The implementation of grid-connected, residential rooftop photovoltaic systems under different load scenarios in Malaysia

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Abstract

The current work discusses the implementation of grid-connected, residential rooftop photovoltaic (PV) systems under the scenario of low (300 kWh/month), medium (600 kWh/month), and high (2100 kWh/month) electric loads. The analysis shows that, under all load scenarios, using rooftop PV systems with increasing PV ratings increased renewable fraction (by at least 5% for 1 kW PV under high electric load to as much as 89% for 12 kW PV under low electric load) and reduced carbon emission (by at least 5% for 1 kW PV under high electric load to negative carbon emission for 12 kW PV under low electric load). Furthermore, the highest PV rating (12 kW PV) was preferred under low, medium, and high electric loads, with net present cost (NPC) 29%, 72%, and 29% lowered than the respective grid reference systems. Nevertheless, a long discounted payback period was required, especially under low electric load (above 20 yr). A few scenarios with regard to PV module price, PV sellback rate, tariff rate, and carbon tax were therefore analyzed, which led to NPC reductions of 20%, 40%, 40%, and 12%, respectively, for 6 kW PV under low electric load, in addition to shortened discounted payback periods. Although Malaysian data were used for analysis purposes, the current work has worldwide implications, where it serves as a techno-economic model that provides a sustainable development framework for understanding technically and economically the installation of rooftop PV systems for residential households and driving the implementation of rooftop PV installations especially across Southeast Asia.

Keywords: Grid-connected PV; rooftop PV; residential sector; net present cost; discounted payback period.

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1.0 Introduction

Renewable energy targets are in place in nearly all countries. In the power sector, renewable energy has grown to account for more than 33% of the total installed power generation capacity worldwide [1]. Global renewable power capacity has totalled 2378 GW, with hydropower, wind power, photovoltaic (PV) power, and other renewable power capacities comprising 48%, 25%, 21%, and 6%, respectively. Among these renewable power options, the growth of PV installations has been the highest – PV power accounted for about 55% of renewable capacity additions in 2018; this was followed by wind power (28%) and hydropower (11%) [1]. As of 2019, global cumulative PV capacity topped 627 GW, with PV contributed to reducing global carbon emissions by 5.3% of electricity related emissions, compared to a world without PV [2]. To date, PV continues to play a significant and growing role in electricity generation worldwide, and the contribution of PV to decarbonizing the energy mix is progressing. Moreover, PV is expected to lead the way in the transformation of future electricity sector [3]; the substitution of fuel-based electricity by renewable electricity has been regarded as the key to tackle global climate change [4].

The growth of PV technology and the rapid reduction in the cost of PV has demonstrated the potential of PV to be installed on a large-scale basis worldwide. According to the International Energy Agency [2], PV electricity could generate 22% of the world's electricity by 2050. This would remove a significant fraction of the growing global carbon emissions from conventional fuel-based electricity generation. Existing fuel-based technologies possess high carbon emission intensity through the combustion of carbon rich fuels, while PV technology produce little or zero emissions during operation, albeit that PV technology may incur carbon emissions during manufacture. PV electricity can therefore help to mitigate carbon emissions by replacing more carbon intensive sources of electricity. For example, the Committee on Climate Change [5] estimated that PV electricity contributed less than one tenth of carbon emissions compared to coal-based electricity. PV technology could therefore meet the world's needs for low-carbon power generation, thus contributing to a low-carbon world.

Generally, PV deployment can be classified into two main categories. First, PV is used for off-grid solutions, typically for places with no access to grid electricity or when the cost of connecting the load to grid electricity is high. This usually involves small-scale projects in rural areas, and the main targets are residential households and villages willing to be disconnected from the grid. Second, PV is integrated to the grid (grid-connected), in which PV electricity not only supplies its adjacent load, but also transports through the grid to supply other loads interconnected to the grid. This can be a centralized grid-connected PV system (with PV arrays mounted on the ground) that performs the functions of a centralized power system to supply bulk power, whereby power utilities develop PV to fulfil renewable purchase obligations or preferential tariffs. Alternatively, a distributed grid-connected PV system can be installed on residential, commercial, or industrial customers' premises to provide power to grid-connected customers or directly to the grid network. This is also commonly known as a rooftop PV system, whereby retail customers drive the installation of PV to benefit from attractive policies and regulatory environments.

Electricity demand growth in Southeast Asia, estimated at 6% per annum, has been among the fastest in the world [6]. With abundant sunshine and an annual average daily solar radiation ranging from 4.03 $kWh/m^2/d$ to 5.21 $kWh/m^2/d$ [9-11], Southeast Asia has a huge potential to harness PV electricity. In their commitment to achieving United Nations renewable energy and climate change goals, Southeast Asian nations are stepping up plans to deploy PV power [7]. Specifically, Thailand, the Philippines, Malaysia, Indonesia, and Vietnam are leading in renewable power policies in the region [8]. In these countries, policies are evolving to address growing challenges and adapting to changing conditions relevant to renewable energy, including PV. In Thailand, for example, the installed PV capacity reached more than 2 GW in 2016; in the Philippines, the installed PV capacity was nearly 1 GW in 2016 [8]. For Malaysia, the installed PV capacity was small (less than 300 MW) at that time in comparison, but the estimated PV power potential was 268.9 GW, of which ground-mounted PV, rooftop PV, and floating PV could accumulate up to 210.2 GW, 42.2 GW, and 16.5 GW of power capacity, respectively [12]. Although the contribution of PV power to the electricity demand in Malaysia amounted to merely 1% of 26,426 MW total energy mix in 2017 [13, 14], Malaysia then showed its strong commitment to increase PV electricity, with 410 MW of PV capacity added in 2018; grid-connected PV capacity amounted to 314 MW. By the end of 2018, the cumulative PV capacity in Malaysia increased to 740 MW, of which the ground-mounted PV, rooftop PV, and off-grid PV consisted of 397 MW, 307 MW, and 36 MW, respectively. Such a similar growth in PV electricity has been observed across other Southeast Asian countries, with the main aim of achieving their targeted renewable energy mix and carbon emission reduction [6-8].

Of note, the PV market in Southeast Asia is dominated by grid-connected PV systems; the installation of off-grid PV systems is very little compared to grid-connected ones [15]. In Malaysia, specifically, this is mainly driven by the feed-in tariff (FiT) scheme (introduced from December 2011 until December 2018), the net energy metering (NEM) scheme (introduced since 2019), and the large-scale solar (LSS) scheme (introduced since 2016); the first two schemes are under the purview of the Sustainable Energy Development Authority (SEDA) Malaysia while the other scheme is under the purview of the Energy Commission (EC) of Malaysia. According to the International Energy Agency [15], Malaysia, in 2018, achieved a cumulative installed PV capacity of 383 MW based on FiT, of which 22% came from individual households, 2% came from the community, and 76% came from the commercial/industrial sector. Meanwhile, under the LSS commercial scheme, 401 MW solar PV was operational as of 2018, with an additional 807 MW expected to be operational in 2019 and 2020.

Thus far, grid-connected PV systems have been primarily harnessed through large-scale PV installations. These large-scale, commonly centralized PV stations are preferred by utilities as they largely follow the current electrical power management model and provide little disruptions to the current electricity market model. In addition, centralized PV stations can provide much lower costs due to economies of scale, such as those involved in bulk purchasing, installation labor, and permitting fees [16]. However, Schoechle [17] argued that cost assessments of centralized PV stations often did not take into account all installation costs, such as the cost of transmission (transmission losses), connection charges, distribution support, and capital asset recovery. These large stations also require huge capital investments for infrastructure like electrical substations, and may require new transmission lines to transfer power from the stations to the loads. When all the integration costs were taken into account, Bachner et al. [18] implied that the societal welfare effects of a large-scale expansion of PV were no longer competitive compared to distributed (rooftop) PV systems. Unlike large-scale PV projects which tend to be one-time deals that mainly provide rewards for bondholders, investors, and speculators, rooftop PV systems benefit the general public through their direct involvement; rooftop PV systems offer solutions for empowering consumers to play a more active role in the renewable energy market. Rooftop PV systems also benefit distribution systems by reducing losses, deferring system capacity expansion, and alleviating feeder loading [19].

The great advantages of rooftop PV systems should be enough to achieve their massive implementation worldwide [20]. Globally, the installation of residential rooftop PV systems has increased significantly in recent years. For example, Germany, Japan, and the United States have significant shares of rooftop PV installations [21]. In particular, the residential PV market in the United States has grown 44% annually since 2005 and about 2.5% of households in the United States have installed a PV system [22]; the adoption of distributed energy is expected to continue to grow rapidly [23]. This is due to supporting regulatory policies and financial incentives such as through the FiT scheme, the NEM scheme, and government's investment in PV equipment [24-26]. In addition, declining installation costs of PV is an important driver of PV installations, where the average cost of a typical PV system has declined more than half from 2009 to 2016, mostly driven by a reduction in module prices [27]. Consumers installing rooftop PV systems can reduce their utility bills by consuming less from the grid and there is a potential for getting credits as a result of generating more electricity than needed [28]. This is especially true for high electricity-consuming households experiencing steeply-tiered electricity price structure [28]. Therefore, generating PV electricity for own use has become more attractive from an economic point of view than buying electricity from the conventional grid. The excess electricity can be fed back to the grid, giving the customers and other people the opportunity to make use of the electricity that otherwise would have been wasted. The act of feeding the electricity back to the grid also contributes to a more resource efficient energy production since it increases the share of renewables in the energy generation mix.

The FiT scheme has been successful for jumpstarting PV markets and contributing to higher deployment rates of grid-connected PV in Europe, the United States, and a number of emerging countries [29-32]. FiT is financially attractive to customers due to the premium tariff rates set by early policy adopters. The consequence of this high success rate is the high financial returns associated with feed-in tariff contracts. Under FiT, consumers get financially compensated for every unit of excess electricity fed back to the grid for a specific duration – the compensation is above retail rates. By guaranteeing access to the grid and setting a favorable price per unit of renewable energy, the FiT mechanism ensures that renewable energy becomes a viable and sound long-term investment for companies, industries, and individuals. Nevertheless, the FiT rate has to be regularly adjusted downward in line with PV market growth and rapidly declining PV prices to avoid unexpected financial woes from over-subsidies of FiT [33, 34].

As the percentage of PV adopters increases, FiT rates have to be reduced to retail rates. Consequently, the NEM scheme has, in many countries, replaced the FiT scheme. NEM is popular because of its favorable political implications and low bureaucratic costs [35, 36]. NEM creates a framework where PV is interconnected to a utility grid through a meter that allows surplus generated electricity to be transferred to the grid, thus offsetting the costs of power drawn from the utility grid. NEM enables PV owners to offset their power consumed from the grid with the power produced by PV; consumers receive the excess energy that they feed back to the grid as credit. In addition, PV owners are to be compensated for their excess generation (kWh produced greater than kWh used) at a minimum of avoided costs – avoided costs has multiple definitions depending on the utility's interpretation of the law, but it generally means avoided cost of fuel [37]. The financial attractiveness of NEM is therefore mainly influenced by the costs of avoided electricity bills, and can be improved if coupled with other financial incentives [31, 38].

To ensure the sustainability of PV subsidy schemes, many Southeast Asian countries have adopted the NEM scheme for the installation of residential rooftop PV systems. Nevertheless, small-scale PV systems commonly installed in residential households have higher installation costs compared to larger utility-scale systems [39]. The financial viability of installing small-scale PV systems is therefore highly sensitive to various factors such as investment costs, electricity tariffs, government incentives, and solar irradiation. These have been demonstrated in comparative studies assessing the financial attractiveness of small-scale PV systems in many different countries around the world [29, 32, 38, 40]. For comparing the electricity prices of residential solar PV systems, Yamamoto [41] demonstrated that, if the amount of electricity that could be reduced by installing a solar PV system was small, the FiT scheme became more beneficial than the NEM scheme, and vice versa.

The number of residential customers in Southeast Asia has been projected to grow rapidly. For example, the total number of Malaysian households grew nearly twofold from 4.8 million in 2000 to 8.0 million in 2019 [42, 43]; a rapid growth in the residential sector is expected, where residential dwellings are projected to increase by about 150,000 every year [44]. As such, the installation of grid-connected, residential rooftop PV systems can be the way forward to boost PV power capacity. Recently, Gabr et al. [45] conducted a techno-economic evaluation of rooftop grid-connected PV systems in Egypt, a country experiencing a hot desert climate, and reported that the feasibility of PV installation in Egypt's residential areas was influenced by the energy consumption pattern, the incentive policy, and the economical indices of PV systems. As suggested by Gabr et al. [45], there can be many factors and conditions that affect the implementation of PV systems in different countries. These include weather and climate conditions, incentive policies, and tariff structure for grid-connected PV installations.

As far as we are aware, little research has been conducted on a regular basis on the current techno-economic outlook of installing residential rooftop PV systems under different load scenarios, especially based on the "one-on-one" offset basis of the NEM scheme. The purpose of our study here was therefore to analyze the techno-economic feasibility of implementing residential rooftop PV systems under different load scenarios by looking into Malaysia, a country experiencing an equatorial climate, as an exemplar case of Southeast Asia. This was first conducted by determining PV technical parameters, cost competitiveness, and discounted payback periods of rooftop PV systems with regard to different load scenarios based on the concept of the "one-on-one" offset basis of the NEM scheme. Thereafter, the technical viability of PV system capacities, net present values, and discounted payback periods with regard to electricity cost escalation rates, electricity resale rate, carbon tax, and declining PV prices were analyzed. The contributions of the current study are therefore as follows: i) analyses of residential rooftop PV systems under different load scenarios based on a "one-on-one" offset basis of the NEM scheme were carried out to determine the feasibility of such a scheme in residential rooftop PV systems under different load scenarios; ii) practicality of residential rooftop PV systems was considered by taking into account various size range of the inverter with respect to the size of the PV array, with the PV-to-inverter ratio rated up to 1.5; iii) analyses of the NEM scheme based on the "one-on-one" offset basis was conducted under the equatorial climate by considering Malaysia as an exemplar case of Southeast Asia in the implementation of residential rooftop PV systems; and iv) strategies to drive the implementation of rooftop PV systems, including the incorporation of carbon tax, were analyzed. The contributions of the study are thus at the intersection of two phases of the rooftop PV adoption: analyses that examine the techno-economic performance of the current residential rooftop PV systems under the NEM scheme, and analyses that assess the techno-economic drivers to encourage the adoption of residential rooftop PV systems. This will provide an insight as to whether residential rooftop PV systems provide a resilient renewable energy solution to the renewable energy generation challenges and facilitates policy makers and potential investors' evaluation of the systems.

