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Optimal sizing and location of energy storage systems for transmission grids connected to wind farms[☆]

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ABSTRACT

Although modern renewable power sources such as solar and wind are increasing their share of the world's power generation, they need to grow faster to replace a greater share of coal and gas power generation and thus, help prevent CO_2 and other greenhouse gas emissions to reach critical levels. Renewable energy generation must be coupled with energy storage systems, which are unfortunately expensive investments. However, substantial cost savings may be possible if a system-wide solution is sought. This paper presents such an attempt for a transmission grid that has a mixture of renewable and non-renewable sources. The particular problem is to find the type, location and size of the storage systems in the grid, as well as the structure of the transmission network, to minimize total investment and system-wide operating costs of power generation, transmission and storage. A mixed integer linear programming formulation is devised for the problem, which can be very large because various operational decisions are made at short intervals. Hence, we develop a "divide-and-conquer" type solution approach based on time decomposition, wherein the problem is first solved in monthly time segments. Subsequently, optimal or near-optimal monthly generation schedules are merged to construct the greater portion of a grand schedule for the whole year. Although still considerably large, the model can be solved effectively after another set of heuristically developed restrictions on the transmission network structure. The formulation and solution method are implemented on a series of realistic instances for a modest-sized transmission grid adapted from Sardinia Island of Italy to demonstrate the effectiveness of the approach and the insight into related design decisions.

1. Introduction

The global demand for electricity has increased almost every year, except in times of severe economic downturns. Lately, even the rate of increase appears to have increased in the last few decades [1]. For example, between 2015 and 2019, the average annual increase rate in world energy consumption was 3.1% [2], a full one point above the average increase in the 1990s [1]. This trend will most likely continue given the potential of electric cars in the future. However, the bad news is the continued heavy reliance on fossil fuels for electricity generation. Coal and gas-generated power represented about 60% of the world's electricity production in 2019 [3] and the largest offender, coal-generated power, alone was responsible for about 30% of all global CO_2 emissions in 2021 [4].

Unfortunately, these fossil-fuel-burning generators are just too costly to replace. Nuclear power, once a contender to replace coal as a cleaner base-load provider, at least in the developed world, has lost its appeal due to increasing public sentiments towards its safety risks. Another major source, hydro, is also unlikely to scale up to coal because it not only consumes valuable land but also causes irreversible changes in local climate, flora, and fauna. As a result, modern renewable energy systems (RESs), led by wind and solar, have received considerable interest as potential alternatives.

In all accounts, the share of modern RESs in total electricity production has been increasing and will continue to increase in the future [5]. Among these sources, wind and solar currently contribute the most to the overall share of the electricity generation from modern renewable energy sources. According to the 2020 Renewables Global Status Report, these sources have sufficient capacity to provide about 10% of the global electricity demand, of which 6% comes from wind [6]. Although its share may be decreasing, wind power generation is estimated to

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be 40% of all new renewable generation installations by 2038 [7]. Finally, in the report prepared by the International Energy Agency, it is estimated that global penetration of RES is expected to increase by more than 60% between 2020 and 2026 [8].

Although the future of modern RES looks bright, some industry experts believe that RES adoption on the market is "fast, but not fast enough" [6]. The main reason is their naturally intermittent and highly variable generation patterns, which require substantial energy storage capacity to supply electricity grids with some degree of stability and reliability [9]. However, the high installation and operational costs of storage systems remain as major obstacles to an ideal level of RES adoption. Although a great technological race is underway on all fronts to improve energy storage, there may also be improvement opportunities by using the current resources more effectively by redesigning the configuration of energy storage systems (ESSs) in the transmission network.

Therefore, this paper considers the energy storage issue from a system design perspective. In particular, we consider an electricity transmission grid with its existing demand centers and a variety of non-renewable power generators, as well as RESs. Our problem is to decide on the configuration of ESSs (i.e., types, locations, and sizes of ESSs) and the capacities of the transmission lines (a.k.a., transmission network capacity) that minimize the system-wide operational cost of energy generation, storage, and transmission and the commensurate investment costs of the ESSs and transmission lines.

Due to their popular nature, one might mistakenly believe that ESSs are nothing more than battery energy storage systems (BESS) placed at the sites of renewable generation units. The literature follows this suit as well; vast majority of papers on energy storage deal with problems related to such systems (see [5] for a review). However, the most economical utility-scale ESS is a mechanical system called pumped hydro storage (PHS) that utilizes altitude differences between water reservoirs. It has been around for almost a century and has achieved great popularity in the 1970s and 1980s to store excess nuclear power generation during off-peak hours, before its current popularity [10,11]. PHS can support a single generating facility or support the entire grid as common storage.

Most other works in the related literature consider these systems as owned by a single company that participates in the bidding process on the energy market [12–14] or multiple firms competing in the market and among themselves [15]. Our model has a markedly different focus in that we consider a single decision-making authority that makes investment decisions of ESSs and transmission lines, as well as operational decisions of power generation and storage charge/discharge. In other words, a single authority makes almost all decisions in an electricity grid except the local distribution. We are unsure whether such a monopoly is left in any country or region; indeed, the reality seems to be quite the opposite, where many firms own and operate some part of the electricity systems under a wide variety of market structures, regulations, and incentives. Hence, the purpose of this study is to find a system-wide optimal solution, which might help a state or a regional authority to evaluate the current status in their jurisdiction and modify their regulations and/or incentives to steer different entities to move closer to the system-wide better solutions, such as prescribed with this model.

An obvious omission here is the power generator investment and disinvestment decisions, which are inexorably connected to the other decisions. There are two main reasons for this omission: Firstly, we consider this problem to be more a "tactical" problem than a strategic one. Investment or disinvestment decisions of power generation must involve a much longer time-span as they require a longer time to plan and execute. However, perhaps with the exception of some PHS features, many of the system design decisions in our problem can be planned and executed in much shorter periods. For example, a BESS facility is nothing more than a collection of stacked batteries, parts of which can easily be removed and moved elsewhere. Secondly, such an inclusion might obscure the other benefits that ESSs provide, which include those related to transmission networks. For example, the capacity of transmission lines can be insufficient to meet the energy demand in peak time. In such cases, *transmission and distribution upgrade deferral*, storage reduces the need for line upgrades by using ESSs that can be located appropriately downstream. *Transmission congestion relief* is another concept of ESS utilization that aims to minimize congestion charges that occur at peak times and on outdated transmission lines [16].

We consider a fairly generic system, where there are some conventional and renewable generators already established in the grid with their operating characteristics, such as ramp-up and down rates, start-up and shut-down rates, etc. Although our model can easily accommodate other types, currently there are two storage alternatives that are dominating other alternatives in development and cost. One is PHS and the second one is Li-ion BESS which is currently the leading battery technology. ESSs may also have operating constraints, as some generators do. A hydroelectric plant can also be used as a PHS, and therefore it may also have certain operating characteristics as mentioned above. Several hydroelectric plants can serve as both traditional hydroelectric and PHS facilities. Some countries retrofit their existing facilities by transforming their primary function to store electricity produced by other renewable sources like wind or solar, while still allowing for hydroelectricity generation. These hybrid systems have already been in use in the United States and Europe, demonstrating their viability. A pump turbine and a reservoir are added to the hydroelectric plant to allow energy storage and release on demand. Therefore, the increased flexibility of being able to store and release energy as required makes it a valuable choice for grid operators [17,18].

It should be noted that these operational limitations require various complicated constraints. Sometimes accurate representations of these constraints may even be infeasible in our modeling structure and, therefore, need to be approximated. Furthermore, unlike traditional distribution networks, the flow of electrical transmission lines is two-way, that is, the direction of the flow can be changed [19]. Hence, the bidirectional electricity flow makes the ESSs decisions more complex and critical for the transmission networks.

For this purpose, we develop a mixed integer linear program (MILP) formulation that determines the type, location, and size of the ESSs to be installed, as well as transmission line capacities, with the objective of minimizing the total investment and operating costs throughout the system. Next, we propose a simple "divide-and-conquer" type solution approach, wherein the problem is first solved in smaller time segments, i.e. monthly. These segment-wise optimal operational schedules, which are essentially indicator variables representing if thermal generator units are on/off or in warm-up, are merged to construct the grand schedule for the whole year. There is the necessary step of adjusting the schedules to each other where each segment meets, which we carried out by a simple inspection. In the second step, this yearly operational schedule is fed to the full model. Although still considerably large, the model is now a pure linear program that can be solved optimally with moderate effort. Finally, we demonstrate the performance of our solution algorithm in a series of realistic instances for a modest-size transmission grid system adapted from Sardinia Island, Italy. In our experiments, we compare the performance of two energy storage systems, i.e. solving the problem with both BESS and PHS as alternatives and with only BESS.

The remainder of this paper is organized as follows. Section 2 provides the related work on ESS configuration and transmission network design studies with a summary of the key features and contributions of our work. Section 3 presents preliminaries and a detailed description of the problem followed by the MILP formulation in Section 4. Section 5 contains our solution approach and the results of our numerical experiments based on a case inspired by the island of Sardinia. Finally, Section 6 concludes the paper with a few remarks and possible future research directions.

2. Related work

In this section, we first provide a review of past work that deals with ESS configuration and transmission network design problems that involve ESS location and size decisions and/or transmission network capacity decisions. Then, we discuss the key features and contributions of our study.

In our review of the literature, we have encountered several studies that consider the problem of electric grid design from different perspectives and with different ingredients. Since we are interested in decisions related to the transmission of energy between generation facilities and demand nodes, we focused our review on the design of transmission lines of general transmission networks. We have found it useful to group the literature into three categories as studies focusing on (*i*) sizing of ESSs, (*ii*) sizing and location of ESSs, and (*iii*) integrated design of ESS and transmission network design.

The first group of studies which focus on the sizing problem mostly assume that a given number of ESSs are already located in an isolated region and seek to determine the optimal investment plan with the objective of minimizing the total fixed and operational costs. Being one of the first studies of the sizing of ESS, Korpaas et al. [20] proposed a Dynamic Programming (DP) approach to find the optimal operational schedules for ESS in the electricity market associated with wind farms in an isolated area, in order to maximize total profit. The model enables power trading in the market through the external grid connection, and this connection is facilitated by a single-capacity transmission line. Subsequently, through simulations, the authors demonstrate the potential of storage technologies to enhance the market value of wind energy, taking into account distributed resources. Kuznia et al. [21] addressed the system design problem for a remote area that relies on a local thermal generator, facing an imminent increase in electricity demand. The study explores the installation and capacity decisions for renewable energy generation, particularly wind energy, along with the potential development of storage systems and transmission networks. The authors opt not to model the local generator's operations, focusing instead on long-term system configuration to reduce complexity. They employ a scenario-based mixed-integer linear programming (MILP) model to capture the optimal configuration under the randomness of renewable energy generation and demand. Utilizing Benders' decomposition, the solution is enhanced through Pareto-optimal cuts, applying a modified Magnanti-Wong method, and incorporating maximum feasible subsystem-generated cuts. This approach effectively addresses variability in energy demand and generation, particularly from renewable sources, offering a comprehensive stochastic discrete optimization model for the design of hybrid systems in remote areas.

A more recent study, Xie et al. [22], presents a distributionally robust optimization model for remote renewable power plants to address the size of the ESS and the capacity of the transmission line to connect to the main grids. Their study demonstrated that transmission line costs significantly influence storage size decisions and that ESS deployment can significantly reduce the total investment cost for transmission lines longer than 500 km.

The second group of relevant studies includes those that jointly consider the ESS sizing and location decisions for transmission networks. Most of these studies include conventional generators and related constraints such as on/off status and generation ramping limits. Among such works, Pandžić et al. [23] have developed a bi-level MILP model for transmission network design, integrating location, sizing, and operational decisions to minimize generator operation and ESS investment costs. Initially, they established a day-ahead schedule by addressing each day separately, focusing on determining the ESS locations. The second stage involves solving the problem daily again, this time making ESS sizing decisions based on the locations identified in the first stage. Finally, the model is run daily for an entire year, utilizing the predetermined locations and sizes of the storage units. Dvijotham et al. [24] investigated a location and sizing problem for an ESS based on a direct current optimal power flow (DC-OPF) formulation with the objective of minimizing electricity generation costs and storage investment costs. The problem is formulated as an LP model which does not include technical constraints related to generators. They implemented a greedy heuristic to solve the problem and tested it on a transmission network that includes wind power.

Fernández-Blanco et al. [19] presented a MILP formulation for an ESS location and sizing problem where the objective is to minimize the sum of the expected operating cost of conventional generators over a set of representative days and the investment cost of ESSs for a transmission network. Unlike other studies, the objective function also includes a societal cost related to the spillage of renewable energy. Dvorkin et al. [25] proposed a bi-level MILP model to find the optimal sizing and location decisions for BESSs in a market environment. They tested their model by using ISO New England, the regional electricity authority in the data of the New England Region of the US, to assess the effect of storage devices on the day-ahead electricity price. A similar sizing and location problem for a transmission network with renewable energy is studied by Fiorini et al. [26]. This study attempted to minimize the total energy production cost and investigated the most stressed lines in the network. It also developed a ranking methodology to reduce line congestion to effectively determine the locations of batteries. They showed that locating the BESSs close to wind farms is not always the best course of action to relieve congestion in lines connected to wind farms; rather locating the BESSs with respect to the stressed transmission lines promises to be more beneficial. Similarly, Lara et al. [27] introduced a multi-period MILP model that aims to optimize the size and location of the electric grid infrastructure to minimize operating, investment, and penalty costs. In particular, the study focused on determining the optimal number and placement of generation units and storage systems. The authors proposed a decomposition algorithm based on Nested Bender's Decomposition to tackle this deterministic problem. The efficacy of the proposed approach is validated through a case study in the Electric Reliability Council of Texas (ERCOT) region. Their results indicate that employing four representative days per year is a sufficiently accurate to capture the variability in their case.

The study by Peña et al. [28] distinguishes itself from other studies by focusing specifically on optimizing BESSs in the presence of hydroelectric power, which may dominate energy production. Their objective is to minimize investment and operational costs by proposing a MILP formulation that incorporates constraints on the hydro plant and unit commitment within the optimization problem. The model is solved over a one-month period, represented by 720 hourly intervals. The authors highlighted that the size and location of the BESSs not only enhance the use of renewable sources but also facilitate the deferral of new transmission line investments. The work of Mohamad et al. [29] takes a different approach aiming to minimize the reduction of renewable energy in the objective function. Their study focuses on a network that includes solar energy and proposes a two-part framework to determine the optimal location and size of batteries. In the first part, the buses where batteries should be installed are identified, while the second part focuses on determining the size of each battery, considering power flow constraints. The results indicate that optimizing the battery sizes can lead to a reduction in solar energy curtailment compared to a scenario in which the BESS capacity is equally distributed among all deployed BESSs.

