The transition to low-carbon hydrogen in France

Opportunities and challenges for the power system by 2030-2035

JANUARY 2020

MAIN RESULTS

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EXECUTIVE SUMMARY

Low-carbon hydrogen: An asset for the energy transition

The development of low-carbon hydrogen is an important part of the energy transition.

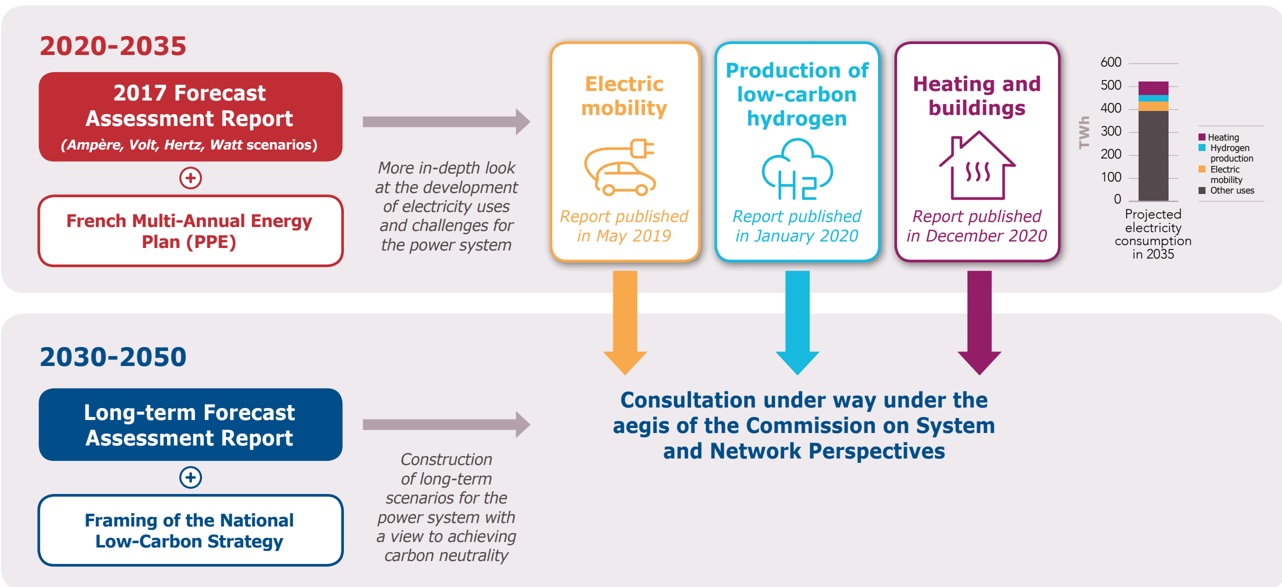
In the medium term, it offers a solution that can reduce emissions from the industrial sector by replacing the hydrogen that is currently produced using fossil fuels, as provided for by law and as set out in the French Multi-Annual Energy Plan (French National Energy and Climate Plan, NECP). It also creates opportunities to reduce emissions in the transport sector (heavy transport, as a substitute for petroleum fuels) and gas networks.

In the long term, developing the production and storage of low-carbon hydrogen can offer additional ways to make the power system more flexible, particularly interesting in the light of scenarios including a high share of renewable energies.

In all cases, the first step is to develop significant volumes of low-carbon hydrogen production in France over the next ten years. This development will be largely based on electricity, which has the advantage of already being mostly decarbonised (93%), via the electrolysis of water.

How this transition will take place needs to be specified. The large-scale development of electrolysis will be based on the growth in production of carbon-free electricity planned under the French Multi-Annual Energy Plan, and will result in additional electricity consumption. Its consequences, and the opportunities it offers, will depend on how electrolysers are operated. The technical conditions, the emission reduction performance, the cost of processing and the economic balance depend largely on this.

These are the issues to be addressed in the RTE report.



The report will examine a large number of variables to answer the questions raised by a wide variety of stakeholders during the consultation (ability to accommodate new uses of electricity, effects on emissions, economic consequences).

As such, it is part of the work programme initiated in 2018 and developed over the past two years on new uses of electricity: electric mobility (summary of the main results published in May 2019), hydrogen production by electrolysis (the subject of this document) and heating in the building sector (in collaboration with ADEME).

It also contributes to implementation of the hydrogen deployment plan published by the government in June 2018, by responding to the energy minister's request regarding the services that electrolysers can provide to the power system.

Finally, it contributes to the work and consultation under way on the construction of the next long-term scenarios for the Forecast Assessment Report to 2050, and in particular the "100% renewables" scenarios.

Two distinct reasons to develop hydrogen are often confused

In projections on the evolution of the energy mix over the long term, hydrogen is often presented both as a source of flexibility and as a factor in reducing greenhouse gas emissions.

However, the theories behind these reasons are quite distinct, and must be distinguished in the analysis:

- On the one hand, the goal is to decarbonise existing uses, for instance current industrial uses of hydrogen, but potentially also heavy transport (as a complement to fully electric solutions) or, in the medium term, to supply the existing gas network as a substitute for fossil gas (within a certain limit).
- On the other hand, hydrogen could contribute, under certain conditions, to the balance of the power system by providing a storage and discharge solution (the power-to-gas-to-power principle).

By 2030-2035, the development of low-carbon hydrogen will indeed contribute to decarbonisation, and thus support the first goal. In this timeframe, the use of hydrogen for storage is not needed to achieve a diversified electricity mix (reduction of the nuclear share to 50%) and to accommodate the volumes of renewable energy planned under the French Multi-Annual Energy Plan.

In the longer term (to 2050), however, scenarios based exclusively or to a very large extent on renewable energies will necessarily have to rely on storage. **In such cases, the power-to-gas-to-power loop, via hydrogen, is an option to consider,** despite its low energy efficiency (currently between 25% and 35% with today's technologies).

1

Decarbonising gas uses (hydrogen, methane...) or mobility

To help meet French and international decarbonisation targets

→ Opportunities in 2020-2035

2

Helping achieve a supply-demand balance on the power system by offering a storage/discharge solution

Seasonal storage via a power-to-gas-to-power loop

→ Possibly of interest as a long-term solution

In the medium term, a clear interest in decarbonising the hydrogen used in industry

At present, the hydrogen consumed in France corresponds almost exclusively to non-energy industrial uses, primarily in the oil refining and chemical sectors.

The hydrogen used for these purposes is mainly derived from processes using fossil fuels (95% from gas, oil and coal), which emit CO_2. Part of this production is "by-product" and inherent to the industrial activities concerned. Another share (about 40%) is produced by dedicated steam methane reforming plants: this share could be replaced by low-carbon hydrogen.

One of the priorities identified by the State for the development of hydrogen is to convert the conventional production of industrial hydrogen to a carbon-free production method. The law of 8 November 2019 on energy and the climate thus provides for the development of low-carbon and renewable hydrogen, with the prospect of reaching about 20 to 40% of total industrial hydrogen consumption by 2030.

Among the possible technologies for producing low-carbon hydrogen, the priority is to develop electrolysis and thus limit the use of carbon capture and storage technologies, which still present uncertainties regarding availability, reliability and acceptability.

The replacement of steam reforming by electrolysis, as provided for in the guidelines from public authorities, will lead to a reduction in emissions in France of around 6 million tonnes of CO_2 per year by 2035, i.e. slightly more than 1% of national emissions.

Ultimately, the development potential of hydrogen could go far beyond these references. For example, a number of studies identify the potential for using hydrogen for other applications, such as in the steel industry, which would open up significant development prospects.

Hydrogen as an energy vector can also be a substitute for petroleum fuels (for heavy transport) or fossil gas (via direct injection into the gas network or as a replacement for the gas used in some industrial processes). If these applications come to fruition, the potential for reducing greenhouse gas emissions will increase accordingly.

The power system planned under the French Multi-Annual Energy Plan can accommodate the development of electrolysis without any real difficulty

From a technical point of view, the integration of a large number of electrolysers into the electricity sector will first of all result in significant additional electricity consumption, in the order of 30 TWh by 2035.

Accommodating such a volume does not present any particular technical difficulty in the framework of the energy roadmap set by the public authorities.

From an energy point of view, the Multi-Annual Energy Plan puts the carbon-free electricity generation potential at approximately 615 TWh by 2035. This appears to be more than sufficient to cover the development of electrolysis envisaged by public authorities.

Indeed, even assuming a strong increase in electrolyser capacity over the next few years (making it possible to produce 630,000 tonnes of hydrogen a year, i.e. 60% of current hydrogen consumption), less than 5% of total carbon-free electricity generation capacity (nuclear and renewable) would be devoted to electrolysis by that time.

Nor would accommodating electrolysis be a source of concern from the point of view of coverage of power demand or security of supply.

This is because the power system planned under the Multi-Annual Energy Plan should have significant margins by this time with the development of renewable energies, load management and interconnections. In addition, electrolysers are flexible by nature and can be turned off during peak consumption periods.

Electrolysers should be "technically capable" of providing flexibility services to the power system, but the associated value remains of secondary importance in the medium-term hydrogen economy

The ability of electrolysers to vary their level of electricity consumption in a matter of seconds means that it is technically possible for them to provide services to the power system, for supply-demand balance and for grid operation. RTE will work to integrate this new equipment into existing mechanisms.

Except in very specific cases, the value associated with the provision of these services is nonetheless likely to be limited in relation to the costs of the electrolysers.

Indeed, the provision of services to balance supply and demand (system frequency services, fast and complementary reserves, etc.) can be remunerative, but this is a small market in which competition with other flexibility solutions is fierce (active demand management, batteries). The participation of electrolysers in these services is also associated with real constraints in terms of availability and activation that can affect the volume of hydrogen produced.

With regard to the services that can be provided to the grid, the analyses carried out as part of the network plan published in September 2019 show that the value associated with resolving congestion remains low compared with other solutions (network development, localised curtailment), including in areas of high development of renewable energies. One case of particular interest has been identified at this stage: the siting of an electrolyser on the Normandy coast to help resolve network congestion on the Normandy-Manche-Paris axis in the event of strong development of electricity production in this area (offshore wind and nuclear).

The RTE report makes it possible to test different low-carbon hydrogen production operating modes with very different technical and economic characteristics

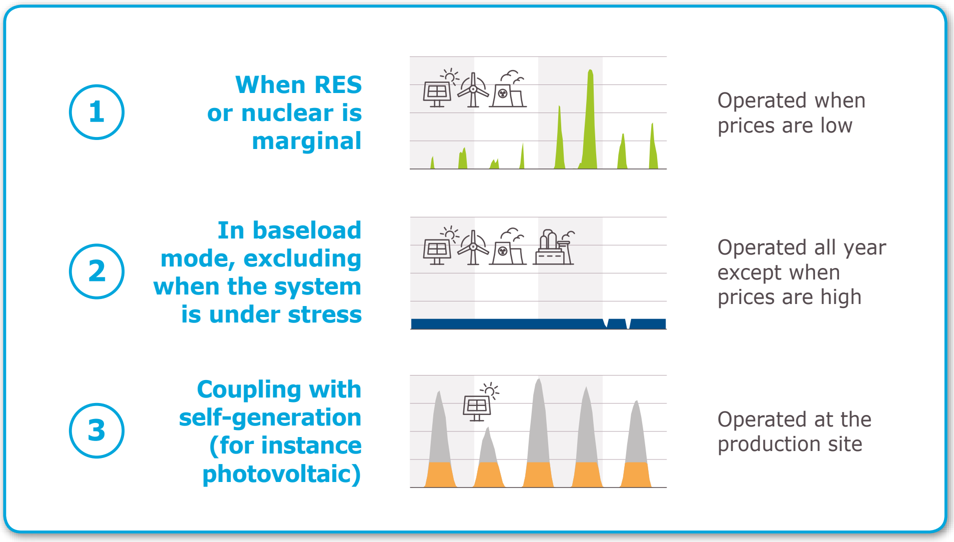
An analysis of the models currently being considered for the production of carbon-free hydrogen in France suggests several possible operating modes for electrolysers. The study explores three modes, which are deliberately very distinct:

1) supply on the electricity market when RES or nuclear is marginal;
2) supply on the "baseload" electricity market, excluding situations where the system is under stress;
3) coupling with renewable production (e.g. photovoltaic) in the framework of "local" models.

Each of these models leads to very different electrolyser load factors and technical and economic challenges.

As an example, the study shows that even by 2030-2035, periods of marginal carbon-free electricity production, i.e. when electricity prices will be low or even zero, will be very unevenly distributed throughout the year and likely to be highly variable. A model in which low-carbon hydrogen is produced only during these periods would lead to irregular hydrogen production, raising important issues for the organisation of the downstream part of the chain (industrial integration and/or the need to develop dedicated hydrogen storage capacities to ensure continuity in hydrogen supply).

These model situations are intended to be illustrative, and it is likely that different models will emerge, judging by the great diversity of projects currently being set up, particularly in the context of initiatives supported by certain regional and metropolitan authorities. To achieve economies of scale and meet France's energy goals, significant load factors nevertheless seem necessary for at least some electrolysis facilities (between 3,000 and 6,000 hours a year).



Gains in emissions reductions are clear from a national accounting perspective

The electricity produced in France is already very largely decarbonised (93%), and the announced closure of the last coal-fired power stations will further improve the country's carbon balance over the coming years.

This situation is favourable to the development of new uses, such as the switch to electrolysis for conventional hydrogen production. Regardless of how the electrolysers are operated, the reductions in emissions from steam reforming are real (reduction of nearly 6 million tonnes of CO_2 per year in France), while the impact on emissions from the French electricity sector remains low.

However, a rigorous analysis of the effect on emissions must necessarily take into account the interconnection of the French system with its neighbours, as well as the change in the mix that accompanies the development of new uses of electricity:

- with an unchanged mix, the analysis at the European level is more nuanced. All other things being equal, the increase in electricity consumption in France (to supply the electrolysers) leads to a reduction in exports of carbon-free electricity to other countries. Yet exporting carbon-free electricity to avoid production from coal or gas-fired power plants – the latter will still have a strong presence in the European mix in 2035 – saves more CO_2 than replacing gas with electricity to produce hydrogen;
- this effect is offset by the increase in carbon-free production called for in the French Multi-Annual Energy Plan. By integrating this adaptation, carbon-free generation capacity is increased as new uses of electricity, such as electrolysis, are developed.

Taking all these effects into account, the development of electrolysis associated with the adaptation of the carbon-free electricity generation mix in France leads to the avoidance of at least 5 million tonnes of CO_2 emissions a year by 2035 in the scenario of the draft French Multi-Annual Energy Plan.

The potential can be increased by integrating possible gains in the transport sector (heavy transport) or in the scope of gas consumption (injection into networks).

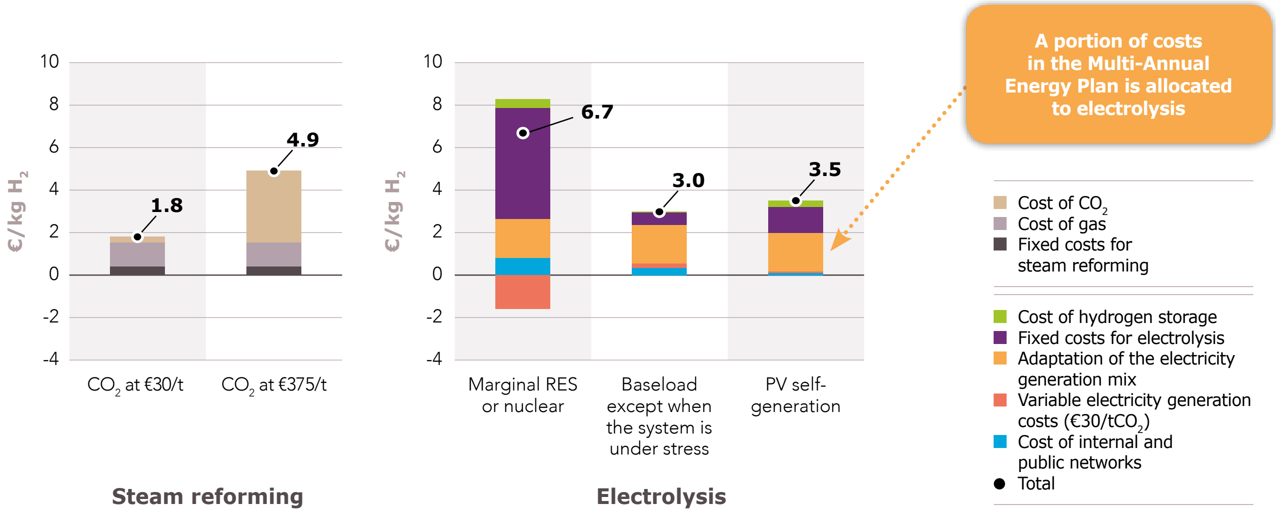
The social welfare analysis demonstrates that, in most of the cases studied, the production of low-carbon hydrogen is justified from an economic point of view if a high value is integrated for carbon

Reasoning from the point of view of the social welfare, the comparison of the full cost of electrolysis with that of steam reforming is highly dependent on the value assigned to the CO_2 externality.

If a low CO_2 value (€30/t) is assumed, the total cost of electrolysis appears to be much higher than for steam reforming. This explains why the hydrogen used today is of fossil origin.

On the other hand, if a high value is put on the environmental externality – by applying the shadow price of carbon in 2035 (€375/t), for example – electrolysis appears to be generally less expensive. This shows the socioeconomic justification for substituting steam reforming with electrolysis over the next 15 years.

Comparison of the welfare cost of steam reforming versus electrolysis



For economic actors, the economic benefits depend on government support and taxation regimes, and are based on many parameters other than the cost of the electrolysers

In practice, the effective development of the sector will be determined by the comparative competitiveness of the different methods of hydrogen production (carbon and carbon-free) from the point of view of economic actors, integrating all the economic signals they are confronted with.

Based on the current regulatory and tariff framework, the price of carbon-free hydrogen produced by electrolysis appears, with all three operating modes, to be higher than that of steam reforming, even taking into account significant reductions in the cost of electrolysers. The development of the sector will therefore depend on changes in taxation and government support.

The three operating modes are, nevertheless, sensitive to different factors:

- For operating mode 1 (electricity purchased on the market when marginal renewable or nuclear generation is available), wholesale electricity prices have little effect on the economic equation because the operation is, by design, based on periods of low price. Nevertheless, this production mode implies reduced operating times, leading to an increase in the sizing of the electrolysers for the same hydrogen production, and possibly to the development of a downstream hydrogen distribution chain including dedicated storage facilities to compensate for the variability of electrolyser operation.
- For operating mode 1 (baseload electricity), the cost of the electrolysers does not appear to be a key factor, which may put a different perspective on the current debate on the evolution of investment costs for electrolysis facilities. The issue identified by the study is more about access to low-price electricity. Paradoxically, the increase in the price of carbon on the European ETS market does not favour low-carbon hydrogen (compared with hydrogen from fossil fuels) with this method: the price of European electricity does not reflect the moderate cost and carbon-free nature of the French mix and remains highly dependent on the CO_2 price on the ETS market. Thus, an increase in the CO_2 price ultimately penalises production of low-carbon hydrogen from electrolysis.
- Finally, for operating mode 1 (coupling with self-generation), the decisive factor in the economic model is the full cost of the renewable production facilities coupled to the electrolysers.

In the long term, the role of hydrogen as an energy vector and storage solution will depend on the choices made for the French electricity mix

Beyond 2035, the role of hydrogen as an energy vector, and possibly as a seasonal storage solution in electricity mixes with a significant share of renewable energy, will depend on the choices made in development of the power system, and should therefore be the subject of in-depth studies.

RTE has undertaken studies of this type as part of the construction of the long-term scenarios for the next Assessment Forecast Report, which will cover the period 2035-2050. This work was launched at the beginning of 2019 under the aegis of the Commission on System and Network Perspectives, and is currently the subject of extensive consultation structured around various thematic working groups. The work will continue throughout 2020, and will include a specific contribution on the "100% renewables" scenarios in cooperation with the International Energy Agency.

The priorities currently identified from the consultation concern the study of the development of a large number of possible uses for hydrogen, such as different ways of greening gas (direct injection into the gas network, transformation into synthetic methane), different industrial uses (the steel industry in particular), seasonal storage solutions, or the positioning of these analyses in relation to green gas import scenarios.

These analyses will help clarify the role of hydrogen in the scenarios for decarbonisation of the energy system with a view to achieving carbon neutrality by 2050. They will make it possible to anticipate the growth of the hydrogen sector and its interactions with the power system, and to provide guidance on the most valuable uses and services to ensure that hydrogen participates fully in the energy transition.

CONTENTS

1. WHERE THINGS STAND NOW

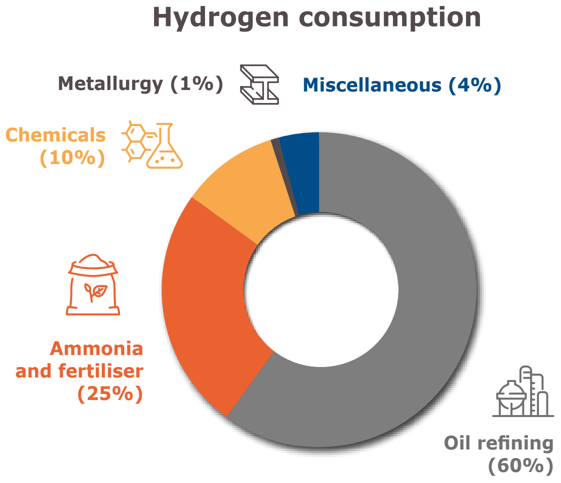
PUBLIC POLICIES GIVE PRIORITY TO DECARBONISING THE HYDROGEN USED IN INDUSTRY BY 2030

1.1 Hydrogen is already being used for industrial purposes in France

In the debate about the energy transition, hydrogen is sometimes presented as a revolutionary solution for transport and energy production, in the same way that electricity and natural gas, for instance, were celebrated in the past. Hydrogen may indeed ultimately replace the petroleum fuels used in transport (for trains, boats, cars, heavy trucks, etc.) or be substituted for the natural gas burnt in boilers and power plants, a substitute with no greenhouse gas emissions.

