Accepted Manuscript

Optimum inverter sizing of grid-connected photovoltaic systems based on energetic and economic considerations

H.X. Wang, M.A. Muñoz-García, G.P. Moreda, M.C. Alonso-García

PII: S0960-1481(17)31164-3
DOI: 10.1016/j.renene.2017.11.063
Reference: RENE 9465
To appear in: *Renewable Energy*
Received Date: 24 May 2017
Revised Date: 05 October 2017
Accepted Date: 22 November 2017

Please cite this article as: H.X. Wang, M.A. Muñoz-García, G.P. Moreda, M.C. Alonso-García, Optimum inverter sizing of grid-connected photovoltaic systems based on energetic and economic considerations, *Renewable Energy* (2017), doi: 10.1016/j.renene.2017.11.063

This is a PDF file of an unedited manuscript that has been accepted for publication. As a service to our customers we are providing this early version of the manuscript. The manuscript will undergo copyediting, typesetting, and review of the resulting proof before it is published in its final form. Please note that during the production process errors may be discovered which could affect the content, and all legal disclaimers that apply to the journal pertain.

Highlights

- An optimum sizing ratio interval benefiting in both energy and economy is proposed
- The clipping effect of undersized inverter is interpreted
- An accurate inverter efficiency model is used and assessed
- Inverter characteristics affected AC output more than sizing ratio
- 1% degradation rate and 20-year lifetime lead to a 10% rise of optimum sizing ratio

Optimum inverter sizing of grid-connected photovoltaic systems based on energetic and economic considerations

H.X. Wang¹, M.A. Muñoz-García ^{1*}, G.P. Moreda¹, M.C. Alonso-García²

¹ Dep. Ingeniería Agroforestal. LPF-TAGRALIA. ETSIAAB, UPM

Av. Puerta de Hierro, 2-4, 28040 Madrid, Spain

² Photovoltaic Solar Energy Unit, Department of Energy, CIEMAT

Av. Complutense, 40, 28040 Madrid, Spain

Abstract

The optimum sizing ratio of the photovoltaic (PV) array capacity, compared to the nominal inverter input capacity, was determined in grid-connected PV (GCPV) systems from two points of view: energetic and economic. The optimum ratio was determined by both empirical and analytical approaches, and based on two PV arrays connected to their inverters, plus three simulated inverters.

The flatness of the optimum-energy region due to the inverter characteristics was decreased when economic factors were taken into account. The energetic and economic optimum sizing intervals were defined as the sizing regions causing less than 1% losses from their corresponding optimum points. Subsequently, a compound optimum sizing interval was proposed to maximise the energy injected to the grid and minimise economic costs simultaneously. The results showed that the GCPV system with lower specific DC power generation (kW_{DC}/kWp) and inverter/module cost ratio presented a wider interval (1.12–1.25) than the interval (1.17–1.19) of the system with higher specific DC power generation and cost ratio, for all the analysed inverters. Finally, the optimum sizing ratio was completed by considering a PV module degradation rate of 1%/year, which resulted in a 10% increase in the optimum sizing ratio for a 20-year lifetime.

Keywords: Grid-connected photovoltaic; Poly-Si; PV/inverter sizing ratio; Inverter characteristic

1. Introduction

Solar photovoltaic (PV) energy is a renewable energy source that is clean and environmentally friendly. In 2016, the globally installed PV capacity increased by 75 GWp, leading to a cumulative capacity of 303 GWp [1]. A well-designed grid-connected PV (GCPV) system with optimally sized inverter(s) contributes to continued PV penetration. The optimum relationship between the peak power of the GCPV system ($P_{PV,P}$) and the nominal power of the connecting inverter ($P_{inv,N}$), has been an object of analysis. The common expression of the sizing ratio (R_S) is:

$$R_S = \frac{P_{PV,P}}{P_{inv,N}}. \quad (1)$$

When $0 < R_S < 1$, the inverter is oversized. For $R_S > 1$, the inverter is undersized, and occasionally encounters the clipping effect, which is due to the power limitation leading to a flattening effect on the daily production profile of the system [2]. In this study, the direct current (DC) R_S is evaluated.

* Corresponding author.

E-mail address: miguelangel.munoz@upm.es (M.A. Muñoz-García).

With regard to the optimum energetic sizing ratio ($R_{s,E}^{opt}$), Camps et al. claimed that simulation studies were more abundant than experimental ones [3]. These extensive studies have been carried out from either the physical or technological aspects of the GCPV system. The physical aspects involve variables like location [4–6], mounting type [7], and orientation and inclination [8,9], as well as temperature and irradiance [7]. Technological aspects refer to the PV technology [9], inverter efficiency [10], sun tracking system [11], and sampling interval [5,12]. These simulations are almost straightforward programming, while others are based on complex artificial intelligence algorithms [13–15].

Due to the inverter characteristics, $R_{s,E}^{opt}$ can span a wide interval [11]. Kil and Weiden, in a study conducted in Portugal and Netherlands, reported that there was only a 0.5% output energy variation when R_s ranged from 1.05 to 1.54 [16]. Macedo and Zilles verified that R_s between 0.98 and 1.82 did not significantly affect the GCPV system's final yields in Brazil [17]. Both the simulation and emulation procedures conducted by Camps et al. in Barcelona (Spain) confirmed that the final yields experienced a reduction of less than 3% for an alternating current (AC) R_s ranging 1.00–1.24 [3]. Peippo and Lund verified the flatness around $R_{s,E}^{opt}$, and stated that deviations of $\pm 20\%$ from $R_{s,E}^{opt}$ commonly resulted in only 2% energy loss [10]. These studies suggested an optimum interval instead of a fixed optimum size value to facilitate pre-design of GCPV systems.

Furthermore, there are fewer studies based on the economic aspect than on energetic considerations to investigate the optimum sizing ratio. Ramli et al. considered unmet load, excess electricity, fraction of renewable electricity, net present cost, and carbon dioxide emissions to assess optimal sizing of the GCPV system in Saudi Arabia [18]. Chen et al. computed the maximum savings for the optimum inverter size with considerations of PV incentives and electricity rates in nine locations in the USA [19]. However, these economic criteria are country dependent due to different socioeconomic structures. Mondol et al. and Peippo and Lund suggested two more general and simple economic criteria for GCPV system sizing optimisation, namely, the annual energy output per system investment cost (C_c) and the energy output per annualized investment cost (C_A) [10,11]. Analogously, R_s depending on these two economic criteria (C_c and C_A) should have an optimum interval, because C_c and C_A are related to the energy output as well.

