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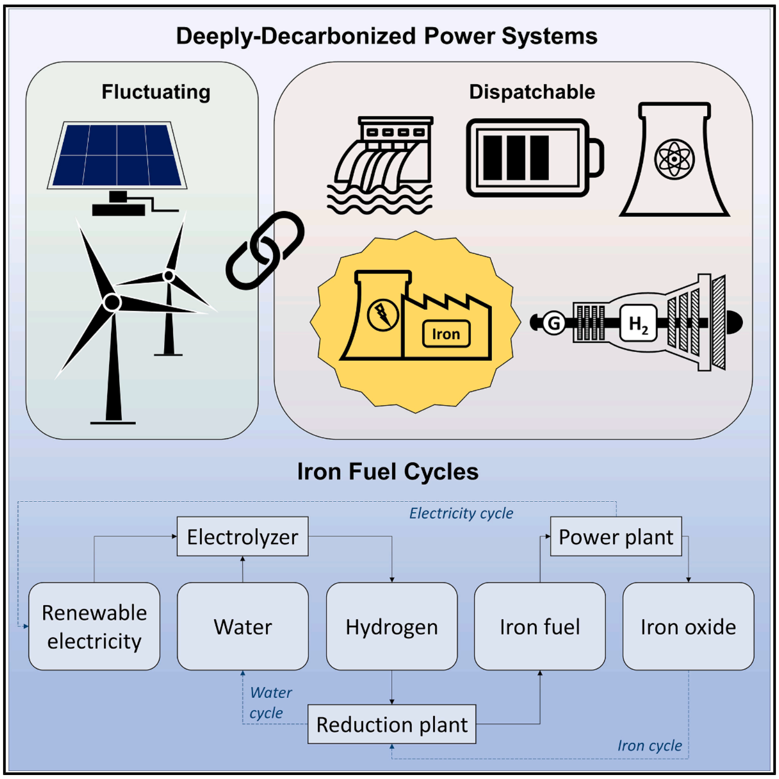
A new iron age? The potential role of iron fuel in Europe's clean energy transition

Graphical abstract



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In brief

The circular concept of metal fuels promises long-term energy storage and dispatchable, renewable power generation for deeply decarbonized energy systems. This study demonstrates that iron fuel, combusted in retrofitted coal power plants, can complement hydrogen-based electricity generation in Europe—for instance, in countries lacking underground hydrogen storage or hydropower.

Highlights

- Iron fuel offers a firm, renewable power supply by repurposing former coal plants
- System modeling shows iron can complement hydrogen in European power grids
- Iron fuel provides long-duration storage where hydrogen caverns are absent
- Iron fuel expands dispatchable options in renewables-heavy energy systems

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A new iron age? The potential role of iron fuel in Europe's clean energy transition

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CONTEXT & SCALE Decarbonizing the power sector requires reliable and flexible generation assets to complement the variability of wind and solar power. While hydrogen is a leading candidate in deeply decarbonized scenarios, economically viable large-scale storage is currently limited to regions with suitable underground geological formations. This study explores whether iron, used as a recyclable metal fuel that can be combusted in former coal-fired steam power plants, could provide a complementary pathway for long-term energy storage and dispatchable power generation. Like hydrogen, iron fuel offers the advantage of re-using existing infrastructure. Using a detailed energy system model, the analysis tests whether iron-fired power plants can find a role in Europe's diverse energy system on the path to net zero emissions by 2050.
The results suggest that iron fuel can become part of the cost-optimal energy mix in several European countries, especially where hydropower or underground hydrogen storage are limited. Converted or newly built iron-fired power plants provide power for a few hundred to about 1,000 hours per year, thereby helping to cover periods of low renewable generation. Although the overall system cost savings identified in this analysis are modest, the technology offers strategic value by diversifying options for long-term energy storage and dispatchable supply. From a policy perspective, the findings point to a narrow but promising window of opportunity: as Europe phases out coal, existing steam power plants could be repurposed for iron combustion rather than dismantled. This could preserve valuable infrastructure while enhancing security of supply. Scaling such a pathway will depend on continued advances in iron reduction and combustion technologies.

SUMMARY

The search for firm, dispatchable capacities to complement variable renewable energy is a central challenge of the global energy transition. Metal fuels, and in particular iron, have recently emerged as a promising option. However, a comprehensive assessment of their potential role within large-scale energy systems remains absent. This study presents a European energy system expansion and dispatch model that includes the conversion of former coal-fired power plants to iron combustion for electricity generation. Model results indicate that in several countries, iron fuel can form part of a cost-optimal system configuration and complement hydrogen-fired power plants in providing flexible generation capacity. The concept is particularly attractive in countries lacking seasonal energy storage options, such as hydrogen caverns or large-scale hydropower. These findings support the potential of iron fuel as a strategic element of decarbonized and resilient energy systems.

INTRODUCTION

The installed capacity of fluctuating renewable energy in global power generation has grown rapidly over the past decade,[1,2] and both political ambitions and economic incentives suggest a continued expansion in the coming years.[3,4] To balance the increasing variability of electricity generation, dispatchable electricity storage and generation assets will remain essential in the transitioning power sector.[5,6] Even in regions with abundant renewable energy potentials and under scenarios featuring substantial cost reductions for renewables and batteries alongside extensive exploitation of demand-side flexibility, the integration of firm generation capacity provides economic benefits.[6] In deeply decarbonized future energy systems, this supply-side

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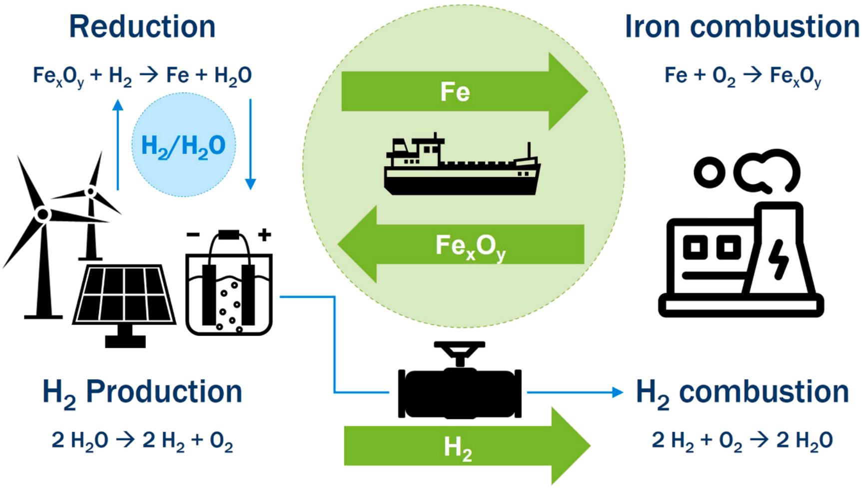

Figure 1. Production, transport, and power generation in circular iron fuel concept versus linear hydrogen supply

flexibility can be provided by hydropower, battery storage, and a range of thermal power plants including biomass-fired plants,[5–8] geothermal[5,7] and solarthermal power,[5,9] flexible nuclear reactors,[6,7,10,11] hydrogen gas turbines,[7,8] and fossil-fueled plants equipped with carbon capture.[6,7,12] More recently, metal fuels have been proposed as an additional renewable and dispatchable option for electricity generation.[13–15]

In this concept, powdered metals are combusted with air to produce heat, which can be harnessed in steam cycles. Combustion produces solid metal oxides that can be collected and reduced back to the initial metal fuel product using clean primary energy sources, enabling theoretically infinite "metal cycles." Metal fuels are particularly promising for long-distance transport and long-term storage of energy, as their solid state offers exceptionally high volumetric energy density and enables straightforward bulk handling and storage using existing, flexible infrastructure.[14,16] Figure 1 illustrates the metal cycle principle using iron fuel, transported in bulk carriers, in comparison with linear hydrogen supply through pipelines. In addition to the primary iron/iron oxide material loop, Figure 1 highlights a second circular aspect, depicted by the smaller blue circle: water can remain within the export region, forming a closed cycle between the electrolyzer and the reduction plant. This contrasts with the hydrogen pathway, where hydrogen atoms are exported from the production region. Detailed descriptions of the iron reduction-oxidation cycle are provided in, e.g., Debiagi et al.[13]

Among the metals considered as potential energy carriers, iron stands out due to its availability, large-scale ore-mining capacity, favorable market price, and the relative ease and safety of its handling.[15,16] Moreover, direct reduction presents a commercially available technology that could be adapted for the iron fuel cycle through the use of green hydrogen. Such adaption, however, is not straightforward, as shaft furnace direct reduction requires pelletizing or sintering of feedstock, thereby introducing additional process steps that adversely affect the cost and efficiency of iron fuel. Fluidized bed direct reduction can directly process powders but implies challenges related to sintering, particle-size increase, and particle porosity.[16–19] Flash ironmaking is a promising alternative—though currently with a low technology readiness—capable of processing fine powders while mitigating particle sticking, thereby aligning well with the operational requirements of the iron fuel cycle.[20–22]

Another key advantage of iron fuel discussed in several studies is the potential retrofitting of former coal power plants for iron firing, enabled by the similarity in combustion properties.[13,16,20,23,24] Besides eliminating carbon dioxide emissions, such retrofits could substantially reduce nitrogen oxide and sulfur dioxide emissions and may also yield slight improvements in overall power plant efficiency due to higher steam pressure, reduced flue gas temperature, enhanced particle-level heat transfer, and the removal of redundant coal mills as well as desulfurization and denitrification systems.[23,24] Moreover, continued operation of retrofitted coal power plants would preserve rotational inertia through the synchronous generators, supporting frequency stability in future deeply decarbonized, inverter-dominated energy systems. The retrofitting of coal power plants for iron combustion can further reduce the problem of stranded assets within the energy transition, which for the European coal fleet alone is estimated to amount to several tens of billions of euros.[25] This concept may be particularly interesting for countries with a large number of relatively new coal power plants, most notably China.[26] Key characteristics of iron fuel are provided in Section S2.2 of the supplemental information.

The majority of existing research on metal fuels has focused on technical aspects (e.g., Neumann et al.,[20,24,27–30] Wiinikka et al.,[20,24,27–30] Stevens et al.,[20,24,27–30] Spitzersen et al.,[20,24,27–30] Kuhn et al.,[20,24,27–30] and Prasidha et al.[20,24,27–30]), while economic evaluations remain scarce. The limited studies addressing economic aspects have examined case studies or conducted isolated energy supply chain comparisons against hydrogen and hydrogen-based energy carriers.[31–34] To date, metal fuels have not been assessed within the context of complex energy systems.