Yet hydrogen is not only a solution of the future. It is already being used in industry. Global demand for it currently stands at close to 110 million tonnes a year (70 million tonnes of pure hydrogen and 40 million tonnes mixed with other gases, partly as a by-product), including about 1 million tonnes a year used in France.

Figure 1. Hydrogen consumption in France today



Nearly all existing applications for hydrogen are industrial. It is used to refine petroleum products; it is needed, mixed with nitrogen, to produce ammonia, notably for making fertiliser; in the chemicals sector, it is notably used to make methanol; and it is used in other sectors as well including metallurgy, in glass factories…

Examples of hydrogen (H2) being used as an energy fuel are few and far between for now (liquid hydrogen is used to power space shuttle and satellite launchers), though some see fuel cell vehicles as a credible option for reducing emissions in the transport sector. For the time being, there are only a few hydrogen vehicles on the roads of France.

It is nonetheless important to note that the hydrogen used today is not carbon-free. While its use does not emit greenhouse gases per se, the method currently used to produce it mainly involves transforming hydrocarbons (gas, coal, petroleum), and thus emits CO_2. **In France, hydrogen production results in emissions totalling close to 10 $MtCO_2$/year, which represents about 2 to 3% of the country's total emissions.**

1.2 The first priority is to decarbonise the production of the hydrogen used in industry

It is difficult to find substitutes for the hydrogen used as an industrial input (notably for refining and fertiliser manufacturing), so the first priority is to decarbonise its production.

A portion of hydrogen production is a by-product, and inherent to certain industrial processes: electrolysis of brine to produce chlorine, oxidation of petroleum fractions for refining, and gasification of coal. The latter two processes emit CO_2, whereas the electrolysis of brine does not. It is difficult to find alternatives to these production modes.

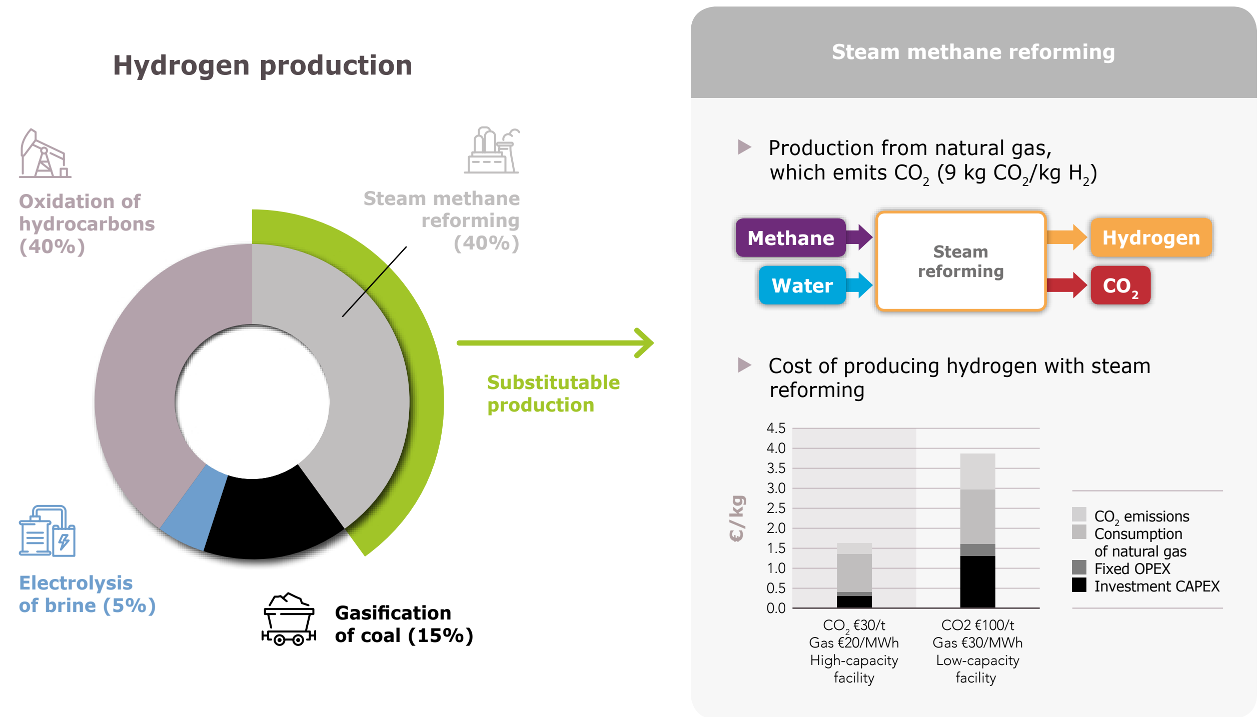
Beyond this by-product production of hydrogen from fossil fuels is associated with certain industrial processes, a significant share of today's hydrogen production is ensured by dedicated steam methane reforming units. This process accounts for some 40% of hydrogen production in France, resulting in about 4 $MtCO_2$ of emissions a year.

The transition to low-carbon production methods is therefore a credible option for reducing CO_2 emissions from the industrial sector.

In France, **the public policies defined in the energy-climate law and draft Multi-Annual Energy Plan and National Low-Carbon Strategy clearly focus on decarbonising the hydrogen already used in industry.** The targets recently included in the energy-climate law illustrate this priority: they aim to lift the share of low-carbon hydrogen to 10% by 2023 and then to between 20 and 40% by 2030.

These objectives could prepare the sector for the introduction of other hydrogen uses over the long term.

Figure 2. Hydrogen emissions and production costs based on steam methane reforming volumes



1.3 New hydrogen uses could also be developed, a possibility reflected in different European and regional scenarios

In addition to serving as an input for industrial processes, hydrogen can be used as an energy vector, for instance to replace gas, oil or electricity.

It is notably being considered for direct uses in:

- Mobility, especially heavy transport, which is more difficult to electrify than light vehicles: ground and maritime transport, potentially rail transport on lines where electrification would be technically challenging or not profitable…
- Industry, notably in steelmaking, for ore reduction, or in cement works;
- Thermal uses in the industrial and building sectors, involving burning hydrogen or using it in fuel cells for combined heat and power generation.

When produced from decarbonised sources, hydrogen can also help reduce emissions from the gas system, which currently generates about 100 $MtCO_2$ of emissions a year in France (compared with about 20 $MtCO_2$/year for the electricity industry). Three modes of operation are currently being explored to this end:

- Mixing hydrogen with methane in natural gas networks, in small proportions (6% to 20% in volume terms, which is 2% to 7% in energy terms according to the most recent data made public by gas system operators)[1];
- Transformation into synthetic methane via a methanation process that requires the addition of CO_2: the synthetic methane thus produced has the same characteristics as natural gas and can be injected into gas transmission and distribution networks without limits;
- Conversion of the grid or portions thereof to pure hydrogen and adaptation of equipment on the user end (boilers, etc.).

The degree to which these new uses will develop is very uncertain and will depend on different factors, some technical (efficiency gains with certain technologies, particularly fuel cells used for mobility, or methanation and CO_2 capture in producing synthetic methane) and some economic (price of low-carbon hydrogen relative to hydrogen produced with fossil fuels and merit order between different methods of reducing emissions).

Consequently, there is no consensus on the role low-carbon hydrogen will play over the long term in scenarios involving massive decarbonisation. Beyond projected hydrogen demand for industrial uses, estimates vary widely: some call for limited use of hydrogen as an energy vector, while others factor in significant use of hydrogen in energy (gas greening, etc.) and mobility (heavy transport). Certain sector players expect to see large-scale development of hydrogen use in France, with demand doubling by 2030 and rising fivefold by 2050.

1. *Technical and economic conditions for injecting hydrogen into natural gas networks* – GRTgaz *et al.* 2019

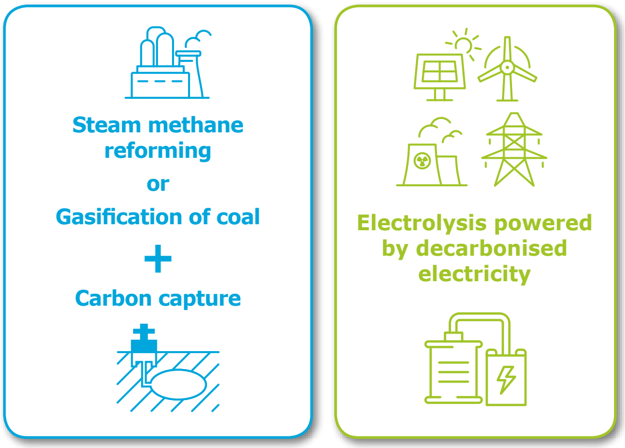
1.4 Among the low-carbon technologies that could potentially be used to produce hydrogen, electrolysis of water appears to be the preferred solution in France

If hydrogen is to be an effective tool for tackling global warming, then the hydrogen used in France must be produced with the least possible greenhouse gas emissions.

Several low-carbon hydrogen production technologies are being considered. Two are sufficiently mature to potentially be used in industrial settings:

- Steam methane reforming or gasification of coal in conjunction with a carbon capture and storage system;
- Electrolysis of water powered by decarbonised electricity.

Figure 3. Technologies that could be used for low-carbon hydrogen production on a large scale



Other possible solutions that are sometimes mentioned include steam reforming of biogas and gasification of biomass. However, while the hydrogen produced using these processes is indeed carbon-neutral, certain scenarios, particularly the National Low-Carbon Strategy, give priority to using biogas and biomass in other ways because of their limited supply. Based on the logic of the National Low-Carbon Strategy scenario, these sources would in theory be reserved in priority for thermal uses delivering greater energy efficiency.

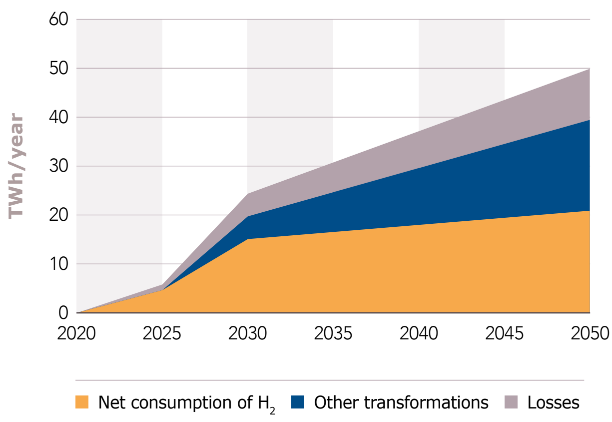
The draft version of the National Low-Carbon Strategy also implies limited use of carbon capture and storage solutions. Indeed, it calls for "*cautious and reasonable reliance on carbon capture and storage technologies relative to other scenarios. [...] For instance, they are not used to capture and store emissions from the combustion of fossil fuels.*"

Electrolysis of water is thus left as the main option for developing low-carbon hydrogen in France.

This technology requires significant quantities of electricity. Following the trajectories set out in the National Low-Carbon Strategy – as mentioned above, they are below the projections of some actors – would already result in nearly 30 TWh of additional electricity consumption in 2035 (for annual hydrogen production of close to 630,000 tonnes), and as much as 50 TWh by 2050.

These projections make it necessary to study an environment in which electrolysis solutions are developed on a large scale within the power system. Such is the purpose of the present report.

Figure 4. Projected trends in electricity consumption for hydrogen production (Source: French Directorate General for Energy and Climate, summary of the base-case scenario for France's energy and climate strategy)



2. WHAT AN IN-DEPTH STUDY IS DESIGNED
TO PROVIDE A DETAILED UNDERSTANDING OF METHODS OF PRODUCING LOW-CARBON HYDROGEN IN FRANCE

2.1 Two distinct reasons are advanced to justify developing low-carbon hydrogen production in France

Different studies examining the long-term evolution of the energy mix assume that hydrogen will either be needed as a means of storage, as the share of wind and photovoltaic generation increases, or used as a means of reducing emissions in certain sectors at less cost, or in some cases for both purposes.

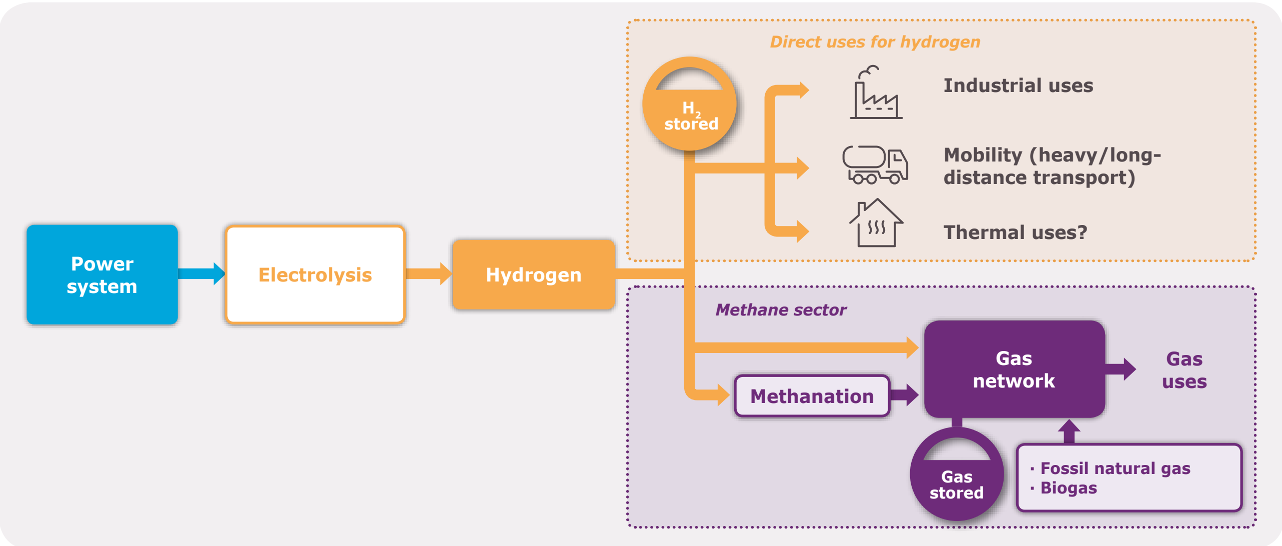
However, in terms of methodology, a distinction must be drawn between the two justifications advanced for developing a low-carbon hydrogen sector in France. Indeed, the challenges vary depending on the time horizon considered, and do not necessarily support the development of the same types of solutions.

▶ **First justification: Produce low-carbon hydrogen to replace fossil fuel energies**

The first goal is to *decarbonise existing end-uses.* This includes not only the ways hydrogen is currently used in industry – for which there are few substitutes – but also uses in the transport sector (heavy transport) and energy (supply to the existing gas network as a substitute for fossil gas).

On a 10- to 15-year time horizon, building a low-carbon hydrogen industry, as public policies call for (Multi-Annual Energy Plan and hydrogen plan), is primarily geared to meeting this goal.

The RTE report therefore focuses on this objective, the main one set for 2035.



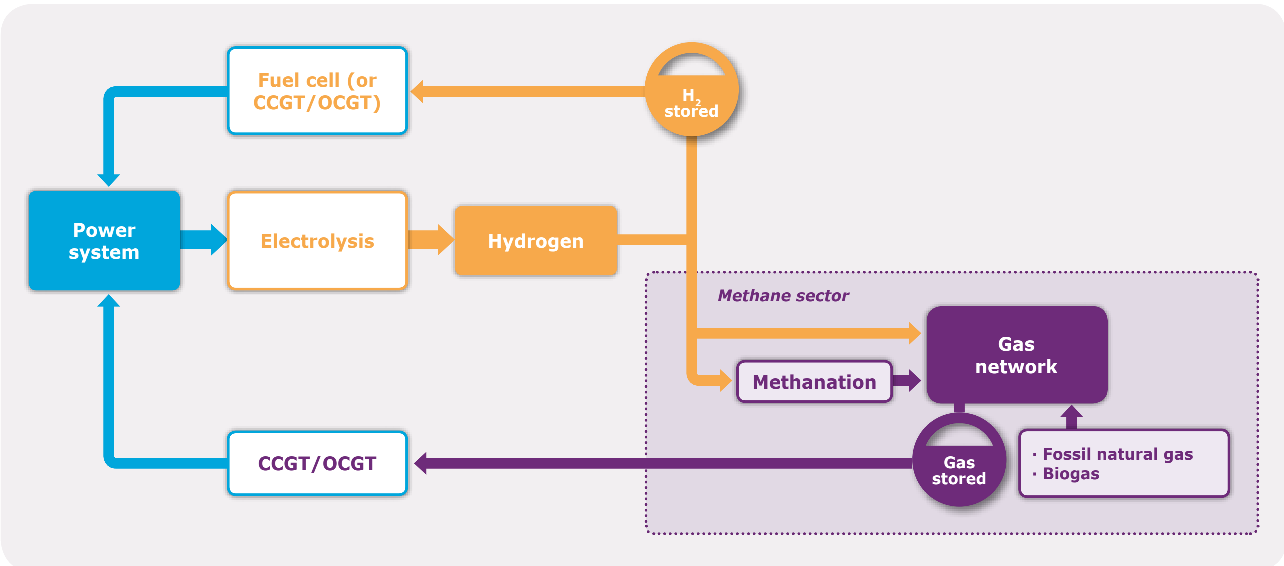
Timeframe for at-scale development: 2030-2035

Second justification: Develop a storage solution to help balance electricity supply and demand

Another justification is that hydrogen could be used as a storage and discharge (power-to-gas-to-power) solution to help balance supply and demand on the power system. In this case, hydrogen serves as a "buffer": it is produced via electrolysis using decarbonised electricity, then stored (for instance in salt caverns or in gas networks after conversion into synthetic methane), then transformed into electricity when wind or photovoltaic power production is low. In this case, it becomes an integral part of the power system (similarly to today's dispatchable generation capacity).

However, energy efficiency is low with this solution (25% to 35% with existing technologies).

There is good reason to explore its long-term potential, particularly for providing seasonal storage in electricity mixes with a high percentage of variable renewable sources. That being said, given its technical and economic maturity, and the projected characteristics of the electricity mix over the medium term, this solution is unlikely to be move past the demonstration phase in mainland France within the next ten years.



Timeframe for at-scale development: 2040-2050, depending on the scenario

2.2 In 2035, storage via hydrogen will not be indispensable as a means of compensating for the variability of renewable energies

The analyses in the 2017 Forecast Assessment Report, for instance the Ampère and Volt scenarios, or the one included in the French Multi-Annual Energy Plan, show that an increase in the share of electricity from non-dispatchable wind and photovoltaic sources drives up the need for flexibility on all time horizons: annual, weekly and daily.

That said, in 2035, the power system will still have significant flexibility through other sources:

- In France, from dispatchable generation units (nuclear, hydro, etc.), demand-side management (domestic hot water, electric vehicles), load shedding, possible curtailment for renewables,
- In neighbouring countries, from dispatchable generation units that are accessible via interconnections, per the rules of the internal energy market.

Consequently, while flexibility needs will increase over the next 15 years, the power system in France could technically function without new demand modulation or hydrogen storage solutions and continue to comply with current standards in terms of security of supply (the regulatory three-hour criterion).

Even if it is not necessary, however, electrolysis can offer an additional solution, and partially replace some others. In particular, electrolysers have the flexibility to consume power during off-peak periods for the power system, thus removing the need to curtail wind and PV output and modulate nuclear generation.

With specific regard to annual flexibility requirements, the analyses conducted by RTE on the scenarios in the Forecast Assessment Report and Multi-Annual Energy Plan (shown in the box opposite) do not suggest that it is technically necessary to develop seasonal storage resources between now and 2035 to accommodate the volumes of renewable energies called for in public policy guidelines.

Likewise, from an economic standpoint, based on the assumptions and forecasts known today, it seems that in mainland France in 2035, there will not be economic space for storing hydrogen produced with decarbonised electricity and then returning it to the power system. The cost of producing decarbonised hydrogen via electrolysis on that horizon will be at least in the region of €3/kg (see section 6). Taking into account the efficiency of the methods used to return that energy to the power system (about 40 to 50%), the variable cost of generating electricity from stored hydrogen works out to around €250/MWh. Lastly, for this solution to appear competitive relative to a gas-fired plant, the implicit cost of CO_2 emissions from the plant would have to be €400/t, which is above the shadow price projected through 2035.

The economic benefits of such a storage solution could become advantageous more quickly in other situations, for instance with island energy systems where renewable generation conditions are more favourable and peak generation is currently ensured by small diesel units that are very expensive to run.

Seasonal modulation in 2019 and 2035

Annual flexibility involves adapting to seasonal variations in residual consumption, which corresponds to electricity consumption minus production from wind, PV and must-run hydro resources. Fossil-fired and dispatchable hydro generation, located in France or accessible via interconnections, also helps meet these needs.

Figure 5 shows, on a weekly timeframe, the stacking of production resources used to meet demand with today's mix and the projected mix in 2035. The curves are perfectly symmetrical: production (positive) = consumption + export balance (negative). Seasonal changes in wind and solar power generation tend to offset one another, with more wind power produced in winter and more solar power in summer. Consumption in France follows a seasonal pattern, with demand rising in winter.

