CESI Studies

Italian Hydrogen Strategy: What Impact on the Power System?

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CESI Studies
Italian hydrogen Strategy
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from renewable sources.

Mario Draghi

”

Introduction

"It is clear that the transition must be aimed at the use of green hydrogen, which will require unprecedented effectiveness in reaching the targets of electricity generation from renewable sources." These are the words, spoken in front of the Italian Chamber of Deputies last April, with which Prime Minister Mario Draghi commented on the key role of hydrogen in the Italian ecological transition. Indeed, in recent months, the underlying advantage of an increase in the penetration of green hydrogen into the energy mix has been the subject of various analyses.

In this respect, the objective of the CESI study is to investigate the impact of the Italian Hydrogen Strategy, developed by the Italian Ministry of the Economic Development (MiSE) on the power system by 2030, comparing different scenarios in the installation of electrolyzers and location of additional renewable energy sources (RES) power plants. In fact, hydrogen could hold a unique position in the contribution to reach the national environmental objectives.

According to the European Commission communication "*A hydrogen strategy for a climate-neutral Europe*," issued in July 2020, hydrogen currently represents a modest fraction of the global and EU energy mix, and is still largely produced from fossil fuels, notably from natural gas or from coal, resulting in the release of 70 to 100 million tons CO_2 annually in EU countries. For hydrogen to contribute to climate neutrality, it needs to achieve a far larger scale and its production must become fully decarbonized. Electricity generated from renewable sources is expected to decarbonize a large share of the EU energy consumption by 2050, but not all of it. Hydrogen has a strong potential to bridge this gap, especially by addressing the so-called "hard-to-abate sectors," such as chemical, heavy industry, and heavy-duty transport, which can hardly be decarbonized through direct electrification. Large-scale deployment of green hydrogen at a fast pace is key for the EU to achieve its goals in the fight against climate change, on the path of reducing greenhouse gas emissions by at least 55%[1] by 2030 in a cost-effective way.
Within this scenario, the preliminary *National Hydrogen Strategy* envisions that, through a series of initiatives, Italy could produce enough green hydrogen to cover 2% of the energy demand forecast by 2030 in the country, which would require about 5 GW of electrolyzers by 2030, for an investment of around € 10 billion. As a result, Italy should benefit from a CO_2 reduction of 8 Mton by 2030, as well as the creation of 200,000 temporary jobs and 10,000 permanent jobs.

1. Compared to the GHG emissions in 1990.

In this respect, our study "**Italian Hydrogen Strategy: What Impact on the Power System?**" aims to explain how **2% of the energy demand forecast by 2030 in Italy**, equivalent to 0.7 Mton/yr., could be met by green hydrogen within the end of this decade.

Moreover, in order to attain this objective, the present study assesses how **5 GW of electrolyzers by 2030** should be geographically placed across the Italian territory to produce green hydrogen in order to reach the 2% energy demand goal.

About **5GW** of electorlyzers by 2030

2% energy demand: **0.7 Mton/yr** by 2030

The study "*Italian Hydrogen Strategy: What Impact on the Power System?*" examines **four possible implementation scenarios for H_2 production, transport, and consumption,** which will be presented more in-depth in the next chapters:

1. **The decentralized off-grid scenario**
2. **The decentralized grid-connected scenario**
3. **The grid-connected transport of electricity scenario**
4. **The grid-connected transport of hydrogen scenario**

Assumptions

To evaluate what happens in the four scenarios, it is necessary to share the assumptions from which we started. As briefly mentioned in the introduction, this study regards **2030 as the target year**, while **economic assumptions on costs towards 2030 are based on sources from relevant institutions such as IEA**, IRENA, and NREL. The analysis assumes the demand of hydrogen according to the indications provided in the *National Hydrogen Strategy*, therefore considering the use of hydrogen in **chemicals & refining, trucks, trains, blending** in gas pipelines **and others (hydrogen valleys – projects to create hydrogen supply chains that combine production, infrastructure and use in a single region – local public transport, biologic methanation, secondary metallurgy)**, and locating the demand according to current use and future needs.

H_2 Demand location

In terms of renewable energy sources, the additional RES power plants necessary to cover electrolyzer consumptions in the various scenarios are firstly dimensioned in terms of energy. Assuming an efficiency of the electrolyzers of 50 kWh/kgH_2, for an annual production of 700 kton of hydrogen, an energy consumption of 35 TWh is estimated, which shall be produced by additional RES plants. In fact, in every scenario presented in the study, it is necessary to increase renewable energy in order to feed 5 GW of electrolyzers.

Moreover, scenarios 3) and 4) consider the sites with the best capacity factors/lower Levelized Cost Of Energy (LCOE) for the location of the additional RES power plants.

RES

Electrolyzer

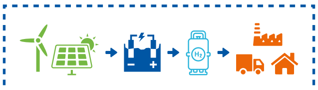
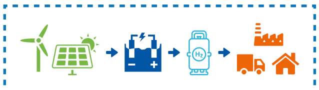
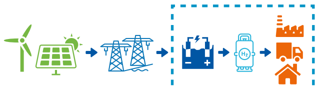
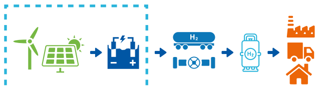
Concerning the electrolyzers, considering their target size (5GW) and hydrogen production (700 kton/year), it turns out that they will be working on average as a base load with 7,000 equivalent hours per year.

