Long-term optimization of the hydrogen-electricity nexus in France

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Abstract

We model the optimal hydrogen and electricity production and storage mix for France by 2050. We provide a central scenario and study its sensitivity to the cost of electrolyzers, the hydrogen demand and the renewable energy deployment potential. The share of electrolysis vs. methane reforming with CO_2 capture and storage in hydrogen production is sensitive to the cost of electrolyzers, with the former providing around 60% in the central scenario. However, the system cost and hydrogen and electricity production costs are much less sensitive to these scenarios, thanks to the wide near-optimal feasible space of the solutions. The electricity production mix is almost fully renewable in the central scenario, while nuclear has a significant role only if the wind & solar potential limits their deployment, or if blue hydrogen is not authorized.

Keywords: Power system modelling; electricity markets; low-carbon hydrogen; levelized cost of hydrogen; green hydrogen; blue hydrogen; large-scale renewable integration; renewable energies; prospective planning; optimization.

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1. Introduction

While nuclear power currently produces around 70% of electricity in France, all nuclear reactors in operation will most likely have shut down by 2060 at the latest (RTE, 2021). Hence, a debate is going on concerning the country long-term electricity mix. Since the official national climate strategy implies zero CO_2 emissions from the power sector by 2050, the debate focuses on whether the long-term electricity mix should include new nuclear reactors or should be fully renewable. Several governmental and non-governmental organisations have recently published energy scenarios which have fuelled the public debate (RTE 2021, Ademe 2021, négaWatt 2021). The main differences among these scenarios are the above-mentioned respective role of nuclear power and renewables for electricity generation, but also the amount of electricity consumption and that of hydrogen which, in most of these scenarios, is used in the industry and transportation sectors to replace part of fossil fuels.

While the first two points (electricity mix and electricity consumption) have attracted a lot of attention, this is less the case for the latter (hydrogen consumption). However, the choices made for hydrogen production and consumption cannot be analysed independently of those made for electricity generation, especially if part of hydrogen is produced by water electrolysis. Firstly, electricity procurement cost constitutes an important part of the hydrogen generation cost, so the latter will depend on the electricity price – in particular, hydrogen may be cheaper if based on otherwise curtailed wind and solar generation, when the residual electricity demand is negative. Secondly, large hydrogen consumption might saturate low-carbon electricity deployment potential, thus impacting the electricity mix. Thirdly, in many scenarios featuring a majority of renewable in the electricity mix, hydrogen is used as a long-term storage option, through the power-to-gas-to-power loop.

Therefore, we develop a model to analyse simultaneously the optimal hydrogen and electricity production mixes. The model, labelled EOLES_elec_H_2, belongs to the EOLES (Energy Optimisation for Low-emission Energy Systems) family (De Guibert et al., 2020; Shirizadeh et al. 2020; Shirizadeh and Quirion, 2021, 2022). It optimises investment in, and dispatch of, production and storage options, minimising the annualised cost while satisfying electricity demand every hour for one year, subject to a zero net CO_2 emissions constraint.

The model allows us to address timely policy-relevant questions such as the respective role of new nuclear power stations and renewable energies in the electricity production mix; the hydrogen production mix, which may include electrolysis or blue hydrogen (steam methane reforming or autothermal methane reforming combined to CO_2 capture and storage); the energy storage options, including hydrogen, methane, batteries, and pumped-hydro storage. We analyse the cost of the optimal mix, as well as its robustness to various uncertain parameters, i.e. the cost of electrolyzers, the amount of hydrogen demand by the industry and transport sectors, and the renewable energy deployment potential.

We conclude that in our central scenario, the optimal electricity mix is almost 100% renewable, and that hydrogen is generated by electrolysis for around 60%, the rest being blue hydrogen, more precisely autothermal methane reforming combined to CO_2 capture and storage (CCS). These results are robust to uncertainty on the electrolyzer cost. Nuclear is significant only if wind & solar deployment potential becomes binding, either because hydrogen demand is very large or because the assumed deployment potential is low. Finally, we conclude that the overall system cost is more

robust to the uncertainty on the electrolyzer cost than to the uncertainty on hydrogen demand and on the renewable energy deployment potential.

In the rest of the paper, we present in turn the model (section 2), the scenarios (3) and the results (4) before concluding (5).

2. Methods and assumptions

2.1. EOLES_elec_H2 model

EOLES_elec_H2 belongs to the EOLES (Energy Optimisation for Low-emission Energy Systems) family of models (Shirizadeh et al., 2020). It performs greenfield and simultaneous optimisation of investment and dispatch, minimising the annualised system cost (investment costs, fixed and variable operation costs and fuel costs), subject to a series of constraints, the most important being:

- Zero direct net CO_2 emissions, implying that hydrogen produced through fossil methane reforming without CCS is ruled out, because its CO_2 emissions are too high. Moreover, even blue hydrogen (fossil methane reforming with CCS) generates residual emissions because not all the CO_2 is captured – we assume that 90% is captured and stored. Therefore, negative emissions have to compensate these positive emissions. In the model, such emissions occur through biomethane reforming with CCS. We assume biomethane production to be carbon neutral, so to reach zero net CO_2 emissions, hydrogen generation through methane reforming must be based on at least 10% of biogas.
- Electricity generation must satisfy demand every hour during one year. Ideally, several weather-years should be modelled to take into account the interannual variability of wind and solar production. Yet, to limit the computational burden, we only model the weather-year 2006, chosen because in previous work, we showed that it is representative of the 2000-2018 period (Shirizadeh et al., 2020).
- Hydrogen production must satisfy demand every hour during the same year. We assume a constant hourly profile for hydrogen demand, since hydrogen is assumed to be used in heavy industry (especially primary steel and ammonia manufacturing) and heavy transportation (shipping and aviation, plus perhaps long-haul road freight), generating a rather flat demand profile.
- Frequency Restoration Reserves for electricity generation are required, following ENTSO-E's guidelines given by equation (6) in Shirizadeh and Quirion (2021). The required amount of reserves increases with the proportion of solar and wind in electricity generation, and with annual electricity consumption. The aim is to be able to provide extra electricity in case of an unexpected decrease in wind or PV output, or of an unexpected increase in electricity consumption.

Electricity may be generated by solar PV, onshore and offshore (fixed or floating) wind, hydro (run-of-river, which is not dispatchable, and dam-based, which is), biogas used in open cycle (OCGT) or combined cycle gas turbines (CCGT), and nuclear (Figure 1).

Hydrogen can be produced by electrolysis, based on electricity directly sourced from a specific technology (wind, PV or nuclear) or from the grid. It can also be produced by steam methane reforming or autothermal methane reforming combined to CCS (blue hydrogen), in which case methane can be fossil or biogenic.

Energy can be stored in batteries, in pumped-hydro stations (PHS), in the form of hydrogen in salt caverns, or in the methane reservoirs. The power-to-gas-to-power loop is based on the direct combustion of hydrogen in CCGT[3].

