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RESEARCH ARTICLE

Impact of Natural Gas Price Variations and Consumption Limitation on the Decarbonization of Sector-Coupled Energy Systems

PERIKLIS P. CHINARIS, GEORGIOS N. PSARROS, (Member, IEEE), EVANGELOS S. CHATZISTYLIANOS, AND STAVROS A. PAPATHANASSIOU, (Senior Member, IEEE)

School of Electrical and Computer Engineering, National Technical University of Athens (NTUA), 15780 Athens, Greece

Corresponding author: Periklis P. Chinaris (perischinaris@mail.ntua.gr)

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ABSTRACT This paper assesses the effects of fossil natural gas (NG) price variations and NG consumption restrictions on the development and decarbonization of future cross-sector and cross-vector coupled energy systems. For this purpose, a capacity expansion planning model built upon the linear programming mathematical optimization is developed, optimizing operation and investment in technologies for generation, storage, conversion and final consumption of electricity, hydrogen (H_2), and NG, while carbon dioxide (CO_2) sector encompassing carbon capture, storage and utilization is incorporated in the model. A base case scenario adopting REPowerEU expectations about NG price levels by 2050 is analyzed, with the Greek sector-coupled energy system selected as a case study, aiming to demonstrate that anticipated NG price is inadequate to stimulate full decarbonization of the integrated energy system and even moderately reduce dependence on NG. Thus, increased fossil NG prices and consumption restrictions are assessed regarding their potential contribution towards incentivizing energy system complete decarbonization. Decarbonization is achieved both with a NG price of 120 €/MWh and with elimination of fossil NG consumption, at a similar cost, yet with a different energy system development. In both cases, a cumulative renewable energy sources (RES) capacity of 106 GWe accompanied by substantial long-duration storage is required. Interestingly, as decarbonization levels increase, onshore wind farms prevail over PVs in the generation mix. Residential heating-cooling and transport needs are predominantly electrified, while industrial heating is exclusively supplied by H_2.

INDEX TERMS Capacity expansion planning, energy system decarbonization, fossil natural gas price, fossil natural gas consumption, renewable energy, sector-coupling.

NOMENCLATURE

A. INDICES

com	Index of commodities.
EC	Index of energy carrier.
r	Index of reserves types.
t	Index of hours in optimization horizon.
tech	Index of installed and existing technologies.
use	Index of end use sector i.e. {cooling - cool, heating - heat, industry - ind, transport - transp}.
v	Index of vehicle type.

B. SETS

COM	Set of commodities i.e. {H_2O, O_2}.
EnCar	Set of energy carriers i.e. {electricity - EL, H_2, NG}.
RSRV	Set of reserve types
T	Set of installed technologies excluding end use appliances.

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T_{CC} Set of CC equipped technologies.
T_{CCGT} Set of CCGT types.
T_{CE} Set of electricity consuming technologies.
T_{flexhy} Set of flexible hydropower plants.
T_{rsrv} Set of technologies providing reserves.
T_{PE} Set of dispatchable, electricity producing technologies i.e. $T_{CCGT} \cup T_{flexhy} \cup$ {fuel cell - fc}.
T_{smr} Set of SMR types.
T_{st} Set of electrical storage technologies i.e. BESS, closed-loop PHS.
T_{vres} Set of variable RES.
vehicles Set of vehicle type.

C. PARAMETERS

C_{com} Selling/buying price of commodity com $\in$ COM.
$C_{EC}^{use,fix}$ Annualized CAPEX + Fixed O&M cost of end use appliance consuming EC $\in$ EnCar for use $\in$ {heat, ind}.
C_{em} Price of CO_2 emissions.
$C_{heat,EL}^{var}$ Variable cost of heat pump.
$C_{ind,EL}^{var}$ Variable cost of electric boiler.
$C_{ens,EC}$ Cost of energy not served of EC $\in$ {EL, NG}
C_{NG} Price of NG.
C_{other} Other system costs.
C_{rsrv} Reserves provision cost.
C_{seq}^{var} Variable cost of CO_2 sequestration.
C_{tech}^{fix} CAPEX + Fixed O&M cost of tech $\in$ T-T_{st}.
$C_{tech}^{e,fix}$ CAPEX + Fixed O&M cost of energy. component of tech $\in T_{st}$.
$C_{tech}^{p,fix}$ CAPEX + Fixed O&M cost of power. component of tech $\in T_{st}$.
C_{tech}^{var} Variable cost of electricity production from tech $\in T_{res}$.
D_t^{cool} Final hourly cooling demand.
D_t^{EL} Final hourly exogenous electricity demand.
D_t^{use} Final hourly demand of use $\in$ {heat, ind}.
D_v^{transp} Final yearly transportation demand for v $\in$ vehicles.
f_{heat} Conversion factor from toe to MWh.
n_{EC}^{use} efficiency of installed appliance consuming EC $\in$ EnCar for use $\in$ {heat, ind, transp, cool}.
n_{tech} Single-trip efficiency of tech $\in T_{smr} \cup T_{CCGT} \cup T_{st} \cup$ {electrolyzer - elz, methanation - meth, fc} / round-trip efficiency of tech $\in T_{flexhy}$.
$P_t^{use,pu}$ Hourly demand profile (per unit) for use $\in$ {heat, ind}.
$P_{t,v}^{EC,pu}$ Hourly charging/refueling profile (per unit) for type v $\in$ vehicles with EC $\in$ EnCar.
$q^{use,em}$ CO_2 released emissions factor for use $\in$ {heat, ind}.
RoR_t Run of river hydropower plant hourly electricity production.
$RR_{t,r}$ Hourly reserves requirement for r $\in$ RSRV.

D. VARIABLES

A_{EC}^{use} Capacity of end-use appliance consuming EC $\in$ EnCar for use $\in$ {heat, ind}.
A_{tech} Capacity of tech $\in$ T-T_{st}.
A_{tech}^{e} Energy capacity of storage tech $\in T_{st}$.
A_{tech}^{p} Power capacity of storage tech $\in T_{st}$.
$Cons_{com}^{net}$ Net consumption of com $\in$ COM.
D_v^{EC} Final transportation demand for $v \in$ vehicles consuming $EC \in$ {EL, H_2}.
D_{EC}^{use} Final demand for EC $\in$ EnCar in use $\in$ {heat, ind}.
E_t^{ens} Hourly electricity demand not served.
E_t^{transp} Hourly electricity demand from transportation sector.
E_t^{vres} Hourly aggregate electricity production by variable RES.
$E_{t,tech}$ Hourly electricity production (consumption) by tech $\in T_{PE}$ (T_{CE}).
$E_{t,tech}^{pump}$ Hourly electricity consumption for pumping of tech = open-loop PHS.
$E_{t,tech}^{ch}$ Hourly charging rate of tech $\in T_{st}$.
$E_{t,tech}^{disch}$ Hourly discharging rate of tech $\in T_{st}$.
G_t^{ens} Hourly NG demand not served.
G_t^{imp} Hourly NG imports.
$G_{t,tech}$ Hourly NG consumption by tech $\in T_{CCGT} \cup T_{smr}$ and SNG production by tech = meth.
H_t^{transp} Hourly H_2 demand from transportation sector.
$Q_{t,tech}^{rlsd}$ Hourly released CO_2 by tech $\in T_{CCGT} \cup T_{smr}$.
$Q_t^{use,rlsd}$ Hourly released CO_2 by use $\in$ {heat, ind}.
$Q_{t,tech}^{seq}$ Hourly sequestered CO_2 by tech $\in T_{CC}$.
$R_{t,tech,r}$ Hourly provision of reserves type r $\in$ RSRV by tech $\in T_{rsrv} - T_{vres}$.
$R_{t,r}^{vres}$ Hourly provision of reserves type r $\in$ RSRV by variable RES.

I. INTRODUCTION

The apparent results of climate change caused by the considerable rise in the anthropogenic carbon dioxide (CO_2) emissions during this century [1] led, until today, 193 countries and the EU to pledge to conform to the Paris Agreement [2]. The goals set for 2050 encompass restraining the mean temperature increment well below 2°C and, ideally, up to 1.5°C, with respect to pre-industrial levels. A prerequisite for effective global warming mitigation is the significant reduction of greenhouse gas (GHG) emissions from the production, transmission, and consumption of energy [3]. However, reaching carbon neutrality by mid-century could remain feasible only if the international community succeeds in accelerating the implementation and expanding all established policies and national zero emissions plans [4]. The decarbonization of the energy system cannot rely solely on integrating clean and renewable power generation [5], [6]. All end-use energy sectors need to be addressed [7], given their substantial contribution to the total GHG emissions originating from the use of fossil fuels [8]. Currently, integration of the energy system remains limited, not exploiting synergies between different energy carriers and sectors [9].

The notion of sector-coupling is placed at the core of the energy system integration strategy. From a holistic perspective, sector-coupling involves creating interlinkages and interactions between supply and demand-side energy sectors and carriers, aiming to cope with temporal and spatial system challenges through the provision of adequate and multivalent flexibility [10]. Direct and indirect electrification of end-use sectors [11], [12], constitute the two predominant approaches to sector-coupling, both based on integrating high amounts of variable renewable energy. In the first case, residential and industrial heating and transportation needs are covered via electricity-consuming devices, in place of fossil fuel-fired systems [13], minimizing sector-coupling energy losses [12]. In the latter case of indirect electrification, renewable electricity is initially converted to another energy carrier (such as H_2 and methane) and then supplied to the individual end-use sectors [13]. The beneficial effect of this approach involves defossilising difficult to electrify end-use sectors via energy-dense carriers and taking advantage of existing infrastructure to store and transport low-carbon fuels [14], [15].

Since the path towards climate neutrality involves a growing share of electricity originating from intermittent renewable energy sources, operational flexibility and long-term storage capacity provided by sector- coupling is of utter importance to address fluctuations and uncertainty in renewable power supply in low-carbon systems [16], [17]. At the same time, the multitude of cross-sector interconnections and the alternative energy carrier conversion pathways enhance system resilience, reliability [18] and adequacy [19]. Additionally, exploiting low-cost renewable production, and especially surplus – otherwise curtailed – energy [20] establishes a business case regarding the direct and indirect decarbonization of fossil-derived energy carrier consuming sectors [21], [22]. Exploiting synergies between energy sectors contributes to the optimal planning and operation of the energy system, at resource and infrastructure level, offering potential for operating cost reduction and benefits both for producers and consumers [23], [24].

Sector-coupling has received increasing attention lately for its potential contribution to energy system decarbonization. Several studies in the literature implement energy system modelling tools to assess synergies between sectors, targeting carbon neutrality. On one hand, capacity expansion planning (CEP) models built upon the (mixed-integer) linear programming - (MI)LP mathematical modelling [25], [26], [27], [28], with hourly time step, emphasize the integration of different energy carriers on the supply side, rather than bridging them with end-use sectors, with demand time-series corresponding to energy carriers rather than end-use services, thus excluding competition between different energy carriers to cover final demand requirements. While authors of [25] and [28] outline the coupling between power, hydrogen (H_2), natural gas (NG) and CO_2 sectors under a variety of policy measures, the work of [26] and [27] includes only the electrical and H_2 sectors. Author of [25] finds that a business case for power-to-H_2-to-gas route as a potential storage and flexibility provider exists only when high ($>70\%$) RES penetration targets are imposed. Reference [26] underline that green H_2 production is a cost-effective alternative to conventional power plants in providing flexibility to the electricity system and, at the same time, facilitates higher RES penetration when combined with storage of shorter duration, such as batteries. The work of [27] reports that coupling electricity and H_2 sectors results in declining decarbonization costs, favoured by a further rise in H_2 demand for end-usage.

In contrast to the studies mentioned above, several research efforts concentrate on linking energy supply and end-use sectors. Synergies between electricity and H_2 supply sectors, linked either with road transport [29], [30] or with residential heating [31], [32] under carbon emission constraints are investigated, while both road/rail transport and residential heating are incorporated in [33]. Joint integration of flexible electric and fuel-cell vehicles in the transportation sector results in improved economies than in scenarios considering separately the integration of each option [29], while the power-to-H_2 route is proved to facilitate low-emission goals and prevent additional RES investment [30]. Cross-sector flexibility offered by district heating, compared to heat pumps and electric vehicles, increases RES market prices in [31], while possible beneficial effects of renewable H_2 in a deeply decarbonized system along with a green H_2 supply curve are determined in [32]. Flexibility offered from cross-sectoral integration eliminates the business case for battery energy storage, whilst the expansion of cross-border interconnectors fosters the least-cost system development planning [33].

A broader approach, simultaneously integrating power, H_2 and NG supply with the residential & industrial heating and the transportation sectors, is followed in [34], [35], [36], [37], [38], and [39]. The conversion pathway linking electricity, H_2 and synthetic NG (SNG) could play a crucial role in future low-carbon energy systems [34]. Reference [35] conclude that flexibility options from cross-sector linkages could prevent severe curtailment and load shedding incidents in energy systems experiencing high penetration levels of intermittent renewables. Reference [36] investigate the level of granularity used in the aggregation of heat pumps in the cross-sector coupling problem by examining three different heat pump representations and conclude that such aggregations might lead to adequately accurate results at reduced computation time. Concurrently, the analysis performed in [37] reveals system cost minimization and reduction in power sector

TABLE 1. Summary of literature on modelling of the energy sector-coupling in the context of energy system decarbonization.

