An inverse finite element method for beam shape sensing: theoretical framework and experimental validation

International Journal of Hydrogen Energy 210 (2026) 153627

Contents lists available at ScienceDirect

International Journal of Hydrogen Energy

journal homepage: www.elsevier.com/locate/he

Hybrid superconducting energy pipelines: key cost thresholds and system implications for Italy

Matilde Cais [a], Matteo Nicoli [a,b,*], Marta Gandiglio [a], Michela Bracco [c], Marco Breschi [d], Lorenzo Cavallucci [d], Stefania Farinon [c], Antonio Macchiagodena [d], Giovanni Mangiulli [a], Riccardo Musenich [c], Laura Savoldi [a]

[a] Department of Energy "Galileo Ferraris", Politecnico di Torino, Italy
[b] Department of Economics and Statistics "Cognetti de Martiis", Università degli Studi di Torino, Italy
[c] National Institute for Nuclear Physics, Genova, Italy
[d] Department of Electrical, Electronic and Information Engineering "Guglielmo Marconi", Università di Bologna, Italy

ARTICLE INFO

Handling Editor: Ramazan Solmaz

Keywords:
Superconducting pipelines
Energy system modeling
Energy planning
Decarbonization
Transmission systems

ABSTRACT

Hydrogen is a key vector for energy-sector decarbonization by 2050, yet large-scale transmission options are limited. This study evaluates the cost-competitiveness of a hybrid SuperConducting Energy Pipeline (SCEP) simultaneously delivering electricity and liquid hydrogen, firstly introduced in a scenario-based capacity expansion analysis within a multi-vector energy system model. A multi-region optimization model of the Italian power and hydrogen sectors is developed using the open-source TEMOA-Italy framework. Multiple scenarios to 2050 explore emission targets, hydrogen generation options, and techno-economic parameters to assess SCEP deployment relative to conventional transmission lines. Results show the specific SCEP configuration becomes cost-effective below a capital cost around 610 M€/km/MW, or 1430 M€/km/MW if conventional line costs double. When adopted, SCEP promotes centralized hydrogen generation in high-renewable regions, increasing 2050 electrolysis output in Sardegna by ~10 times. Findings highlight SCEP's potential role in the Italian energy transition under specific economic and policy conditions.

Nomenclature

Acronyms	
AEM	Anion Exchange Membrane
AGNES	Adriatic Green Network of Energy Sources
CCS	Carbon Capture and Storage
CCUS	Carbon Capture, Utilization and Storage
CF	Capacity Factor
CHP	Combined Heat and Power
EMHIRES	European Meteorological derived High Resolution RES generation time series
ENSPRESO	ENergy System Potentials for Renewables
ESOM	Energy System Optimization Model
ETS	Emissions Trading System
EU	European Union
GDP	Gross Domestic Product
GHG	Greenhouse Gas
GH_2	Gaseous Hydrogen
IEA	International Energy Agency
INECP	Integrated National Energy and Climate Plan
IRENA	International Renewable Energy Agency
Istat	Italian Statistics Institute
JRC	Joint Research Centre
LH_2	Liquid Hydrogen
LNG	Liquefied Natural Gas
NREL	National Renewable Energy Laboratory
NUTS	Nomenclature of Territorial Units for Statistics
O&M	Operation and Maintenance
PEM	Proton Exchange Membrane
PRIN	Projects of Relevant National Interest
PSOM	Power System Operational Model
REPowerEU	European Commission Strategy for Energy Transition
SC	SuperConductor
SCEP	SuperConducting Energy Pipeline
SDD	Scenario Description Document
SOEC	Solid Oxide Electrolysis Cell
TEMOA	Tools for Energy Modeling Optimization and Analysis
Terna	Italian Transmission System Operator
TSO	Transmission System Operator

* Corresponding author.
E-mail address: matteo.nicoli@polito.it (M. Nicoli).

https://doi.org/10.1016/j.ijhydene.2026.153627
Received 28 October 2025; Received in revised form 16 December 2025; Accepted 19 January 2026
Available online 23 January 2026

Region Labels	
ABR	Abruzzo
BAS	Basilicata
CAL	Calabria
CAM	Campania
EMR	Emilia-Romagna
FVG	Friuli-Venezia Giulia
LAZ	Lazio
LIG	Liguria
LOM	Lombardia
MAR	Marche
MOL	Molise
PIE	Piemonte
PUG	Puglia
SAR	Sardegna
SIC	Sicilia
TOS	Toscana
TAA	Trentino-Alto Adige
UMB	Umbria
VDA	Valle d'Aosta
VEN	Veneto

1. Introduction

The expansion and modernization of transmission grids is set to become essential for the energy transition [1]. As energy system electrification is increasing to facilitate decarbonization [2], the importance of power transmission has grown [3]. An efficient transmission grid increases the cost-effectiveness of renewable capacity installations for regions where the spatial distribution of renewable generation potentials does not match the demand distribution [4]. Transmission grids need to be modernized and expanded through a comprehensive approach considering both the economic and technical aspects of grid operation, and the policy framework the grid operates in Ref. [5]. The transmission of electric power via cables is the standard option to link electricity production and consumption. Due to its favorable mechanical properties and low costs, the most used conductor type is aluminum conductor steel reinforced, while aluminum alloys and copper are usually adopted where the mechanical stresses are lighter and the priority is on increasing the cable conductivity [6]. As transmission distances and transmitted power increase, minimizing transmission losses becomes crucial. Research has increasingly focused on superconductors (SC) as electricity transmission options with negligible power losses [7]. However, for SC to become a practical substitute for part of the existing transmission infrastructure, significant cost barriers must be addressed, along with the integration of efficient cable cooling systems [8].

These technological challenges resonate with broader debates on how to enable efficient, secure, and low-carbon energy carriers across Europe. In this regard, both the REPowerEU Strategy [9] and the European Strategy for Hydrogen [10] identify hydrogen as a vector to facilitate the decarbonization of hard-to-abate sectors – such as transport and industry – while enhancing energy security. Additionally, hydrogen is recognized as a potential long-term storage option, with characteristics complementary to batteries [10]. Increasing the energy system reliance on hydrogen will require developing an efficient hydrogen transmission network, both at European and national level [10]. Although technologies for hydrogen transmission are available, their cost limits their application to point-to-point delivery from the production site to the location where the demand occurs. However, with the growing need for long-distance energy transmission, the transmission of the hydrogen energy carrier could become a viable alternative to conventional electricity transmission [11,12]. In this context, liquid hydrogen emerges as a promising medium for future energy networks, offering characteristics that complement and, in some cases, enhance traditional transmission approaches. The use of liquid-hydrogen transfer lines is well established in industrial applications, largely due to developments within the NASA space program [13]. Commercial solutions are available from several suppliers [14,15]. Their feasibility for energy-distribution purposes has already been demonstrated on a small scale; for instance, the icefuel® project showed in 2010 that a mass flow rate of 10 MWt, a pipe diameter of approximately 20 mm, and a heat load below 1 W/m could enable transport distances of up to 10 km without intermediate cooling stations [16]. Given the hydrogen quantities required for climate-neutral energy systems, significantly higher mass flow rates are needed today.

The concept of hybrid pipelines combining high-temperature superconductors (HTS) with liquid hydrogen was first introduced as an early proposal in the early 2000s [17], followed by initial schematic designs [18]. Subsequent studies provided general technical background [19] and assessed long-term, continental-scale potential [20,21]. The simultaneous transmission of electrical power, chemical energy, and cooling potential through the use of cryogenic fuel as a cooling medium for SC cables [22] was found very promising to improve the overall efficiency of energy transmission [22]. Serving multiple functions at once could help overcome the high installation costs of the technology, making it more appealing despite its upfront economic challenges [23]. More detailed technical configurations were proposed, involving REBCO conductors and liquid hydrogen, with liquefied natural gas used as a refrigerant for an outer electrical-shielding layer [24,25]. A recent design and techno-economic assessment of a hybrid pipeline using REBCO and liquid hydrogen was presented in Ref. [26], where the corresponding transmission configuration was intended for railway systems rather than for a stationary transmission grid. The analysis in Ref. [27] presents a case study and conceptual design of a gigawatt-class, 75-km hybrid pipeline operated without intermediate cooling stations, combining a REBCO direct-current cable and a non-corrugated rigid pipe for liquid hydrogen, for a representative case study connecting between Brunsbüttel and Hamburg in Germany. The study is focused on the component and does not present any attempt of investigating the possible penetration of the technology in the German energy system.

REBCO offers higher current-carrying capability and a broader operating-temperature margin, allowing either reduced material use or enhanced safety margins, yet MgB_2 is more cost-competitive: in Ref. [28], a SuperConducting Energy Pipeline (SCEP) is designed, enabling the simultaneous transfer of electricity and liquid hydrogen (LH_2). The SCEP is composed of a superconducting cable in MgB_2 allowing the transfer of electric power, while LH_2 is the cryogen that cools the cable and transfers chemical power [29]. The study of the SCEP became part of the Italian Research Projects of Significant National Interest (RPNI) in 2023, in the framework of the Italian National Hydrogen Strategy [29]. In 2024, an innovative design for a SCEP configuration with a nominal power of 300 MW_e was proposed [28,30] to comply with constraints similar to those from the Adriatic Green Network of Energy Sources (AGNES) offshore renewable energy installation [31], while the design of the active auxiliaries, and the analysis of the pipeline operation in fault conditions are currently being assessed [32–34].

These studies on SCEP design and operation should be complemented by assessments that define the cost threshold for technology competitiveness. For now, the profitability of this specific configuration has not been characterized yet due to its low Technology Readiness Level. As SCEP remains in the pilot stages of development, significant uncertainties remain about its techno-economic parameters, particularly with respect to its large-scale deployment. For this reason, an economic evaluation of SCEP technology should be coupled with a sensitivity analysis to evaluate the maximum cost of the technology, making its installation profitable. In summary, although the concept and preliminary designs of the SCEP have been proposed, a significant gap remains in the techno-economic literature assessing its competitiveness as a transmission option, particularly under different cost assumptions and deployment scenarios.

Due to energy consumption and production patterns, Italy provides an ideal case study for assessing the techno-economic viability of this technology. Indeed, despite its relatively small extension, Italy is characterized by strong regional differences both regarding its socio-economical features [35], and its demand and resources distribution [36]. These aspects affect the energy intensity of each region and the capacity factors of generation technologies [37]. As a result, a mismatch between areas with high electricity demand and others with high resource availability occurs, making interregional transmission a crucial element of the Integrated National Energy and Climate Plan (INECP) [38], in accordance with Terna's Scenario Description Document (SDD). As the decarbonization of the power sector accelerates and the integration of variable renewable energy increases, an increased capillarity of the transmission grid is expected to be essential for efficiently balancing supply and demand across the country [39,40].

In this context, energy models are powerful tools as they enable the representation of complex systems used to execute exhaustive scenario analyses. They aim to represent phenomena or conditions which cannot be described or captured through experiments [41]. Two different approaches can be employed when modeling transmission systems at multi-regional level: focusing on capacity expansion on long time scales or analyzing the operational dispatch and the flexibility provision by storage facilities over shorter time scales [42]. Energy System Optimization Models (ESOMs) aim at finding cost optimal solutions for energy systems capacity expansion under defined constraints [43]. They are often used to explore and compare different scenarios to evaluate long-term investment planning [44]. Although multi-sectoral ESOMs can in principle describe multi-regional systems, most are designed to analyze capacity expansion scenarios across end-use sectors within a single or a few regions. As a result, transmission systems are rarely represented in detail. Even when they are included, the emphasis is typically on capacity expansion of traditional lines rather than on the techno-economic competition between conventional and innovative options. This leaves a clear gap in the literature regarding comparative analyses of innovative transmission technologies (as the SCEP) with conventional ones.

Among ESOMs, various modeling frameworks have been developed. In particular, models like TIMES and OSeMOSYS are considered best practice in long-term scenario analysis [45]. One of these is the bottom-up tool TEMOA (Tools for Energy Modeling Optimization and Analysis) [45] which presents technology-explicitness (each technology being characterized by lumped technical and economic parameters), possibility to represent the energy system under investigation as a network of more spatial regions, partial equilibrium in competitive markets with perfect foresight. Furthermore, a recent study compared the TEMOA framework to three other open-source capacity expansion models in a US case study, highlighting the intrinsic similarity in their results when inputs are aligned [46]. In Ref. [47] TEMOA-Italy was tested on its capability to model the technology mix from its base year (2006) to the first year of the optimization (2022): the model results fit historical data by the Eurostat Energy Balances for that period. Additionally, TEMOA endogenously includes techniques to handle uncertainties like stochastic optimization [48], modeling to generate alternatives [49], and multi-objective optimization [50]. Given such features, the capability of representing multi-sectoral interactions (crucial for hybrid technologies [51]) and the possibility of producing capacity expansion scenarios not neglecting operational issues (e.g., matching load and production profiles, capacity factors, etc.), TEMOA has been used for the analysis presented in this paper.

This paper aims at exploring the techno-economic conditions under which the SCEP may be cost-effective compared to traditional energy transmission systems in the Italian context, while also assessing its system-wide implications on electricity and hydrogen production and consumption patterns. The innovation of this work is twofold. First, it contributes to the emerging research field on superconducting energy pipelines by providing a transparent and model-based framework for multi-scenario analysis, enabling the exploration of the techno-economic conditions under which SCEP could become competitive with conventional transmission options. Specifically, it investigates the effects of alternative emission reduction targets, maximum potentials for renewable energy sources, and hydrogen production mode on the future Italian electricity and hydrogen production and transmission system. Second, it advances the field of temporally and spatially detailed energy system modeling by integrating an innovative transmission technology – characterized by hybrid electricity-hydrogen transport, cryogenic requirements, and parameter uncertainty – into a multi-regional ESOM. This allows the system evolution to be assessed under the potential availability of such an option, capturing interactions between electricity and hydrogen sectors, long-distance transmission needs, and regional resource disparities.

