Can a fully renewable system with storage cost-effectively cover the total demand of a big scale standalone grid? Analysis of three scenarios applied to the Grand Canary Island, Spain by 2040

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Abstract

The extensive use of carbon-free energy sources is essential to achieving zero CO_2 emission goals in electricity generation. But these systems are not yet used to cover 100% of the energy demand in areas with many inhabitants. This study answers the question ¿Can a fully renewable system with storage cost-effectively cover the total demand of a big scale standalone grid? The system is applied to Grand Canary Island by 2040, with forecasts of approximately 1 million inhabitants by then. Given the high variability of weather conditions, renewable systems have to be used with storage technologies to meet demand with high reliability. Three energy demand scenarios are analyzed: Business as usual plus efficiency measures, partial electrification, and finally, total electrification scenario. For modeling the scenarios, HOMER software was used. The best generation mix has been estimated according to engineering, land occupation, and economic criteria, obtaining the lowest Levelized Cost of the Energy. Focusing on the last scenario, the most realistic one according to Canary Island Government, the feasibility of electrifying the economy in an off-grid location with high energy needs (6.4 TWh/year) at affordable prices and using exclusively renewable energy has been analyzed. The optimized results propose installing a 2.5 GWp photovoltaic system, a 1.2 GWp wind power system, a 9.73 GWh pumped storage (607 MW), and a 5.82 GWh Lithium-ion battery system (2.3 GW), obtaining an LCOE of 13.4 c€/kWh. The results quantify and show the need to bring a reliable autonomous system to store energy. Even having a significant capacity to store energy, 33.4% of the produced energy cannot be used or stored because the system is based on renewable sources. The cost of the batteries is a limitation for a more profitable system.

Keywords: Renewable energy; storage system; reversible pumped storage; mega-batteries; standalone system; statistical analysis.

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Nomenclature and Abbreviations

BAU	Business As Usual
E	Energy (MWh)
ESH	Equivalent Sun Hours
G	Generator
GDP	Gross Domestic Product
GE	General Electric
HOMER	Hybrid Optimization Model for Multiple Energy Resources
IEA	Internation Energy Agency
IRR	Internal Rate of Return
ITC	Instituto Tecnológico de Canarias (Canary Islands Institute of Technology)
LCOE	Levelized Cost Of Energy
LHV	Lower Heating Value of H_2 (120 MJ/kg, 0.033 MWh/kg)
M	Hydrogen Mass (kg)
$\dot{M}$	Hydrogen Mass Consumption (kg/s)
MERRA	Modern-Era Retrospective analysis for Research and Applications
NASA	National Aeronautics and Space Administration
η	Efficiency
NPC	Net Present Cost
NREL	National Renewable Energy Laboratory
O&M	Operation and Maintenance
P	Electric Power (MW)
PNIEC	Plan Nacional Integrado de Energía y Clima (National Integrated Energy and Climate Plan)
PTECan	Plan de Transición Energética de Canarias (Canary Islands Energy Transition Plan)
PV	PhotoVoltaic
PVGIS	PhotoVoltaic Geographical Information System
t	Time (hours)
V2G	Vehicle To Grid
EV	Electric vehicle

1 Introduction

1.1 Context and State of the art

According to IEA, world energy demand has continuously increased during the last decades (except for a slight decrease of 5% in 2020 because of the Covid-19 pandemic) [1]. But the growth trend is returning for 2021 even though the pandemic has not yet ended [2]. Most of this energy comes from fossil fuels. The situation is similar regarding the power generation installed capacity: a very high percentage, approximately 2/3, is covered by fossil fuels [3]. This scenario entails a double problem: on the one hand, the foreseeable depletion of fossil fuels if the current consumption rate continues, which would jeopardize the continuity of electricity supply in the coming decades [4,5]. The second problem, probably even more serious and in the shorter term, is the unacceptable growth of emissions of different pollutant gases due to the use of these fossil fuels, such as greenhouse gases, acid rain precursor gases, etc. [6,7].

As mentioned in the previous paragraph, there are several reasons for renewable energies to be present in any energy mix that aims to reduce/eliminate the presence of fossil fuels [8]. Focusing the problem on electricity generation, the inclusion of renewable energies is necessary, as electricity has a growing share in the final energy consumption of all countries [9], expecting to exceed 30% in a short time in many of them [10]. The current power generation system is responsible for a significant percentage of the total polluting gas emissions [3]. This situation is even more aggravated for isolated regions as islands [11]. Due to their small size and isolated location, connecting to a large grid is difficult. Therefore, the classic solution is usually based on fossil fuels such as diesel, coal, and gas because of their high reliability. However, this dependence on fossil fuels is a problem because of the high emissions they produce, but also because they depend on a supply chain and, in many cases, the countries producing these fuels are unstable, with the consequent risk of shortages that can reduce system reliability [11].

A sustainable energy system should integrate cleaner technologies [12,13] and renewable sources [14,15]. However, the exclusive use of these types of energies, due to their wide variability, especially in the case of wind and photovoltaic, presents significant management challenges. For the large-scale use of these energies, it is essential to store the inevitable excess of electricity produced under certain conditions due to the existing decoupling between demand and production [16–18]. Large-scale storage systems, as mega-batteries and/or pumping stations, present an additional problem in islands since many sites would be required, which may not be available [19].

This work proposes an optimized system of autonomous CO_2 zero-emission electric power generation based on renewable energy and storage technologies (reversal pumping and mega-battery systems) based on economic criteria, optimization of the energy wastages, and consideration of different electrification degrees of the final energy demand. The analysis is applied to the Grand Canary Island in Spain. The use of pumping as a storage system is motivated by its suitability given the orography of the island. In addition, there is currently a first project that focuses on installing a first pumping system to manage the growing solar photovoltaic and wind generation that is being installed on the island. Also, if required, mega-batteries have been used to complement the pumping station contribution to optimize the system size.

Consequently, renewable energy generation systems, especially wind and solar photovoltaic, are the only mature technologies that nowadays could allow the progressive substitution of conventional fossil technologies [20,21]. Other mature technologies, as hydroelectric power plants, cannot be used due to the scarcity of the existing water resources in the Grand Canary Island. However, the feasibility of this substitution is not attractive, mainly due to economic and reliability problems. The solution to these feasibility problems probably involves energy storage [22,23]. A renewable energy system based on more than one renewable energy source supported by a storage system will meet the local energy demand more efficiently than a single renewable energy installation due to hourly changing regional weather and irradiation conditions [24].

As it is well known, decarbonization must become a reality. It is expected to be a reality by 2050 in the countries of the European Union. Thus, the Canary Islands are working against the clock in their strategy to reduce their dependence on fossil fuels to take advantage of the abundant natural resources of the archipelago, such as the sun and the wind. But the Canary Island government is even more ambitious and has planned to advance 10 years the end of the decarbonization process (PTECan project)[25]. The Canary Islands Technological Institute (ITC), the entity in charge of preparing the studies to reach the level of total decarbonization, has considered up to ten scenarios to reach 100% clean energy generation. Large-scale storage technologies would be necessary for all ten scenarios to achieve the objectives. These ten scenarios range from the first one that proposes to cover 100% of the buildings' demand through self-consumption; each building has the needed individual storage capacity. In any case, a large centralized storage capacity is required to manage the generation-demand balance. The last one proposes that self-consumption should cover 40% of the buildings' demand without storage systems, but with distributed storage groups, it could be covered up to 70% of the demand in buildings, storing the surplus energy in large centralized storage systems. Consequently, all of them need a high capacity of centralized storage. In particular, for Grand Canary Island, a reversible pumped-storage hydroelectric power plant, the Chira-Soria project, is proposed [26]. The Chira-Soria pumped-storage power plant would have a storage capacity of between 3.2 and 3.6 GWh, with a total generation capacity of 200 MW. Additionally, it is expected to, at least, double this capacity shortly, as the connection of the Soria reservoir with the Las Niñas reservoir is being studied.

Several research works have developed models to analyze the viability of renewable energy systems in remote areas and islands. Lorenzi et al. has carried out a techno-economic analysis of utility-scale energy storage for Terceira Island of Azores Archipelago (Portugal). The system produces energy from wind, waste and geothermal energy and covers 46% of energy demand from renewable energy; a Li-ion battery system that stores 30 GWh is included in the analysis. The system was modeled using genetic algorithms [27]. Arévalo et al. carried out a plan for the electrical energy system for Santa Cruz and Baltra islands of Galapagos Archipelago (Ecuador) using different renewable energy technologies. The energy demand to cover is 73 GWh/year. The optimal energy production option is reached by employing a 25.4 MW solar PV system and 2.25 MW wind system to cover 100% of the energy demand. The surplus energy is stored in a pumped hydro system, having tested the use of a Li-Ion battery system. The simulations have been carried out through HOMER [28]. Curto et al. evaluate the optimal renewable electricity mix for Lampedusa Island (Italy). They use a standalone system to cover 36.2 MWh/year using a 3 MW PV system, a 10.5 MW wind system, and a 1.55 MW wave system. The system would cover 40% of the energy demand through renewable systems [29]. Jahangiri develops an On-Grid Hybrid Microgrid for Remote Island Using HOMER Software for Kish Island (Iran), an island of 25000 inhabitants, 26 % of the total demand could cover a PV a wind system. The simulation was carried out using HOMER [30]. Uwineza et al. has studied the feasibility of integrating the renewable energy system in Popova Island (Russia) using the Monte Carlo model and Homer. The system has a solar PV and a wind subsystem and a Li-Ion battery bank to store the energy surplus [31]. Islam et al. have carried out a techno-economic optimization of a zero-emission energy system for a coastal community in Newfoundland (Canada), which is a residential community of 50 households. The energy is provided by a solar PV, a wind and a hydro system, and the surplus is stored in a pumped hydro storage system. The simulation was carried out using HOMER software [32]. Finally, Suresh et al. have modelled and optimized an off-grid hybrid renewable energy system for electrification in Kollegal block in Chamarajanagar District (India) through the combined use of solar PV, wind, biomass and biogas systems. The energy is stored in Hydrogen (and in batteries). The model was developed using HOMER and Genetic algorithms [33]. Table 16 provides additional information on this research and other related works carried out in recent years. Other similar works show information about Techno-economic analysis for rustic electrification renewable energy based on PV, wind and Fuel Cell [34], Artificial intelligence applied to clean energy community [35], optimized sizing of a standalone PV-wind-hydropower station with pumped-storage installation hybrid energy system [36], interaction between a wind-PV-battery-heat pump trigeneration system and office building electric energy demand including vehicle charging [37], economic Modeling of Hybrid Renewable Energy System: A Case Study in Saudi Arabia [38], new Software for Hybrid Renewable Energy Assessment for Ten Locations in Saudi Arabia [39], a Novel Design and Optimization Software for Autonomous PV/Wind/Battery Hybrid Power Systems [40], an effective stochastic framework for smart coordinated operation of wind park and energy storage unit [41], multi-agent energy management of smart islands using primal-dual method of multipliers [42], and finally a distributed based energy transaction in a clean smart island. All of these works have analyzed different techniques applied to hybrid microgrids: artificial intelligence, how to optimize a system, how to integrate EV, and economic analysis, but none of them analyzes techno-economics future scenarios to cover 100% of the energy demand of a big scale standalone grid from renewable energy system.

1.2 Research gap and objectives

The research addresses the challenge of a zero-emission generation system based entirely on renewable energies, meets economic and technological criteria, and has 100% demand coverage due to the need for high system reliability since it is a standalone grid.

According to the current state-of-the-art analysis (See section 1.1 and Table 16), this research contrasts with most of the carried out works that analyze small power systems for current demand, cover just a part of the demand from renewable systems, or develop the research in pilot plants. This study is by far the biggest system analyzed in a high impact research work for a relatively large island and considering a long-term future demand forecast (around 1,000,000 inhabitants in 2040), and additionally covering 100% of the energy demand (up to 6.4 TWh per year) employing renewable sources (PV and wind systems) and two storage systems (pumped-storage and EV batteries). Also, three future scenarios contemplated by the Canary Islands government have been analyzed. The main contribution of this work is the analysis of the exclusive use of renewable energies, in particular, solar PV and wind, together with two different kinds of storage technologies to achieve a reliable and economically competitive generation mix covering the 100% of demand using renewable systems. All modeled scenarios are zero-emissions systems during their operation time. These calculations have been applied to the Grand Canary Island, which has a high energy consumption, making it challenging to implement a fully renewable system. Also, most studies analyze scenarios to cover the current energy demand, not considering future energy consumption. Additionally, most of the studies just carry out an economic analysis.