2. Materials and methods

2.1. Grid-connected photovoltaic systems description

A 21.77-kWp grid-connected roof-standing solar plant has been in operation [20] since December 2012 at ETSIAAB (Madrid, Spain, 40.4426° N, 3.7295° W). This solar GCPV plant includes a larger field composed of polycrystalline silicon (poly-Si) modules, and a smaller field with three arrays of three different technologies, viz., poly-Si, amorphous silicon, and cadmium telluride. In this study, we have focused on the two systems based on poly-Si technology, hereinafter referred to as *System 1* from the smaller field and *System 2* from the larger one. The details of these two systems are shown in Table 1. All the modules are mounted in an open-rack structure with a 30° tilt angle and oriented with an azimuth angle of 3° (i.e., almost south-facing).

Table 1. Main characteristics of the GCPV analysed systems.

	<i>System 1</i>	<i>System 2</i>
$P_{PV,P}$ (kW)	1.61	16.83
$P_{inv,N}$ (kW)	1.32	15.34
R_s	1.22	1.10
Inverter max. efficiency (%) / Euro-eta (%)	92.1/90.9	98.1/97.7
Cell type	Poly-Si	Poly-Si
Recording interval (min)	15	15
Performance degradation rate (%/year)	1	1

2.2. Actual power estimation at power limitation points

The inverters of the two GCPV systems are undersized, which means that the peak power of the two PV arrays is higher than their respective inverters' nominal capacity. The R_s values are 1.22 and 1.10 for *System 1* and *2*, respectively (Table 1). One reason for installing an undersized inverter is that the standard test conditions (STC: irradiance of 1000 W/m² for a solar spectrum of AM1.5G and module temperature 25 °C) are hard to reach in certain areas, resulting in lower actual generated power than its STC power [21].

An undersized inverter clips the power output and blurs the actual power at high insolation conditions, as shown in Fig. 1. When the power limitation is reached, the inverter forces the PV array to increase its operating voltage instead of working at the maximum power point voltage (V_{mp}), thus reducing the maximum power point current (I_{mp}) and maximum power (P_{mp}).

Fig. 1. Effect of in-plane irradiance (G_i), ambient temperature (T_a), and power limitation on maximum power (P_{mp}), operating current (I_{mp}), and voltage (V_{mp}) of *System 1* on 25 August 2016.

For both GCPV systems, a data acquisition system integrated in the inverter centre measured and recorded the DC and AC power output data as well as the power limitation events. During the one-year period, *System 2* seldom met the power limitation, whilst approximately 13% of the records in *System 1* were affected by power limitation. The objective of this work is to define optimum inverter sizing of GCPV systems. Due to the more undersized inverter of *System 1*, a model has been applied to simulate the power in the inverter clipping areas in order to obtain comparative results between the two systems. This model includes two sub-models to simulate I_{mp} and V_{mp} separately.

The sub-model for I_{mp} was extracted from the work by King et al. [22]:

$$I_{mp} = I_{mp0} \cdot (C_0 \cdot E_e + C_1 \cdot E_e^2) \cdot (1 + \alpha_{mp} \cdot (T_c - T_0)), \quad (2)$$

where E_e is the effective irradiance, defined as the ratio of the irradiance measured by the PV cells to the total irradiance incident on the module; I_{mp0} is the I_{mp} at STC, which is provided by the manufacturer; T_c (°C) is the PV cell temperature inside module and in this study it was assumed to equal the back-of-module temperature; α_{mp} (°C⁻¹) is the temperature coefficient of current; C_0 and C_1 are empirical parameters

obtained from Sandia National Laboratory module database; and T_0 is the standard back-of-module temperature, and equals 25 °C.

The sub-model for V_{mp} was obtained through linear regression (Eq. (3)) on one year of V_{mp} and T_c filtered measurements. The filtering criteria include: 1. Power limitation points were excluded in cases where V_{mp} increased abnormally in the clipping area (see Fig. 1), 2. Data were excluded when the irradiance varied from the maximum to the minimum for more than 10% of the 15-min recording interval.

$$V_{mp} = 206.5 \cdot (1 - 0.0045 \cdot (T_c - 25)). \quad (3)$$

The maximum power prediction model was built by combining the two sub-models, Eq. (2) and Eq. (3):

$$P_{mp} = I_{mp} \cdot V_{mp}. \quad (4)$$

This power model (Eq. (4)) was validated by a series of tests at solar noon with high irradiance ($G > 900$ W/m²). These tests were conducted with a Solar-4000® I-V curve tracker during April–November 2016. A high degree of conformity was obtained (see Fig. 2), i.e., the measured and simulated results were very close, with a root mean squared error (RMSE) (Eq. (5)) of 1.42%.

$$RMSE(\%) = \frac{100 \cdot \sqrt{\frac{1}{N} \sum (m_i - s_i)^2}}{\bar{m}_i}, \quad (5)$$

where m_i is the i th measured value and s_i is the i th simulated value, N is the number of samples, which herein equals 117, and $\bar{m}_i$ is the average of the measured values.

In order to maintain most of the original DC power profile of *System 1*, only the abovementioned 13% of records encountering the power limitation were replaced by their corresponding values calculated using Eq. (4). Hereinafter, the investigation on R_s of *System 1* is based on the mixing data profile, i.e., 13% simulated and 87% original.

Fig. 2. Comparison of measured and simulated maximum power values at high-irradiance solar noon for *System 1*.

2.3. Inverter efficiency and AC energy output model

Solar inverter conversion efficiency is a function (Eq. (6)) of the actual partial load ($P_{mp}(t)/P_{inv,N}$), neglecting the dependency on the inverter input voltage [13,23].

$$\eta(P_{mp}(t)) = b_0 \cdot \frac{P_{inv,N}}{P_{mp}(t)} + b_1 + b_2 \cdot \frac{P_{mp}(t)}{P_{inv,N}}, \quad (6)$$

where b_0 is the constant normalised self-consumption loss coefficient, b_1 is the linear efficiency coefficient, and b_2 is the coefficient for losses proportional to the square of the output power [10].

