SUPLEMENTARY INFORMATION

100% Renewable Electricity in Indonesia

Supplementary Information A: Data

10 years of hourly electricity demand data is synthetical demand. Java Bali's load pattern is scaled up for 3 MWh and 6 MWh per capita demand scenario while Singapore's 9 MWh load pattern – assuming Indonesia's future electricity demand will be like Singapore at present - is scaled up to represent a 10 MWh per capita scenario.

Historical hourly solar irradiation data comes from Solcast. The weather data was transferred into hourly AC output using the System Advisor Model [58]. The calculation has been done and published in our previous study [12]. Average modelled solar generation across the 34 cities included in the study is 3.7 kWh/kWp per day with a standard deviation of +/- 6% (as shown by Figure S1).

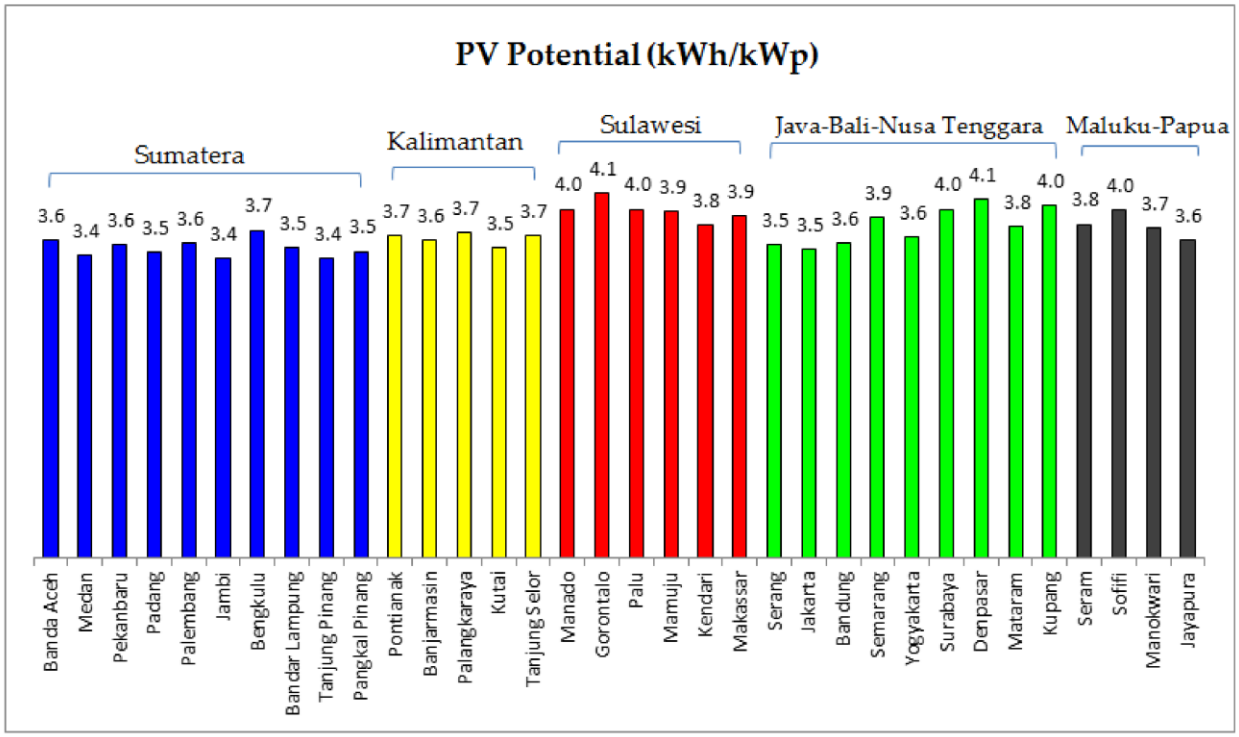


Figure S1. PV output potential (kWh/kWp) daily average in Indonesia [12]

Table S1. Indonesia's coal fired power plant retirement plan up to 2060 [59]

Regional	Coal Power Plant Capacity up to 2060 (GW)								
	2020	2025	2030	2035	2040	2045	2050	2055	2060
Sumatera	4.4	5.1	5.0	5.0	5.0	3.7	1.9	0.3	-
Java	24.2	28.5	29.5	28.3	27.7	16.7	10.1	1.0	-
Bali Nusa Tenggara	0.8	0.8	0.8	0.8	0.8	0.3	0.3	0.0	-
Kalimantan	2.4	2.7	2.7	2.7	2.4	1.2	0.9	-	-
Sulawesi	2.6	1.8	1.7	1.7	1.7	1.2	0.7	-	-
Maluku Papua	0.2	0.1	0.1	0.1	0.1	0.1	0.1	-	-
Total	34.6	39.0	40.0	38.8	37.8	23.2	14.0	1.3	-