Study	Optimization method	Temporal resolution / horizon	Energy carriers and commodities included	End-use sectors representation	Reserves requirements	Decarbonisation policy examined	Competition between energy carriers in end-use sectors
[25]	LP	Hourly / 1 year	Electricity, H_2, NG, CO_2	Indirectly as electricity & H_2 demand	-	Minimum RES share in power and H_2 demand	-
[26]	LP	Hourly / 1 year	Electricity, H_2	Indirectly as electricity & H_2 demand	-	CO_2 emissions price increase	-
[27]	MILP	Hourly / 30 representative weeks	Electricity, H_2	Indirectly as electricity & H_2 demand	mFRR not included	CO_2 emissions price increase	-
[28]	LP	Hourly / 5 years	Electricity, H_2, NG, CO_2	Indirectly as electricity, H_2 & NG demand	-	Direct CO_2 emissions reduction	-
[29]	MILP	Hourly / representative weeks	Electricity, H_2, NG, CO_2	Directly as road transport, indirectly as electricity demand	mFRR not included	Direct CO_2 emissions reduction	✓
[30]	MILP	Hourly / 1 year	Electricity, H_2, NG, CO_2	Directly as road transport, indirectly as electricity demand	Spinning reserves	Direct CO_2 emissions reduction	-
[31], [32]	LP	Hourly / 1 year	Electricity, H_2, NG, CO_2	Directly as residential heating, indirectly as electricity & H_2 demand	-	Direct CO_2 emissions reduction in electricity production	Only in residential heating sector between electricity and H_2
[33]	MILP	Hourly / 1 year	Electricity, H_2, NG, CO_2	Directly as road & rail transport, residential and service sector heating demand, indirectly as electricity demand	-	Direct CO_2 emissions reduction	Only in heating sector between electricity, H_2 & NG; Vehicles fleet formation predefined and not optimized
[34], [35]	LP & MILP	12- 24 representative hours	Electricity, H_2, NG, CO_2	Directly as residential, industrial, agriculture commercial & transport	-	Direct CO_2 emissions reduction	✓
[36], [37]	LP	Hourly / 1 year	Electricity, H_2, NG, CO_2	Directly as residential and industrial heating, transport, indirectly as electricity demand	-	Direct CO_2 emissions reduction (CC not considered)	✓ (H_2 vehicles not considered)
[38]	MILP	Hourly / 1 year	Electricity, H_2, NG, CO_2	Directly as residential and industrial heating, transport demand, indirectly as electricity demand	-	Direct CO_2 emissions reduction; Minimum RES share in power production	Electricity excluded from competing with H_2 & NG in transport, industrial & residential heating
[39]	MILP	specific hours/days of representative weeks	Electricity, H_2, NG, CO_2	Directly as residential and industrial heating, transport demand, indirectly as electricity demand	mFRR not included	-	H_2 excluded from competing with electricity and synthetic NG; Transport demand allocation per fuel and type of vehicle predefined
This paper	**LP**	**Hourly / 1 year**	**Electricity, H_2, NG, CO_2, H_2O, O_2**	**Directly as residential and industrial heating, residential cooling, transport demand, indirectly as electricity demand**	**FCR, aFRR, mFRR**	**NG price increase; NG consumption limitation**	✓

investment due to flexible cross-sectoral transactions, while, in [38], power-to-H_2-to-power pathway efficiently competes with standard storage technologies in providing long-term electricity services. As indicated in [39], higher levels of coupling between energy system sectors imply greater reduction in CO_2 emissions.

A concise and tabulated review of the relevant literature is presented in Table 1. Notably, all papers are built upon the state-of-the-art (MI)LP mathematical programming, while most of them adopt a simplified analysis paradigm, neglecting active power reserves requirements of the power sector, even though they may impact substantially the analysis results [40]. Representation of competitionbetween carriers in end-use sectors varies significantly, with more detailed approaches usually compromising with a short temporal horizon [29], [34], [35]. Overall, all modelling frameworks reviewed fail to combine the following modelling features: high temporal resolution and optimization horizon, detailed representation of reserves requirements and flexible fulfillment of energy demand in each end-use sector. Further, all studies focus on the policies required to reduce CO_2 emissions, rather than consumption of fossil fuels *per se* and achieve the participation of a minimum level of renewables in the energy mix.

In this work, a coherent methodology is developed, bridging the previously identified gap, while two factors affecting integrated energy system CEP decisions, which are absent from the available literature, are thoroughly investigated. Notably, the contribution of our work can be summarized in the following two points:

1) Firstly, the analysis concurrently integrates high (hourly) temporal resolution in tandem with long (yearly) optimization horizon, a detailed representation of active power reserves requirements and flexible coverage (endogenously defined by the optimization algorithm) of final energy demand per modelled end-use sector by different energy carriers. More specifically, energy demand time-series corresponding to the considered end-use sectors (residential/industrial heating and transportation) can be flexibly covered by each available energy carrier, meaning that the technology mix linking the energy carrier supply side with the end use sectors is endogenously defined. Specifically for transportation, this paper differentiates from the rest of the standard literature practice by incorporating four vehicle types with different hourly charging/refueling profiles per type and fuel. Additionally, oxygen (O_2) and water (H_2O), which are by-products or feedstock in particular processes, are tracked and treated as commodities with a simplified representation of the respective markets, further differentiating our work from previous studies. The hourly temporal resolution and yearly horizon adopted allows for a fine representation of system assets' operation and captures the mid- and long-term benefits of sector-coupling with a higher fidelity. Further, the proposed model employs a detailed representation of reserves requirements per time interval, that intends to adequately address the flexibility needs of the power system and reveal possible benefits emanating from sector-coupling related to fulfilling such requirements. To the best of our knowledge, other attempts so far in the relevant literature focus at most on two of the aforementioned modelling aspects, falling behind in capturing relevant benefits from energy system cross-sector and cross-vector coupling.
2) Secondly, our work omits the single-dimensional focus of available literature dealing with integrated energy system CEP on CO_2 emission reduction as a policy instrument. Instead, the main target of this analysis is to identify the impact that unexpected geopolitical developments affecting fossil fuel supply, such as increased NG prices and consumption limitations (equivalent to imports restrictions), may have on CEP decisions for cross-vector and cross-sector coupled energy systems, to display their potential contribution towards achieving decarbonization targets, along with the associated caveats and costs. This assessment reveals the potential of such unwelcome geopolitical events to incentivize investments that, in the long run, will facilitate the transition towards an energy system free from fossil NG. Especially, examination of a NG consumption total elimination scenario is included in the analysis leading to a fossil-free development of the energy system inherently immunized against volatility of NG price and imports uncertainty. Shedding light on such correlations is a matter of great importance and urgency, especially in EU, where NG is a predominantly imported commodity introducing additional geopolitical risks that seriously jeopardize security of supply, as demonstrated by the 2022 energy crisis developed as a result of the war in Ukraine.

To address these aspects, we developed a CEP model for energy systems, built upon the LP mathematical optimization, aiming to outline the benefits stemming from cross-vector and cross-sector coupling trajectories for future integrated energy systems. Energy carriers considered include electricity, H_2, and NG, while a CO_2 sector encompassing carbon capture (CC), storage and utilization facilities is incorporated in the model. The proposed model is utilized to assess the decarbonization of the Greek energy system, selected as a study case in this paper, with 2050 serving as the target year of analysis. Initially, we evaluate the attained decarbonization in the electricity, NG, and H_2 sectors assuming the NG price levels anticipated for 2050 in the REPowerEU plan [41]. Then, we analyse and compare the effects of both elevated NG prices and imports restrictions on future sector-coupled optimal system development.

The remainder of this paper is organized as follows. Section II introduces the adopted methodology, thoroughly describes the structure of the developed model, presents the case study assumptions and describes the examined scenarios. In Section III, results are outlined for the base case scenario and two parametric investigations and further discussed in Section IV. The main conclusions are summarized in Section V.

II. METHODOLOGY AND DATA

A. METHODOLOGY

This Section presents a qualitative description of the sector- and vector-coupling LP problem, while the mathematical formulation in its entirety is listed in the Supplementary Material. The objective is to minimize the investment and variable operating cost of generation, storage and conversion technologies. The proposed modeling framework adopts annual horizon with hourly resolution, without resorting to temporal clustering. A single-node approach is chosen regarding the spatial representation, excluding modelling of transmission and distribution infrastructure of energy carriers, as is typical in similar studies [25], [28], [38] to maintain tractability and computational efficiency. A greenfield development is assumed, whereby the aggregate capacities of all technologies are endogenously determined, excluding hydropower, which is predetermined given the constraints in developing new assets; interconnections with external systems are ignored. Four types of battery electric or H_2 fuel-cell vehicles are available as alternative means of transportation, while all energy vectors considered may be used to satisfy power, industrial and residential heating needs. Implementation of the suggested LP optimization problem takes place in GAMS, using CPLEX solver. The problem incorporates 954,879 variables and optimal solution is traced in 7850 sec (or 2.2 h) on average. The model has been built by the authors without resorting to existing, off-the-shelf energy system modelling software to perform the analysis. A representation of the modeled sector-coupled energy system is illustrated in Fig. 1.

B. MODEL FORMULATION

1) OBJECTIVE FUNCTION

The objective function (1) aims to minimize total system cost, while satisfying exogenous end-use demand for electricity and residential cooling, residential and industrial heating and transportation. Three different cost terms are included in (1): fixed, variable and other costs. Fixed costs, defined in (2), comprise all investment expenditure related to energy infrastructure, introduced via the annualized overnight investment cost of each technology, as in [42] for power generation and storage. Equation (3) presents the variable costs, associated with the operation of each component. They include fossil NG cost, CO_2 emissions rights cost, variable costs of renewable and hydropower plants, if any, cost of permanent CO_2 storage and end-use energy conversion appliances and devices, and net costs associated with water and oxygen transactions. The rightmost part of (1), further developed in (4), represents other costs, supporting the efficient execution of the optimization algorithm. Specifically, a relatively low cost is attributed to the allocation of reserves to participating units to avoid over-provision in excess of system requirements, while an increased cost is assigned to energy not served (ens) to avoid solution infeasibility.

$$\boldsymbol{obj} = \min\left(\boldsymbol{C_{fix}} + \boldsymbol{C_{var}} + \boldsymbol{C_{oth}}\right) \tag{1}$$

$$\begin{aligned} C_{fix} = & \sum_{tech \in T - T_{st}} A_{tech} \cdot C_{tech}^{fix} \\ & + \sum_{\boldsymbol{tech} \in \boldsymbol{T_{st}}} (\boldsymbol{A_{tech}^{p}} \cdot \boldsymbol{C_{tech}^{p,fix}} + \boldsymbol{A_{tech}^{e}} \cdot \boldsymbol{C_{tech}^{e,fix}}) \\ & + \sum_{\substack{use \in \{heat, ind\} \\ EC}} A_{EC}^{use} \cdot C_{EC}^{use,fix} \end{aligned} \tag{2}$$

$$\begin{aligned} C_{var} = & \sum_{t} G_t^{imp} \cdot C_{NG} + \sum_{\substack{t \\ tech \in T_{cc}}} Q_{t,tech}^{seq} \cdot C_{seq}^{var} \\ & + \sum_{\substack{\boldsymbol{t} \\ \boldsymbol{tech \in T_{flexhy}}}} \boldsymbol{E_{t,tech}} \cdot \boldsymbol{C_{tech}^{var}} + \sum_{\substack{\boldsymbol{t} \\ \boldsymbol{tech \in T_{vres}}}} \boldsymbol{E_t^{vres}} \cdot \boldsymbol{C_{tech}^{var}} \\ & + C_{em} \cdot \left[\sum_{\substack{t \\ use \in \{heat, ind\}}} Q_t^{use,rlsd} + \sum_{\substack{use \in \{heat, ind\} \\ EC}} A_{EC}^{use} \cdot C_{EC}^{use,fix} \right] \\ & + f_{heat} \cdot \left[D_{EL}^{heat} + \sum_{t} D_t^{cool} \right] \cdot C_{heat,EL}^{var} \\ & + f_{heat} \cdot D_{EL}^{ind} \cdot C_{ind,EL}^{var} + \sum_{com} C_{com} \cdot Cons_{com}^{net} \end{aligned} \tag{3}$$

$$\begin{aligned} C_{other} = & \left[\sum_{t,r} R_{t,r}^{vres} + \sum_{\substack{t,r \\ tech \in T_{rsrv} - T_{vres}}} R_{t,tech,r} \right] \cdot C_{rsrv} \\ & + \sum_{t} (E_t^{ens} \cdot C_{ens,EL} + G_t^{ens} \cdot C_{ens,NG}) \end{aligned} \tag{4}$$

2) MODELLING POWER SYSTEM ASSETS

NG-fired, combined-cycle gas turbines (CCGTs) is the only conventional generation technology considered, further subdivided into two categories, without or with a co-located CC unit. The latter feature higher investment cost, as well as lower efficiency [43], [44] due to self-consumption associated with CO_2 emissions capture. More specifically, post-combustion CC technology is assumed, that demands auxiliary electricity and heat for its operation [45], covered through supplementary NG consumption, leading to a lower aggregate efficiency than equivalent non-CC units. Overall, the carbon footprint of CCGT with CC is 90% lower than without CC technology [43], [46].

Regarding hydropower plants, two groups are considered in the model: (a) hydropower plants with flexible electricity production, including reservoirs with natural inflows and no pumping capability, or open-loop pumped-hydro stations (open-loop PHS) with natural inflows and pumping functionality, and (b) hydropower plants with inflexible production, namely run-of-river (RoR) units. The latter are represented by an exogenously defined hourly production time-series introduced into the model as a parameter. Flexible hydropower plants comply with a minimum daily production requirement, i.e. mandatory water discharge for purposes other than power generation, such as irrigation and river basin ecological supply.

Intermittent renewable energy technologies include solar PVs, onshore and offshore wind, all modelled via respective hourly availability profiles.

Two principal electricity storage technologies are included in the model, namely Li-ion batteries (BESS) and closed-loop pump-hydro storage (closed-loop PHS). BESS are assumed capable of seamlessly switching between charging and discharging states [47], [48], whereas closed-loop PHS are not capable of continuously transitioning between these states.