Most of the studies mentioned above incorporate a single type of energy storage technology. Wogrin and Gayme [30], on the other hand, adopted a DC-OPF model to jointly optimize location and sizing decisions for a transmission-constrained network for multiple types of ESSs. In particular, the authors considered two problems: The first problem is posed as an allocation problem and is solved for a fixed total storage capacity for a portfolio of ESSs. The second model expands the approach to optimize the mix of storage technologies, the investment in new capacities, and their deployment in the network. Although the results reveal that the location of the storage systems mainly depends on the network structure, PHSs tend to be located at the load center, whereas, distributed storage technologies are typically found closer to wind farms.

None of the studies mentioned above incorporates transmission line investment decisions into their modeling framework. Qi et al. [31] consider a transmission network planning problem that aims to determine the optimal transmission line capacities and the sizes and locations of ESSs for wind farms that do not have a connection to the main grid and develop a mixed-integer second-order conic program (MISOCP). The objective is to determine the size and location of the ESSs that are connected to these wind farms to minimize installation and energy loss costs (i.e. costs occurring due to friction loss, overflow loss, and curtailment loss). However, their model is somewhat stylized in that they only consider a single demand node and an approximation of the cost implications of capacitated ESSs.

Several studies also explore strategies to address transmission congestion, including the use of energy storage as an alternative to building new transmission lines from scratch. In addition, some researchers have investigated the joint decision-making process for both storage investment and transmission line expansion. Pudjianto et al. [32]; Qiu et al. [33]: Wang et al. [34] are a sample of such works. Pudjianto et al. [32] developed a comprehensive model that aims to minimize investment costs for new production and storage units, capital costs associated with the expansion of transmission and interconnection capacities, and operating expenses. The authors thoroughly tested their model on Britain's electricity network, examining how bulk and distributed energy storage system (DESS) technologies differ in performance and impact. Similarly, Qiu et al. [33] present an integrated storage configuration and transmission expansion problem. Their numerical results on a 24-node grid system reveal that the integrated design approach reduces the required number of transmission lines, highlighting the benefits of considering a transmission line. Lastly, Wang et al. [34] propose a robust bi-level MILP formulation for planning integrated energy storage and transmission lines in a grid, which is solved by a column and constraint generation algorithm developed by the authors. The numerical findings of a specific case study also demonstrated that investing in energy storage is a more cost-effective solution to mitigate transmission congestion compared to the construction of new long-distance transmission lines.

Table 1 presents a concise summary of our review of the literature. The table provides an overview of the key characteristics of the reviewed studies, organized into three broad categories: decision explicitly included in the model (sizing, location, type, line capacity), nature of grid components (RES type, generator type, ESS type), and model features and solution approach (mathematical model type, solution methodology, objective function). In Table 1, it is important to mention that the labeling of the "ESS" type is based on the type specified in the mathematical model or, if applicable, in the numerical experiments or the cases studied by the respective works. In cases where a specific ESS type is not explicitly defined, it has been labeled as "Generic" in the table.

The first notable observation from this table is that none of the aforementioned studies adopted a holistic perspective which incorporates sizing, location, type, and line capacity decisions at the same time. Our study differs from these works in a number of ways. For example, Qi et al. [31] considered a single demand node and ESS type without accounting for the generators. Pudjianto et al. [32],Qiu et al. [33], on the other hand, considered the expansion of existing transmission line networks. It should also be noted that the latter, along with Lara et al. [27] in a long-range investment planning model, are the only works that also consider generation investment jointly with the other decisions, a feature that is missing in our model. The table also shows that most of the studies incorporated a single generator and ESS type in their modeling framework. Our review also reveals that almost all studies consider cost minimization as the main objective, which mostly include investment and operational costs associated with the ESSs and/or transmission lines and/or some type of penalties related to renewable energy curtailed or wasted somehow.

Considering the features of the previous work on the ESS and transmission design problem, we can summarize the key characteristics of our work and its contributions to the literature as follows:

(*i*) We adopt an integrated approach by jointly considering several important decisions about the transmission network, such as the type, location, and size of ESS and the decision on the deployment of transmission lines.
(*ii*) Our proposed framework offers a fairly general structure that accommodates various storage systems, conventional and renewable generators.
(*iii*) Within our modeling framework, we incorporate several practical technical constraints associated with conventional generator operations, including on/off status, ramp-up and ramp-down limitations, and warm-up periods.
(*iv*) We develop a time-decomposition-based heuristic approach to obtain high-quality solutions with modest computational resources.

3. Transmission network design with energy storage

In this section, we first give some background information on PHS and BESS, which are currently the two most commonly used storage technologies in the world. Next, we provide a more detailed description of the ESS location, sizing, and transmission network capacity problem.

3.1. PHS and BESS

Bulk storage systems are considered utility-scale storage systems that may need to be installed at distant locations from load centers and generator locations. The single most popular such system is the PHS with the largest number of installations worldwide [35]. It is among the class of mechanical storage systems that uses the altitude difference as a way to store energy. A typical PHS has two reservoirs; an upper and a lower one, which can be artificial (e.g. dam reservoirs) or natural (e.g. lakes, rivers, and seas). Water is pumped from the lower reservoir to the upper one when there is excess supply in the system and is released downward to generate electricity at times of need.

There are very large pumped hydro plants that can produce electricity at power ratings of up to 3.6 GW and can store up to 40 GWh of energy. Their round-trip efficiency varies between 76%–85%. The duration of discharge varies from 4-24 h according to the power rating. For example, the Rocky Mountain pumped hydro plant has more than 10 h of discharge time with a maximum power rate of 1095 MW [36]. Compared to other storage systems, their lifetimes are relatively long, with an average of 50-60 years, and, like other hydro plants, they can also quickly react to changes in system demand or supply.

Although large PHS is well-established as a utility-scale energy storage technology, small or medium-scale DESSs are attracting more attention due to increasing need to store from intermittent power generators. In contrast to bulk storage systems, DESSs can be located close to load centers or generation locations, or essentially anywhere on the grid. These systems are assumed to be BESSs (e.g., flow batteries, high-temperature batteries, and super capacitors) that are connected to the grid [37]. Most common battery technologies are lead–acid, Lithium-ion (Li-ion), sodium-sulfur (NaS), and sodium-nickel-chloride. In contrast to PHSs, batteries have a shorter discharge duration that generally varies between a few minutes and up to several hours.

The cost components of an ESS consist of fixed investment costs and operation and maintenance (O&M) costs. The investment cost includes the capital cost as well as the costs associated with the planning and design of the project, transportation, and installation costs during the construction phase. Specifically, for BESSs, the cost is assigned for electrodes, electrolytes, and separators. Capital costs for PHSs consist mainly of water reservoirs, pumps, turbines, generators, and waterways

Table 1
A synthesis of the ESS design studies.

	Decisions				Grid Components			Modeling features and solution approaches		
	Size	Location	Type	TR	RES	XPow	ESS	Model	Method	Objective Function
Korpaas et al. [20]	+				W	–	Generic	DP	DRA [H]	(max) Revenue - O&M
Kuznia et al. [21]	+			+	W	C	Generic	MILP	BD [H]	(min) ESS + TR + O&M
Pudjianto et al. [32]	+		+	+	W	C	Generic	MILP	Solver	(min) ESS + TR + GEN + O&M
Dvijotham et al. [24]	+	+			W	C	B	LP	Solver+GH	(min) ESS + O&M
Pandžić et al. [23]	+	+			W	C	B	MILP	DA+GH [H]	(min) ESS + O&M
Wogrin and Gayme [30]	+	+	+		W	C	P, B, C	NLP	Solver	(min) O&M
Qi et al. [31]	+	+		+	W	–	Generic	MISOCP	Solver+[H]	(min) ESS + TR + O&M
Dvorkin et al. [25]	+	+			W	C	Generic	2L-MILP	Solver	(min) ESS + O&M
Fernández-Blanco et al. [19]	+	+			W, PV	C, H	Generic	MILP	Solver	(min) ESS + O&M
Qiu et al. [33]	+	+		+	W	C	B	MILP	Solver	(min) ESS + TR + O&M
Fiorini et al. [26]	+	+			W, PV	C	B	LP	Solver+[H]	(min) O&M + Penalty
Lara et al. [27]	+	+			W, PV	C, N, NG	B	MILP	BD+LR [H]	(min) ESS + GEN + O&M + Penalty
Wang et al. [34]	+	+		+	W, PV	C	B	2L-MILP-RO	C&CG	(min) ESS + TR + O&M
Mohamad et al. [29]	+	+			PV	C	B	MILP	DA+GA [H]	(min) Penalty
Peña et al. [28]	+	+			W, PV	C, H	B	MILP	Solver	(min) ESS + O&M
Xie et al. [22]	+			+	PV	–	Generic	2L-LP-RO	Solver+[H]	(min) ESS + TR
Our work	+	+	+	+	W	C, H	P, B	MILP	DA [H]	(min) ESS + TR + O&M

Decisions
Size: If ESS Size(s) is explicitly modeled
Location: If ESS Location(s) is explicitly modeled
Type: If different ESS types are considered simultaneously
TR-Line: If transmission line decision(s) is explicitly modeled

Grid components
(RES) W: Wind, PV: Solar photovoltaic
(XPow: Nonrenewable) C: Conventional (coal or unspecified)
H: Hydro, NG: Natural Gas, N: Nuclear
(ESS) B: Battery, P: Pumped Hydro, C: Compressed Air

Modeling features and solution approaches
(Model) LP/NLP/MILP/DP: Linear/Nonlinear/Mixed-integer linear/Dynamic program
MISOCP: Mixed-integer second-order conic program, 2L: Bi-level, RO: Robust
(Method) [H]: Heuristics, DRA: Decision rule approximation
DA/GH/GA: A decomposition/greedy/genetic algorithm, LR: Lagrangean relaxation
BD: Benders decomposition, C&CG: Constraint and Column Generation
Solver: Commercial or open-source general-purpose solver
(Objective Function) O&M: Operations and maintenance costs
ESS/TR/GEN: Investment costs of storage/transmission/generation
Penalty: Curtailment, loss, and/or shortage costs

to connect reservoirs. The O&M costs include labor cost, taxes, costs to charge or discharge energy, as well as the cost of the annual discharge output, which is the primary metric to assign the O&M cost.

Power rate, energy rate, round trip efficiency, and ramp rate are some of the important terms to describe the characteristics of an ESS [38]. *Power rate* can be defined as the rate at which a storage system can discharge energy, while *energy rate* is the total amount of energy that can be stored in the system. *Round-trip efficiency* of the ESS refers to the amount of energy released from storage compared to the amount of energy charged into storage and the *ramp rate* is the rate at which power flow can increase or decrease. The latter is generally expressed as percentage per minute, but in our model we do not consider such ramp rates since the PHS and BESS technologies can adjust their power flows practically to any value between zero and the maximum power rate in the unit of time in our model.

3.2. Assumptions and problem definition

We consider a grid system that consists of buses (nodes) that may represent demand centers and/or the location of some existing generation plants. A node can contain any number and type of generation plants as well as demand centers. Our design decisions involve the type, location, and size of the ESSs to be set up and the configuration of the major transmission lines in the network. We consider two types of ESS technologies: one is lithium-ion BESS as a small-scale system and the other is PHS as a utility-scale system, both of which are leading technologies in their own classes. Since the deployment of ESSs can significantly alter the electricity flows across the grid, resizing or restructuring transmission lines is a natural part of the design process.

Although we use a singular form, that is, the "size", for the capacity of an ESS, it actually refers to a pair of values; one is the total capacity or the "energy rate" of the ESS, which is the total energy an ESS can store, and the other is the "power rate" of storage, which is the maximum rate at which an ESS can discharge electricity. First of all, although we consider both of these sizes to be decided independently of each other, it is plausible that not all combinations may be feasible for the underlying ESS technology and therefore we place some mild restrictions on the feasible energy and power rate combinations. Secondly, these sizes are related to the different parts of ESSs, and therefore, their costs are largely separate from each other. For example, the power rate in a PHS depends on the turbines and penstock, the pipe that delivers water from the upper reservoir to the turbines, and the capacity of the lines connecting to the transmission network. Likewise, the energy rate of a PHS depends on the size of the reservoirs and the amount of work to be done. A similar distinction of costs is also present in a BESS technology and, therefore, considered as such in our model.

There are also operational decisions to be made in each period that have a great influence and are also influenced by design decisions. Therefore, our model also includes hourly decisions such as how much electricity is generated from conventional generators, energy flows across the transmission grids, ESS charges and discharges, and finally planned energy dumping or shortages. We also consider the mandatory warm-up or lead time for the fuel-based generators in the grid. Most of such generators require extended warm-up periods to reach safe operating temperatures and have a stable output that can reliably feed the grid. During this period, we assume that the generator consumes some fuel (running) but does not contribute to power production [39]. The generators that have long warm-up periods (e.g., coal and nuclear) are also the ones that provide the base load, and therefore, they seldom get shut down.

The objective is to find a solution to minimize the costs of the installation of the storage and transmission line, the operating and maintenance cost of the storage systems, the costs due to the use of conventional generators, and finally the penalty costs incurred for energy shortages. In the particular case and numerical study, we have set this penalty cost to a very large number to virtually eliminate such planned shortages.

4. The model

Based on the aforementioned framework and assumptions, we now provide our model. First, we introduce the notation (indices, sets, parameters, and decision variables), followed by the problem formulation.

Finally, we review the critical assumptions of our model and discuss their justifications and implications.

4.1. Nomenclature

Let $G = (B, K)$ indicate the graph of a power network, where B represents the set of buses (nodes) and K represents the transmission lines (edges). Buses can represent locations for conventional and renewable generators as well as load centers. A bus can also include all of the components at the same time.

