasters.

1.2 Overview of Economic Indicators

In this research, quantitative comparisons were made between different PV systems by using two financial indicators, namely: Net present value (NPV) and real levelized cost of electricity (LCOE). Net present value is a well-recognized and understood financial metric that presents the sum of discounted cash flows as a single number, which is representative of the system of interest and accounts for a multitude of effects and issues. The net present value can also be viewed as the net profit of an investment [8]. When net present value of a PV system is equal to zero, which represents a break-even scenario, it is equal to the cost of electricity purchased from the local utility. This point is called “grid-parity.” Net present values greater than zero (i.e. positive values) represent economically favorable or profitable outcomes.

With regards to the second indicator, the real Levelized Cost of Electricity (LCOE) is the discounted costs of the project over the discounted lifetime electricity produced by the project [9]. The real levelized cost of electricity represents the price that the project’s electricity must be sold in order to make back the costs. The LCOE is a relative measure so it needs to be compared to the other sources of electricity, which are commonly supplied by the local utility. Specifically, the LCOE is frequently used to
compare the cost of generating electricity from different sources. A real LCOE equal to the rate provided by the utility is considered “grid-parity.” It should be noted that there is no relationship between the NPV and the real LCOE reaching grid parity because they are different and separate calculations. A real LCOE less than the rate provided by the utility means that the PV project provides cheaper electricity than the utility and is economically favorable, which is a positive result for renewable energy. From here on, LCOE will always refer to the real LCOE unless otherwise noted to refer to the nominal LCOE.

1.3 Objective

The objective of this study is to investigate the cost effectiveness of building applied photovoltaics (BAPV) and building integrated photovoltaics (BIPV) for a range of configurations versus a conventional shingle roof. To do this, NPV for conventional shingle roof was calculated in Excel. The cases involving BAPV or BIPV were modeled by using the System Advisor Model software package, which generates NPV and LCOE as part of its simulation. The economic comparisons to be made are between the following three groups of cases below.

- Conventional Roof Replacement
- Conventional Roof Replacement + BAPV
- Partial Roof Replacement + BIPV
It should be noted that the NPV applies to all cases while LCOE does not apply to the conventional roof replacement because it does not generate electricity, but it does apply to the other two cases. The three configurations were compared over three different parameters, namely: system size, inverter type, and climate region by representative city. The system size parameter was varied from the base case 5.8 kW to 11.5 kW in order to evaluate the effects of increasing system size. The second parameter, namely inverter types, were varied among the string inverter, DC power optimizer, and microinverter in order to evaluate the effects of different inverter types. Lastly there are the seven climate regions as defined by the International Energy Conservation Code (IECC) in the Continental United States, and the systems were evaluated and compared over the full range. It should be noted that the seven climate regions were each represented by a city with each city comprising a multitude of factors including latitude, solar irradiation, utility electrical rate, net metering policy, and tax rates among others.
2. LITERATURE REVIEW

The literature review and evaluation to be included in the thesis will focus on a series of applicable publications. Examples of these papers are as follows:

Fu, R. et al.’s report is NREL’s recent comprehensive pricing report for solar equipment and installation available [10]. Fu, R. et al. created a national benchmark pricing model for residential, commercial, and utility scale installations from the viewpoint of a solar installer and calculates the total price per installed watt-DC ($/W-dc). The total price per installed watt-DC includes solar equipment costs, labor costs, sales tax, and business operation costs for installers and integrators. For residential scale installations, different inverter models are compared as well as state level variations in pricing, with the resulting model being evaluated in terms of the available publicly reported costs by solar installers and integrators.

Drury, E. et al. reported on the wide array of economic performance metrics used to evaluate solar projects, and how they may reach different conclusions [8]. The economic performance metrics compared were net present value, profitability index, benefit-to-cost ratio, internal rate of return, modified internal rate of return, simple payback, time-to-net-positive-cash-flow payback, annualized monthly bill savings, and levelized cost of energy. A sensitivity analysis was performed on each metric to determine which variables had the most effect on the outcome. The choice of economic performance metric was found to have a significant impact on the representation of the value of a PV system. The immediate nature of the investment tax incentive in the US
also changes economic performance compared to calculations done internationally.

Sensitivity analysis showed that different metrics were sensitive to different variables. Care must be taken by policy makers when adjusting incentives so that they show up in the metrics commonly used by each market, whether residential or commercial.

Sweeney, J. et al. performed validations and simulations of the solar electric and solar hot water systems installed in a residence in the Houston area [11]. System Advisor Model was used in the study to conduct an energy and economic analysis and was followed up with a sensitivity analysis for a variety of parameters including system design and orientation, weather, loan rates, inflation rates, and discount rates. NPV and LCOE results were reported across the sensitivity analysis.

Grid parity is achieved when the LCOE drops to the retail price of electricity, which is considered the tipping point for the adoption of solar. However, Yang, C.-J. cautions that LCOE is inconsistently defined and that it may not be enough to reach grid parity [12]. Yang, C.-J. points out that residential solar water heating has already reached grid parity in some locations, but it has not seen widespread adoption, which could turn out to be a similar scenario for residential solar electricity production, especially if consumers have concerns other than simply economical.

Branker, K. et al. builds on Yang’s work about inconsistently defined LCOE and attempts to set a standard methodology for defining LCOE with clear and reasonable assumptions [9]. The concept of “grid parity”, which was defined earlier as lifetime generation costs of electricity from PV being comparable to electricity costs from the grid is discussed in detail and its complex nature being dependent on a myriad of factors
is stressed. Furthermore, Branker, K. et al. performs sensitivity analysis on the selected criteria to determine those variables that are the most important, which were found to be system costs, financing, lifetime, and loan term. Finally, a review of previous LCOE methods from literature was compiled and the tools available within SAM were ranked well.

Kwan, C. L. developed a statistical model combining environmental, social, economic, and political data in order to evaluate and predict the distribution of residential solar PV arrays at a zip code level in the United States [13]. Kwan, C. L. concluded that the most important variables are the amount of sunlight, cost of electricity, and financial incentives. Also noted was the tendency of solar PV installations to cluster together and the observation that Texas and Florida underperformed relative to the high amounts of sunlight. Kwan did not investigate why Texas and Florida underperformed.

Rai, V. et al. analyzed the results of a survey of residential PV adopters in northern California in order to address the question of how and why residential PV are installed [14]. Specifically, “spark events,” which are events that sparked interest in installing residential PV, were categorized with the findings being that the most popular were direct marketing, planning for retirement, increases in electricity rate, and neighbor-related events if there were prior installations in the neighborhood. Additionally, it was noted that residential PV was commonly installed contemporaneously to other energy efficiency improvements, such as new roofing, smart thermostats, and plug-in electric vehicles. Financially savvy customers that calculated
the financial returns on a residential PV system while not being as concerned with operation and maintenance costs tended to outright buy rather than lease their systems, so as to obtain higher returns.

Abreu, J. et al. conducted a survey by polling participants about their attitudes towards installing residential rooftop PV [2]. A fairly conclusive list of motivations for and concerns against rooftop PV from prior literature was presented. 400 people were surveyed about their opinions about rooftop PV after looking at brochures of either conventional rooftop PV or adhesive building applied PV. The resulting views of adhesive building applied PV were generally favorable and did not invoke more concern than conventional rooftop PV. Abreu, J. et al. also concluded from their survey that PV adoption is more related to individual attitudes and concerns about social norms, with the reasons for choosing to adopt solar being subjective rather than rational.

Duke, R. et al. analyzed the residential PV market from the demand side and predicted that it would be cost effective to install PV in 125,000 new homes per year at a price of $1.5/W for solar panels [3]. Duke, R. et al notes that there are some pricing inefficiencies that distort the cost of residential PV, with net metering being regarded as a useful surrogate for efficient electricity pricing mechanisms that factor in the externalities of renewable energy. Some of the benefits documented include deferral of a variety of capital expenses by utilities, reduced risk from fossil fuel pricing fluctuations, and increased electrical grid reliability. The authors recommend that net metering be implemented broadly to help incentivize the residential PV market as well as implement regional and local buydown subsidies.
O’Shaughnessy, E. investigated the trends in the solar installation industry from 2000 to 2016 [15]. O’Shaughnessy found that the solar installer market was split between small local installers that installed less than ten systems total and large regional or national level installers. Initially, the market was quite mixed in terms of small and larger installers but over time, high volume installers held an increasing market share. It is hypothesized that the reason for this was because of the third-party ownership financing option becoming available to consumers, which can only be offered by larger companies. However, it was noted that falling PV system prices have resulted in a shift back towards customer ownership. O’Shaughnessy does not give conclusive statements about whether any of the trends noted have positive or negative effects on the solar industry, instead hypotheses were provided for both.