Their operation mode is modelled considering **two levels of flexibility**. In the **low flexibility level**, there is a low real-time coordination between RES generation and electrolyzers; hence, we assumed that the system must compensate RES variability necessary to produce green hydrogen with additional system reserves. In the **high flexibility level**, there is a high real-time coordination between RES and electrolyzers, therefore there is no need to rely on additional reserves to cope with the RES intermittence. In this context, the flexibility concept refers to the way the electrolyzer reacts to market signals, while fulfilling the constraint of hydrogen production in a pre-defined time window, eventually envisaging an adequate local storage of the produced hydrogen. The analyses refer to alkaline electrolyzers, which present the most binding operation constraints; however, the results are applicable also to electrolyzers characterized by different technologies (e.g., PEM electrolyzers).


Hydrogen H_2

Scenarios and solutions

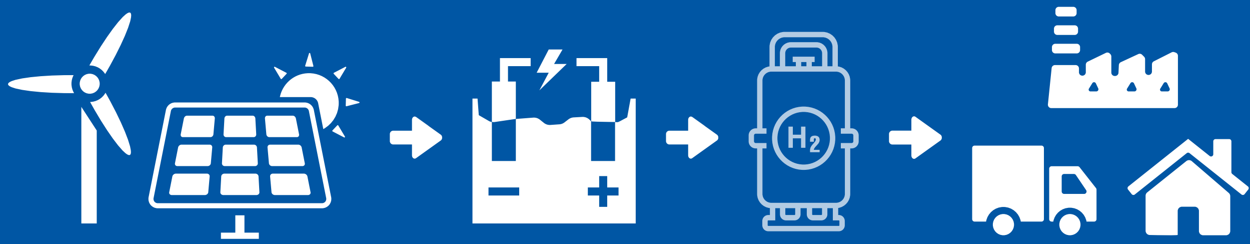
In this section, starting from their description, we deepen the analysis of the **four possible implementation scenarios** already mentioned in chapter 1, evaluating their pros and cons. Such scenarios have been divided in **two macro-areas, off-grid**, and **grid connected**, depending on the presence of network connection.

	Off-grid	Connection with power grid		
	1. Decentralized	2. Decentralized	3. Transport of Electricity	4. Transport of H_2
				
DESCRIPTION	RES and electrolyzers are installed close to hydrogen demand sites. RES *capacity factor* depends on location of demand sites and surplus of generation or insufficient hydrogen production cannot be managed through the power grid.	RES and electrolyzers are installed close to hydrogen demand sites. RES *capacity factor* depends on location of demand sites.	RES are built in market zones with a high *capacity factor*. Electrolyzers are installed close to hydrogen demand sites.	RES and electrolyzer are built in the same market zone (with a high *capacity factor*). Hydrogen demand sites are potentially located in different zones.
PROS	No transmission network costs.	Lower cost for additional investments in power transmission. No need of hydrogen transmission cost.	RES can be installed in the most convenient sites enabling higher *capacity factors*. No need of hydrogen transmission cost	RES can be installed in the most convenient sites enabling higher *capacity factors*. Electrolyzers can better exploit zonal energy surplus avoiding RES curtailment and providing flexibility services
CONS	RES *capacity factors* could be lower in hydrogen demand locations Higher need for storage for the simultaneity constraint Oversizing of V-RES capacity to reach the target utilization factor of electrolyzers.	RES *capacity factors* could be lower in hydrogen demand locations. Potential additional cost to export exceeding power from RES (installed RES > electrolyzer capacity).	Potential additional cost to avoid power congestions between RES generation and electrolyzers consumption.	Additional cost for hydrogen transmission from electrolyzers to demand sites.

Assets placed on the same site

1 Decentralized off-grid scenario

Decentralized off-grid scenario assumes that electrolyzers and RES power plants are both installed at consumption centers (i.e., factory, town, etc.) in the same location. In this off-grid scenario, RES power plants are not connected to the grid. Therefore, the RES capacity factor depends on the location of consumption centers, and the absence of network connection implies that the surplus of generation or the insufficient hydrogen production cannot be managed through the power grid. In terms of costs and feasibility, the decentralized off-grid scenario should be considered viable only in particular contexts (e.g., remote areas in extra-EU countries). In fact, it has the highest cost if compared with the cases that consider electrolyzers and the related renewable source plants connected to the grid. In this scenario, a substantial increase in renewable installed capacity is required, much higher than the size of the electrolyzer, in order to allow a stable production of hydrogen generation. Moreover, additional batteries are required to reach the electrolyzer target, (equivalent to 7,000 hours per year). Finally, the absence of connection to the grid causes a curtailment of renewable production when it exceeds the consumption of electrolyzer and batteries. This scenario was included in the analysis to offer a comparison with the other grid-connected solutions, although this is an option that can be implemented in specific regulatory situations, or in very particular locations (e.g.: remote areas not connected to the network).



PROS

As the connection to the grid is not provided, there are no extra costs related to transmission networks, unlike the other scenarios.