Indices and Sets:

Indices and Sets:	
$i \in I$:	Set of storage types
$t, t' \in T$:	Set of time slots
$k \in K$:	Set of transmission lines
$b, b' \in B$:	Set of buses
$g \in G$:	Set of generator units
$K_b \subset K$:	Subset of transmission lines that are connected to bus b
$G_b \subset G$:	Subset of generators at bus b
$G_b^h \subset G_b$:	Subset of hydro power plants at bus b
Parameters:	
G_{bt}^r:	Wind energy generation at bus b at time t,
G_{bgt}^h:	Energy accumulation in reservoir of hydro plant g at bus b at time t
H_{bg}^{max}:	Maximum reservoir level of hydro plant g at bus b
D_{bt}:	Demand at bus b at time t
rd_g:	Ramp down rate for generator g
ru_g:	Ramp up rate for generator g
G_g^{min}:	Minimum output generator g can provide
G_g^{max}:	Maximum output generator g can provide
C^{pen}:	Unit penalty cost of not satisfying the demand
C_k^{tr}:	Cost of building line k
C_g^{up}:	Start-up cost of generator g
C_g^{om}:	Operating and maintenance cost of generator g
C_i^e:	Energy related investment cost of storage type i
C_i^p:	Power related investment cost of storage type i
C_i^{om}:	Operating and maintenance cost of storage type i
E_i^{max}:	Maximum energy rate that can be invested of storage type i
P_i^{max}:	Maximum power rate that can be invested of storage type i
α_{bg}:	Average loss factor of generator g at bus b
β_k:	Average transmission loss on line k
η_i^c:	Charging efficiency of storage type i
η_i^d:	Discharging efficiency of storage type i
L_g:	Warm-up lead time for generator type g
M:	A large number
Decision Variables:	
$x_{bgt} =$	$\begin{cases} 1, & \text{if conventional generator } g \text{ at bus } b \text{ is on at time } t, \\ 0, & \text{otherwise} \end{cases}$
$y_{bgt} =$	$\begin{cases} 1, & \text{if conventional generator } g \text{ at bus } b \text{ starts up at time } t, \\ 0, & \text{otherwise} \end{cases}$
$z_{bgt} =$	$\begin{cases} 1, & \text{if conventional generator } g \text{ at bus } b \text{ shuts down at time } t, \\ 0, & \text{otherwise} \end{cases}$
$v_{bgt} =$	$\begin{cases} 1, & \text{if conventional generator } g \text{ at bus } b \text{ is warming up at time } t, \\ 0, & \text{otherwise} \end{cases}$
$G_{bgt}^c =$	Energy produced by generator g at bus b at time t
$H_{bgt} =$	Reservoir level of hydro plant g at bus b
$E_{ib} =$	Energy rate of storage type i at bus b
$P_{ib} =$	Power rate of storage type i at bus b
$X_k =$	$\begin{cases} 1, & \text{if line } k \text{ is constructed,} \\ 0, & \text{otherwise} \end{cases}$
$S_{ibt} =$	Energy level at storage type i at bus b at time t
$S_{ibt}^{ch} =$	Charging rate of storage type i at bus b at time t
$S_{ibt}^{dis} =$	Discharging rate of storage type i at bus b at time t
$X_{bkt}^{in} =$	Inflow to bus b through line k at time t
$X_{bkt}^{out} =$	Outflow from bus b through line k at time t
$L_{bt} =$	Dump load at bus b at time t
$Y_{bt} =$	Penalty term if demand cannot be satisfied at bus b at time t

4.2. Formulation

Here, we present the MILP formulation that conventionally begins with the objective function and ends with the variable definitions; in between, constraints are presented in four convenient groups.

$$\textbf{(P)} : \min \sum_{i\in I}\sum_{b\in B}(C_i^e E_{ib} + C_i^p P_{ib}) + \sum_{k\in K} C_k^{tr} X_k + \sum_{b\in B}\sum_{g\in G_b}\sum_{t\in T}(C_g^{up} y_{bgt} + C_g^{om} G_{bgt}^C) + \sum_{i\in I}\sum_{b\in B}\sum_{t\in T} C_i^{om} S_{ibt}^{dis} + \sum_{b\in B}\sum_{t\in T} C^{pen} Y_{bt} \tag{1}$$

$$\text{s.t.}\quad y_{bgt} - z_{bgt} = x_{bgt} - x_{bg(t-1)}, \quad \forall b\in B, g\in G_b, t\in T \tag{2a}$$

$$y_{bgt} + z_{bgt} \le 1, \quad \forall b\in B, g\in G_b, t\in T \tag{2b}$$

$$L_g y_{bgt} \le \sum_{t'\in\{t,\dots,t+L_g-1\}} v_{bgt'}, \quad \forall b\in B, g\in G_b, t\in T \tag{2c}$$

$$v_{bgt} \le \sum_{t'\in\{[t-L_g]^+ +1,\dots,t\}} y_{bgt'} \quad \forall b\in B, g\in G_b, t\in T \tag{2d}$$

$$G_g^{min}(x_{bgt} - v_{bgt}) \le G_{bgt}^c \le G_g^{max}(x_{bgt} - v_{bgt}), \quad \forall b\in B, g\in G_b, t\in T \tag{2e}$$

$$rd_g \le G_{bgt}^c - G_{bg(t-1)}^c \le ru_g, \quad \forall b\in B, g\in G_b, t\in T \tag{2f}$$

$$H_{bgt} = H_{bg(t-1)} + G_{bgt}^h - G_{bgt}, \quad \forall b\in B, g\in G_b^h, t\in T \tag{2g}$$

$$H_{bgt} \le H_{bg}^{max}, \quad \forall b\in B, g\in G_b^h, t\in T \tag{2h}$$

$$G_{bt}^r + \sum_{g\in G_b}(1-\alpha_{bg})G_{bgt}^c + \sum_{k\in K_b}(1-\beta_k)X_{bkt}^{in} + \sum_{i\in I} S_{ibt}^{dis} + Y_{bt} = D_{bt} + \sum_{k\in K_b} X_{bkt}^{out} + \sum_{i\in I} S_{ibt}^{ch} + L_{bt}, \forall b\in B, t\in T \tag{3}$$

$$0 \le E_{ib} \le E_i^{max}, \quad \forall i\in I, b\in B \tag{4a}$$

$$0 \le P_{ib} \le P_i^{max}, \quad \forall i\in I, b\in B \tag{4b}$$

$$S_{ibt} \le E_{ib}, \quad \forall i\in I, b\in B, t\in T \tag{4c}$$

$$S_{ibt}^{ch}\eta_i^c \le P_{ib}, \quad \forall i\in I, b\in B, t\in T \tag{4d}$$

$$S_{ibt}^{dis}/\eta_i^d \le P_{ib}, \quad \forall i\in I, b\in B, t\in T \tag{4e}$$

$$S_{ibt} = S_{ib(t-1)} + S_{ibt}^{ch}\eta_i^c - S_{ibt}^{dis}/\eta_i^d, \quad \forall i\in I, b\in B, t\in T \tag{4f}$$

$$X_{bkt}^{in} \le M X_k, \quad \forall b\in B, k\in K_b, t\in T \tag{5a}$$

$$X_{bkt}^{out} \le M X_k, \quad \forall b\in B, k\in K_b, t\in T \tag{5b}$$

$$X_{bkt}^{in} = X_{b'kt}^{out}, \quad \forall b, b'\in B, k\in K_b, t\in T \tag{5c}$$

$$X_{bkt}^{out} = X_{b'kt}^{in}, \quad \forall b, b'\in B, k\in K_b, t\in T \tag{5d}$$

$$x_{bgt}, y_{bgt}, z_{bgt}, v_{bgt} \in \{0,1\}, \ \forall b\in B, g\in G, t\in T \tag{6a}$$

$$X_k \in \{0,1\}, \forall k\in K \tag{6b}$$

$$G_{bgt}^c \ge 0, \quad \forall b\in B, g\in G, t\in T \tag{6c}$$

$$S_{ibt}, S_{ibt}^{ch}, S_{ibt}^{dis} \ge 0, \quad \forall i\in I, b\in B, t\in T \tag{6d}$$

$$X_{bkt}^{in}, X_{bkt}^{out} \ge 0, \quad \forall b\in B, k\in K_b, t\in T \tag{6e}$$

$$L_{bt}, Y_{bt} \ge 0, \quad \forall b\in B, t\in T \tag{6f}$$

The objective function (1) to be minimized is the total annual cost that consists of the five parts: The first two are the total annual investment costs for ESSs and transmission lines. The third term is the total operating costs of conventional generators that includes fixed start-up and variable generation costs. The next part covers the operating and maintenance costs for the storage systems, which depend on their total usage expressed with their total annual energy discharges. Finally, the last term accounts for the total penalty cost for shortages.

The first constraint group, (2a)–(2h), is about the operational characteristics of the conventional generators, within which, Constraints (2a) and (2b) ensure that generators' hourly operating status are correctly accounted for throughout the year. At each hour, their status are either maintained as they were from the previous hour or changed (from "on" to "off" or the other way around). Here, the second constraint can be dispensed with, as it would never be optimal to shutdown and start-up a generator at the same time. However, they are valid inequalities and kept in the formulation for potential computational benefits. Some conventional generators, thermal ones being among such prominent examples, cannot be turned on immediately; that is, some amount of time is needed for the warm-up. Constraints (2c) and (2d) keep track of the warm-up periods and together with Constraints (2e) ensure that no electricity is generated during those periods. Except for warm-up periods, these two constraints have no bearing and Constraint (2e) alone makes sure that minimum and maximum output levels are maintained when a generator is operational. Similarly, no electricity is produced when it is shut down or in warm-up. The constraint (2f) imposes the ramp-up and ramp-down rates, a typical feature that exists essentially in all generation technologies, although with widely varying characteristics. Finally, the last subset of constraints applies to hydroelectric plants. The constraint (2g) controls the reservoir level, while the constraint (2h) enforces the hydro reservoir capacity.

The core of the formulation are the flow balance constraints , which bind the entire transmission system together. The left-hand side is the total *supply* of electricity at a bus that may include generators, discharges from storage systems, and/or sent through transmission lines. The right-hand side is the total *demand*, which includes the load at the bus and may include the electricity used to charge storage systems at the bus or sent through transmission lines. In order to ensure the feasibility of the formulation, the supply/demand balance must be achieved at each period and bus. This is achieved by accounting for shortages to be incurred or excesses to be dumped by adding the related variables on each side. In this constraint, we have explicitly accounted for the losses during the generation and transmission, based on long-run averages, but we have assumed, without any loss of generality, that given load and wind data are already adjusted for losses on their part.

The next group of constraints, (4a)–(4f), is related to the design and operational decisions of the storage system. Constraints (4a) and (4b) impose external restrictions on sizes due to reasons such as technology, geography, policy, etc. The following three constraints, (4c)–(4e), ensure that the design capacities of the energy rates in storage, as well as the power rates during charges and discharges, are imposed in each period. The last constraint of this group is the storage balance equations, (4f), which explicitly take into account the expected losses during the charge and discharge actions.

Finally, the last group, (5a)–(5d), is about the transmission lines; the first two impose the designed capacity limitations on flows over the lines, which in our case are practically unlimited provided a line is deployed and the latter two ensure that what is sent from one bus to another is fully received (with the transmission losses being accounted for in above). This is the common way to model flow in both directions, using two sets of positive variables, instead of one set that can be unrestricted in sign. These and other variable definitions are given in (6a)–(6f), which end our formulation.

4.3. Remarks

Here, we review and discuss some of our key assumptions. Many of them are made in the interest of notational parsimony and can be relaxed in a straightforward manner or without significantly altering the structure of our formulation. There are, however, a few that are admittedly less innocuous but are generally justifiable for the purposes for which they are used. In what follows, we elaborate on them.

Firstly, our model is based on the assumption that the nodes in the underlying network are fixed. This assumption is reasonable, as demand centers, including established residential, commercial, and industrial areas, as well as generation plants, have already been constructed at specific sites. Therefore, the transmission network is expected to be superimposed onto these existing nodes. This is not a very limiting assumption. For example, PHSs can only be located at a few suitable sites, which can be added to the network as nodes with zero demand and zero generation. However, the high costs associated with current BESS technologies make them impractical for bulk storage purposes that would justify the construction of separate sites.

Our model is designed with a specific focus on storage and transmission in the context of electricity generation and consumption. This perspective justifies our selection of lithium ion as a representative battery technology and PHS as the bulk storage technology, both of which are leaders in their respective categories. However, our model does not extend to the broader spectrum of energy production and consumption. As a result, other common bulk-storage technologies such as thermal storage (e.g., molten salt) or emerging technologies like hydrogen storage, which are more commonly used for non-electric energy needs, are not included in our analysis.

In terms of conventional generation technologies, our model mainly considers coal-fired and hydroelectric plants. Not only are these technologies widely used in electricity generation, but also their production characteristics are representative of other widely used technologies. For example, the operational constraints of a nuclear power plant are somewhat similar to those of a coal-fired plant. Likewise, the modeling of a natural gas power plant can be compared to that of a hydroelectric plant in terms of its operational characteristics.

Our model considers only the variable capacity investment costs for ESSs and transmission lines. This approach is well-justified for BESSs, where their modular design and compact size make any fixed investment costs relatively insignificant for both energy and power rate decisions. In the case of a PHS, although investment costs can vary significantly due to site-specific geographical characteristics, they are largely influenced by the size of the storage facility. This observation has been supported by various studies, including those conducted in the United States and Australia [17,40–42]. Perhaps the most comprehensive cost study on this subject is commissioned by the US Department of Energy and conducted by members of the three leading research laboratories, reports on the cost characteristics of a wide variety of storage technologies, including several battery and mechanical systems [43,44]. That is not to say that fixed costs are negligible in the construction of ESS. However, all of those studies mentioned above account for these by adding a generic overhead cost, often estimated at 10%–20% of the variable investment cost. Hence, our investment cost assumptions are driven by the findings of those reports.

The investment costs of transmission lines are largely the variable costs in length. Much of these costs, for example, material, construction, right-of-way and a greater portion of operations and maintenance costs, are highly dependent on the length of the line. According to a comprehensive report prepared for England and Wales and endorsed by the Institution of Engineering and Technology, true fixed costs are estimated on the order of 2 4% of variable costs for overland lines of 15 km or more [45]. Since we already assume the existing set of lines as alternatives, we treat the entire cost of each line as fixed.

In our model, self-discharge of storage systems is not explicitly considered. Self-discharge is not limited to battery systems, but is a feature of all storage systems. For example, PHSs can also experience self-discharge through evaporation or may even be charged through inflows from rain or rivers. Such discharges depend on many factors and inherently posses randomness. The common modeling approach to discharges is reductions in the energy level from one period to the next through average self-discharge rates. In comprehensive reviews of storage technologies, Chen et al. [46],Kebede et al. [47] report self-discharge rates for Li-ion batteries on the order of 0.03%–0.3% per day. They do not quantify any self-discharge rate of PHSs, except the latter only declare it as "very small". Some works consider even lower rates of self-discharge. For example, Peña et al. [28] uses a self-discharge percentage of just 0. 0000625% per hour (that is, approximately 0.15% per day) for a Li-ion BESS. Hence, it is justified to ignore self-discharges, but in case there are circumstances or technologies with consequential self-discharge rates, they can easily be accommodated in constraints (4f) employing such average discharge rates as commonly done in the literature.