The parameters were determined by *least-squares fitting (LSF)* of the efficiency curve points from the database of PVsyst® v.6.4.7 (Fig. 3). In addition, based on the work by Peippo and Lund [10], three sets of b_i coefficients (b_0 , b_1 , b_2) were selected to represent the generic high-, medium-, and low-efficiency inverters (Table 2). Hereinafter, inverters 1, 2, and 3 refer to the high-, medium-, and low-efficiency inverters, respectively.

Fig. 3. *Least-Squares fittings (LSFs)* of the inverter's efficiency as a function of partial load based on PVsyst® v.6.4.7 inverter database.

Table 2. Characteristics of three simulated inverters, from Peippo and Lund (1994a), and the two actual inverters of the analysed solar plant, obtained through *LSF*.

	b_0	b_1	b_2
High efficiency (inverter 1)	-0.35%	99.50%	-1.00%
Medium efficiency (inverter 2)	-2.00%	97.50%	-8.00%
Low efficiency (inverter 3)	-5.00%	91.50%	-15.00%
System 1 (SMA SB 1200)	-1.00%	94.30%	-4.00%
System 2 (SMA 15000TL)	-0.26%	98.70%	-1.10%

Subsequently, the AC power output of an inverter is expressed as Eq. (7), which is derived from Eq. (6) by three DC-power input regimes. When P_{mp} is lower than the switch-on power (P_{min}) of the inverter, there is neither power output nor standby losses from the GCPV system. Once there is insolation, the inverter starts to operate based on Eq. (6) until P_{mp} is higher than $P_{inv,N}$. Then, the input of the inverter (or the DC power output of the PV array) is limited at $P_{inv,N}$. In other words, the input power above the inverter input capacity is rejected [9,10].

$$P_{AC}(P_{mp}(t), P_{inv,N}) = \eta(P_{mp}(t)) \cdot P_{mp}(t)$$

$$= \begin{cases} (b_0 + b_1 + b_2) \cdot P_{inv,N}, & P_{mp}(t) > P_{inv,N} \\ \left(b_0 \cdot \frac{P_{inv,N}}{P_{mp}(t)} + b_1 + b_2 \cdot \frac{P_{mp}(t)}{P_{inv,N}} \right) \cdot P_{mp}(t), & P_{min} \leq P_{mp}(t) \leq P_{inv,N} \\ 0, & P_{mp}(t) < P_{min} \end{cases} \quad (7)$$

where P_{min} is assumed to be 0 in this study.

The AC annual energy output (E_{AC}) of the two GCPV systems as a function of various R_S or $P_{inv,N}$ was obtained using an empirical method (*Method 1*) and an analytical method (*Method 2*).

Method 1 uses one-year measurements of $P_{mp}(t)$ to calculate E_{AC} :

$$E_{AC} = \sum P_{AC}(P_{mp}(t), P_{inv,N}) \cdot \Delta t, \quad (8)$$

where Δt is the recording interval of 15 min.

Method 2 uses an analytical method proposed by Demoulias [23], including the concept of the DC power duration curve (*PDC*) and its linear fitting. The *PDC* is defined as the curve that shows the aggregate time percentage in a period during which the DC power is larger than or equal to a certain value. The mathematical derivation of this analytical method is presented in the Appendix.

Then, two economic criteria mentioned by Mondol et al. and Peippo and Lund are used to investigate the related economic optimum sizing ratios [10,11]. The first one, C_C (kWh/€), is defined as the ratio of annual energy output to the system's initial investment cost:

$$C_C = \left(\frac{E_{AC}}{R_{PV} \cdot P_{PV,P} + R_{inv} \cdot P_{inv,N}} \right), \quad (9)$$

where R_{PV} is the overall initial cost of the array (excluding the inverter cost) per PV-array watt-peak (€/Wp) and R_{inv} is the inverter cost per watt-peak (€/Wp).

The second one, C_A (kWh/€), refers to the annual energy output per annualised investment cost with the considerations of PV module (L_{PV}) and inverter (L_{inv}) lifetime:

$$C_A = \left(\frac{E_{AC}}{CRF_{PV} \cdot R_{PV} \cdot P_{PV,P} + CRF_{inv} \cdot R_{inv} \cdot P_{inv,N}} \right), \quad (10)$$

where CRF is the capital recovery factor:

$$CRF_{PV} = \frac{I}{1 - (1 + I)^{-L_{PV}}} \quad (11)$$

$$CRF_{inv} = \frac{I}{1 - (1 + I)^{-L_{inv}}} \quad (12)$$

where I is the real interest rate.

Through the mathematical derivation of E_{AC} detailed in the Appendix, the two corresponding optimum sizing ratios ($R_{S,C}^{opt}$, $R_{S,A}^{opt}$) are obtained as the solutions of the first-order derivatives for these two economic criteria:

$$\left. \frac{dC_C}{dR_S} \right|_{R_C^{opt}} = 0 \quad (13)$$

$$\left. \frac{dC_A}{dR_S} \right|_{R_A^{opt}} = 0. \quad (14)$$

3. Results and discussion

3.1. Annual efficiency of high-, medium-, and low-efficiency inverters

Inverter annual efficiency is plotted against R_S in Fig. 4 for the high-, medium-, and low-efficiency inverters. These curves were generated from one-year measurements $P_{mp}(t)$ (referred to as *Method 1* in section 2.3)

for *System 1* (dashed line) and *System 2* (solid line). In a rather wide range of R_s from 0.8 to 1.1, the annual efficiencies are approximately constant. The major advantage of a high-efficiency inverter is that it features a wider optimum sizing range without affecting the annual efficiency significantly.

On the other hand, the annual efficiency discrepancy between *System 1* and *System 2* does not emerge until R_s is higher than 1 in high- and medium-efficiency inverters, whilst the discrepancy in the low-efficiency inverter decreases until R_s equals 1, and subsequently increases.