Section 2 presents the modeling framework, the characterization of transmission technologies, the main model constraints, and the explored scenarios. Then, the assumptions for the sensitivity analysis to verify SCEP competitiveness are discussed. A further description of the structure of the power and hydrogen sectors of the model and of the input data required for the characterization of all technologies is reported in the Supplementary Materials. Section 3 includes the discussion of the results for the electricity and hydrogen sectors, and the investigation of the cost barrier for SCEP to become a viable transmission option in the Italian energy system. Finally, Section 4 concludes the work and presents its main limitations and potential future perspectives.

2. Methodology

This section presents the modeling environment developed to explore the expected future evolution of the Italian electricity and hydrogen systems and the cost-effectiveness of SCEP in such a context. In this regard, a spatially detailed TEMOA model instance is used, adopting the same structure of the TEMOA-Italy power [47] and hydrogen sectors [52] concerning the considered technology options. The system is described as a network of 20 regions and several lines representing transmission lines between adjacent regions, as illustrated in Fig. 1.

The model objective function is reported in Equation (1), where $Cap_{t,p}$ and $Act_{t,p}$ represent the installed capacity and activity of technology t in period p, $C^{inv}_{t,p}$ denotes the annualized investment cost, $C^{fix}_{t,p}$ fixed O&M costs, and $C^{var}_{t,p}$ variable O&M costs.

$$\min \sum_{p \in P} \frac{1}{(1+r)^p} \left(\sum_{t \in T} C^{inv}_{t,p} \cdot Cap_{t,p} + \sum_{t \in T} C^{fix}_{t,p} \cdot Cap_{t,p} + \sum_{t \in T} C^{var}_{t,p} \cdot Act_{t,p} \right) \tag{1}$$

The optimization is subject to technical and environmental constraints such as capacity limits, activity bounds (which account for capacity factors and efficiency coefficients), service demand balancing, and emissions ceilings. Indeed, lumped techno-economic and environmental parameters are used to represent the aggregated performance of each technology, allowing complex physical and operational behaviors to be simplified into values suitable for tractable long-term optimization. In line with standard practice in the energy planning literature, the technologies included in the model are characterized by the following parameters (discussed for the TEMOA case in Ref. [52]):

- Input and output commodities.
- Input and output fuel shares.
- Efficiency, defining the conversion of input energy into useful outputs and capturing intrinsic technological performance.
- Existing capacity at the base year.
- Investment cost, representing capital expenditures annualized using a global discount rate and technology-specific lifetimes.
- Fixed operation and maintenance (O&M) cost.
- Variable O&M cost.

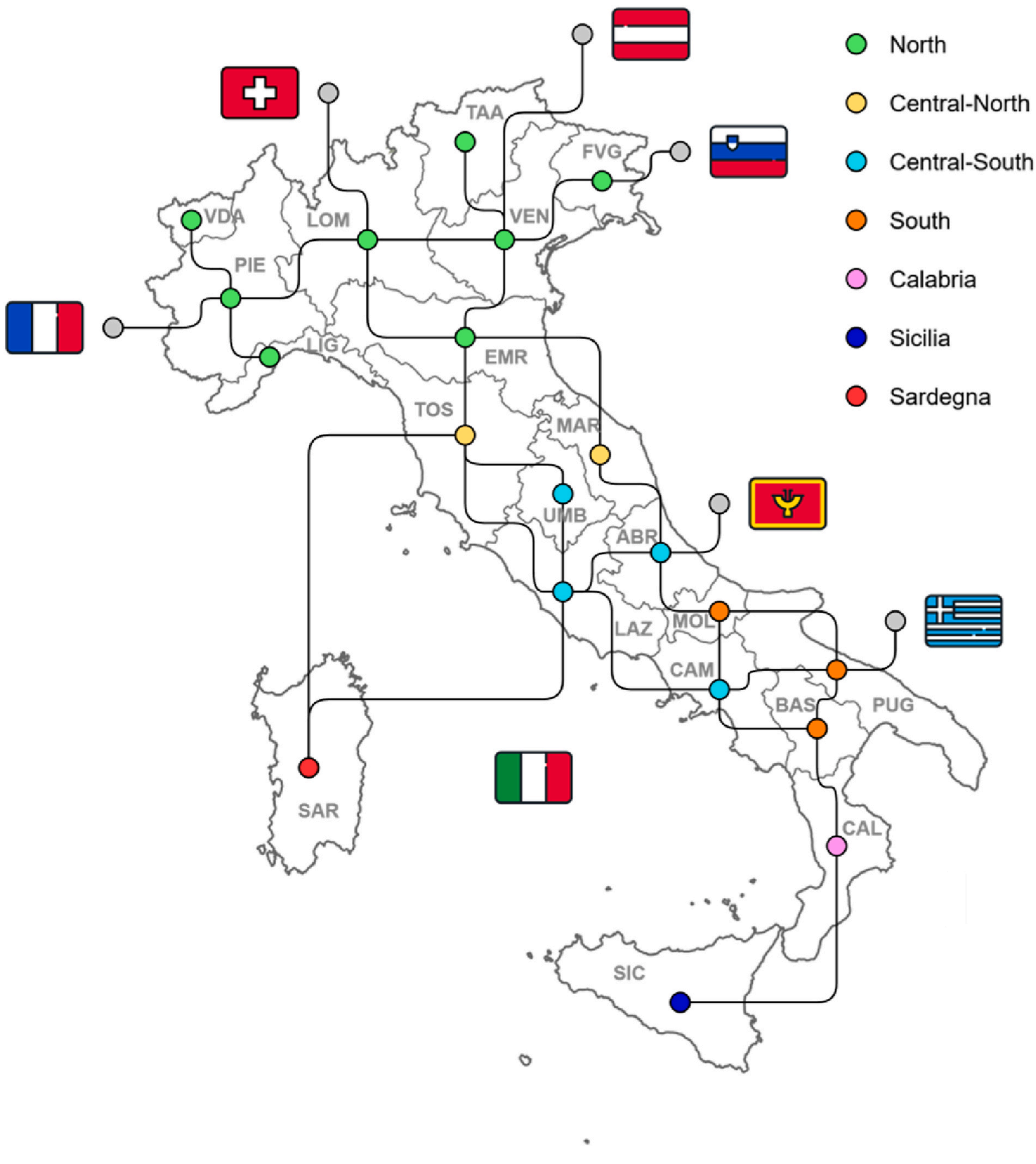

Fig. 1. Representation of spatial regions and transmission lines between adjacent regions as implemented in the model, where different colors represent bidding zones of the Italian Transmission System Operator (Terna). Icons are from Ref. [53]. (For interpretation of the references to color in this figure legend, the reader is referred to the Web version of this article.)

- Capacity factor, reflecting availability, maintenance needs, and underlying resource variability.
- Emission factors determining direct GHG or pollutant emissions per unit of output or input consumed.
- Material intensity.

In addition to such cost and performance parameters, the model includes several attributes used to represent reliability and environmental impacts. Time slice-dependent capacity factors determine the maximum achievable utilization of technologies throughout the year and are defined on a seasonal and diurnal basis. Technology reliability is also captured through constraints on maximum availability and derating parameters, which limit operable capacity when needed. In this context, technologies at earlier stages of maturity generally exhibit higher investment costs, lower efficiencies, and parameter uncertainty, which collectively influence their deployment potential.

The model covers the 2022–2050 period. Specifically, 2022 serves as the base year, representing the first time-period of the model in which the energy system is fully characterized. The base year is the starting point for building the model: national and regional energy balances [54] are used to define regional service demands and the technology mix required to meet them. Moreover, the techno-economic characteristics of each technology in the mix are known, as described in Ref. [47]. The model is then optimized from 2025 on, with a time-step of five years, specifically including 2025, 2030, 2035, 2040, 2045 and 2050. For each milestone year, the optimal technology mix for each region is calculated by minimizing the cost of the system while satisfying the electricity and hydrogen demands.

The model adopts a simplified intra-annual time resolution by dividing the year into four seasons, each representing one quarter of the year, a customary practice for capacity expansion ESOMs [47]. Within each season, a representative day is modeled using 24 hourly time slices, resulting in 96 time slices per year. Even though the modeling framework chosen does not allow a close representation of the intermittency inherent in renewable electricity production [55], this time-resolution is selected to catch the seasonal and daily fluctuations in the output of renewable technologies. In fact, with the focus being on the power sector dynamics, it is crucial to have an accurate time-resolution to represent both power and energy balances with better approximation.

The power sector produces and delivers centralized and distributed electricity, as well as heat. The upstream sector encompasses both the production of primary and secondary energy carriers - including fuels and hydrogen - and foreign trade through import and export activities. All sectors generate emission commodities such as CO_2, CH_4, and N_2O, with CO_2 also serving as a potential input for synthetic fuels production [52].

Technologies are classified as either existing or new. Existing technologies are those already present in the base year, with an existing capacity assigned in 2022 following energy balances by Ref. [54]. Specific constraints are included in the model to prevent new capacity of existing technologies being deployed and to represent their progressive end-of-life, allowing substitution by investment in new technologies. Given that, no investment costs are provided for existing technologies. The techno-economic parameters of new technologies, on the other hand, are specified from the first year of availability on. The details of the general model structure are described in the supplementary material. This included techno-economic characterization of existing and new power generation and storage options, hydrogen production and storage options, electricity and hydrogen demand levels, and their temporal distribution.

The characterization of the electricity and hydrogen transmission system, including the SCEP's techno-economic characterization, is presented in Section 2.1. Section 2.2 discusses the investigated scenarios aimed at exploring the system response under different assumptions concerning emission reduction targets, maximum potentials for renewable energy sources, and biomass versus electrolysis hydrogen production shares. Finally, Section 2.3 presents the methodology adopted for the evaluation of SCEP cost-effectiveness.

2.1. Electricity and hydrogen transmission

The modeling of the transmission infrastructure is the key feature of the multi-regional model, as it is essential to characterize the exchange of energy commodities consisting of the way regions interact. This step requires estimating representative transmission distances and existing transmission capacities between different couples of regions. Moreover, given the characteristics of the Italian territory, natural barriers sometimes prevent or discourage the installation of significant inter-regional lines. For these reasons and consistently with the current absence of significant transmission capacities, the deployment of new capacity is not allowed between some specific couples of adjacent regions (e.g., between Marche (MAR) and Umbria (UMB), as shown in Fig. 1).

Concerning representative distances for electricity transmission lines, in the context of this analysis they are estimated for each couple of interconnected regions with three different distance levels, namely 100 km, 150 km and 200 km (selected as proper qualitative representation of the average distance ranges between Italian regions). As shown in Fig. 1, twenty-five representative transmission lines are identified. Most of them are overhead lines, except for those connecting Sardegna (SAR) to Lazio (LAZ) and Toscana (TOS) and Calabria (CAL) to Sicilia (SIC), which include submarine lines. These line types and distances are used in the present study for the techno-economic characterization of both electricity and hydrogen transmission technologies. In fact, most of the parameters of these technologies are distance-dependent and therefore scaled according to the assumed distances. Moreover, modeling the electrical connections between adjacent regions with a single line is by itself a simplification of reality induced by the model structure. Although this modeling choice certainly introduces approximations in the estimation of the investment costs for deploying new transmission lines, this assumption is consistent for all the technological options competing for the same transmission lines, thus expected to not significantly affect technology competition.

2.1.1. Electricity transmission characterization

The model includes both existing and new technologies for electricity transmission. The first group mimics the current grid configuration: an existing capacity for each transmission line is assumed in the base year, based on the regional energy import data in 2022 [56]. The proposed disaggregation of existing capacities between macro-regions into existing capacities between single regions is made based on the historical electricity import/export value of each region [56], as reported in Table 1.

As regards the distances between different regions and due to the lack of available data for these specific model input, such existing capacities are characterized by significant uncertainties. Nevertheless, this is expected to marginally affect the model results especially far from the beginning of the time horizon, as any existing capacity constraints are disposed within the technology lifetime span. In any case, the adopted disaggregation method is supported by comparing the resulting transmission capacities between different bidding zones to 2022 Terna data, reported in Table 2.

The new conventional technology still describes the traditional electricity transmission infrastructure, but it is available for capacity additions according to specific future scenarios. Following common practices in the ESOM field, existing capacities are progressively phased out by applying decreasing constraints which start in this case with a cap at 80 % of the 2022 capacity in 2025 and reach 0 in 2050. The new

Table 1
Assumed existing capacity for the existing electricity transmission between couples of interconnected regions in 2022.

Interconnected Regions		Existing Transmission Capacity (GW)
ABR	LAZ	1.27
ABR	MAR	0.78
ABR	MOL	0.31
BAS	CAL	1.10
BAS	CAM	0.94
BAS	PUG	1.92
CAL	SIC	1.11
CAM	LAZ	1.90
CAM	MOL	0.94
CAM	PUG	2.64
EMR	LOM	0.59
EMR	MAR	1.08
EMR	TOS	1.02
EMR	VEN	2.31
FVG	VEN	2.43
LAZ	SAR	1.42
LAZ	TOS	1.59
LAZ	UMB	1.39
LIG	PIE	1.69
LOM	PIE	1.63
LOM	VEN	1.91
MOL	PUG	1.92
PIE	VDA	1.70
TAA	VEN	1.93
TOS	UMB	0.85

Table 2
2022 transmission capacities between bidding zones from Terna [56].

Interconnected Bidding Zones		Existing Transmission Capacity (GW)
Northern Italy	Central Northern Italy	3.70
Central Northern Italy	Central Southern Italy	2.85
Central Northern Italy	Sardegna	1.17
Central Southern Italy	Southern Italy	3.70
Southern Italy	Calabria	1.73
Calabria	Sicilia	1.40

technology progressively substitutes the existing one, allowing the model to develop a more flexible system, free from the hypotheses made at the existing capacity of 2022.

