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The Impact of Time-of-Use Electricity Rate Plans on Solar Array Installation Breakeven Period

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Abstract

This paper describes a computational model for determining the breakeven period for time-of-use (TOU) and standard electricity plans. To determine the breakeven period, the model compares a solar array rooftop system installation with a grid-based system. The model is applied to a house in northern Nevada. Because of uncertainties in electricity rate increases and market interest rates, the model predicts significant variability in the breakeven period, ranging from 10 to 30 years. The model also analyzes the impact of: 1) solar array orientation and 2) making daylight saving time permanent on the customers' bills and the breakeven period.

Keywords

Solar Panels, Solar Arrays, Solar Modules, Cash Flow, Present Value, Standard Rate Plan, Time-of-Use Rate Plan, Energy, Payback Period

1. Introduction

In late 2022, we began exploring options for installing a grid-tied solar array on our Sparks, Nevada, house rooftop. Our first step was to communicate with solar installers about the available options. We consulted with six installers. As we do not have a south-facing roof, some installers suggested installing the array modules (FSEC, n.d.) on the west-facing roof, while others recommended placing the array on the east-facing roof.

The installers offered a variety of options, ranging from 10 to 12 solar modules. The offered modules were rated at around 400 watts each. Five installers suggested a centralized SolarEdge string inverter, which includes power optimizers. One installer offered Enphase micro-inverters, a system where each inverter is paired with one solar module.

The quoted prices we received for the installations, after the 30% federal tax credit, ranged from \$6500 to \$12,000. The installers also offered a variety of loan options, which ranged from 3% to 7%. They projected that their solar array would generate about 6000 kWh of annual AC (alternating current) electricity output, which is close to our yearly electricity consumption. Some installers quoted 9 years as the breakeven time to recover the purchase cost of the solar array. As the assumptions underlying these breakeven quotes were not provided, we decided to investigate the breakeven topic.

The solar system breakeven period, also known as the payback period, has received wide coverage in the technical literature. In a 2009 National Renewable Energy Laboratory (NREL) report, Denholm et al. (2009) described breakeven considerations for photovoltaics in the United States. Lee et al. (2018) published a more recent economic analysis of residential photovoltaics in 51 cities in the US. Katsamakas & Siegrist (2019) focused on the Bronx Borough of New York City. Hayat et al. (2017) reported on regional payback periods and economic benefit studies in Australia. Similarly, Dellosa (2015) studied the impact of the payback period on solar installations in Butuan City, the Philippines.

Other studies, rather than investigating the regional aspects of the breakeven period, considered its impact on a small number of selected installations. Kessler (2017) studied capital payback periods as well as energy payback periods in three New Hampshire locations. Nyer et al. (2019) studied the economic considerations of solar panels placed on a single residential home in Orange, California. These studies focused on the impact of tier-based electricity rates (Nyer et al., 2019) and time-of-use (TOU) rates (Nyer et al., 2020). Nyer et al. (2020) used an installed solar system to obtain hourly solar generation data for their TOU calculations.

Today, when a solar array installer offers a solar system to a potential buyer, the installer estimates the size, the cost, and the breakeven period for the array. For the estimate, the installer relies on the buyer's monthly electricity usage and a prediction of the monthly solar generation at the buyer's house. Such estimates are suitable for standard electricity rate plans, for which the per-kWh cost is fixed regardless of time of use. However, these estimates are inadequate for TOU rate plans. This paper provides a novel mathematical model that combines hourly electricity consumption data with predicted hourly solar generation data to calculate the breakeven period for TOU rate plans.

The paper focuses on the breakeven period for a specific residential home, our house, in northern Nevada. We mainly used two sources of information: 1) our electricity provider, Nevada Energy (NE), and 2) the PVWatts calculator, developed by the National Renewable Energy Laboratory (NREL).

NE provides its customers with up to 2 years of historical electricity usage in 15-minute intervals. Our second source, the PVWatts calculator data (PVWatts Calculator, n.d.), provides solar array AC electricity generation predictions.

These predictions are based, among others, on the solar array's geographical location, tilt angle, and power rating. The PVWatts solar AC electricity data are given for the entire year at one-hour intervals. Both the NE and the PVWatts data are provided in PST (Pacific Standard Time).

