International PtX Hub

Supported by:

Federal Ministry for Economic Affairs and Climate Action

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IKI INTERNATIONAL CLIMATE INITIATIVE

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Artelys OPTIMIZATION SOLUTIONS

DECARBONISATION & ALLOCATION SCENARIOS FOR LOW EMISSION HYDROGEN AND POWER-TO-X IN ARGENTINA

Final Report

IMPRINT

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Buenos Aires, October 2023

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Disclaimer

This document contains a robust and comprehensive analysis of energy transition scenarios for Argentina, including discussions and consultations with different stakeholders from the energy and industrial sector in Argentina. As it is a prospective study, it uses as a basis a set of assumptions and scenarios that were defined within the framework of the study. This analysis was carried out prior to the launch of the Energy Transition Plan (*Plan de Transición Energética*) developed by the Secretary of Energy of Argentina, therefore, the scenarios used are not necessarily the same as those resulting from the aforementioned Plan. Due to the limitations of the model used, the study does not include a sectoral assessment that identifies in which sectors hydrogen or its derivatives could be competitive in relation to other decarbonisation options.

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ACSG	Artelys Crystal Super Grid
AT	"Advanced Transition" scenario
BAS	Buenos Aires (region as defined by Cammesa)
CABA	Autonomous City of Buenos Aires
CAMMESA	Wholesale Electricity Market Administration Company, Argentina
CAPEX	Capital expenditure
CAREM	Central Argentina de Elementos Modulares (small-sized nuclear reactors)
CAT	Climate Action Tracker
CC	"Current Commitments" scenario
CCGT	Combined Cycle Gas Turbine
CCS	Carbon Capture and Storage
CCUS	Carbon Capture, Utilization, and Storage
CEN	Centro (region as defined by Cammesa)
CNG	Compressed natural gas
CO2e	Carbon dioxide equivalent
COD	Commissioning date
COM	Comahue (region as defined by Cammesa)
CSP	Concentrated Solar Power
CUY	Cuyo (region as defined by Cammesa)
DHW	Domestic Hot Water
EU	European Union
EV	Electric vehicles
FODER	Fondo para el Desarrollo de Energías Renovables
GBA	Gran Buenos Aires (region as defined by Cammesa)
GDP	Gross Domestic Product
GH2	Green hydrogen
GHG	Greenhouse Gases
GT	Gas Turbine
GWh	Gigawatt hours
H2	Hydrogen
H2LC	Low-Carbon hydrogen
HDT	Hydrotreating
IEA	International Energy Agency
IRENA	International Renewable Energy Agency
KPIs	Key Performance Indicators
LATAM	Latin America
LCOA	Levelized Cost Of Ammonia

LCOE	Levelized Cost Of Energy
LCOH	Levelized Cost Of Hydrogen
LHV	Low Heating Value
LNG	Liquefied Natural Gas
MMBtu	Million British Thermal Units
MMtoe	Million ton of oil equivalent
Mt	Million tons
MW	MegaWatt
MWh	MegaWatt hour
NB	Nota Bene
NDC	Nationally Determined Contributions
NEA	Noreste (region as defined by Cammesa)
NG	Natural Gas
NH3	Ammonia
NOA	Noroeste (region as defined by Cammesa)
NREL	National Renewable Energy Laboratory
NTC	Net transfer capacities
NZE	"Net Zero" scenario
OD	Oil derivatives
O&M	Operation and Maintenance
OCGT	Open-Cycle Gas Turbine
OPEX	Operation costs
PAT	Patagonia (region as defined by Cammesa)
PtH2	Power to Hydrogen
PtHeat	Power to Heat
PtX	Power to end products (X, derivatives from hydrogen)
PV	Photovoltaic
RES	Renewable Sources
SMN	National Meteorological Service of Argentina
SMR	Steam Methane Reforming
SWOT	Strength, Weaknesses, Opportunities, Threats
tCO2	Ton of CO2
TSO	Transport System Operator
TWh	Terawatt-hour
USD	US dollars
V2G	Vehicle to Grid
VRES	Variable Renewable Energy Sources
WACC	Weighted Average Costs of Capital
WP	Work Package

1 Executive Summary

1.1 Objective of the study and methodology

This study, commissioned by GIZ and integrated in the framework of the International PtX Hub, aims at developing a range of detailed energy transition pathways/scenarios for Argentina towards 2050, to **inform how hydrogen and PtX products can contribute to the decarbonisation** of the country's power, heat, transport and industrial sectors, as well as the potential for hydrogen exports, while testing different decarbonisation ambition levels, technology assumptions, infrastructure development levels, etc.

