Estimating the cost of producing grid-connected solar PV in Indonesia

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Abstract. Indonesia has set itself a very challenging set of objectives about introducing renewables into the energy mix, particularly large-scale, on-grid, solar photovoltaic (PV). Being on the equator, Indonesia is blessed with year-round sunlight. Although solar PV is the fastest-growing renewable generation source worldwide, Indonesia has hardly started to install it. One of the reasons for the slow development of solar PV in Indonesia is the lack of information for investors regarding the cost required to build and operate a solar PV over a specified cost recovery period. Therefore, this study aims to estimate the cost of producing grid-connected solar PV in Indonesia. As the results of this study, we have constructed a simple tool that calculates the cash flow of a typical project, and then computes levelised cost of electricity (LCoE), internal rate of return (IRR), payback period (PBP), and return on investment (RoI) to explore the business case faced by investors of solar PV in Indonesia.

1 Introduction

Indonesia has set itself a very challenging set of objectives regarding introducing renewable energy into the energy mix, particularly the introduction of large-scale on-grid solar PV. Being on the equator, Indonesia is blessed with year-round sunlight. Although, worldwide, solar PV is the fastest-growing source of renewable generation, Indonesia has hardly started to install [1]. According to PLN's business plan [2], only 139 MWp of solar generation had been installed by the end of 2021, with the primary growth occurring in the last three years, as shown in Fig. 1.

Nevertheless, in its National Energy Policy, Indonesia has committed to at least 23% renewable energy by 2025 [3]. This implies an overall capacity of 5,544 MW, of which Solar PV is expected to contribute 1,631 MW (29.4%) by 2025. In the RUPTL 2021–2030, planned solar PV capacity addition is increased to 4,680 MWp by 2030 (compared to 0.9 GWp in RUPTL 2019–2028 and the latest published capacity of only 139 MW in 2021). Around 63% percent of the planned capacity (2.9 GWp) is expected to be built by the private sector (IPPs). Some planned capacity additions are directed toward village electrification and a diesel conversion program. Under the National Grand Energy Strategy (GSEN), the government also seeks to add 38 GWp of renewable installed capacity by 2035 [4]. In a longer time frame, MEMR is also devising a net-zero emissions roadmap, in which solar PV is projected to be

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the primary (62%) power generator in 2060, and all electricity is intended to come from clean energy. Furthermore, IEA has recently estimated the potential for utility-scale solar PV in Indonesia [5], as shown in Figure 2.

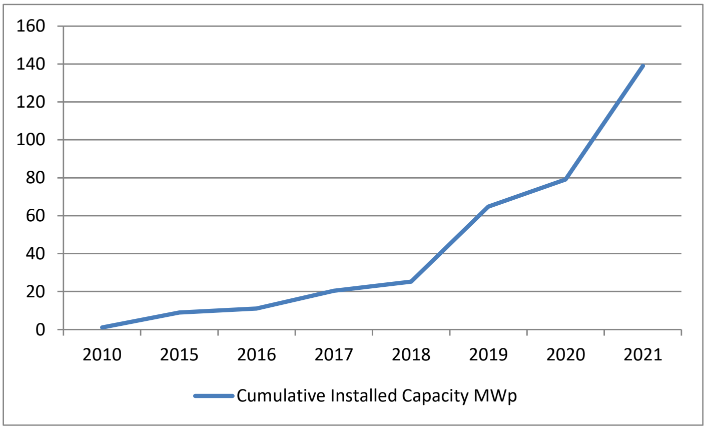

Fig. 1 Cumulative Installed Solar PV capacity in Indonesia (MWp).

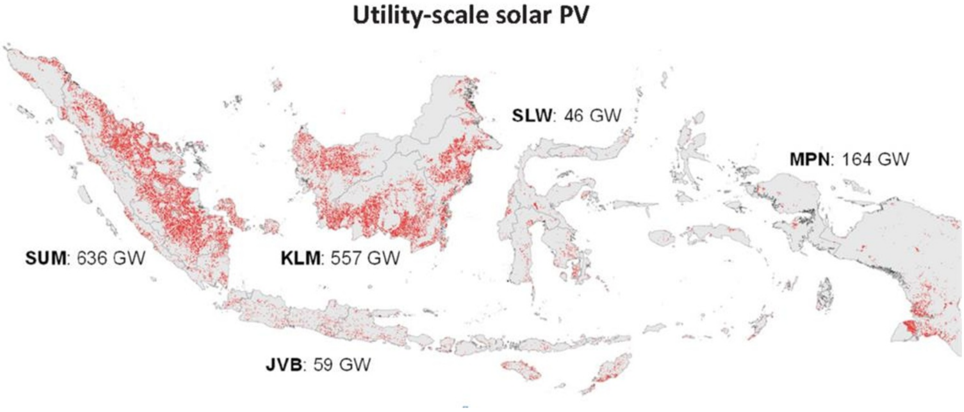

Fig. 2 IEA Estimates of utility-scale Solar PV potential in Indonesia.