NE offers two rate plans: a standard plan and a time-of-use (TOU) plan. For the standard plan, the customer pays the same rate per kWh throughout the year. Under the TOU plan, the kWh rates vary by month and time of day. For 2022-2023, NE is offering 75% credit to its residential customers for excess solar electricity generation. From 2012 to 2021, NE customers did not experience significant rate increases. However, in 2022, NE increased electricity rates by 18% for residential customers as compared to the previous 10 years average (PUCN, 2023).

Because we did not have an existing installed solar system to provide us with solar electricity data, we used the PVWatts Calculator hourly solar AC electricity generation data to predict: 1) the breakeven period for our house under TOU and standard rate plans; 2) the optimal solar array orientation; and 3) the impact of daylight saving time on the breakeven period.

In the next sections, we will describe a mathematical model to determine the breakeven period for rooftop solar systems. It compares two options: a grid-tied solar system and a grid-only system. We assumed loan financing for the solar system. We applied the NE billing algorithm to calculate the monthly bill for a grid-tied solar system and a grid-only system.

2. Solar Arrays Breakeven Calculation

Our primary goal is to determine the number of months, n, for which a cost breakeven is achieved for a solar array system. We compare two options:

1) Purchase a solar array at a cost of K dollars to supplement grid electricity. The purchase is funded by a 25-year loan at a p' percent annual interest rate with a monthly loan repayment of h dollars. For the rest of this paper, we will refer to this grid-tied solar system as the solar system.

2) Keep using the grid-only system as the only source of electricity. For the rest of this paper, we will refer to the grid-only system as the grid system.

To determine n, we compare the Net Present Value (NPV) for option (1) with the NPV for option (2) by computing the difference:

$$\Delta_j = \text{NPV}(a, j) - \text{NPV}(b, j) \tag{1}$$

Prior to the breakeven month n, $\Delta_j < 0$. At the breakeven month $\Delta_j \geq 0$.

Model assumptions:

1) Monthly consumption of electricity is unchanged from year to year.

2) Solar irradiation is unchanged from year to year.

3) Solar array electricity generation is degraded by δ% per year.

4) Electricity rates per kWh rise by r% annually.

5) The percent credit given to customers per excess kWh of solar electricity

transmitted to the grid does not change over time.

6) An annual discount rate of *d*.

For option (1), we have

$$\mathrm{NPV}(a,n) = -S_n - K_n \tag{2}$$

S_n, the cumulative discounted dollar value of the solar system electricity, is given by

$$S_n = \sum_{j=1}^{n} s_j / q^j \tag{3}$$

s_j is the dollar value for the solar system electricity generated in the *j*th month and $q = 1 + d/12$ is the monthly discount rate. K_n is the cumulative discounted cash flow on the loan *K*. We consider two cases for K_n:

1) If $n \geq 25 \times 12 = 300$, the loan is completely paid off for which K_n is given by

$$K_n = \sum_{j=1}^{300} h / q^j \tag{4}$$

h is given by the mortgage Equation (Fixed-Rate Mortgage, 2023):

$$h = \frac{pK}{1-(1+p)^{-300}} \tag{5}$$

where $p = p'/12$ is the monthly loan interest rate. For $n \geq 300$, K_n remains unchanged because there are no longer loan payment *h* cash flows.

2) If $n < 300$, we assume that the loan is terminated early and its remainder, o_n, is paid off at the breakeven month *n* yielding,

$$K_n = \sum_{j=1}^{n} h / q^j + o_n / q^n, \tag{6}$$

where

$$o_n = K(1+p)^n - \frac{(1+p)^n - 1}{p} h. \tag{7}$$

The NPV for option (2) comprises of cumulative discounted G_n the grid system electricity,

$$\mathrm{NPV}(b,n) = -G_n. \tag{8}$$

G_n is given by

$$G_n = \sum_{j=1}^{n} g_j / q^j. \tag{9}$$

g_j is the cost of the grid system electricity for the *j*th month.

Using Equation (2) and Equation (8), Δ_n (Equation (1)), can be written as

$$\Delta_n = G_n - S_n - K_n. \tag{10}$$

Defining

$$E_n = G_n - S_n, \tag{11}$$

we can express Δ_n as

$$\Delta_n = E_n - K_n . \tag{12}$$

Using Equation (3) and Equation (9), E_n is given by

$$E_n = \sum_{j=1}^{n} g_j / q^j - \sum_{j=1}^{n} s_j / q^j , \tag{13}$$

which can be rewritten as

$$E_n = \sum_{j=1}^{n} \frac{e_j}{q^j} , \tag{14}$$

where

$$e_j = g_j - s_j . \tag{15}$$

To compute Δ_n (Equation (12)), we calculate E_n and K_n. E_n is calculated for the TOU and STD (standard) plans using Equation (14). In the next section, we shall be applying the NE billing algorithm to calculate e_j, defined by Equation (15).