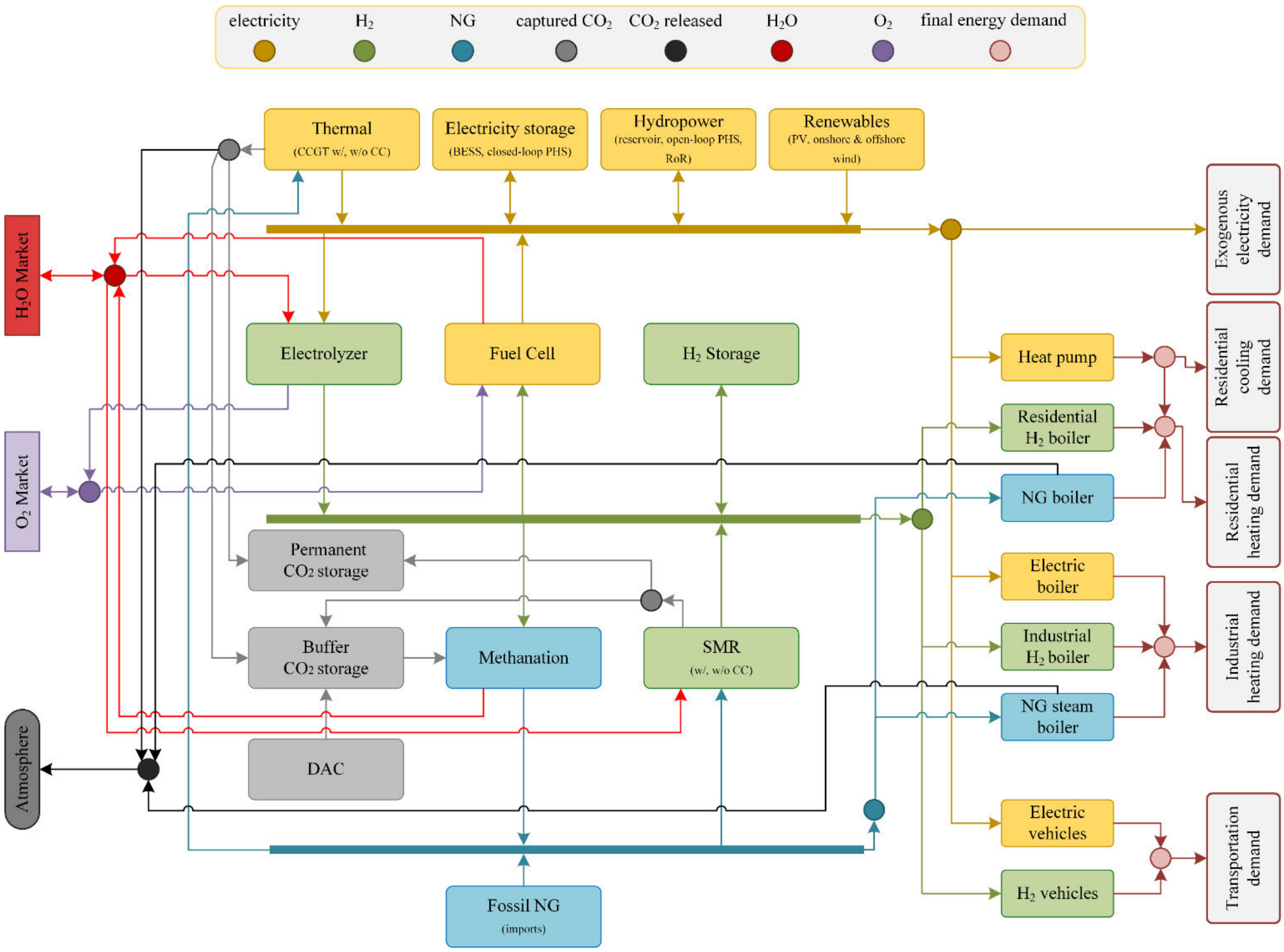

FIGURE 1. Sector-coupled system representation.

Management of storage assets ensures that energy stored is adequate to cover allocated reserves [49].

3) CROSS-VECTOR COUPLING TECHNOLOGIES BETWEEN ELECTRICITY AND H_2

Technologies implementing cross-vector coupling of the electricity and H_2 sectors comprise electrolysers, fuel cells and H_2 storage units, allowing to model multidirectional and flexible energy flows, as shown in Fig.1. Polymer electrolyte membrane (PEM) electrolyzers and fuel cells are considered in this paper due to their fast dynamic response to load variations [50], [51], allowing their contribution in upward and downward reserves. Electrolyzer and fuel cell operation involves consumption and production of water and oxygen, in proportion to the quantity of produced and consumed H_2 respectively. Water and oxygen quantities are calculated based on stoichiometric ratios, with the exception of water consumption for electrolysis, that exceeds the stoichiometric ratio due to additional needs for water treatment [52], [53].

4) FULFILMENT OF RESERVES REQUIREMENTS

Ancillary services considered include frequency containment reserve (FCR), automatic frequency restoration reserve (aFRR) and manual frequency restoration reserve (mFRR) reserves, both upward and downward. Constraint (5) ensures that the sum of reserves provided by each participating technology, per reserve type, satisfies the corresponding system requirements. Technologies capable of contributing to FCR are CCGTs, BESS, electrolysers and fuel cells. Flexible hydropower plants and closed-loop PHS participate in aFRR and mFRR provision. Downward mFRR needs can further be met through curtailments of available RES production, via tertiary regulation.

$$\sum_{tech \in T_{rsrv}} R_{t,tech,r} + R_{t,r}^{vres} \geq RR_{t,r}, \quad \forall t, r \tag{5}$$

5) CROSS-VECTOR COUPLING TECHNOLOGIES BETWEEN H_2 AND NG

H_2 and NG sector linking is achieved through catalytic methanation (meth) and steam-methane reforming (SMR) units. Catalytic methanation is a procedure based on Sabatier reaction which, in the presence of a catalyst, combines H_2 and CO_2 producing methane (CH_4) or so-called SNG and water, [15]. The amount of by-product water is calculated using a stoichiometric ratio. The process requires auxiliary electricity consumption [54]. SMR involves fossil NG and water steam as reactants. H_2 formation results in CO_2 emissions [55]. The reaction takes place in the presence of a catalyst under high temperatures (800-900°C). In order to fulfil the reaction's thermal needs, additional NG is consumed as fuel [56]. This extra NG consumption is incorporated into the efficiency factor of the SNG to H_2 conversion. Except for thermal energy requirements, the unit needs auxiliary electricity to carry out the H_2 production process. Two types of SMR units are considered here, differing in the presence of CC technology. Inclusion of CC entails increased thermal and electricity needs, which is translated as a further drop in efficiency and rise in unit electricity consumption [57]. Water requirements for the SMR plants comprise quantities necessary to generate steam and in the cool down process [52].

6) CAPTURED CO_2 EMISSIONS HANDLING

Two separate paths pertaining to the management of captured CO_2 are included in the analysis. Captivated CO_2 in CCGT and SMR plants equipped with CC units is permanently stored (sequestration), thus excluding possible future reuse and exploitation. Bound CO_2 can be alternatively directed to a temporary CO_2 storage tank (buffer), to supply the catalytic methanation process. To disengage the methanation process from CO_2 derived from CCGT and SMR plants, we also examine the possibility of capturing CO_2 through direct air capture (DAC). DAC technology requires high-temperature heat and electricity to operate [58], which are considered to be met solely by electricity [59].

7) SECONDARY RAW MATERIALS AND BY-PRODUCTS MANAGEMENT

In the model, oxygen and water quantities engaged in reactions and processes as raw materials and by-products are bought and sold at predetermined market prices.

8) CROSS-SECTOR COUPLING TECHNOLOGIES BETWEEN CARRIERS AND END-USE SECTORS

Representation of the residential heating/cooling and industrial heating end-use sectors relies on exogenously defined energy demand time-series. To satisfy end-use hourly demand, investments in a variety of linking technologies are considered and competition between energy carriers is allowed, aiming to achieve the cost-optimal fulfilment of end-use energy needs. Heat pumps, residential H_2 and gas boilers are considered to cover residential heating demand, in (6). Industrial heat demand is satisfied by electric boilers, industrial H_2 boilers and gas steam boilers (6). Constraint (7) specifies the capacity of all aforementioned cross-sector coupling technologies, operating as indicated by hourly per unit end-use demand profiles ($P_t^{use,pu}$). NG-consuming appliances release the same emissions, per unit of consumed gas, as CCGT and SMR units without CC (8). Residential cooling needs are served solely by heat pumps utilized also for residential heating purposes, working on electricity. As a result, their capacity must be able to cover the sum of hourly cooling and heating demand, as defined in (9).

$$\sum_{EC \in EnCar} D_{EC}^{use} = \sum_{t} D_t^{use}, \quad \forall t, use \in \{heat, ind \tag{6}$$

$$D_{EC}^{use} \cdot P_t^{use,pu} \cdot f_{heat} \leq A_{EC}^{use}, \quad \forall t, EC, use \in \{heat, ind\} \tag{7}$$

$$Q_t^{use,rlsd} = \frac{D_{NG}^{use}}{n_{NG}^{use}} \cdot P_t^{use,pu} \cdot f_{heat} \cdot q^{use,em}, \quad \forall t, use \in \{heat, ind\} \tag{8}$$

$$\left(D_{EL}^{heat} \cdot P_t^{heat,pu} + D_t^{cool}\right) \cdot f_{heat} \leq A_{EL}^{heat}, \quad \forall t \tag{9}$$

Transportation end-use demand is divided into four categories, corresponding to different types of vehicles: private cars, buses, trains and heavy duty trucks. We exogenously define a yearly aggregate demand per vehicle type. Only electric and H_2 fuel cell vehicles are considered as sector-coupling technologies pertaining to transportation. Constraint (10) determines the quota (with respect to total annual demand) corresponding to battery electric and H_2 fuel cell vehicles, per type. Each vehicle type features an hourly per unit charging/refuelling profile, representing the ratio of hourly over the total yearly demand corresponding to that type. Hence, hourly electricity and H_2 demand for transportation are shaped according to (11) and (12), respectively.

$$D_v^{EL} + D_v^{H_2} = D_v^{transp}, \forall v \tag{10}$$

$$E_t^{transp} = \left(\frac{1}{n_{EL}^{transp}}\right) \cdot f_{heat} \cdot \sum_{v \in vehicles} D_v^{EL} \cdot P_{t,v}^{EL,pu}, \quad \forall t \tag{11}$$

$$H_t^{transp} = \left(\frac{1}{n_{H_2}^{transp}}\right) \cdot f_{heat} \cdot \sum_{v \in vehicles} D_v^{H_2} \cdot P_{t,v}^{H_2,pu}, \quad \forall t \tag{12}$$

9) ELECTRICITY AND NG BALANCE EQUATIONS

The electricity system equilibrium per time interval is represented by (13). The terms in the left-hand side of the equation correspond to electricity inflows (production and storage discharge), while those on the right constitute electricity outflows (demand, storage charging and auxiliaries consumption). A similar approach is adopted for hourly NG balance in (14), with fossil NG and SNG supply equalling total outflows.

The variables E_t^{ll} and G_t^{ll} represent potentially non-satisfied electricity and NG demand and are highly penalised.

$$\sum_{tech \in T_{PE}} E_{t,tech} + E_t^{vres} + RoR_t + \sum_{tech \in T_{st}} E_{t,tech}^{disch} + E_t^{ens}$$
$$= D_t^{EL} + \left(\sum_{use \in \{heat,ind\}} \frac{D_{EL}^{use}}{n_{EL}^{use}} \cdot P_t^{use,pu} + \frac{D_t^{cool}}{n_{EL}^{cool}} \right) \cdot f_{heat}$$
$$+ E_t^{transp} + \sum_{tech \in T_{st}} E_{t,tech}^{ch} + \sum_{tech \in T_{CE}} E_{t,tech}, \quad \forall t \tag{13}$$

$$\sum_{use \in \{heat,ind\}} \frac{D_{NG}^{use}}{n_{NG}^{use}} \cdot P_t^{use,pu} \cdot f_{heat}$$
$$+ \sum_{\substack{tech \in T_{CCGT} \\ \cup T_{smr}}} G_{t,tech} = G_t^{imp} + G_{t,meth} + G_t^{ens}, \quad \forall t \tag{14}$$

C. CASE STUDY ASSUMPTIONS & SCENARIOS EXAMINED

The mathematical optimization sector-coupling model proposed in this paper is applied in a power system resembling Greece's, in its future development, indicatively for year 2050, as regards demand, renewable generation and hydropower capacity. Exogenous electricity demand and renewable production profiles for intermittent RES (solar PV, onshore and offshore wind) and hydro plant inflows are obtained from [60]. Mandatory water discharge profiles are retrieved from publicly available data provided by the Greek Power System Operator with daily resolution [61].

The residential heating and cooling demand profiles for Greece are presented in Appendix A and correspond to average weather conditions. Industrial demand encompasses heating needs in industrial plants and manufacturing processes. To form a representative industrial heating demand profile, hourly resolution data derived from the Greek Gas System Operator [62] are used. In our study, transportation encompasses only means of road transport, leaving out maritime and air transport. In total, four vehicle types are considered, each associated with an annual profile of energy supply needs with hourly resolution. Investment in vehicles is not included in the optimization process, effectively assuming similar purchase costs for battery electric and H_2 vehicles, but individual demand profiles and efficiencies are accounted for. Annual demand for exogenous electricity, residential heating & cooling, industrial heating, and transportation is given in Table 2. Annual and daily profiles are presented in Appendix A.

Historical data for Greece indicate that the methane content of imported NG is higher than 89.5%, reaching up to 98% in some cases [64]. If SNG produced through catalytic methanation meets content requirements to safely inject in NG pipelines, then it can be treated as a climate neutral substitute for fossil NG [65], provided that catalytic methanation relies on green H_2 produced by renewable electrolysis and captured CO_2. The necessary quantity of reactant CO_2 to compose SNG is regarded equal to the amount of CO_2 released from burning NG, namely 0.202 tonnes of CO_2 per MWh of NG, [28].