This study presents a system-level assessment of iron-based electricity generation to explore the potential role of iron fuel in the European power sector, employing a tailored instance of the PERSEUS energy system model ecosystem.[35–39] The developed model version PERSEUS-PtX, including the complete input dataset, is publicly available. Starting from the 2025 European energy system, the model optimizes the expansion and dispatch of energy conversion, storage, and transport infrastructure to achieve emission-free electricity generation by 2050. The European hydrogen backbone is a vision for a pan-European hydrogen network proposed by gas transmission system operators, comprising newly built pipelines as well as repurposed

Table 1. Total installed capacities in 2050 in scenarios with and without the iron fuel option

Total installed capacities 2050		No iron fuel	Iron fuel	
Electricity generation capacity (GW_{el})		4,641	4,627	(−0.3%)
Power plants	iron fuel	–	17	
	hydrogen	161	146	(−9.3%)
	nuclear	27	26	(−3.7%)
Renewables	photovoltaics	2,451	2,447	(−0.2%)
	wind on	995	995	–
	wind off	283	290	(+2.5%)
	run-of-river	58	58	–
Storage	battery	476	459	(−3.6%)
	pumped storage	65	65	–
	hydro reservoirs	125	125	–
Electrolysis (GW_{el})		586	594	(+1.4%)
Hydrogen cavern storage (TWh_{H2})		419	405	(−3.3%)
Iron fuel storage capacity (TWh_{Fe})		–	27	

natural gas infrastructure, alongside import terminals and underground storage facilities.[40] In our analysis, cross-border hydrogen transport and import capacities, based on published project data,[41] are introduced exogenously from 2030 onward without endogenous consideration of associated costs. Rather than reassessing the backbone plans or exploring how iron fuel might reduce the need for such infrastructure, we evaluate whether iron fuel can still be part of the cost-optimal solution under these rather hydrogen-supportive assumptions.

RESULTS

A niche for iron fuel in Europe's power mix

With a total installed capacity of 17 GW_{el} across Europe in 2050, iron-fired power plants emerge as part of the cost-optimal system configuration in a base scenario. This suggests that iron fuel can be a competitive option in future energy systems even within a modeling setup that disadvantages its employment in several aspects, including the exogenously given hydrogen transport infrastructure, the conservative iron oxide reduction plant parameters applied in the base scenario, and additional factors as discussed in the limitations section. Iron fuel adoption, however, varies across countries and depends on national power system characteristics and their integration within the broader European system, as examined in the subsequent subsection.

Table 1 compares the 2050 system capacities of a decarbonized European power system with and without the iron fuel option. Installed capacities by country and model year are reported in Tables S19–S24. Iron power plants replace hydrogen power plant expansion (particularly in Germany) and, to a lesser extent, reduce battery storage and nuclear capacities, the latter mainly in the Czech Republic. Electrolysis capacities increase slightly, while national expansions of photovoltaics (PV) and wind generation remain largely unchanged between the two scenarios. The inclusion of iron fuel also leads to a modest reduction in hydrogen storage expansion, particularly in Germany, Norway, and the United Kingdom. Alongside conversion of coal power plants to iron combustion in multiple countries, new iron power plant capacity is constructed in Finland and Ireland, and reduction plants for producing iron powder from iron oxide are established in nine countries. The total system cost savings from adopting iron fuel are relatively modest, on the order of a few billion across all scenarios (see Table S25).

In 2050, hydrogen is predominantly produced within Europe, with imports to Europe accounting for only 12% of the hydrogen volume, as illustrated in Figure 2. Most imports occur via pipelines from Africa to Spain and Italy, which operate at utilizations of 84% and 83%, respectively, while the Slovakia-Ukraine connection, where hydrogen costs are about 20% higher (see Table 4), reaches only 37% utilization. Seaborne hydrogen imports total only 5 TWh across all countries. The lower diagram of Figure 2 illustrates that most iron fuel is also produced within Europe, with reduction plants concentrated in the Czech Republic, Finland, France, Hungary, Ireland, Italy, Poland, Sweden, and Slovenia. Only 17% of iron fuel demand is supplied by extra-European sources via marine imports to Germany, the Netherlands, and Denmark. While hydrogen is extensively transported between European countries, cross-border iron fuel trade occurs exclusively from Poland to the Czech Republic and from Sweden to Denmark.

The hydrogen backbone exhibits similar utilization in the scenarios with and without iron fuel, with the biggest net trade volumes in 2050 occurring through import pipelines from Africa to Spain and Italy and interconnectors from Denmark to Germany, the United Kingdom to Belgium, Austria to Slovakia, and Finland to the Baltic interconnector supplying Germany and Sweden, as shown in Figure 3. Figure 3 further illustrates hydrogen cavern storage capacities, electrolyzer production, and iron power plant capacities across European countries in 2050.

Heterogeneous utilization of iron retrofit potentials

The retrofit of coal power plants to iron fuel displays a heterogeneous pattern across countries, as shown in Table 2. Denmark, Finland, France, Hungary, Italy, and the Netherlands fully repurpose their former coal capacities, whereas Slovenia, the Czech Republic, Germany, and Croatia retrofit only partially; Bulgaria, Spain, Greece, Poland, and Romania, by contrast, implement no iron power plants at all.

Understanding why some countries convert power plants for iron firing while others do not is not straightforward. An intuitive hypothesis is that countries with limited prospects for domestic hydrogen production, particularly due to the lack of cheap surplus renewable power for electrolysis, would be more likely to adopt iron fuel in the power sector. However, Figure 2 shows that iron-adopting and -refusing countries are not homogeneous in their roles as hydrogen importers or exporters in the year 2050. For instance, Denmark, Finland, and Italy exhibit substantial hydrogen surpluses that are exported to neighboring countries but still fully repurpose their former coal power plants for iron fuel. In contrast, Bulgaria and Romania rely on hydrogen imports to meet their demands but do not implement any iron power plants.

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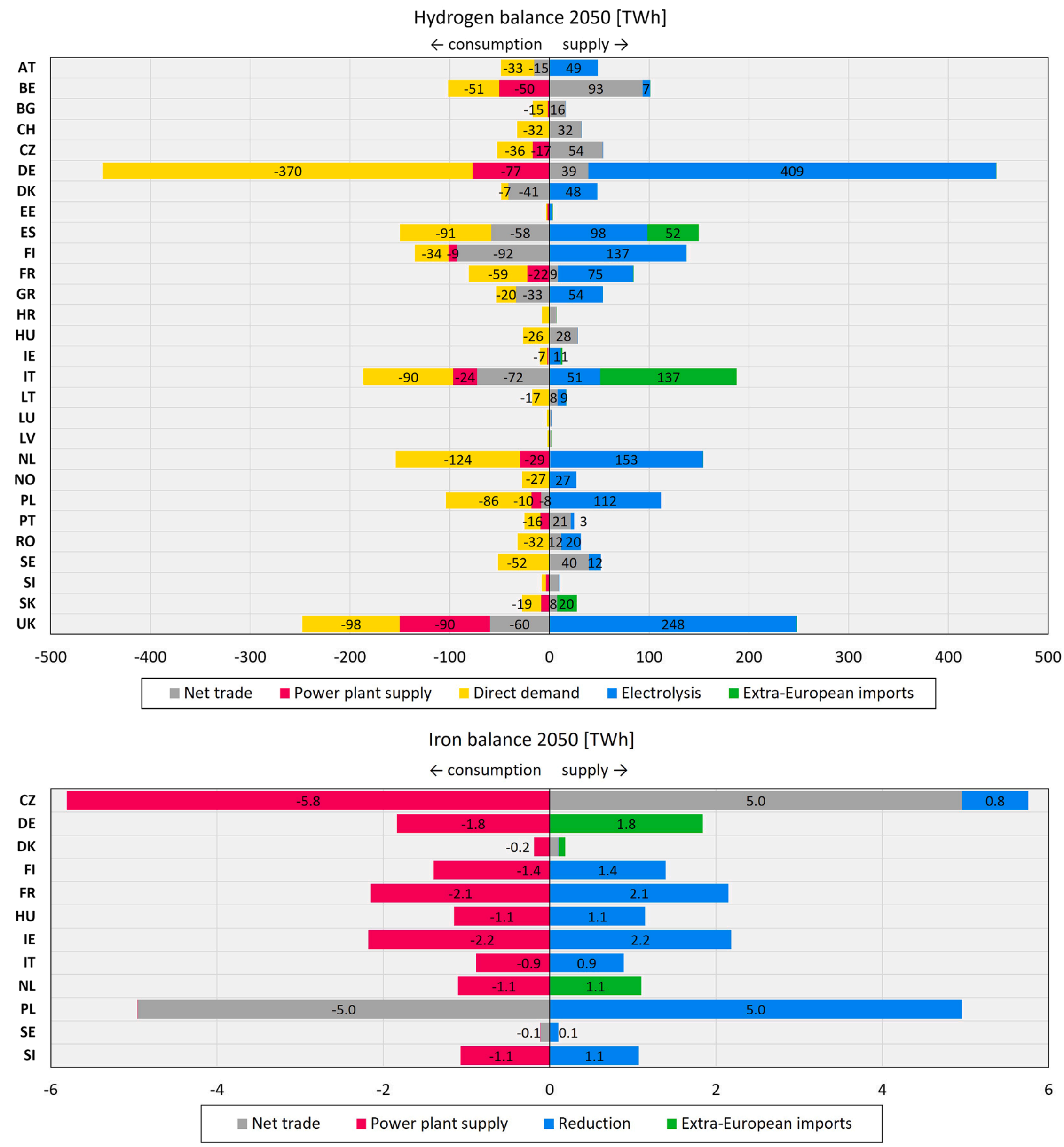

Figure 2. Hydrogen and iron fuel balances for model regions in 2050, in TWh

A more compelling explanation for patterns of iron fuel adoption than the annual hydrogen balance is the possibility of long-term energy storage through iron fuel: The Czech Republic, Finland, France, Hungary, Ireland, Italy, and Slovenia convert domestic surplus renewable electricity into hydrogen and subsequently into iron powder, which is combusted during periods of low renewable generation (see Figure 2). These countries do not possess hydrogen cavern storage potential or, in the case of France, have only limited capacity that is fully utilized (dark-blue bars in Figure 3). As no country opts for more costly hydrogen tank storage, these seven countries, along with 11 others without cavern storage potential, must balance domestic electrolyzer production and hydrogen demand on an hourly basis via hydrogen backbone connections to neighboring countries, with capacities defined exogenously. Iron provides them with a location-independent storage option for surplus hydrogen with flexible reconversion to power during periods of hydrogen scarcity.

Spain, Greece, and Poland possess cavern storage capacities that can be used for intermediate hydrogen storage, thereby eliminating the need to retrofit available power plant capacities for iron combustion (see Figure 3). Benefiting from excellent solar conditions in Spain and Greece and strong wind potentials in Poland, available cavern storage enables oversizing of PV or wind-generation capacities, respectively, by converting surplus electricity generation into hydrogen. The comparatively small residual load is covered through battery storage and hydropower.