Applying an iterative procedure, K_n is calculated until year 25 with equation (6). If $n < 300$ and $\Delta_n < 0$ (no breakeven so far), we subtract o_n / q^n from K_n and proceed to the next month until $\Delta_n \geq 0$. If $n \geq 300$ (the loan is paid off) and $\Delta_n < 0$, K_n is calculated using Equation (4).

3. Nevada Energy Bill

To determine the breakeven point for the solar system, we calculate e_j (Equation (15)). For that, we apply the NE billing algorithm to calculate the *j*th month, s_j, and g_j, the solar and grid systems monthly bills, respectively, for both the TOU and STD rate plans as follows:

The solar system/TOU:

$$s_j^{TOU} = Au_j + \theta_P B_R^{(P)} \left(u_j^{(P)} - v_j^{(P)} \right) + \theta_O B_R^{(O)} \left(u_j^{(O)} - v_j^{(O)} \right) + C \tag{16}$$

The solar system/STD

$$s_j^{STD} = Au_j + \theta_T B \left(u_j - v_j \right) + C \tag{17}$$

The grid system/TOU

$$g_j^{TOU} = Au_j + \theta \left(B_R^{(P)} u_j^{(P)} + B_R^{(O)} u_j^{(O)} \right) + C \tag{18}$$

The grid system/STD

$$g_j^{STD} = Au_j + \theta B u_j + C \tag{19}$$

In Equation (16) through Equation (19), u_j is the *j*th month electricity consumption in kWh. Under assumption 1, the monthly consumption does not change from year to year, such that $u_{j+12} = u_j$. $u_j^{(P)}$ and $u_j^{(O)}$ are the peak and off-peak electricity monthly consumptions, respectively, where $u_j = u_j^{(P)} + u_j^{(O)}$. As with $u_j, u_j^{(P)}$ and $u_j^{(O)}$ do not change from year to year. v_j is the *j*th month solar AC electricity generation in KWh. $v_j^{(P)}$ and $v_j^{(O)}$ are the peak and off-peak AC electricity monthly solar generation, respectively, where $v_j = v_j^{(P)} + v_j^{(O)}$. Negative values for the factors $\left(u_j^{(P)} - v_j^{(P)}\right)$, $\left(u_j^{(O)} - v_j^{(O)}\right)$ in Equation (16), and $\left(u_j - v_j\right)$ in Equation (17), imply excess solar electricity credit to the customer.

Under assumption 2, solar irradiation does not change from year to year. However, under assumption 3, there is a $\delta\%$ degradation from year to year, such that $v_{j+12} = v_j\left(1-\delta\right)$. Similarly, $v_{j+12}^{(P)} = v_j^{(P)}\left(1-\delta\right)$ and $v_{j+12}^{(O)} = v_j^{(O)}\left(1-\delta\right)$. In all our calculations, we assume (Benjamin, 2018) $\delta = 0.5\%$ (Mow, 2018). The other parameters of Equation (16) through Equation (19) are defined in **Table 1**.

The factors, θ_T, θ_P, and θ_O in **Table 1** correspond to 0.75 customer credit with respect to retail electricity costs for excess solar kWh generation. If electricity consumption is greater than solar generation—then the customer pays 5% local tax on the difference between consumption and solar generation, for which the values of θ_T, θ_P, and θ_O are 1.05. The implication is that the customer only pays tax for electricity received from the grid. The customer does not pay tax for solar-generated electricity, either consumed or sold to the grid.

In our calculation, we assume that *A*, *B*, B_P, B_O, B_P, and *C* remain unchanged throughout a given year. However, these parameters may change from year to year. We now apply Equation (16) through Equation (19) to Equation (15) to determine e_j for TOU and STD

$$\begin{aligned} e_j^{TOU} &= g_j^{TOU} - s_j^{TOU} \\ &= \theta\left(B_R^{(P)}u_j^{(P)} + B_R^{(O)}u_j^{(O)}\right) - \theta_P B_R^{(P)}\left(u_j^{(P)} - v_j^{(P)}\right) - \theta_O B_R^{(O)}\left(u_j^{(O)} - v_j^{(O)}\right) \end{aligned} \tag{20}$$

Table 1. Definition of NE billing parameter for Equation (16) through Equation (19).