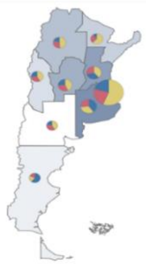
Due to the design of the model used, the study does not include a sectoral assessment that identifies in which (industrial) sectors (e.g. steel or chemistry) hydrogen or its PtX derivatives could be competitive in relation to other decarbonisation options.

Argentina is currently committed to the energy transition and has taken several steps to promote the use of renewable energy sources and reduce its greenhouse gas emissions. It has international commitments to reduce CO_2 emissions in the medium term (NDC 2030: 349MtCO_2e[1]) and in the long term ("net zero" emissions by 2050, in line with the Paris Agreement, i.e. equivalent to dividing by 4 its current CO_2 emissions).

The study has consisted in three main steps:

- The scenarios definition, which consisted in proposing a general framework and detailed assumptions for three long-term pathways reflecting different levels of ambition for total CO_2 emissions reduction, and analysing the **main routes towards decarbonisation of the energy sector as a whole.**
- The detailed modelling and **simulation of the electricity and hydrogen systems[2], for 3 main pathways**. This is done using **Artelys Crystal Super Grid** modelling tool, which main characteristics for this study are presented below:

[1] As a reference, total emissions in 2018 where 366 MtCO_2e.
[2] The model does not represent and optimize the gas system, the CO_2 system and the PtX production (it estimates volumes of H_2 which could be converted in different PtX afterward).



- Regional representation (9 zones and simplified modelling of interconnected countries).
- Temporary scope: Hourly time-steps for different time horizons (current, 2030, 2040, 2050).
- Joint optimization of investment costs and operating costs, to supply electricity and hydrogen demands (local and exports).

The simulation of 9 sensitivities, to test the robustness of the results and account for the large uncertainties on the future evolution of techno-economic parameters of the hydrogen production.

1.2 Scenario definition

Chapter 4 provides an overview of the scenario definition for the three energy transition pathways (Current Commitments - CC, Advanced Transition - AT, and Net Zero 2050 - NZE).

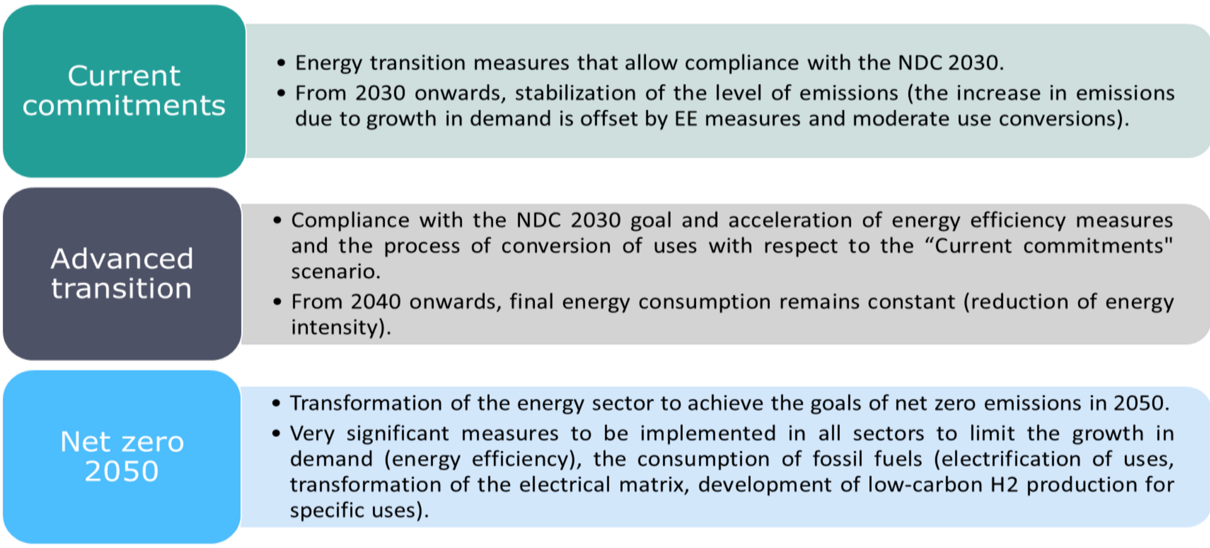


Figure 1: High-level description of the three pathways

The envisioned pathways reflect different levels of ambition in terms of total emission reduction, which are underpinned by a set of specific targets aiming at the sectoral transition from current fossil-based production technologies to low carbon technologies, prioritizing rather mature and economical options:

- Energy efficiency and behavioural changes in energy consumption, for energy savings;
- Electrification of uses (performance improvement), with a greener electricity generation mix;

- Temporary and partial use of gas in the transportation sector, to replace liquid fuels, as a complement to the development of electro mobility.
- Low carbon H_2 for uses that are not suitable for direct electrification and replacement of existing uses of grey H_2 in the industrial sector.

