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Costs of utility-scale photovoltaic systems integration in the future Italian energy scenarios

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Abstract

This study aims at introducing a new metric to evaluate the production costs of photovoltaic plants that includes the impacts of adding them in the existing energy system. In other words, the levelized cost of electricity concept is enlarged to incorporate the so-called integration costs. They consider the costs of reinforcing the grid infrastructure to accept the increase of variable renewable sources production and the effects on the operating conditions of the existing fossil fuel power plants. These costs are applied to the utility-scale photovoltaic plants to analyse how their market parity and profitability would change in the future if a more systematic approach is used to evaluate their production costs. Moreover, a bottom-up energy system model performing an operational optimization is introduced and coupled with a genetic algorithm to perform the expansion capacity optimization. This model is used to study the effects on the utility-scale photovoltaic plants' dispatchability if the integration costs are included. The Italian energy system and photovoltaic market projected to the year 2030 are taken as reference. The results of the market parity highlight that its achievement will not be compromised when the integration costs are considered, mainly thanks to the strong decrease of the investment costs expected in the future years. The results of the optimization underline that the future role of photovoltaic plants in the energy mix with low CO_2 emissions will not be significantly affected, even when these additional costs are applied as annual costs.

KEYWORDS

integration costs, levelized cost of electricity, photovoltaic systems, PV profitability, techno-economic analysis

List of abbreviations: BESS, battery energy storage system; CCGT, combined cycle gas turbine; HV, high voltage; IPCC, Intergovernmental Panel on Climate Change of the United Nations; IRR, internal rate of return; LCOE, levelized cost of electricity; LV, low voltage; MV, medium voltage; NOCT, nominal operating cell temperature; NPV, net present value; O&M, operation and maintenance; PBT, pay-back time; POA, plane-of-array; PNIEC, Piano Nazionale Integrato per l'Energia ed il Clima; PPA, power purchase agreement; PUN, Prezzo Unico Nazionale; PV, photovoltaic; RES, renewable energy sources; SOC, state-of-charge; TSO, transmission system operator; VRES, variable renewable energy sources.

1 | INTRODUCTION

The world will face a strong energy transition in the next decade due to the urgent need of slowing down the climate change to avoid unknown consequences. The scientific community, through the voice of the Intergovernmental Panel on Climate Change of the United Nations (IPCC), warned recently that roughly a decade remains to strongly reduce CO_2 emissions to avoid an increase of the average earth temperature above 1.5–2°C at the end of this century.[1] Thus, authorities in several states worldwide are establishing policies to guide the economy towards a greener, fairer, and more sustainable transition. For example, the European Union has presented the Green New Deal[2] in the year 2019 that determines how Europe can become a carbon-neutral continent within the year 2050.[3]

Regarding the energy sector, renewable energy sources (RES) represent the primary if not even exclusive option, since 100% renewable-based energy systems are possible and desirable in the future.[4] Solar and wind are expected to have the key role, but since they are characterized by an intermittent nature, i.e. they are strongly variable in space and time, they could bring out problems in terms of grid stability. Several studies demonstrated how the use of ancillary services in solar PV can mitigate the grid stability issues.[5,6] Pierro et al., for example, present two strategies for the mitigation of power imbalances and related costs resulting from increasing PV penetration onto the Italian grid. However, although relevant and promising, these concepts are not yet mainstream nor widely adopted by transmission system operators (TSOs). Nevertheless, it is necessary to understand the impact of high intermittent RES penetration in the current energy system focusing the attention to the technical challenges and the costs associated to the energy transition. Moreover, a significant share of renewables raises questions on how the electricity markets must be re-designed to let them participate avoiding cannibalization phenomena.[7] In fact, it is common that the RES bids in the electricity markets based on marginal price are currently close to 0 €/MWh, and if the amount of zero-valued offers increases, with the current energy market, there will be a strong risk of negative or zero electricity prices (e.g. around midday where solar is predominant) that would jeopardize the future investments in RES power plants, since they would be no more economically attractive. On another side, the opportunity of close to zero price electricity will be a driver for the cost-effective use of power-to-X in a more integrated and sector coupled energy landscape (e.g. power to gas, power to heat, power to transport).

For this reason, the aim of this research study is to understand how the future profitability and exploitability of RES power plants would evolve, focusing the attention on the utility-scale photovoltaic (PV) plants with and without electrical storage systems. In this study, two different point of views will be adopted: an investor in utility-scale PV plants and the energy system manager. Two important concepts for the investor are the market parity; i.e. the generation costs shall not exceed the price at which the electricity produced can be sold, and the investment profitability calculated as net present value (NPV), pay-back time (PBT) and internal rate of return (IRR): an investment is generally assumed to be cost-effective when its IRR is at least equal to the discount rate applied in the power sector. For the energy system manager, the investment costs and the annual fixed and variable costs for each technology are important to dispatch the generation resources minimizing the costs for the whole system and, consequently, for the community.

In this context, the generation costs related to each power production technology are the reference value for both. They are commonly calculated as the levelized cost of electricity (LCOE), a techno-economic parameter that represents the costs of producing 1 kWh of electricity with a specific power plant. In other words, the LCOE is the total costs sustained divided by the total energy produced by the power plant during its lifetime, applying a discounting method. The main input data are the investment costs, the annual operation and maintenance (O&M) costs (including the fuel costs when applicable) and the annual electricity production net of the annual components' degradation. The basic LCOE formula for the PV plants is that the one proposed in Fraunhofer[8] that can be extended as in Vartiainen et al.,[9] where the annual electricity production is calculated based on the utilization and degradation rates, while the O&M expenditure is discounted with the nominal weighted average cost of capital (WACC) and the annual electricity production by the real WACC. This LCOE formulation is the following:

$$\mathrm{LCOE} = \frac{\mathrm{CAPEX} + \sum_{t=1}^{n} \frac{\mathrm{OPEX}(t)}{(1+\mathrm{WACC_{nom}})^t}}{\sum_{t=1}^{n} \left[\frac{\mathrm{Utilization_0} * (1-\mathrm{Degradation})^t}{(1+\mathrm{WACC_{real}})^t}\right]} \ [€/\mathrm{kWh}],$$

where CAPEX is the total investment expenditure of the system in the year t = 0, OPEX(t) is the operation and maintenance expenditure in year t, $\mathrm{WACC_{nom}}$ is the nominal WACC per year, $\mathrm{WACC_{real}}$ is the real WACC per year, $\mathrm{Utilization_0}$ is the initial utilization in the year t = 0 (without considering degradation), Degradation is the annual degradation of the nominal power of the system, n is economic lifetime of the system and t the year of lifetime (1, 2, …, n).

Other parameters can be added to the LCOE formulation depending on the application and the focus of the research. For example, Hernandez-Moro and Martinez-Duart[10] focus the attention on the ground-mounted PV plants and included in the LCOE formula the land costs (i.e. the costs related to the land purchased for the installation of the PV plant), the insurance costs, the tracking factor that is equal to 1 for optimally inclined and south-oriented PV plants, and the performance factor to convert the total irradiation into the real amount of electricity produced per watt installed. Darling et al.[11] introduced in the LCOE formula the residual value, i.e. the possible earnings coming from the disposal or re-sale of the power plant at the end of its useful life. For commercial and industrial PV plants, the authors add also other financial parameters like the depreciation, the interest paid on the loan and the tax rate.

It is possible to notice that none of these approaches considers the interaction of the new power plant with the existing energy system, and this can have an impact in scenarios with high RES penetration. In other words, the LCOE as usually intended is not able to account for the technical and economic issues connected to grid stability and change of the usual operating conditions of fossil fuel power plants as a consequence of a significant increase of electricity production from variable RES (VRES). In fact, the VRES, such as solar and wind, are intermittent and non-programmable, and their electricity production is difficult to be predicted. Moreover, they can be exploited installing power plants directly on the site where the electricity is needed; thus, they are very commonly applied on residential and commercial buildings, connected to the distribution system. However, not all instances of overgeneration may be injected into the grid due to possible grid constraints as the VRES production cannot be directly controlled. Typical issues are overvoltage at the buses or reverse power flows from the points of distribution towards the low-voltage (LV)/medium-voltage (MV) transformer. At the same time, since a larger portion of electricity is produced and directly consumed on site, the overall electricity demand profile changes and the existent fossil fuel power plants, which were initially aimed to satisfy the baseload, are now forced to modulate their production level to cover the variable residual load and higher ramps caused by inherent VRES non-programmability. All these effects are expenses for the community and the energy system, and thus, they shall be included in the techno-economic evaluation of new power plants. These costs are usually called integration costs, and adding them to the LCOE, a new techno-economic parameter named system LCOE can be defined as in Ueckerdt et al.[12] The addition of integration costs in the LCOE can also improve the comparison of any solution apt to transform VRES into programmable unit, e.g. use of electrical storage, curtailments and forecasting.[6]

The integration costs can be subdivided into different components depending on the impacts considered. The grid costs[12–15] reflect the economic effort to reinforce and extend the grid infrastructure (i) to support the geographical diffusion of VRES capacity, (ii) to accept the increasing VRES production and (iii) to guarantee the grid reliability, avoiding overvoltage and reverse power flows. Another cost component is related to balancing,[12,13,16] which includes all the effects that VRES production has on the existing fossil fuel power plants. In fact, the non-programmability of VRES production generates rapid fluctuations in the output that shall be overcome by the fossil fuel power plants that are forced to operate at partial load conditions providing additional balancing services. The intermittency of VRES production adds also issues related to the system reliability and security of supply, whose costs can be expressed as capacity costs[13,16] or adequacy costs.[12] The cost of storage,[14,15] the cost of VRES production curtailment[15] and the profile costs[12] can also be included as part of the integration costs.