Parameter	Description
A	A monthly rate factor given in dollars per kWh
B	A monthly STD rate factor given in dollars per kWh
$B_R^{(P)}$	A monthly peak TOU rate factor given in dollars per kWh; *R* stands for either SUMMER or WINTER rates
$B_R^{(O)}$	A monthly off-peak TOU rate factor given in dollars per kWh *R* stands for either SUMMER or WINTER rates
C	A fixed monthly payment given in dollars
θ_P	Excess peak solar production factor for TOU, if $v_j^{(P)} > u_j^{(P)}$ $\theta_P = 0.75$ otherwise $\theta_P = 1.05$
θ_O	Excess off-peak solar production factor for TOU, if $v_j^{(O)} > u_j^{(O)}$ $\theta_O = 0.75$ otherwise $\theta_O = 1.05$
θ_T	Excess solar production factor for STD, if $v_j > u_j$ $\theta_T = 0.75$ otherwise $\theta_T = 1.05$
θ	Local tax factor, $\theta = 1.05$ for grid STD

$$e_j^{STD} = g_j^{STD} - s_j^{STD} = \theta B u_j - \theta_T B\left(u_j - v_j\right). \tag{21}$$

We observe that when e_j is calculated in Equation (20) and Equation (21), the A and C terms are eliminated from these equations. The implications of this elimination are simpler formulas, and no assumptions are needed to account for changes to A and C over time.

4. Results

We implemented the calculations described by Equation (1) through Equation (21), in Python. **Table 2** and **Figure 1** present our annual and monthly electricity usage, respectively. These are based on NE data (NV Electric Rates, 2022) and PVWatts solar AC electricity generation prediction for our house (PVWatts Calculator, n.d.). **Table 3** provides the key parameter values used by PVWatts. For the remaining parameters, the default PVWatts parameter values were used. **Table 2** shows that a solar array facing south generates the maximum annual kWh of solar electricity. Also, an east-facing solar array generates more electricity than a west-facing array.

The annual electricity cost for the first year of the solar array's operation for STD and TOU is presented in **Figure 2**. In our calculation, we assume that the purchase cost of the solar array is $10,000. Parameter values for the cost calculations are given in **Table 3** and **Table 4**.

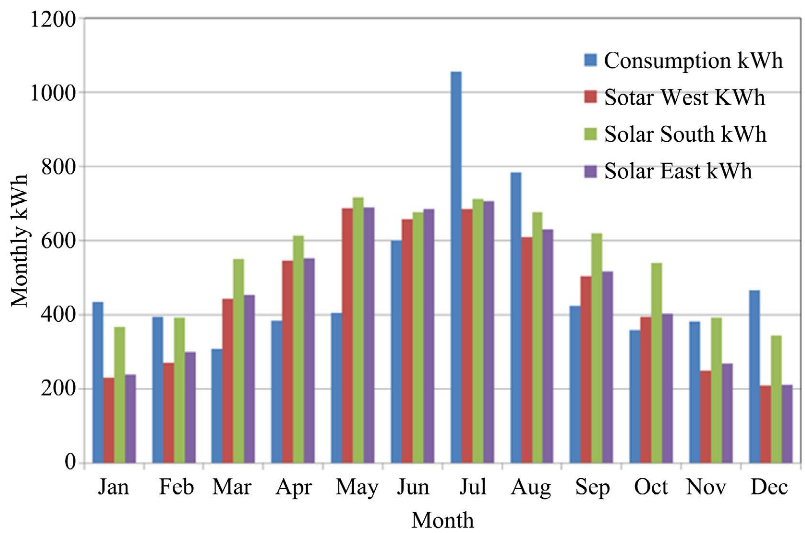

Figure 1. Monthly electricity consumption and solar AC electricity generation for east, south and west facing array; DC Size 4 kW solar array.

Table 2. Annual electricity consumption and solar AC electricity generation in kWh for east, south and west facing array; DC Size 4 kW solar array.

