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A high-level model of electric isolated systems to assess energy transition planning

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Abstract

Electric island power systems are both a challenge and an opportunity to assess the design of new energy storage and generation hubs. We propose a framework model to analyze the energy surpluses in an island energy system. The proposed methodology is based on simulation techniques that allow for the estimation of the energy demand and production in energy hubs. With this information, planning energy surpluses and curtailments and dimensioning the associated energy storage systems can be done. In the proposal, we study a real application on a renewable energy hub in the island of Tenerife. The case study estimates both the generation and the demand on a long-term horizon from 2020 to 2040. Different scenarios are analyzed according to the considered pace of clean energy penetration. For these scenarios, the proposal predicts the annual demand increase, the electric vehicle fleet penetration, the annual installed wind power, the annual installed photovoltaic power, the annual installed energy storage and the grid losses. The obtained results show the importance of energy storage systems as a key element for an optimal use of the energy resource. Furthermore, these results offer insights on the potential of these studies for a correct planning of energy systems in island territories.

Keywords: Decarbonization, Energy Transition Planning, Isolated Systems; Modeling Framework

1. Introduction

The prevailing global dependence on fossil fuels for energy supply makes energy production and consumption the most important sources of CO_2 emissions on the planet. Since the accumulation of CO_2 is the main cause of the greenhouse effect, reducing energy consumption, increasing the production of clean energy and improving energy efficiency are fundamental objectives for mitigating the effects of climate change. These measures also make it possible to alleviate the problems of energy security and dependence of many countries (International Energy Agency, 2021).

These problems are more pressing in the case of isolated systems such as islands. Their geographic peculiarities and small size make it difficult to supply energy in a sustainable and reliable manner, causing deep external dependence, and increasing both the complexity to achieve grid stability and the associated supply costs (Sigrist et al., 2017).

The Canary Islands is an Atlantic archipelago that comprises eight islands and a number of islets. The electricity systems of each island are isolated systems and only 3% of primary energy demand in 2019 came from renewable sources. Besides, only 16% of the electricity generated in 2019 was from renewable sources (Gobierno de Canarias, 2019). The Canary Islands count on an Energy Transition Plan (PTECan) (currently in the public presentation phase) for the development of a sustainable energy model, based on energy efficiency and renewable energies (Instituto Tecnológico de Canarias, 2023). In this new framework, small and large-scale storage, localized or distributed, and demand management will provide greater flexibility and resilience in the islands' electricity systems.

There are many specific barriers to consider when dealing with energy planning and management in island territories. The first problem arises because, due to the limited resources and space, the potential for large-scale energy infrastructure is constrained. Additionally, these fragile territories are specially affected by environmental impact of any infrastructure. In this context, it is critical an optimal planning and management of the resources and variables involved in the energy system. Main aspects are planning of installed power according to the mentioned limitations, defining and adequate energy mix to minimize the impact of energy generation, transportation and distribution and planning an adequate infrastructure in concordance with installed power.

The research proposed here is intended to contribute to this end. Thus, the aim of the work is to provide a modeling framework that would constitute the basis for assessing different strategies for energy transition planning. In particular, the work focuses on the analysis of energy surpluses for the correct dimensioning of energy storage systems in renewable energy plants. In our proposal, modeling and simulation techniques are the basis for the design of the proposed solutions.

This work has two main elements of relevance. Firstly, we present an efficient yet simple methodology to analyze the main variables of the electrical system. Secondly, we apply this methodology to an isolated electrical system, where there are many specific challenges mainly related to grid stability.

The rest of this document is organized as follows. Section 2 presents a brief background on isolated systems and storage technologies. Section 3 depicts the main methodological components of the proposed model. Section 4 details the main findings extracted from the results of running the model. Finally, Section 5 summarizes the main conclusions of this contribution.