On the other hand, another aspect to mention is the simulation of the Pumped-storage system using the Hydrogen module available in homer. Several scientific works explain how to integrate storage systems or renewable sources not integrated by default in the software. For instance, there are publications about integrating pumped-storage hydroelectricity or a biomass gasification plant in HOMER [43,44]. However, it was not found information about integrating two different kinds of storage systems in HOMER, so a way to introduce the pumped-storage hydroelectricity through the hydrogen tank plus Li-ion batteries has been developed. Since adding two storage systems was a way to reach the paper's goals, we have not considered it the main contribution, but it can help other researchers integrate two storage systems in HOMER.

Consequently, it would be interesting to explore the possibilities for covering electricity needs with fully renewable generation sources and the aforementioned storage capacities. The Hybrid Optimization Model for Multiple Energy Resources (HOMER) has been used to compare the different systems. The software was developed by the National Renewable Energy Laboratory (NREL). [45] The criterion used by the software is primarily economic so that the program estimates the optimal size of a system based on the investment to be made, the LCOE (Levelized Cost of Energy), and the payback depending on the energy sources to be installed [46]. HOMER allows the simulation of hybrid renewable systems [43,47–50] , including different storage technologies [33,51].

To achieve the objectives mentioned above, section 2 describes the methodology followed. To contextualize the problem, section 3 describes the future generation system of the island. Then, in section 4, the characteristics and information of all the systems necessary to carry out the simulations in the desired horizon have been briefly described since the used data are those presented in the previous section. Section 5 describes the main results of the simulations performed. While section 6 is dedicated to the discussion and conclusions of the present study according to the needs of the generation system.

2 The Electricity Supply in Grand Canary Island

Grand Canary is a middle-sized island with a total population of slightly over 850,000 people (forecasts of 1 million by 2040); general data about the island and key electricity supply data have been included in Figure 1. The island is oriented towards the tourism sector (mainly for international travelers), with a high degree of maturity, so the energy demand is much stabilized. It has not varied appreciably during the last fifteen years. In the following lines, a brief description of the electric demand and generation system of Grand Canary Island will be shown. The historical data shows that no significant variations in the demand curves have occurred during the last years. Consequently, the data presented in the following paragraphs can be used as a reference for future calculations.

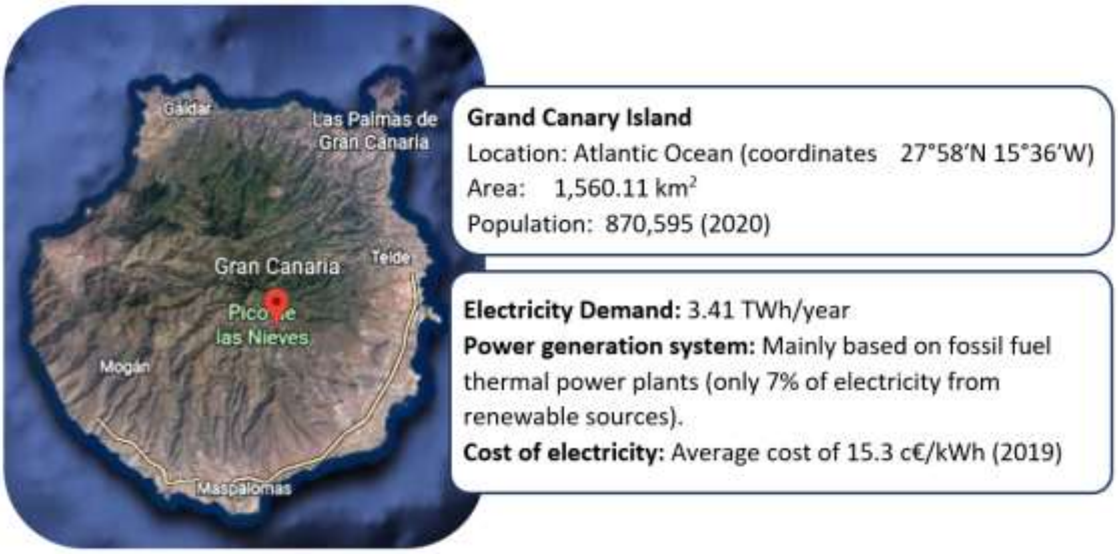


Figure 1. Map [52] ***and general data*** [51,53] ***about Grand Canary Island.***

2.1 Energy Demand

The total energy demand in Grand Canary Island in 2019 was 3.41 TWh/year. The maximum and minimum power (average in an hour) were approximately 450 and almost 300 MW, respectively. Figure 2 shows the daily average energy demand curve for the year 2019. The daily average energy demand is 9.34 GWh. But, as has been said above, when consulting the available historical data of the island [54], it presents stable demand values in recent years.

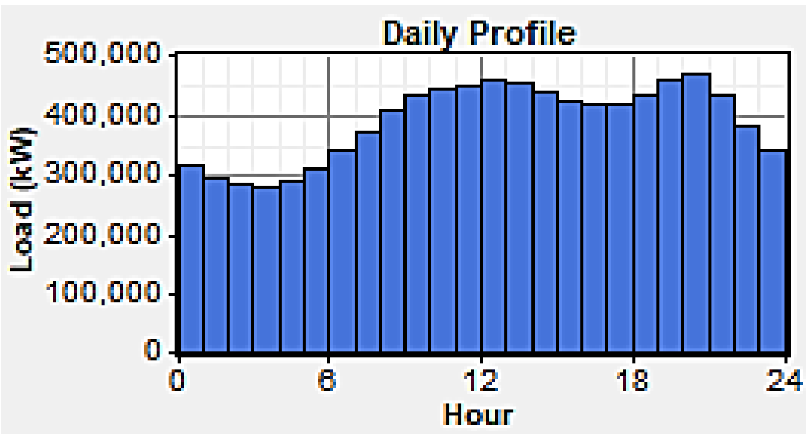


Figure 2. Average daily electricity demand in Grand Canary Island in 2019 [45]**.**

2.2 Power Generation System

The information on total installed power and energy generation has been obtained from the energy yearbooks of the Canary Islands ("Anuario Energético de Canarias" yearbooks from 2011 to 2019 [53]), where it is observed that main electricity production comes from fossil fuel thermal power plants. In 2019, the total power generation installed capacity was 1,200 MW, where wind and solar PV were 160 and 40 MW, respectively, so only 16.7% of the total installed power was based on renewable plants and produced only 7% of annual electricity generation

Regarding electricity demand evolution, historical data is shown in Figure 3, and the maximum value is observed for 2008, with a marked decrease caused by the Covid-19 pandemic in 2020. Then, a yearly demand of around 3.5 TWh has been considered a representative value.

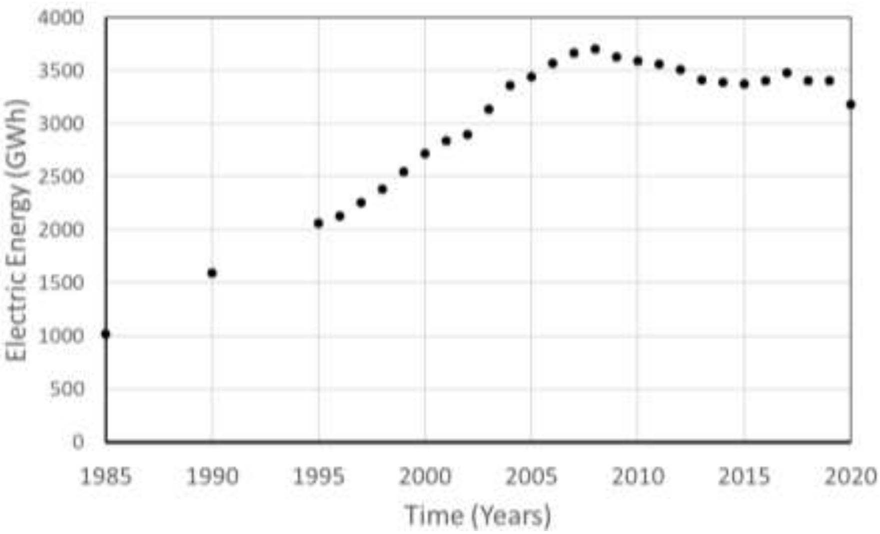


Figure 3. Historical evolution of electricity demand for the Grand Canary Island adapted from [53]**.**

2.3 Cost of electricity

The cost of electricity is not available disaggregated by source, so the considered cost is the real hourly cost for the whole Canary Archipelago electricity mix (including renewable and no renewable plants). The energy data cost for 2019 was obtained from the Spanish electric system operator [54]. The minimum, average and maximum hourly cost was 10.4, 15.3, and 24.4 c€/kWh, respectively.

3 Methodology

The methodology includes a description of the input data needed to perform the simulation and a scheme of the implemented steps, as shown in Figure 4. Among the required inputs, it could be mentioned: annual data of the hourly energy demand to be covered; technical information and cost of the generation system to be considered (in this case, photovoltaic and wind power plants); technical information and cost of the storage system (reversible pumping and mega-batteries); the energy resource of each generation system (solar and wind resource available in Grand Canary Island); other economic data (such as the annual interest rate and the lifetime of the project). Using this information as input into the HOMER software, the best options for the combination of generation systems to supply all the necessary power can be estimated, particularly the rated power to be installed, the power generation of each system, the storage capacity required, etc. The software also provides economic information such as LCOE, initial capital, NPC, payback, and internal rate of return (IRR).

The selection criteria in the methodology are the Net Present Cost but keeping CO_2 gas emissions at zero. The economic criteria imply a compromise between the sizing of the generation and storage facilities to meet the demand requirements, reaching the optimal point between oversizing generation and storage systems, even if a significant amount of energy potential is not produced. The economic data for 2019 are used to carry out the estimation. The methodology has been applied to three different scenarios, coming from the electrification degree of the Grand Canary Island by 2040.

HOMER simulates the operation of a system by means of an energy balance in each time step in one year (for instance, every hour), comparing the energy demand to the energy that can be supplied by the energy generation system, as well as how to operate the generators and if it is necessary to use the batteries. After simulating all system configurations, HOMER displays a list of feasible systems sorted by Net Present Cost (NPC). The program shows a list of feasible solutions that fulfill all requirements. As a result, a list of solutions is obtained. The optimal solution (The global optimum) heads the list, but other options can also be considered. In this case, the global optimum has been chosen as the best solution. [45,55].

Key uncertainty issues can be associated with electricity demand evolution, electricity costs, and solar/wind resources. Different future scenarios have been considered and analyzed separately regarding uncertainty in demand evolution (as described in point 3.1), and the optimal solution is provided for each scenario. Regarding electricity cost, it has been considered the present cost of electricity (as described in point 2.3), so acceptable, as future electricity cost is expected to be equal or higher, so obtained feasibility of alternative generation systems would be even higher. Solar radiation and wind resources can present uncertainty, but for the time of analysis (25 years), it can be considered no significant changes, and typical values (from PVGIS and Global Wind Atlas) are considered representative (as described in point 4).

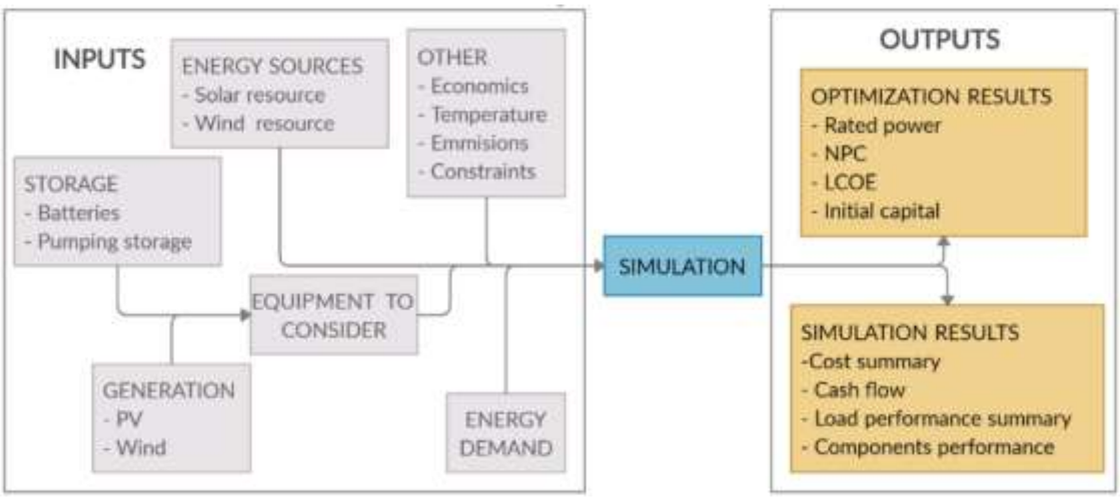


Figure 4. Schematic overview of inputs and outputs of HOMER Software.