Although Fig. 4 was obtained by the empirical *Method 1*, it can be mathematically interpreted in the light of the inverter characteristics and the different power duration curves (Fig. 5) of the two systems. From the mathematical derivation included in the Appendix (*Method 2*), the inverter annual efficiency can be expressed as:

$$\eta = \frac{E_{AC}}{E_{DC}} = 2 \cdot \left(\frac{P_{PV,P}}{R_s \cdot P_{max,L}} \cdot b_0 + \frac{P_{max,L} \cdot R_s}{3P_{PV,P}} \cdot b_2 \right) + b_1, \left(R_s \leq \frac{P_{PV,P}}{P_{max,L}} \right) \quad (15)$$

$$= 2 \cdot \frac{P_{PV,P}}{P_{max,L} \cdot R_s} \cdot (b_0 + b_1 + b_2) - \frac{P_{PV,P}^2}{P_{max,L}^2 \cdot R_s^2} \cdot \left(b_1 + \frac{4b_2}{3} \right), \left(R_s > \frac{P_{PV,P}}{P_{max,L}} \right). \quad (16)$$

When R_s varies from 0.4 to $P_{PV,P}/P_{max,L}$ (this ratio is typically approximately 1), the inverter annual efficiency is expressed by Eq. (15). Its first addend, $2 \cdot \left(\frac{P_{PV,P}}{R_s \cdot P_{max,L}} \cdot b_0 + \frac{P_{max,L} \cdot R_s}{3P_{PV,P}} \cdot b_2 \right)$, is smaller than the other constant addend b_1 , especially for the high- and medium-efficiency inverters, resulting in a flat efficiency curve in this R_s range. For medium-efficiency inverters, the first addend is less than 3.5% and b_1 is 97.5%. For high-efficiency inverters, the first addend is less than 2% and b_1 is 99%. However, for low-efficiency inverters, b_1 is only 91.5%. Thus, there is a slight difference between two systems because of the characteristics of *PDCs* (Fig. 5), i.e., $P_{PV,P}/P_{max,L}$.

However, when R_s is higher than $(P_{PV,P}/P_{max,L})$, the annual efficiency is expressed by Eq. (16). The increasing R_s results in a steep drop in the annual efficiency curve; meanwhile, the characteristics of *PDCs* (Fig. 5), i.e., $P_{PV,P}/P_{max,L}$, lead to a higher discrepancy between *System 1* and *System 2*.

Fig. 4. Annual inverter efficiency as a function of *sizing ratio* for high-, medium- and low-efficiency inverters. Dashed line: *System 1*; Solid line: *System 2*.

Fig. 5. Power duration curves and linear fittings of (a) *System 1* and (b) *System 2* from July 2015 to June 2016.

3.2. Monthly AC energy and energetic optimum sizing ratios

The monthly *PDCs* (solid blue lines) of *System 2* for one year are depicted in Fig. 6, together with the corresponding linear fittings (dashed orange lines). The linearities of the monthly *PDCs* ranged from the worst case (Jan. 2016, with the lowest R^2 and highest *RMSE*) to a relatively better case (Mar. 2016, with the maximum R^2 and lowest *RMSE*), which are detailed in the last two columns of Table 3.

The two abovementioned methods are assessed by the comparisons between the monthly energy produced by *System 2* (Table 3). E_{AC0} , E_{AC1} , and E_{AC2} are the AC energy generated by *System 2*, simulated by *Method 1*, and simulated by *Method 2*, respectively. ΔE_1 is the relative error between E_{AC0} and E_{AC1} ($(E_{AC0} - E_{AC1}) / E_{AC0}$), and ΔE_2 is the relative error between E_{AC0} and E_{AC2} ($(E_{AC0} - E_{AC2}) / E_{AC0}$). The rather low ΔE_1 (annual value of 0.6%) confirms the validation of *Method 1*, or the inverter power output model (Eq. (7)). However, E_{AC2} is slightly overestimated, as seen from Table 3. These errors in *Method 2* occurred mostly in winter months, featuring worse linearities of *PDC* and lower irradiance (e.g., from Dec. 2015 to Feb. 2016). This result suggests that the application of *Method 2* to calculate E_{AC} in low-irradiance regions, like northern Europe, might be less efficient.

The next two columns of Table 3 are the monthly $R_{S,E}^{opt}$ values obtained by *Method 1* ($R_{S,E1}^{opt}$) and *Method 2* ($R_{S,E2}^{opt}$), respectively. Both $R_{S,E}^{opt}$ values are characterised with a similar seasonal trend: higher values in cold and low-irradiance seasons; lower values in hot and high-irradiance seasons. This seasonal trend indicates that the GCPV systems at low-irradiance sites need a more undersized inverter than those exposed to high irradiance, to achieve better performance.

Fig. 6. Monthly DC power duration curves (solid blue lines) and linear fittings (dashed orange lines) during the period from Jul. 2015 to Jun. 2016, for System 2.

Table 3. The monthly generated and simulated system energy output (E_{AC}), together with energetic optimum sizing ratio ($R_{S,E}^{opt}$) by Method 1 and Method 2. R^2 and RMSE are the fitness parameters of the monthly power duration curves' linear fittings.

Month	E_{AC0} (kWh)	E_{AC1} (kWh)	E_{AC2} (kWh)	ΔE_1 (%)	ΔE_2 (%)	$R_{S,E1}^{opt}$	$R_{S,E2}^{opt}$	R^2	RMSE (x100%)
Jul.2015	2844	2831	2867	0.46	-0.81	0.97	0.93	0.98	0.12
Aug.2015	2990	2975	3004	0.50	-0.47	0.93	0.90	0.98	0.10
Sep.2015	2467	2456	2482	0.45	-0.61	0.94	0.91	0.99	0.09
Oct.2015	1624	1611	1641	0.80	-1.05	1.09	1.03	0.98	0.12
Nov.2015	1842	1829	1876	0.71	-1.85	1.03	0.98	0.96	0.15
Dec.2015	1401	1394	1449	0.50	-3.43	1.27	1.19	0.95	0.19
Jan.2016	834	829	881	0.60	-5.64	1.19	1.21	0.90	0.31
Feb.2016	1794	1784	1854	0.56	-3.34	1.04	0.99	0.95	0.19
Mar.2016	2380	2357	2398	0.97	-0.76	0.94	0.90	0.99	0.08
Apr.2016	2364	2348	2448	0.68	-3.55	1.02	0.96	0.95	0.18
May 2016	2555	2540	2624	0.59	-2.70	1.08	1.02	0.96	0.16
Jun.2016	3030	3014	3065	0.53	-1.16	0.97	0.93	0.98	0.11
Annual	26125	26099	26703	0.60	-2.21	1.01	0.96	0.98	0.12