Table S2. Indonesia's gas fired power plant retirement plan up to 2060 [59]

Regional	Gas Power Plant Capacity up to 2060 (GW)								
	2020	2025	2030	2035	2040	2045	2050	2055	2060
Sumatera	3.8	4.1	4.1	4.1	4.1	3.0	1.6	0.2	-
Java	13.6	17.0	17.0	16.3	15.9	9.6	5.8	0.6	-
Bali Nusa Tenggara	1.0	1.0	1.0	1.0	1.0	0.4	0.4	-	-
Kalimantan	0.8	0.8	1.0	1.0	0.9	0.4	0.3	-	-
Sulawesi	0.7	1.1	1.1	1.1	1.1	0.8	0.5	-	-
Maluku Papua	0.5	0.5	0.5	0.5	0.5	0.5	0.5	-	-
Total	20.4	24.5	24.6	24.0	23.5	14.7	9.0	0.8	-

Table S3. Indonesia's hydropower plant capacity [60,61]

Regional	Hydropower Capacity (GW)	
	2020	2030
Sumatera	1.8	8.6
Java Bali Nusa Tenggara	2.6	2.8
Kalimantan	0.3	1.4
Sulawesi	0.9	2.3
Maluku Papua	0.0	0.1
Total	5.6	15.3

Table S4. Indonesia's hydro power plant capacity (run off river/base load) [60,61]

Regional	Hydropower Capacity (GW)	
	2020	2030
Sumatera	0.2	0.9
Java Bali Nusa Tenggara	0.2	0.9
Kalimantan	0.0	0.0
Sulawesi	0.1	0.3
Maluku Papua	0.0	0.1
Total	0.5	2.2

Table S5. Indonesia's geothermal power plant capacity [60,61]

Regional	Geothermal Capacity (GW)	
	2020	2030
Sumatera	0.7	2.2
Java Bali Nusa Tenggara	1.3	3.0
Kalimantan	-	-
Sulawesi	0.1	0.2
Maluku Papua	-	0.1
Total	2.1	5.4

Table S6. Type and length of transmission lines. Distance measured on Google Maps [62]

No.	Transmission Lines	Type	Length (km)
1	Medan_BandaAceh	Overhead	430
2	Medan_Pekanbaru	Overhead	465
3	Padang_Pekanbaru	Overhead	200
4	Pekanbaru_Jambi	Overhead	340
5	Jambi_Palembang	Overhead	200
6	Bengkulu_Palembang	Overhead	295
7	Palembang_Tanjungkarang	Overhead	275
8	Tanjungkarang_Serang	Submarine	32
9	Bandung_Jakarta	Overhead	120
10	Ende_Mataram	Submarine	610
11	Mataram_Denpasar	Submarine	100

12	Semarang_Bandung	Overhead	320
13	Semarang_Yogyakarta	Overhead	100
14	Serang_Jakarta	Overhead	100
15	Surabaya_Denpasar	Submarine	400
16	Surabaya_Semarang	Overhead	260
17	Banjarmasin_Surabaya	Submarine	480
18	Palangkaraya_Pontianak	Overhead	560
19	Palangkaraya_Banjarmasin	Overhead	150
20	Balikpapan_Palangkaraya	Overhead	345
21	Tanjungselor_Balikpapan	Overhead	455
22	Balikpapan_Mamuju	Submarine	279
23	Manado_Gorontalo	Overhead	220
24	Gorontalo_Palu	Overhead	460
25	Palu_Kendari	Overhead	450
26	Palu_Mamuju	Overhead	225
27	Mamuju_Makassar	Overhead	275
28	Makassar_Ambon	Submarine	985
29	Jayapura_Sorong	Submarine	1062
30	Sorong_Ambon	Submarine	472
31	Sorong_Ternate	Submarine	466