Perez, R. et al. compared using either simple payback or cash flow as methods of evaluating the worth of installing a residential PV system [16]. Using simple payback can indicate a poor economic choice despite having positive cash flow on a per year basis. Simple payback is discouraged from being used as it is too simplistic of a measure. Additionally, Perez argues that PV systems are undervalued because they tend to produce power during peak hours when pricing is higher than average while homeowners are reimbursed by the utility at average rates.

Black, A. J. analyzed the possibility of positive financial return for residential PV systems in California [17]. Black found using internal rate of return method that the return on installing a PV system exceeds other common investments provided the system meets certain criteria. Also mentioned is that energy savings typically adds value to the
resale value of a home, but there is little empirical data for solar homes as few have been sold.
3. RESEARCH DESIGN

The research tasks performed herein broadly fall into data collection, simulation, and analysis phases. This section will focus primarily on the data collection portion. Information for setting a multitude of variables were researched and collected as a first step to running the simulations in SAM. While the setup was labor intensive and time consuming, SAM simulation run time was minimal. Results were compiled on a spreadsheet where information external to SAM can then be factored in as well, which leads the way into a full analysis of results.

Searching and finding accurate values for the many variables to be input in the SAM simulation tool was critical to the real-world relevance and accuracy of the project. This search was done via comparisons to prior literature, government statistics, commercial industrial contacts, expert knowledge, and when none of the above were available, then reasonable assumptions were necessary. Once the information was gathered, the simulation and analysis processes could be accomplished. The seven main steps to be presented in sections that follow are summarized below:

1. Define Economic Indicators
2. Define and Describe Control Residential Building Model
3. Define BAPV System Specifications – SAM
4. Determine Costs and Financial Parameters
5. Define Climate Regions and Representative Cities
6. Determine City Specific Parameters
3.1 Relevant Economic Theory and Economic Indicators

There are economic indicators that can be used to determine whether or not a project makes financial sense and the two being chosen for this proposal are net present value (NPV) and levelized cost of electricity (LCOE). The NPV gives a sense of whether or not the project, as an investment, will give a positive or negative return over doing nothing. Net present value is a well-established economic metric that compares the investment made at the present time to the summed expected returns in the future discounted to the present. A positive NPV at the end of the period being evaluated is suggestive of a good investment. The equation that defines NPV while also providing the means to calculate a value is as follows.

\[
NPV = \sum_{t=0}^{n} \frac{R_t}{(1 + i)^t}
\]

(Eqn. 1)

where \( R_t \) is the net cash flow at period \( t \), \( n \) is life cycle in years, \( t \) is the time period index in years from present, \( i \) is the discount rate in \%, and \( R_0 \) is the initial investment that includes the cost of PV modules, balance of system, installation, etc.

In our case, the initial investment is a large negative cash flow at year 0 because of the purchases and installation of the PV system while every year thereafter a positive net cash flow is expected from the savings and/or sale of electricity produced by the PV system, less operation and maintenance costs along with taxes. As noted above, it is hoped that at the end of the life or evaluation period, the system under consideration will
have paid for itself or produced a net positive cash flow, thus showing that the system is viable.

LCOE as another economic indicator offers a way to make a comparison to the cost of electricity that one would buy from the utility and is valuable for comparing and evaluating electricity from different sources, especially renewable power sources. The levelized cost of energy (LCOE) is a metric that measures the summed yearly cost of a system discounted to the present over the yearly value of electricity generated discounted to the present and gives a dollar per kWh value, which can easily provide a comparison to buying electricity from the utility when the cost to the customer is specified by the utility in dollars per kWh such as $0.10/kWh or $0.20/kWh or some other value. The equation of LCOE is stated below.

\[
LCOE = \frac{\sum_{t=0}^{n} C_t (1 + i)^t}{\sum_{t=1}^{n} Q_t (1 + i)^t}
\]

(Eqn. 2)

where \(C_t\) is the annual project cost in year \(t\), \(Q_t\) is the annual electrical energy generated in year \(t\), \(n\) is the life cycle in years, \(t\) is the time period index in years from present, and \(i\) is discount rate in %.

Having the LCOE be the same price as retail electricity from the utility, is called reaching grid parity, which has long been the goal for solar proponents, and as such is seen as the tipping point for PV adoption. It is important to note that simply having favorable results from the economic indicators, such as a positive NPV and/or LCOE that is at grid parity or lower, may not be enough to incentivize the installation of a PV
system as other factors may be at stake. And likewise, a PV system may be installed even in the face of unfavorable economic indicators if there are other motivations.

3.2 Overview of System Advisor Model (SAM)

System Advisor Model (SAM) is free software developed and maintained by the National Renewable Energy Laboratory (NREL) for performance and financial modeling of renewable energy systems. SAM Version 2017.9.5 Revision 4, SSC Version 186 is the release used for the purposes of this research. Included in SAM are databases for solar data, weather, performance parameters of solar modules and inverters, electricity rates, and building electrical loads. Even with this built-in information, SAM still has multiple tabbed panels to input model information. Broadly speaking, useful inputs include, but are not limited, to location data, PV equipment and costs, installation costs, financial parameters, incentives, electricity rates, and electrical loads. The specific tabs for a residential photovoltaic system are shown in Figure 4.
After all the inputs are set, SAM simulates the performance of the model and can output a variety of energy production and financial performance metrics for the system of interest. An example of simulation output is shown in Figure 5. NPV and LCOE are the primary financial outputs for examination; however, not everything can be done in SAM in that Excel spreadsheets will be necessary for additional processing of NPV and LCOE results to summarize and present data that cannot be performed within SAM.
3.3 Base Case PV System Model

3.3.1 Control Residential Building Design

Since each region is separately influenced by a myriad of factors, it is important to establish a base or control model by which to compare them all. The standard residential unit or base case house is simplified to a one story, 2000 square foot, square building. The roof pitch was set to 4/12, that is 4” rise over 12” run or 18.42°. This angle also represents the solar module tilt as they are intended to lay flush on the roof. The house is oriented so that the walls are normal to the cardinal directions, that is the south wall faces due south, the west wall faces due west and so on. When laying out solar panels on the roof, it is possible that the solar panel area exceeds one-fourth the total roof area for larger sized PV systems. The order for which section of the roof solar panels are laid on were the south-facing portion of the roof first and then the west-facing
portion of the roof. A stylized diagram of the top view of the roof with solar panels that overflow onto the west-facing portion of the roof is shown in Figure 6. The blue rectangles represent the solar panels.

![Diagram of Base Case Residential Roof](Image)

**Figure 6: Diagram of Base Case Residential Roof**

There are some additional roof parameters that must be defined for roof replacement. After consulting with industry contacts, the assumptions used for roof replacement will be: 2400 sq-ft roof, only one layer of shingles needs to be removed, install new plywood decking, install new synthetic felt underlayment, 30-year shingles, and replace and paint all roof jacks and vents to match roof color. Roof replacement is required for the full roof area for BAPV installations, while only a partial roof
replacement is necessary for BIPV installations because the BIPV makes up part of the new roof and will not be replaced.

3.3.2 Control PV System Design

A common BAPV control system design was selected for both the PV systems studied because residential BIPV is still rare and is just beginning to be put into practice. The PV system design was largely derived from the model parameters used in NREL’s U.S. Solar Photovoltaic System Cost Benchmark [10]. The presentation of the PV system design will roughly follow SAM’s tabbed panels as seen back in Figure 4.

3.3.2.1 Module

The control PV system is an array made up of individual PV modules with these modules being electrically daisy chained together in parallel on a “string.” Furthermore, multiple strings can be electrically combined in parallel to form a system. Finally, the number of modules per string and the number of strings used will determine the overall system size. It is important to note that there can only be an integer number of modules, which means that, modules, as purchased from a solar supplier cannot be subdivided.

The BAPV modules selected were specified to have an efficiency of 16.2%, cover an area of 1.48 m², and produce a maximum of 239.8 W-dc. The efficiency was taken directly from NREL’s assumptions in their cost benchmark report. Market research and SAM’s PV module internal database were consulted when sizing the PV module. A simple efficiency model was used instead of a specific commercially available module in order to make the PV model in this study more general. As a result, the PV module modelled herein by SAM represents any commercially available module
at N% efficiency instead of a specific commercially available module, with one downside being a reduction in real-world accuracy. The area and power of each module was found as part of a process that will be described in Section 3.3.2.3.

3.3.2.2 Inverter

It is important to note that PV modules produce DC power, and it is necessary to use an inverter to invert DC power from the solar array into AC power, which is what the electrical grid and homes operate on. The inverters used in this study were set to an efficiency of 98%, a maximum AC Power Output of 2500 W-ac, and a lifetime of 15 years. The inverter efficiency and lifetime were taken directly from NREL’s assumptions in their cost benchmark report. Both market research and SAM’s inverter database were consulted when sizing the inverter. Similar to how a simple efficiency model was utilized for the PV module, the inverter used the Inverter Datasheet to simplify and generalize the inverter being simulated.