The aim of this research is to (i) understand how the future market parity and profitability of utility-scale PV plants with and without storage system will be affected by the integration costs in the LCOE calculation and (ii) analyse if and how the introduction of these costs could affect the diffusion and dispatch of utility-scale PV plants with respect of the other technologies in the energy mix. These goals are pursued by comparing the results of the expansion capacity optimization model with and without the integration costs.

The optimization of the energy mix and generation resources dispatch is performed by the oemof-moea[17] model, which couples a genetic algorithm to the linear programming energy system model oemof.[18] The analysis is focused on the Italian PV market, taking as reference the year 2030 according to energy transition traced with the national Energy and Climate Plan (PNIEC acronym from the Italian Piano Nazionale Integrato per l'Energia ed il Clima[19]) that sets targets to be reached in the year 2030 in terms of RES penetration and CO_2 emissions reduction.

This paper is structured in the following way: (i) the methodology used in this analysis is described in detail in Section 2; (ii) the case study and the main assumptions adopted are presented in Section 3; (iii) the results obtained are discussed in Section 4; and (iv) the conclusions are drawn in Section 5.

2 | METHODOLOGY

This section describes the methodology adopted in this analysis. Firstly, the new parameter accounting for the integration costs and used to evaluate the production costs is defined. Secondly, the oemof-moea model[17] is briefly explained pointing out the implementation of the integration costs to perform the optimization of future energy systems.

2.1 | System LCOE as a new metric to evaluate the PV production costs

2.1.1 | General definitions of the integration costs

The PV generation costs can be calculated including the possible impacts of the new PV installations on the existing energy system and power plants. Examples of definitions of integration costs are the ones proposed in some papers.[12–16] As in Ueckerdt et al.,[12] the new parameter used in this analysis to evaluate the PV production costs is called system LCOE because it embraces a more systematic approach to the estimation of the costs of producing electricity. It includes both the power plant costs, as in the LCOE common calculation, and the integration costs, which have been split into grid and balancing costs.

The grid costs comprise the impacts that the VRES production has on the grid infrastructure at both distribution and transmission levels. Thus, they are accounted in the system LCOE to represent the economic effort needed to enhance the transport of the additional VRES production, avoiding grid instability and guaranteeing the security of supply. The grid costs are the sum of the transmission, and distribution network reinforcements, adequacy, and curtailment costs, which will be better described later.

The balancing costs, instead, consider the impacts that the additional VRES production has on the existing fossil fuel power plants in terms of the efficiency reduction and the start-up costs. Thus, the system LCOE used in this analysis can be schematically represented as in Figure 1.

Even though the methodology and the definitions used in this paper are general and can be used in different contexts, it must be remembered that the absolute values of the integration costs, both

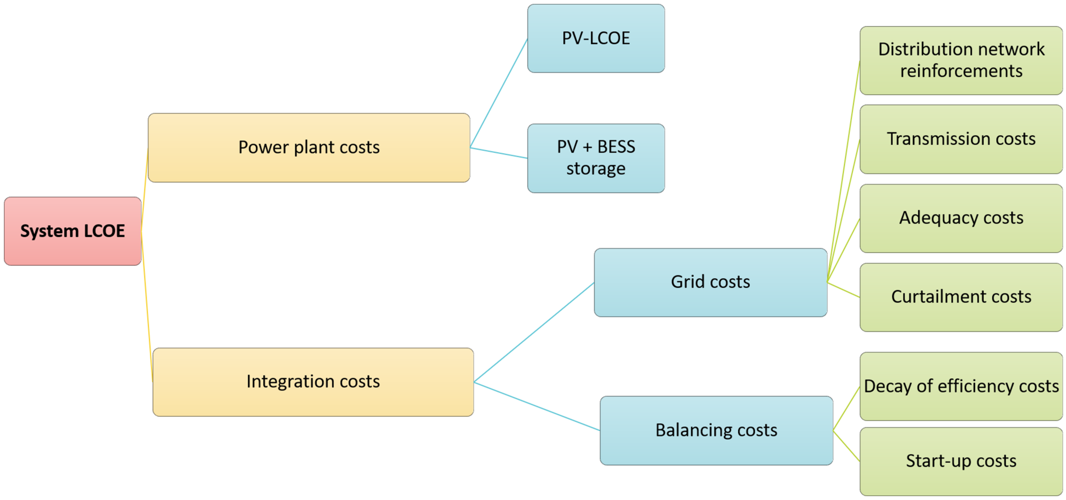

FIGURE 1 Schematic representation of the system levelized cost of electricity (LCOE) cost components [Colour figure can be viewed at wileyonlinelibrary.com]

grid and balancing costs, are strictly dependent on the energy system configuration, i.e. transmission and distribution grid infrastructure, number and geographical distribution of the existing power plants and storage systems, etc. For this reason, the methodology requires a case study which in this paper is the Italian case.

The power plant costs represent the cost of generating the electricity with the PV plants, considering it coupled or not with a battery energy storage system (BESS). Since the Italian energy system and electricity markets are managed dividing the country into macro regions, the power plant costs, as well as some of the other cost components, are calculated according to the Italian macro regions: North, Central North, Central South, South, Sardinia and Sicily. In this way, the PV generation costs can be more precisely estimated by considering the variation of the solar irradiation at different latitudes and, thus, the different production potential.

One of the main advantages of the PV technology is that it is scalable, so it can be exploited to produce the electricity directly on the site where it is needed. For this reason, PV plants are mainly installed nowadays on residential and commercial buildings roofs to increase the self-consumption as well as to reduce the electricity bills. However, this widespread diffusion of small PV plants raises some issues on the grid stability. In fact, originally, the electricity was supplied into the grid from the centralized power production units (mainly fossil fuel power plants and hydropower plants) connected to the high voltage (HV) network and then distributed to the final users connected to the MV and LV networks following a one-directional path; today, the electricity can flow both directions in the distribution grid, since the small-scale PV plants can produce overgeneration because of the mismatch between PV production and user demand. To solve this issue, the distribution network needs to be renovated and the costs associated are called reinforcing distribution network costs. They require a power flow model of the distribution grid to be precisely estimated, but its creation is beyond the scope of this study. For this reason, it has been decided to use in this analysis the values provided in the PV Parity Project.[14]

As the distribution network, also the transmission grid has been influenced by the widespread diffusion of VRES of the last years. In fact, there are different impacts of increasing VRES production for the transmission grid: on the one side, the increase of self-consumption at the distribution level modifies the national residual demand profile,[20] and on the other side, the mismatch between production and consumption generates overproduction at the distribution level that might cause reverse power flows at the connection points between LV/MV grid and HV grid. Moreover, the diffusion of utility-scale VRES power plants connected at the transmission level stresses the grid infrastructure for the additional intermittent production. Again, one possible solution is to invest in reinforcing and renovating the transmission grid infrastructures and extending the transport capacity of powerlines, and the consequent costs are included in the system LCOE calculation as transmissions costs. As for the reinforcing distribution network costs, the transmission costs shall be calculated with a power flow model to evaluate their variation as a function of the VRES penetration and mitigation strategies that can be adopted, like the diffusion of distributed and centralized storage systems. Since the development of such model is beyond the scope of this analysis, a simplified approach has been adopted: the transmission reinforcement costs are directly estimated from the investments planned by the national TSO for RES integration and spread over the additional PV and wind production expected within the reference year 2030. In mathematical terms, the transmission costs are calculated as follows:

$$C_{\text{trans}} = \frac{\sum_{m}^{\text{macroregions}} \text{Inv}_{\text{TSO,RES int}}(m)}{\sum_{m}^{\text{macroregions}} \text{Prod}_{\text{VRES,2030}}(m) * \text{PV\_lifetime}},$$

where $\text{Inv}_{\text{TSO,RES int}}$ (m) is the total investment made by the national TSO for RES integration in the macro region m expressed in €, $\text{Prod}_{\text{VRES,2030}}$ (m) is the added production of VRES (wind and PV) expected in the future in the macro region m in terms of MWh and PV_lifetime is the service lifetime of PV power plants in years (the adoption of PV_lifetime instead of the transmission line one is conservative).