2. Background

In islands, due to the small size of the electricity systems, power-frequency control presents different challenges and constrains in comparison with continental and interconnected electrical systems. The intermittency of renewable energy production introduces a higher level of complexity in frequency control, necessitating fast-response backup systems that can support stability, grid security and quality of supply in the event of any contingency (Pusceddu et al., 2021; Zhang et al., 2017). In a scenario where the main energy source is of renewable origin, backup systems should be ready to support generation systems immediately, within 30 seconds (Akram et al., 2020), as is the case of energy storage technologies. It is important to remark that, although the introduction of storage systems such as pumped storage allows for the storage of large amounts of energy, they do not provide an instantaneous response as would lithium-ion battery systems distributed throughout the grid.

Energy storage systems are one of the pillars for achieving the decarbonization of electricity systems (Berna-Escriche et al., 2024). These systems allow, among other functions, capturing surplus energy from intermittent renewable sources such as solar and wind, storing it and subsequently returning part of it to the grid. Hence, they are a key part of Hybrid Renewable Energy Systems (HRES) (Datta et al., 2011).

In regions with isolated electricity systems, large-scale energy storage is essential to increase the penetration of renewables to over 40-50% of the electricity mix (Díaz et al., 2015). If we review the different storage systems capable of storing large amounts of energy for subsequent introduction into the system, we do not have a wide variety of mature technologies (Technology Readiness Levels – TRLs – greater than 7). In general, we can distinguish four different types of alternatives according to the physical principle of energy transformation (Nadeem et al., 2019; NREL & U.S. Department of Energy, 2020):

1. Mechanical storage systems: Based on the electromechanical conversion of energy (using the

operating principle of potential energy, kinetic energy, pressurized gas and forced spring) until it is required again by the electricity grid. E.g. pumped-storage hydroelectric power plants and the use of compressed air.
2. Thermal storage systems: They take advantage of thermal gradients and the release of energy during changes in the state of matter. Depending on the operating temperature, they classify into 1) high operating temperature, such as salt storage in solar thermal power plants; and 2) cold storage, such as liquid air systems.
3. Chemical storage systems: They extract energy from the rearrangement of molecules of certain compounds through chemical reactions of electron transfer. Hydrogen is one of the key chemical carriers for energy storage. The advantages of hydrogen are the abundance of the element, its high calorific value, its multiple applications and its carbon-free combustion. Depending on its source and the way it is extracted, we can classify hydrogen into different types according to the IEA (International Energy Agency): black, gray, brown, blue, turquoise and green hydrogen. The green color is the only one with a 100% renewable production guarantee based on energy surpluses, as proposed in the study.
4. Electrochemical storage systems: They provide a wide variety of technologies and chemistries with different characteristics. Among the technologies, we can mention ultracapacitors, flow batteries or electrochemical batteries, the latter being ideal for stationary applications such as the use of surpluses, coverage of demand peaks or market arbitrage.

Currently, Lithium based storage technology is the most explored and expanding systems, mainly for its use in portable consumer electronic devices and electric vehicles (Miao et al., 2019). Among the different lithium based batteries, lithium iron phosphate (LFP, $LiFePO_4$) offers the best guarantees for stationary applications at a reasonable cost. Despite their low energy density (between 90-180 Wh/kg), they offer a long lifetime (<4-6k cycles, at 80% SOH, with discharge rates below 1C), optimum performance with high response at high loads, being able to discharge up to 5C. Another key point is the high thermal stability and safe operation. These batteries are 95% recyclable and require up to 3 times less lithium than other chemistries and the elimination of rare chemical elements. This last point means that their medium to long term price does not depend on volatility in the prices of raw materials such as lithium, cobalt, manganese, titanium, or nickel. Among their limitations is the faster self-discharge rate of lithium batteries (<3% per month).

3. Materials and Methods

The assessment of the planning of energy storage or new renewable infrastructures in an isolated system requires analyzing technical, economic and environmental impact of the proposed solutions. Hence, we pose a holistic assessment methodology that comprises four main steps: 1) modeling the electrical system; 2) simulation/optimization of different strategies for hub storage/renewable infrastructure; 3) financial economic evaluation; and 4) calculation of emissions and carbon footprint. We will focus on the first step within this contribution, using Tenerife as a case study.