Single-phase string inverters were picked for the system since string inverters account for the majority of inverters used in installations and are, thus, more representative [10]. Different inverters types perform differently in response to shade, the specifics of which will be further elaborated on in Section 3.5.1; however, shading was considered outside the scope of this thesis. SAM only models the performance for different inverter types based on inverter specific losses when shading data is not taken into account. In addition to the base case, two other inverter types, namely DC-optimizers and microinverters, will be analyzed.
There were two competing interests when setting the system size, namely matching the system size itself and matching the DC-to-AC ratio to NREL’s values. The system size should ideally be matched to NREL’s system size for validation purposes. The DC-to-AC ratio, or the ratio of the PV system’s DC power output to the inverter’s AC power output, is important match because NREL gives inverter pricing based on certain DC-to-AC ratios. Ultimately, matching the DC-to-AC ratio was deemed more important because being able to reliably use NREL’s pricing was more critical than having the same system size that NREL modeled.

Inverter pricing was based on a DC-to-AC ratio of 1.15, which is therefore the DC-to-AC ratio to be matched. System sizing was set as close as possible to 5.7 kW, which is considered to be the average residential system size [10]. Since there are an integer number of modules in the system, each with a set capacity, it was not possible to specify a system size of exactly 5.7 kW while also setting the DC-to-AC ratio to 1.15. As a result, the area of each module was adjusted until the DC-to-AC ratio matched at 1.15, with the system capacity being finalized at 5.754 kW. Area of each module combined with the efficiency set the maximum power output of each module. To summarize, the BAPV control system uses two inverters, each with four strings of modules in parallel, and each string being comprised of six PV modules.

One advantage of PV is that it is solid-state, meaning it has no moving parts, which contributes to the longevity of PV systems. There have not been enough long-
term residential PV systems to know the lifetime of such systems [9]. For the purposes of this research, we will consider the lifetime of the PV system to be 30 years. There is PV module degradation as a result of exposure to the outdoor elements with the annual module DC output degradation being set to 0.5% per year.

3.3.3 Control Costs and Financial Parameters

The system costs were largely derived from information in NREL’s U.S. Solar Photovoltaic System Cost Benchmark [10]. The presentation of the PV system costs and financial parameters will roughly follow SAM’s tabbed panels which were discussed previously and presented in Figure 4: SAM Information Tabs Figure 4. In addition to system costs, roof replacement costs are necessary for the analysis of both BIPV and BAPV installations. Roof replacement costs being determined via a mix of industry contacts and online calculators.

3.3.3.1 System Costs

System cost was based on NREL’s accounting of system costs in their cost benchmark report, which was followed herein because it gave PV costs in dollars per watt, matching one of the three types of pricing input that SAM can utilize. This benchmark report also has pricing data for items that might otherwise be hard to find, such as installer overhead. Figure 7 below is the graph from the NREL cost benchmark report showing the cost breakdown for each inverter type for both installers and integrators.
Figure 7: NREL Cost Benchmark in $/W-dc [10]

The column for weighted average, which was used herein, represents the installer and the integrator prices averaged and weighted by their market share. It should be noted that SAM does not have one-to-one inputs for each part of the pricing breakdown. For example, in SAM, there is no way to directly input the price per watt for the sales tax presented in Figure 7; rather, sales tax is calculated by applying the sales tax rate to the “direct capital costs.” The pricing breakdown was redistributed among the available SAM parameters, and then it was validated to make sure that it correctly totaled to match NREL’s cost benchmark totals.

The operation and maintenance (O&M) costs of the system must also be accounted for, and it was set to $21/kW-yr. The O&M costs come from NREL’s LCOE historical trends reporting. Lastly, inverter lifetime was set to 15 years so an inverter replacement at year 15 must be planned with the inverter replacement price being set to
the same $/W price as year 0, which was $0.13/W for string inverters. This value changed when using different inverter types, such as those that are no specified in the base case.

3.3.3.2 Roof Replacement Costs

Based on discussions with the roofing industry, a conventional shingle roof has a lifetime of about 15 years, which is the result of wear and tear from the elements accordingly. For the 30 year lifetime of this analysis, roof replacement is assumed to occur at year 0 and year 15. Unfortunately, there are no readily available and reliable sources for roof replacement pricing, which made it necessary to synthesize a standard from a variety of sources. Calls and emails were made to roofers to get an estimate on cost for roof replacement for the control building. These estimates were averaged with roof replacement cost estimate ranges taken from online calculators in order to obtain the final number used for roof replacement cost, namely $4.07/square foot.

Ideally, in BIPV installations, the roof shingles and BIPVs would be installed at the same time by the same installer. However, since residential BIPV installations are so uncommon, no installers were able to be successfully contacted. The increased cost of BIPV installation compared to BAPV was accounted for separately from the roof replacement cost.

3.3.3.3 Financial Parameters

Table 1 shows the system’s relevant financial parameters that were assumed and for the overall economic analysis. The specifications in italics are assumptions shared with NREL’s LCOE historical trends reporting. The federal tax rate was set using data
from CBO’s report on Distribution of Household Income and Federal Taxes assuming a household income of half a million per year and is lower than NREL’s assumption of 35% [18]. State income tax and sales tax were varied by state, according to their respective state income tax and sales tax rates instead of assuming a common tax rate. The insurance rate was a SAM default value that did not seem necessary to change. Salvage value is assumed to be $0 just to be conservative even though it may not necessarily be true. Analysis period was selected to be 30 years to match the PV system lifetime and two 15 year roof lifetimes.

**Table 1:** Financial Parameters

<table>
<thead>
<tr>
<th>Loan Parameters</th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td>Debt Fraction</td>
<td>40%</td>
</tr>
<tr>
<td>Loan Term</td>
<td>18 years</td>
</tr>
<tr>
<td>Loan Rate</td>
<td>4.8%/year</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Analysis Parameters</th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td>Analysis Period</td>
<td>30 years</td>
</tr>
<tr>
<td>Inflation Rate</td>
<td>2.5%/year</td>
</tr>
<tr>
<td>Real Discount Rate</td>
<td>6.9%/year</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Tax and Insurance Rate</th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td>Federal Income Tax Rate</td>
<td>30%/year</td>
</tr>
<tr>
<td>Insurance Rate (of installed cost)</td>
<td>1%</td>
</tr>
<tr>
<td>Salvage Value</td>
<td>$0</td>
</tr>
</tbody>
</table>

3.4 Climate Region and City Specific Parameters

The economic analysis of PV systems is highly dependent on the location, mostly because of weather and solar insolation, but also because of incentives and electricity
costs. In terms of weather conditions and city selection, Figure 8 shows the climate regions based on the 2015 International Energy Conservation Code (IECC) on a climate zone map, which is important for identifying a representative city was chosen from each of the seven regions within the Continental United States.

**Figure 8**: IECC Climate Zone Map [19]

These seven cities were selected to provide good distribution and representation of climate, solar insolation, net metering policy and incentives. The climate regions and cities selected for the study herein are presented in Table 2.
Table 2: **Climate Region and Representative City**

<table>
<thead>
<tr>
<th>Climate Region</th>
<th>City</th>
<th>State</th>
</tr>
</thead>
<tbody>
<tr>
<td>1</td>
<td>Miami</td>
<td>Florida</td>
</tr>
<tr>
<td>2</td>
<td>Houston</td>
<td>Texas</td>
</tr>
<tr>
<td>3</td>
<td>San Francisco</td>
<td>California</td>
</tr>
<tr>
<td>4</td>
<td>Nashville</td>
<td>Tennessee</td>
</tr>
<tr>
<td>5</td>
<td>Pittsburgh</td>
<td>Pennsylvania</td>
</tr>
<tr>
<td>6</td>
<td>Minneapolis</td>
<td>Minnesota</td>
</tr>
<tr>
<td>7</td>
<td>Fargo</td>
<td>North Dakota</td>
</tr>
</tbody>
</table>

Every geographic location comes with it a plethora of factors such as solar insolation and weather with both varying day-to-day and year-to-year which can complicate predictions. To resolve this variation, one approach is to look at a generalized year, which SAM achieves by loading data from the Typical Meteorological Year 3 (TMY3) dataset. TMY3 is the latest meteorological data set that contains hourly data of weather conditions for approximately 1000 locations across the US and hence the nearest TMY3 datapoint was loaded for every city of interest in this study.

3.4.1 Electrical Load

Because of different climates, each control building will experience different electrical loads, which are largely driven by the differences in HVAC loads. For example, Miami has high cooling loads in the summer whereas Fargo has high electrical heating loads in the winter, assuming gas heating is not used. Electrical loads were imported from the OpenEI Residential and Commercial Building Load database for every city by using a tool within SAM. This database contains hourly load profile data for commercial and residential buildings for each of the TMY3 locations in the US. The
residential building hourly load profile data is generated from simulations based on the Building America House Simulations Protocols. Of the three residential building types available, namely BASE, LOW, and HIGH, the BASE was selected for this study. Knowing the electrical load is critical because it is the other half of the PV system analysis. Considering that energy use and energy production are the two parts of interest for this study specifically, the energy produced by the PV system is subtracted from the expected electricity demand of the control house and, when applicable, the excess is sold back to the utility and represents the savings, or revenue, of the PV system.