In fact, losses due to self-discharge of storage systems pale in comparison to the losses observed in other parts of transmission and distribution grids: There are losses at the load centers due to distribution, various types of losses attributed to main transmission lines, and losses at the generation sites, as well as "non-technical losses" (e.g. theft). Each and every one of those losses have a multitude of reasons, degrees of randomness associated with them. In terms of transmission lines, there are many intertwined and complex effects of transmission line design elements, generation and consumption patterns, and real-time load balancing decisions of the central transmission grid operator that affect losses. The technical and economic issues related to these losses are so diverse that the reduction and other aspects of electricity losses in transmission are subjects of intense study in their own right. Our model neglects all those issues as commonly done in grid design frameworks [48] and assumes an average loss rate throughout the network and time. As for the losses in the generation and distribution parts of the grids. We considered an average loss rate for the generators. Although we have not explicitly considered losses at the distribution sites, we consider them as already accounted for in load values, which are assumed to represent the "gross demand". All of these approaches are commonly adopted in the literature [49].

We do not consider performance degradation in storage systems as they would probably not degrade appreciably during the planning horizon of a year. For longer periods, however, not just the storage systems but the entire major grid entities are expected to go thorough periodic reviews for some maintenance and/or re-fitting decisions. However, our model can also be adapted to consider such degradation issues by introducing some average degradation rates. One way to adapt the model would be to introduce an average hourly degradation rate coefficient for power and energy. Specifically, this coefficient would be multiplied on the right-hand side of constraint (4c) to account for energy degradation and would be applied similarly to the right-hand side of constraints (4d) and (4e) to capture power degradation.

Perhaps the least innocuous feature of our model is the neglect of uncertainties related to demand and renewable energy generation, the latter of which is particularly renowned for its intermittency. Obviously, the main reason for such a neglect is the heavy computational burden of incorporating randomness in a model that aims to account for hourly operational decisions in the storage and transmission design decisions. We have consciously chosen a finer operational decision time window with deterministic demand and generation data over a coarser time window with random data. We believe that this choice is justified due to our particular focus on ESS decisions. Currently, there are no storage technologies that are economically viable as means of providing electricity for extended periods of time. This is certainly the case for BESSs, but even the largest PHSs are generally intended for 4–12 h of electricity storage during significant drought periods of renewable energy generation [50]. Therefore, we have chosen to account for hourly variations at the expense of neglecting short-term randomness in load and renewable generation. In effect, our model does account for expected systemic imbalances, but neglects random disturbances. Hence, our model may slightly underestimate optimal capacity levels. However, one should not dismiss such a choice because no model is really expected to be utilized in practice without extensive sensitivity analyses and post-processing.

5. An implementation

We have implemented our model on a case that is inspired by the electricity grid of Sardinia Island, which is the second largest island in the Mediterranean and has particularly favorable environmental conditions for wind power. The island is connected to mainland Italy and the French island of Corsica through high voltage direct current (HVDC) lines that are predominantly used for export. There are several features that make Sardinia an attractive case for the implementation of our model. It is relatively isolated from major regional grids, and apart from the imports, it is largely self-contained. Moreover, despite its modest size, it possesses a variety of generation technologies; a substantial wind-power penetration, a hydro-plant as a quick-response technology, and several conventional thermal plants. Finally, its size enables us to implement our model within our computational resources; it is by no means a trivial exercise. Hence, the island is also attractive to demonstrate the effectiveness of our solution approach.

In the rest of this section, we first introduce the relevant features and data of the case. We then outline our solution approach along with our experience and report on the effectiveness of the approach. We conclude this section with a summary of structural and operational results that provide important insights into the problem in general.

5.1. The case

Fig. 1 and Table 2 below outline the most important features of Sardinia's electricity grid that are relevant to the case. Much of the island-related data are based on Corona et al. [51] and the Terna S.p.A. website, the Italian transmission system operator [52]. The maps in Fig. 1 show the main important locations and the existing main transmission lines on the island. There are in total 13 locations, 11 of which represent the main load centers of the city itself and their vicinity. Many of them also have some renewable and/or conventional generation facilities. Two nodes of the network are solely for generation: Sarlux is the site of a major thermal plant, and Taloro is the site of the only hydroelectric plant on the island.

Currently, there are 17 main transmission lines on the island; that is, those with 220 kV or higher. There are also two main transmission lines that connect Sardinia to Corsica and mainland Italy. The older one, SACOI, is a series of overland and submarine lines of 300 MW capacity leaving Codrongianos and connecting to Corsica and later to the mainland. The new one, SAPEI, is a submarine HVDC line with a capacity of 1000 MW that connects the island directly to the mainland via the Fuimesanto power plant. These lines are not shown on the map since their main use is on the outside of the island. The island also has several sets of sub-transmission grids that are left out of our model as well as from the maps. In our implementation, we consider these 17 main lines as the set of alternative transmission options.

Table 2 reports a summary of electricity generation and load data for the 13 locations. The load data are the hourly average of "gross" demand on the island and the exports. That is, potential losses at the distribution and at the sub-transmission grids are already taken into account when these loads are estimated. In total, Sardinia has an hourly average load of 1015 MW in addition to an average of 432 MW of exports. The island load data are distributed over the 11 population centers according to the populations of their metropolitan and nearby regional demands. The average export rates of Codrongianos and Fiumesanto are obtained from Corona et al. [51] and added to their own demands to obtain the loads for these two nodes.

As mentioned earlier, there are three major generation technologies on the island. The base load is provided by nine independent thermal generation units in four plants with their design capacities reported in Table 2. These capacities represent the maximum "gross" generation rate for each unit; that is, once the losses in the generation units are

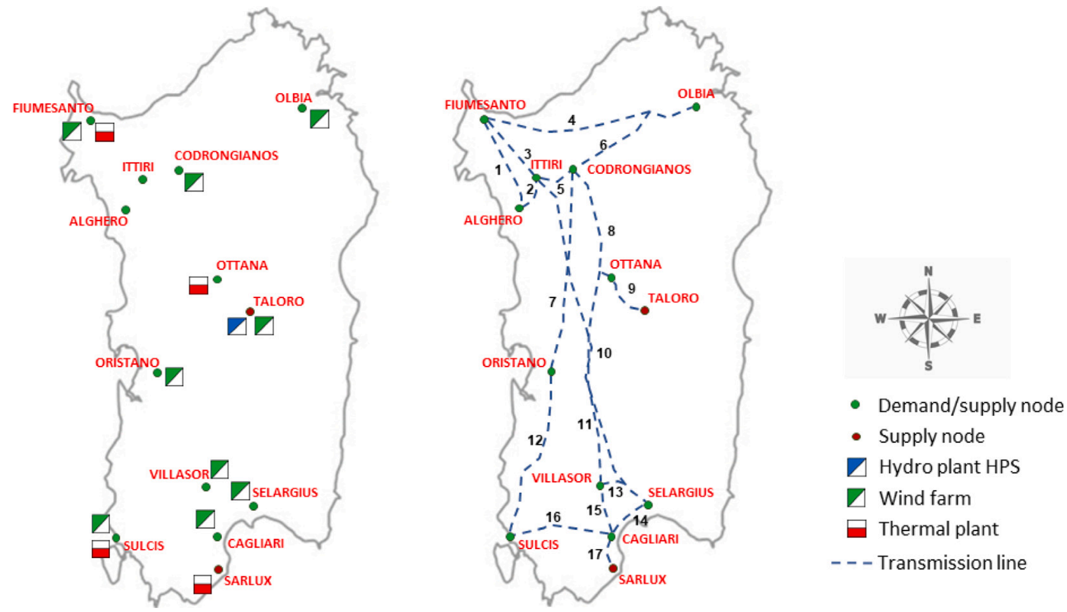

Fig. 1. Main transmission network configuration of Sardinia.

Table 2
Hourly load and generation data for Sardinia (all in MW).

City/Region	Avg. Load	Avg. Wind	Generator Cap.
Fiumesanto+Exp	418	14	320+320
Cagliari	415	20	–
Codrongianos+Exp	155	146	–
Olbia	101	6	–
Alghero	72	–	–
Ittırı	71	–	–
Ottana	59	–	70+70
Oristano	52	55	–
Selargius	49	8	–
Sulcis	45	27	350[a]+240
Villasor	12	51	–
Sarlux	–	–	185+185+185
Taloro (Hydro)	–	38	240[b]
Total	1,448	365	2,165

[a] Excluded from the case.
[b] Avg. generation = 46.5 MW, Reservoir size = 10 GWh.

taken into account, the effective production rates will be reduced by a loss factor explicitly included in the model above. We excluded the larger thermal unit at Sulcis from the case because early experiments have shown a substantial amount of idle times and quite sporadic use of this unit. Coal-fired power plant technologies require a stable generation schedule with limited load cycles; i.e., shut-down and start-up cycles. Frequent load cycles are associated not only with increased costs and risks of severe damage to various critical parts of power plants, but also with increased environmental and other operational risks [53–55]. Likewise, long idle times, termed as "lay-ups" in the industry, are also quite undesirable which involves substantial effort and expense to protect the facilities from corrosion, deposit accumulation and other hazards [56,57].

The generation capacity of the Taloro hydro plant is also given at a gross level, but its effective generation rate is also affected by its reservoir size and its fill rate throughout the year. Hence, although it has a design capacity of 240 MW, the average generation rate is much lower, and it is also subject to losses during generation. At the time of the collection of these data, in August 2024, Sardinia had 30 major wind farms with a combined installed capacity of a little over 1215 MW. In the table, there are nine nodes with wind farms with their average generation rates. With the exceptions of Olbia, Selargius, and Sulcis, each of which has only one, the wind farms at other nodes actually represent the combined generation of the several farms nearby. At the extreme of such nodes is Codrongianos, with a dozen nearby wind farms, all combined into a single source. The average wind generation rate is given as the "net" output of wind farms with the assumption of 30% efficiency in the design capacity, which, although dependent on many factors, is a typical generation level used in practice. We refer the reader to Appendix A, which gives a more detailed account of the wind farms and the hydro plant generation.

Although we were able to obtain accurate aggregate load and wind generation data, we could not access them at the necessary temporal level. Therefore, we have chosen to produce hourly data for Sardinia synthetically based on the three-year hourly data set of El Hierro Island in Spain (available in REE [58]). El Hierro is a small island that has an average load of 5.03 MW per hour and a wind farm with installed capacity of 11.5 MW and approximately 3.60 MW generation per hour; that is, with around 30% efficiency. We have first utilized this dataset to estimate the parameters of models for hourly load and wind generation; a fixed-effect additive model with monthly and hourly components for the former and a first-order Markov chain model for the latter. We refer the reader to Sevgen [59] for the details of these estimation procedures and results. In the end, using these models, we have generated hourly synthetic data for each load center and wind farm based on the average values given in Table 2.

Table 3 reports some of the basic technological and economic data related to storage and generation technologies and transmission lines. The generator data are based on numerous industry reports and articles that were reviewed and collected in Sevgen [59]. Among them, we have relied heavily on Corona et al. [51] and Anisie and Boshell [60], the former of which also give an estimation of the average transmission loss. All of these characteristics vary according to a multitude of technological, operational, and environmental factors. What is provided in the table are generic estimations that might not be applicable to specific generators on the island. For example, the ramp rate has been widely reported to vary between 1%–4% of the nominal power *per minute* for thermal generators. Hence, our estimate of 35% per hour is somewhat approximate, as we lack precise data on the thermal units currently employed on the island. There is no restriction on the ramp rates of hydro power nor on those of either storage technologies, as they are among the highly responsive generation and storage technologies.

Table 3
Relevant technical and cost characteristics.

	BESS	PHS	Thermal	Hydro	Transm.
Power rate ($/MW/year)	15,821[a]	74,896[a]	–	–	–
Energy rate ($/MWh/year)	35,453[a]	2,797[a]	–	–	–
O&M cost ($/MWh)	0.5125	0.5125	20	10	–
Efficiency/loss (%)	90[a]	80[a]	6.5	6.5	2.5
Start/finish conditions	50%	50%	Free	50%	–
Warm-up time (hr)	–	–	48	–	–
Start-up cost ($/MW)	–	–	100	–	–
Ramp rate per hour	–	–	35%	–	–
Minimum generation level	–	–	30%	–	–

[a] "Likely" costs and round-trip efficiencies of storage technologies (see Appendix B for the "Optimistic" and "Pessimistic" estimations).

Similarly, a minimum level constraint is more applicable for coal-fired thermal units, for which the minimum output is usually reported to be around 25%–40% of its nominal power. Hence, we simply set 30% as the minimum output of the thermal generation units.

The cost and technical data on the storage technologies are also based on generic data provided primarily by Mongird et al. [44]. We have performed extensive analysis of the data provided by them, supported by other sources, to develop three-point estimates, that is, "likely", "optimistic", and "pessimistic". Table 3 only reports the likely estimates, but we refer the reader to Appendix B for a detailed account of our estimation procedure and the other estimates. As mentioned earlier, we consider the 17 existing major transmission lines of the island's main grid as alternatives. Much of the costs of transmission lines are variable in length, but fixed in capacity. We have made extensive use of the publicly available report by Parsons-Brinckerhoff and Associates [45] to estimate the annual costs of the lines. The assumptions we have made and additional sources we have used to make our estimations are quite detailed, and therefore, they are also relegated to an appendix (Appendix C). Finally, we have also used an average transmission loss factor of 2.5% throughout [51].

To determine the cost of unsatisfied demand, it is necessary to consider various factors. Different types of consumers can have varying costs associated with power outages. For example, if a factory is unable to produce goods worth $100,000 due to an outage that lasts one hour, the cost of the power outage would be at least that amount. Similarly, industrial and commercial customers may incur opportunity costs related to idle resources such as labor and equipment, as well as costs associated with shutting down and restarting operations. Residential customers also experience negative impacts from power outages, including spoiled food and potential health and safety hazards [61]. However, in most cases, the duration and impact of electricity outages for residential customers can be considered lower compared to industrial and commercial customers. Taking into account that the majority of customers on the island are residential, we considered a cost of $5,000 per MWh to be reasonable. However, we must note that this value is largely case-dependent, estimates of which might pose challenges. We have chosen such a large number to minimize the unsatisfied as much as possible. Given this difficulty and relative subjectivity, better courses of actions may include conducting what-if scenarios or imposing explicit service-level constraints.

It is imperative to implement the model for a horizon of at least one year so that the main seasonal effects on supply and demand patterns are adequately captured. On the other hand, one would also need to consider hourly, if not more often, operational decisions of the grid. Even the most archaic generators have large enough ramp rates that enable them to easily alternate between their technological minimum and maximum generation levels in a few hours. More critically, however, energy storage systems for electricity re-supply purposes are not viable to accommodate persistent supply shortages or excesses over extended periods. For example, typical industry service time averages for BESSs and PHSs range between two and eight hours and between six and 24 h, respectively [42]. Hence, we have decided to implement our model for a year with 8760 hourly operational decisions.

