UNDERSTANDING THE IMPACT OF DISTRIBUTED PHOTOVOLTAIC ADOPTION ON UTILITY REVENUES AND RETAIL ELECTRICITY TARIFFS IN THAILAND

USAID CLEAN POWER ASIA

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Authors: Sopitsuda Tongsopit, Chulalongkorn University's Energy Research Institute and USAID Clean Power Asia

Owen R. Zinaman, National Renewable Energy Laboratory and Clean Energy Transition Partners, LLC

Naïm Darghouth, Lawrence Berkeley National Laboratory

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DEDE	Department of Alternative Energy Development and Efficiency
DPV	Distributed Photovoltaics
EGAT	Electricity Generating Authority of Thailand
EPPO	Energy Policy and Planning Office
GW	Gigawatt
kW	Kilowatt
kWh	Kilowatt-hour
LGS	Large General Service
MEA	Metropolitan Electricity Authority
MGS	Medium General Service
NEM	Net Energy Metering
OERC	Office of Energy Regulatory Commission
PEA	Provincial Electricity Authority
RES	Residential
SCO	Self-Consumption Only
SGS	Small General Service
THB	Thai Baht

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EXECUTIVE SUMMARY

BACKGROUND

As the costs of solar photovoltaic technology continue to decline, the production of electricity from distributed solar photovoltaics (DPV) systems has become an increasingly attractive option for consumers in many countries. We define DPV as a smaller scale photovoltaic electricity production system which is located “behind” a customer’s electricity meter, in locations such as the rooftops or on the surrounding land of homes, buildings, or factories. The increasing ubiquity of customers who self-produce and self-consume their own electricity has created a new class of players in the electric power industry referred to as “prosumers” (producer + consumer). Prosumers supplement their purchases of electricity from their electric utility with electricity that they produce from their own systems, enabling them to reduce their electricity bills and earn a positive return on their investment.

While the global DPV market is growing quite quickly, creating new jobs and accruing significant environmental benefits, it is at the same time posing some new challenges. One of the most common concerns cited by retail electricity distributors is the impact that DPV may have on their revenue, and, perhaps more existentially, on their business model. How will utilities continue to recover costs and serve ratepayers if segments of their customer base are increasingly shifting towards producing their own electricity? What will happen to retail electricity tariffs for the remaining ratepayers?

More broadly, how can the interests of utilities, prosumers, ratepayers, and society at large be balanced in the DPV policymaking process? There have been a diversity of analyses conducted attempting to answer these questions for various settings, with no single pathway or one-size-fits-all solution arising. Emerging solutions tend to be locally appropriate and significantly customized to the conditions of each power system, considering a range of factors, including the specifics of the regulatory structure for the electric utility (i.e., the rules defining how the utility creates revenue and recovers costs).

ANALYSIS QUESTIONS

Against the backdrop of consumers’ increasing interest in DPV in Thailand, as well as a DPV policy to be launched by the Thai government in late 2017, this study looks to quantify the impact of 3,000 MW of DPV deployment in the year 2020 on (a) Thai distribution utilities’ revenue in the short-term (i.e., before the next rate case), and (b) retail electricity tariffs in the medium-term (i.e., after the next rate case). The amount of 3,000 MW of DPV by 2020 corresponds to a PV penetration of approximately 2.5% on an energy level, a relatively ambitious target given that today’s DPV penetration is near zero. This quantity was intentionally selected to provide analysis insights based on an aggressive deployment scenario.

QUALITATIVE ANALYSIS RESULTS

The research and analysis process began with a series of in-depth stakeholder interviews aiming to uncover (1) the power sector regulatory structure and detailed ratemaking procedures and considerations in Thailand; (2) whether and how the deployment of DPV would be accounted for in this ratemaking process in practice; and (3) how the deployment of DPV would financially impact distribution utilities and ratepayers under existing ratemaking regulations in Thailand. Beyond interviews, the research process was strongly focused on building consensus on which exact research questions should be considered, and which methodologies should be used to answer these questions. The key institutional stakeholders and interviewees involved in this process are listed in Table 1.

Table 1: List of key study institutional stakeholders

Institution	Description
Metropolitan Electricity Authority of Thailand (MEA)	State-owned Thai distribution utility serving over 3.6M retail customers in the Bangkok metropolitan area
Provincial Electricity Authority of Thailand (PEA)	State-owned Thai distribution utility serving over 18.8M retail customers throughout the remainder of Thailand
Office of the Energy Regulatory Commission (OERC) of Thailand	Central government agency responsible for the regulation of the energy sector in Thailand (including MEA and PEA)
Department of Alternative Energy Development and Efficiency (DEDE)	Central government department responsible for the formulation of Thailand's DPV public policy
Electricity Generating Authority of Thailand (EGAT)	State-owned transmission and generation utility that sells wholesale electricity to MEA and PEA.[1]

Key findings from the qualitative research, which have been confirmed across stakeholder institutions through a formal feedback process, include:

1. Thailand's current regulatory paradigm allows for 100% of all net costs associated with DPV deployment to be passed through to customers via tariff increases; thus, DPV deployment will cause no direct medium- or long-term net revenue impacts on the distribution utilities[2]. Retail tariffs in Thailand are based on expected future sales, and hence distribution utilities can fully recover costs even with increasing DPV levels.

2. Thailand's regulatory structure is well-suited to support DPV deployment while protecting distribution utility revenues, provided that increases in deployment are properly planned and accounted for in rate cases. The financial health of the distribution utilities should not be affected by DPV in the current regulatory environment.

3. When DPV electricity is self-consumed by the user, this consistently results in a short-term utility revenue loss followed by a rate increase after the rate case. If the compensation rate for injected DPV electricity is below EGAT's wholesale electricity price, this will result in a net benefit. That

[1] While this analysis focused on quantifying DPV deployment impacts on the Thai distribution utilities, EGAT's inputs proved critical to understanding certain aspects of the Thai regulatory paradigm.
[2] It should be noted that DPV could reduce earning opportunities for distribution utilities in the medium- and long-term, as any avoided or deferred investments would lead to lower earnings under a rate-of-return regulation.

benefit is passed through to ratepayers via the F_t mechanism[3], resulting in a reduction in retail tariffs. If the compensation rate is above EGAT's wholesale electricity price, this will result in a net cost, which would be passed through as an increase in the F_t to retail tariffs.

QUANTITATIVE ANALYSIS RESULTS

Upon gaining a more detailed theoretical understanding of how distribution utilities in Thailand would be impacted by DPV deployment, the analysis team gathered a range of Thailand-specific data from stakeholders and built a customized spreadsheet model which (1) quantifies the impact on revenue associated with DPV deployment in the short-term (i.e., before the next rate case) and (2) quantifies the impact of DPV deployment on retail tariffs in the medium-term (i.e., after the next rate case). Five scenarios were designed to help the analysis team understand the range of potential impacts, including a low and high impact scenario (effectively bounding the results). Table 2 describes the scenarios, while Figure 1 and Table 3 present the average retail tariff increase for each scenario for both MEA and PEA. To put this in perspective, the magnitude of the change in the F_t charge, mostly due to volatility in fuel costs, was on average 7.98 satang/kWh for each change between 2007 and 2017.

Table 2: Abbreviated description of five analysis scenarios

Scenario Name	DPV Compensation Scheme	Customer Mix
Base Scenario – 1 THB	Net Billing. DPV grid injections compensated at 1.0 THB/kWh sell rate	DPV installations proportional to total distribution utility load by customer class
Base Scenario – 2 THB	Net Billing. DPV grid injections compensated at 2.0 THB/kWh sell rate	
Base Scenario – 3 THB	Net Billing. DPV grid injections compensated at 3.0 THB/kWh sell rate	
Low Impact	Self-consumption only. Customer does not receive compensation for DPV grid injections	
High Impact	Net Energy Metering. DPV grid injections credited at full variable retail electricity tariffs.	DPV only installed in two rate classes with highest impact on distribution utility revenue and rates

[3] The F_t is an automatic adjustment mechanism to help the utility recover its costs through retail rates. The F_t is a direct adder on retail electricity rates, and regularly fluctuates over time (as frequently as every 4 months).

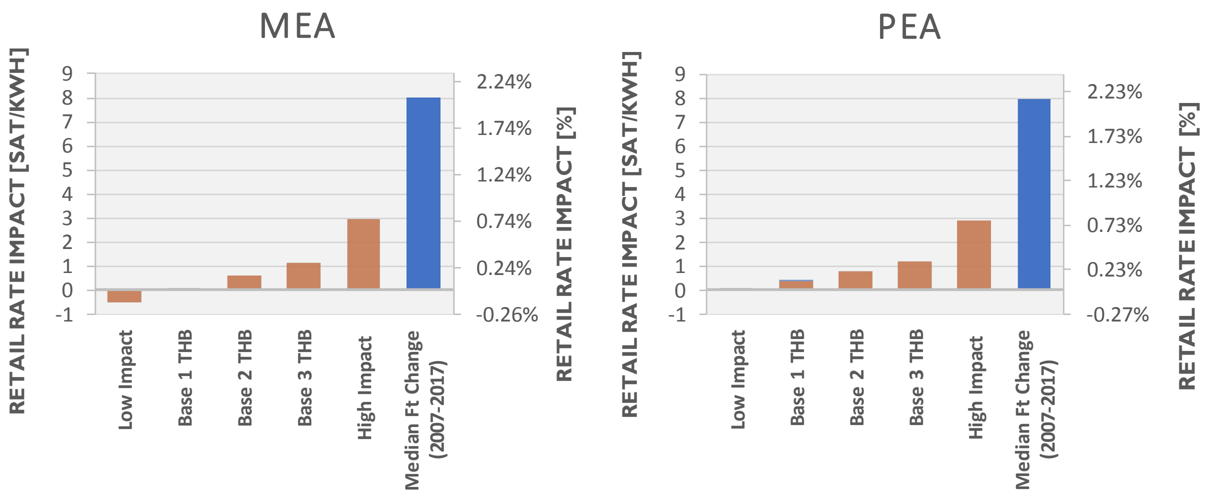


Figure 1: Summary of retail tariff impacts resulting from 3,000 MW of DPV deployment in Thailand in 2020 by distribution utility and analysis scenario compared with median F_t change from 2007-2017
Note: SAT = satang. 100 Satang = 1 Thai baht (THB)

Table 3: Summary of retail electricity rate impacts from 3000 MW of DPV in 2020

Retail Tariff Impact	Utility	Low Impact	Base 1 THB	Base 2 THB	Base 3 THB	High Impact		Median F_t Change 2007-2017
Satang/kWh	MEA	-0.48	0.06	0.60	1.14	2.96		7.98
	PEA	0.01	0.41	0.82	1.22	2.91		
%	MEA	-0.12%	0.02%	0.16%	0.29%	0.76%		2.1%*
	PEA	0.00%	0.11%	0.22%	0.33%	0.78%		

*An F_t change of 7.98 satang/kWh would result in an average retail tariff increase of 2.1% in the year 2020, based on the assumptions of this analysis.

Key findings from the quantitative analysis include:

1. Under our 'Base Scenario' conditions, average retail electricity tariffs for all customers were found to increase approximately 0.1-0.3% relative to baseline conditions for Net Billing sell rates of 1.0-3.0 THB/kWh.

2. In the 'High Impact' scenario, modeled to serve as an upper bound for the potential impacts of DPV and where 3,000 MW of DPV is deployed by 2020 under Net Energy Metering, average retail electricity tariffs increase by approximately 3 satang/kWh (or 0.8%) relative to baseline conditions. To provide a point of comparison, the median change in the F_t (an automatic rate adjustment mechanism that regularly fluctuates due to changing fuel costs) was 7.98 satang/kWh at each step from 2007-2017.