The figure below represents the evolution per pathway and per time horizon (2021 to 2050) of the final energy consumption, the non-fossil electricity production mix, the electrification of final consumption and the resulting CO_2e emissions.

- The NZE pathway is characterized by a reduction of final energy consumption, 100% of non-fossil electricity production mix, close to 60% of electrification of the final consumption and CO_2e emissions´ reduction complying with the Paris agreement.
- The average electricity demand CAGR varies from 2.1% to 2.9% depending on the pathway (without accounting for electricity demand for electrolysers)

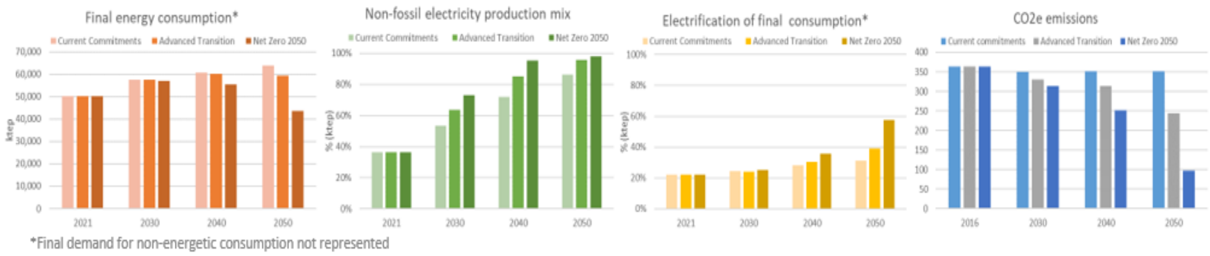


Figure 2: Key indicators per pathway (Final energy consumption, ktoe, Non-fossil electricity production mix, %, Electrification of final consumption, % and CO_2e emissions, Mt CO_2e

In the future, the **main drivers for local demand for low carbon hydrogen in Argentina** are likely to be the country's commitment to reducing greenhouse gas emissions, its abundance of renewable energy sources, the role of hydrogen as a **feedstock in the industry sector,** industrial sector competitiveness and the i**nternational regulations regarding the carbon footprint of the products that the country exports**.

- Presently, H_2 is used in oil refining and industrial key sectors such as ammonia and methanol production, and the steel sector. The existing uses of H_2 in different industrial sectors are expected to continue and grow in volume thanks mainly to GDP growth and the potential for imports substitution (especially fertilizers).
- Demand of H_2 for transport is assumed to be limited to the maritime and aviation sectors.
- Total H_2 local demand differs in each pathway, with a higher growth projected in the NZE scenario (demand multiplied by 5 in the period 2021-2050).

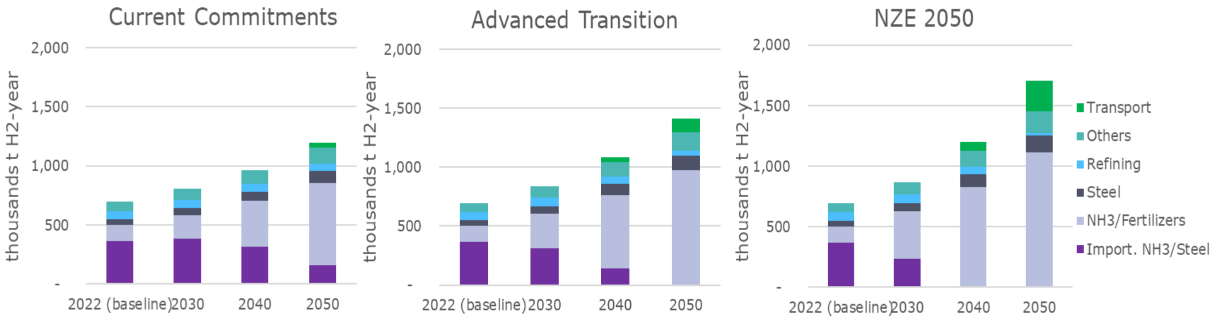


Figure 3: H_2 internal demand projection and NH_3/Steel imports (thousands t H_2-year)

- The **main drivers for green H_2 derivatives exports** are likely to be the market share that Argentina may be able to supply, depending on its relative competitiveness with other PtX exporting countries, as well as the level of production cost it will be able to reach and the rhythm of development of renewable energies.
- **Off-grid projects to export GH_2 derivatives may be deployed independently of the local carbon intensity of electricity**, if the price conditions are favourable.
- The main drivers of the production cost (LCOH) of grey, blue and green H_2 are:
  - **Grey H_2** mainly depends on NG price and CO_2 cost
  - **Blue H_2** mainly depends on NG price and CAPEX from the CCS.
  - **Green H_2** is highly CAPEX intensive and depends on electricity cost (wind power plants CAPEX) and electrolizers CAPEX.
- The three pathways assume different levels of carbon tax (0, 60 and 120 USD/tCO_2), which implies different configuration in terms of competitiveness between H_2 production options. In particular, we can recall that with a carbon tax ≥ 60 USD/tCO2 (AT, NZE):
  - Blue H_2 is more competitive than grey H_2.
  - Green H_2 is more competitive than blue H_2 from 2040 onwards.