As mentioned earlier, BESSs do not require any particular geography; they can be installed practically anywhere with almost any size. However, certain geographical conditions must be present for PHSs to also be economically viable. However, for illustrative purposes, we assume that any node in the transmission grid has a nearby site that is suitable for a PHS construction. However, we have restricted the energy rate to a maximum possible value of 1500 MWh. Ultimately, should there be appealing locations distant from the existing nodes, the case may be extended to accommodate them as separate nodes and associated transmission line alternatives.

We have three different instances changing with respect to the storage systems' cost and efficiency scenarios; namely, optimistic, likely, and pessimistic. We have observed that no BESS investment ever takes place in the presence of PHS alternatives. Despite having a higher round-trip efficiency and lower power rate costs, it seems that BESS's high energy rate costs are much too overwhelming to make it more attractive than PHS at any node. Hence, we have also decided to solve those three scenarios with BESS as the sole storage alternative. These instances might be considered applicable to geographies where PHSs are not feasible. Hence, we have solved six different instances; three scenarios with BESS as the sole alternative, and likewise three with both storage alternatives.

Finally, we must point out that none of the results presented here should be taken as suggestive for Sardinia's real transmission design, but rather as illustrations of impacts of certain cost and technological characteristics on energy storage and main transmission line decisions under particular generation and load profiles. Although there are features specific to the island with some realism, the major part of the case data are from generic sources or synthetically derived. Moreover, many technological characteristics, such as efficiency rates, losses, ramp rates, warm-ups, etc., are applied on "average" basis. One should keep in mind that many of those parameters depend on a number of factors in the actual system (e.g., technology, age, condition, etc.) and sometimes even on the hourly operational decisions. Transmission loss is one of such examples, which actually depends on the conditions of the lines and also on the real-time flow decisions in the grid. The issue of transmission loss are myriad with so many complexities that it alone commands a sizable body of literature. Such details cannot be accommodated properly in a design decision problem such as ours, either due to lack of relevant information or substantial growth in complexity.

5.2. Solution approach

The resolution of problem **(P)** even for small grid systems can quickly become intractable due to the large number of operational decisions through the planning horizon, particularly those decisions that are modeled using binary variables. Hence, we have resorted to a "divide-and-conquer" type approach accompanied by additional pre- and post-processing steps. In this section, we would like to outline our approach that is customized by the features of the case and finalized along with our experiences, as a matter of course. All problems and sub-problems are implemented in Gurobi 9.1.2 and run on a PC with Intel(R) Xeon(R) CPU E3-1240 v5 3.5 GHz processor and 64 GB of memory running on Microsoft Windows 10 64-Bit operating system.

5.2.1. Time decomposition

A direct attack on the problem with a commercial solver has failed to yield any results. In none of the instances, whether with only BESS or both storage technologies, Gurobi could find even a feasible solution after 24 h of runtime. We have surmised that the large number of binary variables used for some operational decisions may be the main culprit, whose effects may also be further aggravated by constraints (2c)–(2e). Hence, we have decided to exclude them and related binary variables in warm-up-time modeling (i.e., v_{bgt}' s). Hereafter, we will be dealing with the instant-warm-up case until we return to the issue at the very end of this section. Under this setting, now it has also become possible to introduce symmetry breaking constraints for thermal plants that have identical units; but still to no avail. As a last resort, we have also tried the LP relaxation of the yearly instances with the sole exception of 17 binary variables for transmission lines. Although Gurobi was able to find feasible solutions in 24 h of run-time, the optimality bounds were extremely poor.

It has then become clear that some type of decomposition approach is needed as the memory requirements are much too great to deal with even the modest size case. A time-based decomposition appears to be not only a natural candidate but also a quite promising one because schedules of neighboring planning horizons unlikely effect each other except for at the most a few days or even a few hours at their borders. As a result, after solving the problem in shorter planning horizons, we may fix schedules of some thermal units and thereby reduce the problem into a manageable one, hopefully, only with slight loss of optimality. After a few similar trials and similarly discouraging results with quarterly planning horizons, we have eventually settled down to monthly instances (i.e., $8,760 \div 12 = 730$ hours each). Even then, there were many instances in which solutions are only obtained with provable bounds of around some 10% after two hours of runtime. Nevertheless, a larger majority, especially the ones with only BESS, have been solved optimally or with low single-digit optimality gaps.

5.2.2. Thermal unit schedules

The primary purpose of time decomposition is to be able to fix some thermal unit schedules without serious adverse effects on the quality of the solution. We have observed that in monthly instances, none of the units of Sarlux and Fiumesanto is shut down except for an hour or two at the end of some months. However, the larger unit at Sulcis is employed very sporadically with long off-hour periods in between. The other three units are kept operational much of the time, but also shut down for extended periods and likewise towards the end of the months. Hence, we have decided to keep the Fiumesanto and Sarlux units operational throughout the year and excluded the Sulcis 350 MW unit entirely from all instances. As a result, the optimizer has only three thermal schedules to find.

Keeping the Fiumesanto and Sarlux units open for the entire year would have very negligible cost consequences. First of all, Fiumesanto with its exports and Cagliari with Selargius are the two largest load centers with negligible wind power. Therefore, they need to be supplied primarily from thermal sources. For Fiumesanto, it is clear that its own plant would be the cheapest thermal source because of the absence of transmission loss. The case for Sarlux is less clear: Although its proximity to Cagliari is an advantage over Sulcis, in the end if both transmission lines are employed (and they were) they would be on par in terms of transmission loss. Responsiveness, however, seems to be the true advantage of Sarlux with its three smaller units, enabling the grid to better adapt to changing conditions than with the two bulky Sulcis units. Consequently, we see very little use of the larger Sulcis unit, and even its smaller unit's utilization will turn out to be the lowest among eight units.

While we have strong justification for the heavy use of Fiumesanto and Sarlux units, we need a further analysis to justify their nonstop operation throughout the year. Recall that both plants have identical units and therefore, at either plant it would most likely be suboptimal to overwork one unit, while all of its units can share the generation at their technological minimum. For example, it would be better to operate all three Sarlux units at 30%, rather than operating one at 90% and keeping the other two shut because one or both of those two units will ultimately need to be re-started, incurring unnecessary start-up costs. Hence, only at times of very low demands, shutting down some units may be desirable. Also note that it would not be optimal to shut down a unit for periods less than six hours. Because with a start-up cost of $100 per MW and unit generation cost at $20 per MW, the former barely covers the cost of operation for five consecutive periods, even if the entire generation is grounded in the meantime.

The combined minimum net generation level of two Fiumesanto and three Sarlux units is approximately 335 MW (that is, 1195 MW capacity at 30% with 6.5% loss). In Fig. 2, where we provide the box plots of six-period moving averages of total net loads (load less wind) on the island, one can see that there are at least two such instances of loads less than 335 MW in the month of November; there is actually a third with a value of 307 MW, which is within the Tukey fence and hence does not appear in the figure. The two outliers are observed consecutively, and so together they span a period of seven hours. We have explored the net loads of these 13 h and found out that at the most a total of 1795 MWh can be dumped assuming no useful target for them whatsoever, for a total of $35,900 in savings. However, to achieve these savings, at least three load cycles must be performed and three start-up costs must be incurred. Assuming that smaller units of Sarlux are sufficient for that purpose and there is no dumped energy or unsatisfied demand in those schedules, the model must incur at least $16,650 in start-up costs (i.e., bringing a Sarlux unit to a minimum 30% level, twice and another one once). Hence, the *maximum* possible extra cost of not shutting down these units would be less than 20 thousand dollars; most likely, even much less than that. Considering the annual total costs in the neighborhood of 300 million dollars, this extra cost virtually amounts to no more than a rounding error.

The above argument is obviously a heuristic; as it assumes that Fiumesanto and Sarlux can economically cover the entire island's demand and neglects the hydro plant entirely. The common feature of these 13 periods explored above are the extreme levels of wind generation that bring the net load requirement of the entire island substantially lower than usual, but given the negligible power capacities at Fiumesanto and Sarlux, the net requirements of them remain quite strong. In fact, when we look at the net loads at the Fiumesanto and Cagliari in those 13 h, their total net loads far exceed the minimum generation level 335 MW in each and every hour.

5.2.3. Transmission lines

In the preceding section, we have established that working Fiumesanto and Sarlux units non-stop would have almost no adverse effect on the solution. Therefore, we have proceeded to experiment with the yearly problem with three thermal units' schedules to be decided (two at Ottana and one at Sulcis). These yearly instances are run for 24 h with five instances producing feasible solutions and lower bounds, which are reported in the first two columns of Table 4. Clearly, this variable-fixing scheme thus far has been unsatisfactory with optimality gaps ranging from some 10% to over some 20%.

When we review the yearly solutions, we have noticed that Gurobi prescribes all transmission lines to be employed in all five instances. Clearly, it could not prune the branch and bound tree effectively, most likely due to large memory requirements, and could barely produce such feasible solutions with all lines. This is somewhat contrary to expectations because given the virtually unlimited capacity of transmission lines, one would reasonably expect some of them to not be

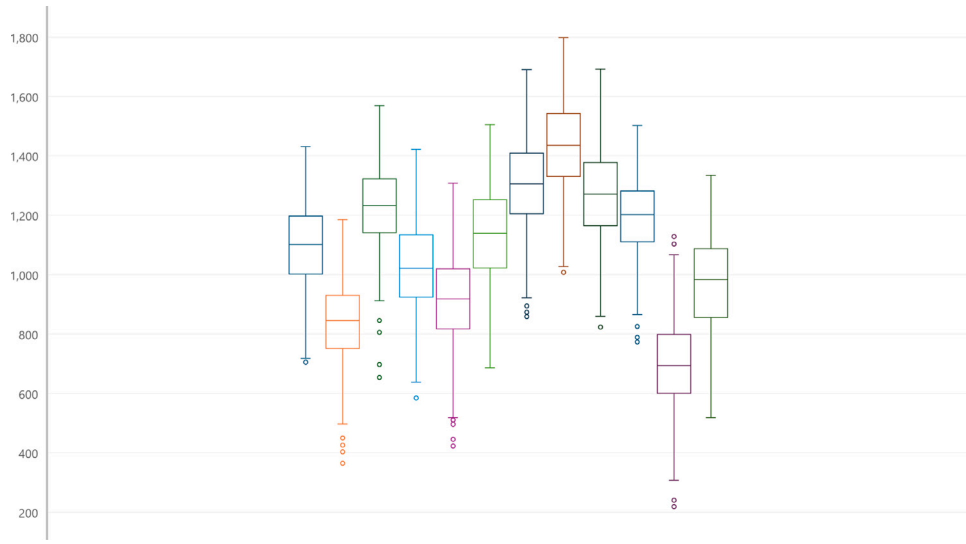

Fig. 2. Six-hour moving average of net loads (i.e., load less wind) from January (left) to December (right).

Table 4
Performance of the solution approach.

	Total Cost ($M)				Optimality Gap (%)	
	Gurobi	LB-Gurobi	LB-Approx.	Heuristic	Worst	Approx.
BESS-O	N/A	N/A	298.2	305.6	N/A	2.42
BESS-L	366.5	304.8	309.6	330.3	7.7	6.28
BESS-P	404.4	357.7	369.1	369.7	3.3	0.16
PHS-O	324.7	248.7	285.4	285.7	12.5	0.11
PHS-L	335.5	263.9	297.6	297.7	11.4	0.03
PHS-P	348.3	281.6	311.4	311.5	9.6	0.03

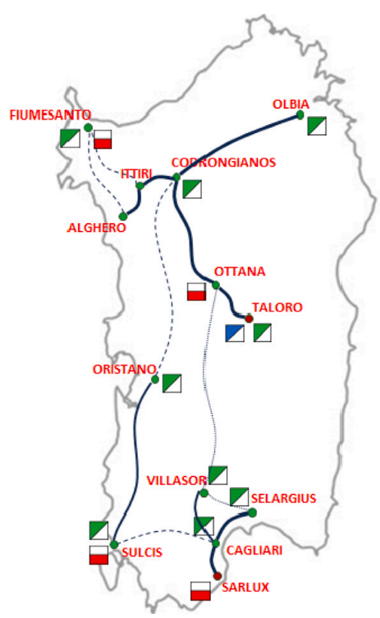

Fig. 3. Transmission decisions in monthly subproblems (thickest ones appear in all 72 or 71 cases; the number of occurrences decreases with line thickness and style ; e.g., Ottana-Villasor appears three out of 72 instances).

employed at all. In fact, in our monthly instances we have not noticed a single instance that employs all the lines. Hence, we next proceed to do a more detailed analysis to see if we can exclude some of the lines from the consideration.

Fig. 3 is a visual summary of the transmission line employment decisions of 72 monthly instances. It seems almost certain that Sarlux-Cagliari-Selargius lines and the five-line cluster centered at Codrongianos would be employed in the optimal solution. Although it is important to identify the lines to be employed, which after all reduces the solution space, we believe that the optimizer would benefit more from those lines that can be excluded. The Fiumesanto-Olbia and Ittırı-Selargius lines are never used in any of the 72 monthly instances, and hence, they are prime candidates for exclusion. After another round of experimentation, we have also decided to exclude Ottana-Villasor, which appeared only in three of the monthly instances. Having fixed the decisions for 10 transmission lines, we have resolved the yearly instances. This time we have obtained solutions for all six instances and although we have not observed substantial improvement in feasible solutions (Gurobi has continued to prescribe all lines to be employed except the three we have excluded), the lower bounds improved quite noticeably, as reported in the third column of Table 4. Although there is ample reason to believe that such a variable fixing should not harm optimality, we nonetheless call it “LB-Approx.” to acknowledge the heuristic nature of these arguments and the ensuing results.

5.2.4. The heuristic

Having a foothold on the characteristics of an optimal solution, we then launch on a heuristic following a similar approach. We have returned to our monthly instances and resolved them, now with relative ease, with all Fiumesanto and Sarlux thermal units set operational throughout and fixed 10 transmission as above. We then combined the monthly schedules of thermal units after modifying those of the Sulcis and Ottana plants, to be described below, and solved the yearly instances with additional three transmission lines fixed as employed; namely, Fiumesanto-Alghero and Codrongianos-Oristano-Sulcis, consequently, leaving only transmission line variables to be decided. The cost results of these yearly problems appear in 4 as “Heuristic”. The last two columns of the table also report the optimality gaps based on the theoretical and heuristically obtained bounds. Even if one might not rely on these bounds alone, the improvements over the best feasible solutions Gurobi was able to obtain are substantial. The improvements are particularly pronounced in the instances where both storage technologies are considered, which are particularly difficult to solve for Gurobi as compared to the BESS-only instances.