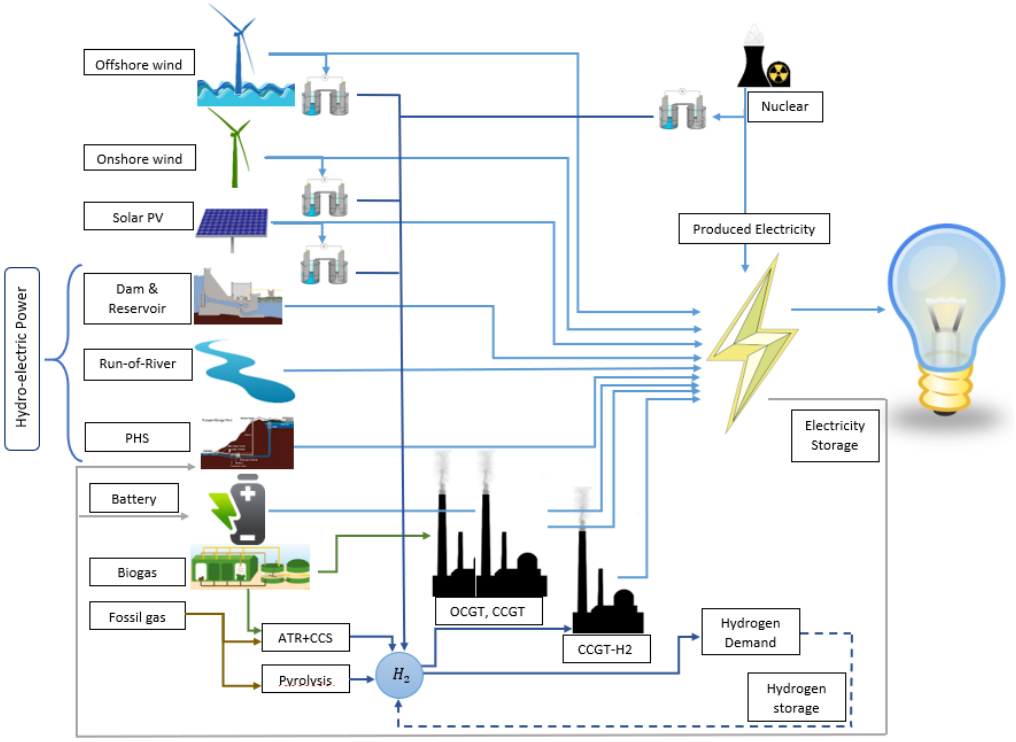

Figure 1. The EOLES_elec_H2 model

2.2. Main input parameters

2.2.1. Technology-related parameters

Table 1 shows the cost projections of the main electricity supply technologies by 2050, which are mainly from RTE (2021). The values from different sources than those mentioned in the last column are put between parentheses with the reference in footnote. The annuity is calculated, taking into account the interests during constructing, assuming a single discount rate of 4.5% per year (Shirizadeh and Quirion, 2021).

[3] In previous EOLES model, e.g. Shirizadeh et al., 2021, it was based on methanation (the production of methane from hydrogen and biogenic CO_2), which generated an additional cost and energy losses, but had the advantage of not requiring hydrogen storage.

Table 1. Electricity generation technologies parameters

Technology	Overnight costs (€/kW$_e$)	Lifetime (yr.)	Annuity (€/kW$_e$/yr)	Fixed O&M (€/kW$_e$/yr.)	Variable O&M (€/MWh$_e$)	Construction time (yr.)	Efficiency (%)	Source
Offshore wind, Floating	1,900+800*	40	159.9319	50	0	(2)[4]	-	RTE (2021)
Offshore wind, Fixed	1,300+800*	40	124.3915	36		(2)[1]	-	RTE (2021)
Onshore wind	900 + 28.5***	30	59.1238	25	0	(1)[5]	-	RTE (2021)
Solar PV ground-mounted	480 + 28.5***	30	31.92	8	0	(0.5)[6]	-	RTE (2021)
Solar PV commercial rooftop	680 + 28.5***	30	44.47	15	0	(0.5)[3]	-	RTE (2021)
Hydroelectricity – dam	-	60	-	11.4	0	-	-	JRC (2017)
Hydroelectricity – river	-	60	-	14.9	0	-	-	JRC (2017)
Biogas	-	-	-	-	80 (€/MWh$_{th}$)	-	-	RTE (2021)
Fossil gas	-	-	-	-	17 (€/MWh$_{th}$)	-	-	RTE (2021)
Nuclear power	4,700+180	60	342.86	115	10	(10)	-	RTE (2021)
CCGT	900	30	57.739	40	-	(2)[7]	57%	RTE (2021)
OCGT	600	30	38.493	20	-	(1)**	40%	RTE (2021)
CCGT for Hydrogen	1100	30	66.917	40	-	(2)**	57%	RTE (2021)

*Additional €800/kW$_e$ is the cost of the connection to the onshore electricity grid, based on French electricity transmission network operator's evaluation of existing offshore wind farm projects (RTE, 2019).
**Own assumption based on OCGT and CCGT plant construction time.
***RTE's updated 2020 network connection cost: https://assets.rte-france.com/prod/public/2021-04/Panorama%20T4-2020-V2.pdf

Table 2 shows the parameters for storage technologies, most of which come from RTE (2021).

Table 2. Storage technologies parameters

Technology	Power-related CAPEX (€/kW$_e$)	Energy-related CAPEX (€/kWh)	Lifetime (yr)	Power-related Annuity (€/kW$_e$/yr)	Fixed O&M (€/kW$_e$/yr)	Variable O&M (€/MWh$_e$)	Energy-related annuity (€/kWh$_e$/yr)	Const. time (yr)	Efficiency (in/out)	Source
Historical PHS	-	-	70	-	15	0	-	-	90%/90%	RTE (2021)
New PHS	1000	(20)	70	55.655	15	0	0.53	(4)[8]	90%/90%	RTE (2021)
1h Battery storage	-	255	15	-	8.925	0	19.85	(0.5)*	90%/95%	RTE (2021)
4h Battery storage	-	150	15	-	21	0	11.67	(0.5)*	90%/95%	RTE (2021)
Salt cavern	-	1	30	-	-	-	0.07	(2)[9]	100%/97%	Papadias et al. (2021)

*Own assumption

[4] https://events.renewableuk.com/images/documents/GOW/RUK16_000_3_Offshore_Timeline_Final_Web.pdf
[5] https://www.fws.gov/midwest/endangered/permits/hcp/r3wind/pdf/DraftHCPandEIS/MSHCPDraftAppA_WindProjectLifecycle.pdf & https://www.wind-energy-the-facts.org/construction-issues.html
[6] https://www.ysgsolar.com/blog/how-long-does-it-take-construct-solar-farm-ysg-solar
[7] https://www.ge.com/content/dam/gepower-pgdp/global/en_US/documents/product/power%20plants/power-plant-best-practices-2015.pdf
[8] https://www.hydro.org/wp-content/uploads/2017/08/PS-Wind-Integration-Final-Report-without-Exhibits-MWH-3.pdf
[9] https://theicct.org/sites/default/files/icct2020_assessment_of_hydrogen_production_costs_v1.pdf

Table 3 shows the hydrogen production cost from centralized alkaline electrolyzers and autothermal methane reforming (ATR) with carbon capture and storage, using either natural gas or biogas. While ATR without CCS is generally considered more costly than steam methane reforming (SMR), the inverse stands when both options are combined to CCS because the CO_2 flux is more concentrated with ATR (France Stratégie, 2022).

