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Indonesia's Solar Policies

Designed to Fail?

Executive Summary

Consistent and market-relevant enabling policies are key to building affordable solar power. Unfortunately, this basic principle has been overlooked as Indonesia has cycled through a patchwork of solar policies that have driven many experienced investors and developers to the sidelines.

The proof is in the numbers. Despite having substantial solar resources, Indonesia's solar policy framework has failed to deliver cost-effective renewables to the grid. According to Institute for Energy Economics and Financial Analysis (IEEFA) estimates, only 24 MW of solar, including solar rooftop units, are currently installed and dispatchable to the grid. At the same time, Perusahaan Listrik Negara (PLN), Indonesia's dominant state power company—is plagued by an inflexible and high-cost coal independent power producers (IPP) program that is burdening the system with grid development challenges.

The string of policy missteps has persisted even as public and commercial interest in developing solar continues to rise. The most recent setback took place in November 2018, as the government released a much-anticipated guideline for rooftop solar power. The new Ministerial Regulation No. 49/2018 was advertised as a policy that would enable owners of residential, commercial and industrial rooftop PV systems to "sell" excess power to the grid. Based on IEEFA's analysis, however, the headlines do not match the reality. Our modelling shows that many will find the policy hard to assess and difficult to realize financial benefits from installing rooftop solar systems.

This is symptomatic of a sector which faces a range of policy-based barriers to scale:

- Problems associated with the Ministry of Energy and Mineral Resources' (MEMR) Build Own Operate Transfer (BOOT) policy undermine the economics of many solar projects. Despite industry pushback over the past two years, there is no sign the MEMR will address this policy in order to unlock the pipeline of high-quality projects.

- The local content requirements have created a vicious cycle for the whole solar industry. Projects are stalled because IPPs are obligated to use more expensive local panels, while at the same time they are forced to match the cost profile of baseload coal power units which are heavily subsidized. This has made it impossible for local manufacturers to scale up and match the competitive pricing that other countries enjoy.

- PLN's opaque grid management practices are another major hurdle. The single-minded focus on large baseload suppliers comes at the expense of more flexible technologies. This robs PLN of the opportunity to learn from what forward-thinking utility companies have done in other countries and deters investments in the solar sector.

- Quite surprisingly, IEEFA found that financing is rarely seen as a crucial barrier for solar projects in Indonesia. There are indeed enough local and foreign banks lining up to finance utility-scale solar projects. The barrier, however, lies in the lack of scalable projects of sufficient size and quality to meet bankability standards.

The recently launched Indonesia Electricity Supply Business Plan (RUPTL) 2019-2028 pretty much confirmed PLN's lack of willingness to support the solar sector. Instead of following global trends on solar escalation, PLN decreases its solar plan by 137MW or 13% less compared to the previous RUPTL. In addition, the system is still to a large extent dominated by the coal base-load scenario, indicating no innovative design to accelerate renewable implementation nor grid flexibility.

Despite these policy and implementation challenges, Indonesia still has the opportunity to be a smart laggard. The cost of industrial-scale solar technology continues to fall and the flexible grid strategies needed to deliver affordable solar are now market-tested. This means that the pay-back for a solar policy redesign will be even higher. But for Indonesian consumers to get the long-term benefits of solar power, this work needs to start soon before coal lock-in makes it impossible for PLN to diversify its generating mix without stranding over-priced coal IPPs on the crowded Java-Bali grid.

The opportunity is there, but political will and leadership will need to be mobilized in order to address the PLN's implementation challenges. If not, Indonesians will face significant economic, environmental and social costs unless a new consensus can be reached about the future of the country's power sector.

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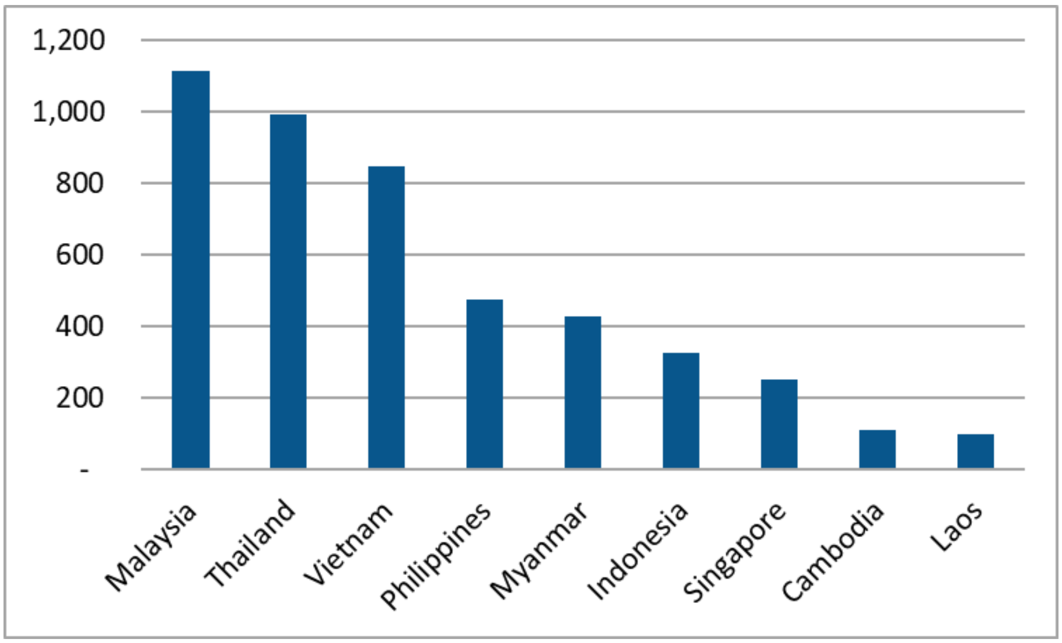
Introduction

Indonesia is fortunate to have excellent daily solar energy thanks to stable irradiation levels through most of the year. Based on daily solar irradiation averaging 4.80 kWh/m2, Indonesia in theory, has more than 500 GW of potential solar sources.[1] Given the rapid move toward solar in countries like India, it is surprising that the installed base of solar PV in Indonesia totals a mere 80 MW, lagging far behind neighbouring South East Asian countries such as Thailand (2.6 GW) and Philippines (868 MW). The graph below represents forecasts for additional solar PV installations in ASEAN countries through 2020.

Figure 1: Forecast New Solar Capacity Installations Through 2020 (MW)



Source: The Lantau Group, Southeast Asian Solar: Market Outlook and Policy Overview, August 2017.

And while countries like Vietnam are working hard to add more than 3,000 MWp of solar and wind to the grid in 2019 and 2020,[2] most of Indonesia's limited capacity is off-grid. According to Solar Plaza, around 80 MWp of installed solar PV systems in Indonesia were dominated by stand-alone off-grid systems in remote locations (64 MWp), while the on-grid systems account for only 16 MWp. It is notable that the off-grid systems were mostly financed with subsidies or grants from the government or donor agencies and have limited capacity of not more than 1 MWp. The on-grid units tend to be utility-scale, with a few rooftop units installed in recent years.

Indonesia's solar PV sector has not been carefully tracked. Neither the normally detail-oriented Ministry of Energy and Mineral Resources (MEMR) nor the state power utility, PLN, produce regular data on how many solar PV systems have been

[1] Global Solar Resource Map, Solargis 2017.
[2] Dezan Shira & Associates Vietnam Briefing. Vietnam's Solar Power Market. September 28, 2018.

installed nationally. Based on various sources, we estimate that there are approximately 14.7 MW of solar PV system running on-grid, 48 MW under construction, and an estimated 326 MW in the pipeline. This is fairly consistent with the new numbers issued in the new RUPTL 2019 which states that current installed solar capacity owned by IPPs is approximately 12.56 MW.[3]

The pipeline was subject to a high degree of uncertainty due to the fact that the largest project, involving 200 MW of floating solar, may not prove viable under current pricing. The new RUPTL seems to have taken this project out, and replaced it, interestingly with a plan for more distributed solar microgrids. IEEFA also found approximately 8.9 MWp of solar rooftops with 2.1 MWp for residential use, while the rest are either commercial or industrial units.[4] It is worth noting that in the new RUPTL, PLN considered the need for an additional 3,200 MW of PV rooftops, on top of the ones listed in the RUPTL, to reach the 23% renewable energy mix by 2025.[5]

The current installed base is almost exclusively made up of small units that lack the economics associated with the industrial-scale solar units commonly found in other markets. The largest utility scale solar power plant that is currently running in Indonesia has an installed capacity of only 5 MW and is located on an isolated island grid in Kupang, East Nusa Tenggara. By contrast, the largest installed PV facility in Thailand is 128 MW while in the Philippines, the largest facility is 132.5 MW.[6] It is expected that several new solar plants will be commissioned in 2019, the largest with a capacity of 15 MW. A more detailed breakdown of the data is presented in Annex 1.

