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The purpose of this analysis is to determine the optimal replacement strategy for a residential photovoltaic (PV) array. Specifically, the optimal year and number of solar modules that should be replaced on a residential solar panel system. This analysis aims at saving the stakeholder, a homeowner with a residential PV array, money. A Monte Carlo simulation and nonlinear mixed-integer programming are the analytic techniques used in determining the replacement strategy. Localized cost of electricity (LCOE) is the objective function in these analyses. Modular, environmental, and market factors are all variables that can affect the LCOE. University of Maryland's LEAFHouse was the basis of these analyses because it is a house equipped with an aging PV array and readily accessible data. Based on the findings in this report, it was determined that 0 ± 0 solar modules should be replaced after 1.42 ± 0.32 years with a reference year of initial installation being 2007. While the analysis results were not expected, they were proven to be reasonable based on cost trends for solar panels and the calculated monetary value of the power production lost from the PV array.

I Introduction

It is well documented that PV cells degrade from extreme temperatures, UV exposure, and mechanical damage. Long-term UV exposure or cycling temperatures can lead to the internal resistance of the cell increasing due to infiltration of contaminants, such as water vapor. Elevated temperatures can also lead to a decrease in shunt resistance, or resistance of the path to ground, when metal ions migrate through the cell. Furthermore, the module's anti-reflective coating can deteriorate due to heat, UV exposure, and exposure to contaminants. Degradation resulting from mechanical damage typically results from poorly installed PV cells that are stressed by wind loads or are in a place where objects are contacting them [1]. All of these factors can lead to a PV cell degrading, resulting in decreased power output. This effect can be magnified if multiple PV modules are wired in series because, similar to shading effects, if one module has a higher degradation rate than other modules in the same string then it will affect the entire string. A way to combat this degradation and loss of power is to replace aging modules with new ones. However, it is important to take into consideration the cost to install, maintain, and operate these modules. There needs to be a methodical and mathematical approach towards deciding when to replace modules and how many to replace. This report details exactly that and takes a look at the economics and feasibility of a replacement strategy.

Localized cost of electricity (LCOE) is defined as the ratio of the PV array's lifecycle cost to its lifetime energy production. It can be thought of as the price at which energy must be sold to break even over the lifetime of the system [2]. Naturally, a homeowner wants this value to be as low as possible to reduce the financial burden of the PV array. LCOE is the primary objective function in the analyses and the factors, or decision variables, that influence the value of LCOE can be broken down into three major categories: module factors, market factors, and environmental factors. Fig. 1 shows a response model diagram for this system, which depicts the output metrics of interest and factors which effect that value. Module factors, or factors that relate to the PV array power output, include power output of each module, P_{mod}, degradation rate, σ, module efficiency, ϵ, and lifecycle time, tlife. Market factors are all factors that relate to lifecycle costs. These include the total cost of solar panels, C_i, total cost of operation and maintenance, C_{om}, and investment tax credit, ITC. Environmental factors are those related to the surroundings of the PV array that would affect its performance. These factors include solar irradiance, E_e, and ambient air temperature, T.

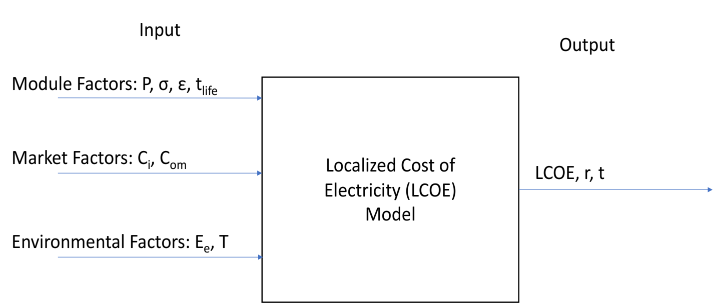

Fig. 1. *Response model for determining LCOE value, number of replaced modules, and time of replacement.*