The adequacy costs, as explained before, reflect the impacts of VRES production on the system reliability and the security of supply. Thus, they are strictly connected to the ability of the grid infrastructure to withstand the stress factors. Again, a power flow model is required for their better estimation, but it is beyond the scope of this analysis. For this reason, they are calculated similarly to the transmission costs using the TSO investments aimed to guarantee the quality of the service when also the RES integration issue is involved and spread over the additional PV and wind production. Thus, the adequacy costs are expressed similarly to the transmission costs as follows:

$$C_{adequacy} = \frac{\sum_{m}^{macroregions} Inv_{TSO,Q\&S}(m)}{\sum_{m}^{macroregions} Prod_{VRES,2030}(m) * PV\_lifetime},$$

where $Inv_{TSO,Q\&S}$ (m) is the total investment made by the TSO for quality and security of the grid in the macro region m in €.

The curtailment costs represent the economic loss that a power plant owner faces due to the energy curtailed in a certain region to avoid grid instability. Since there is no remuneration scheme in Italy for the curtailed production nowadays, this cost component is calculated directly in the power plant costs as a decrease of the annual electricity produced in percentage terms. The percentage of PV curtailed is estimated for each macro region in respect of the macro regional PV production as calculated by the energy system model, Oemof, for the reference year.

Lastly, the increase of VRES electricity production has a direct effect on the operating conditions of fossil fuel power plants. In fact, they were designed to satisfy the national baseload demand, while now they are used to cover the residual peak demand arising when the VRES production is lower than the load or completely unavailable. To be noted that in some countries with particular energy mix (e.g. Australia), some of these services are already provided with cost-competitive marginal costs by batteries. In this analysis, the balancing costs are represented by the decay of efficiency and the start-up costs that are evaluated as in Memoli,[21] taking into account the operational limits of the fossil fuel power plants (combined cycle gas turbine [CCGT], in the Italian case study) and the time-dependency of their transient operation. The start-up costs are defined as a function of the CCGT power plant downtime and are calculated applying the following formulation:

$$C_{start-up} = \frac{\sum_{u}^{units} \sum_{start-up}^{starts} \sum_{t}^{time} [C_{start-up,\ \Delta t} * P_{nom} * X(t)]}{P_{tot}},$$

where $C_{start\text{-}up,\ \Delta t}$ is the specific start-up cost depending on downtime Δt in €/MWh, P_{nom} the nominal power in MW and X(t) is a Boolean variable that returns 1 if the power plant at time t has been down for an interval of time equal or higher than the downtime Δt; otherwise, it returns 0.

The decay of efficiency costs, instead, depends on how much the current operating conditions of the CCGT power plant are far from the normal operating ones, and they are mathematically defined as follows:

$$C_{decay} = \frac{\sum_{u}^{units} \sum_{t}^{time} [\Delta F_{additional,\ u(t)} * C_{fuel}]}{P_{tot}},$$

where $\Delta F_{additional,\ u(t)}$ is the additional fuel consumption of unit u at time t due to decay of efficiency in MW, C_{fuel} is the specific fuel cost in €/MWh and P_{tot} is the total electricity generated by fossil fuel power plants in MWh.

Since no macro regional values are given in Memoli,[21] these costs are applied with the same value to all the macro regions.

Alternative methods for the evaluation of balancing costs are explained in Fan et al.[22] and Trahey et al.,[23] focusing on the BESS demand-side management applications.

2.1.2 | System LCOE, market parity and profitability analysis

The system LCOE just explained is used as the reference parameter to evaluate the PV production costs instead of the common LCOE approach. The integration costs are included in the system LCOE formulation as annual costs multiplied by the annual PV production and discounted, in the same way as the annual O&M costs are discounted in the common LCOE calculation. However, even though the definitions of the system LCOE and its cost components are applicable in general, for the methodological limits highlighted above, e.g. the absence of a power flow model for a more accurate estimation of transmission and adequacy costs, the system LCOE is applied in two different ways, distinguishing between the cases of only PV plant and PV plus storage system.

In the case of PV plants with BESS, following the approach suggested in Lai and McCulloch[24] for the estimation of the power plant costs, the system LCOE is determined with the formula below:

$$S_{LCOE} = \frac{PV_{capex} + BEES_{capex} + \sum_{t=1}^{N} \left(\frac{PV_{opex} * N_{sur\_h}}{(1+i)^t} + \frac{PV_{opex} * N_{dir\_h}}{(1+i)^t} + \frac{(C_{trans} + C_{bal} + C_{adeq} + C_{distr}) * PV_{prod}}{(1+i)^t} \right)}{\eta \frac{PV_{sur}(1-d_{EES})^t}{(1+i)^t} + \frac{PV_{dir}(1-d_{PV})^t}{(1+i)^t}},$$

where PV_{capex} is the PV investment costs (€), $BEES_{capex}$ the BESS investment costs (€), PV_{opex} the annual O&M expenditures (€), N_{sur_h} the hourly fraction of PV surplus (—), N_{dir_h} the hourly fraction of directly consumed PV production (—), C_{trans} the transmission costs (€/MWh), C_{bal} the balancing costs (€/MWh), C_{adeq} the adequacy costs (€/MWh), C_{distr} the reinforcing distribution network costs (€/MWh), PV_{prod} the annual PV production (MWh), η is the BESS round-trip efficiency, PV_{sur} the annual PV energy surplus (MWh), PV_{dir} the annual PV energy directly consumed (MWh), d_{EES} the annual storage system degradation rate (—), d_{PV} the annual PV degradation rate (—), i the discount rate (—), N the system lifetime (years) and t the year of lifetime (1, 2, …, N). In this case, the curtailment costs are not included. In fact, the PV curtailment is estimated using the hourly dispatch optimization model Oemof. The application of this model to the reference scenario 2030 has shown no curtailment, mainly thanks to the additional storage capacity expected in that year. Details regarding the assumptions made to build the reference scenario are discussed in Section 3.

For the case of only PV plants, the system LCOE is applied in the following way:

$$S_{LCOE} = \frac{PV_{capex} + \sum_{t=1}^{N}\left(\frac{PV_{opex}}{(1+i)^t} + \frac{(C_{bal} + C_{distr}) * PV_{prod\_net}}{(1+i)^t}\right)}{\frac{PV_{prod\_net}(1-d_{PV})^t}{(1+i)^t}},$$

where PV_{capex} is the PV investment costs (€), PV_{opex} the annual O&M expenditures (€), C_{bal} the balancing costs (€/MWh), C_{distr} the reinforcing distribution network costs (€/MWh), PV_{prod_net} the annual PV production (MWh) net of the macro regional PV curtailment in percentage terms, d_{PV} the annual PV degradation rate (—), i the discount rate (—), N the system lifetime (years) and t the year of lifetime (1, 2, …, N).

In this case, the curtailment costs are included as a percentage reduction of the annual nominal PV production and the percentage reduction results from the simulation done with the energy system model without considering the additional storage capacity expected in the reference year. Another difference in respect of the previous case is that the transmission and adequacy costs are not present. In fact, they are estimated based on the investments planned by the national TSO to reach the PNIEC targets in the year 2030; thus, they are determined taking already into account the additional storage capacity established by the Italian PNIEC. As said before, without a power flow model of the national transmission and distribution grid, it is difficult to evaluate how these two costs components will change with different scenarios of VRES penetration and different combinations of distributed and centralized storage systems. Therefore, it has been decided to not include these two cost components in the case of PV plant without BESS.

The system LCOE is here used to assess how the market parity[*] of utility-scale PV plants could evolve in the future. To be consistent with the current Italian electricity market subdivision for which the Italian territory is managed through macro regions, the market parity is analysed comparing the macro regional system LCOE with the average macro regional electricity price. The profitability analysis is studied in parallel to the market parity, focusing the attention on some more investment-specific parameters like the PBT, the NPV and IRR to understand if the market parity is accompanied by positive investment parameters. In particular, the comparison is made between the IRR and the discount rate applied in the system LCOE calculation: if the IRR is higher than the discount rate, the investment in the PV plant is considered economically attractive.

The market parity and profitability are determined by a Python code that, starting from an hourly annual profile of plane-of-array (POA) irradiation is able to size the PV and BESS systems and to evaluate the LCOE, NPV, PBT and IRR, as in Veronese et al.[25] The first step consists in the estimation of the annual PV production using as input data the annual POA hourly profile, technical PV module parameters like area, efficiency, specific power and considering the temperature effect that requires as input the annual hourly profile of ambient temperature, the Nominal Operating Cell Temperature (NOCT) and the power temperature coefficient. Afterwards, the energy balance among PV, BESS and grid is optimized taking in input also the minimum and the maximum state-of-charge (SOC). Finally, the calculation of the system LCOE, PBT, NPV and IRR is performed giving as inputs some economic data such as investment costs as well as annual O&M costs of the PV and BESS systems, integration costs, discount rate, degradation rate of both PV and BESS components, and the average zonal electricity price.