Supplementary Information B: Model formulation and result

This study uses a modified version of the modelling framework "FIRM" introduced by Lu et al [20] determines the upper bounds on the capacity of renewable generators and storage required for a 100% renewable electricity network. The FIRM model has been extensively used in previous studies [16-20]. FIRM model uses a net-load approach to balance electricity demand with generation on an interval basis (typically 1-hour or 30-minute intervals) over a period of many years (typically 10 to 40 years). It allows analysis of the levelized cost of electricity at a network level to be performed. The FIRM model determines the least-cost electricity system configuration for a pre-defined electricity network that meets certain reliability, resource, energy, and transmission constraints. These constraints are defined as follows:

- **Reliability constraint**: electricity generation must meet demand in every timestep unless a specified amount of deficit is allowed, to represent load shedding in certain scenarios.
- **Resource constraint**: installed capacity of a technology in a service area must not exceed the identified technical resource potential of this technology in this service area.

- **Energy constraint**: total generation from a certain technology must not exceed the specified maximum generation from this technology.
- **Transmission constraint**: power flow in a transmission line must not exceed the specified maximum capacity of this transmission line.

The model is implemented in Python and uses differential evolution to identify the least-cost electricity system configuration that meets defined reliability, resource, energy, and transmission constraints. This section will first introduce the algorithm of the model in detail, and then introduce the modifications made for this study.

For a given set of optimization parameters (e.g., PV, and storage capacity in each service area) with defined upper bounds determined by the resource constraint, the model uses differential evolution to find the parameters with which an objective function returns the lowest value. The objective function consists of the LCOE calculated based on energy balance simulations, and the penalties for not meeting the reliability, energy, or transmission constraints.

The model consists of the following modules:

- **Input**: import model inputs and assumptions, including time series of electricity demand and meteorological data, cost assumptions, energy constraints, resource constraints etc.
- **Simulation**: for a given set of optimization parameters (PV, and storage capacity), simulate long-term hourly energy-demand balance in a perfectly interconnected system (aggregation of generation, demand, and storage in all service areas). Hourly generation from solar PV is calculated based on the defined generation capacity and hourly meteorological data. Hourly generation from hydro and other renewables is an input parameter for this module (discussed later in the 'Optimization' module). Hourly net load is calculated using the following equation:

  Equation 1

  $$Netload(t) = Demand(t) - GPV(t) - GHydro(t) - GGeo(t),\ t = 1,2,\dots 87599, 87600$$

  Where $GPV(t)$, $GHydro(t), GGeo(t)$ refers to the generation from PV, hydro, geothermal respectively. Positive netload means generation cannot meet demand therefore energy from storage is required. Negative netload means excess electricity is available and can be stored.

  Charging and discharging of storage are then calculated by:

  Equation 2

  $$Charge(t) = \min\left(-1 \times \min\big(0, Netload(t)\big), Pcapacity, \frac{Scapacity - Storage(t-1)}{efficiency}\right)$$

  Equation 3

  $$Discharge(t) = \min\left(\max\big(0, Netload(t)\big), Pcapacity, Storage(t-1)\right)$$

Where $Pcapacity$ and $Scapacity$ are the power (GW) and energy (GWh) capacities of storage. $Storage(t-1)$ is the storage level in the previous hour. $Efficiency$ is the roundtrip efficiency of storage. For simplicity, discharging is assumed to be 100% efficient and all loss occurs during charging. When the netload is positive and larger than either the energy available in storage or the storage power capacity, discharge is smaller than netload and demand cannot be met. In this case energy deficit exists:

Equation 4

$$Deficit(t) = \max(0, Netload(t) - Discharge(t))$$

When the netload is negative and its absolute value is larger than the storage power capacity or the difference between the maximum storage level and current storage level, charge is smaller than absolute value of netload and energy spillage exists:

Equation 5

$$Spillage(t) = -1 \times \min(0, Netload(t) + Charge(t))$$

Storage level is then adjusted accordingly based on charging and discharging:

Equation 6

$$Storage(t) = Storage(t-1) - Discharge(t) + Charge(t) \times efficiency$$

Hourly profiles are then exported to be used later in other modules.

- **Transmission**: simulate electricity transmission based on the results from the 'Simulation' module. Outputs from the 'Simulation' module are system-wide hourly profiles, which are scaled to create regional profiles based on the capacities in each region. Required energy import is then calculated for each region and for each hour:

  Equation 7

  $$Import(t,j) = Load(t,j) + Charge(t,j) + Spillage(t,j) - PV(t,j) - Hydro(t,j) - Discharge(t,j) - Deficit(t,j)$$

  Where t represents the current timestep and j represents the current region (service area).
  Electricity transmission between regions is then determined by each region's need for energy import. For each line, its transmission capacity (power) is determined by the maximum electricity transmitted in any hour. This is then used to calculate system costs in the 'Optimization' module.