Although Indonesia's solar sector is small compared to its South East Asian peers, the debate over policy incentives for solar has had a long history. Much of the policy literature discusses energy access and strategies to catalyse solar in remote island grids. By contrast, this report analyses the policy gaps that have inhibited the development of the commercial on-grid sector, including utility scale on-grid PVs and residential and industrial rooftop installations. Grid-connected solar PV has proven transformative to power markets globally. As a result, Indonesia's solar resource potential has motivated a diverse community of solar manufacturers, developers, and investors to be early movers in the sector. This report builds on IEEFA analysis of the history of on-grid solar regulations and the market outcomes that have resulted.

[3] RUPTL 2019-2028, page IV-8.
[4] Please see Annex 1 and 2 for detail breakdown.
[5] RUPTL 2019-2028, page VI-2
[6] Solar Plaza, Updated Facts and Figures: Solar Energy 2018 South East Asia.

Why Solar Energy Investment is Not Moving in Indonesia

The Solar Regulatory Jungle

Since its inception in 2009, the Directorate General of New and Renewable Energy and Energy Conservation (DGNREEC) of the Ministry of Energy and Mineral Resources (MEMR) has struggled to design effective policies to enable swift and steady development of the solar energy sector in Indonesia. Its efforts, although appreciated by solar developers who require policy guardrails, have been characterized by a lack of market insight and inconsistent implementation. In the worst case, such as with the recent rooftop policy, their initiatives have actually backfired, scaring away leading global solar players that would be willing to take on market risk in order to gain early market access.

This lack of market orientation might have been understandable in the early years when solar technology was still perceived as untested and expensive relative to conventional technologies. It would also have been understandable ten years ago when MEMR and PLN were unfamiliar with the experience of integrating intermittent technology.

But rather than benefitting from lessons learned from early missteps, it appears that DGNREEC continues to struggle with the policy learning curve. The most notable characteristic of the policy roadmap has been the lack of consistency and the number of course corrections. In fact, change occurred almost yearly, as illustrated in the figures below.

Figure 2: Indonesian Solar Policy Roadmap

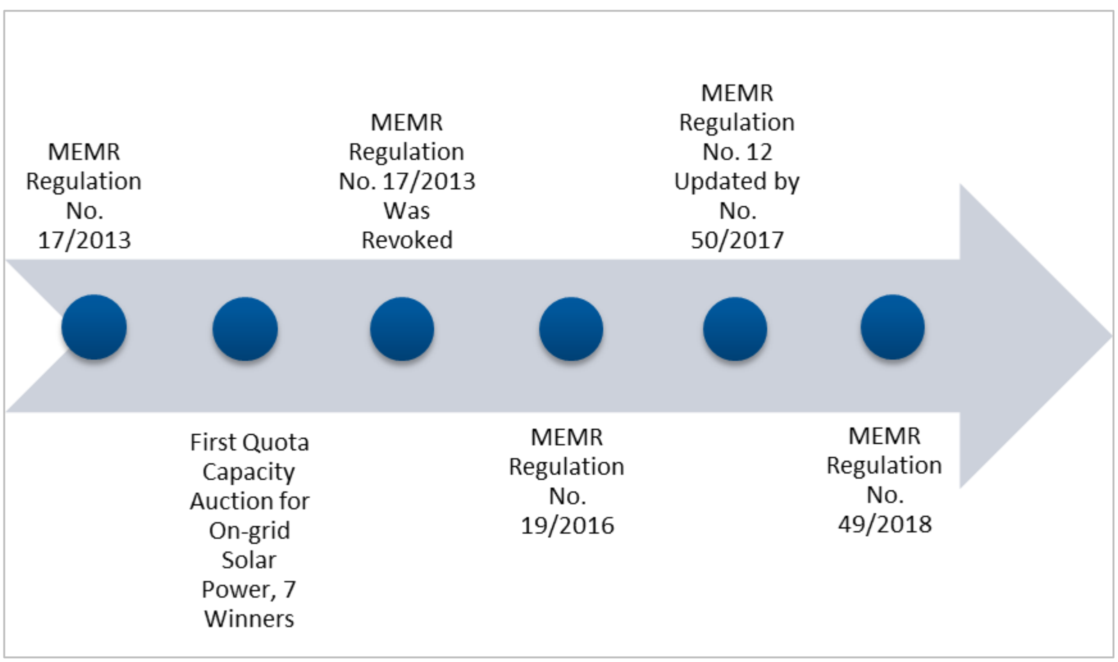


Table 1: Comparison of Solar Energy Policies in Indonesia

	MEMR Regulation No. 17/2013	MEMR Regulation No. 19/2016	MEMR Regulation No. 12/2017 Updated by No. 50/2017	MEMR Regulation No. 49/2018 – (Solar Rooftop)
Price Cap	• US$ 0.25/kWh (using modules with <40% local content). • US$ 0.30/kWh (using modules with >40% local content).	Range between US$ 0.145 – 0.25/kWh depending on project location.	Tariff should be lower than National supply cost of electricity (National BPP) or no more than 85% of local electricity supply cost (regional BPP) which ranges from US$ 0.048 – 0.144/kWh depending on the location.	Net metering scheme. Exported electricity will be offset with imported electricity from PLN. Exported electricity is valued at 65% for compensation. If export is higher, the balance can be accumulated for up to 3 months before it expires.[7]
Procurement method	• Auction based on quota per annum. • Direct appointment allowed if only 1 company bids.	• Auction based on quota for certain pre-determined regions. • Project size per developer is subject to a limit based on the available quota in the region.	Direct selection based on quota capacity.	Self-procurement.
Local Content Requirement	Yes	Yes	Yes	Yes
BOOT	No	No	Yes	No
Deemed Dispatch in case of force majeure	Not regulated	Not regulated	In 2017, MEMR released several regulations concerning deemed dispatch.[8] The latest issued was No 10/2018, where in case of force majeure (from natural disaster), PLN is not obligated to pay deemed dispatch to IPPs.[9]	Yes Industry/commercial rooftop users are charged with parallel operation charges which includes emergency charge.

[7] Under previous internal PLN policy, the balance would be re-set annually instead of quarterly.
[8] MEMR Regulation No. 10/2017 introduced the concept of risk sharing in case of force majeure. This regulation was then updated by MEMR Regulation No. 49/2017 and latest by No. 10/2018.

For Utility Scale On-Grid Solar Power Plants

The DGNREEC started the push for solar deployment by introducing a capped feed-in-tariff (FiT) scheme with MEMR Regulation No. 17/2013. To support the local solar panel manufacturing industry, the Ministry made sure that projects using panels with high local content received higher tariffs than those using imported ones. This regulation also introduced for the first time, a quota capacity auction mechanism.

FiT is commonly used to provide incentives to investors in early-stage solar power sector markets. In other countries, the FiT mechanism is usually implemented to support the growth of solar energy until the sector reaches a certain maturity in the market, and the market is ready to transition to more competitive auction structures.