This economic analysis is made for the year 2020 as a starting point from which the 2030 scenario is compared. The results are shown by means of maps made with QGIS,[26] an open source GIS-based tool.

2.2 | Implementation of the integration costs in an energy system model

To understand how the integration costs could affect the diffusion of utility-scale PV plants on a larger scale, a bottom-up ‘expansion capacity optimization energy system’ model is applied to the Italian case study. In this way, it is possible to study the evolution of the Italian energy mix with and without the integration costs applied to the utility-scale PV plants by comparing the energy mix of the optimization results.

The energy system model chosen for this analysis is oemof,[18] an open source energy system model developed in the Python environment that uses a multi-node approach to dispatch the power generation sources at the minimum variable costs for the system.[27] Since the Italian Energy and Climate Plan reports only aggregated values at the national scale of the expected additional installed capacities and production for each technology, these values are transformed into macro regional production profiles thanks to this energy system model. The six Italian macro regions are the nodes of the model that are connected one another by the transmission constraints, i.e. the transport capacity of the powerlines that are connecting one macro region to the others. Each node is characterized by the electricity demand, the installed capacity of each technology and the average normalized hourly profiles of electricity demand and RES production, that are built as in Prina et al.[28] Other input parameters needed by oemof model are the specific technology costs, fuel costs and CO_2 emissions

*The market parity is reached when the PV production costs, i.e. the system LCOE, are equal to or lower than the price at which the electricity produced can be sold, i.e. the national average electricity price (PUN from the Italian Prezzo Unico Nazionale).

that are used to evaluate the costs for the system given a certain technology configuration. The economic input data are the investment costs in terms of €/kW (or €/kWh in the case of storage systems), O&M costs provided as a percentage of the investment and the operational lifetime in years for each technology involved in the energy mix. For this analysis, the integration costs are added as annual variable costs only for the utility-scale PV plants.

The energy system model Oemof is used to compare two different cases, with and without integration costs applied to the utility-scale PV plants. The scope of this phase is to evaluate and compare the best energy mixes obtained through the modelling in the two cases. To achieve this, an expansion capacity optimization model is required. The choice fell on Oemof-moea model which couples a multi-objective evolutionary algorithm (MOEA),[29] which performs the expansion capacity optimization with multi-objective approach to Oemof, which is used in the operational optimization (or dispatch optimization) mode. The full code of the Oemof-moea model is available in this repository.[30] The multi-objective optimization is aimed to minimize two objective functions: the total annual costs for the energy system and the total annual CO_2 emissions. Some decision variables should be identified to define the domain of the expansion capacity optimization problem. In this study, the oemof-moea model is applied to the Italian energy system, limited to the electricity sector; and the selected decision variables are the installed capacities of (i) utility-scale PV plants (subdivided into fixed and with tracking system, which differ only for a slightly higher investment and O&M costs in this latter case), (ii) residential rooftop PV plants, (iii) building-integrated PV (BIPV) intended as facade PV plants, (iv) wind power plants and (v) stationary lithium-ion batteries. In addition, other decision variables are the capacities of the transmission powerlines, which represent the connection among the nodes of the model, that can be enlarged to solve congestion problems.

A minimum bound and a maximum bound are defined for each of these decision variables and for each Italian macro region. The minimum bound is identified by the configuration of the Italian electricity sector in the year 2017, which has been used also for a preliminary validation of oemof model. The maximum bound, instead, defines the maximum capacity that could be installed for each technology. The maximum potential of utility-scale PV plants is estimated putting together the information available in some papers,[31–33] and the latter[33] is used also to estimate the upper bound of wind potential. For the rooftop PV and the BIPV maximum installable capacity, the data reported in some papers[28,34,35] are used respectively.

The overall maximum potential of lithium-ion batteries has been estimated equal to 600 GWh and equally subdivided among the six macro regions resulting in a maximum lithium-ion capacity battery equal to 100 GWh of for each zone. Starting from the current transport capacities of transmission powerlines provided by the Italian TSO,[36,37] the maximum potential for each interconnection results to be equal to 10 GW after a series of simulations. The powerline connections are characterized by a 3% of transmission losses.[28]

3 | INPUT DATA AND ASSUMPTIONS

3.1 | Market parity and profitability analysis

The market parity and the profitability analysis are based on some technical and economic parameters to calculate the PV production; the energy balance among PV, BESS and grid; and the LCOE, NPV, IRR and PBT.

For the PV and BESS design, the technical inputs are summarized in Table 1.

The PV module technical parameters are chosen considering the average characteristics of the PV models currently available on the market, while the BESS characteristics are taken from Lai and McCulloch.[24]

It has been assumed that the utility-scale PV plant is of 10 MW and the BESS capacity is selected considering the ratios suggested in Vartiainen et al.[38]: for the 2020 scenario, considering the present high prices of BESS, it has been assumed a ratio of 1:1 between PV and BESS installed capacities, whereas this ratio increases to 1:1.5 in the 2030 scenarios thanks to the decrease of BESS prices. Therefore, the BESS installed capacities are 10 and 15 MWh for the 2020 and the 2030 scenarios, respectively.

The mean annual hourly profiles of POA irradiance and ambient temperature necessary to estimate the PV production and the energy balance are created by averaging the profiles extracted by the Italian weather stations available in the software Meteonorm v.7,[39] grouping them accordingly to the macro regions considered. In Table 2, the resulting specific yield and annual average ambient temperature of each macro region are shown.

The main economic parameters applied to evaluate the LCOE, NPV, PBT and IRR are summarized in Table 3.

The market parity is reached when the PV generation costs are equal or lower to the electricity price at which the produced electricity can be sold. In this case, the generation costs are the system LCOE that is compared with the average Italian zonal prices, summarized in Table 4.

Starting from the methodology explained in a previous study,[25] the profitability analysis is performed updating some inputs and

TABLE 1 Technical input parameters used to design the PV and BESS systems

PV module area	1.6 m^2
PV module power	0.3 kWp
PV module efficiency	18.33%
PV NOCT	44°C
PV module temperature coefficient	−0.0038%/°C
PV plant performance ratio	85%
BESS minimum SOC	30%
BESS round-trip efficiency	90%

Abbreviations: BESS, battery energy storage system; NOCT, nominal operating cell temperature; PV, photovoltaic; SOC, state-of-charge.

TABLE 2 Average specific yield and ambient temperature for each Italian macro regions coming from the average annual hourly profiles used in this analysis

Macro region	Specific yield (kWh/kWp)	Ambient temperature (°C)
North	1,271.02	11.8
Central north	1,397.79	15.1
Central south	1,424.99	16.2
South	1,459.29	16.7
Sardinia	1,503.69	16.9
Sicily	1,563.04	18.8

TABLE 3 Economic input data used for the profitability and market parity analysis of utility-scale PV plants

Lifetime	30 years
Discount rate	7%
PV capex 2020	431 €/kWp
PV capex 2030	275 €/kWp
BESS capex 2020	251 €/kWh
BEES capex 2030	117 €/kWh
PV opex	2% of PV capex
BESS opex	4% of BEES capex
PV annual degradation rate	0.5%
BEES annual degradation rate	2%

Note: Most of these values are taken from Vartiainen et al.,[38] with the exception of the BESS annual degradation rate that is taken from Lai and McCulloch[24] and refer to Li-ion batteries.
Abbreviations: BESS, battery energy storage system; PV, photovoltaic.

TABLE 4 Average Italian zonal prices used to compare the PV generation costs for the market parity evaluation

Macro region	Average zonal electricity price (€/MWh)
North	56.52
Central north	56.04
Central south	54.62
South	53.03
Sardinia	54.38
Sicily	61.56

Note: These average values are calculated from the monthly report of the Italian TSO collected from November 2016 to the end of the year 2019.[40]
Abbreviations: PV, photovoltaic; TSO, transmission system operator.

adding the integration costs to estimate the system LCOE for the PV plants in the year 2030 instead of the common LCOE.

As explained before, the reinforcing distribution network costs for the Italian case study are in the range of 0.25–0.9 €/MWh for a PV penetration of 16% and 7% respectively.[14] To be conservative, since the model of the Italian distribution grid is not available and no detailed information on this regard is given in Pudjianto et al.,[14] the highest value is used for this analysis and applied to all the macro regions as it is.[14]

TABLE 5 Total investment for each macro region on which the transmission and the adequacy costs are calculated

Macro region	TSO investment for RES integration (M€)	TSO investment for quality of the service (M€)
North	523.4	532.2
Central north	307.9	127.9
Central south	976.3	189.1
South	407.2	293.0
Sardinia	389.3	100.4
Sicily	891.7	521.8

Note: These values are estimated from the data provided by the TSO itself in some papers.[20,41,42]
Abbreviations: PV, photovoltaic; RES, renewable energy sources; TSO, transmission system operator.