The technical parameters of existing and new conventional electricity transmission technologies are identical, while investment costs are defined only for new technologies. The efficiency for each line is calculated by considering power losses of 7 %/1000 km as in Ref. [57]. To assign the proper techno-economic parameters, each transmission line is classified as either Alternating Current (AC) or Direct Current (DC) based on the contribution of each line type along the distance between the centers of adjacent regions. For example, the lines connecting SAR to LAZ and TOS are categorized as DC lines, as most of their length is submarine. In contrast, the line between CAL and SIC is considered an AC line since the submarine portion is negligible compared to the overall distance between the centers of the two regions. In accordance with [58], the investment cost for each overhead AC line is set at 400 €/km/MW [59] and at 970 €/km/MW [60] for each DC submarine line. For both the line types, the fixed operational and maintenance cost is set to be 2 % of the investment cost, and a discount rate of 5 % is applied. The Capacity to Activity ratio, representing a conversion factor related to the energy that would be produced when one unit of capacity is fully used in one year, equals 31.536 PJ/GW [61].

2.1.2. Hydrogen transmission characterization

Hydrogen transmission is still an innovative technology; hence, its techno-economic characterization carries significant uncertainties. According to the literature [62], gaseous hydrogen (GH_2) transmission in pipelines is considered the most cost-effective solution for hydrogen mass flow rates exceeding 150 t/day. Alternative transmission means consist of hydrogen transport via trucks or rail, both in compressed gaseous and in liquefied form [62]. The transmission of LH_2 is competitive by truck for low hydrogen mass flow rates on annual basis, and by rail for long distances and low hydrogen mass flow rates, while GH_2 on-road transport is never competitive [63]. Given the transmission distances and hydrogen demand adopted (as detailed in Section 2.3) [63], dedicated pipelines for GH_2 are the most appropriate technology to characterize hydrogen transmission in the analysis, thus they are the only hydrogen transmission technology described in the model. The possibility of transporting hydrogen via repurposed natural gas pipelines is neglected for simplicity, being less of a cost-effective solution in long-term scenarios [64].

Pipelines for hydrogen transmission are introduced in the model as a new technology, available from 2025 as for all other hydrogen-related ones (see the supplementary material). The technology represents a single-line 70-bar pipeline (conservative assumption in line with [65]), with nominal power in the range 250–500 MW (consistent with both SCEP capacity and the modeled hydrogen demand as in Section 2.3). The information describing this technology is included in a dataset for transmission technologies from the Danish Energy Agency (DEA) [66] for 2020, 2030 and 2050. Values for 2025 are obtained by interpolating the data of 2020 and 2030. The techno-economic characterization of the hydrogen transmission pipeline as it is included in the model is reported in Table 3.

The electricity needed to compress hydrogen is embedded in the technology description and is considered as the sum of a fixed component for hydrogen compression and a variable one, to cover pressure losses depending on the length of the pipeline. For offshore pipelines, the investment cost values in Table 3 are increased by 40 % as resulting from Ref. [67].

2.1.3. SuperConducting energy pipeline characterization

The Superconducting Energy Pipeline (SCEP) is modeled as a dual-purpose infrastructure capable of simultaneously transmitting electricity and hydrogen [28]. SCEP is included in the model as a new technology, and it is implemented starting from 2025. The cable, with the layout shown in Fig. 2a, was originally designed for submarine installation over a length of several tens of kilometers without re-cooling stations, and can potentially carry 10 kA with a LH_2 mass flow rate up to 1–2 kg/s.

The first step for the inclusion of SCEP in the reference energy system consists of determining the electricity and hydrogen input and output shares for the technology. As stated in Ref. [30], the nominal electric power of SCEP is set at 300 MW. The cable is designed to operate at 20 K, and the LH2 acts as the coolant for the SC line, removing the parasitic heat load entering the cryostat with a typical lineic parasitic heat rate of 2 W/m. The mass flow rate can be tuned to guarantee the SC state everywhere along the cable, which can have a maximum outlet temperature $T_{out} < 29\,K$, as highlighted in Fig. 2b. Fig. 2c reports the layout of the hybrid pipeline, with evidence of the auxiliaries for the supply and management of the LH2. The GH2 in input to the process is assumed to be produced in a dedicated facility, while the LH2 in the storage tank can be either extracted in liquid form or in gaseous form to be then sent to downstream uses.

The presence of liquid hydrogen is necessary for SCEP operation and considering the electricity input for such an energy-intensive process becomes necessary. From the literature, current hydrogen liquefaction processes present a specific electricity consumption between 11.9 and 15.0 kWh/kg_{LH2} [68]. By averaging these values and applying the proper conversions, the electricity requirement for the liquefaction process is 0.404 kWh/kWh_{LH2}. The liquefaction process is included in the model as part of SCEP technology, as shown in Fig. 3. These liquefaction needs are considered embedded in each segment of the pipeline.

As from Fig. 2b, the hydrogen mass flow rate can vary between 0.6 kg/s and 3.5 kg/s with the respective operating conditions: $T_{out} = 29$ K, $\Delta p_{out} = 0.8$ MPa; $T_{out} = 23$ K, $\Delta p_{out} = 1.6$ MPa. In the operating range of the SCEP, five mass flow rate levels are selected and for each of them the following parameters – serving as an input for the model – are calculated and reported in Table 4:

a. the equivalent output power for hydrogen transmission P_{H_2}, determined as reported in Equation (2), where LHV_{H_2} is the lower heating value of hydrogen and $\dot{m}$ is the hydrogen mass flow rate in the pipeline;
b. the overall electricity-to-electricity and H_2-to-H_2 efficiencies representing both the losses of electricity and H_2 across the pipeline

Table 3
Techno-economic characterization of hydrogen transmission pipelines from Ref. [66].

Parameters	2025	2030	2050	Units
Electricity demand for compression	0.89	0.84	0.75	kWh_{el}/kWh_{H2}
Pressure losses	6.1	5.8	5.2	kWh_{el}/kWh_{H2}/1000 km
Investment costs	1.063	1.063	1.063	€/kW/km
Fixed O&M costs	0.404	0.266	0.199	€/km/MW/y

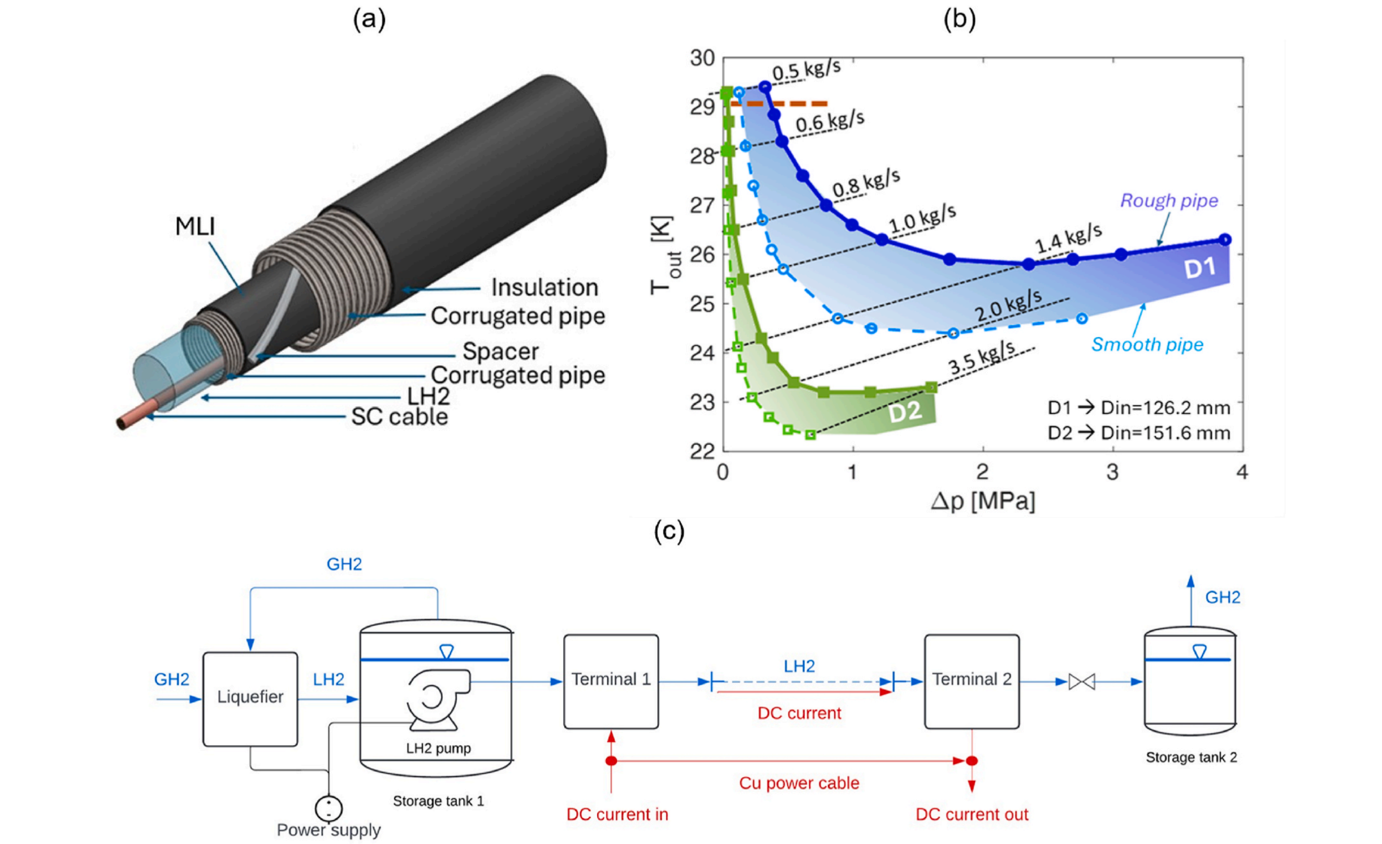

Fig. 2. Tentative layout of the SCEP considered in the present analysis (as designed in Ref. [28]), with a sketch of the auxiliaries. (a) Cable cross section, highlighting the superconducting (SC) cable, the inner corrugated pipe, confining the LH2 and surrounded by Multi-Layer Insulation (MLI), the low-conductivity spacer, the outer corrugated pipe constituting the outer cryostat, surrounded by the thermal insulation. (b) Operation range for the LH_2 pipeline in terms of outlet temperature and pressure drop along the duct. D2 is the cryostat corrugated pipe with $D_{in} = 126.2$ mm, D1 the one with $D_{in} = 151.6$ mm. [30]. (c) Layout of the hybrid pipeline, with the auxiliaries for the supply and management of the cryogen. These figures are modified from Ref. [59].

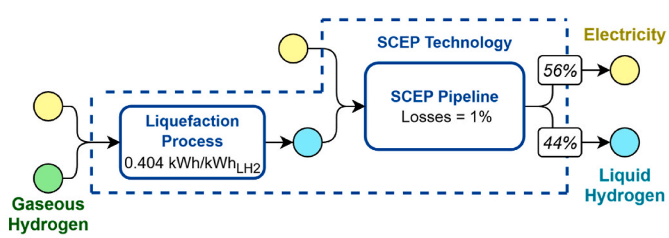

Fig. 3. Conceptual structure for modeling SCEP technology with a transmitted hydrogen mass flow rate of 2 kg/s.

Table 4
SCEP working parameters according to hydrogen mass flow rate in its operating range.

H_2 Mass Flow Rate (kg/s)	0.6	1.0	1.4	2.0	3.5
Electricity Power Output (MW)	300	300	300	300	300
H_2 Equivalent Power Output (MW)	72	120	168	240	420
Electricity-to-Electricity Efficiency	0.90	0.85	0.81	0.75	0.64
H_2-to-H_2 Efficiency	0.99	0.99	0.99	0.99	0.99
Input Electricity Share	0.82	0.74	0.69	0.62	0.53
Input H_2 Share	0.18	0.26	0.31	0.38	0.47
Investment Cost (€/km/MW)	2960	2620	2350	2040	1530

section (assumed equal to 1 %) and the electricity consumption for the liquefaction section;

c. the shares of both electricity and hydrogen being input to SCEP are calculated backwards considering the electricity needs for hydrogen liquefaction as well as electricity and hydrogen losses across SCEP;
d. the specific cost of the technology calculated by scaling the SCEP investment cost estimate – assumed of 1.1 M€/km for the superconducting cable [69] – according to the nominal power of the system, including both the electric and hydrogen equivalent power conveyed by the SCEP.

Since a precise cost estimation is not yet available for SCEP specifically, the aim of the activity is investigating at which cost-thresholds SCEP would become competitive, which could be achieved either by technology learning, or by subsidies to be introduced. The capital expenditures associated with SCEP within this study only serve as a reference cost value, necessary when analyses are made through least-cost-based models. The sensitivity analysis in Section 2.3 presents the methodology used for defining the cost thresholds for the SCEP technology to be tested in a selected scenario for the energy system.

$$P_{H_2} = LHV_{H_2} \cdot \dot{m} \tag{2}$$

The condition selected to test the cost-competitiveness of SCEP in the Italian power sector is far from thermodynamic limits. It consists of a mass flow rate of 2 kg/s with a T_{out} between 24 and 25 K and a Δp_{out} of around 1.8 MPa [30]. In this case, an electric output power of 300 MW corresponds to a hydrogen equivalent power of 240 MW, so the output electricity share is 56 % and the hydrogen one is 44 %, as represented in Fig. 3.

The selected configuration is used to compare the investment costs for traditional transmission (AC [59] and DC [60] electricity cables and hydrogen transmission via pipelines [66]) with SCEP one. The comparison is based on the equivalent cost of technologies, calculated using Equation (3) for both the onshore and offshore line configurations, where CI_{eq}, CI_e, and CI_{H_2} are the cost investments for the equivalent conventional transmission configuration, traditional electricity transmission, and hydrogen transmission, respectively. P_{eSCEP} and $P_{H_{2SCEP}}$ are the nominal electric and hydrogen equivalent power for SCEP and $P_{n_{SCEP}} = P_{e_{SCEP}} + P_{H_{2SCEP}}$ is the nominal total power of the technology.

$$CI_{eq} = \frac{CI_e \cdot P_{eSCEP} + CI_{H_2} \cdot P_{H_{2SCEP}}}{P_{nSCEP}} \tag{3}$$

As a result, the offshore configuration costs 1.7 times more than the onshore one. SCEP costs 2.9 times the traditional onshore configuration, and 1.7 times the traditional offshore configuration.