3.4.2 State and Local Taxes

Table 3 summarizes the relevant tax rates of each city and state, with the top marginal rate assumed for the state income tax for simplicity and also because residential solar installations are, at least for the initial costs, typically expensive projects associated with those at the top marginal rate. The rates with asterisks are ignored in the model due to solar incentives tabulated in a Section 3.4.4 Table 5.

<table>
<thead>
<tr>
<th>Climate Region</th>
<th>City</th>
<th>State</th>
<th>City Sales Tax (%) [20]</th>
<th>State Income Tax (% Top Marginal Rate) [21]</th>
<th>Property Tax (% State Mean from 2012) [22]</th>
</tr>
</thead>
<tbody>
<tr>
<td>1</td>
<td>1A Miami</td>
<td>Florida</td>
<td>7*</td>
<td>0</td>
<td>1.16</td>
</tr>
<tr>
<td>2</td>
<td>2A Houston</td>
<td>Texas</td>
<td>8.25</td>
<td>0</td>
<td>2.02*</td>
</tr>
<tr>
<td>3</td>
<td>3C San Francisco</td>
<td>California</td>
<td>8.5</td>
<td>13.3</td>
<td>0.88*</td>
</tr>
<tr>
<td>4</td>
<td>4A Nashville</td>
<td>Tennessee</td>
<td>9.25*</td>
<td>0</td>
<td>0.91*</td>
</tr>
<tr>
<td>5</td>
<td>5A Pittsburgh</td>
<td>Pennsylvania</td>
<td>7</td>
<td>3.07</td>
<td>1.55</td>
</tr>
<tr>
<td>6</td>
<td>6A Minneapolis</td>
<td>Minnesota</td>
<td>8.025*</td>
<td>9.85</td>
<td>1.28*</td>
</tr>
<tr>
<td>7</td>
<td>7A Fargo</td>
<td>North Dakota</td>
<td>7.5</td>
<td>2.9</td>
<td>1.54</td>
</tr>
</tbody>
</table>
3.4.3 Local Utilities and Net Metering

Utility companies were picked based on the provider that serviced the majority of the metropolitan area for each selected city. SAM includes a database to automatically load and input electricity rate schedules, and where possible, rate schedules were chosen as single phase, single home, electric heating, and non-time-of-use rate schedules for consistency. Some utility companies have net metering policies even if the state does; however, such cases did not occur in this study. Table 4 summarizes the utility selected and the net metering policy of each city/state.

Table 4: State and Utility Net Metering Policy [23]

<table>
<thead>
<tr>
<th>Climate Region</th>
<th>City</th>
<th>Utility Company</th>
<th>Net Metering</th>
<th>Monthly Rollover Credit</th>
<th>Annual True Up Rate Basis</th>
<th>Annual True Up Rate ($/kWh)</th>
</tr>
</thead>
<tbody>
<tr>
<td>1</td>
<td>1A</td>
<td>Miami</td>
<td>Y</td>
<td>$ at retail</td>
<td>avoided-cost</td>
<td>0.01987</td>
</tr>
<tr>
<td>2</td>
<td>2A</td>
<td>Houston</td>
<td>N</td>
<td>N/A</td>
<td>N/A</td>
<td>N/A</td>
</tr>
<tr>
<td>3</td>
<td>3C</td>
<td>San Francisco</td>
<td>Y</td>
<td>$ at retail</td>
<td>cash-out or indefinite rollover</td>
<td>0.0893</td>
</tr>
<tr>
<td>4</td>
<td>4A</td>
<td>Nashville</td>
<td>N</td>
<td>N/A</td>
<td>N/A</td>
<td>N/A</td>
</tr>
<tr>
<td>5</td>
<td>5A</td>
<td>Pittsburgh</td>
<td>Y</td>
<td>$ at retail</td>
<td>price-to-compare</td>
<td>0.0653</td>
</tr>
<tr>
<td>6</td>
<td>6A</td>
<td>Minneapolis</td>
<td>Y</td>
<td>$ at avoided-cost*</td>
<td>N/A</td>
<td>N/A</td>
</tr>
<tr>
<td>7</td>
<td>7A</td>
<td>Fargo</td>
<td>Y</td>
<td>$ at avoided-cost*</td>
<td>N/A</td>
<td>N/A</td>
</tr>
</tbody>
</table>

While specifics differ, the net metering policies for the selected utilities generally work as follows: Any excess electricity generated on a monthly basis is credited to the
next month’s bill on a dollar basis, usually at the retail rate, meaning the rate at which the utility customer buys electricity. The credit can continuously roll over for 12 months before it is bought back by the utility at a set rate.

In addition to the above retail rate definition, other rates are also important and applicable to this study. For example, the avoided-cost rate is a rate equal to the electricity the utility calculates it avoids producing due to an external source such as residential PV. The price-to-compare rate is the cost for the utility to generate and deliver electric over transmission lines and does not include the portion of the cost the utility needs for equipment, maintenance, and customer service.

The cash-out rate is a special rate provided by the Clean Power SF program run by the Services of San Francisco Public Utilities Commission. This cash-out rate is significantly higher than the base sell rate provided by the utility. The Clean Power SF program allows a homeowner to choose between the annual cash-out option or indefinite rollover of credit. The annual cash-out option was picked over indefinite rollover because it was better accommodated by SAM’s net metering options.

The specifics of net metering policy were fairly complicated and did not always fit well into the options provided in SAM. Best judgement was used to match the closest option in SAM to actual policy. In most net metering policies, homeowners receive credit for excess electricity produced monthly, and at the end of the year, the utility will reimburse the homeowner for their accumulated credit at the annual true up rate. In Minnesota, state net metering policy stipulates an annual true up at avoided-cost; however, there was no mention of any annual true up policy on Xcel’s net metering
billing guide. Xcel customer support was contacted and they were unwilling to clarify or disclose their avoided-cost rate beyond what was already available on their website.

Annual true up was chosen to be ignored. Similarly, no response was ever received from Cass County Electricity, representing Fargo, about their avoided-cost rate and monthly rollover credit was thus ignored.

3.4.4 Other Solar Incentives

Table 5 summarizes the relevant local and state incentives, which mostly come in the form of sales tax and property tax assessment exemptions. N/A signifies no special exemptions were offered and the Table 3 rate in applies. Sales and property tax exemptions often stipulated purchases from a certain provider or CEC certified equipment.
### Table 5: State Tax Exemptions and Other Solar Incentives [23]

<table>
<thead>
<tr>
<th>Climate Region</th>
<th>City</th>
<th>Utility Company</th>
<th>Sales Tax</th>
<th>Property Tax</th>
<th>Other Incentives</th>
</tr>
</thead>
<tbody>
<tr>
<td>1</td>
<td>1A</td>
<td>Miami</td>
<td>Florida Power and Light</td>
<td>Exempt</td>
<td>Exempt</td>
</tr>
<tr>
<td>2</td>
<td>2A</td>
<td>Houston</td>
<td>Centerpoint</td>
<td>N/A</td>
<td>Exempt</td>
</tr>
<tr>
<td>3</td>
<td>3C</td>
<td>San Francisco</td>
<td>City &amp; County of San Francisco</td>
<td>N/A</td>
<td>Exempt</td>
</tr>
<tr>
<td>4</td>
<td>4A</td>
<td>Nashville</td>
<td>Nashville Electric Service</td>
<td>Exempt</td>
<td>Capped at 12.5% of installed value</td>
</tr>
<tr>
<td>5</td>
<td>5A</td>
<td>Pittsburgh</td>
<td>Duquesne Light</td>
<td>N/A</td>
<td>N/A</td>
</tr>
<tr>
<td>6</td>
<td>6A</td>
<td>Minneapolis</td>
<td>Xcel Energy</td>
<td>Exempt</td>
<td>Exempt</td>
</tr>
<tr>
<td>7</td>
<td>7A</td>
<td>Fargo</td>
<td>Cass Country Electricity Coop</td>
<td>N/A</td>
<td>Exempt for first 5 years</td>
</tr>
</tbody>
</table>

#### 3.5 Cases of Interest

In order to broaden the usefulness of the study reported herein, a number of special cases were investigated and compare to the base case of BAPV with a string inverter and a size of 5.8 kW. The three areas of interest to be explored for additional cases are inverter type, system size, and BIPV.