2.0 Modeling and simulation

2.1 HOMER software

In the current work, Hybrid Optimization of Multiple Energy Resources (HOMER) software [46, 47] was used to simulate the operation of many different residential rooftop PV system designs. This enabled the identification of the least cost system as a function of user-defined factors such as system configuration, component size, load size, and grid price. The results were then used to analyze the net present cost (NPC) threshold above which rooftop PV systems became more cost-effective than the conventional grid system. These allowed the design of rooftop PV systems and the comparison of various PV generation options based on technical and economic factors to be considered using HOMER through simulation, optimization, and sensitivity analysis.

Of note, HOMER ranks its choice of optimal systems based on the NPC of a system. The NPC is the present value of all the costs, such as the capital costs, operating and maintenance costs, fuel costs, and the costs of buying power from the grid, minus the present value of all the revenues, such as the salvage value and grid sale revenue, that occur within the system's lifetime. The calculation of NPC is shown in equations (1) and (2), where $C_{ann,tot}$ is the total annualized cost (in $/yr) while $CRF(i,N)$ is the capital recovery factor, which takes into account the effect of the annual real interest rate i and the project lifetime N. Based on the data from The World Bank [48, 49], Malaysia's annual real interest rate i and annual inflation rate f for a 25-yr period (1993-2017) averaged at about 3.17% and 2.66%, respectively. These numbers were therefore used in the analysis, with a project lifetime of 25 yr, based on equation (3), where i' represents the nominal discount rate. These are important in determining the discounted payback period as opposed to the simple payback period used in many renewable energy analyses. Of note, the payback period indicates the number of years at which the cumulative cash flow of the difference between the PV system and the conventional grid system switches from negative to positive; simple payback is reflected through the difference in nominal cash flow while discounted payback is reflected through the difference in discounted cash flow.

$$NPC = \frac{C_{ann,tot}}{CRF(i,N)} \tag{1}$$

$$CRF(i,N) = \frac{i(1+i)^N}{(1+i)^N - 1} \tag{2}$$

$$i = \frac{i' - f}{1 + f} \tag{3}$$

2.2 Electricity pricing and net energy metering

Since January 2014, the electricity tariff, also known as the cost of energy (COE), for Malaysian residential consumers has been rated based on different tariff blocks (see Table 1 [50]) to ensure that less electricity-consuming households pay for cheaper electricity, and vice versa. Of note, HOMER does not have the flexibility of categorizing the aforementioned electricity rates for simulation purposes. Therefore, average rates of $ 0.070/kWh, $ 0.100/kWh, and $ 0.130/kWh were assumed to represent low (300 kWh/month), medium (600 kWh/month), and high (2100 kWh/month) electricity consumptions, respectively, in Malaysia [51, 52]. Feasibility analysis of rooftop PV systems under these three electricity consumption patterns could therefore be comparatively assessed.

Table 1: Residential electricity tariff in Malaysia since 2014 [50]

Tariff	**Rate ($/kWh)**
For the first 200 kWh (1 - 200 kWh) per month	0.055
For the next 100 kWh (201 - 300 kWh) per month	0.084
For the next 300 kWh (301 - 600 kWh) per month	0.129
For the next 300 kWh (601 - 900 kWh) per month	0.137
For the next kWh (901 kWh onwards) per month	0.143

Table 2 compares various tariff rates implemented in Malaysia under the FiT (2011-2018) and NEM (2019-2020) schemes [53]. Of note, the maximum allowable size of a single-phase rooftop PV system on a residential premise does not exceed 12 kW. Under the NEM concept, electricity from PV can be consumed by residential households and fed to the grid, and this will allow excess PV electricity to be exported back to the grid on a “one-on-one” offset basis, in contrast to the displaced cost scheme under the FiT concept. Since the focus of the current analyses was to reflect on the current prospective of rooftop PV installations in Malaysia, the NEM rate was used for analyzing low, medium, and high electric loads for a household, unless otherwise mentioned. Therefore, the grid power price was set the same as the grid sellback price for the respective electric loads to satisfy the NEM scheme. Specifically, the grid power price and the grid sellback price was set at $ 0.070/kWh for low electric load, $ 0.100/kWh for medium electric load, and $ 0.130/kWh for high electric load, respectively, with the net purchases calculated monthly.

Table 2: Residential solar PV FiT and NEM rates [53]

Installation capacity	FiT rate ($)								NEM rate ($)	
	2011	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**
Up to 4 kW	0.308	0.308	0.283	0.260	0.229	0.206	0.186	0.167	One-on-one basis	One-on-one basis
Above 4 kW and up to 12 kW	0.300	0.300	0.276	0.254	0.224	0.201	0.181	0.163		

2.3 Load profile

As defined earlier, three electric loads were analysed to represent low, medium and high electricity consumptions. First, a household with low electricity consumption of 300 kWh/month (10 kWh/d), with scaled average peak load of 0.42 kW and scaled peak load of 1.39 kW, was analyzed; this resulted in a load factor of 0.30. An example of the daily load profile under low electricity consumption is illustrated in Fig. 1a. Slightly higher power demand occurred in early morning and at noon, representing consumers getting ready for work and returning home for lunch. A surge in power demand occurred at night when consumers returned home from work. Since the size and shape of the load profile varied from day to day, a day-to-day variability factor of 10% and a time-step variability factor of 20% were taken into account; this produced realistic-looking load data. Meanwhile, the monthly load profile for low electricity consumption is illustrated in Fig. 1b, with the highest monthly average estimated between June and August. Based on the daily and monthly electricity consumption behaviors for low electric load, the scaled annual average load was doubled for medium electric load. This led to a second case, where a household with medium electricity consumption of 600 kWh/month (20 kWh/d) was analyzed. Lastly, a household with high electric load of 2100 kWh/month (70 kWh/d) was analyzed. The daily and monthly load profiles for medium and high electricity consumptions are not shown, for brevity.

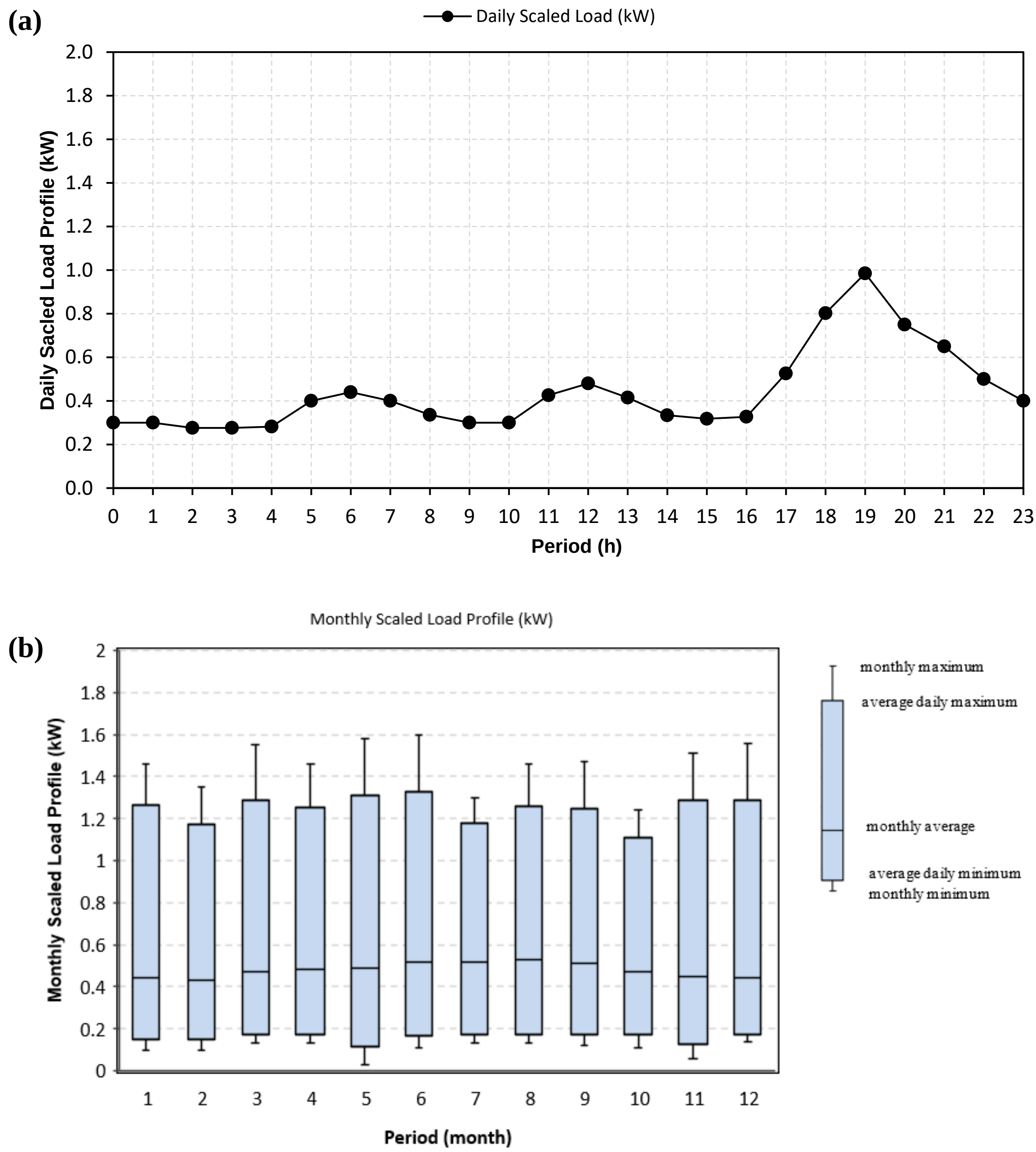


Fig. 1. (a) Daily scaled load profile, (b) monthly scaled load profile containing load size information on monthly maximum, average daily maximum, monthly average, average daily minimum, and monthly minimum, for low electricity consumption.

2.4 Solar radiation

1º 24' north latitude and 103º 37' east longitude representing a location in Johor Bahru, Malaysia, was used in the current simulation. The scaled annual average daily solar radiation generated from HOMER for the location was 4.69 kWh/m^2/d; the monthly average daily solar radiation and clearness index are shown in Fig. 2. These solar radiation data, obtained from HOMER based on satellite estimations, are reasonably acceptable [54, 55], and correspond well to Malaysia's annual average daily solar radiation of 4.03-5.21 kWh/m^2/d [9].

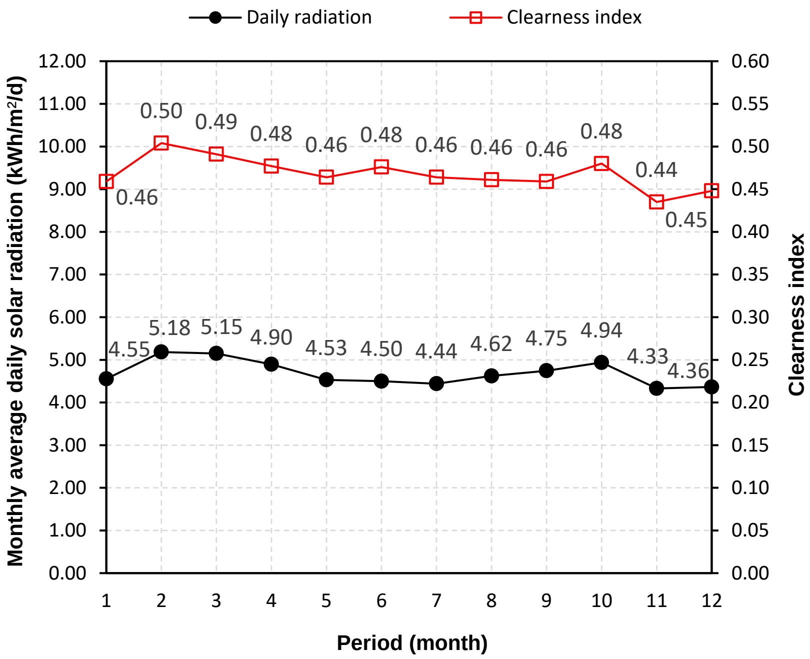


Fig. 2. Monthly average daily solar radiation and clearness index obtained from HOMER.

2.5 Design specifications

A grid-connected, residential rooftop PV system generally comprises a grid network, a PV array, an inverter, and a main distribution panel (a PV meter and an NEM meter can be integrated into this panel or installed separately), with an optional battery storage. In the current work, the operation of the grid-connected, residential rooftop PV system is illustrated in Fig. 3. The PV array converted the sunlight to direct current (DC) electricity and served as the base-load power source that delivered power continuously to meet the alternating current (AC) local loads. The inverter converted the DC current to AC electricity prior to supplying power to the loads via the main distribution panel. Meanwhile, excessive DC power from the PV array was fed to the utility grid. Synchronization of the AC electricity with the grid was done through the main distribution panel so that the excess electricity was compatible with the grid's AC electricity. Of note, the PV meter measured the output from the inverter and collected information regarding PV output, and energy storage batteries were not available. The NEM meter was used to calculate the net energy fed to or taken from the grid. The grid-connected PV system operated a load following dispatch strategy, where the utility grid would supply power only if the PV array failed to produce enough power to meet the load demand. A carbon dioxide emission factor of 720.6 g/kWh [56] was used for calculating pollutant emissions resulted from grid power purchases and avoided pollutant emissions resulted from grid power sale (based on the NEM scheme).

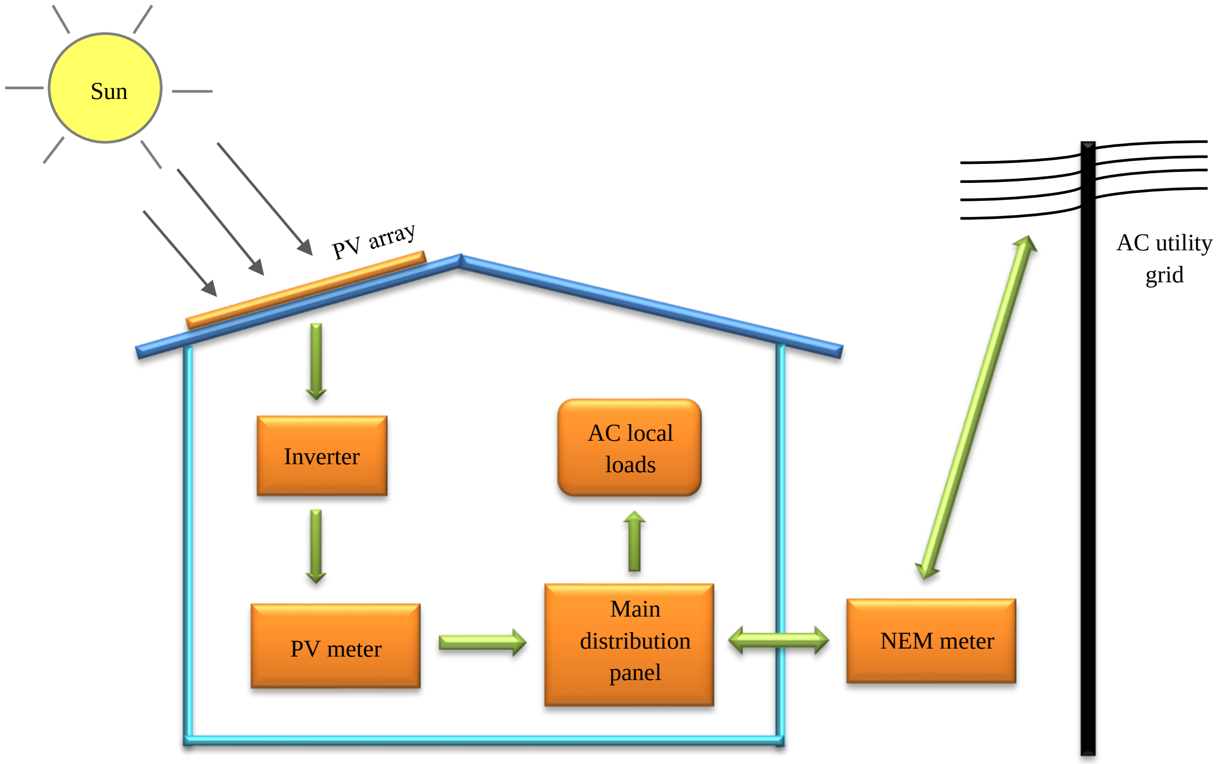


Fig. 3. Grid-connected, residential rooftop PV system.

