Renewable Energy Support Programme for ASEAN (ASEAN-RESP)

Recommendation Report

Guidelines for Implementing Small Scale Embedded Generation (SSEG) Support Mechanism for the ASEAN Region and Beyond

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Recommendation report on Guidelines for Implementing Small Scale Embedded Generation (SSEG) Support Mechanisms for the ASEAN region and beyond

This publication is developed by the Renewable Energy Support Programme for ASEAN (ASEAN-RESP), a joint cooperation between ASEAN Centre for Energy (ACE) and Gesellschaft für Internationale Zusammenarbeit (GIZ) GmbH, on behalf of the German Federal Ministry for Economic Cooperation and Development (BMZ).

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Content

1 Glossary

ACE	ASEAN Center for Energy
ASEAN	Association of South-East Asia Nations
AMS	ASEAN Member States
DU	Distribution Utility
FiT	Feed-in Tariff: Fix Tariff per kWh for the remuneration of electricity produced by SSEG
GIZ	Deutsche Gesellschaft für International Zusammenarbeit
HAPUA	Heads of ASEAN Power Utilities/Authorities
Net-Metering	Compensation scheme for Small Scale Embedded Generation (SSEG), which is predominantly for self-consumption but in which excess generation is credited by the distribution utility
PV	Photovoltaic
RE	Renewable Energy
RESP	Renewable Energy Support Programme
RFGD	Regional Focus Group Discussion
SSEG	Small Scale Embedded Generation (e.g. rooftop PV)

2 Background

Renewable energy (RE) has an important role to play in delivering a sustainable energy future. It enhances energy security, decreases dependence on imported fuels and contributes to the mitigation of climate change by reducing CO_2 emissions. In the ASEAN region, there are significant potentials for the use of RE. Over the past years, many ASEAN member states (AMS) have stepped up their effort in developing national RE programs, setting RE targets, putting into place regulatory frameworks and policies to support the deployment of RE systems.

One approach which is currently discussed in several AMS is net-metering for small scale embedded generation (SSEG). While net-metering can be an effective means to deploy small-scale generation and to foster private investments into RE by the electricity customers, technical as well as regulatory considerations have to be taken into account. Clear technical guidance for the interconnection of decentralized RE generation systems, especially photovoltaics (PV) has to be in place as well as a favourable pricing/tariff structure to incentivise investments.

2.1 Focus Group Discussion and Regional Workshop on Net-metering

In the framework of its cooperation with the Heads of ASEAN Power Utilities/Authorities (HAPUA), the Renewable Energy Support Programme for ASEAN (ASEAN-RESP), jointly implemented by the ASEAN Centre for Energy (ACE) and the Deutsche Gesellschaft für Internationale Zusammenarbeit (GIZ), organised a Regional Focus Group Discussion (RFGD) on **"Technical and Regulatory Aspects of Net-metering"** on 24-25 November 2015 in Jakarta, Indonesia. The workshop served as a forum for discussing and exchange good practices, expertise, and experiences on net-metering on the regional and international level. Both technical and regulatory aspects were discussed.

Inputs and learnings from participants and from international experts during the workshop are included as parts of this report.

2.2 The Guideline

The "Guidelines for Implementing SSEG Support Mechanisms for the ASEAN region and beyond" is developed jointly by ASEAN-RESP and international experts as an output of the "Technical and Regulatory Aspects of Net-metering" workshop. The purpose of this guideline is to provide a basic framework and introduce important aspects that must be considered in the implementation of SSEG supporting mechanism. Experiences and good practices from the region and international are provided as parts of the guideline

This guideline is to be used by policymaker and regulatory bodies when SSEG supporting scheme is to be rolled out in their country. It can also be read by interested person to understand important aspects of SSEG supporting mechanism.

This guideline consists of four main chapters.

- Chapter 3 provides general considerations on implementation of SSEG.
- Chapter 4 introduces general scheme for SSEG. Although the exact definition of net-metering and feed-in tariff may vary in different countries, the general definition and differences are provided.
- Chapter 5 provides an overview of the situation of RE development in the ASEAN.
- Chapter 6 summarizes the key findings.

3 General considerations in implementing the SSEG support mechanisms

3.1 General

Tariff structures and support mechanisms for SSEG vary greatly from countries to countries. The main reasons are as the following:

- The **objectives** for supporting SSEG are different in different countries.
- There are large variations of **cost of electricity generation** from conventional power plant and retail tariffs.
- Structure and **regulatory frameworks** of the electricity supply industry are different (e.g. vertically integrated utilities vs. unbundled and liberalised markets)

Therefore, it is difficult to identify generally applicable tariff models.

3.2 Objectives of SSEG Supporting Mechanisms

The objectives of different countries for supporting the installation of SSEG are the following:

- Reduction of conventional fuel consumption and CO_2 emissions (**"fuel saving"**)
- Adding generation for reducing load shedding and marginal cost of production.
- Avoiding **"illegal connections of SSEG"** for ensuring electrical safety and for avoiding grid disturbance caused by unregulated SSEG.

These different reasons for supporting renewable SSEGs will be discussed in the following sections.

3.2.1 Reduction Conventional Fuel Consumption and CO_2 emissions ("fuel saving")

In most countries, reduction of CO_2 emissions is the main driver for supporting renewable SSEGs (in particular rooftop PV). Nevertheless, in most cases, SSEG typically cannot yet compete with variable cost of conventional generation and subsidies are still required to stimulate SSEG installations. The level of financial support for renewable SSEGs depends mainly on national targets for CO_2 reduction.

The actual amount of reduced CO_2 emissions resulting from the use of renewable SSEGs depends mainly on two aspects:

- CO_2 emissions of SSEGs - energy required during the production/construction and during power plant operation.
- CO_2 emissions of conventional power plants – which are to be displaced by SSEG (saved fuel)

In the case of solar PV and wind power, there are no CO_2 emissions caused by the plant operation. All CO_2 emissions are caused during manufacturing, construction, and installation. Therefore, CO_2 emissions per kWh of generated electricity can vary considerably. They depend on the overall amount of energy generated over the lifetime of these systems and the CO_2 balance of the energy used during the manufacturing process. The latter is extremely difficult to be estimated and their published figures vary significantly. According to the VDI study[1] a range of 25 - 360 g CO_2/kWh and a typical range between 50 and 100 g CO_2/kWh can be estimated to be realistic (for wind turbine, this figure is estimated at around 30 – 45 g CO_2/kWh).

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[1] *„CO_2 emission of electricity production (CO_2 Emissionen der Stromerzeugung)", VDI, 2007*

For conventional fossil-fired power plants, majority of CO_2 emissions are from the actual operation of the power plants. This represents by far the largest contribution to the overall CO_2 emission of these power plants. This includes CO_2 emissions resulting from actual combustion processes, fuel production and fuel transportation. CO_2 emissions resulting from the construction and equipment/component manufacturing plants are very small compared to CO_2 emissions during actual operation.

With regard to different technologies, the following approximate figures can be given in Figure 1.

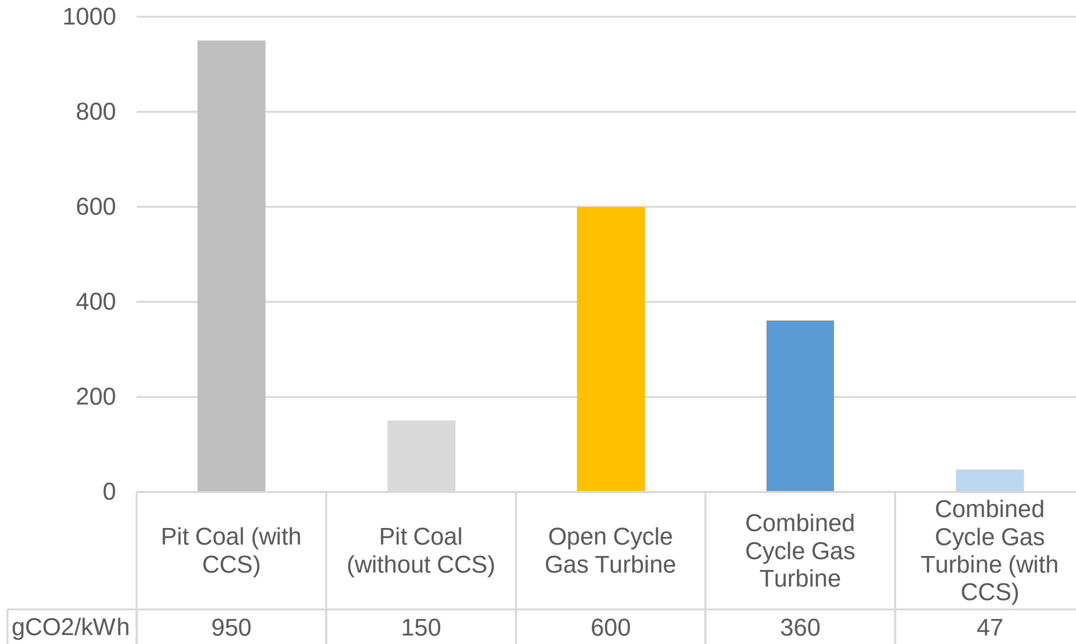

Figure 1: Approximate CO_2 emission from power plant with different technologies

Consequently, the amount of avoided CO_2 emissions resulting from electricity generated by PV power plant mainly depends on the efficiency of existing conventional power stations and the type of fuel that can be avoided because of electricity generation by PV (see Figure 2). Assuming that power plants are dispatched according to their variable cost of electricity production, PV power plant will initially displace the peaking plants (with highest variable cost of generation). In case of higher PV penetration level, mid-merit power plants can also be displaced.

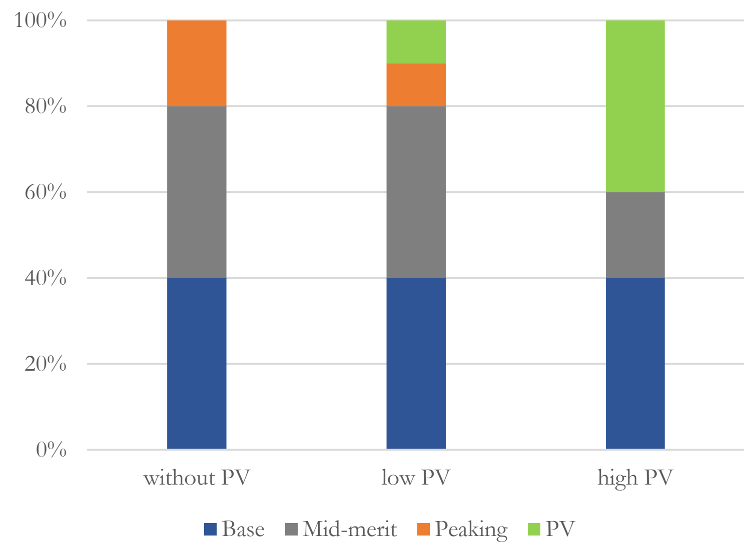

Figure 2: Power plant dispatch in the case of no PV, low PV generation and high PV generation

Therefore, in systems with relative low penetration of PV, the avoided CO_2 emissions per kWh of produced PV electricity are usually close to avoided CO_2 emissions of peaking plants (typically, gas or diesel-fired power plant). However, at the larger PV penetration levels, the solar PV power plant also displaces mid-merit power plants (typically, coal-fired power plant).