**3.5.1 Inverter Type**

As was shown in Figure 7, NREL includes pricing data from 3 types of inverter, namely the string, DC power optimizer, and microinverter. As noted, the base case uses
a string inverter, and including cases for the DC power optimizer and the microinverter are natural continuations of NREL’s work. The DC power optimizers and microinverters are collectively called module-level power electronics (MLPE). The most important difference between string inverters and MLPE is that the latter are unaffected by shading of individual modules, which has several implications. In string inverters, due to the way the PV module and DC electronics work, shading on a module, and thus lower power output by this module, reduces the power output of the entire string. For DC power optimizers, each PV module has an additional DC power optimizer that performs DC-to-DC conversion on the string such that any one individual module does not affect the rest of the string. For microinverters, each PV module has a microinverter that does DC-to-AC conversion circumventing the problem with strings entirely.

It should be noted that there can be manufacturing differences in each PV module such that they do not produce the same amount of power. A string can only produce as much as its weakest module. This is a loss called module mismatch that MLPE is not affected by. Shading from nearby trees or a chimney can negatively impact the total power production of an array with a string inverter. In contrast, the MLPE will be less affected for the same situation because only individual modules will have reduced power instead of the entire string. Also, the MLPE typically has module level monitoring of performance and troubleshooting capabilities which can be attractive to homeowners. Lastly, microinverters have 30 year lifetimes compared to 15 year lifetimes for string and dc power optimizers. However, the MLPE incur greater costs than string inverters. Regarding changes within the SAM model, different inverter types incurred different
costs, and the only other difference in SAM was in the modeled losses of each inverter type.

3.5.2 System Size

Another area of interest was system size. While average residential system size has not changed significantly in the recent past, it has seen a slow and small upward trend [10]. Additionally, it was found after creating the base case model that a 5.75 kW array covers less than one fourth of the total roof area for this study, meaning there is a clear opportunity for growth in system sizes. With this in mind, two larger system sizes were also investigated, namely 8.63 kW and 11.51 kW. These specific system sizes were selected as a result of the integer increase in the number of inverters and strings. The base case had four strings and two inverters, which corresponds to two strings per inverter. The number of modules per string was kept constant at six. Adding another inverter to make two inverters total, would consequently mean six strings of modules, and SAM calculated this system size to be 8.63 kW. Similarly, four inverters meant eight strings and a resulting size of 11.51 kW.

3.5.3 BIPV

Lastly, the difference between BAPV and BIPV was explored. By definition, BAPVs are applied on top of a conventional roof and BIPVs are the roof. In theory, BIPV has a longer lifetime than a conventional roof, and therefore, it does not need replacing as frequently, while also generating some revenue. Whether this is a worthwhile investment over a plain, conventional roof or a conventional roof with BAPV is the crux of this research.
The setup of the BIPV system is similar to the base BAPV system. There is only one manufacturer, CertainTeed, for commercially available BIPV modules and they come as small 60W modules or solar “shingles.” While it would be possible to model these solar shingles for the BIPV system in SAM, it would not be possible to exactly match the system size to the BAPV system size due to needing an integer number of modules in the system. Again, it should be noted that SAM only simulates the system as an aggregate and does not simulate the performance on individual modules, absent shading. The major difference between BAPV and BIPV that SAM considers is BIPV’s lower efficiency, which is 16.2% vs 13.2% respectively. To compensate for BIPV’s lower efficiency, module area was increased in such a manner that the maximum power of each module remained constant at 239.8 W-dc. As an effect, the total area covered by the BIPV system was larger but this was considered a reasonable tradeoff in order to preserve the system size (and DC-to-AC ratio) between the BAPV and BIPV cases.

BIPV costs were unavailable from the NREL cost benchmark unlike BAPV costs. Authorized installers of CertainTeed BIPV systems were contacted via email to inquire about solar shingle costs. Their cost estimates were averaged to total about $5.77/W-dc as-installed. This total as-installed cost includes their increased cost of installation compared to BAPV.

3.5.4 Summary of Cases

In summary, three broad categories of cases were investigated and compared in this study: Conventional roof alone, conventional roof with BAPV, and mixed conventional roof and BIPV. The conventional roof alone was the case that all other
cases were benchmarked against. Since BAPV is still by far more common, BAPV was investigated in all seven cities, in three sizes, and with three different types of inverter. This totals to 63 different test cases and simulations for BAPV. BIPV was investigated in all seven cities, in three sizes, and with just the string inverter. This totals 21 different test cases and simulations for BIPV. All together there were 85 test cases that were simulated and studied.

3.6 Running Simulations

Once all data was entered and properly set up, which was time consuming and labor intensive, running simulations in SAM took only a few seconds, and then SAM generated a plethora of system performance data and financial metrics that needed sorting and identifying. Figure 9 shows a sample of the summary page of the simulation results, which is just one of many results pages.
3.7 Compiling Data

The data that SAM produces cannot be manipulated inside SAM; therefore, it was necessary to transfer needed data into an Excel spreadsheet to be further processed, compared, and prepared for presentation. Additionally, SAM cannot handle roof replacement costs, so it was necessary that NPV for roof replacement be calculated in Excel. It is important to remember that while BAPV requires that the whole roof be replaced, BIPV only requires that the remainder of the roof not covered by BIPV modules be replaced. SAM calculates the area covered by the PV system modules automatically, so finding the area remaining was not difficult, with tables of calculations being used to determine the total roof replacement costs.
NPV for roof replacement costs were calculated manually, with roof replacement being scheduled at year 0 and year 15 as mentioned before. Roof replacement costs at year 15 were estimated to keep up with annual inflation (2.5%) and then brought back to present value, which was added to the roof replacement cost at year 0 to calculate the roof replacement NPV. Roof replacement NPV is useful on its own as the “No PV System” case and for manually adding to the PV systems’ NPV to get their total and final NPV.

From the “Data tables” tab as presented Figure 9, annual energy, NPV, real LCOE, total installed cost, electricity bill without a system, and electricity load total (year 1) were collected to be analyzed and copied in a spreadsheet. Electricity bill without system and electricity load total (year 1) were used to calculate an “effective electricity rate” (EER) because electric rates are normally on a rate schedule, which may not be easily understood. This “effective electricity rate” provides a single number that can be compared to real LCOE.

Plots of results were generated for ease of comparison, with the plots being split in four different categories: BAPV with string inverter, BAPV with DC power optimizer, BAPV with microinverter, BIPV with string inverter. The values of NPV and real LCOE were graphed separately for each of the 4 categories. Graphs were first divided by city and then by system size. Results are presented in the next section.
4. RESULTS AND DISCUSSION

In the following section, results of the SAM simulations and Excel spreadsheet calculations will be presented. For every case, net present value (NPV) and real levelized cost of electricity (LCOE) are the metrics being compared for the cases investigated in this study. NPV gives a net profit for the investment in real terms and can indicate a good or bad investment. Real LCOE is what the cost of electricity produced by the system must be in order to pay off the system costs in real terms. Real LCOE alone cannot indicate a good or bad investment and needs to be compared to the electricity rate a homeowner would otherwise pay to be meaningful. The comparison electricity rate to be used is the effective electricity rate (EER), which is an electricity rate schedule that is weighted by use and then condensed into a single number.

SAM computes dozens of other metrics besides NPV and real LCOE including some that will be helpful in explaining the results and trends which are shown below in Table 6. The latitude determines the angle of the sun relative to the fixed angle of the PV panels so it is expected that lower latitudes where the sun is relatively higher in the sky will produce more energy. However, it can be seen that the direct normal irradiance, a measure of the solar radiation received on a surface perpendicular to the sun per unit area per day, not latitude, is correlated with the annual energy produced of the PV system. Direct normal irradiance comes from the TMY3 weather file and is an annual average which presumably considers cloud cover as well, explaining why latitude does not directly correspond with energy produced. The total installed cost at each city varies
depending on the sales tax rate and the sales tax exemptions seen in Table 3 and Table 5 in Sections 3.4.2 and 3.4.4 respectively. Total install cost will directly impact NPV and LCOE as the year 0 cash flow. Tables Table 4 and Table 5 in Sections 3.4.3 and 3.4.4, respectively, tabulate each city’s net metering policy and production based incentives if they have any.

**Table 6: Additional Metrics for 5.8 kW System**

<table>
<thead>
<tr>
<th>City</th>
<th>Latitude ('N)</th>
<th>Direct Normal Irradiance (kWh/m²/day)</th>
<th>Annual Energy (kWh)</th>
<th>Total Installed Cost ($)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Miami</td>
<td>25.8</td>
<td>3.98</td>
<td>8273</td>
<td>14846</td>
</tr>
<tr>
<td>Houston</td>
<td>30.0</td>
<td>3.88</td>
<td>7790</td>
<td>15373</td>
</tr>
<tr>
<td>San Francisco</td>
<td>37.6</td>
<td>4.85</td>
<td>8875</td>
<td>15313</td>
</tr>
<tr>
<td>Nashville</td>
<td>36.1</td>
<td>3.98</td>
<td>7863</td>
<td>14846</td>
</tr>
<tr>
<td>Pittsburgh</td>
<td>40.5</td>
<td>3.12</td>
<td>7188</td>
<td>15293</td>
</tr>
<tr>
<td>Minneapolis</td>
<td>44.9</td>
<td>4.12</td>
<td>7621</td>
<td>14846</td>
</tr>
<tr>
<td>Fargo</td>
<td>46.9</td>
<td>4.21</td>
<td>7784</td>
<td>15325</td>
</tr>
</tbody>
</table>

First to be presented is the roof replacement or control case. Next are the Building Applied Photovoltaic (BAPV) cases separated by inverter type, followed by the Building Integrated Photovoltaic (BIPV) cases. BAPV are solar panels that lie flush on top of a roof while BIPV are solar panels that structurally act as the roof. Last is an alternative “slicing” of the data looking at all cases together for a constant system size. For each case, the simulation and calculation results are followed by discussion of the data.
4.1 Complete Roof Replacement Only

As a reminder, the NPV for the roof replacement is just the cost of the roof replacement at year 0 and the cost of the roof replacement at year 15 brought back to present value. We should expect the NPV to be negative because the only cash flows are negative. The NPV for a complete roof replacement was -$19500. This NPV is also factored into the BAPV cases.