To take into account the techno-economic feasibility of different rooftop PV systems, PV ratings between 1 kW and 12 kW, with 1 kW step-size, were considered in the analysis. The designated PV range was considered based on the data estimated from the PV monitoring system provided by SEDA, Malaysia [14], which indicated that the most frequent nominal power of a residential PV was rated between 4 kW and 12 kW. Meanwhile, the inverter was chosen with respect to the size of PV array, with the PV-to-inverter ratio rated up to 1.5 (with 1 kW step-size), based on the technical guidelines provided in the literature [57, 58]. The choice of PV-inverter combinations based on the aforementioned PV-to-inverter ratio is illustrated in Fig. 4.

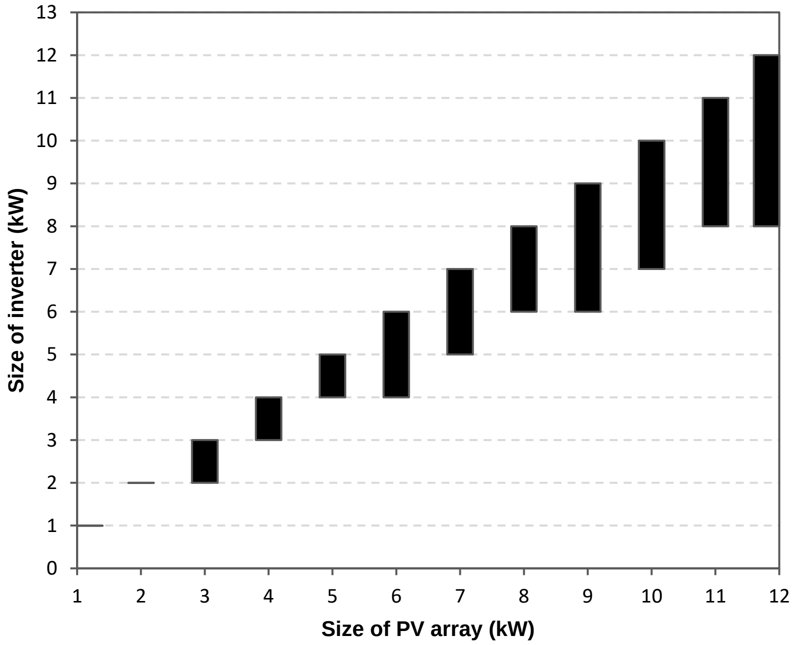


Fig. 4. Different sizes of inverters matched to different sizes of PV arrays, with the array-to-inverter ratio rated up to 1.5.

For the current analyses, the price of the PV array (including soft costs but excluding the price of the inverter) was assumed as in Fig. 5. Briefly, the price of the PV array could be as high as $ 2100/kW for a 1 kW PV system, which dropped linearly to $ 1380/kW for a 6 kW PV system, and further reduced to $ 1050/kW for a 12 kW PV system – these assumptions were in good agreement with the PV prices estimated by SEDA, Malaysia, and TNB under the residential PV program [59, 60]. Of note, prices of PV systems vary depending on their system installation sizes and soft costs such as installation labor, installer margins, inspection costs, market acquisition and loan fees [39, 61, 62]; analyses on the PV pricing variability can be referred to elsewhere [55]. Table 3 summarizes the simulation parameters used in the analyses, unless otherwise mentioned.

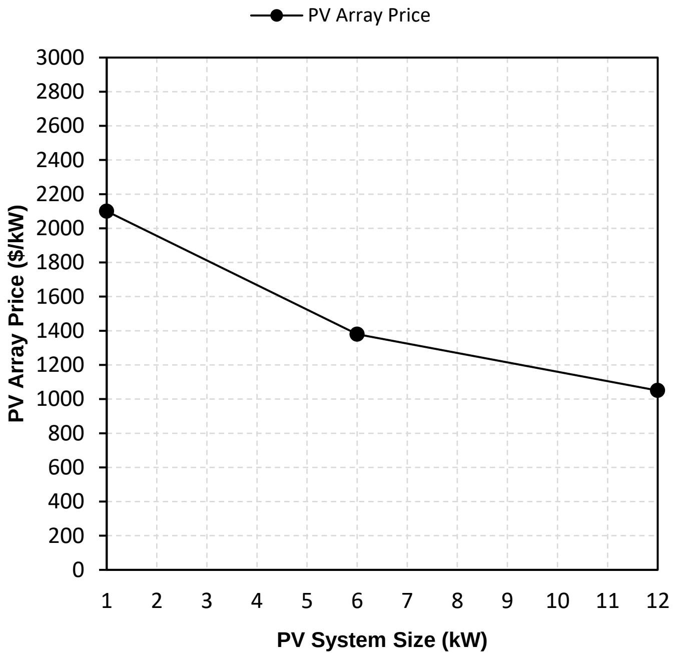


Fig. 5. PV array prices vary based on different PV system sizes.

Table 3. Simulation parameters

Description	**Data**
PV array	
Size	0-12 kW choices
Capital/replacement cost	$ 1050-2100/kW
Operating and maintenance cost	$ 10/yr
Lifetime	25 yr
Inverter	
Size	0-12 kW choices
PV-to-inverter ratio	1.0-1.5
Capital/replacement cost	$ 150/kW
Operating and maintenance cost	$ 10/kW/yr
Lifetime	15 yr
Efficiency	98%
Utility grid	
Electricity tariff	$ 0.070/kWh (low electric load), $ 0.100/kWh (medium electric load), $ 0.130/kWh (high electric load)
NEM rate	$ 0.070/kWh (low electric load), $ 0.100/kWh (medium electric load), $ 0.130/kWh (high electric load)
NEM calculation	Net purchase calculated monthly
Carbon emissions	720.6 g/kWh
Economics	
Nominal discount rate	5.91%
Expected inflation rate	2.66%
Real discount rate	3.17%
Project lifetime	25 yr

It is noteworthy that the operating and maintenance cost can come from the PV array and the inverter, which HOMER treats as two separate units that represent a PV system. To avoid overestimation of the operating and maintenance cost contributed by both the PV array and the inverter in the PV system, the operating and maintenance cost for the PV array was fixed at $ 10/yr. This was because the operating and maintenance cost of the PV array was assumed as the recurring annual cost that occurred regardless of the size or architecture of the PV array. Since the operating and maintenance cost of the PV array was negligibly small compared to the primary investment cost and that the PV array's fixed operating and maintenance cost affected the total net present cost of each system configuration equally, it had no significant effect on the system rankings. For the inverter, however, the operating and maintenance cost was assumed at $ 10/kW/yr to represent the operating and maintenance cost of the PV system.

3.0 Results and discussion

3.1 Techno-economic analyses of rooftop PV systems under the current scenario

3.1.1 Grid reference system

The conventional grid system served as a reference system. In this system, electricity was drawn directly from the utility grid to meet the load demand whenever necessary; no excess electricity was generated. From Fig. 6, three different NPCs under low (300 kWh/month), medium (600 kWh/month), and high (2100 kWh/month) electric loads can be noticed. First, low electricity consumption resulted in an NPC of $ 4368 (and a COE of $ 0.07/kWh). Second, medium electricity consumption resulted in an NPC of $ 12,480 (and a COE of $ 0.10/kWh). Last, high electricity consumption resulted in an NPC of $ 56,784 (and a COE of $ 0.13/kWh).

From Fig. 6, the COE did not increase linearly with the increase in load consumptions. Specifically, the increase in the COE between medium and high electricity consumptions was not as much as the increase in the COE between low and medium electricity consumptions. This was because the COE did not change, or not very much, with changing interest rates. We therefore considered our feasibility analyses with respect to the NPC.

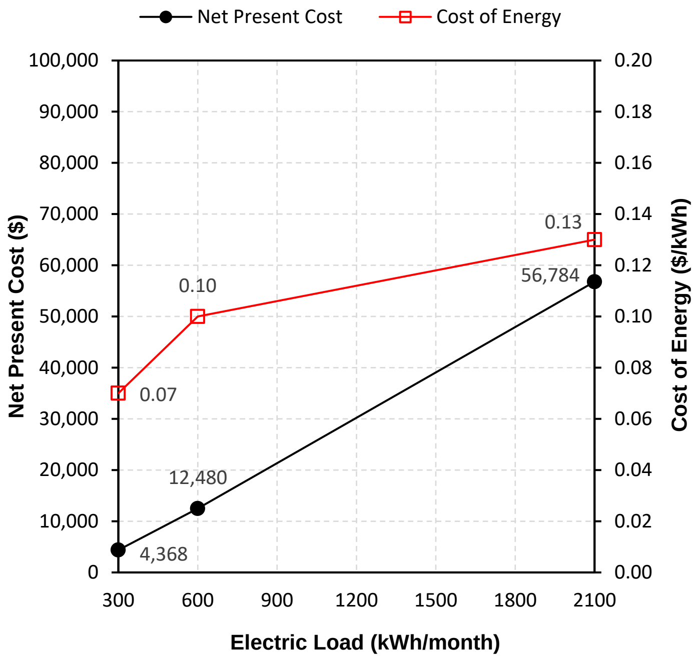


Fig. 6. The effect of low, medium and high electric loads on the net present cost and the cost of energy of the grid reference system.

3.1.2 Feasibility of rooftop PV systems under low, medium and high electric loads

Fig. 7a, Fig. 7b, and Fig. 7c show the effect of PV and inverter ratings on the NPC of the rooftop PV system under low, medium, and high electric loads, respectively. The horizontal reference line along the x-axis in Fig. 7a, Fig. 7b, and Fig. 7c indicates the NPCs of the respective grid reference systems.

From Fig. 7a, the use of a small-size rooftop PV system (typically less than 9 kW) did not lead to a lower NPC than the grid reference system ($ 4368), under low electric load. The NPC of the rooftop PV system became lower than that of the grid reference system when a rooftop PV rating of at least 9 kW, matched with a 6 kW and a 7 kW inverter, was used; this resulted in NPCs of $ 3977 and $ 4267, respectively. Of note, the NPC reduced with bigger size rooftop PV systems under comparable PV-to-inverter ratios, and that higher PV-to-inverter ratios further reduced the NPC. For example, the combination of a 12 kW PV array and a 10 kW inverter (with PV-to-inverter ratio of 1.2) resulted in an NPC of $ 3115, 29% lower than the grid reference system. Meanwhile, the combination of a 12 kW PV array and an 8 kW inverter (with PV-to-inverter ratio of 1.5) resulted in an NPC of $ 2469, which was 43% lower than the grid reference system.

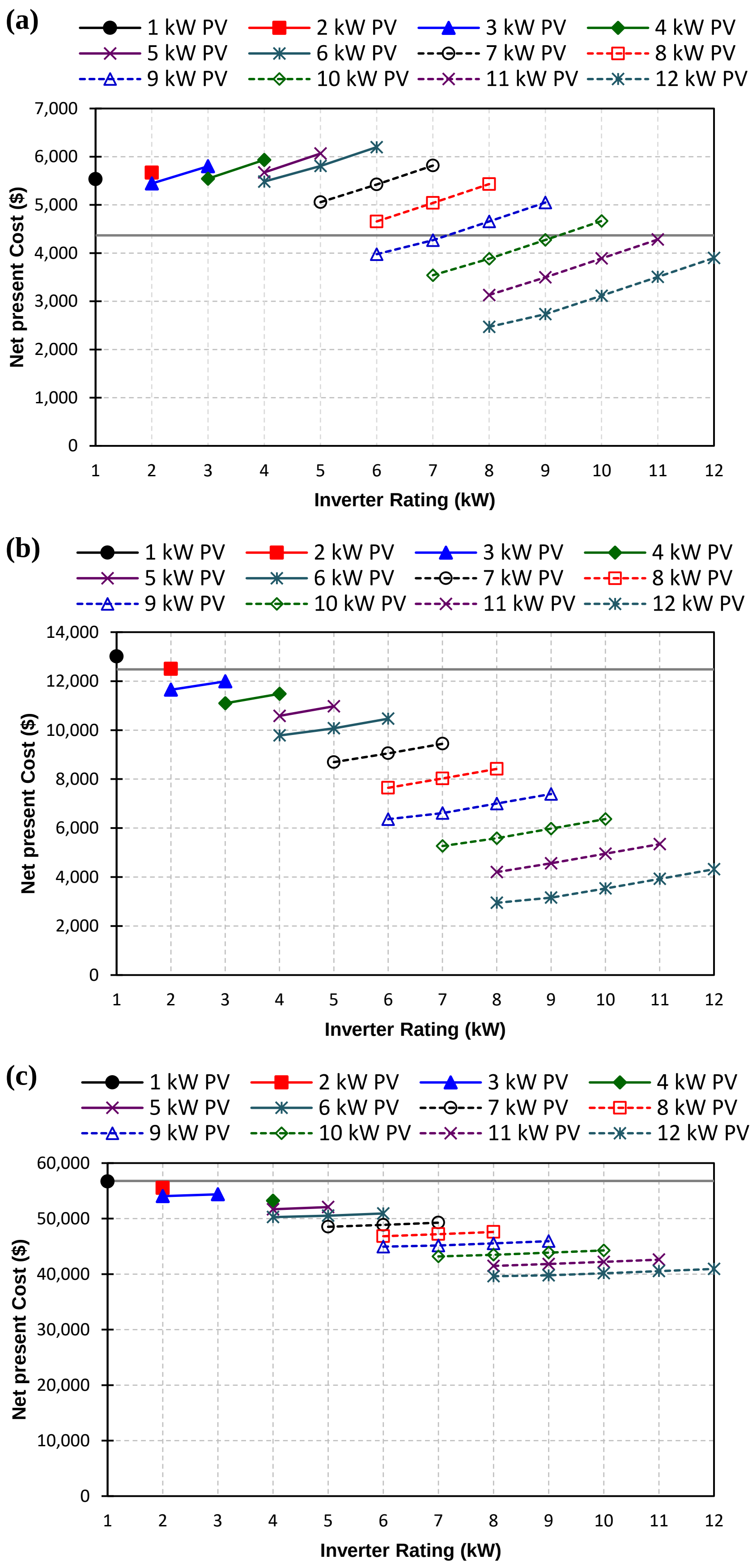


Fig. 7. The effects of PV and inverter ratings on the net present cost of the rooftop PV systems for three analyzed cases of (a) low electric load, (b) medium electric load, (c) high electric load. The reference line along the x-axis indicates the net present costs of the respective grid reference systems.