Table 3. Hydrogen technologies parameters

Technology	Overnight cost (€/kW_e)	Lifetime (yr)	Annuity (€/kW_{H2}/yr)	Fixed O&M (€/kW_{H2}/yr)	Variable O&M (€/MWh_{H2})	Construction time (yr)	Efficiency (E_{out}/E_{in})	Source
Electrolyzer	200-**350**-500	variable* (20 for on-grid)	22.35-39.10-55.86	5.33-9.33-13.33	2.4 + 16.66****	(2)[6]	0.75	IRENA (2020), BNEF (2020), Deloitte (2021), Agora (2021), etc.
ATR with CCS natural gas	750	25	57.41	22.5	0.25+30**	(3)[10]	0.72	Deloitte (2021)
ATR with CCS biogas	750	25	57.41	22.5	0.25+110.8***	(3)[7]	0.72	Deloitte (2021)

*According to IRENA (2020), electrolyzer lifetime for 2050 is expected to be between 100,000 and 120,000 hours, which would account for 30 years for a utilization rate of 38% and 20 years for a utilization rate of 57%. According to Deloitte (2021) this value is 20 years for centralized on-grid electrolyzers, and Agora (2021) projects 30 years of electrolyzer lifetime. With all these values in hand, and by launching some initial simulations, we find roughly 5,800 hours/year of functioning time which translates into 17 to 21 years based on IRENA's lifetime functioning hours. Therefore, we choose 20 years as the electrolyzer lifetime.
**The second part of the variable cost accounts for the natural gas market price estimation for 2050, which is equal to €25/MWh_{th}.
***The second part of the variable cost account for the biomethane supply cost estimation of €80/MWh_{th} for 2050.
****Hydrogen network cost.

The recent literature on the electrolyzers' cost highlights prices even below €200/kW_e for both PEM and alkaline electrolyzers by 2050, once they are in the order of 1 MW capacity. For instance, IRENA's *Green hydrogen cost reduction* study (IRENA, 2020) forecasts costs below \$200/kW_e for PEM and Alkaline electrolyzer costs by 2050. According to NREL (2019), the whole PEM electrolyzer system installed cost can be in the order of €220/kW_e once the production line of electrolyzers is between 100 to 1000 units per year. Global CCS institute's low electrolyzer cost scenario leads to €200/kW_e of the electrolyzer cost by 2050 (Global CCS institute, 2021). Deloitte's Hydrogen for Europe study (Deloitte, 2021) highlights a cost reduction of up to 73% for the whole electrolyzer system from 2020 to 2050 (leading to similar overnight costs). Therefore, we identify €200/kW_e as the lower boundary of the PEM or Alkaline electrolyzer cost. Currently, to the best of our knowledge, the cheapest announced PEM electrolyzer project in Europe has a system cost of €675/kW_e (in Spain)[11] and the cheapest announced Alkaline electrolyzer project in Europe has been announced for €500/kW_e of installed system cost (in France)[12]. Therefore, we set our highest cost scenario to €500/kW_e. Accordingly, we define three electrolyzer cost scenarios, and we take €350/kW_e (€467/kW_{H2}) as the central cost scenario.

2.2.2. Electricity and hydrogen demand

For electricity demand, we build hourly time-series for 2050 by combining projections from the French National low carbon strategy (MTES, 2020) and from RTE.

According to French National low carbon strategy (MTES, 2020), the final electricity consumption in 2050 is projected at 648 TWh_e, of which 53.33 TWh_e is for hydrogen production (40 TWh_{H2} of hydrogen demand with 75% electrolyzer efficiency). Therefore, by subtracting this part, the final annual electricity demand in France excluding hydrogen production is assumed to be 595 TWh_e. 100 TWh_e of this demand is assumed to be for the transport sector, of which 70 TWh_e is for electric

[10] https://ieaghg.org/exco_docs/2017-02.pdf
[11] https://nelhydrogen.com/press-release/awarded-iberdrola-contract-for-20-mw-green-fertilizer-project-in-spain/
[12] https://www.sudouest.fr/economie/le-port-de-bordeaux-va-accueillir-un-grand-projet-de-production-d-hydrogene-100-renouvelable-2294752.php

vehicles. Excluding this last part leads to a final electricity demand of 510 TWh_e which we assume to have a similar demand profile to the 2035 demand profile forecast of French transmission network operator, kindly provided by RTE.

The electricity demand profile is based on RTE's 2035 central electricity profile which is equal to 484 TWh_e of annual electricity demand, without power-to-gas electricity demand and including 31 TWh_e for electric vehicles. Excluding the latter part, the annual electricity demand is 451 TWh. We assume the demand profile (still excluding electric vehicles) to be the same for 2050, rescaled from 451 to 510 TWh. The electric vehicle transport demand profile of 31 TWh_e is also multiplied by a correction coefficient to provide the same shape of the profile for 70 TWh_e of annual electricity demand for electric vehicles, as projected in the French national low carbon strategy. The addition of these two profiles leads to the final electricity demand profile of 595 TWh_e for 2050 which takes into account all the end-uses except hydrogen production.

Hydrogen demand is assumed constant throughout the year because is it supposed to feed mostly heavy industry and long-range transportation. Since hydrogen has a very limited storage cost in salt caverns (in the order of \$0.2/kg_{H2} of stored hydrogen, Papadias et al, 2021), this assumption does not impact the results. Table 4 summarizes the electricity and hydrogen demand values and profiles. Since 2050 hydrogen demand is highly uncertain, we consider three hydrogen demand scenarios, keeping the 40 TWh from the French National low carbon strategy (MTES, 2020) as the central scenario.

Table 4. Hydrogen and electricity demand values and profiles

	Demand level (in TWh_e or TWh_{H2})	**Source**	**Demand profile**	**Source**
Electricity	595 TWh_e	MTES (2020)	See GitHub[13]	RTE (2019)
Hydrogen	20-**40**-80 TWh_{H2}	MTES (2020)	flat	Own assumption

2.2.3. Maximal capacities and energy supply potentials

Table 5 shows the existing (meaning that they will remain until 2050) and the maximal potential values of installed electricity generation capacities of renewable electricity supply sources, charge and discharge capacities and storage energy volume of pumped hydro storage, annual biomethane supply for the electricity production, and the energy volume for hydrogen storage in salt caverns. We assume no new capacity addition for hydroelectric generation technologies, and all the remaining potential values are taken from the cited sources in the table (mainly from Ademe, 2021).

[13] https://github.com/BehrangShirizadeh/EOLES_elec_pro/blob/main/inputs/demand2050_RTE.csv

Table 5. Existing and maximal installed capacities of the constrained technologies

Technology	**Variable**	**Existing**	**Potential**	**Source**
Floating offshore wind	Installed capacity (GW)	-	46	Ademe (2021)
Grounded offshore wind	Installed capacity (GW)	-	30	Ademe (2021)
Onshore wind	Installed capacity (GW)	-	120	Ademe (2021)
Ground-mounted solar PV	Installed capacity (GW)	-	100	Ademe (2021)
Commercial rooftop solar PV	Installed capacity (GW)	-	123	Ademe (2021)
Hydroelectricity – dam	Installed capacity (GW)	12.855	12.855	Own assumption
Hydroelectricity run-of-river	Installed capacity (GW)	7.5	7.5	Own assumption
Pumped hydro storage	Discharging capacity (GW)	5.2	7.2*	Ademe (2021)
	Charging capacity (GW)	4.2	6.2*	Ademe (2021)
	Storage energy volume (GWh)	101.1	135.5*	Ademe (2021)
Biomethane	Annual supply (TWh_{th}/year)	-	30**	Ademe (2017)
Hydrogen storage	Storage capacity (TWh)	3	510	Caglayan et al. (2020)

*Assumption of possibility of adding 2 GW (average of 1 GW and 3 GW capacity addition scenarios of Ademe, 2022) charging and discharging capacities in Auvergne Rhône-Alpes region of France, with the proportional increase of the storage volume keeping the same discharge time in this region (17.2 hours). This leads to 2 GW of increase in storage charge and discharge capacities and 34.4 GWh of increase in the storage energy volume.