3.1. General methodology to model an isolated electrical system

We pose an hourly dispatch simulation model, which relies on the system balance equation

$$D = P \tag{1}$$

where the hourly Demand for electricity (D) must be equal to the hourly Production of energy (P). Figure 1 summarizes some key variables that contribute to the calculation of each member of the equation, including onshore wind power (in MW), photovoltaic solar power (in MW, including both large scale and self-consumption), offshore wind power (in MW), stationary batteries (in MW/MWh, both large-scale and domestic), electrolyzers (in MW), and increase in the fleet of electric vehicles. Therefore, we will require input data from several sources:

1. Generation of a daily demand curve profile.
2. Wind resource profile.
3. Photovoltaic resource profile.
4. Future scenarios (annual demand increase, electric vehicle fleet penetration, annual installed wind power, annual installed photovoltaic power, annual installed energy storage, grid losses, etc.).

The first member of Equation 1 is calculated as

$$D = (\Delta D \times D_H + D_{EV}) \times (1 + L) \tag{2}$$

where D_H is the historical demand, computed by aggregating "similar days" according to whether it is a holiday, the day of the week, and the month. Hence, the historical demand for a specific time of day is the median of all the "similar days".

ΔD is the percentage increase over historical demand, which depends on the scenario and year. This factor is a percentage over the base demand. Values below 1 indicate that demand is decreasing with respect to the base year, while values above 1 indicate a growth in demand.

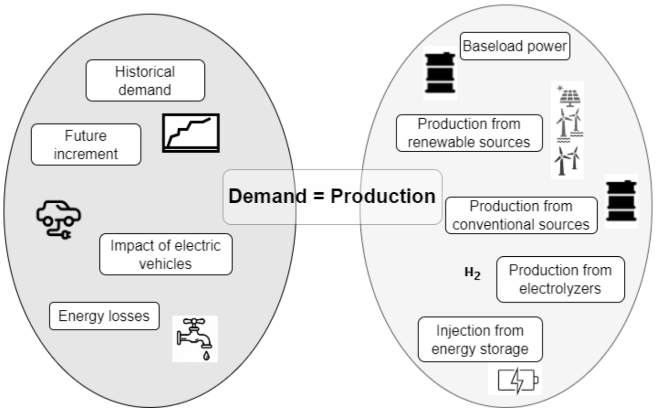

Figure 1. General overview of key variables used in the creation of scenarios.

If we consider the current fleet of electric vehicles in Tenerife, we may discharge their contribution to the historical demand. Starting from this assumption, we define D_{EV} as the daily demand derived from the electric vehicle charging profile, expressed as

$$D_{EV} = C_{EV} \times |EV| \times e_{EV} \times U_{EV} \times \overline{Dist} \qquad (3)$$

where C_{EV} is an hourly electric vehicle charging curve for a typical day (expressed in percentage); $|EV|$ is the number of electric vehicles on the isolated system per year and month; e_{EV} is the charger efficiency; U_{EV} is the average unit consumption per electric vehicle; and $\overline{Dist}$ is the average distance driven per day.

We also require adding the network losses (L) to the demand coverage, adjusted by year and month.

The second member of Equation 1 is the electricity production mix by technology, expressed as

$$P = BP + P_{REN} + \mathbb{C} \qquad (4)$$

where BP is the baseload power per hour for conventional technologies (such as gas turbine, steam turbine, combined cycle and diesel engines); and P_{REN} is the production from non-manageable renewable technologies such as photovoltaic, onshore and offshore wind

$\mathbb{C}$ is a system balance variable that represents balancing technologies such as diesel engines and gas turbines, and also energy storage, in case it is introduced in the system. The fit of the equation for the balancing technologies ($\mathbb{C}$) depend on the result of whether the equilibrium of the system is positive or negative:

$$\mathbb{C} = \begin{cases} P_{BES-} + P_{CON} & , \mathbb{C}_t > 0 \\ -S + P_{BES+} + P_{ELEC} & , \mathbb{C}_t \leq 0 \end{cases} \qquad (5)$$

When $\mathbb{C}$ is positive, we must contribute energy to the system from an energy storage that has the capacity and availability to inject energy into the system (P_{BES-}). We use conventional technologies (P_{CON}) only when the energy storage is not enough.