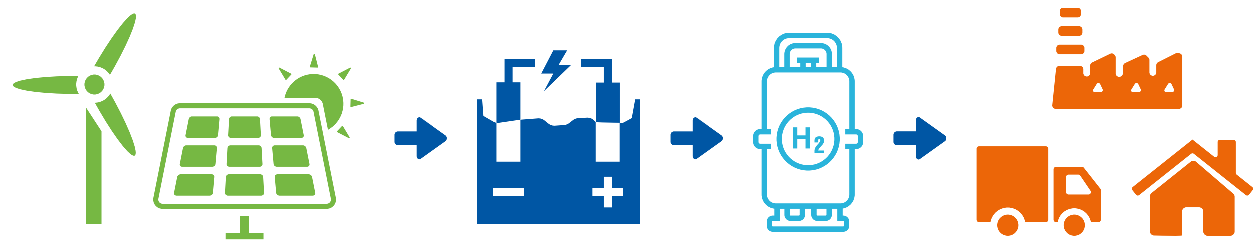
CONS

The capacity factor, in other words the energy producibility of RES, may not be satisfactory. In this scenario, the RES plants are located exclusively in correspondence with the demand for hydrogen and not in areas where renewable energy producibility is more favorable. Furthermore, storage equipment (e.g., batteries) is needed, entailing additional costs. Finally, it is necessary to increase the installed RES capacity, to obtain the necessary utilization factor for electrolyzers.

The substantial increase in renewable installed capacity implies higher costs compared to the other scenarios

2 Decentralized grid-connected scenario

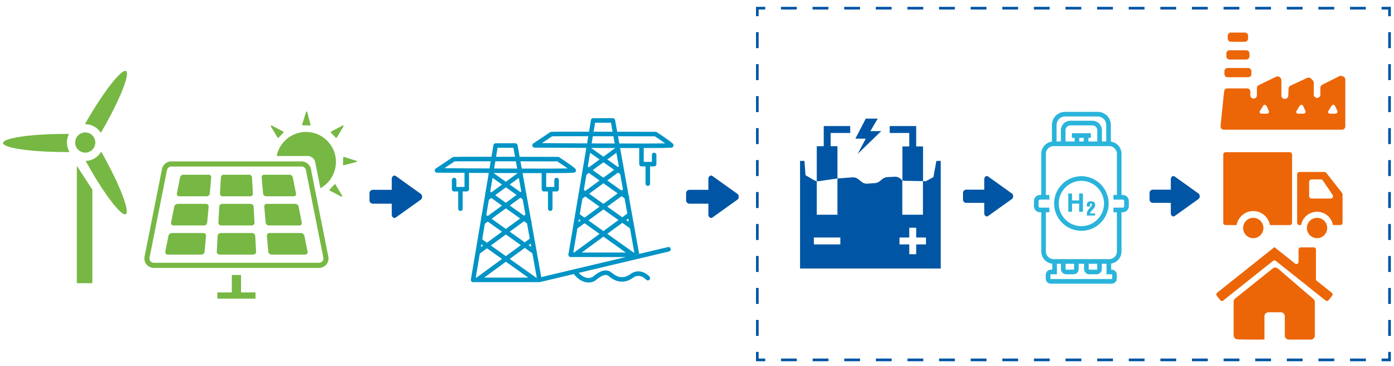
The **decentralized grid-connected scenario** assumes also in this case that electrolyzers and RES are both at consumption centers, in the same location, but in this configuration the renewable power plants are connected to the grid. Also in this scenario, the RES capacity factor depends on location of demand sites, with the consequent risk of being forced to increase the installed RES capacity.



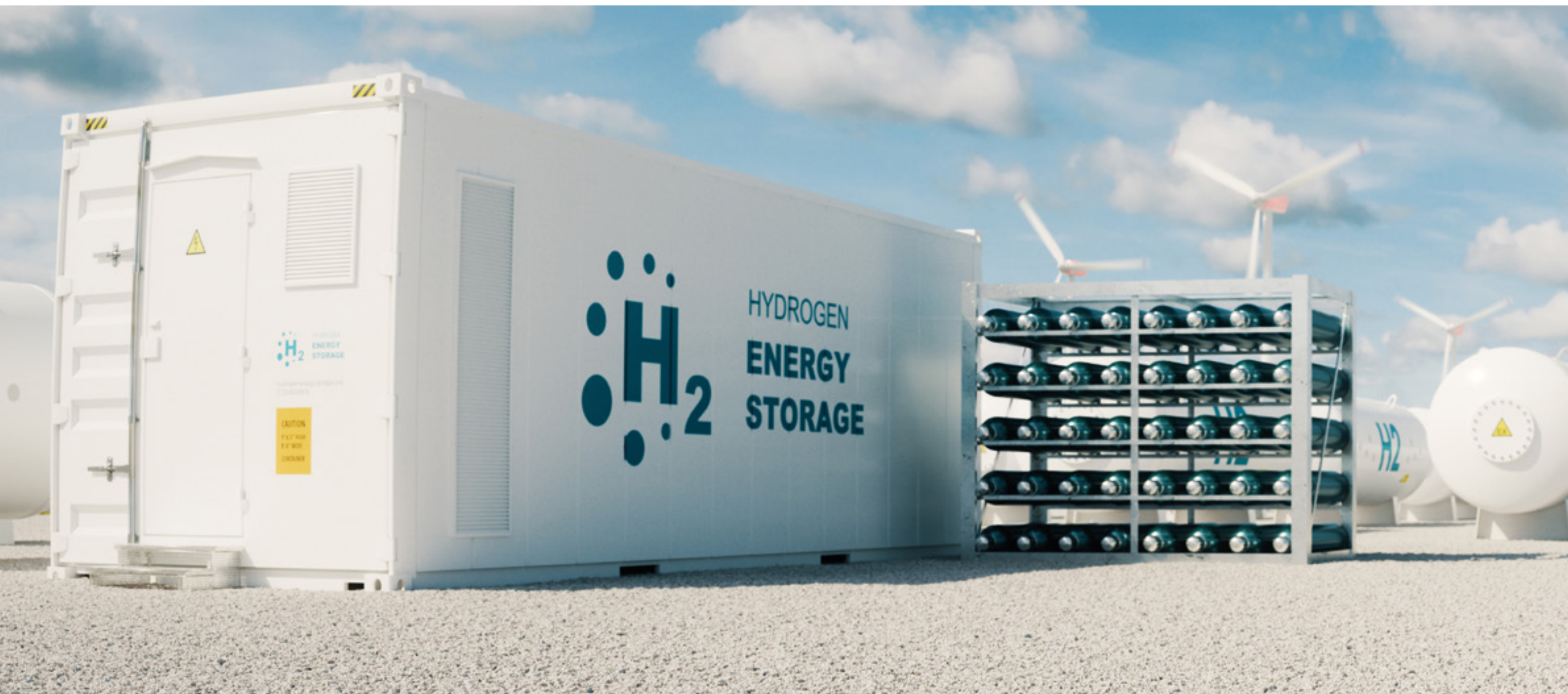
PROS	CONS
Due to the presence, in the same location, of RES and electrolyzers, this scenario entails lower costs for investments in power transmission and there is no need of hydrogen transmission cost since the electrolyzers are located close to hydrogen demand sites.	RES capacity factors could be lower in hydrogen demand locations, just as reminded in the previous scenario (1). Furthermore, there is a potential additional cost related to exporting the exceeding power from RES, in all occurrences where renewable energy generation is higher than the local electrolyzer demand.