Electricity Consumption	Solar generation west	Solar generation south	Solar generation east
6005 kWh	5491 kWh	6605 kWh	5658 kWh

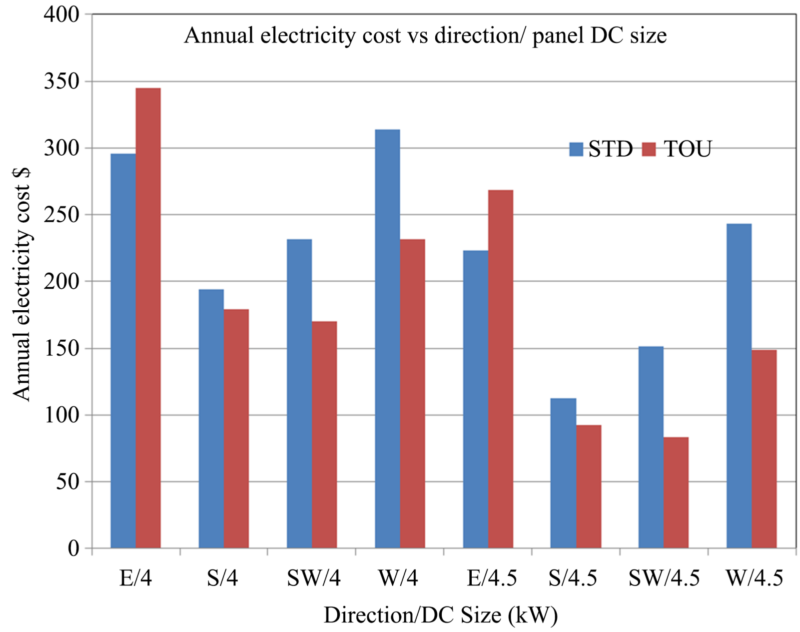

Figure 2. Annual electricity cost for east, south, west and south west-facing solar array for STD and TOU rates and 4 kW and 4.5 kW arrays DC sizes.

Table 3. PVWatts calculator parameter value used in the calculations.

PVWatts parameter	Value
Solar array tilt	20 degrees
DC system size—solar array power rating	4 kW & 4.5 kW
Location	Sparks Nevada

Table 4. Northern Nevada Energy (NE) first year monthly rates for 3Q2022 (NV Electric Rates, 2022).

NE Parameters	Value
$B^{(P)}_{SUMMER}$ -peak summer rate (TOU)	\$0.55130 per kWh
$B^{(O)}_{SUMMER}$ -off-peak summer rate (TOU)	\$0.08277 per kWh
$B^{(P)}_{WINTER}$ -peak winter rate (TOU)	\$0.11025 per kWh
$B^{(O)}_{WINTER}$ -off-peak winter rate (TOU)	\$0.08277 per kWh
B-standard rate (STD)	\$0.11666 per kWh
A	\$0.00538 per kWh
C	\$16

Figure 2 shows that for STD, the south-facing solar array provides the greatest savings in electricity costs (\$194 for the 4 kW array and \$113 for the 4.5 kW array). The south-west is the second-best direction (\$232 for the 4 kW array and

$152 for the 4.5 kW array), followed by the east ($295 for the 4 kW array and $223 for the 4.5 kW array), and lastly, the west-facing array ($314 for the 4 kW array and $244 for the 4.5 kW array).

The TOU preferred direction pattern is different from the STD pattern. The south-west-facing array offers the most cost savings ($170 for the 4 kW array and $83 for the 4.5 kW array). It is followed in the order of south ($179 for the 4 kW array and $92 for the 4.5 kW array), west ($232 for the 4 kW array and $149 for the 4.5 kW array), and east-facing arrays ($345 for the 4 kW array and $269 for the 4.5 kW array). Although the east-facing arrays receive more solar irradiation than the west-facing arrays, as **Table 2** indicates, the model predicts that placing arrays on the west-facing rooftop offers more savings for TOU than placing the array on the east-facing rooftop.

The NE TOU defined periods are:

Winter: October 1 to June 30.

Peak: 5 p.m. to 9 p.m. daily. Off-peak: all other hours.

Summer: July 1-September 30.

Peak: 1 p.m. to 6 p.m., Monday-Friday. Off-peak: all other hours Monday-Friday, and all hours Saturday and Sunday.