3. DPV deployment has a *net* impact on rates depending on the scenario considered, with each scenario having a distinct set of costs and benefits. The way in which DPV customers are compensated for grid injections matters significantly in quantifying retail electricity tariff impacts. For instance, if DPV customers are compensated for injected electricity at a sell rate below what MEA and PEA purchase wholesale electricity for (i.e., EGAT's wholesale price), a short-term rate *decrease* can occur.

IMPLICATIONS FOR STAKEHOLDERS

MINISTRY OF ENERGY

1. This study demonstrates that policymakers can move forward with a DPV interconnection and compensation policy in Thailand without being deterred by concerns around utility revenues or retail tariff impacts.

2. The design of DPV policy can be viewed as a balancing act between (1) incentivizing customers to deploy DPV and (2) a desire to moderate the impacts on utilities and other ratepayers that do not invest in DPV.

3. Should concerns still exist, system-wide DPV deployment caps or retail tariff impact caps – relatively common policy tools – can be considered at the national level.

OFFICE OF THE ENERGY REGULATORY COMMISSION

1. OERC can ensure the financial health of the utilities by maintaining their current interpretation of the rules, which allow for under-collection of revenue in previous rate cases to be recovered in subsequent rate cases.

2. OERC can support the creation of a national DPV registration and data collection system, which can be used to validate lost revenue claims and formulate improved estimates of DPV deployment for future rate cases.

METROPOLITAN AND PROVINCIAL ELECTRICITY AUTHORITIES OF THAILAND

1. MEA and PEA can collaborate with OERC to design a national DPV registration and data collection system.

2. Technical requirements for DPV metering and billing infrastructure can be proactively designed by MEA and PEA to enable data collection to occur.

3. MEA and PEA can begin building internal capacity to perform circuit-level DPV technical impact and planning studies.

4. MEA and PEA can begin carefully tracking DPV program administration and interconnection costs.

ELECTRICITY GENERATING AUTHORITY OF THAILAND

1. EGAT can begin studying the expected financial impact of DPV deployment on its ability to recover costs, as well as wholesale electricity costs.

2. EGAT can increase the number of time windows in its wholesale electricity pricing scheme to mitigate DPV financial impacts.

3. EGAT, in collaboration with MEA and PEA, can begin formulating a data collection scheme to increase the visibility and controllability of DPV systems on the Thai power system.

1. INTRODUCTION

Thailand is proceeding with a plan to announce a national interconnection and compensation scheme for distributed PV (DPV)[4]. In 2016, the Thai government launched a Rooftop Solar Pilot Project, enabling electricity users in various market segments to produce their own electricity using DPV systems. Under the Rooftop Solar Pilot Project, any DPV electricity generated in excess of customer consumption would flow back to the grid without compensation. The government is currently considering a compensation scheme for injected electricity in the next phase of a national program.

It has been well documented throughout the literature that the deployment of DPV can fundamentally alter (and in many cases, challenge) how utilities create revenue (see e.g., RMI 2013, Barbose et al., 2016; Synapse, 2016). Under some circumstances, DPV adoption can lead to reduced utility electricity sales and revenue and/or higher retail electricity tariffs (sometimes referred to as "retail tariffs" or "tariffs") for non-adopting customers. If utilities are unable to recover their fixed costs to operate the power system from DPV customers, either the utilities themselves or those who do not adopt solar may be left covering the bill. These concerns have prompted policymakers, regulators, and electric power utilities in many jurisdictions around the world to investigate the potential impacts of DPV on utility revenues and customer tariffs.

With the increasing momentum for DPV market expansion in Thailand, and in the context of a forthcoming national program, Thai distribution utilities have expressed concerns on the potential decline in their revenues and the potential increase in customer tariffs. In late 2016, when policymakers in Thailand began to develop the next phase of a DPV support program, concerns of utilities' revenue losses and customers' tariffs appeared to be a key deterrent to a timely policy launch.

To develop an evidence-based investigation into these issues, Thailand's Office of Energy Regulatory Commission (OERC) sought assistance from USAID Clean Power Asia to help increase the understanding on how DPV might impact utility revenue and customer tariffs. USAID Clean Power Asia collaborated with Chulalongkorn University's Energy Research Institute research team, with the assistance of the U.S. National Renewable Energy Laboratory (NREL) and Lawrence Berkeley National Laboratory (LBNL), to analyze the financial impact of various DPV deployment scenarios and compensation mechanisms for distribution utilities in Thailand. The analysis was based on extensive consultation with the key institutional stakeholders, listed below in Table 4.

[4] We define DPV as a smaller scale photovoltaic electricity production system which is located "behind" a customer's electricity meter, in locations such as the rooftops or on the surrounding land of homes, buildings, or factories.

Table 4: List of key study institutional stakeholders

Institution	Description
Metropolitan Electricity Authority of Thailand (MEA)	State-owned Thai distribution utility serving 3.6M retail customers in the Bangkok metropolitan area (MEA, 2016)
Provincial Electricity Authority of Thailand (PEA)	State-owned Thai distribution utility serving over 18.8M retail customers throughout the remainder of Thailand (PEA, 2016)
Office of the Energy Regulatory Commission (OERC) of Thailand	Central government agency responsible for the regulation of the energy sector in Thailand (including MEA and PEA)
Department of Alternative Energy Development and Efficiency (DEDE)	Central government department responsible for the formulation of Thailand's DPV public policy
Electricity Generating Authority of Thailand (EGAT)	State-owned transmission and generation utility that owns 38% of generation capacity and sells wholesale electricity to MEA and PEA.[5]

The engagement of such a broad range of institutional stakeholders allowed for consensus-building on which research questions should be considered, and which methodologies should be used to answer these questions. Ultimately, the analysis team was able to perform a holistic assessment of both the costs (e.g., foregone sales revenue) and benefits (e.g., avoided wholesale power costs) of DPV implementation for the distribution utilities in Thailand, seeking feedback and verifying assumptions from stakeholders throughout the process. The analysis was also framed around the feedback received during a February 2017 DPV stakeholder workshop in Bangkok, which focused on utility tariff and revenue impact issues. Following this workshop, the circulation of a study Terms of Reference document elicited feedback that helped build realistic scenarios and garner buy-in from key institutions.

Section 2 discusses the study's *qualitative* findings related to the regulation of the power sector in Thailand, and how the deployment of DPV would financially impact distribution utilities and ratepayers under existing ratemaking regulations. **Section 3** describes the key assumptions and methods for a *quantitative* analysis that examines the expected impact of 3,000 MW of DPV deployment in Thailand by the year 2020. **Section 4** presents key results across scenarios from the quantitative analysis. **Section 5** describes the implications of the analysis for various stakeholder institutions in Thailand.

Through meetings with the relevant stakeholders and drafting and circulating a Policy Brief[6], the results of this analysis have been formally contributed as inputs to the design of the forthcoming national DPV interconnection and compensation scheme for Thailand, scheduled for launch in late 2017.

[5] As of August 2017 from: https://www.egat.co.th/en/index.php?option=com_content&view=article&id=80&Itemid=116. While this analysis focused on quantifying DPV deployment impacts on the Thai distribution utilities, EGAT's inputs proved critical to understanding certain aspects of the Thai regulatory paradigm.

[6] The Policy Brief is a publication produced under the USAID Clean Power Asia program, which can be found at http://usaidcleanpowerasia.aseanenergy.org.

2. QUALITATIVE ANALYSIS

The research and analysis process began with a series of in-depth stakeholder interviews aiming to uncover:

(1) the power sector regulatory structure and detailed ratemaking procedures and considerations in Thailand;
(2) whether and how the deployment of DPV would be accounted for in this ratemaking process in practice; and
(3) how the deployment of DPV would financially impact distribution utilities and ratepayers under existing ratemaking regulations in Thailand.

This section summarizes the learnings from that effort, and serves as a preamble to the quantitative analysis presented in Section 3.

2.1 SUMMARY OF UTILITY COST RECOVERY AND RETAIL RATEMAKING IN THAILAND

Retail electricity tariffs in Thailand are calculated as a function of all the costs associated with electricity supply and delivery, plus a reasonable rate of return for the regulated utilities. Equations 1 and 2 show a simplified calculation of average retail tariffs, without any consideration of DPV deployment.

$$T_{avg} = T_B + F_t = \frac{\mathrm{RR}}{\mathrm{ES}} + F_t \qquad \text{(Equation 1)}$$

$$RR = (RAB * (1 + r)) + OPEX + D + T + BFC \qquad \text{(Equation 2)}$$

T_{avg} [THB/kWh] = average tariff
T_B [THB/kWh] = base tariff
RR [THB] = utility revenue requirement for rate period
ES [kWh] = expected sales during rate period
F_t [THB/kWh] = automatic rate adjustment mechanism revisited every 4 months; corrects initial estimates of fuel costs, power purchase costs from IPPs, and other policy-driven expenditures
RAB [THB] = regulatory asset base (also known as: "rate base") which includes capital expenditures for rate period
r [%] = regulated rate of return, which is a return on invested capital typically no more than the utility's weighted average cost of capital
D [THB] = asset depreciation expense over rate period
OPEX [THB] = allowed operating expenses over rate period
T [THB] = tax expense over rate period not counted as OPEX
BFC [THB] = Base variable costs, including fuel costs, power purchase costs from IPPs, and other policy-driven expenditures over rate period

The base tariff, the primary component of retail tariffs, is calculated in each rate case, which occurs every 3-5 years. This base tariff is calculated from the revenue requirement divided by the expected sales in the rate period, as shown in Equation 1. The revenue requirement consists of all the capital expenditures that are expected to be incurred by the utilities during the rate period, including operating expenses, a base variable cost component, and a return on investment as a percentage of the capital expenditures, as shown in Equation 2. After the base tariff is approved by the OERC and before the next rate case, any divergence from the estimated variable costs including fuel costs or power purchase costs is addressed through an automatic adjustment mechanism called the "F_t", which is adjusted every 4 months. It is important to note that ratemaking in Thailand is forward-looking, as retail tariffs are based on an expectation of future sales and expenditures over the rate period – this will have important implications for how DPV deployment is addressed in the ratemaking process.

***Key Point**: Ratemaking in Thailand is forward-looking, with retail tariffs being based on an expectation of future sales and expenditures over the rate period – this will have important implications for how DPV deployment is addressed in the ratemaking process.*

2.2 THE IMPACT ON REVENUE AND RATES OF DISTRIBUTED PHOTOVOLTAICS

Equation 3 shows how an average retail tariff would be calculated in Thailand, while accounting for DPV deployment. The equation was developed collaboratively on February 17, 2017 during a meeting with staff from multiple MEA departments, augmented during a meeting with OERC, and thereafter corroborated with the PEA staff. The relationships in the equation describe how average tariffs would be impacted by an increment of DPV deployment.

$$T_{avg} = \frac{RR_0 - DI_B + DI_C + AC - DL - AP_{SC}}{ES_0 - SC} + \left(F_{t,0} + \frac{C_{inj} - AP_{inj}}{ES_0 - SC}\right) \quad \text{(Equation 3)}$$

T_{avg} [THB/kWh] = average tariff
RR_0 [THB] = utility revenue requirement without DPV
DI_B [THB] = deferred or avoided new investment in distribution network due to DPV deployment
DI_C [THB] = required new investment in distribution network to integrate DPV
AC [THB] = administrative costs for DPV program
DL [THB] = avoided distribution losses
AP_{SC} [THB] = avoided EGAT purchases due to self-consumption
ES_0 [kWh] = expected sales without DPV
SC [kWh] = expected self-consumption (kWh)
$F_{t,0}$ [THB/kWh] = F_t without distributed photovoltaics
C_{inj} [THB] = Cost of purchased DPV grid injections
AP_{inj} [THB] = avoided EGAT purchases due to DPV grid injections

When DPV is taken into account in the tariff calculation, the revenue requirement must be adjusted by accounting for new costs and benefits associated with the expected increase in DPV deployment. The costs include additional distribution investment (if needed), administrative costs associated with the DPV program (typically quite small), and the cost of purchasing DPV electricity that the system injects into the grid (provided the utilities are required to purchase it). The benefits include avoided distribution losses and avoided EGAT purchases.