3.3. Compound optimum sizing intervals

E_{AC} , C_G , and C_A as a function of R_S and inverter type are shown in Fig. 7, where the results are generated by Method 1 (orange dashed line) and Method 2 (blue solid line). Fig. 7a represents System 1, and Fig. 7b

represents *System 2*. The economic inputs for calculating C_C and C_A are described in Table 4, where the two financial terms R_{PV} and R_{inv} are the actual cost of the ETSIAAB PV plant. Table 5 summarises the three sizing ratios obtained by *Method 1*.

Table 4. Economic parameters used for calculating C_C and C_A .

	System 1	System 2
Array cost ¹ (R_{PV}) (€/Wp)	3	3
Inverter cost (R_{inv}) (€/Wp)	1	0.5
Real interest rate (I) (%)	5	5
Lifetime of PV module (L_{PV}) (years)	20	20
Lifetime of inverter (L_{inv}) (years)	10	10

¹ GCPV system overall cost, excluding inverter.

All the curves in Fig. 7 have similar shapes in both systems, although the results of *Method 2* are slightly overestimated, with *RMSE* values smaller than 4%.

The low sensitivities (i.e., the flatness of the curves as a function of R_S) of E_{AC} around $R_{S,E}^{opt}$ are noticeable from Fig. 7 and Table 5. The values within brackets are the sizing ratio ranges corresponding to the 1% variation of E_{AC} from the maximum point calculated by *Method 1*. The low sensitivities were also reported in the works of Camps et al. [3], as well as Peippo and Lund [10]: both groups of researchers suggested defining an optimum sizing interval for $R_{S,E}^{opt}$ instead of focusing on the precise value.

Regarding the terms C_C and C_A , the convexities of their curves around the respective optimum sizing ratios ($R_{S,C}^{opt}$ and $R_{S,A}^{opt}$) increase compared to E_{AC} , owing to the additional constraints and relevance to obtain the two terms. Their 1% variation ranges are narrower than the range of E_{AC} , as shown in Table 5. Subsequently, a combination from the energetic and economic considerations is proposed to define the optimum interval of R_S . That optimum interval is the overlap region of the three optimum sizing ranges at the last columns— $R_{S,I}^{opt}$ —of Table 5.

This compound optimum sizing ratio interval ($R_{S,I}^{opt}$) has benefits in terms of both energy and economic yield. It is able to mitigate the dispute between policy makers and investors. Concretely, a policy maker would desire as much energy being injected to grid as possible from the GCPV system, therefore he/she would prefer a higher-capacity inverter (compared to the inverter with the highest economic benefit). On the contrary, the first priority of an investor would presumably be cost reduction with its subsequent financial benefit; thus, he/she would adopt a lower-capacity inverter (compared to the energetic-benefit inverter).

The different *PDCs* affect the compound optimum interval more than the type of inverter. It is seen in Table 5, where *System 2* features a wider $R_{S,I}^{opt}$ (1.12–1.25) and *System 1* a narrower one (1.17–1.19).

Accounting for the comparison between *System 1* and *System 2* in Table 5, from the energetic aspect, $R_{S,E}^{opt}$ values of *System 2* are higher than those of *System 1* due to the lower specific DC power output, as shown in Fig. 5. Therefore *System 2* needs a more undersized inverter to achieve a better energetic performance. However, from the economic considerations, the higher R_{inv} of *System 1* requires an inverter with higher R_S (or more undersized) to improve C_C , resulting in higher $R_{S,C}^{opt}$ values than those of *System 2*. Analogously, the higher R_{inv} value leading to a higher replacement cost of the inverter of *System 1* intensifies the necessity of a further undersized inverter to maximise C_A .

Fig. 7. Annual energy output (E_{AC}), the annual energy output per system investment cost (C_C), and the energy output per annualised investment cost (C_A) as a function of sizing ratio for different inverters in (a) System 1 and (b) System 2; the dashed orange line is generated by Method 1, whereas the solid blue line corresponds to Method 2.

Table 5. Optimum sizing ratios (energetic optimum sizing ratio ($R_{S,E}^{opt}$), economic optimum sizing ratio ($R_{S,C}^{opt}$) based on system investment cost, economic optimum sizing ratio ($R_{S,A}^{opt}$) based on annualised system investment cost) and the optimum intervals ($R_{S,I}^{opt}$) generated by Method 1. The values within brackets are the sizing ratio range corresponding to the 1% variation from the maximum point.

	$R_{S,E}^{opt}$	$R_{S,C}^{opt}$	$R_{S,A}^{opt}$	$R_{S,I}^{opt}$
System 1 Inverter 1	0.97 (0.40–1.20)	1.24 (1.12–1.36)	1.29 (1.18–1.44)	1.18–1.20
System 1 Inverter 2	0.95 (0.62–1.18)	1.23 (1.10–1.36)	1.29 (1.17–1.44)	1.17–1.18
System 1 Inverter 3	1.01 (0.79–1.19)	1.23 (1.11–1.36)	1.29 (1.17–1.44)	1.17–1.19

System 1 SMA SB 1200	0.95 (0.56–1.19)	1.23 (1.12–1.36)	1.29 (1.17–1.44)	1.17–1.19
System 2 Inverter 1	1.09 (0.41–1.25)	1.22 (1.08–1.34)	1.25 (1.13–1.38)	1.13–1.25
System 2 Inverter 2	0.99 (0.64–1.23)	1.21 (1.07–1.33)	1.25 (1.12–1.37)	1.12–1.23
System 2 Inverter 3	1.08 (0.82–1.24)	1.21 (1.07–1.33)	1.25 (1.12–1.37)	1.12–1.24
System 2 SMA 15000TL	1.01 (0.40–1.25)	1.22 (1.08–1.34)	1.25 (1.13–1.38)	1.13–1.25

3.4. Optimum sizing ratio as a function of degradation rate

For investment decisions, the degradation rate (R_d) of the PV module is of great importance, as it affects the lifetime energy generation of the GCPV system [24,25]. The effects of R_d on the economic parameters C_C and C_A can be obtained by simply analysing the effect on E_{AC} , as the denominators in Eq. (9) and Eq. (10) will not be altered with the inclusion of R_d .

