energies

Article

Cost–Benefit Analysis of Rooftop PV Systems on Utilities and Ratepayers in Thailand

Aksornchan Chaianong [1,2], Athikom Bangviwat [1,2,*], Christoph Menke [1,2,3] and Naïm R. Darghouth [4]

1 The Joint Graduate School of Energy and Environment, King Mongkut's University of Technology Thonburi, Bangkok 10140, Thailand; achaianong@gmail.com (A.C.); c.menke@blv.hochschule-trier.de (C.M.)
2 Center of Excellence on Energy Technology and Environment, PERDO, Bangkok 10140, Thailand
3 Department of Building Engineering Services, Trier University of Applied Sciences, Trier 54293, Germany
4 Ernest Orlando Lawrence Berkeley National Laboratory, 1 Cyclotron Road, Berkeley, CA 94720, USA; ndarghouth@lbl.gov
* Correspondence: athikom.bangviwat@outlook.com; Tel.: +66-2-872-9014-5 (ext. 4136)

Received: 6 May 2019; Accepted: 5 June 2019; Published: 13 June 2019

Abstract: Driven by falling photovoltaic (PV) installation costs and potential support policies, rooftop PV is expected to expand rapidly in Thailand. As a result, the relevant stakeholders, especially utilities, have concerns about the net economic impacts of high PV adoption. Using a cost–benefit analysis, this study quantifies the net economic impacts of rooftop PV systems on three utilities and on ratepayers in Thailand by applying nine different PV adoption scenarios with various buyback rates and annual percentages of PV cost reduction. Under Thailand's current electricity tariff structure, Thai utilities are well-protected and able to pass all costs due to PV onto the ratepayers in terms of changes in retail rates. We find that when PV adoption is low, the net economic impacts on both the utilities and retail rates are small and the impacts on each utility depend on its specific characteristics. On the other hand, when PV adoption ranges from 9–14% in energy basis, five-year retail rate impacts become noticeable and are between 6% and 11% as compared to the projected retail rates in 2036 depending on the PV adoption level. Thus, it is necessary for Thailand to make tradeoffs among the stakeholders and maximize the benefits of rooftop PV adoption.

Keywords: cost–benefit analysis; rooftop PV; utility; ratepayer; Thailand

1. Introduction

Electricity generation from renewable energy has been of interest to the power sector in Thailand. The long-term goal, as stated in the Alternative Energy Development Plan 2015–2036 (AEDP 2015), is to establish renewable energy as 30% of the country's final energy consumption by 2036 [1]. One of the most well-known renewable technologies is solar PV technology, which has low installation costs and is supported by government policy.

AEDP 2015 has set a target of 6000 MW for solar PV (ground-mounted and rooftop) to be achieved by 2036. (This is based on Thailand's current Power Development Plan (PDP 2015). At the time of writing, there is a draft of the revised PV goal, which is still not officially announced and is not included in the analysis.) As of 2017, the installed capacity of solar PV is about 3211 MW (188 MW for rooftop and 3023 MW for ground-mounted), according to the public data of Thailand's Energy Regulatory Commission (ERC). In the past, Thailand was interested in supporting ground-mounted PV, but the government has been moving forward with rooftop PV with Feed-in Tariff (FiT) schemes since 2013. (The rooftop PV systems were defined as having sizes less than 1 MW and being connected to the distribution grid.) The Deutsche Gesellschaft für Internationale Zusammenarbeit has summarized the details of solar policy in Thailand [2]. According to Tongsopit (2015) [3], Thailand's support for rooftop solar FiT differs from that of international practices by including a quota and a short application period, as well as by not having a regression rate, revision timeline, or continuous policy support.

In 2016, the Thai government shifted rooftop PV policies from a FiT scheme to a self-consumption scheme under a pilot project of 100 MW of total installed PV capacity. The difference between these two schemes is how the PV generation is compensated. For the FiT scheme, all PV electricity are repurchased at a FiT rate. In contrast, for the self-consumption scheme, PV electricity is self-consumed first, and any excess PV generation is repurchased at a buyback rate. However, for a self-consumption pilot project, there was no buyback rate for excess PV generation and the Thai government was moving towards a monthly net-billing scheme with a flat buyback rate that was less than or equal to the wholesale rate. However, the details of the upcoming rooftop policy support are still pending at the time of writing [4].

Cycling through various compensation mechanisms, the Thai government still has not been able to settle on a single rooftop PV support policy due in part to the concerns raised by stakeholders, particularly electric utilities, about the economic impacts of high PV adoption. (From this point on, the word "PV" will refer only to rooftop PV in this paper. Although we realized that there is potential for other renewable energy technologies including ground-mounted PV, these were not included in the analysis due to the country's current focus on distributed generation sources.) Since the increase in PV adoption is expected to disrupt the existing business structures of Thai utilities as has been the case in many countries in recent years, there are heated debates on the impacts of PV on utilities and ratepayers in terms of the utilities' revenue losses and the costs shifting between solar and non-solar customers [5–8], leading to an interest in quantifying the total economic impacts of PV on both utilities and ratepayers.

Cost–benefit analysis (CBA) systematically evaluates the positive and negative impacts of a given system, such as those related to energy system as discussed in [9–11]. According to the context of this paper, CBA has been selected for quantitative analyses to address the total economic impacts of PV [5,7,12]. As illustrated in Figure 1, the CBA of PV systems can be evaluated from various perspectives, including those related to solar customers, ratepayers, utilities, total resource, and the overall society. The CBA of each stakeholder group (solar customers, ratepayers, and utilities) can be straightforward, whereas the total resource level means the sum of the PV impacts on all stakeholders while the overall society level means the sum of (1) the total resource level, (2) environmental impacts, and (3) macroeconomic impacts. However, as stated earlier, this study only focuses on evaluating economic impacts from perspectives of electric utilities and ratepayers.

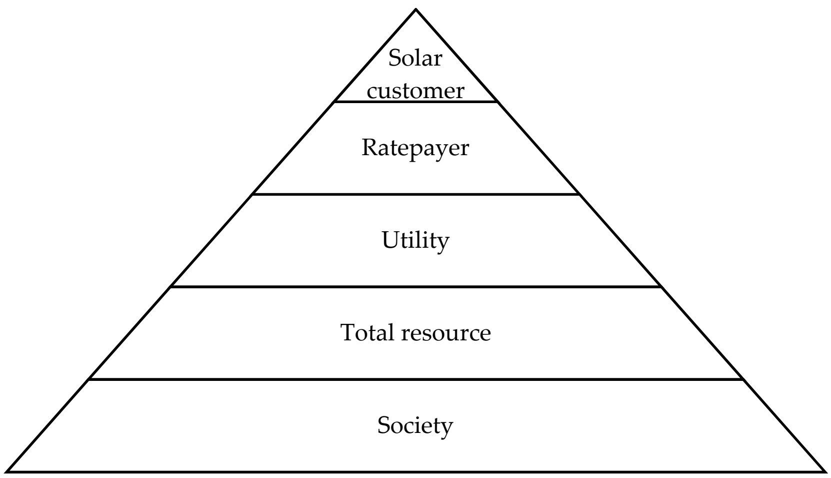
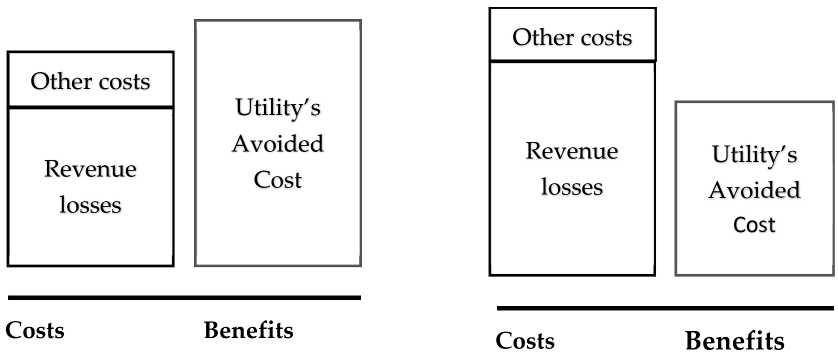


Figure 1. Several perspectives of cost–benefit analysis (CBA) of PV systems (Adapted from [12]).

Other studies, including [6,13–17], have also discussed the benefit and cost components from the perspective of the utilities. The PV benefits and costs can be classified into seven categories [17]: (1) energy, (2) environmental, (3) transmission and distribution (T and D) losses, (4) generation capacity, (5) T and D capacity, (6) ancillary services, (7) other factors.

Energy and Environmental Economics, Inc. (E3) used CBA to evaluate the net energy metering impacts in California and Nevada [5,12]. A utility's cost components due to PV are mostly related to revenue losses resulting from lower sales and additional costs required to accommodate PV into the grid (e.g., integration costs), whereas utility's benefit components are related to the value of PV in terms of avoided costs, as mentioned in the above seven categories. There are two possible interpretations, as illustrated in Figure 2. In scenario (a), PV systems have a positive value to a utility (total benefits are greater than total costs) and retail rates are reduced whereas in scenario (b), the PV systems lead to a net negative impact on the utility (total costs are greater than total benefits), causing an increase in retail rates. As demonstrated in these two studies, PV impacts can result in either positive or negative values to a utility depending on the level of PV adoption, policy support, and PV compensation methods (self-consumption only, export only, or both). In most of the scenarios considered in these two analyses, PV tends to lead to more revenue losses than benefits. Higher PV adoption levels lead to even stronger impacts on the revenues of utilities and on retail rates.



(**a**) Total benefits > Total costs (**b**) Total benefits < Total costs

Figure 2. Interpretations of CBA from a utility's perspective (Adapted from [5]).

Satchwell et al. [7] studied the financial impacts of net-metered PV on the utilities and ratepayers in the United States. The authors analyzed a variety of scenarios, most of which resulted in total revenue losses from distributed PV that were greater than the associated total benefits, leading to revenue erosion and lost opportunities for future earnings, depending on the specific circumstances of each utility and the assumptions of the analysis. Additionally, the authors found that average retail rates tended to increase when utility revenues eroded, depending on the regulatory rate-making framework.

USAID Clean Power Asia and its partners [18] studied the short-term impacts of distributed PV on distribution utilities and retail rates in Thailand. The cost components included revenue reductions and excess PV generation purchases, whereas the benefit components were related to the avoided wholesale electricity purchases. Several scenarios with various types of PV compensation schemes, such as self-consumption only, net billing, and net energy metering, were included. PV adoption was 3000 MW to be achieved by the year 2020. The impacts on electricity rates and utility revenues in the medium term were found to be minimal. There were options for maintaining minimal impacts on retail rates. However, the analysis focuses on the impacts of the two distribution utilities—Metropolitan Electricity Authority (MEA) and Provincial Electricity Authority (PEA)—in the short term and so does not include integration costs to accommodate PV, avoided costs of deferral distribution investment, and distribution losses. Moreover, the analysis does not address the impacts on the Electricity Generating Authority of Thailand (EGAT), which is Thailand's transmission and generation utility, as the focus is on the rate impacts for end-use customers.