TABLE 2. Annual values of energy demand components for 2050, [63].

	Annual value - *2050*
Exogenous electricity	75.7 TWhe
Residential heating	1.880 Mtoe
Residential cooling	1.140 Mtoe
Industrial	2.661 Mtoe
Transportation – *total*	4.200 Mtoe
Private cars	1.900 Mtoe
Buses	0.600 Mtoe
Trains	0.300 Mtoe
Trucks	1.400 Mtoe

Permanent CO_2 storage for sequestration purposes is considered to take place in onshore underground saline aquifers. As mentioned in [66], a substantial underground CO_2 storage potential exists in Greece, estimated at about 640 MtnCO_2.

Investment and variable costs for each component are given in Appendix B, along with relevant technical characteristics of storage and conventional generation units.

The model is first applied to evaluate the decarbonization potential of a sector-coupled energy system, adopting a NG price of 40 €/MWh, in line with the REPowerEU plan assumptions [41]. A base case scenario addresses the viability of ambitious energy transition strategies. Then, two investigations are conducted, concerning NG price and supply availability: first, the sensitivity of the optimal energy system planning is evaluated against variations in NG price between 20 and 200 €/MWh, aiming to highlight the significance of NG cost as an indirect decarbonisation driver; a second case explores the impact on planning decisions when a hard constraint is imposed on the quantity of NG imports.[1] In this analysis, NG price remains fixed. Table 3 summarizes the scenarios evaluated.

TABLE 3. Summary of examined scenarios.

	NG price	NG consumption limitation
Base case	40 €/MWh	none
Case 1	20 - 200 €/MWh	none
Case 2	40 €/MWh	0%-100% of base case

III. RESULTS

A. ENERGY SYSTEM IN THE BASE CASE SCENARIO

Optimal planning based on a NG cost of 40 €/MWh and a CO_2 emissions cost assumption of 150 €/tnCO_2, leads to markedly unbalanced decarbonization levels in different energy system sectors. As shown in Table 4, installed renewables reach an aggregate capacity of 76.2 GWe, covering 90.21% of the total energy demand of 194 TWhe, 64.1 TWhe of which are due to the direct electrification of heating-cooling and transportation demand. A total capacity

[1] Since Greece does not extract fossil NG, any restriction on imported NG quantities is equivalent to a restriction on fossil NG consumption.

TABLE 4. Installed capacities per technology in the base case scenario of optimal energy system planning.

Technology	Capacity	Technology	Capacity	Technology	Capacity
Onshore Wind *(GWe)*	28.9	Closed-loop PHS (*energy*) *(GWe)*	121.4	CO_2 Buffer Storage *($MtnCO_2$)*	-
Offshore Wind *(GWe)*	4.5	Electrolyzer *(GWe)*	6.2	DAC *($ktnCO_2/h$)*	-
PV *(GWe)*	42.9	Fuel Cell *(GWe)*	0.1	Heat Pump *(GWh_{th}/h)*	14.6
CCGT w/o CC *(GWe)*	1.6	H_2 Storage *($GWh_{th\text{-}H_2}$)*	33.5	H_2 Boiler (*residential*) *(GWh_{th}/h)*	-
CCGT w/ CC *(GWe)*	4.4	Methanation *($GWh_{th\text{-}NG}/h$)*	-	NG Boiler *(GWh_{th}/h)*	-
BESS (*power*) *(GWe)*	13.4	SMR w/o CC *($GWh_{th\text{-}NG}/h$)*	-	Electric Boiler *(GWh_{th}/h)*	-
BESS (*energy*) *(GWhe)*	65.4	SMR w/ CC *($GWh_{th\text{-}NG}/h$)*	6.0	H_2 Boiler *(industrial)* *(GWh_{th}/h)*	4.0
Closed-loop PHS (*power*) *(GWhe)*	5.4	CO_2 Permanent Storage *($MtnCO_2$)*	11.9	NG Steam Boiler *(GWh_{th}/h)*	-

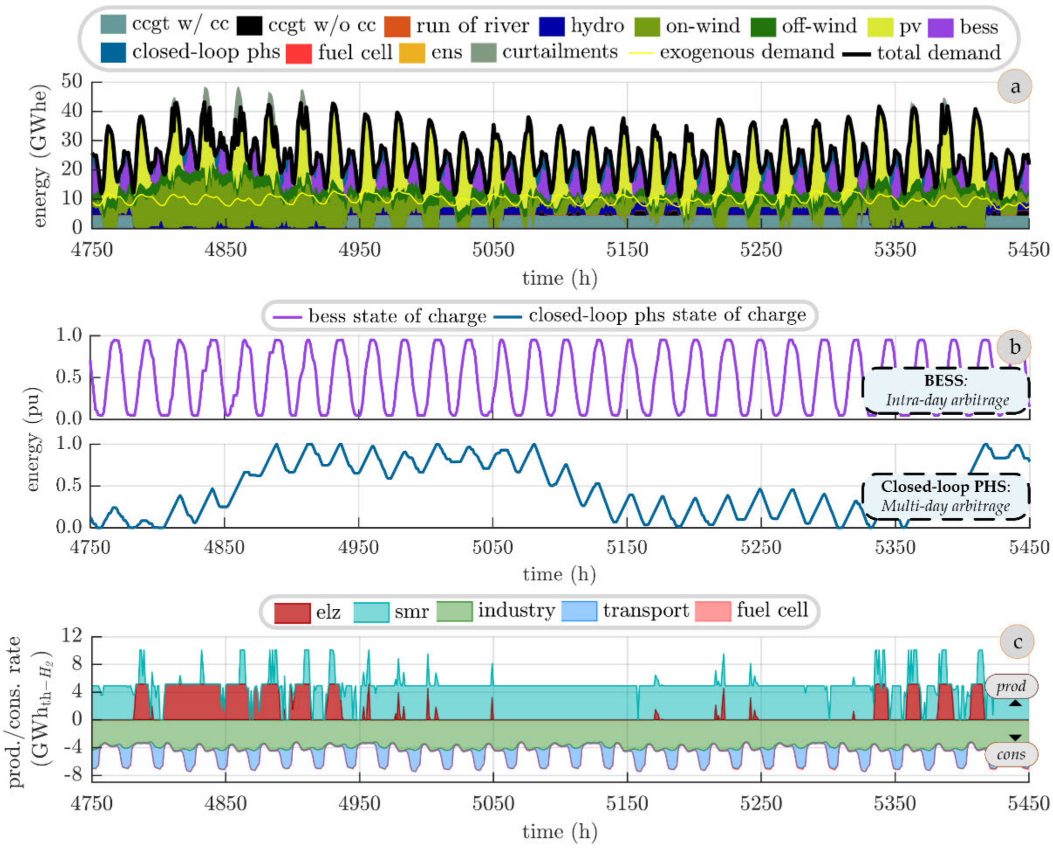

FIGURE 2. Hourly variation of (a) electricity generation mix, (b) BESS and closed-loop PHS state of charge, (c) H_2 production & consumption, during an indicative monthly period.

of 18.7 GWe/186.9 GWhe of electrical storage complements the large installed capacity of intermittent RES. BESS, due to their technical capabilities and cost characteristics (low power but high energy capacity cost), are deployed in low energy-to-power ratios, used to provide power intensive system services and intra-day arbitrage. On the other hand, closed-loop PHS, being characterized by cheap energy and expensive power component costs, are selected as longer duration storage assets, utilized for energy shifting over time horizons that extend beyond thedaily cycle, as shown in Fig. 2, where closed-loop PHS cycle electricity between periods of high and low wind or solar potential. Notably, conventional gas-fired units remain a cost-competitive and necessary generation and flexibility option, with CCGTs equipped with CC prevailing due to their significantly lower emission rate.

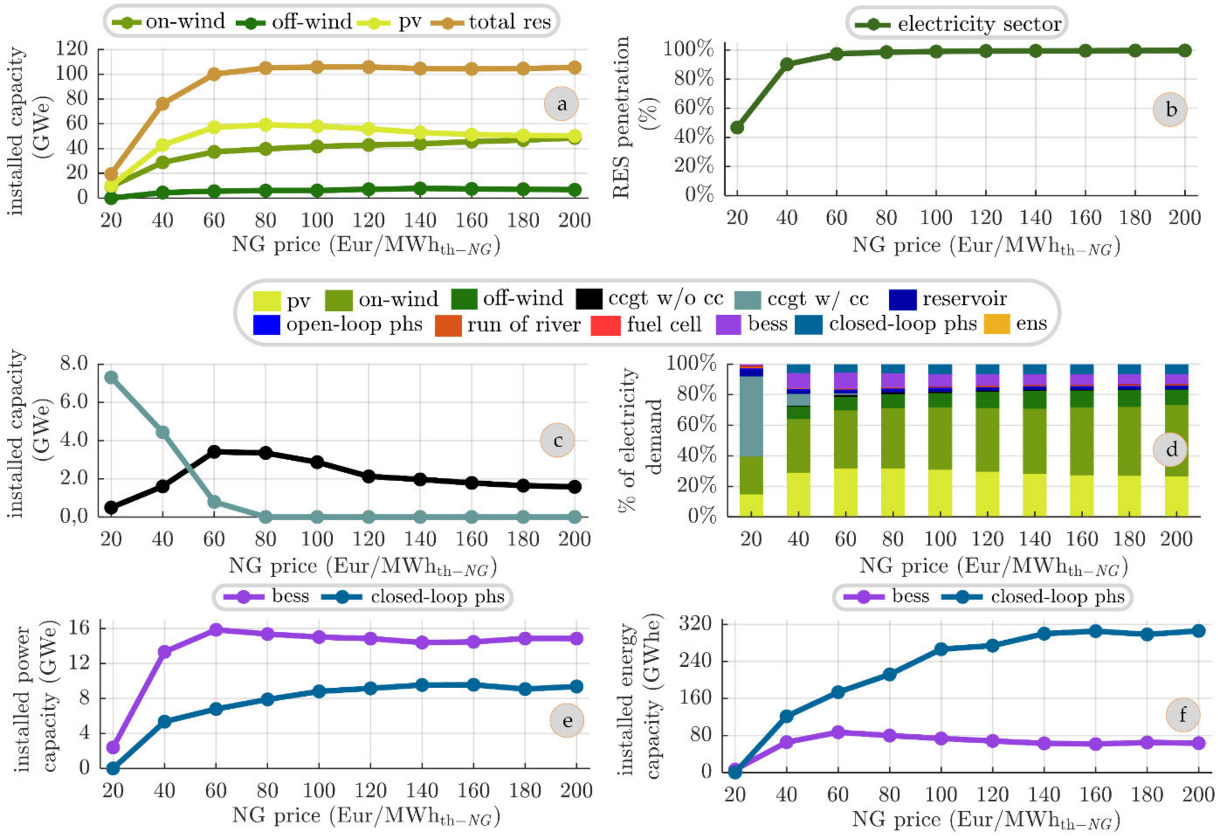

FIGURE 3. Variation with the price of NG of (a) RES installed capacity, (b) RES penetration in the electricity sector, (c) CCGT capacity, (d) energy mix in electricity, (e) electricity storage power capacity, and (f) electricity storage energy capacity.

The H_2 sector, on the other hand, is only moderately developed and depends markedly on fossil NG, as the demand for 43.8 TWh of H_2 is primarily supplied by low-carbon H_2 from SMR with CC, leaving only a share of 30.02% to renewable H_2 from water electrolysis. Fig. 2 shows that the electrolyzers, mostly operating at times of high RES availability, enhance and complement SMR production to charge H_2 storage. In terms of end-uses, H_2 is used as a transportation fuel to a limited extent, only in fuel cell trucks, while it constitutes the sole industrial heat provider. Regarding the latter, NG is rejected as its direct use in gas boilers entails CO_2 emissions, while H_2 outweighs electricity, and the decisive factor is the figure of industrial demand time-series (see Appendix A). The hourly minimum industrial energy requirement reaches 2,84 GWh_{th}/h. Low carbon H_2 from SMR with CC proves more cost-effective than low-carbon electricity from CCGT with CC or renewable electricity respectively for covering continuous industrial energy needs, due to low investment cost of SMR units and constant NG availability – unlike electricity from intermittent RES – at relatively low cost.

NG supply consists entirely of imported fossil gas since it is considered a more cost-effective option than SNG. Although NG is absent from the end-use sectors, it is still needed for H_2 production (37.29 TWh) and secondarily for electricity generation (29.5 TWh), corresponding to a total of 66.84 TWh of fossil NG, very close to the actual domestic NG consumption in year 2021 (69.96 TWh, with 48.03 TWh being used for power generation, [67]). Thus, a NG price at the REPowerEU estimated level does not eliminate dependence on fossil NG; in fact, reliance on fossil NG remains the same as today, with NG usage largely diverted from end-use and electricity generation to low-carbon H_2 production. In the following sections, the impact of NG pricing and potential hard restrictions in fossil NG imports is evaluated in relation to the achievement of energy system decarbonization targets.

B. SENSITIVITY TO NG PRICE

1) ELECTRICITY SECTOR

Both installed RES power capacity (Fig. 3a) and RES penetration (see Appendix C) in electricity production (Fig. 3b) increase drastically at NG prices above 40 €/MWh, saturating at 60-80 €/MWh. Installed CCGT generation capacity follows the opposite trend, however conventional units remain in the generation portfolio even at NG prices as high as 200 €/MWh (Fig. 3c), because CCGTs are needed for capacity adequacy purposes, as well as for the provision of ancillary services at a competitive cost compared with alternative flexibility options. As a result, RES penetration

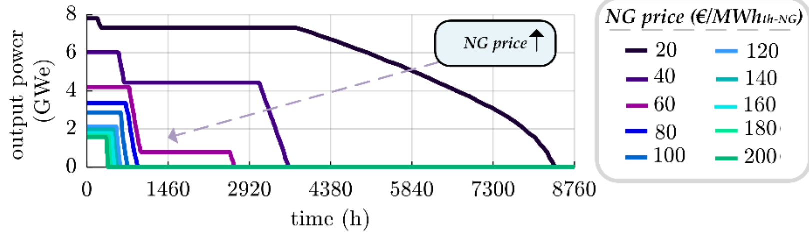

FIGURE 4. Duration curves of CCGT capacity dispatched for operation, at different NG price levels.