The qualitative analysis found that it was quite critical to methodologically distinguish between short-term and medium-term impacts. **Short-term impacts** are defined as those that occur in the period *before* the next rate case. During this period, the PEA and MEA may have to temporarily shoulder certain revenue losses, or experience changes to the F_t. **Medium-term** impacts are defined as those that occur *after* the next rate case.

This finding on how DPV deployment is accounted for is foundational for the quantitative analysis, and reveals important mechanisms of ratemaking and utility cost recovery paradigms that make Thailand quite unique. In the short-term, the costs of purchasing DPV exports (C_{inj}) are fully passed through to the rates through the F_t mechanism; however, the costs that are ultimately passed through to ratepayers are a *net* cost, as the distribution utility also avoids EGAT purchases (AP_{inj}) when DPV electricity is injected into the grid. Reductions in sales due to self-consumption (SC), however, will show up as a revenue loss to the utility in the short-term, less the avoided cost of EGAT purchases associated with DPV self-consumption (AP_{sc}).

In the medium-term, we found that all of the costs and benefits associated with DPV can be incorporated into the rates, including rectifying past reductions in sales. If a revenue loss occurs in the short-term due to a reduction in sales, Thai distribution utilities can request a "true-up" in the next rate case[7]. This temporary revenue loss can then be recovered through tariffs, such that there is no net revenue loss to the utilities in the medium- to long-term.

***Key Point**: Thailand's ratemaking process enables 100% of additional costs and benefits associated with DPV to be recovered through customer tariffs. Any changes to the cost of service due to DPV deployment (whether ultimately positive or negative) are passed through to customers via tariffs.*

Furthermore, we have found that due to Thailand's forward-looking ratemaking process, it is possible to take into account the impact of DPV on the utility system *in advance*, and calculate customer tariffs based on this expected increase. In order to ensure full recovery of revenue requirements in the following rate case period, estimates of both expected DPV self-consumption and expected grid injections can be forecasted and included in the calculation of future tariffs. Thus, Thailand's ratemaking process enables all additional costs and benefits associated with DPV to be recovered through customer tariffs; with proper forecasting, distribution utilities will continue to recover all of their costs in the medium- or long-term. This regulatory design protects distribution utilities from the potential financial impacts of DPV.

***Key Point**: Due to Thailand's forward-looking ratemaking process, it is possible for distribution utilities to take into account the impact of DPV on their networks in advance, and calculate customer tariffs based on expectations of increased deployment.*

[7] Similarly, if a utility over-estimates their sales reduction, they must decrease their rates in the next rate case to account for the over-recovery of their costs.

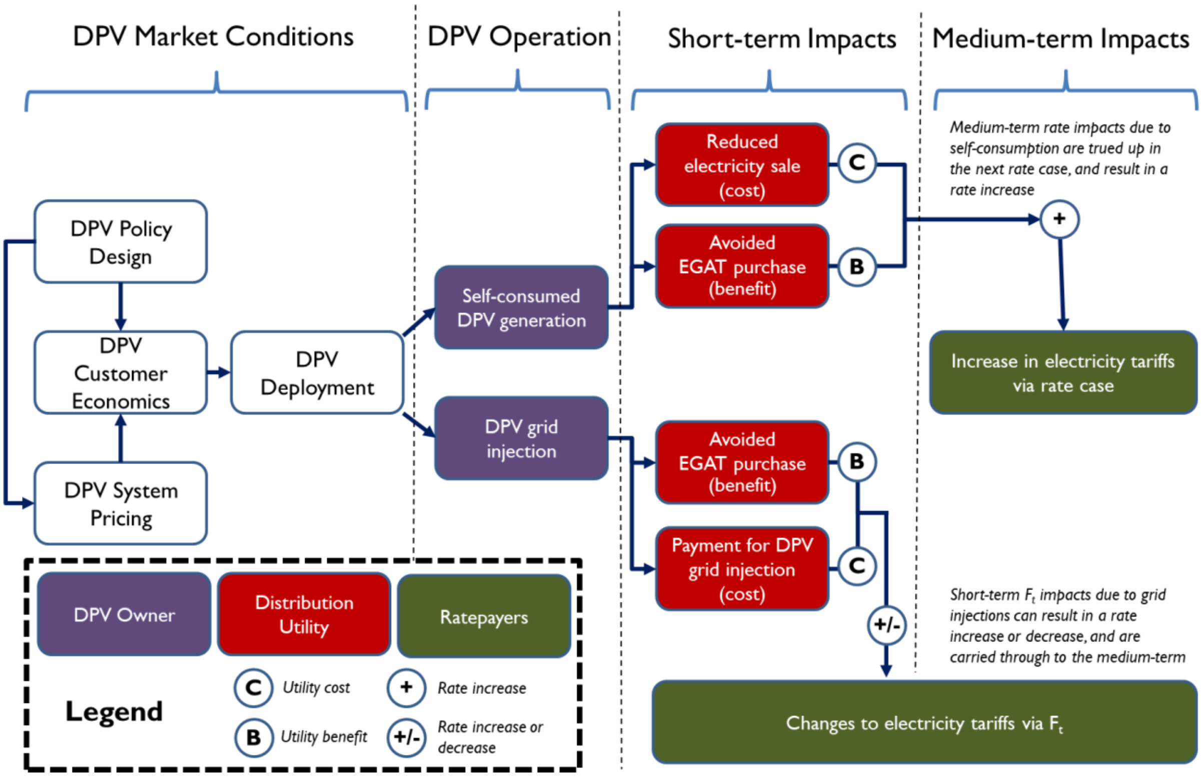


Figure 2: Framework for understanding the revenue and tariff impacts of DPV deployment in Thailand

The impact of DPV on utilities' revenue and rates is illustrated in Figure 2. In practice, DPV electricity can either be (1) utilized on-site as self-consumed DPV generation or (2) injected back into the grid. DPV systems help offset the electricity that the DPV customer must otherwise purchase from the grid.

Following the purple '*Self-consumed DPV generation*' box, we know that each unit of self-consumed DPV electricity results in one less unit of electricity sold to the DPV customers at the applicable retail tariff. At the same time, fewer units sold also leads to fewer units of wholesale electricity purchased from EGAT (adjusted for avoided line losses, as well[8]). Therefore, from the utility standpoint, self-consumption of DPV leads to a *net* negative revenue impact as the retail electricity tariff is always higher than the EGAT wholesale electricity purchase price. Note that this net impact occurs in the *short-term*, i.e., before the next rate case. In the medium-term, the net impact due to self-consumed DPV generation would translate to changes in retail electricity tariffs. In order to recover their allowed costs with the lower electricity sales, utilities would need to increase retail electricity tariffs, as signified by the plus (+) sign in Figure 2.

[8] By generating electricity at the end-use location, losses associated with transporting the electricity over the transmission and distribution networks are avoided (in addition to the avoided costs of generation). Note that the point-of-sale for EGAT's wholesale electricity is at interconnections between the transmission and distribution networks; thus, from the standpoint of the distribution utility, only avoided distribution network losses accrue.

__Key Point__: Self-consumption of DPV electricity leads to a negative net revenue impact for the utility before the next rate case, comprising a lost kWh sale at the applicable retail rate [cost] less an avoided purchase of a wholesale kWh from EGAT [benefit]. Under the current regulatory paradigm, this revenue impact is ultimately recovered in the next rate case via a "true-up." Thus, this temporary short-term revenue loss due to self-consumption can be recovered through tariffs, such that there is no net revenue loss to the utilities in the medium-term.

Following the purple '*DPV grid injection*' box, when a DPV system generates in excess of the customer's instantaneous consumption, DPV electricity is injected into the grid. The distribution utility receives this DPV electricity and re-distributes it to other retail customers at the applicable retail tariff. This results in the benefit of an avoided EGAT purchase, but also a cost for compensating the customer for their injected DPV electricity at the specified sell rate, if applicable. The value of injected DPV electricity, and how it impacts the distribution utility's revenues and tariffs, depends largely on the design of the DPV compensation scheme for injected electricity. As the Government of Thailand expressed a strong interest in DPV compensation schemes where customers can self-consume DPV electricity, this analysis explores the impact of Net Energy Metering (NEM), Net Billing, and Self-Consumption Only (SCO) schemes, which are briefly defined (as they relate to this analysis) below[9].

Net Energy Metering: In NEM compensation schemes, injected electricity is used to offset future electricity consumption both within and between billing cycles through the granting of kWh credits. From the customer standpoint, NEM treats injected electricity identically to self-consumed electricity, providing a financial credit at the full variable retail tariff. Because MEA/PEA would grant kWh credits for injected electricity rather than a cash payment, there would be no change to the F_t under a NEM scheme. Rather, all DPV electricity, whether self-consumed or injected into the grid, results in a reduced sale (cost) and avoided EGAT purchase (benefit). Since the retail tariff is always higher than the rate at which MEA/PEA will purchase wholesale power from EGAT, NEM will result in a cost increase being passed through to ratepayers.

Net Billing: In a net billing compensation scheme, all injected DPV electricity is credited to the customer at a pre-determined rate; there are no kWh credits granted to offset future consumption, as occurs under NEM. In Thailand, the cost difference (if any) between EGAT wholesale electricity and the DPV sell rate would be recovered through the F_t. Thus, under a net billing scheme, injected electricity has no impact on distribution utility revenues, and will only have an impact on the tariff through short-term changes to the F_t. If the compensation level for injected electricity is higher than the EGAT wholesale electricity price, then retail tariffs will rise via the F_t. If the compensation level is lower than EGAT's wholesale price, then those cost savings would also be passed through to ratepayers, resulting in a tariff decrease.

[9] For more complete definitions of Net Energy Metering and Net Billing schemes, please see Zinaman et al. (2017).

Self-Consumption Only: Under an SCO scheme, all injected DPV electricity is uncompensated (i.e., delivered to the utility free of charge), to be redistributed and sold at the applicable retail electricity tariff. The customer is allowed to self-consume electricity, which results in both a lost sales and avoided EGAT purchased for the utility, similar to the other schemes. If DPV electricity is injected into the grid, there will be no change to the F_t, as no utility expenditure is being made for the kWh. Rather, because the DPV kWh has no cost to the utility, this will result in the full utility benefit of an avoided EGAT purchase.

The financial impact of the three DPV compensation schemes on distribution utilities is summarized in Table 5.