In Indonesia, however, a FiT mechanism with sufficient incentives to kickstart the solar market was only implemented for a very short period between 2013-2014. The FiT policy was derailed when the whole procurement process was disrupted by legal action taken by the Indonesian Solar Panel Manufacturing Association (APAMSI) which protested the local content requirement. Instead of allowing projects with higher than 40% local content to receive a higher tariff, APAMSI wanted to ban foreign bidders and to ensure that all projects used locally-produced solar panels. Their legal challenge was successful and in 2015, the regulation was revoked, and MEMR cancelled all plans for procurement of solar power from IPPs. The initial auction winners however, are allowed to continue with their projects.[10]

In 2016, the MEMR repositioned after the legal setback, but nevertheless came out with a well-priced FiT scheme for the solar IPPs that would have resulted in more deployment of the technology. The market responded positively and the number of interested IPP players grew resulting in a number of new project feasibility studies. However, momentum stalled in late 2016 following the appointment of a new MEMR Minister who reversed course and backed away from the earlier FiT regime.

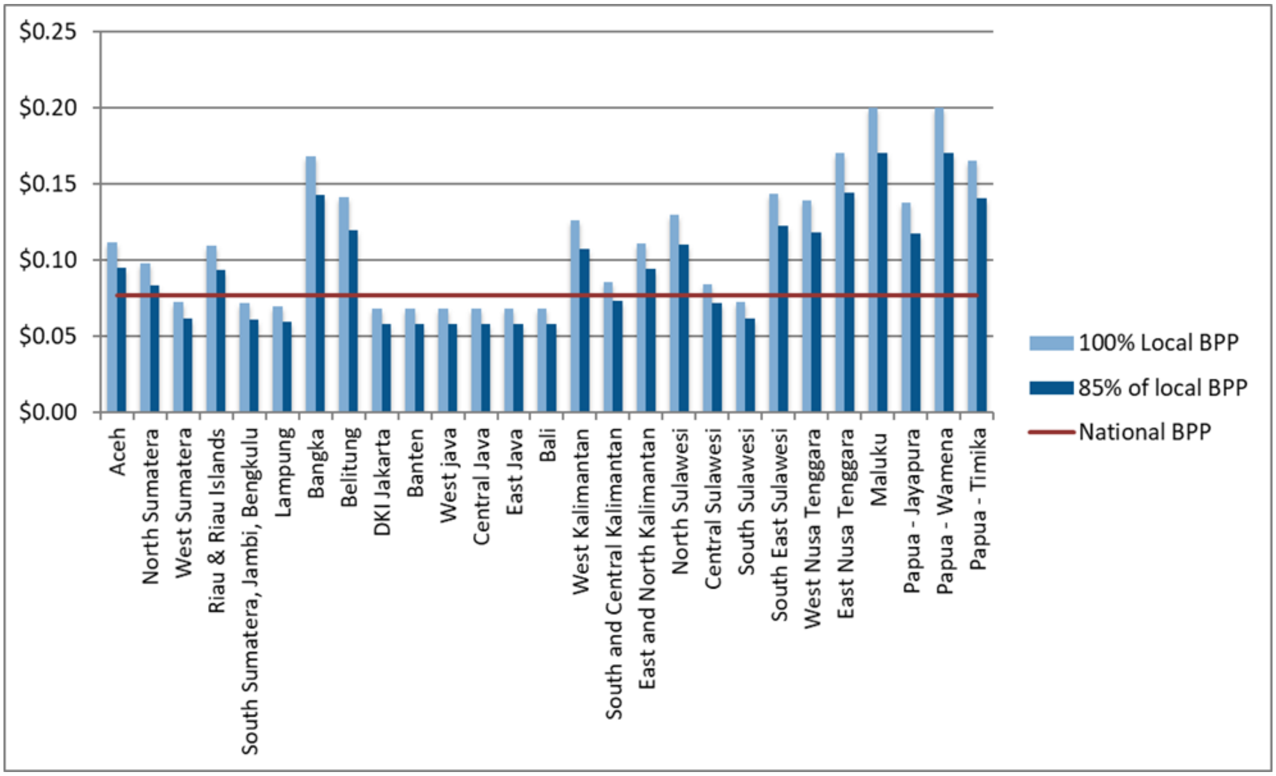
Driven by growing concern about the rapid run-up in PLN's fixed generating costs, the government issued a new solar tariff regime in early 2017, which was updated again within the same year. This latest regulation for commercial on-grid solar power generation is MEMR Regulation No. 50/2017. The regulation states that the solar tariff is now determined by benchmarking against the applicable Electricity Generation Cost or the "Biaya Pokok Pembangkitan" (BPP).

This link to the BPP is a dramatic departure from the earlier more supportive policy framework and instead ties the solar tariff to the cost of prevailing conventional baseload power generation and forces new solar units to compete with a diverse range of coal facilities using cheap domestic coal. Where the local BPP is higher than national BPP, a maximum 85% of the local BPP will be applied for solar, wind, biomass, biogas and tidal projects. In addition, the policy introduces a preference for other sources of renewable and alternative generation with a provision that 100%

[10] https://www.beritasatu.com/ekonomi/288662-dibatalkan-ma-permen-lelang-plts-diganti.html

of the local BPP will be applied to hydro, municipal solid waste and geothermal projects. If the local BPP is equal to or lower than national BPP, then the tariff will be based on mutual agreement between the IPP and PLN.

Figure 3: Electricity Feed-In Tariffs Capped per Region



Note: Locations where the local BPP is higher than national BPP receive tariffs up to 85% of local BPP. The graph shows that areas with more attractive prices are located mostly in the Eastern part of Indonesia, where infrastructure such as roads and ports are not as well developed as the ones on Java-Bali island which leads to higher project costs.

This one regulation has changed the whole game for renewable IPPs and caps a period of regulatory volatility that has steadily damaged market confidence. Interviews with Indonesian solar IPP developers confirm that both domestic and international players do not expect perfect policy implementation, but they are naturally more cautious due to the fact that now the DGNREEC has made it clear that the country will not follow the typical policy roadmap which would encourage developers to gradually scale up and prepare for increased cost competition. Instead, Indonesia's policy instability has triggered a wait-and-see strategy that robs potential investors of incentives to take risks, stay engaged, spend on project development, or build capacity.

In addition, the new solar policy framework highlights the crucial dilemma that bedevils the energy sector and threatens Indonesia's ability to benefit from renewables like their global peers. The question of cost competitiveness is naturally a focus given the billions paid from the Treasury each year to subsidize PLN because the all-in costs of Indonesia's coal-heavy power system are not covered by revenues.

This raises questions about the decision to use the BPP as the key benchmark for solar tariffs. The calculation of the BPP is not transparent and there is no disclosure to demonstrate how it changes year to year, or may fluctuate in the future due to coal price volatility. This makes it impossible for developers assessing solar projects to know how it accounts for the real costs of generation.

Moreover, no effort has been made to address the market logic of applying one pricing benchmark to two technologies with very different financial, developmental, and environmental profiles. Coal power is, of course, a mature technology that requires significant associated infrastructure which affects the total cost that PLN must pay to deliver power to consumers. This is particularly true in the case of remote mine-mouth coal power plants that often require large investments in single purpose transmission and distribution lines.

By contrast, industrial solar is typically smaller in scale than baseload coal and the required grid spend costs less at this stage of its development. Reliance on the BPP also overlooks the rapid pace of innovation which is driving down the cost of solar in other markets as developers gain scale economies and grids work to optimize dispatch of clean energy. As a result, relying on a benchmark that does not take total system costs into account is unlikely to deliver the best power generation mix.

For Residential Solar Rooftop Users

Sector participants were further disappointed by more recent developments as the long-awaited solar rooftop regulations do little to balance risk with opportunity. In late November 2018, after almost two years of policy debate, guidelines for rooftop buyers were finally released. Regulation No. 49 in 2018 establishes a net metering scheme for PLN customers who are residential, commercial and industrial customers that have solar rooftop installations with excess power available for the grid.

Despite the Government's good intentions to accommodate public demand for solar, this much anticipated regulation has failed to meet the expectations of many by ignoring alternative policy norms that would have resulted in more fair and transparent net metering systems, as is generally the case in other markets.