3.1 The analyzed Electricity Demand Scenarios in 2040

Three scenarios have been analyzed through the current work; in all of them, the electric generation is fully renewable with zero emissions (Figure 5). The first one is a Business as Usual (BAU) scenario of the electricity demand, but with a reduction of consumption, mainly due to the adoption of energy efficiency measures. The second scenario includes energy savings by efficiency measures (as BAU) but compensated by the electricity demand increase. The demand grows because it is considered partial electrification due to a partial inclusion of the EV. The last scenario is a fully electrified energy consumption implementing energy efficiency measures. This one considers full penetration of electric vehicles and the decarbonization of the residential and services sectors, with a noticeable electricity consumption increase.

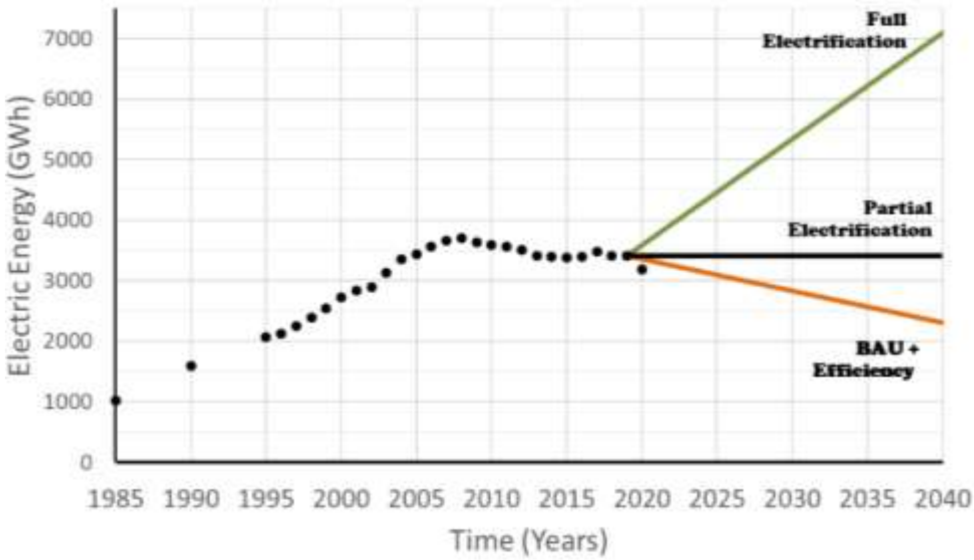


Figure 5. Scenarios of electricity demand per year. Adapted from [53]**.**

3.1.1 First scenario: BAU plus efficiency

A BAU scenario of the electric energy consumption is proposed in the document Estrategia de Almacenamiento Energético de Canarias [56]. The Canary Islands Government published this report in December 2020. There are another two documents [57,58], so all three documents describe, analyze, and provide different options to face the current challenges concerning future energy systems. This study uses the time series of historical values by islands published in the Anuario Energético de Canarias 2019 to reference electricity [53]. The analysis also considers the increase in the Grand Canary Island population, reaching a million inhabitants by 2040 and 2% of the GDP (Gross Domestic Product) per year. Specifically, linear correlations between these explanatory variables and demand have been analyzed based on these data. This situation would lead to a growing trend in the electricity demand. However, it is essential to consider that the energy efficiency policies application is mandatory, and the PNIEC 2021-2030 (National Integrated Energy and Climate Plan) [59] already orchestrates a set of measures to reduce consumption in terms of energy, in particular a decrease of 39.6% of the demand values of 2005. This reduction in consumption is projected to assume more significant progress in the first years of the plan's application, as it will be increasingly difficult to reduce electricity consumption in the Canary Islands archipelago. Specifically, the reduction in consumption would be 38% in the year 2030, 62% in the year 2040, and 79% in the year 2050 (all of them referring to the year 2005). So, with this increasing trend in electricity consumption (motivated by the increase in population and GDP) and the decreasing trend due to the implementation of efficiency measures, the report presents the final trend year by year until 2050 for the whole archipelago for each of the islands. Grand Canary's yearly electricity consumption would then be reduced from the current 3.41 TWh (electricity consumption in 2019) to only 2.3 TWh in the year 2040. This would mean a ratio of 0.675 between the demand forecast for 2040 and the current demand for 2019. Regarding the average hourly demand values, given that this is a BAU scenario and there are no significant implementations that affect demand, it is considered that these will maintain the currently existing form (Figure 2).

In scenario 1, greenhouse gas emissions would be significantly reduced because, on the one hand, consumption would be reduced (efficiency measures). On the other hand, all electricity would be generated from renewable sources. However, there would still be significant emissions, mainly caused by the transport sector, which would continue to be based on fossil fuels.

3.1.2 Second scenario: Partial electrification

Due to the transition of the energy system, which has already begun, leads to the widespread use of electricity in many sectors, particularly the introduction of the electric vehicle. Scenario 1 is unlikely, as the current electricity consumption pattern is assumed to continue until 2040. According to the study Estrategia del vehículo eléctrico de Canarias [58], with the full implementation of electric vehicles in the Grand Canary Island, an increase of about 2.2 TWh of annual electricity consumption would be produced. This total electrification forecast for 2040 is ambitious and will probably be challenging to achieve; in fact, European Union plans to decarbonize the European and Spanish economies by 2050 [25]. Therefore, a less ambitious scenario has been analyzed, scenario 1 plus 50% penetration of the electric vehicle. Compared to scenario 1, it has been considered a more likely and realistic scenario for 2040. Then this second scenario implies an annual consumption of around 3.5 TWh for Grand Canary Island, which would mean maintaining the annual demand values that the island has been having over the last decade. As mentioned in the previous scenario, it is considered that the average hourly values of demand maintain the currently existing form (Figure 2), given that the annual consumption is the same as the current one and no important measures affecting demand management have been implemented.

In this scenario 2, greenhouse gas emissions would be further reduced since, in addition to efficiency measures and the generation of all electricity from renewable sources (implemented in scenario 1), there would be the electrification of final energy consumption (by 2040 of around 50%, as an intermediate step towards the total electrification of the economy, planned at the European level for 2050). Thus, in this scenario, there would still be significant emissions, mainly associated with the transport sector, which would continue to be partially based on the use of fossil fuels.

3.1.3 Third scenario: Full electrification

Scenario 3 considers the pass from the current system to total decarbonization. The whole generation system would be based on renewable energy systems, and final energy consumptions are at the highest degree of electrification. This scenario leads to the highest increase in the electric energy demand in the Grand Canary Island, up to 6.42 TWh.

The transition to this scenario would be carried out in gradual stages. The first step planned until 2026 would be the shutdown of the most pollutant generation systems, along with the start of operation of the Chira-Soria reverse pumping station, so the surpluses of renewable sources could be partially recovered. While for the second one, by 2033, the first and second stages of the pumping stations project would be active. During this second transition stage, most fossil fuel installations would be eliminated. Finally, the last step, by 2040, would be the implementation of wind and solar generation power plants together with the storage system able to cover the full electrification scenario employing renewable generation systems.

In scenario 3, energy consumption requires implementing extra measures leading to total electrification. At the same time, the implementation of this scenario entails increasing the energy consumption and modifying the energy demand curve. Each of these aspects will be developed below to have a detailed vision of the conditioning factors of the scenario.

The transport sector accounts for 60-80% of the final energy consumption in the Spanish non-peninsular territories. Consumption of petroleum products predominates in this sector, almost 100%. The residential and services sectors account for 20-30% of the final energy consumption, and a high degree of electrification, between 70-80%. The industrial sector has a much lower consumption, of around 5%, having partial electrification.

Consequently, the major contribution by far is the passenger transport. Its complete decarbonization requires the renewal of the vehicle fleet, mainly the promotion of electric vehicles, and a modal shift to public transport and non-motorized means of transport. The key aspect is the change to electric transport for passengers and goods. For example, implementing electric vehicles in the Grand Canary Island would increase about 2.2 TWh in the annual electricity consumption [58]. In this consumption, the vehicle fleet forecast for 2040 has been considered. The investment in recharging points to supply the fleet of electric vehicles is considered to be around 1,250 M€; this would be the largest investment to be made, in addition to the installation of renewable generation sources to cover this significant increase in demand.

To determine the impact of electric vehicles on the electricity system, it would be necessary to estimate the increase in annual consumption, evaluate user behavior, and, consequently, predict the hourly demand profile foreseen to supply the electric vehicle energy needs. The hourly demand forecasting will be a standard behavior and depend on the type of recharging point used. For example, there will be fundamentally different charging profiles in parking lots linked to private homes, public roads, workplaces, hotels, shopping centers, regulated parking lots, and service stations [58]. This report details the distribution of recharging points according to the different typologies described throughout the geography of each island so that the different demand profiles can be assigned according to the unique characteristics of each identified point. The final result is the aggregation of demand curves by zones and recharging typologies, obtaining in a precise way the characteristic curve of the electricity demand of the electric vehicle for each of the Canary Islands.

Consequently, significant changes are expected regarding the current demand curve (Figure 2) for both shape and values. As displayed in Figure 6, the hourly demand profile forecast of the Grand Canary Island for the year 2040, assuming full electrification, presents a much flatter shape, added to the demand increase. As can be seen in the figure, there is an increase in demand during night hours, which will help flatten the demand curve (valley filling) naturally. Therefore, the difference between peaks and valleys of demand is reduced, which in principle would be favorable for the management of the electricity system.

In future works, this last scenario could be taken a step ahead by including other complementary sceneries aiming to optimize the generation/demand balance. For instance, the consideration of a dynamic demand response based on developed technologies and previous studies [21,60,61], implementation of Vehicle-to-Grid strategies (V2G) [62], and promotion of self-consumption with/without distributed storage would be addressed [56].

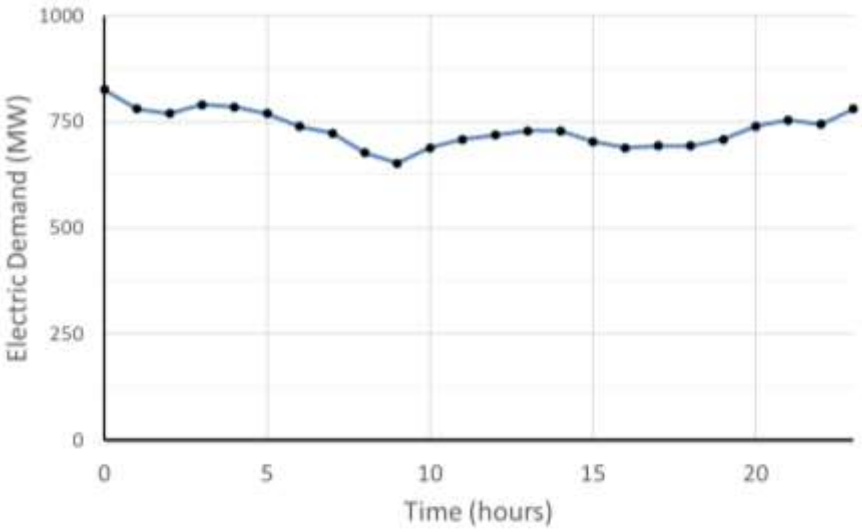


***Figure 6. Third scenario: electricity demand profile forecast of the Grand Canary Island for 2040. Adapted from* [58].**

3.2 Simulation inputs

The sources analyzed are solar photovoltaic and wind systems, combined with reversible pumping storage and battery systems to reach the optimal generation system design, which reaches a compromise solution between costs, minimization of excess energy, and reasonable land occupation. The system is designed to cover 100% of the Grand Canary Island energy demand. In addition, the commented criteria of zero CO_2 emissions at a low price (LCOE) with low electric energy wastages and reasonable land occupation have also been met. Figure 7 shows a schematic view of the analyzed sources to cover the energy demand for the three scenarios. In scenario one, the daily demand to cover is 6,315 MWh/day, and peak power is 355 MW. For Scenario 2 and scenario 3, the daily demand increases to 9,334 and 17,531 MWh/day, respectively. Regarding peak power demand, it is 525 MW for scenario 2 and 961 MW for scenario 3.

