DISTRIBUTED PHOTOVOLTAIC ECONOMIC IMPACT ANALYSIS IN INDONESIA

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Acronyms

BASA	buy-all-sell-all
DPV	distributed photovoltaics
GDP	gross domestic product
ICED	Indonesia Clean Energy Development
MEMR	Ministry of Energy and Mines
NEM	net metering
NPV	net present value
NREL	National Renewable Energy Laboratory
O&M	operations and maintenance
PLN	Perusahaan Listrik Negara
SAM	System Advisor Model
TMY	typical meteorological year
USAID	U.S. Agency for International Development

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Executive Summary

Like other countries in the region, the Government of Indonesia aims to increase its use of renewable energy in the near term from various technologies, including grid-connected distributed photovoltaics (DPV). While little DPV has been installed to date, the policy landscape has been shifting over the past few years with recent pronouncements from the state-run utility Perusahaan Listrik Negara (PLN) and the Ministry of Energy and Mines (MEMR) that have begun to provide a more supportive policy framework for the deployment of DPV. Nonetheless, many questions remain as to how DPV impacts customers, the utility, and the economy as a whole.

This report presents a holistic view of DPV economic impacts in the Java-Bali region of Indonesia by assessing customer economic impacts, utility revenue impacts, and jobs and economic development impacts. It includes three interrelated analytical undertakings:

- The **customer economic impact analysis** assesses how current electricity tariffs, metering, and billing arrangements for DPV compensation, DPV system prices, and solar energy resources influence commercial and industrial customer decisions to invest in DPV technology. Results demonstrate that, overall, the economic incentive for residential, commercial, and industrial customers to deploy DPV is low given the long payback periods and often negative net present values over the lifetime of the DPV investment. Small residential and commercial customers are expected to face very long (>20 years) payback periods for DPV investments under various compensation mechanisms, primarily due to low electricity rates and relatively high minimum monthly bills. Larger residential, commercial, and industrial customers, on the other hand, face shorter payback periods than the smallest customers; however, almost all customers considered in the analysis have payback times longer than about 10 years under current regulations and retail electricity tariffs.
- The **utility revenue impact analysis** assesses the short-term financial impacts of DPV generation, with a focus on state-owned utility PLN's net revenues. Both costs and benefits of DPV generation to the utility under net energy metering and net billing scenarios are quantified. Results demonstrate that overall, the net revenue impacts to PLN are relatively low—a 0.2% reduction in total revenue collection for 3 GW of DPV deployed in the next 5 years in the Java-Bali grid.
- The **jobs and economic impact analysis** assesses the direct and indirect workforce and economic impact of DPV deployment in Indonesia. The gross economic impact of the theoretical deployment of one thousand 4.9 kW and one thousand 4.2 kW residential solar PV systems in 2019 would support approximately 710 job-years and a total of $4.9 million in gross domestic product (GDP). Results indicate that the construction and manufacturing industries see the greatest job growth and increase in GDP because of DPV installations compared to other economic sectors.

Taken as a whole, these results indicate that the current set of tariffs and regulations governing DPV in Indonesia—used as inputs to our analyses—would not induce strong deployment among commercial and industrial utility customers. Nonetheless, in the near-term, even if up to 3 GW of DPV deployment were to occur, it would have a minimal impact on PLN's revenue collection. DPV deployment, however, would have an initial and ongoing positive effect on jobs and economic development, primarily accruing to the Indonesian construction and manufacturing sectors. Decision makers can use this information to determine how to balance DPV customer, utility, and broader social priorities going forward.

1 Introduction

Jurisdictions around the world, including the Government of Indonesia, are implementing distributed generation programs in response to declining technology costs and burgeoning customer demand. Distributed generation programs are often designed to accommodate a range of technologies; however, under current market conditions, photovoltaic technologies dominate the global distributed generation market, and thus distributed generation program design discussions are often dominated by discussions of "distributed solar," "rooftop solar," "rooftop photovoltaics," and other synonymous terms.

Distributed photovoltaics (DPV), defined as small-scale solar photovoltaics systems that are located at or near the point of electricity consumption, are gaining popularity around the world as PV module and balance of system costs continue to decline. Most countries have programs which allow DPV to be installed by customers, encouraging the self-consumption of electricity from DPV, which enables utility customers to be "prosumers." The amount of deliberation that goes into the design of these programs will impact the rate of customer adoption and, subsequently, utility revenue collection, retail electricity tariffs, and technical impacts of DPV on the power grid.

Indonesia, a country rich in renewable energy, particularly solar energy resources, aims to achieve an energy mix that includes 23% from renewable energy resources by 2025 and 31% by 2050 per its 2014 National Energy Plan (Government of Indonesia 2014; Ministry of Energy and Mineral Resources 2014). To increase renewable energy levels in the national energy mix, the Indonesian government through the Ministry of Energy and Mineral Resources (MEMR) aims to encourage the use of solar energy for electricity, including DPV technology. Key goals include:

- To accelerate the installation of DPV in the Perusahaan Listrik Negara (PLN) service territory
- To promote self-consumption from DPV generation
- To establish installation and interconnection procedures and track DPV generation totals in the PLN service territory.

Since the announcing of the National Energy Plan, a number of laws and regulations have been enacted in the last decade by Indonesia's Ministry of Energy and Mineral Resources (MEMR) and PLN that define the legal framework and the billing and metering arrangements for behind-the-meter DPV in country.

In 2013, PLN issued a regulation (0733.K/DIR/2013) allowing DPV systems to be installed behind the customer meter and defining the billing and metering arrangements for DPV in Indonesia, initially allowing DPV customers to receive a full kWh credit for all electricity injected into the grid with the possibility of credits rolling over from one month to the next (i.e., classical net metering). This regulation also subjects PLN customers to a minimum monthly bill that is based on the DPV system capacity. This was closely followed by a new regulation in 2014 (0009.E/DIR/2014) which set an upper limit on the size of the DPV system a customer could install, set at 30 kW(Mulyono 2018).

The initial billing and metering arrangement, which effectively described full retail tariff net metering, was changed in November 2018 by MEMR in a new decree (MEMR Regulation 49/2018), replacing it with net billing, where all DPV generation injected into the grid provides the DPV with bill credits valued at 65% of the full retail tariff, effectively reducing the average compensation for DPV and encouraging self-consumption (since under net billing, self-consumed DPV generation is more valuable than that which is exported into the grid) (Baker McKenzie 2018; Sastrawijaya et al. 2018).

These regulations lead to 1,435 DPV systems and a total capacity of 3.6 MW interconnected to the PLN network as of September 2019, with the majority of systems being installed in 2019 alone, as shown in Figure 1. Most systems are installed on the island of Java (94% of systems, 83% of DPV capacity), while the remainder are on Bali (4% of systems, 15% of capacity) and other islands. About 89% of the systems are residential customers, 7% are commercial, 2% are government, with the remaining 1% among other customer types.

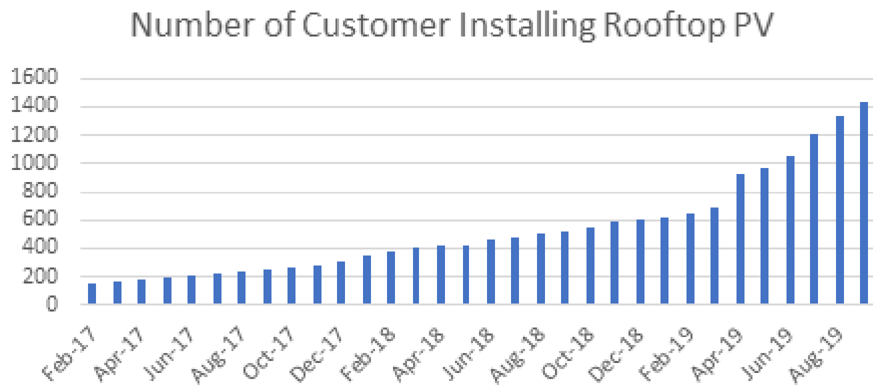

Figure 1. Number of DPV systems installed in the PLN distribution network as of September 2019

Source: MEMR 2019

To address the slow growth of DPV in the commercial and industrial sectors, MEMR revised two regulations in 2019 meant to simplify procedures and decrease additional costs for DPV systems installed in those sectors. The first (MEMR No. 13/2019) simplifies the permitting procedures for all DPV systems smaller than 500 kW. The second (MEMR No. 16/2019) reduces by a factor of eight the DPV capacity charge (similar to a standby charge) for industrial customers, increasing the bill savings from DPV and hence making DPV investments more attractive for industrial customers.

As interest in DPV continues to increase in Indonesia and DPV prices continue to decline, growth in the DPV market is likely to continue in the near future; however, PLN has expressed concerns that increasing DPV penetration in its networks may also have challenging technical and financial implications. Given the policy objectives set by the government of Indonesia, MEMR aims to continue to encourage the deployment of DPV. Analysis that can shed light on how to balance customer and utility needs and interests with respect to DPV deployment is key to understanding the impacts of the DPV program. To that end, this report comprises three DPV impact analyses for the Java-Bali region of Indonesia:

- Customer economic impact (Section 2) evaluates how current electricity tariffs, incentives, DPV prices, and solar resource in Java-Bali influence DPV customer investment;
- Utility revenue impact (Section 3) evaluates how DPV deployment in Java-Bali impacts PLN's net revenues; and
- Jobs and economic development impact (Section 4) evaluates how DPV deployment may stimulate jobs and economic development at the national level.

2 Customer Economic Impact Analysis

A key component to evaluating the potential impacts of a DPV program is to evaluate the customer economics of DPV, which provides information on the attractiveness of a DPV investment. The factors which impact the customer economics of PV the most include the current electricity tariff rates, solar resources, the upfront price of DPV systems, and available compensation mechanisms for DPV. This analysis evaluates the economic impacts for a selection of representative PLN customers who install DPV in the Java-Bali distribution grid.