Although the thermal unit schedules might be rather decoupled among distant time periods, special attention is needed when the monthly schedules are combined. As described earlier, we only need to concern with three units; one at Sulcis and two at Ottana. If there are some load cycles (i.e., shut-down and start-ups) completed within a month, we leave them as they are in the combined schedule. There are many instances, however, where one or two, or all three of them, may be shut down in the last few hours of the months. Clearly these shut-downs are due to end-of-period effects of not having to incur a start-up cost, but they may nonetheless appear in the optimal solution, if the conditions are favorable at the beginning of the following month.

Here we follow the following heuristic argument dealing with end-of-month shutdowns. For Sulcis, we count the number of hours in the beginning of the following month in which no more than the technological minimum amount is generated. If the total number of combined hours is six or more, we let the optimizer choose the schedule variables in that interval (i.e., we do not fix them). For Unit 1 at Ottana we follow the same approach; but for Unit 2, we count the number of hours until the maximum possible generation of Unit 1 is not sufficient to cover the generation needed from both units. In short, when we combine the schedules of consecutive months we leave schedule variables unrestricted at the borders if there is a chance that any of those three units might be shut down at least six-hours or more and re-started later. Otherwise, the units are scheduled to operate at those hours. In the end, although there were several shut-downs, particularly in the month of November, there were almost no at the borders of the months. Hence, the model clearly chooses not to incur start up costs. Apparently, there is ample room for reduction in generation at other plants or energy storage, despite the transmission and storage losses.

We believe that the success of the heuristic comes mainly from its reduced memory requirements, which are achieved primarily through a substantial number of variable fixing, particularly of the thermal unit schedules as well as, even though only a few, elimination of some transmission line decisions. The conditions for variable fixing are well founded within the assumptions in the model, particularly unlimited transmission line capacities and decoupled thermal schedule decisions due to technological limitations of the existing storage technologies. Fortunately, both assumptions are also well justified in practice.

5.2.5. Warm-up times

Thus far, we have been concerned primarily with the problem under the assumption of instant warm-ups. As we have mentioned earlier, we also consider the impact of warm-up lead times. What we have observed throughout the instances is the complete lack of load cycling, with the chief exception of November. There was one between the months of April and May and few between November and December, which we counted in November. The presence of different generation technologies and sizes combined with virtually uncapacitated transmission lines and opportunities for storage is apparently sufficient to prevent too many expensive load cycles. The results for the month of November should not come as a surprise in view of the net load box plots in Fig. 2 and the fact that it also has the highest average hydro reservoir accumulation rate in the year.

The first three columns of Table 5 report the total idle hours of the three thermal units in the month of November and those of Ottana's second unit at the border of April and May in all instances. The heuristic that we conceive for cases with positive warm-up times (e.g., 48 h in our case) is to revise the solution of the instant warm-up instances to restore the feasibility with little effort and, we hope, with little deterioration in optimality. In our instances, if any unit has a load cycle with more than 48 h of shut-down time, most likely preserve the same schedule as there is sufficient time to cover the warm-up time. Hence, our chief concern would be cases where there is no such sufficient time, and hence the original solution is infeasible with the positive lead time. The heuristic we conceive is to introduce the excluded variables (i.e., v_{bgt}'s) and the corresponding constraints (i.e., (2c)–(2e)) around these infeasible periods and let the optimizer decide on the revised schedule.

To better convey the idea of the heuristic, let us consider one of such infeasibility: In the BESS-P instance, Unit 2 at Ottana has a scheduled shut-down of seven hours from Hour 2916 to Hour 2922 (inclusive), which is at the border of April and May, and the idea of our heuristic is to free a portion of this unit's schedule so that it may start generation as early as at Hour 2923 or shut-down as late as by Hour 2916. To accommodate these conditions, all schedule variables between the hours of $2,923-48 = 2,875$ and $2,916+48 = 2,964$ must be freed, and hence the optimizer can decide to shut down the unit at any time during this interval or not. Provided that there are no substantial numbers of such occurrences, which actually also are unacceptable for technological reasons, the complexity of the model should not increase substantially. Moreover, if there are some overlapping intervals, they are simply combined, which actually reduces the total number of variables to be introduced.

When we review the unit schedules of our instances we have observed that Sulcis and Unit 2 at Ottana had none or only one such feasibility and Unit 1 at Ottana had two or three. Ordinarily, Unit 2 had infeasible intervals only in the months of April–May, but we added one in November to eliminate two such intervals of Unit 1, which was produced due to symmetry-breaking assumption previously. If the intervals of infeasibility are short, the optimizer most likely would choose not to do load-cycles in those intervals, but if they are sufficiently long, it would be better to do so, provided there are attractive sources of generation available.

We have not implemented this heuristic in our instances, however, as the instances themselves do not lend them such undertaking worthwhile. After identifying the infeasible intervals, we have calculated the imposed costs of 48-hour warm-up lead time under rather liberal allowances. We have extended the Sulcis intervals to 48 h with extra generation elsewhere with ample transmission loss cushions (thermal capacities were available) and a start-up cost. For Ottana units, we assume that they operate at their minimum levels and all they generate is grounded. The extra *yearly* costs of this heuristic approach are given in the last column of Table 5. Clearly, these amounts, which are calculated with the most liberal allowances, are tiny in comparison even to the optimality gaps of some instances.

Although that may seem unfortunate, it also suggests that in the presence of many thermal plants and a flexible source like a hydro plant supported with sufficiently capacious transmission network, such warm-up lead times can be dealt with little burden even without the aid of storage resources. We have strong belief that transmission and storage design decisions would be rather robust to warm-up lead time considerations under these conditions.

5.3. Structural results

In this section, we would like to give an overview of the design decisions and operational outcomes of the case carried out in six scenarios. As mentioned earlier, in the presence of PHS alternatives, BESSs are not employed anywhere on the island. The cost disadvantage of BESS in energy rate is just too great to be overcome by its advantage in power rate cost and round-trip efficiency. The second common result is that wherever storage is employed, their power rates are fixed to their maximum allowed to provide six and 18 h of service, respectively. Hence, in both technologies, the energy rate cost is the driver of storage

Table 5
Idle hours of thermal units[a].

	Idle Hours				Infeasible Hours			
	Sulcis	Ottana 1	Ottana 2[a]		Sulcis[b]	Ottana 1	Ottana 2	Max. Cost
BESS-O	672	95	375		–	64	14	32,760
BESS-L	601	74	588	(11)	–	34	11	18,900
BESS-P	597	73	589	(7)	–	34	7	17,220
PHS-O	603	94	399		41	48	–	28,860
PHS-L	658	144	540	(9)	41	32	9	25,920
PHS-P	590	135	589	(9)	40	33	9	26,340

[a] All idle times are in November; Ottana 2 also has in April–May (in parenthesis).
[b] Forced to a shut-down for 48-hour with extra generation elsewhere and a start-up cost.

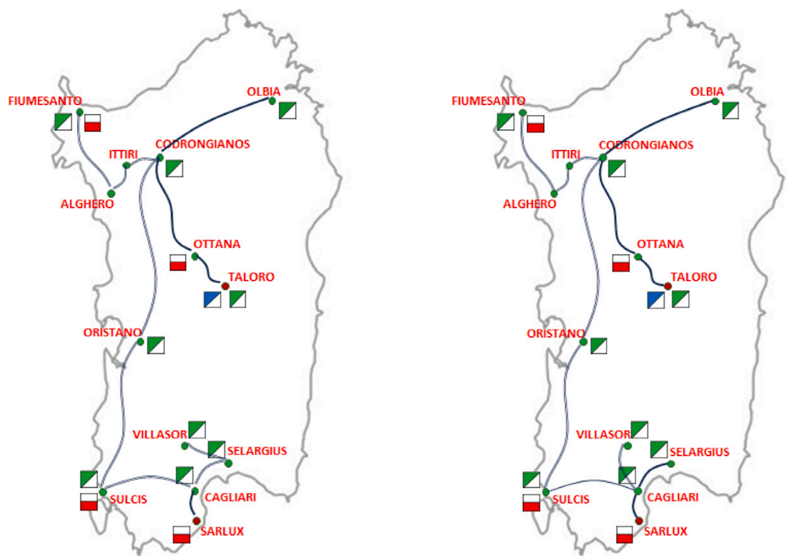

Fig. 4. Prescribed transmission designs: BESS-L and PHS-P (left) and others (right).

design decisions. The third common result is that load centers without a major generation facility appear to have priority for storage installation. Finally, although there are not many opportunities for different transmission grid structures to arise in our case, we also observe that storage and transmission decisions may be somewhat intertwined.

Table 6 and Fig. 4 give a general overview of the yearly solutions of the grid design decisions and the operational consequences. It is clear that the single most important driver in the total cost of energy provision is the storage cost, while the generation and transmission costs remain virtually unchanged across scenarios. Shortages are very rare, and consequently penalties are rather small fractions of the cost. As technologies become less attractive (i.e., optimistic to pessimistic), storage investments increase not just in cost but also in size, which may seem puzzling at first. However, remember that not only costs, but also round-trip efficiencies deteriorate in those scenarios. Therefore, in our case, the penalty cost is large enough to overcome the mitigation of cost increases. Hence, this result should be treated with caution; if it was not, we might have observed the exact opposite or mixed results.

Alghero, Ittırı, Olbia, and Selargius are the four load centers that were consistently chosen for storage installations with over 95% of the total storage capacity installations in five of the six instances. The common feature of these nodes is that they have no or very little generation of any type. In retrospect, this result should not come as a surprise. Since loads at different locations would peak around similar hours and seasons, it would be preferable to store energy at such load centers to avoid shortages due to transmission losses at those hours. Cagliari, too, has no sizable generation facility, but its direct connection to Sarlux as well as its size probably render any storage facility nonviable. Besides these four nodes, Villasor and Codrongianos are the only ones that have some storage investment, insights for which needs some elaboration with the transmission decisions and operations.

For the transmission network, we see two configurations, both of which are in the form of spanning trees. Although the grid size does not allow for much variation, it is noteworthy that it is not economical to have cycles. The only difference between the two configurations is the lines in the Cagliari-Selargius-Villasor triangle. It is hard to guess why a particular choice is made over the other in seemingly different scenarios, as the transmission cost difference between them is quite small. However, whenever the Cagliari-Villasor direct line is not used, we see a major increase in storage capacity at Villasor. The reason is the same as before; that is, the optimizer tries to avoid additional transmission loss during peak hours when the direct link from Cagliari is not present.

Table 7 reports more detailed results on generation and storage operations. In general, we see stable use of thermal units across different scenarios, and as also noted earlier, the Sulcis plant is the least utilized among all. However, the Taloro hydro plant shows a predictable pattern; that is, when storage becomes more disadvantaged, it is used less often but with a higher generation rate. However, the effect is dampened by a further disadvantage. (e.g., note how Taloro's generation rate changes from optimistic to likely and from likely to pessimistic scenarios). When we look at the storage operations, we observe that the further away the storage is from a thermal source, the more frequently it is used. In all scenarios, the usage rates are highest in Olbia and Villasor, followed by Ittırıand Selargius, and the lowest are in Alghero or Codrongianos.

We now move on to transmission operations, which are summarized in Table 8. The upper portion of the table is assigned to the lines with the unidirectional flow, followed by those with the bidirectional flow. The bottom portion reports on the Cagliari-Selargius-Villasor triangle.

Table 6
Summary of design decisions and operational results.

	BESS			PHS		
	O	L	P	O	L	P
Total cost ($/hr)	34,885	37,703	42,206	32,609	33,979	35,563
Generation	23,812	23,845	23,877	23,900	23,912	23,935
Storage	5,712	8,481	12,368	3,041	4,524	6,151
Transmission	5,284	5,327	5,284	5,284	5,284	5,327
Penalty	76	51	678	384	259	150
Storage decisions						
Total energy rate (MWh)	1,796	1,948	2,078	5,072	5,685	6,464
Service time (hr)	6	6	6	18	18	18
Total power rate (MW)	299	325	346	282	316	359
Alghero	59	59	68	76	83	81
Codrongianos	–	–	–	–	1	47
Ittırı	71	80	85	83	83	83
Olbia	138	145	152	83	83	83
Selargius	29	29	35	39	66	49
Villasor	3	13	6	–	–	15
Operations summary (all in MW)						
Thermal generation (gross)	1,167	1,169	1,170	1,171	1,172	1,173
Hydro generation (gross)	46	46	46	46	46	46
Transmission flow (gross)	1,073	1,104	1,131	1,136	1,149	1,139
Discharge rate (net)	33	23	20	19	18	18
Total shortage (MWh)						
North	93	67	1,156	600	453	256
Selargius+Villasor	41	22	31	73	–	7
Total dumped load (MWh)						
North	10	17	11	101	55	13
South	90	52	77	192	18	42

Table 7
Generation and storage operations details[a].

	BESS						PHS					
Avg generation (MW)	O		L		P		O		L		P	
Fiumesanto (640)	545		535		531		531		530		529	
Sarlux (555)	378		376		377		382		382		383	
Ottana (140)	108	(.97)	109	(.96)	110	(.96)	109	(.97)	110	(.96)	110	(.96)
Sulcis (240)	151	(.92)	165	(.93)	169	(.93)	165	(.93)	168	(.92)	167	(.93)
Taloro (240)	106	(.44)	120	(.39)	124	(.37)	123	(.38)	129	(.36)	130	(.36)
Avg charge/discharge rates (MW)												
Alghero	38	(.05)	37	(.04)	41	(.04)	51	(.05)	53	(.05)	48	(.05)
	31	(.06)	29	(.05)	32	(.05)	39	(.06)	37	(.06)	31	(.05)
Codrongianos	–		–		–		–		.4	(.06)	39	(.05)
	–		–		–		–		.3	(.06)	33	(.04)
Ittırı	50	(.11)	54	(.08)	59	(.09)	63	(.10)	63	(.10)	65	(.09)
	41	(.13)	46	(.09)	50	(.09)	48	(.12)	48	(.10)	48	(.09)
Olbia	92	(.27)	93	(.15)	99	(.13)	67	(.15)	68	(.12)	67	(.11)
	92	(.26)	89	(.14)	87	(.13)	62	(.14)	57	(.12)	52	(.10)
Selargius	23	(.11)	23	(.14)	27	(.09)	32	(.11)	46	(.10)	35	(.12)
	22	(.11)	22	(.14)	24	(.09)	26	(.11)	36	(.11)	29	(.11)
Villasor	3	(.17)	11	(.19)	6	(.13)	–		–		14	(.12)
	3	(.18)	9	(.22)	5	(.13)	–		–		9	(.14)

[a] Fraction of related activity hours are in parentheses; averages exclude idle times.