Table 5: DPV impacts for three compensation schemes for self-consumed and injected DPV electricity

How is a DPV kWh utilized?	DPV compensation scheme	Net impact, medium-term	Net impact, short-term	Gross utility cost	Gross utility benefit
If DPV electricity is self-consumed	Net Energy Metering	Net revenue loss passed through in rate case to increase tariffs	Utility net revenue loss	Lost utility kWh sale	Avoided EGAT wholesale purchase
	Net Billing				
	Self-Consumption Only				
If DPV electricity is injected into grid	Net Energy Metering	Net revenue loss passed through in rate case to increase tariffs	Utility net revenue loss	Lost utility kWh sale	
	Net Billing	Passed through F_t Utility revenue not impacted Tariffs can increase or decrease Adjustments occur every 4 months		DPV injection sell rate	
	Self-Consumption Only	Passed through F_t Utility revenue not impacted Tariffs decrease Adjustments occur every 4 months		Utility does not pay for DPV injection	

Tariff Decrease　Tariff Increase　Tariff Change

__Key Point__: The costs associated with purchasing injected DPV electricity, regardless of the DPV sell rate, will have no impact on distribution utility revenues; rather, those costs are recovered through the F_t mechanism, with 100% of incremental costs or benefits being passed through to ratepayers. The difference in cost between utility purchases of bulk electricity (i.e., the EGAT wholesale electricity price) and the sell rate for DPV injections will impact the F_t in the short-term. If the compensation level for injected electricity is higher than the EGAT wholesale electricity price, then retail tariffs will rise via the F_t. If the compensation level is lower, then those cost savings would also be passed through to ratepayers, resulting in a tariff decrease.

3. QUANTITATIVE ANALYSIS – METHODS AND ASSUMPTIONS

The following methodology was developed by the analysis team and validated by stakeholders during their review of the Terms of Reference. Financial impacts from DPV deployment are examined for MEA and PEA independently, in order to understand the distinct revenue and tariff impacts of DPV deployment on each distribution utility.

Short-Term Impacts

Impact 1 – Net impact on utility revenue associated with self-consumption of DPV before the next rate case. Consistent with current practice, we assume that DPV deployment was not accounted for in the previous rate case, and thus PEA/MEA must temporarily absorb the net loss in revenue caused by current DPV deployment. An estimate of expected self-consumed DPV generation is the basis of this impact calculation. It is formulated by assuming a distinct mix of DPV customer types, each with distinct tariff structures, electricity consumption patterns, and geographic locations within Thailand.

Impact 2 – Net impact on retail tariffs through changes to the F_t caused by purchases of DPV grid injections before the next rate case. The F_t mechanism will change before the next rate case, depending on the amount of injected DPV electricity and the purchase price for that electricity. An estimate of expected grid injections of DPV generation is the basis of this impact calculation – the calculations performed to estimate self-consumed DPV generation for Impact 1 also yield estimates of injections of DPV electricity into the grid for that same mix of customers.

Medium-Term Impacts

Impact 3 – Net impact of DPV deployment on retail electricity tariffs after the next rate case due to the DPV deployment present in 2020. Revenue losses occurring in the short-term are trued up in the next rate case, and rates are also adjusted to ensure that this DPV deployment is accounted for moving forward.

Through an extensive series of in-person meetings with stakeholder institutions, as well as a technical workshop held in Bangkok in February 2017, the analysis team developed a framework of scenarios to explore which will be described in this section. Sections 3.1 – 3.6 detail the analytical approach and key modeling assumptions that apply to all scenarios. Section 3.7 describes the parameters of the five modeled scenarios in the quantitative analysis.

3.1 MODELED COSTS AND BENEFITS

In Section 2.2, Equation 3 describes the financial impact of DPV on retail tariffs in Thailand, considering a range of DPV costs and benefits. Table 6Table 6 lists which specific costs and benefits are considered or omitted in the quantitative analysis across scenarios.

Table 6: DPV costs and benefits included/omitted in quantitative analysis

	Costs	Benefits
Included	**SC** x $\mathbf{T_{avg}}$ = Utility revenue loss due to self-consumption (calculated as self-consumed DPV generation multiplied by the average retail tariff for the applicable rate period) $\mathbf{C_{inj}}$ [THB] = Cost of purchased DPV grid injections	$\mathbf{AP_{SC}}$ [THB] = avoided EGAT purchases due to self-consumption $\mathbf{AP_{inj}}$ [THB] = avoided EGAT purchases due to DPV grid injections
Omitted	$\mathbf{DI_C}$ = required new investment in distribution network to integrate DPV **AC** = administrative costs for DPV program	$\mathbf{DI_B}$ [THB] = deferred or avoided new investment in distribution network due to DPV deployment **DL** [THB] = avoided distribution losses

Because the scope of this analysis is focused on the short- to medium-term impact of DPV deployment, the variables that are excluded from the analysis include deferred or avoided new investment in the distribution network (DI_B), new investment in the distribution network to integrate DPV (DI_C), and avoided distribution losses (DL)[10]. It is expected that these variables do not change significantly with the amount of DPV deployment modeled in this analysis. Utility costs for administrating a DPV program (AC) tend to be quite small in scale relative to the other costs and benefits; due to this fact, in combination with an inability of the analysis team to obtain a credible administrative cost estimate for Thai utilities, has resulted in that cost being omitted from consideration in the study.

Costs and benefits associated with higher penetrations of solar deployment on the Thai power system are not considered in this analysis, given that 3,000 MW represents approximately 2.5% of expected sales in 2020. One key benefit not considered was a reduction in system-wide generation costs due to solar – in practice, this might manifest as an overall reduction in EGAT's wholesale electricity prices[11]. One key cost that can potentially be introduced at higher penetration levels is

[10] The avoided distribution losses occur both due to the generation being at the point-of-use and due to the slight increase in voltage resulting from PV generation which reduces line losses generally. Both of these effects are small, particularly for customers near the transmission point of sales and, for the voltage boosting, due to the fact that DPV penetration levels on individual distribution feeders are not expected to be high enough to result in measurable increases in voltage.
[11] Reductions in wholesale market prices resulting from increasing penetrations of near-zero variable cost renewables are becoming commonplace in many jurisdictions around the world. See Hirth (2013) for a review of declining wholesale prices from solar, reducing solar's market value.

changes to conventional generation operation due to solar. For a comprehensive list of system-level costs and benefits of DPV to utilities, see Denholm et al. (2014).

3.2 DISTRIBUTED PHOTOVOLTAIC DEPLOYMENT ASSUMPTIONS

Through an extensive consultation with stakeholder institutions, the analysis team chose to model a quantity of 3,000 MW of DPV deployment by the year 2020. This level of deployment represents 50% of DEDE's 2036 national solar PV target in the Alternative Energy Development Plan and is approximately the remaining target to be achieved under this plan. An amount of 3,000 MW of DPV by 2020 corresponds to DPV generation equal to approximately 2.5% of projected electricity sales in Thailand in that year – a relatively ambitious target given that today's DPV penetration is near zero. This quantity was intentionally selected to provide analysis insights that might bound utility concerns.

DPV impacts are examined separately for MEA and PEA in this analysis. We assume that DPV deployment occurs in each service territory proportionally to each distribution utility's 2016 retail sales. This results in approximately 851 MW of DPV deployment on MEA's distribution network, and 2,149 MW on PEA's distribution network.

Distinct solar resource data are utilized for each geographic location where a customer is modeled. This impacts how much energy the DPV system generates, as well as the timing of that generation throughout each day. That in turn impacts the mix of DPV self-consumption versus DPV grid injections for the customer. MEA serves the Bangkok metropolitan area, and thus all DPV deployment on the MEA system is assumed to occur in this area. PEA serves all Thai retail customers outside Bangkok metropolitan area. An equal spread of DPV deployment is assumed across four geographic regions (Northern, Northeastern, Central and Southern).

Key assumptions from this section are summarized in Table 7.

Table 7: DPV deployment assumptions

Assumption	Description
Total DPV Deployment Level and Timeframe	3,000 MW by 2020
DPV Deployment by Utility	Metropolitan Electricity Authority: 851 MW Provincial Electricity Authority: 2,149 MW
Geographic Distribution of DPV Deployment	Metropolitan Electricity Authority: Bangkok Provincial Electricity Authority: Equal spread of deployment across four regions of Thailand

3.2 DISTRIBUTED PHOTOVOLTAIC CUSTOMER ASSUMPTIONS AND MODELING TOOL

To model utility revenue impacts from DPV, we make a number of assumptions about DPV systems and customer characteristics which allow us to simulate individual customer bill savings and payments for electricity injected into the grid. These customer bill savings are then aggregated by tariff class to the utility level.

We model the deployment of DPV on the following retail customer tariff classes[12]:

- Residential (RES) – Though there are two residential customer tariff classes, we only model the larger residential customers in Thailand who consume more than 150 kWh per month. Customers who consume less than 150 kWh per month have a low, cross-subsidized rate which makes solar less financially attractive under the three compensation schemes considered.

- Small General Service (SGS) – Commercial, industrial, or government customers whose peak demand is less than 30 kW. We model tariffs applicable to customers connected to <12 kV lines for MEA and <22 kV for PEA.

- Medium General Service (MGS) – Commercial, industrial, or government customers whose peak demand is between 30-1000 kW and have an average energy consumption of less than 250,000 kWh per month. We model tariffs applicable to customers connected to 12-24 kV lines for MEA and 22-33 kV lines for PEA.

- Large General Service (LGS) – Commercial, industrial, or government customers whose peak demands exceeds 1000 kW, and/or an average energy consumption of over 250,000 kWh per month. We model tariffs applicable to customers connected to >69 kV lines for both MEA and PEA.

For each tariff class, the behavior of an "average" DPV customer is modeled on an hourly basis for a full year, intended to serve as a scalable agent exhibiting representative characteristics for the customer class. Simulation results for all customer tariff classes are then scaled upward to a desired mix of customers for a particular service territory, forming the underlying DPV deployment and generation behavior underpinning the revenue and rate impact analysis.

The NREL System Advisor Model (SAM) is used to simulate bill savings – or reduced utility revenues – for individual customer classes for PEA and MEA[13]. Using representative hourly load profiles for each customer class provided by MEA and PEA, solar generation profiles by location, as well as current

[12] While there are several other retail tariff classes in Thailand, customers with these particular tariffs made up approximately 93% of retail sales in 2016, and are thus the focus of this analysis.
[13] For more information on the NREL SAM model, see: http://sam.nrel.gov

tariff structures for each utility, customer bills with and without DPV are simulated in order to calculate the average cost paid by the utility for self-consumed electricity under each tariff type.

In total, eight average DPV customer load profiles are explicitly modeled in this analysis (for each customer class for each utility) and 56 DPV generation profiles are modeled, resulting in bill calculations for four hundred and 48 modeled DPV customers.

Table 8: Description of modeled DPV customers

Distribution Utility	Total Number of Modeled DPV Customers	Tariff Classes	Distinct Locations
MEA	8	8 *RES*: Block rate / Time-of-use rate *SGS*: Block rate / Time-of-use rate MGS: Regular rate / Time-of-use rate LGS: Time-of-day rate / Time-of-use rate	1 Bangkok
PEA	440		55 cities in 4 regions Northern, Northeastern, Central, and Southern

3.2.1 CUSTOMER CHARACTERISTICS

In order to calculate reductions in utility revenues for MEA and PEA from DPV deployment, we simulate individual customer bills both with and without DPV generation for various customer tariff classes.

We use representative customer load data for Residential (>150 kWh/month), Small General Service, Medium General Service, and Large General Service customers, as described above, available on MEA's and PEA's website.[14] The data set utilized contains hourly consumption patterns for a representative weekday, weekend day, holiday, and peak day for each month for each tariff class; this was then aggregated into a single 8760-hour load profile for each of the four customer classes modeled for each utility.