**According to Ademe's *Visions 2035-2050* report, 15 TWh_e can be produced from biomethane. However, based on the choice of the power plant type, this value can be translated differently to the required biomethane in thermal energy unit. For OCGT power plants with 40% of efficiency, this value is 37.5 TWh_{th}, while for CCGT power plants with 57% of efficiency, it is 26.3 TWh_{th}. Since the majority of existing gas combustion plants in France are CCGT, we choose a value in between but closer to the required biomethane for CCGT power plants: 30TWh_{th}.

2.2.4. Electrolyzer lifetime calculation

According to IRENA (2021), electrolyzer lifetime depends on the number of hours it is utilized, and this value varies between 100,000 to 120,000 hours of utilization. Electricity production from wind and solar technologies is highly variable, and in case of a highly renewable power system, electricity production can follow high price variability, leading to periods of low-price and high-price electricity in the centralized national spot market. If an electrolyzer is used 2000 hours per year, its lifetime can exceed 50 years if, following IRENA, it can be used for 100,000 to 120,000 hours of functioning. Therefore, we define off-grid hydrogen production by each of the main low-carbon options: offshore wind, onshore wind, solar PV and nuclear power. Moreover, we add the possibility of on-grid hydrogen production. The difference between them is defined based on the hours of functioning of electrolyzers that is a result of the optimization. Since EOLES_elec_H2 model is a linear programming model, the lifetime of the electrolyzers cannot be introduced as hours of utilization. To internalize this lifetime based on utilization hours, we develop an iterative calculation method, where we first introduce annual functioning hours based on the values introduced by the existing literature (25 years), and then, using the hydrogen production profiles of electrolyzers (output of the previous iteration), we identify the hours of functioning of the electrolyzers, and we re-calculate the annualized capital cost of the electrolyzers based on the new lifetime for each type of off-grid and on-grid electrolyzer installation. In case one of the hydrogen production methods are not in the optimal results, we introduce different lifetime estimations for each of these technologies (5000 hours of annual functioning for nuclear hydrogen, 4000 hours of annual functioning for wind and on-gird hydrogen and 1460 hours of annual functioning for solar hydrogen). We continue the same process until the functioning hours of the electrolyzers converge to a fixed value. This value changes by the cost of the electrolyzers, therefore, we do the same iterative calculation for each of the cost scenarios for electrolyzers, and we define their lifetime based on the results of this first part.

3. Studied scenarios

Based on the high uncertainties in the level of hydrogen demand and the cost of electrolyzers, we defined three scenarios for each of them. Moreover, renewable capacity availability scenarios are of high importance for the production of green hydrogen, thus we also defined two alternative renewable potential scenarios (Table 6).

3.1. Electrolyzer cost scenarios

Our electrolyzer cost scenarios are based on the very recent electrolyzer cost projection literature: BNEF (2020), Deloitte (2021), IRENA (2020), etc. We identified a 2050 centralized alkaline electrolyzer cost range of €200/kW_e to €500/kW_e from these recent publications. Keeping the average value as the central electrolyzer cost scenario, 3 electrolyzer cost scenarios are: €200/kW_e (€266.7/kW_{H2}), €350/kW_e (€466.7/kW_{H2}) and €500/kW_e (€666.7/kW_{H2}).

3.2. Hydrogen demand scenarios

The future hydrogen demand for France in the French national low carbon strategy is projected at 40 TWh_{H2}/year (MTES, 2020). 20TWh_{H2}/year of this hydrogen demand corresponds to hydrogen feedstock demand for the industrial processes, especially for steel production, chemicals industry and refinery where low-carbon hydrogen is expected to replace coal and gas. This value also corresponds to the Agora Energiewende *No regret hydrogen* report demand projection for 2050 (Agora Energiewende, 2021), which considers using hydrogen only for the sectors where no other decarbonisation alternative exists. The remaining 20 TWh_{H2}/year of hydrogen demand corresponds to hydrogen usage as energy source, mainly for industrial high temperature heating and transport sector. We assume two alternative hydrogen demand scenarios for the future: either only no-regret hydrogen feedstock demand for industry is taken into account (20 TWh_{H2}/year) or hydrogen demand is doubled.

3.3. Renewable capacity potentials

Ademe's 2021 renewable capacity potentials are the same as the ones in Ademe (2018), with an upward revision of fixed offshore wind potential from 20 GW to 30 GW. However, these potential estimations are among of the most pessimistic ones in the existing literature (Dupré la Tour, 2021). Moreover, we aim to study the impact of increased hydrogen demand in its supply feedstock. Therefore, to account for this impact, we consider 25% upwards and downward variations of the main variable renewable electricity supply technologies: floating and fixed offshore wind power, ground-mounted and rooftop solar PV, and onshore wind power.

3.4. Blue hydrogen authorization

Based on high political uncertainties regarding the authorization of blue hydrogen and carbon capture and storage installations in France, we add a variant scenario where blue hydrogen is not authorized. We check the importance of blue hydrogen and sensitivity of the cost of the system and power and hydrogen supply mix to the availability of blue hydrogen via an alternative scenario where blue hydrogen is not allowed.

Table 6. Scenarios

Varying parameters	Electrolyzer cost (€/kW_e)	Hydrogen demand (TWh_{H2}/year)	VRE potential	Blue hydrogen availability
Scenarios	200-**350**-500	0-**40**-80	**Central** ±25%	**Yes**/No

4. Results & discussion

4.1. Central scenario

4.1.1. Main economic characteristics of the hydrogen-electricity system

In the central scenario, electrolyzer cost is €350/kW_e (466.7€/kW_{H2}), hydrogen demand is 40TWh_{th} and VRE potentials are the values represented in Table 5 (floating and grounded offshore wind potentials of 46GW and 30GW, onshore wind potential of 120GW and ground-mounted and commercial rooftop PV potentials of 100GW and 123GW). This scenario is specified by bold font in table 6.

For this scenario the annualized system cost (including electricity storage and hydrogen storage and transport/transmission) is €31.4bn/year. This cost must be decomposed to show the levelized costs of electricity and hydrogen. To do so, we first calculate the levelized cost of hydrogen (LCOH). Hydrogen is used to both (1) satisfy the exogenous hydrogen demand for the industry and transport sectors (40TWh_{th}) and (2) provide flexibility to the power system, while it can be produced either from electricity or gas (fossil and biogas). The calculation of LCOH then must take into account the electricity price in the hours of hydrogen supply from electricity, while the use of hydrogen for electricity supply (with all its inefficiencies) should be the cost of the electricity and not hydrogen. Thus, we calculate the LCOH as below:

$$LCOH\ (\frac{€}{kW_{th}}) = \Big[\sum_{H_2} Q_{H_2} \times \left(Annuity_{H_2} + fO\&M_{H_2}\right) + \sum_{H_2,h} E_{H_2,h} \times vO\&M_{H_2} + \sum_{H_2 \in electrolysis\ ,h} \frac{E_{H_2,h} \times Price_h^{electricity}}{\eta_{electrolysis}} + Q^{en}_{salt\ cavern} \times Annuity^{en}_{salt\ cavern}\Big] / \sum_{H_2,h} E_{H_2,h} \qquad \text{(Eq. 1)}$$

Where H_2 represents the hydrogen production technology, Q_{H_2} is the capacity of the hydrogen supply option H_2, $Annuity_{H_2}$[14] and $fO\&M_{H_2}$ are the annualized investment and fixed operation and maintenance costs of that technology and $E_{H_2,h}$ is its hydrogen production at hour h. Hydrogen supply technologies are defined under the set H2 and its subset electrolysis defined as only off-grid hydrogen production via electrolysis options: $electrolysis \subset H_2$. Hourly electricity price is represented by $Price_h^{electricity}$ and the electrolysis efficiency by $\eta_{electrolysis}$, therefore, the electricity price is taken into account in the formulation:

$$\sum_{H_2 \in electrolysis\ ,h} \frac{E_{H_2,h} \times Price_h^{electricity}}{\eta_{electrolysis}}.$$

Finally, $Q^{en}_{salt\ cavern}$ is the energy capacity of the salt cavern for hydrogen storage (in kWh_{th} of hydrogen) and $Annuity^{en}_{salt\ cavern}$ is the annualized investment cost of the salt cavern adaptation for hydrogen storage. Therefore, the cost of hydrogen storage is also taken into account in the LCOH calculation.