The transmission and adequacy costs are based on the Italian TSO investment planned for the next decade to reach the PNIEC targets. In its 2019 Development Plan[20] and its annexes,[41,42] the interventions are listed for each macro region and classified based on four different aims (decarbonization, market efficiency, security, quality and resilience, and sustainability) and eight different goals (RES integration, quality of the service, interconnections, congestions resolution, resilience, connection to the national transmission grid, integration of the national railway and energy transition). The transmission costs are calculated from the investments with the purpose of RES integration, while the adequacy costs are based on the investments for the quality of the service when coupled with the RES integration goal. The transmission costs also consider the current state of the art in forecasting. Since the intervention could involve more than one macro region and more than one objective, in those cases, the total investment is equally split among the macro regions and the objectives to avoid double counting. These macro regional investments planned by the TSO are summarized in Table 5.

The total macro regional investment is then proportionally subdivided to the macro regional PV and wind production for the year 2030 and spread over the 30 years lifetime of the PV plant, to obtain the transmission and adequacy costs in terms of €/MWh. The resulting macro regional costs components are summarized in Table 6.

The curtailment costs, as said before, are indirectly considered as loss of PV production due to the curtailment that needs to be performed at the macro regional level to avoid grid instability. For this reason, the curtailment costs are not economically evaluated but simply applied as a percentage reduction (see Table 7) of the annual PV production only for the case of PV plant without storage system. This percentage is based on the total macro regional curtailment estimated with oemof for the year 2030 and proportionally subdivided between PV and wind.

TABLE 6 Transmission and adequacy costs resulting from the Italian TSO investments at the macro regional level

Macro region	Transmission costs (€/MWh)	Adequacy costs (€/MWh)
North	0.87	0.88
Central north	1.91	0.79
Central south	2.80	0.54
South	0.66	0.48
Sardinia	3.10	0.80
Sicily	3.69	2.16

Abbreviation: TSO, transmission system operator.

TABLE 7 Percentage of PV production that needs to be curtailed in the 2030 scenario in each macro region

Macro region	% of PV curtailment
North	2
Central north	3
Central south	0
South	7
Sardinia	5
Sicily	4

Abbreviation: PV, photovoltaic.

The balancing costs are taken from Memoli[21] and are equivalent to 6.4 €/MWh. This value corresponds to a RES penetration level of around 50% that is about the RES penetration level in the reference 2030 scenario (59.8%). These costs are the sum of the specific decay of efficiency costs and start-up costs that are estimated in Memoli[21] as 1.6 and 4.8 €/MWh, respectively. Similarly to the reinforcing distribution network costs, the total balancing costs are also applied to all macro regions with the same value, since no detailed information on this regard is given in Memoli.[21] These balancing costs are estimated considering an energy system without BESS. The inclusion of BESS in the energy system can reduce the need for fast ramps and the usage of CCGTs. This could reduce the overall balancing costs. The implementation of these costs in this study follows the choice of using a conservative approach, which is relevant since the scope of the work is to compare the two extreme cases: without and with the integration costs. Table 8 lists the system LCOE cost components for each Italian macro region, excluding the curtailment costs, and provides the total macro regional integration costs.

3.2 | Reference scenario for the year 2030 and optimization process

The Italian energy system and its expected energy system configuration in the year 2030 are taken as reference for this analysis. The energy system configuration in the year 2030 is based on the Italian PNIEC, which fixes the RES penetration and CO_2 emissions reduction targets according to those fixed at European Union level to follow the Paris Agreement. Italy has to commit itself to reduce the CO_2 emissions of 40% by 2030 with respect to the emissions registered in 1990 and to cover more than 30% of the gross energy demand by RES and in different percentage in the three major sectors: 55.4% in the electricity sector (considering an annual increase of 5% of the electricity demand in the year 2030), 33% in the heat sector and 21.6% in the transport one.[19] The Italian energy mix projected to the year 2030 is represented in Table 9.

This energy mix with high percentage of RES production will be supported by a better management of the existing pumped hydro power plants and by adding other 3 GW of storage capacity. Moreover, it is expected that BESS coupled with PV plants will continue to increase for further 15 GWh within the year 2030 in addition to 24 GWh of centralized BESS that need to be installed in the same time frame. Finally, the transmission grid infrastructure will be reinforced and renovated to foster and better manage the increase of VRES production according to the Italian TSO Development Plan. The investment needed on this regard is estimated and listed by the Italian TSO in its Development Plan of the year 2019[20] and its annexes.[41,42] This is the starting point with which it is possible to compare the optimization results.

TABLE 8 Macro regional system LCOE cost components and total integration costs, apart from the curtailment costs

Macro region	Distribution costs (€/MWh)	Transmission costs (€/MWh)	Adequacy costs (€/MWh)	Balancing costs (€/MWh)	Total integration costs (€/MWh)
North	0.9	0.87	0.88	6.4	9.05
Central north	0.9	1.91	0.79	6.4	10.00
Central south	0.9	2.80	0.54	6.4	10.64
South	0.9	0.66	0.48	6.4	8.44
Sardinia	0.9	3.10	0.80	6.4	11.20
Sicily	0.9	3.69	2.16	6.4	13.15

Abbreviation: LCOE, levelized cost of electricity.

TABLE 9 Italian energy mix as expected in the year 2030 according to the legal provisions of the PNIEC

	PNIEC 2030 (TWh)
Import	28.7
CCGT	123
Coal	0
Others (oil, etc.)	0
Hydro (total)	49
Biomass	16
PV (total)	75
Wind	40
Geothermal	7
Total production	338.7
Demand	337.3

Note: The data are taken from the Italian TSO Development Plan of the year 2019.[20]
Abbreviations: CCGT, combined cycle gas turbine; PNIEC, Piano Nazionale Integrato per l'Energia ed il Clima; PV, photovoltaic; TSO, transmission system operator.

As explained before, the optimization made with the energy system model is aimed to understand if and how the optimal energy mix will change if the integration costs are applied to the utility-scale PV plants. The energy system model built through Oemof has been previously validated based on the energy mix of the year 2017, and the result is shown in Table 10.

TABLE 10 Validation of Oemof model based on the Italian energy mix of the year 2017

	Oemof 2017 (TWh)	TSO 2017 (TWh)
Import	37.8	42.9
CCGT	117.5[a]	133.6
Coal	32.4	32.4
Others (oil, etc.)	24.1	24.1
Hydro (total)	42.4	38
Hydro reservoir	19.3	20.3
River hydro	23.1	17.7
Biomass	19.2	19.1
PV	23.8	24.4
Wind	17.8	17.7
Geothermal	5.9	6.2
Total production	320.8	338.4
Demand	320.6	320.6

Note: The energy mix obtained with the simulation is compared to the production for each technology provided by the Italian TSO for the same year.[43]
Abbreviations: CCGT, combined cycle gas turbine; PV, photovoltaic; TSO, transmission system operator.
[a]Includes both CCGT and cogeneration CCGT and comes from subtracting the coal and others power plants provided by the Italian TSO to the total CCGT estimated by Oemof.

The reference 2030 scenario has been also simulated with Oemof model to evaluate the additional capacity to be installed in each macro region. In fact, the Italian Energy and Climate Plan provides only aggregated values at the national scale of the additional installed capacity of RES required to reach the targets. Thus, to distribute them into each macro region, it has been assumed that their current geographical distribution coincides also in the year 2030, because it is supposed that the current RES geographical distribution reflects their exploitability based on the geography, irradiation level, windiness, rainfall and legislative limits of each specific Italian region.

For the Oemof-moea model, the decision variables chosen are the installed capacities of utility-scale, residential rooftop PV plants, BIPV, wind power plants, stationary lithium-ion batteries and transmission powerlines. As explained in Section 2, macro regional minimum and maximum bounds for each of them have been estimated. The lower bound for PV and wind technologies is represented by the installed capacity in the year 2017,[44,45] while the upper bound is set by the maximum exploitable potential (Table 11); these two limits are compared with the expected installed capacity in the reference year 2030 at the national scale.

As said in Section 2, the overall maximum potential of lithium-ion batteries is equal to 100 GWh of for each macro region. The minimum bound, corresponding to the installed capacity in the year 2017, is set equal to 0 since in the year no significant storage capacity was installed in the Italian country. The transport capacities of transmission powerlines in the year 2017, representing the minimum bound for the optimization, are summarized in Table 12, and compared with those expected for the reference year 2030.

Their maximum bound is set to 10 GW for each interconnection, as previously said in Section 2.