- **Optimization**: implement differential evolution to calculate the objective function for different sets of optimization parameters. The objective function consists of the Levelized cost of Electricity

(LCOE) calculated based on the results from the Simulation and Transmission modules, and the penalties (heavily penalized by multiplying the results by 10^6 as shown below) for not meeting the reliability, energy or transmission constraints:

Equation 8

$$F(x) = LCOE + P_{deficit} + P_{energy} + P_{transmission}$$

Equation 9

- $LCOE = \frac{Cost_{PV} + Cost_{hydro} + Cost_{geothermal} + Cost_{transmission} + Cost_{storage}}{annual\ electricity\ demand}$

Equation 10

- $P_{deficit} = max(0, 10^6 \times (\sum_{t=0}^{n}(Deficit(t)) - allowance))$;
  - n: number of timesteps (e.g., $n = 87600$ for 10-year hourly modelling).
  - $allowance$**:** specified allowable deficit due to demand shedding

Equation 11

- $P_{energy} = max(0, 10^6 \times \sum(\sum_{t=0}^{n} G(i,t) - GMax_i))$;
  - $G(i,t)$: generation from technology i (e.g., hydro) at timestep t;
  - $GMax_i$: specified maximum generation from technology i

Equation 12

- $P_{transmission} = max\ (0, 10^6 \times \sum(CT_k - CTMax_k))$;
  - CT_k**:** calculated required capacity of transmission line k
  - $CTMax_k$: specified maximum capacity of transmission line k

Equation 13

- $LCOBalancing = \frac{Cost_{transmission} + Cost_{storage} + Cost_{spillage}}{annual\ electricity\ demand}$

Equation 14

- $LCOGeneration = \frac{Cost_{PV} + Cost_{hydro} + Cost_{geothermal}}{annual\ electricity\ \ generation}$

As mentioned earlier one of the inputs parameters for the 'Simulation' module is the hydro generation profile. In the 'Optimization' module, 'Simulation' is performed twice with different hydro generation profiles:

- 1st Simulation: hydro = baseload 24/7. This assumes only run-off-river hydro is used for generation. Energy deficit is calculated and is assumed to be filled by flexible hydro. Total hydro generation ($GHydro$) is then calculated by the sum of run-off-river generation and flexible generation required to fill this deficit. This total generation is used to calculate P_{energy} for hydro.
- 2nd Simulation: hydro = maximum capacity 24/7. This assumes all hydro runs at full capacity continuously. Energy deficit is calculated again and is expected to be zero. $P_{deficit}$ is calculated.

After these two 'Simulations', the 'Transmission' module runs, and required transmission capacities are estimated. LCOE is then calculated for this set of optimization parameters. When the 'Optimization' module finishes an optimization system configuration that results in the lowest LCOE as well as zero penalty is generated.

- **Dispatch**: determine the actual generation profile for flexible hydro. In the first simulation all deficit is expected to be filled by flexible hydro. However, the hourly deficit profile cannot be directly used as flexible hydro generation profile because deficit may exceed hydro capacity. The 'Dispatch' module starts with a hydro profile that operates at maximum capacity continuously, which is expected to result in zero deficit. Then for each hour of the modelling period, flexible hydro is turned off so that the hydro generation is from run-off-river hydro only. The 'Simulation' model is used to calculate deficit again. If the deficit is still zero then flexible hydro is turned off for this hour, otherwise it is turned on again. By the end of the 'Dispatch' module, a hydro generation profile is created while making sure the reliability constraint is still met.
- **Statistics**: check the feasibility of the solution and export energy balance profiles and statistics. In this study, the following modifications are made to better represent the electricity system in Indonesia:
- Incorporate flexible hydrogen as another method for balancing variable PV generation. In addition to PV and storage capacities, hydrogen capacity in each service area is added to the optimization parameters. Hydrogen is also added to the 'Simulation' and 'Transmission' modules and works in the same way as flexible hydro. However, additional simulations are performed to estimate the annual hydrogen generation in the 'Optimization' module.
    - 1st Simulation: hydro set to baseload (run-off-river) and hydrogen set to zero for the entire modelling period. The deficit is expected to be filled by both flexible hydro and hydrogen.
    - 2nd Simulation: hydro set to maximum capacity and hydrogen set to zero. The deficit is expected to be filled by flexible hydrogen. $GHydrogen$ is then calculated and subtracted from

the deficit in the 1st simulation to calculate $GHydro$. P_{energy} is then calculated for both hydro and hydrogen using Equation 11 for energy constraint.