Conversely, a negative $\mathbb{C}$ implies an energy surplus (S). This energy surplus can be recovered, first, by battery demand (P_{BES+}) and, secondly, by starting up the electrolyzers for green hydrogen production (P_{ELEC}). The injection of energy into the grid by these technologies will be limited by the installed power of each of the storages and whether stored energy is available within the operating limits of the storages. These limiting factors are summarized in

$$P_{BES-} \leq PI_{BES-} \qquad (6a)$$

$$P_{BES+} \leq PI_{BES+} \qquad (6b)$$

$$DOD_{Max} > SOC(t-1) > DOD_{Min} \qquad (6c)$$

$$E_{BATT} \times SOC(t) = E_{BATT} \times SOC(t-1) + (P_{BES+} \times e_{BES}) - (P_{BES-}) \qquad (6d)$$

Where PI_{BES+} and PI_{BES-} are the instantaneous power for charging and discharging, respectively. Batteries will be defined by both their energy capacity (E_{BATT}), expressed in MWh, and the storage (P_{BES+}) and grid injection power (P_{BES-}), which will be limited to 1C to extend their lifetime.

We use an hourly model of the battery state of charge (SOC), in percentage, subject to the restrictions in Equations 6a-6d. An efficient handling of the charging/discharging of batteries requires adhering to pre-specified maximum and minimum depth of discharge (DoD).

The SOC for a specific hour (SOC(t)) depends on the previous SOC (SOC(t-1)), the energy that was injected to the grid (P_{BES+} - e_{BES}), and the energy that was stored (P_{BES-}). Table 1 shows the relationship between SOC and the efficiency of the charging process.

Table 1. Relationship between SOC and efficiency of the charging process.

SOC range	Efficiency
>90%	80%
> 50% and ≤ 90%	85%
≤ 50%	90%

The last components to balance this system are electrolyzers. They would start operating at variable load until reaching their maximum power to try to collect all the surplus energy.

3.2. Case study: the Tenerife Electric System

We developed a simulation model of the Tenerife electrical system, based on the proposed methodology, and built on previous work from the authors (Díaz et al., 2015; López et al., 2023; Ramírez Díaz, 2018; Ramos-Real, Barrera-Santana, et al., 2018). This model took into account the estimated progression of the growth of renewables in the time horizon 2024-2040 and produced an estimation on how the limitations due to discharges would affect the design of storage systems or new renewable sources attached to generation hubs.

A non-negligible level of uncertainty on technical, market, regulatory, etc. factors is intrinsically associated to the prediction of the future energy scenario. Consequently, we designed two scenarios in terms of penetration of renewable energies: an optimistic scenario based on the PTECan (which estimates almost 3.7 GW of renewable energy installed by 2040), and a more conservative scenario (1.6 GW).

We considered a 1% annual growth in electricity demand for both scenarios. Furthermore, after analyzing the different alternatives, we ruled out a pumped storage facility, since it would not be feasible to implement it before 2040 on the island of Tenerife. Therefore, the accumulated energy storage will be formed by stationary battery installations both in self-consumption (domestic, industrial and commercial), as well as in the distribution network or in large plants.

The optimistic renewable power scenario proposes a higher growth in installed capacity, as well as in the demand for electric vehicles, based on the strategies proposed by the Government of the Canary Islands in the context of the PTECan (Figure 2) (Government of the Canary Islands, 2022). The scenario states that offshore wind installations will start operating as of 2028, with an initial power of 300 MW, reaching 600 MW in 2040. In addition, the installation of electrolyzers to produce renewable hydrogen would begin in 2030. Besides, Figure 4 proposes an energy storage capacity in this scenario that starts from 199 MWh in 2024 and reaches 2,615 MWh in 2040. These figures are suitable when assuming a growth of the electric vehicle fleet on the island that reaches 100% electric vehicles on the road.