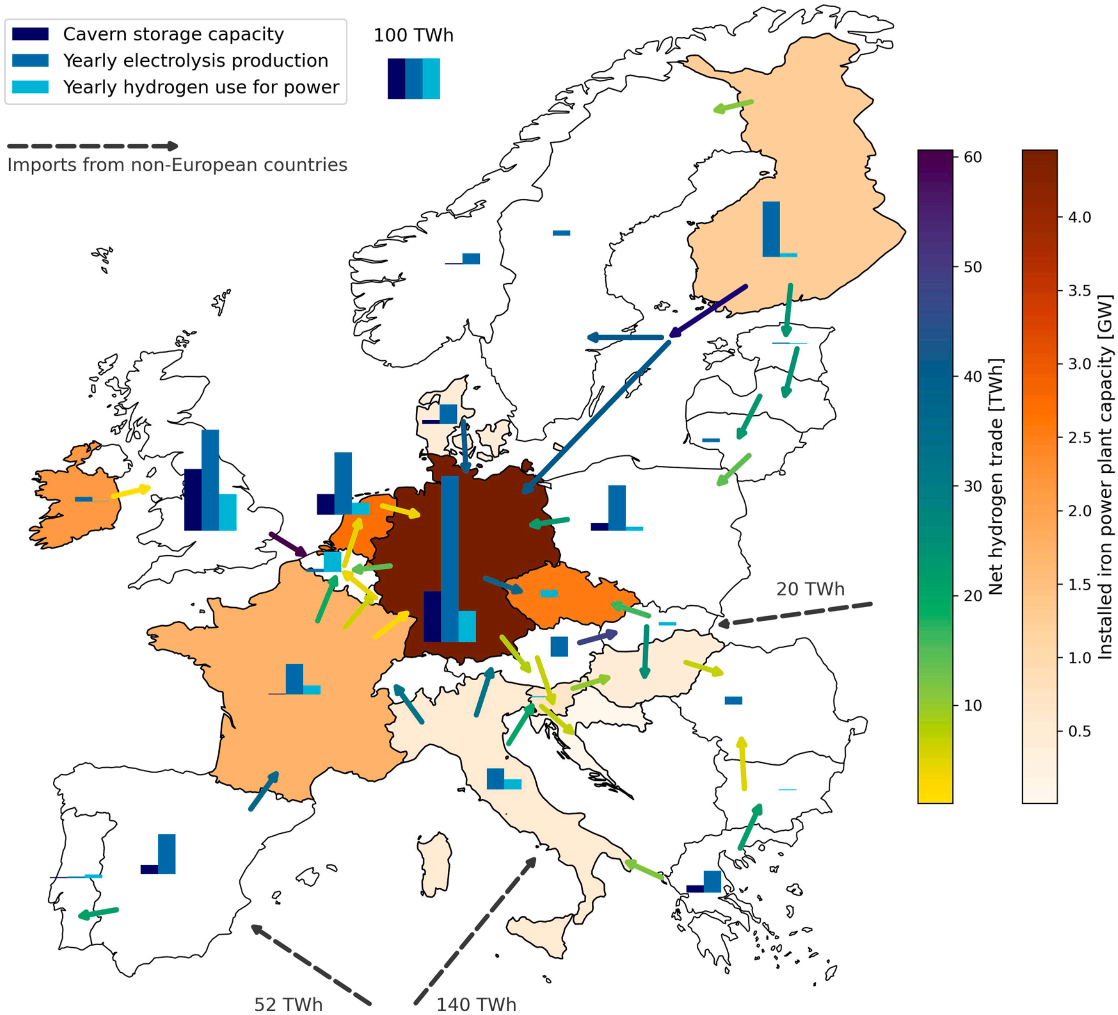

Figure 3. National hydrogen storage capacities, electrolysis production, hydrogen use for power generation, net hydrogen trade flows, and installed iron power plant capacities in 2050

The remaining countries that undertake no or only minimal retrofitting to iron are Bulgaria, Romania, and Croatia, even though none of them possesses domestic hydrogen cavern storage capacities (see Figure 3). The explanation lies in the ample hydrogen import capacities available to all three countries from Greece, Hungary, and Slovenia, which are only moderately utilized, as well as in their substantial hydropower resources (see Tables S13 and S19–S24, and figures in Section S3.2) that reduce the need for additional firm power generation, rendering not only iron power plants but also hydrogen turbines redundant.

The Czech Republic stands out, as the addition of 2.5 GW_{el} of iron power plants in 2050 not only reduces battery storage from 4.6 GW_{el} to 3.4 GW_{el} but also lowers nuclear capacity from 4.5 GW_{el} to 3.4 GW_{el}. Moreover, its iron fuel demand far exceeds domestic production, necessitating imports from Poland (see Figure 2), a country that, despite its extensive coal fleet, does not retrofit to iron fuel. Figure 4 shows the operation of iron power plants in the Czech Republic, Germany, and the Netherlands during the modeled January week in 2050, during which they complement hydrogen turbines, batteries, hydro reservoir, and pumped-storage power plants (PSPs) to provide flexible generation during nighttime hours. The thin pink line below the abscissa denotes the operation of reduction plants in Poland, where favorable conditions incite a large-scale expansion of wind capacity balanced mainly by batteries, hydrogen turbines, and electrolysis, with the hydrogen produced stored in domestic caverns. Equivalent electricity balance diagrams for all countries and all modeled timesteps in 2050 are provided in the supplemental information.

Germany and the Netherlands do not carry out iron oxide reduction but nonetheless implement iron power plants, supplied with iron fuel imported from outside Europe (see Figure 2). Both countries possess substantial hydrogen cavern storage potential that is only partially developed, making the incentive to additionally employ iron fuel as an alternative storage medium less apparent. For the Netherlands, retrofitting former coal power plants to iron fuel is likely more attractive than expanding hydrogen-based generation because the

Table 2. Iron power plant retrofit potential, retrofitted, and newly built capacity by 2050 (MW_{el})

	Retrofit potential	Retrofitted		New
DK	410	410	100%	0
FI	170	170	100%	1,077
FR	1,724	1,724	100%	0
HU	412	412	100%	0
IT	517	517	100%	0
NL	2,671	2,671	100%	0
SI	1,026	685	67%	0
CZ	4,354	2,524	58%	0
DE	23,307	4,456	19%	0
HR	290	9	3%	0
BG	2,663	0	0%	0
ES	260	0	0%	0
GR	660	0	0%	0
PL	20,005	0	0%	0
RO	1,860	0	0%	0
IE	–	–	–	2,129
Total	60,329	13,578		3,206

We use ISO 3166 Alpha-2 country codes as listed in Table S2.

retrofit potential of former gas plants to hydrogen is already fully exploited with 15.4 GW_{el}, and any further hydrogen capacity would require new construction, which is more costly (see Table S4).

Germany, by contrast, still has natural gas open-cycle units available for hydrogen retrofit yet opts for iron power plants despite their higher retrofit costs. This outcome is driven by recurring situations, such as the nights of January 18–21, when German hydrogen cavern storage operates at maximum discharge capacity to supply both domestic sectoral demand and power plants in Germany and neighboring countries. While cavern capacity in Germany could in principle be expanded, thereby proportionally increasing discharge capacity, the results indicate a trade-off between investing in larger cavern storage combined with additional hydrogen power plants and deploying iron power plants alongside hydrogen-based generation for dispatchable power supply.

Ireland and Finland represent special cases, as they are the only two countries where new iron power plants are constructed: 1.1 GW_{el} in Finland and 2.1 GW_{el} in Ireland. Neither country possesses hydrogen cavern storage potential, and both have relatively limited dispatchable hydropower capacity. During the first days of the modeled January week, their hydrogen import corridors—via sea and from neighboring Sweden and the United Kingdom, respectively—are heavily utilized. Building new iron power plants is the more economical option for both countries compared with expanding battery capacity or, alternatively, hydrogen-based power generation coupled with steel tank hydrogen storage. In the scenario without the iron fuel option, Finland installs 6.4 GW (25.6 GWh) of battery storage, compared to 3.8 GW (15.2 GWh) in the iron scenario. For Ireland, the difference is even more significant, with battery storage increasing to

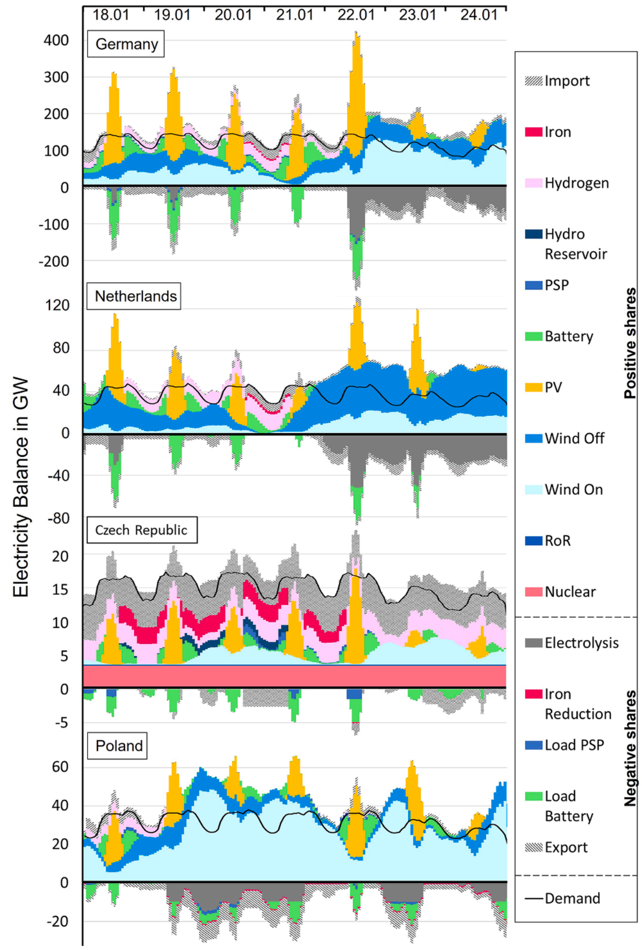

Figure 4. Electricity balance for multiple countries, January 18–24, 2050

17.1 GW (68.4 GWh) compared to 5.6 GW (22.4 GWh), when iron fuel is available, as detailed in Tables S23 and S24.

Variations in key assumptions reinforce iron fuel's system value

To further assess the dynamics of iron fuel adoption within the energy system, sensitivity analyses are performed for key iron fuel cycle parameters that carry substantial uncertainty. The scenario discussed so far applies conservative reduction plant parameters based on real-world data of an early-generation fluidized bed hydrogen direct reduction facility (CAPEX €898/kW_{Fe}, OPEX €26.9/(kW_{Fe}, a), hydrogen demand 1.61 MWh_{H2}/MWh_{Fe}, electricity demand 0.06 MWh_{el}/MWh_{Fe}, 40 years' lifetime; see Table S4),[42] along with power plant retrofit costs of €200/kW_{el}, corresponding to 10% of the investment for a new coal power plant[43] based on an expert interview. Under these assumptions, this base scenario results in 16.8 GW_{el} of iron power plant capacity across Europe by 2050, as reported in Tables 1 and 2. Figure 5 illustrates how increasing retrofit costs affect iron power plant deployment in this base scenario (blue bars): as retrofit costs

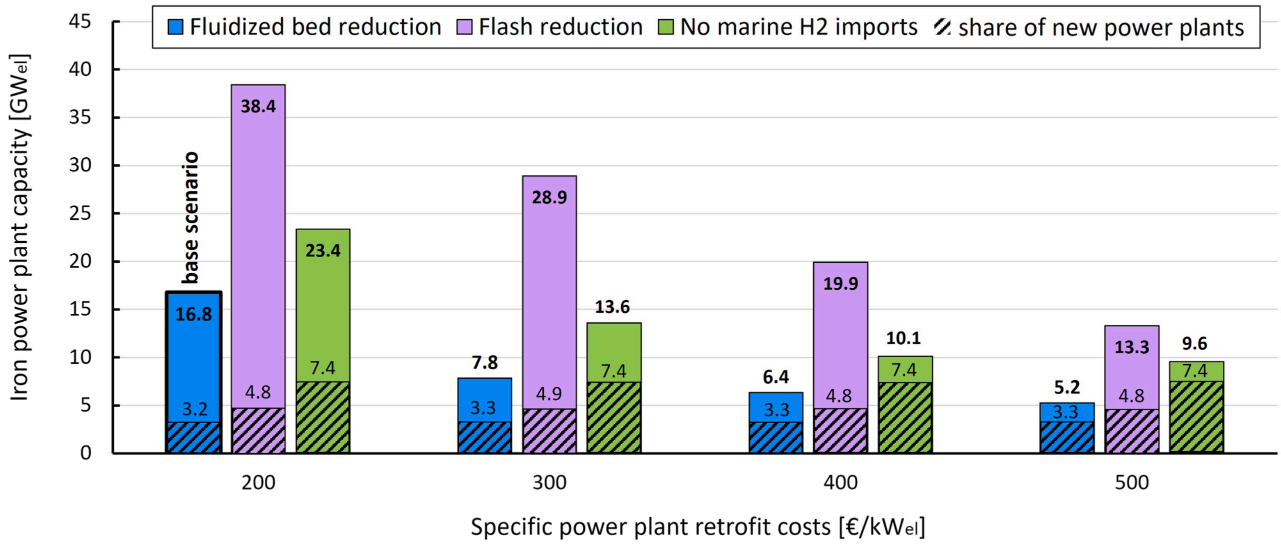

Figure 5. Sensitivity analysis of iron power plant capacity by 2050 under varying assumptions for power plant retrofit costs in three scenarios: The base scenario with fluidized-bed iron oxide reduction parameters, a scenario using flash reduction reactors, and a base scenario variant without the option for marine hydrogen imports

rise, iron power plant capacity declines substantially, shrinking by roughly 60% when costs are doubled relative to the base scenario. The construction of new iron power plants, indicated by the hatched bars and occurring in Finland and Ireland, remains largely unaffected, as it is independent of retrofit costs.