A Monte Carlo simulation was developed to characterize the uncertainty and sensitivity in the values for number of solar modules replaced, year of replacement, and the LCOE resulting from the replacement strategy. There are known distributions for various factors affecting LCOE and these distributions lead to the necessity of a Monte Carlo simulation. Nonlinear mixed-integer programming was also used with the Monte Carlo simulation to determine the optimal number of modules that should be replaced and how many years after initial PV array installation. Mixed-integer programming was used, as opposed to ordinary nonlinear programming, because the amount of solar modules replaced is restrained to being an integer value, but time of replacement (in years) does not need to be an integer value because the modules can be replaced at any time during the year.

II System Description

The system of interest in this analysis is the PV array on top of the University of Maryland's LEAFHouse. The PV array consists of 34 Sanyo HIT 205BA3 modules, wired in series, connected to a DC bus. The system was installed in 2007 and is a perfect option for this study because its PV array is 10 years old and has real-time power output data collection available to support model parameter values. Fig. 2 shows the system domain block definition diagram (BDD), which depicts the different blocks (components) of the system domain. The system domain consists of the PV system, environment, and maintenance, with the environment containing two components; market and climate. The PV system block contains all of the module factors seen in the response model diagram. These values include power generation, degradation rate, module efficiency, array size (area), and time in operation. The environment block contains two components, market and climate. The market block's values have market factors from the response model diagram. These include solar panel costs and operation and maintenance costs. The climate block's values are solar irradiance and temperature, both of which are consistent with the environment factors in the response model. Finally, the maintenance block represents maintenance required for the PV array during its lifecycle.

Fig. 3 depicts the system-level internal block diagram (IBD), which shows data flows between the PV system and its environment and maintainer. The IBD depicts how the PV system sends information to the maintainer, indicating that maintenance is required. This information could include significant and extended decreased power output data, indicating a malfunctioning panel. While these occurrences are uncommon, it is still significant to show the relationship nonetheless.

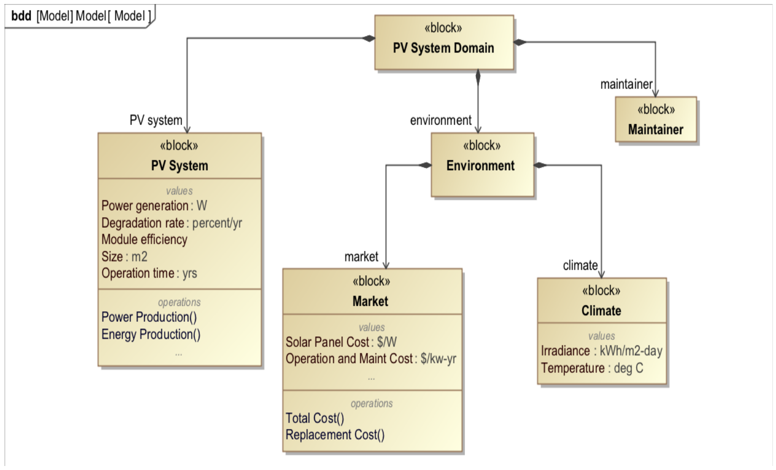

Fig. 2. *PV system system-level BDD.*

The maintainer interacts with the PV system by providing maintenance actions. Finally, the environment block provides irradiance, temperature, and costing data to the PV system block and the PV system ultimately sends costing data to the environment block. This could include cost of the number of modules in the array, amount of years in service resulting in more costs, etc. In the environment, the irradiance and market data is the specific data analyzed in this report.