4.2 All System Sizes Compared

The first and largest, based on multiple inverter types, set of cases investigated are those done for BAPV systems for a range system sizes. The results will reveal the economic viability of using a larger system size that produces more of a household’s share of electricity or more expensive inverter type with less losses.

Generally, positive NPVs are economically favorable while negative NPVs are economically unfavorable. However, since the roof replacement NPV was added to the SAM outputted BAPV system NPV, the NPVs are expected to be mostly, if not all, negative as well. A summary of the unfavorable and favorable NPVs is presented in the bullet points below:

- **NPV < -$19500**: Worse investment than just roof replacement
- **NPV = -$19500**: Parity with roof replacement
- **NPV > -$19500**: Better investment than just roof replacement
The real levelized cost of electricity (LCOE) can be seen as the cost of electricity produced by the PV system. Thus, it can be said that lower is better for real LCOE. The point of comparison is a calculated “effective electricity rate” (EER) as discussed in Section 3.7, which represents the cost of electricity provided by the utility without the PV system. A summary of the unfavorable and favorable real LCOEs vs EERs results is presented in the bullet points below:

- Real LCOE < EER: Electricity rate cheaper than that provided by utility
- Real LCOE = EER: Parity with electricity rate provided by utility
- Real LCOE > EER: Electricity rate more expensive than that provided by utility

4.2.1 BAPV – String Inverter

The first set of cases presented, and arguably most important, are the BAPV using string inverters. Among all cases, BAPV using a string inverter at 5.8 kW can be considered a baseline against which all other PV systems will be compared. Locations represented by cities and also system size are the changing variables to be investigated.

Figure 10 shows the NPVs for the 21 cases of BAPV with string inverters plus the roof replacement NPV for comparison. It can be seen for every city that NPVs grow more negative with increasing system size except for Minneapolis, which had a slight increase in NPV with increasing system size. The NPVs as a percentage difference from the baseline 5.8 kW case to 11.5 kW ranged from -7% for Minneapolis to +47% for Fargo.
The trend of decreasing NPV for increasing system size means that the additional electricity generating capacity of a larger system does not offset the increased cost of a larger system. It is not completely clear why Minneapolis alone has an increasing NPV for increasing system size. It may be because the utility offers production based incentive (PBI) which is active for the first 10 years, which front-loads the reward for producing excess electricity. When discounting to the present, the NPV calculation has a bias towards money closer to the present. Therefore, a larger system producing more excess electricity early on would positively affect the NPV, which in fact may be the case for Minneapolis.

**Figure 10: NPV for BAPV with String Inverter**
From examining Figure 10 and seeing two set of bars with values greater than -19500, there were two cities where their NPV showed favorable results: San Francisco, where its NPV for all system sizes was nearly half the value of the roof replacement NPV, and, surprisingly, for Minneapolis for all system sizes where Minneapolis’ NPVs are just slightly less negative than the roof replacement NPV. San Francisco’s favorable NPV is driven by a high effective electricity rate (which can be seen in Figure 11 to be introduced later), a strong net metering policy, and a low electrical load. High EER combined with strong net metering policy means the electricity being displaced by the PV system is sold at the relatively high EER and is worth more than in other cities. Low electrical load means that more electricity is produced in excess to be sold back to the utility. Minneapolis’s favorable NPV is driven by a strong net metering policy and a production based incentive. The PBI awards $0.08/kWh produced for the first ten years with excess electricity produced in the first ten years being worth approximately 166% of the EER. As mentioned before, the NPV calculation favors cash flows closer to the present so the PBI is more valuable to have early on.

For the baseline 5.8 kW system size, Miami and Pittsburgh are less than $4000 away from reaching parity with roof replacement in absolute terms. Miami’s NPV is hampered by its low EER despite having net metering. Pittsburgh is similar to Miami except that it is at higher latitude, gets less solar insolation, and produces 13% less electricity than Miami as a result. While Houston, Nashville, and Fargo for all system sizes are all quite far away from reaching parity with roof replacement. Houston and Nashville both do not have net metering and net metering was ignored for Fargo for
reasons stated in Section 3.4.3. Nashville has a $0.09/kWh PBI but the lack of net metering made a bigger negative impact that outweighed the positive impact of a PBI. Nashville’s PBI pays out lower than if Nashville had a net metering policy that paid out retail and the PBI expires after 20 years, two-thirds of the way through the analysis period.

Figure 11 shows the LCOE for the 21 cases of the BAPV with a string inverter compared with the EER for each city. LCOEs range from a low of 9.1 ¢/kWh in Nashville to a high of 16.9 ¢/kWh in Pittsburgh. In addition, every city except San Francisco had an EER between 10-16 ¢/kWh, with San Francisco’s EER being an outlier at 24¢/kWh with its LCOE being less than half that value. It should be noted that San Francisco’s high EER is due to the utility’s aggressive electric rate schedule. For each city there is little variation in the LCOE with increasing system size, with no more than a 1 ¢/kWh difference between the lowest and highest LCOE. From this, it can be concluded that an increased cost due to an increase in system size results in a near one-to-one increase in the value of electricity produced by the additional PV panels, meaning there are no scaling effects from increase in system size.
Figure 11: Yearly Average Electricity Rate vs Real LCOE – BAPV String Inverter

The majority of the seven cities showed favorable results through the lens of real LCOE compared to NPV, with Houston, San Francisco, Nashville and Minneapolis showing real LCOE values lower than their respective EERs. San Francisco has a favorable real LCOE due to its high EER that is almost double the average of the other cities’ EERs. However, San Francisco’s real LCOE is still low enough such that it would be favorable even with at the city average EER of 12.8 ¢/kWh. Houston and Nashville both had unfavorable NPVs but favorable values in the real LCOE, which is probably because real LCOE values all electricity produced regardless of net metering policy, thus helping lower the real LCOE. Neither city has net metering and without net metering,
the NPV only counts the electricity savings and excess electricity is worthless. For Minneapolis, the PBI helps lower the yearly costs, which also lowers the real LCOE.

This leaves Miami, Pittsburgh, and Fargo with LCOE values higher than their respective EERs. Miami suffers partially because of its low EER, while Pittsburgh’s system generates the lowest annual energy out of any city, which in turn lowers the real LCOE. Pittsburgh and Fargo are the only cities that do not have any form of sales tax exemptions nor property tax exemptions, thus raising the initial installed cost and raising the real LCOE. All in all, it can be said that no one factor is responsible for creating a favorable or unfavorable real LCOE.

4.2.2 BAPV – DC Power Optimizer

The next set of cases presented are the BAPV with DC power optimizers, which helps determine whether decreased losses offset the increased cost of module-level power electronics (MLPE). Locations represented by cities and system size are the changing variables investigated.

Figure 12 shows the NPVs for the 21 cases of a BAPV with a DC power optimizer plus the roof replacement NPV for comparison purposes. The results are in many cases similar to those for the BAPV with a string inverter. Once again, it can be seen for every city that NPVs grow more negative with increasing system size except for Minneapolis, which had a slight increase in NPV with increasing system size. The NPV as a percentage difference from the baseline 5.8 kW to 11.5 kW ranged from -6.2% for Minneapolis to +47.8% for Fargo.
The same two cities showed favorable NPVs as in the string inverter cases: San Francisco and Minneapolis. For the 5.8 kW system size, Miami and Pittsburgh show similar results to the string inverter cases and are less than $4000 away, in absolute terms, from reaching parity with roof replacement, while Houston, Nashville, and Fargo for all system sizes are quite far away from reaching parity with roof replacement.

Figure 13 shows the LCOE for the 21 cases of BAPV with DC power optimizers compared with the EER for each city. LCOEs range from 9.2 ¢/kWh in Nashville to 17.1 ¢/kWh in Pittsburgh. The San Francisco LCOE is still less than half its EER. There appears to be little variation in the LCOE with increasing system size, as evidenced by there being no more than 1 ¢/kWh difference between the lowest and highest LCOE for
each city. Again, more cities showed favorable results through the lens of LCOE compared to NPV. Houston, San Francisco, Nashville and Minneapolis showed LCOE values lower than their respective EERs, meaning that the PV system provides electricity cheaper than the utility and is a favorable outcome, which leaves Miami, Pittsburgh, and Fargo with LCOE values higher than their respective EERs.