For example, an awkward approach was adopted to compensate rooftop generators for power sold to the grid. Under the proposed rules, users cannot actually "sell" power to the grid because PLN, by law, cannot "pay" back its customers. Instead, the excess electricity becomes a credit for the rooftop owners to net-off their electricity usage from PLN. This will be calculated every month and carried forward for a maximum of three months before the credit expires.

Ironically, this is even less attractive than PLN's earlier regulation. The 2013 PLN internal policy allowed 'credit savings' up to one year or until the end of the year, before the balance was reset to zero. Another setback from global norms and previous PLN rules was the decision to not value exported electricity credits at 100%, instead, the MEMR decided to value them at 65% of the PLN tariff.

Previously, for every kWh of power exported to the PLN grid, customers would be given credits equal to 100% of the applicable PLN customer tariff. With the new regulation, any energy exported by the customer to the PLN grid will be discounted (in kWh terms) by 35%.

The apparent rationale for this decision was based on the determination reached in the 2017 audit of PLN by the State Audit Board (BPK) that power generation costs represented 62% of PLN's total operational costs. The remaining 38% is attributed to transmission and distribution costs as well as line losses.[11] Using PLN's operating model as the reference point, MEMR is attempting to impose the principle that a credit of 65% should be enough to motivate people to install solar rooftops units.

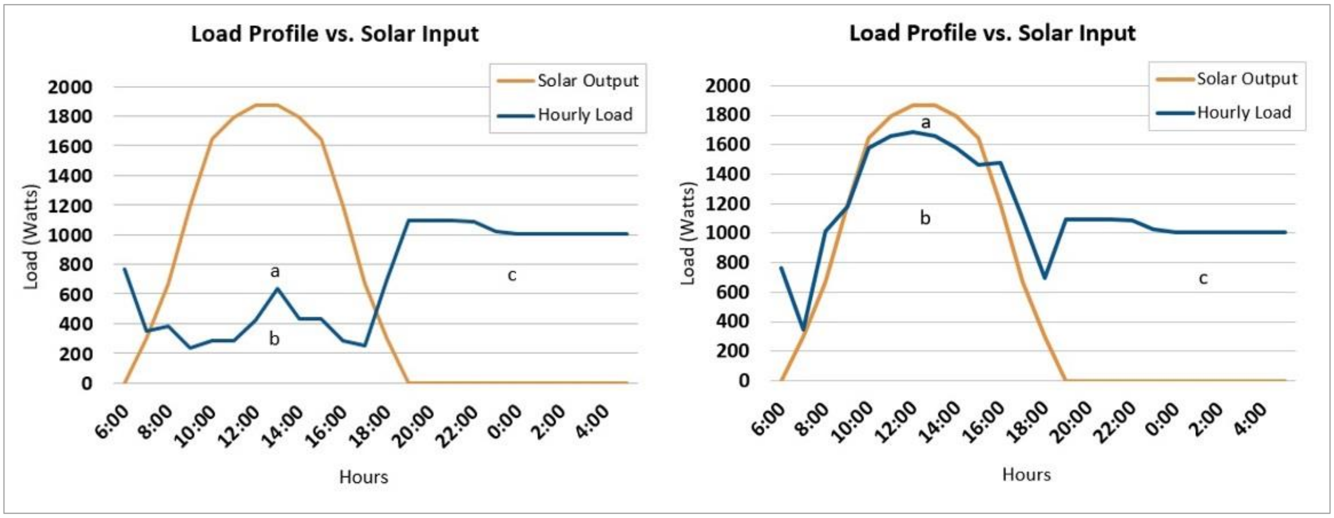
This is exactly the type of policy-design decision that has raised ongoing questions about MEMR's actual intentions for accelerating solar energy. Not only has the strategic role of solar been ignored in shaping policy, but the reasonable needs of developers and off-takers willing to provide capacity to the grid have been disregarded in the policy design process—a practice that again calls into question MEMR's underlying intent.

Rooftop Case Study

This contradiction becomes clear when specific policies are modelled to explore how different types of users would be treated under the regulations in real-world circumstances. IEEFA has modelled the impact of the new net metering scheme on a representative residential user comparing the situation of a high versus low daily load user.

[11] Baker McKenzie. A Glimmer of Sunshine for Indonesian Rooftop Solar PV Projects. December 2018.

Figure 4: Daily Load Profile vs. Solar Input (in Watts) During Low Daily Usage (Left) and High Daily Usage (Right)



Assumptions:

- The Load profiles are assumed for a PLN residential customer having connected capacity at 2,200 VA. A house with standard equipment of 2 A/Cs, one fridge, at least 6 lamps, a water pump, a TV, computer, and chargers. This assumption is by no mean typical for all Indonesian households, however we believe it would represent quite a wide range of households in urban areas.
- Load profile for such house is assumed to be similar every day, hence resulting in constant exported/imported power from PLN daily. IEEFA acknowledges that, in reality, such cases rarely happen, but assumptions are made to simplify calculations.
- The load profiles are also assumed to have the same night-time use, while having different loads during daytime.

Notes:

a. Area A under the dark yellow curve is energy output produced by solar systems (kWh produced by solar energy).
b. Area B under the blue curve is solar energy that is directly consumed by the household (kWh consumed during sun hour).
c. Area C under the blue curve is energy consumed by the household that is imported from the PLN grid (kWh import).
d. A - C = exported energy to PLN grid (kWh export).
e. Under the new rooftop regulation, excess energy exported to PLN grid is valued at 65%.
f. B (self-consumed) is the area valued as 100% savings.

Based on our simulation, it becomes clear that many households will face serious challenges gauging the potential financial benefits of installing a rooftop system and making practical decisions about the best solar system size to maximize savings. Our analysis shows how the potential payback calculations are complex and require sufficient data and analysis to support assumptions about individual households’ load, system efficiencies, and payback periods. Outcomes are particularly sensitive to the user’s daytime load profile and system size. Our payback analysis suggests that the policy will likely favour users with high daytime load profiles who export minimal amounts to the grid. This usage pattern is unusual, however, and although the estimated payback is roughly six years, most households do not fit into this usage profile and the more common low daytime load profile offers a less attractive eight-year payback.

A second conclusion from the simulation is that the policy is designed to discourage residential users who maximize exports to the grid in excess of their own requirements. We found that residential customers with minimal daytime load requirements who install large systems that are capable of exporting most of the output to the grid will face the least attractive financial advantages with an estimated payback period of more than 20 years.

A rather discouraging statement by the CEO of PLN confirmed how the government sees the role of solar rooftops. According to him, the real intention of the regulation is to specifically allow, but not necessarily incentivize solar rooftop users, especially those who live in Java Bali island where the grid is already over-supplied. He even went further by saying rooftop PV should not be installed in Java-Bali but rather in Eastern Indonesia.[12] It is ironic that instead of mining the benefit from the excess solar generation of residential rooftops like many countries, MEMR and PLN are choosing instead to discourage such benefits.

[12] https://economy.okezone.com/read/2018/11/27/470/1983640/rumah-di-jakarta-seharusnya-tidak-pakai-rooftop-panel-surya-ini-alasannya

Table 2: Comparison of Payback Period for Different Scenarios in Rooftop Solar Installations

	Units	2200 VA - 65% Credit		2200 VA - 100% Credit		5,500 VA - 65% Credit	
CALCULATION FOR PLN BILLS		High day time	Low day time	High day time	Low day time	High day time	Low day time
Net energy monthly	kWh/month	391	170	380	58	(62)	(272)
Solar PV cost savings	IDR	642,857	493,470	658,390	614,453	893,696	420,809
CAPEX @USD1.5/Wp	IDR	46,530,000	46,530,000	46,530,000	46,530,000	116,325,000	116,325,000
Simple Payback Period	**Years**	**6.03**	**7.86**	**5.89**	**6.31**	**10.85**	**23.04**

For Industrial Solar Rooftop Users

Use of solar rooftops for industrial customers is also regulated by MEMR Regulation No. 49/2018. The same net-metering and 65% export value applies, plus additional parallel operation charges, which are a combination of a one-off connection charge, a fixed capacity charge, and a punitive energy charge, including an emergency energy charge. This represents a significant burden for potential investors and seems intended to discourage any but industrial users with the deepest pockets.