Because the NE quarter hourly and PVWatts hourly data are given for PST, in our calculation we converted all the NE TOU periods to PST. (For example, the summer peak hours, 1 to 6 p.m. PDT, were converted to 12 to 5 p.m. PST.)

In all calculations, we used the March 2023 Federal Reserve discount rate of 5% and a loan interest rate of 7.5%, which was close to the prevailing 30-year mortgage interest rate. Unless otherwise specified, the calculations assume switching from PST to PDT (Pacific Daylight Saving Time) on March 13 and switching back to PST on November 5 (2022 dates).

Table 5 displays the breakeven year (BEY) for our house for a 4 kW size solar array for both STD and TOU as a function of the annual electricity rate increase (RI). It shows that for TOU, the east-facing array yields the longest BEY (e.g., at 11% RI the BEY is 13.6). The south-facing array provides the best results (e.g., at 11% RI the BEY is 11.4), while the west-facing array is not far behind (e.g., at 11% RI the BEY 11.8). For STD, the south-facing array yields the shortest BEY (e.g., at 11% RI the BEY is 12.2), whereas the east-facing array provides slightly better results (e.g. at 11% RI the BEY is 13.5) than the west-facing array (e.g., at 11% RI the BEY is 13.8). For TOU, a west-facing array offers a significantly shorter BEY than STD for west or east-facing array results. (At 11% RI, the west BEY TOU is 11.8 versus the west STD BEY of 13.8 and the east STD BEY of 13.5).

Figure 3 provides the annual dollar gain for the solar system over the grid system after the breakeven year of 13 for TOU at an annual 8% rate increase. The south-facing array shows the largest gain. It is followed by the west-facing array, which is followed by the east-facing array. For example, **Figure 3** shows $1213, $1135, and $962 dollar for south, west, and east-facing arrays, respectively, 20 years after the solar array installation and 7 years after the breakeven year.

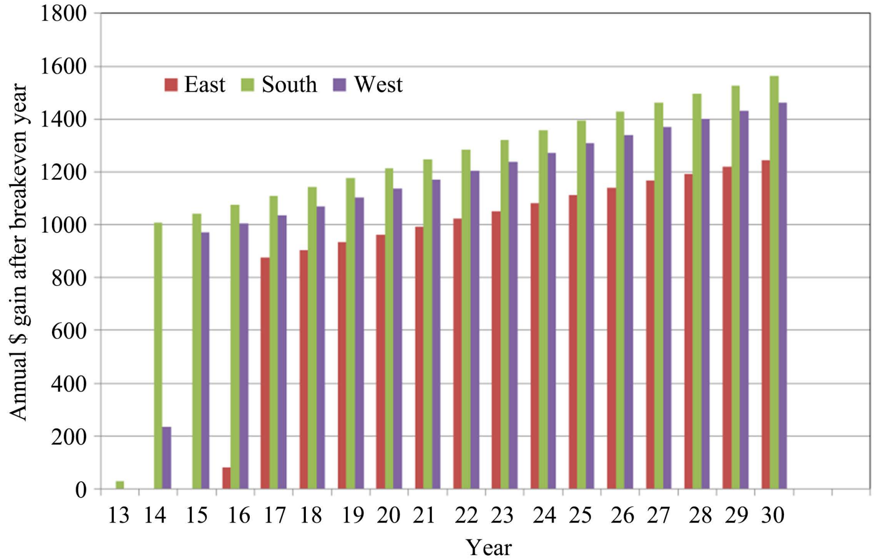

Figure 3. Annual $ gain after breakeven year, 13, for TOU rates, solar system facing east, south and west; discount rate = 5%; loan interest rates 7.5%; 8% annual electricity rate increase; 4 kW DC solar array size.

Table 5. Solar panel breakeven year vs annual electric rate increase for NE STD and TOU rates; discount rate = 5%; loan interest rates 7.5%; 4 kW DC solar array size; arrays facing east, south and west.