Under medium electric load, the use of smaller-sized rooftop PV systems became feasible over the grid reference system (see Fig. 7b). Analysis from HOMER showed that 3 kW to 12 kW PV systems all resulted in lower NPCs than the grid reference system; the 2 kW PV system had a slightly higher NPC ($ 12,499) than the grid reference system ($ 12,480). Again, the NPC reduced with bigger size rooftop PV systems under comparable PV-to-inverter ratios, and that higher PV-to-inverter ratios further reduced the NPC. For instance, the combination of a 12 kW PV array and a 10 kW inverter (with PV-to-inverter ratio of 1.2) resulted in an NPC of $ 3537, which was 72% lower than the grid reference system.

As electricity consumption increased (high electric load, see Fig. 7c), similar trends described above were observed, and all analyzed PV systems (1-12 kW) had lower costs (NPC-wise) compared to the grid reference system ($ 56,784). For example, the combination of a 12 kW PV array and a 10 kW inverter (with PV-to-inverter ratio of 1.2) resulted in 29% lower NPC ($ 40,150) than the grid reference system.

Fig. 8a shows the effect of PV sizing (1-12 kW) on the discounted payback period under low, medium and high electric loads. Since the discounted payback period varied based on the PV-to-inverter ratio, Fig. 8a considers the least discounted payback period based on PV-to-inverter ratios up to 1.3, as commonly practiced in the PV industry [56, 57]. Of note, higher PV-to-inverter ratios would slightly reduce the payback period, but this is not shown for brevity. Meanwhile, the discounted payback period, rather than the simple payback period, was taken into account since the former considered the effect of interest rate on the rooftop PV systems; this would provide a more sensible estimation of the payback period in reality.

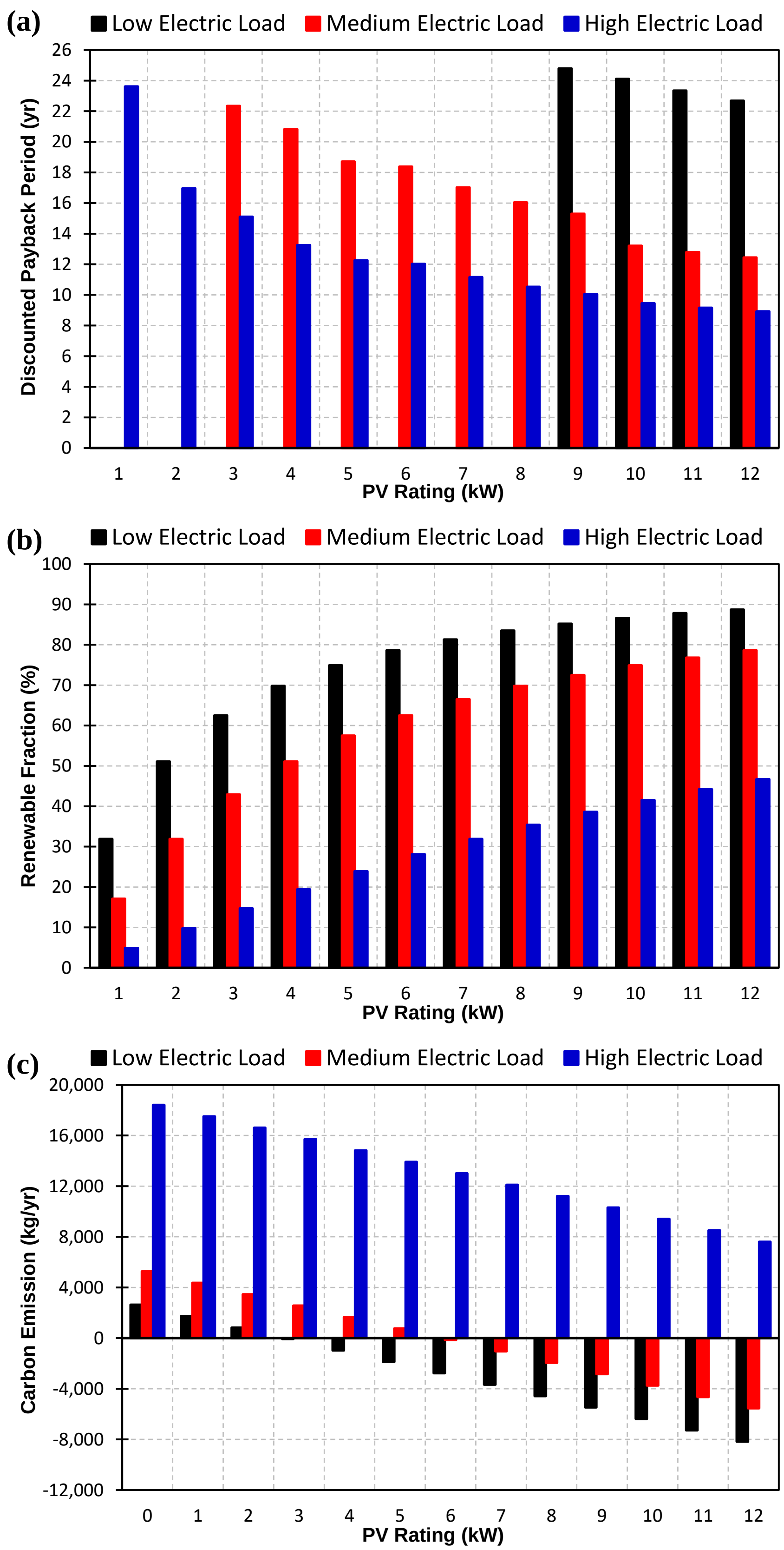


Fig. 8. The effect of PV sizing on (a) discounted payback period, (b) renewable fraction, (c) carbon emission of the grid-connected PV systems for three analyzed cases of low, medium and high electric loads.

Of note, all the analyzed PV systems resulted in an extremely long discounted payback period under low electric load. Although 9 kW, 10 kW, 11 kW, and 12 kW PV systems could be used in place of the grid reference system, a very long discounted payback period (more than 20 yr) was still required. Under medium electric load, the discounted payback period of the analyzed PV systems reduced compared with that under low electricity consumption, but the period remained long (between 12-23 yr). Significantly, high electricity consumption yielded a discounted payback period of less than 10 yr especially for PV systems with PV sizes higher than 9 kW. These results indicate that the installation of rooftop PV systems was more feasible under high electric load and large PV sizes.

The installation of rooftop PV systems encouraged the generation of renewable energy under low, medium, and high electric loads, as shown in Fig. 8b; the data remained the same for PV-to-inverter ratio up to 1.5. Minimum renewable fractions of 32%, 17%, and 5% were achieved under low, medium, and high electric loads, respectively, with the use of a 1 kW PV system. With the use of a 12 kW PV system, high renewable fractions of 89%, 79%, and 47% were achieved under low, medium, and high electric loads, respectively. Therefore, higher rooftop PV ratings led to higher renewable fractions as more solar electricity could be generated. Of note, more electricity was required from the grid as the electric load increased, so the renewable fraction became lower with increased electric loads.

With increased rooftop PV ratings, hence increased renewable fraction, carbon emissions became reduced under low, medium, and high electric loads (see Fig. 8c) – the grid reference system is referred to as 0 kW. Specifically, under high electric load, carbon emission reduced 59% from 18,411 kg/yr (based on the grid reference system) to 7606 kg/yr (based on a 12 kW PV system). This was because HOMER credited the sale of PV electricity from rooftop PV systems to the grid by a compensation between avoided and generated carbon. This resulted in reduced overall carbon emissions from the rooftop PV systems. Meanwhile, under low electric loads, carbon emission reduced from 2630 kg/yr (based on the grid reference system) to zero emission (based on a 3 kW PV system); the carbon emission value further reduced to -8175 kg/yr (based on a 12 kW PV system). Such a similar trend of zero or negative carbon emission was also observed under medium electric loads, where carbon emission reduced from 5260 kg/yr (based on the grid reference system) to -5545 kg/yr (based on a 12 kW PV system). Negative carbon emissions, as noted under the low and medium electric loads, means that the rooftop PV systems sold a lot of low-emission electricity, in overall, to the grid.

3.1.3 Comparative assessments of rooftop PV systems under low (6 kW) and high (12 kW) PV ratings

Since different PV and inverter combinations resulted in different techno-economic results, detailed analysis of two representative rooftop PV systems, i.e., a PV system consisted of a 6 kW PV array and a 5 kW inverter (briefly referred to as “6 kW PV” hereafter) and a PV system consisted of a 12 kW PV array and a 10 kW inverter (briefly referred to as “12 kW PV” hereafter) is further discussed. Analyses of these PV systems served as a basis in understanding the techno-economic feasibility of other PV and inverter combinations.

Fig. 9a and Fig. 9b show the annual energy production and consumption behaviors of the 6 kW PV and the 12 kW PV, respectively, for low, medium, and high electric loads. In general, the 6 kW PV could produce total PV electricity of 7650 kWh/yr while the 12 kW PV could produce total PV electricity of 15,300 kWh/yr, irrespective of the load profile. However, the consumption of PV electricity by the loads and the sale of PV electricity to the grid became very different under low, medium, and high electric loads.

Under low electric load, which consumed 3650 kWh/yr of electricity, about half of the electricity was obtained from the grid (56%), while the rest was obtained from the 6 kW PV. Of note, 77% of PV electricity generated by the PV was fed to the grid rather than supplied to the load (see Fig. 9a). Although PV electricity increased with the use of the 12 kW PV (see Fig. 9b), about half of the electricity was still obtained from the grid (52%). This suggests that there was a mismatch between peak solar PV production and higher self-consumption. Indeed, much electricity was consumed in the early morning and at night, where PV output was scarcely available (compare Fig. 1a with Fig. 9c and Fig. 9d). So, electricity would have to be obtained from the grid no matter how much PV electricity was generated. The huge amount of excess PV electricity fed to the grid led to a high renewable fraction and low carbon emissions, as discussed earlier.

Under medium electric load, which consumed 7300 kWh/yr of electricity, the use of the 6 kW PV (see Fig. 9a) resulted in more PV electricity consumed by the load, hence less PV electricity fed to the grid. Of note, the use of the 12 kW PV (see Fig. 9b) reduced the dependence of grid electricity to 56% from 62% (6 kW PV). Under high electricity consumption (25,550 kWh/yr), the use of the 12 kW PV also resulted in reduced dependence on grid electricity by as much as 8% compared with the 6 kW PV. Much less PV electricity was fed to the grid under high electric load in comparison with low and medium electric loads.

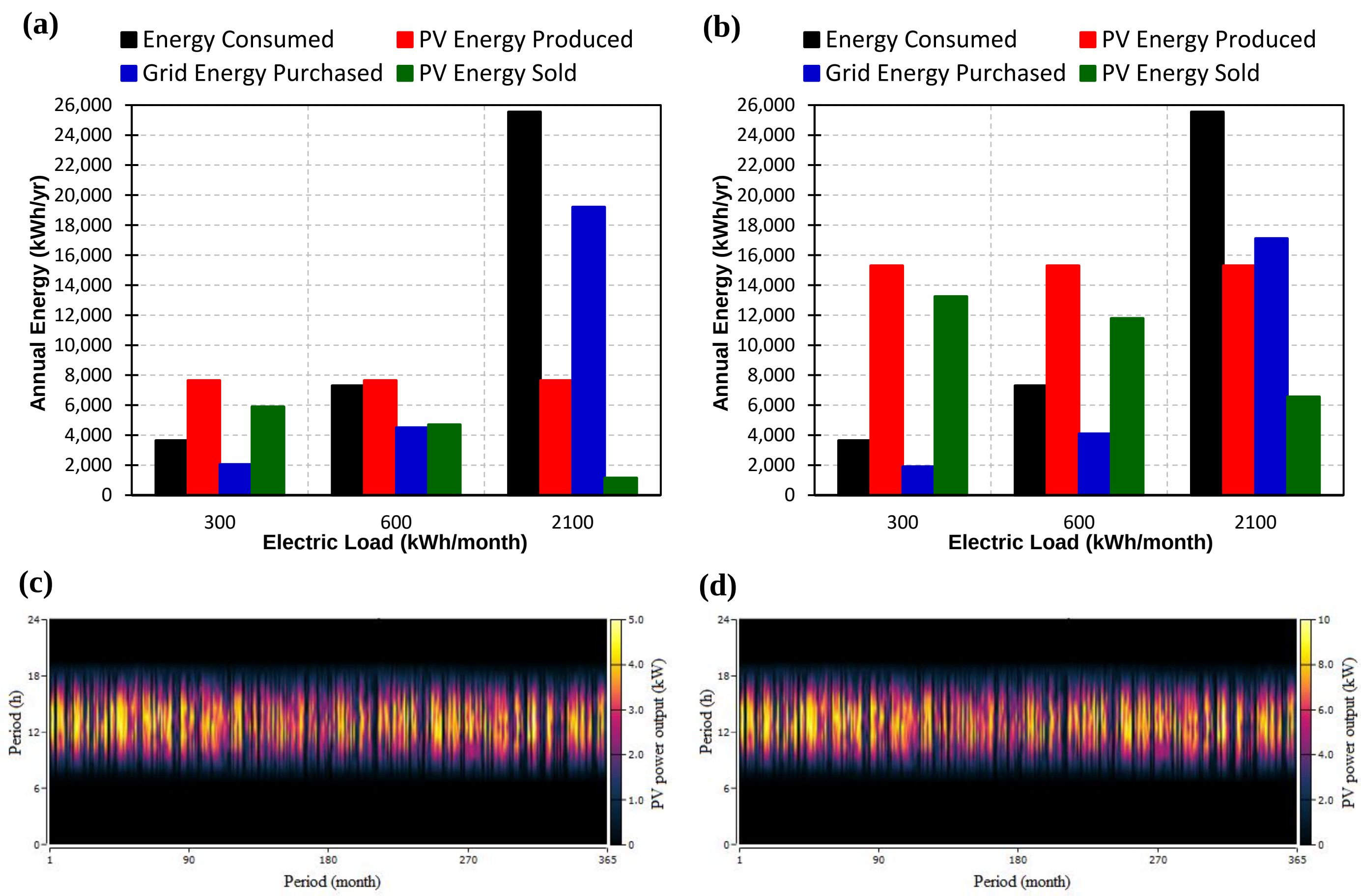


Fig. 9. Annual energy for (a) 6 kW PV, (b) 12 kW PV, and PV power output for (c) 6 kW PV, (d) 12 kW PV.