All unidirectional lines are heavily used, which is rather straightforward to explain. Codrongianos-Olbia line is a curious one with lower utilization in BESS-only instances, while fully utilized when PHS is allowed. This observation is actually important to explain the storage employment in Codrongianos. Olbia is only connected to Codrongianos and given its low wind capacity received most of its load requirements via Codrongianos. In the absence of no capacity limitations, i.e., with BESS, a large BESS installation at Olbia suffices and sometimes, satisfied only from the storage. In the absence of capacity limitations, i.e., PHSs, even the largest allowed is not sufficient at Olbia, and therefore the storage at Codrongianos is employed essentially to supplement the one in Olbia. Of course, the model could have also installed BESS at Olbia in addition to PHS, had it not been for the insurmountable cost disadvantage.

The other transmission flows point out the dual hub structure on the island, although the entire island is interconnected. In the south, Cagliari qualify as the region's hub, which apart from the obvious case of Sarlux and in some scenarios, Selargius engage in bi-directional flows with the others. In the north the obvious hub is Codrongianos; it is a net receiver from Ottana and Taloro; a net supplier of Olbia, and as the

Table 8
Average transmission flows (MW)[a].

		BESS						PHS					
Line	Route	O		L		P		O		L		P	
6	Codrongianos-Olbia	124	(.81)	109	(.92)	108	(.94)	101		101		101	
8	Ottana-Codrongianos	116		115		116		116		116		116	
9	Taloro-Ottana	79		79		79		79		79		79	
17	Sarlux-Cagliari	354		351		353		357		357		358	
1	Fiumesanto-Alghero	110	(.95)	112	(.88)	112	(.87)	112	(.86)	113	(.85)	113	(.85)
	Alghero-Fiumesanto	31	(.01)	51	(.06)	57	(.08)	59	(.08)	56	(.11)	55	(.11)
2	Ittırı-Alghero	52	(.10)	62	(.24)	71	(.25)	72	(.27)	77	(.27)	76	(.28)
	Alghero-Ittırı	56	(.64)	57	(.63)	56	(.63)	56	(.64)	58	(.63)	59	(.61)
4	Ittırı-Codrongianos	18	(.01)	26	(.05)	25	(.06)	24	(.06)	35	(.09)	34	(.09)
	Codrongianos-Ittırı	76	(.56)	89	(.60)	94	(.62)	100	(.59)	99	(.62)	96	(.65)
7	Oristano-Codrongianos	74	(.69)	77	(.79)	80	(.82)	80	(.83)	81	(.83)	81	(.84)
	Codrongianos-Oristano	32	(.05)	32	(.04)	31	(.05)	31	(.05)	26	(.04)	27	(.04)
12	Sulcis-Oristano	92	(.63)	107	(.65)	107	(.68)	107	(.69)	110	(.69)	111	(.69)
	Oristano-Sulcis	38	(.18)	42	(.21)	40	(.19)	39	(.19)	40	(.19)	40	(.20)
16	Sulcis-Cagliari	76	(.80)	85	(.75)	84	(.76)	78	(.76)	81	(.74)	80	(.73)
	Cagliari-Sulcis	25	(.05)	32	(.07)	30	(.09)	30	(.09)	31	(.10)	30	(.10)
13	Villasor-Selargius	–	-	53	(.71)	–	-	–	-	–	-	54	(.70)
	Selargius-Villasor	–	-	6	(.16)	–	-	–	-	–	-	7	(.22)
14	Selargius-Cagliari	–	-	34	(.38)	–	-	–	-	–	-	63	(.36)
	Cagliari-Selargius	43		35	(.58)	43		43		44	(.98)	36	(.58)
15	Villasor-Cagliari	57	(.69)	–	-	56	(.69)	57	(.69)	57	(.69)	–	-
	Cagliari-Villasor	8	(.29)	–	-	7	(.28)	9	(.31)	9	(.31)	–	-

[a] Fraction of flow directions are in parentheses; averages exclude idle times.

need arises, it engages both in export to and import from other nodes with the entire western centers of the island.

6. Conclusion and future outlook

In this paper, we study a transmission network design problem that includes transmission line decisions and the configuration of energy storage systems, i.e., their types, locations, and sizes. In particular, we consider a grid system in which electricity generation units from both renewable and non-renewable sources are already established and alternative transmission lines are predetermined. We formulate the problem as a mixed integer linear programming model that minimizes total investment costs and system-wide operating costs of power generation, storage, and penalty costs.

One of the complicating factors of the model is the presence of several conventional thermal generation units that have particular operational constraints. Therefore, we adopt a "divide-and-conquer" type heuristic solution approach that first solves the problem for smaller time segments (i.e., monthly), subsequently combine the monthly thermal generation schedules to construct much of the yearly grand schedule, and finally solve the full model via a commercial optimizer. Our construction of the schedule is based on some heuristic rules that we have devised utilizing monthly solutions and properties of the system components; namely, loads, wind power generation, and thermal unit capacities. Even then, the optimizer still needed more help, particularly in restricting transmission lines. Hence, we have also fixed some of the transmission line decisions again heuristically using monthly solutions.

We have implemented our model and the solution approach on a case based on the modest transmission network of Sardinia Island under a variety of scenarios. On the computational side, we have strong evidence to support the effectiveness of our solution approach. Although the commercial optimizer could not even produce a feasible solution and lower bounds for the yearly problems in their raw form, as a result of our approach, we were able to obtain high-quality solutions with relative ease. The main reason for the failure of the commercial optimizer is most likely related to massive memory requirements, Sardinia's transmission grid is quite modest in size. Hence, our approach has significant potential for an effective solution of larger and even more complex networks.

We were also able to generate some managerial insights into the storage and transmission decisions, although some of them must also be interpreted with caution. Firstly, whether BESS or PHS is employed, the main driver of the configuration decisions of them are driven by their energy rate costs, which suggests that as the technologies stand currently, it is more dominant than the power rate cost. Secondly, PHS has an overwhelming cost advantage despite its lower efficiency. However, this conclusion should be treated with caution, as our model does not consider uncertainty in the model or certain geographical or configurational restrictions that might be present for PHSs. Hence, utility storage options such as PHS might be more attractive for predictable variations, but BESSs might also be adopted to better deal with more unpredictable smaller variations and improve grid stability. Finally, the most attractive locations for storage installations are those that lack any substantial level of generation near them. In fact, the farther away a center from generation sources is, the more likely a storage investment would be prescribed there. The driver of this result is the desire to avoid losing power to the transmission during peak hours. However, this result is also important, in its own right, as it points out potential benefits for the whole system when transmission system operators or distribution companies engage in storage investments rather than the generation companies.

Although we aim to provide a reasonably comprehensive treatment of the problem, it is still far from capturing all the complexity of real grids. However, we believe that this work also points to new avenues of investigation in several directions. There are some immediate extensions that may be pursued. For example, case-specific constraints on PHSs or other utility-scale storage alternatives, more refined transmission loss modeling, and inclusion of system reliability and frequency and voltage maintenance issues are important avenues for research.

The lack of uncertainty and intermittency in demand in wind power generation was a difficult choice we had to make given our early experience with computational needs. However, the inclusion of those factors with the necessary frequency of operational decisions in design problems is still an open area to pursue. It may also be important to investigate how such an approach would perform when there are more varied renewable and non-renewable generation facilities and larger national or regional grids. Although this study considers a single investment decision opportunity, in reality, energy systems require a long-term approach due to massive investment costs of generators, storage systems, and transmission lines. Therefore, a multi-period framework for investment and disinvestment decisions is necessary for the grid systems where conventional generators that are already installed will be slowly replaced by renewable sources over the years. Given the increased level of renewable penetration and many initiatives to accelerate conversion to clean energy (e.g., "Europe's Coal Exit" movement, an initiative driven by an umbrella organization called Beyond Fossil Fuels (see website https://beyondfossilfuels.org/europes-coal-exit/) calls for such approaches. In addition, concepts such as distributed generation are also gaining momentum, and distributed storage, such as the use of electric vehicles, is already showing signs of greater adoption [62], all of which are important developments to consider in future work. Finally, it should also be mentioned that electricity systems, by and large, consists of many different bodies of organizations of generation, transmission, and distribution amidst myriad of regulations and markets. Models such as ours, however, they may prescribe some system-wide improved solutions, achieving such improvements require a whole set of analysis to develop the necessary conditions such as regulations, incentives, penalties, etc. by policy makers.

Disclaimer

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Arya Sevgen Misiç: Writing – review & editing, Writing – original draft, Visualization, Validation, Software, Methodology, Formal analysis, Data curation, Conceptualization. **Mumtaz Karatas:** Writing – review & editing, Writing – original draft, Supervision, Methodology, Formal analysis. **Abdullah Dasci:** Writing – review & editing, Writing – original draft, Supervision, Methodology, Formal analysis, Conceptualization.

Declaration of competing interest

The authors declare that they have no known competing financial interests or personal relationships that could have appeared to influence the work reported in this paper.

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Appendices

In these appendices we will give further details on the generation units in Sardinia and estimation methods and sources for the cost and other characteristics of transmission lines and storage technologies used in our experiments. Among the publicly available sources, we have relied mainly on the Global Energy Monitor Wiki (gem.wiki) and Power Technology (power-technology.com) for generation units, both of which are quite comprehensive data sources globally. For cost estimations, we have relied mainly on the reports of Parsons-Brinckerhoff and Associates [45] for transmission and Mongird et al. [44] for storage alternatives. The reasons we have chosen these works are, first, that they are publicly available and commissioned or endorsed by important governmental or industrial bodies. Secondly, they are quite comprehensive and detailed in their content, data sources, assumptions, and procedures. All of them will be augmented by additional sources when necessary and will be mentioned in due course.

Appendix A. Generation units on the island

At the start of this study, we have chosen Sardinia as it had many attractive features for the implementation of our model; that is, a portfolio of conventional generators (several thermal and one hydro), major wind power plants and relatively small solar PV installations, mostly rooftops spread across the island, producing less than half of the wind. Although this study has not intended for the island itself *per se*, it must nonetheless rely on some features present on the island; i.e., the number and nature of generators, network structure, etc. As this research has matured, we have also witnessed a great transformation on the island electricity generation portfolio, but those attractive features continue to hold to a large extent.

Our research from two aforementioned major data sources indicates that all nine thermal units at four locations are still operational with their capacities given in the text. The island also has one hydro power plant with a maximum generation capacity of 240 MW per hour and an estimated reservoir capacity of 10 GWh. The effective rate of generation naturally depends to a greater extent to the accumulation rate of the reservoir. The average rate of hydro generation is much lower than the maximum. A regional generation summary by the Italian transmission operator Terna S.p.A. indicates that Sardinia has produced 425 GWh of hydro in 2020 [52], while an Italian renewable energy company Gestore dei Servizi Energetici (GSE, S.p.A.) cites 337 GWh (29 kilotonnes of equivalent oil) in 2021 [63]. They correspond to hourly average generations of 48.4 MW and 38.5 MW, respectively. We simply took the average of these two years as a net generation and padded to account for a 6.5% generation loss, to reach an hourly average gross rate of 46.5 MW. Naturally, seasonal variations are also expected throughout the year. However, we could not find a publicly available source, and therefore we have used the rainfall index (obtained from https://weatherandclimate.com/italy/sardinia) on the island as a proxy for the average monthly reservoir accumulation rate. Consequently, the monthly precipitation averages and the corresponding reservoir accumulation rates are provided in Table 9.

Finally, we have recompiled the list of wind farms operating on the island and identified in total 30 major farms as of August 2024, listed in Table 10. The table contains relevant information on the characteristics of the farm (e.g., capacity and location) and the source of information. Although some farms are very close to one of the 13 nodes in our network, some are relatively further away from any of them. Therefore, we have considered the existing transmission and sub-transmission grid structure on the island, for example the one given in Corona et al. [51], and visually assigned them to their nearest nodes accordingly. As a result, we identified nine locations with some wind generation. Note that the listed capacities are design capacities; actual average production rate is assumed to be 30% of the capacity, which is given in the main text in Table 2.

Appendix B. BESS and PHS cost estimations

Our main source for the costs of both technologies is Mongird et al. [44], who has substantially improved on their original work [43]). In their report, they provide cost estimates for 12 different Li-ion battery configuration; a combination of three power rates (1 MW, 10 MW, and 100 MW) and four service times at maximum powers (2, 4, 6, and 8 h). We have chosen a 10 MW power rate configuration, as the other two seemed too small or too large for the island. We have also picked the 6-hr case. Eventually, all these estimations are rough

Table 9
Average monthly precipitation in Sardinia.

Month	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Avg
Avg. precipitation (mm)	102.9	103.3	107.3	104.0	126.4	67.4	47.4	65.8	90.4	90.4	135.8	80.3	93.4
Reservoir fill rate (MW)	51.2	51.3	53.3	51.7	62.8	33.5	23.6	32.7	44.9	44.9	67.5	39.9	46.5

Table 10
Major wind farms on the Island.

Node/Wind Farm	Capacity (MW)	Latitude	Longitude	URL: https://www.gem.wiki/
Cagliari	68			
Energia Verde–1	21	39.3424	9.3593	`Energia_Verde_wind_farm`
Nurri	22	39.7236	9.1851	`Nurri_wind_farm`
San Basilio	25	39.5480	9.2344	`San_Basilio_wind_farm`
Codrongianos	488			
Nuova Altanurra	12	40.8383	8.2947	`Nuova_Altanurra_wind_farm`
Viddalba	23	40.9215	8.9854	`Viddalba_wind_farm`
Tula–1	33	40.7786	8.9731	`Tula_wind_farm`
Florinas	20	40.6422	8.6638	`Florinas_wind_farm`
Littigheddu	54	40.8511	8.7800	`Littigheddu_wind_farm`
Nulvi	16	40.7660	8.7446	`Nulvi_wind_farm`
Ploaghe	27	40.6652	8.7455	`Ploaghe_wind_farm`
Sedini	10	40.8511	8.7800	`Sedini_wind_farm`
Tula–2	51	40.7579	8.9543	`Tula_wind_farm`
Bonorva	74	40.3958	8.8073	`Bonorva_wind_farm`
Buddusò-Alà Dei Sardi	138	40.6121	9.2222	`Buddusò-Alà_Dei_Sardi_wind_farm`
Anglona S.R.L.	30	40.7838	8.7437	`Anglona_S.R.L._wind_farm`
Fiumesanto	46			
Fiume Santo	16	40.8332	8.2914	`Fiume_Santo_wind_farm`
Fiurme Santo	30	40.8312	8.3781	`Fiurme_Santo_wind_farm`
Oristano	184			
Monte Grighine	99	39.9041	8.5844	`Monte_Grighine_wind_farm`
Energia Alternativa–2	24	40.1207	9.0130	`Energia_Alternativa_wind_farm`
Villacidro	31	39.8730	8.4412	`Villacidro_wind_farm`
Siamanna	30	39.9205	8.7610	`Siamanna_wind_farm`
Taloro	126			
Ulassai–1	96	39.7201	9.4944	`Ulassai_wind_farm`
Ulassai–2	30	39.7201	9.4944	`Ulassai_wind_farm`
Villasor	171			
Campidano (Alerion)	70	39.4833	8.8994	`Campidano_(Alerion)_wind_farm`
Campidano (EDF)	70	39.5341	8.6002	`Campidano_(EDF)_wind_farm`
Medio Campiadano	31	39.4582	8.7352	`Medio_Campiadano_wind_farm`
Olbia–Bortigiadas	18	40.8923	9.0429	`Bortigiadas_wind_farm`
Selargius–Guardionara	25	39.5371	9.1982	`Guardionara_wind_farm`
Sulcis–Portoscuso	90	39.1988	8.4385	`Portoscuso_wind_farm`

for similar installations, differing only for scales. For the PHS, there are cost estimates for two main sets of configurations; i.e., those with 100 MW or 1000 MW power rates. Given that the hourly demand on the island is in the vicinity of 1000 MW per hour, the larger option is clearly excessive. Therefore, we have chosen the smaller one. i.e., the one with 100 MW power rate. The particular investment cost estimates are taken from them for the chosen configurations (see pp. 87 in Appendix 1 for BESS and pp. 61 for the PHS) and reproduced is in Table 11.