As DPV system size and customer load determine the amount of DPV injected to the grid, we make a number of assumptions on the DPV-to-load ratio (the ratio of annual DPV generation to annual customer load). The larger the ratio, the more electricity is injected into the grid (and thereafter compensated at the injection sell rate, when applicable). For all modeling scenarios, we assume that RES and SGS DPV systems generate 80% of annual customer load (i.e., an 80% DPV-to-load ratio), whereas medium and large general service DPV systems generate 50% of annual customer load (i.e. 50% DPV-to-load ratio). Customers typically aim to reduce their customer bills with DPV, but larger customers tend to be limited by available roof space. These ratios were selected based on typical

[14] For MEA load data, see: http://www.mea.or.th/e-magazine/2786
For PEA load data, see: http://peaoc.pea.co.th/loadprofile/

DPV system sizing trends, and were validated by stakeholders in Thailand during workshops and via a formal review process. The resulting average sizes, in kW terms, for each customer class for each utility are shown in Table 9.

For those customers subject to inclining block energy tariffs, higher consumption customers benefit the most from DPV generation, as DPV displaces the more expensive segments of consumption. Hence, higher consumption customers under inclining block rates tend to adopt DPV, as these have the highest bill savings. In this analysis, we assume that the modeled residential and SGS DPV customers uses twice as much electricity as the mean customer in that tariff class. We assume that the modeled DPV customer loads for MGS and SGS customers are equal to the mean load for the corresponding tariff class. The average annual load for the mean customer by tariff class is shown in Table 9; MEA customers tend to have higher annual electricity consumption than PEA customers, particularly for RES, SGS, and MGS customers.

For each tariff class, there are two types of tariffs available, generally classified as time-invariant and time-of-use. The RES and SGS customers can either choose a time-invariant tariff with inclining block energy charges and a fixed charge, or a time-of-use tariff with peak and off-peak energy charges and a fixed charge. We assume that 75% of RES DPV customers are under the time-invariant tariff, and 25% are under the time-of-use tariff. For SGS customers, we assume that DPV customers are split evenly between time-invariant and time-of-use tariffs.

MGS customers have the option of either a time-invariant energy tariff (which consists of a time-invariant energy charge, a demand charge, and a fixed charge) or a time-of-use energy tariff (which consists of a peak and off-peak energy charge, a peak period demand charge, and a fixed charge). LGS customers can choose from either a time-of-use demand tariff (which consists of a time-invariant energy charge, a peak/partial peak period demand charge, and a fixed charge) or a time-of-use energy charge (which consists of a peak and off-peak energy charge, a peak period demand charge, and a fixed charge). Generally, demand charges are higher for customers connected to higher voltage lines. For both MGS and LGS DPV customers, we assume that 75% are on the time-of-use rate.

All percentage breakdowns between time-invariant and time-of-use tariffs are typical for each customer class; these assumptions were validated by Thai stakeholders during workshops and formal review processes. Tariff structures and levels for MEA and PEA can be downloaded from their respective websites[15].

Key assumptions from this section are summarized in Table 9.

[15] For MEA retail electricity tariffs, see: http://www.mea.or.th/en/profile/109/111
For PEA retail electricity tariffs, see: https://www.pea.co.th/webapplications/CheckRate/checkrate.html

Table 9: DPV customer assumptions for all modeled tariff classes

	MEA		PEA		System Design	Tariff Design	
	Annual Consumption of modeled DPV Customer [kWh/year]	Modeled DPV System Size [kW]	Annual Consumption of modeled DPV Customer [kWh/year]	Modeled DPV System Size [kW]	PV:load Ratio	Time-Invariant [% Customers]	Time-of-Use [% Customers]
Residential (>150 kWh / month)	10,780	6.4	6,766	4.3	80%	75%	25%
Small General Service	16,807	10.0	7,774	4.9	80%	50%	50%
Medium General Service	468,089	173.0	279,460	110.0	50%	25%	75%
Large General Service	9,270,085	2,060.0	8,446,735	1,994.0	50%	25%	75%

3.3.1 SOLAR RESOURCE DATA

The other basic element needed to simulate customer bill savings, other than customer load, is solar generation profiles, for which solar resource data is needed. We simulated hourly DPV generation profiles for each location considered (Bangkok for MEA, and 55 cities in four regions of Thailand for PEA), using representative hourly solar insolation data from typical meteorological year (TMY) weather data purchased from White Box Technologies.[16]

Solar resource data set for Bangkok was used for all MEA analysis. The list of cities for which the solar resource data set was used in the PEA analysis is found below in Table 10.

Table 10: Cities with distinct solar resource modeled for PEA quantitative analysis

Region	Cities
Northern Region	Uttaradit, Tak, Mae Sot, Prae, Pitsanulok, Phetchabun, Phayao, Nan, Nakhon Sawan, Mae Sariang, Mae Hong Son, Lopburi, Lamphun, Lampang, Kampaengphet, Chiang Rai, Chiang Mai
Northeastern Region	Udon Thani, Ubon Ratchathani, Thatum, Surin, Sakon Kakhon, Roi Et, Nong Khai, Nakhon Ratchasima, Nakhon Phanom, Mukdahan, Loei, Khon Kaen, Chaiyaphum
Central Region	Aranyaprathet, Thongphaphum, Suphan Buri, Sattahip, Prachin Buri, Koh Sichang, Khlong Yai, Kanchanaburi, Chonburi, Chanthaburi

[16] See http://weather.whiteboxtechnologies.com/faq for more information on how the weather files were developed.

Southern Region	Trang, Surat Thani, Songkhla, Ranong, Prachuap Khirikhan, Phuket Ap, Phuket, Pattani, Narathiwat, Nakhon Si Thammarat, Koh Samui, Koh Lanta, Hua Hin, Hat Yai, Chumphon

3.4 AVOIDED COST ASSUMPTIONS AND METHODS

MEA and PEA purchase the majority of their electricity directly from EGAT at a regulated wholesale purchase price. We assume that all DPV generation, whether it is self-consumed or injected into the grid, ultimately offsets a purchase of wholesale electricity from EGAT. EGAT offers a "Peak" and "Off-Peak" purchase price for wholesale electricity[17].

Table 11: EGAT wholesale electricity purchase prices

EGAT Wholesale Electricity Purchase Price	Hours	Rate [THB/kWh]
Peak Hours	Mon-Fri: 09h00 – 22h00	3.1508 (MEA) 3.1042 (PEA)
Off-Peak Hours	Mon-Fri: 22h00 – 09h00 Sat-Sun*: 00h00 – 23h59	2.0902 (MEA) 2.0436 (PEA)

*Includes weekday public holidays

Because our simulation of DPV customers is performed on an hourly basis, this provides sufficient fidelity to accurately model distinct mixes of peak and off-peak purchases (and associated utility benefits) for each modeled DPV customer. Specifically, hourly schedules of DPV self-consumption and grid injections were mapped to the peak/off-peak schedule for each customer, generating an appropriate EGAT avoided cost.

3.5 2020 FORECASTING ASSUMPTIONS

Because this analysis quantifies the impact of DPV deployment in the year 2020, certain key assumptions were made to bridge the gap between what is known about the conditions of the Thai power system in 2017, versus what occurs in the interim between 2018 and 2020. These assumptions are listed in Table 12.

Table 12: Key 2020 forecasting assumptions

Forecasting Assumption, 2018-2020	Rate [% per year]
Annual projected load growth rate	3.75%
Annual EGAT wholesale electricity price increase	4.80%
Annual retail electricity tariffs increase	3.50%
Annual macroeconomic inflation rate	1.50%

[17] Note: EGAT wholesale peak and off-peak purchase periods are the same as the retail time-of-use tariff purchase periods offered to consumers.

We use these forecasting assumptions, in combination with 2016 total sales (in MWh and THB) to model the underlying revenues and rates in 2020, without DPV. From the MEA and PEA annual reports, total annual sales in 2016 are 51 million and 129 million MWh, respectively, corresponding to 187 billion and 455 billion THB of sales revenue, respectively. By estimating the total changes in net revenues resulting from DPV, including reduced purchase costs, reduced revenues from self-consumption, and the costs of exported electricity, we calculated the differences in revenue with the calculated 2020 sales numbers to determine the change in average rates in absolute and percentage terms.

3.6 DESCRIPTION OF MODELING SCENARIOS

Five scenarios were designed to help the analysis team understand the range of potential impacts that 3,000 MW of DPV deployment could have on Thai distribution utilities. The key differences between scenarios are:

- *DPV Compensation Scheme* – Specific rules defining how the distribution utility compensates the customer for injecting DPV generation into the grid
- *Customer Mix* – Proportion of each customer class' contributions to overall DPV deployment

Scenarios are summarized in Table 13 below, and described in more detail in Sections 3.6.1 – 3.6.3.

Table 13: Abbreviated description of five analysis scenarios

Scenario Name	DPV Compensation Scheme	Customer Mix
Base Scenario – 1 THB	Net Billing. DPV grid injections compensated at 1.0 THB/kWh sell rate	DPV installations proportional to total utility load by customer class
Base Scenario – 2 THB	Net Billing. DPV grid injections compensated at 2.0 THB/kWh sell rate	
Base Scenario – 3 THB	Net Billing. DPV grid injections compensated at 3.0 THB/kWh sell rate	
Low Impact	Self-consumption only. Customer does not receive compensation for DPV grid injections	
High Impact	Net Energy Metering. DPV grid injections credited at full variable retail electricity tariffs	DPV only installed in two rate classes with highest impact on utility revenue and rates

3.6.1 BASE SCENARIOS: 1, 2 & 3 THB

At the time this research was being conducted, the Thailand Ministry of Energy indicated that a national Net Billing DPV compensation scheme was under consideration. Thus, the base scenarios modeled in this analysis assume DPV customers are placed under a Net Billing scheme. However, because the exact sell rate for DPV grid injections has yet to be determined, we consider DPV sell rates of 1.0, 2.0 and 3.0 THB/kWh[18]. This aids in understanding the impact of sell rate level on utility revenues and rates, and was presented to the Ministry of Energy for their consideration.

[18] Note that the average retail rate in Thailand is currently higher than any of the proposed sell rates; considering the four tariff classes modeled in this study, and excluding the F_t, the average retail rate is approximately 3.62 THB/kWh in 2017.

For these scenarios, we assumed a DPV customer mix such that each customer class deploys an amount of DPV proportional to their class' contribution to their utility's overall electricity consumption, using 2016 as a base year. For example, in 2016, RES customers accounted for 25.3% of MEA's annual retail sales, and thus we assume that 25.3% of the DPV installed capacity in MEA's service territory would be installed by RES customers.

Philosophically, the Base Scenarios are intended to represent a reasonable, middle-of-the-road estimate of the expected impact to Thai distribution utilities and ratepayers of 3,000 MW of DPV deployment.

3.6.2 LOW IMPACT SCENARIO DESCRIPTION

In the Low Impact scenario, we assumed a DPV compensation scheme that would lead to a lower level of impacts to utilities and ratepayers. Specifically, we assume that DPV customers are put under an SCO compensation scheme, where all injected DPV electricity is uncompensated, and thus delivered to the distribution utility free of charge for re-sale. Otherwise, this scenario is identical to the Base Scenarios.

Philosophically, the Low Impact scenario is intended to represent a relative lower bound on the expected impact to Thai distribution utilities and ratepayers of 3,000 MW of DPV deployment.