4 | RESULTS

4.1 | Impacts of integration costs in the market parity and profitability analysis

Figure 2 shows that the market parity is largely achieved in 2020 by the utility-scale PV plants without storage system, whereas it is obtained for only two zones when the PV plant is coupled with BESS because of its high investment costs. The only two macro regions that result to be cost-effective already now for PV plants coupled with BESS are Sardinia and Sicily, mainly thanks to their high irradiation and higher zonal price for Sicily.

Another important aspect is that the market parity at the macro regional level does not strictly follow the trend of the generation costs. In fact, even though the generation costs decrease with the increase of irradiation from North to South (as shown in Table 13), there are some northern regions that have more advantages than other southern regions thanks to their higher zonal prices.

Nowadays, the average PBT, NPV and IRR for PV plants without storage in Italy are on average 9 years, 4.7 million € and 15.9%, respectively. For the PV plants with BESS, instead, the PBT is around

TABLE 11 Summary of the PV and wind technologies installed capacities in the years 2017 and 2030 as well as their maximum exploitable potential at the national scale

Technology	Installed capacity 2017 (GW)	Installed capacity 2030 (GW)	Maximum potential (GW)
Utility-scale PV	3.6	11.2	43.1
Fixed	3	8.9	35.3
With trackers	0.6	2.3	7.8
Rooftop PV	13.5	39.7	161
BIPV	0	0	13.4
Wind	9.8	23	29

Abbreviations: BIPV, building-integrated photovoltaic; PV, photovoltaic.

TABLE 12 Comparison between the transport capacities of transmission powerlines in the years 2017 and 2030

	Scenario 2017 (MW)	Scenario 2030 (MW)
North → CNorth	3,600	4,100
CNorth → North	1,100	2,100
Cnorth → CSouth	1,300	1900
CSouth → CNorth	2,500	3,100
CSouth → South	No limits	No limits
South → CSouth	3,800	5,700
CSouth → Sardinia	870	1,100
Sardinia → CSouth	720	720
South → Sicily	1,100	1,100
Sicily → South	1,000	1,150

27 years, the NPV is 0.019 million € and the IRR is 3.2% on average. The IRR gives information about the cost-effectiveness of the investment: if the IRR is higher than the discount rate, the investment is profitable. In this case, the IRR is almost half the discount rate used in the LCOE calculation (assumed equal to 7%) on average, and the only macro region with a higher IRR and equal to 7.8% is Sicily.

Considering now the case of utility-scale PV plants without BESS in the year 2030, the market parity is still guaranteed for all the macro regions thanks to the investment costs that are expected to strongly decrease in the future,[38] as shown in Figure 3a. In this case, the PBT is on average 5 years, the NPV is 5.7 million € and the IRR is 27.3%, significantly higher than the discount rate applied.

Also including the integration costs, the system LCOE still remains lower than the electricity price all over the Italian country, thus maintaining the market parity (Figure 3b). However, what is changing is the geographical trend of the PV production costs. In fact, comparing the common LCOE and the new system LCOE in Table 14, it is possible to notice that the Central South macro region has lower generation costs than the South when the integration costs are taken into account. This is due to the macro regional PV curtailment that has direct impacts on the potential annual PV production. In fact, the Central South has no PV curtailed in the year 2030, as shown in Table 7, against a PV production loss of 7% in the South. This means that the descending trend of PV production costs going from North to South is no more valid when the integration costs are included and the system LCOE calculated.

From an investment point of view, the average values of the PBT, NPV and IRR are slightly worse but still satisfying when the

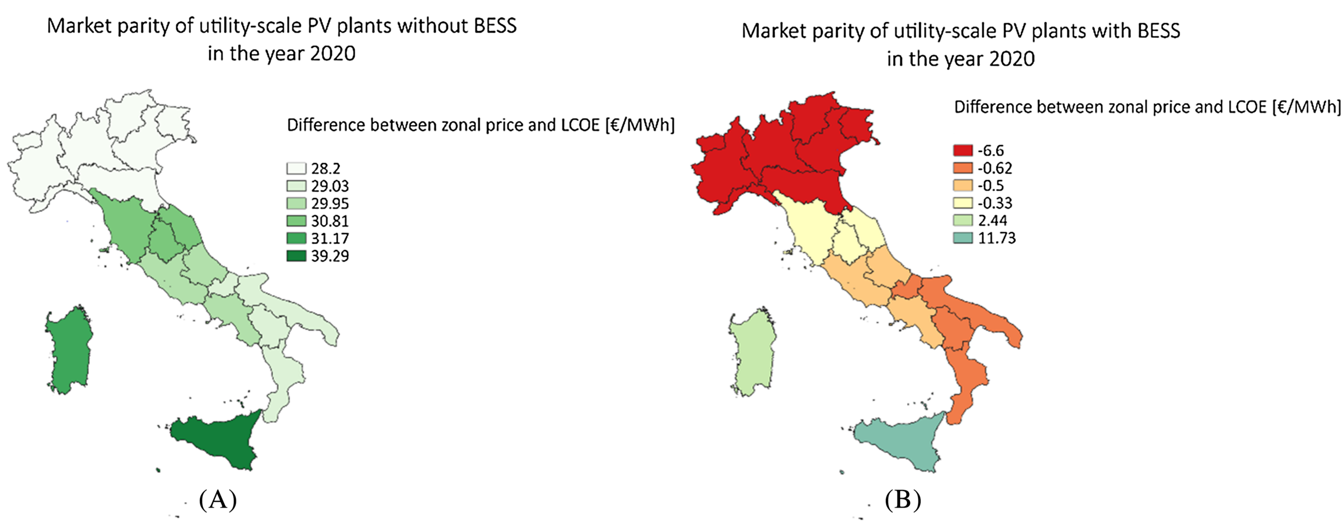

FIGURE 2 Market parity comparison between photovoltaic (PV) plants without (a) and with (b) storage system for the year 2020 [Colour figure can be viewed at wileyonlinelibrary.com]

TABLE 13 Macro regional LCOE of PV plants without and with storage system for the year 2020

Macro region	LCOE only PV (€/MWh)	LCOE PV plus BESS (€/MWh)
North	28.32	63.12
Central north	25.23	56.37
Central south	24.67	55.12
South	24.00	53.65
Sardinia	23.21	51.94
Sicily	22.27	49.83

Abbreviations: BESS, battery energy storage system; LCOE, levelized cost of electricity; PV, photovoltaic.

TABLE 14 Macro regional LCOE and system LCOE of PV plants without storage system for the year 2030, i.e. the comparison between the generation costs including or not the integration costs

Macro region	LCOE (€/MWh)	System LCOE (€/MWh)
North	15.93	23.35
Central north	14.22	21.75
Central south	13.90	20.99
South	13.52	21.64
Sardinia	13.10	20.89
Sicily	12.55	20.17

Abbreviations: LCOE, levelized cost of electricity; PV, photovoltaic.

integration costs are considered and equal to 6 years, 4.9 million € and 22.1%, respectively.

Comparing the market parity of utility-scale PV plants with storage system for the year 2030, the difference in market parity achievement among macro regions including or not the integration costs is more evident (see Figure 4). Even though Sicily still remains the macro region with the greatest difference between zonal price and system LCOE, looking at Table 15, the South has the lowest production costs, due to the fact that is has the lowest total integration costs (see Table 8).

In this case, the PBT goes from 12 to 20 years on average, the NPV from 3.1 million € to 1 million € and the IRR from 12% to 6.7%, not including or including the integration costs, respectively.

This last IRR, in particular, highlights an interesting point: the market parity achievement does not always guarantee the profitability of the investment, and this issue is underlined in Figure 5.

Although the market parity of utility-scale PV plants with BESS is reached all over Italy in the year 2030, the IRR is higher than the discount rate only in Sicily and equal to the discount rate in the South of Italy. All the other macro regions obtain the market parity without sufficient IRR values.