Fig. 10a and Fig. 10b show the cost breakdown of the 6 kW PV and the 12 kW PV, respectively, under low, medium, and high electric loads. Of note, the capital cost of the PV systems remained the same irrespective of the load profile; the capital cost of the 6 kW PV remained unchanged at $ 9030 while the capital cost of the 12 kW PV remained unchanged at $14,100 under low, medium, and high electric loads. This was because the capital cost consisted of the cost for installing PV and inverter, and had not association with the load profile.

Under low and medium electric loads, the NPC of both the 6 kW PV and the 12 kW PV was mainly contributed by the capital cost (see Fig. 10a). The operating and maintenance cost associated with the purchase of grid electricity was less significant in contrast. This was because PV electricity was sold to the grid to offset the grid purchase. In contrast, the operating and maintenance cost associated with the purchase of grid electricity became more significant under high electric load as a lot of grid electricity was needed to supply the load. Consequently, the capital cost became less dominant under high electric load.

As the PV rating increased from 6 kW to 12 kW, the NPC of the 12 kW PV under low, medium, and high electric loads reduced compared with the NPC of the 6 kW PV (compare Fig. 10b with Fig. 10a). This was largely due to reduced operating and maintenance cost as a consequence of increased sale of PV electricity to the grid to compensate for the grid electricity purchased. This implies that the use of bigger sizes PV was favorable under all the investigated load profiles.

By comparing Fig. 10c (discounted cumulative cash flow of the 6 kW PV as opposed to that of the grid reference system) with Fig. 10d (discounted cumulative cash flow of the 12 kW PV as opposed to that of the grid reference system), the advantage of the 12 kW PV over the 6 kW PV became more apparent, especially with regard to discounted cumulative cash flow. Although the initial investment cost of the 12 kW PV was higher than the 6 kW PV, the discounted cumulative cash flow of the 12 kW PV became less than that of the 6 kW PV under the respective low, medium, and high electric loads as time passed (within the 25 yr period). This was mainly attributed to the advantage of the 12 kW PV for having reduced PV array price per kW as compared with the 6 kW PV, as illustrated in Fig. 5. In addition, higher amounts of PV electricity could be sold to the grid to compensate for the grid electricity purchased. Consequently, the discounted payback period for the 12 kW PV was shorter than the 6 kW PV under the respective low, medium, and high electric loads. For example, under high electric load, the discounted payback period for the 12 kW PV became 8.92 yr instead of 12.02 yr for the 6 kW PV. This suggests that a bigger size PV should be employed where possible.

Furthermore, the discounted payback period under high electric load was shorter than that under low electric load for the respective 6 kW PV and 12 kW PV. For the 12 kW PV, for example, the discounted payback period under low, medium, and high electric loads were 22.68 yr, 12.44 yr, 8.92 yr, respectively. The rooftop PV systems could therefore achieve the grid parity quicker under high electric load.

Fig. 10e and Fig. 10f show the discounted cumulative cash flow of the respective 6 kW PV and 12 kW PV based on different components, i.e., PV, inverter, and grid. From Fig. 10e, the discounted cumulative cash flow of the PV and the inverter was the same under low, medium, and high electric loads, hence not shown separately for brevity. This was because the rating of the PV was the same at 6 kW and the rating of the inverter was the same at 5 kW in Fig. 10e. Similarly, in Fig. 10f, the size of the PV (12 kW) and the inverter (10 kW) was the same for low, medium and high electric loads, so the discounted cumulative cash flow of the PV and the inverter was the same. From both Fig. 10e and Fig. 10f, the inverter was replaced at 15th year, causing the discounted cumulative cash flow to notably increase on that particular year.

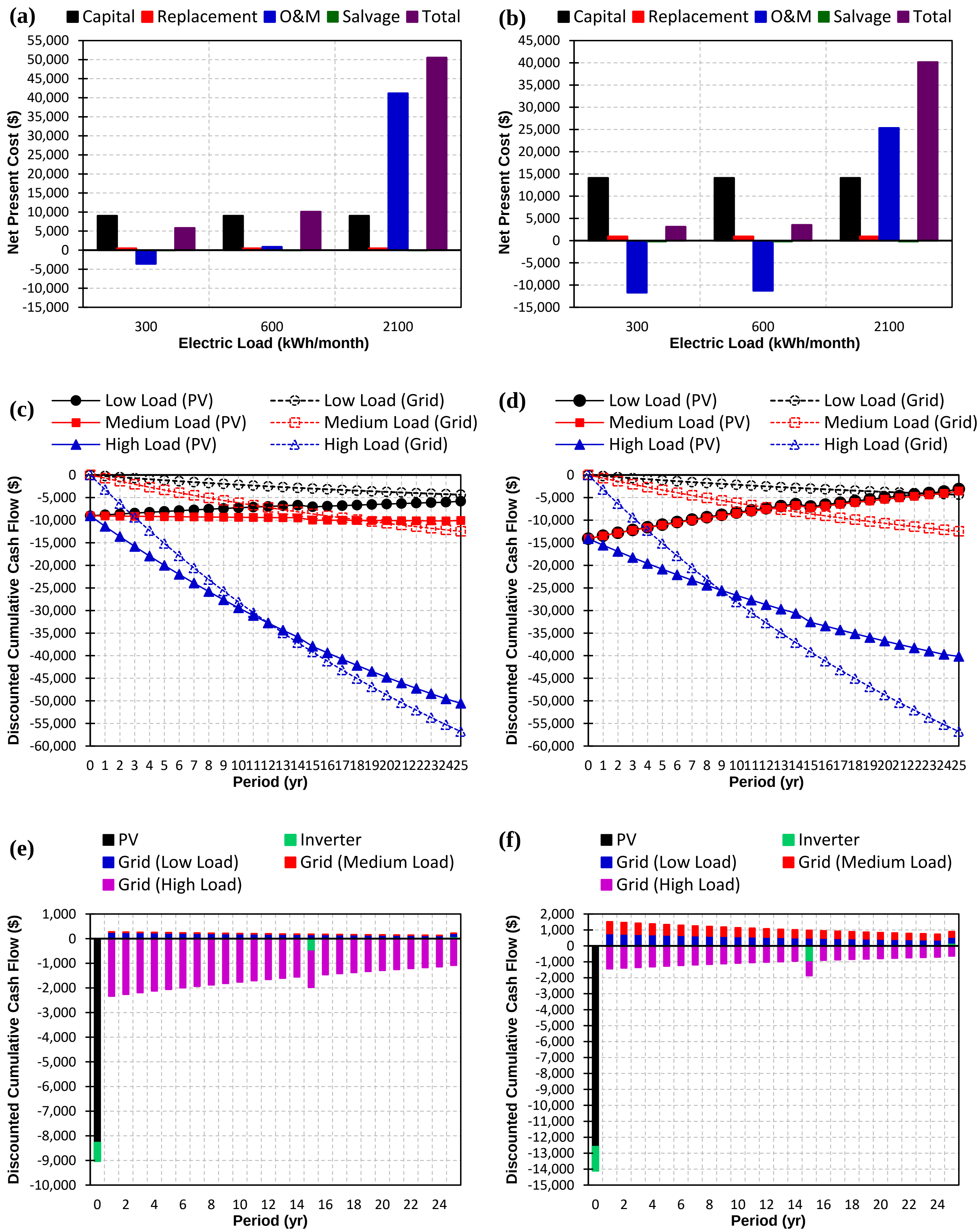


Fig. 10. Cost breakdown of (a) 6 kW PV, (b) 12 kW PV, discounted cumulative cash flow of (c) 6 kW PV, (d) 12 kW PV as opposed to that of the grid reference system under low, medium and high electric loads, and discounted cumulative cash flow of (e) 6 kW PV, (f) 12 kW PV based on different components.

Of note, using the 12 kW PV could cater for larger variations in solar radiation levels compared with the 6 kW PV; this is shown in Fig. 11. Under low, medium, and high electric loads, the 12 kW PV could serve as an optimal system type for a wider range of solar radiation. Similarly, the 12 kW PV could cater for larger variations in nominal discount rate compared with the 6 kW PV under low, medium, and high electric loads, as shown in Fig. 12. Therefore, the current analysis shows that the 12 kW PV (the maximum allowable size of a single-phase rooftop PV system in Malaysia's residential sector) was a better choice compared with smaller size PV systems.

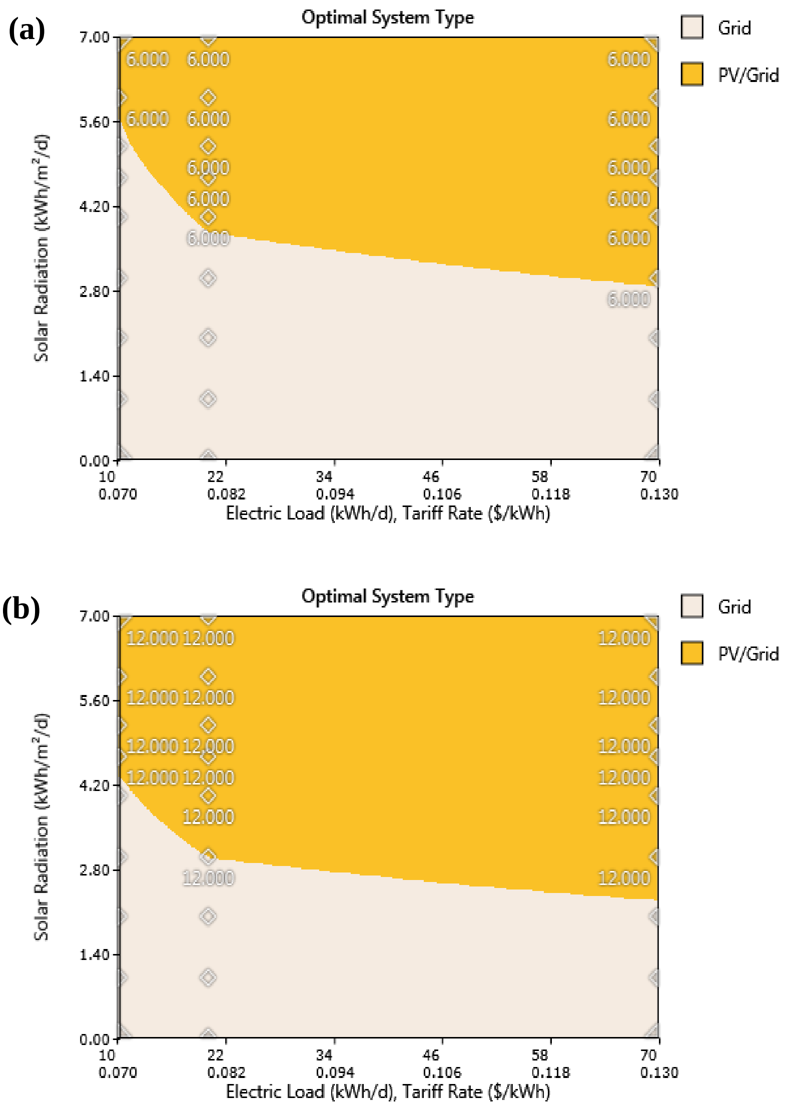
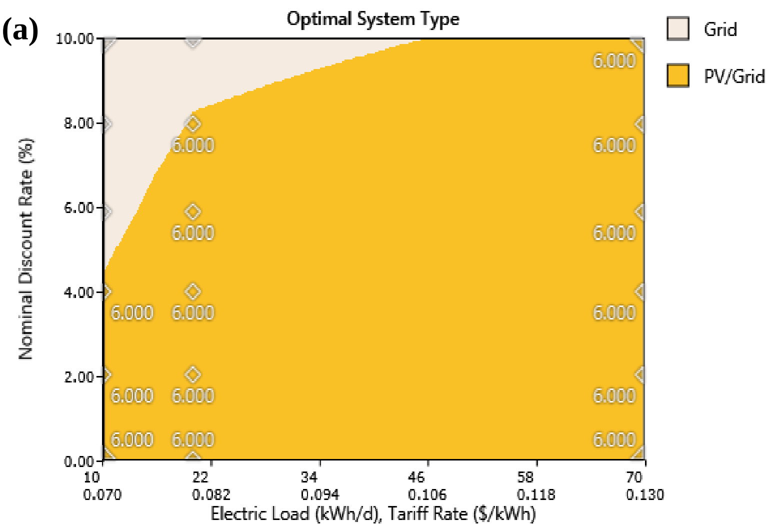


Fig. 11. Effects of varying solar radiation levels on low, medium, and high electric loads under (a) 6 kW PV, (b) 12 kW PV

(a)



(b)

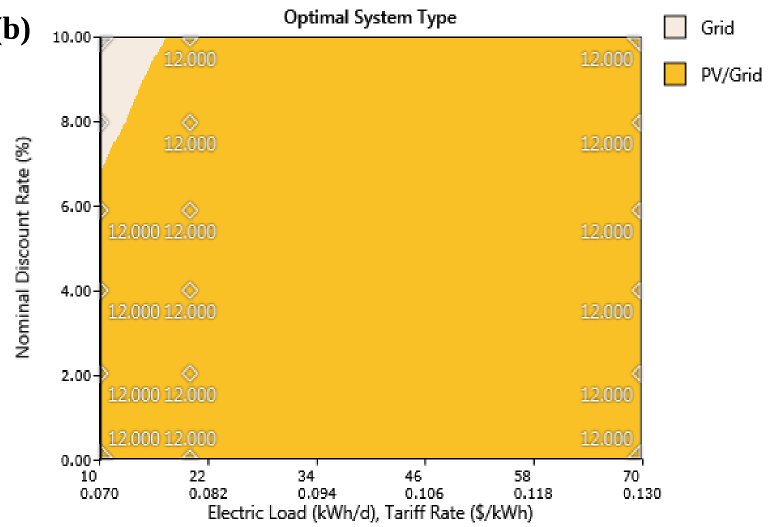


Fig. 12. Effects of varying annual real interest rates on low, medium, and high electricity consumptions under (a) 6 kW PV, (b) 12 kW PV

3.1.4 Insights on the techno-economic feasibility of rooftop PV systems

The current analysis shows that the implementation of rooftop PV systems is possible especially when electricity consumption is high. For example, using a 12 kW PV array and a 10 kW inverter under high electric load (2100 kWh/month) resulted in an NPC of $ 40,150 (in contrast to $ 56,784 for the grid reference system) over a 25-yr period, which led to 8.92 yr of discounted payback period. This is a promising and sound investment for residential households. Although the implementation of rooftop PV systems is also possible under low electricity consumption (300 kWh/month), PV with high ratings are required such that the project remained feasible over the grid reference system within the 25-yr period. For example, using a 6 kW PV rating under low electric load was not feasible over the grid reference system as it took longer than 25 yr to reach grid parity. Meanwhile, using a 12 kW PV rating under low electric load became feasible as the payback period reduced to 22.68 yr – the payback period was, however, still very long.