3.6.3 HIGH IMPACT SCENARIO DESCRIPTION

In the High Impact scenario, we assumed a set of conditions that would lead to higher (and conceptually speaking, a relatively bounding) financial impact to Thai distribution utilities and ratepayers. Specifically, we assume that DPV customers are put under a Net Energy Metering scheme, which from a utility financial standpoint equates the cost of DPV self-consumption with the cost of a DPV grid injection.

Further, we assume that deployment is concentrated in the two customer classes with the highest impact on utility finances and rates when DPV is deployed. In this case, we estimate that the potential bill savings (on a percentage-of-bill basis) are on average highest for RES and SGS customers in Thailand, and thus we assume that DPV capacity is installed equally between both of these customer classes.

Philosophically, the High Impact scenario is intended to represent a relatively extreme (and perhaps unlikely) upper bound on the expected impact to Thai distribution utilities and ratepayers of 3,000 MW of DPV deployment.

4. QUANTITATIVE ANALYSIS RESULTS

This section of the report provides a summary of quantitative analysis results across the five scenarios, following the methodological approach presented in Section 3. Detailed numerical results are available in Annex B. Importantly, the magnitude of rate impacts are reported in Satang per kilowatt-hour, where 100 Satang is equal to 1 THB.

4.1 SUMMARY OF RESULTS

Looking across model scenarios, the quantitative analysis found that the impact of 3,000 MW of DPV deployment by the year 2020 on average electricity tariffs for PEA and MEA ranged from 0.06 satang/kWh to 1.14 satang/kWh in the Base scenarios, depending on the sell rate for injected electricity. The lowest impact on average tariffs was in the Low Impact scenario, with a decrease in rates of 0.48 satang/kWh for MEA and an increase of 0.01 satang/kWh for PEA. The High Impact scenario led to a 2.91 satang/kWh increase in rates for MEA and 2.92 satang/kWh for PEA. The average changes in tariffs for each scenario and utility are shown in Figure 3 and Table 14. To put this in perspective, the magnitude of the change in the F_t charge, mostly due to volatility in fuel costs, was on average 7.98 satang/kWh for each change between 2007 and 2017.

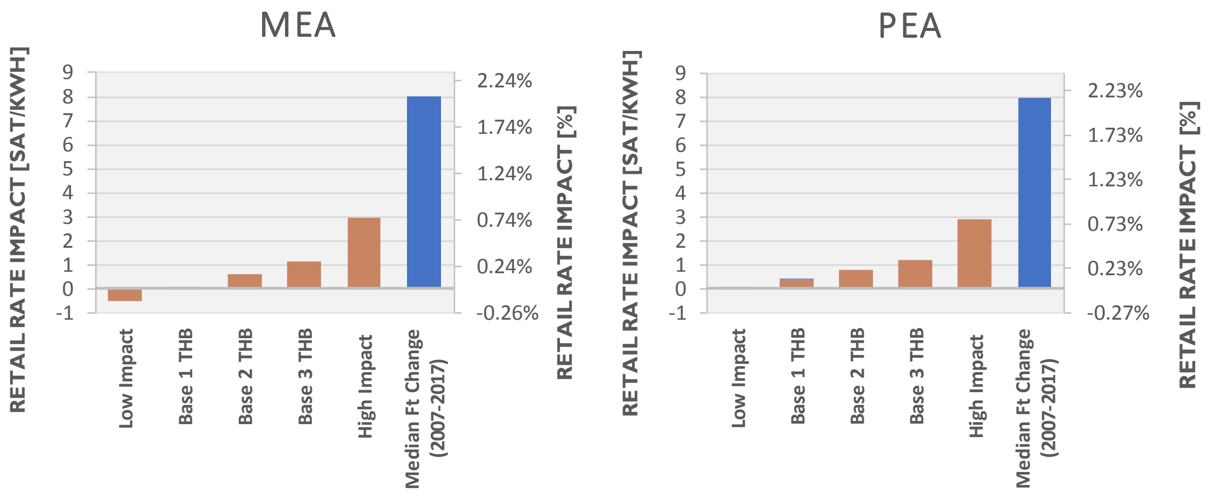


Figure 3: Summary of retail tariff impacts resulting from 3,000 MW of DPV deployment in 2020 by utility and scenario, compared with median F_t change from 2007-2017

Table 14: Summary of retail electricity rate impacts from 3000 MW of DPV in 2020

Retail Tariff Impact	Utility	Low Impact	Base 1 THB	Base 2 THB	Base 3 THB	High Impact		Median F_t Change 2007-2017
Satang/kWh	MEA	-0.48	0.06	0.60	1.14	2.96		7.98
	PEA	0.01	0.41	0.82	1.22	2.91		
%	MEA	-0.12%	0.02%	0.16%	0.29%	0.76%		2.1%*
	PEA	0.00%	0.11%	0.22%	0.33%	0.78%		

*An Ft change of 7.98 satang/kWh would result in an average retail tariff increase of 2.0% in the year 2020, based on the assumptions of this analysis.

***Key Point**: The retail electricity tariff impacts associated with 3,000 MW of DPV deployment, even under upper bound conditions for driving tariff increases, are small relative to normal fluctuations in retail rates due to the F_t.*

PUTTING RETAIL TARIFF IMPACTS IN CONTEXT

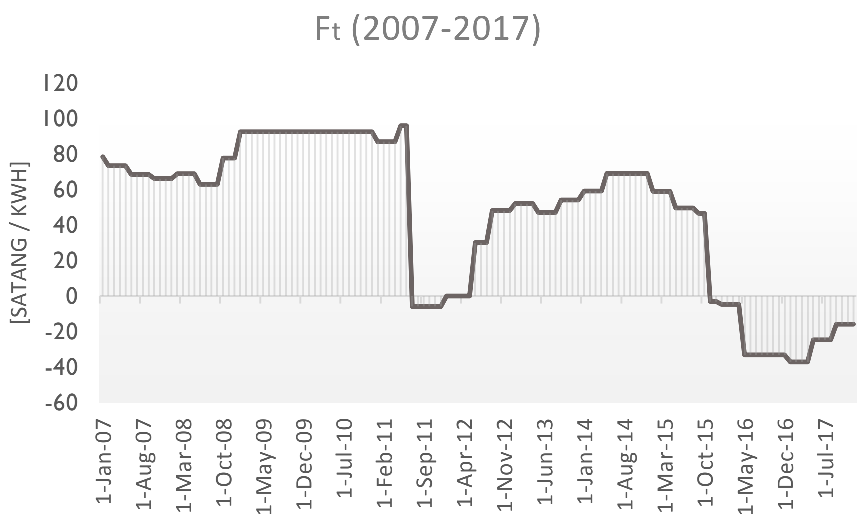
When certain utility expenditures diverge from *ex-ante* estimates created during rate cases (these include but are not limited to: capital expenditures, fuel costs, power purchase costs), the F_t serves as an automatic adjustment mechanism to help the utility recover its costs through retail tariffs. The F_t is a *direct adder* on retail electricity rates, and regularly fluctuates over time. Thus, it serves as a robust point of comparison to understand the relative magnitude of the DPV retail tariff impacts quantified in this analysis.

In order to better understand the magnitude of retail tariff fluctuations that Thai electricity consumers normally experience, publicly available monthly data on the F_t was examined for 2007 through 2017. It was found that the F_t changed 27 times between January 2007 and December 2017*, including being reset to a value of zero in one occurrence. The median magnitude of the F_t change for the time (excluding the reset) was found to be 7.98 Satang / kWh.

Summary of F_t Changes

Median F_t Change (2007-2017) [satang/kWh]	F_t Changes (2007-2017)	# of F_t Resets (2007-2017)
7.98	27	1

The magnitude of these routine retail tariff fluctuations can be compared to the DPV rate impacts quantified in this analysis. The evolution of the F_t between 2007 and 2017 is graphically depicted below in Figure T1 as well.



Evolution of F_t between 2007 and 2017

4.2 BASE SCENARIOS: 1, 2 & 3 THB

Under the Base scenarios, where customers are under a Net Billing scheme with various sell rates for grid injections, average tariffs increase 0.0%-0.3% from the 3,000 MW of DPV deployment by 2020, depending on the DPV sell rate. For the lowest sell rate considered in the Base scenarios, DPV customers are compensated 1 THB/kWh for all DPV generation which is not consumed on-site, whereas self-consumed electricity is effectively compensated at the DPV customer's underlying tariff.

In the 1 THB/kWh sell rate Base scenario, the total avoided purchases from EGAT are almost equivalent to the average compensation for DPV generation (a weighted average of the sell rate and the customer's retail tariff), and hence the average tariff only increases slightly (0.0% for MEA and 0.1% for PEA)[19]. The increase in average tariff is 0.2% for both MEA and PEA at the 2 THB/kWh sell rate and 0.3% at the 3 THB/kWh sell rate. For higher sell rates considered, the average compensation for DPV is higher, and hence the retail tariff impact is slightly higher. The total change in tariff is broken down into two components (from self-consumed vs. injected generation) in Figure 4.

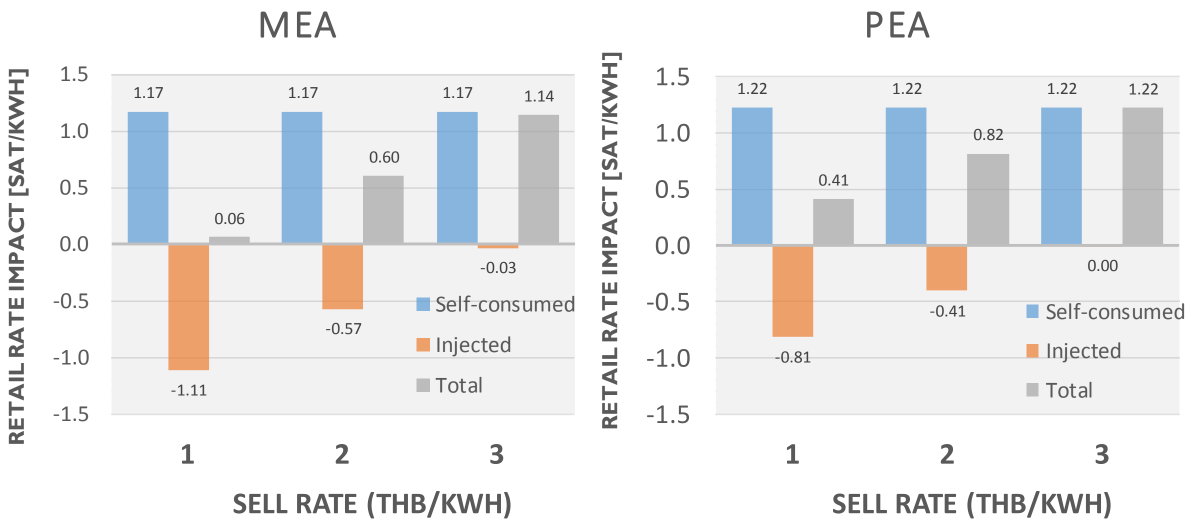


Figure 4: Tariff impacts from 3,000 MW of DPV by 2020 for three Base scenarios, broken down by self-consumed versus injected DPV generation

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***Key Point**: Under Net Billing schemes, retail electricity tariffs are impacted distinctly by self-consumption versus grid injections of DPV. If grid injections are sold to the utility below EGAT's wholesale electricity purchase price (such as under Base Scenarios 1 THB and 2 THB), the rate impact associated with DPV grid injections may be negative.*

In the short-term, before the next rate case, utility revenues would fall as a result of the self-consumed DPV generation. MEA revenue collection would fall 644 million THB/year (for 851 MW of DPV) and PEA revenues would fall 1,670 million THB/year (for 2149 MW of DPV). It is important to note, however, that any lost revenues due to overestimation of electricity sales during the previous rate case can be recovered in the following rate period, and hence these short-term losses are recovered in the medium-term (i.e., during the next rate case period).