Figure 5. Annual balance between supply (top) – demand (bottom) in France, on a weekly timeframe

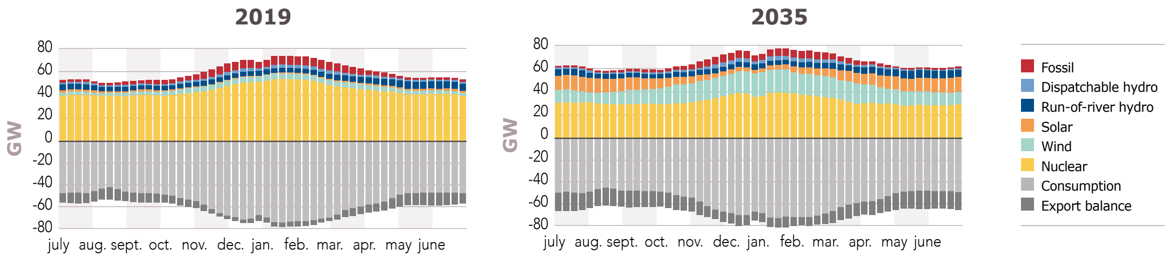
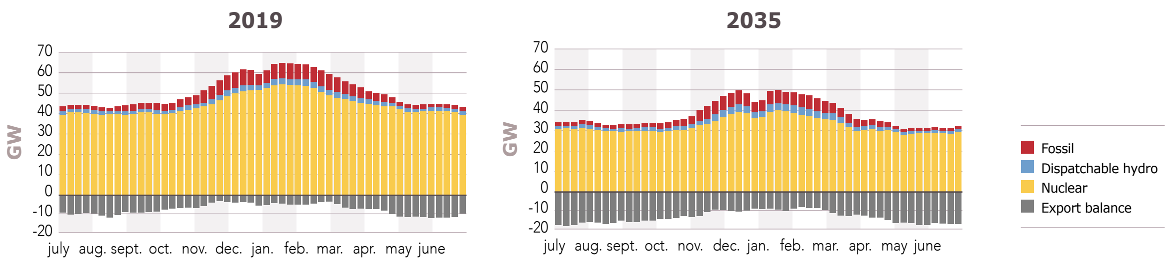


Figure 6 shows this balance taking into account only dispatchable generation, both on the supply side (nuclear, dispatchable hydro, thermal generation) and the demand side (electricity export balance). It shows seasonal fluctuations offsetting those seen with consumption and non-dispatchable production (wind, solar, run-of-river hydro). In this scenario, between 2019 and 2035, output from nuclear and fossil-fired thermal plants declines sharply and the export balance increases, yet their roles in seasonal modulation remain the same: increase in nuclear and fossil-fired thermal generation and decrease in the export balance in winter.

Figure 6. Production and consumption based exclusively on dispatchable generation in 2019 and 2035



These illustrations show that by 2035, in this scenario, the seasonal modulation required to maintain the supply-demand balance in France can be achieved without seasonal storage of hydrogen or synthetic gas, given the dispatchable generation resources available in France or accessible via interconnections. Hydrogen production with electrolysis, if production was much higher in summer than in winter, would help limit the need for seasonal modulation by compensating for seasonality associated with other electricity uses. Depending on how the hydrogen produced is used, this seasonality could nonetheless require significant storage capacity (see section 3).

2.3 The outlook for hydrogen-based seasonal storage (power-to-gas-to-power) in 2040-2050 will depend on future choices about the electricity mix

Seasonal modulation of generation in France is currently done through domestic dispatchable generation (nuclear, fossil and, to a lesser degree, hydro) and ones in neighbouring countries via the modulation of exchanges at interconnections, since the French power system operates as part of the larger European one. Current scenarios suggest that this will still be the case in 2035, despite the anticipated reduction in dispatchable generation in France and neighbouring countries.

Forecasts for the longer term (2035-2050) are more uncertain. The need for large-scale storage solutions on that horizon will depend in large part on developments in the different European countries.

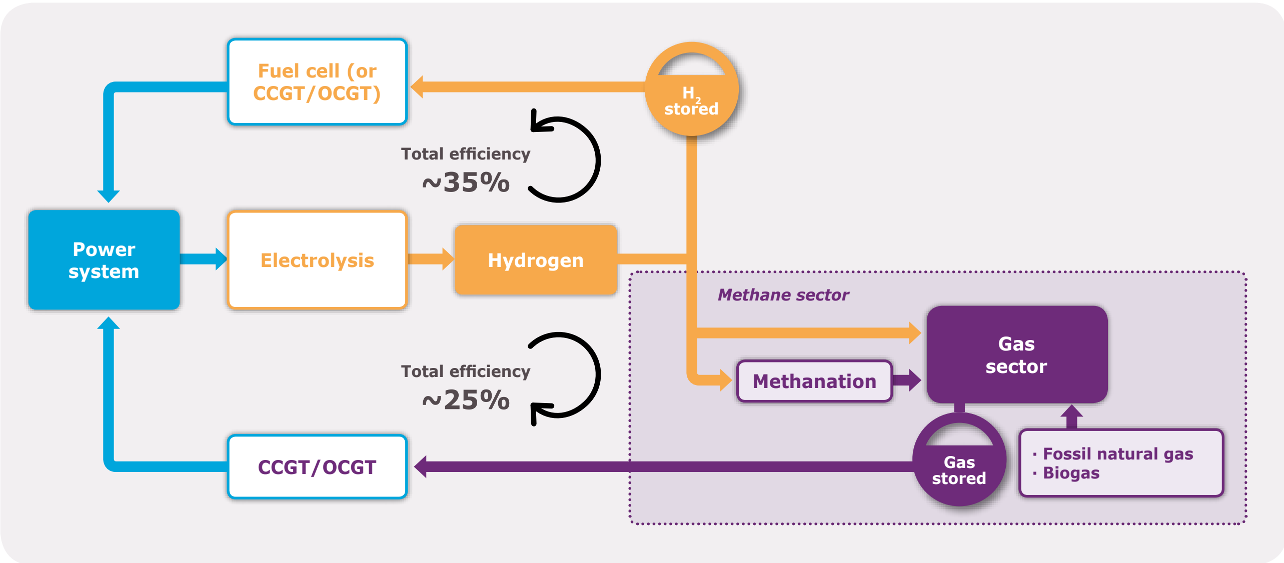
From a technical standpoint, the disadvantage of relying on power-to-gas-to-power for electricity storage is **its low round-trip efficiency (25%): electricity is transformed into hydrogen and potentially into synthetic methane so it can be stored, then turned back into electricity via a gas-fired power plant. A "round trip" involving a fuel cell (or direct combustion of hydrogen in CCGT or OCGT plants if this solution proves technologically feasible) has an only slightly higher efficiency of around 35%.**

From an economic standpoint, this solution's appeal will also depend in large part on available alternatives, and thus on future government decisions about the electricity mix (particularly when it comes to nuclear):

- In a scenario with no nuclear and limited recourse to electricity generation from biogas or biomass due to limited resource availability, initial simulation results show that power-to-gas-to-power could be a technical necessity in the absence of alternative dispatchable generation options;
- On the other hand, if constraints related to the limited supply of biogas, biomass and biofuels are lifted thanks to imports (including of gas or synthetic fuels) from extra-European countries, or if other European countries authorise the continued use of thermal generation in conjunction with carbon capture and storage, or if some nuclear power plants are kept in service, then power-to-gas-to-power will be one economic option among others. Choices will have to be made factoring in the cost of imported green fuels and the cost of extending the service life of the nuclear fleet.

The next edition of the Forecast Assessment Report, with a time horizon of 2050, will include specific analyses of the future role of seasonal storage based on hydrogen or methane. Consultation on these new scenarios began in 2019 and call for a detailed analysis of the interactions between electricity and hydrogen in very different scenarios, notably in terms of renewable energy and nuclear power use. The origin of the carbon used in methanation and the carbon cycle will also be examined in detail.

Figure 7. Efficiency of different technologies used in producing or transforming hydrogen



2.4 The hydrogen study looks at the technical and economic aspects of deploying decarbonised hydrogen in the power sector, using the method tested in the May 2019 electric mobility report

The analysis on which this report is based does not focus on the target for developing hydrogen and electrolysis between now and 2030-2035. It is assumed that target is already set in France's energy-climate plans, via the law of 8 November 2019 on energy and the climate and the draft documents of the French Multi-Annual Energy Plan and National Low-Carbon Strategy.

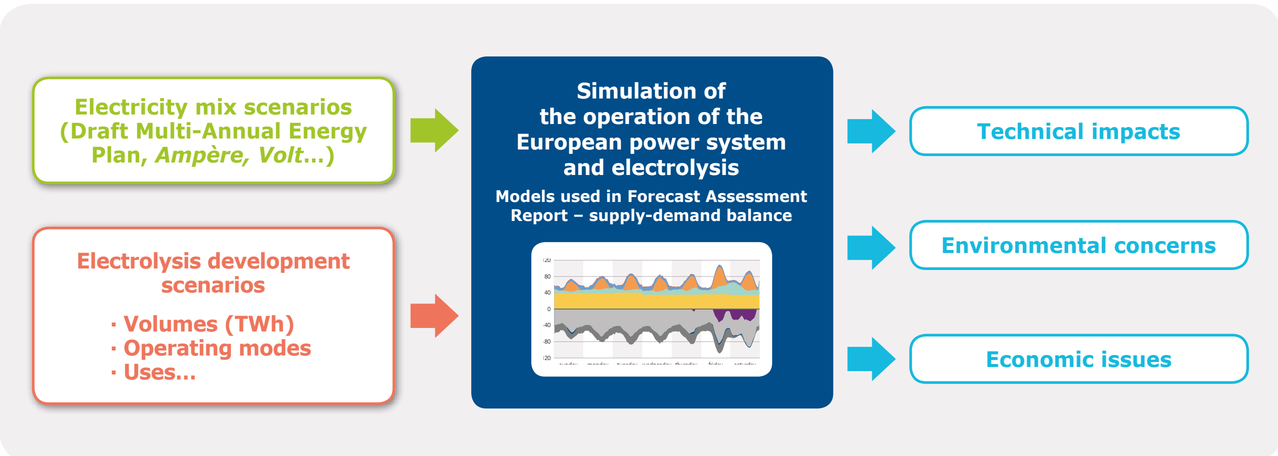
Rather, this RTE study looks at the modalities of electrolysis operations and the consequences for the power system.

RTE's method of analysis is based on the principles applied in its study on the development of electric mobility[2] published in May 2019. It involves simulating the operation of the European power system (considering the possibility of exchanges at interconnections), on an hourly basis, for numerous series of variables (consumption, wind, solar and hydropower generation, availability of nuclear and fossil-fired power plants, etc.) and for different scenarios in terms of the number and operating modes of electrolysers.

The assumptions about future changes in the electricity mix applied in the analysis are based on the goals set forth in the draft Multi-Annual Energy Plan published by the government. They notably factor in:

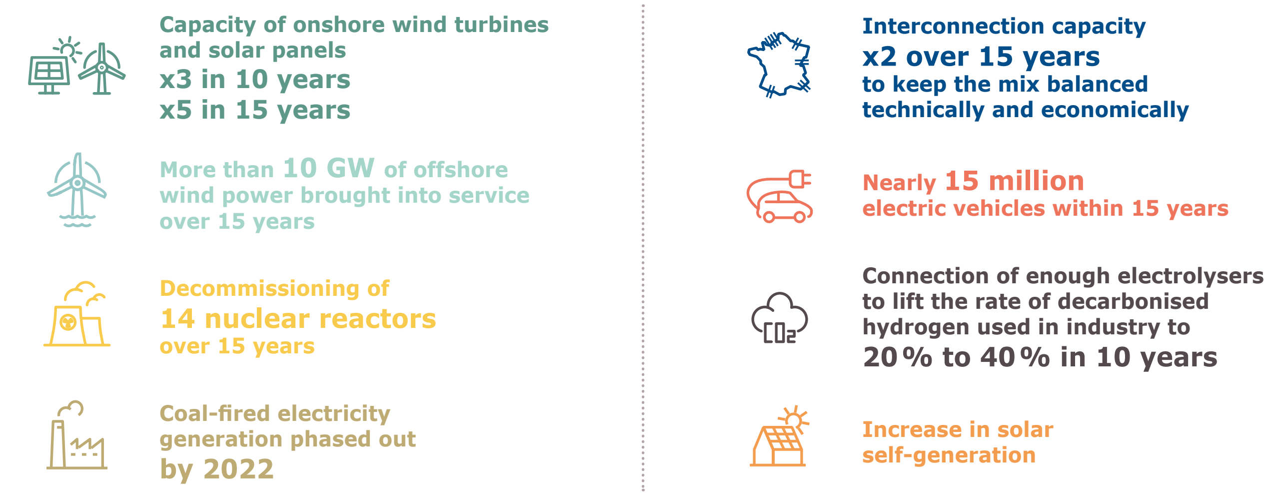
- An acceleration in renewable energy source (RES) development between now and 2028, a trend assumed to continue in 2029-2035,
- The closure of coal-fired power plants over the medium and the absence of new fossil-fired thermal power plant projects,
- The decommissioning of 14 nuclear reactors by 2035 (including the Fessenheim units) per the preliminary schedule announced by the government,

Figure 8. Principles applied to models included in analyses



2. https://assets.rte-france.com/prod/public/2020-06/Rte%20electromobility%20report_-_eng.pdf

Figure 9. Government targets for transforming the energy mix, drawn from the draft Multi-Annual Energy Plan and National Low-Carbon Strategy



- The development of electric mobility, with several million vehicles brought into circulation,
- For the coming years, broadly flat final electricity consumption and an increase in hydrogen production through electrolysis,
- Sustained development of interconnections.

Costs and carbon footprints are calculated at the scale of the entire system (European power system and hydrogen industry), regardless of who bears the costs and what business models industry players adopt.

3. DIFFERENTIATED SCENARIOS
TO REFLECT THE DIFFERENT OPERATING MODES OF PRODUCING HYDROGEN WITH ELECTROLYSIS

3.1 Operating modes may vary greatly depending on operators' business models

The trajectories considered in the RTE report will make it possible to produce 630,000 tonnes of "low-carbon" hydrogen a year by 2035, paving the way to meet the targets defined by public authorities in the framework papers of the Multi-Annual Energy Plan and National Low-Carbon Strategy. This corresponds to about 60% of total industrial hydrogen consumption in France today.

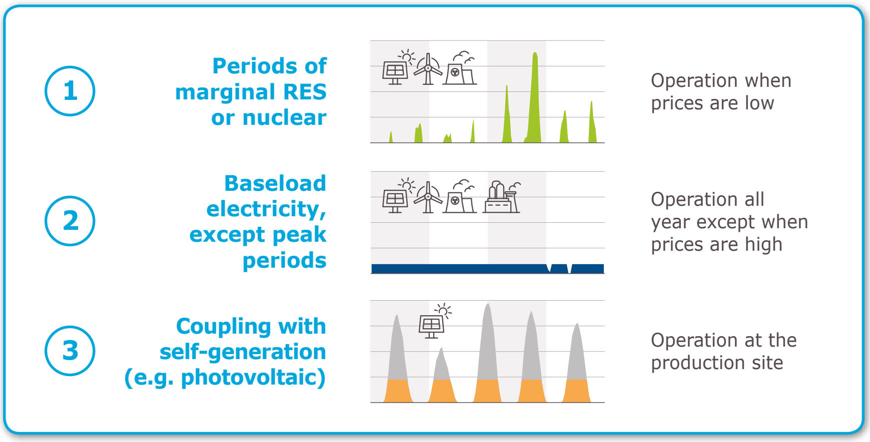
Beyond the quantity of electrolysis capacity to be developed over the next 15 years, the study shows that the mode in which electrolysers are operated will largely determine the issues the power system will face. A production target may be reached with different operating modes, resulting in very different overall sizing requirements, hydrogen storage challenges and economic and environmental impacts.

The RTE study explores electrolysis development scenarios with three separate modes of operation, described in detail in the following pages:

1) Operating mode 1: Supply on the market when **RES or nuclear is marginal;**
2) Operating mode 2: Baseload electricity, **except when the system is under stress;**
3) Operating mode 3: **Coupling of electrolysers with local renewable generation** (wind and/or solar). In the RTE study, this operating mode is tested using PV self-generation.

These three modes are given as examples, to provide a "framework". The intent is not to predict which operating modes will actually be developed, but rather to assess the impacts on the power system of several extreme electrolysis development scenarios.

Assumptions about operating modes in analyses



Assumptions about operating modes in analyses

In practice, operators could settle on an intermediate between the three modes, basing their choices on several parameters.

Hydrogen production costs and economic considerations: To produce hydrogen at a competitive cost, electrolyser operators must in theory compromise to find a length of operation that allows them to amortise fixed costs (which favours long hours of operation annually) while taking advantage of low electricity prices (which favours operation primarily at times when prices are low). The choice of operating mode may also depend on tax incentives or subsidy systems put into place by public authorities.

Industrial constraints, especially the potential need for continuity of hydrogen supply: With industrial applications, purchasing non-baseload electricity may result in additional costs. If electrolysers do not operate continuously, a storage solution must be planned (or the process that uses the hydrogen must be made more flexible). This must be factored into the economic analysis and the estimated cost of switching to low-carbon hydrogen. Direct injection into the gas network does not require interim storage as long as local injection and evacuation limits are not reached.

Environmental impacts, particularly in terms of CO_2 emissions, vary depending on the operating mode (see part 5) and can thus also influence operators' decisions. Indeed, hydrogen producers may be incentivised to select the production method with the smallest carbon footprint, either through standards, economic signals (taxes, subsidies...) or marketing advantages (advertising the fact that their hydrogen is carbon-free).

Figure 10. Components of the fixed costs associated with an electrolyser and electricity supply costs based on load factors (projections for 2035)

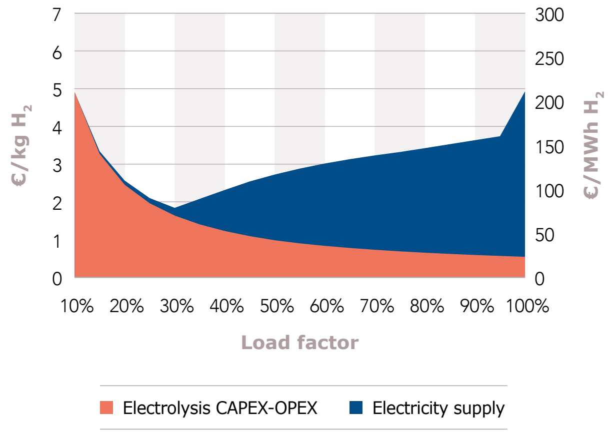


Figure 11. Illustration of hydrogen storage and discharge cycles in operating mode 1

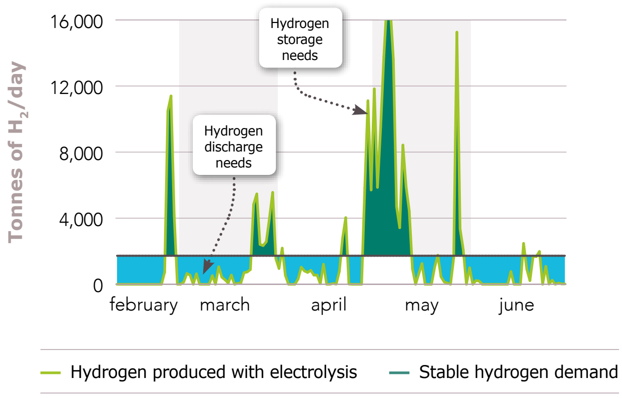
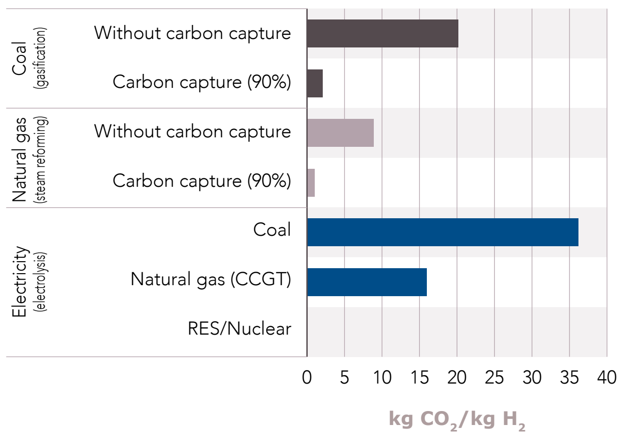


Figure 12. Emissions factor during operation for hydrogen production depending on technology used *(Source: IEA)*



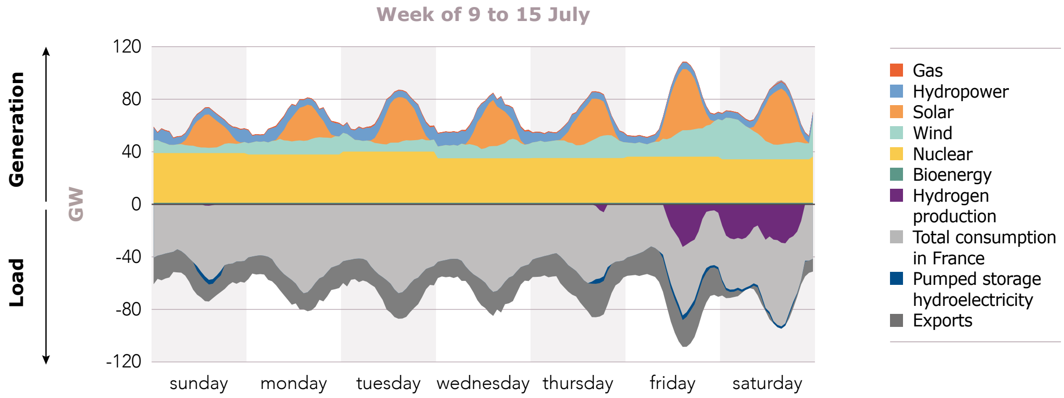
3.2 Three modes of operation, analysed in detail

Mode 1: Operation during periods of marginal RES or nuclear

Principle

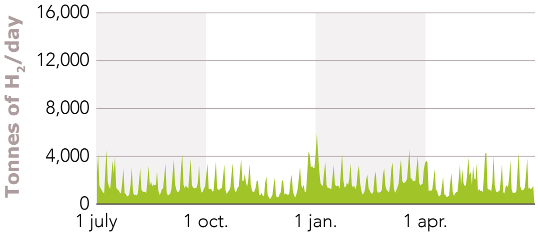
Electrolysers operate at times when marginal renewable or nuclear electricity is available, i.e. when price signals are low. It is not possible to meet France's low-carbon hydrogen production targets if electrolysers operate only when marginal renewable generation is available, since quantities will be well below the 30 TWh required in 2030-2035.