To fill these gaps in the literature and address stakeholder's concerns in the country, this study aims to quantify the benefits and costs of PV on three electric utilities and on ratepayers (Ratepayers include all utility customers regardless of having installed rooftop PV systems.) under different scenarios by varying the buyback rate of excess PV generation and the percentage of annual PV installation cost reduction. We employ cost–benefit analysis (CBA) to address the total economic impacts on the utilities and provide recommendations to accommodate high PV adoption in Thailand. (This work does not consider the technical impacts of PV but focuses on the impacts on utility revenues and retail rates.) The three Thai electric utilities are the (1) MEA, (2) PEA, and (3) EGAT. The first two are distribution utilities whereas the third owns and manages generation and transmission throughout the country. This work also applies a PV adoption scenario based on the maximum economic potential posited by Chaianong et al. [19] to help assess the economic impacts of PV on Thai utilities and ratepayers in the long term from 2018 to 2036 (the final year of the AEDP).

This remainder of this paper is structured as follows. Section 2 provides the background of the relevant issues in the power sector of Thailand. Section 3 describes the methodology. Sections 4 and 5 presents and discusses the results of the CBA, respectively. Finally, Section 6 presents the conclusions, summarizes the key findings and policy implications, and makes recommendations for future research.

2. Background of Power Sector and Tariff Structure in Thailand

This section presents an overview of the power and tariff structures in Thailand before introducing the CBA framework and results.

Thailand's power structure is known as an "Enhanced Single Buyer (ESB)" model. According to the public data in 2017 from the Energy Policy and Planning Office (EPPO) and EGAT, EGAT owns about 37.87% of the generation and 100% of the transmission assets. The remaining generation assets are operated by private companies, including Independent Power Producers (IPPs) for 35.23%, Small Power Producers (SPPs) and Very Small Power Producers (VSPPs) for 17.76%, and power imports for 9.14%. IPPs and SPPs can generate and sell electricity to the high voltage transmission system owned by EGAT whereas VSPPs cannot sell directly to EGAT but may sell power through the two distribution utilities, which are the MEA and PEA. MEA is responsible for Bangkok and two neighboring provinces whereas PEA is responsible for the remaining provinces in the country. Other than purchasing electricity from VSPPs under a power purchase agreement, MEA and PEA purchase most of their electricity from EGAT at a wholesale price. Additionally, there is also a regulator organization, the Energy Regulatory Commission (ERC), that regulates the implementation of Thai policies related to electric power and natural gas transmission as illustrated in Figure 3. Focusing on power generation mix in 2017, more than 90% are from natural gas, coal, and imported electricity while the remaining includes renewable energy, hydropower, and oil.

The retail tariff structure (the rates charged by MEA and PEA) in Thailand consists of three main components: (1) base tariff (volumetric, demand, and fixed charges), (2) fuel adjustment charge, (3) value-added tax (7%). The base tariff reflects the utility revenue requirements with the appropriate profits of each utility, investment costs in generation, transmission and distribution systems, fuel costs, purchasing costs, and government expenditures, including renewable subsidies, exchange rates, and inflation rates. The base tariff is revised every 3–5 years. The fuel adjustment charge (Ft) is a mechanism for adjusting the power tariff, which reflects the actual fuel supply cost that differs from the base cost at a given time. Normally, Ft is adjusted every four months.

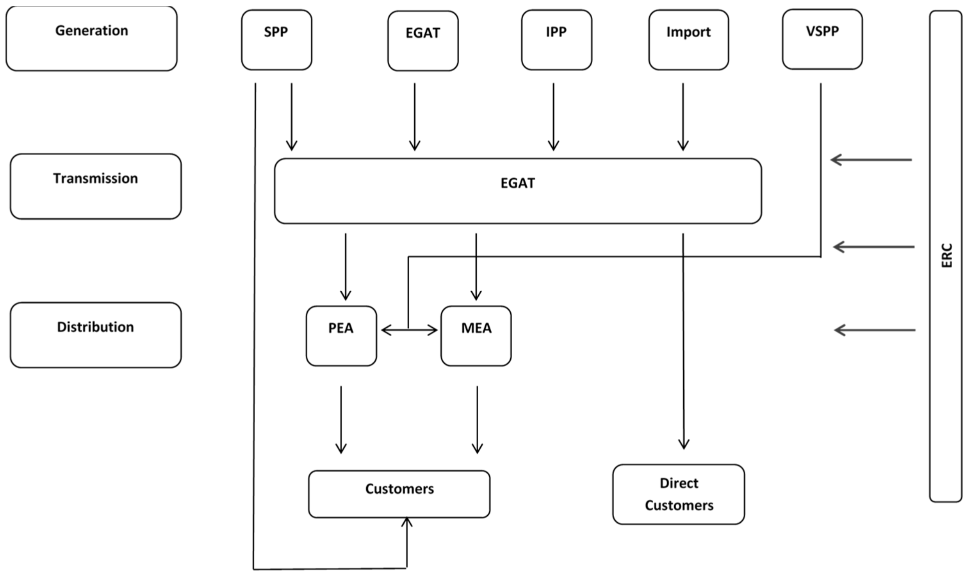


Figure 3. Thailand's power structure (adapted from public data from the Energy Policy and Planning Office (EPPO)).

3. Methodology

3.1. Scope of Work

For this study, four electricity customer groups were selected: *(1) Residential (RES)*. The residential scale is categorized into two main sub-groups according to monthly consumption: less and more than 150 kWh/month. The latter group and the group with normal block rate subscriptions were selected. *(2) Small general service (SGS)*. Small general service means those customers with a maximum 15-min integrated demand of less than 30 kW through a single Watt-hour meter. The SGS customers with block rate subscriptions at voltage levels of <12 kV for MEA and <22 kV for PEA were selected. *(3) Medium general service (MGS)*. Medium general service means those customers with a maximum 15-min integrated demand from 30 to 999 kW and an average energy consumption for three consecutive months through a single Watt-hour meter not exceeding 250,000 kWh per month. The MGS customers with TOU rate subscriptions at voltage levels of 12–24 kV for MEA and 22–33 kV for PEA were selected. *(4) Large general service (LGS)*. Large general service means those customers with a maximum 15-min integrated demand over 1000 kW or an average energy consumption for three consecutive months through a single Watt-hour meter exceeding 250,000 kWh per month. The LGS customers with TOU rate subscriptions at voltage levels of 12–24 kV for MEA and 22–33 kV for PEA were selected. The load profiles of each customer type, as summarized in Supplementary Materials, were based on data shared by the utilities and scaled according to PV sizes. These customer groups account for the majority of MEA and PEA customers who are quite likely to install PV. Table 1 shows the customer groups and PV sizes which have been addressed by stakeholder consultations and constraints, such as available roof spaces and income levels. High-demand customers are expected to be the first group to install rooftop PV as they should have high income and large roof space, especially for households. The other sectors (MGS and LGS) are not critical since they have larger demand than PV production. These PV size selections are also well aligned with a range of appropriate PV production and annual load consumption ratio (PV-to-load ratio) as discussed in [20,21], reflecting high economic feasibility of rooftop PV installation under net-billing scheme for each customer group in Thailand.

Table 1. Details of selected customer groups.

Groups	PV System Size (kW)
Residential scale (RES)	5
Small general service (SGS)	5
Medium general service (MGS)	100
Large general service (LGS)	1000

We selected net billing as the principal compensation scheme in this analysis. As stated earlier, this scheme is currently being considered by the Ministry of Energy. With net billing, PV electricity is self-consumed first, and any excess PV generation of the customer's instantaneous consumption is injected back to the grid and compensated at the predefined buyback rate. The scenarios used in this analysis are illustrated in Figure 4. There are three main groups of scenarios:

- **Minimum cost reduction**. Buyback rates are 0, 1, 2, and 2.6 (the average wholesale electricity rate) THB/kWh. Weighted average wholesale rate is from the rate at voltage level of 69–115 kV. A fuel adjustment charge (Ft) was included as of September–December 2017 (−0.0045 USD/unit for MEA and −0.0071 USD/unit for PEA). Buyback rates of 0, 1, 2, and 2.6 THB/kWh would be 0, 0.03, 0.06, and 0.07 USD/kWh, respectively (exchange rate: 35 THB/USD). An annual PV installation cost reduction is 2%. The timeframe of this analysis starts from the date of this writing (2018) to the end of AEDP (2036).
- **Maximum cost reduction**. Buyback rates are as above with an annual PV installation cost reduction of 4%.
- **AEDP**. Self-consumption only (the buyback rate is 0 THB/kWh with an annual PV installation cost reduction of 2%).

As mentioned, through customer-adoption modeling, the annual PV adoption forecasts were defined to reflect the feasibility of PV investments in a particular year for each customer group using a technology diffusion curve as detailed in [19]. Although this paper [19] focuses only on Bangkok, we adopted the same methodology and extended into the country context in order to apply these PV adoption scenarios in the analysis. Table 2 summarizes the maximum economic potential of each PV adoption scenario used in this analysis. To summarize, in 2036, the levels of PV adoption in Thailand will range from 25 to 37 GW or 9–14% of power consumption in that year (on an energy basis), compared to the projected electricity generation of 355,536 GWh in 2036. The level was calculated by using the electricity generation (183,581 GWh) in 2017 and a 3.54% growth rate based on the historical growth rate of the last 10 years. For the AEDP scenario, we set the total PV capacity at 2800 MW (the remaining PV capacity to achieve the AEDP plan) and based the annual PV adoption forecasts on the Min. cost reduction_0 scenario as detailed above. Therefore, the fixed adoption goal of 2800 MW (928 MW for MEA and 1872 for PEA) would be achieved in 2025 instead of 2036 as originally stated in the AEDP plan.

Table 2. PV adoption scenario in this analysis.

Utility	Maximum Forecasts of PV Adoption (MW)							
	Min. Cost Reduction_0	**Min. Cost Reduction_1**	**Min. Cost Reduction_2**	**Min. Cost Reduction_Average Wholesale**	**Max. Cost Reduction_0**	**Max. Cost Reduction_1**	**Max. Cost Reduction_2**	**Max. Cost Reduction_Average Wholesale**
MEA	5946	6066	6185	6256	7483	7618	7749	7827
PEA	18,668	19,836	20,984	21,671	25,345	26,688	28,003	28,778
Total	24,614	25,902	27,169	27,927	32,828	34,306	35,752	36,605
% PV adoption (country level; energy basis)	9.3%	9.8%	10.3%	10.6%	12.4%	13.0%	13.6%	13.9%

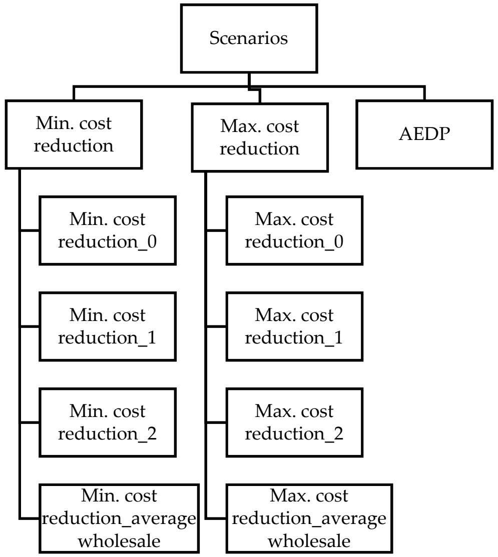


Figure 4. Details of various scenarios used in this analysis. (Codes: Percentages of annual PV installation cost reduction_buyback rate in THB/kWh).

3.2. Methodology

The framework for this analysis is summarized in Figure 5. First, we analyzed the load profile and PV generation of an individual customer from each group of MEA and PEA to simulate the amount of self-consumed and excess generated PV. For this, we used the System Advisor Model (SAM) developed by the U.S. National Renewable Energy Laboratory (NREL) to simulate the results. All assumptions used in the performance model in SAM was summarized in Supplementary Materials.