Of note, implementing the NEM scheme has led to reductions in renewable tariff rates compared to the FiT scheme. Indeed, our current analyses demonstrate that NEM-based rooftop PV systems will have limited success, especially under low and medium electric loads and low PV ratings, due to the long discounted payback period required by installing rooftop PV systems. This is in line with the global trend of rooftop PV installations, where the adoption of NEM-based rooftop PV systems has thus far been slow [15]. This is attributed to, not the inadequacy of the NEM policy, but rather the lack of additional incentive policies, as argued by Romalho et al. [31]. In some countries for example, utility companies may not always buy back excess energy at the retail rate. Consequently, any mismatch between peak PV production and higher self-consumption will discourage the adoption of solar PV in the residential sector as the overall economic impact is not favorable to PV consumers [15, 24]. This is particularly true if a consumer is always away from home during the mid-day when PV production is the highest, where higher amounts of solar electricity will continue to be sent back to the grid, reducing self-consumption. In Malaysia, however, the NEM scheme is implemented where excess electricity generated by PV is allowed to be exported back to the grid on a "one-on-one" offset basis. This means that every 1 kWh exported to the grid will be offset against 1 kWh consumed from the grid. Nevertheless, our current analyses show that the hurdle toward NEM-based PV adoption, especially under low electric load, may lie at the low electricity tariff rates (at the point of self-consumption) and the low PV electricity selling cost (at the point of sale to the grid as a result of surplus) as electricity tariffs in Malaysia are being subsidized, as with many Southeast Asian countries like Indonesia, Thailand and Vietnam [63]. In addition, higher PV array prices per kW under lower PV ratings may discourage the implementation of rooftop PV systems.

Significantly, the implementation of rooftop PV systems has favorable effect towards carbon reduction. In all analyzed cases, carbon emission of the rooftop PV systems was lower than the grid reference system.

Under the respective low, medium, and high electric loads, carbon emissions further reduced with increasing rooftop PV ratings. This suggests that, while rooftop PV systems may not be economically feasible under low and medium electric loads, the implementation of rooftop PV systems contributes significantly to electricity decarbonization compared to the use of the grid reference system.

3.2 Scenario analyses to drive the implementation of residential rooftop PV systems

Incentive programs to encourage distributed generation in the form of rooftop PV technologies have been extremely effective in many cases, and customers have embraced them in many countries. New technologies, such as rooftop solar tiles and building integrated PV (BIPV), are now becoming available, broadening the future potential of rooftop PV systems. To date, many countries have various policies, such as direct capital subsidies, tax incentives, and building integrated PV incentives, to encourage PV applications [62]. In this section, a few scenarios are considered in the hope of driving the implementation of grid-connected, residential rooftop PV systems in Malaysia.

As observed from Fig. 10a and Fig. 10b, the NPC under low and medium electric loads was mainly contributed by high capital cost for installing PV arrays and inverters. In contrast, the operating and maintenance cost associated with the purchase and sale of grid electricity was relatively small. Now in Fig. 13a and Fig. 13b, the cost breakdown for the capital cost and the operating and maintenance cost, respectively, for the 6 kW PV, under low, medium, and high electric loads, are shown. While the capital cost remained the same ($ 8280 for PV, $ 750 for inverter, and $ 9030 for salvage) under low, medium, and high electric loads, the operating and maintenance cost under low, medium, and high electric loads became noticeably different at -$ 3578, $ 689, and $ 41,147, respectively. This was mainly attributed to the cost associated with the grid, i.e., the grid purchase price and the grid selling price. Under high electric load, for example, the high operating and maintenance cost of $ 41,147 was closely related to the grid purchase of $ 40,121. This means that a lot of money was spent in purchasing electricity from the grid under high electric load. The NPC associated with the operating and maintenance cost was therefore very high. Meanwhile, the operating and maintenance cost was very low for medium electric load, or negative for low electric load, due to a lot of grid sale. The negative grid cost for both low and medium electric loads indicates that the cost contributed by grid purchase was negligibly small compared to the capital cost – all purchasing cost was offset by the PV selling price. As shown in Fig. 13c and Fig. 13d, the cost breakdown data from the 12 kW PV also reveal a similar trend as described above. This implies that the capital cost and the operating and maintenance cost (which is closely associated with the grid purchase price and the grid selling price) can be exploited to reduce the NPC and the payback period of low, medium, and high electric loads.

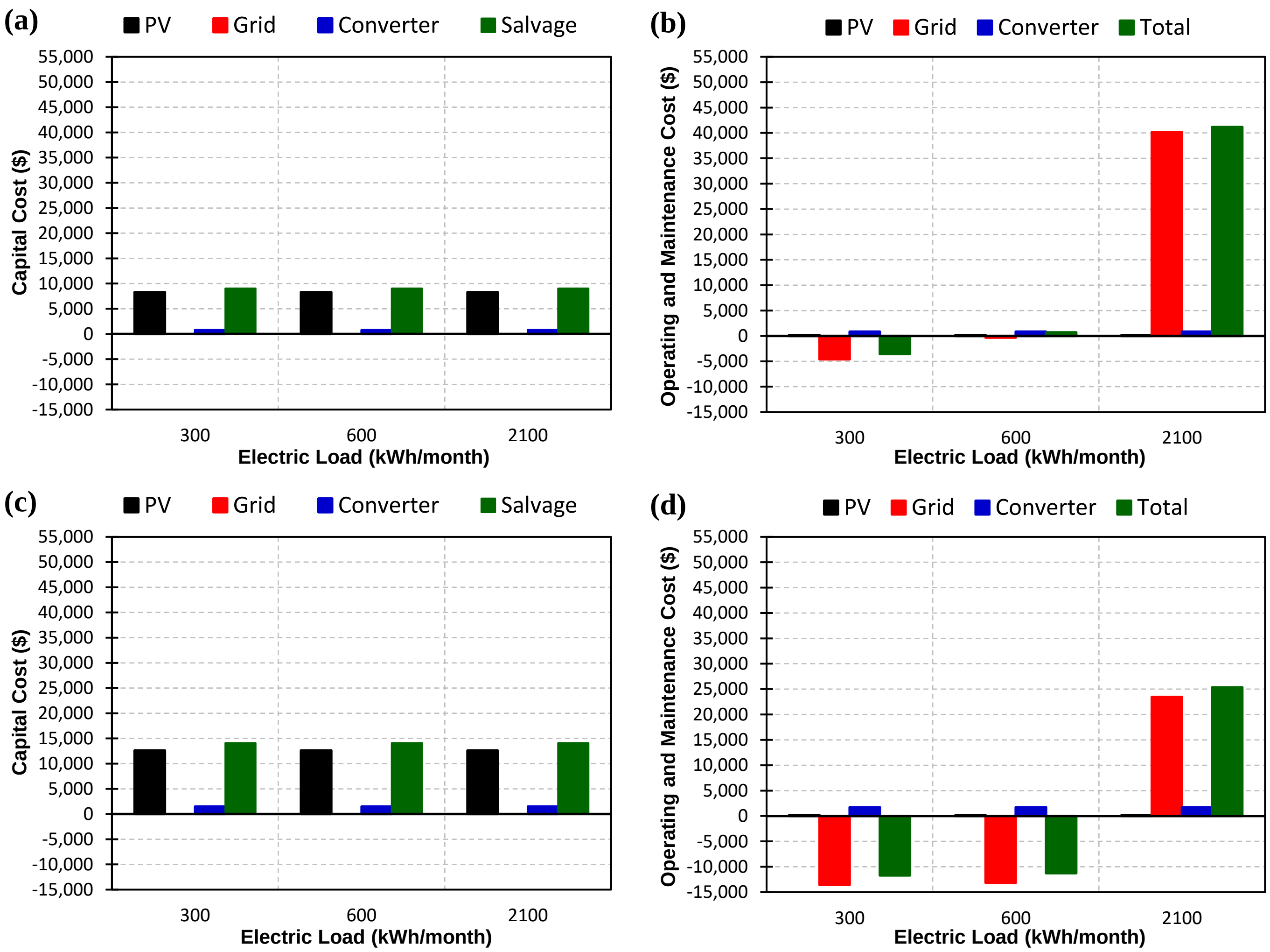


Fig. 13. Breakdown of (a) capital cost, (b) operating and maintenance cost for 6 kW PV and breakdown of (c) capital cost, (d) operating and maintenance cost for 12 kW PV

3.2.1 Scenario 1: Reduction in PV module prices for lower PV ratings

From our simulation, one of the main factors behind high NPCs of PV systems was the high module price of the PV array under low PV ratings. As shown in Fig. 5, the PV module price depends very much on the PV rating. This is re-illustrated in Fig. 14, where a PV system rated at 1 kW costed as much as $ 2100/kW compared with $ 1050/kW for a PV system rated at 12 kW. If prices of low ratings PV systems can be reduced, this will a have better impact on the feasibility of rooftop PV systems under low PV ratings, NPC-wise. In Fig. 14, a possible initiative where PV prices are revised so that $ 1050/kW remained applicable even for low PV ratings, is illustrated. This is also commonly known as direct capital subsidies [63].

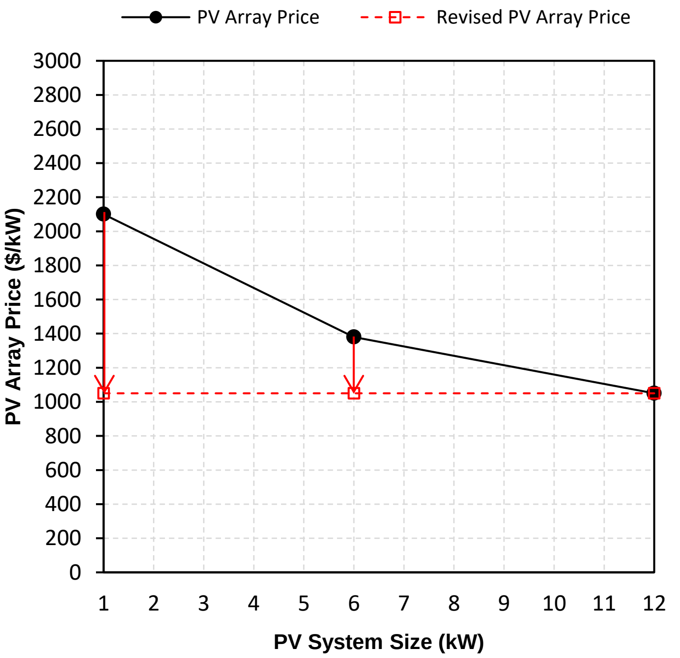


Fig. 14. Revised PV array prices for lower PV sizes. The arrow indicates the suggested downward price revision for lower PV ratings.

Fig. 15 illustrates the effects of lowered PV module price for the 6 kW PV. “Revised PV Price 1” represents $ 1215/kW while “Revised PV Price 2” represents $ 1050/kW; the “Original PV Price” represents the originally analyzed PV price of $ 1380/kW for the 6 kW PV. Of note, the NPC of the rooftop PV system would reduce as the PV module price reduced (see Fig. 15a). Meanwhile, “Grid 0”, “Grid 1”, and “Grid 2” shows that the use of the Original PV Price, the Revised PV Price 1, and the Revised PV Price 2, respectively, had no effects on the NPC of the grid reference system. This resulted in shorter discounted payback period under all electric loads. For example, under low electric load, the NPC and the discounted payback period of the 6 kW PV reduced by 20% (see Fig. 15a) and 5.83 yr (see Fig. 15b), respectively, based on the Revised PV Price 2 when compared with the original PV price. Significantly, the use of the 6 kW PV could have its NPC reduced as much as 34% (see Fig. 15a) and its discounted payback period reduced to 23.03 yr (see Fig. 15b) based on the Revised PV Price 2, under low electric load; the same PV system required a higher NPC and more than 25 yr of payback period under the Original PV Price (see Fig. 10c for details). Of note, reducing the PV module price for lower PV ratings had no effect on the NPC and the payback period of the 12 kW PV since the module price of the 12 kW PV remained unchanged (as shown in Fig. 15c and Fig. 15d).