Repeating the analysis with more optimistic reduction plant parameters based on process simulations for the novel flash ironmaking process (CAPEX €745/kW_{Fe}, OPEX €22.4/(kW_{Fe}, a), hydrogen demand 1.04 MWh_{H2}/MWh_{Fe}, electricity demand 0.01 MWh_{el}/MWh_{Fe}, 20 years' lifetime; see Table S4), an ultra-fast hydrogen direct reduction method for fine iron oxide particles that has not yet reached commercial maturity[44] fundamentally changes the picture. Iron power plant capacity increases to 38.4 GW_{el} by 2050 at €200/kW_{el} retrofit costs. Compared with the base scenario, Croatia, the Czech Republic, and Slovenia employ their full iron retrofit potentials, and the retrofit share in Germany rises to 95%, amounting to a German iron power plant capacity of 22 GW_{el}. As in the base scenario, newly built iron power plants appear only in Finland and Ireland, although capacity in Finland doubles. The group of countries that do not deploy any iron power plants remains unchanged from the base scenario.

In the base scenario, the utilization of marine hydrogen import capacities is extremely low compared with pipeline imports from Africa and Ukraine: port terminals supply only 0.3% of hydrogen demand in 2050. The exogenously imposed presence of these terminals, however, might still be relevant in situations of scarcity. To address this unrealistically low utilization, we introduce a third scenario, shown by the green bars in Figure 5, in which marine hydrogen imports through sea terminals are not available. This scenario does not question the potential future role of imported hydrogen derivatives such as ammonia or methanol for industrial or transport applications. Rather, it investigates a system in which infrastructure for reconverting hydrogen derivatives back into gaseous hydrogen for injection into the hydrogen grid, and ultimately for supply to power plants, is absent. Again, the conservative reduction plant parameters of the base scenario are applied. The retrofitted power plant capacity in Germany nearly doubles at €200/kW_{el} retrofit costs compared to the base scenario. Newly built iron power plant capacity in Finland and Ireland increases to 3.7 and 3.4 GW_{el}, respectively, and an additional 310 MW_{el} of new capacity is built in Estonia. In this scenario, hydrogen tank storage is deployed for the first time, with 110 GWh_{H2} of capacity installed in Ireland by 2050. These results confirm the presence of hydrogen scarcity situations that are mitigated through marine hydrogen imports in the base scenario, which with the elimination of marine imports are addressed through additional iron power plants in Germany, Finland, Ireland, and Estonia, as well as through the deployment of hydrogen tank storage in Ireland. Relative to the base scenario, this scenario without marine hydrogen imports incurs an additional system cost of only €1.4 billion (see Table S25).

A final scenario not shown in Figure 5 that combines optimistic flash reduction parameters with the absence of marine hydrogen imports results in 44 GW_{el} iron power plant capacity in 2050 at retrofit costs of €200/kW_{el}. Here, Germany and all other countries that exhibited only partial retrofit in the base scenario (see Table 2) fully utilize their respective retrofit potentials.

Overall, the sensitivities demonstrate that iron fuel deployment is highly responsive to reduction parameters and retrofit cost assumptions and is considerably strengthened when hydrogen import options are constrained. These observations indicate that the economic viability of the iron fuel cycle depends critically on technological innovation, particularly improvements in the reduction step. According to the results, improvements in reduction plant parameters can compensate for higher power plant retrofit costs, thereby preserving the attractiveness of iron fuel even if power plant retrofit costs, an aspect not yet widely studied, turn out to be higher than anticipated. Moreover, the scenario omitting marine hydrogen imports confirms that hydrogen system dynamics play a decisive role in shaping the spatial distribution of iron power plant capacity across Europe.

DISCUSSION

Key findings

The findings highlight that iron power plants could emerge as a viable complement to hydrogen in Europe's decarbonized power mix, even in a future with extensive hydrogen transport infrastructure. Notably, countries with coal power plants exhibit no uniform strategy regarding retrofitting to iron fuel: some do not retrofit at all, others retrofit partially or fully, and a few even pursue new iron power plant construction. The use of iron fuel in power generation therefore appears neither as an obvious investment nor as an inherently uneconomic one; rather, its viability depends on how the characteristics of the iron fuel cycle align with the specific features of each national power system and its integration within the broader European context. Iron fuel offers a long-duration energy storage option that leverages existing infrastructure while mitigating reliance on hydrogen imports where hydropower is limited and underground hydrogen storage is unavailable, such as in the Czech Republic, Finland, Hungary, Ireland, and Italy. Periods of hydrogen scarcity, when import capacities through the European hydrogen backbone and marine terminals are fully utilized, drive the expansion of iron power plants for those countries, as they offer a more cost-effective alternative to further battery capacity or domestic hydrogen storage in expensive steel tanks.

Conversely, in countries with strong renewable resources and geological hydrogen storage potential, such as Poland, Greece, and Spain, the absence of bottlenecks in hydrogen supply supersedes the need for iron power plants. However, this holds only as long as the hydrogen infrastructure achieves sufficient utilization. Germany illustrates this sensitivity: despite remaining potential for cost-effective gas turbine retrofits to hydrogen and additional cavern expansion, 4.5–22 GW_{el} of iron power plant capacity is developed, depending on the scenario. This coexistence suggests a systemic trade-off between reinforcing hydrogen infrastructure and diversifying flexibility options through iron fuel for covering residual load. In all countries incorporating iron power plants, their annual utilization remains low, ranging between 2% (Germany, Denmark, and the Netherlands) and 14% (Hungary) in the base scenario. Owing to its favorable storage and transport characteristics as a solid powder and the cost-effective option for power plant retrofits, iron fuel is still competitive in many countries despite low utilization. Sensitivity analyses underscore that the economic potential of iron fuel hinges critically on reduction plant parameters and power plant retrofit costs and highlight the value of iron fuel not only as a firm power supply option but also as a flexibility resource that can relieve pressure on regional hydrogen networks.

Model validation

As no prior studies have assessed iron fuel at the system level, a direct comparison of our iron-related findings with the literature is not possible. Instead, we benchmark our model by comparing the energy system design in the scenario without iron fuel to similar studies. Two notable studies by Neumann et al. (published in *Joule*)[45] and Kountouris et al. (published in *Nature Communications*)[46] have recently analyzed the transition of the European energy system toward decarbonization, both focusing on the role of hydrogen. We select these two studies because they are widely recognized in the field and employ comparable European energy system models (PyPSA-Eur-Sec and Balmorel). However, both Neumann et al. and Kountouris et al. include the Balkan countries (Albania, Bosnia and Herzegovina, Montenegro, North Macedonia, Serbia, and Kosovo), which are excluded from our analysis.

Table 3. Comparison of capacities in a decarbonized European energy system

	Neumann et al.[45]	Kountouris et al.[46]	This work
Scenario	diverse net zero 2050 scenarios	Green Hydrogen Europe (GH2E)	scenario without iron fuel
Year	not defined	2050	2050
Photovoltaics (GW_{el})	2,666–3,598	2,672	2,451
Onshore wind (GW_{el})	1,691–1,776	576	995
Offshore wind (GW_{el})	206–245	213	283
Electrolysis (GW_{el})	937–1,250	466	586
H_2 storage (TWh_{H2})	26–43	66.6	419

Table 3 shows that PV expansion in our model is somewhat lower than in the two benchmark studies, as PV deployment reaches exogenously set expansion limits in many countries. Offshore wind capacities in our model are slightly higher, while onshore wind capacities lie between the two studies. Neumann et al. do not allow hydrogen imports to Europe, which likely contributes to their higher renewable capacity expansion,[45] whereas our model and the Green Hydrogen Europe scenario of Kountouris et al. include both domestic electrolytic hydrogen production and hydrogen imports to Europe.[46]

Electrolyzer capacities in our study are comparable with those reported by Kountouris et al., who present a similar total hydrogen demand for 2050, amounting to 1,700–1,800 TWh (51–54 Mt), comprising both exogenous demand and endogenous hydrogen use in power plants. This range is close to the average of more than 30 studies assessing future European hydrogen demand.[46] Also, the European Union's Hydrogen strategy mentions 500 GW of electrolyzer capacity as a target magnitude for 2050.[47] Hydrogen demand is considerably higher in Neumann et al., exceeding 2,300 TWh in all scenarios.[45] Combined with their assumption of no hydrogen imports to Europe, this explains the substantially larger electrolyzer capacities in their study.

The comparatively large hydrogen cavern storage expansion observed in our model may reflect, on the one hand, the higher flexibility in hydrogen demand and the endogenous expansion of hydrogen interconnector capacities in the other two studies. In addition, the assumed ratio between injection or withdrawal capacity and cavern storage volume, set to 1 GW per TWh in our model, strongly influences the storage volume. In the study by Kountouris et al., this ratio is considerably higher at approximately 5.4 GW/TWh, implying that for the same installed injection capacity, the resulting cavern volume is 5.4 times smaller.[46] Neumann et al. do not report the factor they apply.[45]

However, in our study, storage volumes correspond to 24.5% of total hydrogen demand in 2050, a proportion that appears plausible when compared with European natural gas storage capacities, which amount to roughly 30% of annual demand.[48] Based on this ratio, Talukdar et al. estimate hydrogen storage needs between 150 and 1,500 TWh in 2050.[48] The magnitude of our storage capacity is further supported by the European Ten-Year Network Development Plan (TYNDP) 2024, which projects only 25–45 TWh of hydrogen storage capacity in 2050 but notes that "[…] the model seems to underestimate the need for hydrogen storage. If conventional production and imports provide only (very) limited flexibility, the hydrogen storage capacity requirement will be a factor up to 9 higher than shown for the various scenarios."