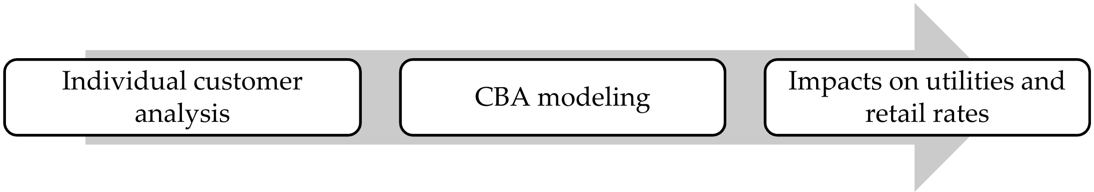


Figure 5. Framework diagram of this analysis.

Next, the cost and benefit components for each utility in Thailand were identified from the literature review and in consultation with the technical and managerial staff from EGAT, MEA, PEA, EPPO, and DEDE (Department of Alternative Energy Development and Efficiency), as well as the private sector as briefly presented in [22] and summarized in Tables 3 and 4. To understand the overall economic impacts of PV on each utility in a particular year, each component was calculated according to the assumptions summarized in Supplementary Materials and the PV adoption scenarios. The assumptions were based on Thailand's Power Development Plan 2015 (PDP 2015) [23] and public data from three utilities, EPPO, and ERC. These data are available on their websites. Other financial assumptions such as the inflation rate are based on Thailand's market.

Table 3. Cost and benefit components of the Metropolitan Electricity Authority (MEA) and Provincial Electricity Authority (PEA).

	Benefits	Costs
Distribution utilities (MEA/PEA)	- **Avoided Electricity Generating Authority of Thailand (EGAT) purchases** =Total PV generation × Weighted average wholesale price during solar production hours. (It equals to 3.05 THB/kWh as of 2017—during solar production hours, it is mostly on-peak period on weekdays while it is off-peak period on weekends.) - **Avoided cost of distribution (D) loss** = Avoided EGAT purchases due to self-consumption × % Distribution line loss - **Avoided cost of distribution (D) capacity** = Deferred investment cost due to decreases in peak demand × % utility interest rate - **Resale margin of exported PV** = (Excess generation) × (Average wholesale rate − Export rate)	- **Revenue loss from lower customer sales** - **Integration cost** (For MEA and PEA, the integration costs are related to distribution system upgrades and balancing issues to accommodate PV.)

To calculate the avoided cost of capacity for each utility, the decreases in peak demand were calculated by using the hourly demand and PV generation profiles for each utility in each PV adoption scenario. The average value of the top 100-h demand reduction was used to calculate the avoided cost of capacity (a method highlighted in [24]). The decrease in peak demand implies the capacity value of solar power in terms of deferral investments. If the demand for each utility peaks in the evening time, the capacity value of solar power is set to zero in the calculation (since solar capacity cannot contribute to reducing the peak load).

For the avoided cost of energy, it is necessary to discuss the dispatch strategy of power plants by EGAT before introducing the framework. The System Control Operation Division of EGAT is responsible for the dispatch of power plants. Internationally, the base load is covered by low cost plants and the higher cost plants are more suitable for peak loads. With this concept, the energy value of solar power in terms of the avoided cost of energy can be determined by the supply curve. However, EGAT does not dispatch power plants only on the basis of production costs (merit order) [25] due to limitations in the availability of natural gas from Myanmar or the availability of water, given the supply schedules for agriculture. "Must run" generators are dispatched in priority, followed by "Must take" and "Merit order". The objective of "Must run" is to secure the power supply by using the base load (coal and some natural gas), whereas that of "Must take" is to maintain the minimum SPP, import and natural gas contracts.

Table 4. Cost and benefit components of EGAT.

	Benefits	Costs
Generation/ Transmission utilities (EGAT)	- **Avoided cost of energy** = Total PV generation × % Energy mix × Fuel price × Heat rate × Value Factor - **Avoided cost of transmission (T) loss** = Avoided energy × % Transmission line loss - **Avoided cost of generation/transmission (G/T) capacity** = Deferred investment cost due to decreases in peak demand × % utility interest rate - **Avoided cost of reserve** = Avoided cost of G/T capacity × % reserve	- **Revenue loss from fewer sales to distribution utilities (MEA/PEA)** = Total PV generation × Weighted average wholesale price during solar production hours - **Integration cost** (For EGAT, the integration costs are related to generation and transmission system upgrades as well as balancing and power back-up issues to accommodate PV.)

It is not possible to define a supply curve under the power plant dispatch criteria of EGAT. To quantify the avoided costs of energy due to PV generation, we assume that PV offsets a mix of peaking plants (oil-fired combustion turbines and imports) and intermediate plants (natural gas combined cycle turbines) using the percentages of the projected energy mix based on Thailand's PDP 2015 and average cost of each fuel type for each year. Moreover, to interpret the energy value of solar power more accurately, the value factor (VF) for each year based on total PV adoption (both ground-mounted and rooftop PV) was applied as discussed in [26]. The VF was defined as the ratio of the energy value of solar power to the average wholesale price (average fuel cost). The VF is greater than 100% at low PV adoption levels, indicating that the energy value of solar power is higher than the average wholesale price (average fuel cost) because using solar power allows avoiding more expensive fuels at peak time. As PV adoption increases, the VF decreases as PV generation increasingly displaces lower cost conventional generation. We developed a simple relationship between the VF and PV adoption rates using the results from [26], as shown in Figure 6. Though the relationship between the VF and PV adoption rates was developed in the context of California, we use it in this analysis because of the similarities between the electricity mix there and in Thailand—most notably, the large percentage of natural gas generation.

The final step in the analysis is to calculate the retail rate impacts. In the Thai regulatory rate-making context, utilities must pass through any net economic impacts due to PV on ratepayers resulting from the changing of retail rates, which were reset every five years (as determined by the frequency of rate cases) and calculated with the equations below:

$$\text{Net economic impacts (USD)} = \text{Total benefits (USD)} - \text{Total costs (USD)} \tag{1}$$

$$\begin{gathered}\text{Retail rate impacts (USD/kWh) in every 5 years} = \\ \text{-Net economic impacts in 5 years (USD)/Net electricity consumption in 5 years (kWh)}\end{gathered} \tag{2}$$

Note: Net electricity consumption = Total electricity consumption − PV generation based on each scenario. Total electricity consumption was 183,581 GWh as of 2017 and was assumed to increase every year at 3.54%.

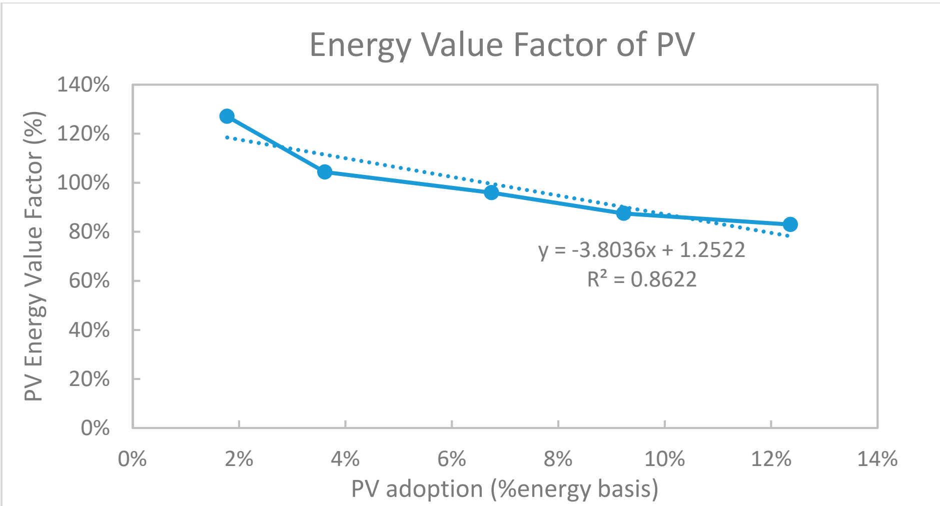


Figure 6. The relationship between energy value factor of PV and total PV adoption based on California Independent System Operator (CAISO) (Adapted from [26]).

4. Results

4.1. Net Economic Impacts on MEA, PEA, and EGAT

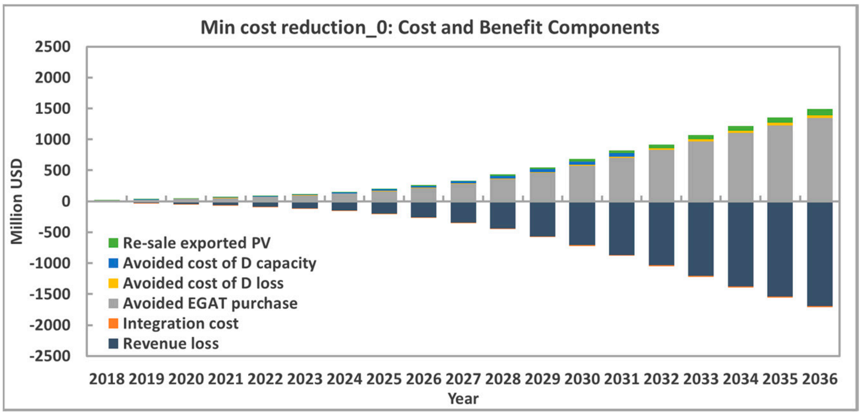
4.1.1. Minimum and Maximum Cost Reduction Scenarios

As indicated in the Methodology section, each cost and benefit component was quantified for each utility according to different levels of PV adoption. For the minimum cost reduction scenario, we found the total PV deployment ranging from 25–28 GW (or 9–11% PV adoption on an energy basis) according to the buyback rate. For the maximum cost reduction scenarios, we found the PV adoption levels ranging from 33–37 GW (or 12–14% PV adoption in energy basis), as summarized in Table 2. Figures 7–9 show the breakout of each cost and benefit component, as well as the total economic impacts (net costs and benefits), for MEA, PEA, and EGAT. Only the minimum and maximum cases of the minimum and maximum cost reduction scenarios are shown to avoid complexity. For the other scenarios, the annual net costs and benefits are summarized in Supplementary Materials. Also, Table 5 focuses on the net costs and benefits at the end of AEDP (in 2036) for each case.

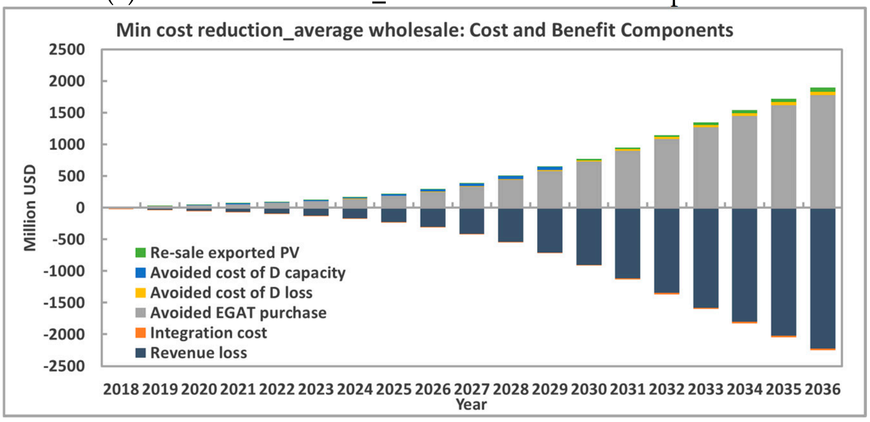
In the early years, as PV adoption is still low, the avoided costs from PV generation are relatively high. Hence, the annual net economic impacts for each utility are very low or even positive for some cases of PEA. These annual net economic impacts tend to increase in magnitude each year in proportion to the level of PV adoption. In 2036, the net economic impacts or net costs/benefits range from:

- −225 to −360 million USD (or approximately −1 to −2% of projected revenue in 2036 for MEA). (The negative percentages mean that the net costs are greater than the net benefits, while the positive percentages mean that the net benefits are greater than the net costs.);
- −238 to 259 million USD (or approximately −0.59% to 0.63% of projected revenue in 2036) for PEA;
- −4254 to −6537 million USD (or approximately 9 to 14% of projected revenue in 2036) for EGAT.