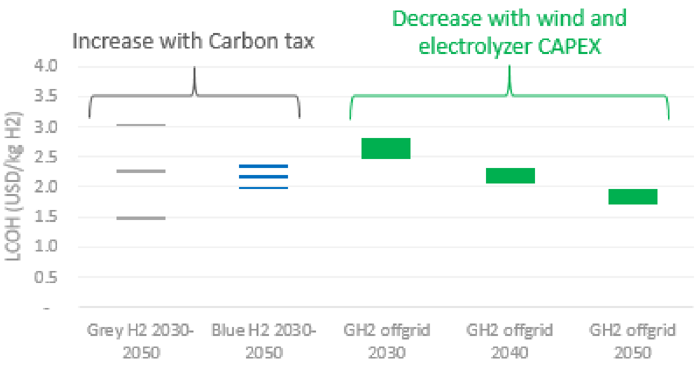


Figure 4: LCOH for grey, blue and green off-grid H_2, USD/kg H_2

1.3 Main findings from the energy transition pathways

Chapter 5 provides an overview of the main results and findings from the optimisation of the electricity and hydrogen production, storage and network for the three energy transition pathways and the nine sensitivities, highlighting the impact on electricity system (generation, inter-regional flows), hydrogen production and exports, CO_2 emissions and pathways costs.

1.3.1 Electricity system

In all scenarios considered, **the increase of power demand is mostly met by additional renewable capacity**.

- Renewables are competitive in all scenarios, although the absence of CO_2 tax in CC does not enable a significant reduction of gas-based electricity generation in volume in 2050.
- The share of low-carbon energy (RES and nuclear) reaches between 55% and 73% by 2030 and at least 73% in 2050.

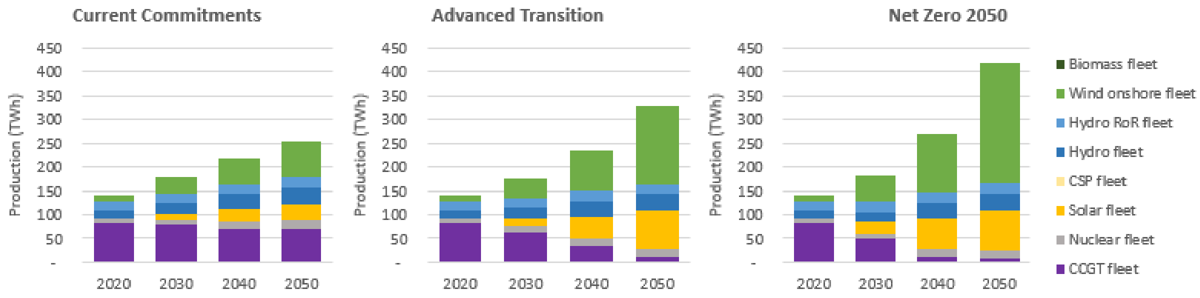


Figure 5: Electrical production mixes of the three pathways

Solar and Wind capacities are economically competitive compared to gas-based electricity generation.

- Despite the intrinsic variability of their generation and potential investment needs in flexibility and interconnection when developing renewables, an electricity system relying on RES appears more economical than a system relying on gas-based electricity generation.
- The economic optimisation of the systems leads to a maximum possible investment in wind capacities. Solar capacities however do not reach their maximum potential in AT and NZE. The value of solar for the system is progressively reduced with the increase of capacity.

The economic preference order between gas power plants and renewables is greatly **influenced by the WACC** (Weighted Average Cost of Capital) **and the gas price**.

- In the sensitivity with a higher WACC (14% instead of 7.5%) which would increase LCOE of solar and wind by around 60%, the amount of solar and wind invested is reduced by 45% compared to the baseline.
- In the sensitivity with lower gas price (3.2 USD/MMBtu instead of 5.7), the amount of solar and wind invested is reduced by 65% compared to the baseline.

In all the pathways, **the expansion of the electricity grid is a necessity to optimize the use of large renewable quantities** and benefit from regional characteristics (strong wind in the South, high solar irradiation in the North).