It is striking that MEMR has designed a policy that appears to discourage precisely the type of industrial users that have been important early adopters of rooftop solar in other countries. This policy tilt will be a particular setback for Indonesian manufacturers that export to global brands. Many of these prized customers are increasingly focused on greening their supply chains and favour those top-tier suppliers that shift to renewable energy. Unfortunately, barring a change of policy, these grid-dependent suppliers may struggle to find cost-effective renewables solutions that PLN would be willing to accommodate.

Unworkable Project Requirements

The erratic regulatory roadmap for Indonesia's aspiring solar developers is made even more challenging by two pillars of power sector regulation that are particularly ill-suited to this nascent sector. The Build Own Operate Transfer (BOOT) rules and local content regulations effectively undermine the ability of project developers to optimize financing and deliver the best low-cost solutions to Indonesian power users.

Build Own Operate Transfer (BOOT)

Since 2017, MEMR regulations have stipulated that all IPPs are expected to transfer projects back to PLN after the power purchase agreement (PPA) expires. This restricts the economic life of solar projects to 20 years. For utility-scale projects that require large tracts of land, this can be a key hurdle for establishing project viability because the BOOT scheme is regarded as a major barrier to bankability due to the following:

1. There is often a high level of risk associated with land acquisition and meeting all of the legal requirements associated with land transfer and ownership.

2. PLN does not provide clear guidance on the valuation of land, specifically whether it will be valued at market price at the time of BOOT transfer. For projects with sites close to residential areas or bordering on urban areas, this would mean a risk of forfeiting any upside from land appreciation.

3. Smaller IPPs, with limited financial capacity, find that the BOOT structure undermines their ability to use land as collateral.

4. For larger players that can handle higher leverage, BOOT rules out opportunities to lease land—a restriction that would prevent such investors from opening up more locations and reducing upfront cash requirements making solar less attractive in terms of profitability.

5. IPP developers are reluctant to make speculative land purchases prior to having a signed PPA. This imposes more risk on the project development process and limits the pool of potential developers.

6. BOOT reduces the likelihood of attractive refinancing opportunities and can severely damage exit opportunities for investors.

Problems associated with the BOOT structure—and their impact on the viability of projects—have been much debated over the past two years since the first issuance of MEMR Regulation No. 50/2017. Nevertheless, the MEMR has shown no willingness to tailor the policy in ways that would unlock the capital required to bring high-quality projects to market. It would appear that MEMR has no intention of exploring alternative interpretations of the Supreme Court's rulings which reaffirm the Constitutional principle that all electricity infrastructure for public use should be under/owned by the Government.

Local Content Regulation

While the BOOT rules frustrate the financing patterns that are common to the solar sector elsewhere, Indonesia's local content rules are also out-of-step with market realities. Currently, any power project in Indonesia is subject to local content requirements set forth by Ministry of Industry (MOI) Regulation No. 54/2012. The local content regulation for solar power projects was updated through MOI Regulation No. 5/2017, and further detailed in MOI Regulation No. 4/2017. Taken together, these rules set a high threshold for using local content that makes it hard for the power sector to scale.

The local content regulations effectively set a minimum threshold for local content both for materials and services used in solar power generation. According to the regulations, there are separate sets of local content guidelines for all the main components involved in solar projects including solar panels, inverters, solar charge controllers, and batteries. The guidelines also extend to services such as delivery, installations, and construction. A more detailed breakdown of the rules is presented in the appendix.

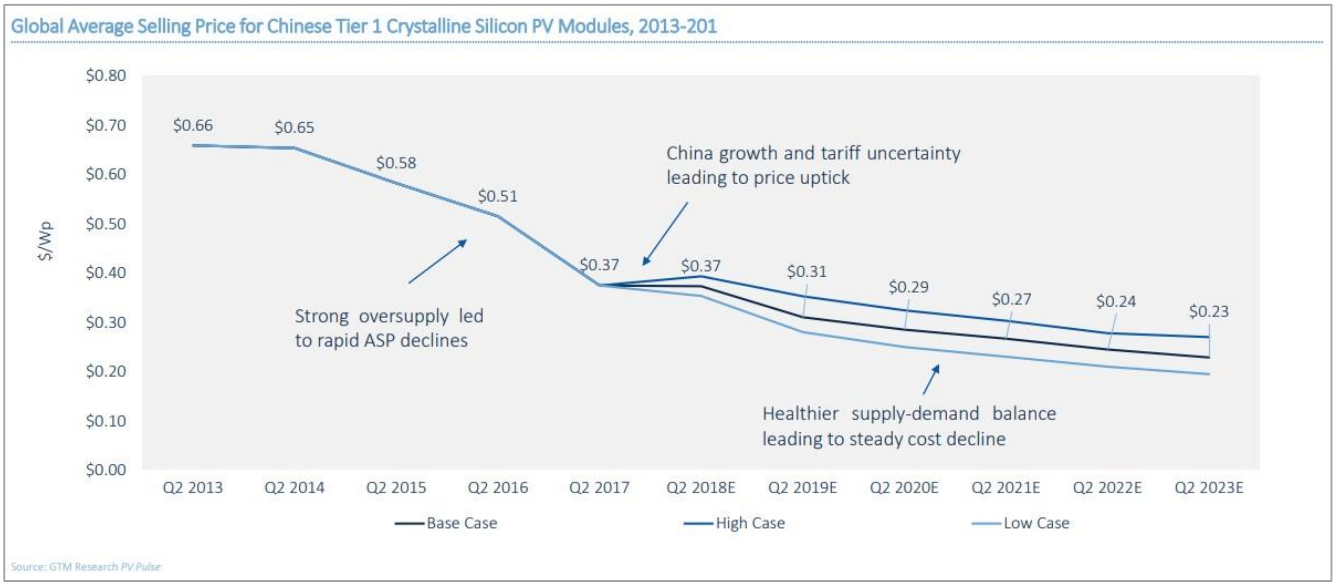
The Vicious Cycle—It All Comes Back to Scale

The local content requirements have resulted in a vicious cycle for the entire solar industry. On the one hand, local content requirements were meant to encourage development of the domestic solar panel manufacturing industry. On the other hand, the domestic industry lacks the technology and market needed to achieve the scale that is now transforming the economics of solar power.

IEEFA has surveyed several of the 11 Indonesian solar manufacturers and found that all sell their panels at a significant premium compared to similar products produced by leading Chinese manufacturers.[13] Based on interviews, domestic manufacturers say they are struggling due to very limited market opportunities which have made it impossible to scale up both in terms of projects size and in purchasing raw materials (especially solar cells). The graph below demonstrates how module prices have fallen significantly over the last five years in the US market, and how they are expected to fall further through 2023.

[13] Please see Annex 3 for a list of Indonesian Solar Panels Manufacturers.

Figure 3: Global Average Selling Price for Chinese Tier 1 Crystalline Silicone PV Modules



Source: GTM Research, Trends in Solar Technology and System Prices, 2018.

To achieve scale, manufacturers need solid market prospects that will support investment. Unfortunately, policy roadblocks have stifled the market and projects have largely been limited to less economically attractive units in the 5-15 MW range. Meanwhile, many international solar component markets are highly competitive, and countries that are not restricted by high local content requirements are now able to pass on significant cost benefits to consumers due to aggressive competition among Chinese producers.

For example, Daqo, one of the biggest Chinese solar panel manufacturers, recently announced it is pressing ahead with plans to more than double output to 70,000 MT by March 2020. Credit Suisse, in its Alt Energy in 2019 report for investors, calls it a smart move because of the hugely more ambitious solar targets the Chinese government is expected to announce in early 2019.[14] Panel prices are expected to continue falling, although not as aggressively as they have over the past five years.

China's dominant position in the core solar technologies is a clear threat to Indonesia's current approach to import substitution. Because Indonesia does not produce its own solar cells, they are usually imported from China. According to industry sources, these cells are typically expensive relative to global market prices and cost almost as much as a complete solar module due to the fact that Chinese manufacturers receive incentives from their government to sell assembled products as opposed to simple components or raw materials.