The high-level approach to quantifying the customer economics is shown in Figure 2.

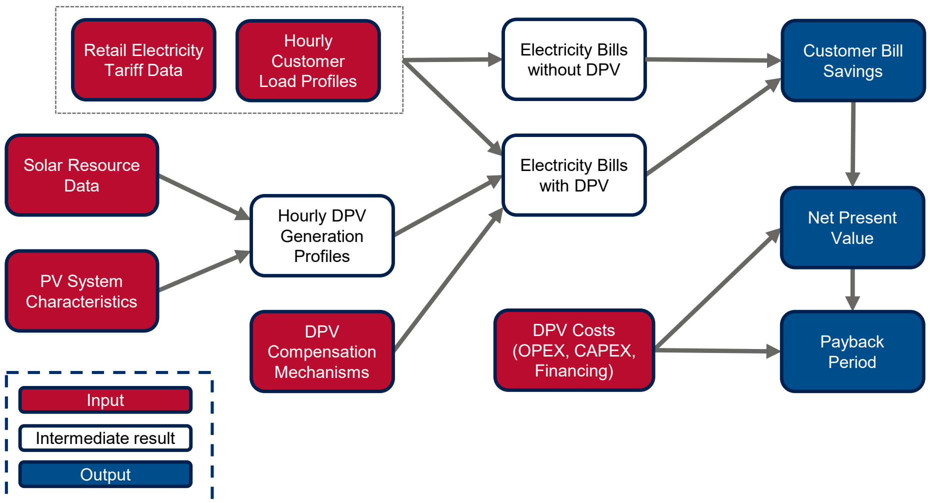

Figure 2. DPV customer economics analysis framework

Potential DPV adopters take many factors into consideration before investing in a DPV system, including its cost, potential bill savings from DPV (dependent on the compensation mechanism and retail rate design, sell rate design), financial incentives, and potential financing options and terms. Given DPV customer consumption patterns and investment signals, this analysis uses solar data from the Java-Bali region of PLN's service territory to model the technical and economic performance of representative DPV systems. Each modeled DPV system, representing a unique set of the aforementioned factors, was used to quantify the various investment indicators under each compensation mechanism. Table 1 outlines the design elements of compensation mechanisms pertinent to this analysis.

Table 1. Design Elements of DPV Compensation Mechanisms

Design Elements	Explanation
Metering and Billing Arrangement	DPV generation can be categorized into two uses: self-consumption and grid injection. While self-consumed electricity is valued at the volumetric portion of the applicable retail electricity tariff (i.e., the per-kWh portion of the tariff), the exported DPV generation may be valued distinctly depending on the prevailing metering and billing arrangement and sell rate.
Sell rate	If DPV generation injected into the grid is compensated, a sell rate will be applied to it. Under net metering, when DPV injections are valued in energy terms (i.e., a kWh credit), the sell rate is effectively the energy-volumetric portion of the retail electricity tariff, except if the kWh credits expire at the end of a banking period and are compensated by the utility at a pre-determined sell rate.
Netting frequency	The netting frequency is the time period under which DPV grid injections and customer electricity consumption are summed and measured for billing purposes. Put differently, it is the time period under which kWh credits for electricity are allowed to accrue and be netting against consumption. Netting frequency can be hourly, daily, or spanning the billing cycle (e.g., monthly). In the case that the sell rate for excess generation is lower than the retail rate, the longer the netting frequency, the greater the potential benefits for the prosumer.
Billing period	The billing period is set by the electric utility and defines how often the utility meters and charges customers on their electric bill. In most cases, the billing period is set to repeat on a monthly basis.
Banking period	A banking period is a finite number of billing periods. At the end of the banking period, any remaining credits from excess generation can either expire or be compensated at a predetermined rate. Banking periods can be rolling or fixed.

Source: Adapted from Zinaman, Aznar, et al. 2017; Hughes and Bell 2004

This analysis explores the impact of three DPV compensation mechanisms on the customer economics of DPV, including:

- Net Metering (NEM). The utility provides kWh credits for grid injections (i.e., each kWh of DPV generation exported to the grid leads to a kWh credit). This credit can be used to offset future electricity consumption. This allows the customer to bank excess generation and reduce their overall electric bill; this is effectively a form of financial storage;
- Net Billing. Any grid injections are purchased by the utility at a predetermined sell rate. This price is often set at the avoided cost of generation of the utility but can be set at any value; and
- Buy-all-sell-all (BASA). Under BASA schemes, all DPV generation is purchased by the distribution utility at a pre-determined sell rate and self-consumption is not allowed. The customer continues to purchase the same amount of electricity from the utility at the applicable retail tariff and is provided a bill credit or cash payment for all DPV generation sold to the utility.

Additional details on metering and billing arrangements can be found in Zinaman et al. (2018).

2.1 Base Scenario Inputs and Data

The customer economic impact analysis uses the System Advisor Model (SAM)[1] developed by the National Renewable Energy Laboratory (NREL). SAM is a free tool that calculates the technical and economic performance of renewable energy systems, including customer-sited DPV systems. This subsection summarizes key inputs and assumptions used to create the base scenario in this analysis. Unless otherwise noted, SAM default values were used for the DPV systems modeled. The performance models within SAM used for the analyses were "Photovoltaic (PVWatts), Residential" and "Photovoltaic (PVWatts), Commercial."

2.1.1 Location and Solar Resource

SAM utilizes localized weather and solar insolation data files as a key input for calculating a DPV system's production. This analysis uses weather data that represents a Typical Meteorological Year (TMY). TMY files

[1] For more information, see https://sam.nrel.gov/.

contain the mean relevant solar insolation and weather-related metrics averaged over a 20-year period. The TMY files for Jakarta and Surabaya—both at the latitude and longitude of their respective airports—were downloaded from the European Union's Photovoltaic Geographical Information System (European Communities 2019). Jakarta was used as the location for the base scenario.

2.1.2 System Design

For each customer class modeled (residential, small commercial, large commercial, and industrial) in the analysis, a crystalline silicon (c-Si) DPV system was designed to produce an annual amount of electricity equivalent to 75% of the customer's annual electric demand. Table 2 details SAM inputs on the system design tab for the base scenario.

Table 2: SAM System Input Parameters

SAM Parameter	Input
Array type	Fixed roof mount
Tilt	6° (equal to latitude)
Azimuth	0° (north-facing)
DC:AC ratio	1.2
System losses	14.08%*
System degradation	0.5% per year*
System life	25 years

*SAM default value based on empirical DPV system observations

2.1.3 Financial Parameters

DPV system costs were based on quotes received from ATW Sejahtera Solar, a local solar installer in Tangerang, Banten, Indonesia. Average capital cost data for Jakarta or country-wide is not collected by PLN or other organizations. Capital costs for a DPV system were assumed to be 19,600 IDR/W for the overall system costs, whereas operations and maintenance (O&M) costs were assumed to be 350,000 IDR/kW installed per year. O&M costs include both labor and materials. The sales tax rate was set at 10% based on the prevailing national value-added tax rate in Indonesia.

The analysis assumes that the DPV systems are purchased up-front with cash. There are currently no financing mechanisms available for DPV system purchases to reduce up-front capital costs. As no incentives are currently available for DPV systems in Indonesia, none were assumed or explored in this analysis.

2.1.4 Electricity Tariffs

Electricity tariffs are based on PLN tariff sheets (PLN 2019) and are shown in Table 3. There is a minimum monthly charge for each customer based on the customer's connected circuit size (in kVA) and represented by "Max power" in the tariff table below. One connection size was chosen for each representative customer based on their assumed demand profiles, resulting from the minimum monthly bill structure. The minimum monthly charge was modeled in SAM as a minimum monthly bill. PLN offers a diversity of tariffs to various customer types—a subset of these customer types and associated tariffs were modelled based on available data, differing tariff structures, and to represent a range of annual load for both large and small electricity usage. Customers chosen to represent the different rates were:

- **Residential**: R-1/TR-900 & R-1/TR-2200
- **Commercial (Small)**: B-1/TR-450 & B-1/TR-6660
- **Commercial (Large)**: B-2/TR-23000 & B-3/TM-200kVA

  Industrial: I-2/TR-82500, I-3/TM-200kVA, and I-4/TR-30000kV

Table 3. Increasing Block Tariffs: R-1/TR and B-1/TR

Rate Name	Max Power Connection	Monthly Capacity Fee (IDR/Month)	Block 1 Level (kWh)	Block 1 Rate (IDR/kWh)	Block 2 Level (kWh)	Block 2 Rate (IDR/kWh)	Block 3 Level (kWh)	Block 3 Rate (IDR/kWh)
R-1	900 VA	20,000	<30	169	30-60	360	>60	495
B-1/TR	450 VA	23,500	<30	254	>30	420	-	-

Table 4. Minimum Monthly Bill Tariffs: R-1/TR, B-2/TR, and B-3/TM Tariffs

Rate Name	Max Power Connection	Minimum Energy Charge (IDR/Month)	Volumetric Rate (IDR/ kWhs)	On-Peak Time (IDR/kWh)	Off-Peak Time (IDR/kWh)	Demand Charge (IDR/kVA)
R-1/TR	2200VA	Max. Power x 1352 x 40	1,467.28	-	-	-
B-2 / TR	6600 VA - 200kVA	Max. Power x 1352 x 40	1,467.28	-	-	-
B-3 / TM	>200 kVA	Max. Power during peak period x 1352 x 40	-	K *1035	1035	1114

K is a peak-time rate multiplier and equals 1.5

Table 5. Industrial Tariffs: I-2/TR, I-3/TM, and I-4/TT Tariffs

Rate Name	Max Power Connection	Monthly Capacity Fee (IDR /kVA/Month)	Minimum Energy Charge (IDR/Month)	Volumetric Rate (IDR/ kWh)	On-Peak Time (IDR/kWh)	Off-Peak Time (IDR/kWh)	Demand Charge (IDR/kVA)
I- 2 /TR	>14 kVA - 200 kVA	total capacity of inverter (kW) x 5 hours x applicable electricity tariff[2]	Max. Power during peak period x 1352 x 40	-	K*972	972	1057
I-3/TM	>200 kVA	total capacity of inverter (kW) x 5 hours x applicable electricity tariff	Max. Power during peak period x 1352 x 40	-	K*1035	1035	1114
I-4/TT	>30000 kVA	total capacity of inverter (kW) x 5 hours x applicable electricity tariff	Max. Power x 1352 x 40	996.74	-	-	996.74

K equals 0.667

An annual electricity rate escalation value was assigned for each customer. Volumetric electricity tariff escalation rates were assumed to be 5.8% and 4.9%, for commercial and industrial customers, respectively, based on historical tariff data.