In conclusion, **avoided CO_2 emissions of PV typically increase with increasing penetration levels[2].**

3.2.2 Adding generation for reducing load shedding and saving conventional fuels

In many developing and emerging countries, in particular in Africa (e.g. South Africa, Nigeria, and Ghana) but also in Asia (e.g. Pakistan) and ASEAN Member States (e.g. the Philippines and Vietnam), there are veritable or looming energy crises, resulting from insufficient generation capacity. Typically, the capacity shortages are the result of:

- Considerable demand growth during the past years, which was faster than the planning and installing of new power plants.
- Retirement of old thermal power plant (e.g. ones built in the sixties and seventies)
- Lack of financing capacity and lack of investment.

There are critical consequences arising from the generation shortages. They are:

- Frequent and continuous planned load shedding
- Basically, all existing thermal power plants (including expensive peaking plants) must be in operation, more or less, permanently. Marginal cost of generation can be high.
- Maintenance activities are reduced to maximize their short-term availability. This leads to accelerated aging of thermal power plants and reduces their lifetimes.

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[2] *In case of power systems with large hydro contribution, this can be different.*

Consequently, there are high economic impact resulting from unavailability of electricity and high cost of electricity.

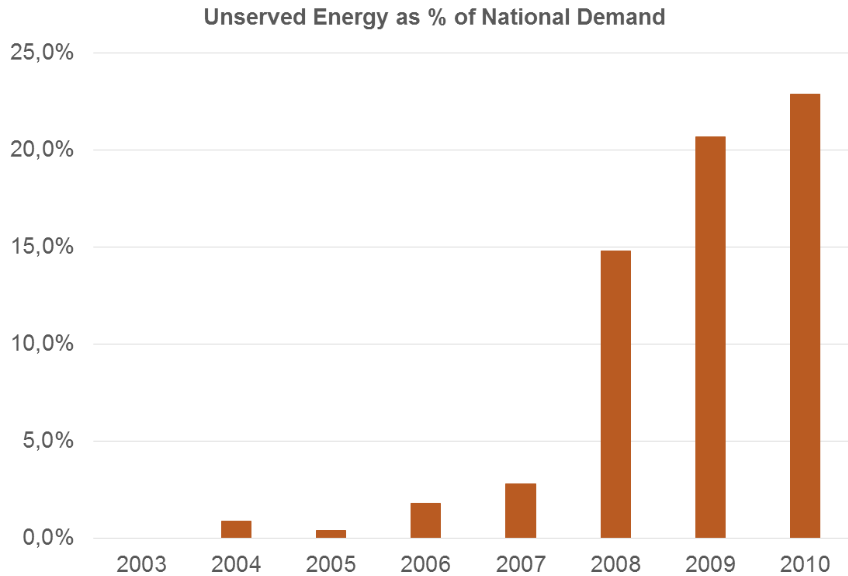

Figure 3: Unserved Energy in % of national demand in Pakistan[3]

As an example, Figure 3 shows the level of unserved energy in Pakistan between 2003 and 2010. Regular load shedding has been in place since 2003 and remained even during the financial crises in 2009, the amount of energy not supplied (ENS) is still increasing.

A second example is South Africa. Since 2014, there has been a considerable amount of load shedding as a result of insufficient generation capacity. Even during times in which no load shedding, expensive open cycle gas turbines (OCGT), originally planned to be stand-by reserves, are in operation[4]. The marginal generation cost is high due to enormous fuel costs.

Since 2011, South Africa promotes utility-scale variable renewable energies by the so-called "Renewable Energy Procurement Program"[5]. This program was successful and by the end of 2014, there were 600 MW installed wind power and around 1000 MW installed Solar PV power.

According to the estimation by CSIR[6] the avoided cost of coal and diesel fuel and the avoided cost resulting from reduced load shedding amounted to (per kWh of produced PV/wind electricity):

- USD 16.9 cents/kWh from avoided diesel fuel and coal
- USD 7.4 cents/kWh from avoided load shedding
- Total economic benefit: USD 24.3 cents/kWh

The average tariffs paid for projects were offered within the different bidding-windows. They are depicted in Figure 4. As shown by this figure, the avoided fuel cost and load shedding cost exceeded the tariffs paid for wind and PV

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[3] *Source: NTDC: National Power System Expansion Plan 2011-2030, published in 2011*
[4] *and which are operated with diesel fuel (in the lack of suitable gas infrastructure)*
[5] *based on a tendering scheme*
[6] *CSIR: Financial benefits of renewable in South Africa 2014, all figures based on a exchange rate of 1 USD=10 ZAR*

projects (except from the initially procured 0.6 GW of solar PV project in 2011). There was an overall economic benefit resulting from wind and solar PV projects in 2014 that amounted to around USD 530 million in total.

On the other hand, the South African wholesaler (ESKOM) paid tariffs of around USD 450 million to the operators of wind and solar PV projects.

The resulting net benefit to the South African economy from the use of wind and solar PV is USD 80 million (or equivalent to USD 3.6 cents/kWh of electricity produced from wind or solar PV).

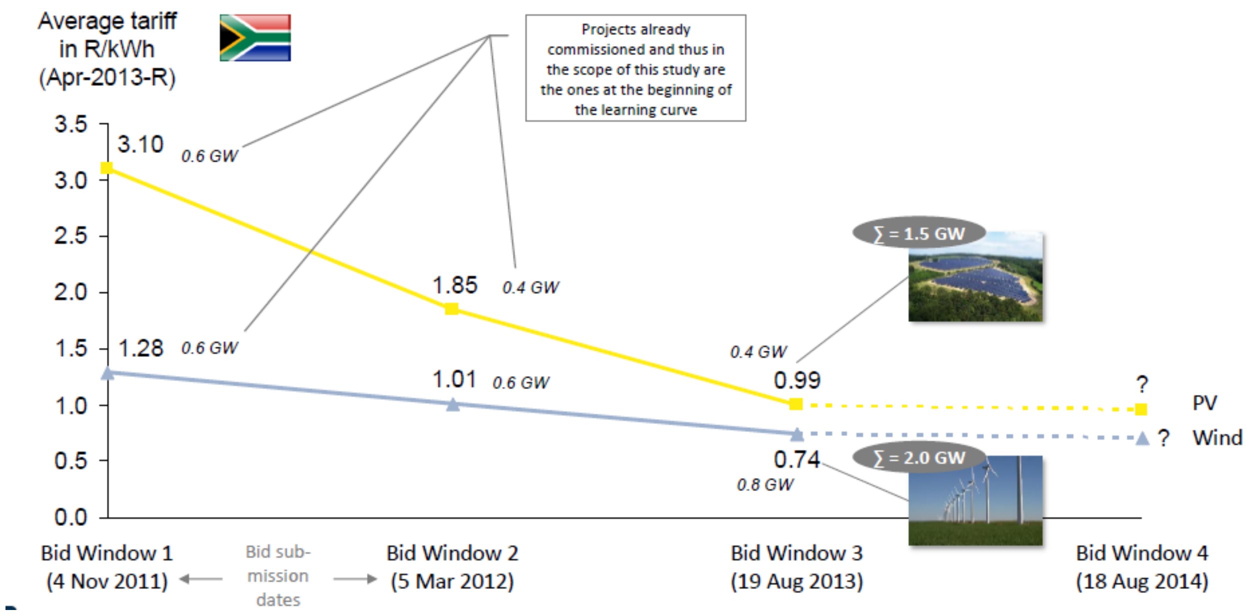

Figure 4: Average tariffs paid to utility-scale wind and PV

The tariffs, especially for utility-scale solar PV, have considerably decreased since the South African procurement scheme for renewable IPP started in 2011 (see Figure 4). So, it can be expected that the financial benefit of PV will further increase.

Solar PV Rooftop is currently not supported in South Africa. Only the installation of solar PV rooftop for own consumption is permitted without the right to export excess energy to the grid. However, the National Energy Regulator of South Africa (NERSA) has recently published a consultation paper to propose a regulatory framework for rooftop PV based on a net-billing scheme. This paper is supposed to be published by end of May 2015.

In a situation like in South Africa, there is a motivation for the installation of variable renewable generation from the economic considerations. CO_2 reduction is not the main driver but can be a welcomed side effect.

For power systems with insufficient conventional generation capacity, the very short lead time for planning, installing and finally commissioning SSEGs is another very positive aspect to be considered. When compared to large thermal power plants, the lead time of SSEG is extremely low. Therefore, SSEG is a suitable option to mobilise additional generation capacity during times when it is mostly needed. Typical lead times of various types of power plants can be estimated as follows:

- Coal fired power stations: 9 years
- Combined cycle gas turbines: 3 years

- Utility-scale wind: 3 years
- Utility-scale PV: 2 years
- SSEG: 0.5 years[7]

Hence, there is a clear and considerable benefit from very short lead time of SSEG. They are resulted from the fast availability of these technologies, which can be very important in the case of capacity shortages.

3.2.3 Avoiding "illegal connections of SSEG"

A third reason for governments, regulators and power utilities to support SSEGs is the problem of so-called "illegal connections".

In countries, where levelised cost of electricity (LCOE) of solar PV rooftop systems drops below the retail tariff ("grid parity" is reached), many consumer may start connecting solar PV rooftop systems, predominantly for own consumption to the grid without the consent of the distribution utility. This means there are installations of generation systems that may not comply with any safety or performance regulations. Consequently, there is an inherent risk with respect to safety and performance of distribution networks resulting from unregistered grid connected solar PV rooftop systems.

For mitigating this problem and to comply with relevant technical interconnection standards of rules, power distribution companies start providing incentives for registration by offering credits for excess energy which can be fed into the distribution grid. However, these credits are usually low. They are in the order of magnitude of variable cost of electricity of these distribution companies. Very often, these incentives are not sufficient for registration and to become compliant with technical regulation. So, "illegal connections" just continue.

3.3 Cost of support schemes

3.3.1 Levelised Cost of Electricity (LCOE) of PV systems

The Levelised Cost of Electricity (LCOE) is equivalent to the tariff that a utility (or trader) would have to pay to a generator so that system costs, cost of financing and expected return of investment will be covered over the lifetime of the system.