- 3rd Simulation: both hydro and hydrogen are set to maximum capacity. Deficit is calculated and is expected to be zero. $P_{deficit}$ is calculated for reliability constraint.

- Refine the 'Dispatch' module. The original 'Dispatch' module is computationally intensive, as the 'Simulation' model needs to run for every hour of the modelling period, corresponding to 10*8760 = 87,600 runs for this study. Therefore, in the study the 'Dispatch' module is largely refined to a deficit targeted model. The model iterates through each value in the hourly deficit profile calculated from the 2nd simulation and attempts to calculate the expected hydrogen generation in that hour. If the deficit cannot be fully met by the real-time hydrogen, either because the maximum hydrogen capacity is reached in that hour or the annual hydrogen generation reaches the limit, the model will increase the hydrogen generation in the hours ahead to the required level (subject to capacity and annual generation limit) until the remaining deficit is met. In another word, hydrogen is used to pre-charge storage. By the end of this process, all deficit from the 2nd Simulation is expected to be met by flexible hydrogen and a hydrogen profile is generated. It is then modelled together with run-off-river hydro to calculate the deficit that needs to be filled by flexible hydro. The same process is repeated until all deficit is filled and a hydro generation profile is generated.

Table S7. Modelling results

Electricity System	Electricity Demand per year (TWh)	PV (GW/ TWh)	Hydro (GW/ TWh)	Geo (GW/ TWh)	PHES (GW)	Spillage	Cost ($/MWh)			LCOB component costs ($/MWh)			Storage (GWh)
							LCOG	LCOB	LCOE	Storage	Transmission	Losses and Spillage	
Java Bali Nusa Tenggara	2,065	2,295/3,225	4/8	3/24	741	36%	35	60	95	28	12	19	11,093
Sumatera	726	762/977	10/11	2/17	218	27%	36	45	80	19	8	17	1,999
Kalimantan	206	212/283	2/1	-	61	27%	36	45	81	25	6	14	1,052
Sulawesi	247	243/349	3/3	0.2/2	78	30%	35	42	77	23	6	13	957
Maluku Papua	115	129/177	0.2/1	0.1/0.5	44	34%	36	67	102	32	15	20	706
Indonesia Supergrid	3,358	3,565/4,772	18/14	5/43	1,031	29%	37	58	95	20	22	15	10,291

Prolonged periods of low insolation can be natural or human-induced. For example, we analysed 520 weeks of solar output in Tanjungselor, Kalimantan. There is an anomaly in the solar weekly output during the dry season (April – August) for 2012, 2013, 2014. We conclude that anomalously low insolation was related to forest and peat fires, often caused by people creating new agricultural areas by burning forests.