Looking back at Figure 7, DC power optimizers are only $0.02/W-dc more expensive than string inverters. The total installed costs did not change much as a result nor did the change in losses make a significant impact on energy production. Therefore,

**Figure 13:** Yearly Average Electricity Rate vs Real LCOE – BAPV DC Power Optimizer
the reasons for the results and trends in NPV and real LCOE should be the same as that presented in Section 4.2.1 for BAPV with string inverter.

4.2.3 BAPV – Microinverter

The next set of cases presented are the BAPV with microinverters. These cases will help determine whether the decreased losses offset the increased cost of module level power electronics (MLPE). Locations represented by cities and system size are the changing variables within this section.

Figure 14 shows the NPVs for the 21 cases of BAPV with microinverters plus the roof replacement NPV for comparison. The behavior shown has some similarities to that of the BAPV string inverter. For example, it can be seen that NPVs grow more negative for every city with increasing system size except for Minneapolis, which increased slightly going from 5.8 kW to 8.6 kW and then decreased to original values when going from 8.6kW to 11.5kW. It is not entirely clear why Minneapolis’s NPV shows this behavior for different inverter. The range for NPV as a percentage difference from 5.8 kW to 11.5 kW varies from +0.5% for Minneapolis to +50.9% for Fargo. The same two cities showed favorable results: San Francisco and Minneapolis. For the 5.8kW system size, Miami and Pittsburgh are less than $6000 away, in absolute terms, from reaching parity with roof replacement, which is farther than the BAPV string inverter and DC power optimizer cases, while Houston, Nashville, and Fargo for all system sizes are all quite far away from reaching parity with roof replacement.
Figure 14: NPV for BAPV with Microinverter

Figure 15 shows the LCOE for the 21 cases of BAPV with microinverters compared with the EER for each city. LCOEs range from 10.5 ¢/kWh in Nashville to 19.3 ¢/kWh in Pittsburgh, while San Francisco’s LCOE is now a little over half its EER. There is little variation in the LCOE with varying system size with no more than 1.5 ¢/kWh difference between the lowest and highest LCOE for each city.
Figure 15: Yearly Average Electricity Rate vs Real LCOE – BAPV Microinverter

Again, more cities showed favorable results through the lens of LCOE compared to NPV but this time, not all system sizes for each city were competitive with their respective EER. Houston and San Francisco showed LCOEs lower than their respective EERs, though Houston was only narrowly so. Nashville and Minneapolis had LCOEs that were lower than the EER for the 5.8 kW and 8.6 kW system sizes but not for the 11.5 kW system size. At some point, it got more expensive to add PV panels than the value of electricity that was obtained by the increased system size. For Nashville, the 11.5 kW system size started to produce substantial amounts of electricity over its expected electrical load. Because Nashville lacks net metering, this excess has no value
and the additional system size is not economically viable, which leaves Miami, Pittsburgh, and Fargo with LCOE higher than their respective EERs.

### 4.3 Partial Roof Replacement + BIPV

The last set of cases presented here are the building integrated photovoltaics (BIPV) with string inverters. These cases will enable a determination to be made of the economic viability of the more expensive BIPV systems. Unlike the building applied photovoltaic (BAPV) cases, the complete roof replacement net present value (NPV) is not added to the System Advisor Model’s calculated BIPV NPVs. Because only part of the roof is covered by traditional shingles, a separate roof replacement NPV was calculated for the remainder of the roof not covered by BIPV panels. This remainder roof replacement NPV was -$15,700, -$13,800, and -$11,900 for the 5.8 kW, 8.6 kW, and 11.5 kW systems, respectively. However, the total NPVs for the BIPV with string inverter cases will still be compared to the complete roof replacement NPV that was covered in Section 4.1 because that is the control case. Changing variables within this section are locations represented by cities and system size.

Figure 16 shows the NPVs for the 21 cases of BIPV with string inverters, plus the roof replacement only NPV for comparison. Every city had decreasing NPV for increasing system size. The trend of decreasing NPV for increasing system size means that additional electricity generating capacity of a larger system does not offset the increased cost of a larger system. The range for NPV as a percentage difference from 5.8 kW to 11.5 kW was +30.9% for Minneapolis to +64.1% for Fargo.
None of the cases showed favorable NPVs compared to roof replacement with San Francisco’s 5.8 kW system being the closest, at under $1000 in absolute terms, to reaching parity with roof replacement, mirroring San Francisco’s good performance in other cases. The majority of cities were over $10000, in absolute terms, away from reaching parity with roof replacement, meaning the total installed cost of a BIPV system was simply too high to be economically viable.

Figure 17 shows the LCOE for the 21 cases of BIPV with a string inverter compared with the EER for each city. LCOEs range from 23.5 ¢/kWh in Nashville to 36 ¢/kWh in Pittsburgh. What did not change is that there is little variation in the LCOE with varying system size, with no more than a 1.5 ¢/kWh difference between the lowest
and highest LCOE for each city. Being electrically similar to the BAPV with string
inverters, this is an expected result. For the BIPV set of cases, NPV and LCOE agreed
that there were no cities with favorable results. In other words, in all cities, a BIPV
system was a worse investment than just roof replacement and produced electricity that
was more expensive than could be purchased from the local utility. While no city had
economically favorable results, San Francisco was close, according to both NPV and
LCOE results, in part, due to the high EER in San Francisco. High EER makes
electricity sold back to the utility more valuable in the NPV calculation and is a higher
benchmark against which LCOE is compared. San Francisco’s 5.8 kW system LCOE
was 25.4 ¢/kWh compared to its 25.0 ¢/kWh EER, just 0.4 ¢/kWh difference. Every
other city’s LCOE was around double its EER. High LCOEs were driven primarily by
the high total installed cost. Overall, the economic metrics for the BIPV cases indicate a
homeowner’s money is better invested elsewhere.
Figure 17: Yearly Average Electricity Rate vs Real LCOE – BIPV String Inverter

4.4 All Configurations Compared

In this section, the same data as the previous 3 sections is presented in an alternate manner. There are three variables being considered at once: Locations represented by cities, system size, and specific PV and inverter configurations. Two variables can be represented clearly on a 2D chart at any one time. In Sections 4.2 and 4.3, the two variables represented were city and system size for each specific PV and inverter configuration. In this section, the two variables are the city and specific PV and inverter configuration at a constant system size. This allows for a better comparison of the specific PV and inverter configurations that may not have been clear in the prior sections. Only the 5.8 kW data will be presented as all system sizes follow similar
trends, so that results found for the 5.8 kW system size should be applicable to the other two system sizes. Data and charts for 8.6 kW and 11.5 kW system sizes can be found in the Appendix.

Figure 18 shows the NPVs for the 28 cases that represent all configurations at the 5.8 kW system size plus the roof replacement only NPV for comparison. The base PV system to be compared is BAPV with string inverters. There is less than a 3% difference between the DC power optimizer NPVs compared to the string inverter case. Most cities average about 7% more negative values for BPAV microinverter NPVs compared to their respective BAPV string inverter cases. San Francisco has nearly a 16% more negative NPV than the BAPV string inverter case. BIPV NPVs are significantly more negative that the BAPV string inverter cases, ranging from 33% more negative for Houston to 113% more negative for San Francisco and averaging 54% more negative overall.
**Figure 18:** NPV for All 5.8 kW Configurations

The trend of more negative NPVs going through the configurations follows the trend of higher installed cost for each respective system type. As an example, the total installed costs for Miami are shown in Table 7.

**Table 7: Total Installed Cost for Miami – 5.8 kw System Size – All Configurations**

<table>
<thead>
<tr>
<th></th>
<th>BAPV - String</th>
<th>BAPV - DC Power Opt.</th>
<th>BAPV – Micro</th>
<th>BIPV - String</th>
</tr>
</thead>
<tbody>
<tr>
<td>Total Installed Cost</td>
<td>$14,800</td>
<td>$15,200</td>
<td>$17,400</td>
<td>$33,200</td>
</tr>
</tbody>
</table>

For the BAPV cases, this means that the increased cost of module level power electronics (MLPE) is not outweighed by their greater efficiency. The BAPV using a
string inverter is the best inverter choice because it has the greatest net present value (NPV). For the BIPV case, the NPV is more negative solely because the cost per watt installed and thus total installed price is higher than that of the BAPV using a string inverter case. This result was expected because the BIPV is more expensive, but otherwise it does not differ from an electricity generating perspective from the BAPV using a string inverter case. The data shows that San Francisco has proportionally larger changes in the NPV than the other cities, which may be because San Francisco has a combination of lowest electrical load, a high effective electricity rate, and a generous net metering policy. Even the smallest size, namely the 5.8 kW case, generates excess electricity over its electrical load. San Francisco therefore has less to gain from any increases in electricity production capacity and more to lose from increased installed costs.