Hence, LCOE can be calculated by equalling the net present value (NPV) of the generated income and the incurred cost of a plant over its lifetime:

$$\sum_{t=1}^{n} \frac{LCOE \times E_t}{(1+p)^t} = I_0 + \sum_{t=1}^{n} \frac{A_t}{(1+p)^t}$$

The definition of parameters is the following:

- LCOE: Levelised Cost of Electricity
- E_t: Energy generated during year t
- p: discount rate
- t: index of the year

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[7] *Considering that there are no bottlenecks with regard to available components, installers etc.*

- n: time of use
- I_0: Initial investment
- A_t: Cost (O&M, reinvest) during year t

With the assumption that LCOE is constant over the lifetime of the plant, LCOE can be calculated as follows:

$$LCOE = \frac{I_0 + \sum_{t=1}^{n} \frac{A_t}{(1+p)^t}}{\sum_{t=1}^{n} \frac{E_t}{(1+p)^t}}$$

The discount rate reflects interest rates on debt and the expected return of investment. It can be expressed by the Weighted Average Cost of Capital (WACC) approach as follows:

$$WACC = se \times re + sd \times id$$

With:

- WACC: Weighted Cost of Capital
- se: share of equity
- re: expected return on equity
- sd: share of debt
- id: interest rate on debt

When expressing all incurred expenses and incomes in real quantities relating to the original year of the investment, WACC must be corrected by the expected inflation rate. It is then implicitly expected that LCOE will be adjusted by the inflation rate during the lifetime of the plant:

p=WACCreal=WACCnom-in

With:

- p: discount rate
- $WACC_{real}$: Weighted Cost of Capital expressed in real quantity (inflation is considered)
- $WACC_{nom}$: Weighted Cost of Capital expressed in nominal quantity (inflation is not considered)
- in: inflation rate

Example:

An example for the calculation of the Weighted Average Cost of Capital considering share of equity, share of debt, expected return on equity, interest rate on debt and inflation rate is depicted in

Table 1

Table 1: Calculation of WACC (real)

Description	Symbol	Value
share of equity	se	25,00%
share of debt	sd	75,00%
Expected return on equity	re	14,00%
Interest rate on dept	id	12,00%
Weighted Cost of Capital (nominal)	**$WACC_{nom}$**	**12,50%**
inflation rate	in	5,00%
Weighted Cost of Capital (real)	**$WACC_{real}$**	**7,50%**

Table 2: Project-specific parameter

Description	Value
Installed cost (per kWp)	2.000,00 USD
Cost of annual O&M (per kWp)	40,00 USD
Time of Use (in years)	20
Annual energy degradation	0,80%

Using the parameters of a PV-rooftop system according to Table 2, the LCOE of a rooftop PV-system in function of annual energy yield in kWh/kWp and WACC (real) was calculated (see Figure 5).

As shown by the results according to Figure 5, LCOE of PV-systems heavily depends on the expected return of investment and the energy yield at the particular location.

Generally, the expected $WACC_{real}$ of commercial investors will be in the range between 5.5% to 7.5%.

In the case of private investors, this is more difficult because every investor has different expectations with regard to the profitability of a PV rooftop system. Some investors may install the system providing that it just pays itself back over its lifetime because they simply prefer the technology. Some other investors are only willing to invest, if they can really earn certain profit.

Consequently, it is impossible to specify or define one single value of LCOE for residential rooftop PV systems in a country. Instead, a function specifying the mobilization of the potential rooftop capacity in function of the paid tariff (or value of kWh produced) seems to be a more realistic approach. Such a function can only be obtained by surveys to identify the expectations of potential investors with regard to return of investment.

Besides this, it is not only the paid tariff, which is relevant in this context, but also the actual tariff scheme and other aspects, like safety of investment, predictability of the return on investment and other factors which will have a considerable influence on the mobilised PV capacity as well.

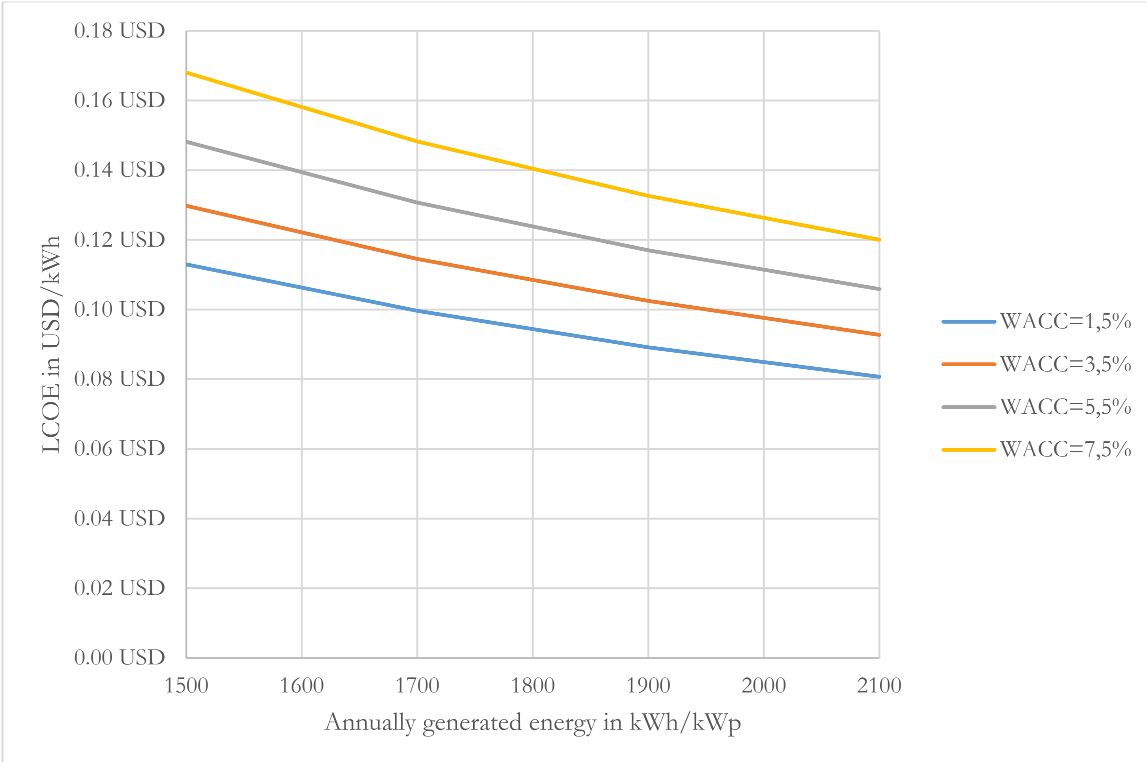

Figure 5: LCOE in USD/kWh in function of the generated annual energy in kWh/kWp

3.3.2 Avoided Cost of Energy

Each kWh produced by solar PV reduces fuel cost of conventional power plants. This can be represented in an Avoided Cost of Energy (ACE). Due to economic consideration, solar PV first displaces the most expensive power plants, which are in operation during times of PV production. Therefore, for small PV penetration levels, avoided fuel cost is close to the marginal cost of energy generation during day-time.

For larger penetration levels, avoided fuel costs are reduced because solar PV displaces less expensive power plants more (compare also Figure 2).

Therefore, in countries with capacity or energy problems, marginal cost of energy can be very high. Even the most expensive power plants must be in operation during times of high demand in order to avoid load shedding. For those countries, avoided fuel costs resulting from electricity generation by solar PV can be very high (see also the South African example in section 3.2.2).

However, in countries with very low marginal cost of electricity (e.g. because of subsidies for primary energy like coal or gas) avoided fuel costs are relatively low.

In the longer run, not only the "fuel saving aspect" of PV must be considered but also its contribution to the installed capacity (capacity credit). The capacity credit will highly depend on the correlation between PV production and demand. If PV generates electricity during times of high demand, the contribution of PV to the equivalent firm capacity of a system (capacity credit) can be considerably high. However, in countries with a very strong evening peak load, capacity credit of PV can almost be equal to zero.

With the additional consideration of the impact of PV on installed capacities of thermal and hydro power plants, the overall economic costs and benefits of PV (including rooftop PV) are very difficult to estimate and can only be quantified with the application of special software for generation expansion planning.

3.3.3 Cost/benefit of support schemes for rooftop PV

For a successful support scheme, it is essential that the value of every kWh of energy produced by rooftop PV is greater or equal than the expected LCOE.

The "value of every kWh of energy produced by rooftop PV" can either be a feed-in-tariff, which is paid to the generator or it could result from savings on consumed electricity in case of a self-consumption scheme.

The amount of subsidies required for supporting such a scheme (or the expected economic benefit) depends on the avoided cost of energy (ACE).

Hence, assuming that the value of generated PV electricity is equal to LCOE, the following equation describes the economic impact (EI) per generated kWh:

EI= ACE-LCOE

In the case that EI is greater than zero (LCOE<ACE), there is an economic benefit (like in the South African example according to section 3.2.2).

In the case that EI is lower than zero (LCOE>ACE), subsidies have to be paid (direct or indirect subsidies) for motivating the installation of rooftop PV (e.g. for reducing CO_2 emissions).

However, the avoided cost calculation is sometimes quite difficult because primary fuels of thermal power plants are subsidized in many countries. In these cases, the avoided cost calculation must include these subsidies, e.g. by considering the world-market prices of fuel or gas instead of the actual price at which a power plant operator can buy (subsidized) fuels.

For implementing a successful support scheme for inciting rooftop PV, it is therefore recommended to carry out the following studies:

- Mobilised PV capacity in function of tariff (or generally: value of kWh produced). For commercial rooftop installations, such a study can be based on a LCOE calculation. For residential PV systems, a representative survey would have to be carried out.
- Assessment of the avoided fuel cost in function of installed PV capacity: Such a study requires an analysis of the available thermal and hydro power plants and a study about the impact of rooftop PV on the generator dispatch.

Based on the results of these studies, the cost or economic benefit of rooftop PV can be assessed and an optimized support scheme with which the goals with respect to the installation of rooftop PV can be achieved at minimum cost can be defined.

4 Overview and Comparison of Typical SSEG support schemes

4.1 Introduction

When analysing regulatory frameworks for rooftop PV, it becomes evident that basically each country defines an individual regulatory framework and that common terms and definitions like "Feed-In-Tariff" or "Net-Metering" are interpreted differently in different countries.

When comparing these different regulatory frameworks for rooftop PV, four standard schemes can be identified, which can be seen as "standard models" and which will be described in the following sections of this report.