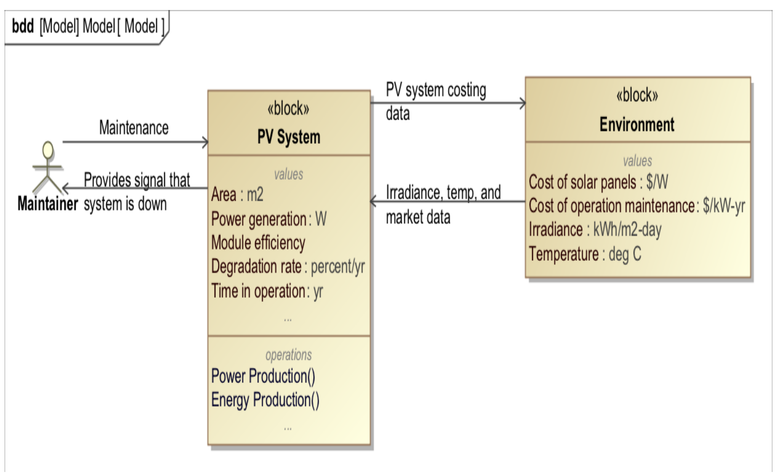

Fig. 3. *PV system system-level IBD.*

III Analysis Approach

A Monte Carlo simulation was used to identify the uncertainty involved with the lifetime of the PV array, daily solar irradiance, degradation rate, and projected cost of solar panels. Values for these factors rely on a multitude of factors and statistical distributions were applied to these factors in an attempt to obtain accurate enough values for the purpose of this analysis. To apply a Monte Carlo simulation, statistical distributions for appropriate system and environment factors must be established. In addition, the number of simulation iterations will need to be determined to ensure that the results of the analysis are accurate enough.

In addition to a Monte Carlo simulation, nonlinear mixed-integer programming must be used to determine the optimal number of solar modules that should be replaced and the time after initial PV array installation. This optimization technique requires the use of a utility function (function being optimized) and constraints for that equation. Because nonlinear programming is used, the utility function will have a nonlinear relationship with the two variables and/or nonlinear constraints. In this model, the utility function is nonlinear and the constraints are linear. The constraints and utility function will need to be modeled because there is no formula already developed that can be used in this analysis. The utility function will be the LCOE function, which is already well-established for a set PV array. However, the LCOE function does not include replacement of solar modules, requiring a new LCOE equation be derived in subsequent sections. It is important to note that the models detailed below can be applied to any homeowner with a PV array. However, the simulations and values used for certain variables in this analysis are specific to the LEAFHouse PV array.

IV Supporting Models and Simulations

In this section, all models and variable values needed in the analysis will be established. Refer to Table 1. for definitions and units of all variables. Before going into model development, it is necessary to list the assumptions involved in this analysis:

1. Module replacement is only with the exact same make and model of the original.

2. Temperature and daily solar irradiance was averaged for College Park, MD and are assumed to be that value for the entire year.

3. Decreases in individual solar panel and installation prices follows a linear trend.

4. There is a set degradation rate for the PV array.

Table 1. Data dictionary

	Acronym or Variable	Description	Units
Economic	LCOE	Localized cost of electricity	cents/kWh
	C_{i0}	Total system installation cost in 2007	\$
	C_{it}	Total cost of installing new modules in year t	\$
	p_{i07}	Cost of solar panel installation per W in 2007	\$/kW
	P_{mod}	Max power production per module	kW/module
	p_{i20}	Estimated cost of solar panel installation in 2020	\$/kW
	dp_i	Percent decrease in installation cost per year	%/yr
	OM	Cost of operation and maintenance per year	\$/kWh-yr
	C_{om}	Total system cost of maintenance and operation	\$
	ITM	Investment tax credit	%
Module	t	Time of replacement	yrs
	tlife	Number years system is in operation	yrs
	m	Number of initial modules in PV array	modules
	r	Number of replaced solar modules	modules
	σ	PV array degradation rate	%/yr
	ϵ	Efficiency of PV module	%
	A_{sp}	Total solar panel area	m^2
Environment	E_e	Average daily solar irradiance	kWh/m^2-day
	E_p	Average daily energy production per module	kWh/m^2-day-module
	T	Average temperature	^oC