Generally, regulations set the sell price for NEM credits at the end of the year and the sell price for net billing and BASA for grid injections. This sell price is often based on the avoided cost of generation for the utility but can vary. Currently, there is no guidance for these sell rates, so this analysis estimated a sale price based on the avoided cost of generation during solar producing hours calculated in the utility rate impacts section (Section 3). For the NEM sale price for annual net excess generation (i.e., kWh credits at the end of the year[3]), we assume 825 IDR/kWh. This value was also used as the sell rate for grid injections in the net billing and BASA schemes. The only exception for this was the B-1/TR-450 (subsidized) customer, because the sell value was greater than the price of electricity. For a B-1/TR-450 customer the sale price is set at 65% of the lowest tiered rate or 165 IDR/kWh, which is based on regulations under discussion to set the NEM credit value at 65%.

2.1.5 Customer Electricity Demand

PLN provided average monthly demand for residential, commercial, and industrial customers, presented in Table 6. Hourly load profiles were not available. The monthly load profiles were used to scale an hourly load profile obtained from a similar analysis of Thailand's electric utility customers (Tongsopit, Zinaman, and Darghouth 2017). The Thai residential, commercial, and industrial loads are the average from surveyed customers.[4]

[2] For industrial customers, there is a capacity charge for hosting a PV system on-site. This capacity charge was recently revised under MEMR Regulation No. 16 of 2019 for industrial customers with DPV (i.e., total capacity of inverter (kW) x 5 hours x applicable electricity tariff) in addition to the minimum energy charge for all industrial customers. This capacity charge was added to the minimum monthly energy charge in SAM to model both charges affecting customers at the same time.

[3] NEM credits expire at the end of a 3-month period in Indonesia. SAM is not currently able to model any credit expiration outside of the end of the year; however, this shouldn't significantly impact the results unless a customer has a very seasonal load profile (e.g., high consumption in some months and much lower consumption in others). The monthly PV generation in Indonesia doesn't change significantly from one month to the next so rolling over credits is not expected during a particular season; if there are rollovers over a 3-month period, there will also be rollovers over a 12-month period.

[4] Though these represent an average load, specific load profiles can differ depending on the customer's commercial or industrial activity.

To model the benefits of net billing schemes (where excess power is immediately credited in cash terms rather than banked as a kWh credit), an hourly profile was required to determine the amount of excess electricity exported to the grid. Thai customer load profiles are in similar weather conditions to those in Indonesia and were deemed to be the closest proxy of data available for the analysis. PLN provided small commercial, large commercial, and industrial customers monthly load data that was used to scale the hourly load profiles from Thailand to accurately represent Indonesian customers. Table 6 shows the monthly load profiles and DPV systems sized to meet 75% of annual load for representative DPV customers. The largest industrial customer (I-4/TR 30000kVA) was modified from the other industrial monthly load profiles to represent the large connection size needed to qualify for this tariff.

Table 6. Monthly Load Profiles (kW) for Commercial and Industrial Customers (With Tariff Customers Represented)

	Residential (R-1/TR-900 & R-1/TR-2200)	Small Commercial (B-1/TR-450 & B-1/TR-6660)	Large Commercial (B-2/TR-23000 & B-3/TM-200kVA)	Industrial (I-2/TR-82500 & I-3/TM-200kVA)	Industrial (I-4/TR-30000kVA)
Jan	874	2,380	4,887	26,054	260,540
Feb	946	1,720	4,891	28,234	282,340
Mar	1,066	1,643	4,633	25,625	256,250
Apr	1,069	3,271	5,538	27,991	279,910
May	1,179	2,862	5,711	28,245	282,450
Jun	1,161	2,919	6,123	28,891	288,910
Jul	1,116	2,910	5,977	12,152	121,520
Aug	1,104	2,322	5,351	28,932	289,320
Sep	1,079	3,088	5,341	26,545	265,450
Oct	1,044	2,780	5,665	24,076	240,760
Nov	1,081	2,640	6,074	24,375	243,750
Dec	1,037	2,645	5,760	20,317	203,170
Annual	12,764	31,179	65,951	301,437	3,014,370
Calculated DPV System Size (kW)	6.79	16.61	35.13	160.57	1,605.67

2.2 Results and Implications

There are three main sets of results for this analysis: the simple payback period (in years) of investing in a DPV system, the year 1 bill savings in million IDR (MM IDR), and the net present value (NPV) in MM IDR. We first present results for the base scenario, described above, with a system sized at 75% of annual load, followed by sensitivity scenarios for various system sizes and locations.

For each customer type considered in the base scenario analysis, the metering and billing scheme impacts the payback, with NEM resulting in the shortest payback period, followed by net billing and then BASA. NEM leads to the shortest payback as the value of excess PV generation injected into the grid is effectively compensated at the volumetric rate, which is higher that the net billing and BASA sell rate.

Table 7. Economic Analysis for Residential Customers for the Base Scenario

Residential	Tariff					
	R-1/TR-900			R-1/TR-220		
Compensation Mechanism	Payback (Years)	Annual Bill Savings (MM IDR)	NPV (MM IDR)	Payback (Years)	Annual Bill Savings (MM IDR)	NPV (MM IDR)
NEM	19.2	4.7	(103.6)	8.7	14.0	21.7
Net billing	23.5	3.3	(122.1)	10.4	11.2	(14.1)
BASA	>25	1.6	(146.3)	13.6	7.9	(61.1)

Each type of residential customer experiences different investment signals. The R-1/TR-900 customer has a long payback period (over 19 years) due to high minimum monthly bills and low volumetric tariff rates (i.e., the minimum bill is dominant factor for the electric bill total). The R-1/TR-2200 customer has a smaller proportional minimum bill and almost triple volumetric sale rates, so offsetting electricity purchases has a large impact on the payback period, reducing to 8.7 years for NEM customers. Note that the R-1/TR-2200 customer with NEM is one of the two positive NPVs for all customers in this base analysis, which is consistent with that tariff class having the highest adoption rates currently for DPV systems. Other residential customers with similar tariffs should exhibit the same trends.

Table 8. Economic Analysis for Small Commercial Customers for the Base Scenario

Small—Commercial	Tariff					
	B-1/TR-450			B-2/TR-6600		
Compensation Mechanism	Payback (Years)	Annual Bill Savings (MM IDR)	NPV (MM IDR)	Payback (Years)	Annual Bill Savings (MM IDR)	NPV (MM IDR)
NEM	21.4	2.11	(60.20)	11.3	24.69	(74.10)
Net billing	>25	1.52	(67.93)	12.1	22.37	(104.52)
BASA	>25	0.84	(77.45)	13.6	19.28	(149.28)

For representative small commercial customers, the payback period is about 11 years for both customers modeled (Table 8), which is high relative to internationally recognized benchmarks. For a B-1/TR-450 customer, the main driver of the high payback period is lower retail electricity tariffs which greatly reduce the value of solar generation to the customer for offsetting grid purchases. For a B-2/TR-6660 customer, the minimum monthly bill contributes to the higher payback period of 11 to 12 years. For the base scenario, all customers use all generation credits by year-end—this is largely a result of system sizing assumptions. For all customers in this analysis, the minimum monthly energy charge on all tariffs reduces the magnitude of bill savings.

Table 9. Economic Analysis Results for Large Commercial Customers for the Base Scenario

Large—Commercial	Tariff					
	B-2/TR-23000			B-3/TM-220kVA		
Compensation Mechanism	Payback (years)	Bill Savings (MM IDR)	NPV (MM IDR)	Payback (years)	Bill Savings (MM IDR)	NPV (MM IDR)
NEM	8.8	71.2	104.3	11.5	751.4	(2,568.3)
Net billing	10.1	60.1	(45.3)	12.2	692.2	(3,321.8)
BASA	13.6	40.8	(315.7)	13.6	598.4	(4,633.2)

For a large commercial customer, the average payback periods are shorter than for small commercial customers, but still longer than investment signals in other countries (Table 9). A DPV system installed for a B-2/TR-23000 customer under a NEM scheme results one of two positive NPVs for representative customers examined in this analysis. For a B-3/TM-220kVA customer, there is 2 year longer payback period and a reduction in year one bill savings due to the inclusion of a demand fee in this customer's tariff structure, which PV does not reduce very effectively resulting from temporal misalignment between customer's peak load and PV generation; however, B-3/TM-220 customers could look to shift load to solar producing hours to reduce the monthly demand fee through changes to their electricity load profiles or the installation of storage devices.

Industrial customers (Table 10) follow similar trends to large commercial customers.