3 Grid-connected transport of electricity scenario

The **grid-connected transport of electricity scenario** assumes that the RES power plants are in the most favorable areas in terms of producibility; the electricity is then transmitted through the network infrastructure to the electrolyzers, which are installed close to hydrogen demand sites. In this respect, the benefits deriving from the freedom to build RES in convenient areas is counterbalanced by potential additional costs to transport the electricity.

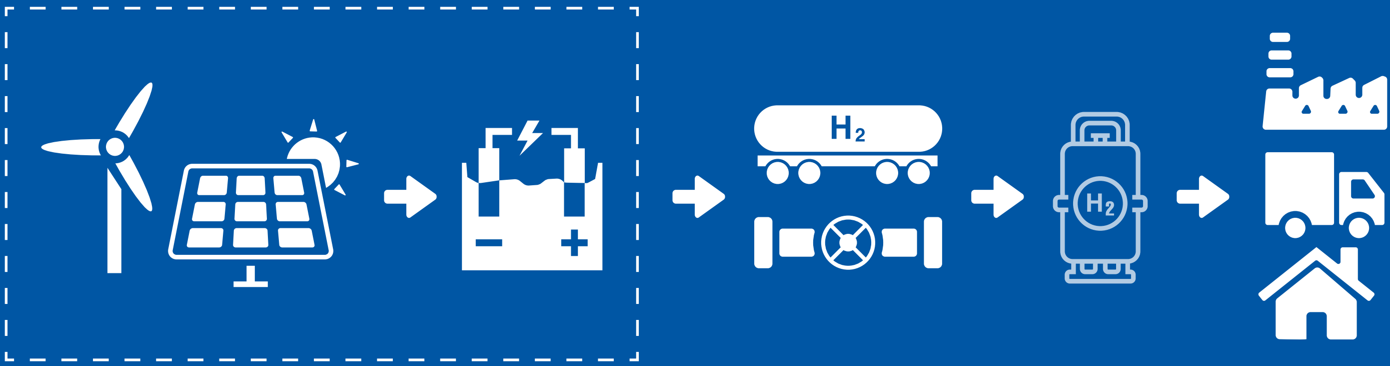


PROS	CONS
Due to the flexibility in locating them, RES can be installed in the most convenient sites enabling higher capacity factors; moreover, in this case there is no need of hydrogen transport, avoiding consequently the related transport costs.	Considering the necessity to transport renewable electricity from the power plants to the hydrogen consumption centers, there could be a potential additional cost for transmission system reinforcements to relieve grid congestions between RES power plants and electrolyzers.



4 Grid-connected transport of hydrogen scenario

The **grid-connected transport of hydrogen scenario** assumes that electrolyzers and RES power plants are installed in the same location and the hydrogen is supplied through new hydrogen pipelines or repurposed gas pipelines to the demand sites, potentially located in different areas. In this scenario, the additional cost for hydrogen transmission from electrolyzers to demand sites is compensated by the possibility to exploit the most favorable RES sites.



PROS	CONS
RES can be installed in the most convenient sites enabling higher capacity factors and electrolyzers can better exploit zonal energy surplus avoiding RES curtailment and providing flexibility services.	There could be additional costs related to hydrogen transport from electrolyzers to demand sites.

Land use

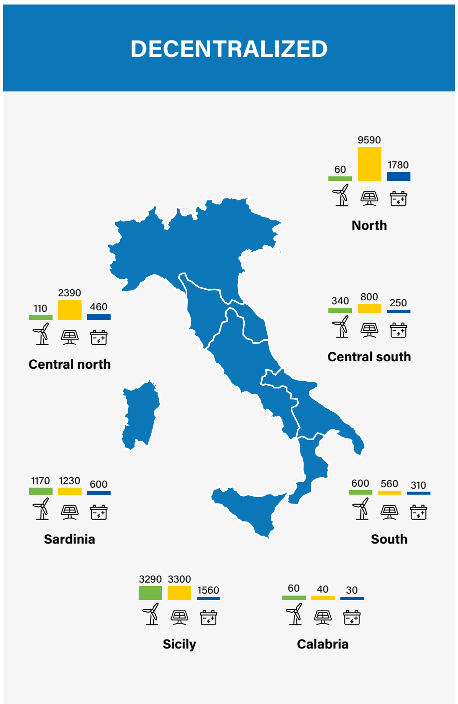
In consideration of the different scenarios presented in the previous chapter, and due to the need of **additional RES installations** to achieve the goals explained above, it is important to understand how the Italian territory could be impacted by the new power plants.