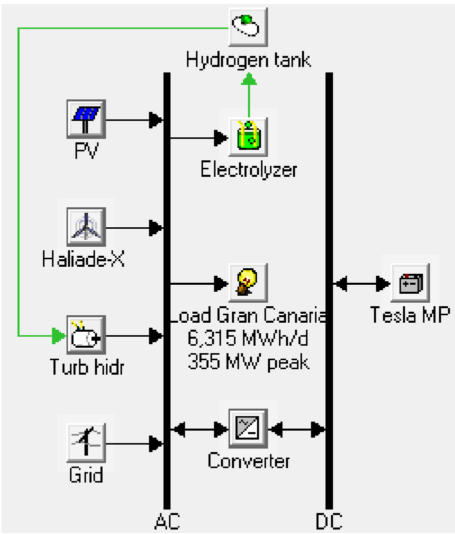


***Figure 7. Scheme of the energy demand for Scenario 1 (BAU+Efficiency) and the analyzed energy sources. Adapted from* [45].**

3.2.1 Modeling of the Energy Sources and Demand

The main objective of the simulations is to estimate the installed power and storage capacity needed to cover the demand in possible future scenarios by 2040. Considering the electricity costs to optimize engineering, land occupation criteria, and investment and O&M costs, these estimations have been carried out. Inputs required to simulate the photovoltaic and wind systems are described in points 4.1 and 4.2, respectively. The selection of wind turbine (main characteristics included in Table 6) has been motivated by land occupation criterion and attending to wind stability and predominance; then, an offshore option has been chosen, even though the ratio cost/power is higher than onshore models.

The demand curves are also needed. For the first two scenarios, the daily hourly demand curves were assumed to have the same shape as those for 2019 but multiplied by the quotient of the total annual demand estimated for 2040. In the first simulated scenario, as the estimated consumption in 2040 is reduced to 2.3 TWh, and that of 2019 was 3.41, all values have been multiplied by 0.675. While for the second scenario, as electricity consumption remains constant, the 2019 curves have been used directly. Finally, for the third scenario, that of full electrification of consumption with a total yearly demand of approximately 6.42 TWh, the data of the average demand curve estimated for the year 2040 (Figure 6) has been used [55]. However, a day-to-day random variability (standard deviation in the sequence of the daily average) of 5% has been used, and also a time-step-to-time-step (standard deviation in the difference between the hourly data and the average daily profile) of 3.65% to take into account the variations in demand hour by hour and day by day.

Pumping storage plants have been used; however, this technology cannot be directly simulated in the HOMER code. Given the impossibility of defining a pumping station in the code, it has been necessary to develop an alternative. This has been done by implementing a hydrogen storage system (electrolyzer, hydrogen tank, and generator). This means that the maximum electrolyzer electricity consumption is equivalent to the water pump power needed to propel the water from the bottom to the top dams at its maximum flow. The hydrogen tank's capacity simulates the upper reservoir's capacity (equivalence between the total potential energy stored by the difference in elevation between reservoirs when the upper one is full and the amount of Hydrogen stored to contain that same energy). While hydrogen power generation (fuel cell or hydrogen-burning) simulates the maximum turbine power when transferring water from upper to lower reservoirs.

The equations necessary to make the basic calculations behind the pumping station are schematically presented below. The maximum energy consumed by pumping stations during generation surpluses is:

$$E_{P,max} = P_P \cdot \eta_P \cdot t_P \tag{1}$$

where $E_{P,max}$ is the maximum energy stored in the upper reservoir (upper dam filled), P_P is the pumping power, η_P is the efficiency of the pumping phase, t_P is the time needed to fill the upper reservoir fully.

While the power returned to the grid during demand peaks through the turbining process is given by:

$$P_T = \frac{E_{P,max} \cdot \eta_T}{t_T} \quad (2)$$

where P_T is the turbining power, η_T is the efficiency of the turbining phase, t_T is the time needed to empty the upper reservoir fully.

Hydrogen is stored in a tank and afterward used in a generator to produce electricity when needed. Then, the hydrogen tank capacity can be calculated through the expressions:

$$M_{max} = \frac{E_{P,max}}{LCV_{H_2}} \quad (3)$$

where M_{max} is the mass storage capacity of the hydrogen tank produced by the electrolyzer, a value which corresponds to the energy stored in the upper dam when it is filled, LHV (Lower Heating Value of H_2) is 120 MJ/kg. The hydrogen consumption at full load is calculated through:

$$\dot{M}_{max} = \frac{M_{max}}{t_E} \quad (4)$$

where $\dot{M}_{max}$ is the hydrogen consumption of the generator at full load, t_E is the maximum time of operation to consume the whole amount of Hydrogen that can be stored.

As for the pumping station, $E_{E,max}$ is the maximum energy consumed by this facility during electric energy generation surpluses, which can be calculated as follows:

$$E_{E,max} = P_E \cdot \eta_E \cdot t_E \quad (5)$$

where P_E and η_E are the power and efficiency of the electrolyzer.

Finally, the power generation through this Hydrogen can be calculated as:

$$P_G = \frac{E_{E,max} \cdot \eta_G}{t_G} \quad (6)$$

being P_G the rated power of the generator, η_G is the generator's efficiency, t_G is the time needed to empty the hydrogen tank.

Table 1 Summary of correspondence data between pumping and hydrogen storage [63,64].

Reverse Pumping Storage	**Hydrogen Storage**
DATA	
$P_T = 200$MW	$\mathbf{P_G = 200MW}$
$t_T = t_P = 16$ hours	$\mathbf{t_G = t_E = 16}$ **hours**
$\eta_P = \eta_T = \sqrt{\eta_{tot}} = \sqrt{0.8} = 0.894$	$\boldsymbol{\eta_E = \eta_G = \sqrt{\eta_{tot}} = \sqrt{0.8} = 0.894}$
CALCULATIONS	
$E_{P,max} = \frac{P_T t_T}{\eta_T} = \frac{200 \cdot 16}{0.894} = 3{,}580 \text{ MWh}$	$\boldsymbol{E_{E,max} = \frac{P_G t_G}{\eta_G} = 3,580 \text{ MWh}}$
	$\boldsymbol{M_{max} = \frac{E_{E,max}}{LHV_{H_2}} = \frac{3,580(\text{MWh}) \cdot 3,600(\frac{s}{h})}{120\ (\text{MJ/kg})} = 107,400 \text{ kg}}$
	$\boldsymbol{\dot{M}_{max} = \frac{M_{max}}{t_E} = \frac{107,400}{16} = 6,712.5 \text{ kg/h}}$
$P_P = \frac{E_{P,max}}{\eta_P \cdot t_P} = \frac{3{,}580}{0.894 \cdot 16} = 250 \text{ MW}$	$\boldsymbol{P_E = \frac{E_{E,max}}{\eta_E \cdot t_E} = \frac{3,580}{0.894 \cdot 16} = 250 \text{ MW}}$

Depending on the available information of the pumping storage plant, the procedure to pass to the hydrogen storage system will be slightly different. As an example, the calculations for the first pumping plant are developed, the Chira-Soria project. In this plant, the total turbining power is 200 MW, being able to operate up to 16 hours at full load if the upper dam is filled and supposing the same time to fill the upper dam. The assumed efficiency of the round-trip process has been 0.8 (usual values between 0.7-0.85), equal pumping and turbining efficiencies $\left(\eta_P = \eta_T = \sqrt{\eta_{tot}} = 0.894\right)$. The equivalences between pumping and hydrogen storage technical data needed by the code are displayed in Table 1. Finally, the battery storage has been implemented by introducing the values displayed in Table 7, which summarizes the major characteristics of the batteries used in the current study.

4 Renewable Power Generation System

As mentioned above, decarbonization must become a reality by 2050 in the countries of the European Union. However, the non-peninsular territories of Spain are leading the ecological transition and implementation of a decarbonized energy system [25], and so present more ambitious objectives. There is an Energy Transition Plan (PTECan), with the main objective of achieving the decarbonization of the Canary Islands economy by 2040. Within this development, three strategies are also being elaborated on relevant aspects for the Canary Islands system: self-consumption, batteries, and electric vehicles. Consequently, all the Canary Islands are working against the clock to reduce their dependence on fossil fuels. But, they have an advantage because of the abundant natural resources of the archipelago, mainly sun and wind. The Canary Islands Technological Institute (ITC) has considered up to ten different scenarios to reach 100% clean energy generation to reach this decarbonized scenario. For Grand Canary Island, its huge natural resources could be utilized by integrating storage systems to balance the variability of the resources, such as wind and sun.

4.1 The Photovoltaic System

The solar resource in Grand Canary Island could be an essential power generation source. The Canary Archipelago has the highest insolation in Spain. The solar resource can be estimated using the European photovoltaic geographical information system (PVGIS) [65]. The monthly solar energy resource of the Grand Canary Island is displayed in Figure 8. The clearness index is a measure of the clearness of the atmosphere. It is the fraction of the solar radiation transmitted through the atmosphere to strike the surface of the Earth [45]. This energy supposes a potential global horizontal irradiance of 1,826 ESH/year (equivalent sun hours), a value that can be increased up to 2,442 ESH/year by using solar trackers. These data are used assuming that this irradiation is maintained throughout the period analyzed in this study. The additional information regarding used solar PV system inputs is shown in Table 2, while the information of the selected photovoltaic panel is shown in Table 3 .

Table 2 Inputs used for the PV system.

Lifetime (years)	25
Derating factor (%)	82
Tracking system	Two axes

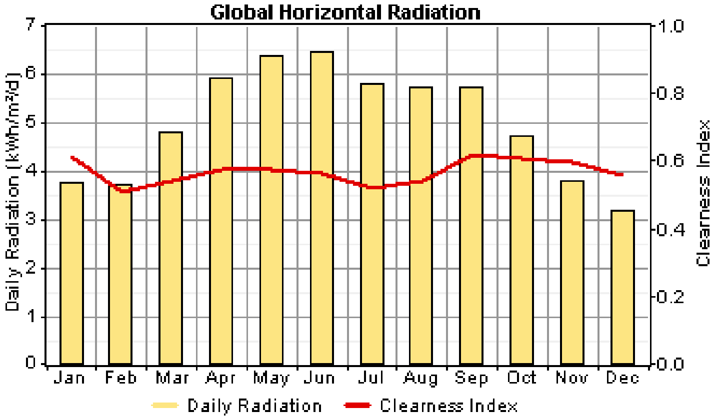


Figure 8. Monthly solar energy resource in Grand Canary [65].

Table 3 Inputs used for the PV system [66,67].

Used panel	**Trina solar TSM-DE19**
Temperature coefficient of power (%/°C)	-0.36
Peak Power (W)	550
Nominal operating cell temperature (°C)	42.6
Efficiency of the panel at standard conditions (%)	20.5
Cost (€/kW)	800
O&M cost (per 1MW peak power) (€/year)	3,500

4.2 The Wind system

The wind resource in Grand Canary Island is, at least, as important as the solar resource. This wind resource can be estimated using the global wind data of the second Modern-Era Retrospective analysis for Research and Applications (MERRA-2), which has been developed by NASA [68].

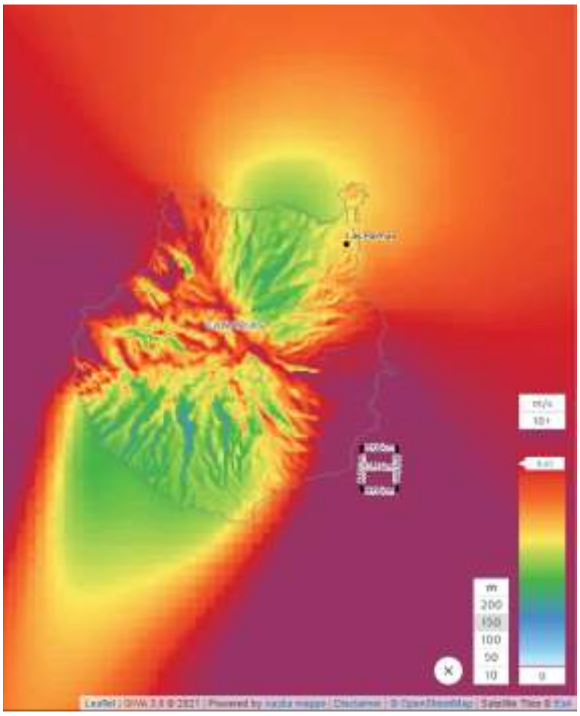


Figure 9. The offshore wind resource in Grand Canary [69].