Limitations

It is conceivable that the role of iron fuel could become more significant when further increasing the level of detail of the energy system model, as several simplifications in this study tend to disadvantage iron power plants. For instance, the general omission of construction times does not favor iron power plants, which require only moderate retrofit measures, whereas hydrogen caverns, for example, entail long construction times, exceeding 10 years at least for new sites requiring leaching.[49] Moreover, minimum fill levels and the initial loading with cushion gas are neglected for hydrogen caverns. In our base scenario, exogenously defined hydrogen import terminal capacities are used only sporadically, limited to a few hours of scarcity, thereby reducing the need for iron power plant capacity. However, the implementation of such infrastructure in reality appears questionable in the light of very low utilization. Only cross-border energy transport is represented in the model, whereas intra-regional transport with potential bottlenecks in electricity, hydrogen, and natural gas grids is not captured, which could also be disadvantageous for iron fuel, given its ease of transport and storage.

Also, the simplified representation of hydro reservoirs in this PERSEUS model version, implemented to reduce time-linking constraints and, thus, computing time, provides greater flexibility than in reality, as the total annual inflow can be shifted across seasons, constrained only by installed turbine power. Since hydro reservoirs primarily operate as peak suppliers, they compete directly with iron fuel in this role.

On the other hand, only caverns are considered for underground hydrogen storage, as broadly validated evidence on the technical and economic feasibility of storage in porous media, such as depleted oil and gas fields, is still lacking.[48,50,51] First field demonstrations show encouraging results,[52] indicating that subsequent analyses could include porous media storage as an additional option, thereby extending underground hydrogen storage potential to more countries.

Our depiction of hydrogen and natural gas pipeline networks does not account for their inherent buffering capability through line packing. However, this operational flexibility is substantially reduced for hydrogen due to its lower volumetric energy density, lower compressibility, and increased material stress it imposes on the pipeline compared to natural gas.[53] Some studies suggest that hydrogen pipeline networks may not be able to accommodate the rapid demand ramps associated with starting hydrogen turbines, making local hydrogen buffer storage necessary,[54] which may provide an additional incentive for deploying iron power plants.

Further limitations include the temporal resolution of five representative weeks per model year, which captures seasonal patterns but may miss rare but critical events such as *Dunkelflauten*, extended periods of low renewable generation. Consequently, the model underestimates the need for firm capacity, including iron power plants. The analysis further differs from a security of supply assessment, as it does not account for planned or unplanned infrastructure outages or inter-annual weather variability, which are typically considered in such studies. Instead, the analysis is based on a single representative weather year, namely 2016. Dynamics below the hourly resolution, such as ramping constraints, as well as non-linear or discrete characteristics including part-load efficiency losses, economies of scale, or unit commitment conditions are not captured in the linear model, which in turn permits incremental infrastructure expansion that would be unrealistic for certain technologies.

The spatial aggregation at the country level inhibits precise localization of infrastructure and representation of intra-regional transport with associated capacities and costs. Country-level case studies with higher spatial and unit-level resolution, rather than our approach of aggregating units by type and age at the national level, could provide valuable insights into iron fuel adoption—particularly regarding the selection of power plants for retrofit considering plant characteristics, location, and supply logistics (inland waterways or rail), as well as the optimal number and spatial distribution of reduction facilities.

The cost-optimal, centrally planned framework assumes perfect foresight and neglects market behavior, risk aversion, imperfect information, and strategic investment decisions, which affect the real-world deployment of novel technologies such as iron fuel. Techno-economic parameters for iron fuel cycle processes and infrastructure are highly uncertain due to the absence of system-scale data; model inputs therefore rely on expert interviews and extrapolations from similar processes, and this uncertainty has been addressed through sensitivity analyses. Other technology costs, fuel prices, and infrastructure assumptions are taken from external projections (e.g., TYNDP) and are also subject to uncertainty, particularly given the long-term modeling horizon extending to 2050.

Our model targets zero emissions in the European power sector by 2050 through a portfolio of carbon-free technologies. Pathways based on the sequestration of carbon, such as the combustion of fossil fuels combined with either direct air capture or oxyfuel processes and point source capture, biomass-based fuels, or hydrogen from steam reforming with carbon capture, are excluded from the analysis. The integration of carbon sequestration technologies represents one of the most important future model extensions, enabling a more comprehensive exploration of decarbonization pathways.

Research gaps for iron fuel

This study focuses on the electricity sector, with only simplified representation of interdependencies with other sectors through exogenous demands for hydrogen, natural gas, and electricity. Future research could extend the scope to examine the role of iron fuel in providing high-temperature heat in the industrial sector or low-temperature district heating through combined heat and power applications. Moreover, future studies could investigate potential synergies between the iron fuel concept and the steel industry. One idea is the use of the iron fuel cycle for material purification, as certain impurities, such as phosphorus, molybdenum, copper, and nickel, can evaporate during combustion.[55] More broadly, promising synergies arise from accessing existing and emerging material streams within the steel industry for iron fuel. These are discussed in the next subsection, which also demonstrates that a competition for primary resources, namely iron ores, between material and energetic uses is unlikely.

Furthermore, the potential for iron fuel adoption beyond the European context remains to be explored. Moreover, iron fuel import corridors could be refined by explicitly modeling potential exporting regions worldwide, where lower local hydrogen costs could translate into more competitive iron fuel import costs than assumed in our current scenarios.

In our analysis, hydrogen import and transport infrastructure based on the European hydrogen backbone initiative becomes gradually available from 2030 onward, modeled as an exogenous input without accounting for associated costs. The objective of this study was not to assess whether the deployment of iron power plants could reduce the need for hydrogen infrastructure but, rather, to evaluate whether iron fuel remains economically viable when hydrogen transport capacity is exogenously available without associated investment. Future work could investigate this interaction further, for instance by examining how a delayed hydrogen backbone, deviations from current capacity plans, or additional cross-border hydrogen transport capacities influence overall system design and the competitiveness of iron power plants.

Although the overall system cost savings identified are modest, the inclusion of iron power plants can provide strategic value that extends beyond the aspects monetized in this analysis. Iron fuel diversifies the portfolio of long-duration energy storage and firm generation options, thereby strengthening system resilience against variability in renewable generation and potential supply disruptions in hydrogen infrastructure. Its solid-state form enables low-cost storage and straightforward transport using flexible, well-established bulk logistics infrastructure. This represents a significant advantage over hydrogen, which is largely grid bound and requires substantial upfront investment in dedicated transport and storage infrastructure. Beyond transport costs, as for hydrogen, the safe handling of iron fuel warrants further investigation, although initial studies indicate encouraging results regarding the risk of dust explosion.[28]

The re-use of infrastructure for iron fuel through retrofitting existing steam power plants, as well as for hydrogen via gas turbine retrofits and for fossil fuel-fired power plants complemented with carbon capture systems, offers several advantages. Technically, it preserves synchronous generation capacity and thus supports frequency stability by maintaining physical inertia in increasingly inverter-dominated power systems. From a socio-economic standpoint, the potential to preserve jobs in bulk logistics and power plant operation and mitigate stranded assets represents an additional aspect worth consideration. Further socio-political and environmental aspects to compare iron fuel with alternative dispatchable power generation options include dependence on critical minerals and the associated environmental impacts, which are relevant for both batteries and electrolyzer-based pathways, as well as geopolitical risks, which are closely linked to critical materials but should also be considered when evaluating fossil fuel use with carbon capture. Iron fuel can be particularly valuable in regions without seasonal energy storage potential through hydropower or underground hydrogen storage and those exposed to hydrogen or fossil fuel import dependencies. From a circularity perspective, water use represents a notable advantage of the iron fuel cycle, as it allows for local water recycling rather than the implicit export of water associated with hydrogen and the hydrogen derivatives trade (see Figure 1). Addressing these aspects would help position iron fuel more clearly relative to linear fossil fuel and hydrogen pathways as well as to circular storage concepts such as pumped hydro and batteries.

Required iron fuel inventory

In the base scenario results for the year 2050, the total amount of iron powder supplied to power plants amounts to 8.7 Mt. To estimate the circulating stockpile required for energetic use, a relatively high number of oxidation-reduction cycles per year can be assumed, as 83% of the iron oxide is reduced within Europe and only 17% is imported from other continents, where long-distance maritime transport adds time, and European reduction plants operate with an average utilization rate of 59% across countries. Assuming five cycles per year, the necessary iron fuel stock amounts to 1.7 Mt. Given that global iron ore production in 2024 totaled 2,500 Mt,[56] with an iron content of 1,600 Mt,[57] the additional production required to establish this stockpile would be negligible, particularly as it could be accumulated gradually over several years.

While this study assumes the deployment of iron oxide reduction facilities dedicated to the iron fuel cycle, potential synergies with the ongoing transformation of the steel industry and its established and emerging low-carbon products could be an interesting investigation. For example, the expected increasing adoption of direct reduction enables a spatial decoupling of ore reduction and steelmaking, potentially giving rise to a global trade in sponge iron.[58] If such material proves suitable for energetic applications, the iron fuel concept could directly benefit from this development. Besides, accessing products from electric arc furnace steelmaking, or basic oxygen steelmaking potentially equipped with carbon capture in the future, would diversify the sourcing of iron fuel and enhance the robustness of the overall concept. Another potential, widely available iron fuel source under discussion is mill scale, a by-product from steel slab production.[59]

Although current iron fuel research predominantly focuses on high-purity iron powder, there is growing recognition of the need to systematically investigate the effects of impurities on iron combustion and reduction in order to link iron fuel cycles with established and emerging ironmaking and steelmaking processes and material streams.[60] Initial studies have demonstrated that impurities can significantly influence key properties of the iron fuel cycle, including combustion temperature, NOx formation, evaporation and nanoparticle formation, energy density, and reduction kinetics. These studies reveal both beneficial and negative effects of specific impurities on the performance of iron fuels.[55,61,62] However, a conclusive definition of acceptable impurity levels and particle-size ranges has yet to be established. Such a definition would be essential for enabling economic assessments of synergies between iron fuel and the steel industry.

Conclusions

This study explored the potential role of iron fuel in the decarbonization of the European power sector using detailed bottom-up energy system modeling. Under the applied iron fuel cycle parameters, the results indicate that iron power plants can represent an economically viable option for providing dispatchable capacity for a limited number of hours per year with high residual load, particularly in countries with limited hydropower resources or lacking hydrogen cavern storage potential. That iron power plants appear as part of the cost-optimal energy system in our analysis, even under several modeling assumptions that disadvantage iron fuel, is an encouraging outcome for the metal fuel community. This provides a solid foundation for further research into the role of iron fuel within complex energy systems, exploring its competitiveness with other dispatchable supply options in local contexts through, for example, sensitivity analyses of key techno-economic parameters or higher-resolution studies for selected regions. Moreover, our findings underscore the importance of progress in reduction and combustion technologies to determine and improve metal fuel cycle parameters.

On a policy level, the study emphasizes the importance of timely decisions regarding the preservation and retrofit of existing steam power plants, as the planned coal exits across Europe leave a rapidly closing window to grant these valuable infrastructures a second, defossilized life. This window narrows further as plants approach retirement, since they are increasingly operated in low-maintenance modes, training of new staff ceases, and dismantling or alternative conversion plans progress, rendering retrofit to iron fuel increasingly unattractive. Seizing this opportunity for clean, dispatchable power depends on proactive policy measures that bridge technology development with infrastructure planning, in close collaboration with researchers and plant operators.