However, there is one important point that needs to be stressed out in this analysis: a strong assumption is made to allow the comparison between generation costs and possible earnings in the 2030 scenario. It is supposed that the future electricity zonal price remains the same as the current one. But this is not necessarily true. The present electricity market design is based on the marginal costs concept, with which the electricity bids are made. In this context and considering the past incentives schemes for RES, the offers in the electricity market of RES power plants are almost zero since they do not have marginal costs. Consequently, the larger the share of RES offers in the market, the lower will be the national electricity price since it is built on them. It is thus clear that this market design with an increasing RES share could lead to cannibalization phenomena among RES power plants, significant reduction of the electricity price and thus discouragement of the investors due to the uncertainty of electricity prices and future earnings. At the same time, as previously mentioned, on top of the profitable introduction of electrical storage, the availability

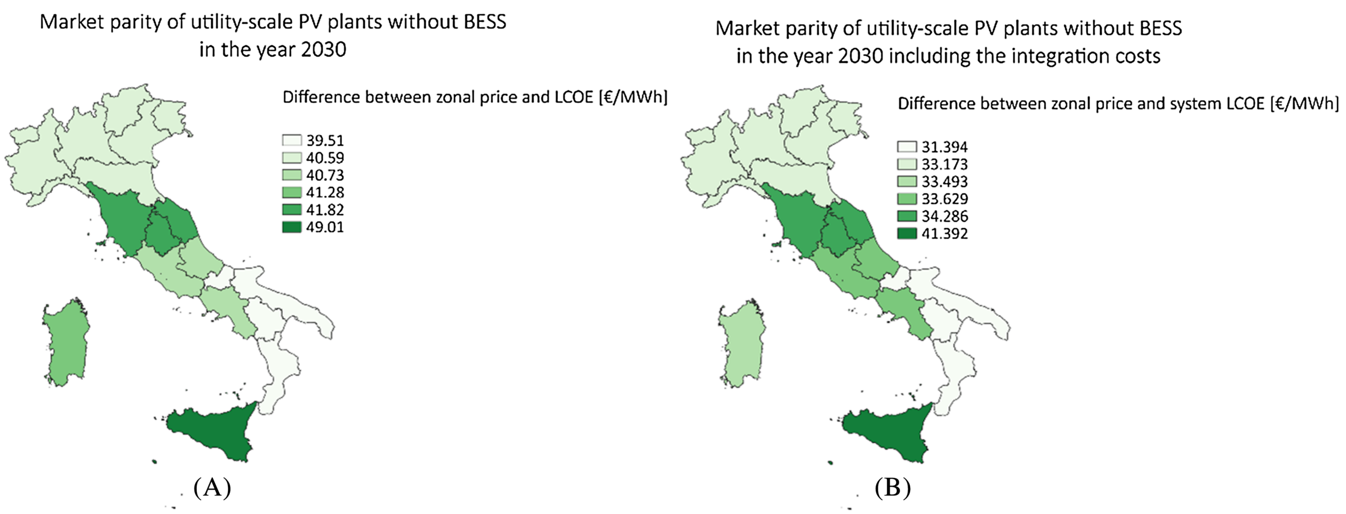

FIGURE 3 Market parity comparison between photovoltaic (PV) plants without storage system for the year 2030 in the case of not including (a) or including (b) the integration costs [Colour figure can be viewed at wileyonlinelibrary.com]

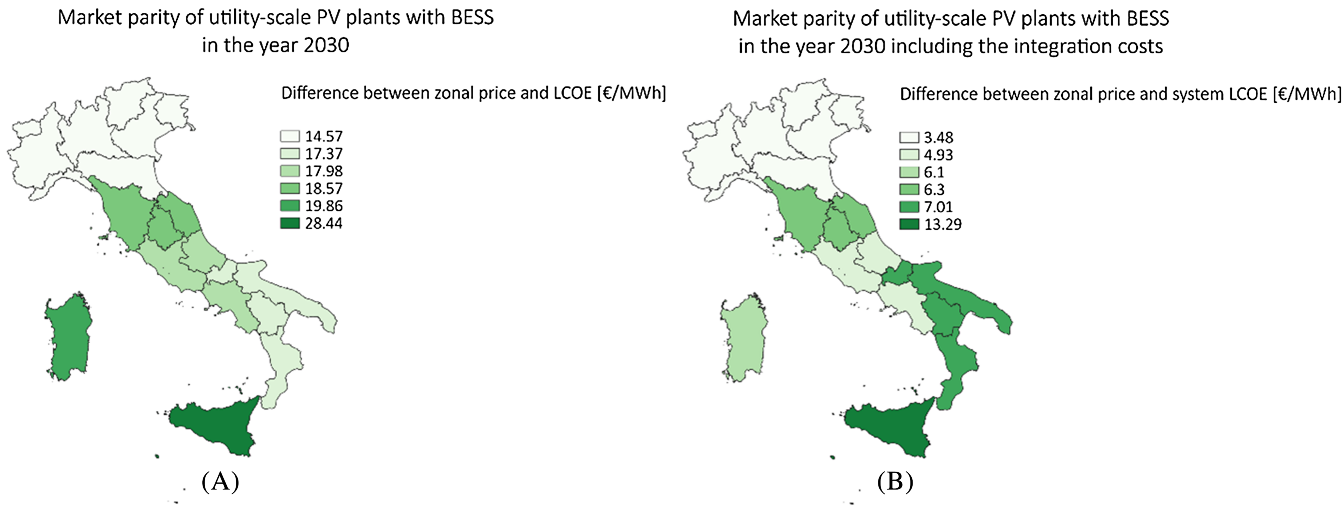

FIGURE 4 Market parity comparison between photovoltaic (PV) plants with storage system for the year 2030 in the case of not including (a) or including (b) the integration costs [Colour figure can be viewed at wileyonlinelibrary.com]

TABLE 15 Macro regional LCOE and system LCOE of PV plants with storage system for the year 2030, i.e. the comparison between the generation costs including or not the integration costs

Macro region	LCOE (€/MWh)	System LCOE (€/MWh)
North	41.95	53.04
Central north	37.47	49.74
Central south	36.64	49.70
South	35.66	46.02
Sardinia	34.52	48.28
Sicily	33.12	49.27

Abbreviations: LCOE, levelized cost of electricity; PV, photovoltaic.

of high share of RES in the market can be used in power-to-X, thus reducing or avoiding the cannibalization effect. Another important aspect to mention is related to CO_2 price on the wholesale market, which has not been considered in this publication but will be included in future analysis.

4.2 | Impacts of integration costs in the 2030 scenario optimization

Figure 6 shows the results of the two optimization problems without (Figure 6a) and with (Figure 6b) the integration costs as annual costs for the utility-scale PV plants. In particular, the figure outlines the values of the decision variables for the optimal solutions on the Pareto front.

The optimization results highlight that there is not an optimal VRES technology that prevails on the other, but the integration of various PV sources and wind power produce the optimum thanks to the complementarity of their different production profiles. It is possible to

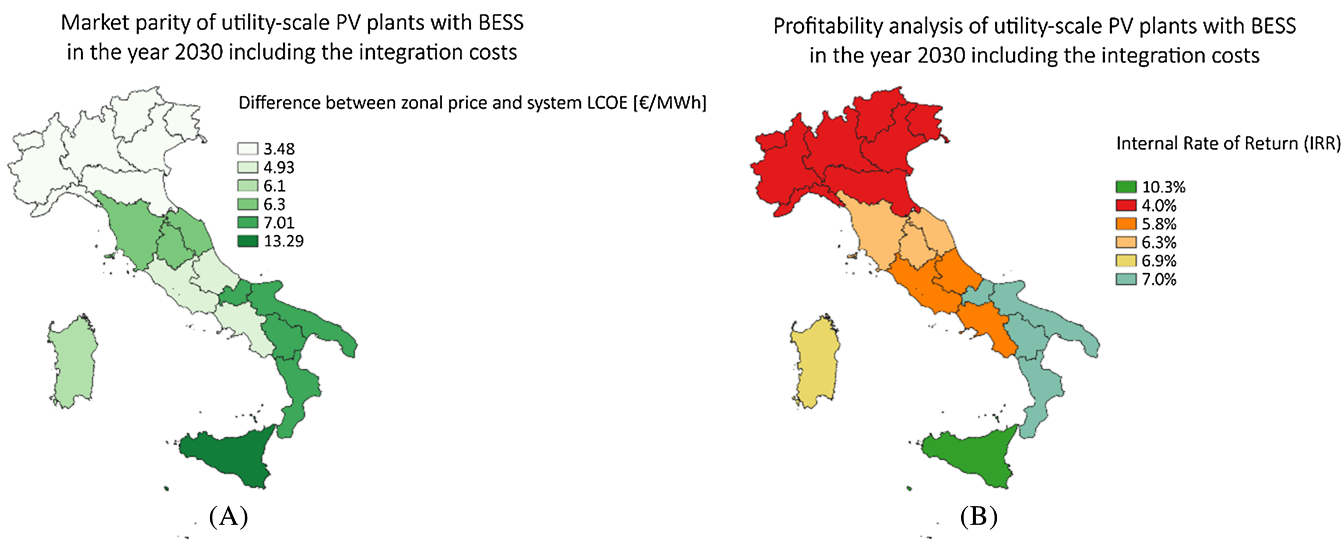

FIGURE 5 Comparison between the market parity achievement (a) and the profitability (b) of photovoltaic (PV) plants with storage system for the year 2030, including the integration costs [Colour figure can be viewed at wileyonlinelibrary.com]