Tanjungselor - Kalimantan											
Week	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	
1	29.8	27.1	20.4	21.4	25.9	20.5	27.9	26.0	22.3	22.6	
2	29.8	27.1	20.4	21.4	25.9	20.5	27.9	26.0	22.3	22.6	Rainy season
3	29.8	27.1	20.4	21.4	25.9	20.5	27.9	26.0	22.3	22.6	
4	29.8	27.1	20.4	21.4	25.9	20.5	27.9	26.0	22.3	22.6	
5	29.8	27.1	20.4	21.4	25.9	20.5	27.9	26.0	22.3	22.6	
6	29.8	27.1	20.4	21.4	25.9	20.5	27.9	26.0	22.3	22.6	
7	29.8	27.1	20.4	21.4	25.9	20.5	27.9	26.0	22.3	22.6	
8	29.9	27.2	20.5	21.4	25.8	20.5	27.8	26.1	22.3	22.7	
9	30.0	27.2	20.7	21.5	25.8	20.5	27.7	26.1	22.4	22.9	
10	30.1	27.2	20.7	21.6	25.8	20.6	27.4	26.2	22.5	23.2	
11	30.2	27.1	20.9	21.7	25.8	20.6	27.3	26.3	22.5	23.7	
12	30.2	27.2	21.1	22.0	26.0	20.5	27.1	26.6	22.3	24.1	
13	30.3	27.3	21.1	22.4	26.3	20.3	26.8	27.0	22.3	24.7	
14	30.3	27.4	21.0	22.8	26.4	20.0	26.6	27.3	22.4	25.4	April
15	30.2	27.4	20.9	23.3	26.5	19.6	26.4	27.5	22.6	25.9	
16	30.1	27.5	20.8	23.6	26.7	19.3	26.3	27.5	22.7	26.2	
17	30.0	27.6	20.7	23.7	26.7	19.1	26.1	27.6	22.6	26.4	
18	30.0	27.6	20.7	23.8	26.8	19.1	26.1	27.6	22.5	26.4	Dry season
19	30.0	27.6	20.7	23.8	26.8	19.1	26.1	27.6	22.5	26.4	
20	30.0	27.6	20.7	23.8	26.8	19.1	26.1	27.6	22.5	26.4	
21	30.0	27.6	20.7	23.8	26.8	19.1	26.1	27.6	22.5	26.4	
22	30.0	27.6	20.7	23.8	26.8	19.1	26.1	27.6	22.5	26.4	
23	30.0	27.6	20.7	23.8	26.8	19.1	26.1	27.6	22.5	26.4	
24	30.0	27.6	20.7	23.8	26.8	19.1	26.1	27.6	22.5	26.4	
25	30.0	27.6	20.7	23.8	26.8	19.1	26.1	27.6	22.5	26.4	
26	30.0	27.6	20.7	23.8	26.8	19.1	26.1	27.6	22.5	26.4	
27	30.0	27.6	20.7	23.8	26.8	19.1	26.1	27.6	22.5	26.4	
28	30.0	27.6	20.7	23.8	26.8	19.1	26.1	27.6	22.5	26.4	
29	30.0	27.6	20.7	23.8	26.8	19.1	26.1	27.6	22.5	26.4	
30	30.0	27.6	20.7	23.8	26.8	19.1	26.1	27.6	22.5	26.4	
31	30.0	27.6	20.7	23.8	26.8	19.1	26.1	27.6	22.5	26.4	
32	30.1	27.5	20.7	23.8	26.6	19.1	26.0	27.5	22.5	26.6	
33	30.2	27.6	20.8	23.9	26.3	19.2	26.0	27.4	22.5	26.9	
34	30.3	27.7	20.9	24.1	26.0	19.3	25.8	27.4	22.4	27.3	
35	30.6	27.7	21.2	24.3	25.8	19.5	25.7	27.4	22.3	27.6	August
36	30.8	27.6	21.8	24.6	25.8	19.9	25.7	27.4	21.9	28.1	
37	31.0	27.6	22.3	24.8	25.7	20.4	25.6	27.5	21.6	28.6	
38	31.3	27.6	22.8	25.0	25.6	20.8	25.5	27.4	21.5	29.2	
39	31.5	27.7	23.2	25.0	25.6	21.1	25.4	27.4	21.5	29.7	
40	31.6	27.8	23.5	24.8	25.6	21.3	25.4	27.3	21.3	30.0	Rainy season
41	31.6	27.8	23.5	24.7	25.4	21.4	25.4	27.3	21.2	30.2	
42	31.6	27.9	23.6	24.7	25.4	21.4	25.4	27.2	21.1	30.2	
43	31.6	27.9	23.6	24.7	25.4	21.4	25.4	27.2	21.1	30.2	
44	31.6	27.9	23.6	24.7	25.4	21.4	25.4	27.2	21.1	30.2	
45	31.6	27.9	23.6	24.7	25.4	21.4	25.4	27.2	21.1	30.2	
46	31.6	27.9	23.6	24.7	25.4	21.4	25.4	27.2	21.1	30.2	
47	31.6	27.9	23.6	24.7	25.4	21.4	25.4	27.2	21.1	30.2	
48	31.6	27.9	23.6	24.7	25.4	21.4	25.4	27.2	21.1	30.2	
49	31.6	27.9	23.6	24.7	25.4	21.4	25.4	27.2	21.1	30.2	
50	31.6	27.9	23.6	24.7	25.4	21.4	25.4	27.2	21.1	30.2	
51	31.6	27.9	23.6	24.7	25.4	21.4	25.4	27.2	21.1	30.2	
52	31.6	27.9	23.6	24.7	25.4	21.4	25.4	27.2	21.1	30.2	

Figure S2. Ten years weekly solar output (kWh/week) of 1 kWp solar PV in Tanjungselor, Kalimantan

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