[14] PV Magazine. The outlook is sunny for solar in 2019, according to Credit Suisse. December 19, 2018.

Even if Indonesian assemblers were able to buy the solar cells more cheaply, they would still face numerous other competitiveness challenges because Indonesian manufacturers tend to use less sophisticated semi-automatic assembly equipment, which sometimes results in lower quality panels. This is due to the lack of the experienced engineers needed to design and operate the factories. It also reflects the high capital costs associated with building sophisticated solar manufacturing. To make matters worse, some market participants have found that although they would consider using local producers, the products are not always bankable, due to distrust from the bank regarding product quality.

Unsurprisingly, Indonesian solar panel manufacturers feel vulnerable given the sector's very slow start. One manufacturer admitted that out of their 45MW production capacity, they are only producing a maximum of 10 MW of panels per year, less than 30% of their capacity. Given the sparse domestic solar pipeline, they cannot plan on achieving economies of scale, either as a catalyst to push production or to bolster their bargaining position when negotiating procurement for raw materials.

The local content regulation, in short, has become a noose for both the IPPs and for solar panel manufacturers. IPPs are obligated to use local panels, which are more expensive and sometimes of lesser quality. At the same time, they are also pressed to match the cost profile of mature coal power providers that receive generous subsidies for infrastructure, equipment, and finance.

Consequently, many IPPs and project developers see this as an unfair treatment from the government as it creates an unlevel playing field for the solar IPPs. It also raises questions about the Indonesian Government's commitment to realizing the benefits of renewable energy and to achieving its 23% renewable energy mix target.

PLN Grid Management Practices

As a vertically integrated utility company, PLN is subject to multiple conflicts of interest that have arguably restricted investment in renewable projects. As the single buyer as well as the single seller of electricity in Indonesia, PLN typically has the authority to decide which projects are approved and prioritized. Having control of the transmission and distribution systems under one roof also means PLN gets to choose where and when the grid should be built next. Theoretically speaking, of course, MEMR has oversight concerning all of PLN's decisions, but the reality is that PLN holds immense power when it comes to virtually all aspects of Indonesia's grid management and power generation strategy.

Of course, as with any traditional utility company, there is a strong bias toward incumbent players and technologies as they are well understood and often fit with existing grid structures and dispatch patterns. For PLN, coal has uncontested primacy as the baseload fuel of choice due to Indonesia's significant domestic coal reserves. This bias is reinforced economically by the use of long-term thermal power PPAs with capacity payments and artificial caps on the price of domestic coal which reduce price volatility risk and shield domestic coal producers from competition.

PLN's lack of interest in more flexible technology options lags behind even conservative scenarios sketched out by the International Energy Agency (IEA). While PLN maintains a single-minded focus on large baseload supply fixes, sophisticated demand-side solutions have been largely ignored, including digital smart-grid strategies.

This resistance to newer grid management strategies is often deployed as a barrier to solar and wind projects. Based on IEEFA research, it is not uncommon for solar IPP developers to see projects halted by local PLN officials based on what they claim to be grid constraints. IEFFA research indicates that this explanation is especially common for projects that are planned for locations outside the main Java Bali grid. PLN still prefers to run the grid the way they know how. This translates to a dispatch system that depends very much on inflexible base load, with minimal efforts to address different types of demand-response.

The potential impact of more affordable battery storage has also been overlooked by PLN despite the fact that new storage options could unlock flexibility options that would increase grid stability and reliability.[15] Bloomberg New Energy Finance (BNEF) recently forecast that lithium-ion battery prices, already down by nearly 80% per megawatt-hour since 2010, will continue to fall as electric vehicle manufacturing builds up through the 2020s. Seb Henbest, head of Europe, Middle East and Africa for BNEF and lead author of New Energy Outlook 2018, said: "We see USD 548 billion being invested in battery capacity by 2050, two-thirds of that at the grid level and one-third installed behind-the-meter by households and businesses".[16]

Industry contacts confirm that PLN's opaque grid management strategies are frequently deployed as a barrier to securing higher level commitments to solar projects. In one instance, a construction-ready utility scale solar project by a prominent player was halted due to a large gap between day-time and night-time demand in the local grid system. With peak hours occurring during night time, local baseload generators were often idle during the day. As a result, local PLN officials worried that, were solar power to penetrate during day-time, the lack of storage options would result in curtailment.

In addition, PLN's production costs rise during night-time hours as high cost peakers are often dispatched to meet night-time peak demand. In this scenario, solar IPPs have found that local PLN officials have resisted permitting new solar units on the basis that they would not be able to compete with lower day-time cost producers. This type of ad hoc decision-making is out of step with MEMR's regulations, but it has not stopped local officials from reinterpreting tariff terms to rule out solar projects even when they appear to meet all other requirements.

Solar IPPs also report dispatch problems for operating facilities due to difficulties in managing intermittency and the lack of spinning reserves. Sometimes local PLN officials even go so far as to ask the IPP to bear the cost of the spinning reserve. This is particularly true for one solar operator on a grid with limited spinning reserve

[15] World Energy Outlook 2018, p. 301.
[16] BNEF Outlook 2019.

capacity that the local PLN officials are reluctant to deploy. Their solar-generated electricity is still not fully absorbed by the grid due to the grid's inability to manage intermittency. This creates constant curtailment, resulting in financial losses for the operator due to the take and pay terms of their PPA.

Is Financing Really a Problem?

In light of the many operational barriers that solar IPP developers encounter in Indonesia, one surprising outcome of IEEFA's research has been that financing is rarely the most critical barrier to building utility scale solar projects. Many of the IPPs interviewed confirmed that there are sufficient numbers of local and international banks lining up to finance utility scale solar projects, including Development Finance Institutions (DFI) such as the International Finance Corporation (IFC) and Asian Development Bank (ADB). In reality, the major barrier is the non-existence of scalable projects with sufficient size to qualify for financing from these institutions.

The DFI's minimum size for financing is typically in the range of USD 25 million. For a solar project, assuming capital spending of USD 1 million/MW, there would need to be a solar project on the scale of 25 MW to attract such financing. The minimum project size required to receive financing by certain commercial foreign banks is even higher. Some say, a minimum project size of 50 MW is needed to qualify for project financing. Anything below that level will need to rely on traditional corporate financing.

Alternatively, to reach scale, Indonesian IPPs could adopt a portfolio financing strategy for a package of aggregated projects that could be of interest to the DFIs. Last year, ADB announced a landmark transaction that could become a model for future IPPs in Indonesia. The USD 215 million Eastern Indonesia Renewable Energy project, consisting of a portfolio of one 72MW wind (Tolo phase 1), and four solar power plants aggregating to 42 MW (phase 2) on Sulawesi and Lombok Island received financing from ADB as the sole lender. Vena Energy, previously known as Equis Energy, is the project sponsor, and it managed to raise USD 160 million in limited-recourse project financing through an ADB direct loan. In addition, they raised two additional tranches of senior debt from an administered trust fund—the Leading Asia's Private Infrastructure Fund (LEAP) backed by Japan' International Cooperation Agency (JICA) with concessional funding from the Canadian Climate Fund for Private Sector in Asia (CFPS II) funded by the Government of Canada.[17]

The portfolio approach is particularly innovative as it drives down costs for small-size projects that would have made project financing challenging on a stand-alone basis. By developing four projects in parallel, based on substantially the same project documents, counterparties, and substantially the same terms of financing, sponsors and lenders expedited the due diligence and financing processes.

Having a portfolio would also increase the bankability of some of the smaller projects, compared to executing them as stand-alone projects. In the case of the Vena Energy transaction, the lender and sponsor jointly engineered a discrete

[17] PFI 2018 – Landmark for Indonesian Renewables.

mechanism in the finance documents to permit the larger Phase 1 project—which had a higher tariff and debt service coverage ratio than Phase 2—to support the Phase 2 projects and mitigate the impact of certain additional risks specific to the projects in the later phase.[18]

It is worth noting however, that not every renewable deal may qualify for portfolio financing, and transaction-specific obstacles may remain. Considerable creative thinking on the sponsor's and lender's side is required to engineer such portfolio mechanisms.