Figure 19 shows the LCOE for the 28 cases of all configurations at the 5.8 kW system size compared with the EER for each city. The BAPV DC power optimizer LCOE results were less than 2% higher compared to the BAPV string inverter LCOE results. The BAPV microinverter LCOEs averaged 1.45 ¢/kWh or 11.1% higher than the BAPV string inverter LCOEs. The BIPV string inverter LCOEs averaged 15.7 ¢/kWh or 121.4% higher than the BAPV string inverter LCOEs.
Figure 19: Yearly Average Electricity Rate vs Real LCOE – All 5.8 kW Configurations

Real LCOEs for BAPV DC power optimizers and BAPV microinverters do not change much compared to BAPV with string inverters for similar reasons as NPV, the increased installed cost of MLPE is nearly made up for by the increased electricity production. The additional cost has a stronger effect on the LCOE than the increased efficiency and the real LCOE is marginally higher as a result. The BIPV case total installed cost is 123% greater than that of the BAPV using a string inverter which nearly matches the 121% increase in real LCOE for BIPV. It makes sense for the increase to be one-to-one because LCOE can be viewed as the cost of electricity necessary to pay off the project. A doubling of the project cost means a doubling of the cost of electricity.
4.5 Reaching BIPV Parity

In previous sections it was shown that BIPV was not economically favorable compared to just roof replacement but that begs the question, at what pricing will BIPV reach parity with roof replacement? Answering the question of BIPV parity with roof replacement will also answer the question of BAPV with string inverter parity because they are electrically the same. To differentiate the two system configurations, the question of BIPV parity will instead be compared to more expensive roof types such metal shingle, clay tile, or synthetic shale since these roofing materials are “premium goods” like BIPV shingles or tiles.

The more premium roofing materials are in the range of $9/sq-ft, more than double compared to the estimated cost of $4.07/sq-ft for conventional asphalt shingles. The partial roof replacement for the remaining roof area not covered by BIPV modules was also assumed to be a more premium roofing material. The price per watt of the BIPV modules was adjusted in the “System Costs” tab in SAM through a “guess and check” method until the average city NPV of a BIPV system with string inverter matched that of roof replacement using premium materials. Figure 20 shows the results of BIPV parity for each city.
Unsurprisingly, the cities that were above or below average NPV’s, or their magnitudes relatively to each other, stayed the same as other cases analyzed. It is important to remember that with increasing system size, the remainder of roof to be covered by premium conventional roofing materials is reducing, meaning the contribution to the NPV by the roof replacement is decreasing with increasing system size. When NPVs decrease with increasing system size, like for all cities except Miami, San Francisco, and Minneapolis, that means that the NPV contribution from the BIPV system is growing more negative faster than the decreasing contribution from the roof replacement. For the majority of cities, the NPV is growing more negative with
increasing system size, meaning that the increased installed cost from additional system size is not worth the increased production in electricity gained from a larger system.

To reach parity with roof replacement, price per watt-dc for BIPV had to drop to $3.75/W-dc, a -37% reduction from the current estimated price, $5.96/W-dc. Some of this price reduction can be expected to come as the technology matures and installers become more familiar with BIPV products and how to install them. How exactly to drive the cost down for BIPV products and estimating when they will reach parity with roof replacement is outside the scope of this research.

4.6 Model Limitations

As a result of a number of challenges, the model effects reported and used herein has a number of limitations. Examples of these modeling limitations are shading and snow effects, integrating secondary benefits in the NPV calculation, the year 15 roof replacement, and some of the net metering policies. Of special importance, these limitations could potentially affect NPV and real LCOE either positively or negatively.

With regards to limitations, an obvious question is how will snow affect solar panels in the winter? As mentioned previously in Section 3.3.2.2., shading was considered outside the scope of this research and snow covering solar panels in the winter is considered a type of shading. However, some discussion about the effects of snow and shade is important in terms of understanding the model and its results.

A homeowner will likely not be clearing the snow off their roof and solar panels every day so electricity production in the winter will be negatively affected when snow
covers the panels, especially in the higher numbered climate zones, indicative of northern regions and cities. With string inverters, the problem of snow is especially acute because solar panels on a string will only perform as well as the weakest solar panel on the string. Having even one panel covered by snow will significantly reduce the output of the entire string. The problem is reduced by using module level power electronics with the output reduced on a per panel level instead of per string.

Another compounding factor is that electrically heated homes, which is one of the electricity rate assumptions, have greater electrical load in the winter than in the summer. Higher winter load is in contrast to solar electricity production that is greater in the summer than in the winter. As an example, Figure 21 shows the electrical load and PV system output for Fargo with the reduced electricity output due to snow coverage in winter being doubly problematic. Solar roofing installations in climates with snowy winters will overreport their electricity production in the SAM simulation leading to artificially higher NPVs and lower real LCOEs. For this research, in climate regions where it snows in the winter, NPVs should be lower and real LCOEs should be higher. Minneapolis narrowly had favorable NPVs and real LCOEs in many cases but probably would be unfavorable if snow and shading were considered.
An aspect of the research that was unaccounted for includes the “secondary benefits” of renewable energy. Secondary benefits of renewable energy include reduced maintenance cost and lower insurance premiums from a more durable roof and increased property value of having a solar roof. The increased home value from having a solar roof was used in SAM to calculate the property tax paid (when not exempt) but was not considered to have increased the homeowner’s net worth. In a related sense, the benefit of a new roof was also not calculated for the standalone roof replacement model which is why the NPV for the roof replacement is negative. In general, secondary benefits are hard to estimate and integrate into NPV calculations and were thus ignored.
Another simplifying assumption made was that the year 15 roof replacement did not account for removing the BAPV solar panels and reinstalling them after the roof was replaced. This was ignored because no roofers with experience in this practice could be identified or provide reasonable estimates for its cost. Accounting for the removal and reinstallation of BAPV panels would cause a greater negative cash flow in year 15 and reduce the overall NPV.

Lastly, several similar net metering policy stipulations were ignored apart from the ones already mentioned in Section 3.4.3, which were the avoided-cost annual true up rate in Minneapolis and avoided cost monthly rollover credit in Fargo. The net metering policy stipulations ignored are described in Table 8.

**Table 8:** Net Metering Policy – Size Limits

<table>
<thead>
<tr>
<th>City</th>
<th>Size Limits</th>
</tr>
</thead>
<tbody>
<tr>
<td>Miami</td>
<td>Systems not be sized to produce energy exceeding 115% of the household’s yearly kWh consumption</td>
</tr>
<tr>
<td>Nashville</td>
<td>Systems greater than 10 kilowatts in size will be subject to a load requirement. System’s maximum capacity will be limited so that it should not generate more than 100% of the energy usage or consumption at the home or business.</td>
</tr>
<tr>
<td>Minneapolis</td>
<td>Customer’s system capacity may not be more than 120% of the customer's on-site annual energy consumption</td>
</tr>
</tbody>
</table>

The 11.5 kW system size violated the size limits in all three respective cities listed in Table 8. In other words, these systems would not have been allowed to have been built in reality, but they were kept in the simulations and reported in the results for consistency and to be available for comparison.
5. CONCLUSION

In this research, electrical and financial performance of residential photovoltaic roofing was simulated in System Advisor Model and compared to a control traditional roof. Simulation set up relied heavily on prior NREL literature but information for model parameters were also gathered from a variety of sources including industry contacts and government statistics. The model generated results for 84 different test cases where variations in climatic region represented by select cities, system size, and system configuration were investigated. Data for the traditional roof replacement was generated in Excel and SAM results were imported into Excel for further analysis.

For building applied photovoltaic solar roofing, only one city of seven, San Francisco, had strongly favorable economic indicators, net present value and levelized cost of electricity. Minneapolis showed slightly favorable net present value and levelized cost of electricity. Houston and Nashville had mixed favorable and unfavorable metrics between net present value and levelized cost of electricity respectively. Miami, Pittsburgh, and Fargo had unfavorable metrics according to both net present value and levelized cost of electricity. The trends in the results suggest that increasing system size is not cost effective compared to the base case 5.8 kW size, expensive module level power electronics have parity with or are only slightly less cost effective compared to base case string inverters, and building integrated photovoltaics are far too expensive to be economically competitive to traditional shingle roofing. The costs of building
integrated photovoltaics have to and are expected to come down as the technology and market matures.

5.1 Future Work

The model limitations listed in Section 4.5 could be addressed in future work. The effect of shading and snow is expected to have substantial impact on the favorability of different inverter types. SAM has a module which should have the capability to estimate the losses from shading and snow. A thorough analysis would also try to account for the secondary benefits of owning a solar roof as well as account for the removal and reinstallation of building applied photovoltaic panels.
REFERENCES