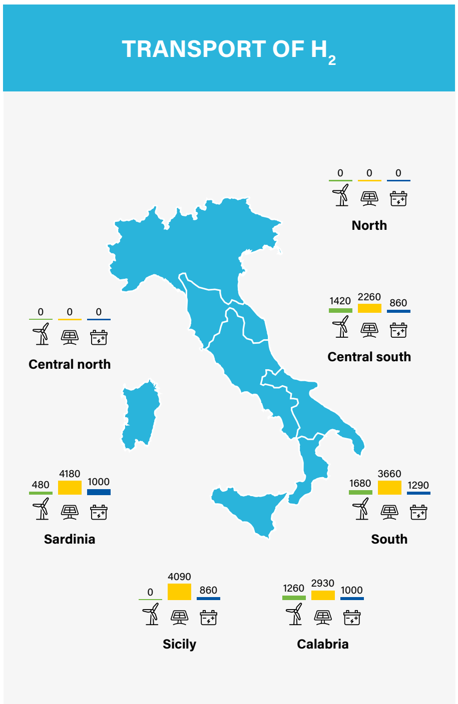
As shown in the table below, the additional installed RES capacity needed by 2030 to feed electrolyzers to generate fully green hydrogen depends on each scenario.
In terms of renewable sources, this study has considered **solar photovoltaic (PV) and wind energy**. The **National Trend** is used as the baseline scenario taken as a starting point for the analyses, as it has been adopted also by **Terna** for its **National Development Plan**.

	PV installed (MW)	Wind installed (MW)
2030 NT (National Trend)	51140	18410
Scenario 1 Off-grid (additional RES)	23500	4850
Scenario 2 Decentralized (additional RES)	17900	5650
Scenario 3 Tr. Electricity (additional RES)	17100	4850
Scenario 4 Tr. H_2 (additional RES)	17100	4850

In our scenarios, solar photovoltaic will take the majority of new installations, as also expected in the baseline National Trend scenario.

The maps below present the split of RES installation and electrolyzers in the different areas according to the examined scenarios.





Land use for PV installations

The use of land for the installation of wind farms depends on the specific morphology and wind regime of the selected sites. As such, an estimation of land use cannot be easily provided at large scale.

On the contrary, an estimation of land use for the installation of PV can be provided based on some key assumptions on the technology adopted to build the PV panels. In this respect, there are mainly two types of technologies: **monocrystalline or polycrystalline silicon solar cells** and thin-film solar cells. The expected extension for such technologies is about **1.5/2.0 hectares for each MW of power** adopting monocrystalline or polycrystalline solar cells and about **3.0 hectares for each MW of power** adopting thin-film solar cells. These footprints include the land occupied by PV panels, the space between the arrays and the space required for connections and the internal substation towards the external grid. The larger extension required by thin-film is due to the lower efficiency of these solar cells compared to the 'classic' silicon solar cells. Nevertheless, **thin-film solar panels are cheaper than crystalline-based solar cells** and their application may be preferable in situations of big power plants where space is not an issue, thanks to the reduced investment costs.

Land use for PV installations scenarios for the production of green hydrogen

Based on the above considerations, assuming an average land use of 2 hectares per PV MW, the total land necessary to install the required PV power plants can be seen in the following table (assuming 100% of PV capacity installed through utility-scale plants/solar farms).

	PV Installed (MW)	Land use (km2)
Scenario 1 Off-grid (additional PV)	23500	470
Scenario 2 Decentralized (additional PV)	17900	358
Scenario 3 Tr. Electricity (additional PV)	17100	342
Scenario 4 Tr. H_2 (additional PV)	17100	342

Disregarding the off-grid scenario, the study estimates that, on average, **350 km²** are needed for the PV installation dedicated to the production of green hydrogen in addition to what is foreseen already in the National Trend scenario. In order to better understand the size of the area needed for the deployment of solar PV, it could be useful to make a comparison: 350 km2 is equal to nearly double the surface area of the city of Milan, Italy.

Results

As anticipated in the assumptions section, the four different scenarios have been assessed in two configurations for electrolyzers:

A. LOW FLEXIBILITY

Electrolyzers are operated in a passive mode with their power absorption mainly driven by the hydrogen production needs, with a low coordination between the RES output and the electrolyzers. The electric system shall therefore compensate RES variability needed for green hydrogen production by procuring additional reserves.

B. HIGH FLEXIBILITY

Higher coordination between RES production and electrolyzers, which can be modulated according to the ancillary services market (ASM) signals. In such a context, electrolyzers can be seen as potential market players in the ASM helping to mitigate the related costs.

The results of the four scenarios for each of the two flexibility configurations are presented below.