Illustration of operating mode 1 during a typical week in summer

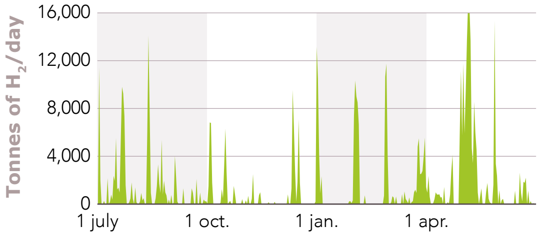


Hydrogen production profile

Hydrogen production depends largely on weather conditions and the availability of generation capacity, making it very intermittent.



Average annual profile



Profile for a particular year

Pros/Cons

- Electricity is carbon-free by definition, relatively inexpensive on wholesale markets.

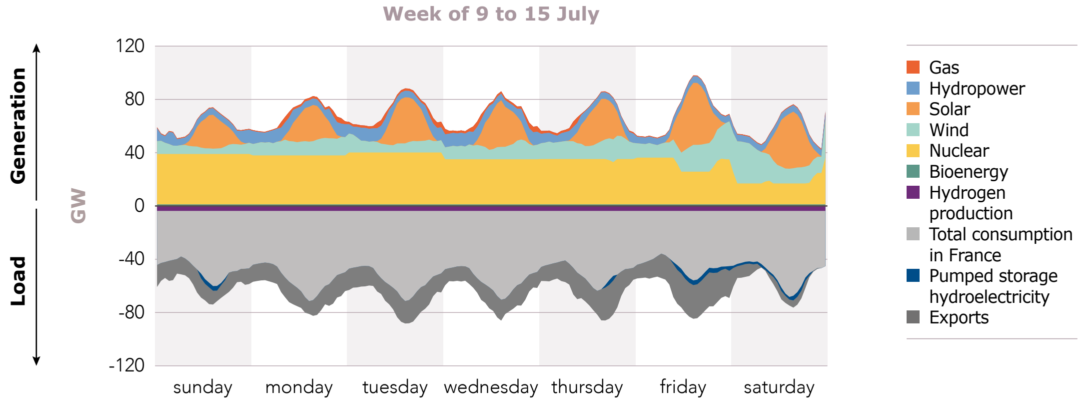
- Annual operating time is low (10 to 20% of the time), especially as the total volume to be produced in France is significant, and there will be competition with other uses in France and abroad when prices are low. As a result, high-capacity electrolysers are needed to produce the required quantities, and they must be depreciated over short periods (high annual payments).
- Production is highly variable and unpredictable, so storage is necessary if usage is constrained.

Mode 2: Operation with baseload electricity except in times of system stress

Principle

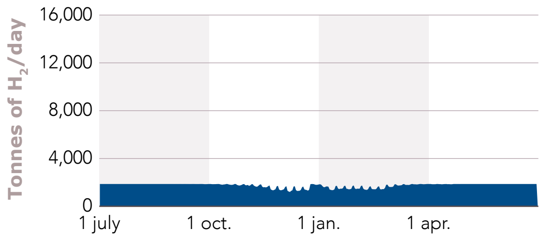
Continuous operation of the electrolyser except when supply is tight on the power system (peak days notified on the capacity mechanism and/or periods when electricity prices are high). Guarantees of origin can be purchased with this operating mode to show that the electricity used is from renewable sources.

Illustration of operating mode 2 during a typical week in summer

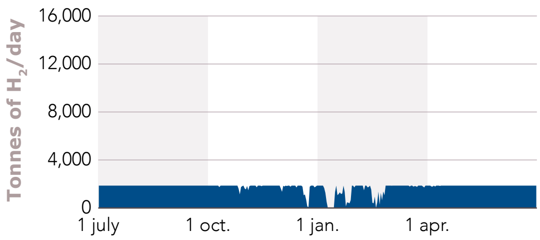


Hydrogen production profile

Hydrogen production is fairly stable, stopping only on some days, mainly in winter.



Average annual profile



Profile for a particular year

Pros/Cons

- Long operation times (7,000 to 8,000 hours a year) allowing good amortisation of fixed costs and steady hydrogen production.

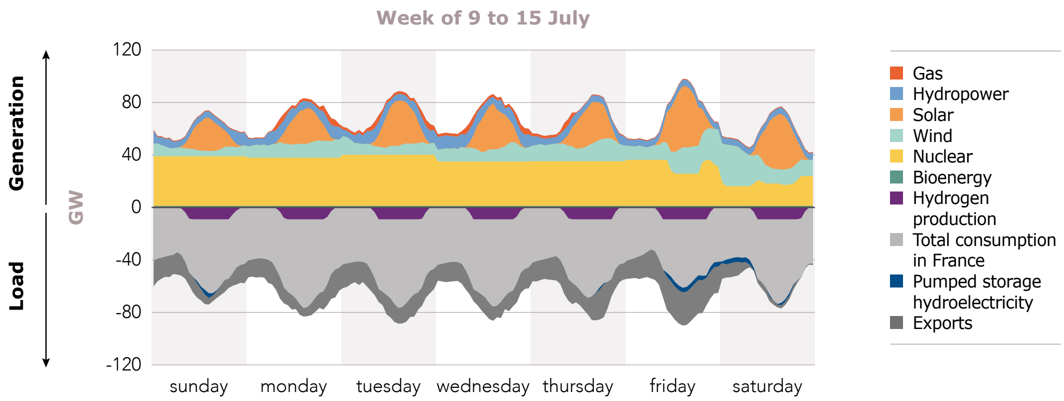
- Potential impact on the direct or indirect CO_2 emissions of the European power system.
- Electricity supply costs are high during certain periods, and sensitive to prices on the European power market, and therefore to fluctuations in fuel and CO_2 prices.

Mode 3: Coupling with self-generation, for instance photovoltaic

Principle

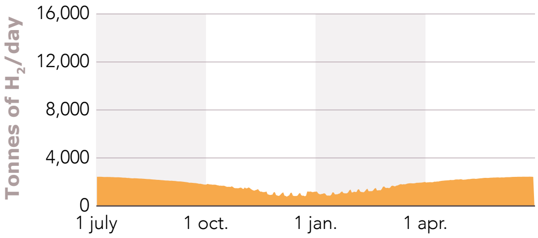
The electrolyser is installed next to a renewable electricity generation facility. To ensure a good load factor, electrolyser sizing is below installed PV capacity. The electricity generated goes to power electrolysis in priority, and the rest is injected into the networks to be sold on whole electricity markets. If supply is tight (i.e. prices are high), all of the electricity generated may be injected into the power grid.
In concrete terms, the simulations involve solar (ground-mounted) self-generation, per the guidance resulting from the consultation, though the model can also work with wind power.

Illustration of operating mode 3 during a typical week in summer

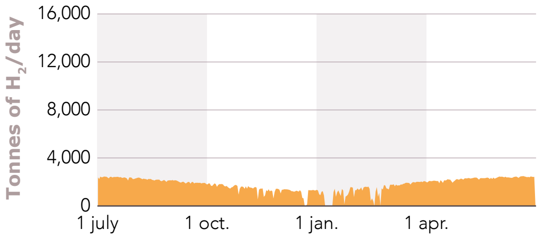


Hydrogen production profile

In the test conducted coupling the electrolyser with photovoltaic self-generation, hydrogen was produced during the daytime, with fluctuations depending on sunlight conditions: production was higher in summer than in winter.



Average annual profile



Profile for a particular year

Pros/Cons

- Limited cost of supply (fixed cost of PV panels).
- Electrolyser operating times potentially significant (>40%).
- Potentially sited far from industries or existing gas networks.
- Business model sensitive to revenues from electricity sales, which depend on market prices (preference is for the highest possible wholesale prices).

3.3 Concrete examples of these different modes of operation are found in a wide variety of projects throughout France

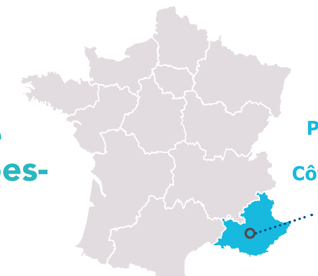
A large number of low-carbon hydrogen projects have been launched in recent months.

Several are part of regional plans adopted by local authorities to promote low-carbon hydrogen. Their policies are part of a broader effort by regional and metropolitan authorities to define a roadmap to become "energy positive" or "carbon neutral" by 2050. Low-carbon hydrogen is often considered central to such plans, and its development includes a local electricity generation component. Different operating modes are considered, based on the geographic area within which electricity is generated and the purpose for which the hydrogen is being produced.

The variety of projects launched reflects the diversity of operating modes possible and also the uncertainty that remains as to business models for producing hydrogen through electrolysis.

Different projects are presented below for illustration purposes. The list is not by any means exhaustive.

"HyGreen Provence" project in the Provence-Alpes-Côte d'Azur region



The Durance Lubéron Verdon (DLVA) urban area is supporting a project coupling PV generation with hydrogen production and storage, making it an example of model 3 above. The goal is to capitalise on the region's assets: a climate that is very favourable to solar power and the existence of a gas storage site in the salt caverns near Manosque.

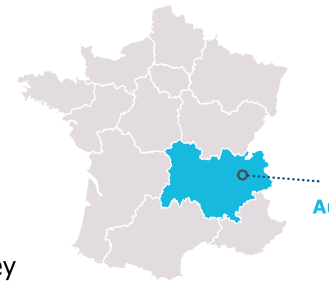
This project is being developed gradually, with a first phase involving the coupling of solar PV farms with a capacity of 120 MW to 12 MW of electrolysis capacity. By 2030, the area could have 900 MW of solar PV capacity divided between about 15 sites, along with 435 MW of electrolysis capacity, enough to produce some 10,000 tonnes of hydrogen a year.

It would be stored in one or more salt caverns, each with capacity to hold approximately 3,000 tonnes of hydrogen.

Authorities are paying special attention to the siting of solar PV farms and the maximisation of local economic benefits of the project. Electrolysis capacity is expected to be located at the existing storage site, which is operated by Géométhane. The electricity transmission system will thus be used to carry power from production sites to the electrolyser, meaning this is not a pure off-grid self-generation model.

As to how the hydrogen produced will be used, several options are being considered: direct injection into public gas networks, use for mobility (public transport, alternative to diesel for Marseille-Briançon rail line), or industrial uses in the Aix-Marseille metropolitan area (in which case the issue of creating dedicated transmission infrastructure would have to be addressed).

"Zero Emission Valley" project in the Auvergne-Rhône-Alpes region



The Zero Emission Valley programme aims to develop a regional hub for mobility fuelled by decarbonised hydrogen by deploying 1,000 vehicles and 20 charging stations by 2023. This rollout will represent 25% of the total "mobility" targets set forth in the national hydrogen development plan.

To this end, the Auvergne-Rhône-Alpes region joined forces with Michelin, Engie, Banque des Territoires and Crédit Agricole to create a company called SAS Hympulsion, which will handle the design and installation of the stations, then the production and distribution of hydrogen within the framework of this project.

The goal of the project is to avoid the consumption of 4.3 million litres of diesel fuel and the emission of 13,000 tonnes of CO_2 a year. This new sustainable mobility industry aims to address climate and air quality concerns in the nine priority territories in the region while at the same time demonstrating its industrial and economic feasibility on a large scale.

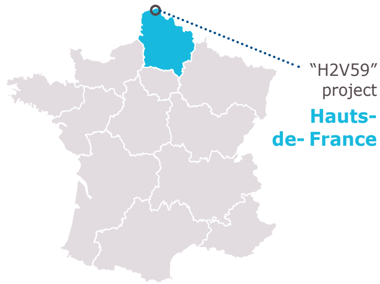
Hydrogen will be produced by 14 electrolysers powered by renewable sources; the issues of tracing the origin of that renewable electricity and the potential implications for how the electrolysers are operated are being analysed (guarantees of origin, PPAs…).

Fourteen 1 MW electrolysers will produce between 40 and 200 kg of hydrogen a day and supply 20 dual pressure stations (350 and 700 bar). Industrial uses may be coupled with mobility uses to allow joint operation of the electrolysers. The first station to be installed under the Zero Emission Valley project will be inaugurated in February 2020 in Chambéry.

SAS Hympulsion, which represents the project partners, communicated with RTE to jointly assess the flexibility of the electrolysers and how it can be rewarded through electricity markets.

- First, the reduction in electric bills for operating electrolysers when different components are added together (procurement of energy and production capacity, network utilisation tariffs, etc.). The goal here is to capitalise on opportunities to defer electricity consumption to periods when supply costs are lowest and when off-peak network utilisation rates apply, reducing demand during what are considered peak periods for the capacity mechanism.
- Second, the addition of another revenue source to the project business model (see § 4.4 and § 7.5) through the provision of services to the power system. This revenue would stem from participation in various market mechanisms: certification of demand response capacity on the capacity mechanism, participation in the tender for fast reserves and system services.

"H2V59" project in the Hauts-de-France region



The H2V59 project, managed by a company called H2V, involves creating a hydrogen production plant at a site that belongs to Grand Port Maritime de Dunkerque.

Hydrogen will be produced at two identical units operating about 7,500 h/year (85% of the time), which corresponds to operating mode 2, base-load electricity except in times of system stress. Each unit will have about 100 MW of capacity and include 26 electrolysers producing an average 14,000 tonnes of hydrogen a year.

The project also calls for the creation of an electrolyser assembly factory in the Hauts-de-France region.

The hydrogen produced would be used by the energy industry, being injected into the natural gas transmission network mixed with methane.

It was specified during the pre-project consultation that "H2V plans to obtain certificates guaranteeing that the electricity consumed and carried over the public transmission grid is from renewable sources […] Renewable energy suppliers will be invited to tender to supply electricity to the H2V59 factory." Electricity origin was a top concern for participants in the consultation, which ended late in 2019, notably because of "unfamiliarity with (and therefore wariness of) guarantees of origin and how they work."

H2V has a similar project in Normandy, in the Port Jérôme industrial zone near Le Havre. Hydrogen produced through that project would be intended for industrial use in the same area.

"Solarzac" project in the Occitanie region

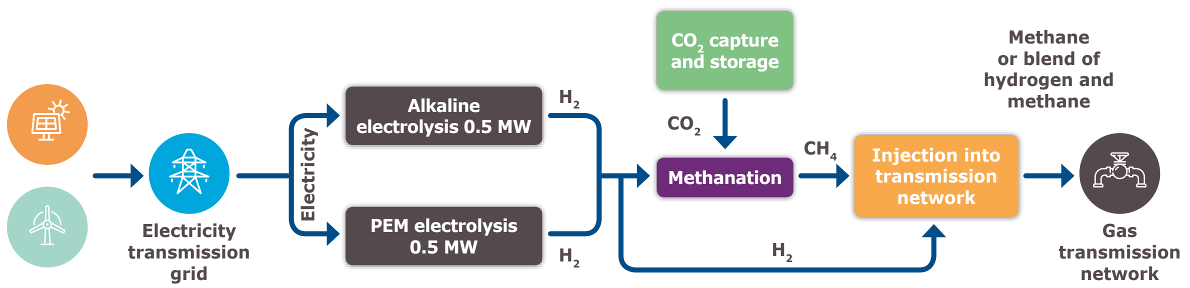
The Solarzac project, managed by a company called Arkolia Énergies, is being billed as an "energy business park" for photovoltaic and agropastoral activities, to be located on what was a large private domain in the southern part of the Larzac plateau.

During the consultation conducted prior to the project launch under the aegis of a guarantor, the contracting owner proposed three scenarios for the project, one of which included the coupling of photovoltaic generation with the production of "green gas" (mode 3). Under this scenario, a portion of the output (~40%) from the 320 MW of photovoltaic panels would be used to produce hydrogen with an on-site electrolyser. This hydrogen would then the recombined, via a bio-methanation process, with CO_2 captured in the ambient air, to then produce methane and inject it into the public gas network. Developers of the Solarzac project say the main benefit of this scenario is that it can optimise the use of locally-generated electricity, limiting the need to develop infrastructure to connect it to the grid and offering a power-to-gas technology that is adapted to the intermittence of photovoltaic generation.

Once the preliminary consultation was complete, with expressions of opposition or caution but also clear interest in the technology proposed, the contracting owner decided to create another scenario, on a smaller scale and with a strong agricultural component, and to provide additional guarantees to facilitate acceptance of the project.

Jupiter 1000 demonstrator

The Jupiter 1000 project entails building a demonstrator (contrary to the projects listed above, which are commercial) at the Grand Port Maritime de Marseille site in Fos-sur-Mer. It is designed to test the injection of hydrogen produced with electrolysis and synthetic methane into the gas transmission network. This would be an innovative 1 MW hydrogen production plant with two electrolysers using different technologies: PEM (membrane) and alkaline. The demonstrator will also have a CO_2 capture unit on the chimney stack of a neighbouring industrial building and a methanation unit to convert the hydrogen produced and the CO_2 thus recycled into synthetic methane.
The consortium is led by GRTgaz.
RTE became part of this project, which brings together about ten industrial partners, in 2017. For RTE, the goal is to test the technical operation of electrolysers under real conditions and to evaluate whether they can provide services to the power system, taking into account not only their technical capabilities but also any operating constraints that may arise if they are integrated into a more complex system that ultimately includes injection into gas networks.



3.4 The development of electrolysis: Identifying key parameters for a comparison to steam reforming

As was done for the studies in the Forecast Assessment Report and electric mobility report, the analysis here uses a base-case scenario and several variants to determine the sensitivity of the results to different key parameters.

2035 Base case | **2035 Variants**

Steam reforming

Cost

€103/kWH_2 p.a.

The cost of hydrogen produced via natural gas steam reforming is based on the depreciation of **steam reformers...**

CO_2 price

$9/MBTUgas

New Policies forecasts (IEA – WEO 2018)

€30/tCO_2

...and the prices of **natural gas** and **CO_2.**

Electrolysers

Cost

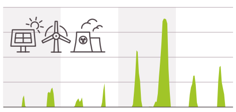
Base case: **87 to €100/kW_e p.a.**[3]

Costs include **the entire electrolysis system, including ancillary equipment.** In addition to CAPEX, annual fixed costs are a key factor, including lifespan, cost of capital, and fixed operating costs.

Variants: **48 to €55/kW_e p.a.**

Operating mode

1 When marginal renewable or nuclear power is available

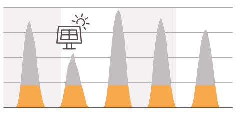


Operation when prices are low.

2 Baseload electricity, excl. when the system is under stress

Operation all year except when prices are high.

3 Coupling with self-generation (for instance PV)



Operation at production site.

Volume produced

Base case: **630 ktH_2 p.a.**

Guidance from public authorities (Multi-Annual Energy Plan/ National Low-Carbon Strategy) for 2035: corresponding electricity consumption is **30 TWh/year.** Efficiency is assumed to be **70%.**

Variants: **420 ktH_2 p.a.**

Corresponding electricity consumption is 20 TWh/year

3. Range depends on annual hours of operation, factoring in the necessary replacement of the battery (Source: IEA 2019, The Future of Hydrogen)

		2035 Base case		2035 Variants
Electrolysers	Uses	**Industry**	**Industrial** use of hydrogen as an input, the decarbonisation of which is a priority, requires **continuous supply** of hydrogen.	Transport; Direct injection into gas network; Synthetic methane; Buildings
Storage	Salt caverns	**€15/MWh discharged**	In the absence of specific data for corresponding costs, a **normative cost** has been applied, based on **standard use of stored gas.** Given the atypical use of stored gas in certain modes, this order of magnitude **could increase sharply,** which will be analysed in later studies.	
Adaptation of the electricity mix	Nuclear	**€226/kW/year**	Electrolysis will not develop in the volumes projected at the margin of the power system; rather it will require an **adaptation of the carbon-free generation mix,** with increases in installed wind or solar capacity and/or preservation of existing nuclear capacity.	
	Wind	**€124/kW/year**		
	Solar	**€54/kW/year**		

	Solar	Wind	Nuclear capacity preserved
CAPEX (€/kW)	550	1,188	737
Fixed OPEX (€/kW/an)	15	40	121
Lifespan (Yrs)	25	25	10
WACC (%/yr)	5%	5%	7%

Variables — Price of CO_2

2035 Base case: **€30/tCO_2**

gas	coal
9 $/MBTU	**84** $/t

New Policies forecasts (IEA – WEO 2018)

Consumption by **electrolysers** and the adaptation of the electricity mix may have an effect on fossil-fired generation, the variable costs of which are shaped by the prices of **gas** and **coal,** and the **CO_2** price.

2035 Variants: **€100/tCO_2**

gas	coal
8 $/MBTU	**67** $/t

Sustainable Development forecasts (IEA – WEO 2018)

Network — Cost

€17/MWh$_e$ **Mode 1**

€7/MWh$_e$ **Mode 2**

€2/MWh$_e$ **Mode 3**

The electrolyser needs access to the **electric grid** either to power its operation or, if it is coupled with self-generation, to inject surplus generation. Different trade-offs are possible in terms of the voltage of the connection to the grid, depending on constraints at the site, the cost of connections, and any additional network infrastructure to be added at the facility.

4. TECHNICAL ANALYSIS

THE POWER SYSTEM CAN ACCOMMODATE THE DEVELOPMENT OF HYDROGEN PRODUCTION THROUGH ELECTROLYSIS

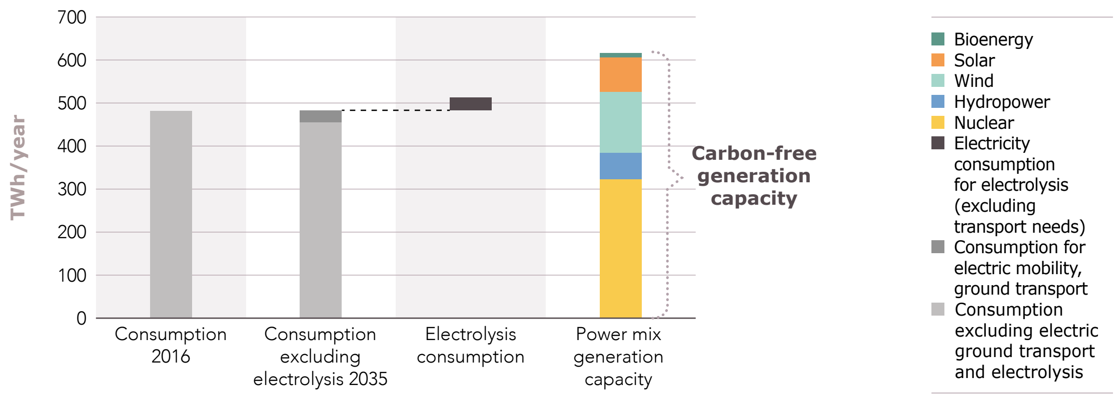
4.1 Regardless of the operating mode adopted, the French electricity mix is more than able to produce the power needed to meet the country's low-carbon hydrogen targets

Meeting the long-term low-carbon hydrogen production targets set by public authorities will require generating large quantities of electricity. The objectives set out in the Multi-Annual Energy Plan / National Low-Carbon Strategy imply about 30 TWh of additional electricity consumption in 2035.