4.2 Self-Consumption and Net-Metering Concepts

4.2.1 Self-Consumption

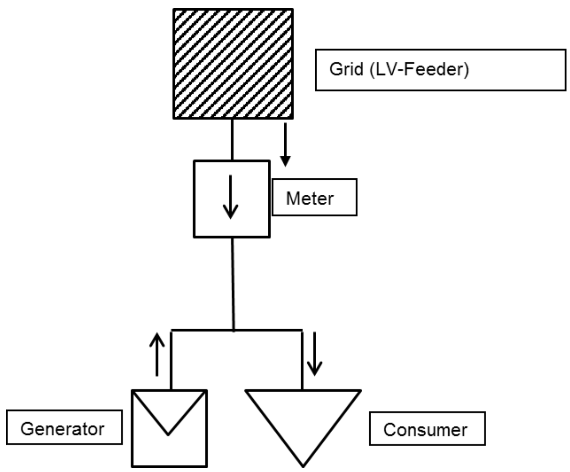

Figure 6: Meter arrangement for a Self-Consumption scheme

Self-Consumption means that it is permitted to install grid-tied PV systems but that it is not allowed to feed surplus energy back into the grid. When using rooftop PV only for self-consumption, surplus power (generation higher than consumption) must be physically avoided by the inverter of the PV system.

In most cases, there are no technical standards in place, which would specify safety and performance requirements of PV inverters operating in self-consumption mode, even if aspects like injection of DC-currents, harmonic distortion, danger to firemen etc. are as important for the safe operation of a PV system for self-consumption as for a PV system for power export.

In the case that there is technical regulation in place, it is very difficult for a distribution network operator to ensure voluntary compliance with these rules because there is no incentive for registration and compliance with technical rules and regulation.

4.2.2 Net-Metering

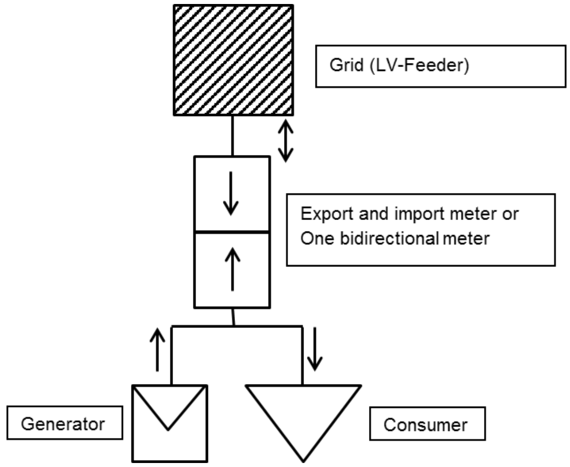

Figure 7: Meter arrangement for a Net-Metering scheme

Net-Metering basically represents an enhancement of a self-consumption scheme. In a Net-Metering Scheme the primary use of the rooftop PV-system is still for self-consumption but during times, in which PV generation is higher than the associated load, it is permitted to feed the power surplus back into the grid and the distribution utility pays a fee or grants a credit for it.

In a classical net-metering scheme, energy that is fed into the grid is credited at the same tariff as consumed energy, as if the meter rotated backwards (which is even the case in some older installations with electromechanical meters). Hence, the term "Net-Metering" applies here to the net energy consumption/generation of a consumer.

In a modified Net-Metering scheme (sometime also called "Net-Billing") energy surplus is credited at a different rate than retail. Therefore, either two uni-directional meters or one bi-directional meter (with two registers, one for imported and one for exported power) have to be installed and power surplus and net power consumption is metered separately.

Typically credits granted for exported energy are below retail tariff. Very often, credit rates are defined on basis of avoided fuel costs or avoided cost of electricity purchase of distribution utilities.

Therefore, such a modified net-metering scheme implicitly creates an incentive for maximizing own-consumption, because the value of electricity generated by a rooftop PV system, which is consumed before it passes the meter is higher than the energy surplus that is fed into the grid. In other words, by shifting load from evening hours towards mid-day, the economic value of a rooftop PV system can be increased by the user.

In Net-Metering schemes (including modified Net-Metering Schemes), the overall electrical energy produced must typically not exceed the totally consumed energy, which means that, when looking at a longer period (e.g. one year), the energy generated by the rooftop PV system can still be interpreted as "self-consumption". Sometimes a model of the grid being a huge electricity storage system is used for describing this aspect of "self-consumption": Assuming that the grid was a storage system, energy surplus generated by a rooftop PV system is "stored" in the grid for later consumption. Hence, with this model, Net-Metering effectively represents a kind of Self-Consumption scheme too.

The key characteristics of a Net-Metering scheme can be summarized as follows:

- Energy surplus is credited at the same rate as consumed energy (meter "rotates backwards", classical Net-Metering) or at a lower rate than consumed energy (modified Net-Metering Scheme or Net-Billing Scheme).
- Total energy generation must not be greater than total electricity consumption (within a "roll-over period", e.g. one year).[8]

Net metering was pioneered in the USA in the early eighties and most US-states nowadays have a net-metering program in place.

Countries, in which modified Net-Metering Schemes (or Net-Billing schemes) are applied are e.g. the Philippines, Jamaica and recently, the South African regulator NERSA proposed a regulation, which is also based on a modified Net-Metering (or Net Billing) scheme.

4.3 Feed-In Tariff Schemes

4.3.1 (Gross) Feed-In Tariff

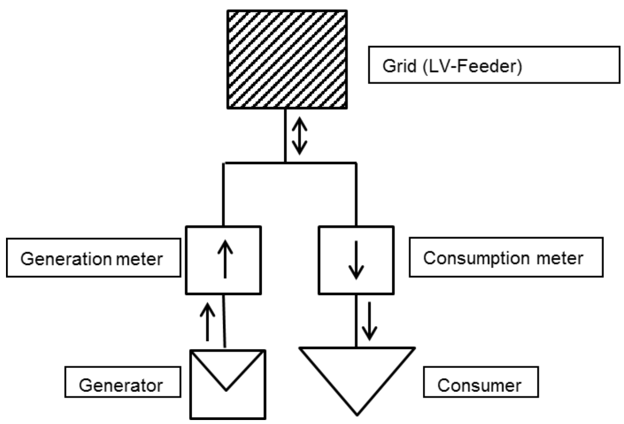

Figure 8: Meter arrangement for a classical Feed-In Tariff scheme (metering gross generation)

Classical Feed-In Tariffs treat rooftop PV as generation, independent from consumption. As shown in Figure 8, gross generation and gross-consumption is metered separately using two independent single-directional meters.

The typical characteristics of a Feed-In-Tariff scheme are the following:

- Fix tariff is paid for every kWh of generated electricity. The tariff can be constant or vary over time but in any case it is pre-defined upon installation.
- Every kWh of generated electricity is remunerated, irrespective of consumption.
- Feed-In tariff usually higher than retail tariff
- Operator of rooftop PV system is considered to be a generator.

[8] *There are also schemes with exceptions from this rule, e.g. the utility buys excess generation at an even lower tariff or the billing-cycle is much longer or even indefinite.*

Feed-In Tariffs are very popular in Europe. In Germany, a classical Feed-In Tariff scheme based on gross energy production used to be the standard concept for supporting the roll-out of rooftop PV until 2011, when the Feed-In Tariff reached grid parity at consumer level.

4.3.2 Net Feed-In Tariff

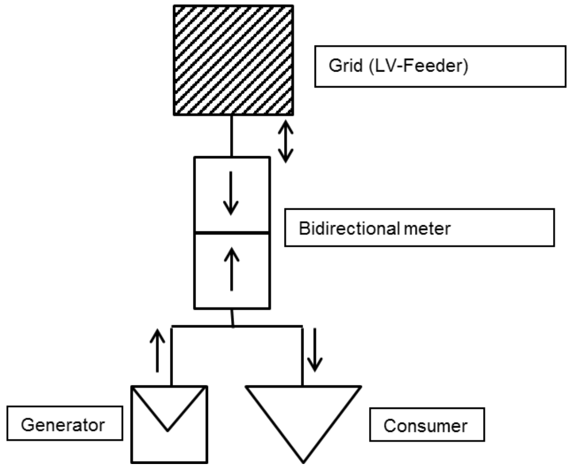

Figure 9: Meter arrangement for a Net-Feed-In Tariff scheme

In countries, in which rooftop PV has reached grid parity (Feed-In Tariff lower than retail tariff) there is a large interest of the consumers to use a part of the generated energy for self-consumption.

The metering arrangement, as shown in Figure 9 looks basically the same as in a Modified Net-Metering (or Net Billing) scheme according to section 4.2.2. The main difference between the two schemes is that in a Net Feed-In Tariff scheme, the exported energy is not limited and is remunerated at the agreed Feed-In Tariff, independent from the amount of consumption.

In Germany, the current support scheme for rooftop PV could be named a Net-Feed-In Tariff scheme. In addition to the meter arrangement according to Figure 9 there is an additional gross generation meter required in Germany because the support scheme includes the constraint that only up to 90% of gross generation can be exported to the grid (or will be paid). Therefore, it is important to meter gross generation as well.

4.4 Discussion

4.4.1 General

When introducing a tariff scheme for rooftop PV systems (especially for residential rooftop PV systems) the following aspects have to be considered:

- Tariff scheme for residential rooftop PV systems must be simple, easy to understand and easy to implement (private instead of professional operators).
- The administrative overhead should be as small as possible.
- Tariff scheme must lead to a secure and predictable return of investment. Sometimes security and predictability is even more important than high profitability.

Besides this, the following aspects should be considered:

- The tariff scheme should provide some incentive for timely generation or consumption (e.g. there should be an incentive for shifting the load towards day-time for maximizing the level of own consumption)
- It should provide sufficient incentive for registering a rooftop PV system so that compliance with technical rules and regulations will be ensured. In the case that the tariff for exported energy is not sufficiently high, there is a high risk that people will continue to connect rooftop PV systems for self-consumption scheme only (see section 4.2.1) without any registration.
- The tariff scheme should avoid hidden side effects on the existing tariff structure, like hidden side effects on cross subsidies, which are built into consumption tariffs, or impact on the cost/tariff structure of distribution network operators.

4.4.2 Self-consumption and net-metering concepts

The main advantage of self-consumption and net-metering concepts is that they are easy to implement. Typically only an agreement between the local distribution utility and consumers is required. Hence these schemes are definitely advantageous with respect to:

- Simplicity
- Small administrative overhead

The level of security of an investment into a rooftop PV system highly depends on the binding period of net-metering tariffs, which is usually not very long. However, in most cases, a PV rooftop installation must justify itself predominantly by reduced electricity import and because in most countries, it is not very likely that electricity tariffs will be reduced in the coming years, the profitability of PV installations resulting from self-consumption will remain high. Credits earned by exporting power-surplus should always be seen as an "add-on" and not represent the main component of the profitability assessment.

The big disadvantages of self-consumption or net-metering schemes are hidden side-effects on revenue and profit of distribution utilities, especially in case of progressive consumer tariffs.