The net economic impacts on EGAT are higher than those on MEA and PEA because EGAT loses revenues directly from PV self-consumption, but MEA and PEA lose revenue only from their lost margins and are able to buy excess PV generation at below or equal to the wholesale rates. Especially for PEA, it is worth noting that when there is low buyback rate (such as 0 and 1 THB/kWh) net benefits are greater than net costs for all years. The range of net economic impacts are mainly due to the level of PV adoption, which is influenced by two important factors—buyback rate and PV installation cost reduction. The detailed discussions of the results are provided in the Discussion section.

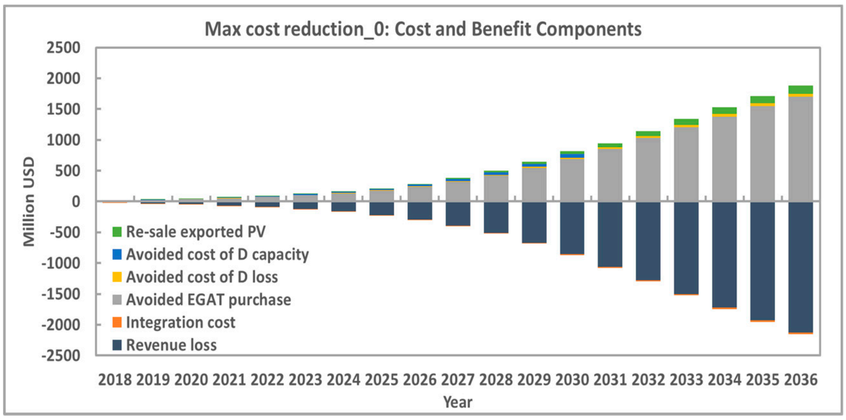


(**a**) Min. cost reduction_0: Cost and Benefit Components

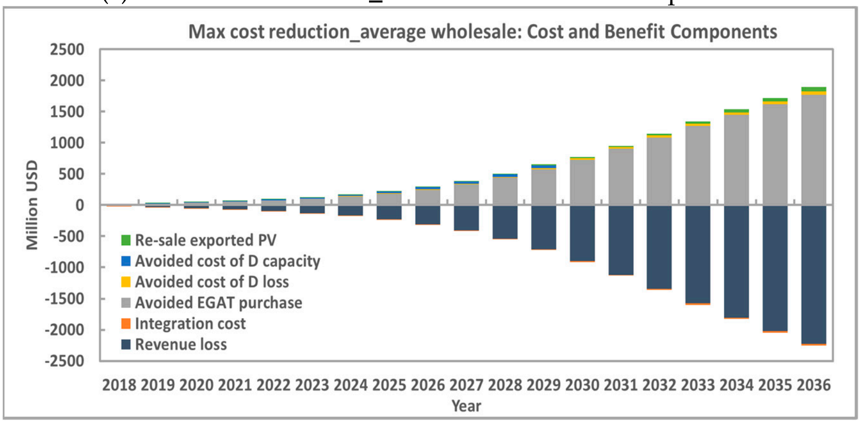


(**b**) Min. cost reduction_average wholesale: Cost and Benefit Components

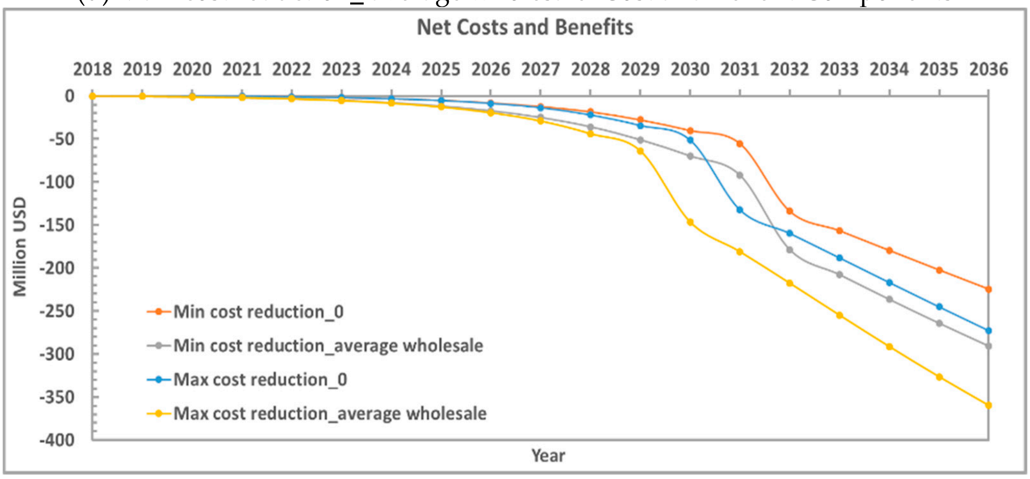
Figure 7. *Cont.*



(**c**) Max. cost reduction_0: Cost and Benefit Components

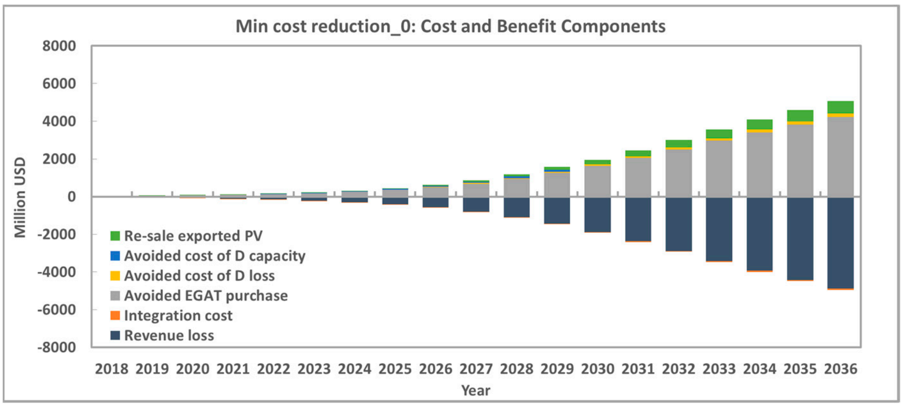


(**d**) Max. cost reduction_ average wholesale: Cost and Benefit Components

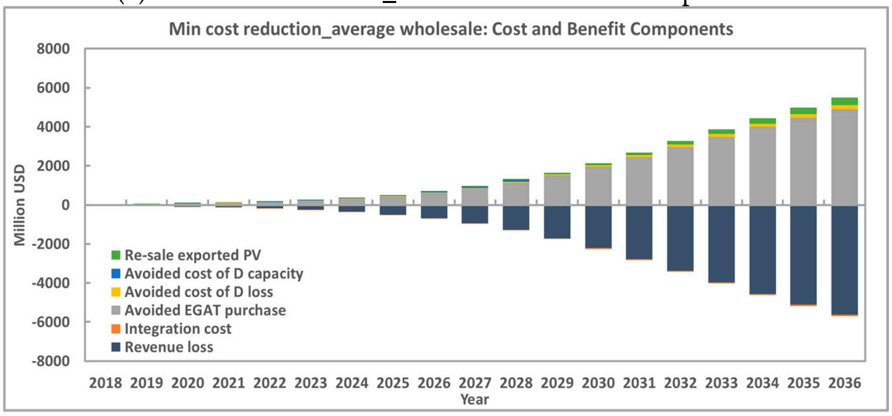


(**e**) Net annual economic impacts (Net Costs/Benefits)

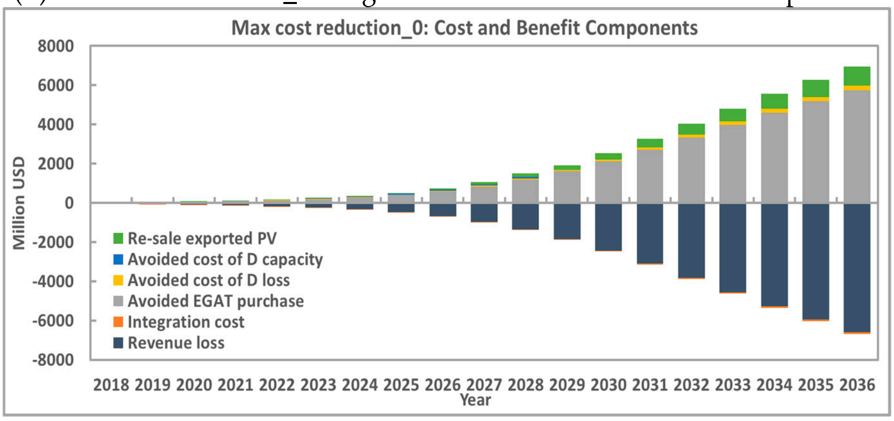
Figure 7. Cost and benefit components with net annual economic impacts on MEA under different scenarios.



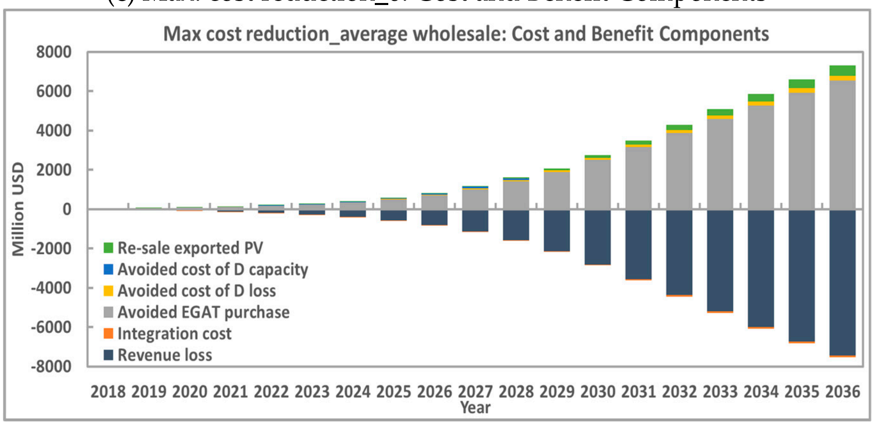
(**a**) Min. cost reduction_0: Cost and Benefit Components