METHODS

Energy system optimization model PERSEUS-PtX

The analyses in this study are conducted using a tailored instance of the PERSEUS (Program Package for Emission Reduction Strategies in Energy Use and Supply) model family, which has been developed and maintained at the Karlsruhe Institute of Technology for over two decades (e.g., Fichtner,[35–39] Rosen,[35–39] Babrowski et al.,[35–39] Yilmaz et al.,[35–39] and Heinrichs and Yochem[35–39]). In particular, the PERSEUS-EU model version[38,63,64] has been updated and extended to incorporate hydrogen and iron fuel as energy carriers within the European energy system, including their respective infrastructure. PERSEUS-PtX is formulated as a linear, deterministic optimization framework, adopting a central planner perspective under perfect foresight. The brownfield approach initiates from the configuration of the existing European energy system and optimizes the dispatch and expansion of energy conversion, storage, and transport infrastructure in a single model run. The objective function minimizes total discounted system costs while meeting exogenous, inelastic, and spatially fixed demands for electricity, natural gas, and hydrogen.

Key decision variables include the expansion of renewables and thermal power plants, energy conversion units (electrolyzers and iron oxide reduction plants), and energy storage infrastructure, as well as the dispatch of all infrastructure including energy conversion, storage, and transport. Crucial constraints are energy balances, weather-dependent renewable energy supply, country-specific potentials for infrastructure expansion (e.g., renewables) and infrastructure retrofitting (coal power plants for iron combustion, natural gas turbines for hydrogen, cavern storage for hydrogen), exogenously defined interconnector capacities for electricity and gas, and compliance with a common European emission reduction pathway.

The geographical scope comprises the EU-27 excluding Cyprus and Malta, as well as the United Kingdom, Norway, and Switzerland. Each country is represented as a single model region without further spatial detail, particularly without the inclusion of infrastructure localization or national transport grids. Consequently, the terms "model region" and "country" are used interchangeably throughout the paper.

The temporal structure consists of five representative weeks per year at hourly resolution (as detailed in the data section), amounting to 840 timesteps per year, in four model years: 2025, 2030, 2040, and 2050.

Included energy conversion technologies are conventional thermal power plants (coal, lignite, natural gas—open and combined cycle, oil, and nuclear), renewables (PV, wind on- and offshore, run-of-river [RoR], and biomass), hydrogen open and combined cycle power plants, iron fuel steam power plants, electrolysis, and iron oxide reduction. A distinction with regard to the commissioning year is applied to most endogenously expanded technologies (PV, wind, battery, and electrolyzer systems), as well as to exogenously defined coal, lignite, and gas units existing in the start year 2025. This allows the model to reflect technological progress for new installations and performance differences among existing plant fleets according to their age structure in terms of efficiency, operating costs, and, for endogenous expansion, capital expenditures (see Table S4). Included storage technologies cover hydro reservoirs, pumped hydro (PSPs), natural gas underground storage, batteries, hydrogen tanks, hydrogen caverns, and iron silo storage. Expansion of the latter four is endogenously optimized, whereas hydro

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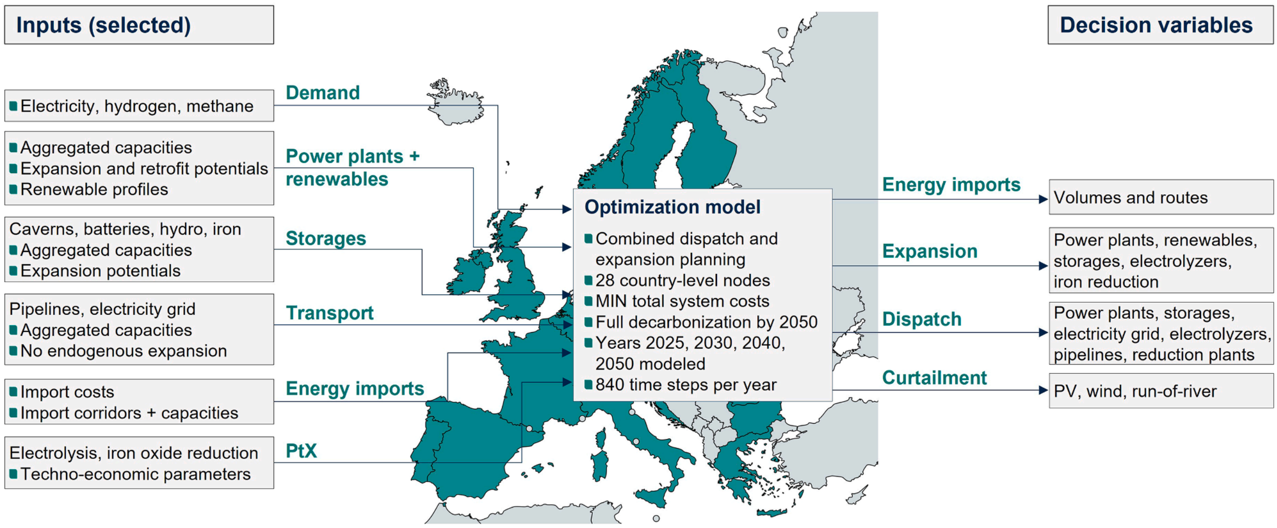

Figure 6. Scope of the optimization model PERSEUS-PtX

and natural gas storage capacities are either fixed to 2025 levels or follow exogenously defined expansion pathways. All storage levels are fixed to 50% of capacity at both the beginning and end of each model year. Transport of electricity, hydrogen, natural gas, and iron fuel between neighboring countries is enabled through aggregated, exogenously defined interconnection capacities that are aligned with common European infrastructure planning, e.g., ENTSO-G/ENTSO-E's TYNDP 2024 or the European Hydrogen Backbone initiative.

Figure 6 provides an overview of the main model characteristics, inputs, and decision variables.

The model is implemented as a linear program in GAMS and solved using CPLEX. The optimization problem comprises approximately 8 million constraints, 9 million variables, and 35 million non-zero entries. Model runs require around 80 min of computing time on a system equipped with an Intel Core i7-14700K processor (3.4 GHz) and 128 GB RAM, using the Barrier solving algorithm on 20 cores.

Data

This section provides a detailed overview of all input data used to parameterize the scenarios in the model. Table S1 gives a consolidated overview of all modeling assumptions and links them to this section as well as the detailed input parameter tables presented in the supplemental information.

Technology parameters

The parameters of the modeled energy conversion and storage technologies include fixed and variable operating costs, efficiencies, energy demands, technical lifetimes, and capital expenditures for technologies subject to endogenous expansion. A list of techno-economic technology parameters is provided in Table S4. Costs are reported in real terms without adjustment to a common reference year, as the primary sources for cost parameters[43,65,66] use closely aligned reference years (2022–2024).

For the iron oxide reduction plants, we apply parameters of hydrogen-based direct reduction in fluidized bed reactors from Lopez et al.,[42] as these better represent the smaller particle sizes relevant to iron fuel applications compared to the shaft furnace process, which requires pelletized input. Lopez et al.[42] report a hydrogen demand of 1.61 MWh_{H2}/MWh_{Fe} for reduction and preheating, based on real-world data from the first commercial-scale "Circored" plant operating in Trinidad since 1999, which employs pure hydrogen to reduce iron ore fines.[67] Process simulations for hydrogen-based shaft furnace direct reduction[68] and flash ironmaking[44] report energy demands up to 60% lower. Consequently, the energy demand of the reduction plant used in our base scenario represents a conservative approximation for emerging iron ore reduction technologies, implying that both reduction and iron fuel import costs are likely overestimated. The impact of more optimistic energy requirements and investment costs based on the flash reduction process is analyzed in a sensitivity analysis.

Likewise, economic parameters for iron-fueled power plants are not yet available. Retrofit measures required to convert existing coal-fired units to iron-based operation are considered moderate compared to the construction of new power plants, primarily involving modifications to the fuel feeding system, burners, and flue gas cleaning.[23] Based on expert interviews, capital expenditures for such retrofits are estimated at 10% of the investment for newly built hard coal power plants. Sensitivity analyses are performed to assess the impact of increasing this parameter. Likewise, the investment required for converting gas turbine power plants to hydrogen combustion is estimated at 10% of the capital cost for new open-cycle gas turbines, based on the implicit definition of hydrogen readiness as outlined in the German *Kraft-Wärme-Kopplungsgesetz* §6.

For newly constructed iron power plants, several major components required for coal operation—such as mills, desulfurization, and, potentially, denitrification systems—are no longer necessary. Conversely, iron fuel operation requires additional equipment for flue gas de-dusting and cleaning systems.[20,23]

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The authors assume that these differences in technical requirements roughly balance out in terms of capital investment. Therefore, the capital expenditures and lifetime of hard coal power plants in Kost et al.[43] are used as proxies for new iron-fueled units. Similarly, operating costs of current hard coal power plants are adopted for both retrofitted and newly built iron-fired units, based on the assumption that reduced operating costs for omitted components (e.g., mills and conventional flue gas cleaning) are offset by increased costs for iron-specific cleaning and filtering systems.

Iron storage is modeled in cement silos, with cost parameters adapted from a 40,000-m^3 woodchip silo as in Sahoo et al.,[69] applying an iron fuel heating value of 2.05 MWh/t for parameter conversion. The investment encompasses a mechanical conveyor system for loading and unloading at 150 t/h throughput and installation costs. The ratios of storage capacity to (un-)loading rate implemented for iron silos and the other storage types are provided in Table S18.

A minimum generation requirement (must-run) is imposed for nuclear and biomass power plants, set at 40%[66] and 30% of their total installed capacities, respectively.

Development of demands

The energy system model is driven by exogenous demand requirements for three energy carriers: electricity, natural gas, and hydrogen. These demands are defined at country level, aggregated across all sectors except power generation, and specified for each model year (see Table S5). The primary data source is the TYNDP 2024,[65] using PLEXOS model results from the Distributed Energy scenario. For model years not explicitly covered in the TYNDP, values are obtained through linear interpolation. Electricity demand in 2025 is assumed to equal the recorded demand of 2024.[70] Natural gas and hydrogen demand data for Switzerland, Norway, and the United Kingdom are not provided in the TYNDP dataset. For natural gas, demand in 2025 for these countries is based on the most recent annual consumption reported in the IEA database,[71] while the development until 2050 is assumed to follow the average relative reduction of gas demand across all other modeled countries. Hydrogen demand trajectories for these three countries are approximated based on the demands of neighboring countries (Austria, Ireland, and Sweden, respectively), scaled by relative population.

Hydrogen demand in 2030, based on the TYNDP National Trends scenario,[65] is adjusted by subtracting each country's current level of conventional hydrogen production as reported by the European Hydrogen Observatory.[72] For 2040, 50% of today's national conventional hydrogen production is deducted from the hydrogen demand in the TYNDP Distributed Energy scenario. The underlying rationale is that additional future hydrogen demand must be met either through hydrogen imports to Europe or domestic electrolysis, while existing steam-reforming facilities, whether with or without carbon capture, are assumed to remain in operation until they gradually phase out. For 2050, national hydrogen demands correspond to the TYNDP values without deductions. This approach aligns with the TYNDP results, in which hydrogen production from European steam reforming plants plays a minor role by 2040 and disappears by 2050.