- The increase reaches up to +180% increase for NZE in 2050
- Limiting the development of interregional transmission capacities (to +50% compared to 2050) as tested in sensitivity S8 would decrease the quantity of renewables installed in the system and increase total costs, although there would be more opportunities for green hydrogen as this energy would need to be consumed locally.

1.3.2 Hydrogen production and exports

In all pathways, the supply response to a growing hydrogen local demand (and exports) is shifting **from a carbon intensive SMR-based production to low-carbon hydrogen production: SMR+CCS and electrolysers.**

- In 2050 in NZE, green hydrogen production reaches 4.4 MtH_2, i.e., 95% of total hydrogen production. Exports are only green hydrogen while 85% of hydrogen demand is green-based.

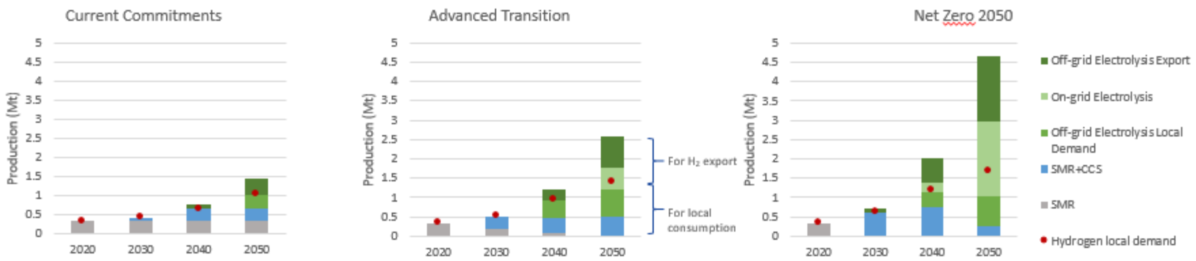


Figure 6: Yearly hydrogen production mixes of the three pathways

On-grid electrolysis is developed only if the electricity generation mix achieves a high share of renewables and if the CO_2 tax is sufficient (AT, NZE).

- Decarbonisation of electricity is a prerequisite for an economic and environmental development of on-grid electrolysis
- For on-grid electrolysis, renewables are preferably developed in Patagonia where wind resources are the best.

- In 2050, in the scenarios NZE, on-grid electrolysis is representing 40% of the total hydrogen production.

The off-grid solution can be deployed independently of the local electricity and hydrogen decarbonisation scenario, if the price conditions are favourable. Off-grid renewables and electrolysis will also develop mostly in Patagonia, given the high wind resources and low resulting LCOH.

Considering fugitive emissions in the investment decision is a key component, especially when comparing blue and green H_2. This can be a **decisive factor when choosing the technology pathway for H_2 production.**

If ambitious renewable installation targets are met, **Argentina has the potential to emerge as a major exporter of hydrogen and its derivatives**.

- The exports from Argentina could reach 3Mt in NZE by 2050 which would represent a revenue of 5.4 billion USD. This revenue is calculated based on H_2 exports ‘international prices. It does not account for derivative of PtX products ‘prices. Added value could generate larger revenues.

The international price of hydrogen has a substantial impact on the quantity exported.

- In a sensitivity of NZE with high international hydrogen prices (S9), exports could increase to 5.4 Mt in 2050 and exports revenues to 11 billion USD.
- A 20% reduction of the export price would reduce exports in 2050 by almost 20% and reduce by a third the exports revenues.

1.3.3 CO_2 emissions

- Currently, grey H_2 production represent less than 1% of Argentina's CO_2e emissions. **In the long-term, the transition from grey to blue and green H_2 has the potential to contribute to reducing Argentina's total emissions** , however this reduction is not as significant (less than 6% in 2050 in the NZE pathway)**,** as the one of other measures such as energy efficiency, electrification of uses and development of a greener electricity generation mix.

- The CO_2 emissions, as calculated by the model[3], decrease in all three pathways with the decrease of gas-based electricity generation.
- The decrease is steeper in the scenario NZE with the rapid development of RES capacities, even if it has the highest electricity demand.