LCOE is defined as the total lifetime cost divided by the system's lifetime energy production. The equation for LCOE for a PV array with no solar panel replacement was defined by Darling et al. as the following [2]:

$$LCOE = \frac{\text{Lifecycle cost}}{\text{Lifetime energy production}} \tag{1}$$

where lifecycle cost and lifetime energy production can be defined as

$$\text{Lifecycle cost} = C_{i0}(1 - ITM) + C_{om} \tag{2}$$

$$\text{Lifetime energy production} = \sum_{n=1}^{tlife} E_p m(1-\sigma)^n \tag{3}$$

The equation for LCOE can be expanded to include module replacement by adding in an extra cost term in the numerator for the cost of installing new modules, modifying the denominator by adding in additional summations for new power outputs from replaced modules, and by modifying the bounds of those summations. The new LCOE equation, which incorporates module replacement, is as follows:

$$LCOE = \frac{C_{i0} + C_{it} + C_{om}}{\sum_{n=1}^{t} E_p \cdot m(1-\sigma)^n + \sum_{n=1}^{tlife-t} E_p \cdot r(1-\sigma)^n + \sum_{n=t}^{tlife} E_p(m-r)(1-\sigma)^n} \tag{4}$$

where $\sum_{n=1}^{t} E_p \cdot m(1-\sigma)^n$ represents energy produced by the original PV array up to when modules are replaced, $\sum_{n=1}^{tlife-t} E_p \cdot r(1-\sigma)^n$ represents the energy produced by replaced modules from time of replacement to the the end of operation, and $\sum_{n=t}^{tlife} E_p(m-r)(1-\sigma)^n$ is the amount of energy produced from the original array after module replacement from time of replacement to the end of operation of the PV array. The cost factors, C_{i0}, C_{it}, and C_{om} are defined as follows:

$$C_{i0} = p_{i07} \cdot P_{mod} \cdot m \tag{5}$$

$$C_{it} = p_{it}(1 - dp_i \cdot t)P_{mod} \cdot r \tag{6}$$

$$dp_i = \frac{p_{i20} - p_{i07}}{(2020 - 2007)p_{i07}} \tag{7}$$

$$p_{it} = dp_i \cdot t \cdot p_{i07} + p_{i07} \tag{8}$$

$$C_{om} = OM \cdot P_{mod} \cdot m \cdot tlife \tag{9}$$

Because no reasonable cost estimations for solar panel installation past year 2020 were found, it was assumed that the percent decrease from 2007 to 2020 was linear and could be extended to the final year the PV array is in operation. Finally, E_p was calculated using the following equation [3]:

$$E_p = \frac{A_{sp} \cdot E_e \cdot \epsilon \cdot 365}{m} \tag{10}$$

With the fundamental models for the analysis derived, it is important now to discuss the range of values that the factors can have. Starting with module variables, max power output of the PV array was found to be 6.98 kW, with the number of modules, m, being 34. The max power output of the array was found by using PV performance models developed by Adomaitis et al [4]. From this, P_{mod} was found to be 0.205 kW/module. Since the area of each module is 1.18 m^2, the total area, A_{sp}, is 40.09 m^2. The efficiency of each module, ϵ, is assumed to be 16.2 %, consistent with manufacturer specs. The total number of years the PV array is in operation, tlife, was determined using conclusions found by Darling et al. They found that the lifecycle of a residential PV array can be modeled using a normal distribution with mean value of 33 years and standard deviation of 11 years. They also determined the degradation rate of a PV array can be modeled using a gamma distribution with a shape factor of 2 and scale parameter of 0.006, which is what is used in this analysis.