Weather-dependent renewable generation and demand time series

The generation profiles of PV, onshore and offshore wind turbines, inflows to RoR and hydro reservoir plants, and load profiles are weather-dependent model inputs. The availability of high-quality time-series data across all model regions limits the selection of a representative weather year to the past decade.[73] Among these, the year 2016 is chosen, based on recent findings showing that it yields the most robust capacity layouts of the historical weather years since 2015, characterized by the highest levels of resource adequacy and the lowest loss of load when tested against 60 operational weather years in energy system modeling.[74]

Due to computation constraints, a reduced temporal resolution of 840 h per year is applied by selecting five representative weeks in full hourly resolution. A manual selection approach is used, preserving the integrity, chronology, and transparency of the original historical time series. The selected representative weeks are as follows:

- Third week of January, representing a winter week outside the holiday season; this week also includes the highest residual load hour aggregated across all model regions.
- Third week of April, selected as a mid-season week that captures the annual peak in PV generation across all model regions.
- Second week of July, chosen to represent summer conditions, characterized by heat-induced electricity demand peaks in southern countries such as Greece, Spain, Italy, and Croatia.
- Final week of September transitioning into October, an autumn mid-season week selected to balance both annual renewable capacity factors and electricity demand with the original full-resolution time series.
- Second week of December, included as an additional winter week featuring a residual load peak in Germany and four other countries, to offset the otherwise over-representation of the warmer season.

Using these representative weeks with each hour weighted equally, the resulting annual utilization across all model regions, weighted by 2025 installed capacities in each country, reach 98% for both PV and onshore wind and 108% for offshore wind, as well as 94% for RoR inflow, relative to the original full-resolution year. Annual demand across all model regions, weighted by each country's 2025 demand level, amounts to 102% for electricity and 106% for natural gas.

Generation profiles based on the weather year 2016 for PV, onshore and offshore wind turbines, and inflows to RoR and hydro reservoir plants are based on data from the Pan-European Climate Database (PECD) version 4.2.[75] For wind power, separate profiles are applied for initial (pre-2025) and endogenously expanded capacities. The profiles for newly installed wind turbines are based on a specific power of 277 W/m^2 and 150 m hub height for onshore wind, and 370 W/m^2 and 155 m hub height for offshore wind. For PV, a single profile is used for both existing and newly built capacities. However, a

Table 4. Energy carrier import costs in €/MWh$_{th}$ lower heating value

	2025	2030	2035	2040	2045	2050	Reference
Hard coal	11.6	6.5	6.1	5.8	5.8	5.8	Kost et al.,[43] ENTSO-G and ENTSO-E[65]
Lignite	2.3	5.0	5.0	5.0	5.0	5.0	Kost et al.,[43] ENTSO-G and ENTSO-E[65]
Oil	45.0	42.1	41.6	41.0	40.3	39.6	ENTSO-G and ENTSO-E[65]
Uranium	8.0	6.1	6.1	6.1	6.1	6.1	Kost et al.,[43] ENTSO-G and ENTSO-E[65]
Biomass	55.3	62.6	64.9	67.0	69.2	69.2	Kost et al.[43]
Natural gas port (LNG)	38.0	22.7	21.6	20.5	19.3	18.0	Kost et al.,[43] ENTSO-G and ENTSO-E[65]
Natural gas pipeline	36.1	21.5	20.5	19.5	18.3	17.1	calc.
Natural gas domestic production	34.2	20.4	19.4	18.5	17.3	16.2	calc.
Hydrogen pipeline, Algeria to Italy and Morocco to Spain	–	78.8	56.4	48.3	48.3	48.3	ENTSO-G and ENTSO-E[65]
Hydrogen pipeline, Ukraine to Slovakia	–	97.5	69.3	58.7	58.7	58.7	ENTSO-G and ENTSO-E[65]
Hydrogen port	–	202	181	168	158	150	Institute of Energy Economics at the University of Cologne (EWI)[78] + calc.
Iron fuel	–	148	112	99	99	99	calc.

performance degradation factor of 0.25% per year is applied to both existing and newly built PV plants.[76]

Hourly electricity demand profiles for 2016 are derived from data provided by ENTSO-E's Transparency Platform.[73] Exogenous demand profiles for natural gas—covering non-electricity sector consumption relevant to determine storage and transport infrastructure utilization—are implemented as monthly averages over the period 2019 to 2024, based on data from BRUEGEL.[77] The absence of hourly and weather-linked time series for natural gas in the model is considered a minor limitation, since large-scale storage capacities enable balancing of intra-daily (e.g., one-shift industrial operation or heating patterns) and intra-weekly (e.g., workday versus weekend) demand fluctuations. Potential distribution grid bottlenecks are not represented, as the model is defined at country level. Finally, for hydrogen, a flat demand profile is assumed for consumption outside the electricity sector. This simplification arises from the absence of historical data and the expectation that hydrogen use for space heating, associated with strong seasonal variation, will remain negligible. Furthermore, intra-daily and intra-weekly fluctuations are assumed to be negligible due to the availability of underground hydrogen storage and inter-regional transport via the hydrogen backbone.

The complete time-series input data used in the model are provided on Zenodo (see data and code availability).

Energy carrier import

Each model region is assumed to have unrestricted access to hard coal, lignite, oil, uranium, and biomass, with fuel prices as specified in Table 4. In contrast, the supply of natural gas, hydrogen, and iron fuel from external regions outside the model's geographic boundaries is subject to country-specific constraints on import capacities—via ports and pipelines—as well as domestic production potentials as detailed in Table S6. Fuel prices for the year 2025 are derived from an annual study on electricity generation costs in Germany,[6,7,10,11] which also provides biomass prices for all years, calculated as the average of solid biomass and biogas prices. For hard coal, lignite, oil, uranium, and liquid natural gas (LNG), price trajectories for 2030, 2040, and 2050 are taken from the TYNDP 2024.[65]

Sixteen modeled countries have LNG terminals and are therefore able to import natural gas—and, starting from 2030, hydrogen—via maritime routes from unspecified locations outside the geographic model scope. Modeled LNG port capacities include operational, under construction (assumed operational by 2030), and currently planned (assumed operational by 2035) terminals.[79,80] Hydrogen port capacities are based on announced infrastructure projects listed in the Hydrogen Infrastructure Map.[41] From 2045 onward, it is assumed that existing LNG terminals have been partially retrofitted to enable hydrogen imports via ammonia or liquefied hydrogen, which is considered technically feasible.[81] The effective hydrogen import capacity is set at one-quarter of the original LNG capacity, reflecting the lower volumetric energy densities of ammonia (11.5 GJ/m^3) and liquid hydrogen (8.5 GJ/m^3) compared to LNG (23 GJ/m^3), as well as the ongoing use of LNG terminals for natural gas imports through 2050. The price path for maritime hydrogen import is taken from the Global PtX cost tool[78]: allowing both liquid hydrogen and ammonia shipping with reconversion to hydrogen, maritime supply routes to Germany are ranked by total costs per MWh of hydrogen delivered. Following the methodology applied in the TYNDP,[65] the sixth-lowest cost option is selected as the price setter and applied uniformly across all countries in the model.

Lower-cost natural gas imports from non-European countries via pipelines are available to Bulgaria, Greece, Italy, Latvia, Lithuania, and Spain, considering respective pipeline capacities. For these countries, a uniform price—denoted as "natural gas pipeline" in Table 4—is set at 95% of the LNG import price, reflecting the cost advantage and aiming to incentivize high pipeline utilization. Hydrogen imports via pipeline are available to Italy, Spain, and Slovakia beginning in 2030, based on announced projects.[40,41] For these routes, two distinct price corridors are applied, following the methodology of the TYNDP 2024.[65]

Eighteen of the modeled countries have the option of domestic natural gas production. At country-specific production capacities,[79] natural gas is made available at 90% of the LNG import price, representing an author-defined assumption to prioritize domestic production over imports within the model.

From 2030 onward, iron fuel imports are assumed to be available to 22 countries with seaports. No import capacity restrictions are applied, as the handling of iron fuel as a bulk material does not require highly specialized port infrastructure. Due to the absence of iron fuel price data in the literature, import costs are calculated using a bottom-up methodology. We include the investment and operational costs of hydrogen-based iron oxide reduction plants, energy input costs (hydrogen and electricity), and shipping costs for both the outbound transport of reduced iron powder and the return transport of iron oxides. Assuming an interest rate of 5%—as a normative approach throughout the model—and a technical lifetime of 40 years for the reduction plant,[42] a capital recovery factor of 0.06 a^{-1} is derived. With an annual utilization of 8,000 full-load hours,[42] the capital and operational costs per MWh of iron fuel produced are calculated. Hydrogen and electricity demand of the reduction plant is multiplied with the corresponding energy costs: for hydrogen, the assumed costs follow the price trajectory for Algerian/Moroccan hydrogen supply to Europe (Table 4), used here as a proxy for hydrogen prices in the unspecified exporting country. For electricity, which represents only a minor share of total supply costs, a flat rate of €70/MWh is assumed. Finally, combined shipping costs for an exemplary 15,000 km outward and return journey are assumed at €7.2/MWh_{Fe}, based on estimates from Schuler et al.[34] An exemplary calculation of iron fuel supply costs in the year 2030 is provided in Equation 1.

$$\frac{898\,\frac{€}{kW_{Fe}} * 0.06\,a^{-1} + 26.9\,\frac{€}{kW_{Fe} * a}}{8,000\,\frac{h}{a}} + 1.61\,\frac{MWh_{H2}}{MWh_{Fe}} * 78.8\,\frac{€}{MWh_{H2}} + 0.06\,\frac{MWh_{H2}}{MWh_{Fe}} * 70\,\frac{€}{MWh_{el}} + 7.2\,\frac{€}{MWh_{Fe}} = 148\,\frac{€}{MWh_{Fe}}. \quad \text{(Equation 1)}$$

The domestic production of hydrogen and iron fuel via electrolysis and iron oxide reduction, respectively, is an endogenous decision variable without capacity limitations. Electricity exchange is permitted between model regions, while cross-border electricity trade with non-European neighboring countries is not considered.

Intra-European energy transport

Since each model region can directly import hard coal, lignite, oil, uranium, and biomass without capacity constraints, inter-region transport is modeled only for natural gas, hydrogen, iron fuel, and electricity. Aggregated cross-border interconnector capacities are exogenously defined model inputs and are detailed in Tables S7–S9. Consequently, energy transport infrastructure, including expansions of electric interconnectors[65] and hydrogen transmission capacity based on currently announced projects,[41] is assumed to be available to the model without the consideration of associated costs.

For electricity, the initial 2025 grid as well as the expansion of interconnector capacities through 2050 are based on data from the TYNDP 2024.[65] A transport efficiency of 99% is assumed for electricity flows between model regions. Intra-regional electricity transmission and distribution losses are included in the demands stated in Table S5.