4.3 LOW IMPACT SCENARIO

[19]Note that PEA and MEA have slightly different tariff impacts as the load profiles, here and elsewhere in the results, the PV generation profiles, and the customer mix are different for each utility, resulting in different relative levels of self-consumed electricity versus electricity injected onto the grid.

Under the Low Impact scenario, where customers are under a Self-Consumption Only scheme, average tariffs fall by 0.1% for MEA and increase by a negligible amount for PEA by 2020. In both these cases, these impacts are negligible because the average compensation for DPV generation is approximately equal to the reduced costs for the utility. Under the low impact scenario, self-consumption of DPV generation is allowed but all grid injections of DPV are made available to the utility at no cost, and hence the average DPV compensation is lower than in any of the Base scenarios. This leads to a slight decrease in rates for MEA and a slight increase for PEA[20], as shown in Figure 5.

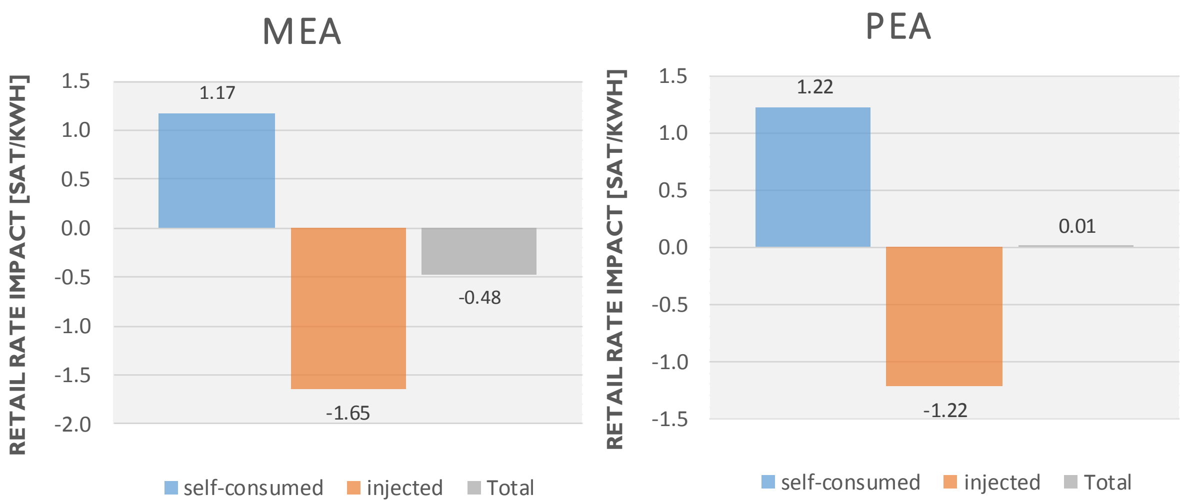

Figure 5: Tariff impacts from 3000 MW of DPV by 2020 for Low Impact scenario, broken down by self-consumed versus injected DPV generation

4.4 HIGH IMPACT SCENARIO

In the High Impact scenario, where customers are under a Net Energy Metering scheme, average tariffs are found to increase by 2.9 and 2.95 Sat/kWh (0.8%) for PEA and MEA, respectively, by 2020, as shown in Figure 6. In this scenario, all DPV generation is compensated at the customer's underlying retail tariff regardless of whether is it self-consumed or injected to the grid. As the average customer retail tariffs are higher than the EGAT wholesale electricity purchase price, this difference (i.e., revenue loss) is recovered by increasing the customer tariff in the next rate case. However, even in this upper bound scenario, the average difference between the average customer bill savings and the average EGAT avoided cost is only 1.4 THB/kWh and the total DPV generation represents only 2% of total projected sales in 2020.

[20] MEA has a greater proportion of residential and SGS customers than PEA, on a MWh basis, and these smaller customers tend to inject a greater proportion of their DPV generation than the larger customers.

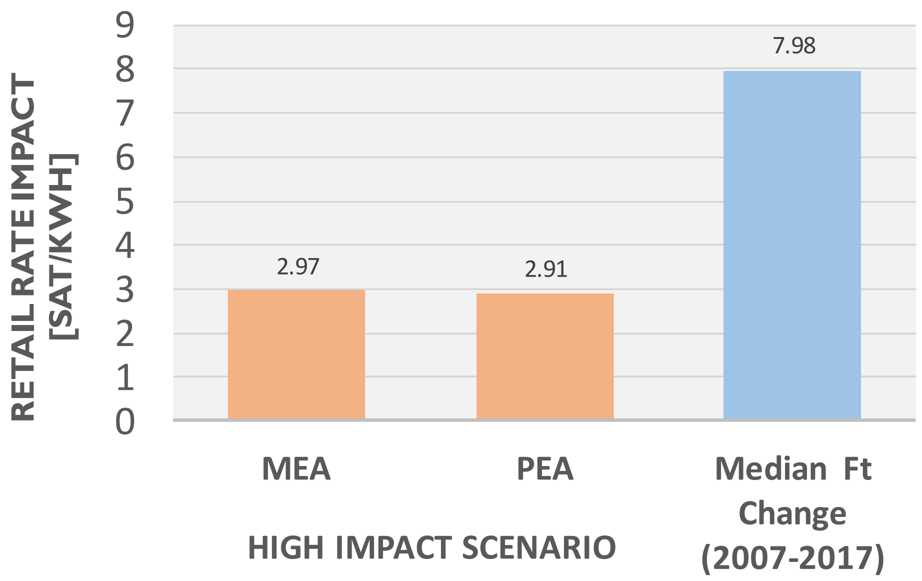

Figure 6: Tariff impacts from 3000 MW of DPV by 2020 for High Impact scenario, compared with median F_t change from 2007-2017

5. IMPLICATIONS FOR STAKEHOLDERS

5.1 IMPLICATIONS FOR MINISTRY OF ENERGY

- **This study demonstrates that policymakers can move forward with a DPV interconnection and compensation policy in Thailand without being deterred by concerns around utility revenues or retail tariff impacts.**

  Even at a penetration level of 3,000 MW of DPV, there is no expected medium-term revenue impact on distribution utilities, and tariff impacts – when viewed in the context of normal fluctuations of the F_t charge – are negligible. If a net billing scheme is rolled out in Thailand with compensation levels for DPV injections set below EGAT's wholesale electricity rate, retail tariffs may even decrease. Similarly, if a national self-consumption only scheme is used (i.e., a national version of the 2016 Rooftop Solar Pilot Project), retail tariffs would also be expected to decrease.

- **The design of DPV policy can be viewed as a balancing act between (1) incentivizing customers to deploy DPV and (2) a desire to moderate the impacts on utilities and other ratepayers that do not invest in DPV.**

  Based on the results of this analysis, it appears that such a balance of interests is quite achievable in Thailand in the immediate-term.

- **Should concerns still exist, system-wide DPV deployment caps or retail tariff impact caps – relatively common policy tools – can be considered at the national level.**

  If policymakers or other stakeholders remain concerned with the expected financial (or technical) impacts of a national DPV program, deployment caps or rate impact caps can also be implemented. Such caps help to mitigate concerns about impacts, while providing clear long-term signals to the private sector. Enacting system-wide caps for DPV programs is common practice in many jurisdictions around the world.[21] Monitoring these caps accurately often necessitates reliable data and in some cases, the creation of new data collection systems (see Section 5.2).

[21]For instance, in the United States, over half of U.S. states have some form of system-wide program deployment cap for their NEM program. Several other states have mandated, deployment-based policy review triggers (i.e., after a certain amount of DPV deployment is reached, policies must be reviewed). For more information, see Heeter et al. (2014).

5.2 IMPLICATIONS FOR THE OFFICE OF THE ENERGY REGULATORY COMMISSION

- **OERC can ensure the financial health of the utilities by maintaining their current rules, which allow for under-collection of revenue in previous rate cases to be recovered in subsequent rate cases.**

  Under Thailand's current rate case, the projection of expected electricity sales utilized did not incorporate a potential increase in self-consumption of DPV. Therefore, if DPV adoption continues to grow within the current rate case, distribution utilities will experience a reduction in sales, which should be allowed to be recovered in the next rate case. In the future, however, it is expected that the OERC should be able to determine the rate more accurately to prevent under-collection of utilities' revenue. While these impacts may be small, it may be worthwhile to track, aggregate and publish figures on DPV rate impacts in a way similar to the F_t.

- **OERC can support the creation of a national DPV registration and data collection system, which can be used to validate lost revenue claims and formulate improved estimates of DPV deployment for future rate cases.**

  Such a data collection system would empower OERC to augment ratemaking processes to better incorporate DPV. The data that will be needed includes the rate class of the customer, installed DPV capacity, geographic location, measurements of grid injections and gross DPV generation, and a variety of other metrics. These data can be used to validate lost revenue claims, and to forecast future amounts of DPV self-consumption and grid injections, which can be incorporated into rate design proceedings to reduce short-term revenue impacts. Registration and data collection systems exist in many contexts around the world; in order to motivate customers to participate in the scheme, eligibility to receive payments for grid injections can be tied to participation.

5.3 IMPLICATIONS FOR METROPOLITAN AND PROVINCIAL ELECTRICITY AUTHORITIES

- **MEA and PEA can collaborate with OERC to design a national DPV registration and data collection system.**

  MEA and PEA can work collaboratively with the OERC to build the registration and data collection system, and to ensure that customers and/or installers have sufficient incentive to participate in it. MEA and PEA stand to benefit significantly from understanding how much DPV deployment is occurring on their systems. First, this will help them to precisely estimate their short-term revenue impacts, ensure that F_t adjustments due to DPV are accurate, and rate case true-ups yield back any/all lost revenue experienced. Second, such data can be used to predict expected DPV deployment in the *next* rate period, helping to prevent short-term revenue under-collection in advance. Third, high fidelity data will help to ensure distribution system operations and planning activities are informed by precise information on the size, location, and production characteristics of all DPV systems – while these activities will not require significant augmentation for several years, implementation of data collection practices in the short-term will ensure good data is available in the long-term.

- **Technical requirements for DPV metering and billing infrastructure can be proactively designed by MEA and PEA to enable data collection to occur.**

  We define DPV metering and billing infrastructure as the equipment/processes that measure data on specific DPV production quantities (e.g., gross production, self-consumption, grid injections) and enable that data to be transmitted to the distribution utility for billing purposes. By careful upfront design of technical requirements for this infrastructure, data collection systems can be set up for success during the system installation process, obviating the need for expensive post-installation retrofit programs. As significant experience exists in this realm globally, international cooperation may be able to yield insights on specific data that can be collected and/or equipment standards to be considered.

- **MEA and PEA can begin building internal capacity to perform circuit-level DPV technical impact and planning studies.**

  This study did not investigate how an increase in DPV could result in the need for additional distribution systems investment, as 3,000 MW of DPV would constitute a relatively low system-wide penetration. While it may be many years before higher system-wide penetrations are reached, higher *local* penetrations (i.e., on individual circuits) may begin to occur after a national DPV policy is launched. To the extent feasible, MEA and PEA can begin building internal capacity to study circuit-level technical impacts of DPV. This can be performed with the goal of understanding both technical impacts of DPV interconnection, as well as investment planning implications of circuits with higher local penetrations of DPV. As there is a growing body of knowledge on this topic around the world, this suggests another area where international cooperation may be beneficial.