Table 10. Economic Analysis for Industrial Customers for the Base Scenario

Industrial	Tariff Class								
	I-2/TR-82500			I-3/TM-200kVA			I-4/TR-30000kVA		
Compensation Mechanism	Payback (Years)	Bill Savings (MM IDR)	NPV (MM IDR)	Payback (Years)	Bill Savings (MM IDR)	NPV (MM IDR)	Payback (Years)	Bill Savings (MM IDR)	NPV (MM IDR)
NM	13.0	207.5	(1,309.8)	12.0	7,452.0	(33,066.0)	12.5	69,853.2	(377,162.0)
Net billing	13.4	201.0	(1,445.6)	12.7	6,837.6	(40,306.4)	13.0	66,369.0	(426,313.0)
BASA	14.3	186.4	(1,633.6)	14.3	5,932.9	(51,990.7)	14.3	59,333.7	(519,958.0)

2.2.1 Sensitivity Analysis—DPV System Sizing

A sensitivity analysis of the size of the DPV system was performed to understand how system sizing impacts customer economics. A DPV system was sized to generate 25%, 50%, 75%, 90%, and 100% of annual load for a B-2/TR-23000 customer. From the analysis above, the B-2/TR-23000 customer with a NEM metering and billing arrangement experienced a positive NPV. Therefore, we would expect a B-2/TR-23000 customer to be among the first to install a DPV system, along with R-1/TR-2200 customers. We choose to focus this sensitivity on the results for a B-2/TR-23000 customer, but other customers experience similar trends. All other inputs from the base scenario were kept constant except system size and the location, used as sensitivities in this section.

In the sizing sensitivity, payback period does not vary much for systems sized to generate up to 75% of annual load. For larger systems, the additional DPV capital expenditures, capacity-based minimum bill fees, and lower year-end value for net excess generation credits begin to outweigh the bill savings. The highest NPV system modeled was 75% system size scenario which reduces the customers electric bill to roughly the minimum monthly fee.

Table 11. Sizing Sensitivity Analysis: Economics Results for B-2/TR-23000 Customer With Differing DPV System Sizes

Percentage of Annual Load	System Size (kW)	Payback (Years)	Year 1 Bill Savings (MM IDR)	NPV (MM IDR)	Year-End Excess Credits (kWh)
10%	4.68	8.7	9.67	14.94	0
25%	11.7	8.7	24.17	37.35	0
50%	23.4	8.7	48.34	74.69	0
75%	35.1	8.8	71.16	104.29	0
90%	42.12	9.3	79.74	63.47	2,086
100%	46.8	9.8	82.71	-6.39	11,004

2.2.2 *Sensitivity Analysis—DPV System Location*

This section explores the impact of location and solar resource on the payback period. This location sensitivity sites a DPV in Jakarta and Surabaya, the two most populous cities on the island of Java-Bali and on different ends of the island. Table 12 shows that the location has a mild impact on the economics of PV in Indonesia. The same B-2/TR-23000 customer described above experiences a 4%-5% decrease in payback period by considering solar resources in Surabaya (1,520 kWh/kW) relative to Jakarta (1,408 kWh/kW).

Table 12. Location Sensitivity Analysis: Payback Periods in Jakarta and Surabaya

	Payback Period (Years) by Location		
	Jakarta	Surabaya	% variance
NEM	8.8	8.4	4.8%
Net billing	10.1	9.7	3.9%
BASA	13.6	12.9	5.4%

In the base scenario, all customers considered in this analysis have payback periods for their DPV systems over 8.8 years. Though further research is needed to determine whether this would be an acceptable payback for investors to decide to adopt PV, international experience suggests that payback periods closer to 5-7 years are more likely to lead to deployment and expansion of solar markets. To achieve lower paybacks in Indonesia, PV prices would have to fall, PV compensation would have to increase (either by changing the DPV compensation mechanisms or the tariff level), or other DPV support policies would have to be enacted.

3 Utility Financial Impact Analysis

In this section, we evaluate the short-term financial impacts of DPV deployment on national electricity utility PLN's net revenues.

To evaluate the net financial impacts of any DPV compensation mechanism, it is crucial to quantify both the cost of DPV generation to the utility—in terms of reduced sales from self-consumption and additional expenditures for purchasing electricity exported from the DPV system onto the utility grid—and the benefits of the PV generation, in terms of avoided costs. A high-level analysis framework is presented in Figure 3.

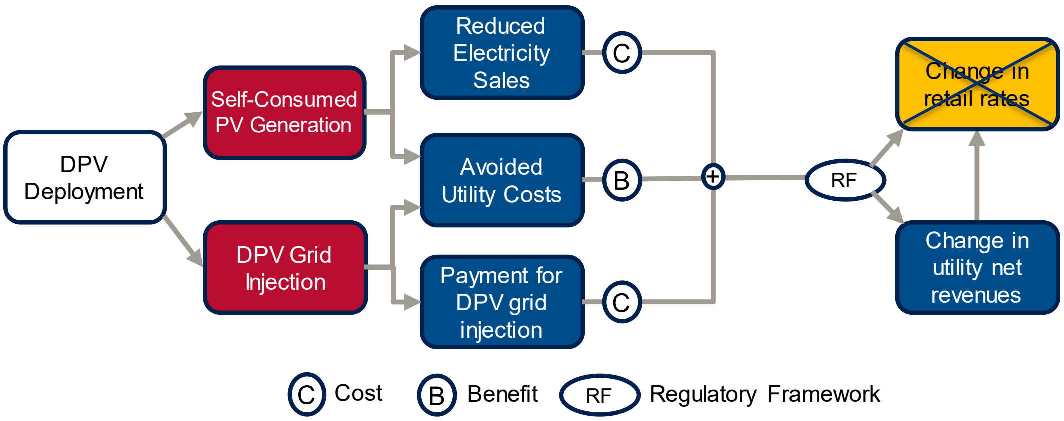

Figure 3. Analysis framework for evaluating the financial impacts of DPV to utility net revenues and retail electricity tariffs

Figure 3 outlines the major components of a DPV impact analysis on tariff and revenue. DPV deployment assumptions, including total deployment levels (in MW) and allocation among various customer classes, are inputs to the analysis. DPV electricity generation that is behind the customer's meter can either be consumed instantaneously by the customer's load (i.e., self-consumption), or injected/exported into the distribution network when the DPV generation is greater than the customer's consumption at any given time. Each of these components can have distinct financial impacts on the utility, depending on the DPV compensation mechanism. Self-consumed generation leads to reduced utility sales and thus reduced utility revenues, which is also dependent on the customer's underlying retail electricity tariff. In Indonesia, currently regulations make the effective payment for DPV grid injections to be 65% of the customer's retail tariff; this is used in the net billing analysis. The second PV compensation mechanisms considered here is a net energy metering scheme, where electricity exports lead to kWh credits for the consumer to use at a later time, effectively compensating those exports at the full retail tariff. Both self-consumed DPV generation and DPV grid injections lead to avoided utility costs, which include reduced fuel costs, potential reductions in capacity investments, and reduced transmission and distribution line losses – the benefit of DPV to the utility. The net financial impact can then be calculated by subtracting the total benefits (or value) from the costs associated with the behind-the-meter DPV.

In Indonesia, tariffs may not be regularly updated to account for changes in operational revenue and costs that result from the rooftop DPV program, so this financial impact analysis assumes that the utility, PLN, bears all net impacts. The 5-year horizon considered in this analysis assumes that the electricity generation mix and retail tariff structures do not change with increased DPV. Given the relatively low levels of DPV penetration, we assume the costs related to integration of this intermittent generation are minor and hence negligible (Hirth, Ueckerdt, and Edenhofer 2015, for example). We analyze PLN's service territory in the Java/Bali interconnected grid as a case study, because DPV has been much more prevalent on the Java and Bali islands than Indonesia's other interconnected grids to date.

The objective of this analysis is to provide DPV stakeholders with a quantitative evaluation of potential DPV adoption on utility net revenues.

3.1 Data and Methods

The first step in calculating the utility's net revenue impact is determining the revenue reduction from self-consumed generation and the costs (and benefits) associated with DPV exports. These costs depend upon how much DPV is deployed, which types of customers choose to adopt DPV, how their systems are sized, and the nature of the retail electricity tariff they are subject to. In this study we consider two scenarios: a Core scenario and a High Revenue Impact scenario, which for a fixed amount of DPV deployment, define which kinds of customers deploy DPV and how they size their individual DPV systems[5] (which has implications on the percentage of the DPV generation that is exported to the grid). These are summarized in Table 13. We consider DPV deployment levels from 0-4 GW in the Java/Bali interconnected grid. This range, although very aggressive given current deployment levels, is relevant to potential deployment given the aggressive country-wide targets (i.e. 23% of electricity generation from renewable energy sources by 2025) and was set in consultation with MEMR and PLN.

Table 13. Scenarios Considered in the DPV Net Revenue Impact Analysis

		Core Scenario		**High Revenue Impact Scenario**	
		Deployment	PV System Size	Deployment	PV System Size
	Tariff Type	% of Total PV Capacity	PV-to-Load Ratio	% of Total PV Capacity	PV-to-Load Ratio
Residential	R-1/TR 1300 kVA	33%	75%	45%	25%
Commercial	B-2/TR 6600 VA	11%	75%	7.5%	25%
	B-2/TR 200 kVA	11%	75%	7.5%	25%
	B-3/TM >200 kVA	11%	75%	7.5%	25%
Industrial	I-2/TR 14-200 kVA	11%	75%	7.5%	25%
	I-3/TM >200 kVA	11%	50%	12.5%	25%
	I-4/TR >30000 kVA	11%	50%	12.5%	25%
	Total	100%		100%	

Only one residential customer class is considered – because small residential consumers in Indonesia have subsidized retail tariffs and thus extremely long payback periods for DPV systems[6]—whereas three customer classes each for commercial and three tariff types for industrial are included as part of the analysis, as depicted in Table 13.

The Core scenario assumes that deployment is evenly distributed across residential, commercial, and industrial customer segments, and that smaller customers have a 75% PV-to-load ratio while larger customers have 50% PV-to-load ratios (due to limited roof space). The High Revenue Impact scenario assumes that deployment is distributed relative to the total annual usage of each customer segment and that all PV-to-load ratios are 25%, thus limiting exports and increasing the revenue reductions to PLN. In the High Revenue Impact scenario, we assume

[5] PV system size is described in this analysis using a PV-to-Load Ratio, which represents the percentage of annual customer demand that is met by the PV system (e.g., a 75% PV-to-load ratio indicates that the DPV system is sized to generate three quarters of the customer's total annual consumption).