A Low flexibility

LOW FLEXIBILITY	Off-grid	Connection with power grid		
	1. Decentralized	2. Decentralized	3. Transport of Electricity	4. Transport of H_2
Total System Cost	3277	2660	2639	2847 - 3080
Investment cost on H_2 transmission grid				234 - 467
Variation of costs in power markets (energy and ancillary)		352	382	396
Investment cost on power transmission grid and batteries	913	202	303	262
New RES cost for hydrogen production	2130	1873	1721	1721
Electrolyzer cost	234	234	234	234
System LCOH	4.7 €/kg_{H2}	3.8 €/kg_{H2}	3.8 €/kg_{H2}	4.1 - 4.4 €/kg_{H2}
Avoided V-RES curtailment (<0 means increase of curtailment)	-6300 GWh	-850 GWh	-780 GWh	-430 GWh

Figures in M€/year

Investment cost on H_2 transmission grid
Variation of costs in power markets (energy and ancillary)
Investment cost on power transmission grid and batteries
New RES cost for hydrogen production
Electrolyzer cost
Total System Cost

As expected, the **off-grid decentralized scenario** (1) **has the highest cost** in comparison to other cases. According to this scenario, an oversizing of the renewable installed capacity is required, much higher than the size of the electrolyzer, in order to allow a stable generation output. Furthermore, additional batteries are needed to reach the high capacity factor target of the electrolyzer (the equivalent of 7,000 hours per year). This scenario shows the highest **levelized cost of hydrogen (LCOH[2])** equal to 4.7 € / kg_{H2}, associated with a RES curtailment of 6,300 GWh.

Finally, the electrolyzer cost is independent from the examined scenarios; therefore, it is equal in all cases. The other three scenarios have been simulated in a grid-connected context. Therefore, in case of connection to the power grid, the impact on costs is different depending on the scenarios, and also on the operation mode of electrolyzers.

The **grid-connected decentralized scenario** (2) needs higher investments in renewables compared to the other grid-connected scenarios, due to the potential lower capacity factor in some consumption sites. Investments in transmission grid and batteries are limited due to the presence of RES power plants and electrolyzers in the same area; on the other side, the variation of costs in power markets represents the second largest expense, due to the low flexibility operation mode. This scenario estimates an overall LCOH of 3.8 €/kg_{H2} with an increase of RES curtailed of 850 GWh.

The **transport of electricity scenario** (3) requires lower investments in renewables thanks to the selection of location with higher RES producibility. Investments in transmission grid and batteries, together with the variation of costs in power markets, are significant due to the power infrastructure needed to transport electricity to the electrolyzers and the need to avoid congestions between generation and consumption. Also, in this case the overall LCOH is 3.8 €/kg_{H2}, but the increase of RES curtailment is lower with a value of 750 GWh.

Finally, the **transport of H_2 scenario** (4) presents the same value of RES cost of scenario (3), since also in this case the location of RES power plants is the same as in the previous case (areas with higher RES potential). Investment in power infrastructure is lower than in the previous case due to the presence of RES plants and electrolyzers in the same area, but are nonetheless necessary to mitigate the risk of RES curtailment during the time intervals characterized by a local surplus of non-programmable renewable generation. On the other hand, the variation of costs in energy and ancillary markets is larger due to the lower investments in transmission grids and batteries and as a result of the configuration of the scenario. This is the only scenario where the cost for **hydrogen infrastructures** is present, since it requires a dedicated grid to convey hydrogen from RES power plants to consumption centers. For hydrogen transport the assumption is based on the average investment cost given by the European Hydrogen Backbone Initiative 2021 which estimates a range between 1,000 and 2,000 k€/km, based on 69% of repurposed gas pipelines and 31% of new hydrogen pipelines. For the volumes assumed in the analysis, the cost of the new hydrogen transport infrastructure is quite substantial even considering a high share of repurposing of existing natural gas pipelines. The total cost for this scenario is between 4.1 and 4.4 €/kg_{H2}, higher than the other grid-connected cases, mainly due to the cost of hydrogen infrastructure, whereas the increase of RES curtailment is 429 GWh.