However, this increase in consumption will only represent 5% of total generation on that time horizon. In other words, **consumption by electrolysers will not pose a challenge for the power system in terms of energy volumes.** The electricity mix outlined in the Multi-Annual Energy Plan will produce ample electricity, even decarbonised, to more than cover estimated consumption on that horizon. The additional production associated with electrolysis, for the volumes called for by law and the National Low-Carbon Strategy, is below electric heating in volume terms, and corresponds to about 12 million electric vehicles.

Nor is this consumption likely to interfere with the power system meeting electricity demand: electrolysers are flexible by nature and will be able to shed load when supply is tight. In this sense, the results presented in this hydrogen study do not raise the same issues as the electric mobility study, which showed that developing smart charging was key to optimising the power system and security of supply.

Figure 13. Annual electricity consumption and carbon-free generation capacity in France (RES and nuclear) in 2035, based on government guidelines on the future of the electricity mix



4.2 The operating mode selected has an impact on the capacity of electrolysers, power demand, and on hydrogen storage needs

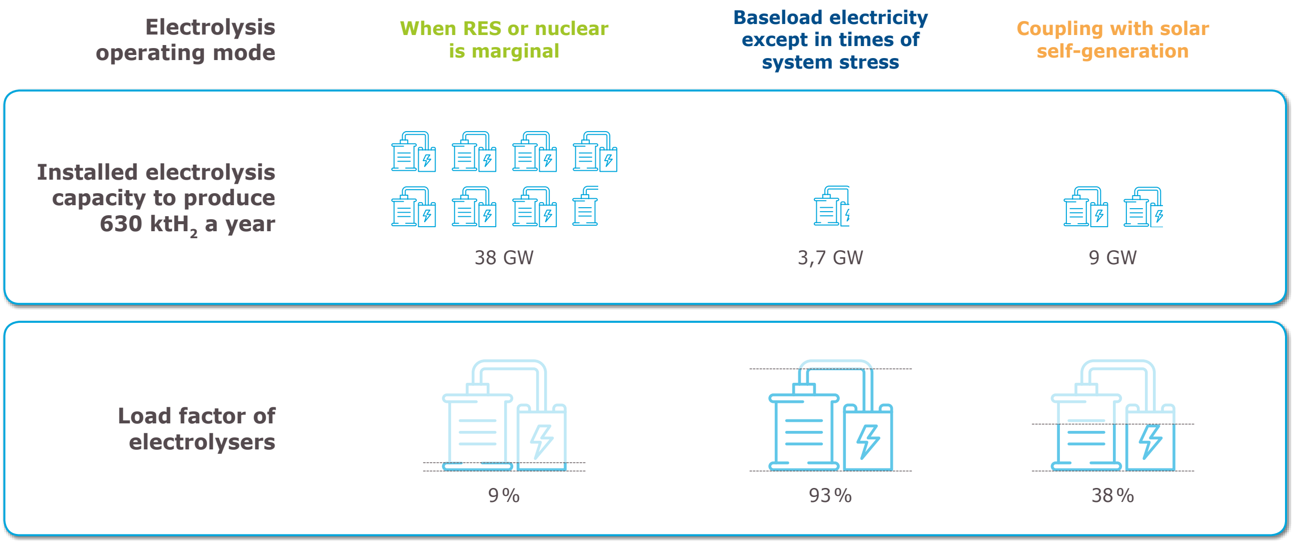
The three operating modes considered in this report can produce large quantities of hydrogen annually, enough to meet the targets set.

That being said, the implications of producing such volumes of low-carbon hydrogen with electrolysis will vary greatly depending on the operating mode used, particularly as regards the sizing of the electrolysers, hydrogen storage needs, and the capacity of related installations and the consequences for the power system. These three indicators are discussed in more detail below.

Electrolyser sizing

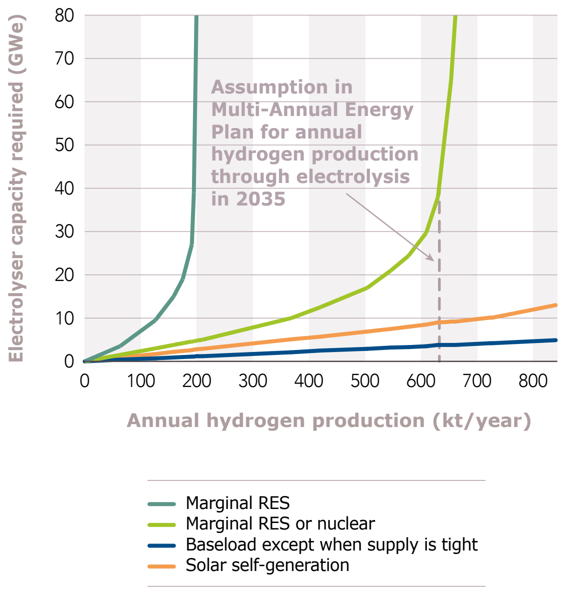
If low-carbon hydrogen is only produced when electricity prices are low (periods during which some marginal renewable or nuclear power is unused), then production will be limited to a certain number of hours per year. Indeed, even in 2030-2035, there will likely not be many periods of the year when no generation from fossil-fired plants is needed to maintain balance on the power system in real time. The consequence of this fact is significant: if (in an extreme case) all 630,000 tonnes of hydrogen were to be produced exclusively during these periods, the combined capacity of electrolysers would have to be 38 GW. This could be a challenge in and of itself since there is no guarantee that enough industrial capacity would be available to develop that many electrolysers in 15 years or so.

On the other hand, with operating modes in which only baseload electricity or solar self-generation is used, electrolysers can operate for more hours, meaning the total capacity required is much lower, either 3.7 GW (mode 2, baseload excluding times when supply is tight) or 9 GW (mode 3, coupled with solar self-generation).



In "marginal RES or nuclear" mode, the average load factor of electrolysers depends in large part on hydrogen production targets

Figure 14. Installed capacity required depending on hydrogen production with no change in the electricity mix



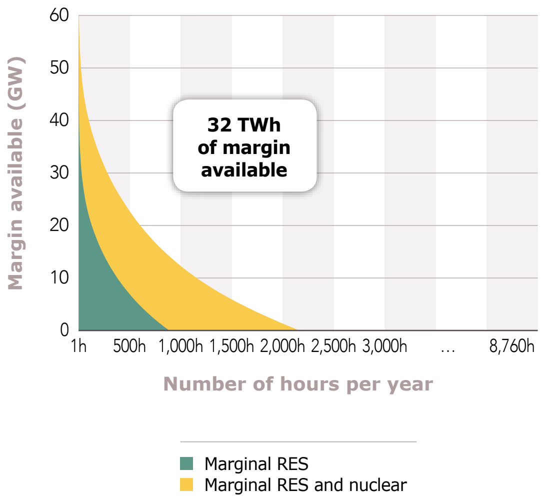
With operating mode 1, electrolysers operate during periods when unused renewable or nuclear power is available, this to guarantee that carbon-free electricity can be purchased at a low cost. However, marginal renewable and nuclear power is not unlimited.

In addition, the more electrolysis facilities operate in this mode, the fewer periods there will be during which marginal carbon-free electricity is available, causing the electrolysers to have a low load factor.

As discussed above, for the low-carbon hydrogen production objectives set out in the Multi-Annual Energy Plan (~600,000 t/year) to be met with electrolysers operated exclusively in this mode, significant capacity would be required (38 GW) for an average load factor of no more than 10%.

On the other hand, if the target for hydrogen produced in this operating mode is lower, then significantly less electrolyser capacity is required: for instance, it would be possible to produce a third of the hydrogen called for in the Multi-Annual Energy Plan (~200,000 t/year) with installed electrolyser capacity nearly ten times below the figure mentioned above (~4 GW), and the electrolysers would have a much higher load factor (about 30%).

Figure 15. Duration curve of marginal renewable and nuclear power generation accessible in France, factoring in interconnections



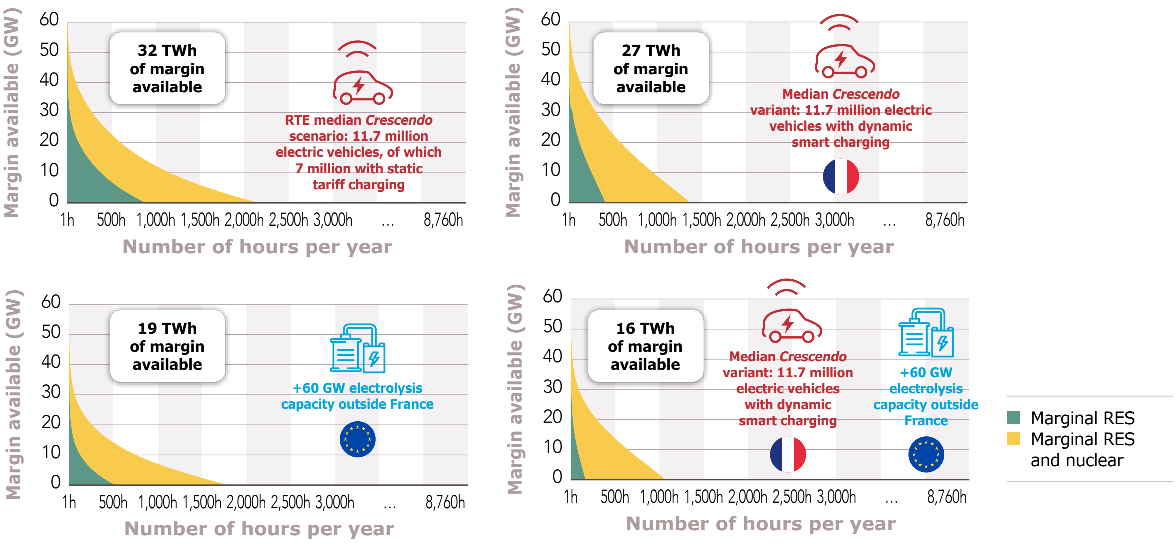
In "marginal RES or nuclear" mode, electrolysers compete with other flexible uses for access to carbon-free electricity

In this operating mode, the goal is to purchase electricity to power electrolysers during periods when marginal carbon-free generation (from renewable or nuclear sources) is available at low cost. It is a way to capitalise on the flexibility of electrolysers and optimise the use of decarbonised electricity generated at low variable cost that otherwise would be lost.

However, it is safe to assume that other flexible electricity uses, or electrolysers elsewhere in Europe, will be pursuing similar strategies to optimise their electricity purchases. The analyses RTE presented in its electric mobility report of May 2019 notably showed significant interest in developing smart charging systems allowing charging to be concentrated in periods when prices are low, especially when marginal renewable or nuclear power is available. Likewise, the potential development of stationary batteries could allow the storage of marginal renewable and nuclear power generated during these periods.
Thus, in operating mode 1, there is competition for access to renewable or nuclear electricity between electrolysers and other flexible resources (uses, storage, etc.).

The base-case scenario used by RTE for this study adopts the median scenario in terms of electric vehicle charging development (median *Crescendo* scenario from the electric mobility report) and electrolysis elsewhere in Europe, using operating modes that do not specifically target electricity purchases during periods when prices are low. In a scenario with even greater development of electric vehicle smart charging and/or a high volume of electrolysers in Europe operating in mode 1, it becomes more difficult, even impossible, to supply power to electrolysers in France exclusively with electricity purchased when marginal renewable or nuclear generation is available.

Figure 16. Marginal renewable and nuclear generation depending on the fleet of electric vehicles subject to smart charging and the power consumed by electrolysers outside France

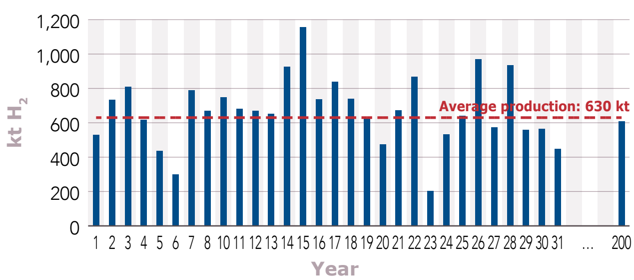


Storage capacity

Similarly, the operating mode selected will have a significant influence on the continuity or variability of hydrogen production, and consequently on the need for hydrogen storage capacity to ensure that demand is always met.

For example, if hydrogen is produced to provide continuous supply for an industrial process, then operating mode 1 (relying on marginal RES or nuclear) would require considerable hydrogen storage capacity (several hundred kilotons) that could (i) take in large quantities of hydrogen over short periods, and (ii) provide seasonal and even inter-annual storage to ensure continuity of supply even in years when periods of low prices are few and far between. Indeed, as illustrated in the figure below, with this mode of operation, production can vary greatly depending on weather conditions and unforeseen events at nuclear power plants.

Figure 17. Effective annual hydrogen production in the different scenarios simulated

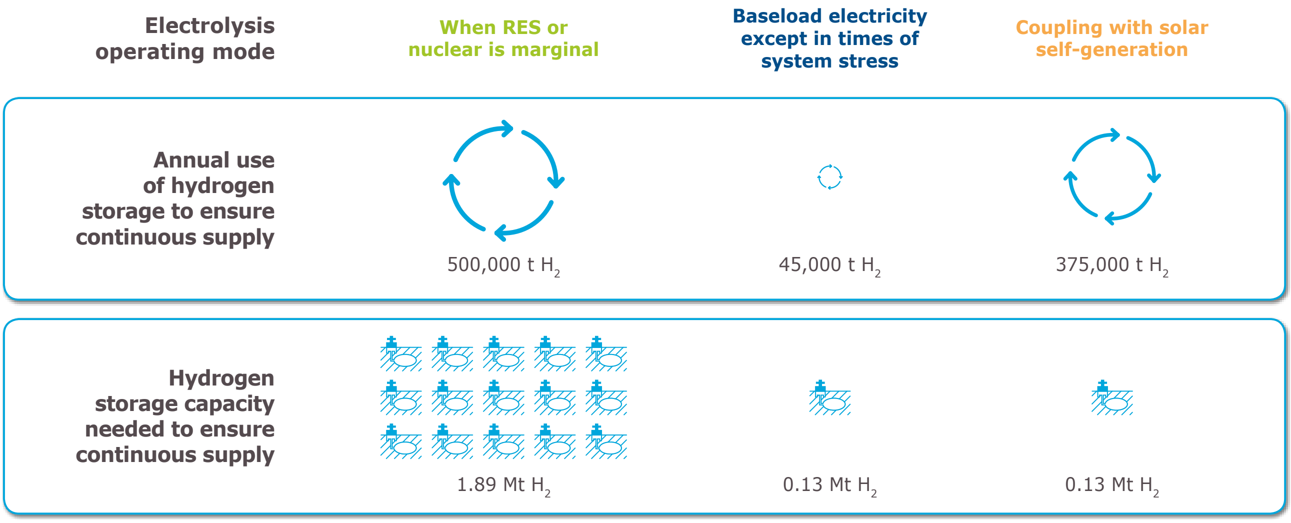


Such storage requirements may also represent a major challenge for this operating mode insofar as it would translate into significant costs, and acceptance of the proximity of storage sites could be problematic, notably due to the perceived risk of industrial accidents.

For uses other than continuous supply of hydrogen for an industrial process (for instance direct injection into the gas network), there is not the same need for continuity of hydrogen supply, though other constraints may arise with this operating mode (e.g. limits on the rate of hydrogen allowed in the gas network at a given point in time).

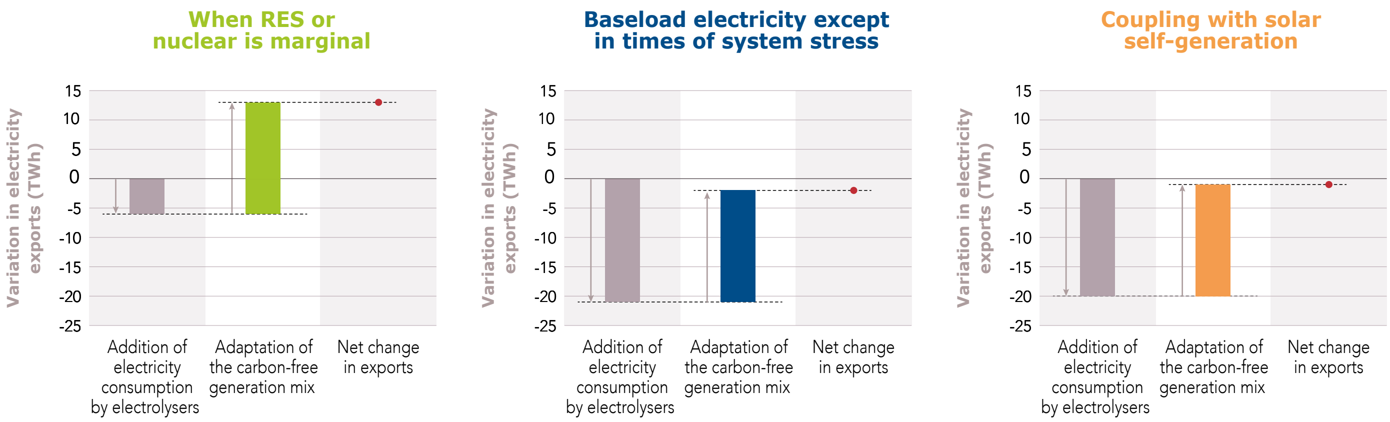
In mode 2 (baseload except when the system is under stress), storage needs are significantly reduced since production is more regular. But storage can guarantee steady supply during periods when the electrolysers are subject to load shedding (high electricity prices or participation in reserve mechanisms).

In mode 3 (coupling with solar self-generation), production is also more regular than in mode 1 (marginal renewable and nuclear). However, differences in production between day and night, and between summer and winter, are such that significant storage capacity is needed to ensure continuous supply.



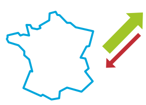
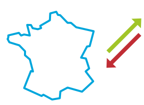
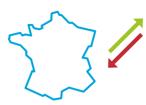
Influence on the electricity export balance

Figure 18. Variation in French electricity exports depending on operating mode of electrolysers



The operating mode used also impacts energy balances (for electricity generation) and electricity export balances.

- If electrolysers consume electricity during periods when renewable and nuclear generation cannot find another end-market, hydrogen production has only a marginal effect on electricity trading (consumption occurs at a time when a portion of carbon-free electricity is available in abundance and might otherwise be lost). Conversely, in baseload and self-generation modes, electrolysers compete directly for electricity with other uses in neighbouring countries, which tends to reduce exports.
- Adapting the electricity generation mix by boosting installed wind and photovoltaic capacity, or maintaining nuclear capacity, would help offset this reduction in exports (baseload excluding peak hours and solar self-generation modes) or increase them (marginal carbon-free electricity mode).

Electrolysis operating mode	When RES or nuclear is marginal	Baseload electricity except in times of system stress	Coupling with solar self-generation
Electricity export balance in 2035	 123 TWh	 108 TWh	 109 TWh

4.3 The siting of electrolysers on French territory is of secondary importance, except in very specific cases

The grid is ready to accommodate electrolysers

One way to meet the objectives set forth in law, and follow a trajectory such as the one in the National Low-Carbon Strategy, is to develop electrolysers with significant capacity (close to 100 megawatts) to benefit from economies of scale. This type of electrolyser would in theory be connected directly to the transmission system at very high voltage. The related costs are a direct function of the distance between the electrolysis facility and the closest point where it can be connected to the grid at the appropriate voltage level.

France currently counts two projects that involve connecting high-capacity electrolysers to the grid, one in Dunkirk and one in Port Jérôme. Both require new infrastructure to connect the units to the 225 kV network: for the Port Jérôme plant, the plan is to create a substation and two new overhead lines about 100 metres long to connect it to the existing 225 kV grid, while the Dunkirk plant would be connected to the Grande-Synthe substation by a new underground 225 kV line about 4 kilometres long.

RTE published an in-depth analysis of the challenges for the French transmission system on 17 September 2019, with its Ten-Year Network Development Plan *(schéma décennal de développement du réseau*[4] – SDDR). The plan shows that the network currently offers good geographic coverage with few potential weaknesses identified (supply to Brittany alone requires specific vigilance as of today).

In sum, projected trends in electricity consumption are not a reason to avoid siting electrolysers in France. Industrial and port areas are often suggested as options given their proximity to industrial activities, and they tend to offer excellent quality of electricity supply with sufficient network capacity nearby.

In a few specific cases, the right location can drive welfare gains

In its Ten-Year Network Development Plan, RTE analysed the sensitivity of required network strengthening to several parameters, notably the development of new electricity uses such as the production of low-carbon hydrogen. Its analyses also sought to explore whether careful siting of new facilities could provide relief to the network and delay, if not eliminate, the need to strengthen grid infrastructure.

This debate seems very timely as certain Northern European countries make hydrogen development plans: there is notably much talk in Germany and the Netherlands about siting high-capacity electrolysers near the landing points of lines connecting offshore wind farms as an alternative to very expensive grid strengthening efforts (for instance, North-South power lines in Germany). This implies using existing gas infrastructure to carry decarbonised hydrogen over long distances, or building new infrastructure specifically for hydrogen.