2.2. The investigated scenarios

In this section, the main assumptions used to build the scenario set necessary to test SCEP cost-competitiveness are explained. The scenario tree represented in Fig. 4 highlights the main variables changing from one scenario to the other.

Five levels of assumptions (reported in the left part of Fig. 4) – regarding demands projections, sectoral emission reduction targets, maximum capacities for solar and wind, and sources for hydrogen production – end up creating twelve scenarios for the Italian power and hydrogen sector. Optimizing the twelve scenarios enables the selection of the most relevant option for the subsequent analysis.

The first constraint regards the electricity and hydrogen demand used as input for the model. The two resulting scenarios groups refer to two different TEMOA-Italy scenarios: the first is a cost-optimal scenario without constraints on emissions, while on the second one a linearly decreasing CO_2 emission limit is imposed from 194 Mt in 2030 to 29 Mt in 2050. Specifically, the trajectory for the latter scenario is obtained from a combination of the Fit for 55 package of the European Green Deal [70] regarding the 2030 constraint and from the Italian Long-Term Strategy for the Reduction of GHG Emissions for 2050 [71]. The demand levels for BAU, Net-zero (N0) and Capture (C) scenarios are extracted from the results of these two TEMOA-Italy scenarios [72] – respectively the free one and the constrained one concerning emission limits – and are reported in Table 5.

The electricity demand in BAU scenario does not vary significantly from 2025 to 2050. Regarding hydrogen, its demand for the BAU scenario is imposed constant and equal to the 2025 hydrogen demand resulting from the TEMOA-Italy scenario with constrained emissions. Concerning N0 and C scenarios, the demand level of electricity steadily grows from 980 PJ in 2025 to 1430 PJ in 2050. Concurrently, hydrogen demand grows more than 10 times in the interval between 2025 and 2050 since hydrogen is a cost-effective solution for the decarbonization of hard-to-abate sectors like transport and industry [73].

To better contextualize and verify the assumptions made in Section 0, the hydrogen mass flow rates corresponding to the total hydrogen demand in the two scenario groups are obtained. The yearly hydrogen mass flow rate needed for the BAU group of scenarios is 69 kt/y from 2025 to 2050, while for N0 and C scenarios it goes from 69 kt/y in 2025 to 1400 kt/y in 2050.

The demand for each scenario is linked to the second set of constraints, regarding CO_2 emissions. From these two levels of constraints, three scenario branches are identified and are presented in Table 6. The emission trajectory for scenarios N0 and C is obtained from the previously cited scenario of TEMOA-Italy. The emitted tons of CO_2 resulting from TEMOA-Italy power sector serve as a constraint for the multi-regional model power sector in both N0 and C scenarios. Concerning the upstream sector, the emission trajectory from TEMOA-Italy is applied to C scenarios, whereas N0 scenarios do not allow a negative emissions cap: the minimum emission limit is set at zero.

The third set of constraints consists of imposing a limit on the maximum power of certain categories of technologies that the model can install. In this case, the two possible constraints imposed, divide scenarios between “constrained” scenarios, and “free” ones. “Constrained” scenarios include the constraints reported in the supplementary material for the maximum installable power for solar and wind sources, while for “free” scenarios such constraints are doubled from 2030 on.

The fourth set of constraints impacts the hydrogen sector since it considers a limit on the share of hydrogen that can be produced by biomass. This constraint distinguishes “non-BIO” scenarios from “BIO” scenarios. In fact, being biomass both the cheapest fuel for hydrogen production processes and a low CO_2 emitting one, other production processes hardly enter the technology mix. Consequently, in the “BIO” scenarios, hydrogen produced from biomass can account for at most 25 % of total hydrogen production.

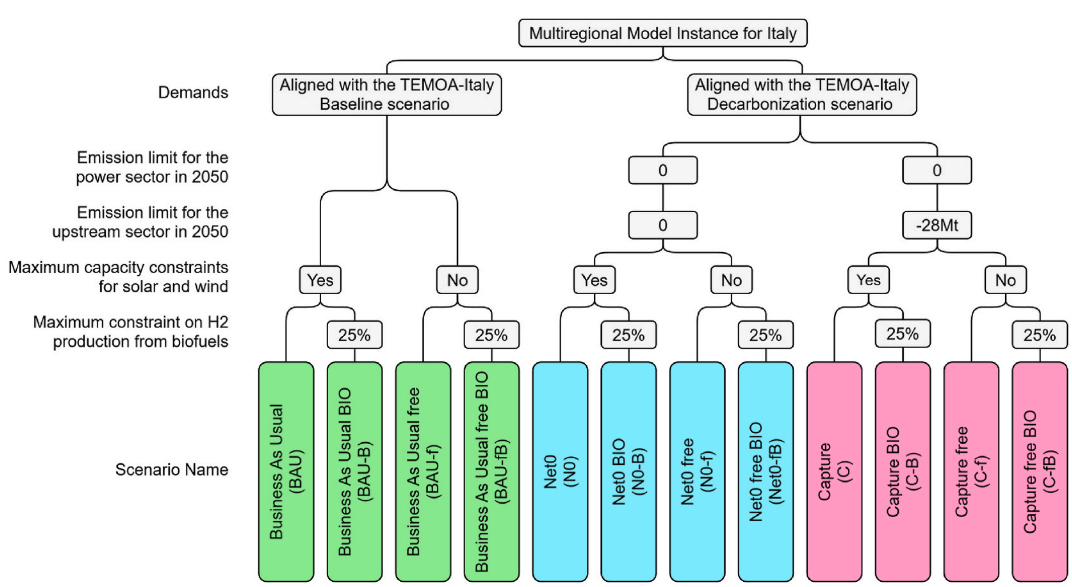

Fig. 4. Scenario tree for the multi-regional model to test SCEP cost-effectiveness in the Italian power sector.

Table 5
Electricity (a) and hydrogen (b) demand levels (PJ) for Italy in BAU and in N0 and C scenarios.

Scenario	Electricity						Hydrogen					
	2025	2030	2035	2040	2045	2050	2025	2030	2035	2040	2045	2050
Business As Usual (BAU)	969	984	979	1002	1017	1038	8	8	8	8	8	8
Net 0 (N0)	984	1086	1191	1295	1393	1432	8	72	106	124	144	164

Table 6
CO_2 emission limits (Mt) across the scenarios for power and upstream sectors of the multi-regional model.

Scenario	Power sector				Upstream sector			
	2035	2040	2045	2050	2035	2040	2045	2050
Business As Usual (BAU)								
Net 0 (N0)	22.5	12.1	9.7	0.0	5.8	1.6	0.0	0.0
Capture (C)	22.5	12.1	9.7	0.0	5.8	1.6	−11.0	−28.1

2.3. Evaluation of SCEP cost-effictiveness

The scenario used to investigate the cost-competitiveness of SCEP should be characterized by the following features: 1) presence of an emission limit, making it compliant with emission reduction targets from the European Union; 2) increasing transmission capacity from 2022 to 2050, to investigate the possible role of SCEP in substituting capacity additions of traditional lines; 3) diversified hydrogen production mix. Indeed, in the case of hydrogen fully produced by biomass, there would be no significant advantage in a hydrogen transmission system since all regions could easily sustain their own demand. The scenario analysis results (see Section 3.1) are used to select one of the twelve scenarios presented in Section 2.2, identifying the one that best aligns with the characteristics outlined above.

A sensitivity analysis is then performed to determine the minimum cost at which SCEP enters the technology mix. Such analysis varying cost parameters is expected to primarily affect the relative competitiveness of the hybrid cable compared with conventional transmission options, with negligible implications for the broader system configuration [74]. Two parameters are considered:

a. SCEP investment and fixed O&M costs;
b. investment costs for conventional electricity transmission.

The choice of the first parameter is consistent with the scope of the article: to investigate cost thresholds allowing SCEP deployment as a transmission option. The specific investment cost varies from 2040 €/km/MW of Tables 4–10 % of it, representing a sort of learning effect for the SC lines. This cost decrease is made in ten steps, each representing a 10 % cost reduction with respect to the starting cost. The fixed O&M costs are assumed 2 % of the investment cost, consistent with typical values for power sector technologies [75] and conservative compared to those reported for oil pipelines [76] and a lower bound is imposed, limiting them to be at least equal to the fixed O&M cost of electricity transmission.

The second parameter is used to highlight the possible effects of an external factor on the possibility of installing SCEP. An increase in the cost of metallic materials (mainly aluminum and copper) consequent to an increase in their demand for clean energy technologies [77] is set to cause an increase in the cost of traditional electricity transmission. Specifically, a cost variation of 0 %, an increase of 50 %, and an increase of 100 % are considered for traditional electricity transmission. The labels used in the rest of the manuscript for the investigated sensitivity scenarios are in the form SCEPXX_TRYY, where XX corresponds to the investment cost of SCEP as a percentage of the reference value, and YY corresponds to the investment cost of conventional transmission lines as a percentage of the reference value.

Subsequently, for a significant cost level, the sensitivity of SCEP capacity installed by the model to the nominal hydrogen mass flow rate in the pipeline is evaluated. To do so, the different hydrogen mass flow rate levels presented in Table 4 are considered, and their parameters are used to create five scenarios.

3. Results

3.1. Electricity generation, storage, and transmission

The first outcome of the model concerns the electricity generation mix in each of the scenarios introduced in Section 2.2. The most relevant results on this aspect are presented in Fig. 5 for 2025, 2030, 2040 and 2050.

In the BAU scenario, a change in the electricity mix from 2025 to 2050 is reported, driven both by the increase in the efficiency and the decrease in the investment costs of renewable technologies, and by the increase in the carbon pricing due to the ETS for fossil fuels (as in the supplementary material). Specifically, 66 % of the electricity in 2050 is expected to be produced from renewable sources, compared to 24 % in 2022 from Terna's data [54]. The results for the BAU-B scenario are not presented, as the differences in the power sector compared to the BAU scenario are negligible. In fact, the differences between these two scenarios lie in the constraints on H_2 production from biomass, and CO_2 is not capped, so electrolysis is not chosen by the model (see Fig. 7). As a result, there is no notable change in either the electric load or the capacity expansion of power generation between the two scenarios. The results of BAU-f and BAU-fB scenarios are not commented on since they obtain the same results respectively as BAU and BAU-B ones. In fact, in BAU and BAU-B scenarios the constraints on the maximum capacity of solar and wind are not reached, so the model configuration is not affected by having these constraints loosened (as in BAU-f and BAU-fB).

In the N0 scenario, the capacities of solar, wind, and thermoelectric increase with respect to BAU ones, to sustain the increased electricity demand. From 2030 to 2040, the electricity produced from thermoelectric source decreases, as expected, to comply with the emission constraints. However, the thermoelectric capacity remains constant to ensure an adequate reserve margin capacity for renewables.

Compared to the N0 scenario, the electricity mixes of both N0-f and N0-fb in 2040 and 2050 present a noticeably higher share of wind production. In N0-f the transition from 2030 to 2050 is smoother than the one in N0-fB scenario. In fact, in the latter, the model is incentivized to install more renewable capacity to decarbonize the power sector, since it is harder to reduce the emission of the upstream sector in case of limited access to biomass. The need for electricity to feed electrolysis hydrogen production – necessary to decarbonize the upstream sector under the constraints imposed – is also visible from the increase in the total electricity demand from scenario N0-f to scenario N0-fB. As in the case of BAU scenario, differences between the electricity mix of N0 and

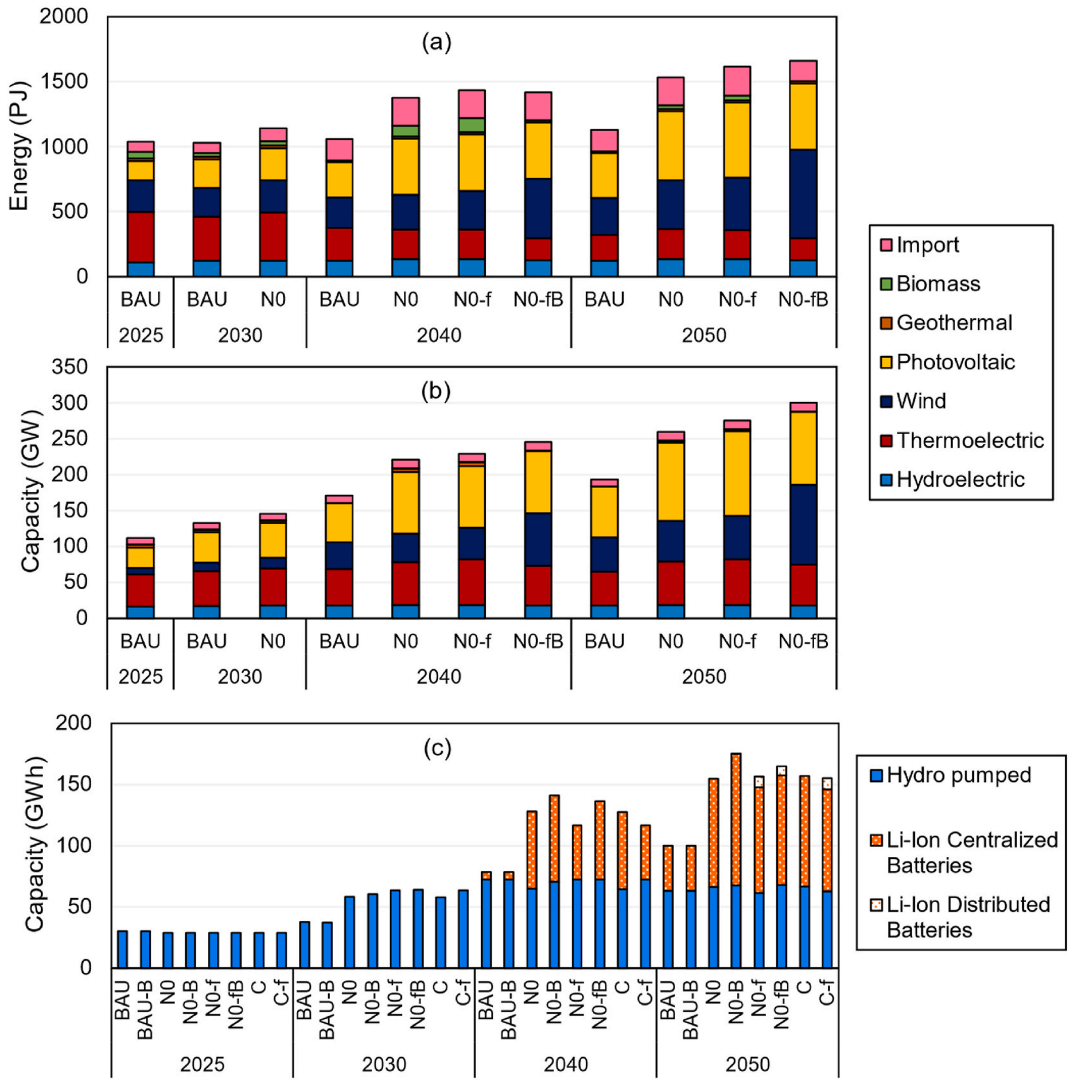

Fig. 5. Evolution of electricity production by source (a) and of available capacity by source (b), respectively, in the BAU, N0, N0-f and N0-fB scenarios. Storage capacity for electricity by technology kind in the scenarios (c).