Moving on to market factors, the cost of operation and maintenance, OM, was modeled with a triangular distribution with a lower bound, upper bound, and peak values of 8, 20, and 10 $/kW-yr, respectively [2]. The price of solar panels in 2020, p_{i20}, was modeled as a triangular distribution with lower bound, upper bound, and peak values of 1,500, 2,250, and 3,000 $/kW, respectively [5]. The investment tax credit, ITC, was assumed to be 0.3 [6]. The cost of solar panel installation in 2007, p_{i07}, was assumed to be 8.50 $/W [5]. Finally, average daily solar irradiance was modeled using a normal distribution with a mean of 4.56 kWh/day and standard deviation of 0.27 kWh/day. The distribution was determined from work by Darling et al. and the mean was found by using a PV performance program, PVWatts, and PV array values from UMD's LEAFHouse.

With the models and variable ranges established, a Monte Carlo simulation was developed and incorporated nonlinear mixed-integer optimization techniques. For the Monte Carlo simulation, 1,000 iterations were used because that was the approximate number of iterations required for the LCOE to reach steady state with minimal uncertainty. Any more iterations would have taken an unnecessary amount of time to run, with 1,000 iterations already taking over 2 minutes. The standard form for the nonlinear mixed-integer optimization is as follows:

Utility Function : $min(LCOE(t,r) = \frac{C_{i0}+C_{it}+C_{om}}{\sum_{n=1}^{t} E_p \cdot m(1-\sigma)^n + \sum_{n=1}^{tlife-t} E_p \cdot r(1-\sigma)^n + \sum_{n=t}^{tlife} E_p (m-r)(1-\sigma)^n})$

Constraints : $r \leq 34; t \leq tlife; t, r \geq 0$

LCOE was minimized because the homeowner wants to minimize the amount they have to pay over the PV array lifetime for each unit of energy produced. The number of replaced modules must be less than or equal to 34 because 34 is the number of original modules installed in 2007 and the size of the roof constrains the number of modules to 34. The time of module replacement must be less than or equal to tlife because modules can't be replaced after the lifetime of the array. Finally, both r and t must be non-negative because a negative amount of modules replaced or negative time can't occur. All modeling and simulations were done using matlab. The matlab function fmincon was used to solve this nonlinear optimization problem. However, the utility of fmincon does not extend to mixed-integer programming, requiring the final number of modules replaced obtained from fmincon be evaluated at the next highest and lowest integers with the final answer being whichever integer value provides the lowest LCOE value. This obtains an integer value for number of replaced modules without the use of a specific mixed-integer optimization tool.

V Analysis and Results

From the analysis, it was determined that 0 modules should be replaced 1.42 years after the PV array is installed. Because the analysis showed 0 modules should be replaced, the number of years is trivial. There is a time associated with replacing 0 modules because the number of modules was restricted to be an integer but the time was not. When checking the upper and lower integer values for the fractional number of modules replaced, a time greater than 0 was obtained. Analysis results are summarized in Table 2.

From the table, the localized cost of electricity for the homeowner is 16.99 ± 0.32 cents/kWh. This value is surprisingly larger than the average localized cost of electricity for homeowners from

Table 2. Results of Monte Carlo simulation.

	Mean	Standard Error
r	0	0
t (yrs)	1.42	0.01
LCOE (cents/kWh)	16.99	0.32

2007 to present. According to Fig. 4 provided by U.S. Energy Information Administration, the average LCOE for U.S. residences in 2007 was 11.14 cents/kWh.