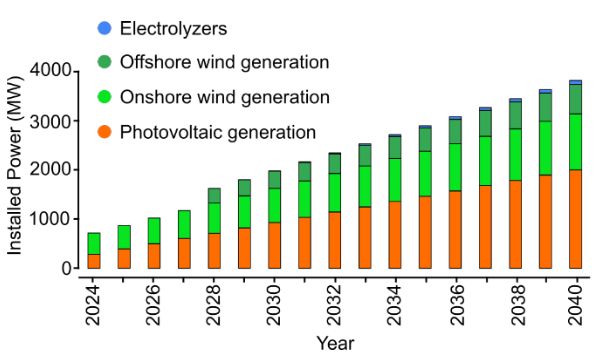

Figure 2. Estimation of installed renewable power in the optimistic scenario.

The conservative renewable power scenario poses a more contained growth of the parameters detailed above (Figure 3), and does not contemplate the installation of electrolyzers for hydrogen production. In addition, we assume that offshore wind installations do not enter the production mix until 2030, with an installed capacity of 100 MW, reaching 300 MW in 2040.

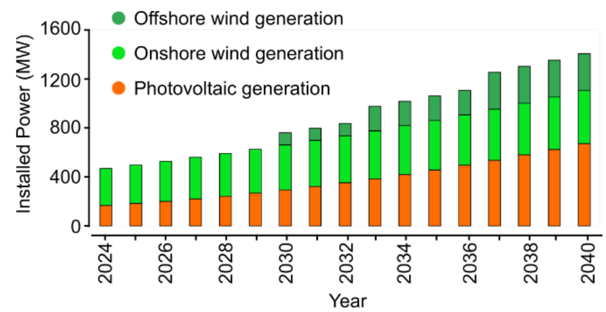

Figure 3. Estimation of installed renewable power in the conservative scenario.

With regard to the energy storage (Figure 4), the optimistic scenario proposes an energy storage capacity that starts from 199 MWh in 2024 and reaches 2,615 MWh in 2040. These figures are suitable when assuming a growth of the electric vehicle fleet on the island that reaches 100% electric vehicles on the road. Conversely, the conservative scenario assumes that not all the vehicles on the island will be electric by 2040; hence, energy storage capacity will evolve from 205 MWh to 766 MWh by 2040.

We used the energy demand from 2019 as base demand to compute the increment in demand (ΔD) in Equation 2. We neglected 2020 or 2021 as base years due to the impact of the global pandemic.

With respect to the parameters for Equation 3, we assume the charger efficiency (e_{EV}) to be 0.89 (Apostolaki-Iosifidou et al., 2017); the average unit consumption per electric vehicle (U_{EV}) to be 0.22 kWh/km; and the average distance driven per day ($\overline{Dist}$), to be 37 km (Ramos-Real, Ramírez-Díaz, et al., 2018; Rodríguez-Brito et al., 2018).

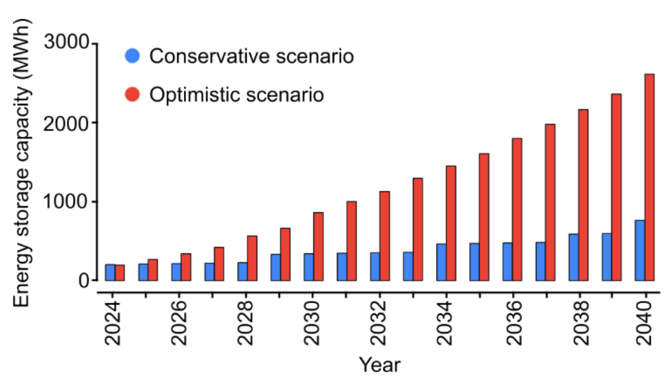

Figure 4. Estimation of energy capacity available due to electric vehicles.

4. Results and Discussion

The simulation of the conservative and optimistic scenarios yields to very different results in terms of both demand and production.

Figure 5 presents the gradual increment of demand of Tenerife's electricity system for the period 2024-2040. The orange color represents the annual demand for electric vehicles, which grows from 3,642 GWh in 2024 to 4,918 GWh in 2040. This growth is due to the general electrification of energy consumption, and in particular to the penetration of electric vehicles. The impact of the electric vehicle on demand progresses from 15 GWh by 2024 (where the consumption of 5,781 electric vehicles represents 0.4% of demand) to 667 GWh in 2040 (where the model estimates a fleet of 211,840 electric vehicles representing 13.6% of total electricity demand).