N0-B scenarios are negligible, except for a slight increase in the total electricity demand in 2040 and 2050 to permit hydrogen production from electrolysis (see Fig. 7). For the C scenario, differences between its electricity mix and the one of N0 are negligible. The same happens between C-f and N0-f results. Apart from a negligible decrease in the thermoelectric generation compensated by a small growth of solar electricity and import, no significant difference is observed. Indeed, the main differences between these two pairs of scenarios are in the upstream sector, as from Fig. 7.

Storage capacity throughout the analyzed period in the different scenarios is presented in Fig. 5c. Two of the three groups of storage technologies are installed from the model: hydroelectric pumped storage and Lithium-Ion batteries. Vanadium-Redox-Flow batteries are not considered optimal in any scenario. Indeed, despite their specific investment cost becoming lower than the one of Lithium-Ion batteries from 2040, their lower efficiency and shorter life do not make them a cost-effective option. Regarding Lithium-Ion batteries, the largest fraction is made of centralized batteries, while distributed ones become cost-effective only in 2050 in N0-f, N0-fB and C-f scenarios. Up to 2030, the hydro pumped storage capacity is sufficient to sustain the needs of the Italian energy system. From 2040 on, Li-Ion batteries are installed in all scenarios. Concurrently, introducing an emission limit, the storage needs of the system significantly increase due to a higher renewable penetration in the technology mix.

To observe the spatial granularity of the results proper of a multi-regional model, photovoltaic, wind and storage capacities for the different regions in BAU, N0 and N0-fB scenarios are represented in Fig. 6. These three scenarios are selected as the most representative, since the others exhibit aggregated behaviors at national level that are comparable to those shown in Fig. 5b. In the northern regions, the installed capacities for these three categories do not vary significantly across the scenarios, except in the case of EMR. This region has the highest resource availability in Northern Italy due to the considered capacity factors and is therefore selected as the optimal location for renewable generation, particularly for solar, in the decarbonization scenarios. In the southern regions, CAM, PUG, and SIC show the largest increases in both renewable and storage capacities, with the largest share of installation being in wind capacity.

Another relevant aspect of the scenario analysis results is hydrogen production, with the evolution of its mix shown in Fig. 7. By observing the results reported in Fig. 7 for the BAU, N0, N0-f, C and C-f scenarios, biomass steam reforming is the cheapest hydrogen production process from 2025 to 2050. However, from 2040 on a small share of electrolysis enters the hydrogen production mix in some scenarios meaning that increasing the cost of natural gas and decreasing the CO_2 emission limit makes the two technologies compete. In C and C-f scenarios, to reach the

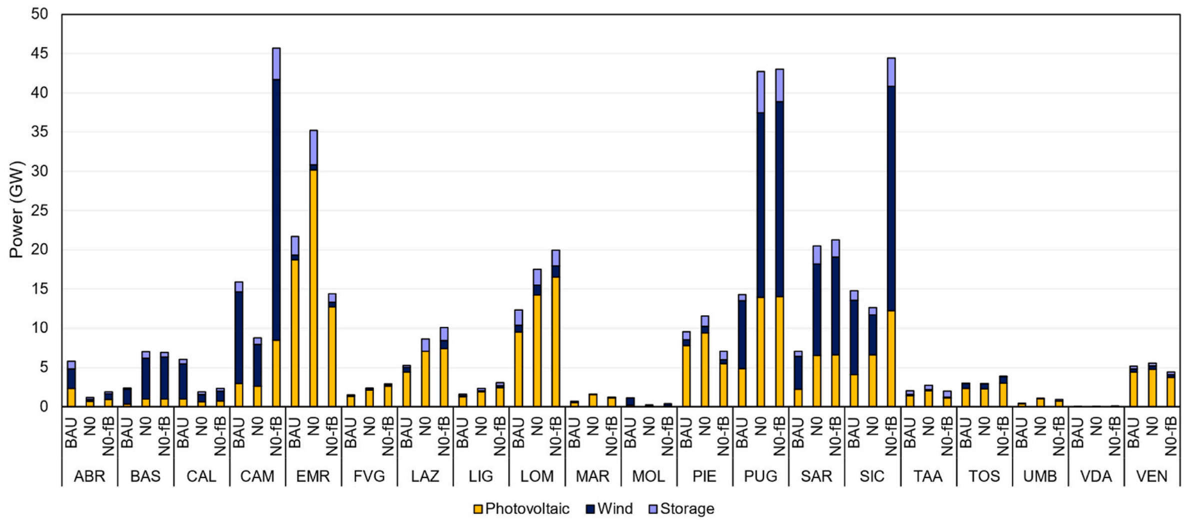

Fig. 6. Regional distribution of photovoltaic, wind and storage capacity in 2050 in scenarios BAU (a), N0 (b) and N0-fB (c).

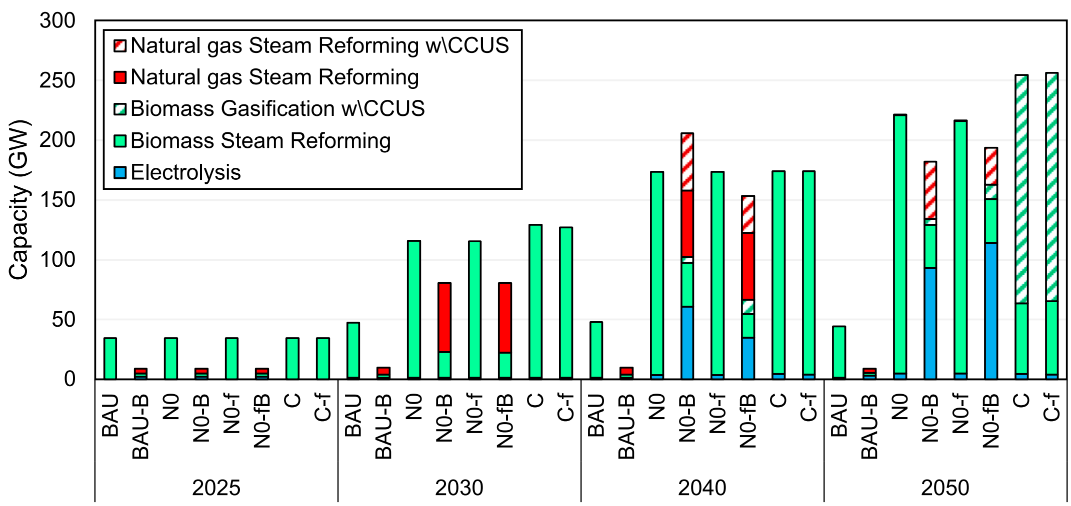

Fig. 7. Hydrogen production processes in different scenarios in the modeled period.

negative emission limits discussed in Section 2.2, the model needs to install biomass gasification plants with carbon capture for hydrogen production, despite the high costs.

The most interesting scenarios to observe are the N0-B and N0-fB ones. Due to the constraints imposed on hydrogen production from biomass and the high cost of electrolysis, up to 2030 the main hydrogen production method is steam reforming of natural gas. In 2040, emission limits become stronger and hydrogen demand grows, so new hydrogen production installations mainly consist of natural gas steam reforming facilities with CCS and of electrolysis ones. Finally, in 2050 hydrogen production from natural gas steam reforming without CCS is completely substituted by electrolysis.

The difference between the hydrogen production level in the different scenarios depends on hydrogen cost, which influences the cost-effectiveness of different hydrogen uses. From Table 5 it is evident that the exogenous hydrogen demand level for end uses is equal for the three scenarios in the same year. However, the total demand varies, mostly due to the quantity of hydrogen blended in natural gas pipelines. When hydrogen is produced by biomass gasification, blending with methane is a cost-effective solution to decrease the carbon content of natural gas. The production of synthetic fuels is not selected from the model except for a small fraction in scenario C-f in 2050 because of its high cost.

3.2. *Investigation of the cost conditions for SCEP competitiveness*

One of the scenarios presented in Section 2.2 is selected to perform the sensitivity analysis introduced in Section 2.3 to assess the possible penetration of the SCEP technology. Based on the results of the scenario analysis in Section 3.1, the N0-fB (Net 0 free BIO) scenario is chosen for evaluating the SCEP potential role in the Italian energy system.

The main electricity transmission lines resulting in the N0-fB scenario for 2050 are reported in Fig. 8a, where connections with the highest installed power in 2050 are those enabling electricity transmission from Southern Italy towards EMR and LOM. The installation of SCEP may be expected on the major power lines, favoring a more efficient electricity transmission.

In Fig. 8b is reported the transmission capacity resulting from scenarios BAU, N0 and N0-fB from 2025 to 2050 is compared to the existing transmission capacities in 2022 (taken from Terna statistics [56]). These three scenarios are selected because, as for the electricity mix, the results regarding transmission capacity for the BAU scenario are the same as BAU-B ones. The same happens for N0, N0-B and C and for N0-f and C-f.

As results of the BAU scenario show, lacking emission reduction targets the transmission capacity reaches values close to Terna ones. The comparison between the BAU and the N0 scenario shows that when emission reduction targets are introduced, the transmission capacity

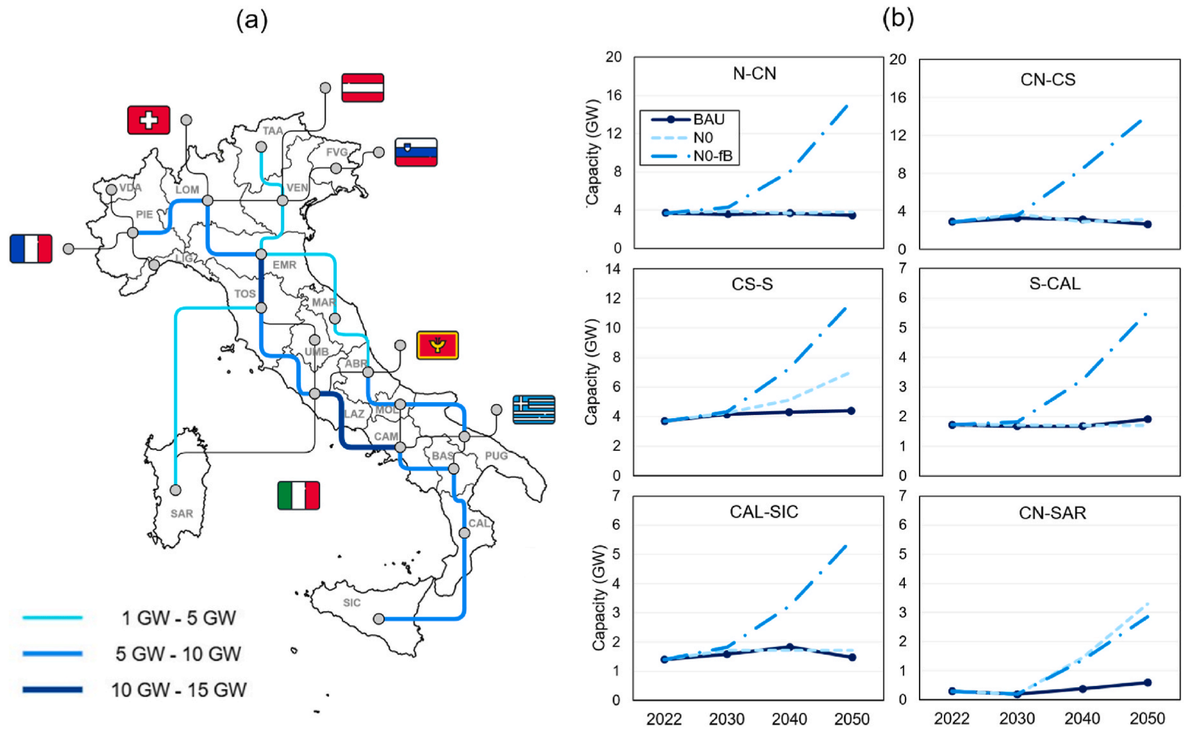

Fig. 8. Regional electricity transmission lines in 2050 for the N0-fB scenario (a) and electric transmission capacity between bidding zones for BAU, N0 and N0-fB scenarios from 2030 to 2050 compared to Terna's values for 2022 [56] (b). Icons are from Ref. [53].

from Central-Southern Italy towards Central-Northern Italy increases as well as that from the Central-Northern Italy to SAR. The N0-f scenario is not represented since it presents a similar behavior to N0-fB: the transmission capacity strongly increases in 2040 and 2050. In fact, Northern and Southern Italy become more interconnected and exploit the higher renewable resource of the South to cover the higher demand of Northern Italy. Specifically, in N0-fB scenario the transmission capacity increase is the most gradual of the two since part of the electricity is used locally for hydrogen production via electrolysis (as from Fig. 7).