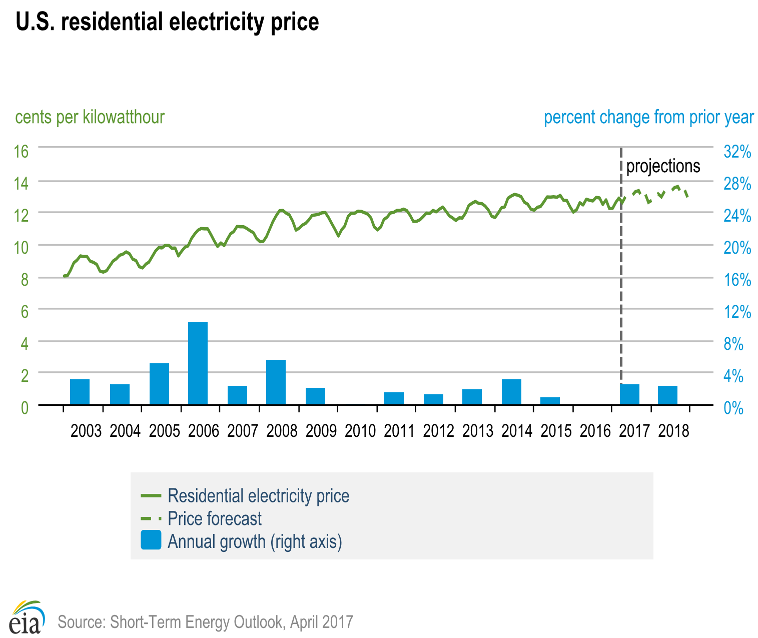

Fig. 4. *U.S. residential electricity price trends since 2003. Note the general increase in price per kWh since 2003 [7].*

While these results are unexciting, they still hold some significance for the homeowner as they try to save money. The motivation behind this analysis was based on the fact that PV arrays degrade, resulting in losses in power production and profit. In the LCOE model, the only term that would result in the need for module replacement is the degradation rate. Because the results rely largely on this term, it becomes crucial that this value is as accurate as possible. From data provided by LEAFHouse on May 3, 2017, the max power output was 6.3 kW. Assuming a max power output of 7.0 kW after the array was installed in 2007, the degradation rate for LEAFHouse would be 1.0 %/yr. This value fits the distribution used in this analysis, resulting in an accurate estimate for degradation rate.

Over 10 years, LEAFHouse has lost 0.7 kW in max power production. A 0.7 kW loss in power over 10 years equates to a loss of 94 kWh/yr, or 940 kWh total according to results generated from PVWatts. PVWatts parameter values and outputs can be seen in Fig. 5 in the Appendix. Using the 11.14 cents/kWh average cost of electricity provided by U.S. Energy Information Administration, the power production losses over 10 years result in a total loss of $104.72. Assuming a cost of 3.75 $/W for solar panels in 2017, the cost of installing one 205 W module would be $768.75 [5]. From this analysis, it becomes quite evident that the cost of installing even one module after 10 years is more costly than the loss of energy over this time. Assuming the same cost of installation in 2017 and average price of electricity between 2007 and 2017, this PV array would have to lose 6,901 kWh over 10 years to break even for the cost of installing one module. For the LEAFHouse PV array to lose 6,901 kWh over 10 years, it would need to have a degradation rate of 7.3 %/yr (loss of 5.1 kW over 10 years). While these cost estimates are only using a 10 year old PV array, the projected decrease in the cost of solar panels past 2017 is not significant enough to make replacing modules economically viable given the projected degradation rate of the array.

VI Conclusions and Lessons Learned

From the analysis results, it is recommended that the homeowners of University of Maryland's LEAFHouse replace no modules over the lifecycle of the array. This is recommended because replacing no modules result in the lowest cost of electricity compared to replacing greater than 0 modules. It can be concluded that the loss in power due to degrading modules for LEAFHouse does not offset the cost required to replace any modules at any time during the array's lifecycle. Even with the current cost and projected cost of solar panels decreasing, replacing modules is not economically feasible. While this analysis incorporates many factors, it is important to note improvements that can be made:

1. Incorporating replacement with different modules and producers because solar panel performance has drastically increased since 2007.

2. Developing a more accurate degradation rate depending on DC bus or micro inverter design, average outdoor temperature, UV light exposure, etc.

3. Investigating the effects of house location in the U.S. House location can result in greater irradiance and thus higher energy production from the PV array. Additionally, different locations have different average outdoor temperatures, which effect PV array performance.

4. Updating cost data for solar panels as it becomes available in the following years.

5. Developing more accurate energy production models. While PVWatts is an effective calculator, it only gives general estimates.