[14] We calculate annuity by taking into account the overnight cost of the technology ($CAPEX_{tec}$), the discount rate (DR), its lifetime (lt_{tec}) and its construction time (ct_{tec}) as: $Annuity_{tec} = \frac{DR \times CAPEX_{tec}((DR \times ct_{tec})+1)}{1-(1+DR)^{-lt_{tec}}}$

Since 1kg of hydrogen contains 33.33kWh$_{th}$ of thermal energy, by multiplying this value by 33.33 [kWh$_{th}$/kg$_{H2}$] we can have LCOH value as the levelized cost of 1kg of hydrogen.

By identifying the levelized cost of hydrogen supply, we can calculate the "system-wide" levelized cost of electricity (to account for the storage and flexibility options needed for a highly renewable electricity system) based on this cost, the overall system cost and the use of the hydrogen for electricity production (Eq. 2):

$$LCOE_{system} = \frac{COST^{total} - (LCOH \times \sum_h demand_h^{H_2,exogenous})}{\sum_h demand_h^{electricity}} \quad \text{(Eq. 2)}$$

Table 7 shows the main characteristics of the coupled electricity-hydrogen system by adding the results of system-wide LCOE and LCOH calculations.

Table 7. Main characteristics of the system for the central electrolyzer cost, renewable potential and hydrogen demand scenario.

System characteristic	Annualized overall system cost (bn€)	Levelized cost of hydrogen (LCOH, €/kgH_2)	Cost per electricity consumed (€/MWh)	Storage losses (%)	Load curtailment (%)
Value	31.4	1.73	50.5	1.3	1.2

The storage losses (in batteries, PHS and the power-to-gas-to power loop) and the load curtailment (the share of non-dispatchable renewable energy which is lost due because it exceeds electricity use) are much lower than in Shirizadeh and Quirion (2021). The latter article is based on a rather similar model, but without hydrogen demand, and with a power-to-gas-to-power loop based, not on the direct use of hydrogen in power plants as in the present paper, but on methanation, i.e., production of methane by combining hydrogen and biogenic CO_2. Possible explanations for the low storage losses and load curtailment in the present paper are that methanation entails more cost and energy losses than direct hydrogen use, and that due to the absence of hydrogen demand, the capacity of electrolyzers is lower, limiting the possibility to use electricity from wind and PV when the residual demand is highly negative.

4.1.2. Electricity production and consumption

Figure 2 shows the electricity mix. We can see that the power system is nearly entirely renewable with 1.4TWh of nuclear electricity over 595TWh of overall electricity production. Grounded offshore and onshore wind and grounded solar power reach their maximal potential values, while neither floating offshore wind is installed, nor solar PV over commercial rooftops.

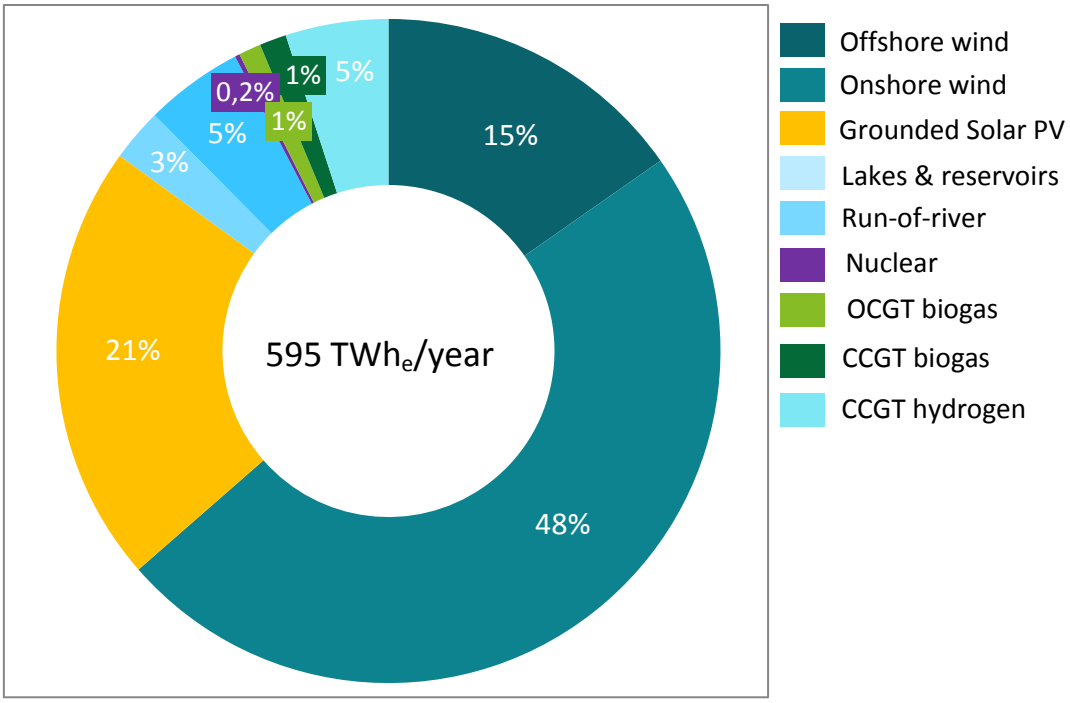

Figure 2. Electricity production mix for the central scenario

5% (29.8TWh) of this electricity is produced from hydrogen, which can be either indirect storage of electricity via P2G2P (electricity => electrolysis => hydrogen => CCGT => electricity) or electricity production from hydrogen as a primary energy source (for the ATR+CCS routes, i.e. blue and bio hydrogen).

The electricity from off-grid technologies to produce hydrogen is not taken into account, therfore, addition of water electrolysis via off-grid options (54.5TWh$_{th}$ of hydrogen) leads to a nearly 668TWh$_{e}$ of annual electricity supply. Therefore, the electricity demand of 593.3TWh is fully satisfied, with small losses due to load curtailment and storage losses as shown I tble 7.

4.1.3. Hydrogen production and consumption

Figure 3 shows the hydrogen supply from each of its supply technologies. We can observe that renewable green hydrogen is the main source of hydrogen supply with 57% of the production, and nuclear hydrogen contributes to 2% of low-carbon hydrogen supply. The remaining hydrogen demand is satisfied by blue hydrogen via autothermal reforming (ATR) of natural gas with carbon capture and storage (CCS) and 4% of the hydrogen demand is satisfied by the biogas ATR coupled with CCS to compensate the residual emissions of blue hydrogen. Exogenous hydrogen demand is 40TWh$_{th}$ to satisfy hydrogen demand as energy and feedstock in the industry and fuel for the transport sectors. On top of that, 52.3TWh$_{th}$ of hydrogen is consumed for electricity supply. Therefore, the biggest demand sector for hydrogen is electricity production that accounts for roughly 56% of hydrogen consumption, followed by transport sector (20TWh$_{th}$), and feedstock for industry (15TWh$_{th}$) and energy for industry (5TWh$_{th}$).