The studies conducted for the Ten-Year Network Development Plan show that the issues facing France are very different:

- The French grid is sufficiently sized and would not require the same magnitude of strengthening as Germany's (investments required over the next decade in the German plan are three times higher than in France);
- The major work required in France between now and 2030 does not involve building new infrastructure on greenfield sites but rather strengthening existing lines; this work is necessary under all the scenarios in which onshore

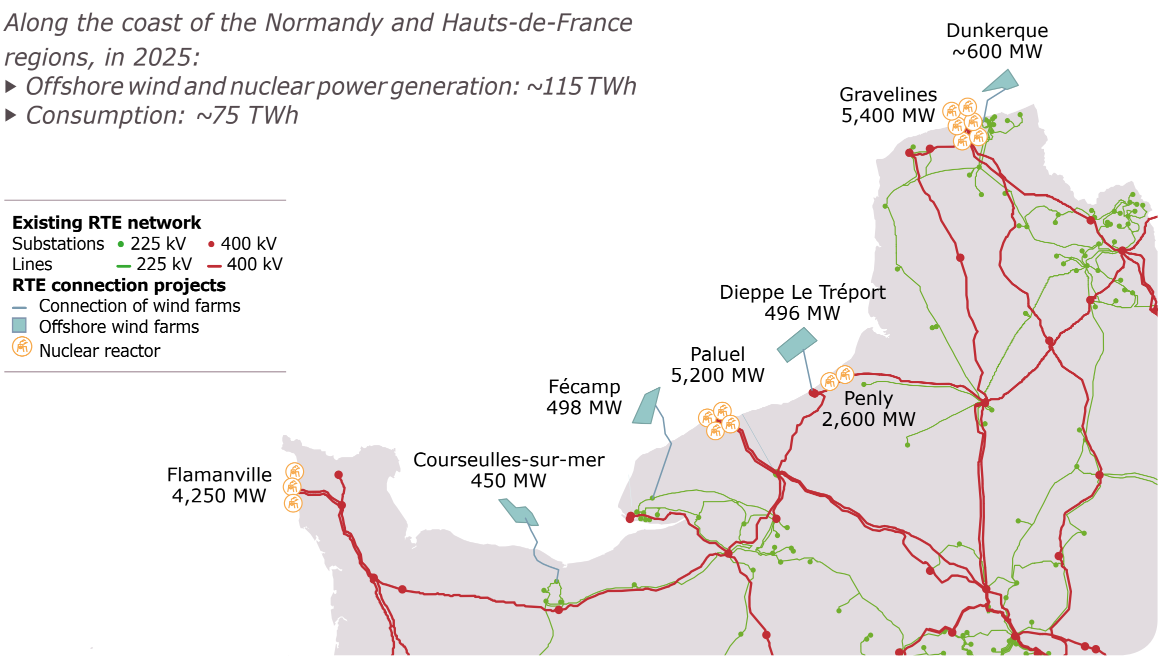
4. https://assets.rte-france.com/prod/public/2020-05/Bilan%20-%20Synthese%20D%C3%A9veloppement%20r%C3%A9seau%20%C3%A9lectrique%20-.pdf

wind and photovoltaic power development follow a trajectory included in the Multi-Annual Energy Plan.

Normandy is one exception: under some scenarios, electricity generation on the coast of Normandy (adding together output from nuclear power plants and the offshore wind farms planned through past or future calls for tender in the area) could increase sharply, making it necessary to revamp the network in the Normandy-Manche-Paris diagonal. In this case, siting high-capacity electrolysers near landing points or nuclear reactors could make it possible to postpone major strengthening.

In the Ten-Year Network Development Plan, RTE called for enhanced planning in certain geographic areas, including the Normandy coast, to anticipate these major upgrades. The potential development of low-carbon hydrogen production could be one of the tools considered within this context.

Figure 19. Network structure and nuclear power plants and offshore wind farms along the cost of the Normandy and Hauts-de-France regions



4.4 Electrolysers are in theory “technically” capable of providing flexibility services to the power system

For the hydrogen plan published by the French government in June of 2018, RTE was asked specifically about the benefits of having electrolysers participate in the different mechanisms that keep the power system balanced (system services and reserves for system balancing).

Since its consumption is flexible, an electrolyser can participate in all system services managed by RTE, which are summarised in Table 1. Where the secondary reserve (aFRR) is concerned, however, extraction sites must participate via a secondary market (exchange or counterparty transactions):

Tableau 1. Possibilities for consumers to participate in power system services managed by RTE and current remuneration

Objective	Activation	Total capacity in France	Direction of consumption	Current remuneration	
				Power	Energy
Contain frequency deviation	< 30 sec Automatic	Interruptible load 1,600 MW	↓	Based on availability and power (~30 to 70 €k/MW/yr)	-
		Primary reserve (FCR) 600 MW	↕	Daily auction (2018*: ~13 €/MW/h)	Spot price
Restore frequency to 50 Hz and re-establish exchanges at borders	< 400 sec Automatic	Secondary reserve (aFRR) 500 to 1,000 MW	↕	Regulated tariff (2020: ~19 €/MW/h)	Spot price
	< 15 minutes Manual	Rapid reserve (mFRR) 1,000 MW	↓	Annual tender (2020: ~5.6k €/MW/yr)	Balancing offer price
Reconstitute primary and secondary reserves, anticipate a future imbalance, manage congestion on the transmission network	< 30 minutes Manual	Complementary reserve 500 MW	↓	Annual tender (2020: ~3.9k €/MW/yr)	Balancing offer price
	Time varies Manual	Balancing 8.4 TWh in 2018	↕	-	Balancing offer price
Ensure security of supply during peak periods	-	Capacity mechanism 95 GW	↓	Capacity auction (2020: ~17k €/MW/yr)	Balancing offer price

In addition to the remuneration available for providing the services listed in this table, flexible consumption can participate in tenders for demand response capacity. This support mechanism is organised annually to promote the development of demand response in order to help meet the targets set out in the Multi-Annual Energy Plan (article L271.4 of the Energy Code).

* Non-consolidated when this report was drafted, the average value of auctions for the primary reserve in 2019 (daily since July 2019) was trending lower, falling below €10/MW/h.

flexible capacity is sold to a reserve manager, which aggregates capacity from several sites and sells it to RTE.

Nonetheless, significant technical capabilities are required to offer system services, and they must be verified ahead of time. For instance, participation in the primary reserve requires very short response times (< 30 sec.). While electrolysers would in theory be able to meet this criterion when they are “hot”, their performance must be tested to confirm their technical ability to provide this service.

Among other purposes, the Jupiter 1000 demonstrator is designed precisely to verify an electrolyser’s ability to meet the requirements to participate in this type of service, taking into account the constraints created when hydrogen is injected into the gas network, stored or methanised.

5. ENVIRONMENTAL ASSESSMENT

THE DEVELOPMENT OF ELECTROLYSIS WILL SIGNIFICANTLY REDUCE CO_2 EMISSIONS FROM INDUSTRY

5.1 Replacing hydrogen produced from fossil fuels with low-carbon hydrogen: National emissions fall under all scenarios

Electricity generation in France is to a large extent already carbon-free.

In 2018, CO_2 emissions related to the electricity sector reached 20 million tonnes, compared, for instance, with 274 million in Germany, 68 million in the United Kingdom and 93 million in Italy. On a per capita basis, power sector emissions in France are among the lowest in the world, matched only by countries like Norway (where almost all electricity is hydropower) and Switzerland (nuclear and hydro).

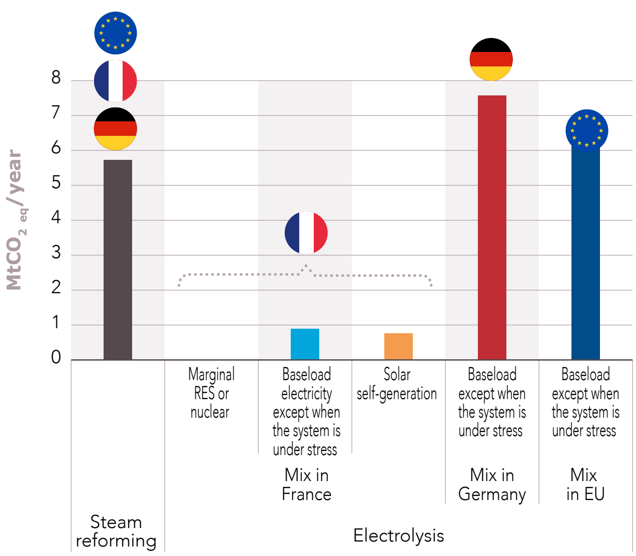
The guidelines set forth in France's Multi-Annual Energy Plan will allow this metric to improve even further. The scheduled closure of coal-fired plants in 2022 will lead to an around 7 million tonne reduction. And starting in 2022, growth in RES use should reduce the operating time of gas-fired plants. Under the Ampère, Volt and Multi-Annual Energy Plan scenarios, emissions associated with the French power system fall to an extremely low level of about 10 million tonnes a year toward 2030-2035.

This configuration is particularly favourable to a switch to electricity for hydrogen production.

Given that natural gas steam reforming emits about 9 kg of CO_2 per kg of hydrogen produced, the transfer of 630,000 tonnes of hydrogen from this production method to electrolysis would reduce France's emissions by nearly 6 million tonnes a year. Over the 2020-2035 period, **the development of low-carbon hydrogen could thus cut French greenhouse gas emissions by some 46 million tonnes.**

This result, consistent with the main studies of this issue, is attributable to France's electricity mix. In countries with mixes that produce electricity primarily (Germany) or almost entirely (Poland) with gas and coal, producing hydrogen through electrolysis has more of a negative impact on CO_2 emissions.

Figure 20. CO_2 emissions in a given country or area (France, Germany or EU, excluding effects on imports and exports) producing 630 kt of hydrogen, with no change in the electricity mix



5.2 For a given power generation mix, exporting electricity, as network capacity permits, nonetheless does more to reduce CO_2 emissions than producing low-carbon hydrogen

It is not possible to analyse the carbon balance of producing a portion of the hydrogen used by industry in France through electrolysis by looking only at national outcomes, as the power system operates as an interconnected whole.

The development of new electricity uses in France may thus impact exchanges with its neighbours and modify interconnected countries' use of fossil-fired power plants.

A comprehensive emissions analysis must therefore look at the entire European power system. This is possible with the model RTE uses in its Forecast Assessment Report, which accurately represents generation capacity and consumption at a European scale.

This type of analysis is particularly important with regard to low-carbon hydrogen production since, all other things being equal, exporting carbon-free electricity appears to be a more efficient way to reduce European emissions than replacing steam reforming with electrolysis of water.

The explanation is that most European countries still have a high carbon content in their electricity mixes when they rely heavily on fossil fuels, even gas. This will remain true of many European countries in 2035, even factoring in changes to electricity mixes called for in national energy and climate plans (NECPs).

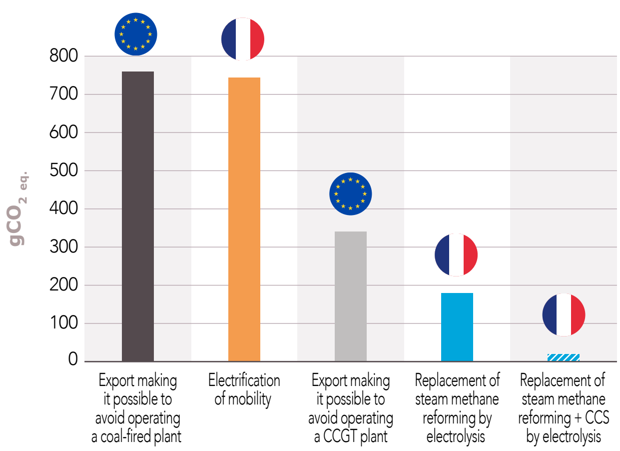
This result is noteworthy and different from the one obtained for electric mobility: RTE had concluded in May 2019 that, all other things being equal, it was more advantageous to decarbonise mobility than to export electricity produced in France to other countries. Indeed, an electric vehicle has a much greater efficiency than an internal combustion engine (by a factor of 3 to 4), and the fuel combustion avoided represents significant emissions. In this case, the reduction in CO_2 emissions is greater than that obtained by avoiding operating a gas-fired plant, and of the same order of magnitude as the reduction obtained by not operating a coal-fired plant.

Producing hydrogen from water electrolysis instead of steam reforming does not offer the same advantages:

- The efficiency of water electrolysis is of the same order of magnitude as steam reforming (about 70%);
- When electricity is produced with natural gas, efficiency is close to 55% for a CCGT plant, while steam reforming uses natural gas directly: thus, in energy terms, it is more beneficial to avoid operating a gas-fired plant than a steam reforming plant.

This analysis, though marginal, gives an idea of the European nature of the power system. It is nonetheless necessarily only partial since situated at the margin of a fixed system, and does not reflect changes in the situation between two given years. A comprehensive analysis would require taking into account the evolution of the electricity mix over the entire period.

Figure 21. Emissions avoided by producing 1 kWh of carbon-free electricity in France depending on whether it is used in France or Europe



5.3 A comprehensive analysis of the carbon balance must factor in the adaption of the French electricity mix called for in the Multi-Annual Energy Plan

Changes in the French electricity mix are guided, in broad terms, by the Multi-Annual Energy Plan. The latter notably calls for a sharp increase in decarbonised electricity production to support the development of new electricity uses (mobility, low-carbon hydrogen, buildings) and reduce greenhouse gas emissions.

It is thus important to factor in changes in the electricity mix corresponding to the transfer of end-uses to electricity when assessing impacts in terms of CO_2 emissions.

From this standpoint, the increase in decarbonised production called for in the Multi-Annual Energy Plan makes it possible to avoid the decrease in exports that would result from the development of electrolysis in France. **At the least, this change in the mix neutralises the effect that an increase in consumption in France could have had on CO_2 emissions from fossil-fired electricity generation in neighbouring countries.**

The chart below shows the breakdown of the three effects:

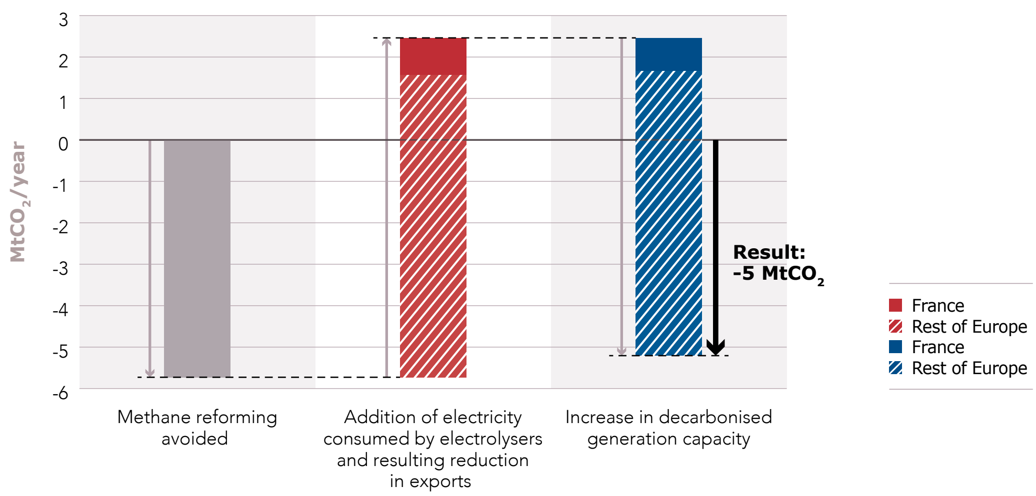
(1) emissions avoided during the hydrogen production phase (methane reforming avoided),

(2) effect on emissions from the European power system due to the additional power consumed by electrolysers and the subsequent reduction in exports,

(3) reduction of emissions in France and Europe associated with the increase in producible decarbonised electricity needed to provide 30 TWh of power for electrolysers.

In operating mode 2 (baseload electricity except when the system is under stress), effects 2 and 3 tend to offset one another. In the end, a switch from steam reforming to electrolysis, together with an adaptation of the decarbonised electricity mix, leads to reduction in European emissions of about 5 million tonnes a year.

Figure 22. Effect of the development of electrolysis on emissions at the European level in 2035 (operating mode 2)



5.4 All cases studied show a significant reduction in national emissions when electrolysis replaces steam reforming

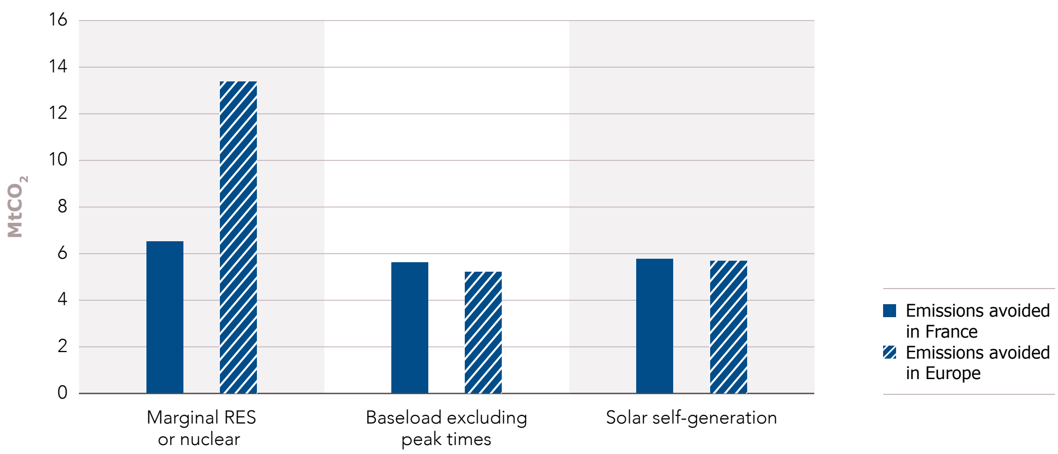
The three operating modes studied for electrolysis do not have the same influence on how the power system functions, and thus on the CO_2 emissions associated with electricity generation at the European level.

A comprehensive analysis of the carbon balance of the three operating modes makes it possible to identify where impacts overlap and where they differ:

- Regardless of the operating mode, increasing use of electrolysis avoids emissions associated with the conventional production method (steam reforming) with no significant rise in CO_2 emissions for the French electricity mix. For 630,000 tonnes of hydrogen production a year, this represents nearly 6 Mt a year of CO_2 avoided in France.
- At the level of the European power system, adapting the decarbonised electricity mix can at least neutralise the effect that a rise in consumption in France could have on the electricity export balance, and thus on CO_2 emissions associated with fossil-fired power generation in other European countries.
- With operating mode 1 (operation when marginal renewable/nuclear power is available), the development of electrolysis as part of the adaptation of the electricity mix delivers benefits both by replacing steam reforming and decarbonising the European power system. This operating mode is optimal in terms of lowering greenhouse gas emissions, but it does have specific drawbacks when it comes to continuous supply of hydrogen and the amortisation of fixed costs (see part 6.1).

Above and beyond the effects of producing hydrogen with electrolysis instead of fossil fuels, greenhouse gas emissions can also be reduced by transferring certain end-uses to hydrogen. By way of example, heavy-duty vehicle traffic currently produces about 20 million tonnes of CO_2 emissions in France a year; replacing 10% of the diesel used by those vehicles (roughly the equivalent of 60,000 heavy trucks) with carbon-free hydrogen would avoid 2 million tonnes of CO_2 emissions a year.

Figure 23. CO_2 emissions avoided in Europe and France, depending on how electrolysers are operated



6. ECONOMIC ANALYSIS FROM THE SOCIAL WELFARE PERSPECTIVE

THE COST OF TRANSITIONING TO ELECTROLYSIS IS HIGH BUT JUSTIFIED BY THE REDUCTION IN CO_2 EMISSIONS

6.1 The investments needed to develop sufficient electrolyser capacity to meet the government's targets depend in large part on the operating modes planned

More and more discussions and studies are focusing on economic analyses of the transformations that will be necessary to decarbonise hydrogen production, including studies from the IEA[5], IRENA[6] and DNV-GL[7]. These studies underscore the potential synergies between renewable energy generation and hydrogen, but also consider that hydrogen will play a modest role over the next because electrolysis is not as competitive as other solutions powered by fossil fuels, and due to the dearth of transmission and storage infrastructure. They also emphasise the role played by international trading of hydrogen-rich products (ammonia, methanol, synthetic hydrocarbons) that are likely to be produced wherever renewable resources are the most abundant and the cheapest.

RTE applies a systematic costing method

Important questions arise about methodology when it comes to evaluating the costs associated with a transformation scenario.

For this report, RTE adopted the generic costing method agreed upon with actors and already applied in the 2017 Forecast Assessment Report and the electric mobility study of May 2019. This method has the advantage of being systematic and integrating the different "system costs" for energy, and it can be applied to different types of public policies.

With this method, the first step is to account for all cost components from a social welfare standpoint, independently of who bears the costs and of any mechanisms that exist for redistribution between different economic actors (taxes, subsidies, etc.). The method, described in detail in the next section of part 6, is thus not intended to estimate the price of hydrogen from actors' viewpoint, but rather to evaluate economic impacts on social welfare in order to guide public policymaking. Part 7 offers additional analysis by evaluating the cost from the standpoint of actors (taxes, subventions…).

This costing method requires drawing a distinction between:

- For steam methane reforming facilities:
  - Full cost of steam reformers (depreciation of the equipment and maintenance costs);
  - Cost of gas supply.

5. IEA, 2019, The Future of Hydrogen
6. IRENA, 2019, Hydrogen: A Renewable Energy Perspective
7. DNV-GL, 2019, Hydrogen in the Electricity Value Chain

- For electrolysis:
  - Full cost of electrolysers (depreciation of the equipment and maintenance costs);
  - Cost of adapting the power system, including the networks (connection of facilities and adaptation of networks upstream) and electricity production; in the analyses presented here, a portion of the cost of adapting the decarbonised electricity generation mix is attributed to the consumption of electrolysers: nuclear, wind and photovoltaic, in proportion to their share of generation capacity;
  - The cost of the hydrogen storage capacity required to ensure continuity of supply for downstream uses.

Hydrogen transmission and distribution costs have not been evaluated at this stage, since (i) they will depend in large part on uses and existing business models, and (ii) they can be assumed to be the same regardless of how the hydrogen is produced (via conventional steam reforming or electrolysis). However, cost analyses could be further honed at a future date by factoring in a more specific picture of the downstream end of the hydrogen distribution chain.