With the consideration of R_d , Table 6 summarises the three optimum sizing ratios, which is based on the following hypothesis:

- R_d is a constant of 1%/year and the period considered is 20 years;
- Inverter conversion efficiency remains constant during its lifetime;
- The DC energy profile from July 2015 to June 2016 is taken as the first operating year.

The three parameters $R_{S,E}^{opt}$, $R_{S,C}^{opt}$, and $R_{S,A}^{opt}$, as well as their intervals, have a relative increase of 10%, compared with Table 5. As the DC annual energy decreases yearly by 1% in the 20-year period, the inverter should be smaller to maximise the lifetime AC output.

Table 6. Three optimum sizing ratios (energetic optimum sizing ratio ($R_{S,E}^{opt, Rd}$), economic optimum sizing ratio ($R_{S,C}^{opt, Rd}$) based on system investment cost, economic optimum sizing ratio ($R_{S,A}^{opt, Rd}$) based on annualised system investment cost) and the optimum intervals ($R_{S,I}^{opt, Rd}$) generated by *Method 1* with degradation rate. The values inside brackets are the sizing ratio range corresponding to the 1% variation from the maximum point.

	$R_{S,E}^{opt, Rd}$	$R_{S,C}^{opt, Rd}$	$R_{S,A}^{opt, Rd}$	$R_{S,I}^{opt, Rd}$
System 1 Inverter 1	1.05 (0.42–1.30)	1.36 (1.21–1.51)	1.42 (1.28–1.59)	1.28–1.30
System 1 Inverter 2	1.04 (0.68–1.29)	1.35 (1.21–1.50)	1.42 (1.28–1.58)	1.28–1.29
System 1 Inverter 3	1.11 (0.87–1.30)	1.35 (1.21–1.50)	1.42 (1.28–1.58)	1.28–1.30
System 1 SMA 1200	1.03 (0.62–1.29)	1.35 (1.21–1.50)	1.42 (1.28–1.58)	1.28–1.29
System 2 Inverter 1	1.13 (0.45–1.36)	1.32 (1.16–1.47)	1.37 (1.22–1.52)	1.22–1.36
System 2 Inverter 2	1.09 (0.71–1.34)	1.31 (1.15–1.46)	1.36 (1.21–1.51)	1.21–1.34
System 2 Inverter 3	1.16 (0.90–1.35)	1.32 (1.16–1.47)	1.36 (1.22–1.51)	1.22–1.35
System 2 SMA 15000TL	1.11 (0.40–1.35)	1.32 (1.16–1.47)	1.37 (1.22–1.52)	1.22–1.36

3.5. Discussion

The main contribution of this study is a pre-design procedure for GCPV systems equipped with optimum-sized inverter(s), with the consideration of PV module degradation rate. The aim is to increase energy production and reduce capital cost.

Owing to technology innovation, current inverters feature improved efficiencies, especially at partial loads. The simulated low-efficiency inverter (inverter 3), and even medium-efficiency inverters (inverter 2 and SMA SB 1200 of *System 1*), are non-existent in large-scale commercial and utility GCPV systems. This is one reason

to choose the high-efficiency inverter (inverter 1) and the SMA 15000TL inverter of *System 2*, of which the efficiency is more than 97%. They could stand for the common inverters used by large GCPV systems. One important result of comparing SMA SB1200 and SMA 15000TL is that the high-efficiency inverter has a wider energetic optimum sizing range than the lower-efficiency inverter.

For a large GCPV system, the optimum inverter sizing ratio or range would differ, as the sizing ratio is affected by the DC power output of the PV system, the characteristics of the connected inverter, and the GCPV system capital cost.

For the pre-design of a GCPV system with an optimum-sized inverter, the first step is to construct the DC power profile (power duration curve stated in the study) using a proper power model with inputs of local climate data. For a large-scale commercial or utility PV plant with a capacity of 1 MW or higher, the main difference with the smaller systems analysed here is the power profile, due to the higher energy losses and possibility of mismatch among other factors. Subsequently, based on the DC power duration curve and adopting the simulated inverter type (low-, medium-, or high-efficiency inverter stated in this study) characteristics, *Method 2* offers a proper inverter sizing range; the realistic inverters are then selected based on this range. However, the realistic inverter's characteristics could be different from those of the simulated inverter type. Finally, the validation of the realistic inverter could be justified through recalculation by *Method 1* or *Method 2*.

Despite the substantial cost reductions for the technical components of GCPV systems ($R_{pv} + R_{inv}$) in recent years, the ratio (R_{pv} / R_{inv}) is in the range of 6 for commercial GCPV systems to 10 for utility GCPV systems in 2016 [26,27]. In this study, the ratio (R_{pv} / R_{inv}) of *System 2* is 6. Accordingly, these cost reductions only decrease the C_C and C_A values, while the stable cost ratio (R_{pv} / R_{inv}) resulted in a similar sizing ratio and interval. However, if this ratio moves towards a higher value, representing a lower inverter cost proportion, the optimum inverter sizing ratio could become smaller as the inverter cost becomes less important.

4. Conclusions

Optimum inverter sizing intervals have been studied for two poly-Si GCPV systems (with inverter input capacities of 1.32 and 15.34 kW). The study utilises measured DC power output profiles through a simplified inverter efficiency model and an analytical method. The following conclusions can be drawn:

For the pre-design of a GCPV system, PV modules' degradation rates should be considered. With respect to the first year, assuming a 20-year lifetime and a module degradation rate of 1%/year, both the optimum sizing ratio and the optimum interval experience an increase of 10%.