This is one area in which the Indonesian government is beginning to be pro-active. There are several new initiatives that have been developed to encourage the private sector to invest more in renewable energy projects. Some of this effort is focused on new funding tools which could target renewables including blended financing, government guarantees, availability payments, and a project preparation fund.

The recent launch of the SDG Indonesia One platform by PT Sarana Multi Infrastruktur (PT SMI), which is backed by the Ministry of Finance, was a promising start. This open platform is designed to coordinate a pool of funds coming from multilateral donors and philanthropies that would help accelerate financing to renewable energy projects and other clean infrastructure investments. The USD 2.4 billion committed fund will be managed by PT SMI, through many different kinds of financing mechanisms.

Can Indonesia Be a Smart Laggard?

As outlined in this report, Indonesia's energy policies and implementation challenges have proven to be significant obstacles to even limited innovation in the power sector. Nevertheless, 2019 will be a critical crossroads for the Indonesian energy sector and the political interests that have shaped recent outcomes. After freezing tariffs for the past two years, it is widely expected that tariffs will see a sharp increase sometime after the April presidential elections as way to tackle PLN's rising operating deficit. (See http://ieefa.org/wp-content/uploads/2018/05/PLNs-Coal-IPP-Funding-Gap-Suggests-Tariffs-Must-Rise-in-2020.pdf) Any power tariff increase is a politically sensitive event, and it is natural to expect the Government to consider adjustments to the electricity supply business plan (known as Rencana Usaha Penyediaan Tenaga Listrik, or RUPTL) that would fit better with the trend in global power changes—particularly the transition to deflationary clean energy.

Given the challenges that Indonesia's struggling solar sector faces, it is important to consider how the Government might begin to better align itself with the trends that are transforming other cost-effective power markets.

1. **Real Consultation:** In the absence of an experienced independent energy regulator, it would be advisable that more public participation be included in future, before the Ministry or Central Government issues or changes regulations. This is especially important to avoid erratic and frequent policy

[18] Ibid.

changes. Attention should be given not only to PLN and its capacity and ability to adapt to the changes, but also to the needs of customers, industry players, financiers and investors. The current PLN-centric policy planning process fails to address broader market issues that will be crucial as new clean energy options bring more diverse stakeholders into the energy discussion.

2. **Focus on the Grid**: Investing in a more flexible grid is the single most important step that forward-looking power companies can take in a period of rapid technology and market change such as the present. PLN's coal bias has dictated the terms of far too many decisions about grid design, investment, and operations. New thinking and mindset and better governance is needed to help PLN de-risk its grid operations. Intermittency is not limited to renewables. Large, badly performing baseload facilities impose a significant cost on brittle grid structures that is often more significant than the minor concerns that PLN raises over small-scale solar facilities.

3. **Transparency**: Perhaps the biggest structural challenge for the development of Indonesia's power sector is the lack of transparency—in terms of policy formation, implementation, and also price competition. This lack of transparency is notable, even by the standards of the Asian region where policy roadmaps, competitive auctions, and grid performance standards have been used to mobilize cutting edge technology and secure large pools of well-priced capital. Indonesia is fortunate to have many pockets of policy expertise backed by technocrats who understand the practical steps that must be taken to reset Indonesia's power policies.

   One key enabler would be the kind of transparency that puts all market participants on an equal footing with a common understanding of how the system actually operates. In light of rapid growth of the electricity system, and frequent reports of local problems, it may be the right time to undertake a thorough audit of the system including how existing units are operating. Attention should also be paid to whether IPP project selection and associated PPAs are aligned with MEMR's state policy goals and how they may advance Indonesia's ability to meet its 23% renewable energy mix targets.

4. **Training**: In line with the Central Government's strategy, infrastructure development should be supported by human resource capacity development. The availability of skilled engineers and technicians will be a critical enabler for Indonesia as the power sector grows and diversifies in coming years, in line with new technology trends. Industrial scale renewables, whether solar or wind, require a talent pool that can support high value construction projects as well as daily maintenance and support roles. The clean energy sector has been a meaningful source of job creation in many countries. It is time for Indonesia to take this opportunity more seriously if future generations are to benefit from the promise of global innovation in the energy sector.

Annex

Annex 1: On-Grid Solar Power Plants in Indonesia

No.	Location	Capacity (MWp)	Status	COD Year	Name of IPP
1	Sumalata, Gorontalo, Gorontalo Province	2	Running	Feb-16	PT Brantas Energi - Adyawinsa KSO
2	Kupang, East Nusa Tenggara	5	Running	Jan-16	PT LEN Industries
3	Atambua, East Nusa Tenggara	1	Construction	Planned 2018	PT Global Karya Mandiri
4	North Lombok, West Nusa Tenggara	2	Running		PT Berkah Surya Madani
5	Maumere, East Nusa Tenggara	2	Construction	2018	PT Indo Solusi Utama
6	Kotabaru, South Kalimantan	2	PPA Signed; Never Constructed		PT Global Karya Mandiri
7	East Sumba/East Nusa Tenggara	1	PPA Signed; Never Constructed		PT Buana Multi Tehindo
8	Isimu, Gorontalo	10	PPA, Under Construction	2019	Quantum Energi
9	Sengkol, Lombok	5	HoA Signed, Under Construction	2019	PT Infrastruktur Terbarukan Cemerlang (Equis Energy Group)
10	Selong, Lombok	5	HoA Signed, Under Construction		PT Infrastruktur Terbarukan Buana (Equis Energy Group)
11	Priggabaya, Lombok	5	HoA Signed, Under Construction		PT Infrastruktur Terbarukan Adhiguna (Equis Energy Group)
12	Likupang, Minahasa, North Sulawesi	15	HoA Signed; Under Construction	2019	PT Infrastrukture Terbarukan Lestari (Equis Energy Group)

13	Sambelia, Lombok (changed location from Kuta Lombok)	5	HoA Signed, Under Construction	2019	NV Vogt Pte. Ltd. - PT Delapan Menit Energi
14	Cirata, West Java (Floating Solar)	200	Cooperation Agreement-Cancelled by Masdar. Now Open for Re-tender.	2019 (first 50MW), 2020 (150MW)	Previously: PT PJB - Masdar
15	Jembrana, Bali	50	Loi Signed, but Then Revoked, and Will Be Retendered.	Unknown	PT Akuo Energi Indonesia
16	Kubu, Bali	50	Loi Signed, but Then Revoked, and Will Be Retendered.	Unknown	PT Infrastruktur Terbarukan Fortuna (Equis Energy Group)
17	Minahasa, North Sulawesi	0.1	Running		PLN
18	Tahuna, North Sulawesi	0.6	Running		PLN
19	Manado, North Sulawesi	0.3	Running		PLN
20	Molawahu, Tibawa, Gorontalo Province	25	Planned; Under Local Gov. Review	Construction Start 2019	PT Quantum Energy
21	PLTS Cirata	1.3	Running	2015	PLN
22	PLTS Karangasem	1	Only Connected Recently	2018	
23	PLTS Morotai	0.6	Running		PLN
24	PLTS Kepri	0.6	Running		PLN
25	PLTS Bangka	0.2	Running		PLN
26	PLTS Belitung	0.1	Running		PLN
27	PLTS Lombok	0.9	Running		PLN
	TOTAL RUNNING (On-Grid)	**14.7**			
	TOTAL UNDER CONSTRUCTION	**48**			
	TOTAL PLANNED (UNCERTAIN)	**326.2**			

Annex 2: On-Grid Rooftop Solar PV

No.	Location	Capacity (MWp)	Status
1	PLTS Jakabaring Palembang	2.0	Running
2	KESDM buildings	0.5	Running
3	PT Badak LNG	0.4	Running
4	PT Pertamina (Persero)	1.2	Running
5	SPBG	0.2	Running
6	PLTS Gelora Bung Karno (Stadium)	1.0	Running
7	AEON Cakung Mall	0.5	Running
8	Households (members of PPLSA)	2.1	Running
9	PT Djarum (ground-mounted – Karawang)	0.4	Running
10	PT Djarum (Surabaya)	0.6	Running
TOTAL		**8.9**	