(**b**) Min. cost reduction_average wholesale: Cost and Benefit Components

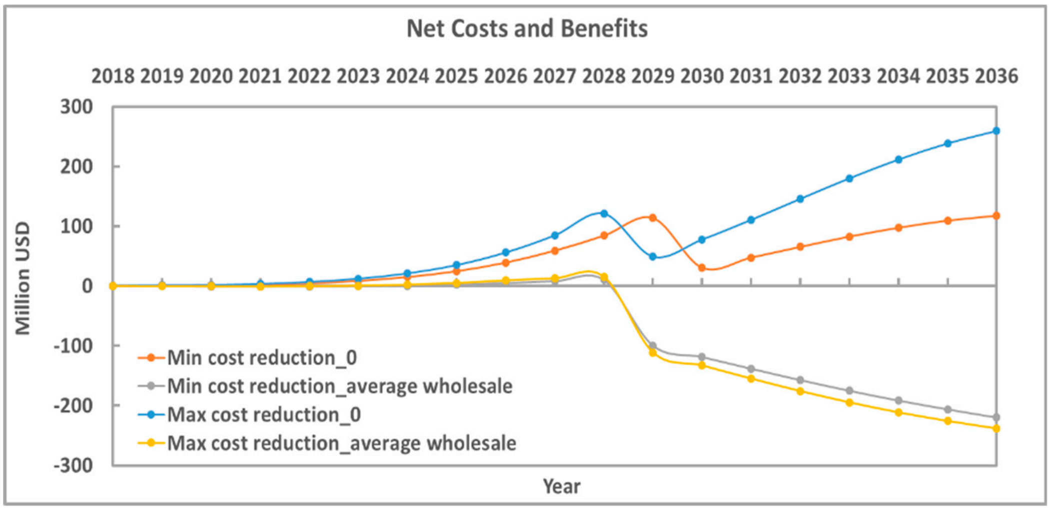


(**c**) Max. cost reduction_0: Cost and Benefit Components



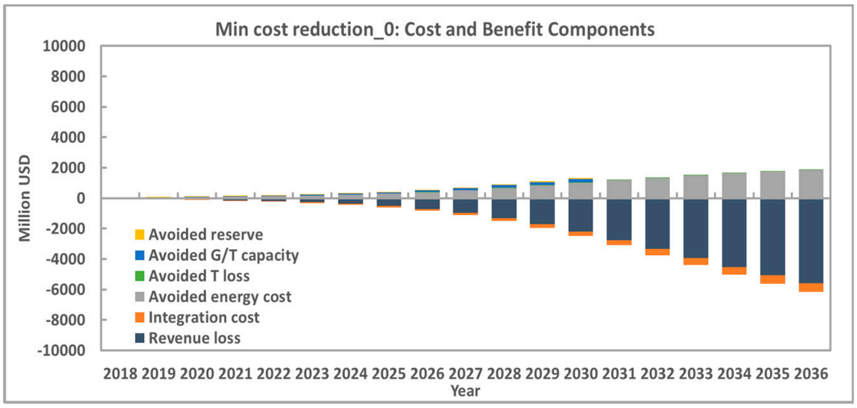
(**d**) Max. cost reduction_ average wholesale: Cost and Benefit Components

Figure 8. *Cont.*

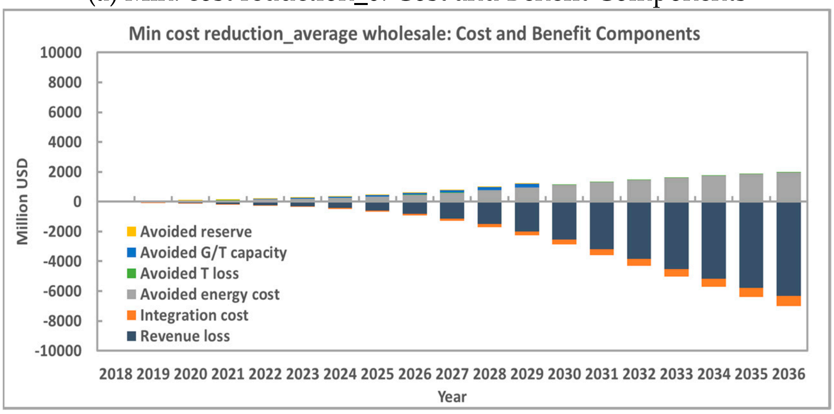


(**e**) Net annual economic impacts (Net Costs/Benefits)

Figure 8. Cost and benefit components with net annual economic impacts on PEA under different scenarios.

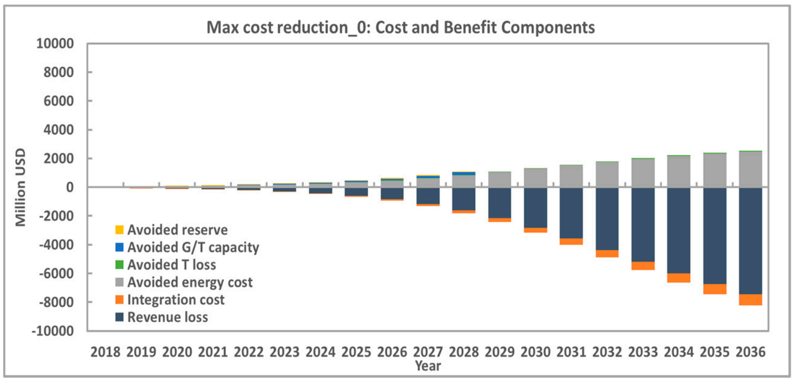


(**a**) Min. cost reduction_0: Cost and Benefit Components

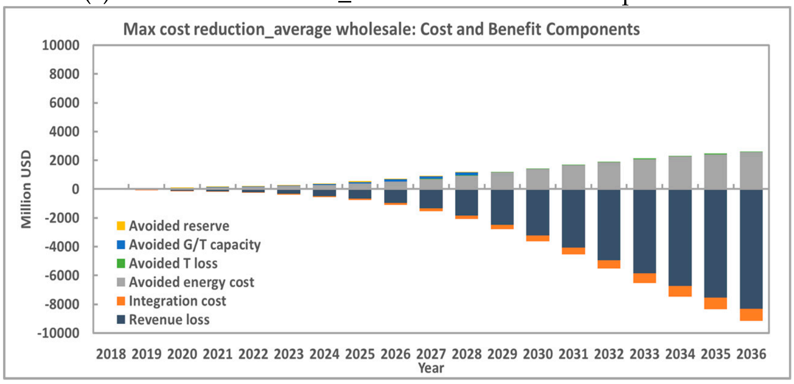


(**b**) Min. cost reduction_average wholesale: Cost and Benefit Components

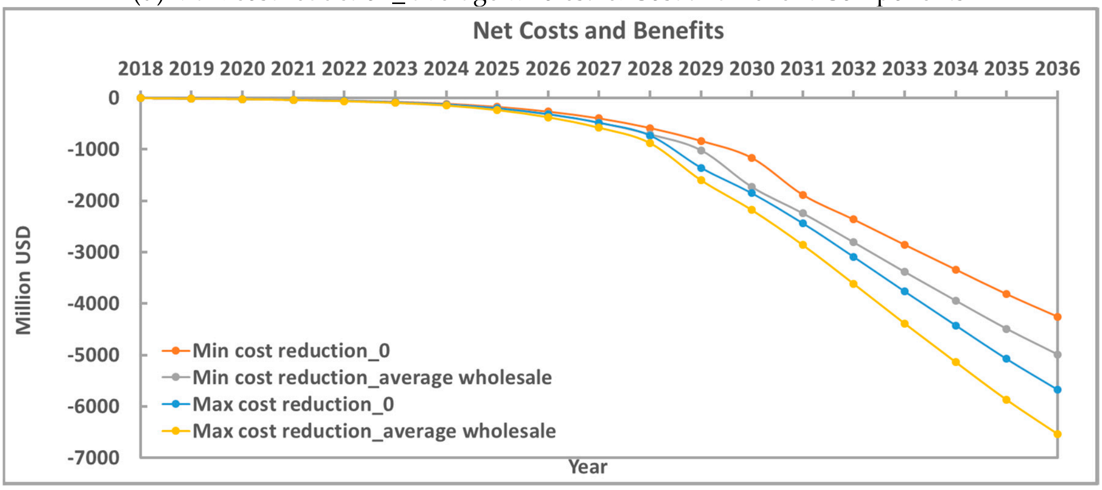
Figure 9. *Cont.*



(**c**) Max. cost reduction_0: Cost and Benefit Components



(**d**) Max. cost reduction_ average wholesale: Cost and Benefit Components



(**e**) Net annual economic impacts (Net Costs/Benefits)

Figure 9. Cost and benefit components with net annual economic impacts on EGAT under different scenarios.

Table 5. Summary of net economic impacts in 2036 on each utility. Percentages in brackets were calculated as compared to projected revenues in 2036. (Projected revenues of each utility = (projected electricity consumption − PV electricity of each scenario) × projected electricity price. The assumptions of the electricity consumption and wholesale/retail price growth rates are summarized in Supplementary Materials. The projected revenues in 2036 are 570,517–586,847 million THB (16,300–16,767 million USD), 1,401,722–1,489,509 million THB (40,049–42,557 million USD) and 1,437,310–1,513,187 million THB (41,066–43,234 million USD) for MEA, PEA, and EGAT, respectively.)

Utility	Net Economic Impacts in 2036 (million USD)							
	Min. Cost Reduction_0	Min. Cost Reduction_1	Min. Cost Reduction_2	Min. Cost Reduction_Average Wholesale	Max. Cost Reduction_0	Max. Cost Reduction_1	Max. Cost Reduction_2	Max. Cost Reduction_Average Wholesale
MEA	−225 (−1.34%)	−245 (−1.47%)	−268 (−1.60%)	−291 (−1.74%)	−273 (−1.67%)	−301 (−1.84%)	−330 (2.02%)	−360 (2.21%)
PEA	118 (0.28%)	33 (0.08%)	−75 (−0.18%)	−220 (−0.53%)	259 (0.63%)	127 (0.31%)	−34 (−0.08%)	−238 (−0.59%)
EGAT	−4254 (8.92%)	−4535 (-9.51%)	−4816 (−10.10%)	−4987 (10.46%)	−5674 (−11.90%)	−6006 (−12.60%)	−6338 (−13.29%)	−6537 (−13.71%)

4.1.2. AEDP Scenario

As previously stated, for the AEDP scenario, the PV adoption pattern of the minimum cost reduction case with no buyback and with a fixed installed capacity at 2800 MW was adopted as a goal for 2025. The annual net economic impacts of PV on each utility revenue are the same as the minimum cost reduction case with no buyback as shown in Figures 7a, 8a and 9a for all years before 2025. Table 6 summarizes the net economic impacts of the AEDP scenario for each utility in 2025. As the level of PV adoption under this scenario is not high (approximately 905 MW for MEA, 1895 MW for PEA, and 2800 MW for overall country (EGAT)), the net small negative impacts on MEA and EGAT are small (less than −1% as compared to the projected revenue for all utilities in 2025) and even the positive impacts for PEA (around 0.1% as compared to the projected revenue for all utilities in 2025).

Table 6. Summary of rooftop PV net economic impacts on utilities in the Alternative Energy Development Plan (AEDP) scenario in 2025. (The projected revenues in 2025 for this case are 294,722 million THB (8,420 million USD), 764,929 million THB (21,855 million USD), and 793,923 million THB (22,683 million USD) for MEA, PEA, and EGAT, respectively.).

Utility	Net Economic Impacts in 2025 (million USD)	% Net Economic Impacts to Projected Revenue in 2025
MEA	−5	−0.05%
PEA	19	0.09%
EGAT	−150	−0.65%

4.2. Retail Rate Impacts

4.2.1. Minimum and Maximum Cost Reduction Scenarios

After quantifying rooftop PV's net economic impacts on each utility's revenue, we could calculate the increase in the retail rate due to PV, since utilities can pass all costs onto the ratepayers at each rate change every 5 years (There were only four-year retail rate impacts in the last period.)