[6] Tariffs are lower than the B1-TR/450VA rates for small commercial customers considered in the previous section, and hence payback times exceed 25 years.

that residential customers install more DPV capacity because they have higher per-kWh rates than other customer segments, leading to greater reductions in electricity sales and net revenues.

Based on the bill savings from DPV for individual customer types, we calculate the total cost to PLN of DPV generation for each scenario. To do so, we use PLN tariffs from August 2019 and representative hourly load profiles from similar customer types in another Southeast Asian country[7], programmed into the System Advisor Model for solar generation and bill calculations. In addition, we consider the DPV capacity charge imposed for industrial customer classes based on DPV system size, as changed in MEMR's Regulation No. 16 of 2019 from October 2019.[8]

We consider three value components in quantifying PLN's benefits from DPV generation:

1. **Energy Value**—DPV generation reduces the amount of centralized generation that the utility must provide. This reduction in generation drives a reduction in fuel costs for the utility;
2. **Generation Capacity Value**—DPV generation can help to reduce a utility's peak load. Thus, less investment is needed for new generating capacity to serve that peak load, which results in a cost savings for the utility; and
3. **Avoided Transmission and Distribution Line Losses**—DPV generation is consumed at or near the point of generation. Thus, the line losses associated with transporting electricity from the central generator to the customer are avoided.

There are other value streams from DPV generation that are not included in the current analysis. Some of these value streams are societal, such as carbon emission reductions related to the displacement of fossil fuel consumption, health benefits from lower coal emissions, job creation and other macro-economic benefits. These societal benefits are not quantified here as the focus of the present analysis is the financial impact of DPV directly leading to changes in net revenue for the utility, PLN. There may be other value elements that could potentially impact the net revenue for PLN, such as fuel price hedging or distribution capacity value, but these are either typically small in magnitude or very-location dependent and difficult to quantify. For a complete list of potential benefits, see Denholm et al. 2014.

The energy value of solar is calculated using hourly load data over 1 year as extracted from PLN's System Operations Division website (RAPSODI), the merit order of generators available for dispatch on the Java/Bali grid (from each generator's capacity, heat rate, fuel type), and simulated hourly PV generation for Jakarta. These three data sets are used to understand which conventional generators would be displaced each hour by DPV generation, and the average value of those reduced purchases due to DPV self-consumption.

A number of assumptions are also made on fuel prices, used in conjunction with plant heat rates to estimate the marginal price of generation for any given generator—see Table 14.

Table 14. Fuel Price Assumptions

Fuel (Indonesian)	Cost	Source
Coal (Batubara)	$95.89/ton	12-month average of MEMR coal price benchmarks (June 2018 – May 2019)
Natural gas (gas alam)	$5.59/mmbtu	MEMR price index 2019
LNG (gas alam cair)	$11.17/mmbtu	12-month average from the Mundi Indonesian Liquefied Natural Gas Monthly Price Index

[7] Reference load profiles from Thailand were used because Indonesian metered data was unavailable. For more details on the load profiles, see: https://www.usaid.gov/energy/resources/distributed-photovoltaic-impact-revenues-tariffs-thailand.
[8] For more details (in English), see https://www.pv-magazine.com/2019/10/30/indonesia-improves-rules-for-rooftop-pv/ and https://www.bakermckenzie.com/en/insight/publications/2019/10/capacity-charge-for-rooftop-solar-projects.

Diesel (minyak diesel)	$880/kL	Globalpetrolprices.com Indonesian Diesel Price Index

For hydropower, several assumptions were made to model how each hydropower resource is dispatched. The hydropower generation in Indonesia is a mix of dams and run-of-river plants, which have different dispatch patterns. Run-of-river plants (i.e., perennial capacity which generates year-round) tend to have lower capacity factors than dams (i.e., seasonal capacity which only generates during the rainy season). Hydropower plants with a capacity factor of greater than 50% were identified as perennial capacity, whereas hydropower plants with less than 50% capacity factors were deemed seasonal capacity. Given that dispatch data was not available for hydro resources, we assume seasonal capacity operates at full capacity during the peak wet months (December through February), then tapers off through the fall shoulder months (March, April), is zero through the dry season (May through September), before ramping back up in the spring shoulder months (October through November). We also assume that the perennial capacity operates at full capacity in the wet months and shoulder months and is only available during peak hours during the dry season. These assumptions were determined after discussions with PLN. Figure 4 illustrates these assumptions.

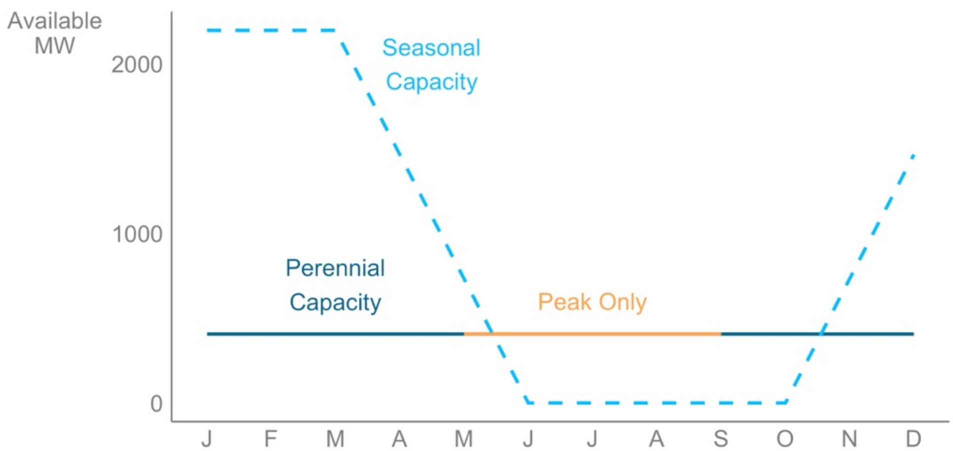

Figure 4. Available hydro generation capacity by month

As DPV penetration increases, more expensive generators get displaced, lowering the average price of electricity. This is illustrated in Figure 5, where the supply curve is relatively flat in the middle sections, implying similar marginal costs over a large range of net loads. This is discussed further in Section 3.2.

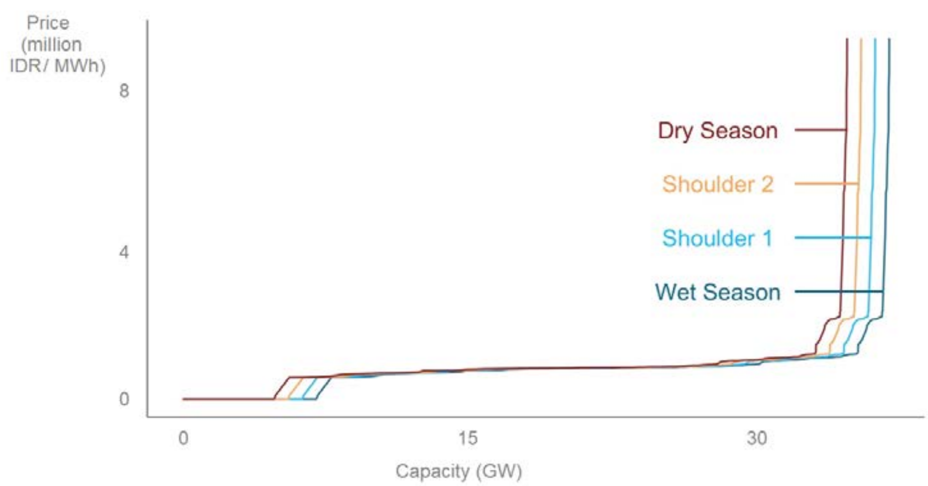

Figure 5. Marginal energy cost of electricity by season

The capacity value of DPV is calculated by first determining how effective PV is at reducing the peak load during the 100 peak demand hours over a 1-year period, which provides a capacity credit of solar, and multiplying this by the levelized fixed cost of a marginal generator (i.e., a combustion turbine). For more details on this methodology, see USAID 2019.

The value from reduced line losses depends upon percentage losses on the transmission and distribution networks. Customers who are connected to low-voltage lines, including residential and smaller commercial customers, are able to reduce both distribution and transmission line losses (an average of 7.2% and 2.3%, respectively, per PLN 2018). Larger customers connected directly to high-voltage lines only avoid transmission line losses. The average value of those losses is calculated by multiplying the line loss percentage by the energy value of DPV.

3.2 Results and Conclusions

The first step in the net revenue impact analysis is to calculate the total costs and the total value of the DPV generation for a given DPV deployment level. Figure 6 shows the total utility costs for net billing and net energy metering, as well as the total value for the Core scenario with 3 GW of DPV deployment on the Java-Bali grid, as an example.