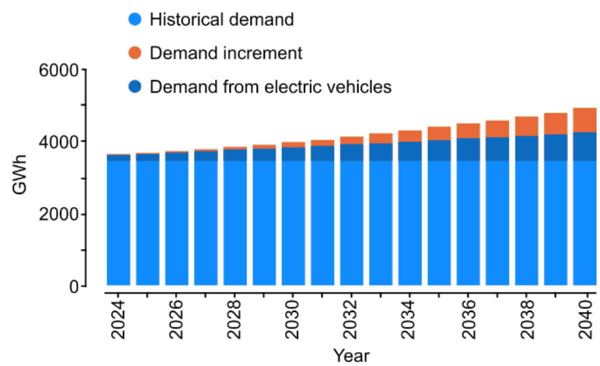

Figure 5. Energy demand in the conservative scenario.

The energy production mix in the conservative scenario (Figure 6) starts from a 28% penetration of renewable energies in the mix up to 57% in 2040. By 2030 there will be a significant jump in renewable production, due to the incorporation of offshore wind power into the electricity production mix, reaching 43% renewable by that year. As for the integration of energy from energy storage (in this case from batteries), we can see that the share is growing from 0.4% in 2024 to 2.1% in 2040.

The lack of large-scale energy storage leaves a large number of surplus energy from renewable plants (see red columns in Figure 7). In total, this figure compares the energy produced at power plant busbars versus the surplus energy from non-manageable renewable plants. Unless some measures are taken during the studied period, such as intelligent energy demand management, this surplus would be lost. Intelligent demand management could be carried out by desalination plants, water pumping plants, manageable electric vehicle loads, or promotion of domestic electricity consumption.

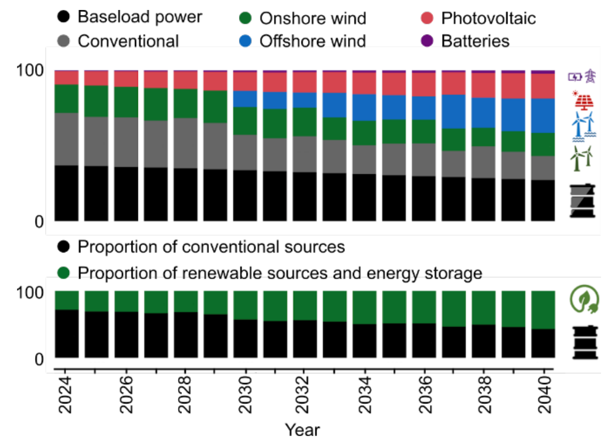

Figure 6. Energy production mix in the conservative scenario.

In the optimistic scenario, the more aggressive progression of the electric vehicle assumes that in 2040 100% of the transport fleet will be electric (almost three times more than the previous scenario). Therefore, electric demand (Figure 8) grows from 125 GWh (45,393 electric vehicles in 2024) to 2,189 GWh (representing around 692,994 vehicles in total by 2040).

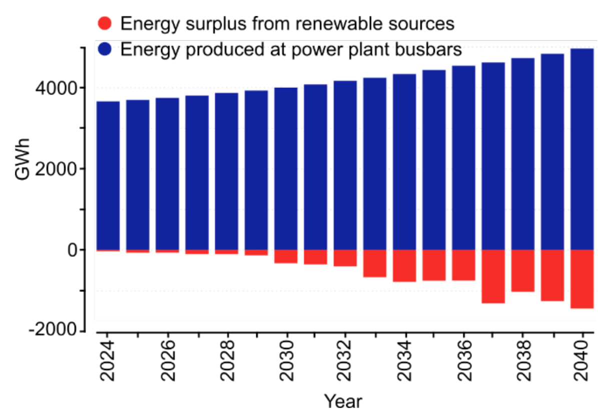

Figure 7. Energy surplus in the conservative scenario.

The proportion of renewable production arises to 70% by 2040 in this optimistic scenario (Figure 9). The remaining 30% is still maintained as a baseload power, assumed to be occupied by conventional technologies such as the current ones. However, there is room to replace these conventional technologies, fully or partially, by manageable renewable technologies such as geothermal or green hydrogen combustion production.