Table 7 summarizes the five-year retail rate impacts in each period for each case. Since total costs are greater than total benefits for all cases, rooftop PV's net economic impacts are expected to increase the retail rate differently according to each scenario's conditions, which are influenced by the buyback rate and PV cost reduction. Generally, when PV adoption is low, such as in the period 2023–2027, the maximum five-year impacts on retail rates is 0.001 USD/kWh or less than 1% of the projected retail rates. On the other hand, when PV adoption is high, we found correspondingly higher impacts on the retail rates. For example, in the final period of the analysis (2033–2036), we found increases in the average rates of 0.012–0.015 USD/kWh (0.42–0.54 THB/kwh; 6–8%, as compared to the projected retail rates) for the minimum cost reduction scenarios and 0.016–0.020 USD/kWh (0.56–0.72 THB/kwh; 9–11%, as compared to the projected retail rates) for the maximum cost reduction scenarios.

Table 7. Five-year retail rate impacts for each case (Percentages in brackets were calculated by comparing to the projected retail rates at the end of each period. Based on Thailand's PDP 2015, the average retail rate was 3.4 THB/kWh and retail rate growth was assumed to be 3.42% per year.).

Year	Retail Rate Impact (USD/kWh)							
	Min. Cost Reduction_0	**Min. Cost Reduction_1**	**Min. Cost Reduction_2**	**Min. Cost Reduction_Average Wholesale**	**Max. Cost Reduction_0**	**Max. Cost Reduction_1**	**Max. Cost Reduction_2**	**Max. Cost Reduction_Average Wholesale**
2018–2022	0.0001 (0.1%)	0.0001 (0.1%)	0.0001 (0.1%)	0.0001 (0.1%)	0.0001 (0.1%)	0.0001 (0.1%)	0.0001 (0.1%)	0.0002 (0.1%)
2023–2027	0.001 (0.6%)	0.001 (0.6%)	0.001 (0.7%)	0.001 (0.8%)	0.001 (0.6%)	0.001 (0.7%)	0.001 (0.8%)	0.001 (0.9%)
2028–2032	0.005 (3.1%)	0.006 (3.6%)	0.006 (4.0%)	0.007 (4.3%)	0.007 (4.3%)	0.008 (4.8%)	0.009 (5.3%)	0.009 (5.8%)
2033–2036	0.012 (6.4%)	0.013 (7.1%)	0.014 (7.8%)	0.015 (8.3%)	0.016 (8.6%)	0.017 (9.5%)	0.019 (10.4%)	0.020 (11.1%)

4.2.2. AEDP Scenario

For the AEDP scenario, the retail rate impacts in each period are summarized in Table 8. With 2800 MW of distributed PV adoption, the retail rate impacts in each period are small (around 0.0001–0.0004 USD/kWh; 0.1–0.4%, as compared to the average projected retail rates in 2025).

Table 8. Summary of retail rate impacts of each period in AEDP scenario.

Period	5-Year Retail Rate Impacts (USD/kWh)	Change in Projected Retail Rate (%)
2018–2022	0.0001 (0.004 THB/kWh)	0.1%
2023–2025	0.0004 (0.02 THB/kWh)	0.4%

5. Discussion

Focusing on the PV cost and benefit components, each utility's unique characteristics lead to different calculations. For distribution utilities (MEA and PEA), the net economic impacts are small and can either be positive or negative depending on the inputs chosen, e.g., level of buyback rate. The cost components are mainly due to revenue losses whereas benefit components mainly come from the avoided EGAT purchases and resale of exported PV. The net economic impacts of MEA and PEA are sensitive to the buyback rate. For example, when comparing the maximum cost reduction scenario with no buyback (Max. cost reduction_0; 25,345 MW) and minimum cost reduction scenario with the average wholesale rate as the buyback rate (Min. cost reduction_average wholesale; 21,671 MW) for PEA, one might expect the latter case to have lower negative impacts on PEA's revenue due to the level of PV adoption. However, this is not the case, as seen in Figure 8e because residential and SGS customers in the PEA area tend to have low demand during the daytime, which leads to higher excess PV generation to the distribution grid, so PEA has more benefits from free excess electricity in the former case (Max. cost reduction_0 case). Thus, the Max. cost reduction_0 case has lower negative impacts than does Min. cost reduction_average wholesale case. The buyback rate affects PEA's net economic impacts more than MEA due to the fact that residential and small general service customers in the MEA area tend to have higher daytime demand and less excess generation. (For MEA, the percentages of PV self-consumption based on the selected PV sizes and load profiles are 84.2%, 98.2%, 99.7%, and 99.9% for RES, SGS, MGS, and LGS, respectively. For PEA, these would be 73.1%, 95.7%, 99.9%, and 99.9% for RES, SGS, MGS, and LGS, respectively.). It was also found from the PEA results that with a low buyback rate net benefits are greater than net costs for all years due to two main components: (1) avoided EGAT purchases during solar production hours and (2) free exported PV back to the grid. In 2028–2029, net economic impacts are also slightly lower. This is due to the fact that avoided cost of distribution capacity becomes zero. After that, the high level of PV adoption increases those two main benefit components (avoided EGAT purchases and resale of exported PV) and brings more positive net economic impacts.

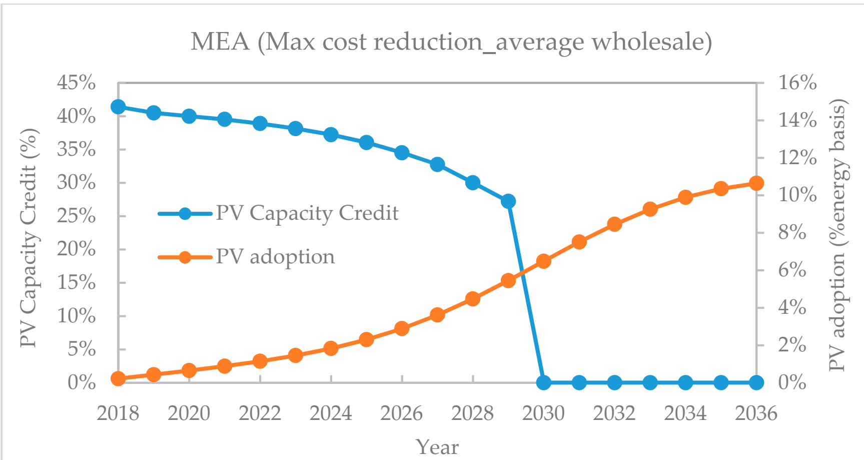
When considering EGAT, the net economic impacts become larger than those of MEA and PEA and are negative for all selected scenarios. EGAT tends to lose their revenues directly from each self-consumed PV unit, leading to higher economic impacts on their businesses, as compared to MEA and PEA, whereas the benefit components of EGAT are mainly due to the avoided cost of energy (reduction in fuel cost) and avoided capacity cost in their generation and transmission systems. Thus for EGAT, only the level of PV adoption matters for their impacts whereas for MEA and PEA both levels of PV adoption and buyback rates matter for their impacts.

For the avoided cost of energy or reduction in fuel costs in all cases, PV was assumed to avoid the use of three types of fuel—oil, imports, and natural gas—in a proportion to the projected energy mix in the PDP 2015. Oil is expected to be about 0.1% while imported electricity ranges from 6–15% and natural gas is expected to be approximately 40–60% of the total energy mix in the country. The avoided cost of energy is the highest value component from rooftop PV to generation systems, as PV always reduced fuel consumption from conventional generators, regardless of the timing of the PV generation. However, it is necessary to consider the energy value factor of PV in order not to overestimate or underestimate the energy value of solar power when PV adoption increases.

MEA, PEA, and EGAT benefit also from the reduction in peak demand due to rooftop PV in terms of avoided capacity cost of generation, transmission, and distribution systems, depending on how well the hours of peak demand are aligned with the PV production profiles. The demand profiles of all utilities are expected to peak during the daytime (around 2–3 p.m.) when the rooftop PV systems generate electricity. As seen in Figure 10, the PV capacity credit in Year 1 was found to be about 41% for MEA and PEA and 37% for EGAT. (PV capacity credits were calculated in a particular year by: Average top 100-hour demand reduction (MW)/PV installed capacity (MW).) The capacity credit of EGAT is slightly lower than MEA and PEA. This is because total PV installed capacity (ground-mounted and rooftop PV) were taken in the calculation. Moreover, this level of capacity credit (around 40%) is due to the fact that it is not every day of the year that peak load is around 2–3 p.m.

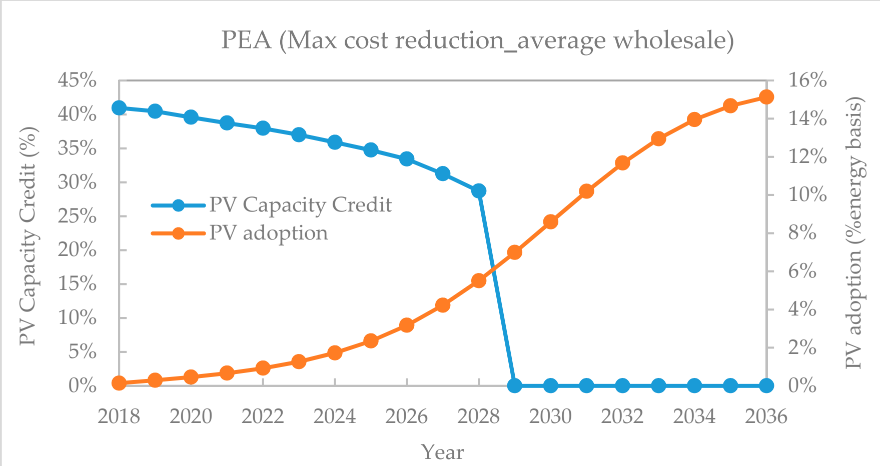
When PV adoption increases to around 6–7%, the PV capacity credit for each utility is expected to decrease to about 27% for MEA, 29% for PEA, and 27% for EGAT. For higher PV adoption levels, the net peak demand is shifted from the daytime (2–3 p.m.) to nighttime (7–8 p.m.) at which point any additional solar capacity cannot further reduce this peak (see Figure 11 of EGAT as an example); at this point, any additional PV has a capacity credit equal to zero. As shown in this analysis, starting in 2028–2031 as well as according to each utility and level of PV adoption, PV no longer has the capacity values to defer a utility's investment. This is why we find that the net economic impact of rooftop PV systems for utilities is worse when PV adoption is high and the value of PV decreases.

Our results may slightly overestimate EGAT's revenue loss and the avoided EGAT purchases for MEA and PEA, as the wholesale prices used (the PDP 2015) do not account for the impact of PV on wholesale price profiles, as discussed in [27–29]. Additionally, assumptions about increases in retail rate and electricity demand were made from the PDP 2015. These assumptions would probably not reflect the actual situation when PV installation increases, which would affect the overall results. For instance, if retail rate increases more than the current assumption, PV installation will be economically attractive to customers, leading to higher PV adoption and higher revenue losses to utilities.