Annex 3: Indonesian Solar Panel Manufacturers

No.	Solar Panel Manufacturer	Year of Establishment	Manufacturing Capacity (MWp/Year)	Apamsi Members	Local Content
1	PT LEN Industry (Persero)	1991	30	Yes	40.11-43.79%
2	PT Surya Utama Putra	2009	20	Yes	40.47-48.76%
3	PT Swadaya Prima Utama	2010	20	Yes	40.05-44.12%
4	PT Adyawinsa Electrical & Power	2009	10	Yes	40.18-40.98%
5	PT Azet Surya Lestari	2003	10	Yes	40.04-40.66%
6	PT Wijaya Karya Industri Energi	1993	10	Yes	40.18-44.19%
7	PT Sankeindo	1988		Yes	40.01-56.79%
8	PT Sky Energy Indonesia	2008	50	Yes	40.18-47.53%
9	PT Jembo Energindo	2013		Yes	40.19-42.09%
10	PT Canadian Solar Indonesia - PT Daya Terbarukan Nusantara (Solaris Group)	2015	60	No	40.18%
11	PT Skytech Indonesia			No	40.04%-43.60%

Note: Indonesian Solar Module Manufacturer Association (APAMSI).

Annex 4: Local Content Regulations

Ministry of Industry Regulations on Local Content Requirements for Electricity Infrastructure

<table>
<tr><th></th><th>Stand-Alone Off-Grid Solar PV System (Including Solar Home Systems or Off-Grid Rooftops)[19]</th><th>Centralized Off-Grid Solar PV System[20]</th><th>Centralized On-Grid Solar PV System</th></tr>
<tr><td>MOI Regulation No. 54/2012</td><td colspan="3">
• Requirement for all electricity infrastructure to use local materials and services.
• The local content regulation applies to all electricity infrastructure built by State Owned Enterprise (SOE), Regional Owned Enterprise (ROE), private sector, or cooperative using the Central Govt. Budgets/Regional Govt. Budget/grant/foreign loan.
• Import of materials may be done in cases in which:
a. Materials are not produced domestically.
b. Technical specifications from domestically-produced materials cannot match requirements.
c. Domestic production quantity is not enough to supply demand (a statement by an association or factory is needed for this).</td></tr>
<tr><td rowspan="2">MOI Regulation No. 5/2017</td><td>Main component of materials includes solar panels, battery, battery control unit, PV mounting system, cable, accessories.

Main component of service includes delivery and installation service</td><td>Main component of materials includes solar panels, inverter and solar charge controller, DC combiner box, distribution panel, cables (AC and DC), protection system, PV mounting system, and energy limiter.

Main component of service includes delivery, installation, and construction service.</td><td>Main component of materials includes solar panels, inverter, DC combiner box, distribution panel, transformer, cables (AC and DC), protection system, PV mounting system.

Main component of service includes delivery, installation, and construction service.</td></tr>
<tr><td>Required local content value:
a. for materials min 39.8%
b. for service 100%
c. combined local content value min 45.90%</td><td>Required local content value:
a. for materials min 37.5%
b. for service 100%
c. combined local content value min 43.72%</td><td>Required local content value:
a. for materials min 34.1%
b. for service 100%
c. combined local content value min 40.68%</td></tr>
</table>

[19] According to MOI Regulation No. 5/2017, the stand-alone off-grid solar PV system is any solar PV system that produces energy that is used directly without using any distribution lines.
[20] Centralized off-grid solar PV system is any solar PV system located in an area where its energy produced is distributed to energy users through non-PLN distribution lines (usually known as simply off-grid).

	Local content required for materials above is described as: a. for solar panels min 40% b. for battery min 40% c. for battery control unit min 42.4% d. for cables min 90%	Local content required for materials above is described as: a. for solar panels min 40% b. for DC combiner box min 20% c. for distribution panel min 40% d. for battery min 40% e. for cables min 90% f. for protection system min 20% g. for PV mounting system min 42.4% h. for energy limiter min 40%	Local content required for materials above is described as: a. for solar panels min 40% b. for DC combiner box min 20% c. for distribution panel min 40% d. for trafo min 40% e. for cables min 90% f. for protection system min 20% g. for PV mounting system min 42.4%
	Local content requirement for solar panels is increased into 50% by 1st January 2018, and 60% by 1st January 2019.		
MOI Reg No. 4/2017	Further regulates how the local content requirement is weighted for each material. This regulation provides a more detailed minimum weight (in %) for each of component in the solar PV system.		

Annex 5: Solar Rooftops Simulation

		2200 VA 65% Credit		2200 VA 100% Credit		5500 VA	
	Usage level	High day time	Low day time	High day time	Low day time	High day time	Low day time
Total PV output	Wh/day	14,960	14,960	14,960	14,960	37,400	37,400
Total own-used solar energy	Wh/day	13,952	7,380	13,952	4,253	15,445	4,700
Total energy export	Wh/day	1,008	10,707	1,008	10,707	21,955	32,700
Valued at	Wh/day	655	6,959	1,008	10,707	14,271	21,255
Total energy imported from PLN	Wh/day	13,688	11,175	13,688	12,642	12,195	12,195
CALCULATION FOR PLN BILLS							
Net energy monthly	kWh/month	391	170	380	58	(62)	(272)
Electricity purchased by PLN	IDR/month	573,580	250,078	558,047	85,159	-	-
Minimum charge (Rp/kWh)*	IDR/month	129,096	129,096	129,096	129,096	322,740	322,740
PLN bill (with solar PV)	IDR/month	573,580	250,078	558,047	129,096	322,740	322,740
PLN bill (without solar PV)	IDR/month	1,216,436	743,549	1,216,436	743,549	1,216,436	743,549
Solar PV cost savings	IDR/month	642,857	493,470	658,390	614,453	893,696	420,809
CAPEX @USD1.5/Wp	IDR	46,530,000	46,530,000	46,530,000	46,530,000	116,325,000	116,325,000
Simple Payback Period	**Years**	**6.03**	**7.86**	**5.89**	**6.31**	**10.85**	**23.04**
Note: The minimum charge is incurred if the monthly bill is less than a specified amount							

The simulation shows that:

1. When the 65% limit on the credit value is imposed, most of the benefits will go to consumers who use a lot of daytime energy. In other words, households that are active during the day will benefit more by installing solar rooftops compared to houses that are empty during the day. This is because their "B" area, which is valued at 100%, is more than their exported energy (A-C), which is valued only at 65% equivalent.

2. Making the right decision about the size of the solar panel based on the load profile is very important in order to realize maximum savings. The comparison tables describe how different and/or wrong sizing would create a significant impact on the payback period. Having higher subscribed power (or installed power) does not necessarily mean the household will benefit more by installing a solar rooftop that matches its installed capacity. Finding the right system sizing that corresponds well to the typical load profile of the customer is more important. The key is to reap the most benefits from own-day-use savings.

3. The minimum charge requirement complicates the calculation for energy savings. It offsets any benefits if the monthly payment is below the minimum charge. In the comparison table, we found that if the monthly payment is constantly below the minimum charge or if the customer only is importing a small amount from PLN, the minimum charge actually decreases its monthly

savings. In effect, if the monthly bill after solar installation is lower than the minimum charge, then the minimum charge reduces the savings as it becomes a fixed cost.

4. When the system is correctly designed, and priced, households with high daytime use would benefit from the installation of solar rooftop units depending on their financial circumstances. The payback period for households with high daytime usage is roughly 6 years. Even when the excess capacity is valued at 65%, it does not have a large effect on the payback period. However, users will need to take the time to study the load profile which is not something that many people are equipped to do, including some of the rooftop installers. Unfortunately, the complexity of the policy will prove challenging to many of those involved in choosing, analyzing and investing in solar systems.

About IEEFA

The Institute for Energy Economics and Financial Analysis conducts research and analyses on financial and economic issues related to energy and the environment. The Institute's mission is to accelerate the transition to a diverse, sustainable and profitable energy. www.ieefa.org

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