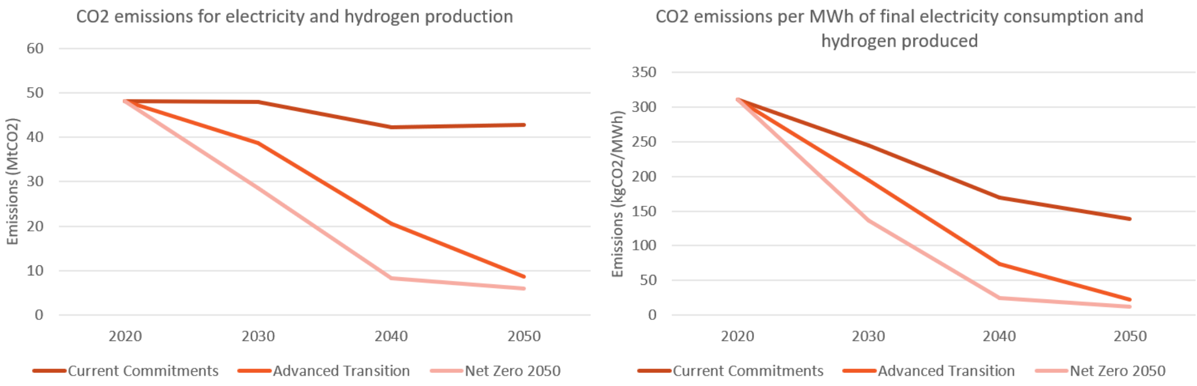


Figure 7: CO_2 emissions of final electricity consumption and hydrogen produced (Total and per MWh)

While the CO_2 emissions drop in 2050 compared to 2020 in all baseline scenarios, the installation of fewer renewables can lead to an overall increase of CO_2 emissions over the pathway.

- In the sensitivity analysis with a higher WACC, the lower installation of renewables leads to an increase of CO_2 emissions in 2050 (by 20 million metric tons compared to 2020).
- This effect is even more pronounced in the sensitivity analysis with low gas prices, where CO_2 emissions are projected to rise by 30 million metric tons between 2020 and 2050.
- Making sure RES capacities are installed in the future (e.g. by setting targets or helping the financing of RES) is key for reducing CO_2 emissions in the long term.

Total CO_2 emissions at country level, accounting for the results of the model and the assumptions presented in Chapter 4 (pathway definition), for the rest of the sectors and end-uses, also show a decrease of CO_2 emissions in all three pathways.

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[3] The model only integrates direct emissions in CO_2e for electricity and hydrogen production (scope 1). In particular, it is not a life cycle assessment and it only computes the emissions of electrified uses. The emissions of what is not electrified (transport still using oil, or heating or industries still using gas and coal for instance) and the potential benefits from providing green hydrogen to other countries via exports are not accounted for.

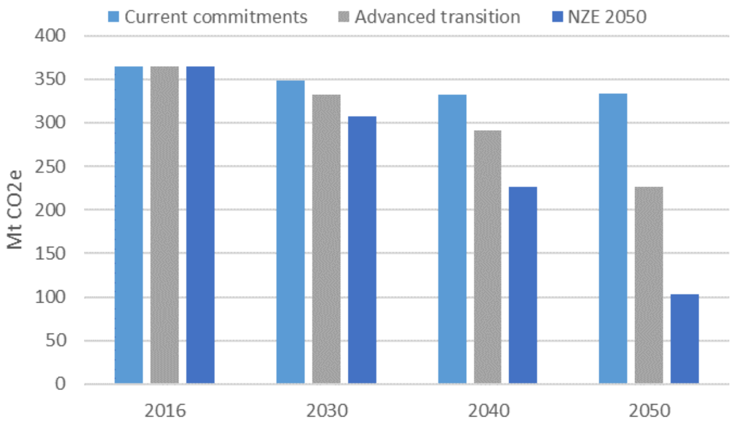

Figure 8: Resulting CO_2e emissions, $MtCO_2$e, per pathway

1.3.4 Total pathways costs

Overall, the total costs of electricity and hydrogen systems are almost proportional to the size of the systems: the costs per MWh of final energy is only 15% higher in NZE (35.6$/MWh) than in CC (30.8$/MWh).

The pathway costs include investments in new assets for electricity and hydrogen production, reinforcement of the inter-regional network, and yearly operation costs for all the system (fuel costs, etc.). They do not include the investment costs of the existing generation technologies (hydro, nuclear, nor the carbon tax.

Note that the quantity of hydrogen produced for exports is significantly higher in NZE (XX Mt) than in AT and CC (respectively XX Mt and XX Mt). The higher costs for NZE could thus be offset by the hydrogen (or hydrogenous molecules) export revenues, depending on the international price of hydrogen (or hydrogenous molecules) in 2040+.

1.4 Conclusions and Recommendations

Chapter 6 summarizes the main conclusions presented in the previous chapters.

In particular, it emphasizes the **commitment of Argentina towards energy transition** and the **main routes towards decarbonisation of the energy sector as a whole**, such as energy efficiency, renewable energy development, electrification of end-uses, and low-carbon H_2 for uses that are not suitable for direct electrification and for existing uses in the industrial sector (feedstock).

Solar and wind capacities are economically competitive and largely deployed in all scenarios (+27GW in CC, +67 GW in AT and +89GW in NZE). Reaching high renewable capacities as fast as possible requires developing this industry, limiting costs of financing and introducing a carbon tax for fossil-fuel based generation. The **development of the interregional network** is a requirement for an economic and efficient use of renewable potentials in Argentina. In particular, the increase of the capacity Patagonia-Buenos Aires is necessary to benefit from the wind potentials in Patagonia.