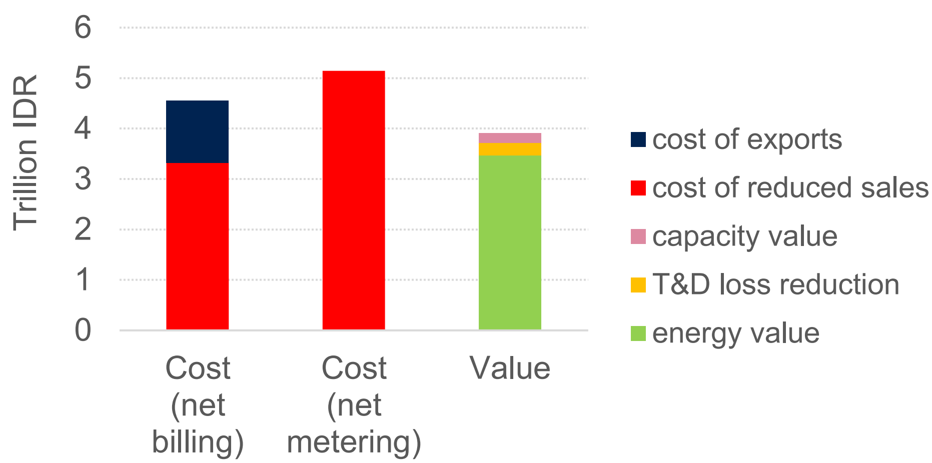

Figure 6. Comparison of PLN's annual cost of 3 GW of DPV with the annual value of 3 GW of DPV

The net billing cost of DPV to PLN (the first bar) is disaggregated into the cost of reduced utility sales due to DPV self-consumption and the cost to the utility of purchasing exported DPV generation from the customer (paid at 65% of the retail tariff). The costs of exports are only a fraction of the total costs, because only a portion of the total DPV generation is exported to the grid—the majority is self-consumed.

The cost of net energy metering to the utility (the second bar) is entirely from reduced sales revenue, as exported DPV generation is credited at the retail tariff, leading to reduced sales over the month or rolled over to the following months.

The total value of DPV (the third bar) is dominated by its energy value (almost 90%). The capacity value of DPV is relatively low, because peak load in the Java-Bali grid tends to be late in the afternoon or early evening when DPV generation is low or zero, hence only marginally reducing the peak load. In the Core scenario, about half of the DPV capacity is assumed to be deployed by industrial customers, who only offset transmission losses. Thus, the total transmission and distribution loss reduction value is relatively low when compared with the energy value.

The total costs of net billing are slightly lower than net energy metering, because PLN pays customers less for exported generation under net billing. Total utility costs of DPV generation for both net energy metering and net billing are higher than its value, implying that DPV imposes a net cost to PLN. The waterfall chart in Figure 7 shows the costs and value of exports and self-consumption. The net impact from exports results in a net revenue gain, because the exports are compensated at a level that is inferior to the value of electricity to the grid. The overall net impact of 3 GW of DPV deployment, however, is a net cost to the utility, as the costs of self-consumption are greater than the value of that electricity.

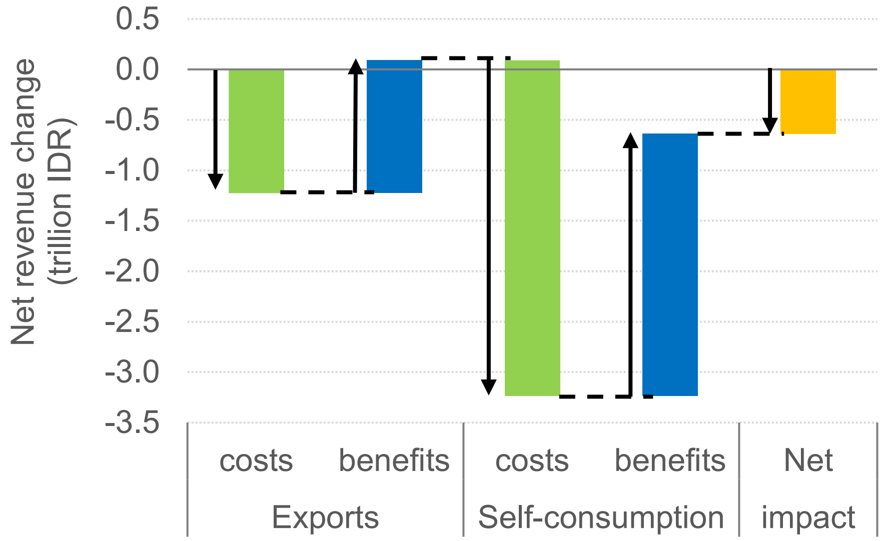

Figure 7. Net revenue impact of 3 GW of DPV under the Core scenario with net billing, with disaggregated costs and benefits of DPV generation displayed by DPV exports and self-consumption

The net impact to the utility is the difference between the costs and benefits of DPV generation. At all DPV deployment levels considered—zero to 4 GW on the Java-Bali grid—DPV costs exceed its values to the utility under both current regulation (i.e., net billing) and net metering for the Core and High Impact scenarios. These net losses are portrayed as negative percent change in annual revenue in Figure 8 and Figure 9. The green line in each of the figures shows the overall average impact on net revenues; each of the other lines show how the total DPV capacity impact each of the other customer segments (e.g., the net revenue impacts fall by 0.2% for industrial customers under net billing in the Core scenario, assuming an overall DPV capacity of 4 GW, one-third of that being installed by industrial customers).

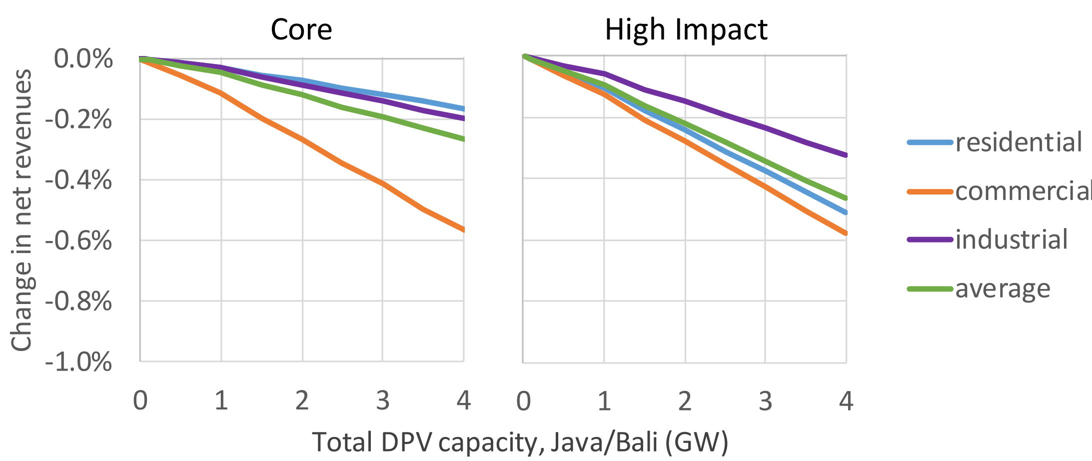

Figure 8. Net revenue impacts from DPV deployment under current regulation (i.e., net billing) on the Java-Bali grid for the Core scenario and High Revenue Impact scenario

Indeed, the PLN net revenues from all customers decline by less than 0.05% over the first 1 GW of DPV, and only about 0.2% over 3 GW of DPV. These impacts do not scale linearly, as seen in Figure 8; the rate of the impact increases slightly with greater PV penetrations, as the benefits from solar (in IDR/kWh) drop slightly as PV levels on the grid increase. To put this change in net revenues into context, if we consider the change in fuel costs for coal and natural gas, the net revenue impact from the increase in the coal and natural gas prices alone from 2017 to 2018 represent a 15% decrease in net revenue.[9]

When considering each customer segment independently, the economic impact of DPV from commercial customers is greater than residential and commercial customers because the volumetric portion of some commercial retail tariffs (including B-2/TR-23000) are higher than for other customer segments. In the Core scenario with net billing, PLN’s net revenue impact from residential PV customers is lowest (left panel of Figure 8) because they export the highest percentage of DPV generation to the grid due to the relatively high-PV to low-demand ratio assumed. With net energy metering under the Core scenario (left panel of Figure 8), PLN’s net revenue impacts from residential DPV customers are slightly higher than for net billing, because the costs of net metering are higher to the utility, as seen in Figure 6.

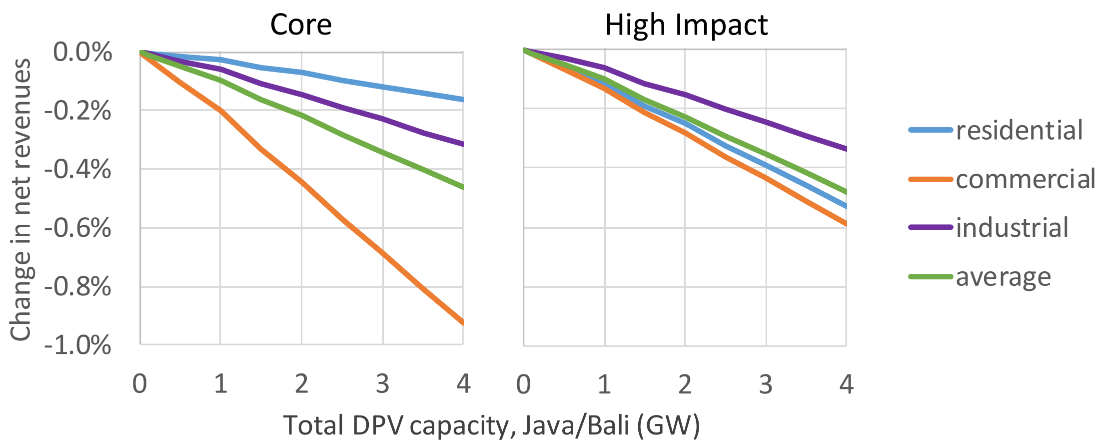

Figure 9. Net revenue impacts from DPV deployment under net-metering on the Java-Bali grid for the Core scenario and the High Revenue Impact scenario

Overall, net utility revenue impacts are relatively low, even for aggressive DPV deployment scenarios over the next 5 years. Even though volumetric part of the retail tariff (i.e., IDR/kWh) is high, most residential customers inject a considerable percentage of their DPV generation into the grid in the core scenario. Because the sell rate for injected DPV generation is less than the utility’s avoided costs, the injected portion of DPV has a small positive impact on net revenues (about 100,000 IDR for 3 GW of DPV capacity). For larger commercial and industrial customers, PLN's reduced electricity revenues are lower than residential customers (in INR/kWh) because volumetric tariffs comprise a smaller proportion of the customer’s total electricity tariff (the remaining portions of the tariff are fixed monthly customer charges, which are not impacted by DPV generation, and demand charges, which are only minimally impacted by DPV generation for most customers).