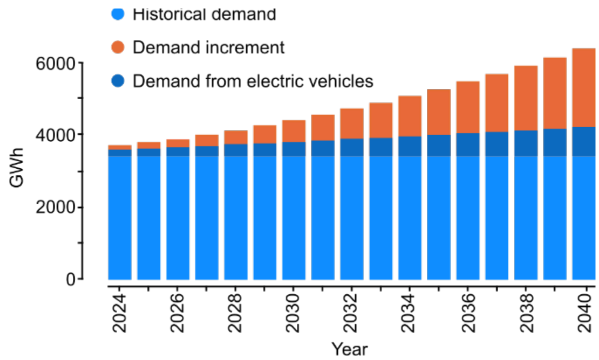

Figure 8. Energy demand in the optimistic scenario.

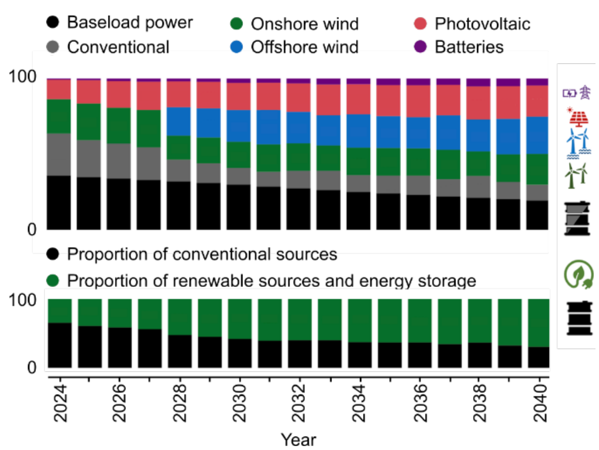

Figure 9. Energy production mix in the optimistic scenario.

The main problem in this scenario is the high amount of energy surpluses (Figure 10), mainly due to the lack of demand management technologies and the limited role of energy storage. The renewable surpluses evolve from 247 GWh in 2024 (18% of the renewable production injected into the grid) to 5,776 GWh in 2040 (118% of the renewable energy injected into the grid). This energy surplus almost equals the amount of electricity demanded for that year (about 6,971 GWh). Therefore, it is to be expected that as these surpluses increase, measures will be taken such as hydrogen production, electricity demand management or the use of more massive energy storage.

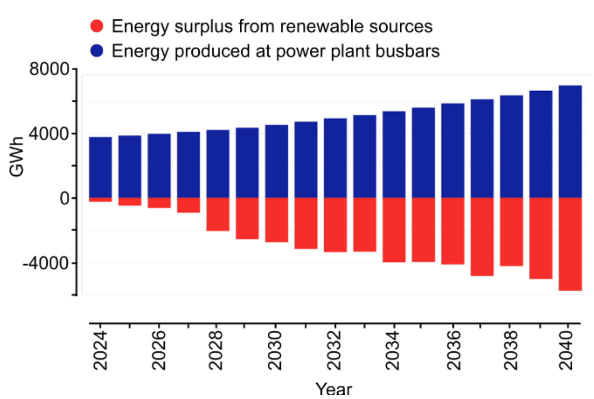

Figure 10. Energy surplus in the optimistic scenario.

Table 2 compares other key performance indicators from both scenarios. For example, emissions fall to less than 23 M t.CO2 in the optimistic scenario compared to above 26 M t.CO2 in the conservative one.

Table 2. Comparison of Key Performance Indicators from both scenarios.

Parameter	Conservative scenario	Optimistic scenario
Total demand (GWh)	71 151	83 034
Max peak demand (MW)	685	950
Min valley demand (MW)	273	291
Emissions (t.CO2)	26 194 K	22 852 K
Emission rate (t.CO2/MWh)	0.38	0.29
Renewable surplus (GWh)	-9 636.98	-51 591.5
Percentage surplus (%)	31%	101%
Average SOC	38%	57%

SOC: State Of Charge

The heterogeneity of results obtained from both scenarios highlights the importance of obtaining accurate prediction of surpluses if the correct sizing and structure of a storage system is to be defined. Moreover, these results have a strong impact on the ideal mix of energy sources and the total power required to cover the demand. Nor should we neglect the importance of the baseload power, which prevents the onset of a pure renewable scenario.