Developing on-grid renewable energy sources (RES) is "no regret". Even when the network is not fully developed (S8), RES are useful for green H_2 exports and contribute to decarbonising the world, at a reasonable cost. However, the main effect is on local emissions: RES, if used for the electricity sector, helps to reduce gas consumption for electricity locally, while if used for green H_2 exports, they contribute to reducing fossil fuels consumption (potentially) in the rest of the world.

In the long-term, the transition from grey to blue and green H_2 has the potential to contribute to reducing Argentina's total emissions (6% in 2050 in the NZE pathway). **Renewables are best used for electricity decarbonisation in a first step and on-grid electrolysis comes in a second step of the decarbonisation of the system**. Argentina is also well-positioned to emerge as a major exporter of PtX products to importing regions such as European Union, Japan and South Korea, which could also contribute to the global decarbonisation

There is currently a wide price gap between green H_2 compared to grey and blue H_2 in Argentina, but incentives such as a carbon tax could promote its development.

Off-grid projects can be developed independently of local decarbonisation scenario (renewable electricity mix), if the price conditions are favourable. They can also play a significant role to overcome energy infrastructure challenges. On the contrary, the use of electricity for on-grid electrolysis requires that the deployment of solar and wind is significant and electricity is already low-carbon overall.

The following figure presents the SWOT analysis of the H_2 development economy in Argentina.

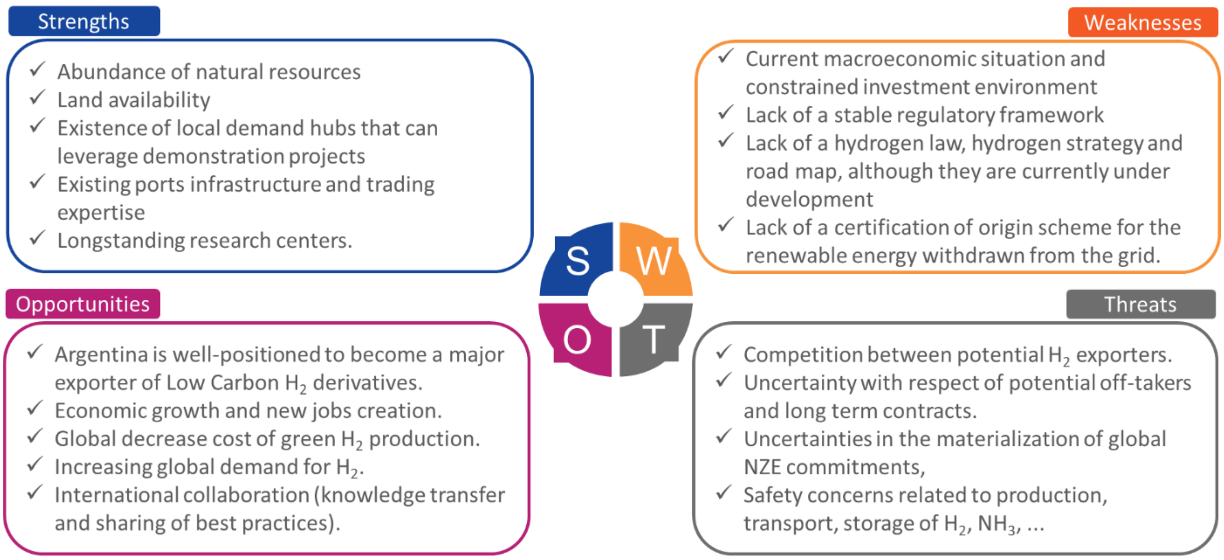

Figure 9: SWOT analysis: H_2 development economy in Argentina

As highlighted in the SWOT analysis, there is a strong **need of establishing a clear and stable policy and regulatory framework**, including a hydrogen law and strategy, to attract investments in the sector.

Accelerating the development of renewable is also essential, ensuring the upgrading and expansion of the transmission networks, the streamlining of permitting procedures, and well-developed supply chain logistics.

The development of the green H_2 economy will also depend on the **establishment of favorable financing mechanisms[4], incentives, and financial support** programs to attract investments in green hydrogen projects: . Additionally, it is necessary to:

- foster the development of domestic and international markets for green hydrogen, facilitate partnerships, and collaborate with other countries and market players.
- promote knowledge exchange, sharing best practices, and the development of global hydrogen standards and markets.

[4] Some examples of favorable financing instruments are Low-Interest loans and loan guarantees; Hedging instruments, preferably through concessional financing or hedges issued by green hydrogen importing countries; Tax incentives, such as tax credits or exemptions; Government Grants and Subsidies; etc.