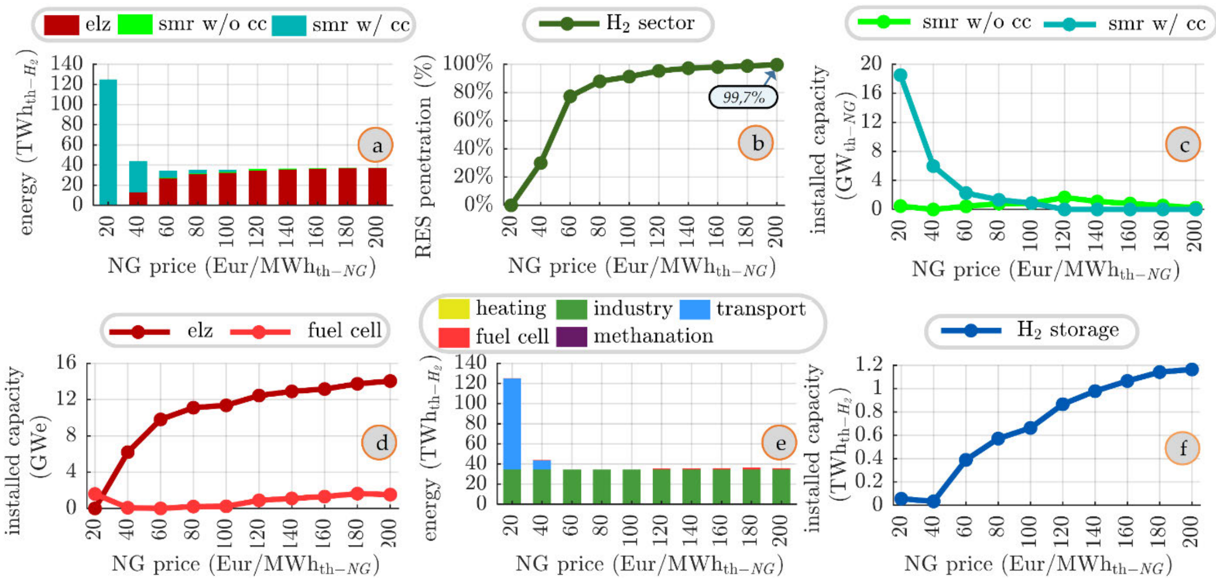

FIGURE 5. (a) H_2 production mix, (b) RES penetration in H_2 sector, (c) SMR capacity, (d) electrolyzer & fuel cell capacity, (e) H_2 usage per end-use sector, and (f) H_2 storage capacity, as a function of NG price.

in electricity production does not reach exactly 100%. Additionally, CCGTs without CC replace CCGTs with CC as NG becomes more expensive; since they are hardly dispatched

for operation at high NG prices, as shown in Fig. 4, investment in low capital cost units without CC is the least cost option in the optimization problem.

As shown in Fig. 3a, the increase in NG prices brings about a rise in the installed capacity of onshore wind, approaching the capacity of PVs, and in their contribution to the electricity mix (Fig. 3d), which exceeds that of PVs. Increased variable operational cost of CCGTs due to high NG prices forces their gradual rejection from the system. Onshore wind feature higher capacity factor than PVs and a more uniformly distributed availability profile (see Appendix A), which makes them increasingly important for covering the gap in base load production.

The increased RES share in the electricity sector at higher NG prices necessitates additional electricity storage to manage the intermittency of renewables and disengage their generation profile from the demand pattern (Fig. 3e-f). Thus, as NG prices increase, closed-loop PHS are gradually establishing their presence in the energy mix, with increasing energy capacities. Note that at very low NG prices, in the order of 20 €/MWh or below, where the overall RES penetration is limited, closed-loop PHS is not required in the system. Another notable trend at NG prices higher than 60 €/MWh, bringing about higher RES penetrations and increased wind capacities, is the reduction in the required BESS capacity, with the system needs for arbitrage and flexibility increasingly addressed by closed-loop PHS, fuel cells and electrolyzers.

2) H_2 SECTOR

At the lowest NG price levels examined (∼20 €/MWh), H_2 production relies on NG using SMR plants with CC (Fig. 5a). A rise in NG prices leads to a significant reduction in total H_2 production, while at the same time favoring the production of green H_2 via water electrolysis supplied by RES, which becomes prevalent at NG prices above 120 €/MWh. Yet, a small fraction of H_2 production presents a high carbon footprint as it is produced by SMR without CC, which is more cost-effective than SMR with CC when producing limited H_2 quantities, since the CC unit requires an increased consumption of NG. Although high carbon H_2 is gradually

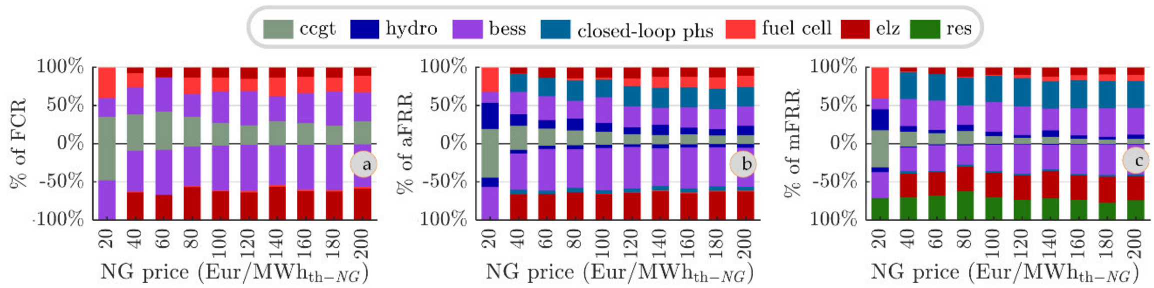

FIGURE 6. Allocation of (a) FCR up (positive) & down (negative), (b) aFRR up & down, (c) mFRR up & down vs NG price.

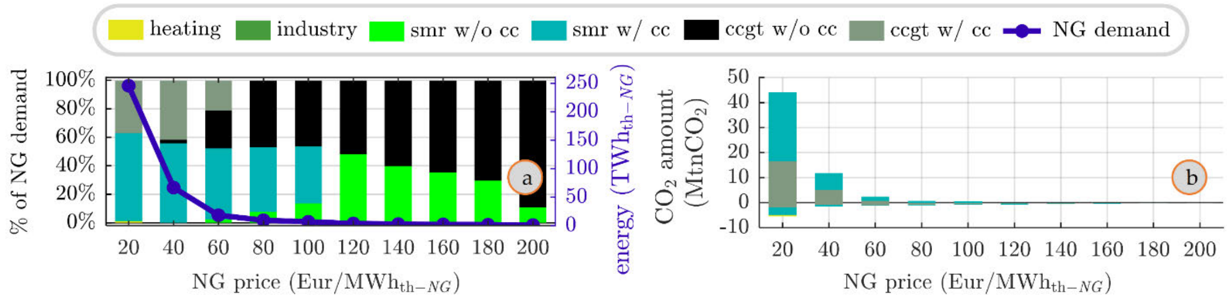

FIGURE 7. (a) Total NG demand (right-hand axis) and allocation to end-usages, (b) captured (positive) and released (negative) CO_2 emissions, against NG price.

displaced by green H_2, RES penetration in the H_2 sector does not reach the 100% target (Fig. 5b). Thus, SMR plants with CC are gradually eliminated (Fig. 5c), while electrolyzer capacity rises (Fig. 5d). Concurrently, H_2 usage changes drastically, as low carbon H_2 becomes more expensive and cannot compete with renewable electricity, especially in the transportation sector, leaving the industry as the main consumer of H_2 (Fig. 5e), with its consumption remaining unaffected by NG price.

It is worth noting that H_2 storage needs remain low at reduced NG prices, despite a high H_2 demand, due to the fact that H_2 from SMR is produced on demand, on the hypothesis of continuous availability of NG fuel. On the other hand, electrolysis-based H_2 production from variable renewables requires enhanced H_2 storage (Fig. 5f). The fuel cells' contribution to electricity production remains well below 1% of the total electricity demand, indicating the minor significance of H_2 as an electricity storage medium. However, fuel cells play a more prominent role in providing reserves (Fig. 6), especially FCR and aFRR, with their importance increasing at higher NG prices, where CCGT contribution to reserves is diminishing.

3) NG & CO_2 SECTOR

Despite the rise in fossil NG price, optimization does not select investing in catalytic methanation to produce sustainable NG. This pathway involves extended energy losses and additional investments in RES and H_2 production and storage. Hence, NG demand is covered solely by fossil gas. Nevertheless, NG consumption shows a steep downward trend (Fig. 7a), in the pursuit of minimum total system cost. At low prices, NG supply is used in CCGT generation and SMR with CC; at high prices, the small NG imports are allocated to CCGT and SMR without CC (Fig. 7a). Notably, regardless of NG price, a minimum quantity of fossil NG is utilized in flexibility resources, when RES and storage cannot cover system needs.

Since the business case for catalytic methanation is not justified, buffer CO_2 storage and DAC, which are closely linked with the operation of methanation plants in our model, are also excluded from the investment portfolio. On the other hand, permanent CO_2 storage is developed, driven by captured emissions from CCGT and SMR CC units (Fig. 7b). Increasing prices of NG reduce the use of CCGT and SMR with CC and, consequently, the required capacity of permanent CO_2 storage. Emissions released in the atmosphere also present a sharp drop, with the slowly decreasing remainder CO_2 emissions being attributed to emission-intensive power and H_2 production.

4) END-USE SECTOR

Heating needs of the residential sector are predominantly covered by electricity, regardless of the NG price level (Fig. 8a). NG is marginally competitive to electricity, serving a small fraction of the total heat demand, only for prices around 20 €/MWh. Residential cooling demand is served by heat pumps; hence a minimum heat pump capacity is installed in any case. Augmentation of the minimum heat pump capacity allows simultaneous coverage of both heating and cooling demand, given that the periods of high heating and

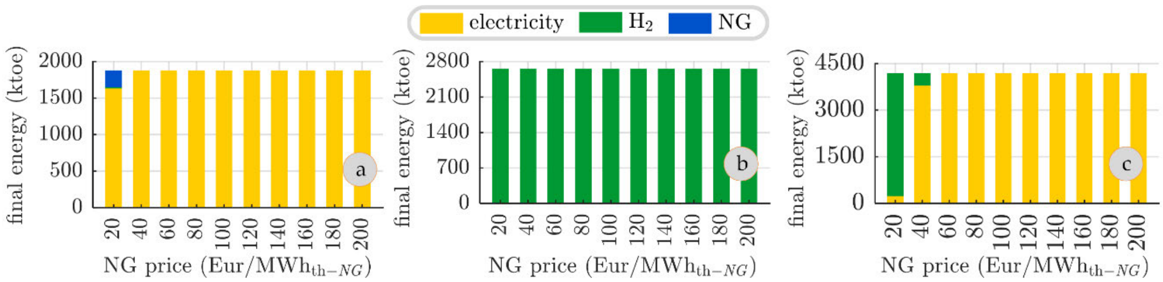

FIGURE 8. (a) Residential heating demand, (b) industrial heating demand and (c) transportation demand coverage by energy vector, vs NG price.

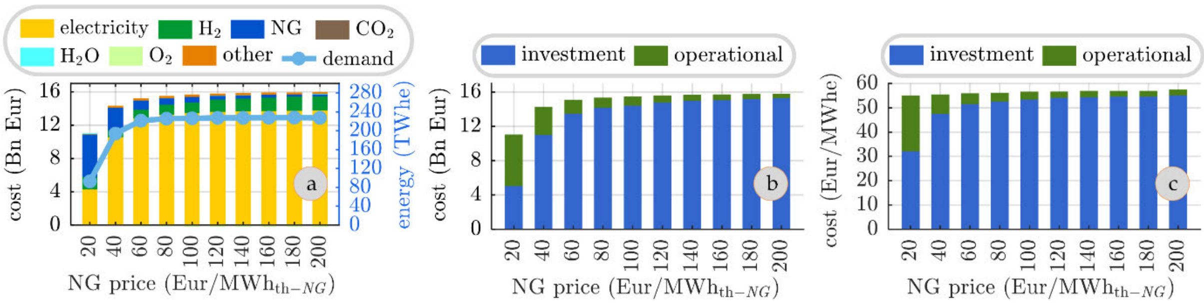

FIGURE 9. (a) Total system cost breakdown by sector (left axis) & total electricity production (right axis) vs NG price, (b) total investment and operating cost vs NG price, (c) power generation cost vs NG price.

cooling demand do not coincide (see Appendix A). In addition, it constitutes the cost-optimal pathway for serving heating demand, since otherwise it would have been necessary to install residential H_2 or NG boilers besides the already needed heat pumps.

As shown in Fig. 8b, regardless of NG price level, H_2 is selected as the most suitable energy vector to supply the industrial sector heating demand. Alternatively, additional RES capacity combined with storage would be a candidate solution to cover industrial heating needs. The optimization algorithm chooses indirect electrification through green H_2 as the cost-optimal pathway for the industrial sector. H_2 storage features the lowest investment cost between energy storage types considered, thus it is a cost-effective means to adapt the stochastic variability of renewable electricity to the pattern of industrial heating needs.