Lastly, there is some debate about the best method for assigning a value to certain externalities, particularly accounting for the cost of CO_2 emissions. For analyses of a transition to decarbonised production modes, the value assigned to greenhouse gas emissions may play an important role in the economic assessment.

The method points to a transition cost of between 2 and 4 billion euros a year

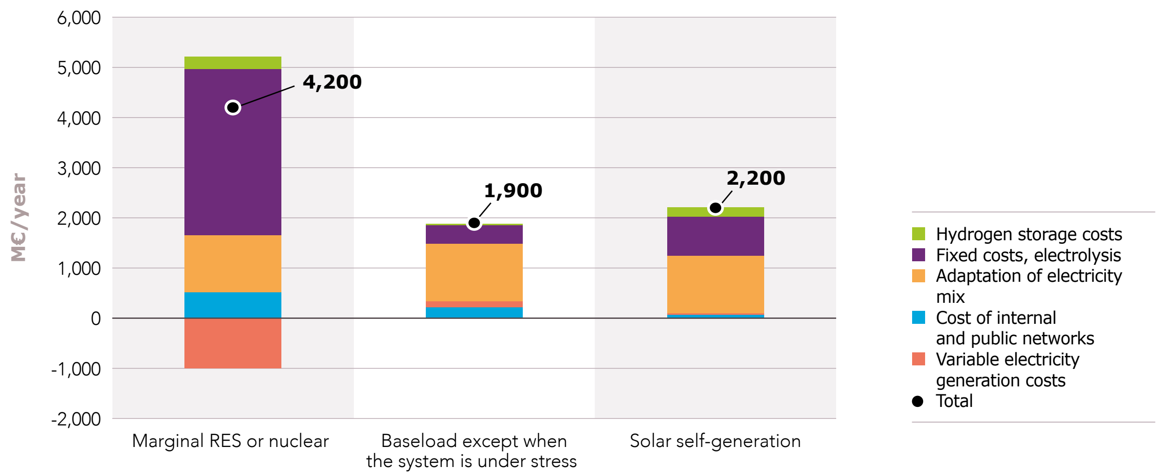
Applying the method presented above, the full cost of the transition by 2035, based on annual production of 630,000 tonnes of low-carbon hydrogen for industrial uses, can be estimated at between 1.9 and 4.2 billion euros a year, depending on the electrolyser operating modes favoured.

Electricity production accounts for a significant share (between 30% and 60%) of the total cost of the transition to low-carbon hydrogen.

Note that this conclusion differs from the one yielded by the electric mobility analysis, for which transition-related costs corresponded primarily to the construction of vehicles and charging infrastructure.

Yet this difference must be put into perspective, as it applies only when industrial uses of hydrogen alone are considered (for an industrial consumer

Figure 24. Cost of producing low-carbon hydrogen depending on mode of operation of electrolysers



of hydrogen, from a technical standpoint, there is no difference between consuming gas produced from fossil fuels or a low-carbon source). The same cannot be said of the new uses for hydrogen that could be envisaged, for instance heavy transport, which would represent a transfer of uses and thus require new equipment on the user end: in this case, the switch will cost more, and the conclusion will be much closer to the one in the electric mobility study.

The cost of reaching the production target set by the government seems to vary greatly depending on the operating mode, consistent with the technical differences outlined in section 4.2:

- Production concentrated exclusively in periods when there is a margin of decarbonised generation (operating mode 1) would require increased electrolyser sizing (38 GW of installed capacity), translating into high fixed costs (powerful electrolysers and creation of dedicated hydrogen storage facilities) and low variable costs (electricity purchased at times when prices are low)[8]. All in all, the social welfare production costs would be close to 4.2 billion euros a year, with about 80% of this corresponding to depreciation of the electrolysers.

- Operating mode 3 (coupling with solar self-generation) leads to lower production costs of about 2.2 billion euros a year, especially because significantly less electrolysis power would be required.

- Operating mode 2 (baseload, off-peak) yields the lowest production cost thanks to lower electrolyser capacity required, related to the longer hours of operation.

8. From France's standpoint, a decrease in variable electricity generation costs abroad as a result of increased electricity exports with this mode has a roughly proportional effect on the electricity trade balance

6.2 Replacing steam reforming with electrolysis drives up hydrogen production costs, even based on optimistic forecasts about trends in electrolyser prices…

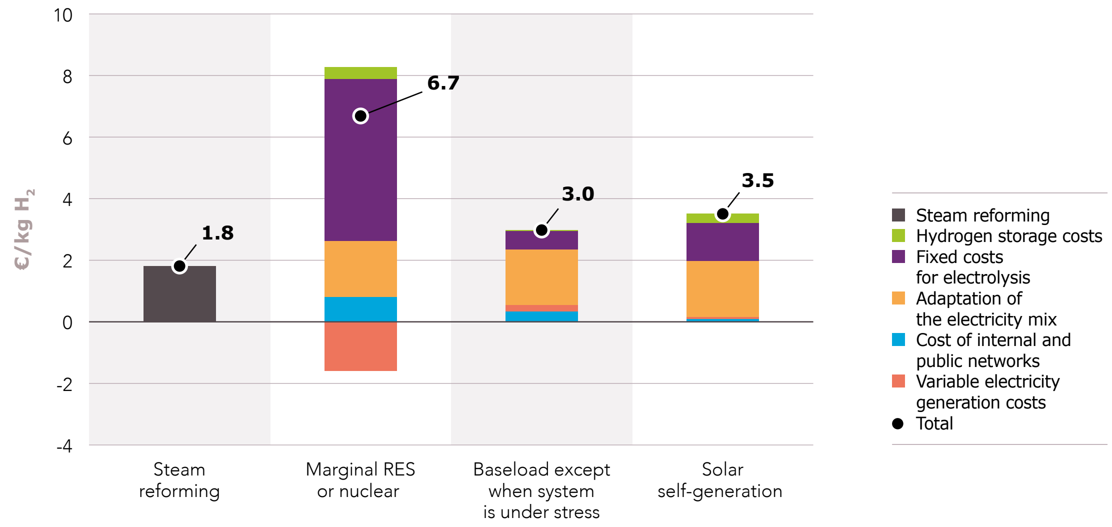
The costs associated with the different modes of producing hydrogen through electrolysis can be compared to those associated with steam reforming through measurements per kilogramme of hydrogen produced. Here again, the analysis is conducted from the welfare standpoint and does not take into account at this stage the taxes and other redistribution mechanisms that can affect the final price of hydrogen from the viewpoint of economic actors.

Without assigning a value to greenhouse gas emissions and for the assumptions adopted here, the analysis shows that the welfare cost of producing hydrogen through electrolysis is greater than with steam reforming, regardless of the operating mode used.

The cost of adapting the power system[9] alone represents, in electrolyser operating modes 2 and 3, about €2/kg of hydrogen produced, which is higher than the full cost of producing hydrogen with steam reforming.

As regards the cost of electrolyser systems, the assumption adopted in this analysis corresponds to annual payments of €87 to €100/kWe depending on hours of operation per year (if long hours, cells are replaced more often). Beyond the initial investment cost, assumptions about equipment lifespan and cost of capital may influence the economic evaluation of electrolysis.

Figure 25. Cost of substituting electrolysis for steam reforming, based on continuous delivery of 630,000 tonnes of hydrogen p.a.



9. Calculation assumes further development of wind and solar power and a reduced rate of decommissioning of nuclear capacity, pro-rated to the generation capacities of the three energy sources included in the Multi-Annual Energy Plan/National Low-Carbon Strategy. Relative to the energy produced, the cost is close to €42/MWh of power.

The assumptions adopted in this study and presented in Table 2 are the product of a literature review and are consistent with other recent analyses (IEA, IRENA, etc.)

Nonetheless, significant questions remain about electrolysis cost trends between now and 2035 in general and particularly about investment costs. Several actors expect costs to decrease much more sharply as production reaches industrial scale. Moreover, Chinese manufacturers say they will be introducing systems with costs in the €200 to €300/kWe range, though more research is needed into issues around reliability, lifespan and security.

A sharp decrease in electrolyser costs would reduce the cost gap between electrolysis and steam reforming but would not eliminate it. Particularly, in operating modes 2 and 3 (baseload electricity purchased wholesale during off-peak times or coupling with local solar self-generation), the cost of electrolysers does not appear to be a central component of the analysis.

The sensitivity of business models to the cost of electrolysers is illustrated and discussed in sections 7.2 and 7.3.

Table 2. Assumptions about standard electrolyser costs

Parameters	Assumptions for 2035
System lifespan	20 years
Battery lifespan	90,000 hours
CAPEX – System	€700/kWe
CAPEX – Battery replacement	€210/kWe
Cost of installation, connection…	30% CAPEX system
Fixed operating & maintenance costs	2%/year CAPEX system
Weighted average cost of capital	5%/year

6.3 ... but the switch to electrolysis is justified in a welfare analysis if the value assigned to the environmental externality is equal to the shadow price of carbon

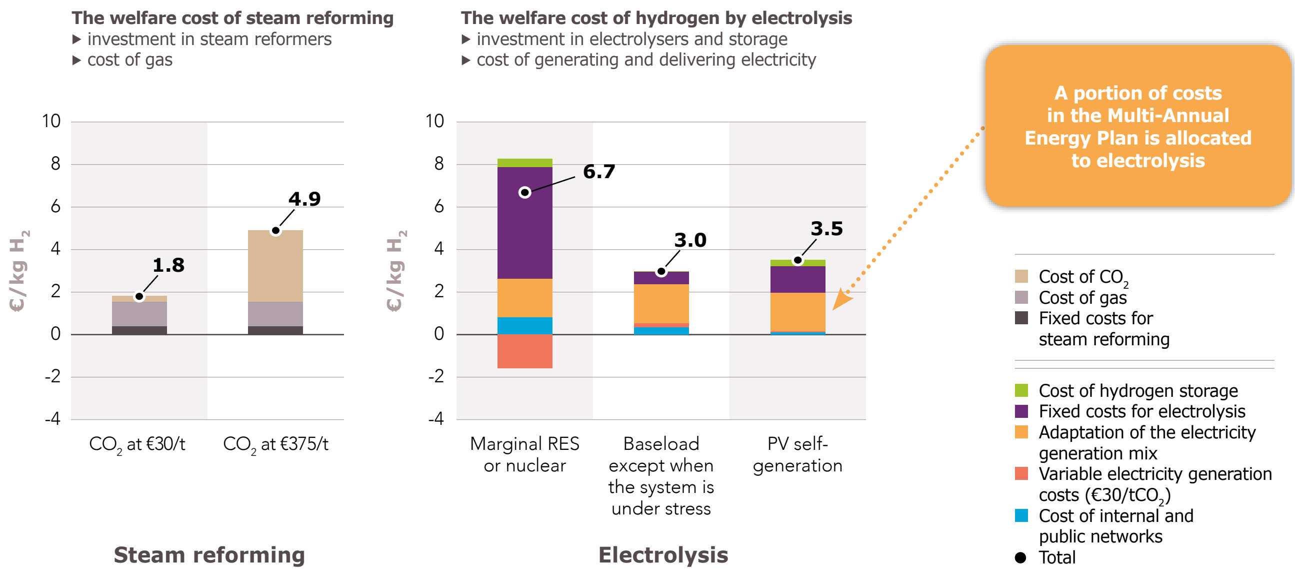
An assessment of the social welfare socioeconomic cost of energy system transitions must factor in environmental impacts, particularly those related to greenhouse gas emissions.

This can be achieved with several methods: assigning a value to emissions based on the carbon price on the European ETS market (currently about €25/t, possibly increasing to about €30/t under certain IEA scenarios) or based on the shadow price of carbon as defined by public authorities. The latter method is the standard for assessing climate-related investments in France.

The economic assessment conducted makes it possible to measure the sensitivity of the cost comparison between electrolysis and steam reforming to the carbon value. It shows that, from an economic standpoint, a value of €30/t of CO_2 emissions does not suffice to justify the development of electrolysis. On the other hand, applying the recently updated shadow carbon price[10] of €375/t in 2035, the result is the opposite: in operating modes 2 and 3 (baseload electricity or coupling with local renewable production), electrolysis appears less expensive than steam reforming from the standpoint of the social welfare. Under operating mode 1 (operation at times when marginal renewable or nuclear power is available), the cost of electrolysis is higher than for steam reforming since the electrolysers do not run long enough to justify the initial investment.

These results are justification for the social welfare to opt for low-carbon production under scenarios where the carbon price is set based on the desire to rapidly reduce emissions in the coming years. They make the case for high load factors to take advantage of the decarbonised generation potential (operating modes 2 and 3).

Figure 26. Comparison of the welfare cost of steam reforming versus electrolysis



10. Quinet A., 2019, The value of climate action: A carbon shadow price to evaluate investments and public policies

6.4 CO_2 abatement costs vary greatly depending on the operating mode and the scope considered (France or Europe)

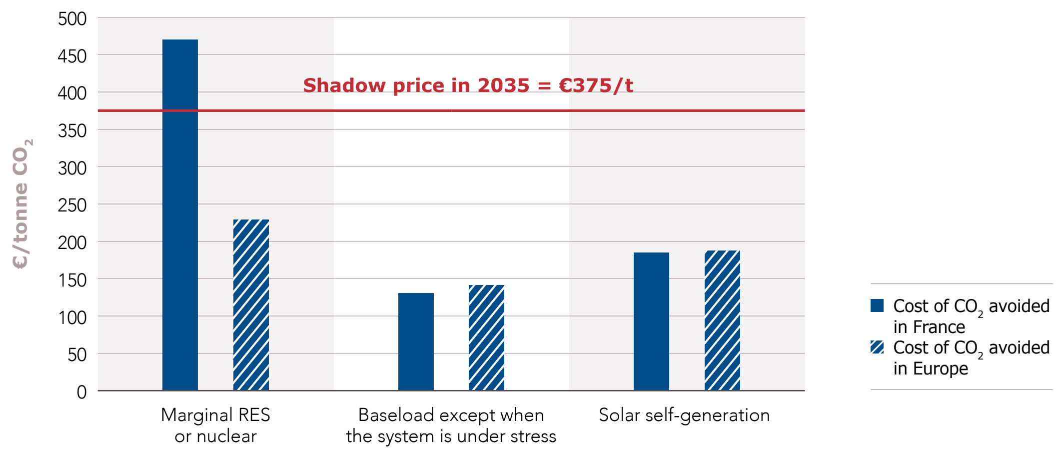
To round out the analysis of the economic justifications for developing hydrogen production through electrolysis as part of a climate action plan, an assessment of the CO_2 abatement cost associated with this transition can be conducted. This indicator is calculated by measuring transition costs in relation to the CO_2 emissions avoided, to identify the least expensive actions to be taken in priority to reduce emissions.

The goal is to determine the implicit cost of the CO_2 emissions avoided depending on the operating mode and scope (France or Europe).

For modes 2 and 3 (baseload electricity outside peak hours and coupling with self-generation), the implicit cost of CO_2 abatement varies little whether the scope is Europe or France, working out to about €150 and €200/t, respectively. These values are well below the shadow carbon price defined in the Quinet II report of €250/t in 2030 and €375/t in 2035, values that would justify introducing public policies to promote the development of electrolysers operating in these modes.

On the other hand, the high cost of operating in mode 1, relying on marginal renewable and nuclear generation, results in a high CO_2 abatement cost in France of about €500/t, above the shadow carbon price. The implicit cost of CO_2 abatement falls to €240/t if Europe-wide emissions are factored in, but this is outside the national framework defined in the carbon neutrality strategy and implicit in the calculation of the shadow price.

Figure 27. Cost per tonne of CO_2 avoided in Europe and France depending on operating mode



7. ECONOMIC ANALYSIS FROM ECONOMIC ACTORS' VIEWPOINT

THE COMPETITIVENESS OF LOW-CARBON HYDROGEN WILL DEPEND ON GOVERNMENT SUPPORT MECHANISMS AND ENERGY TARIFFS

7.1 In practice, the rate of development of electrolysis will depend on its competitiveness from actors' viewpoint

Unless standards are introduced for hydrogen production and consumption in France, the effective rate of adoption of low-carbon hydrogen production will depend not on the overall socioeconomic analysis but rather on this production technique's economic competitiveness relative to conventional ones, as perceived by economic actors (particularly industrial consumers of hydrogen).

Assessing the hydrogen price from economic actors' viewpoint requires looking beyond the welfare socioeconomic analysis and factoring in all methods, in such a way as to reflect the full cost of the hydrogen or energy for actors. While some cost components (depreciation of electrolysers or potentially storage systems) are found in both types of analysis, the economic signals perceived by hydrogen producers may differ from the fundamentals of the welfare cost due to the existence of taxes and subsidies, carbon pricing, and electricity price formation mechanisms. From the actors' standpoint, a price analysis must include these different components.

The price of the electricity drawn from the system to power electrolysers (in operating modes 1 and 2) may vary depending on the mode of operation. In the usual case where industrial firms purchase electricity on the market, the price paid reflects the marginal cost of production for every hour of operation (which notably depends on the variable cost of the most expensive generating plant providing power to the European market), and is thus influenced by trends in fuel prices (gas or coal) and the CO_2 price. In some cases, electricity users may have specific supply contracts that notably give them access to historic electricity (for instance ARENH). This type of contract may play a significant role in the electrolysis economy.

Two methods can be used to take into account long-term trends in electricity prices:

- The first is based on exogenous price scenarios (often average annual prices): this is the method used for instance in the IEA's forecasts;
- The second involves simulating the full cost of electricity per time period, based on the data from the base-case scenario: this is the method used in the Forecast Assessment Report and related studies. In this case, the price scenario is endogenous to the study. It is indispensable to use this second method to take into account differences in procurement costs between the different electrolyser operating modes

In all cases, the cost of electricity purchases on the market does not necessarily reflect costs associated with adapting the decarbonised generation mix in France as calculated in the welfare analysis, which are tied to the fixed costs of wind and photovoltaic power or extending the service life of existing nuclear.

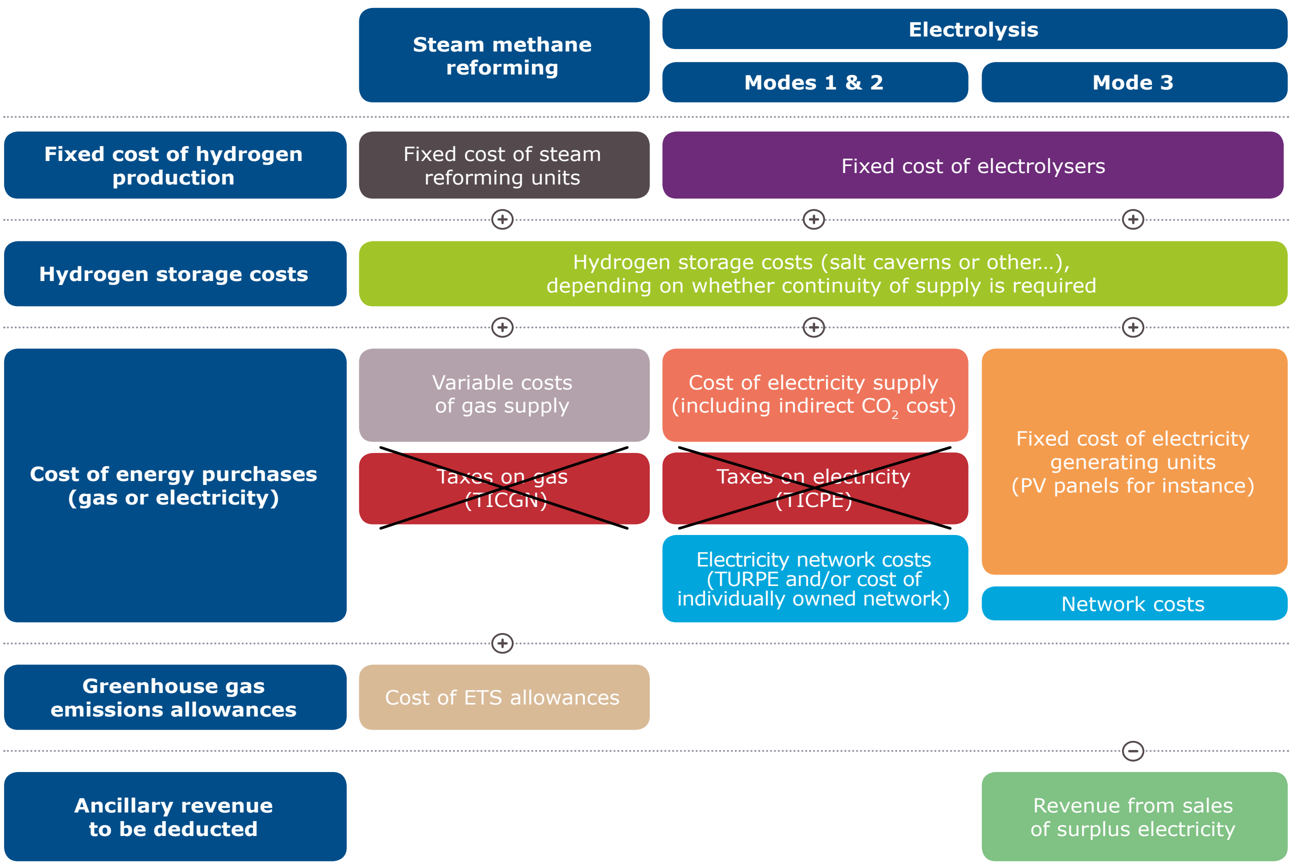
Network costs may be reflected in tariffs for using the public transmission network (TURPE) for users who buy electricity on the market (modes 1 and 2) and / or in the grid infrastructure costs associated with bringing power to the electrolysers (connection costs and the cost of operating and maintaining any grid infrastructure the hydrogen producer may own).