- **MEA and PEA can begin carefully tracking DPV program administration and interconnection costs.**

  Under a national DPV scheme, the responsibility will fall to both distribution utilities to establish a formal process to apply for DPV interconnection, along with suitable technical interconnection standards. Thereafter, they will need to process interconnection applications and certify that constructed systems have been properly connected to the distribution grid. Furthermore, billing systems may also need to evolve if payments for grid injections are to occur. While these costs may be quite small in scale relative to other expenditures, they should be carefully tracked so they can be incorporated into ratemaking processes to ensure cost recovery.

5.4 IMPLICATIONS FOR ELECTRICITY GENERATING AUTHORITY OF THAILAND

EGAT can begin studying the expected financial impact of DPV deployment on its ability to recover costs, as well as wholesale electricity costs. Similar to MEA and PEA, EGAT can expect some form of financial impact resulting from DPV deployment on the Thai power system. However, this impact will be distinct from MEA and PEA with respect to how exactly it accrues.

For example, on the cost side, EGAT may be more likely to experience fixed cost recovery issues than MEA and PEA. On the benefit side, EGAT may experience an avoided fuel cost when DPV systems are producing electricity. As a first step, these potential impacts should be rigorously studied and better understood by EGAT through a combination of (1) production cost modeling exercises and (2) financial analysis of revenue collection and wholesale energy price impacts.

EGAT can increase the number of time windows in its wholesale electricity pricing scheme to mitigate DPV financial impacts.[22] EGAT currently sells wholesale electricity to MEA and PEA at a regulated Peak and Off-Peak tariff. These two time windows with distinct wholesale tariffs are intended to coarsely represent EGAT's cost of generation (which changes continuously throughout the day). Moving towards a more granular pricing scheme – i.e., offering additional time windows with distinct wholesale tariff levels to MEA and PEA – could more accurately reflect EGAT's cost of generation. This change would help to minimize the financial impact of DPV to EGAT, as the scale of the net revenue loss resulting from a self-consumed kWh would be reduced (see e.g., Borenstein 2005).[23] Design of potential wholesale pricing schemes can be informed by the aforementioned production cost modeling exercises, and the value proposition can be further quantified within the financial analysis.

EGAT, in collaboration with MEA and PEA, can begin formulating a data collection scheme to increase the visibility and controllability of DPV systems on the Thai power system. Real-time production data is critically important for managing modern power systems. While utility-scale projects exhibit a high degree of visibility and controllability in Thailand, DPV projects will primarily remain behind-the-meter and connected to MEA and PEA's low voltage networks. Thus, a new approach is required to collect real-time DPV production data to better inform system operations and reduce costs. In the longer-term, a holistically designed data collection and communication system may help MEA, PEA and EGAT more actively control and manage distributed energy resources.

[22] Structural changes to EGAT's wholesale electricity pricing scheme will have a broader set impacts across the Thai power system than just mitigating DPV financial impacts.

[23] A key component of the net revenue loss to EGAT resulting from a self-consumed DPV kWh can be calculated as the wholesale electricity tariff for a given time window, less the average avoided variable cost of generation in the same time window. In theory, the more granular the time window, the more accurately the wholesale tariff would reflect EGAT's avoided variable generation cost, thus resulting in a lower the net revenue loss per self-consumed DPV kWh.

ANNEX A – CITATIONS

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ANNEX B: DETAILED QUANTITATIVE ANALYSIS OUTPUT TABLES

BASE SCENARIO OUTPUTS

Table B1 – Annualized Short-term Revenue Loss due to Self-Consumption of DPV Electricity by Utility and Customer Type (same across Base Scenario 1 THB, 2 THB and 3 THB)

Distribution Utility:	MEA					PEA				
Customer Class:	RES	SGS	MGS	LGS	Total	RES	SGS	MGS	LGS	Total
Reduction in Sales due to DPV Self-Consumption [Million THB]	-585	-458	-655	-1,555	-3,253	-1279	-786	-1,602	-4,542	-8,209
Avoided EGAT Wholesale Purchases due to DPV Self-Consumption, On-peak [Million THB]	+294	+229	+411	+976	+1,910	+636	+384	+968	+2,793	+4,781
Avoided EGAT Wholesale Purchases due to DPV Self-Consumption, Off-peak [Million THB]	+107	+84	+150	+357	+698	+234	+141	+356	+1,027	+1,757

Avoided EGAT Wholesale Purchases due to DPV Self-Consumption, Total [Million THB]	**+401**	**+312**	**+561**	**+1,333**	**+2,607**	**+869**	**+526**	**+1,324**	**+3,820**	**+6,539**
Net Short-term Revenue Impact by Customer Type	**-184**	**-146**	**-94**	**-222**	**-646**	**-410**	**-260**	**-278**	**-722**	**-1,670**

Table B2 – Annualized Short-term F_t Impact due to Grid Injection of DPV Electricity by Utility, Customer Type and Scenario (1 THB, 2 THB and 3 THB)

		MEA					PEA				
	Scenario	RES	SGS	MGS	LGS	Total	RES	SGS	MGS	LGS	Total
Total Cost of Injected DPV Electricity [Million THB]	1 THB	-165	-86	-36	-9	-296	-391	-109	-38	-15	-553
	2 THB	-331	-172	-72	-18	-593	-783	-217	-77	-30	-1107
	3 THB	-496	-259	-109	-26	-889	-1174	-326	-115	-45	-1660
Avoided EGAT Wholesale Purchases due to DPV Grid Injection, On-peak [Million THB]	Consistent Across Scenarios	+370	+193	+81	+20	+664	+859	+239	+84	+33	+1215
Avoided EGAT Wholesale Purchases due to DPV Grid Injection, Off-peak [Million THB]		+135	+71	+30	+7	+243	+316	+88	+31	+12	+447
Avoided EGAT Wholesale Purchases due to DPV Grid Injection, Total [Million THB]		+505	+264	+111	+27	+907	+1175	+326	+115	+45	+1662
Net Short-term Revenue Impact to F_t by Customer Type	1 THB	+340	+178	+75	+18	+611	+784	+217	+77	+30	+1109
	2 THB	+174	+92	+39	+9	+314	+392	+109	+38	+15	+555
	3 THB	+9	+5	+2	+1	+18	+1	0	0	0	+2
Average F_t Impact [THB/kWh] / [%]	1 THB	-0.0111					-0.0081				
	2 THB	-0.0057					-0.0041				
	3 THB	-0.0003					0.0000				
Average Short-term Tariff Impact [% Change]	1 THB	-0.29%					-0.22%				
	2 THB	-0.15%					-0.11%				
	3 THB	-0.01%					0.00%				

Table B3 – Medium-term Rate Impact due to Self-consumption and Grid Injection of DPV by Utility and Scenario (1 THB, 2 THB and 3 THB)

	Scenario	MEA	PEA
Average Medium-term Tariff Impact [THB / kWh]	1 THB	**0.0006**	**0.0041**
	2 THB	**0.0060**	**0.0082**
	3 THB	**0.0114**	**0.0122**
Average Medium-term Tariff Impact (% Change)	1 THB	**0.02%**	**0.11%**
	2 THB	**0.16%**	**0.22%**
	3 THB	**0.29%**	**0.33%**

LOW IMPACT SCENARIO OUTPUTS

Table B4 – Annualized Short-term Revenue Loss due to Self-Consumption of DPV Electricity by Utility and Customer Type

Distribution Utility:	MEA					PEA				
Customer Class:	RES	SGS	MGS	LGS	Total	RES	SGS	MGS	LGS	Total
Reduction in Sales due to DPV Self-Consumption [Million THB]	-585	-458	-655	-1,555	-3,252	-1,279	-786	-1,602	-4,542	-8,208
Avoided EGAT Wholesale Purchases due to DPV Self-Consumption, On-peak [Million THB]	+294	+229	+411	+976	+1,909	+636	+384	+968	+2,793	+4,781
Avoided EGAT Wholesale Purchases due to DPV Self-Consumption, Off-peak [Million THB]	+107	+84	+150	+357	+698	+234	+141	+356	+1,027	+1,757
Avoided EGAT Wholesale Purchases due to DPV Self-Consumption, Total [Million THB]	+401	+312	+561	+1,333	+2,608	+869	+526	+1,324	+3,820	+6,538
Net Short-term Revenue Impact by Customer Type	-184	-145	-93	-222	-644	-409	-260	-278	-722	-1,670

[Million THB]										

Table B5 – Annualized Short-term F_t Impact due to Grid Injection of DPV Electricity by Utility, Customer Type, Low Impact Scenario

Distribution Utility:	MEA					PEA				
Customer Class:	RES	SGS	MGS	LGS	Total	RES	SGS	MGS	LGS	Total
Total Cost of Injected DPV Electricity [Million THB]	0	0	0	0	0	0	0	0	0	0
Avoided EGAT Wholesale Purchases due to DPV Grid Injection, On-peak [Million THB]	+370	+193	+81	+20	+664	+859	+239	+84	+33	+1,215
Avoided EGAT Wholesale Purchases due to DPV Grid Injection, Off-peak [Million THB]	+135	+71	+30	+7	+243	+316	+88	+31	+12	+447
Avoided EGAT Wholesale Purchases due to DPV Grid Injection, Total [Million THB]	+505	+264	+111	+27	+907	+1,175	+326	+115	+45	+1,662
Net Short-term Revenue Impact to F_t by Customer Type [Million THB]	+505	+264	+111	+27	+907	+1,175	+326	+115	+45	+1,662

Average F_t Impact [THB/kWh] / [%]	-0.0165	-0.0122
Net Short-term Revenue Impact to F_t by Customer Type	-0.43%	-0.33%

Table B6 – Medium-term Rate Impact due to Self-consumption and Grid Injection of DPV by Utility, Low Impact Scenario

Scenario	MEA	PEA
Average Medium-term Tariff Impact [THB / kWh]	-0.0048	+0.0001
Average Medium-term Tariff Impact (% Change)	-0.12%	0.0%

HIGH IMPACT SCENARIO OUTPUTS

Table B7 – Annualized Short-term Revenue Loss due to Net Energy Metering of DPV Electricity by Utility and Customer Type

Distribution Utility:	MEA			PEA		
Customer Class:	RES	SGS	Total	RES	SGS	Total
Reduction in Total Sales due to Net Energy Metering [Million THB]	-2,562	-2,575	-5,137	-6,031	-6,131	-12,162
Avoided EGAT Wholesale Purchases due to Net Energy Metering, On-peak [Million THB]	+1,287	+1,287	+2,575	+2,998	+2,998	+5,996
Avoided EGAT Wholesale Purchases due to Net Energy Metering, Off-peak [Million THB]	+471	+471	+941	+1,102	+1,102	+2,204
Avoided EGAT Wholesale Purchases due to Net Energy Metering, Total [Million THB]	+1,757	+1,757	+3,515	+4,100	+4,100	+8,200
Net Short-term Revenue Impact by Customer Type [Million THB]	-805	-817	-1,623	-1,931	-2,030	-3,961

Table B8 – Medium-term Rate Impact due to Net Energy Metering of DPV by Utility, Low Impact Scenario

Scenario	MEA	PEA
Average Medium-term Tariff Impact [THB / kWh]	**+0.0297**	**+0.0291**
Average Medium-term Tariff Impact (% Change)	**+0.77%**	**+0.78%**