[9] Fuel costs from coal and natural gas increased from 407 and 905 INR/kWh to 587 and 1059 INR/kWh, respectively, from 2017 to 2018. This net decrease is based on fuel price, generation levels, and total revenues in PLN’s Statistik 2017 and 2018, available here: https://www.pln.co.id/stakeholder/laporan-statistik.

4 Job and Economic Development Impact Analysis

The deployment of solar PV in Indonesia will require a workforce to install and maintain equipment, and domestic expenditures will support jobs in other affected industries such as wholesalers that sell modules and domestic manufacturers that provide mounting hardware.

This workforce and associated economic impacts can be estimated using the International Jobs and Economic Development Impacts (I-JEDI) model. I-JEDI is a freely available model developed and provided by NREL[10].

4.1 Methods and Assumptions

I-JEDI characterizes projects in terms of expenditures for items and the percentage of those expenditures that are made within the region of analysis—in this case Indonesia—and uses an input-output model to estimate impacts.

Input-output models are widely used tools that characterize an economy in terms of purchases (inputs) and sales (outputs). These purchases and sales are between industries, households, investors, governments, and the rest of the world through imports and exports. By characterizing and quantifying these linkages the model can estimate impacts from solar projects themselves and the ripple effects throughout their supply chains and economy-wide. These impacts are categorized as direct, indirect, and induced.

Direct impacts are those that arise immediately from expenditures specified in I-JEDI. Table 15 shows these expenditure line items for installation, while O&M includes maintenance and repair services and replacement parts. Direct impacts are only in industries that provide these goods and services.

Table 15. Installation Expenditure Line Items in I-JEDI

Module	Design and civil engineering
Inverter	Other (public relations, legal, environmental studies)
Construction and installation costs	Infrastructure - electricity and other
	Transportation - Country Specific

Indirect impacts arise from the greater supply chain. If a construction company, for example, purchases ladders that are made in Indonesia, then the businesses that manufacture these ladders supply indirect jobs. This includes only the supply chain supported by the direct impacts—the expenditures made by the installer and operator. If a module manufacturer outside of Indonesia purchases inputs from Indonesia, then these impacts are not included in scenario results.

Direct and indirect workers earn wages, and these households spend a portion of these wages domestically. Induced impacts are jobs and associated economic activity that is supported by these expenditures. These are often in industries where household spend the most money such as agriculture and retail sales.

Though installation and O&M impacts are over different time frames, all job impacts in I-JEDI are quantified in terms of number of full-time jobs over a 1-year period. If I-JEDI reports 10 jobs, for example, this could indicate 20 jobs over a 6-month period or 5 jobs over a 2-year period. O&M impacts are annual and assume to exist for the life of the installation, so 10 jobs over the 25-year lifetime of the project would be reported as 250 jobs in I-JEDI.

I-JEDI reports four metrics: jobs, earnings, value added, and gross output. Jobs are full time equivalents, or the average of one person working full time for 1 year. Earnings are the total payments that employers make to their employees. Value added is equivalent to GDP and consists of earnings, property-type income, and taxes. Property-type income includes profits and returns on investment. Gross output is an overall level of economic

[10] The International Jobs and Economic Development Impacts (I-JEDI) model is a freely available economic model that estimates gross economic impacts from wind, solar, biopower, and geothermal energy projects around the world. www.i-jedi.org

activity and includes all payments made or received. At the business level, this can be thought of as revenue. All dollar amounts reported are in real 2018 U.S. dollars.

This analysis includes two representative residential rooftop solar sizes: a set of one thousand 4.9-kW installations and a set of one thousand 4.2-kW installations.[11] This was chosen to show the distribution of impacts and is not meant to be representative of any actual expectation of deployment.

The cost and bulk of domestic content data from these scenarios came from a set of customer quotes provided by ATW Sejahtera Solar, a company that installs solar systems for residential, commercial, and industrial settings. Each of these systems used imported REC solar modules and Evershine inverters. While these components are manufactured outside of Indonesia, each scenario assumes that they were purchased from domestic wholesalers. These components are imported and the bulk of replacement expenditures are for inverters. O&M replacement parts are also assumed to be imported.

Inputs to the model were developed reflecting local economic conditions. Other assumptions include: (i) all construction workers who install and maintain projects are residents of Indonesia; (ii) half of design costs are in-country; (iii) 85% of other professional services are domestic; and (iv) electrical infrastructure upgrades are 90% domestic.

4.2 Results and Implications

Table 16. Estimated Installation Impacts From the Deployment of 2,000 Residential Solar Systems Totaling 9.1 MW

	Jobs	Earnings (Thousands USD)	Gross Output (Thousands USD)	Value Added (GDP)(Thousands USD)
Direct	270	$638	$4,559	$1,620
Indirect	270	$668	$4,634	$2,142
Induced	170	$356	$2,167	$1,119
Total	710	$1,662	$11,360	$4,881

The highest total job impacts are found to be in construction, relative to the other sectors, followed by manufacturing (Figure 10). No installation components are assumed to be manufactured in Indonesia, so the high percentage of manufacturing jobs reflects the relative significance of manufacturing throughout the supply chain compared to other affected industries.

[11] This analysis only includes residential systems due to input data limitations. Were larger commercial or industrial systems included in this analysis, impacts would likely be lower resulting from economies of scale.

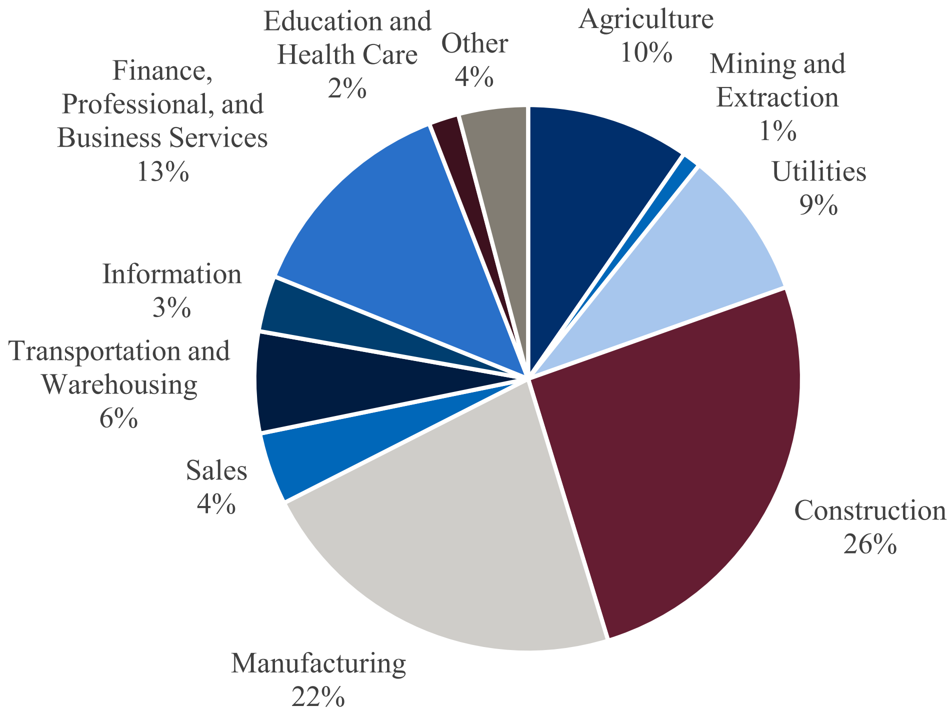

Figure 10. Estimated distribution of total installation job impacts associated with DPV deployment

The value-added contribution of industries differs slightly from the job distribution, reflecting differences in earnings. In this case, manufacturing is the highest category, followed by construction. In both cases finance, professional, and business services are third, followed by utilities.

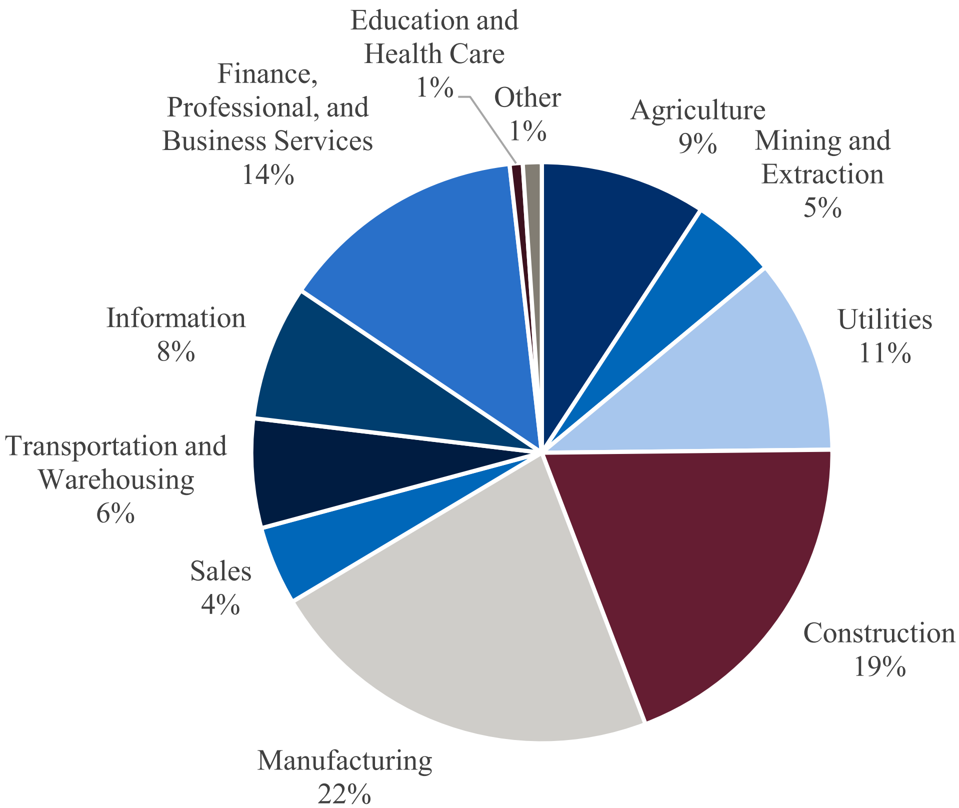

Figure 11. Estimated distribution of total installation value-added impacts

Even though estimates are for the deployment of 2,000 solar systems, the O&M impacts are relatively small. This reflects the fact that DPV systems are far more labor intensive to install than to maintain and, similarly to installation, components (primarily inverters) are assumed to be manufactured outside of Indonesia. In this case, the total job impact is 14 and the total value-added impact is $92,000 (Table 17). Similar to installation, the highest number of jobs are direct and indirect and indirect workers earn the highest average wages. The value-added impact of indirect effects is also the highest.