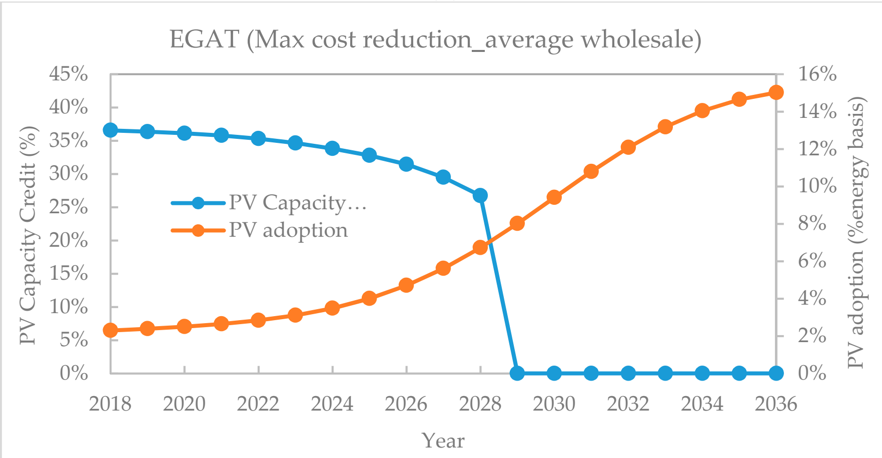


(a)

Figure 10. *Cont.*



(**b**)



(**c**)

Figure 10. PV capacity credits of MEA, PEA, and EGAT for Max. cost reduction_average wholesale: (**a**) MEA; (**b**) PEA; (**c**) EGAT (including utility-scale solar PV). Other cases are summarized in Supplementary Materials. % PV adoption in this figure is the energy basis of each utility.

In sum, the net economic impacts on the utilities depend on each utility's characteristics, level of PV adoption, and buyback rate as well as the load profile of each customer group and the overall utility system. Generally, higher PV adoption influenced by higher buyback rates and higher PV cost reduction leads to higher impacts on utilities. For EGAT, it is clear that the rooftop PV impacts depend on the level of PV adoption and overall system load profile whereas for MEA and PEA several factors are involved (most notably, the level of PV adoption, the buyback rate, individual load profiles, and overall system load profile). However, these negative impacts are only for the short-term period (5 years maximum) since according to the current Thai tariff structure it is possible for the three utilities to pass all costs due to rooftop PV onto ratepayers by increasing retail rates (the higher the PV adoption level, the higher the retail rate impact). In the first five years of this analysis, the retail rate impacts are small relative to normal changes in Ft, and the results are in the same direction as discussed in [18]. On the other hand, in the long term, the retail rate impacts increase due to higher PV adoption.

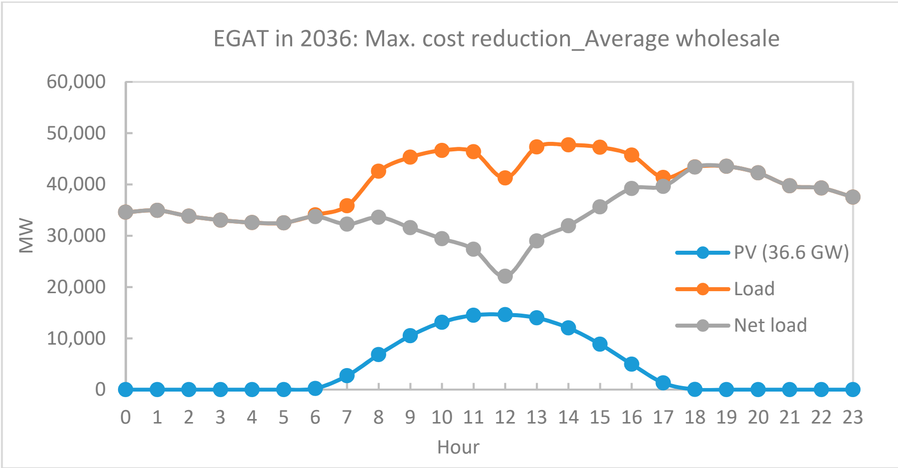


Figure 11. The comparison of load, net load, and PV generation profiles is based on EGAT's system in 2036 with PV adoption at 36.6 GW (Max. cost reduction_average wholesale case). EGAT's peak demand in 2017 was about 29,000 MW and expected to grow at 3.54%. All lines represent the average hourly data in one year.

There are, however, mechanisms that could mitigate these concerns in the future. Since PV policies and retail rate impacts can increase the feasibility of PV investments, which leads to higher PV adoption and increased impacts on retail rates and utilities at the same time (i.e., the utility death spiral), it is necessary to balance costs and benefits from PV among the relevant stakeholders before proposing such a policy. As the Thai government is introducing new support policies for rooftop PV, it will be important to consider a policy framework that balances the costs and benefits of rooftop PV among all stakeholders. In order to ensure that rate impacts are contained, for example, utilities may consider defining PV adoption caps or retail rate impact caps [18,30]. Moreover, re-designing both wholesale and retail rates in the country to reflect actual generation cost and on/off-peak period would enable utilities to recover any revenue losses and the mitigation of economic impacts from PV rooftop installation.

Regulators and utilities may also need to adjust their roles to accommodate the use of rooftop PV and mitigate impacts on retail rates and utility revenues in Thailand, complementing policy mechanisms. On the basis of NREL's publication [31], the authors discussed three generations of PV business models and utility roles. For Zero Generation, the utility role is passive, focusing only on billing and interconnection approaches. On the other hand, for the First and Second Generations, each utility increases their attention to facilitate the use of PV and plans to change their business models to participate in the solar market due to the market's growth. The discussions of new utility business models have been of interest to other countries as discussed in [7,8,32–37]. There is also an example of new utility adaption in Thailand from PEA, one of the distribution utilities, who established a subsidiary company, "PEA Encom International", to introduce new businesses into the renewable energy sector, including rooftop PV [38].

It is also important to address the motivation of each utility to pursue new business models. As discussed in [35,39], the traditional cost-of-service regulatory approach, as in Thailand, does not encourage utilities to incorporate rooftop PV businesses in their services, since high PV adoption resulted in decreases in volumetric sales, leading to their revenue losses and profits. With traditional cost-of-service, utilities must maximize their performances by increasing the profits from sales of electricity. Thus, they would not be interested in venturing into PV businesses. On the other hand, regulators/governments can tie utility earnings with pre-established targets such as increases in rooftop PV in this context by maximizing the value of existing assets. This regulatory approach is called performance-based regulation and would motivate utilities to focus their businesses not only on profits from electricity sales but also on performance targets. Moreover, regulators must ensure that both utilities and consumers are well protected, that any new regulations or tariff designs are fair to the relevant stakeholders, and that the country is able to accommodate rooftop PV on an appropriate level based on a country-specific context.

Additionally, as battery costs are expected to decrease continuously in the medium term [40,41], residential customers are likely to be interested in installing PV-battery systems, given that household demand peaks in the evening when PV cannot generate electricity. A PV-battery system is able to charge with PV electricity during daytime and discharge in the nighttime when demand is high. The use of residential batteries can also have economic implications for utilities. Generally, household batteries can increase self-consumption ratio which means that prosumers will further reduce their electricity purchases from the grid while reducing excess PV generation. Moreover, at the grid level, the use of residential batteries can increase solar capacity and energy values since it helps avoid using expensive fuel and reduce peak demand in the evening that PV-only systems cannot do.

When focusing on each cost and benefit components as discussed in Table 3 for distribution utilities (MEA and PEA), residential PV-battery systems lead to higher costs to MEA and PEA in terms of (1) higher revenue losses and (2) lower re-sale of exported PV due to increasing self-consumption ratio from prosumers. However, the use of residential batteries can increase benefits to MEA and PEA by (1) decreasing PV integration cost due to higher self-consumption ratio and (2) increasing solar capacity and energy values due to shifting PV generation from daytime to nighttime. On the other hand, the implications to EGAT are different. Increasing self-consumption ratio from prosumers does not affect EGAT's revenue losses as the total amount of PV generation does not change (only shifting electricity from daytime to nighttime which is still in the same period of TOU rate). This means there is no additional costs for EGAT whereas there are additional benefits in terms of (1) increasing solar capacity and energy values to EGAT system and (2) decreasing PV integration cost when residential battery installations are taken into account. Therefore, residential PV-battery systems could potentially decrease economic impacts to EGAT whereas the economic impacts to MEA and PEA may be positive or negative.

The important discussion points are summarized:

1. The net economic impacts on utilities depend on the specific characteristics of each utility.
2. With a low level of PV adoption, the net economic impacts and retail rates are minimal.
3. Higher PV adoption influenced by higher buyback rates and higher PV installation cost reductions leads to higher net economic impacts and retail rates as the values of solar power decrease.
4. As PV policies can help increase PV adoption and impact utilities and retail rates at the same time, it is necessary to seek a balance among the relevant stakeholders before proposing such a policy.
5. There are also approaches to mitigating the impacts on utilities and ratepayers in terms of policy mechanisms, utility business models, and regulatory approaches on rate designs that require tradeoffs among the stakeholders.

6. Conclusions

Rooftop PV has been of interest to the relevant stakeholders in Thailand, especially for three utilities who expect it to reduce their revenues and impact electricity prices. Thus, it is necessary for Thailand to understand these economic impacts before moving forward and implementing a rooftop PV support policy. We used cost–benefit analysis to quantify the net economic impacts on the three utilities (MEA, PEA, and EGAT) and ratepayers under nine different rooftop PV scenarios by varying the two main parameters: buyback rates and PV installation cost reduction. The PV adoption scenarios range from 25 to 37 GW. For the AEDP scenario, fixed PV adoption was 2800 MW. The cost components are related to the revenue losses from self-consumed PV electricity whereas the benefit components are related to the energy and capacity values of solar power in terms of avoided costs.

The net rooftop PV impacts depend on the specific characteristics of each utility. Generally, when PV adoption is low, such as in the AEDP scenario, the economic impacts on the utilities and ratepayers are minimal. In contrast, with higher PV adoption influenced by higher buyback rates and higher

PV installation cost reduction, the net economic impacts on the utilities become noticeable. The net economic impacts on MEA and PEA are small and can either be positive or negative. On the other hand, those of EGAT become more significant and are negative for all scenarios. This is because EGAT tends to lose revenues directly from the self-consumed PV units and does not benefit from the low-priced excess PV generation. The decreases in the values of solar power when PV adoption is high are mainly due to the reduction in capacity value as the net load tends to shift towards the nighttime. Thus, PV cannot defer capacity investment. In 2036, the last year of this analysis, the net economic impacts of rooftop PV range from −1 to −2%, from −0.59 to 0.63%, and from −9 to −14% of the projected revenue for MEA, PEA, and EGAT, respectively, according to the PV adoption of 9–14% in energy basis. However, under Thailand's current tariff structure, all utilities are well-protected and able to pass all costs due to rooftop PV onto the ratepayers in terms of increases in the retail rates for every rate base case of five years. The impacts due to PV on the retail rates are in the same direction as the net economic impacts on the utilities. When PV adoption is small, the impacts on the retail rates are minimal relative to the normal fluctuations of the electricity rates in the country. On the other hand, when PV adoption ranges from 9–14% in energy basis, five-year retail rate impacts are in between 6 to 11% of change in the projected retail rates in 2036, depending on the PV adoption levels.

It will be important for Thailand to balance the benefits of the stakeholders and to implement mitigation measures such as those related to policy mechanisms to cap installed PV capacity and retail rate impacts, business models for utilities, and regulatory/tariff models to accommodate the use of rooftop PV effectively. The adoption of each approach depends on country-specific situations and requires tradeoffs to be made among the stakeholders. It is also worth discussing and quantifying how in the future utility businesses and regulatory/tariffs models will help to mitigate rooftop PV impacts on utilities and ratepayers as evaluated in [34].