The first result of the evaluation of SCEP cost-effectiveness throughout the sensitivity analysis scenarios is presented in Fig. 9. The graph shows the installed power (Fig. 9a) and the investment cost of transmission (Fig. 9b) by technology kind in the scenarios presented in Section 2.3 in 2050. The year 2050 is chosen to evaluate the results of this analysis since it allows observing cumulative capacity data in the period investigated. However, in the scenario analyzed, the model optimization installs SCEP starting from 2040 since it is the first year in which its cost and efficiency make it a cost-effective solution compared to conventional alternatives. One of the reasons behind this is the need for a high installed capacity, useful to feed the electricity needs for hydrogen liquefaction embedded in the SCEP.

As from Fig. 9a, traditional electricity transmission is the preferred energy transmission path after the optimization. Both hydrogen transmission and SCEP cost-effectiveness increase with the cost of electricity transmission. The transmission capacity is expressed in GW•km, including both the available transmission power – in GW – and the distances assumed for the different lines – in km. As the investment cost of SCEP decreases, its distance-weighted installed capacity increases sharply, particularly when the cost of traditional electricity transmission is high. Both the assumed investment cost for SCEP and that of traditional lines are identified as important parameters determining the SCEP competitiveness. This finding highlights the importance of the cost of conventional electricity transmission infrastructure, mainly driven by the one of metallic materials, as a key driver for the adoption of SCEP. Fig. 9b highlights the decrease in the total investment cost for transmission system intrinsic to the introduction of SCEP. This trend occurs despite the increase in total installed capacity, as the assumed specific investment cost of transmission technologies decreases progressively across the analyzed scenarios.

Specifically, Fig. 10 compares the installed power and the direction of electricity and hydrogen flows for the different transmission lines where SCEP cost varies between 30 % and 10 % of the initial cost estimate. The cost decrease of SCEP strongly influences the national installed power and the spatial diffusion of the technology. Indeed, the cost decrease favors the partial substitution of traditional lines with SCEP over two parallel transmission backbones transmitting electricity and hydrogen from SIC and from PUG towards EMR, where the commodities are split among the Northern regions.

Despite what emerges from the previous analyses, the cost-competitiveness of SCEP does not necessarily imply widespread deployment across Italy. This technology could prove competitive even if installed on a single transmission line, provided the electric power exceeds 300 MW and considered the electricity and hydrogen transmission shares described in Section 2.1.3.

The level of detail of the model allows looking at the capacity of each transmission line, enabling the identification of cost thresholds at which SCEP becomes a viable option. The overall results of the sensitivity analysis concerning the SCEP installed capacity for each line are summarized in Table 7. SCEP is considered a feasible cost-effective alternative to traditional energy transmission on lines when its total transmitted power exceeds 540 MW – considering 300 MW of electric power and 240 MW of equivalent hydrogen power, as discussed in Section 2.1.3. Based on these findings, SCEP becomes cost-effective when its investment cost is reduced to 30 % of the baseline under current electricity transmission costs. This equals to a specific cost for the SCEP of around 610 M€/km/MW. If electricity transmission costs increase by 50 % and 100 %, SCEP becomes competitive when its cost is reduced to respectively 50 % and 70 % of the baseline, corresponding to a specific investment cost of around 1020 M€/km/MW and 1430 M€/km/MW.

The first line where SCEP is installed in all three scenarios of increased electricity transmission costs is the connection between SAR

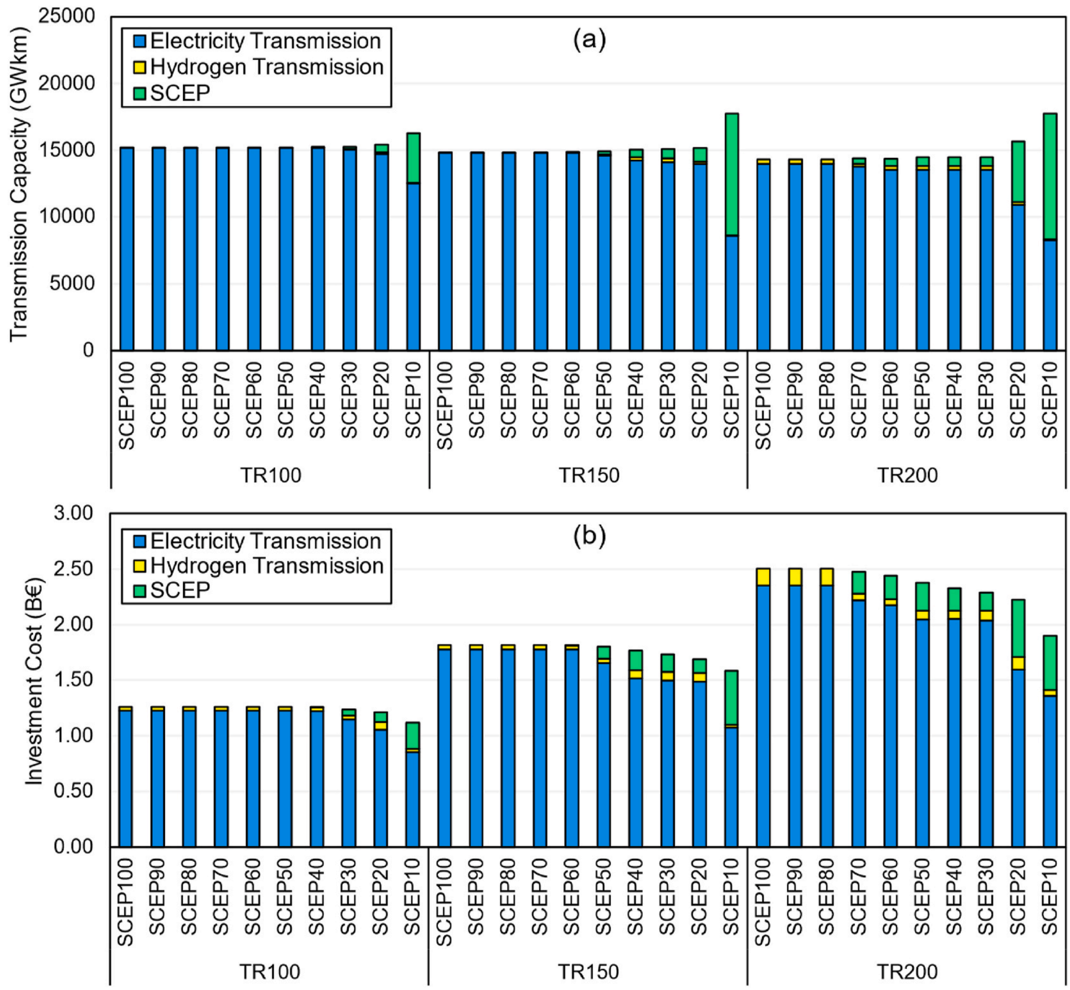

Fig. 9. Transmission capacities by technology in 2050 (a) and cumulative discounted investment cost for the transmission system along the model time horizon (b) across the sensitivity scenarios.

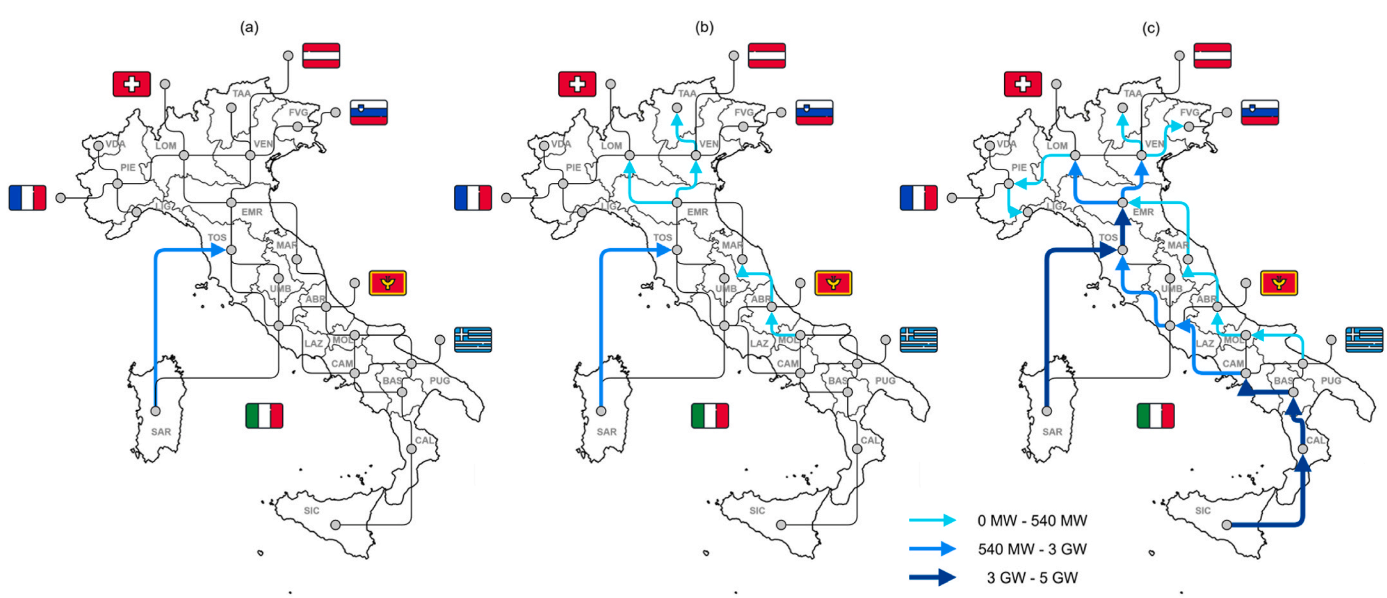

Fig. 10. Installed SCEP capacity and directions of energy flows through SCEP in 2050 for scenarios SCEP30_TR100 (a), SCEP20_TR100 (b) and SCEP10_TR100 (c). Icons are from Ref. [53].

and TOS. To understand the implications of the SCEP activity on the regional electricity and hydrogen sectors, the yearly electricity

Table 7
Installed SCEP power (GW) in the different lines in the sensitivity scenarios (lines with a capacity larger than 540 MW are highlighted in bold).

Interconnected Regions		TR100				TR150						TR200						
		SCEP40	SCEP30	SCEP20	SCEP10	SCEP60	SCEP50	SCEP40	SCEP30	SCEP20	SCEP10	SCEP70	SCEP60	SCEP50	SCEP40	SCEP30	SCEP20	SCEP10
ABR	**MAR**				0.07						**2.90**						0.01	**3.04**
ABR	**MOL**			0.02	0.13						**3.18**						0.17	**3.31**
BAS	**CAL**				**3.01**						**5.79**						**4.30**	**5.90**
BAS	**CAM**				**3.04**					0.02	**5.81**						**4.31**	**5.92**
CAL	**SIC**				**3.25**						**5.94**						**4.55**	**6.05**
CAM	**LAZ**				**2.21**						**4.90**						**3.40**	**5.05**
CAM	**MOL**										0.01							0.01
EMR	**LOM**			0.36	**0.97**					**1.01**	**4.43**						**1.26**	**4.51**
EMR	**MAR**				0.08						**2.54**							**2.68**
EMR	**TOS**				**3.47**						**5.44**							**5.44**
EMR	**VEN**			0.06	**1.29**					0.21	**2.14**						**1.56**	**2.19**
FVG	**VEN**				0.08					0.08	0.31						0.08	0.33
LAZ	**TOS**				**0.94**						**2.95**						**1.66**	**3.12**
LAZ	**UMB**										0.19						0.11	0.19
LIG	**PIE**				0.19					0.18	0.40						0.18	0.42
LOM	**PIE**				0.37					0.36	0.84						0.38	**0.91**
MOL	**PUG**				0.06						**3.10**						0.01	**3.25**
PIE	**VDA**										0.06							0.09
SAR	**TOS**	0.03	**0.91**	**2.37**	**3.42**	0.05	**1.27**	**2.87**	**3.32**	**3.36**	**3.49**	**2.07**	**2.60**	**3.31**	**3.31**	**3.34**	**3.41**	**3.62**
TAA	**VEN**			0.08	0.10					0.10	0.40					0.10	0.10	0.42

generation profile of SAR is investigated both for the SCEP100_TR100 and SCEP20_TR100 scenarios and reported in Fig. 11a and b. The introduction of SCEP on the line connecting SAR and LAZ does not have a significant impact on the generation mix of the region. However, observing the negative quadrant of the same figures, there is a minor variation in the stored and exported power while introducing SCEP, since the electricity load in Fig. 11b increases with respect to Fig. 11a. The largest difference between the electricity load in the two scenarios is furtherly highlighted in Fig. 11c and d and consists of the strong increase in the electricity needed for hydrogen production from electrolysis. Indeed, in the SCEP100_TR100 scenario where SCEP capacity is null, all regions are self-sufficient regarding hydrogen production and with a production mix mainly based on biomass gasification and hydrogen electrolysis. On the contrary, in SCEP20_TR100 the available hydrogen production capacity from electrolysis in SAR increases up to approximately 0.8 GW from roughly 0.1 GW of equivalent power in SCEP100_TR100. Most of the hydrogen produced in the region is exported to TOS through SCEP. In other words, the availability of SCEP deployment at lower investment costs may favor the centralization of hydrogen production, improve the overall production efficiency, and favor the installation of plants in zones with higher renewable production.

Finally, the investigation of results dependency on the assumption made for the hydrogen mass flow rate of SCEP did not reveal a clear dependency of the analysis findings on such an input, with the minimum deployed capacity ranging from the minimum of 930 GW•km when assuming 1.4 kg/s to the maximum of 1280 GW•km, corresponding to 0.6 kg/s in scenario SCEP20_TR100. Compared to 1140 GW•km associated with the reference assumption for the hydrogen mass flow rate (2.0 kg/s), this range translates into an uncertainty for the overall deployed capacity in the order of 30 %.

4. Conclusions, limitations, and perspectives

This paper assessed the potential role of SCEP technology as an alternative to conventional transmission technologies in the Italian energy system. A multi-regional model instance of the Italian power and hydrogen sectors was developed to analyze the techno-economic viability of SCEP and to identify cost thresholds under which its installation is expected to be cost-effective.