The monthly average wind energy resource is shown in Figure 9. There are many suitable locations for installing wind generators onshore and offshore. In particular, there are plenty of suitable sites available on the east side of the island, also in the southeast of the island, especially from 3 to 10 km from the coast. According to the global wind atlas [69], this area has more potential, as is shown in Table 4.

Table 4 Monthly wind energy resource in Grand Canary [68].

Month	Average Wind speed (m/s)
Jan	7.4
Feb	8.2
Mar	9.3
Apr	9.1
May	10.1
Jun	11.6
Jul	14.4
Aug	13.3
Sep	8.5
Oct	7
Nov	7.5
Dec	7.1

Table 5 Inputs used for the simulation [37] [38].

Weibull k	1.7151
Weibull c	9.9695
Measurement reliability (%)	80
Altitude m asl	0
Anemometer height (m)	50
Wind shear profile	Logarithmic
Surface roughness length (m)	0.02 m

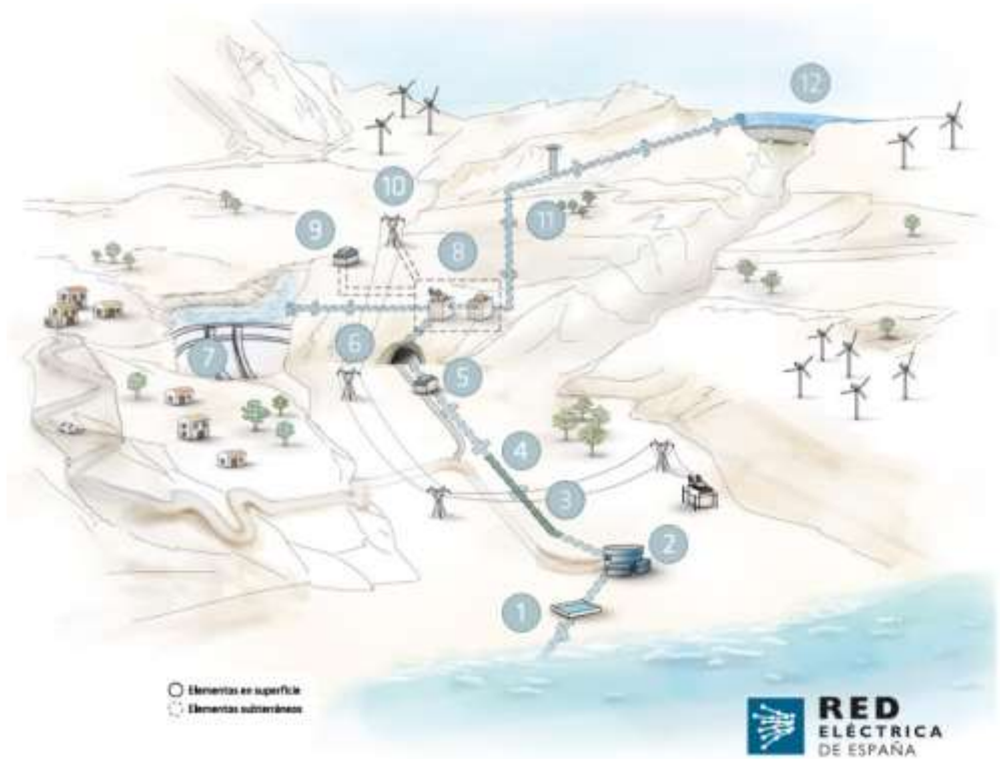
Other required information for wind resources simulations is taken from MERRA-2 [68]. The data are summarized in Table 5, while the datasheet of the selected wind generator is shown in Table 6.

Table 6 Datasheet of the wind turbine [69–72].

Wind generator	Haliade-X General Electric
Rated power (MW)	12
Rotor diameter (m)	220
Height to the axe (m)	140 m
Total height (m)	220 m
Lifetime (years)	25
Cost of the system (M€/turbine)	28.6
M€/MW	2.38
O&M cost (M€/year)	3.5

4.3 The Storage System

A reversible pumped-storage hydroelectric power plant is yet planned; the Chira-Soria project [26] is expected to be operational by 2026-2027. A schematic view of the facility is displayed in Figure 10. The Chira-Soria pumped-storage power plant would store around 3.2-3.6 GWh, with a total generation capacity of 200 MW, which means 16 hours at full power if the higher dam is filled. The Canary Islands Government estimates that the Chira-Soria pumping station would save approximately 122 M€ per year, so the system would be amortized in less than four years since the budget that REINCAN (The subsidiary company of REE in the Canary Islands, which is the sole carrier of the national electricity system, that will execute the work) manages for the Chira-Soria project is around 400 million euros.



Chira-Soria Pumping Station Components: 1. Sea Water Catchment Pitching and Rest of Pipelines; 2. Desalination Plant, 5200 m3/day desalination capacity; 3. Desalinated water channeling; 4. Construction Road; 5. Desalinated Water Pumping Station II; 6. Access Tunnel; 7. Soria Dam, Altitude 608 masl and volume of 32.2 hm3; 8. Central Cavern and Transformer Cavern; 9. Control Building; 10. 220 kV line; 11. Hydraulic circuit connection between the two dams; 12. Chira Dam, Altitude 901 masl and volume of 5.6 hm3.

Figure 10. Schematic view of the Chira-Soria Pumping Station [26]**.**

The high initial capital cost of pumping storage plants can be partially mitigated by its long lifetime up to 75 years or even more. For instance, Manfrida and Secchi [73] state that the life of a hydropower plant is at around 50 years. However, the plant's life can be easily extended with the adoption of maintenance measures and periodic replacement of equipment at an economically relatively cheap cost. In addition, lifetimes of 100 years are stated in a GE report [74]. Another point is the reduced maintenance costs, around 2% of the investment cost per year is usually considered for a standard pumping plant [73]. A reverse pumped storage station is the most widely used form of electricity storage, accounting for about 95% of all storage facilities worldwide. The whole cycle's round trip energy efficiency (including turbine and pumping) ranges from 70% to 85% [75,76].

In the not too distant future, it is expected to at least double storage capacity, as the connection of the Soria reservoir with the Cueva de las Niñas reservoir is being studied. Additionally, the current hydraulic planning considers creating pumping stations between the dams in the Aldea canyon (Parralillo, Siberio, and/or El Caidero de las Niñas). There are many alternatives to place pumping stations in the Aldea Canyonsuch as El Parralilo-Siberio or the El Parralillo-El Caidero de las Niñas pumping stations, both with powers around 40MW and storage capacities of 700 and 625 MWh, respectively [56]. There is a quite long list of appropriate locations, which has a power of approximately 600 MW and a storage capacity of around 10 GWh. Given that there must be a high storage capacity to absorb much of the excess produced by renewable sources, another storage technology would be needed. For that purpose, mega-batteries have been chosen, and their specifications are summarized in Table 7.

Table 7 Standard system specifications of the selected battery system [77–80]**.**

Battery	**Tesla Megapack**
Maximum AC power 2-hour (MW)	1.26
Energy Available per Megapack 2-hour (MWh)	2.53
Round-Trip System Efficiency	87%
Cost of the module (€)	760,000
O&M cost (€/year)	10,800
Lifetime (years)	15

All the above-explained possibilities are explored to achieve the optimal sizing of the electricity generation system, aiming to optimize the renewable generation with the storage capacities.

5 Results And Discussion

A summary of the simulation results for the three scenarios is shown in Table 8. The chosen options are specifically those which have the lowest cost of electricity (LCOE). The major aspects to highlight for each scenario are:

- **BAU scenario plus efficiency**. From the economic point of view, the best option is to install 1,200 MWp of PV, 24 wind generators (12 MW each, 288 MW in total), and the two biggest pumping stations (total power of 400 MW and energy storage capacity of 6.36 GWh). The initial investment is 2,446 M€, the O&M costs are around 162.1 M€/year, and the LCOE is 10.4 c€/kWh, being the total NPC cost of 7,539 M€. The payback of the installation would be equal to 11.9 years.
- **PARTIAL ELECTRIFICATION scenario.** The best option from the economic point of view is to install 1,500 MWp of PV, 40 wind generators (12 MW each, 480 MW in total), and all pumping stations that are considered to be viable (total power of 607 MW and energy storage capacity of 9.73 GWh). The initial investment is 3,558 M€; the O&M costs are around 244.814 M€/year, and the LCOE is 10.4 c€/kWh, being the total NPC cost of 11,251 M€. The payback of the installation would be equal to 11.9 years.
- **FULL ELECTRIFICATION scenario.** The best option from the economic point of view is to install 2,500 MWp of PV, 100 wind generators (12 MW each, 1,200 MW in total), all pumping stations that are considered to be viable (total power of 607 MW, and energy storage capacity of 9.73 GWh) and a storage system compound of 2,300 batteries (each battery with a power of 1.26 MW and storage capacity of 2.53 MWh, the total power is 2,898 MW and a capacity of 5.82 GWh). The initial investment is 7,822 M€, the O&M costs are around 607.1 M€/year, and the LCOE is 13.4 c€/kWh, being the total NPC cost of 26,898 M€. The payback of the installation would be equal to 18.8 years.

Table 8. Results of the analyzed scenarios.

Scenario	**BAU + Efficiency**	**Partial electrification**	**Full electrification**
PV system (MW)	1,200	1,500	2,500
Wind turbines (MW)	288	480	1,200
Turbine power (MW)	400	607	607
Pumped-storage capacity (GWh)	6.36	9.73	9.73
Battery system power (MW)	-	-	2,900
Battery system capacity (GWh)	-	-	5.82
Initial Capital (M€)	2,446	3,558	7,822
O&M cost (M€/year)	162.1	244.8	607.1
Total NPC	7,539	11,251	26,898
COE (c€/kWh)	10.4	10.5	13.4

5.1 Energy analysis

Table 9 summarizes the percentages covered by each energy source; as shown, only renewable sources (solar PV and wind) have been used as a generation source, being the balance of both quite equilibrated, approximately between 40 and 60% in the three scenarios. It should be noted that, despite the high capacity of the storage systems, there are quite high electricity surpluses (between 25 and 33% approximately). These percentages are high, but considering this generation system is based on renewable sources, this value could be considered normal.

If the system is analyzed separately, some significant aspects could be highlighted. The generation map of the solar PV system (Figure 11) shows a fairly constant generation rate for the three scenarios throughout the year. However, it is higher during the summer months but has a considerable generation capacity even in winter. As shown in Table 10, the solar PV system has around 4,000 operation hours with a capacity factor of almost 20% and an LCOE slightly above 4 c€/kWh.

Table 9 Energy demand and energy production per component

Scenario	**BAU+Efficiency**		**PARTIAL ELECTRIFICATION**		**FULL ELECTRIFICATION**	
Production	GWh/yr	%	GWh/yr	%	GWh/yr	%
PV array	1,972	55.9%	2,465	48.8%	4,108	38.8%
Wind turbines	1,554	44.1%	2,591	51.2%	6,477	61.2%
Total	3,526	100.0%	5,056	100%	10,585	100.0%
AC primary load	2,300	100%	3,402	100%	6,384	100.0%
Excess electricity	954	27.1%	1,277	25.3%	3,532	33.4%

a)