In particular, there are the following aspects of residential tariffs, which require particular attention when introducing self-consumption or net-metering tariffs for remunerating rooftop PV:

- Residential tariffs are usually not cost-reflective. In most case residential tariffs are purely variable, defined in function of consumed kWh of electricity (Energy Only tariffs). Fixed costs of distribution utilities resulting from grid usage and administration are translated into variable tariff components. When reducing electricity consumption by PV generation, sales will be reduced in proportion to the self-generated amount of energy but only the variable cost component will be reduced (purchase of electricity), while fixed costs of the utility remain unchanged. Cost of grid usage typically remains the same because the maximum required connection capacity remains unchanged and administrative costs may even increase, e.g. because of additional meter reading. In an extreme situation, a net-metering user having a zero import-export balance doesn't pay for grid usage and administration, even if these services are still required. Consequently, in order to cover their fixed costs, distribution utilities consider introducing special net-metering tariffs for consumers with rooftop PV, which are based on a more cost-reflective tariff structure containing a fixed and a variable component. Such a tariff reduces the financial benefit of rooftop PV systems.
- In many developing and emerging countries, residential tariffs are progressive, meaning that cost of electricity increases with increasing electricity consumption. This ensures that poorer parts of the population can have access to electricity at very low rates. When introducing self-consumption or net-metering schemes, lost

revenues first affect the more expensive tariff components and make the use of rooftop PV more attractive to high-energy consumers than to low energy consumers. As a result, there is a considerable impact on cross-subsidies and distribution utilities may be required to increase tariffs of low energy consumers.

The described side-effects on revenues of distribution utilities can only be mitigated by introducing suitable compensation schemes, which must defined in a manner that cross subsidies are not affected and which have to ensure that distribution utilities can still recover their fixed costs without impacting the tariff structure.

4.4.3 Feed-In Tariff schemes

The great advantage of gross feed-in tariffs (see section 4.3) is that there are no hidden side effects because generation and consumption is metered separately. Therefore, revenues of distribution utilities remain the independent from electricity generation by rooftop PV.

On the other hand, a Feed-In Tariff scheme makes it is necessary to resell and market the electricity generated by rooftop PV and therefore, a very clear and well thought-through regulation is required defining rules and responsibilities of the different players, which requires the involvement of political decision makers.

Besides this, there are several disadvantages and challenges of Feed-In-Tariff schemes that must be considered:

- In a gross feed-in tariff scheme, the size of a rooftop PV installation is independent from any associated load. Therefore rooftop PV installations can be substantially larger than associated loads leading to much more severe grid impact than a net-metering scheme.
- Feed-in tariffs must be permanently re-adjusted in order to avoid overcompensation.
- In a gross feed-in tariff scheme, there is no incentive for timely consumption of electric energy.

Net-feed-in tariffs, in which not gross generation but energy surplus is remunerated, have basically the same problems with regard to unwanted side-effects as self-consumption or net-metering schemes. Actually, the difference between a net-feed-in tariff and a net-metering (or net-billing) scheme is very minor and therefore advantages and disadvantages are very similar.

5 ASEAN Situations – Overview of the SSEG situation

During the Regional Focus Group Discussion and workshop on "Technical and Regulatory Aspects on Net-Metering" held in Jakarta on 24-25 November 2014, the participants from ASEAN Member States shared their current SSEG development situation and relevant regulation in their respective countries. Based on the output of the presentations and discussion, an initial overview of the situation in each country was developed.

5.1 Thailand

In 2013 Thailand's total electricity generation amounted to 177.4 TWh,[i9] mostly from natural gas, of which approximately 5% was provided by RE technologies, predominantly large scale hydro and biomass. The electricity use per capita reached 2,048 kWh[7]. The total electricity generation capacity is 33.7 GW[10] dominated by natural gas, of which 11.1%[11] (3,788 MW) is renewable energy, the vast majority biomass (2.3 GW) generation capacity followed by solar (0.8 GW). Domestic large scale hydro provided another 9.9%.

Thailand's power market is dominated by the public sector with only small subsidies provided for the low income population.

Thailand's electricity tariff ranges from USD 6 cents/kWh to USD 16 cents/KWh. The rates for potential SSEG users are USD 14 cents/kWh for a domestic end user with a consumption of 1,000 kWh/month and USD 16 cents/KWh[12] for a commercial end user with an on-peak consumption of 10,000 kWh/month.

In its Alternative Energy Development Plan (AEDP) 2012-2021 Thailand commits to a target of 25% of renewable energy by 2021. Solar PV is planned to contribute a generation capacity of 3,800 MWp to this goal. Thailand has a long history of support programs for Solar PV starting with the 1st adder program in 2007. However, due to excessive number of application from the private sector, the government decided to suspend the adder scheme for solar PV in 2010. In 2013 a solar roof top program was launched by the National Energy Policy Committee Resolution utilizing Feed-in Tariff over 25 years as incentive mechanism. The total target installation was 200 MWp divided into 100 MWp for households (0-10 kWp) and 100 MWp for small enterprises (10-250 kWp) and medium & large enterprises (250-1,000 kWp). The FiT rate ranged from USD 21 cents/kWh for households to USD 20 cents/KWh for small enterprises to USD 19 cents/kWh for the medium and large enterprises.

While the categories over 10 kWp was heavily oversubscribed with applications amounting to 609 MWp received of which 100 MWp were approved according to the quota, the household category was undersubscribed with applications of total 55 MWp received and applications of about 31 MW approved, leaving a quota of 69 MWp unused. One of the reasons for the low take up among the households was the administrative requirement to register the solar roof top installation with generation capacity of more than 3.7 kWp (5 horsepower) as a factory.

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[9] *http://www.eppo.go.th/info/cd-2014/index.html*
[10] *http://www.eppo.go.th/info/5electricity_stat.htm*
[11] *Energy in Thailand – Facts and Figures 2013 downloaded http://110.164.199.154/dede/index.php?option=com_content&view=article&id=12785%3Aenergy-in-thailand-facts-a-figures-2013-&catid=146%3Ahot-issue&lang=en*
[12] *For 100 kW consumer that is connected to below 12 kV grid*

For 2014-2015 a new FiT scheme for households with a quota of 200 MWp has been introduced leaving the size limit at 10 kWp and slightly reducing the FiT rate to USD 20 cents over 25 years but removing the requirement to register as a factory.

The Department of Alternative Energy Development and Efficiency (DEDE) is now also considering for the AEDP 2015-2036 a net metering scheme to increase the promotion of installations of solar PV for self-consumption as the prices for solar become competitive with retail electricity prices. DEDE is further pushing for additional measures for net metering notably a tax deduction for the company or for personal use. However this proposal has not been approved.

5.2 Malaysia

In 2012 Malaysia's total electricity generation amounted to 134 TWh[13], mostly from natural gas and coal, 6%[14] was provided by RE technologies mostly large scale hydro with a small contribution of biomass. The electricity use per capita reached 3,966 kWh[10]. The total electricity generation capacity is 29.1 GW[10] dominated by natural gas and coal, of which, 2.7% (784MW) is biomass renewable energy and large-scale hydro generation providing another 11.4% (3,317 MW).

Malaysia's average electricity price ranges from USD 7 cents/kWh to USD 18 cents/kWh. The rates for potential SSEG users are USD 10 cents/kWh for a domestic end user with a consumption of 1,000 kWh/month and USD 14 cents/kWh for a commercial end user with a consumption of 10,000 kWh/month.

Malaysia's power market is dominated by the public sector in a managed market industry structure which includes independent power producers, co-generators and RE generators, local distributors and mini utilities together with the three state owned integrated power providers TNB in Peninsular Malaysia, SESB and SESCO in Sabah and Sarawak. Electricity prices are subsidized through a lower than market price sale of LNG and coal to the power utilities. The 2014 introduced Incentive Based Regulation which reduces these subsidies has led to an increase in electricity prices[15].

In 2011, Malaysia passed its Renewable Energy Act and introduced Feed-in Tariff scheme to the country's RE sector.

The National Renewable Energy Policy and Action Plan (NREPAP) targets an increasing part of Malaysia's electricity capacity and generation coming for RE sources:

Table 3. Malaysia's target for electricity capacity and generation from RE

Year	RE capacity	RE generation
2015	6%	5%
2020	11%	9%
2030	14%	11%
2050	36%	15%

[13] Malaysia Energy Statistics Handbook 2014 downloaded http://www.st.gov.my/index.php/download-page/category/116-statistics-energy
[14] *SUSTAINABILITY OF ENERGY SOURCES downloaded www.eria.org/events/Sustainability%20of%20Energy%20Sources.pdf*
[15] *http://www.enerdata.net/enerdatauk/press-and-publication/energy-news-001/electricity-tariffs-malaysia-current-situation-and-outlook_31593.html*

The Malaysian Feed-in-Tariff scheme distinguishes between Solar PV (a) Community (b) Individual (c) Non-individual <= 500 kW and (d) Non-individual > 500 kW[16].

The FiT scheme for individuals distinguishes between small installations below or equal 4 kWp (USD 30 cents/kWh) and installation greater 4 kWp but below 12 kWp (USD 30 cents/kWh) and provides for bonus FiT depending on the building (USD 6 cents/kWh), building materials (USD 6 cents/kWh), localized PV panels (USD 1 cent/kWh) and localized inverters (USD 1 cent/kWh). The eligibility is limited by a yearly quota which amounted to 15 MW for PV installations below or equal 4 kWp in 2014 which was very quickly fully absorbed pointing towards an attractive proposition to the market. The FiT scheme for non-individual solar PV installation consists of more capacity categories above 12 kWp with decreasing FiT rates.

The government is now considering its next steps as the funding pool for the FiT can, at the current rate, subsidize only a further 110 MW capacity from 2015 to 2017 before it comes to an end. As the FiT for solar PV seems to be discontinued after 2017, the government and relevant authorities are looking for alternative means to support RE development. However, the decision on the schemes to be implemented still has to be decided. Malaysia's Sustainable Energy Development Authority (SEDA) is now proposing to introduce a net metering scheme focused primarily on self-consumption and in which excess energy during low load periods is exported to the grid and compensated for by the utility on a net consumption basis, i.e. classic net metering. As benefits of solar rooftop installations under a net metering scheme are listed: the reduction in utility peak demand which coincides with the PV generation profile thereby avoiding distillate and reduced generation by open cycle gas turbine (OCGT) power plants, a reduction in distribution system losses, deferral of distribution and transmission system reinforcement investments, hedging against fuel price volatility especially for imported fuel, a reduction in greenhouse gas emissions and savings for consumers as electricity tariffs continue to rise.