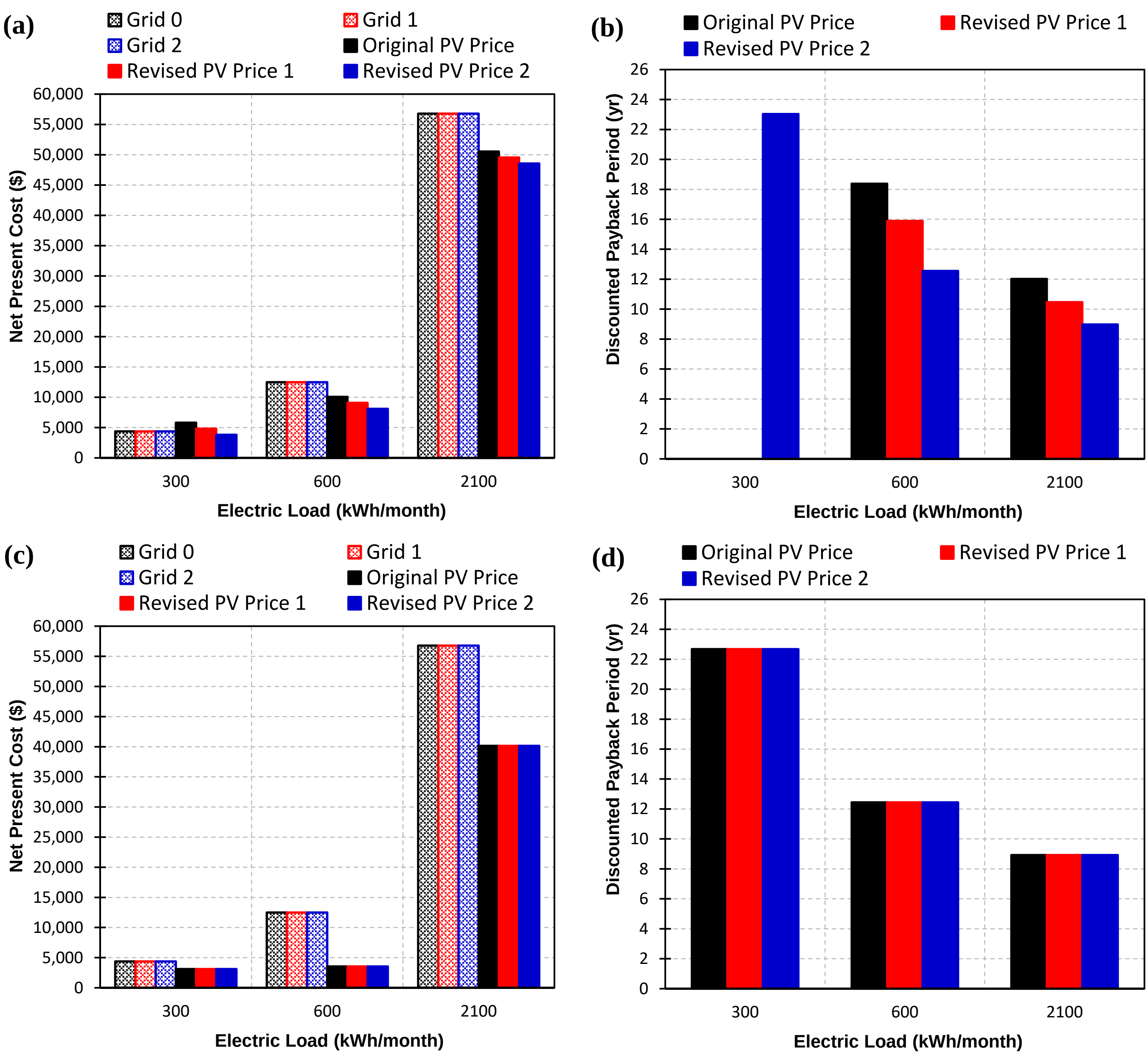


Fig. 15. Effects of revised PV array prices on (a) net present cost, (b) discounted payback period for a combination of 6 kW PV and 5 kW inverter (c) net present cost, (d) discounted payback period for a combination of 12 kW PV and 10 kW inverter

3.2.2 Scenario 2: Increase in PV sellback rate

In this section, the effect of increasing grid selling price, but maintaining the grid purchase price, was analyzed in an attempt to change the operating and maintenance cost associated with the purchase and sale of grid electricity. This approach will deviate from the concept of NEM, but will be helpful to reduce the operating and maintenance cost of PV systems.

Fig. 16a and Fig. 16b illustrate the effects of increased PV sellback rates with respect to fixed grid purchase price on the respective NPC and discounted payback period for the 6 kW PV under low, medium, and high electric loads. In this, “Grid 1.0”, “Grid 1.1”, “Grid 1.2”, “Grid 1.3”, “Grid 1.4”, and “Grid 1.5” represent the grid reference system with a fixed grid purchase price but with the grid selling price changed to 1.0, 1.1, 1.2, 1.3, 1.4, and 1.5 times higher than the current grid selling price, respectively. Meanwhile, “PV 1.0”, “PV 1.1”, “PV 1.2”, “PV 1.3”, “PV 1.4”, and “PV 1.5” represent a rooftop PV system with grid selling price of 1.0, 1.1, 1.2, 1.3, 1.4, and 1.5 times higher than the current grid selling price, respectively.

For the 6 kW PV, increasing the grid selling price did not affect the NPC of the grid reference system under low, medium, and high electric loads because no PV electricity was generated to be sold to the grid. In contrast, increasing the grid selling price would further reduce the NPC of the 6 kW PV (as shown in Fig. 16a). This effect is particularly notable under low electric load, where an NPC reduction as much as 40% was recorded for a grid selling price of 1.5 times higher than the current grid selling price. This subsequently reduced the payback period to 22.35 yr. Under medium electric load, the reduction effect of the NPC became less pronounced – an NPC reduction of 4% was recorded for a grid selling price of 1.5 times higher than the current grid selling price. This was because less electricity was sold to the grid. Under high electric load, increasing the grid selling price had no impact on the NPC and the discounted payback period, as grid sale was much lower than grid purchase, as already discussed based on Fig.10a.

Since low and medium electric loads had higher PV electricity selling capacities, using a bigger size rooftop PV system (the 12 kW PV) led to much higher impact of increased grid selling price on low and medium electric loads. For example, increasing the grid selling price to 1.5 times higher than the current grid selling price would significantly reduce the NPC to -$ 3673 from $ 1757 and the discounted payback period to 13.04 yr from 22.68 yr under low electric load, as illustrated in Fig. 16c and Fig. 16d. Again, the NPC and the discounted payback period under high electric load remained unchanged since grid sale was much lower than grid purchase – the system did not benefit from increased grid selling price under high electric load.

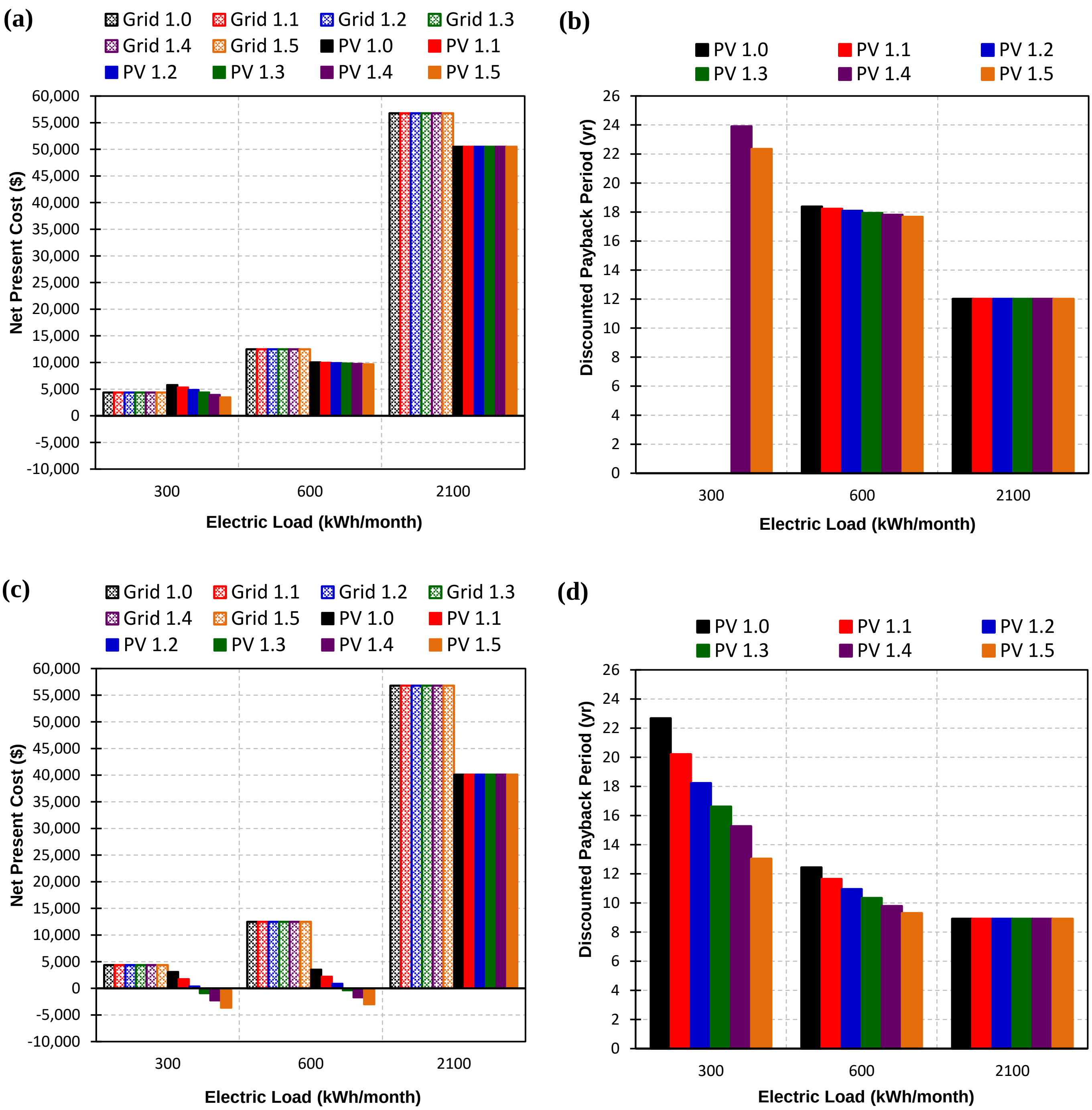


Fig. 16. Effects of increased ratio of PV sellback rate with respect to grid purchase price on (a) net present cost, (b) discounted payback period for 6 kW PV and (c) net present cost, (d) discounted payback period for 12 kW PV.

3.2.3 Scenario 3: Increase in electricity tariff rate

The preceding section demonstrates how an increase in the PV sellback rate could reduce the NPC and hence the discounted payback period of the rooftop PV systems, especially under low and medium electric loads. The approach will, however, deviate from the NEM concept and require the government to take a step back to the FiT concept that already ended in 2018. To avoid policy reversal, an increase in the electricity tariff rate (which represents both the grid purchase price and the grid selling price) was simulated such that the operating and maintenance cost became higher. Fig. 17 illustrates the effects of increased electricity tariff rates on the NPC and the discounted payback period for the 6 kW PV and the 12 kW PV under low, medium, and high electric loads. Of note, “Grid 1.0x”, “Grid 1.1x”, “Grid 1.2x”, “Grid 1.3x”, “Grid 1.4x”, and “Grid 1.5x” represent a grid purchase price of 1.0, 1.1, 1.2, 1.3, 1.4, and 1.5 times higher than the current grid purchase price, respectively. With an increase in the grid purchase price, the grid selling price would increase as well. Consequently, “PV 1.0x”, “PV 1.1x”, “PV 1.2x”, “PV 1.3x”, “PV 1.4x”, and “PV 1.5x” represent a grid selling price of 1.0, 1.1, 1.2, 1.3, 1.4, and 1.5 times higher than the current grid selling price, respectively. The grid purchase price and the grid selling price were tied together during the analysis to resemble the NEM scheme.

For the 6 kW PV, under low electric load, increasing the grid purchase price (and so the grid selling price) 1.5 times higher than the current price increased the NPC of the grid reference system from $ 4368 to $ 6552 but reduced the NPC of the rooftop PV system from $ 5807 to $ 3505 (see Fig. 17a). The increase in the NPC of the grid reference system was mainly contributed by the increase in grid purchase price, which contributed to higher operating and maintenance cost. Meanwhile, the decrease in the NPC of the 6 kW PV was mainly due to lower operating and maintenance cost as a consequence of increased grid selling price which further offset the increased grid purchasing price – lots of PV electricity was sold to the grid. Under medium electric load, increasing the grid purchase price (and so the grid selling price) increased the NPC of the grid reference system, but this had no significant effects on the NPC of the rooftop PV system as the grid energy purchased and the PV energy sold was similar and somehow offset each other, as already explained based on Fig. 9a. Under high electric load, increasing the grid purchase price (and so the grid selling price) increased the NPC of both the grid reference system and the rooftop PV system due to increased operating and maintenance cost from purchasing lots of electricity from the grid. Nevertheless, under all electric loads, the discounted payback period reduced with an increase in tariff rate (see Fig. 17b). This was because, with increased electricity tariff rates, the NPC difference between the grid reference system and the 6 kW PV became greater.

With higher PV ratings, such as the 12 kW PV, more PV electricity could be utilized by the load or fed to the grid. Consequently, the difference between the NPC of the grid reference system and the NPC of the 12 kW PV became much greater as a consequence of more grid sale and less grid purchase. This effect is illustrated in Fig. 17c. Therefore, by increasing the electricity tariff rate, the discounted payback period reduced for all electric loads since the PV systems could generate more PV electricity and became less dependable on the purchased electricity from the grid, as illustrated in Fig. 17d. Again, this effect was more pronounced under low electric load, where a discounted payback period of 22.68 yr under the current electricity tariff rate could be reduced to 11.67 yr under 1.5 times higher electricity tariff rate.

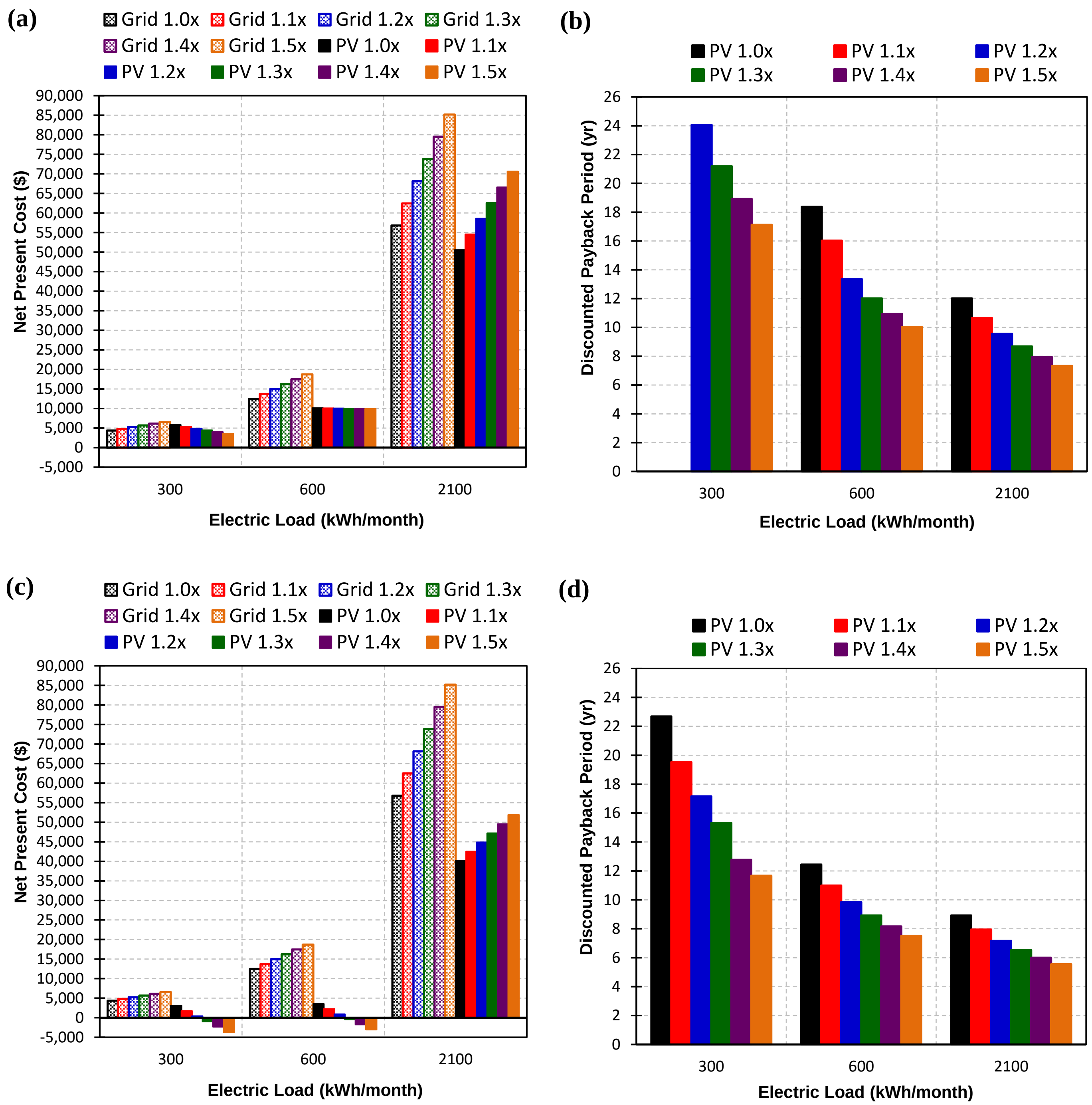


Fig. 17. Effects of increased electricity tariff rates on (a) net present cost, (b) discounted payback period of 6 kW PV and (c) net present cost, (d) discounted payback period of 12 kW PV.