Our study has some limitations that are interesting for future works. First, average load profiles of each customer group were used in the analysis. It would be good to model detailed load profiles (e.g., below average, average, above average load profiles) and PV sizes in order to broadly represent the PV market in Thailand. Second, electricity cost evolution was taken from current PDP and might not reflect actual costs when PV increases, which would affect the CBA results. Third, the scope of this work only focuses on economic impacts of rooftop PV on electric utilities, it is also possible in the future to extend the scope of work to cover: (1) other important technologies (e.g., battery and electric vehicle) and (2) other perspectives of impact analysis (e.g., environmental impacts as discussed in Figure 1).

Supplementary Materials: The following are available online at http://www.mdpi.com/1996-1073/12/12/2265/s1, Table S1: Customer's load profiles in MEA and PEA area; Table S2: Utility system's load profiles; Table S3: System parameters for performance model in SAM; Table S4: PV installation cost; Table S5: Retail rate; Table S6: Other parameters for CBA; Table S7: Net economic impacts (net costs and benefits); Table S8: PV capacity credits.

Author Contributions: Conceptualization, A.C., A.B., and C.M.; methodology, A.C., A.B., C.M., and N.R.D.; software, A.C.; validation, A.C., A.B., C.M., and N.R.D.; formal analysis, A.C., A.B., C.M., and N.R.D.; investigation, A.C.; resources, A.C.; data curation, A.C.; writing—original draft preparation, A.C.; writing—review and editing, A.B., C.M., and N.R.D.; visualization, A.C.; supervision, A.B., C.M., and N.R.D.; project administration, A.C.; funding acquisition, A.C. and A.B.

Funding: The authors would like to express their gratitude to the Joint Graduate School of Energy and Environment, King Mongkut's University of Technology Thonburi, Center of Excellence on Energy Technology and Environment, PERDO, Bangkok, Thailand, and the Petchra Pra Jom Klao Doctoral Degree Research Scholarship from King Mongkut's University of Technology Thonburi for financial support.

Acknowledgments: The authors would like to thank MEA, PEA, EGAT, EPPO, DEDE, and anonymous private entities for their opinions expressed in the interviews held in Thailand during 2016–2017 and for the data used in the calculations. We would also particularly like to thank Andrew Satchwell and Andrew Mills (LBNL) as well as Alexandra Aznar and the SAM team (NREL) for their valuable opinions as a part of this research had been conducted in the United States.

Conflicts of Interest: The authors declare no conflicts of interest.

References

1. EPPO-Energy Policy and Planning Office. Alternative Energy Development Plan. Available online: https://bit.ly/2FIDnJt (accessed on 4 May 2018).
2. GIZ-Deutsche Gesellschaft für Internationale Zusammenarbeit. *Thailand Solar PV Policy Update 01/2017*; Federal Ministry for Economic Affairs and Energy: Bangkok, Thailand, 2017.
3. Tongsopit, S. Thailand's Feed-in Tariff for Residential Rooftop Solar PV Systems: Progress so far. *Energy Sustain. Dev.* **2015**, *29*, 127–134. [CrossRef]
4. International Energy Cooperation Center. News (Available in Thai). Available online: https://goo.gl/jnhPFZ (accessed on 11 October 2017).
5. E3-Energy + Environmental Economics. *California Net Energy Metering Ratepayer Impacts Evaluation*; Energy + Environmental Economics: San Francisco, CA, USA, 2013.
6. RMI- Rocky Mountain Institute. *A Review of Solar PV Benefit & Cost Studies*; Rocky Mountain Institute: Snowmass, CO, USA, 2013.
7. Satchwell, A.; Mills, A.; Barbose, G. Quantifying the Financial Impacts of Net-metered PV on Utilities and Ratepayers. *Energy Policy* **2015**, *80*, 133–144. [CrossRef]
8. Richter, M. Utilities' Business Models for Renewable Energy: A Review. *Renew. Sust. Energy Rev.* **2012**, *16*, 2483–2493. [CrossRef]
9. Kroze, Y. Cost and Benefit of Renewable Energy in the European Union. *Renew. Energy* **2013**, *50*, 68–73. [CrossRef]
10. Pikas, E.; Kurnitski, J.; Thalfeldt, M.; Koskela, L. Cost-benefit Analysis of nZEB Energy Efficiency Strategies with On-site Photovoltaic Generation. *Energy* **2017**, *128*, 291–301. [CrossRef]
11. Leurent, M.; Costa, P.D.; Rama, M.; Persson, U.; Jasserand, F. Cost-benefit Analysis of District Heating Systems Using Heat from Nuclear Plants in Seven European countries. *Energy* **2018**, *149*, 454–472. [CrossRef]
12. E3-Energy + Environmental Economics. *Nevada Net Energy Metering Impacts Evaluation*; Energy + Environmental Economics: San Francisco, CA, USA, 2014.
13. CPR-Clean Power Research. *The Value of Distributed Photovoltaics to Austin Energy and the City of Austin*; Clean Power Research: Austin, TX, USA, 2006.
14. Keyes, J.; Rabago, K. *A Regulator's Guidebook: Calculating the Benefits and Costs of Distributed Solar Generation*; Interstate Renewable Energy Council, Inc.: Latham, NY, USA, 2013.
15. Xcel Energy, Inc. *Costs and Benefits of Distributed Solar Generation on the Public Service Company of Colorado System*; Excel Energy, Inc.: Minneapolis, MN, USA, 2013.
16. APPA-American Public Power Association. *Solar Photovoltaic Power: Assessing the Benefits &Costs*; American Public Power Association: Washington, DC, USA, 2014.
17. Denholm, P.; Margolis, R.; Palmintier, B.; Barrows, C.; Ibanez, E.; Bird, L.; Zuboy, J. *Methods for Analyzing the Benefits and Costs of Distributed Photovoltaic Generation*; National Renewable Energy Laboratory: Golden, CO, USA, 2014.
18. Tongsopit, S.; Zinaman, O.R.; Darghouth, N.R. *Understanding the Impact of Distributed Photovoltaic Adoption on Utility Revenues and Retail Tariffs in Thailand*; USAID Clean Power Asia: Bangkok, Thailand, 2017.
19. Chaianong, A.; Bangviwa, A.; Menke, C. Forecast of Rooftop PV Adoption in Bangkok, Thailand. In Proceedings of the 41st IAEE International Conference, Groningen, The Netherlands, 10–13 June 2018.
20. Chaianong, A.; Tongsopit, S.; Bangviwat, A.; Menke, C. Bill Saving Analysis of Rooftop PV Customers and Policy Implications for Thailand. *Renew. Energy* **2019**, *131*, 422–434. [CrossRef]
21. Tongsopit, S.; Julakarn, S.; Wibulpolprasert, W.; Chaianong, A.; Kokchang, P.; Hoang, N.V. The Economics of Solar PV Self-consumption in Thailand. *Renew. Energy* **2019**, *138*, 395–408. [CrossRef]
22. Chaianong, A.; Bangviwat, A.; Menke, C. A Framework for Evaluating Economic Impacts of Rooftop PV Systems with or Without Energy Storage on Thai Distribution Utilities and Ratepayers. In *IOP Conference Series: Earth and Environmental Science*; IOP Publishing: Bristol, UK, 2017.
23. Ministry of Energy. Thailand Power Development Plan 2015–2036. Available online: https://bit.ly/2JVMXet (accessed on 4 May 2018).
24. Frew, B. *8760-Based Method for Representing Variable Generation Capacity Value in Capacity Expansion Models*; National Renewable Energy Laboratory: Golden, CO, USA, 2017.

25. EGAT-Energy Generating Authority of Thailand. EGAT's Article (in Thai). Available online: https://goo.gl/ttUJmr (accessed on 15 May 2018).
26. Wiser, R.; Mills, A.; Seel, J.; Levin, T.; Botterud, A. *Impacts of Variable Renewable Energy on Bulk Power System Assets, Pricing and Costs*; Lawrence Berkeley National Laboratory and Argonne National Laboratory: Berkeley, CA, USA, 2017.
27. Sensfuß, F.; Ragwitz, M.; Genoese, M. The Merit-order Effect: A Detailed Analysis of the Price Effect of Renewable Electricity Generation on Spot Market Prices in Germany. *Energy Policy* **2008**, *36*, 3086–3094. [CrossRef]
28. Seel, J.; Mill, A.; Wiser, R. *Impacts of High Variable Renewable Energy Futures on Wholesale Electricity Prices, and on Electric-Sector Decision Making*; Lawrence Berkley National Laboratory: Berkeley, CA, USA, 2018.
29. Thakur, J.; Rauner, S.; Darhougth, N.R.; Chakraborty, B. Exploring the Impact of Increased Solar Deployment Levels on Residential Electricity Bills in India. *Renew. Energy* **2018**, *120*, 512–523. [CrossRef]
30. IEA-PVPS—International Energy Agency-Photovoltaic Power Systems Program. *Review and Analysis of PV Self-Consumption Policies*; IEA Photovoltaic Power Systems Program; IEA: Paris, France, 2016.
31. Frantzis, L.; Graham, S.; Katofsky, R.; Sawyer, H. *Photovoltaic Business Models*; National Renewable Energy Laboratory: Golden, CO, USA, 2008.
32. RMI-Rocky Mountain Institute. *Net Energy Metering, Zero Net Energy and the Distributed Energy Resource Future: Adapting Electric Utility Business Models for the 21st Century*; RMI: Snowmass, CO, USA, 2012.
33. Richter, M. German Utilities and Distributed PV: How to Overcome Barriers to Business Model Innovation. *Renew. Energy* **2013**, *55*, 456–466. [CrossRef]
34. Satchwell, A.; Mills, A.; Barbose, G. Regulatory and Ratemaking Approaches to Mitigate Financial Impacts of Net-metered PV on Utilities and Ratepayers. *Energy Policy* **2015**, *85*, 115–125. [CrossRef]
35. Satchwell, A.; Cappers, P.; Schwartz, L.; Fadrhonc, E.M. *A Framework for Organizing Current and Future Electric Utility Regulatory and Business Models*; Lawrence Berkeley National Laboratory: Berkeley, CA, USA, 2015.
36. Barbose, G.; Miller, J.; Sigrin, B.; Reiter, E.; Cory, K.; McLaren, J.; Seel, J.; Mills, A.; Darghouth, N.R.; Satchwell, A. *On the Path to Sunshot: Utility Regulatory and Business Model. Reforms for Addressing the Financial Impacts of Distributed Solar on Utilities*; National Renewable Energy Laboratory: Golden, CO, USA, 2016.
37. Utility Dive. *2018 State of the Electric Utility*; Utility Dive: Washington, DC, USA, 2018.
38. PEA-Provincial Electricity Authority. PEA's Article (Thai). Available online: https://bit.ly/2wh9u3q.2017 (accessed on 4 May 2018).
39. The Regulatory Assistance Project. *Performance-Based Regulation for Distribution Utilities*; The Regulatory Assistance Project for the National Association of Regulatory Utility Commissioners; National Association of Regulatory Utility Commissioners: Washington, DC, USA, 2000.
40. IRENA-International Renewable Energy Agency. *Battery Storage for Renewables: Market. Status and Technology Outlook*; International Renewable Energy Agency: Abu Dhabi, UAE, 2015.
41. Kittner, N.; Lill, F.; Kammen, D.M. Energy Storage Development and Innovation for the Clean Energy Transition. *Nat. Energy* **2017**, *2*, 17125. [CrossRef]