SEDA points towards potentially higher tariffs, thus affecting non net metering consumers, potential grid problems and its negative effect on the utility's finances as consequences if net metering PV installations are not controlled, as discussed in section 4.4.2.

It stresses therefore that the key issue in the implementation of a net metering scheme is its organization and control to maximize the benefits and minimize disruptions.

It also points out that without net metering or with a scheme with severe limitations. Consumers will be encouraged consumers to install PV purely for self-consumption with a storage capability and energy management system for which only a generating license from the Energy Commission for capacity above 72 kWp is required which will lead to even greater losses for the utility and negative impact on safety and security of distribution grids because of non-compliance with technical standards.

The Malaysian Photovoltaic Industry Association (MPIA) proposed in 2014 the introduction of a net metering scheme starting 2015 in which qualified retail electricity customers should have the right to install RE generation facilities such as rooftop solar PV systems at their premises and connect them to the utility grid without discrimination. No capacity limit should be imposed on the total rooftop PV generation as it forms "generation at point of use" and is a valuable addition to the national electricity generation fuel mix. Billing statements from utilities should clearly show the consumer's total electricity use, the PV generated electricity, and where applicable the net energy exported to the utility grid. This "credit" should be available for the consumer to utilize when required. MPIA proposed an annually increasing capacity addition under net metering from the first year's 150 MW (2015) to 1,453

[16] *http://www.seda.gov.my/*

MW in 2025, so that the accumulated PV capacity installed under net metering would reach 1,750 MW by 2020 and 6,634 MW by 2025 contributing 4.75% to the total electricity generation of Malaysia.

SEDA takes a more conservative approach towards net metering and suggests aiming for a total installed PV capacity by 2020 of 2,400 MW of which 1,000 MW would be under net metering, 400 MW under FiT and 1,000 MW under bidding scheme for utility scale PV plants. Net metering's capacity is proposed to start with 100 MW in 2015, 100 MW in 2016 and thereafter 200 MW until 2020.

To further control the expansion of net metering SEDA proposes to limit the size of the installations to 6 kWp if it is connected via single phase and 12 kWp if it is connected via 3 phase to the distribution grid and to only allow connection via the LV network. The limitation to 6 kWp for single phase connection is generally recommended to limit the impact of grid unbalances.

On the commercial aspects SEDA proposes to allow the utility to charge a one-off admin fee for interconnection as well as charge any costs involving changes to metering to the consumer. Exported units would be credited net off at prevailing end user tariff and allowed to be carried forward for a maximum of 12 months.

5.3 Philippines

In 2013 the Philippines' total electricity generation amounted to 75.3 TWh[17] , 26.4% of which was provided by RE technologies mostly large scale hydro and geothermal with wind, solar and biomass contributing 0.4%. The electricity use per capita reached 765 kWh. The total electricity capacity is 17.3 GW, of which 32% (5.5 GW) is renewable energy. The vast majority of RE are hydro, geothermal generation and wind. Solar and biomass are contributing up to 153 MW.

The Philippines' average electricity price ranges from USD 13 cents/kWh to USD 25 cents/kWh. The rates for potential SSEG users are USD 25 cents/kWh for a domestic end user with a consumption of 1,000 kWh/month and USD 20 cents/kWh for a commercial end user with a consumption of 10,000 kWh/month.

As the Phillipines introduced a modified net metering scheme in 2013 as the first country in ASEAN, this chapter describes in detail the background and implementation process as a case study.

Through the implementation of the Electric Power Industry Reform Act (EPIRA) in 2001, the formerly state-owned and monopolistic power industry was unbundled and largely privatized. Power generated by Independent Power Producers (IPPs) and the National Power Corporation (NPC) and power traded at the Wholesale Electricity Spot Market (WESM) is transmitted via the state owned but privately managed National Grid Corporation of the Philippines (NGCP) to the distribution utilities, an atomistic industry composed of 119 electric cooperatives, 17 privately owned and 8 government-owned distribution utilities widely varying in markets, size, technical and financial capacity and operating standards and regulated by the Energy Regulatory Commission.

Aiming to accelerate the development of the country's renewable energy resources, R.A. 9513, the Renewable Energy Act, was passed in the Philippines in 2008 providing fiscal and non-fiscal incentives to private sector investors and equipment manufacturers, fabricators and suppliers. The non-fiscal incentives include

- Renewable Portfolio Standards (RPS)- an on-grid "RE blend" obligation for the distribution utilities,
- Feed-in Tariff (FiT) - guaranteeing fixed selling price for 20 years for RE power plants,

[17] *http://www.doe.gov.ph/electric-power-statistics/philippine-power-statistics*

- the green energy option
- Net Metering, the consumer SSEG RE facility to offset electricity from grid.

The legal basis for net metering is laid out in section 10 of R.A. 9513[18] and Section 7 of its Implementing Rules & Regulations (IRR)[19].

The IRR define net metering as "a consumer-based renewable energy incentive scheme wherein electric power generated by an end-user from an eligible on-site RE generating facility and delivered to the local distribution grid may be used to offset electric energy provided by the DU to the end-user during the applicable period". So, the philosophy of net metering is mainly to maximize the off-setting (savings) effect for the end user of utilizing its own generated energy. It is not a scheme incentivizing the generation of power for export.

The IRR also provides that the Energy Regulatory Commission (ERC), in consultation with National Renewable Energy Board (NREB), shall establish the net-metering interconnection standards and pricing methodology.

After preparation by the NREB technical working group and intense stakeholder consultations and public hearings, ERC Resolution No. 9, Series of 2013 - A Resolution Adopting the Rules Enabling the Net-Metering Program for Renewable Energy[20] was approved on 27 May 2013 and became effective on 24 July 2013 as the first of the non-fiscal incentives described in the RE Act, 5 years after its passing. It contains the Rules Enabling the Net-Metering Program, the technical Net-Metering Interconnection Standards and the Net-Metering Agreement Template.

The Philippines net metering is applicable only to on-grid systems, excluding off grid areas and only for installation of < 100 kW based on the law's definition of distributed power generation. Eligible RE Technologies are wind, solar, biomass or biogas or other RE systems capable of being installed in the qualified end-user's (QE) premises. QEs are defined as End-users in good credit standing in the payment of electric bills to the distribution utility (DU). The RE System must be compliant with the standards set in the Philippine Electrical Code (PEC), Philippine Distribution Code (PDC), Distribution Services and Open Access Rules (DSOAR) and the Net-Metering Interconnection Standards (NMIS).

The interconnection set up contains either two uni-directional meters or one bi-directional meter. A third meter may also be installed to measure the RE power generation.

Learning from the long delay and challenging public discussion concerning the subsidy based FiT, the Technical Working Group Net Metering of NREB decided to apply for an interim pricing methodology without subsidies. It sets the price for export energy as the DU's average blended generation cost. This cost shall be automatically included in the DU's total generation cost to be recovered from all its customers. The DU can also include net metering charges and metering rates based on export rate in the QE's bill. The total billing charge contains the amount due for electricity import less the credit for export electricity. If the total amount is positive the QE shall pay it to the DU, if it is negative it will be credited to the QE's next bill indefinitely. The DU has the option to pay out the amount.

As annex the net metering rules also contain the interconnection standards which describe in detail the application process, the systems parameters such as voltage level, frequency, power quality and power factor, the system protection features such as synchronization, islanding, integration with DU's distribution system grounding, the protective control devices, the operations and maintenance requirements, the metering set up and the testing and commissioning process.

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[18] *http://www.doe.gov.ph/issuances/republic-act/627-ra-9513*
[19] *http://lia.erc.gov.ph/documents/290*
[20] *http://www.erc.gov.ph/Files/Render/issuance/511*

In addition the rules contain a template for the net metering agreement between the DU and the Qualified End-user (QE) which mirrors the provision in the rules enabling the net-metering program i.e. compliance standards, interconnection set-up, DU inspection, meter readings, pricing and other charges. This agreement once signed has to be submitted to ERC, DOE & NREB within 5 days from execution by the DU. It is deemed approved and effective upon submission to ERC.

Manila Electric Company (MERALCO) is the by far largest distribution utility in the Philippines combining 55% of total electricity sales of the country. It has taken a leadership role from the distribution utilities sector and, led by its Utility Economics team, provided technical and administrative expertise in the preparation of net metering and the stakeholder discussions.

To prepare for the advent of net metering MERALCO created a cross-functional working team involved in policy direction, technical standards and commercial process development which worked on all aspects of net metering from a DU perspective such as application requirements for line offices, Distribution Impact Study & commissioning and testing for the back-end technical services and metering, billing and settlement for customer services.

Key in its preparation for the net metering introduction was a capacity building program which started in 2012 and contained workshops, cooperation with other utilities, business and information trips to Germany and hosting the technical training at the first German Solar Training Week. To gain further insights into the practical aspects of a solar PV system, MERALCO installed in 2013 on its premises the 1st net metering installation in the country, a 6.16 kWp solar roof top system, and gained thereby valuable experience for on technical as well as administrative issues. On the technical side especially the performance of the PV solar roof and its distribution impact was studied and the learnings incorporated in the Distribution Impact Study process which each net metering solar installation has to undergo.

MERALCO encountered challenges on the technical as well the commercial and marketing side.

- On the technical aspects MERALCO has now to accommodate new types of power generation, i.e. the injection of solar power, in its low voltage distribution grid with DC conversion to AC by inverter technology. It determined a need to conduct a Distribution Impact Study (DIS) to assess technical feasibility of interconnecting parallel generation at the end-use source. It has also to cope with integration issues for Variable Renewable Energy (VRE) or intermittent generation and establish penetration parameters for parallel generation at the feeder or circuit level which are generally small and connected to secondary lines. Metering is now a two-ways connection to the grid, allowing for bi-directional flow of electricity which needs to be newly accommodated.
- In terms of commercial and administrative issues MERALCO encountered challenges in the documentary requirements as additional information is required about the generating facility and certifications from the local government and regulatory body are needed. Fees have to be collected upon application such as the DIS fee to cover the technical feasibility of the specific customer's condition for interconnection which requires additional man hours for technical evaluation and field survey. Internal procedures had to be enhanced as well as a widespread capacity building program for internal line personnel developed and implemented.
- In terms of marketing, MERALCO embarked on a large scale drive to educate the customers on the Net Metering scheme explaining the mechanism for metering, billing and compensation for excess energy to avoid misunderstandings and to promote the scheme.

After all the preparation the net metering scheme in the Philippine got off a slow start. Only in January 2014, MERALCO connected the first net metering customer. However since then an exponentially increasing number of applications are received and processed so that as of 20 November 2014, 45 net metering customers with an aggregated capacity of 455 kWp utilizing PV solar were connected and a total of 18,000 kWh exported to the DU as of September 2014

MERALCO and the other DUs in the Philippines are registering an increasing customer interest mainly from residential houses in upscale villages and small and medium companies with green energy initiative. The main drivers are the implementation of energy efficiency programs, mitigation of the high electricity cost at the end-use by avoiding grid rate with customers accepting an initial investment and reduction of the carbon footprint.