The main methodological innovation of this work lies in the spatial resolution of the model being used to investigate innovative and hybrid transmission options within a capacity expansion modeling approach. Indeed, a multi-regional representation of the Italian energy system becomes essential when the focus is on transmission technologies. The implemented model was used to formulate scenarios concerning transmission capacity expansion, the evolution of electricity and hydrogen production mixes, and storage requirements. The spatial disaggregation of the model allowed results to be analyzed both at national and regional levels, enabling a more accurate characterization of resource availability and demand in each region.

The results of the analysis indicate that, while the considered SCEP is not universally competitive under current cost assumptions, it becomes a cost-effective solution under specific conditions – specifically when an emission limit is present, when significant increases in cross-regional transmission capacity are needed, and in the case of a diversified hydrogen production mix with a specific reference to biomass-related constraints. In particular, in the scenario analyzed and assuming current cost conditions for conventional electricity transmission, the SCEP must reach a specific investment cost of 610 M€/km/MW to be selected as cost-optimal by the model. The identified cost reduction necessary for SCEP to become viable reduces when costs for metallic materials used in conventional electricity transmission technologies rise. Specifically, if the cost of conventional electricity transmission increases by 50 %, SCEP becomes viable at a specific investment cost around 1020 M€/km/MW; if conventional transmission costs double, viability is reached at around

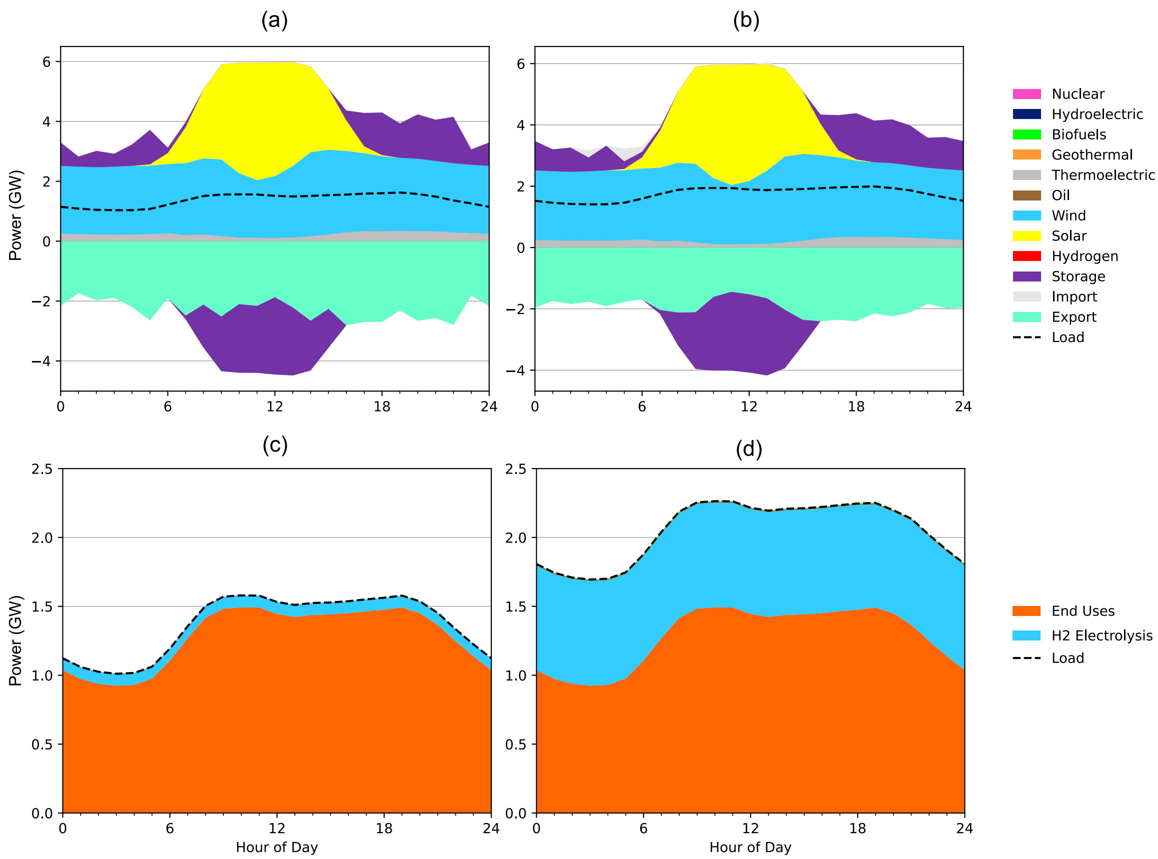

Fig. 11. Electricity generation profile by sources in SCEP100_TR100 (a) and SCEP20_TR100 (b). Electricity load profile by use in SCEP100_TR100 (c) and SCEP20_TR100 (d).

1430 M€/km/MW. Moreover, SCEP installation favors the centralization of hydrogen production plants, mainly for the electrolysis-based ones in regions with high resource availability of renewables like SAR.

Several limitations in the proposed study should be acknowledged. First, the implementation of bottom-up energy models requires reliable data both for technology description and for demand and resource input. Such data is not always complete or available, especially at the regional level, requiring the introduction of assumptions in model development. Despite the regional disaggregation of the model being an improvement over the original TEMOA-Italy structure, achieving greater spatial resolution comes at the expense of the integrated nature of the TEMOA-Italy model, as limiting complexity was necessary to avoid excessively high computational costs.

Another simplification of this model lies in the representation of generation. Regarding renewable resources, average representative days cannot fully capture their inherent intermittency. An increase in the number of time-steps or typical days considered improves the description of resource variability, while intermittency can only be captured by PSOMs based on time series. Moreover, the absence of nuclear power plants limits the possibility of studying alternative pathways for the decarbonization of the Italian power sector. Integrating the possibility for the model of deploying new nuclear fission plants may highlight possible synergies between nuclear and renewable resources at power system level, directly impacting the requirements for transmission lines and storage facilities. For these reasons, the results of this work are not intended to serve as a reference for detailed grid or storage sizing, but rather as a benchmark to evaluate the effects of different constraints on the transmission system.

Lastly, as the techno-economic characterization of SCEP is still in an early research phase, its techno-economic parameters remain uncertain and may evolve as technology matures. SCEP model characterization is based on current literature and preliminary design studies, which may not capture the full range of technical challenges and costs inherent in its operation, and therefore constitutes an intrinsic limitation of the model.

Further methodological research is needed to assess whether the advantages of a multi-regional model are limited to the representation of transmission capacity expansion or if other significant benefits can be identified and quantified.

To conclude, although SCEP is still far from being a mature or widely deployable technology, it shows the potential to play a role in an expanding and increasingly diversified transmission system, in alignment with the energy transition goals. This work contributes to the discussion around hybrid infrastructures and their role in enabling the transition to a low-carbon energy system. It highlights how solutions like SCEP could be relevant in countries like Italy, where regional heterogeneity and need for reliable interconnection systems are fundamental elements for energy system planning.

CRediT authorship contribution statement

Matilde Cais: Writing – review & editing, Writing – original draft, Visualization, Validation, Software, Methodology, Investigation, Formal analysis, Data curation, Conceptualization. **Matteo Nicoli:** Writing – review & editing, Writing – original draft, Visualization, Validation, Supervision, Software, Methodology, Investigation, Formal analysis, Data curation, Conceptualization. **Marta Gandiglio:** Writing – review & editing, Validation, Resources. **Michela Bracco:** Writing – review & editing, Validation. **Marco Breschi:** Writing – review & editing, Validation. **Lorenzo Cavallucci:** Writing – review & editing, Validation. **Stefania Farinon:** Writing – review & editing, Validation. **Antonio Macchiagodena:** Writing – review & editing, Validation. **Giovanni Mangiulli:** Writing – review & editing, Validation. **Riccardo**

Musenich: Writing – review & editing, Validation. **Laura Savoldi:** Writing – review & editing, Validation, Supervision, Project administration, Methodology, Investigation, Funding acquisition, Conceptualization.

Funding

This study was carried out within a project – funded by the Ministry of the University and Research – within the PRIN 2022 program (D. D.104–02/02/2022). This manuscript reflects only the authors' views and opinions, and the Ministry cannot be considered responsible for them.

The work by Matteo Nicoli was funded by the European Union - NextGenerationEU, in the framework of the GRINS - Growing Resilient, INclusive and Sustainable project (GRINS PE00000018 - CUP D13C22002160001). The views and opinions expressed are solely those of the authors and do not necessarily reflect those of the European Union, nor can the European Union be held responsible for them.

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.

Supplementary material

Supplementary material to this article can be found online at https://doi.org/10.1016/j.ijhydene.2026.153627.

Data availability

The TEMOA model version used for the analysis presented in this paper is available at [78], while the TEMOA-Italy model instance version adopted is available at 79.

References

[1] Hevia-Koch P, Wanner B, Kuwahata R. Electricity grids and secure energy transitions. https://iea.blob.core.windows.net/assets/ea2ff609-8180-4312-8de9-494bcf21696d/ElectricityGridsandSecureEnergyTransitions.pdf. [Accessed 23 May 2025].

[2] Franzoso A, Noussan M, Marocco P, Badami M, Fambri G, Gandiglio M. Assessing the role of storage and thermoelectric plants in the energy transition: a short- and medium-term scenario analysis with Italy as a case study. Smart Energy Aug. 2025; 19:100186. https://doi.org/10.1016/J.SEGY.2025.100186.

[3] Arcia-Garibaldi G, Cruz-Romero P, Gómez-Expósito A. Future power transmission: visions, technologies and challenges. Elsevier Ltd; Oct. 01, 2018. https://doi.org/10.1016/j.rser.2018.06.004.

[4] Di Bella A, Canti F, Prina MG, Casalicchio V, Manzolini G, Sparber W. Power system investment optimization to identify carbon neutrality scenarios for Italy. Environ Res: Energy Sep. 2024;1(3):035001. https://doi.org/10.1088/2753-3751/ad5b64.

[5] Medina C, Ríos AC, González G. Transmission grids to foster high penetration of large-scale variable renewable energy sources – a review of challenges, problems, and solutions. International Journal of Renewable Energy Research 2022;12(1). https://doi.org/10.20508/ijrer.v12i1.12738.g8400.

[6] Benato R, et al. CALAJOULE: an Italian research to lessen Joule power losses in overhead lines by means of innovative conductors. Energies Aug. 2019;12(16): 3107. https://doi.org/10.3390/en12163107.

[7] Shields N, Ashworth S, Heidel T, Thomas K, Moriconi F. Overhead superconducting power transmission. ELECTRA - CIGRE's Digital Magazine 2023;330 [Online]. Available: https://electra.cigre.org/330-october-2023/technology-e2e/overhead-superconducting-power-transmission.html. [Accessed 27 June 2025].

[8] K. Cole, "Practicality of superconductors in power transmission," POWER Engineers, Inc. Accessed: June. 27, 2025. [Online]. Available: https://wwwpowerengcom.cdn.prismic.io/wwwpowerengcom/Zyky668jQArT0LVc_PracticalityofSuperconductorsinPowerTransmission_Final.pdf.

[9] European Commission. Communication from the commission | REPowerEU plan. 2022. Brussels, https://eur-lex.europa.eu/resource.html?uri=cellar:fc930f14-d7ae-11ec-a95f-01aa75ed71a1.0001.02/DOC_1&format=PDF.

[10] European Commission. A hydrogen strategy for a climate-neutral Europe. https://eur-lex.europa.eu/legal-content/EN/TXT/?uri=CELEX%3A52020DC0301. [Accessed 14 June 2025].

[11] Miao B, Giordano L, Chan SH. Long-distance renewable hydrogen transmission via cables and pipelines. Int J Hydrogen Energy May 2021;46(36):18699–718. https://doi.org/10.1016/j.ijhydene.2021.03.067.

[12] Patonia A, Lenivova V, Poudineh R, Nolden C. Hydrogen pipelines vs. HVDC lines: should we transfer green molecules or electrons? OIES Paper 2023;ET(27).

[13] Peschka W. Flüssiger Wasserstoff als Energieträger: technologie und Anwendungen. first ed. Wien: Wien: Springer; 1984.

[14] Butting CryoTech GmbH. Vacuum insulated piping (VIP): for common cryogenic media. https://www.butting-cryotech.com/en/standard-transfer. [Accessed 10 December 2025].

[15] ITP Interpipe. Cryogenic pipelines. https://www.itp-interpipe.com/efficient-pipeline-solutions-for-extreme-temperature-fluids/cryogenic-pipelines/. [Accessed 10 December 2025].

[16] Markowz G, Dylla A, Elliger T. icefuel® - an infrastructure system for cryogenic hydrogen storage, distribution and decentral use. In: Proceedings/18th world hydrogen energy conference; 2010. p. 365–71.

[17] Grant PM. The SuperCable: dual delivery of chemical and electric power. IEEE Transactions on Appiled Superconductivity Jun. 2005;15(2):1810–3. https://doi.org/10.1109/TASC.2005.849298.

[18] Yamada S, Hishinuma Y, Uede T, Schippl K, Motojima O. Study on 1 GW class hybrid energy transfer line of hydrogen and electricity. J Phys, Conf Ser Feb. 2008; 97:012167. https://doi.org/10.1088/1742-6596/97/1/012167.

[19] Prats Campmany F. Economical study of electric power transmission with superconducting lines for HVDC systems. Bachelor's Thesis. Escola Tècnica Superior d'Enginyeria Industrial de Barcelona; 2021 [Online]. Available: https://upcommons.upc.edu/server/api/core/bitstreams/9d02ea02-f369-433c-9287-bb3908187b49/content. [Accessed 10 December 2025].

[20] Qin B, Wang H, Liao Y, Liu D, Wang Z, Li F. Liquid hydrogen superconducting transmission based super energy pipeline for Pacific Rim in the context of global energy sustainable development. Int J Hydrogen Energy Feb. 2024;56:1391–6. https://doi.org/10.1016/j.ijhydene.2023.12.289.