Rate Increase	East BEY		South BEY		West BEY	
	STD	TOU	STD	TOU	STD	TOU
3%	26.4	25.9	21.6	19.2	27.4	20.8
5%	20.5	20.5	17.5	15.8	21.2	16.9
7%	17.3	17.2	15.1	13.7	17.7	14.7
9%	15.2	14.8	13.4	12.5	15.5	13.1
11%	13.5	13.6	12.2	11.4	13.8	11.8
13%	12.4	12.4	11.2	10.6	12.6	10.8

Table 5 and **Figure 3** show a clear TOU breakeven advantage for west-facing arrays over east-facing arrays. Yet this TOU advantage is not universal, as **Table 6** illustrates. In **Table 6**, we replaced some of the NE TOU electricity rate parameter values with the relevant California San Jose Clean Energy (SJCE) electricity provider TOU parameter values, given in **Table 7** (SJCE, 2023). The same NE billing algorithm was used for both the NE and SJCE parameters. The SJCR summer rates are from June to September, winter rates are from October to May. Summer and winter peak hour rates are from 4 PM to 9 PM. Off-peak hours are all other hours.

Table 6 shows that the SJCE rates in general provide a faster path to breakeven as compared to the NE rates. For example, at 11% RI, the east SJCE BEY is

Table 6. Solar panel breakeven year vs annual electric rate increase comparing SJCE with NE for TOU; discount rate = 5%; loan interest rates 7.5%; 4 kW DC solar array size; arrays facing east, south and west.

Rate Increase	East BEY		South BEY		West BEY	
	SJCE	NE	SJCE	NE	SJCE	NE
3%	18.9	25.9	15.4	19.2	18.5	20.8
5%	15.7	20.5	13.2	15.8	15.4	16.9
7%	13.7	17.2	11.7	13.7	13.5	14.7
9%	12.3	14.8	10.6	12.5	12.1	13.1
11%	11.2	13.6	9.8	11.4	11.0	11.8
13%	10.4	12.4	9.2	10.6	10.3	10.8

Table 7. SJCE rates used in **Table 6**.

SJCE Parameters	Value
$B_S^{(P)}$ -peak summer rate (TOU)	\$0.19708 per kWh
$B_S^{(O)}$ -off-peak summer rate (TOU)	\$0.14505 per kWh
$B_W^{(P)}$ -peak winter rate (TOU)	\$0.11025 per kWh
$B_W^{(O)}$ -off-peak winter rate (TOU)	\$0.08277 per kWh

11.2 compared to 13.6 for NE. The reason for that is that, except for the peak summer rates, the SJCE rates are higher than the NE rates. For the NE TOU rates, we saw a clear advantage for the west-facing array over the east-facing array. For example, at 11% RI the west BEY for NE is 11.8 as compared to the NE east BEY of 13.6. This advantage does not exist for the SJCE rates. For example, at 11% RI the west BEY for SJCE is 11.0 as compared to the SJCE east BEY of 11.2. The apparent reason for that is that the summer peak time for NE is 1 to 6 p.m. PDT, hours of high solar activity, whereas the summer peak time for SJCE is 4 p.m. to 9 p.m., hours of lower solar activity.

The impact on annual electricity costs of permanently switching to either PST or PDT is shown in **Figure 4**. In **Figure 4**, PST/PDT denotes the current situation, where there is a switch from PST to PDT in March and a switch back to PST in November. The figure shows that PDT has a clear advantage over PST. For example, the annual electricity cost for a west-facing 4 kW array for PDT is \$229 as compared to \$299 for PST. **Figure 4** also demonstrates that making PDT permanent would have a negligible impact on electricity costs for TOU as compared to the present situation of PST/PDT. For example, the annual electricity cost for a west-facing 4 kW array for PDT is \$229 as compared to \$232 for PST/PDT.

Table 8 provides further evidence of the advantage for the solar TOU customer of keeping PDT permanent in northern Nevada. The table shows that the