Regarding energy taxes, electricity consumers pay the "CSPE" (contribution to the electricity public service), also called the "TICFE" (domestic electricity consumption tax), equal to €22.5/MWh. This tax applies to all electricity consumed, though full or partial exemptions and exonerations may be awarded to certain types of consumption (specific uses, electro-intensive customers with a specific load profile, or self-generation for an individual self-consumption model). **Electrolysis processes are among the uses that are exempt.**

Similarly, gas consumers pay the "TICGN" (domestic natural gas consumption tax), which currently stands at €8.45/MWh. As of today, this tax does not apply to hydrogen production via steam reforming, since the gas is used as a raw material and not as an energy fuel.

Lastly, as regards **the carbon pricing** applicable to the industrial and energy generation sectors for their direction emissions, pricing currently depends on the EU ETS (European Union Emission Trading Scheme). The price of the allowances traded on that market may change over time and trade within wide ranges relative to the shadow carbon price (in practice, well below it). This price directly impacts the cost of producing hydrogen via steam reforming (industrial users must buy allowances even if they receive a certain number free of charge) and also hydrogen production through electrolysis, since it affects the electricity price. In the latter case, the indirect impact of the ETS on the cost of electrolysis could potentially be offset by specific types of aid, provided that electrolysis is among the eligible uses identified under EU rules.

Figure 28. Illustration of cost components from actors' viewpoint for different hydrogen production modes



7.2 Each production mode has a specific sensitivity to certain factors

At first glance, there appear to be major differences between the cost structures to which actors in the low-carbon hydrogen sector are exposed, depending on the operating mode they choose.

Of course, there is the initial investment in electrolysers, which many actors see as the decisive factor. Participants in the consultation expressed very different ideas about medium-term trends in the cost of an electrolyser facility: the average cost projected by 2035 was €700/kW (see Table 2, value excludes environmental costs, consistent with the IEA and IRENA studies), but some estimates were as low as €500/kW and even €200/kW or lower (electrolyser construction in China[11]).

The cost analysis conducted for this report nonetheless makes it possible to highlight other parts of the economic equation (notably the electricity supply costs discussed in detail in the previous section). This exercise challenges some deeply anchored perceptions, for instance about the very capital-intensive nature of electrolysers, but also the idea that a drastic reduction in electrolyser costs would suffice to make low-carbon hydrogen production very competitive relative to hydrogen produced with fossil fuels.

Regarding the takeaways from this analysis, it also appears that each model for producing hydrogen through electrolysis has a specific sensitivity profile:

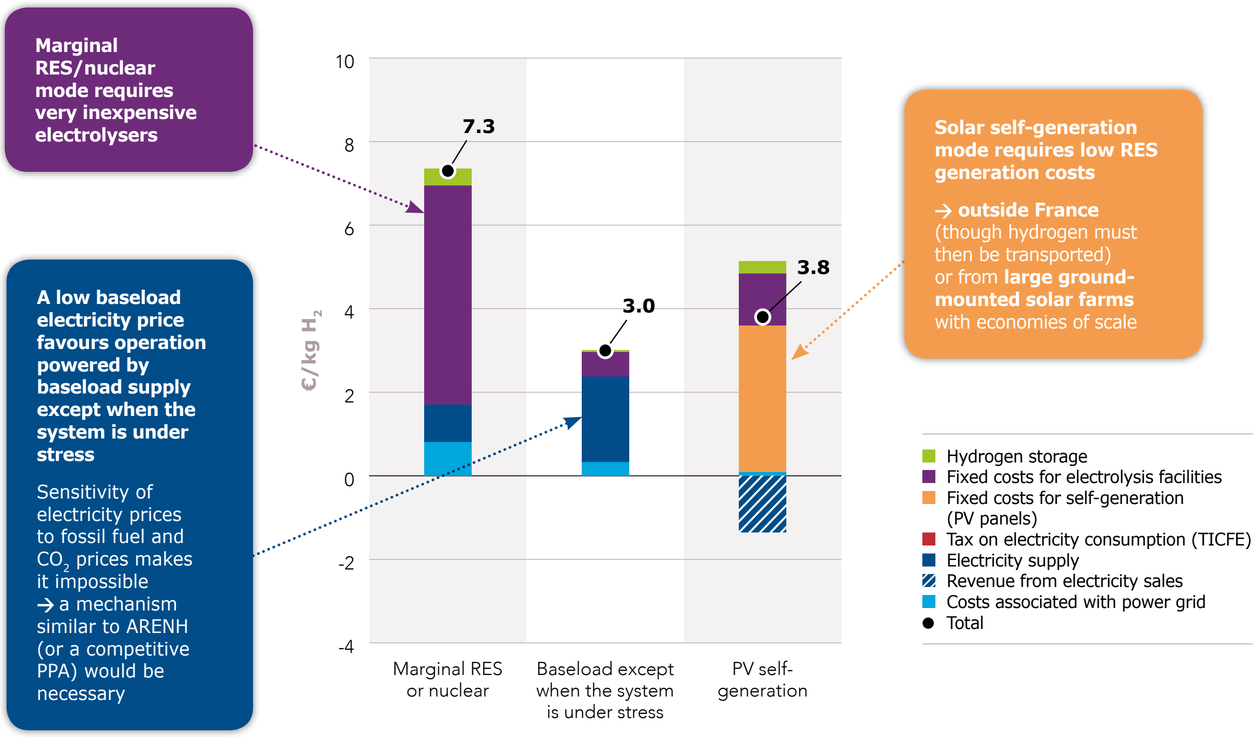
- Operating mode 1, **marginal RES or nuclear,** requires significant electrolysis capacity to maximise low-carbon hydrogen production at times when electricity prices are low: in this case, the unit price of electrolysers is the key parameter;

- Operating mode 2, **baseload except when the system is under stress,** implies "continuous" supply of electricity: in this case, the key variable is average market price and access to cheap electricity, thanks to the economic performance of the French mix and the fact that it is in large part decarbonised. For this model, the fixed costs associated with the electrolyser seem to be of secondary importance in the economic equation;

- Operating mode 3, **self-generation from local resources,** makes the electricity price and thus the CO_2 price unimportant. The key objective here is to keep the full cost of the self-generation unit in check. With photovoltaic power for instance, the main factor is the cost of the solar panels, and this would seem to favour large ground-mounted solar farms (the projects being planned with this operating mode indeed require installing very large facilities in the south of France to produce hydrogen at a competitive price). Different variants could be envisioned, for instance coupling with wind power, notably offshore (with electrolysers being situated near the landing points, though in this case the model factors in grid use) or based on large solar farms outside Europe in order to drive costs down (the economic analysis must then include the maritime transport of the hydrogen produced and its integration into the downstream value chain in France). These models are being studied in greater detail as part of the construction of the scenarios for 2050.

11. See BloombergNEF analysis, Hydrogen: The Economics of Production from Renewables, Costs to Plummet, August 2019

Figure 29. Cost price for a hydrogen producer depending on the mode in which the electrolyser is operated



7.3 To compete with hydrogen produced from fossil fuels, government support remains necessary

In this study, the benchmark price of hydrogen produced from natural gas steam reforming is estimated at about €1.8/kg, including a CO_2 value of €30/tonne (the projection for 2035 in the IEA-WEO 2018 New Policies scenario), not taking into account emissions allowances that may be allocated free of charge to this conventional hydrogen production method.

Even assuming a significant drop in electrolyser costs between now and 2035 and factoring in the possibility of the TICGN tax being applied to steam reforming at the current rate (lifting the price of conventionally produced hydrogen to just over €2/kg), **costs still seem much lower for hydrogen produced with steam reforming than through electrolysis, regardless of the operating mode.** The production cost differential works out to somewhere between +€1/kg and +€8/kg depending on the electrolyser operating mode and the assumptions made about cost trends.

Breaking costs down into components makes it possible to predict the impacts of different assumptions about changes in tariffs and costs associated with fundamentals. For instance, Figure 30 illustrates the effect of several variants on the cost of producing hydrogen with electrolysis: fixed costs of electrolysers reduced by a factor of two, photovoltaic costs reduced by about a third (for self-generation mode), electricity prices increased by a factor of two, or an increase in hydrogen storage costs.

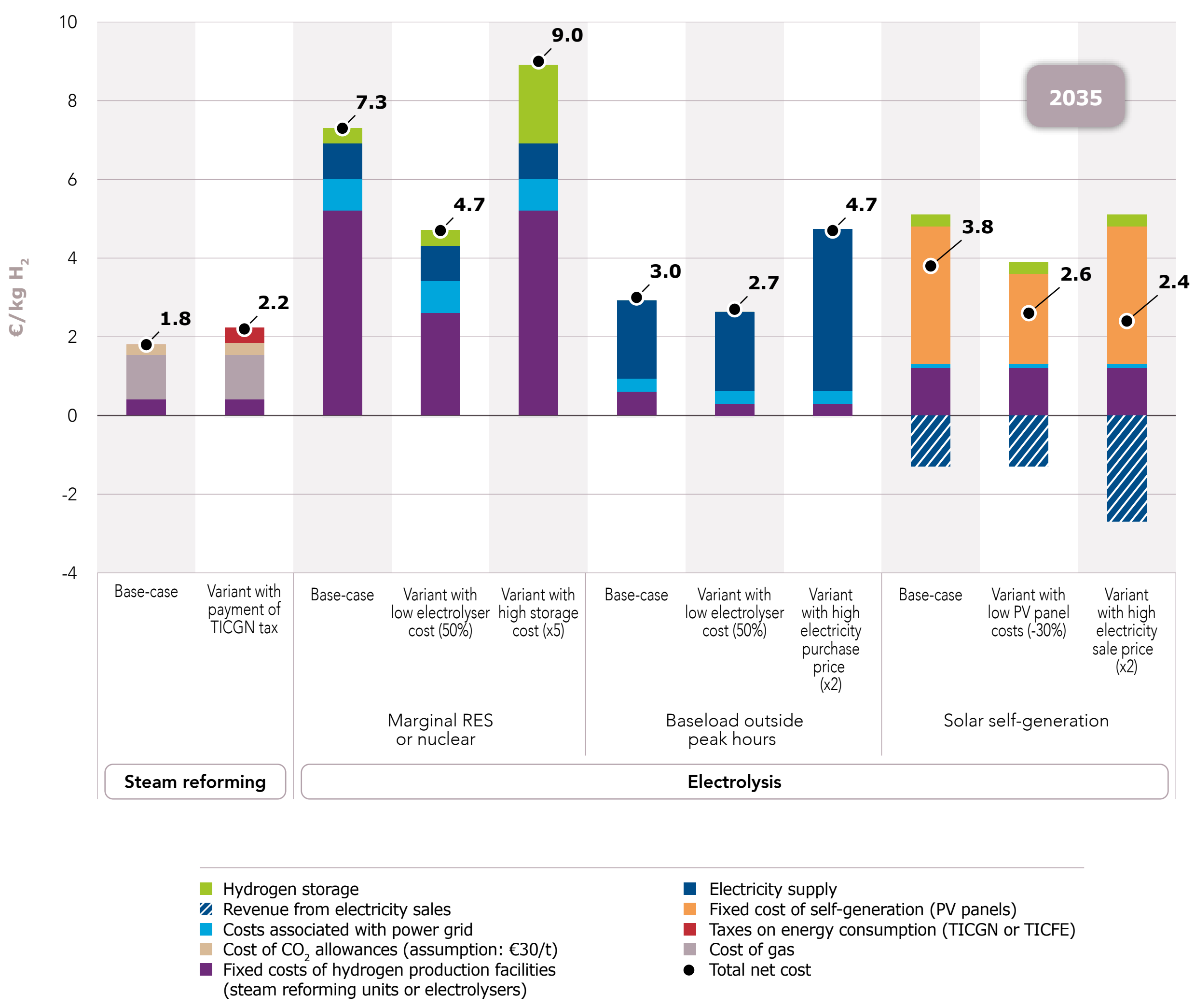
The costs presented in this section correspond to large-scale production, and are in all cases below the cost when hydrogen is delivered, usually by truck, to sites consuming small quantities of hydrogen (small-scale uses in the glass, agri-food, metallurgy, electronics and other sectors). Transport costs can result in a much higher purchase price for hydrogen delivered, driving it as high as €8 to €10/kg, or even €20/kg. This is why some stakeholders are exploring the possibility of developing smaller electrolysers near these "distributed" consumption sites, where electrolysis could be competitive relative to conventional production. This possibility is also advanced in the draft Multi-Annual Energy Plan and the DGEC-CEA report on the deployment of hydrogen submitted to the ministry for the ecological transition in 2018.

While the results presented in the RTE study tend to confirm that the cost of producing hydrogen through electrolysis may be lower than for hydrogen delivered in a conventional manner for distributed industrial uses, it is necessary to analyse the economic space for electrolysis with such uses in greater detail, taking into account the entire hydrogen value chain, including its distribution circuits.

In particular, it should be noted that while it is effectively possible to develop small electrolysers, it is in theory also possible to develop smaller steam reforming units. In both cases, the result is a relative increase in the fixed part of the installations for reasons of scale.

Moreover, when transported in small quantities, hydrogen is usually carried in pressurised steel or composite cylinders, which poses challenges not only for transport but also for packaging and storage. For the comparison to be accurate, these functions must also be factored in: even if hydrogen is produced near the consumption site, packaging it in pressurised cylinders can still represent a sizeable share of costs. These packaging and transport costs can be avoided if the hydrogen is used directly on-site, as it comes out of the electrolyser, which would be operated based on need, possibly very infrequently. In this case, the issue is the depreciation of an electrolyser used in this way. Such an analysis could be conducted at a later time, with a clear identification of the uses planned.

Figure 30. Hydrogen production costs applying different variants in terms of: type of production, operating mode, taxes, electrolyser costs, electricity prices, solar panel costs, storage costs



7.4 Paradoxically, an increase in the CO_2 price on the ETS market could discourage switching to low-carbon hydrogen production in France

Given the favourable carbon balance of electrolysis in France, one could expect a higher penalty for CO_2 emissions via the EU ETS to encourage this production mode by driving up the cost of natural gas steam reforming.

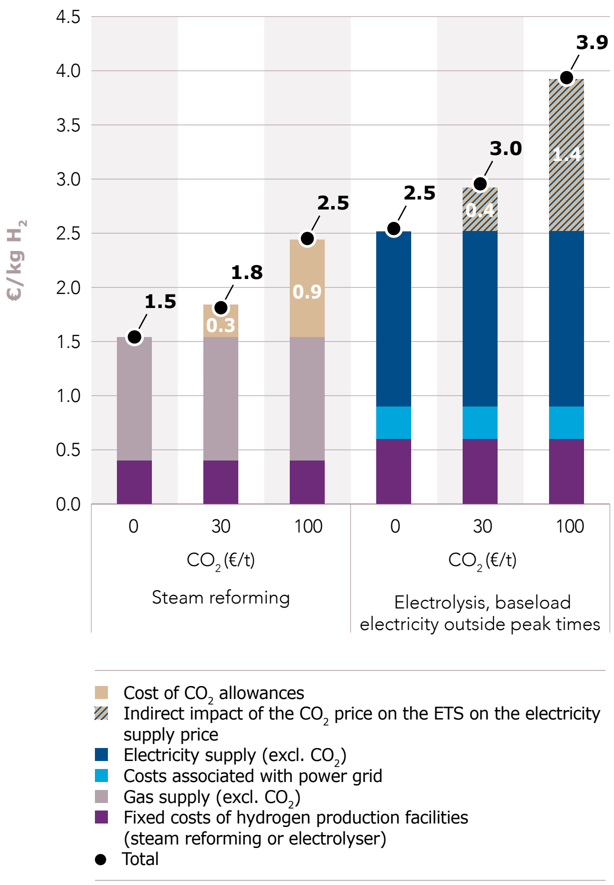
Paradoxically, analysis shows that a higher CO_2 allowance price on the European market could have the opposite effect, driving up the cost of producing low-carbon hydrogen more than the cost of producing hydrogen from fossil fuels.

If the indirect effects of the CO_2 price on the cost of supplying power for electrolysers are not offset, and even if steam reforming no longer receives free allowances, the share of the hydrogen production cost related to CO_2 would increase about 50% faster for electrolysis than for steam reforming. By way of example, in 2035, based on a CO_2 price of €100/tonne on the ETS, CO_2 would make up about €0.9/kg of the production cost for steam reforming compared with €1.4/kg for electrolysis using baseload electricity outside peak hours.

This paradox is explained by the way electricity prices are formed on the European market: though electricity production is in very large part decarbonised in France, price formation is already very much shaped by Europe-wide factors. The market price for electricity is often determined by thermal power plants, which will still account for a large share of the European generation mix ten years from now, even factoring in a surge in renewable energies and the energy programmes of the different European countries. In other words, the "balancing" generation plant fired up to match supply to demand in Europe, often called the marginal plant, determines the spot price on the electricity market, and it is often a fossil-fired power plant outside France (about 70% of the time in the scenario simulated for 2035). This sensitivity of electricity market prices to the CO_2 price thus means that, all other things being equal, exporting electricity would lead to a more significant reduction in power sector CO_2 emissions at the European level than replacing steam reforming with electrolysis in France (as explained in section 5.2).

An increase in the European CO_2 price signal would thus not automatically favour the development of electrolysis in France. Two conditions would have to be met for this to happen: (i) reduction in the free allowances allocated to steam reforming, and (ii) measures to offset the indirect effects of the CO_2

Figure 31. Sensitivity of hydrogen production costs to the CO_2 price for steam reforming and electrolysis (baseload electricity outside peak periods)



price on the ETS market on the cost of electricity delivered to electrolysers. Such compensation is called for in principle in the EU directive on the organisation of the ETS, though hydrogen production through electrolysis is not among the eligible uses listed today[12].

And meeting these two conditions would not suffice: even with a stiff CO_2 emissions penalty of €100/tonne applied only to steam reforming, the cost of conventional hydrogen production would appear to work out to about €2.5/kg, which would still be below the production cost for electrolysis.

Other incentive mechanisms could encourage the development of electrolysis: taxation of fossil fuel energies, investment subsidies, specific tariffs or contracts for electricity purchased for electrolysis…

The share of the CO_2 price in production costs shown in Figure 31 is factored into the electricity market price. This also shows the sensitivity of the business model to changes in the market price of electricity, which could also be triggered by fluctuations in global fuel prices (gas, coal, etc.).

12. State aid guidelines in the context of the system for greenhouse gas emission allowance trading in the 2021-2030 period are currently being reviewed. The final list of industrial sectors that will be eligible for compensation for the resulting higher electricity prices in this period is not yet known, but it seems possible that electrolysis will be excluded from the system.

7.5 Providing flexibility services to the power system may be a source of additional remuneration

A technical analysis of how electrolysers function reveals that they have the capability to provide flexibility services to the system.

Whether they are services that balance supply and demand or manage congestion on the transmission grid, electrolysers will be in competition with other kinds of flexibility: load shedding or postponement of other flexible consumption, stationary or onboard (electric vehicles) storage, dispatchable generation units… These levers are activated by market forces, or by RTE as a last resort, based on the merit order. Remuneration is determined by which flexibility services are the most competitive.

This makes it difficult to anticipate how these services will be remunerated over the medium to long term, as levels will depend on the flexibility services in competition and the cost of activating them.

For instance, France's participation in the European primary reserve is capped at about 600 MW. Since auctions became weekly, and daily since 1st July 2019, remuneration of this reserve has decreased sharply, and varies greatly with the seasons. Over time, if batteries (of all types) and demand response become major participants as expected, it could further depress remuneration of these services on related markets.

Figure 32. Trend in weekly marginal price of tenders for the primary reserve

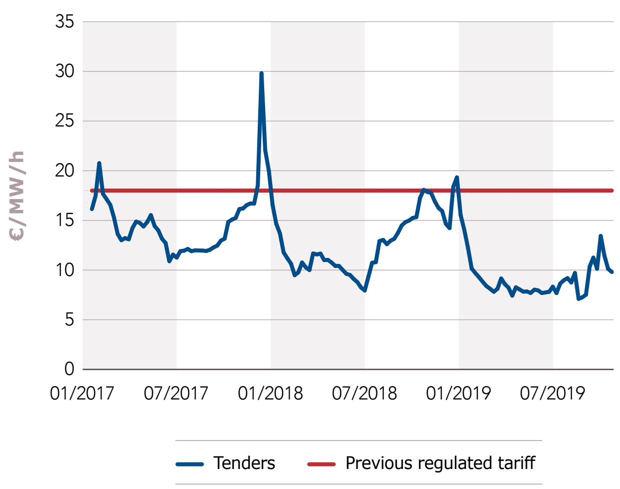
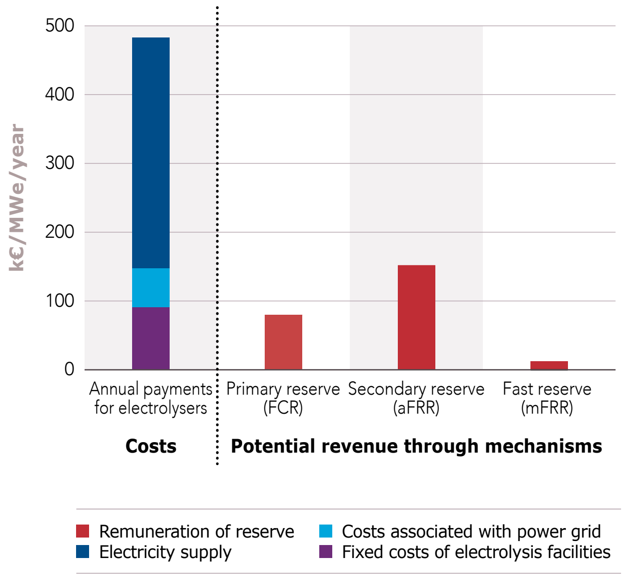


Figure 33. Electrolysis costs in 2035 for operation in baseload mode (8,000 h/year) and remuneration of reserves at current prices



The orders of magnitude of the current cost of flexible services suggest **that the participation of electrolysers in power system services could represent an additional source of remuneration, though this alone would not justify the development of electrolysis.**

Moreover, if electrolysers participate in these services, they will be subject to constraints in terms of availability, modulation and siting, and the additional costs these constraints could represent for hydrogen producers' business models will need to be assessed.

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