[21] Qin B, et al. Challenges and opportunities for long-distance renewable energy transmission in China. Sustain Energy Technol Assessments Sep. 2024;69:103925. https://doi.org/10.1016/j.seta.2024.103925.

[22] Trevisani L, Fabbri M, Negrini F. Long distance renewable-energy-sources power transmission using hydrogen-cooled MgB2 superconducting line. Cryogenics Feb. 2007;47(2):113–20. https://doi.org/10.1016/j.cryogenics.2006.10.002.

[23] Chen Y, et al. Ultra-low electrical loss superconducting cables for railway transportation: technical, economic, and environmental analysis. J Clean Prod Mar. 2024;445:141310. https://doi.org/10.1016/j.jclepro.2024.141310.

[24] Wang L, Bai G, Zhang R, Liang J. Concept design of 1 GW LH 2 -LNG-Superconducting energy pipeline. IEEE Trans Appl Supercond Mar. 2019;29(2): 1–2. https://doi.org/10.1109/TASC.2019.2895461.

[25] Jin J, Wang L, Yang R, Zhang T, Mu S, Zhou Q. A composite superconducting energy pipeline and its characteristics. Energy Rep Nov. 2022;8:2072–84. https://doi.org/10.1016/j.egyr.2022.01.126.

[26] Fu L, Chen X, Chen Y, Jiang S, Shen B. Hydrogen-electricity hybrid energy pipelines for railway transportation: design and economic evaluation. Int J Hydrogen Energy Apr. 2024;61:251–64. https://doi.org/10.1016/j.ijhydene.2024.02.299.

[27] Palacio S, Wolf M, Noe M, Wehr M, Arndt T. Design of a 75 km GW-class hybrid pipeline for the synergetic transmission of liquid hydrogen and electrical energy by high-temperature superconductivity. 2025.

[28] Savoldi L, Balbo A, Bruzek CE, Grasso G, Patti M, Tropeano M. Conceptual design of a SuperConducting energy pipeline for LH2 and power transmission over long distances. IEEE Trans Appl Supercond 2024;34(3). https://doi.org/10.1109/TASC.2024.3370123.

[29] Ministero dell'Università e della Ricerca. Portale dei bandi PRIN della Direzione Generale della Ricerca del MUR. https://prin.mur.gov.it/. [Accessed 6 June 2025].

[30] Bracco M, et al. Design of a Submarine 30-km MgB_{2} Cable for the Combined Transfer of 0.3 GW_e and LH_{2} from Offshore Plants to the Ravenna Port. IEEE Trans Appl Supercond Aug. 2025;35(5): 1–6. https://doi.org/10.1109/TASC.2025.3528923.

[31] AGNES. Eolico offshore in mare Adriatico. https://www.agnespower.com/eolico-offshore-adriatico/. [Accessed 28 June 2025].

[32] Savoldi L, et al. Analysis of the evolution of accidental transients in the cooling of a MgB2-LH2 hybrid power cable. Accepted for Publication on IEEE Trans Appl Supercond 2026.

[33] Mangiulli G, et al. Sizing and economic assessment for auxiliar components and grid connection of a MgB2-LH2 hybrid power cable. IEEE Trans Appl Supercond 2026:1–6. https://doi.org/10.1109/TASC.2026.3651232.

[34] Cavallucci L, et al. Analysis of electric fault in a MV DC MgB2 transmission line cooled by liquid hydrogen. Accepted for Publication on IEEE Trans Appl Supercond 2026.

[35] Fina S, Heider B, Prota F. Unequal Italy: regional socio-economic disparities in Italy. https://fes.de/unequal-italy.

[36] Raihan A, Rahman J, Tanchangtya T, Ridwan M, Islam S. An overview of the recent development and prospects of renewable energy in Italy. Renewable and Sustainable Energy 2024. https://doi.org/10.55092/rse20240008.

[37] Muratori M, et al. Cost of power or power of cost: a U.S. modeling perspective. Renew Sustain Energy Rev Sep. 2017;77:861–74. https://doi.org/10.1016/j.rser.2017.04.055.

[38] Ministry of Economic Development, Ministry of the Environment and Land and Sea Protection, and Ministry of Infrastructure and Transport. Integrated national energy and climate plan 2019. https://commission.europa.eu/energy-climate-cha

nge-environment/implementation-eu-countries/energy-and-climate-governance-and-reporting/national-energy-and-climate-plans_en. [Accessed 19 August 2022].
[39] Rodríguez RA, Becker S, Andresen GB, Heide D, Greiner M. Transmission needs across a fully renewable European power system. Renew Energy Mar. 2014;63: 467–76. https://doi.org/10.1016/j.renene.2013.10.005.
[40] Allard S, Mima S, Debusschere V, Quoc TT, Criqui P, Hadjsaid N. European transmission grid expansion as a flexibility option in a scenario of large scale variable renewable energies integration. Energy Econ Mar. 2020;87:104733. https://doi.org/10.1016/j.eneco.2020.104733.
[41] Laha P, Chakraborty B. Energy model – a tool for preventing energy dysfunction. Renew Sustain Energy Rev Jun. 2017;73:95–114. https://doi.org/10.1016/j.rser.2017.01.106.
[42] Poncelet K. Long-term energy-system optimization models Doctoral Dissertation. Arenberg Doctoral School; 2018. [Online]. Available https://doi.org/10.13140/RG.2.2.21586.45762 [Accessed 29 June 2025].
[43] Trutnevyte E. Does cost optimization approximate the real-world energy transition? Energy Jul. 2016;106:182–93. https://doi.org/10.1016/j.energy.2016.03.038.
[44] Priesmann J, Nolting L, Praktiknjo A. Are complex energy system models more accurate? An intra-model comparison of power system optimization models. Appl Energy Dec. 2019;255:113783. https://doi.org/10.1016/j.apenergy.2019.113783.
[45] DeCarolis J, et al. Formalizing best practice for energy system optimization modelling. Elsevier Ltd.; 2017. https://doi.org/10.1016/j.apenergy.2017.03.001.
[46] Schivley G, et al. Process and policy insights from an intercomparison of open electricity system capacity expansion models. Environ Res: Energy Dec. 2025;2(4): 045006. https://doi.org/10.1088/2753-3751/ade548.
[47] Nicoli M, Faria VAD, de Queiroz AR, Savoldi L. Modeling energy storage in long-term capacity expansion energy planning: an analysis of the Italian system. J Energy Storage Nov. 2024;101:113814. https://doi.org/10.1016/j.est.2024.113814.
[48] de Faria VAD, de Queiroz AR, DeCarolis JF. Optimizing offshore renewable portfolios under resource variability. Appl Energy Nov. 2022;326:120012. https://doi.org/10.1016/J.APENERGY.2022.120012.
[49] Sinha A, et al. Diverse decarbonization pathways under near cost-optimal futures 2024;15(1):1–15. https://doi.org/10.1038/s41467-024-52433-z.
[50] Colucci G, Finke J, Bertsch V, Di Cosmo V, Savoldi L. Combined assessment of material and energy supply risks in the energy transition: a multi-objective energy system optimization approach. Appl Energy Jun. 2025;388. https://doi.org/10.1016/j.apenergy.2025.125647.
[51] Fan G, et al. Collaborative planning for power and hydrogen networks considering hydrogen pipeline slow dynamic and pipe storage characteristics. Int J Hydrogen Energy May 2025;125:214–32. https://doi.org/10.1016/j.ijhydene.2025.04.038.
[52] Nicoli M. An energy planning perspective about the multi-sectorial synergies and implications of the energy transition. PhD Thesis. Politecnico di Torino, Turin; 2025 [Online]. Available: https://iris.polito.it/handle/11583/3001281. [Accessed 7 July 2025].
[53] flaticon. https://www.flaticon.com/. [Accessed 5 December 2023].
[54] TERNA SpA. Download center | Dati terna driving energy. https://dati.terna.it/download-center. [Accessed 8 June 2025].
[55] Novo R, Marocco P, Giorgi G, Lanzini A, Santarelli M, Mattiazzo G. Planning the decarbonisation of energy systems: the importance of applying time series clustering to long-term models. Energy Convers Manag X Aug. 2022;15:100274. https://doi.org/10.1016/j.ecmx.2022.100274.
[56] Terna SpA. Stato del Sistema Elettrico 2023. https://download.terna.it/terna/Terna_Piano_Sviluppo_2023_Stato_Sistema_Elettrico_8db254887149b77.pdf. [Accessed 14 June 2025].
[57] Vaillancourt K, Simbolotti G, Tosato G. Electricity transmission and distribution. In: IEA energy technology systems analysis program (ESTAP); 2014 [Online]. Available: https://iea-etsap.org/E-TechDS/PDF/E12_el-t&d_KV_Apr2014_GSOK.pdf. [Accessed 14 June 2025].
[58] PyPSA | technology-data public. https://github.com/PyPSA/technology-data/blob/master/inputs/manual_input.csv. [Accessed 14 June 2025].
[59] Hagspiel S, Jägemann C, Lindenberger D, Brown T, Cherevatskiy S, Tröster E. Cost-optimal power system extension under flow-based market coupling. Energy Mar. 2014;66:654–66. https://doi.org/10.1016/j.energy.2014.01.025.
[60] Härtel P, Vrana TK, Hennig T, von Bonin M, Wiggelinkhuizen EJ, Nieuwenhout FDJ. Review of investment model cost parameters for VSC HVDC transmission infrastructure. Elec Power Syst Res Oct. 2017;151:419–31. https://doi.org/10.1016/j.epsr.2017.06.008.
[61] N. Tan, "Transport decarbonization and Data-to-Deal. Lecture 6 Hands-on exercise: transport modelling in OSeMOSYS: transport data.," Zenodo. Accessed: September. 8, 2025. [Online]. Available: https://doi.org/10.5281/zenodo.14800591.
[62] Borsboom-Hanson T, Patlolla SR, Herrera OE, Mérida W. Point-to-point transportation: the economics of hydrogen export. Int J Hydrogen Energy Aug. 2022;47(74):31541–50. https://doi.org/10.1016/j.ijhydene.2022.07.093.
[63] Ganda F, Maronati G. Economic data and modeling support for the two regional case studies: Nuclear-renewable hybrid energy systems: analysis of technical & economic issues. Argonne, IL (United States); Aug. 2018. https://doi.org/10.2172/1483989.
[64] Sayani JKS, Wang M, Ma Z, Sharan P, Mehana M, Chen B. Techno-economic analysis of hydrogen transport via repurposed natural gas pipelines: flow dynamics and infrastructure tradeoffs. Int J Hydrogen Energy Jul. 2025;147:150033. https://doi.org/10.1016/j.ijhydene.2025.150033.
[65] Van Rossum R, Jens J, La Guardia G, Wang A, Kühnen L, Overgaag M. European hydrogen backbone: a European hydrogen infrastructure vision covering 28 countries. https://ehb.eu/files/downloads/ehb-report-220428-17h00-interactive-1.pdf. [Accessed 11 September 2025].
[66] The Danish Energy Agency. Technology data for transport of energy. https://ens.dk/en/analyses-and-statistics/technology-data-transport-energy. [Accessed 14 June 2025].
[67] Galimova T, Fasihi M, Bogdanov D, Breyer C. Impact of international transportation chains on cost of green e-hydrogen: global cost of hydrogen and consequences for Germany and Finland. Appl Energy Oct. 2023;347:121369. https://doi.org/10.1016/j.apenergy.2023.121369.
[68] Al Ghafri SZS, et al. Hydrogen liquefaction: a review of the fundamental physics, engineering practice and future opportunities. Energy Environ Sci 2022;15(7): 2690–731. https://doi.org/10.1039/D2EE00099G.
[69] Cavallucci L, et al. Optimization procedure to design a DC transmission line with MgB2 wires in liquid hydrogen. IEEE Trans Appl Supercond 2025;35(5). https://doi.org/10.1109/TASC.2024.3513946.
[70] European Commission. Communication from the Commission. The European Green Deal; 2019 [Online]. Available: https://eur-lex.europa.eu/legal-content/EN/LSU/?uri=COM:2019:640:FIN. [Accessed 17 June 2025].
[71] Ministero dell'Ambiente e della Tutela del Territorio e del Mare, Ministero dello Sviluppo Economico, Ministero delle Infrastrutture e dei Trasporti, and A. e F. Ministero delle Politiche agricole. Strategia Italiana di Lungo Termine sulla riduzione delle emissioni dei gas a effetto serra. Italy. https://www.mase.gov.it/portale/documents/d/guest/lts_gennaio_2021-pdf. [Accessed 17 June 2025].
[72] Nicoli M, Gracceva F, Lerede D, Savoldi L. Can we rely on open-source energy system optimization models? The TEMOA-Italy case study. Energies Sep. 2022;15 (18). https://doi.org/10.3390/en15186505.
[73] AmirKavei F, Nicoli M, Quatraro F, Savoldi L. Enhancing energy transition with open-source regional energy system optimization models: TEMOA-Piedmont. Energy Conversion and Management Mar. 2023:327. https://doi.org/10.1016/j.enconman.2025.119536.
[74] Nicoli M, et al. A framework for global sensitivity analysis in long-term energy systems planning using optimal transport. Energy Nov. 2025;338:138788. https://doi.org/10.1016/J.ENERGY.2025.138788.
[75] IRENA. Renewable power generation costs in 2022. 2023. Abu Dhabi.
[76] Balsamini M, Corradi R, Catini G. CAPEX and OPEX - estimate report. 2021.
[77] Su H, Zhou N, Wu Q, Bi Z, Wang Y. Investigating price fluctuations in copper futures: based on EEMD and Markov-switching VAR model. Resour Policy May 2023;82:103518. https://doi.org/10.1016/j.resourpol.2023.103518.
[78] MAHTEP Group, "MAHTEP/TEMOA - release 2.1," GitHub. Accessed: October. 9, 2025. [Online]. Available: https://github.com/MAHTEP/TEMOA/releases/tag/2.1.
[79] MAHTEP Group, "MAHTEP/TEMOA-Italy - release 3.3," GitHub. Accessed: January. 20, 2026. [Online]. Available: https://github.com/MAHTEP/TEMOA-Italy/releases/tag/3.3.