The effect of fossil NG price on transportation demand coverage by energy vector is shown in Fig. 8c. While at low prices it is completely covered by low-carbon H_2, as this NG conversion pathway involves lower costs and energy losses than electricity generation from CCGT with CC, higher NG prices disengage electricity generation from fossil gas and establish a clear business case for RES generation. At the same time, low-carbon H_2 production from SMR for transportation purposes becomes less viable (for NG prices > 60 €/MWh) and therefore the entire transportation demand is covered by low-cost renewable electricity.

5) IMPACT OF SYSTEM COSTS

As shown in Fig. 9a, the NG sector constitutes the largest system cost component for NG prices lower than 40 €/MWh, due to the wide usage of inexpensive gas. Higher NG price levels lead to the gradual substitution of NG mostly by renewable electricity. This trend manifests clearly itself in the total system cost breakdown, with the NG-related costs declining fast and being replaced by electricity sector costs. The shift to renewable electricity entails increased RES investment costs (Fig. 9b). PVs are partially substituted by wind and less investment takes place in CCGTs and battery energy storage, eventually causing the total system cost to reach a plateau of around 16 B€, i.e. 10,6% higher than the base case scenario.

Interestingly, the power generation cost, shown in Fig. 9c, demonstrates remarkable stability to high NG price levels and the changes they bring to the energy system, as already discussed. It is thus established that a viable path, based on RES and sector-coupling, can effectively respond to increasing fossil fuel prices and at the same time deliver a decarbonised energy system.

C. IMPACT OF FOSSIL NG CONSUMPTION RESTRICTIONS ON SYSTEM DEVELOPMENT

While NG prices were shown to act as an indirect system decarbonization driver, that alleviates dependency on imported NG to a great extent, even though not completely eliminating it, in this Section we investigate the impact on system development and decarbonization level achieved by imposing hard constraints on fossil NG consumption, that could be as well dictated by geopolitical reasons and security of supply considerations.

1) ELECTRICITY SECTOR

Fig. 10a shows that the application of fossil NG consumption restrictions causes a moderate increase in PV and

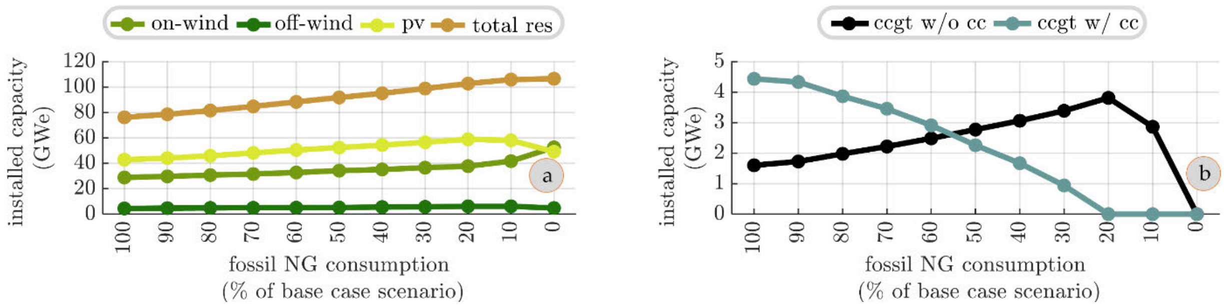

FIGURE 10. Variation of (a) RES capacity, (b) RES penetration in the electricity sector, (c) CCGT capacity, vs fossil NG consumption (% of base case scenario).

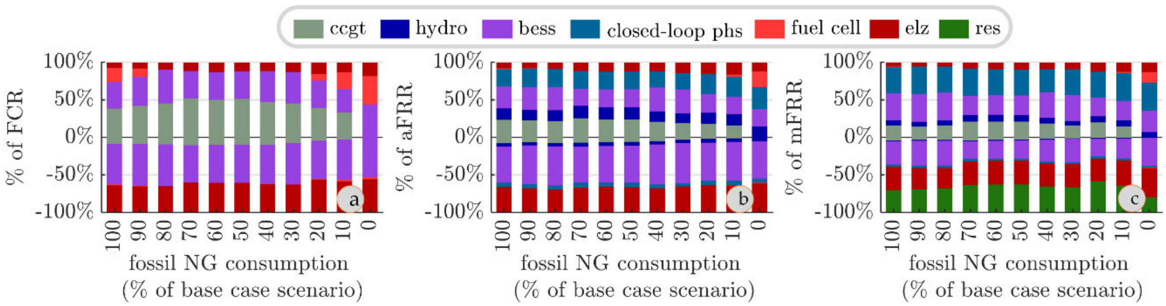

FIGURE 11. Allocation of (a) FCR up (positive) & down (negative), (b) aFRR up & down, (c) mFRR up & down, vs fossil NG consumption (% of base case scenario).

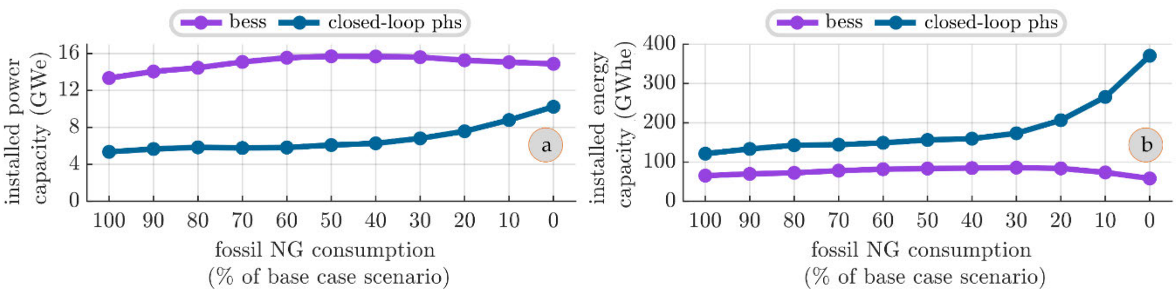

FIGURE 12. (a) Electricity storage power capacity, and (b) electricity storage energy capacity, vs fossil NG consumption (% of base case scenario).

onshore wind capacity, while offshore wind remains practically unchanged. At the same time, conventional plants are gradually phased out, starting with CCGT with CC, when allowed gas imports are limited to 20% of the base case volume (Fig. 10b). CCGTs without CC, on the other hand, remain present in the investment portfolio until gas imports are terminated, since they play an important role in upwards reserves provision (Fig. 11). As fossil gas usage is terminated, electricity supply remains entirely based on RES and storage. To substitute CCGT contribution to base load, the RES mix favours onshore wind in place of PVs (Fig. 10a), due to the higher capacity factor and more uniform delivery pattern, with wind generation becoming the dominant energy source in a completely carbon-free energy system.

System storage requirements show a restrained upward trend, mostly related to moderate BESS capacity increase, as fossil NG consumption is kept over 40% of base case amount (Fig. 12). A heavier decrease in fossil gas usage intensifies the need for storing larger energy quantities to cover medium-term energy requirements, leading to the multiplication of installed closed-loop PHS capacity and the consequent decline in installed BESS capacity.

2) H_2, NG & CO_2 SECTOR

Limitations in NG imports constrain available NG quantities for low-carbon H_2 production by SMR with CC, leading to a moderate reduction in total H_2 production (Fig. 13a), even though the share of electrolysis-based renewable H_2 grows in parallel, while a fraction of low carbon H_2 production relies on SMR without CC. Notably, non-renewable H_2 participates in the mix until gas imports get totally banned. As green H_2 production expands, so are the requirements for H_2 storage

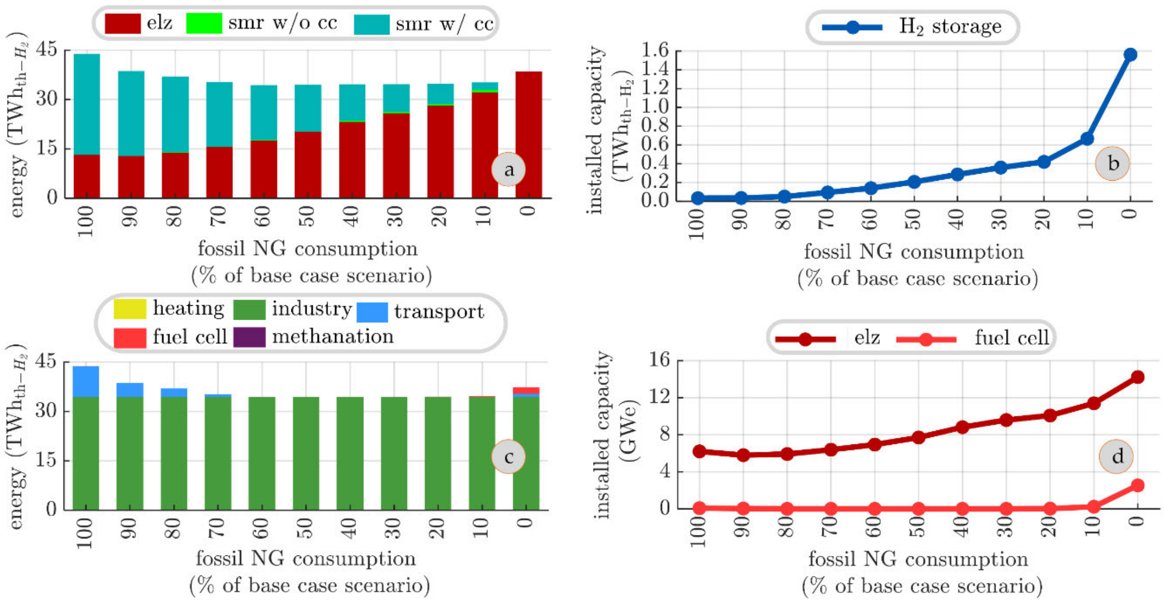

FIGURE 13. (a) H_2 production mix, (b) RES penetration in H_2 sector, (c) SMR capacity, (d) H_2 usage per end-use sector (e) H_2 storage capacity, and (f) electrolyzer & fuel cell capacity, as a function of fossil NG consumption.

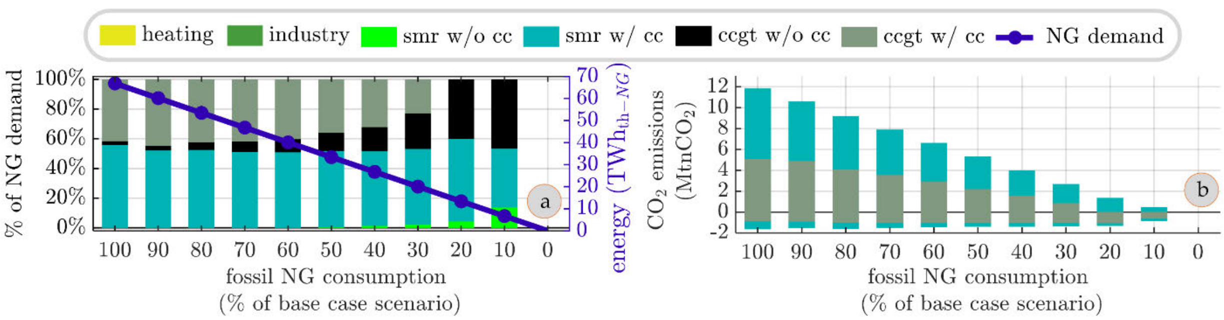

FIGURE 14. (a) Total NG demand (right axis) and allocation to end usages, (b) captured (positive) and released (negative) CO2 emissions, against fossil NG consumption (% of base case scenario).

(Fig. 13b). Despite the eventual slight increase in H_2 generation, total H_2 production remains lower than base case H_2 requirements, indicating that complete elimination of fossil NG leads the H_2 sector to shrink.

Besides the changes in the H_2 production mix as NG imports are restricted, H_2 demand is concurrently reshaped (Fig. 13c). A 40% decline in permitted NG imports leads to the complete elimination of H_2 in the transportation sector, while H_2 quantities destined for industrial heating purposes remain at exactly the same level, covering the entire industrial heating demand. When fossil NG consumption is terminated and CCGTs are retired, fuel cells are called upon (Fig. 13d) to provide the required flexibility to the system, supplementing electricity storage in this functionality (Fig. 11).

Total NG demand follows the same downward trend as NG imports (Fig. 14a), with available NG being allocated solely to electricity and H_2 production. Quantities of NG allocated to CCGTs without CC moderately rise, while, on the other hand, NG quantities directed to SMR and CCGT with CC are gradually decreasing, due to the shift towards technologies without CC (Fig. 14a). The shift towards synthetic NG production via methanation is not a cost-effective option in any of the cases examined, due to the low efficiency of this path. As a result, CO_2 buffer storage and DAC units are not included in the investment portfolio. At a low levels of NG imports, the system needs for CO_2 permanent storage capacity are significantly reduced and eventually completely eliminated when both SMR and CCGTs with CC are removed from the mix of deployed technologies (Fig. 14b). CO_2 emissions follow a downward trend but remain present even at very low NG import levels due to the fact that CCGTs without CC are used in electricity generation as a least-cost solution.

3) END-USE SECTORS

Electrification remains the sole pathway chosen to fulfill heating demand in the residential sector, regardless of the allowed NG imports levels. Similarly, H_2 continues to

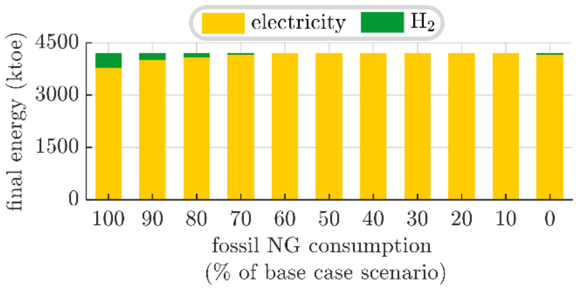

FIGURE 15. **Transportation demand coverage by energy vector vs fossil NG consumption (% of base case scenario).**

exclusively supply the industrial sector heating needs, although the H_2 origin is differentiated, as mentioned before.