VII Acknowledgements

I would like to thank my adviser, Dr. Raymond Adomaitis, for his direction and professional support of this project.

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VIII Appendix

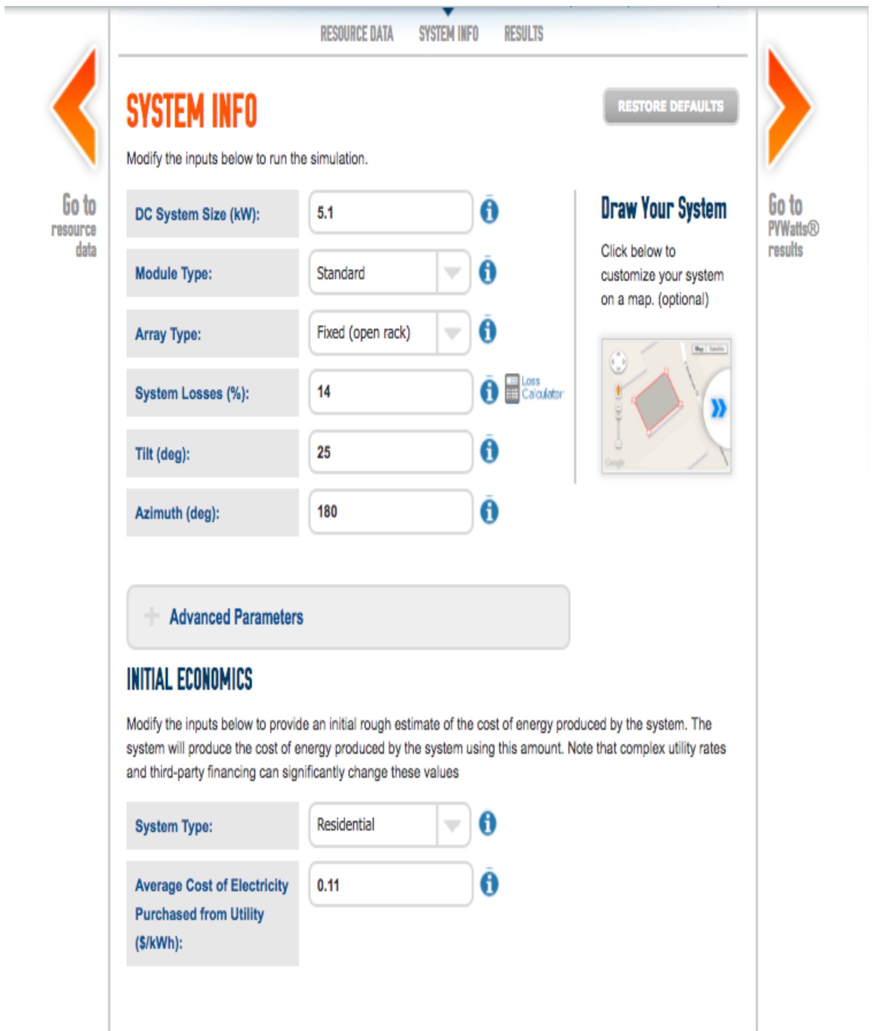

Fig. 5. *Values used in PV Watts to generate energy losses 10 years after initial PV array installation.*

RESOURCE DATA SYSTEM INFO RESULTS

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RESULTS

Print Results

6,843 kWh per Year *

System output may range from 6,540 to 7,107kWh per year near this location.

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Month	Solar Radiation (kWh / m^2 / day)	AC Energy (kWh)	Energy Value ($)
January	3.06	419	47
February	4.03	494	56
March	4.66	609	69
April	5.25	653	74
May	5.60	696	78
June	6.16	710	80
July	6.01	712	80
August	5.49	652	74
September	4.91	575	65
October	4.57	571	64
November	3.22	409	46
December	2.52	343	39
Annual	4.62	6,843	$ 772

Fig. 6. *Output from PV Watts for PV array losses after 10 years of operation.*