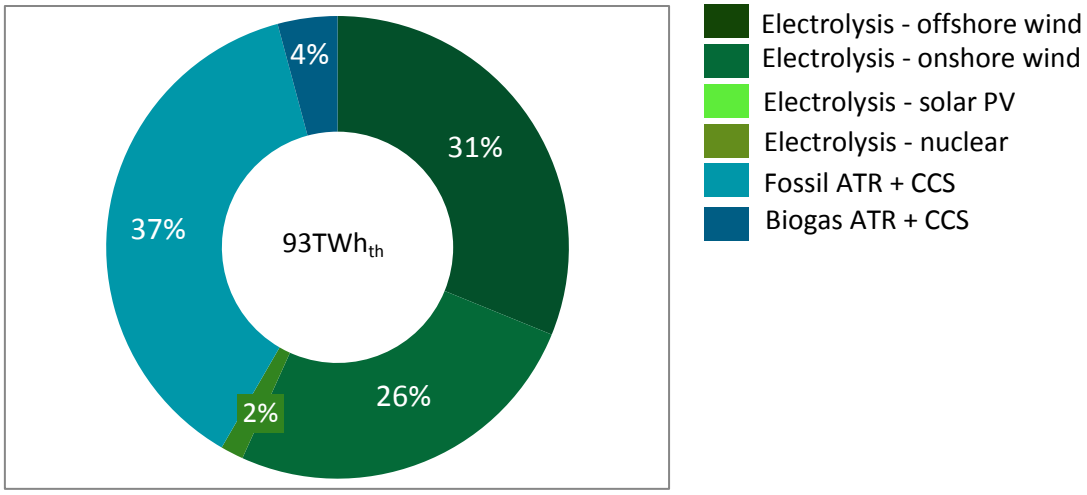

Figure 3. Hydrogen supply for the central scenario

4.2. Sensitivity to the electrolyzer cost

To identify the robustness of the system cost, electricity mix and hydrogen mix to the cost of the electrolyzers, we identified two alternative electrolyzer cost scenarios: 200€/kW$_e$ and 500€/kW$_e$. Since the functioning of the electrolyzers depends on the cost of the electrolyzers, we applied the iterative electrolyzer functioning calculation, to take into account the impact of their utilization hours into their investment costs.

Figure 4 shows the sensitivity of the levelized electricity (a) and hydrogen (b) costs to the electrolyzer cost. Both levelized cost of electricity and hydrogen increase as the cost of electrolyzers increase, however, very marginally. A 43% increase (decrease) in the electrolyzer cost leads to a 0.8% of increase (decrease) in the LCOE of the electricity supply, and a 2.3% (4.1%) increase (decrease) in the LCOH for the hydrogen supply. Since the share of electricity in the overall coupled hydrogen-electricity system is much higher, the impact is more visible in the levelized cost of hydrogen rather than in the cost of electricity supply. Nevertheless, this cost variation remains very marginal compared to the variation of the cost of the electrolyzers.

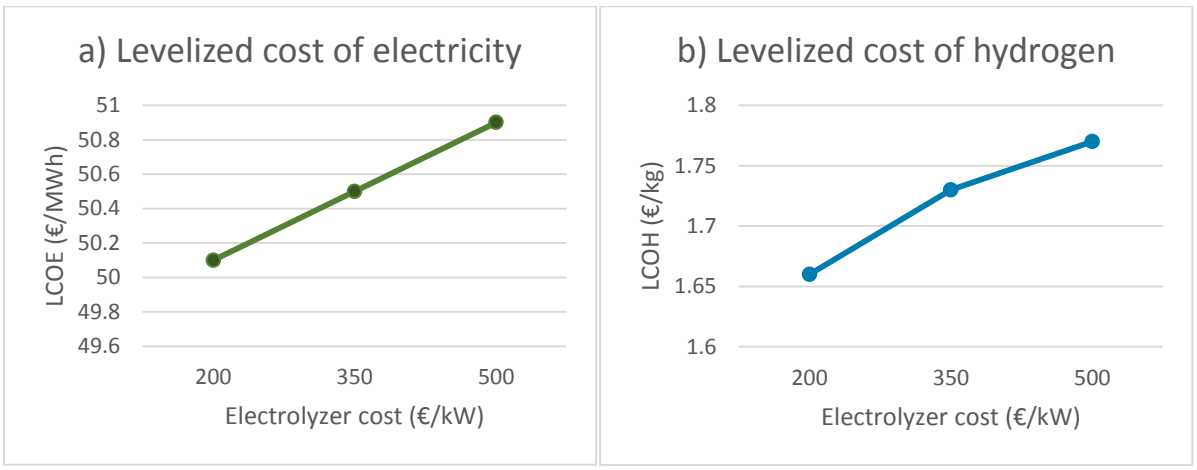

Figure 4. Sensitivity of the LCOE (a) and LCOH (b) to the electrolyzer cost.

Figure 5 shows the hydrogen supply mix for the different electrolyzer cost scenarios. Clearly, as the cost of electrolyzer increases, the share of green hydrogen from low-carbon sources decreases, varying from 70% of the overall hydrogen supply for 200€/kW of electrolyze cost to 37% for the electrolyzer cost scenario of 500€/kW. The overall hydrogen demand remains relatively robust to electrolyzer cost since the only endogenous hydrogen demand (electricity production) is more sensitive to the final cost of hydrogen (LCOH) which doesn't vary significantly by the electrolyzer cost.

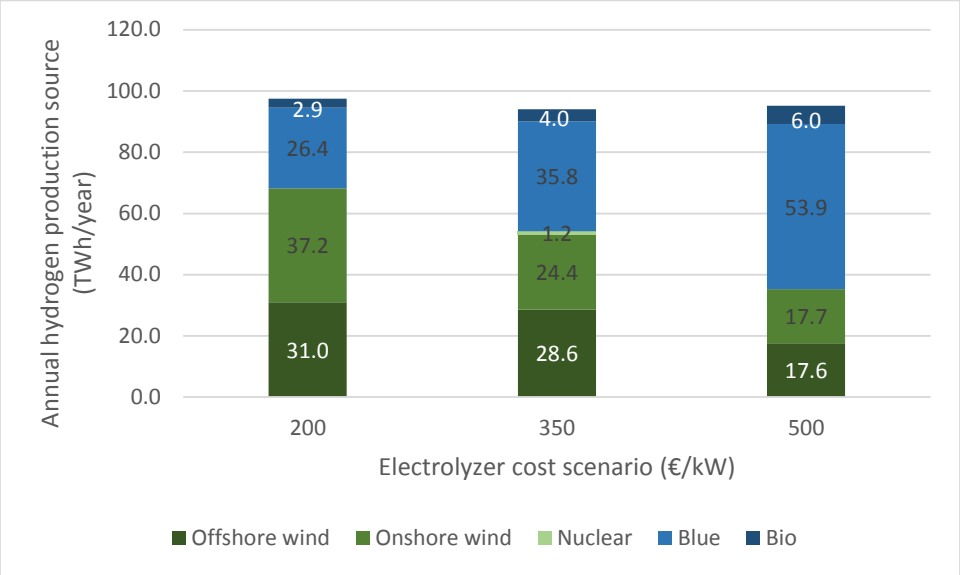

Figure 5. Sensitivity of the hydrogen supply mix to the electrolyzer cost.