In the transportation sector, low-carbon H_2 from SMR with CC is not strongly competitive to renewable electricity in cost terms, due to the price of NG considered in the base case. In addition, as fossil NG imports shrink, electrification of the transportation sector expands to cover the entire demand, given that the electric vehicles present a much higher efficiency than H_2 vehicles (Fig. 15). However, as already mentioned, when gas imports are terminated electricity demand is covered solely by RES, especially from onshore wind. To partially relieve the pressure on the electrical system at 100% RES penetration, especially as regards recharging heavy duty vehicles at low RES availability intervals, large amounts of surplus renewable energy are converted to H_2 and are then used to supply a small fleet of H_2 trucks.

4) IMPACT ON SYSTEM COST

Electrification, as presented in Fig. 16a, the progressive limitation on NG imports shrinks the NG-related component of system cost, which is dominated by the high investment in RES generation, shown in Fig 16b. The increasing decarbonization of H_2 production involves increased investment in production and storage, that leads to an amplified H_2 cost component when NG imports fall below 10%. Complete decarbonization of the system is possible with an increment in the total system cost of about 11,5% with respect to the base case scenario.

IV. DISCUSSION

Analysis of the base case scenario, adopting a NG price assumption of 40 €/MWh, aligned with the REPowerEU plan, shows that this NG price level is insufficient to terminate dependence on fossil NG in the future sector-coupled energy system. Despite the fact that RES generation is largely deployed, to cost-effectively supply exogenous electricity demand and support direct electrification of residential heating-cooling and a major part of the transportation sector, NG demand is hardly reduced compared to 2021 levels. NG is mainly allocated for low-carbon H_2 production through CC-equipped SMR units, to largely decarbonize the industrial heat sector. NG-based power generation is decreased, yet not eliminated, as CCGT units with CC are leveraged to produce low-carbon electricity.

The investigation of the impact of NG prices shows that an imposed increment to the level of 120 €/MWh would substantially limit fossil NG needs and CO_2 emissions, leading to a marginal achievement of system full decarbonization targets, albeit at a total system cost increased by 10.6% compared to the base case. However, a small consumption of fossil NG always persists, even at NG prices as high as 200 €/MWh, to deal with power or H_2 flexibility requirements in periods of low RES availability, coinciding with inadequate electricity or H_2 reserves in the respective storages.

On the other hand, applying a strict limit on fossil NG imports, under an assumedly fixed NG price of 40 €/MWh, reveals that complete decarbonization of the energy system is feasible with the appropriate system development relying heavily on RES generation, and a cost increment of about 11.5% with respect to base case, i.e. to a level similar as for NG prices beyond 120 €/MWh, even though the portfolio of deployed technologies differs considerably. Hence, from a policy and planning perspective, large-scale decarbonization of the energy system at a similar cost is possible, induced either via high fossil NG prices, beyond the level of 120 €/MWh, or by exogenously eliminating fossil NG imports.

As a result, Greek state policymakers should examine directing energy system transition towards a technology mix close to the one arising from the total NG consumption elimination scenario, considering that such a system development trajectory and components dimensioning would intrinsically discard the consumption of fossil NG, regardless of its price. In this manner, the economic operation of the energy system would be immunized against the volatility of NG prices and the availability of imported fuels in general, with system costs being directly comparable to that obtained for optimal system development when NG prices lay beyond 120 €/MWh. Such high NG prices might seem immoderate based on historical records; however, recent energy crises have shown that NG prices even higher than 120 €/MWh are not fictitious ([68]), but can become a reality due to commodity scarcity or abnormal international conditions (e.g. the Ukrainian war).

In both cases large RES investments are needed, with onshore wind gradually overtaking PVs in the capacity mix. Greek authorities should pave the way for private investors in RES by offering sufficient motivation and support to minimize risks and ensure viability and bankability of their investments, such as co-financing of RES projects, securing preferential interest rates and inclusion of RES projects engaged in the market in support mechanisms (e.g. Feed-In Premium, Contract for Difference, capacity remuneration scheme, etc.). Interestingly, the utilization of gas-fueled CCGT units without CC is favored against those equipped with CC, since the very limited consumption of NG does not justify the investment in expensive, less polluting technologies.

Expectedly, electricity storage is of great importance in energy system decarbonization. The high RES penetration is supported by long-duration storage, principally closed-loop PHS. However, challenges linked with development of

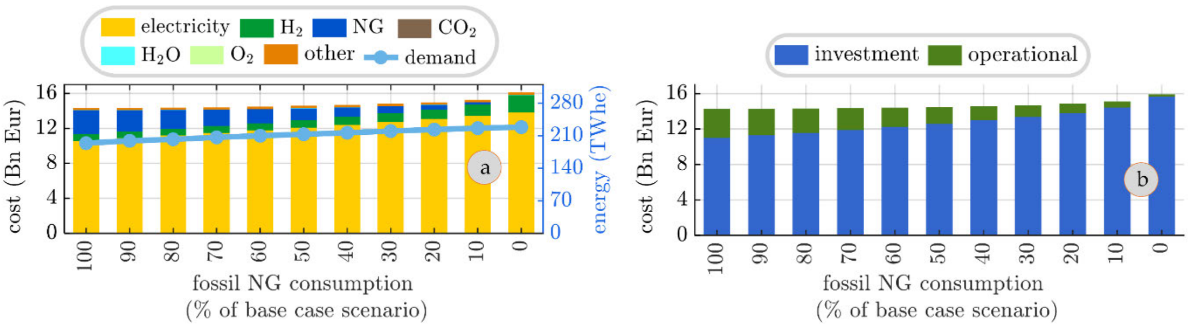

FIGURE 16. (a) Total system cost allocation by sector (left axis) & total electricity demand (right axis) (b) total system investment and operational cost vs fossil NG consumption (% of base case scenario).

PHS systems, such as need of sites with suitable geological formation, possible environmental effects and social impacts, high upfront investment cost and construction time [69], necessitate placing PHS deployment at the top of the investment planning agenda. A substantial BESS capacity is also developed, primarily to provide power-intensive balancing services and intra-day energy arbitrage. Since large-scale BESS integration in Greek power system is still in its infancy, the State should encourage private sectors to invest in BESS by designing support mechanisms to finance BESS installations and a clear and stable legislative framework about their operation in market environment. Overall, the business case for cross-sector coupling through electrification of end-use transportation and heating/cooling is established at moderate NG price levels (over 40€/MWh) and for any level of NG import restrictions.

The cross-vector coupling possibilities lead to the development of the H_2 sector, which is always present in the optimal system planning. On the other hand, low energy efficiency hampers the adoption of SNG as a favorable alternative. Low NG prices or lack of restrictions on fossil NG favor NG-derived low-carbon H_2 against renewable H_2, a trend reversed at high NG prices above 120 €/MWh in favor of green H_2, coming along with huge capacities of electrolyzers and H_2 storage. However, there is a noticeable difference between the installed H_2 storage capacities in the two cases – high NG prices and total NG consumption restriction – stemming from the fact that full decarbonization eliminates the use of SMR to supply H_2 on demand, thus increasing the need for H_2 storage. Produced H_2 is utilized to cover the entire industrial heat demand, irrespective of NG price or imports restrictions, implementing the cross-sector coupling between electricity and industrial heat sectors through indirect electrification. Hence, future energy system planning needs to account for H_2 and exploit its potential as an energy vector to support the cost-optimal transition towards a carbon-neutral industrial sector. Thus, the establishment of a national plan for hydrogen with binding targets and coordinated actions is a prerequisite to accelerate the formation of the hydrogen economy.

In any case, the findings of this study must be seen in light of some limitations. First, the proposed sector-coupled energy system ignores interconnections and energy carrier transactions with neighboring systems, disregarding additional flexibility sources stemming from the supply-demand potential of adjacent energy systems. This may lead to under/over-estimating capacity expansion decisions for the study-case energy system since domestic available renewable potential could be exploited for energy exports in adjacent systems, or, reversibly, neighboring systems could cover domestic demand requirements. Second, despite the granular representation of road transportation presented in this study, air and maritime transport are neglected. The reason is that we did not incorporate fuel options with high volumetric density in our study, neither fossil nor low-emission ones, which are predominantly utilized in aviation and shipping industry for long distance transport [70]. Third, the analysis has been implemented using projections about the evolution of cost and efficiency factors of applied technologies for 2050, as well as availability and demand profiles for RES and end-use sectors respectively. Such assumptions are characterized by inherent uncertainty, considering the influence exerted on these parameters by economic and technological development, implemented policies, and environmental and population changes [71].

However, it should be noted that despite the identified limitations, the study primarily aims to approach the direction in which Greece's energy policy should move rather than claiming to pinpoint the future energy mix with great precision.

V. CONCLUSION

This paper inquires into energy system deep decarbonization prospects through sector-coupling pathways. The focal point is highlighting the effects on future sector-coupled energy system development emerging from the examination of a base case and two different scenarios pertaining to the elimination of fossil fuel consumption: (a) constant gas price of 40 €/MWh aligned with REPowerEU assumptions for 2050, (b) indirect limitation through gas price elevation and (c) direct restriction through the imposition of a cap on gas imports. In other words, in contrast to the aforementioned relevant literature focusing mainly on the restriction of CO_2 emissions, we focus our research on investigating the dependence of

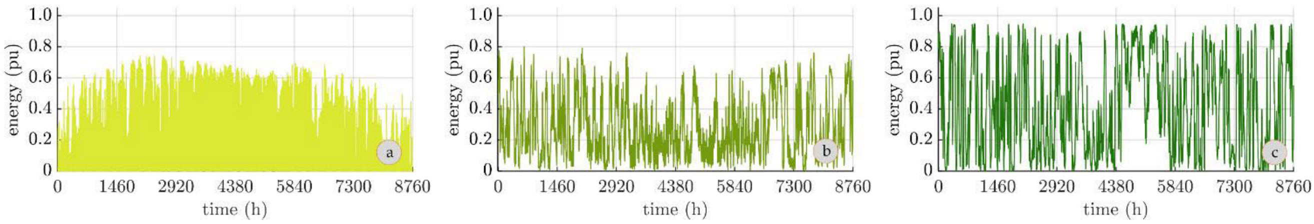

FIGURE 17. Annual profile of available (a) PV, (b) onshore wind, (c) offshore wind generation. Time-series (a)-(c) sourced from [60].

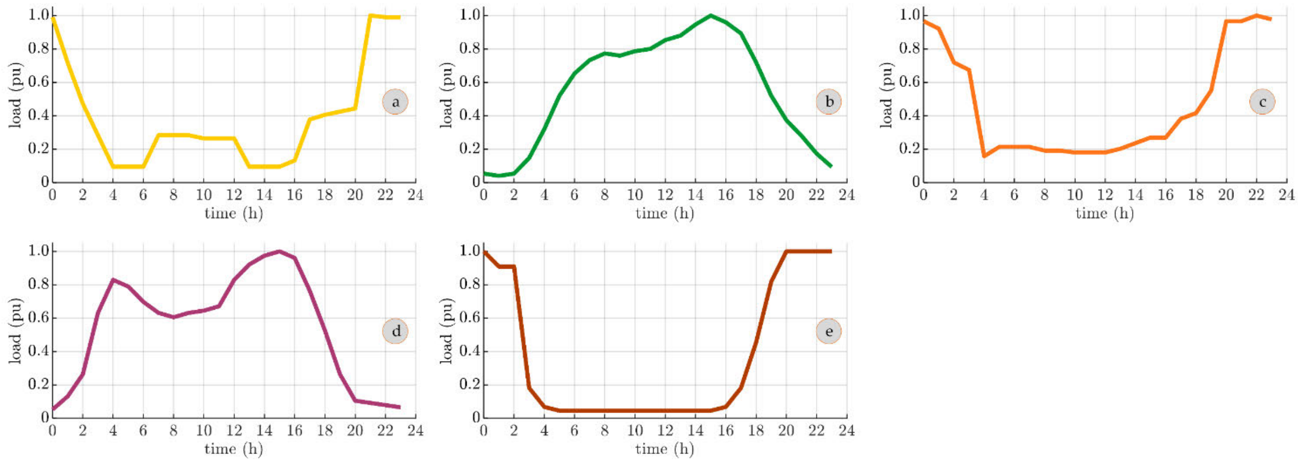

FIGURE 18. Daily profile of demand for (a) battery electric private cars, (b) H_2 fuel cell private cars, (c) buses, (d) trains, (e) trucks. All profiles per-unitized with respect to daily maximum demand/load.

future integrated energy systems on a projected price of natural gas and the level of decarbonization that is feasible to be attained at the lowest cost and we explore how system decarbonization targets, cost, and configuration are affected from natural gas price variation and consumption limitation. For this purpose, a CEP modelling framework, using strictly linear constraints, is deployed, aiming to select the cost-optimal technology mix and combination of energy carriers in order to fully serve end-use sector energy requirements. The optimization procedure is implemented with a one-year horizon and hourly temporal resolution, while 2050 is regarded as the reference year for the analysis. The proposed model, disregarding transmission and distribution system and interconnections with neighboring countries, is applied to the Greek energy system, serving as a case study.

A natural gas price matching REPowerEU expectations about 2050 is proven inadequate to foster independence from imported gas and hardly lessens fossil gas demand with respect to 2021 domestic consumption. On the contrary, raising gas price at 120 €/MWh and fully restricting gas imports entail equal system costs at about 16 B€, while differentiating with regards to the installed technology mix. The total renewable capacity requirements to achieve increased decarbonization levels approaches 106 GWe, with onshore wind qualifying as more appropriate for covering the enlarged electricity demand against PV generation. Massive investments in electricity storage with emphasis on long-duration closed-loop PHS and short-duration BESS are also needed. At almost full decarbonization levels for the energy system, renewable H_2 usage is promoted over low-carbon H_2. Regarding end-use sectors, residential heating-cooling and transportation demand are directly electrified for gas prices over 40 €/MWh, while industrial heating demand is covered solely by H_2.