An increase in the penetration of non-manageable renewable installations, in an isolated system of limited size such as Tenerife's, leads to an incessant increase in energy surpluses caused by the limitation orders issued by the system operator in every scenario. The margin of action for the owners of the plants is reduced to: (i) look for manageable electricity demands located close to their plants to derive part of their production in the event that there is a large wind resource and therefore, appropriations; (ii) introduce large-scale energy storage at the distribution level or in the plants themselves to divert part of the production to such storage; or (iii) not act, assuming a serious loss of income for the plant.

The results of this work reveal that the level of renewable surpluses will be so high that it may slow down the attraction of investment in this type of facilities. In addition, the lack of planning for large-scale energy storage facilities operated by "Red Eléctrica de España" adds further uncertainty to the medium and long-term solution of the surplus problem. This element and the regulatory uncertainty may result in the economic compensation of the curtailments for the island electricity systems being delayed or not being produced at all. Therefore, the investment, through European funds, in energy storage facilities seems to be the most attractive option to capture part of the surpluses derived from the overproduction of renewable energy by the owners of this type of assets in Tenerife's electricity system.

When using this model for the assessment of battery storage, both pros and cons should be carefully weighted. The installation of battery storage at the distribution grid level can provide backup services for primary and secondary reserves. This could allow facility owners to participate in regulation markets, where they are remunerated for capacity and availability as well as for energy injected. Besides, the batteries could provide market arbitrage services, i.e., plan beforehand the time at which energy is to be fed into the grid, injecting at times when the market sets higher prices (such as ramp or peak hours).

However, such an installation also entails a number of significant investment risks. One possible risk is that the installation of new renewable capacity could be drastically delayed. A dry slowdown in installed capacity during the period 2025-2040 leads to under-utilization of the asset (in this case the batteries). If this occurs, it would be necessary to try to make the installation profitable with recurring income (for capacity and availability) derived from participation in auxiliary backup services.

Uncertainty regarding the technological evolution of batteries presents an additional risk. The evolution of batteries (in terms of cost reduction) could mean that from 2030 onwards, costs could be reduced to less than half of what it currently takes to make the investment (Mauler et al., 2021). There is also great uncertainty regarding the evolution of battery and lithium prices. Demand is expected to increase exponentially due to the growth of electric mobility and, although similar growth is expected around lithium mining, the evolution of battery prices cannot be determined. In any case, the support of the European Next Generation funds favors the reduction of investment risk and creates a promising opportunity to invest.

Adequate energy management strategies, and digitalization of the electric system, with an increment of sensors and deeper analysis of the obtained data, should lead to a better efficiency of the electric system. In this sense, initiatives related to self-consumption, aggregators and the constitution of energy communities constitute challenging opportunities to become key drivers for reducing the dependency on fossil fuels.

5. Conclusions and further work

A modeling framework has been presented with the intention of providing researchers and practitioners with a tool to assist in the design of strategies for energy transition planning. Based on the case study presented, at the island level, one of the main conclusions is that the lack of large-scale energy storage results in the loss of a large amount of surplus energy from renewable power plants. On average, loses would be limited to around the equivalent of a third of the production in the conservative scenario, while half of the electricity production of the hub would be lost in the optimistic scenario for the period 2024-2040. Consequently, there are open opportunities to private and public investors to plan and install new energy storage systems. In any case, this work highlights the importance of the proposed framework for an adequate planning of the energy grid in island territories.

The main limitations of this study of this study derive from the substantial uncertainty surrounding the estimates for several key parameters, including the evolution of the price of batteries and energy, the actual penetration of electric vehicles, and changes in the regulatory framework.

Further work is aimed at reducing the impact of such limitations by employing additional methods to improve the accuracy of the estimations; enhancing the modeling framework by incorporating more features; and studying the impact of new realities, such as energy communities. For the latter, the research team is currently involved in the SAtComm project, which is expected to serve as a test field for this kind of models (SatComm Consortium, 2024).

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