The independent Institute for Energy Economics and Financial Analysis (IEEFA) published a review entitled "Indonesia's Solar Policies: Designed to Fail?". This highlighted how design problems with PPPs, local content requirements, opaque grid management practices, repeated changes to regulatory arrangements, and lack of scalable projects led to very few bankable solar projects emerging [6]. One of the reasons for the slow development of solar PV in Indonesia is the lack of information for investors regarding the cost required to build and operate solar PV over a specified cost recovery period. Therefore, this study aims to estimate the cost of producing grid-connected solar PV in Indonesia.

2 Materials and Method

2.1 Key Technical Specifications

Solar cells are semiconductors, usually made from crystalline silicon (c-Si), which generate electricity when exposed to light. Typical modules are 1-2 m2 in size and generate some 100-210 Watt-peak/m2 (Wp/m2). Normally, they have an expected lifetime of around 30 years. A grid-connected PV system also includes a mounting system, dc-to-ac inverters, cables, combiner boxes, optimizers, monitoring/surveillance equipment, and transformers [7]. The PV modules usually account for around 50% of the total system costs, and inverters around 5-10%. In general, energy production from a PV installation with a peak capacity Pp can be calculated as: Pp * Global Horizontal Irradiation * Transposition Factor * (1 - Incident Angle Modifier loss) * (1 - PV systems losses and non-STC corrections) * (1 – Inverter losses) * (1 – Transformer losses).

Inverters typically need to be replaced every 10-15 years, while it is normal to expect 0.25-0.5% physical degradation of c-Si solar cells each year, reflecting typical failure rates. The efficiency of a solar module, ηmod, expresses the fraction of the power in the received solar irradiation that can be converted to useful electricity. A typical value for commercially available PV modules is 15-17%, with high-end products above 20%, when measured in standard test conditions. The module area needed to deliver 1 kWp of peak generation capacity is around 6.25 m2 for today's standard PV modules [8].

2.2 Levelised Cost of Electricity

Levelised Cost of Electricity (LCOE) is a well-established method for calculating the cost of electricity generation at the point of connection (to a load or the electric power grid). It is calculated by dividing the entire lifecycle cost of a solar PV system by its cumulative solar electricity generation. It is usually presented in net present value terms, with each year's cost discounted by the investor's weighted average cost of capital (WACC) [9].

$$\begin{aligned} WACC = {} & (1-D) \times (RFR_{20} + b \times MRP) \\ & + D \times (RFR_{10} + DP)(1-TR) \end{aligned} \tag{1}$$

Where normally:

- Local risk-free rates (RFRs) would be based on Indonesia's government bond yield data, 10 years for the debt cost (RFR10), 20 years for the equity cost (RFR20);
- For the cost of equity, a beta (b) of 1.0 might be applied, assuming an investment of a solar system bears equal risks to investing in the economy of Indonesia;
- Market Risk Premium (MRP), normal rate used by regulators;
- D = debt ratio (percentage of investment financed by an external lender as opposed to 100% equity financing) and DP = debt premium;

While LCOE does not consider external factors or costs associated with grid integration [10].

$$LCOE = \frac{EPCI + \sum_{n=1}^{N} \frac{OM^{*} + IC^{*}}{(1+DR)^{n}} + \frac{IEI^{*}_{n=5,10,15,20}}{(1+DR)^{n=5,10,15,20}} + \sum_{n=1}^{N} \frac{LP}{(1+DR)^{n}}}{\sum_{n=1}^{N} \frac{(IRD \times PR) \times (1-SDR)^{n}}{(1+DR)^{n}}} \tag{2}$$

Where:

EPCI = Equity project cost investment
IC = Insurance cost
N = Number of years in the system's service life
OM = Operation and maintenance
DR = Nominal discount rate
IEI = Inverter warranty extension investment
LP = Loan payment
IRD = Irradiance
PR = Performance ratio
SDR = System degradation rate

2.3 Internal Rate of Return, Payback Period, and Return on Investment

The Internal Rate of Return (IRR) calculates the long-term investment performance for a solar PV project. It gives the total return value over the project's lifetime compared to the costs involved with the system and places a percentage IRR value. It is a long-term financial evaluation measure that is commonly used amongst sophisticated investors in projects with an initial capital outlay followed by many years of financial return. IRR helps to compare investments - e.g. leaving money in the bank versus investing it in a solar PV power system. The formula for IRR is the discount rate for which the project's Net Present Value (NPV) is zero [11].