3.2.4 Scenario 4: Implementation of carbon tax

Carbon tax has been introduced in many countries in an attempt to reduce carbon emissions and promote renewable energy. It is a polluting tax or a penalty cost levied on the production, distribution, and use of fossil fuels based on how much carbon their combustion emits. It encourages utilities, businesses, and individuals to reduce fuel-related consumptions and increase energy efficiency. It also results in renewable energies becoming more cost-competitive compared to cheaper, polluting fuels like coal, natural gas, and oil. With the introduction of carbon taxes, less green users will be penalized for more carbon emissions while green users will get credit for reduced carbon emissions.

The environmental effectiveness of carbon tax has been largely proven in many countries [64]. To date, Sweden has been leading the carbon pricing initiative, with carbon tax as high as $ 127/metric ton. This has been followed by Switzerland ($ 96/metric ton) and Finland ($ 70/metric ton) [65]. Beginning 2018 and 2019, more countries like Singapore, South Africa, and China have embarked on carbon tax initiatives, with the implementation of carbon tax as low as $ 1/metric ton.

In view of the effectiveness of carbon tax in many countries, the effects of carbon tax were simulated here. Of note, changes in carbon tax have commonly been implemented stepwise to give households and firms time to adapt. Carbon taxes of $ 3/metric ton, $ 6/metric ton, $ 9/metric ton, $ 12/metric ton, and $ 15/metric ton were therefore considered to determine their impacts on the analyzed systems. Fig. 18a illustrates the effects of carbon tax on the NPC of the 6 kW PV under low, medium, and high electric loads. Of note, "Grid 0", "Grid 3", "Grid 6", "Grid 9", "Grid 12", and "Grid 15" represent the effect of carbon tax of $ 3/metric ton, $ 6/metric ton, $ 9/metric ton, $ 12/metric ton, and $ 15/metric ton, respectively, on the grid reference system. Meanwhile, "PV 0", "PV 3", "PV 6", "PV 9", "PV 12", and "PV 15" represent the effect of carbon tax of $ 3/metric ton, $ 6/metric ton, $ 9/metric ton, $ 12/metric ton, and $ 15/metric ton, respectively, on the 6 kW PV.

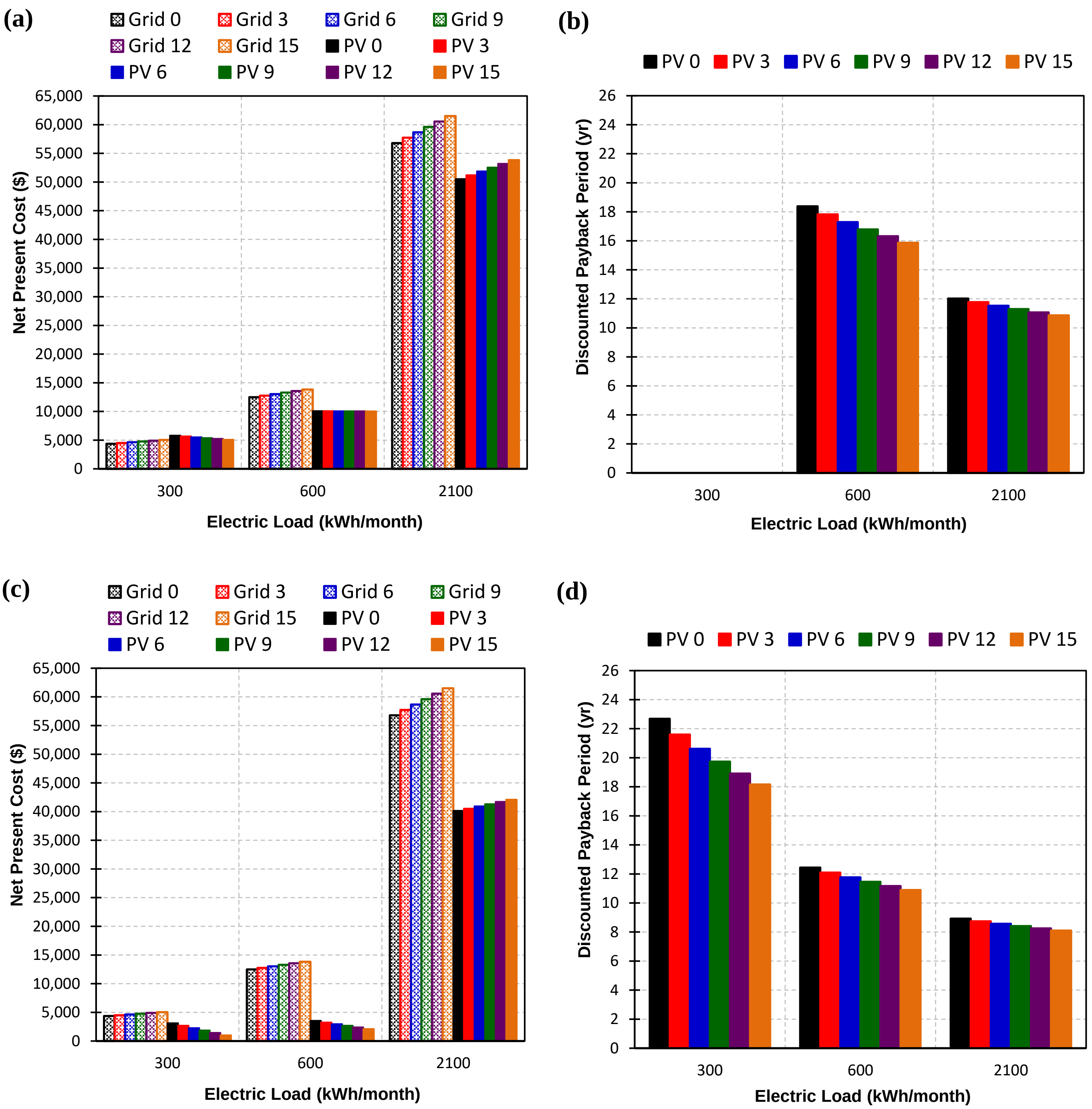


Fig. 18. Effects of carbon tax on (a) net present cost, (b) discounted payback period for a combination of 6 kW PV and 5 kW inverter and (c) net present cost, (d) discounted payback period for a combination of 12 kW PV and 10 kW inverter.

Under low electric load, increasing carbon taxes from \$ 0/metric ton to \$ 15/metric ton would increase the NPC of the grid reference system from \$ 4368 to \$ 5042, but reduced the NPC of the 6 kW PV from \$ 5807 to \$ 5096. Under medium electric load, increasing carbon taxes would also increase the NPC of the grid reference system, but had no significant effects on the NPC of the 6 kW PV. Under high electric load, increasing carbon taxes would increase the NPC of both the grid reference system and the 6 kW PV. The discounted payback also reduced with increased carbon taxes in all three cases of low, medium, and high electric loads (see Fig. 18b) – the discounted payback period under low electric load was still higher than 25 yr, hence not shown in Fig. 18b. Meanwhile, using the 12 kW PV would result in lower NPCs than the 6 kW PV under low, medium, and high electric loads, hence shorter discounted payback period; this is shown in Fig. 18c and Fig. 18d. Of note, the effects of implementing carbon taxes were more apparent under low electric load. This was because a lot of PV electricity was produced to be sold to the grid, which compensated for the grid electricity purchased.

3.2.5 Insights on the analyzed scenarios

The current analyses demonstrate that rooftop PV systems is not yet within the reach of many residential households, especially those consuming low and medium electric loads, due to long discounted payback period, particularly for smaller size rooftop PV systems. Although the use of bigger size rooftop PV systems resulted in shorter discounted payback period, high initial capital cost can otherwise be a hurdle toward the implementation of rooftop PV systems. As such, policy support that encourages additional financial incentives is required to intensify rooftop PV installations across the country. In the current work, four possible scenarios were analyzed to drive the implementation of rooftop PV systems. These include lowered PV module prices for low PV ratings, increased PV sellback rates, increased electricity tariff rates, and the introduction of carbon tax. All these scenarios led to effectively reduced NPC and discounted payback period of rooftop PV systems compared with the current scenario, and the impacts were greater under low electric load. While incentives for lowering PV module prices for low PV ratings and increasing PV sellback rates could come from the government to enable breakthroughs in the implementation of rooftop PV systems, these may result in a burden for the government. Meanwhile, raising electricity tariff rates and introducing carbon tax may cause public burden, especially for some who may not even afford the basic electricity. As such, the suitability of these strategies will depend largely on the government's readiness in implementing additional incentives and the consumers' readiness in accepting additional prices or taxes related to renewable initiatives.

Presently, the implementation of rooftop PV systems is not being driven by policy, but rather by technological and economic forces. Schoechle [17] argued that, in comparison with centralized PV systems, distributed (rooftop) PV systems receive less incentives. Meanwhile, Fridgen et al. [66], in their analysis of electrical tariffs for residential microgrids, suggested that common pricing mechanisms for residential consumers might not be appropriate for residential PV systems. Policy makers will therefore have to redesign the regulatory paradigm by adapting the network revenue model and tariffs, planning the electricity system (by taking into account both utility scale and distributed energy resources), and using price signals. Significant improvement in regulatory and market reforms is key to eliminate market, financial, and economic barriers and skewed incentives that presently impede the efficient evolution of rooftop PV systems. Nevertheless, the speed of adoption and the success in shaping the transformation of future electricity in the most beneficial way for the society and the system overall will depend on a broad range of factors, which fall under four main dimensions: regulation, infrastructure, business models, and customer engagement [67]. Improvement in the innovation of renewable energy business model through external partnerships and suitable organizational structures that promote an integrated renewable electricity utility market nationwide are therefore required. Of note, the transition from fuel-based electricity (based on conventional grid) to solar-based electricity (based on rooftop PV systems) will have to be carried out gradually and reviewed carefully to drive the PV market through the installation of residential rooftop PV systems. The public, private sectors, and policy makers will need to collectively contribute to successfully accelerate the adoption of rooftop PV technologies, as neither can do it alone. Significantly, sufficient assessment of the overall investment efficiency level of renewable energy and the policy impacts on carbon reduction are crucial to ensure a promising potential for the development of renewable energy that meets the goal of reduced carbon emissions [68, 69].

4.0 Conclusions

Based on the current analyses, the use of grid-connected, residential rooftop PV systems was feasible over the conventional grid system under high electric load. With increasing PV ratings from 1 kW to 12 kW, the NPC reduced from $ 56,670 to $40,150 (based on a PV-to inverter ratio of up to 1.3), lowered than $ 56,784 of the conventional grid system. This subsequently resulted in a reduced discounted payback period from 23.62 yr to 8.92 yr. Under medium electric load, the choice of feasible PV ratings reduced to between 3 kW and 12 kW, with the NPC ranged between $ 11,990 to $ 3537 (based on a PV-to inverter ratio of up to 1.3), lowered than $ 12,480 of the conventional grid system. Although the discounted payback period subsequently reduced from 22.34 yr to 12.44 yr, the discounted payback period was considered high. Under low electric load, the choice of feasible PV ratings further reduced to between 9 kW and 12 kW, and the NPC ranged between $ 4267 to $ 3115 (based on a PV-to inverter ratio of up to 1.3), lowered than $ 4368 of the conventional grid system. However, the discounted payback period for these PV systems remained longer than 20 yr. This indicates that the use of rooftop PV systems under low electric load is less reasonable from the consumers' perspective, albeit feasible. Nevertheless, under all electric loads analyzed, the use of rooftop PV systems show a potential to increase renewable fraction (by at least 5% for a 1 kW PV system under high electric load to as much as 89% for a 12 kW PV system under low electric load) and reduce carbon emission (by at least 5% for a 1 kW PV system under high electric load to negative carbon emission for a 12 kW PV system under low electric load), which will encourage renewable power capacity mix. Furthermore, the current analyses suggest that the highest PV ratings permissible (a 12 kW PV system) should be employed for all the investigated electric loads to optimize the techno-economic feasibility of rooftop PV installations.

Since the implementation of grid-connected, residential rooftop PV systems, especially under low electric load and for low PV ratings, resulted in high NPCs and long discounted payback periods, a few scenarios were analyzed in an attempt to drive the implementation of rooftop PV systems, i.e., by reducing the PV module prices for low PV ratings, increasing the PV sellback rate, increasing the electricity tariff rate, and implementing the carbon tax. The analyses showed that the examined scenarios had positive impacts on the techno-economic feasibility of rooftop PV systems, especially under low electric load and for low PV ratings. Specifically, increasing PV sellback rates, raising electricity tariff rates, lowering PV module prices for low PV ratings, and introducing the carbon tax were effective in reducing the NPC as much as 20%, 40%, 40%, and 12%, respectively, for a 6 kW PV system under low electric load, in addition to shortening the discounted payback period. Nevertheless, the suitability of the analyzed scenarios will depend largely on government's willingness in providing additional incentives and the consumers' readiness in accepting additional prices or taxes related to renewable initiatives. Significantly, the current work serves as a techno-economic model that provide a sustainable development framework for understanding technically and economically the installation of rooftop PV systems for residential households and drive the implementation of rooftop PV installations under different load scenarios. While Malaysian data were used for analysis purposes, the findings have worldwide implications and may as well serve as a basis for the evaluation of grid-connected, residential rooftop PV systems in other Southeast Asian countries possessing similar solar radiation levels and tariff rates to Malaysia.

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