Future work should focus on extending the geographical coverage of the proposed sector-coupled energy system model. More specifically, the current capacity expansion framework should be enhanced to simultaneously model neighbouring integrated energy systems - considering the individual climatic and demand forecast data - in order to highlight possible cost and operational benefits arising from synergies and interactions between sectors of adjacent energy systems. Moreover, incorporation of aviation and shipping industry in end-use sectors representation could be an interesting extension of the model since their decarbonization pathway is still deemed a debatable issue. However, considering their respective particular characteristics and international nature as well as the difficulty in decarbonizing such energy-intensive sectors, integrating these sectors could be a challenging task from a modelling perspective. An additional interesting extension of our work would aim to consider uncertainties accompanying input data in the capacity

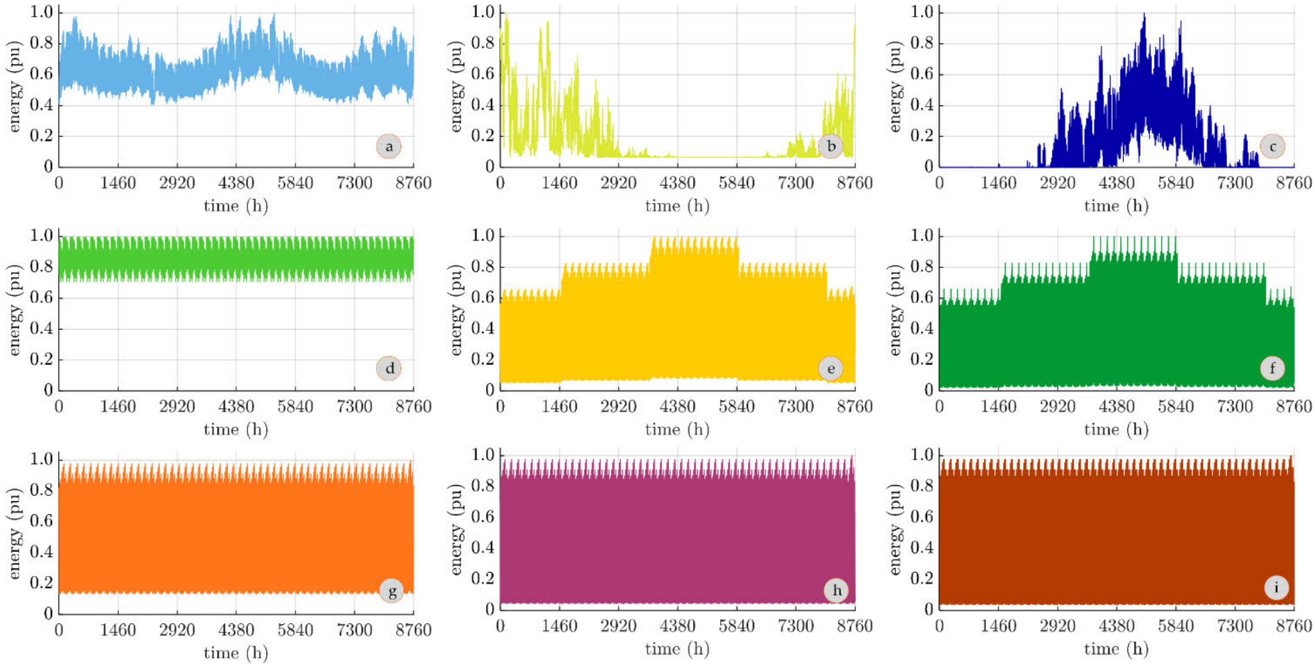

FIGURE 19. Annual demand timeseries for (a) exogenous electricity, (b) residential heating, (c) residential cooling, (d) industrial heat, (e) battery electric private cars, (f) H2 fuel cell private cars, (g) buses, (h) trains, (i) trucks. Time-series (a) is sourced from [60], (b-c) from [84], (d) from [62]; time-series (e-i) constructed based on intra-day refueling profiles and methodology from [60], [85], and [86]. All profiles per-unitized with respect to annual maximum demand/load.

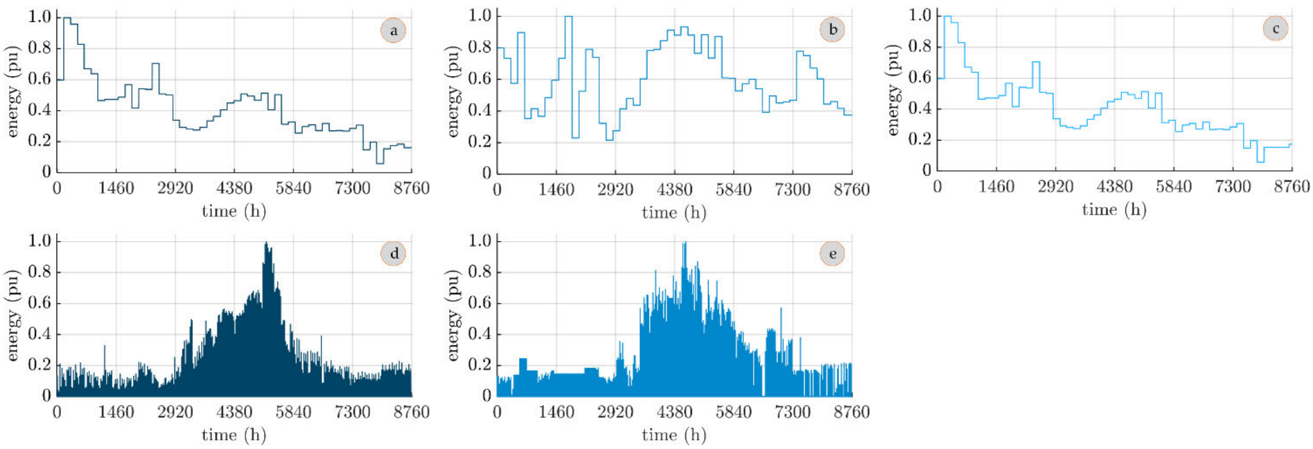

FIGURE 20. Annual time series of (a) inflows of hydro plants with reservoirs, (b) inflows of open-loop PHS plants, (c) production of run-of-river plants, (d) mandatory production of plants with reservoirs, (e) mandatory production of open-loop PHS plants. Time- series (a-c) are sourced from [60], while time-series (d-e) are retrieved from [61]. All profiles per-unitized with respect to annual maximum inflows/mandatory production.

expansion planning procedure by applying stochastic optimization techniques.

APPENDIX A

A. ANNUAL AND DAILY PROFILES OF INPUT QUANTITIES

See Figures 17–20.

APPENDIX B

B. ECONOMIC AND TECHNICAL CHARACTERISTICS

See Tables 5 and 6.

APPENDIX C

C. DEFINITION OF RES PENETRATION PER SECTOR

Renewable energy penetration is calculated separately for the electricity, H_2 and NG sectors, according to (C.1)-(C.3) below. Electricity from variable RES and hydro [83] plants is regarded as renewable, excluding energy generated through previously pumped and stored water in the station's reservoir. H_2 generated by renewable electricity through water electrolysis is considered renewable, unlike NG-produced H_2 through SMR. SNG is considered climate-neutral, since CO_2

TABLE 5. Technology-related cost assumptions.

Technology	CAPEX	Fixed O&M	Variable O&M	Lifetime *(years)*	Source
Onshore Wind	950 *€/kWe*	2.50 %	0.5 *€/MWhe*	25	[72]
Offshore Wind	1700 *€/kWe*	3.50 %	0.5 *€/MWhe*	25	[72]
PV	550 *€/kWe*	1.50 %	0.5 *€/MWhe*	25	[72]
CCGT w/o CC	800 *€/kWe*	2.50 %	Endogenously calculated	30	[46]
CCGT w/ CC	1250 *€/kWe*	3.00 %	Endogenously calculated	30	[46]
BESS (power)	150 *€/kWe*	2.50 %	6.0 *€/MWhe*	15	[73]
BESS (energy)	75 *€/kWhe*	2.50 %	-	15	[73]
Closed-loop PHS (power)	800 *€/kWe*	2.00 %	6.0 *€/MWhe*	50	[73]
Closed-loop PHS (energy)	20 *€/kWhe*	2.00 %	-	50	[73]
Electrolyzer	400 *€/kWe*	4.00 %	Endogenously calculated	30	[74]
Fuel Cell	500 *€/kWe*	4.00 %	Endogenously calculated	20	[75]
H_2 Storage	7 $€/kWh_{th\text{-}H_2}$	2.00 %	-	33	[76]
Methanation	185 $€/kWh_{th\text{-}NG}\cdot h^{-1}$	3.00 %	Endogenously calculated	20	[77]
SMR w/o CC	250 $€/kWh_{th\text{-}NG}\cdot h^{-1}$	3.00 %	Endogenously calculated	30	[75]
SMR w/ CC	350 $€/kWh_{th\text{-}NG}\cdot h^{-1}$	5.00 %	Endogenously calculated	30	[75]
CO_2 Permanent Storage	2 $€/tnCO_2$	37.0 %	1.0 $€/tnCO_2$	30	[78]
CO_2 Buffer Storage	46 $€/tnCO_2$	1.00 %	Endogenously calculated	20	[77]
DAC	2500 $€/tnCO_2\cdot h^{-1}$	4.00 %	Endogenously calculated	30	[79]
Heat Pump	760 $€/kWh_{th}\cdot h^{-1}$	0.30 %	1.7 $€/MWh_{th}$	25	[72]
H_2 Boiler *(residential)*	140 $€/kWh_{th}\cdot h^{-1}$	10.0 %	Endogenously calculated	15	[80]
NG Boiler	240 $€/kWh_{th}\cdot h^{-1}$	5.00 %	Endogenously calculated	20	[81]
Electric Boiler	130 $€/kWh_{th}\cdot h^{-1}$	0.70 %	0.4 $€/MWh_{th}$	20	[72]
H_2 Boiler *(industrial)*	100 $€/kWh_{th}\cdot h^{-1}$	10.0 %	Endogenously calculated	15	[80]
NG Steam Boiler	45 $€/kWh_{th}\cdot h^{-1}$	4.00 %	Endogenously calculated	25	[82]

TABLE 6. Efficiency and maximum reserves provision (as a percentage of installed capacity) per relevant technology.

Technology	Efficiency	FCR	aFRR	mFRR
CCGT w/o CC	60.5 %	7 %	45.0 %	100 %
CCGT w/ CC	53.5 %	7 %	45.0 %	100 %
Hydro Reservoir	87.6 %	-	1.5 GW	1.9 GW
Open-loop PHS	75.0 % (round-trip)	-	75.0 %	100 %
BESS	90.0 % (round-trip)	200 %	200 %	200 %
Closed-loop PHS	75.0 % (round-trip)	-	75.0 %	100 %
Electrolyzer	83.3 % *(HHV)*	100 %	100 %	100 %
Fuel Cell	57.0 % *(HHV)*	100 %	100 %	100 %
RES (PV, onshore, offshore)	-	-	-	50 %

emissions accompanying its consumption are balanced by equal quantities of captured CO_2 used as feedstock in SNG production.

$$Pen_{el} = \left[\sum\nolimits_t \left(E_t^{vres} + RoR_t + \sum\nolimits_{tech\in T_{flexhy}} E_{t,tech}\right) - n_{open-loopPHS}\cdot\sum\nolimits_t E_{t,open-loopPHS}^{pump}\right] \Bigg/ \left[\sum_t \left(E_t^{vres} + RoR_t + \sum_{tech\in T_{flexhy}} E_{t,tech} + \sum_{tech\in T_{CCGT}} E_{t,tech}\right) - n_{open-loopPHS}\cdot\sum\nolimits_t E_{t,open-loopPHS}^{pump}\right] \quad (C.1)$$

$$Pen_{H_2} = \sum_t E_{t,elz} \cdot n_{elz} / \sum_t \left(E_{t,elz} \cdot n_{elz} + \sum_{tech \in T_{smr}} n_{tech} \cdot G_{t,tech} \right) \quad (C.2)$$

$$Pen_{NG} = \sum_t G_{t,meth} / \sum_t \left(G_{t,meth} + G_t^{imp} \right) \quad (C.3)$$

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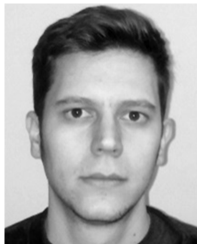
PERIKLIS P. CHINARIS received the Diploma degree in electrical and computer engineering from the National Technical University of Athens, Athens, Greece, in 2022, where he is currently pursuing the Ph.D. degree. His research interests include energy system decarbonization, renewable energy, and storage modeling in electricity market environment.



GEORGIOS N. PSARROS (Member, IEEE) received the Diploma degree in electrical engineering, the M.Sc. degree in energy production and management, and the Ph.D. degree from the National Technical University of Athens (NTUA), Greece, in 2010, 2014, and 2019, respectively. He is currently a Postdoctoral Researcher with NTUA. His research interests include storage integration in the grid, renewable energy technologies, power systems and electricity markets modeling, resource adequacy considerations for large power systems, and energy management of isolated grids.

EVANGELOS S. CHATZISTYLIANOS received the Diploma degree in electrical and computer engineering from the National Technical University of Athens, Greece, in 2021, where he is currently pursuing the Ph.D. degree. His research interests include capacity expansion planning for large power systems and renewable and energy storage systems modeling.

STAVROS A. PAPATHANASSIOU (Senior Member, IEEE) received the Diploma degree in electrical engineering and the Ph.D. degree from the National Technical University of Athens (NTUA), Athens, Greece, in 1991 and 1997, respectively. Since 2002, he has been a Professor with the Electric Power Division, NTUA. He has worked for the Greek DSO, he has been a member of the Executive Board of the Greek TSO and Market Operator and he is collaborating with the industry in RES and storage projects. His research interests include renewable generation, storage and distributed energy resources, including their grid and market integration.