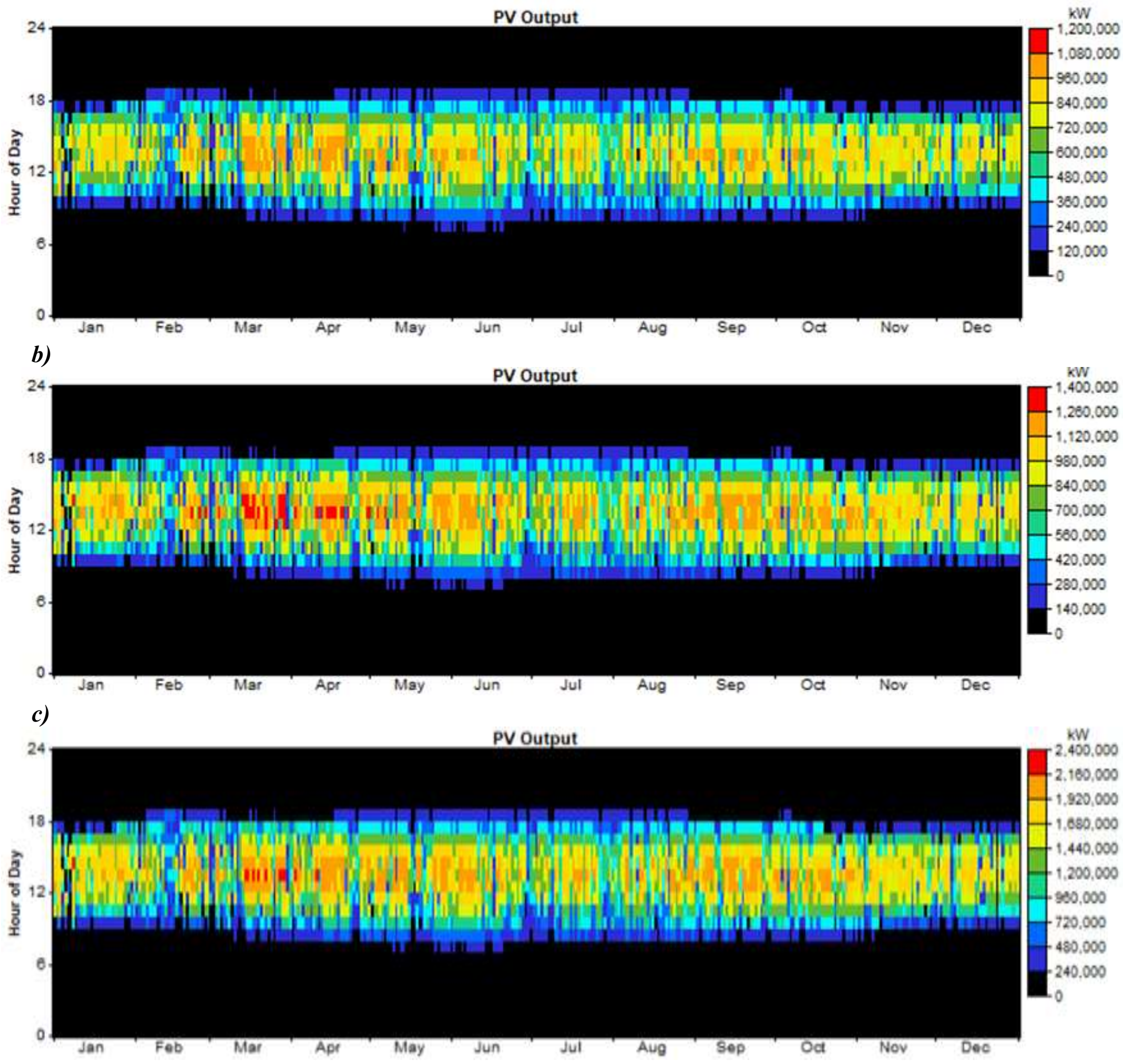


Figure 11. Generation map of the solar PV system: a) BAU + Efficiency; b) PARTIAL ELECTRIFICATION; c) FULL ELECTRIFICATION.

Table 10 PV system summary

	BAU+Efficiency	PARTIAL ELECTRIFICATION	FULL ELECTRIFICATION
Rated capacity (MW)	1,200	1,500	2,500
Mean output (MW)	225	281	469
Mean output (MWh/day)	5,403	6,754	11,256
Capacity factor (%)	18.8%	18.8%	18.8%
Total production (GWh/yr)	1,972	2,465	4,108
Hours of operation (hr/yr)	4,121	4,121	4,121
LCOE (c€/kWh)	4.34	4.34	4.34

a)

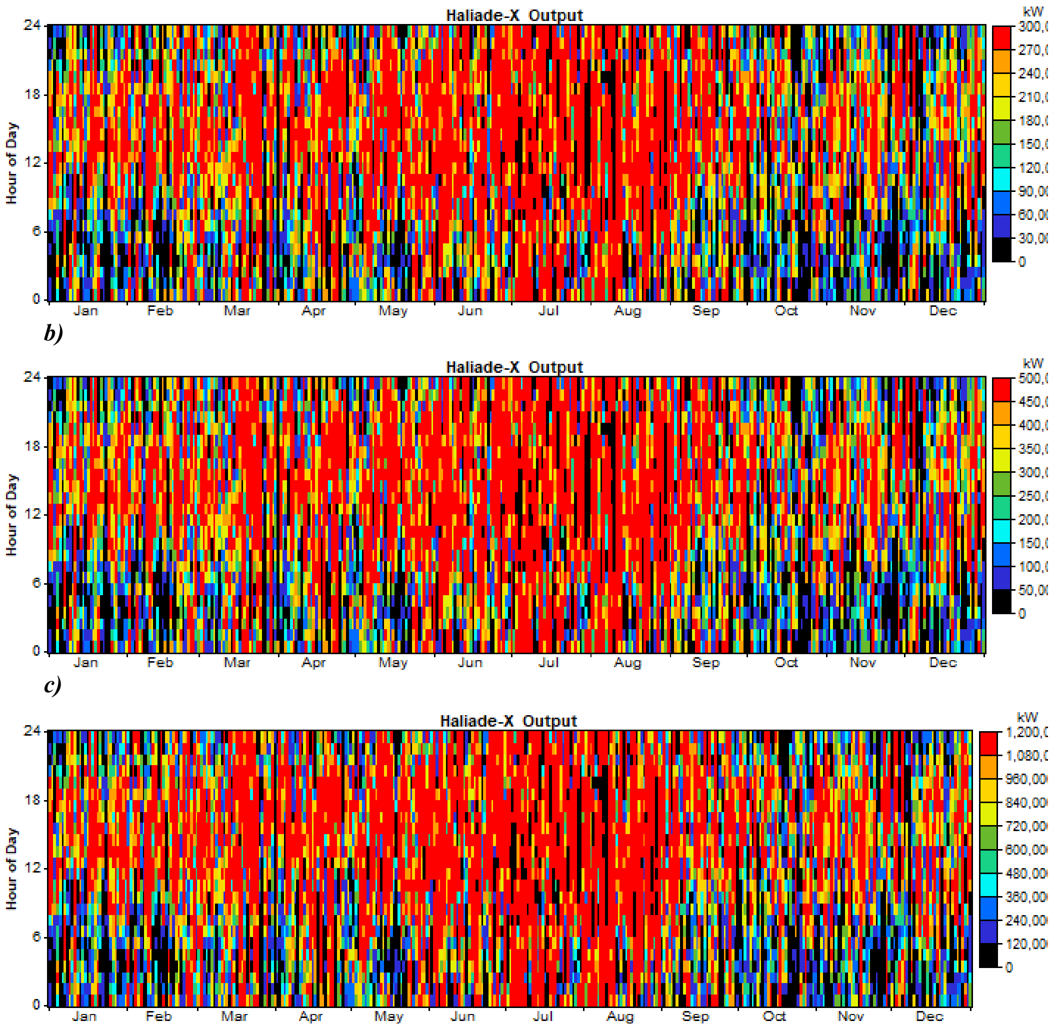


Figure 12. Wind system power production during one entire year: a) BAU + efficiency; b) PARTIAL ELECTRIFICATION; c) FULL ELECTRIFICATION.

Concerning the offshore wind power system, as shown in the generation maps of the three scenarios (Figure 12), the frequency of the system operation is very high. Table 11 shows around 8,200 hours per year of operation and capacity factor values of more than 80%, which is very high for this technology. These values can be achieved due to the privileged location of the island added to the fact that wind generators are placed in the sea. Despite these high potential figures, the cost of offshore wind generation is quite high, with an LCOE of little more than 7 c€/kWh.

Table 11 Wind system summary

	BAU+Efficiency	PARTIAL ELECTRIFICATION	FULL ELECTRIFICATION
Rated capacity (MW)	288	480	1,200
Mean output (MW)	177	296	739
Capacity factor (%)	83.7	84.7	85.7
Total production (GWh/yr)	1,554	2,591	6,477
Hours of operation (hr/yr)	8,177	8,177	8,177
LCOE (c€/kWh)	7.26	7.26	7.26

a)
b)
c)

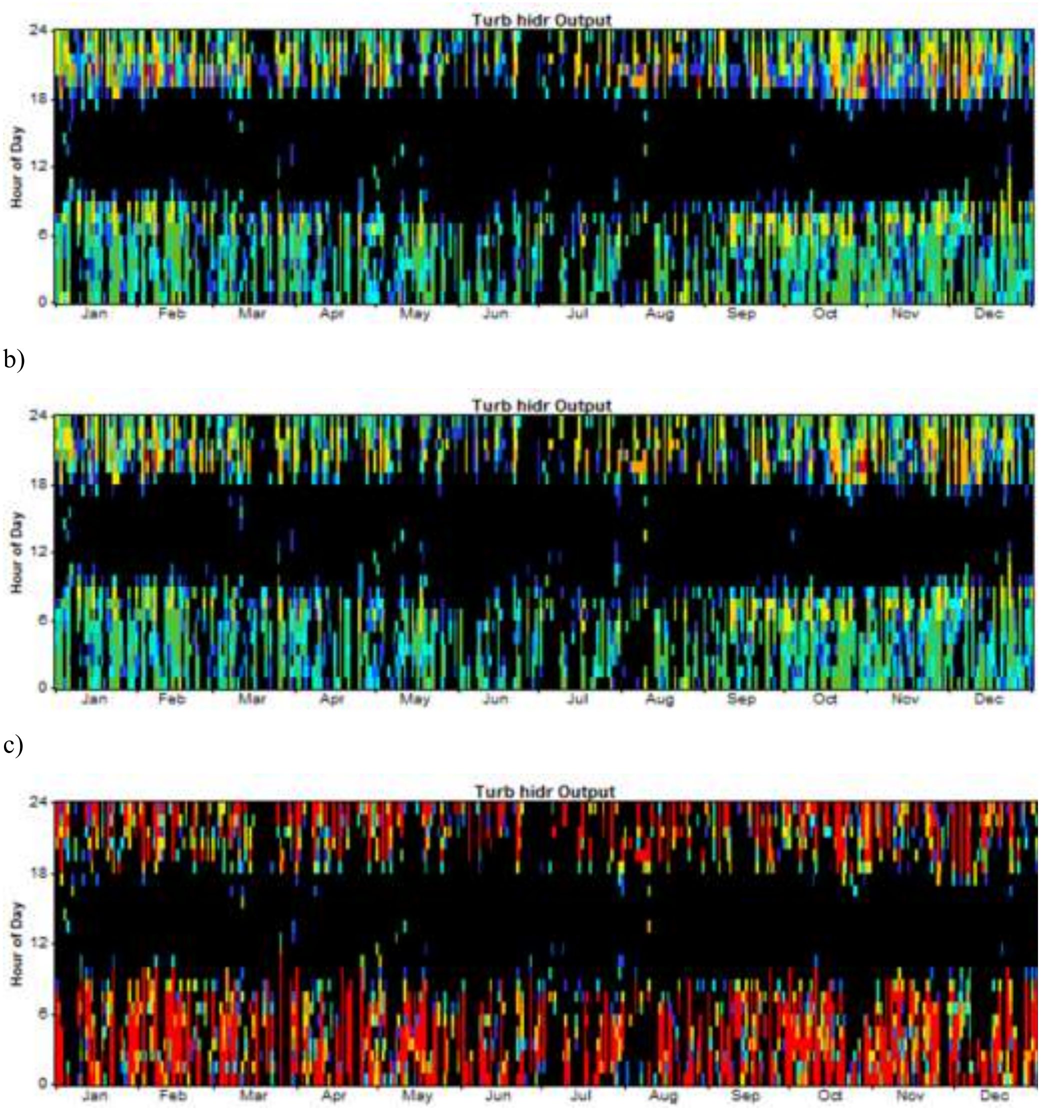


Figure 13. Power discharge to the grid by the "pumping storage" during one entire year: a) BAU + efficiency; b) PARTIAL ELECTRIFICATION; c) FULL ELECTRIFICATION.

Concerning the pumping storage system, As shown in Figure 13, the pumping storage system practically never feds energy to the grid during the mid-day hours. This situation is due to the solar PV system capacity during most mid-day hours, except for cloudy days. Additionally, there is less need to use this storage technology during summertime, particularly between June and August. There are many days in which practically it is not needed (black zones in Figure 13 even at night). The maximum installed power is required during the year (Table 12). The capacity factors are high, between approximately 14 and 23%, depending on the scenario. This important use is especially accentuated in the scenario of full electrification. As the storage technology is not enough to manage the generation surpluses/shortages of the renewable sources, many mega-battery arrays have been additionally used.