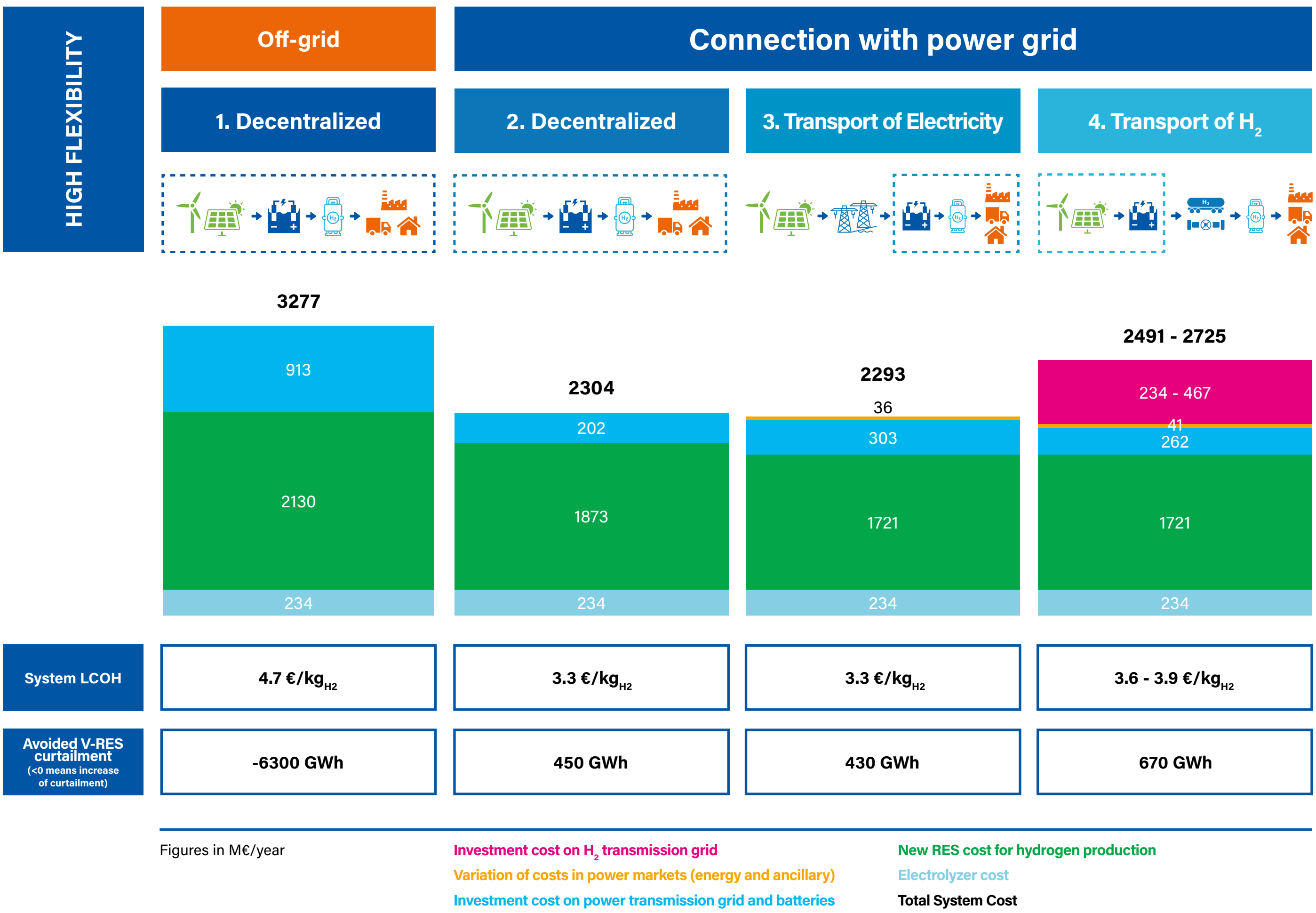
2. LCOH is the indicator considering all relevant capital costs for hydrogen production, converting the total costs of the plant into € / kg of hydrogen. This allows an effective comparison between the analyzed cases.

B High Flexibility

The only item affected by the level of flexibility of electrolyzers is related to the costs of **energy and ancillary services market**, whereas the other costs are not impacted. A **low flexibility of the electrolyzers determines a cost increase in the power markets**, because the system needs to compensate the uncertainty of variable RES by procuring additional reserves and balancing services. With a **high flexibility of the electrolyzers**, the system costs can be lower because no additional ancillary services need to be procured to cover potential imbalances given jointly by RES and electrolyzers.

In addition, a flexible electrolyzer can also provide reserve and balancing services to the power system, allowing even a **reduction of market costs**.

Finally, the flexibility of electrolyzers can also determine **a reduction of renewable curtailment** in the system compared to the reference case without the need for new assets to make the system more flexible.



The **off-grid decentralized scenario** (1) is not impacted by the level of flexibility of electrolyzers since it is not connected with the grid and therefore no power market costs are associated to this case.

In the **grid-connected decentralized scenario** (2) the high flexibility of electrolyzers entails a cost reduction for power markets, with an overall LCOH of 3.3 €/kg, avoiding the curtailment of 450 GWh of non-programmable RES.

The **transport of electricity scenario** (3) resulted in almost zeroing the power markets cost variation with a total LCOH of 3.3 €/kg_{H2}, as in the previous scenario, with 430 GWh of RES not curtailed.

Also, the **transport of H_2 scenario** (4) almost provides a null variation of power market costs with an overall LCOH of 3.6 - 3.9 €/kg_{H2} while avoiding 670 GWh of RES curtailment.

Overall, the total cost in the transport of hydrogen scenario is **up to 20% higher** than the grid-connected decentralized and transport of electricity scenarios, due to the additional investments to build a new widespread transport network for hydrogen. In the grid-connected decentralized and transport of electricity scenarios, the system can leverage on the existing and planned reinforcements in transmission network and batteries, already identified in the **National Development Plan of Terna** to attain the ambitious decarbonization targets of the power sector set by 2030. The lowest cost is provided by the case with **high flexibility electrolyzers** for **grid-connected decentralized** (2) and **transport of electricity** (3) scenarios, with an overall hydrogen cost of 3.3 €/kg_{H2}. However, the high flexibility operation mode could present additional costs for hydrogen storage, which are currently difficult to quantify since they highly depend on the type of final use and its flexibility. It is remarkable to notice that the main cost item in all the possible configurations is represented by the cost of RES power plants.


H_2

Conclusions

In conclusion, the present study highlights that the **connection with the power grid (scenarios 2-3-4) is the best solution** compared to off-grid installation (scenario 1), as the grid allows to export RES generation when their production exceeds the electrolyzer consumption. The same grid can also supply green energy to the electrolyzer when local RES generation does not reach the energy needed for hydrogen production. Overall, the cheapest solution is provided by **high flexibility electrolyzers** in **grid-connected decentralized** (2) and **transport of electricity** (3) configuration, with a total hydrogen cost of 3.3 €/kg_{H2}. In the mid-term, with the current objectives for 2030, the option of a widespread hydrogen transport (scenario 4) entails non-negligible investments in the hydrogen pipelines and additional investments in power network reinforcements to cope with periodic RES surplus generation. Conversely, when hydrogen demand will be higher in the future, and location of demand and profitable production sites will be clearer, as well as the expected technological improvement for the technical-economic performances of the electrolyzers will eventually be confirmed, the **opportunity of investments in a hydrogen transport infrastructure should be re-assessed, especially in the case that it will be possible to realize an extensive repurposing of existing gas pipelines instead of building new hydrogen stretches.**

The power transmission grid should be further developed for the integration of RES and for reaching the decarbonization target of the power sector in 2030, considering additional green hydrogen production. At the same time, a higher **real-time coordination of electrolyzers and RES** could reduce the costs on power markets.