Table 17. Estimated Annual O&M Impacts

	Jobs	Earnings (Thousands USD)	Gross Output (Thousands USD)	Value Added (GDP)(Thousands USD)
Direct	6	$13	$86	$31
Indirect	5	$12	$80	$38
Induced	3	$7	$44	$23
Total	14	$32	$210	$92

Figure 12 shows that most of the full-time equivalent jobs are in construction (26%) and manufacturing (22%). As for installation, this is followed by finance, professional, and business services, but unlike for installation, agriculture is the fourth largest industry. In this case, it comprises nearly 30% of the induced impact, illustrating the high expenditures of direct and indirect workers on agricultural products in Indonesia.

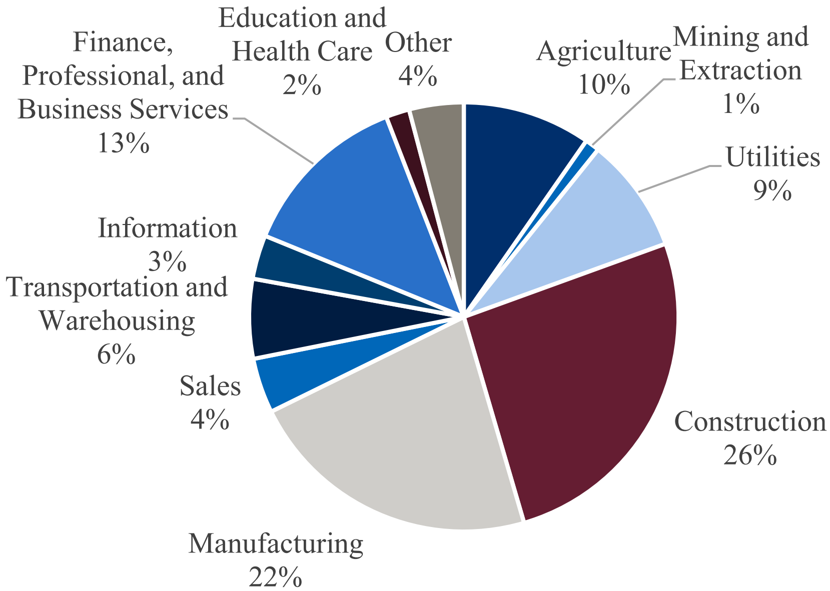

Figure 12. Estimated distribution of total O&M job impacts

As shown in Figure 13, the distribution of the value-added impacts is similar to the job impacts. In this case, however, agriculture exceeds finance, professional, and business services. Agricultural workers earn less than workers in the finance, professional, and business services industry so this reflects higher property-type income and taxes paid in the agricultural sector.

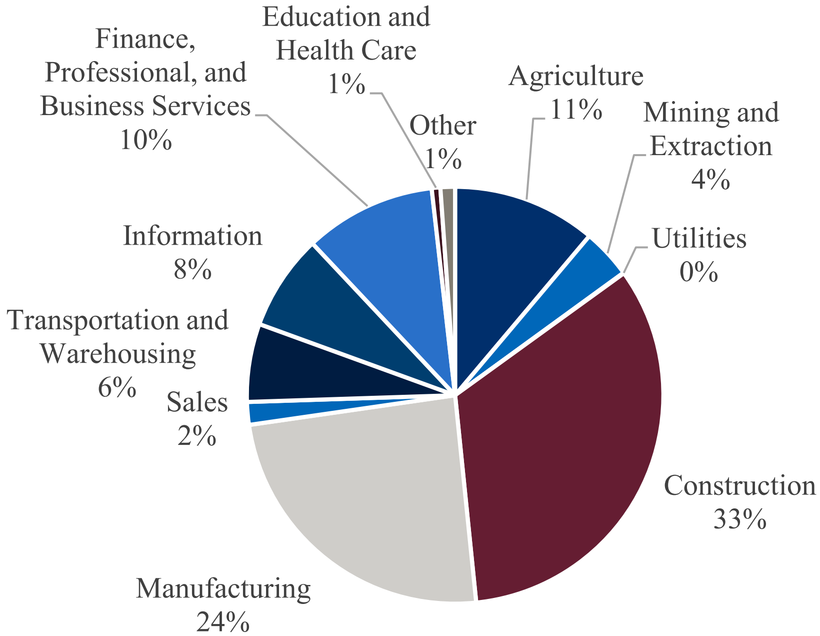

Figure 13. Estimated distribution of total O&M value-added impacts

4.3 Limitations

These results should be interpreted with limitations of the I-JEDI model in mind. As for any economic model, I-JEDI has several limitations that are outlined below.

Results from I-JEDI are gross impacts, not net. This means that I-JEDI does not make assumptions about who pays for solar systems or how. Importantly, if households or taxpayers pay more for solar, it is possible that they may spend less elsewhere in the economy—this displaced activity is not included in the results. I-JEDI does not estimate displacement elsewhere in the power sector. For example, solar generation may reduce the need for generation powered by other fuels. This reduction in generation elsewhere is not factored into model results.

Input-output models such as I-JEDI are static and hence do not make assumptions about changes to the economy. Prices and taxes are assumed to be fixed and there aren't technological changes that lead to changes in how industries operate or households spend money. Also, the model doesn't make assumptions about future changes in the economy. These results reflect estimated impacts as if the PV were deployed today.

At the time of this publication, default data in I-JEDI does not make assumptions about economies of scale. The deployment of one unit, on a per-kW basis, has the same jobs, earnings, output, and value added as that of 1,000 or 10,000 systems. Economies of scale can be specified using customized data, however.

I-JEDI and input-output models in general also assume that inputs, including workers, are available at the same price, again assuming no economies of scale. Prices would remain the same for an installer whether they purchased one or 1,000,000 modules and these modules are assumed to be available.

Impacts reported by I-JEDI assume that a project is economically or otherwise feasible. I-JEDI does not make assumptions about the practicality of a project or whether it can be implemented.

5 Conclusion and Key Findings

This report presents a holistic view of DPV economic impacts in Indonesia by assessing customer economic impacts, utility revenue impacts, and jobs and economic development impacts. Key findings from each analysis are presented below.

5.1.1 Customer Economic Impacts

With current tariff structures, there is little economic incentive for customers to install grid-connected DPV systems in the Java-Bali region of Indonesia. Our analysis indicates that the shortest payback period for a grid-connected DPV systems is 10.1 years under a B-2/TR-23000 electricity tariff with net billing (current regulation). Higher payback periods are primarily driven by high minimum monthly bills stipulated in current electricity tariffs. Under the current tariff structure, sizing the DPV systems to reduce the electric bill to the minimum monthly bill results in the lowest payback periods. The current PV compensations mechanisms—net billing where all excess PV generation injected into the grid is compensated at 65% of the customer's underlying retail rate—may not provide sufficient financial incentives to induce massive DPV deployment in the Java-Bali region that would contribute to Indonesia's National Energy Policy target of producing 23% of their electricity from renewable sources by 2025.

5.1.2 Utility Revenue Impacts

Under the current Indonesian DPV regulatory structure and electricity grid, as defined by MEMR Regulation 49/2018 and revisions from 2019, the customer can self-consume their DPV generation and any excess DPV generation exported to the grid is compensated at a rate that is 65% of the customer's underlying retail electricity tariff. Given the relatively low retail rates in Indonesia, the value of the DPV generation to the utility is only slightly lower than the reduced revenues from self-consumption and exported generation. The resulting net revenue impact from the first 3000 MW of DPV in the Java-Bali grid is about 0.2% of total annual revenues. Though results presented in this report are for the Java-Bali power system, similar results would be expected for other power systems managed by PLN.

5.1.3 Job and Economic Development Impacts

The gross economic impact of the theoretical deployment of one thousand 4.9 kW and one thousand 4.2 kW residential solar PV systems would support approximately 710 total job-years and $4.9 million in GDP. Most of this activity would accrue in the construction industry and manufacturing industries, followed by professional services. On an ongoing basis this scenario would support 14 total jobs annually and $92,000 in GDP. As with installation, these impacts would primarily accrue in the construction and manufacturing industries, followed by professional services.

Our results indicate that under the current regulatory structure governing DPV in Indonesia, low DPV deployment levels would be expected in any customer class due to the high expected payback periods of DPV investments. However, in the near-term, the analysis suggests that even if 3 GW of DPV deployment occurred in the Java-Bali system, it would have a minimal impact on PLN's net revenues. DPV deployment, however, would have an initial and ongoing positive effect on jobs and economic development, primarily accruing to the Indonesian construction and manufacturing sectors. Altogether, this suggests that changes to compensation mechanisms (e.g., the utilization of net energy metering schemes) or the introduction of financial incentives (e.g., tax credits) to improve DPV customer economics could help bolster the Indonesian DPV market and accelerate job creation without significant financial consequences to PLN.

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