Table 12 Pumped-storage system summary

	BAU+Efficiency	PARTIAL ELECTRIFICATION	FULL ELECTRIFICATION
Capacity factor (%)	14.8	13.6	22.7
Electrical production (GWh/year)	520	719	1,197
Mean electrical output (MW)	59.7	82.5	136.7
Min. electrical output (MW)	8.48	0.0144	0.000127
Max. electrical output(MW)	347	513	607

a) b) c)

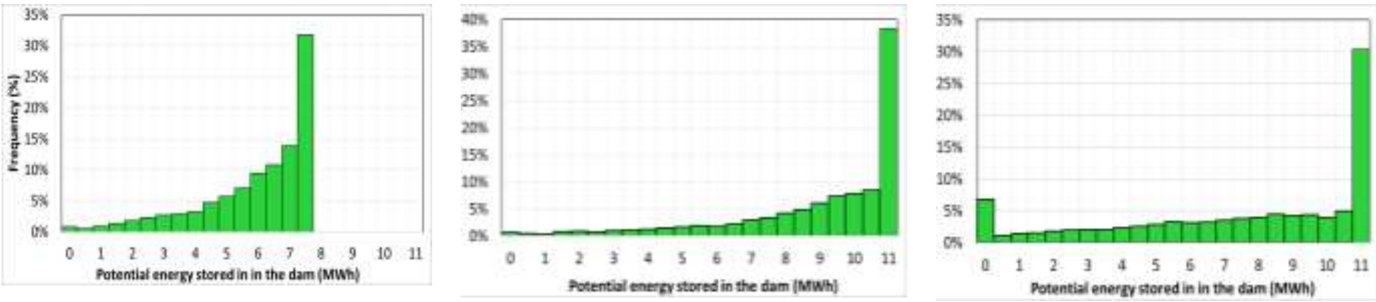
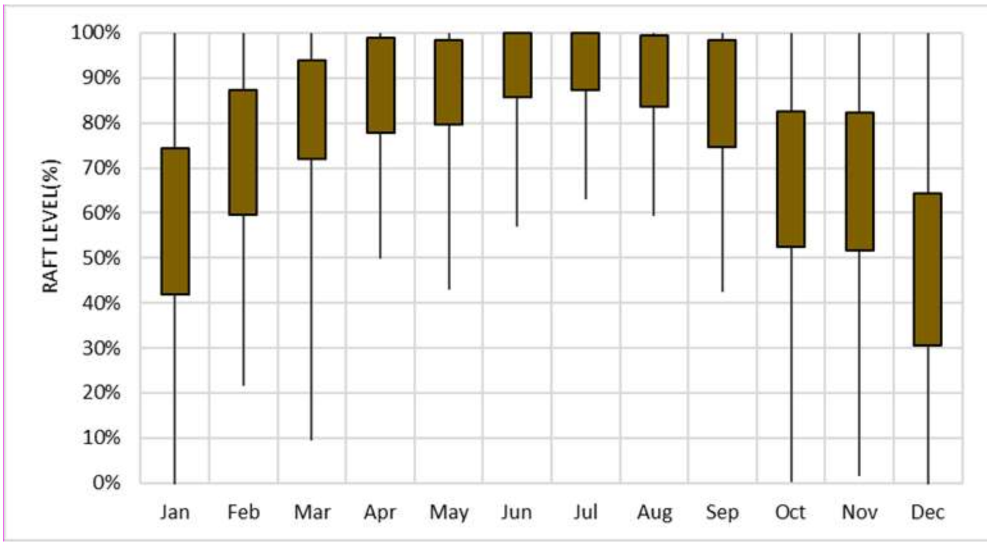


Figure 14. Frequency histogram of potential energy stored in the dam: a) BAU + efficiency; b) PARTIAL ELECTRIFICATION; c) FULL ELECTRIFICATION.

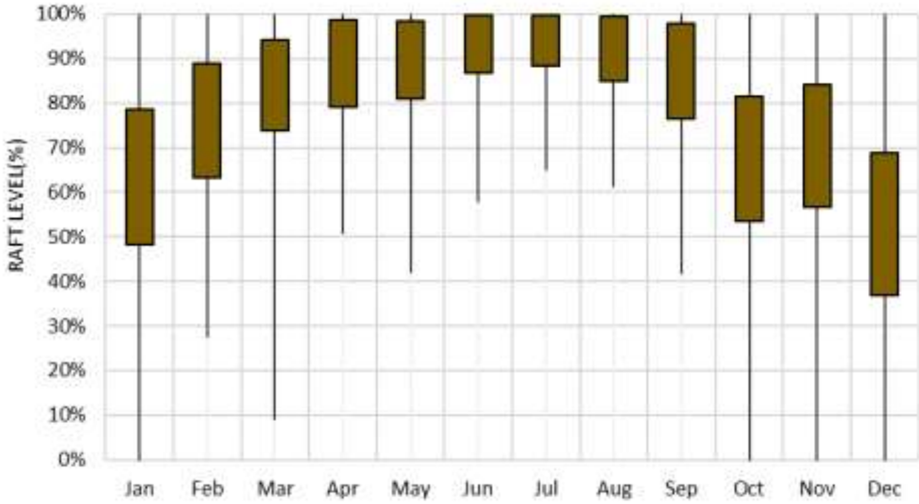
Finally, the mega battery storage system summary is presented in Table 13 and from Figure 17 to Figure 19. Only in the third scenario, this system is required. It has a rated power of 1.26 MW, and the total storage capacity is 2.53 MWh per pack of batteries, which means an autonomy of 2 hours at full load. Table 13 summarizes the data of the batteries.

Regarding the frequency histogram of the batteries, state-of-charge (SOC) mapping (Figure 17) is shown that almost all the time, batteries are at full charge (around 85% of the time, the charge is between 95-100%). Also, this aspect can be shown in Figure 19, where the red color vastly predominates. But in a few cases, when batteries' deep discharge occurs, its importance is demonstrated to cover the energy demand. Without them, an unaffordable installed power would be required to meet the demand and, in addition, a considerable amount of energy would be wasted for many periods. As a result, the battery system is almost discharged during brief periods in most months; particularly in January, March, October, November, and December, almost minimum monthly values close to zero are reached (Figure 18).

a)



b)



c)

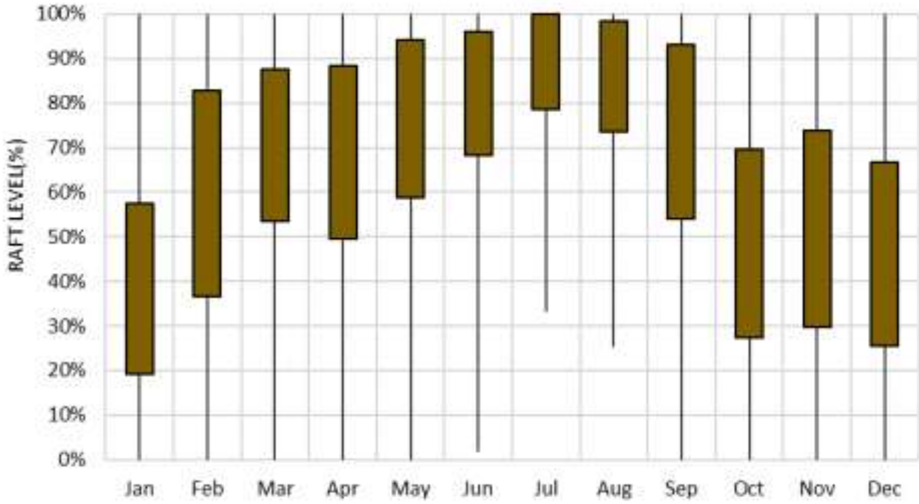
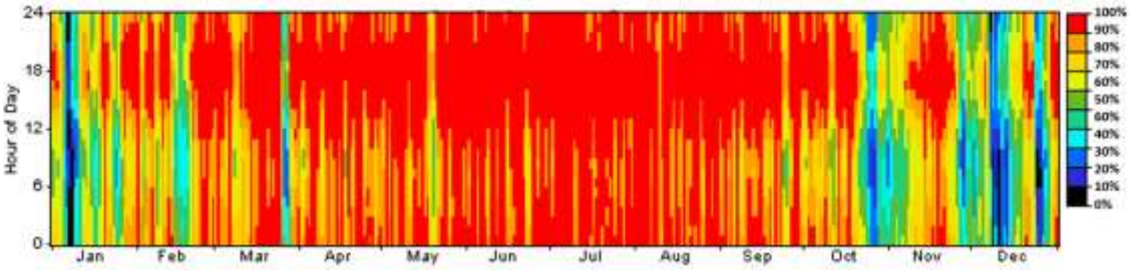


Figure 15. Monthly data of the raft level: a) BAU + efficiency; b) PARTIAL ELECTRIFICATION; c) FULL ELECTRIFICATION.

a)



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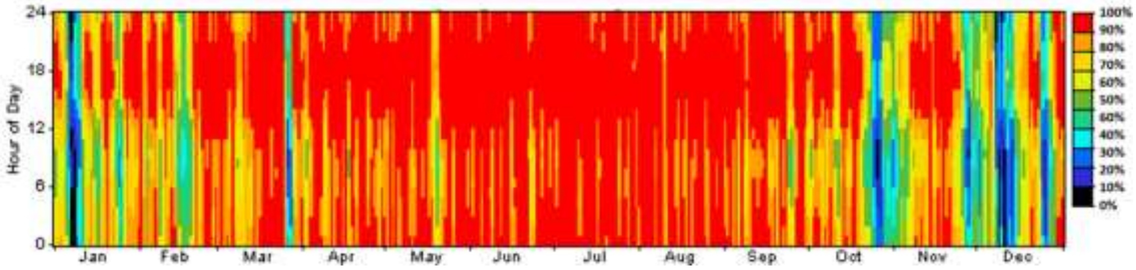

c)

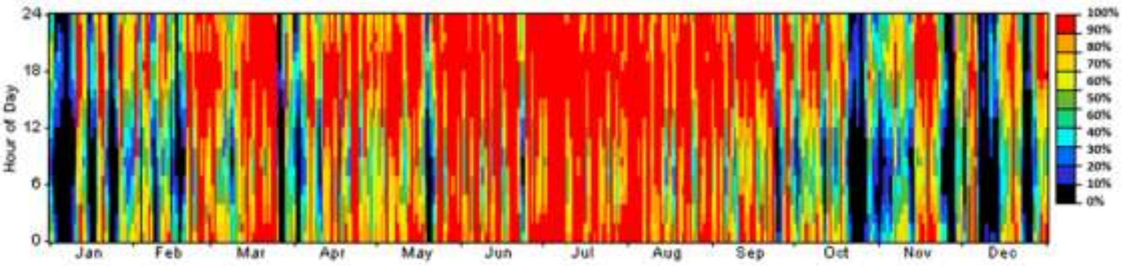

Figure 16. Map of the raft level (SOC): a) BAU + efficiency; b) PARTIAL ELECTRIFICATION; c) FULL ELECTRIFICATION.

Table 13 Mega-batteries storage system summary

	FULL ELECTRIFICATION
Batteries	2300
Bus voltage (V)	505
Nominal capacity (GWh)	5.8
Autonomy (hr)	7.95
Lifetime throughput (GWh)	45,124
Battery wear cost (c€/kWh)	3.3
Energy in (GWh/yr)	345.3
Energy out (GWh/yr)	300.4
Expected life (yr)	15

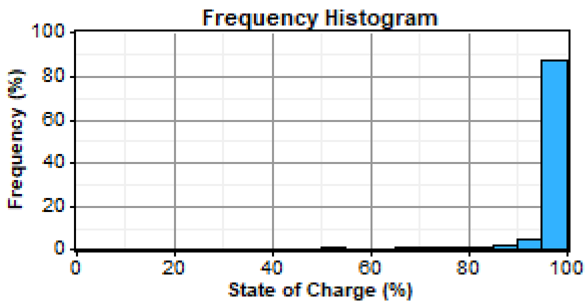

Figure 17 Frequency histogram of the mega-battery storage system.

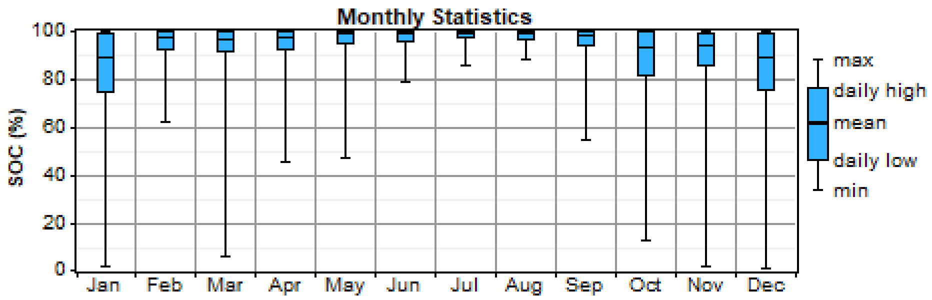

Figure 18 Monthly data of the mega-battery storage system.