IRR is not a sensible measure when financing a project, if the project is cashflow-positive in every year - in this case the investor not really 'net' investing any of their own money in any given year, hence, the IRR is infinite. Generally, the higher a project's internal rate of return, the more desirable it is to undertake the project. IRR is uniform for investments of varying types and, as such, IRR can be used to rank multiple prospective projects a firm is considering on a relatively even basis. Assuming the investment costs are equal among the various projects, the project with the highest IRR would probably be considered the best and undertaken first.

The payback period measures how fast the investment will pay for itself. It is a very unsophisticated financial evaluation metric that only looks at the short-term. Payback is not a sensible financial evaluation metric for financed projects, as the initial investment for financed projects is typically zero. The payback period is the time required to recover the cost of an investment [12]. The payback period of a given investment or project is an important determinant of whether to undertake the position or project, as more extended payback periods are typically not desirable for investment positions. The payback period ignores the time value of money, unlike other capital budgeting methods, such as net present value, internal rate of return or discounted cash flow.

The payback period does not concern itself with the time value of money. In fact, the time value of money is completely disregarded in the payback method, which is calculated by counting the number of years it takes to recover the cash invested. If it takes five years for the investment to earn back the costs, the payback period is five years. Some analysts like the payback method for its simplicity. Others like to use it as an additional point of reference in a capital budgeting decision framework. There are three main variants of payback: simple payback, true payback, and discounted actual payback.

The Return on Investment (ROI) calculates short-term investment performance for a solar PV project. It compares the initial investment with the firstyear solar PV project savings (returns) to calculate a percentage return. The ROI formula is: ROI = First Year Revenue / Upfront Cost [13]. ROI is a well-understood measure of the speed of which the project's investment will 'return' i.e., pay for itself. It is a short-term financial indicator - it does not say how well the project will perform after its paid off, or how well it performs in year 2 or

any year other than year 1. ROI is the inverse of simple payback. When a project is financed, ROI is calculated as the total investment over the system's life, divided by the first-year savings.

3 Results and Discussion

On average Indonesia receives between 1500 kWh and 2200 kWh per m2 of annual solar energy on a horizontal surface (Global Horizontal Irradiance, GHI). Java, Sulawesi, Bali, and East and West Nusa Tenggara are the best locations for solar PV, while Kalimantan, Sumatra and Papua are less good. Locations closest to the equator have the most constant solar experience. A valuable tool for exploring what sort of capacity factor (proportion of the day/year a solar PV plant will generate) might be expected in a particular location can be found at https://www.renewables.ninja/. A 1MW installation in Kupang might expect a capacity factor of up to 19.6%, while one in Banda Aceh might only achieve 13.8%. Tilting the panels can increase power in locations away from the equator, but this has limited benefit in Indonesia. At a cost, irradiation can also be increased by mounting the panels on a sun-tracking device. Minimising problems with soiling or shade maximize electricity production; reducing grid connection, inverter, or transformer losses; reducing cable length and cross section; and increasing the overall quality of components.

In order to explore the incentives faced by investors in Solar PV in Indonesia, we have constructed a simple tool which calculates the cash flow of a typical project, and then computes internal rate of return (IRR), payback period (PBP), levelised cost of electricity (LCOE) and return on investment (RoI). The tool can be used for any type of solar PV installation, whether commercial-scale ground mounted, floating or rooftop. It includes an 'assumptions' page that permits the user to specify Size (MWp), Location, Capacity Factor (%), System Loss (%), Tilt, F-factor for Feed-in Tariff, Degradation Rate per Year (%), Capital Costs (US$/kw), Operating Costs (US$/kw/year), PLN charges (US$/kWh), Inverter Cost as % Total (%), Inverter Replacement (years), and Interest Rate for Invested Cash (%). The tool then develops a cash-flow statement based on these assumptions for the thirty-one years from 2023 to 2053. Investment is assumed to occur in 2023, and operation will start in 2024. Inverters are replaced at specified intervals. We have estimated the LCOE for a large-size ground mounted 5 MWp Solar PV in a favourable location, in Kupang, Nusa Tenggara, with current feed-in tariffs allowed by PLN. Our estimates are based on the following assumptions:

- System Loss : 0.1
- Tilt: 10
- Degradation rate per year: 0.50%
- WACC: 5%

PLN Statistics 2021 highlights how little solar PV – only 139 MWp - had been developed by the latest available data. It also provides high estimated costs, of around US$1,250/kW for ground-mounted and US$2,000/KW for floating solar PV in 2021, although there are some estimates of lower costs in earlier years. Operating costs, taken from PLN, are shown to have risen steeply in the period 2017 to 2021. Based on the data collected and reported in PLN Statistics, we have taken US$1,250 as a typical total installed cost per kw, so that installed cost for a 5 MWp plant will be US$6.5 million. Operating costs per kw have been estimated from a combination of PLN RUPTL and PLN statistics as 11.32 US$/kw. We have assumed cost inflation over the thirty-year life of the plant of 6% per annum for these costs. Inverter costs are assumed to be 7.5% of the capital cost. Inverters are considered to need replacing every 12 years, but they are available at the same nominal cost in future years, thus allowing for technical progress.

Using the climate data provided in https://www.renewables.ninja/ for the Kupang location, we estimate a mean capacity factor for this plant of 19.6%, which means that at initial efficiency it will expect to generate 7,726,320 kWh per annum. The relevant feed-in tariff, with an F-factor of 1.2 applied, is 10.52 US cents/kWh, so annual revenue in the starting year is US$0.81 million. Based on these assumptions, we estimate an LCOE of 73.05 US$/MWh, a pay-back period of 9 years, and an internal rate of return of 5.88%. The Net Present Value (NPV) of the project's net cash flow, discounted at the assumed WACC of 5%, is US$0.35 million. Some additional assumptions are needed to calculate the return on investment (ROI). We assume straight-line depreciation for the main assets over 30 years and the inverters over their 12-year life. We also assume that the revenue earned is accumulated and invested in a simple interest-earning account, earning 2% annually. On this basis, return on investment by the end of the project Return on investment (ROI) = (residual value – total cost)/total cost is estimated to be 1.78%. If the interest earned on the revenue earned was higher, say 3%, this would rise to 2.01%.

It is worth noting that none of these financial measures would likely make the project attractive to investors without some subsidy or other incentive. If our project were in a less favourable location, for example, Bogor, we would have a lower feed-in tariff (8.77 US cents/kwh) and a lower capacity factor of 18.2%. In this case, the LCOE would rise to 78.67 US$/MWh, the IRR would fall to 1.94%, the payback period would be 16 years and ROI would be 1.69%. The tool also includes a second version of the cash flow statement based on 'international benchmark' conditions. Here we take a mid-point estimate of installed cost $750/kw, slightly lower operating costs, and PLN charges more in line with international best practice. The LCOE for the international benchmark, without PLN charges, is in line with those reported in Singapore for a ground-mounted 5 MW installation, 48.60 US$/MWh. The tool calculates an IRR of 16.44%, and a pay-back period of 6 years.

IEA estimated that in 2019, Solar PV installations in Indonesia had an LCOE of 80 US$/MWh. This compares with an IRENA estimate of the worldwide average of 60 US$/MWh in 2019, falling to 48 US$/MWh in 2021. IEA reports even lower LCOE for India of 28-35 US$/MWh, and the Singapore PV roadmap reports 48.6 US$/MWh for 2020 for ground-mounted utility-scale solar PV.

4 Conclusion

We have already noted that the cost of solar PV in Indonesia is far in excess of that in most other countries, for many reasons including local content rules, import duties on foreign components, large margins and overheads required by local suppliers, and the general cost of compliance with Indonesian bureaucracy. There are also very few examples of Indonesian solar PV projects on which to base cost estimates so far. A particular issue which will need addressing is the mismatch between the location of the main load centres – primarily in Java-Bali – and the locations of greatest potential for solar PV. The analysis presented above from the IEA Sector Roadmap suggests that solar may only be able to provide 59 GW in Java Bali, a fraction of the forecast demand there in 2050. Attention will need to be given to a whole-of-Indonesia approach to the introduction of solar, including suitable interconnection, if the hoped-for dominance of solar in the generation mix is to become a reality.

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