Finally, as the costs for the new RES installed capacity are the highest component of total system hydrogen costs, a more aggressive assumption on **lower prices of solar PV and wind generation** can bring to a **System Levelized Cost Of Hydrogen (LCOH) below 3 €/kg already in 2030.**

The cheapest solution is provided by high flexibility electrolyzers in grid-connected decentralized and transport of electricity configuration, with a total hydrogen cost of 3.3 €/kg_{H2}

Market Simulation Tools

Increased activity within model development in recent years has led to several **new models and modelling capabilities**, partly motivated by the need to better represent the integration of V-RES and partly due to the importance of market scenarios required all the more by the need to map the energy sector. For a future with an increasing share of V-RES electrification of the energy system, there are some challenges, such as how to incorporate the effect of climate change and ensure reliable scenarios in modelling studies.

In this respect, **simulation tools** have been fundamental in designing the four scenarios and the results of this study. However, their importance extends to several other studies of energy systems, which are paramount in helping customers decide what the best solution in a given scenario should be, whether in terms of **energy market** or **ancillary market**. Yet, the combination of both can result in a powerful and efficient strategy to assess **market outcomes**.

Therefore, **CESI Group** has developed two different **market simulation tools** which are focused on both energy market and ancillary market.

CESI tools for power market simulations

Day-Ahead Market

Definition of withdrawals and injections schedules for the next day (24 hours).

Intraday Market

Correction of schedules by market operators considering updated forecasts, unplanned unavailability, or because of technical unfeasibility.

PROMEDGRID

PROMEDGRID

PromedGrid: it is adopted by the **Italian TSO (Terna)** for the market benefits assessment of network reinforcements, both at the Italian and European level. PromedGrid carries out an optimal coordinated hydrothermal scheduling of the modeled electric system generation set, over a period of **one year**, with **an hourly discretization**. The optimization is based on a deterministic model considering both the technical and economic characteristics of the power systems. It operates on the energy market, characterized by a system marginal price and by a congestion management based on a zonal market-splitting. PromedGrid is a powerful software for market modeling to help the **decision-making process for the grid investments planning**, as it is among the few simulation market tools able to fulfill all the requirements set by the official guideline.

MODIS

Modis: it is a simulation tool that allows the **quantitative assessment of the impact on the Ancillary Services Market (ASM)** by new transmission infrastructures, storage units or virtual units. Modis simulates a zonal market, reproducing all the balancing actions necessary to guarantee adequate secondary and tertiary reserve margins, with **hourly time discretization**. In addition, the tool is equipped with a library dedicated to modeling the electrochemical storage technology, capable of optimizing the operation of the batteries. Modis has been further updated by introducing the possibility of processing the behavior of Enabled Virtual Units (EVU). Its goal is the **minimization of the overall costs for re-dispatching** due to operational constraints.

The tools described above are able to highlight the key role of batteries and electrolyzers for the **integration of RES into the electricity grid**. These analyses are inevitably tailor-based, as it is necessary to consider the specifics of the electricity system in question. For example, in the Renewable Integration Development Project (RIDP), which involved the Republic of Ireland and Northern Ireland, it was essential to simultaneously optimize the cross-border transmission lines and batteries, in order to minimize the risk of dispersion of V-RES. In other studies, conducted in sub-Saharan countries (such as Ethiopia, Kenya and Zambia) for RES4Africa and Enel Foundation, it was important to evaluate the role of electrochemical and water storage systems for periods of extreme drought. Finally, it should be emphasized that the profitability analyzes conducted by CESI can also identify appropriate regulatory interventions to **facilitate the roadmap for future investments in the sector**.

Terna **Scheduling Ancillary Services Market**

Procurement of reserves margins and re-dispatching for network constraints which can be foreseen some hours in advance (Voltage control, lines congestion, ...).

Terna **Balancing Market**

Activation of reserves margins in order to keep real-time balance between withdrawals and injections.
Real-time re-dispatching for network constraints.

MODIS

Shaping a Better Energy Future

CESI is a world-leading technical consulting and engineering company in the field of technology and innovation for the electric power sector. In particular, through its Division KEMA Labs, CESI is the world leader for the independent Testing, Inspections and Certification activities in the electricity industry. With a legacy of more than 60 years of experience, CESI operates in 40 countries around the world and supports its global clients in meeting the energy transition challenges. CESI also provides civil and environmental engineering services.

The company's key global clients include major utilities, Transmission System Operators (TSOs), Distribution System Operators (DSOs), power generation companies (GenCos), system integrators, financial investors and global electromechanical and electronic manufacturers, as well as governments and regulatory authorities. In addition, CESI works in close cooperation with international financial institutions such as, among others, the World Bank Group, the European Bank for Reconstruction and Development, the European Investment Bank, the Inter-American Development Bank, the Asian Development Bank.

CESI is a fully independent joint-stock company headquartered in Milan and with facilities in Arnhem, Berlin, Prague, Mannheim, Dubai, Rio de Janeiro, Santiago de Chile, Knoxville (USA) and Chalfont (USA).

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