4.3. Sensitivity to the hydrogen demand

On top of the exogenous central hydrogen demand scenario of 40TWh, two alternative scenarios are studied: 20TWh (only considering energy and feedstock for the industry sector) and 80TWh (with high share of hydrogen demand in the transport sector).

Figure 6 shows how the LCOE and LCOH of the coupled electricity-hydrogen system vary with the exogenous hydrogen demand. As hydrogen demand passes from 20TWh to 80TWh, the levelized cost of hydrogen production falls from 1.73€/kg_{H2} to 1.68€/kg_{H2} and the levelized cost of electricity production falls from 50.8€/MWh to 50.3€/MWh. This drop may seem puzzling at first sight, but the explanation is the following. The higher hydrogen demand entails a higher electrolyzer capacity. Since hydrogen demand is flexible, this additional electrolyzer capacity is available for the power-to-gas-to-power loop, reducing the curtailment of wind and solar power and providing extra power at a very low cost for producing hydrogen. Of course, in spite of these decreases in unit cost, the total system cost increases with the level of hydrogen demand.

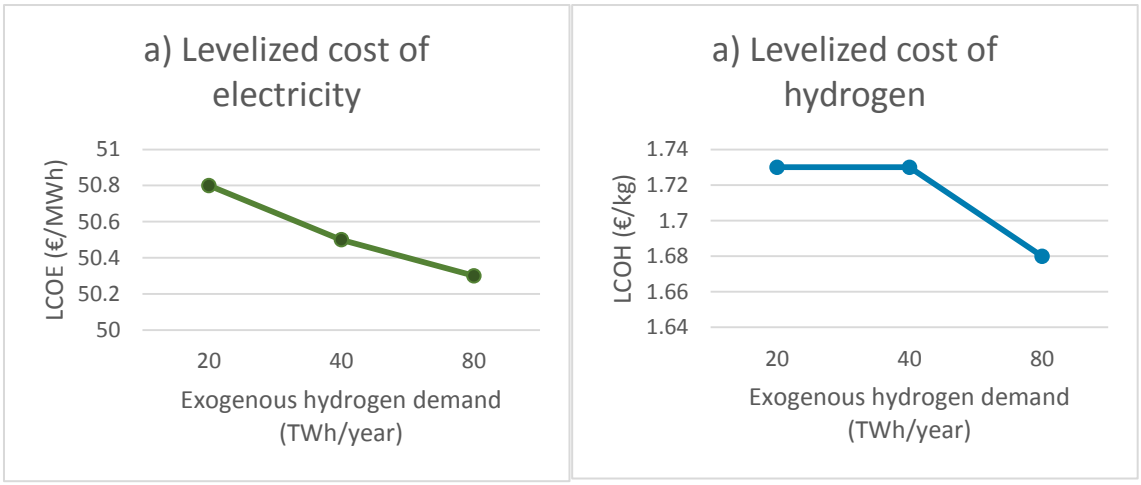

Figure 6. Sensitivity of the LCOE (a) and LCOH (b) to the hydrogen demand level.

As hydrogen demand increases, the share of renewables in the hydrogen supply diminishes, since their potential is limited (Figure 7). Although higher hydrogen demand leads to higher hydrogen production from nuclear electricity (4.8TWh/year for 80TWh vs. 0 for 20TWh/year), this increase is very marginal compared to the demand increase, leading to a lower proportion of electrolysis in hydrogen production (60% for 20TWh/year of hydrogen demand vs. 48% for 80TWh/year), the rest being satisfied by methane reforming.

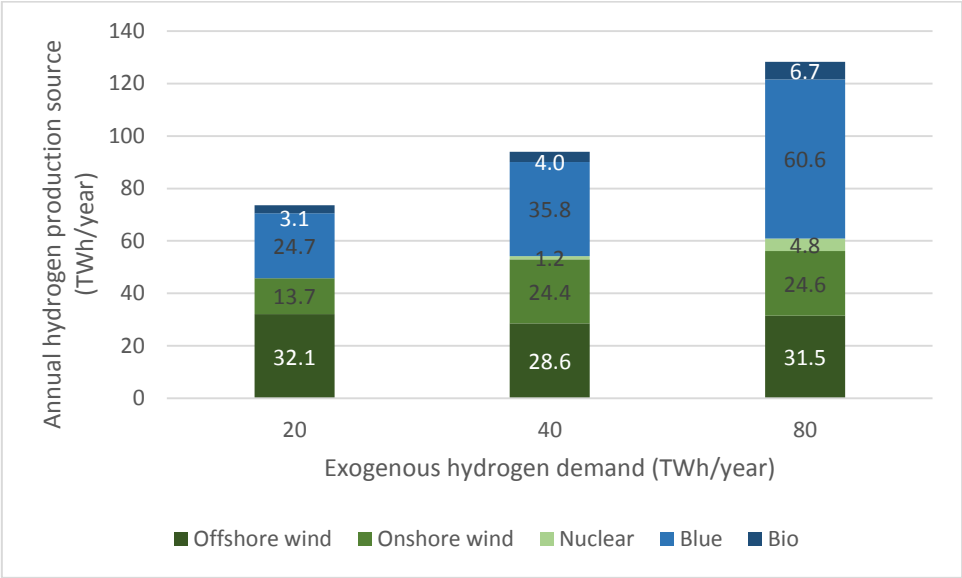

Figure 7. Sensitivity of the hydrogen supply mix to the hydrogen demand.

4.4. Sensitivity to renewable supply potential

Renewables are the cheapest electricity and hydrogen supply options; however, their potential is limited. The importance of this potential is tested via a ±25% variation of the maximal installable capacities of grounded and floating offshore wind, onshore wind and ground-mounted and commercial rooftop solar panels.

As the renewable potential decreases, the share of renewables in the hydrogen supply drops (Figure 9). Therefore, cheaper hydrogen and electricity production options become more constrained and both LCOE and LCOH increase by reduced renewable potential (Figure 8).

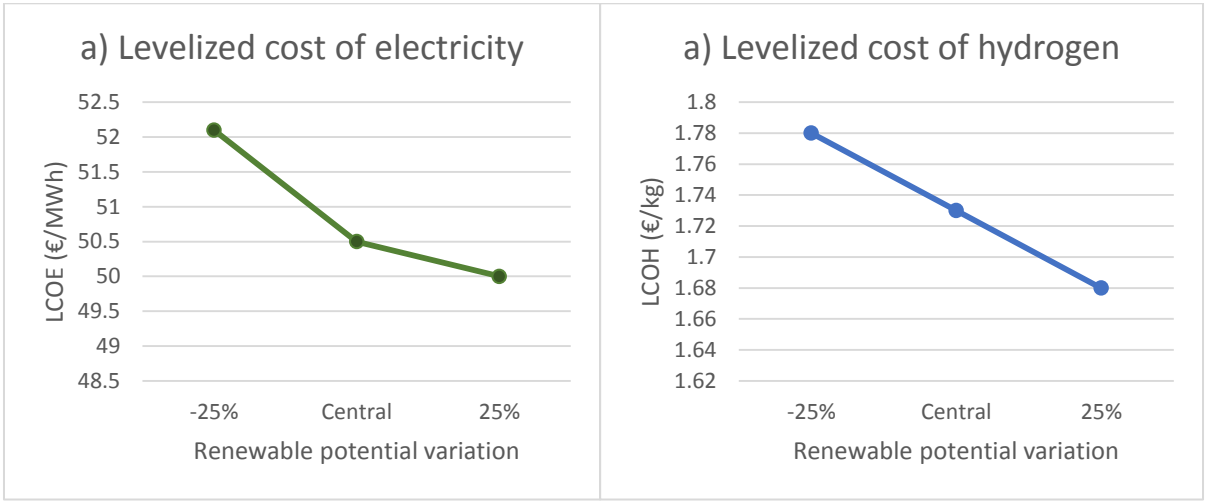

Figure 8. Sensitivity of the LCOE (a) and LCOH (b) to the renewables potential.