MERALCO is planning to address in 2015 the challenges it sees with an increasing number of net metering customers in its distribution grid such as the accreditation of installers for the protection of customers and the utility, the certification of equipment especially inverters and panels, development of smart grid tools to address the challenges of VRE for operational and planning aspects and the conduct of further technical studies to evaluate the integration of renewables.

Other challenges remaining are the administrative barriers on the part of the end user in form of the cost and time for the conduct of distribution impact studies. Also other DUs are slow and show reluctance to fully implement the net metering programs making it difficult for customers outside Manila to avail of net metering.

Reviewing the development of the net metering scheme in the Philippines it can be stated that the following factors were key success factors for its implementation:

1. Legal basis and political will

The RE Act of 2008 and the subsequent IRR provided the legislative basis for the introduction of net metering as the chosen scheme for SSEG in the Philippines.

2. Organized stakeholder collaboration

In an unbundled and largely privatized energy sector such as in the Philippines with extensive democratic consultative processes, stakeholders had to cooperate with each other to implement rules in a timely fashion. Although own interests, especially between the DUs and the solar industry, differed widely at the beginning the legislative obligation, the understanding on DU side that this disruptive technology change cannot be stopped and it is better to shape it rather than being in the end confronted by it and on the side of the solar industry that a no subsidy scheme is the only way to achieve a timely implementation, paved the way for the introduction of net metering. It was also crucial that both groups were professionally organized, the DUs with Philippine Electric Power Operators Association (PEPOA) and the solar industry with the Philippine Solar Power Alliance (PSPA) to be able to consolidate opinions. It is acknowledged that GIZ with its Project Development Program (GIZ PDP SOA) in the context of the renewables – Made in Germany played an important role in the organization of the development and implementation of the net metering rules and interconnection standards. Through its position as "honest broker" it was able to gather all stakeholders from the private, public and civil sector and facilitate the process with targeted activities such as workshops with experienced consultants from the German private sector, info trips to Germany and capacity building programs.

3. Capacity Building

One of the biggest hurdles of the introduction of net metering in the Philippines was the lack of knowledge and experience among the stakeholders on the technologies, notably the inverter based PV installations, the technical impact on the grid in terms of safety and stability and the commercial impact of the scheme for DUs, consumers and installers. Several international organizations provided valuable capacity building activities for all stakeholders ranging from workshops covering technical, project development, administrative barriers and financing issues of SSEG, to facilitating specific consulting for inverter technology by the German private sector.

4. Dissemination

Widespread dissemination of knowledge and transparency is a pre-requisite in building capacity beyond the core stakeholders especially in a just emerging market affecting diverse stakeholders all over the country. Several publications have been made available to guide stakeholders on the net-metering scheme. They are:

- Net Metering Reference Guide
- Distribution Impact Study Guideline
- Solar Roof Top ROI Calculation Template
- Manual for Interconnection
- Administrative Barriers in on grid and off grid RE development

which can be freely downloaded from the DOE website[21].

5.4 Indonesia

In 2013 Indonesia's total electricity generation amounted to 216.2 TWh[22], mostly from coal and natural gas. Around 12.1% of the electricity comes from RE technologies with large scale hydro and geothermal as dominant sources. The electricity use per capita reached 773 kWh. The total electricity capacity is 50.99 GW of which 12.9% is RE (predominately large-scale hydropower and geothermal). Wind, solar, biomass and small scale hydro account for 141 MW.

Indonesia's power market is dominated by the public sector, namely PT Perusahaan Listrik Negara (PLN) and is characterized by high subsidies reaching USD 8.2 billion in 2014. The new administration reduced the subsidy by 8.3% (as of January 2015). It also introduced a variable electricity rates for households with a 1,300 VA or more capacity based on the exchange rate of the rupiah to the US dollar, the oil price, and the inflation rate[23].

The rates for potential SSEG users are USD 11 cents/KWh for a domestic end user with a consumption of 1,000 kWh/month and USD 5 cents/kWh[24] for a commercial end user with a consumption of 10,000 kWh/month.

Indonesia introduced a FiT scheme for utility-scale PV installations in 2013. The scheme consists of a competitive bidding process with a ceiling price of USD 25 cents/kWh[25] and a quota of 140 MW at 80 locations ranging in capacity from 1 MWp to 5 MWp was assigned. As of February 2014, 11 tender locations were published and the winners in 5 locations announced. The lowest winning FiT rate was USD 18 cents/kWh.

On 19 November 2013, the Board of Directors of PLN issued regulation No. 733 on "The Utilization of electricity generated with photovoltaic by PT PLN customers". It recognizes that to accelerate the utilization of renewable energy, encouragement on the use of solar energy for electricity generation is necessary. Furthermore, it will increase Indonesia's electricity supply capacity, accommodate and appreciate society's need of clean RE.

The regulation was operationalised in the "Circular Letter on the Operational Provisions of Photovoltaic Integration from Customer-owned to Electric Power System Area of PT. PLN" on 8 September 2014. It serves as a technical reference on the PV utilization that is integrated to that of PT. PLN (Limited Liability Company) power system. It aims to guarantee the security of field workers, machineries, grid network, and PV, as well as the power quality of

[21] http://www.doe.gov.ph/netmeteringguide/index.php/downloads
[22] Handbook of Energy & Economic Statistics of Indonesia 2014 downloaded http://www.esdm.go.id/publikasi/statistik/handbook.html
[23] http://www.thejakartapost.com/news/2014/12/17/is-adjusting-electricity-tariff-answer-energy-subsidy.html
[24] Estimated based on I-1/TR Tariff, assuming 100 VA consumer
[25] The ceiling price can be increased to -0.30 USD/kWh in case the PV modules are manufactured domestically

supplied electricity. In its operational provisions, interconnection standards including anti-islanding, frequency, power quality, additional function on transaction meter and synchronization are specified.

With the regulation now in place which foresees a net metering arrangement, PLN is preparing the implementation of the regulation. In March 2015 a report is expected which will outline the technical implementation of the net metering scheme. Under discussion is the tariff structure, i.e. whether the scheme will be supported by a subsidy to the consumer or will be set up subsidy free similar to the net metering scheme in the Philippines and an eventual quota system.

5.5 Laos

In 2013 Laos' total electricity generation amounted to 3,976 GWh[26] of which almost 100% provided by RE technologies, namely large scale hydro. The electricity use per capita reached 499 kWh. The total electricity capacity is 2,980 GW of which almost 100% is large scale hydroelectric renewable energy.

Laos' power market is dominated by the public sector. Electricite du Laos (EDL) the state-owned corporation under the Ministry for Energy and Mines owns and operates the country's main generation, some of them in partnership with independent power producers, transmission, and distribution assets.

The rates for potential SSEG users are USD 7 cents/kWh for a domestic end user with a consumption of 1,000 kWh/month and USD 10 cents/kWh for a commercial end user with a consumption of 10,000 kWh/month.

Laos' Ministry of Energy and Mines, supported by KfW, started drafting regulation for the introduction of solar power generation into its power generation mix. This is in line with its Renewable Energy Development plan which foresees the upscale of grid connected solar PV program by 2016. A 200 kW PV plant was installed at the Ministry of Energy and Mines as a first pilot to gain knowledge on the technology and its potential in Laos.

5.6 Cambodia

In 2013 Cambodia's total electricity generation amounted to 1,769 GWh[27] of which 57% was provided by RE technologies namely large scale hydro. The electricity use per capita reached 234 kWh. The total electricity generation capacity is 1,154 MW of which 59% is large scale hydroelectric renewable energy.

Cambodia's power generation market is dominated by the private sector with independent power producers generating 95% of the electricity. Electricite du Cambodge (EDC) the state-owned corporation under the Ministry for Energy owns and operates the country's main transmission and distribution assets serving 48% of the consumers with electricity.

The rates for potential SSEG users are USD 21 cent/KWh for a domestic end user with a consumption of 1,000 kWh/month and USD 16 cents/KWh for a commercial end user with a consumption of 10,000 kWh/month.

Cambodia's primary energy challenge is to ensure energy security and to electrify the country. The government encourages the use of RE, especially solar PV, as an option to supply electricity to un-electrified rural areas. There is currently no regulation for solar and other RE technologies in the EDC system. EDC is in discussion with the private

[26] *EDL ELECTRICITY STATISTICS 2013 downloaded http://www.edl.com.la/en/page.php?post_id=32*
[27] *REPORT ON POWER SECTOR OF THE KINGDOM OF CAMBODIA 2014 EDITION downloaded http://eac.gov.kh/wp-content/uploads/2014/08/report-2013en.pdf*

sector, such as large manufacturing facilities, on the installation of PV for own consumption and the issue of export of excess energy especially during weekends was raised. Such a scheme is in place for sugarcane factories with biomass power plants with which EDC has entered into contract with a unit tariff, stipulating the same tariff for export and import and leading to seasonal export and import situations. EDC has established a new department on rural electrification with a special fund for RE and installed 750 kW in off grid areas. Cambodia is interested to develop models for support mechanisms for SSEG with research institutes.

5.7 Vietnam

In 2009 Vietnam's total electricity generation amounted to 127.7 TWh[28] of which 28.5%% was provided by RE technologies namely large scale hydro. The electricity use per capita reached 1,411 kWh. The total electricity capacity is 30.6 GW of which 49% is renewable energy namely large scale hydroelectric and a small contribution (133 MW) from wind.

Vietnam's power market is dominated by the public sector and regulated by the Electricity Regulatory Authority of Vietnam under Ministry of Industry and Trade (MOIT). Electricity of Vietnam Group (EVN) the state-owned corporation owns and operates the majority of the country's main generation assets and is solely in control of transmission and distribution assets. In 2010, MOIT allowed foreign and private investors to produce and sell electricity to EVN thereby a competitive power generation market developed from 2011-2014. As next steps the country plans to develop a competitive power trading market (2015-2022) and operates a competitive retail sale power market after 2022.

The rates for potential SSEG users are USD 12 cents/kWh for a domestic end user with a consumption of 1,000 kWh/month and USD 17 cents/kWh for a commercial end user with a consumption of 10,000 kWh/month.

Vietnam has experience with a FiT for utility scale wind technology. Due to the low rate of USD 7.7 cents/kWh and other factors however, the scheme did not prosper and only led to less than 50 MW developed capacity.

With excellent solar radiation all year, the Vietnamese solar water heater markets, as well as household and rural solar PV installations are rapidly growing, while utility scale PV projects are still at an early stage of development. Unlike for wind, there is currently no FiT for solar projects.