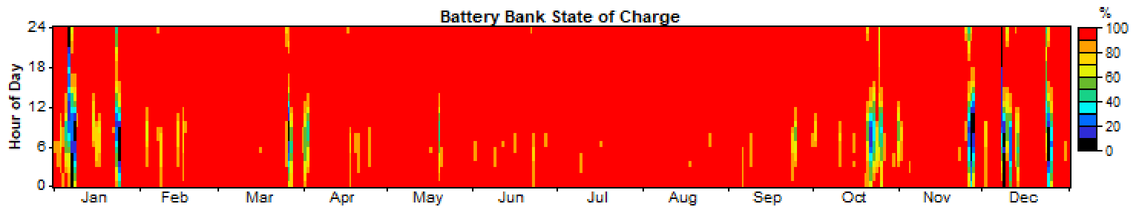

Figure 19 Storage system SoC during one entire year.

5.2 Economic analysis

The initial capital required to implement the systems required in each scenario changes appreciably. The full electrification scenario costs more than triple respect to the conservative BAU scenario (from 7,500 to 27,000 M€). The capital costs are quite equilibrated for the three scenarios, being the initial investment divided approximately equally among all technologies. This is not the case for operation and maintenance; the O&M costs of wind turbines are much higher than the rest, being more than half of total O&M costs.

A summary of the economic analysis is shown in Table 15. It is important to highlight that in all scenarios, despite the strong investments of the implemented systems, the return on investment periods is low. Therefore, all of them can be considered viable and profitable.

Table 14 Initial capital and O&M cost, Total and per source.

	Capital (M€)	Replacement (M€)	O&M (M€)	Total (M€)

BAU + Efficiency	PV	960.0	365.7	1,361.3	2,687
	Wind turbine	686.4	219.4	2,639.6	3,545
	Pumped storage	800.0	0.0	506.7	1,307
	System	2,446.4	585.1	4,507.5	7,539
PARTIAL ELECTRIFICATION	PV	1,200.0	457.1	1,701.6	3,359
	Wind turbine	1,144.0	365.7	4,399.3	5,909
	Pumped storage	1,214.0	0.0	769.7	1,984
	System	3,558	823	6,871	11,251
FULL ELECTRIFICATION	PV	2,000	762	2,836	5,598
	Wind turbine	2,860	914	10,998	14,773
	Pumped storage	1,214	0	774	1,988
	Battery system	1,748	2,353	781	4,882
	System	7,822	4,030	15,388	27,240

Table 15 Economic analysis summary.

	BAU+Efficiency	**PARTIAL ELECTRIFICATION**	**FULL ELECTRIFICATION**
Return on investment (%)	7.63%	7.64%	4.73%
Internal rate of return (%)	7.74%	7.75%	4.30%
Simple payback (yrs)	11.9	11.9	18.8

6 Conclusions

The following summarizes the main conclusions that can be drawn from the analysis carried out in this study:

- The optimal weight reached in the simulations of the solar PV generation system decreases as demand increases. Given that if the PV generation significantly falls, it would produce a strong peak in the central hours of the day, and the storage capacity should be increased with the consequent cost overrun. This is due to the fact that during the central hours of the day, the system must absorb a large part or all of the generation surplus, which will be returned to the system when required. The weight of solar PV generation decreased from almost 65% of the total installed capacity in the first scenario (demand of 2.3 TWh/year) to around 58% for the second scenario (demand of 3.5 TWh/year) and slightly less than 40% for the third scenario (6.42 TWh/year). This shows a decreasing trend in the weight of solar PV due to the difficulty of absorbing part of the large peak generation during central hours on sunny days.
- Consequently, the opposite happens with wind power generation; despite being more expensive to install and operate, it has a tendency to grow in scenarios with an increase in

demand, going from approximately 15% in the first scenario, to slightly below 20% for the other two scenarios.

- This additional cost of batteries, if necessary, increases the costs appreciably, as shown in Table 14. Consequently, their installation is only considered in the third scenario, given the limited storage capacity available by pumping (limitation of the suitability of sites to install these facilities). Therefore, the most appropriate option would be to take advantage of the maximum potential capacity of the pumping stations, leaving the mega-batteries as a last resort. The ratio of stored energy to installed power is appreciably higher in reverse pumping than in mega-batteries, then, since it is usually necessary to have high power, it is more important to have good storage capacity, but over a long period of time, the use of reverse pumping should be maximized.
- The final generation MIX shifts towards lower weights of solar PV generation as electric energy demand increases. This situation is due to restrictions on the increase in storage capacity needed to compensate for the decoupling between solar PV generation and demand. This leads to an increase in wind generation, although in our case the land occupation criterion (use of offshore technologies) has led to a more moderate increase in the installed capacity of wind generation due to its higher cost of construction, operation, and maintenance.
- Pumping stations are at their maximum storage capacity or at nearby points most of the time. However, as scenarios with higher demands are considered, the storage system is pushed to the limit, with stored energy values close to zero. In the case of the total electrification scenario, around 7% of the time, the energy stored is close to zero.
- Due to its cost with respect to the PV power plants, the offshore wind turbines increase the total cost of the entire system. Offshore wind systems are more expensive than onshore wind systems, but they have been chosen because the production is much higher and with less variability, and additionally, also due to the land occupation criterion.
- The system is oversized to cover 100% of the demand, producing more energy than required during long periods, causing significant energy wastages. In fact, for all three scenarios, the electric energy production excesses are around 30% of the total demand. Installed power versus peak consumption ratios ranges from 7 to 10, which also are quite high ratios. When aiming to reduce these values but maintaining zero emissions of greenhouse gases, there would exist several options. The first and easiest one would be the use of a backup system, probably the use of a gas turbine (ideally powered by "green" Hydrogen, although it currently poses serious problems, especially in terms of performance and costs of hydrogen production storage and transport). Another backup option would probably be the use of biomass as another renewable option, although there are limited resources on the island, and importing would considerably increase the price. Finally, another option, this time not a backup system but base energy, also without greenhouse gas emissions, would be the use of nuclear reactors (probably modular reactors, SMRs). Although this option is currently unfeasible in Spain due to the existence

of a nuclear moratorium that prevents their installation, in addition to the usual objections, mainly due to waste management and possible accidental situations.

- A future topic to be studied could be the utilization of these generation surpluses for other uses. For example, it could be used for producing Hydrogen, an energy that could be used later in certain uses that in principle are "difficult to electrify", or even exported to other places.
- Sensitivity analysis related to the uncertainties in the future generation and storage costs of the different technologies used is an option that remains outside the current objectives but could be addressed in future work.
- The realization of an uncertainty analysis related to the capability of the system to be self-sufficient due to the inherent variability/uncertainty in the availability of renewable resources (wind and sun) is an option that could be addressed in future work and is outside the current objectives.
- The analysis of possible generation and demand management policies on the future generation-demand balances could also be left for future studies. Specifically, among other actions, one could consider the effect of encouraging the installation of solar panels or of giving priority to consumption at certain hours (to move the demand curve towards production).
- The presented methodology can be adapted and applied to any standalone grid. For that purpose, it would be necessary to make modifications for both solar PV and wind resources and, in any case, implement other possible considered sources, in which specific resources and demand data under the different considered scenarios would have to be introduced.

7 Acknowledgments

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8 Appendix

Table 16 Previous related works

	Year	Location/Population to cover	Island, Urban or Remote, /Standalone or grid-tied	Energy demand to cover (GWh/year)	Renewable source /Generation potential per source (GWh/year)/Peak power (MW)	Maximum Renewable share	Storage system / Capacity (MWh)	Used tools
Curren paper	2022	Gran Canaria Island//865k	Island/ standalone	6,384	Wind; PV / 4,108; 6,477 / 1,200; 2,500	100%	Li-Ion battery; pumped hydro/5,820; 9,730	HOMER
Lorenzi et al. [27]	2019	Terceira Island (Azores)/ 53k	Island/Standalone	221	Wind; waste; Geothermal / 31.3; 8.7; 9.8 / 12.6; 2.3; 3.5	46%	Li-ion /30	GA
Arévalo et al. [28]	2022	Santa Cruz and Baltra islands of Galapagos Archipelago (Ecuador) / 20k	Islands/Standalone	73	PV; Wind/25.4; 2.25/32.5; 7.5	100%	Pumped hydro/375 Li-Ion battery/ 450	HOMER
Quinn et al. [81]	2020	Lampedusa (Italy) / 6.6k	Islands/Standalone	36.2	PV; Wind; Sea Wave/2.95;10.5; 1.55/1.51; 2.1; 0.64	40%	-----	Author's own mathematical model
Jahangiri [30]	2018	Kish Island (Iran) / 25 k	Island /Standalone	7.67	PV, wind / 18%-19%; 15%-16% / 1, 1	26%	Batteries / 2	HOMER
Uwineza et al. [31]	2021	Popova Island (Russia)/ 1.5k	Islands/Standalone	3.76	PV; Wind/ - /2.8; 1.0	95%	Li-Ion battery/ 5	HOMER
Islam et al. [32]	2021	Residential community / 50 households Newfoundland, (Canada)	Remote	0.993	PV ; Wind; Hydro/ 0.019; 0.575; 0.823/ 0.015; 0.100; 0.098	100%	Pumped hydro storage /4.58	HOMER
Suresh et al. [33]	2020	Kollegal block in Chamarajanagar Dictrict (India)/1.69k	Remote Village / Standalone	0.33	PV; Wind; Biomass; Biogas /0.164; 0.051;0.092; 0.028/0.1; 0.057; 0.05; 0.06	100%	Hydrogen (50kW peak, tank 300 kg); Batteries	HOMER/GA
Das et al.[82]	2017	A residential community in Bangladesh	Remote	0.091	Biogas; PV ; diesel/ 0.100 (total)/ 0.009; 0.010; 0.020	60%	Lead-acid battery/0.164	HOMER
Mandal et al.[83]	2018	Residential community in Bangladesh/ 1.3k	Remote	0.088	PV ; diesel/ 0.128 (total)/ 0.073; 0.057	89%	Lead-acid battery/0.387	HOMER
Mori et al. [84]	2021	Mountain Hut, Panticosa(Spain) / 30/day max	Remote / standalone	0.05	Hydro (microgrid: diesel, boiler hydro, battery)		Batteries / 0.073	HOMER
Elmorshedy et al. [85]	2021	A residential community (Saudi Arabia)	Remote	0.045	Wind; PV / 0.111 (total)/ 0.055; 0.018	100%	Lead-acid /0.325	HOMER, MATLAB/Simulink
Muh and Tabet [86]	2019	Village near Wum (Cameroon) / 2.5k	Remote / standalone	0.0365	PV, wind, micro-hydro	100%	Batteries/-	HOMER
Kumar et al. [87]	2021	Minicoy and Baratang Islands (India)	Island	0.011	PV ; diesel/ 0.028-0.030 (total)/ 0.020; 0.007	93%	ZBF batteries/0.100	HOMER
Chiñas et al. [88]	2021	Laboratory at UPV in Valencia, Spain/-	Laboratory/ Standalone	0	Biomass gasification plant/ - / -	0%	-	GA
Hurtado et al. [48]	2015	Kinshasa (DR Congo)	University/grid tied	0	Biomass Gasification plant; PV /0.006; 0.019 / 0.01 ; 0,01	0%	Lead acid batteries/0.01	HOMER
He et al. [89]	2021	Huraa Island (Maldives)/0.75k	Island/Standalone	Not indicated	PV; Wind/-;-/1.8; 1.0	96%	Li-Ion battery /4	OptiCE
Halabi et al. [90]	2017	Sabah, Malaysia (2 zonas)	Island Remote /standalone	Not indicated	PV / 0% to 100%/2x1.2 (MWp)	100%	Fiamm batteries / 2.88 & 4.32	HOMER
Mori et al. [91]	2022	Refugio de Lizara (Pyrenees) / 78 max	Remote / standalone	Not indicated	PV/ 2929 kWh / 3.7 kWp	44.9%	Lead-acid /0.0384	TRNSYS
Chua et al. [92]	2014	Pulau Ubin (Singapoure)/ 200	Island / standalone	Not indicated	PV, Biomass, Solar / /200-750 kW; 150-300 kW; 125-1000kW	40%	Hydrogen / FC 0.02-0.0350	TRNSYS

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