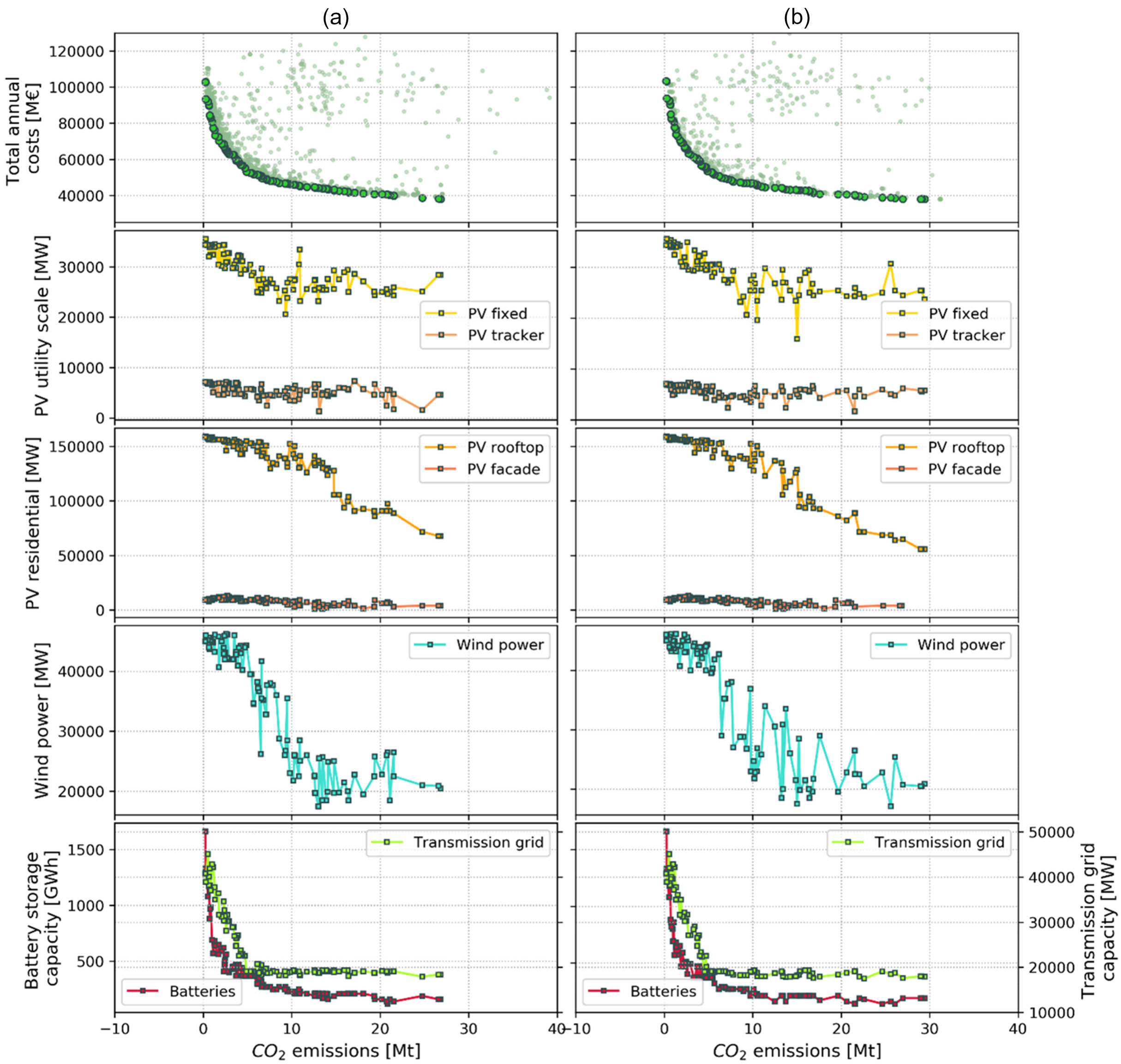

FIGURE 6 Comparison of the results of the multi-objective optimization analysis implemented through Oemof-moea without (a) and with (b) integration costs applied to the utility-scale photovoltaic (PV) plants [Colour figure can be viewed at wileyonlinelibrary.com]

notice a parallelism between the development of stationary batteries storage systems and the enlargement of transmission grid bottlenecks: the Pareto front outlines that, from a certain point, combining storage systems with the expansion of transmission powerlines capacities is crucial to allow the integration of the overgeneration from VRES.

Focusing the attention on the installed capacity of utility-scale PV plants, it is possible to notice that it is not always necessary to exploit the maximum PV potential. Moreover, comparing the trends of both configurations of utility-scale PV plants in the two scenarios without (Figure 6a) and with (Figure 6b) the integration costs, there is no significant difference in most of the Pareto front points. But the average values of the installed power are slightly lower in the scenario with the integration costs. In other words, the higher overall system LCOE of utility-scale PV plants resulting from adding the integration costs as annual costs for this technology has an impact on the future optimal energy mix. However, thanks to the already very low cost of generation, the utility-scale PV plants will be only marginally affected by these additional costs.

5 | CONCLUSIONS

In this paper, the integration costs of VRES power plants into the existing energy system has been introduced in the LCOE concept to define a new metric for the estimation of the future PV production costs. This new parameter is called system LCOE because it includes a larger vision on the impacts that a new VRES installation could have on the electricity system as a whole. The integration costs are split into different costs components (i) grid costs (sum of reinforcing transmission and distribution network, adequacy and curtailment costs), to represent the economic effort needed to adapt the existing grid infrastructure to the increasing VRES production, avoiding grid instability and guaranteeing the electricity's supply; and (ii) balancing costs, to reflect the impacts that the rise of VRES may have on the operating conditions of existing fossil fuel power plants.

The Italian electricity sector and its future evolution to the year 2030 have been taken as reference scenarios to analyse the future profitability of PV plants with and without BESS when the system LCOE is adopted as a metric for the PV production costs evaluation. The Italian electricity sector has been modelled with Oemof to apply a multi-node approach to the generation sources dispatch, minimizing the costs for the system. Oemof model has been coupled with a genetic algorithm to perform an expansion capacity and optimization aimed to study the impacts on utility-scale PV plants' dispatchability when the integration costs are applied to them as annual costs. The reference scenario for the year 2030 is built according to the legal provisions included in the national Energy and Climate Plan.

The impacts of adding the integration costs in the PV production costs are evaluated considering two different points of view: the PV plant investor and the energy system manager. In the first case, the results are provided in terms of market parity achievement (system LCOE vs. zonal electricity price) and profitability indexes, like NPV, PBT and IRR. The results of the optimization process focus the attention on the role played by the utility-scale PV plants in the energy mix, including or not the integration costs as annual costs applied to the PV technology.

The results on the market parity suggest that it is possible to achieve it in all the Italian macro regions in the year 2030, mainly thanks to the investment costs reduction of both the PV and BESS components that are expected within this time frame. Moreover, it is confirmed that applying a more systematic approach to the generation costs estimation, like the system LCOE metric, does not compromise the market parity achievement of future utility-scale PV plant. Nevertheless, some criticalities persist in the investment profitability of utility-scale PV plants coupled with storage system. On this regard, the results show that reaching the market parity does not always imply that the investment is cost-effective. In fact, most of the macro regions have an IRR lower than the discount rate, with the only exceptions of Sicily and the South. However, there is a strong assumption behind this analysis that has a significant influence on the profitability results: it has been supposed that the average zonal electricity prices in the year 2030 are the same as today. The question concerning the electricity market design still remains a big issue that could represent a strong limit to the future VRES deployment. In fact, it is clear that the marginal costs concept, on which the current electricity market is based, should be overcome to let VRES power plant participate in the market avoiding cannibalization phenomena among RES power plants and a significant reduction of the electricity price that can discourage the investors. But until then, the power purchase agreement (PPA) could be a possible mitigation strategy that can be adopted to get over this uncertainty. Another aspect that was not considered in the future evolution of the energy market is the role of CO_2 prices to decarbonize the power sector. A decarbonized power sector will also have a role in the decarbonization of the heat and transport sector through more integrated sector coupling. In fact, the availability of low-cost electricity might act as a driver to power to X applications with also the benefit of avoiding the cannibalization effect.

The optimization performed with the Oemof-moea model highlights that also from the point of view of the energy system manager, there is no significant difference in the role that the utility-scale PV plants could play in the future energy mix, even though a slightly lower capacity is installed when the integration costs are applied to this technology as annual costs. Indeed, the optimal energy mix in a future with high RES penetration will be not dominated by a certain VRES technology, but it will be the result of combining RES power plants with storage systems and enlargement of the transport capacity of the grid powerlines to better manage the overgeneration, avoiding bottlenecks.

To conclude, in this paper, we have presented the results of the inclusion of the integration costs in the metric, system LCOE. When data were not available or the methodology not clearly stated, a conservative approach was selected in assigning all possible integration costs to VRES. This of course can be disadvantageous for VRES; however, even with this conservative approach, we have demonstrated that solar PV remains competitive.

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