There are several large roof top PV between 100KWp and 300KWp installed for own use. As the panel prices drop, this type of installation is likely to become more attractive however for a more widespread use of solar PV a support mechanism is required.

The authorities are currently studying the possibility of a support scheme for SSEG, notably solar, with a plan to introduce it by 2016.

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[28] *EVN Annual Report 2012-2013 downloaded http://cms.evn.com.vn/Portals/0/userfiles/tcdl/BCTN_EVN_2012-2013_%20Tieng%20Anh.pdf*

5.8 Brunei Darussalam

In 2009, Brunei's total electricity generation amounted to 3,612 GWh,[29] almost exclusively from natural gas. The electricity use per capita reached 8,652 KWh. The total electricity capacity is 759 MW of which renewable energy plays very small shares with a 1.2 MW solar power demonstration project.

Brunei's power market is regulated by the state. The Department of Electrical Services (DES) is responsible for power generation, transmission and distribution of electricity to the end-users. It is characterized by the lowest average electricity tariffs in ASEAN of USD 6 cent/kWh based on subsidized energy prices. The rates for potential SSEG users are USD 6 cent/kWh for a domestic end user with a consumption of 1,000 kWh/month and USD 4.5 cent/KWh for a commercial end user with a consumption of 10,000 kWh/month.

In this context Brunei's government released a draft white paper in 2012 and set the country's renewable energy target at 10% of electricity generation by 2035. It plans to release its regulatory framework for SSEG during 2015.

The argument for RE investments in Brunei is the positive benefit in terms of gas savings. As RE production cost is higher than the electricity tariff rates, private sector needs be incentivized to invest on RE projects. The funding for RE incentives could be paid from gas savings, subject to approval from Ministry of Finance (MoF). Electricity surcharges can be collected to pay for RE support mechanisms. This is subjected to approval from the Minister of Energy or could come from the government budget.

To achieve its targets and understanding that raising electricity prices is politically sensitive, the government commissioned in 2014 a study from the Brunei National Energy Research Centre (BNERI) to assess and compare the level of incentive that should be provided to residential households under the feed-in tariff or the net metering policy frameworks. It is expected that the study results will provide guidance in determining the right policy option suitable for Brunei Darussalam.

The study presented at the workshop uses a 10 kWp solar PV system as the reference technology for residential households and explores the effects of a 50 MW target achievement over 5 years involving 1,000 households.

The study assumes turn-key cost of 20,000 USD for the PV system and arrives at a levelised cost of electricity of USD 20 cent/kWh, far in excess of the USD 6 cent/kWh cost of electricity from the distribution utility.

5.8.1 Net-Metering (Net-Billing)

The net metering policy option allows electric consumers to generate electricity on-site from eligible facilities and export excess generation to the distribution network. To determine its feasibility, several scenarios were explored.

Scenario A was developed without subsidies and without export tariff. While easy to implement and not requiring subsidies it was concluded that as the households would not recover their investment, the scheme would not be attractive and will be likely to fail.

Scenario B introduces an export tariff of USD 34 cent/KWh which would allow the household to recover its investment. This scheme would trigger private sector investment of USD 101 million and require a total payment from the utility of USD 182 million over 24 years at an NPV of USD 64 million. This scenario does not require

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[29] *IRENA RENEWABLE ENERGY COUNTRY PROFILES ASIA, January 2013 edition, IRENA*

upfront investment from the government and incentivises households to invest. The weakness of the scheme is its complex implementation and sizeable subsidy.

Scenario C uses an upfront investment subsidy to reach grid parity instead of an export tariff. This scheme would trigger private sector investment of USD 26 million and require a total payment from the utility of USD 75 million over 5 years at an NPV of USD 61 million. While this scenario is easy to be implemented, it requires upfront investment from the government and does greatly incentivize the households and the private sector to invest.

5.8.2 Feed in tariff (FiT)

The FiT policy framework offers long-term contracts to solar PV generators based on electricity generation costs and reasonable investment returns.

Scenario A was developed assuming a FiT tariff of USD 20 cent/KWh. This scheme would trigger private sector investment of USD 101 million and require a total payment from the utility of USD 212 million over 24 years at an NPV of USD 74 million. While not requiring upfront investment from the government and providing incentive for households to invest, the weakness of the scheme would be its complex implementation and sizeable subsidy.

Scenario B assumes an upfront subsidy of the government of around 74% of the total investment cost of a 50 MW utility scale solar power plant. At turnkey price of ISD 1.81 per Wp, the total investment cost for 50 MW solar PV park is USD 90.5 million. While easy to implement and manage, this scheme would not involve households and would require substantial upfront public sector investment and management.

The study recommends to either implement a Feed-in Tariff Scheme or Net Metering with Export Tariff as appropriate policy for residential households if the government does not provide upfront subsidy, and if an investor payment is to be passed on to consumers or to be absorbed by DES/MoF. If the government will provide upfront subsidy to reduce generation cost up to grid parity the study recommends to better focus on utility scale investments rather than households. This could be in the form of joint venture with the private sector and to implement net metering only after 5 to 10 years when PV system costs will substantially go down.

6 Summary and Conclusions

The massive growth of the solar market is driven by the rapidly decreasing cost of PV panels and other system cost. This development is inevitable in all countries and, in the absence of regulation, will lead to unregulated installations by consumers leading to serious grid safety and impact issues for the distribution utilities. DUs and the regulators have to consider channelling this development through regulation rather than expose themselves to the risk of those unregulated installations.

Overall, ASEAN countries are actively developing regulation with SSEG support mechanism. Thailand and Malaysia utilized the FiT approach while the Philippines took the pioneer role for net metering, the emerging preferred option in ASEAN.

In developing a country's SSEG support mechanism it is recommended to take the decision on the "best fit" support mechanism based on a solid and country specific scenario study under consideration of LCOE, relevant electricity rates and avoided cost of power generation and growth of electricity needs.

The growth of electricity consumption in the ASEAN countries ranges from 3% to 16% annually. SSEG has the potential to contribute substantially to energy security and is increasingly considered as a contributing factor to the country's power generation mix.

A session at the workshop explored the issue of relevant electricity rates as the consumer and commercial electricity rates for potential SSEG users vary widely in ASEAN driven by different power generation cost but also subsidy schemes. In addition, the average rates can be misleading in determining the applicable relevant rate for the feasibility of support schemes as they include sections of the population that are not the prime potential users of solar roof top solutions. In determining the relevant rate it was assumed that a typical potential domestic user of PV solar in South East Asia has a monthly consumption of 1,000 kWh /month and a typical potential commercial user a monthly consumption of 10,000 kWh.

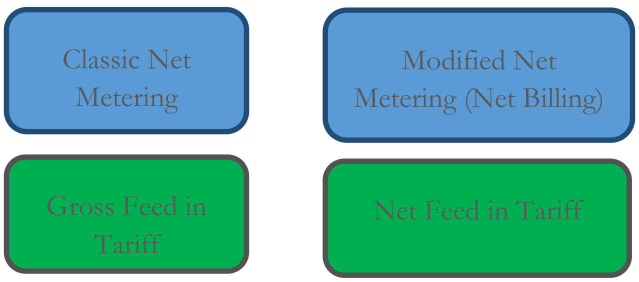
Based on an informal survey at the workshop the following rates were determined.

Country	Rate for domestic end user with a consumption of 1,000 kWh/month	Rate for commercial end user with a consumption of 10,000 kWh/month.
Thailand	0.11	0.16
Malaysia	0.10	0.14
Philippines	0.25	0.20
Indonesia	0.11	0.05
Laos	0.07	0.10
Cambodia	0.21	0.16
Vietnam	0.12	0.17
Brunei	0.06	0.045

Those rates can give an indication together with LCOE, load profile and avoided cost of power generation which support mechanism should be considered.

Furthermore, the tariff scheme should be easy to understand and to implement with minimal administrative procedures and overheads for consumers and DUs. The support mechanism should provide a secure and predictable return on investment at an incentive level sufficient to encourage registration of PV installations to ensure compliance with regulation and assure distribution grid safety and integrity. In implementing SSEG support mechanism the success factors of the Philippine example should be considered. Here the legal basis and political will provided the foundation for champions from the public, private and civil sector to take the lead in an organized collaborative stakeholder process supported by a sustained capacity building effort to develop and pass the regulation and standards which were then disseminated in an information and education campaign to the consumers, distribution utilities and all other stakeholders.

Four standard SSEG support mechanism models have emerged over time which can be used as a basis from which to develop the country specific model.



The expected growing SSEG market is foreseen in the medium term to affect the commercial situation of the distribution utilities as own consumption will reduce the amount of electricity sold to residential and commercial users, however counterbalanced by the growth in general electricity consumption. Mechanisms to control the growth of SSEG discussed are

- Feed-in-Tariff schemes, which are based on gross energy consumption instead of surplus generation.
- Quotas which on the other hand would come with the danger of continued un-regulated installations.
- Compensation of lost revenues for distribution utilities

In terms of tariff structure it was discussed to introduce special net-metering tariffs for users of solar increasing the fixed portion of the electricity bill and reducing the variable part to recover the fixed cost of the distribution utility. However such schemes run counter the idea to promote RE and any SSEG support scheme and create unwanted incentives for increased electricity consumption.

Many distribution utilities are cross subsidizing certain consumer groups usually the poorer population with very low electricity consumption. This cross subsidy comes under stress if the more affluent population participates in SSEG and thereby reducing the income from electricity sales. While not an issue in the immediate future as SSEG is still not very widespread it could develop earlier into a public relation issue that needs to be addressed.

The positive news for the promotion of renewable energy is that support mechanism for SSEG are either already introduced or in the planning phase of being introduced in nearly all of the ten ASEAN countries. While the preferred support scheme for utility scale remains the FiT, the emerging support scheme for SSEG is net metering. The following table illustrates that one country has already implemented net metering and five are considering its introduction within the next three years.

Country	Support Mechanism	Status	Year of Introduction/Plan
Thailand	FiT NM	Conversion from FiT to NM considered	2016/2017
Malaysia	FiT NM	Phased out by 2016 Under consideration	2011 2015/2016
Philippines	NM	Implemented	2013
Indonesia	NM	Regulation issued, Implementation plan under consideration	2015
Laos	-	Initial discussion	2016
Cambodia	-	-	-
Vietnam	FiT or NM	Study on scenarios for FiT and NM	2016
Myanmar	-	-	-
Brunei	FiT or NM	Development of regulatory framework after decision FiT/NM	2015
Singapore	-	-	-

Based on these plans of regulators and DUs it can be foreseen that SSEG will provide a substantial contribution to energy security based on clean technologies offering benefits to consumers in ASEAN. The support mechanism will vary based on the country specific electricity market and should be based in the parameters and experiences laid out in this document.