Annual inverter efficiency remaining at its maximum over a wide sizing ratio range was due to the inverter characteristics, among which the loss coefficients were much smaller than the linear efficiency coefficient. The improvement of inverter efficiency along with technical innovations intensified this parameter's resistance to sizing ratio variation within a wide range, which facilitated the adoption of proper inverter capacity from the energy point of view. However, once economic factors were taken into account, the optimum sizing ratio interval would shrink due to additional constraints, such as module price and lifetime.

A compound optimum sizing ratio interval is proposed to maximise the energy yields and to reduce capital costs. The different DC power profiles and investment costs had a greater effect on the compound interval than the inverter type. The GCPV system with lower specific power generation and inverter cost exhibited a wider interval (1.12–1.25) than the system with higher specific power generation and inverter cost (1.17–1.19).

The annual AC energy output (E_{AC}), calculated by the inverter power output model, was close to the measured value, with a 0.6% annual error. However, the analytical method yielded a 2.2% overestimation of the annual E_{AC} . The analytical method performed worse in winter months, suggesting it might be less efficient in low-irradiance regions. Meanwhile, due to the low power generation of GCPV systems in low-irradiance regions, the optimum sizing ratio would be higher for them than for the systems operating in high-irradiance regions.

ACKNOWLEDGEMENTS

The authors would like to thank the LPF-TAGRALIA research group of the Universidad Politécnica de Madrid (UPM) for the funding of the project and CIEMAT for their cooperation. Additionally, we wish to acknowledge the financial support from the programme of the China Scholarships Council (CSC). Personally, we greatly appreciate the valuable help of Jorge Muñoz, a technician at ETSIAAB (UPM).

Appendix

The DC power is described by the following equation, which is the linear fitting of PDC (Fig. 8):

$$P_{mp}(t) = A \cdot t + P_{max,L} \quad (17)$$

where $P_{max,L}$ is the maximum value of PDC 's linear fitting. E_{AC} is calculated for two distinct cases due to the different inverter capacities ($P_{inv,N}$) by using Eq. (17) and Eq. (7). The first case is $P_{inv,N} > P_{max,L}$. The second case is $P_{inv,N} < P_{max,L}$.

Fig. 8. Power duration curve and its linear fitting for System 1, from Jul. 2015 to Jun. 2016.

When $P_{INV,N} \geq P_{max,L}$, E_{AC} can be expressed as:

$$\begin{aligned} E_{AC} &= \int_0^T P_{mp}(t) \cdot \eta(P_{mp}(t)) \cdot dt \\ &= \left[-\frac{P_{max,L}}{A} \cdot \left(b_0 \cdot P_{inv,N} + \frac{b_1}{2} \cdot P_{max,L} + \frac{b_2 \cdot P_{max,L}^2}{3 \cdot P_{inv,N}^2} \right) \right] \cdot T_{total} \end{aligned} \quad (18)$$

For maximum E_{AC} :

$$\left. \frac{dE_{AC}}{dP_{inv,N}} \right|_{P_{inv,N}^{opt}} = \left[-\frac{P_{max,L}}{A} \cdot \left(b_0 - \frac{b_2 \cdot P_{max,L}^2}{3 \cdot P_{inv,N}^2} \right) \right] \cdot T_{total} = 0. \quad (19)$$

The optimum inverter capacity is:

$$P_{inv,N}^{opt} = P_{max,L} \cdot \sqrt{\frac{b_2}{3b_0}} \quad (20)$$

Note that, in this case, the fact that $P_{inv,N} \geq P_{max,L}$ results in : $|b_2| \geq 3|b_0|$, otherwise, $P_{inv,N}^{opt} = P_{max,L}$.

When $P_{inv,N} < P_{max,L}$, the inverter's annual energy output can be expressed as:

$$\begin{aligned} E_{AC} &= \int_0^T P_{mp}(t) \cdot \eta(P_{mp}(t)) \cdot dt \\ &= \int_{T_1}^{T_2} P_{mp}(t) \cdot \eta(P_{mp}(t)) \cdot dt + P_{inv,N} \cdot T_1 \cdot \eta(P_{inv,N}) \\ &= \left[P_{inv,N}^2 \cdot \frac{\frac{b_1}{2} + \frac{2b_2}{3}}{A} - \frac{P_{max,L} \cdot P_{inv,N} \cdot (b_0 + b_1 + b_2)}{A} \right] \cdot T_{total} \end{aligned} \quad (21)$$

and the optimum inverter capacity is:

$$\left. \frac{dE_{AC}}{dP_{inv,N}} \right|_{P_{inv,N}^{opt}} = \left[2P_{inv,N} \cdot \frac{\frac{b_1}{2} + \frac{2b_2}{3}}{A} - \frac{P_{max,L} \cdot (b_0 + b_1 + b_2)}{A} \right] \cdot T_{total} = 0 \quad (22)$$

$$P_{inv,N}^{opt} = \frac{P_{max,L} \cdot (b_0 + b_1 + b_2)}{b_1 + \frac{4b_2}{3}}. \quad (23)$$

In this case, $P_{inv,N}$ should be smaller than $P_{max,L}$, resulting in : $|b_2| < 3|b_0|$, otherwise, $P_{inv,N}^{opt} = P_{max,L}$.