Although lower renewable potential leads to higher hydrogen supply from nuclear electricity, this increase cannot compensate the reduction resulting from lack of renewable potential (Figure 9). Therefore, the proportion of electrolysis in hydrogen supply drops from 62% for high renewable potential to 54% for low renewable potential.

It is worth to mention that for the case with low renewable potential, both hydrogen and power systems require more low-carbon electricity source, leading to 12.2GW of installed capacity for nuclear power: the highest installed capacity for nuclear power plants among the different scenarios. This capacity produces 59.4TWh$_e$/year for the electricity grid, and 35.6TWh$_{th}$/year of hydrogen (47.5TWh$_e$/year).

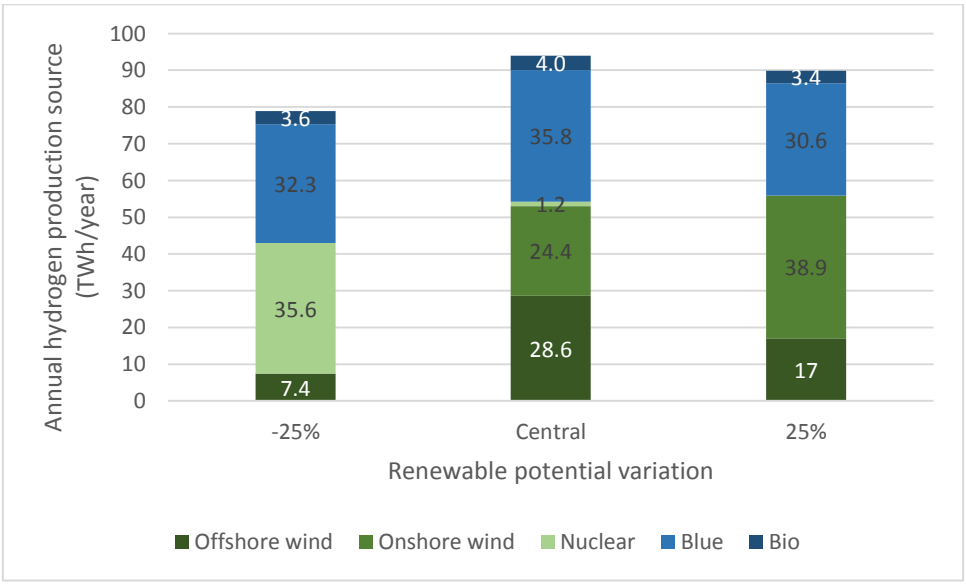

Figure 9. Sensitivity of the hydrogen supply mix to the renewables potential.

4.5. The relative importance of blue hydrogen

As we saw previously, an important part of hydrogen comes from blue and biogas-originated hydrogen. However, blue hydrogen has fossil origins, and it has residual emissions. The methane emissions associated with the whole value chain of blue hydrogen (extraction of natural gas, its transport and distribution, processes and residual emissions during ATR process with carbon capture and storage) might eliminate the benefits of carbon capture and storage. Therefore, an alternative case with no blue hydrogen has been studied, to identify the importance of this technology. Table 8 shows the main characteristics of the power-hydrogen nexus for this variant scenario and its difference from the case with blue hydrogen. We can see that the absence of blue hydrogen increases the LCOH, but by only 4%, and the overall system cost increase is even smaller: 0.96%. This is thanks to the small difference in the LCOE of the power system (0.79%) which is the main component of the power-hydrogen coupled system.

Table 8. Main characteristics of the system for the central electrolyzer cost, renewable potential and hydrogen demand scenario, in the absence of blue hydrogen and its difference with the central scenario with blue hydrogen.

System characteristic	Annualized overall system cost (bn€)	Levelized cost of hydrogen (LCOH, €/kgH_2)	Cost per electricity consumed (€/MWh)	Storage losses (%)	Load curtailment (%)
Value	31.7	1.80	50.9	1.3	1.1
Difference from central scenario	+0.96%	+4.05%	+0,79%	0	-8.33%

In the scenario without blue hydrogen, hydrogen is mainly produced from renewables but nuclear contributes to a significant part of hydrogen supply too (Figure 10). Since the potential of variable renewables is limited and they are also needed to satisfy the electricity demand, without blue hydrogen the system becomes more constrained and more nuclear power plants are installed (4.5GW vs. 0.4GW for the case with blue hydrogen). These 4.5GW produce 15.1TWh/year of electricity for the grid and 18.3TWh_{th} of hydrogen (24.4TWh_e).

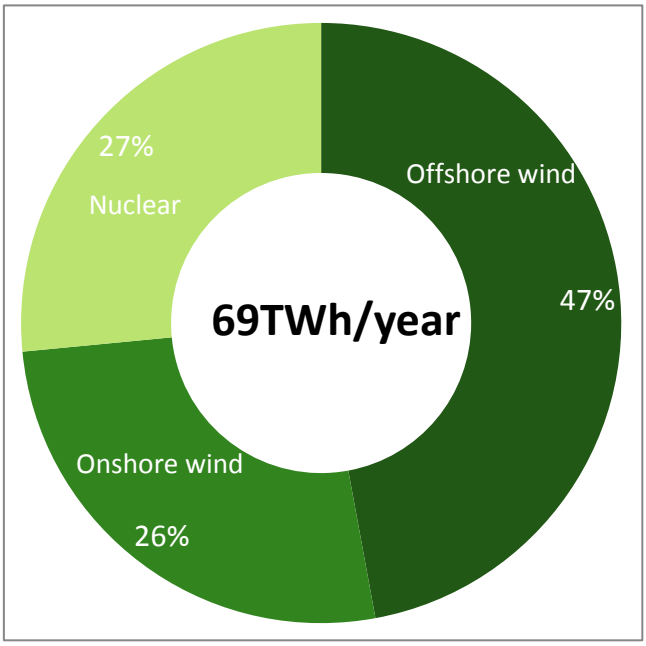

Figure 10. Hydrogen supply mix if blue hydrogen is not available.

5. Conclusion

We developed a model optimising simultaneously hydrogen and electricity production and storage in France by 2050.

The cost-optimal, zero-emission electricity production mix is almost fully renewable in our central scenario. The share of electrolysis vs. methane reforming is sensitive to the cost of electrolyzers, with the former providing around 60% of hydrogen production in the central scenario, in which electrolyzers cost around €350/kW.

Concerning electricity generation, nuclear has a significant role only if the wind & solar potential limits their deployment, which may happen if this potential is lower than in our central scenario, and if hydrogen demand is higher than in this scenario, requiring more electricity for electrolysis.

Finally, our sensitivity analyses show that the electrolyzer cost is less important for the overall system cost than the other two parameters analysed, i.e. the amount of hydrogen demand and the renewable potential.

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