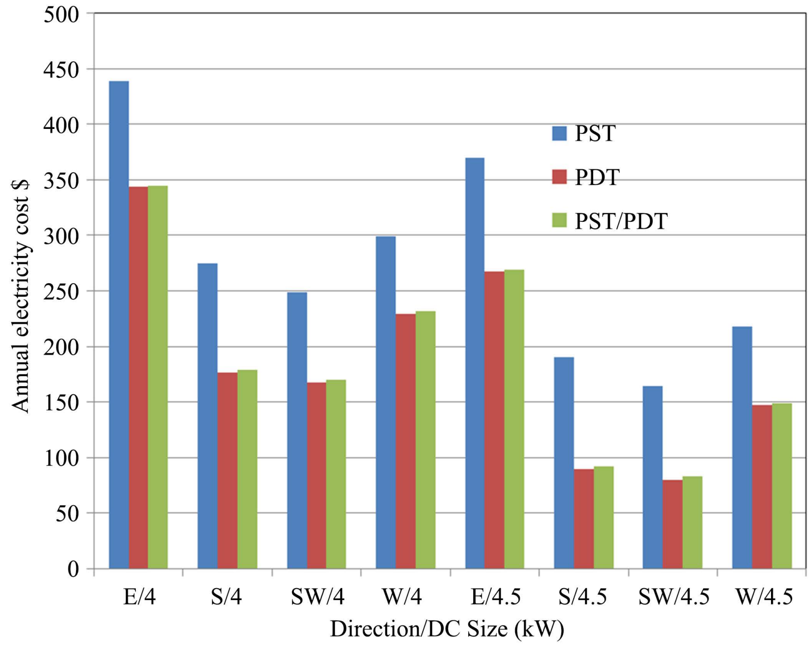

Figure 4. First year electricity cost for east, south, west and south west facing solar array for PST, PDT and PST/PDT for TOU; 4 kW and 4.5 kW DC sizes.

Table 8. PST, PDT, and PST/PDT solar array BEY vs annual electric rate increase for NE TOU; discount rate = 5%; loan interest rates 7.5%; 4 kW DC solar array size; arrays facing east, south and west.

Rate increase	East BEY			South BEY			West BEY		
	PST	PDT	PST/PDT	PST	PDT	PST/PDT	PST	PDT	PST/PDT
3%	30.4	25.8	25.9	21.6	19	19.2	22.7	20.7	20.8
5%	22.8	20.5	20.5	17.6	15.8	15.8	18.3	16.8	16.9
7%	18.8	17.2	17.2	14.9	13.7	13.7	15.6	14.7	14.7
9%	16.5	14.8	14.8	13.5	12.5	12.5	13.7	12.9	13.1
11%	14.6	13.6	13.6	12.1	11.4	11.4	12.6	11.8	11.8
13%	13.4	12.4	12.4	11.2	10.6	10.6	11.6	10.8	10.8

breakeven year for PDT is shorter than PST. For example, at 11% RI, the BEY for east PST is 14.6 as compared to 13.6 for PDT; for south, the BEY for PST is 12.1 as compared to 11.4 for PDT; and for west, the BEY for PST is 12.6 as compared to 11.8 for PDT.

5. Discussion

In this paper, we studied the breakeven period for solar array rooftop installation for TOU and standard electricity rate plans. We also analyzed the effect of solar array orientation and the impact of making daylight saving time permanent on customers' bills.

Our calculations demonstrate that there is no simple answer to the breakeven prediction. Uncertainties regarding future interest rate changes and a lack of stability in electricity prices complicate predictions. Depending on the electricity plan, rate increase, interest rates, and the solar array's facing direction, we have estimated that the breakeven period can range from 10 years to 30 years.

We have seen that for our house in northern Nevada, TOU offers lower rates and a shorter breakeven period as compared to standard rates. For TOU, south-west facing arrays offer the maximum electricity cost savings, followed by south, west, and east-facing arrays. This cost-saving order changes for standard rates; the highest saving is for south facing arrays, followed by south-west, east, and west-facing arrays. Yet, if we had a TOU rate plan similar to the San Jose Clean Energy TOU rate plan, the NE TOU advantage would vanish.

Switching to a permanent PST in Nevada would increase electricity costs for TOU solar customers. Switching to a permanent PDT in Nevada would have only a marginal positive impact on the customers' bills.

6. Limitations

In our model calculation, we assumed a permanent 75% credit from NE for excess solar electricity generation. However, NE guarantees the 75% credit for 20 years. Early NE adopters of solar electricity received 95% credit, which was reduced for later adopters to 88% and then to 81%. Based on this credit trend, it is likely that after 20 years, lower solar electricity credit rates are to be expected.

We also assumed that the TOU peak and off-peak hours' schedules would not change over time. Unfortunately, NE does not guarantee these schedules. Such changes could significantly impact the credit paid to NE customers for generating excess solar energy.

While the calculation and analysis of Section 2 are quite general, the bill calculation of Section 3 is specific to NE. The simplification brought about by the cancellation of terms in the breakeven calculations is likely to be unique to NE billing.

NE also offers TOU periods for electric vehicles recharging. However this topic is not addressed in this paper.

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Conflicts of Interest

The author declares no conflicts of interest regarding the publication of this paper.

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