Table 12 first gives values of operational characteristics of the storage technologies, i.e., lifetime and the round-trip efficiency estimates, both of which depend very much on the operating conditions, maintenance, and refurbishments activities. Mongird et al. [44] take 86% round trip efficiency and 10-year life for the BESS as the standard, but also refer to two past works that give ranges of as wide as 77%–98% or as narrow as 83%–87% (see pp. 13 of their report). Another report, published by the US government agency National Renewable Energy Laboratory, gives a range of low 80% to low 90% and a lifetime of 10–20 years [64]. Hence, based on these results, we have chosen such three point estimations BESS characteristics, which might be perceived as slightly on the optimistic side. For PHS, [44] give 80% of round-trip efficiency and 40 years as the lifetime, but again quote a range for the efficiency of 70%–87% and lifetimes of upwards of 50 years. In a more in-depth study of PHSs, Blakers et al. [42] quote a potential round-trip efficiency of as high as 90% and lifetimes of over 60 years. Therefore, based on these they we have given again such three point estimations, which again might be slightly on the optimistic side overall, but certainly within reasonable values.

Based on these operational characteristics and the cost figures given in the previous table, we have annualized them to give a three-point estimate with an annual discount rate of 2.75%. Given that such major energy investments are supported or sometimes even undertaken by governments, we have used a discount rate of 2.75% to find the annual investment costs. The last data given in the table are also from Mongird et al. [44], for the operations and maintenance costs for both technologies and all scenarios, which is quite different from what was reported in Mongird et al. [43] particularly for PHS, but we update these costs as such according to their latest report along with the investment costs.

Appendix C. Transmission line costs

Our main source for transmission line costs is a report by Parsons-Brinckerhoff and Associates [45] for England and Wales, overseen and endorsed by the Institution of Engineering & Technology, a global organization with more than 150,000 members representing a wide range of engineering and technology fields. This is a very comprehensive report covering a variety of transmission lines, with detailed cost breakdowns, and sources for raw data. It is perhaps the most comprehensive costing study that is publicly available, to the best of our knowledge. There are, however, some challenges in utilization of this report's results as they differ from storage cost data in three main points; geographically, temporally, and in currency. While Mongird et al. [44] report storage costs for the United States in US dollars (USD) for the year 2020, this

Table 11
BESS and PHS investment costs, due to [44].

BESS (Li-ion, 10-MW, 6-hr)	Optimistic	Likely	Pessimistic
Energy rate costs (all in $/kWh)	315	375	427
Storage block	155	172	189
Storage balance of system	35	39	43
System integration	33	45	50
Eng, procure, and construct	42	54	65
Project development	50	65	80
Power rate costs (all in $/kW)	100.2	111.8	122.4
Power equipment	66	73	80
Controls and comm.	7	8	9
Grid integration	22	25	27
Fixed O&M	5.2	5.8	6.4
PHS (100-MW, 10-hr)			
Energy rate costs (all in $/kWh)	73	81	89
Reservoir construction, etc.	73	81	89
Power rate costs (all in $/kW)	768	1,239	1,363
Powerhouse construction, etc.	321	742	817
Electro-mechanical	420	467	513
Fixed O&M	27	30	33

Table 12
BESS and PHS cost estimations.

Operational characteristics	Optimistic	Likely	Pessimistic
Round-trip eff. (%); BESS (PHS)	95 (85)	90 (80)	85 (75)
Operational life (year); BESS (PHS)	15 (60)	12 (50)	10 (40)
Annual costs (Discount rate = 2.75%)			
BESS energy rate ($/MWh-year)	25,624	35,453	48,830
BESS power rate ($/MW-year)	12,948	15,821	19,645
PHS energy rate($/MWh-year)	2,314	2,797	3,421
PHS power rate ($/MW-year)	52,580	74,896	88,260
Variable O&M costs ($/MWh)		0.5125[a]	

[a] Applies to both PHS and BESS ın all cases [44].

report is mainly for England and Wales based on the prices in the last quarter 2011 and in the currency of GB Pounds (GBP). Naturally, one might also question the suitability of these sources for a case study based on Sardinia. We must re-iterate that the choice of Sardinia is mainly due to its suitability for the implementation of our model. i.e., heavy wind penetration, portfolio of conventional units, and its manageable size. As for the cost data we believe BESS costs particularly must be rather more uniform globally, while PHS and transmission costs very much dependent on the topography of the region under study. Hence, anything short of island-specific cost information for the latter two is bound to be rather imperfect. Furthermore, we have found no comparable data source particular to the island of Sardinia, nor to Italy, nor even to a comparable region in Europe.

There are several attractive features of the Parsons-Brinckerhoff and Associates [45] report, in addition to its comprehensiveness and transparency. Firstly, although it is done for England and Wales, its raw data had come from all over the world (listed on pages 177–178 of their report). As they admit, not all organizations have responded with the same quality or care, but the authors state that those estimations related with overhead lines (OHL) are perhaps the most complete and detailed among other types of line they report. Secondly, the major part of OHL costs comes from various sources. For example, construction costs, estimated to be about one-third of the total, are obtained from one UK and three European Union (EU) countries, while particular material costs are obtained from several other sources: those of towers from Turkey, strings and insulators from Sweden, Germany, and a UK/Austrian firm, conductors from Bahrain and India, and optical ground wire costs from the UK (see Appendix E-7 in their report). Hence, the cost data produced for the particular transmission lines that we use has quite a significant global input to render it a more plausible source in general.

In this part of the Appendix, we will describe our assumptions, procedures, and additional sources to bring the transmission costs at a reasonably commensurate level with the storage costs. For that purpose, we have also made use of the UK Producer Price Index (PPI) for the production price of electrical equipment, supplied by Statista, Inc.[65], US PPI for electric power production supplied by the Federal Reserve of Bank of St. Louis [66], and the GBP/USD exchange rates for the years 2010 and 2020 from the website of Exchange Rates UK [67].

We now move on to the particular portions of the report and first use their estimates to construct a cost model. We then describe the utilization of the model and other sources to update those estimates for the transmission line options in our case. The most relevant parts of the report by Parsons-Brinckerhoff and Associates [45] are those related to 400 kV AC OHL with the lowest capacity; those with 3190 Mega volt amperes (MVA), which is practically sufficient for all the transmission needs of the island. Parsons-Brinckerhoff and Associates [45] give detailed cost estimates for the specified lines for lengths of 3, 15, and 75 km on pages 22, 28, and 34 of their report, respectively. From these estimates, we only consider fixed and variable "build costs" as investment costs. They have also reported three major operating costs; costs of power losses, energy losses, and operations and maintenance (O&M) costs. We have disregarded the first two and considered only the last one. The costs of power losses are due to transmission losses that require additional generation, and the costs of energy losses are due to *building* extra generation capacity to compensate for power losses and shortages. In our model, we have already taken the former into account by explicitly considering losses on the lines. For the latter, we really have no basis for inclusion as it refers to the cost related to additional generation capacity investment, which is not part of our model. In any case, we do have a large penalty cost in the model that prevents power shortages, and thus, perhaps, acting as a proxy.

Table 13
Transmission cost estimation: Part I.

Length	Load	Length	Total costs (£K)		Modified costs (£K)		Residuals (£K/km)	
(km)	Factor	Factor	Build	O&M	Build	O&M	Build	O&M
1.5					1,784	108	0.0	0.0
3.0	0.733	± 0.459	4,500	200	3,299	200	28.8	−3.8
4.5					4,813	292	30.8	−5.4
7.5					8,192	422	−22.4	0.0
15.0	0.725	± 0.472	21,400	800	15,515	800	−0.3	0.1
22.5					22,838	1,178	0.0	−0.1
37.5					36,364	1,883	22.6	0.6
75.0	0.713	± 0.491	100,200	3,700	71,443	3,700	10.7	0.0
112.5					106,521	5,517	0.0	−0.5

Build cost = 88 + (1,150)Length$^{0.959}$ and O&M cost = 24 + (57)Length$^{0.965}$.

Table 14
Transmission cost estimation: Part II (see the bottom for reference values).

	Length	Build costs (discount rate: 2.75%)				O&M costs (discount rate: 6.25%)				Total ($K, 2020)	
Line	(km)	(£K, 2010)	($K, 2010)	($K, 2020)	Annual	(£K, 2010)	(£K, 2020)	($K, 2020)	Annual	Annual	Monthly
1	40	39,582	62,243	69,936	2,883	2,028	2,229	2,854	193	3,076	256.3
2	27	27,183	42,746	48,029	1,980	1,396	1,534	1,963	133	2,112	176.0
3	40	39,582	62,243	69,936	2,883	2,028	2,229	2,854	193	3,076	256.3
4	120	113,314	178,187	200,210	8,252	5,810	6,386	8,174	553	8,805	733.7
5	20	20,409	32,093	36,060	1,486	1,051	1,155	1,478	100	1,586	132.2
6	90	86,023	135,271	151,990	6,265	4,407	4,844	6,201	419	6,684	557.0
7	100	95,156	149,634	168,128	6,930	4,876	5,360	6,861	464	7,394	616.1
8	80	76,847	120,842	135,778	5,596	3,936	4,327	5,538	374	5,971	497.6
9	20	20,409	32,093	36,060	1,486	1,051	1,155	1,478	100	1,586	132.2
10	200	184,858	290,689	326,617	13,463	9,495	10,437	13,360	903	14,366	1,197.2
11	120	113,314	178,187	200,210	8,252	5,810	6,386	8,174	553	8,805	733.7
12	110	104,252	163,937	184,199	7,592	5,344	5,874	7,518	508	8,101	675.1
13	30	30,063	47,274	53,117	2,189	1,542	1,695	2,170	147	2,336	194.7
14	7	7,516	11,819	13,279	547	397	436	558	38	585	48.8
15	25	25,256	39,715	44,624	1,839	1,297	1,426	1,825	123	1,963	163.6
16	65	62,992	99,055	111,298	4,587	3,226	3,546	4,539	307	4,894	407.9
17	30	30,063	47,274	53,117	2,189	1,542	1,695	2,170	147	2,336	194.7

1 GBP = 1.57 USD (2011, Q4), 1.28 USD (2020); UK PPI = 98.8 (2011), 108.6 (2020); US PPI = 133.5 (2011), 150.0 (2020).

Therefore, we have taken the fixed and variable build costs and O&M costs given by Parsons-Brinckerhoff and Associates [45], which are reproduced on the left side of Table 13. Also reproduced from their report are the load factors to adjust the costs for the 17% circuit loading (which is the lowest given in the report and sufficient for the Island's all needs) and length factors to approximate ±50% long lines from reported values (see, pages 23, 29, and 35 in their report). Using these factors, we have generated costs for nine lengths, which are produced in the middle portion of the table. We have used the length factor in both costs, but we used the load factor only for construction costs, as it seems to be irrelevant for the O&M costs. The authors describe the cost components in O&M as "Route patrols and inspections, vegetation management, tower painting, and other work needed to maintain serviceability…" (see Appendix E-5 of the report), which probably depends more heavily on the length of the line than the load. Altogether, these three cost components suggest that transmission costs in our model are essentially a fixed cost and independent of flow.

Using these reproduced costs, we then move to find an estimate for the build and O&M (we have preferred to keep them separate for reasons to be explained shortly). We have tried and tested a linear and a particular concave cost forms with several measures i.e., ordinary least squares and mean absolute (percent) deviation. All of them fit the data near perfectly with upwards of some 99% R-squared, but the residuals of linear models have indicated some slight non-linearity, which might particularly impact the quality of estimations used in extrapolation. Therefore, we have chosen concave cost functions with the minimization of the mean absolute percent deviation criterion. In any case, however, except for the two line lengths at the extremes, the values from all those models are rather close.

Using these concave functions, we have estimated the transmission line costs of the island, which are given in Table 14. As mentioned above, we need to bring these estimates to 2020 USD figures. Naturally, there are significant price changes in more than nine years, but also dramatic changes in the exchange rates. It is difficult to claim that there is one perfect way, but we have opted to convert the build cost first to US dollars in 2011 and then apply the US price index to bring the prices to the 2020 dollars. As mentioned earlier, this part of the cost is to a very large extent obtained globally and given the prominence of US dollar in the global trade, we believe this to be a more prudent approach. O&M costs, on the other hand, are most likely driven by domestic estimates (although we could not detect a particular note in the report, its description suggests mainly locally driven costs), for which we have found it more acceptable to adjust them to 2020 GB pounds and then convert to US dollars. The large portions of 14 show the estimation steps of these two cost components.

While Parsons-Brinckerhoff and Associates [45] estimate the total build costs as upfront costs, they actually estimate first the yearly O&M costs and then compute its net present value for a 40-year lifetime and 6.25% annual discount rate (see Appendix D-8 in their report). They justify such a high discount rate "for the purposes of assessing rate of return on investment for transmission companies". Hence, we have used their rate to find the annual O&M costs. For investment costs, however, it is probably more appropriate to use a discount rate that is closer to the cost of borrowing. Given that such major energy investments are supported or even undertaken by governments, we have used a much lower discount rate of 2.75% to find the annual cost of construction. This is also the same discount rate we have used in storage costs. Table 14 details all of these procedures for the 17 line alternatives that we have in our case. The last two columns give total annual costs, which is the sum of those two components and the monthly costs, which are not further discounted, but taken as 1/12th of the annual cost.

Data availability

Data will be made available on request.

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