References

- [1] IEA-PVPS, Snapshot of Global Photovoltaic Markets 2016, IEA-PVPS report. 2017. doi:ISBN 978-3-906042-42-8.
- [2] F. Serdio Fernández, M.A. Muñoz-García, S. Saminger-Platz, Detecting clipping in photovoltaic solar plants using fuzzy systems on the feature space, Sol. Energy. 132 (2016) 345–356. doi:10.1016/j.solener.2016.03.013.
- [3] X. Camps, G. Velasco, J. de la Hoz, H. Martín, Contribution to the PV-to-inverter sizing ratio determination using a custom flexible experimental setup, Appl. Energy. 149 (2015) 35–45. doi:10.1016/j.apenergy.2015.03.050.
- [4] P. Bakas, K. Papastergiou, S. Norrga, Solar PV array-inverter matching considering impact of environmental conditions, Conf. Rec. IEEE Photovolt. Spec. Conf. (2011) 001779–001784. doi:10.1109/PVSC.2011.6186299.
- [5] B. Burger, R. Rüther, Site-dependent system performance and optimal inverter sizing of grid-connected PV systems, Conf. Rec. IEEE Photovolt. Spec. Conf. (2005) 1675–1678. doi:10.1109/PVSC.2005.1488469.
- [6] S. Chen, P. Li, D. Brady, B. Lehman, The impact of irradiance time behaviors on inverter sizing and design, 2010 IEEE 12th Work. Control Model. Power Electron. COMPEL 2010. (2010) 2–6. doi:10.1109/COMPEL.2010.5562387.
- [7] G. Velasco, F. Guinjoan, R. Piqué, A. Conesa, J.J. Negroni, Inverter power sizing considerations in grid-connected PV systems, 2007 Eur. Conf. Power Electron. Appl. EPE. (2007). doi:10.1109/EPE.2007.4417317.
- [8] J.D. Mondol, Y.G. Yohanis, B. Norton, Optimising the economic viability of grid-connected photovoltaic systems, Appl. Energy. 86 (2009) 985–999. doi:10.1016/j.apenergy.2008.10.001.
- [9] G. Notton, V. Lazarov, L. Stoyanov, Optimal sizing of a grid-connected PV system for various PV module technologies and inclinations, inverter efficiency characteristics and locations, Renew. Energy. 35 (2010) 541–554. doi:10.1016/j.renene.2009.07.013.
- [10] K. Peippo, P.D. Lund, Optimal sizing of solar array and inverter in grid-connected photovoltaic systems, Sol. Energy Mater. Sol. Cells. 32 (1994) 95–114. doi:10.1016/0927-0248(94)90259-3.

- [11] J.D. Mondol, Y.G. Yohanis, B. Norton, Optimal sizing of array and inverter for grid-connected photovoltaic systems, *Sol. Energy*. 80 (2006) 1517–1539. doi:10.1016/j.solener.2006.01.006.
- [12] B. Burger, R. Rüther, Inverter sizing of grid-connected photovoltaic systems in the light of local solar resource distribution characteristics and temperature, *Sol. Energy*. 80 (2006) 32–45. doi:10.1016/j.solener.2005.08.012.
- [13] R. Bakhshi, J. Sadeh, H.-R. Mosaddegh, Optimal economic designing of grid-connected photovoltaic systems with multiple inverters using linear and nonlinear module models based on Genetic Algorithm, *Renew. Energy*. 72 (2014) 386–394. doi:10.1016/j.renene.2014.07.035.
- [14] A. Fernández-Infantes, J. Contreras, J.L. Bernal-Agustín, Design of grid connected PV systems considering electrical, economical and environmental aspects: A practical case, *Renew. Energy*. 31 (2006) 2042–2062. doi:10.1016/j.renene.2005.09.028.
- [15] A. Mellit, S.A. Kalogirou, L. Hontoria, S. Shaari, Artificial intelligence techniques for sizing photovoltaic systems: A review, *Renew. Sustain. Energy Rev.* 13 (2009) 406–419. doi:10.1016/j.rser.2008.01.006.
- [16] a. J. Kil, T.C.J. Van Der Weiden, Performance of modular grid connected PV systems with undersized inverters in Portugal and the Netherlands, *Proc. 1994 IEEE 1st World Conf. Photovolt. Energy Convers. - WCPEC (A Jt. Conf. PVSC, PVSEC PSEC)*. 1 (1994) 1028–1031. doi:10.1109/WCPEC.1994.520136.
- [17] W.N. Macedo, R. Zilles, Operational Results of Grid-Connected Photovoltaic System With Different Inverter's Sizing Factors (ISF), *Prog. Photovolt Res. Appl.* 15 (2007) 337–352. doi:10.1002/pip.
- [18] M.A.M. Ramli, A. Hiendro, K. Sedraoui, S. Twaha, Optimal sizing of grid-connected photovoltaic energy system in Saudi Arabia, *Renew. Energy*. 75 (2015) 489–495. doi:10.1016/j.renene.2014.10.028.
- [19] S. Chen, P. Li, D. Brady, B. Lehman, Determining the optimum grid-connected photovoltaic inverter size, *Sol. Energy*. 87 (2013) 96–116. doi:10.1016/j.solener.2012.09.012.
- [20] H. Wang, M.A. Muñoz-García, G.P. Moreda, M.C. Alonso-García, Seasonal performance comparison of three grid connected photovoltaic systems based on different technologies operating under the same conditions, *Sol. Energy*. 144 (2017) 798–807. doi:10.1016/j.solener.2017.02.006.
- [21] L. Keller, P. Affolter, Optimizing the panel area of a photovoltaic system in relation to the static inverter—Practical results, *Sol. Energy*. 55 (1995) 1–7. doi:10.1016/0038-092X(95)00032-M.
- [22] D.L. King, J. a Kratochvil, W.E. Boyson, Photovoltaic array performance model, *Online*. 8 (2004) 1–19. doi:10.2172/919131.
- [23] C. Demoulias, A new simple analytical method for calculating the optimum inverter size in grid-connected PV plants, *Electr. Power Syst. Res.* 80 (2010) 1197–1204. doi:10.1016/j.epsr.2010.04.005.
- [24] G. Belluardo, P. Ingenhoven, W. Sparber, J. Wagner, P. Weihs, D. Moser, Novel method for the improvement in the evaluation of outdoor performance loss rate in different PV technologies and comparison with two other methods r&t, *Sol. Energy*. 117 (2015) 139–152. doi:10.1016/j.solener.2015.04.030.
- [25] G. Makrides, B. Zinsser, M. Schubert, G.E. Georgiou, Performance loss rate of twelve photovoltaic technologies under field conditions using statistical techniques, *Sol. Energy*. 103 (2014) 28–42. doi:10.1016/j.solener.2014.02.011.
- [26] Fraunhofer I. S. E., Photovoltaics Report 2016, 2017. <https://www.ise.fraunhofer.de/content/dam/ise/de/documents/publications/studies/Photovoltaics-Report.pdf>.
- [27] A. Jäger-waldau, PV Status Report 2016, European Commission, 2016. doi:10.2790/749737.