Natural gas transport capacities between model regions are based on data from ENTSO-G[79] and remain constant across all model years. Inter-region transport efficiency is uniformly set at 99.6% for all countries, reflecting gas consumption by compressor stations in the magnitude of around 0.4% of the transported energy.[82] Intra-region transport and distribution are assumed to operate at 100% efficiency, given that gas consumption by preheaters—used when gas is expanded to lower pressure levels in regulating stations—accounts for only around 0.1% of the transported volume.[82]

The same efficiency assumptions are applied to hydrogen transport. The hydrogen backbone enabling inter-region hydrogen transport and imports to Europe via ports and pipelines becomes available in the model from the year 2030. Initial capacities and subsequent expansions are primarily based on announced infrastructure projects[41] and, where capacity data are not explicitly available, complemented with capacities from TYNDP's hydrogen reference grid.[65]

Iron fuel transport is introduced in the model from 2030 onward when the iron fuel option becomes available in the model. Transport is permitted between countries connected via freight rail or waterways, as identified by TENtec.[83] Unlike natural gas, hydrogen, and electricity, no capacity constraints are imposed on iron fuel transport. Transport costs are assumed to be uniform across all country pairs and estimated using average German rail freight rates of €11 per ton in 2006, as reported by Kille and Schmidt.[84] Adjusting for inflation using the German producer price index for rail freight transport (2006: 76.6 and 2025: 133.6, with 2021 as the reference year[85]), the resulting iron fuel transport cost applied in the model is €9.4/MWh_{Fe}:

$$\frac{11\,\frac{€}{t} * \frac{133.6}{76.6}}{2.05\,\frac{MWh_{Fe}}{t}} = 9.4\,\frac{€}{MWh_{Fe}}. \quad \text{(Equation 2)}$$

Initial power plant and storage capacities

Initial 2025 capacities are defined for renewables, conventional power plants, and natural gas underground storage. With the exception of hydropower plants and underground natural gas storage, the availability of these existing assets declines over the modeling horizon due to decommissioning, which is determined based on technology-specific age structures, and can be replaced by endogenous new builds. The exogenous capacity inputs used for the base year and subsequent model years are detailed in Tables S10–S13.

For PV, onshore and offshore wind, and biomass, country-specific installed capacities in the initial year 2025 and their availability in subsequent model years are based on annual IRENA publications[1]: a phase-out is assumed based on lifetimes for those existing plants of 20 years for PV, 25 years for onshore wind, 30 years for offshore wind, and 25 years for biomass. Solid biofuels, biogas, and liquid biofuels are aggregated under the general category of "biomass."

For battery storage, current installed capacity is based on the combined total of residential and utility-scale installations, building on data from EASE.[86] It is assumed that charging and discharging rates are equal, and the total energy storage capacity is set at four times the charging power[65] (Table S18). The full installed capacity in 2025 is assumed to remain available up to and including the year 2040.

For thermal units, installed capacities in 2025 are sourced from the European Resource Adequacy Assessment (ERAA) 2024[66] and ENTSO-E's Transparency Platform.[73] To account for country-specific, age-dependent characteristics of the power plant fleet, multiple technology categories are defined. For hard coal, lignite, and oil-fired plants, three age-based categories are distinguished: units commissioned before 1990, between 1990 and 2008, and after 2008. Corresponding operation costs and plant efficiencies are provided in Table S4. The national allocation to these categories is derived using the JRC Open Power Plants Database,[87] a database that provides commissioning years of thermal power plants, which are used to allocate installed capacity to the defined age categories. However, as the database reflects the status as of 2019, discrepancies exist when compared to currently installed capacity from ENTSO-E.[66,73] To reconcile these differences, it is assumed that the oldest units have been decommissioned. Units without a commissioning date stated Hidalgo Gonzalez et al.[87] are put in category 1.

Future availability of oil-fired plants, as well as coal and lignite capacities in the nine countries that have not yet phased out coal or announced a phase-out before 2030, is scheduled according to these age categories: assuming an average technical lifetime of 45 years,[88] category 1 units are decommissioned by 2035, whereas categories 2 and 3 remain available until the respective national coal phase-out year for coal and lignite and until 2045 for oil-fired plants.

For nuclear power, only a single technology category is represented, due to the lack of age-specific operational parameter data. Installed capacities in 2025 are based on ERAA 2024,[66] while future phase-out trajectories follow the national age structures of existing reactors,[87] assuming a technical lifetime of 55 years in line with the Global Ambition scenario of the TYNDP 2024.[65] Capacity expansion beyond 2025 is included for reactors currently under construction, namely Hinkley Point C and Sizewell C in the United Kingdom and Paks II in Hungary.

For natural gas-fired power plants, categorization should reflect not only the age of the fleet but also their technical configuration, specifically distinguishing between open-cycle (OCGT) and combined-cycle (CCGT) plants. Due to the absence of a comprehensive dataset that includes both commissioning years and OCGT/CCGT differentiation across the European gas fleet—despite efforts in, e.g., Open Power System Data[89] and PyPSA/powerplantmatching,[90] though with significant data gaps—the following methodology is applied: total installed gas power plant capacities in 2025 from ENTSO-E[73] are allocated to four categories (CCGT and OCGT older and younger than 2010; for operational parameters, see Table S4) based on commissioning year information from Hidalgo Gonzalez et al.[87] and country-specific CCGT/OCGT ratio derived from the Pan-European Market Modeling Database (PEMMDB) version 2.5 for the year 2030, used because of the unavailability of equivalent data for 2025. The PEMMDB is referenced in and available through the download section of the TYNDP 2024.[65] CCGT and OCGT capacities commissioned before 2010 are decommissioned en bloc by 2035 after at least 25 years' lifetime,[65] while those commissioned after 2010 stay available throughout 2045.

In contrast, capacities for hydropower plants (pumped storage, RoR, and reservoirs) as well as underground natural gas storage are treated as exogenous inputs for all model years, including their expansion. This approach mirrors the treatment of energy transport infrastructure, which is also exogenously defined throughout the modeling horizon. Capacity developments in these technologies are not modeled as decision variables, due to the limited expansion potential in European countries and the long lead times associated with new infrastructure. Projects expected to become operational within the modeled timeframe up to 2050 are commonly already in planning or under development today and are therefore reflected as input data.

For hydro, installed generation capacities (Table S12) and reservoir volumes (Table S15) are taken from Quaranta et al.[91,92] and De Felice et al.,[91,92] and expansion projects until 2035 from ENTSO-E.[66] Open-loop and closed-loop pumped storage are aggregated into a single category, as are RoR and pondage power plants. Reservoir sizes for the hydro reservoir category are not explicitly modeled, as the adopted methodology treats these units not as storage systems but as electricity generation processes constrained by an annual upper limit. This limit corresponds to the annual reservoir inflow, as shown in Table S16, which is derived from Copernicus data for the modeled weather year 2016[75] and, where applicable, adjusted proportionally to reflect reservoir capacity expansions. Neglecting reservoir size induces greater operational flexibility in the model compared to real-world conditions; however, this simplification is considered acceptable given the significant reduction in computational effort it enables.

Underground natural gas storage capacities (Table S14) include existing facilities, those under construction (assumed to be operational by 2030), and currently planned projects (assumed operational by 2035).[93] In the absence of site-specific data, injection and withdrawal rates are assumed to be equal and are derived from storage capacities using a proxy coefficient of 0.0005 MW per MWh[50] (Table S18). This assumption is oriented toward the characteristics of porous media storage, which accounts for over 80% of Europe's total underground gas storage capacity.[93]

Infrastructure expansion and retrofit potentials

While the expansion of batteries, natural gas and hydrogen turbines and combined-cycles units, electrolyzers, hydrogen tank storage, nuclear power plants, newly built iron power plants, reduction facilities, and iron silo storages is unrestricted, the development of other infrastructure components is subject to country-specific limitations. Maximum installed capacities per country are provided in Table S17. For biomass, capacity expansion is restricted to at most replacing decommissioned units, such that total national capacities do not exceed 2025 levels, reflecting limited land availability and broader concerns related to the food-versus-fuel conflict. National capacity potentials for PV, onshore wind, and offshore wind are based on the maximum 2050 expansion caps reported in the TYNDP 2024.[65] As these caps include socio-economic considerations, they often fall substantially below the technical potential, particularly for PV and onshore wind. To reflect these surplus potentials, the caps are increased by 25% in all countries where the geospatially derived technical potential reported by Ruiz et al.[94] exceeds the TYNDP caps by more than 50%. The power plant capacity available for iron combustion retrofit is defined as the total hard coal and lignite capacity installed in each country in 2025. Gas turbine retrofits to hydrogen are permitted only in the final 2050 period, with the retrofit potential constrained by the endogenously expanded open and combined cycle gas turbine capacity up to and including 2040.

The model provides three options for hydrogen storage development: retrofitting former natural gas caverns, constructing new caverns, and building steel tanks. Retrofitting is possible in Germany, Denmark, France, the Netherlands, Poland, Portugal, and the United Kingdom, with capacity potentials based on Talukdar et al.[48] New cavern construction is permitted in Germany, Denmark, Spain, Greece, the Netherlands, Norway, Poland, Portugal, and the United Kingdom, using potentials from Caglayan et al.[95] Steel tank storage is feasible in all model regions, without capacity restriction. All three storage options are available from 2030 onward, with techno-economic characteristics specified in Table S4. For both retrofitted and newly built caverns, injection and withdrawal rates are assumed to be equal and are modeled using a proxy coefficient of 0.001 MW per MWh of storage capacity, based on data from a representative hydrogen cavern storage facility[50] (see Table S18). For new caverns, only offshore and nearshore potentials within 50 km of the coast are considered, due to constraints related to brine disposal.[95] To reduce computational burden, hydrogen cavern storage potentials exceeding 500 TWh, equivalent 0.5 TW injection capacity, are assumed unlimited (denoted as "INF" in Table S17). This simplification is uncritical, as model results show that hydrogen cavern capacity expansion remains well below this threshold. Hydrogen storage in porous media is not included in the model, due to the current lack of generalizable evidence supporting its technical and economic feasibility,[48,50,51] in line with other recent energy system studies.[45,46,96]

Greenhouse gas restriction

The model imposes an aggregated emissions cap across all modeled countries, effectively representing a simplified emission trading scheme. The cap is based on 1990 greenhouse gas emissions from public electricity and heat production in the EU-27, reported at 1.232 Mt_{CO2}.[97] To account for the inclusion of non-EU countries—primarily the United Kingdom—this baseline is increased by 5%. The model enforces a 55% reduction from this adjusted 1990 level by 2030, followed by a linear decline to zero emissions by 2050, in accordance with the EU's climate targets. Direct emission factors of 0.34 t_{CO2}/MWh_{th} for hard coal, 0.40 for lignite, 0.27 for oil, and 0.20 for natural gas are utilized.[66]

RESOURCE AVAILABILITY

Lead contact

Requests for further information, resources, and materials should be directed to the lead contact, Julia Schuler (julia.schuler@kit.edu).

Materials availability

No physical materials were used or generated in this study.

Data and code availability

- All model data have been deposited at Zenodo and are publicly available as of the date of publication at https://zenodo.org/records/19480835 and https://doi.org/10.5281/zenodo.19480835.
- All original code (the energy system model PERSEUS-PtX) has been deposited and is publicly available at the same repository as of the date of publication.
- Any additional information required to reanalyze the data reported in this paper is available from the lead contact upon request.

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AUTHOR CONTRIBUTIONS

Conceptualization, J.S., A.A., V.S., and W.F.; data curation, J.S., A.A., and V.S.; methodology, J.S., A.A., and V.S.; investigation, J.S.; writing – original draft, J.S.; writing – review & editing, J.S.; software, J.S.; formal analysis, J.S.; visualization, J.S.; validation, J.S. and A.A.; resources, A.A. and W.F.; funding acquisition, J.S., A.A., and W.F.; supervision, A.A. and W.F.

DECLARATION OF INTERESTS

The authors declare no competing interests.

SUPPLEMENTAL INFORMATION

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