2 Introduction to the project

2.1 Background of the study

Argentina has diverse and abundant natural resources: vast fertile land for agricultural and livestock production chains, natural gas, wind, solar, hydropower, as well as lithium and uranium deposits. The economy of the country highly relies on agri-food exports, and in the future, green molecules exports could play a role. The accelerating pace of technology innovation and climate change poses uncertainty in the future pathways to achieve the goals of the Paris Agreement.

The PtX Hub identified Argentina as a country with a high potential to produce Power-to-X (PtX),based on domestic renewable energy , which could represent a lever for the country's decarbonisation pathways as well as for its exports, enabling the development of the economy[5].

Currently, the country has committed to limit its emissions to 349 $MtCO_2eq$ by 2030 and to make efforts in achieving net zero emissions by 2050. Although Argentina does not have a clear roadmap towards net zero emissions yet, nor clear legislation to achieve its decarbonisation targets, policy makers expressed their interest in advancing a hydrogen economy to meet the climate goals[6]. Additionally, the development of a National hydrogen strategy has been included as one of the key work streams ("líneas de acción") of Argentina's National Adaptation and Mitigation Plan published in November, 2022[7].

On the demand side[8], decarbonising existing hydrogen production could be the starting point for the deployment of low-carbon hydrogen. Presently hydrogen is used in oil refining and key industrial sectors such as the production of ammonia (for nitrogenous fertilizers) and methanol, and steel. Also paramount is the deployment of sustainable mobility technologies in road freight transport, given the relatively low population density of Argentina, its limited railway infrastructure and regional trade relying mainly on long-distance truck driving. The heating of households and buildings relies on natural gas consumption thanks to a well-developed gas distribution network and is subject to

[5] PtX Hub in Argentina - PtX Hub (ptx-hub.org)
[6] The development of the National Hydrogen Strategy is a multi-sectorial process led by the Secretariat of Strategic Affairs, currently underway, and expected to be officially launched in August 2023.
[7] Ministerio de Ambiente y Desarrollo Sostenible de la República Argentina. (2022). Plan Nacional de Adaptación y Mitigación al Cambio Climático.
[8] https://www.iea.org/reports/hydrogen-in-latin-america

strong winter-summer seasonality. In the medium and long term, Argentina could produce large amounts of low-carbon (green and blue) hydrogen at low costs, due to its wind resources in Patagonia, solar irradiation in the north and natural gas deposits in the west. However, considering the power/hydrogen system of Argentina, these regions are located at distance from the current hydrogen demand hubs.

2.2 General objectives and contents of the report

2.2.1 General objective of the study

This study aims at developing a range of detailed energy transition pathways/scenarios for Argentina towards 2050, to inform how hydrogen and PtX products can contribute to the decarbonisation of the country´s power, heat, transport and industrial sectors, as well as the potential for hydrogen exports, while testing different decarbonisation ambition levels, technology assumptions, infrastructure development levels, etc. The study does not include a sectoral assessment that identifies in which (industrial) sectors (e.g. steel or chemistry) hydrogen or its PtX derivatives could be competitive in relation to other decarbonisation options.

2.2.2 Main contents of this report

This report is structured as follow:

- "Chapter 3 - Model set-up and Data collection" presents:
    - the main modelling characteristics applied to both the electricity and the hydrogen system, as well as how the model optimized these systems,
    - the main data sources and how input data were elaborated/calculated for the Baseline year simulation and for the future pathways
- "Chapter 4 - Scenario definition" presents the general framework and definition of the three main scenarios/pathways as well as the corresponding hypothesis used for the modelling of the years 2030, 2040 and 2050.
- "Chapter 5 - Analysis of energy transition pathways" describes the main results of the three energy transition pathways, as well as the main hypothesis and results along the nine sensitivities analysed in this study.
- Finally, "Chapter 6 - Main conclusions and recommendations" aims at summarizing the key findings and conclusions of the study.

The report also includes in its Annexes additional detailed assumptions and results of the study.

3 Model set-up and Data collection

3.1 Model set-up

3.1.1 Objective and main characteristics of the model

This study on the evolution of the Argentinian energy system relies on three different **pathways** or **scenarios.** They are built on combined assumptions on the evolution of key parameters (such as GDP, demand by sector, etc.), based on exogenous planning exercises and discussions with Argentinian stakeholders as well as on an economic optimization of electricity and hydrogen generation via Super Grid. All three pathways share the same starting point and are subsequently optimized for the milestone years of 2030, 2040 and 2050. These pathways represent different levels of ambition for the energy transition and the decarbonisation of the country[9], the scenario Net Zero 2050 (NZE 2050) being the most ambitious one.

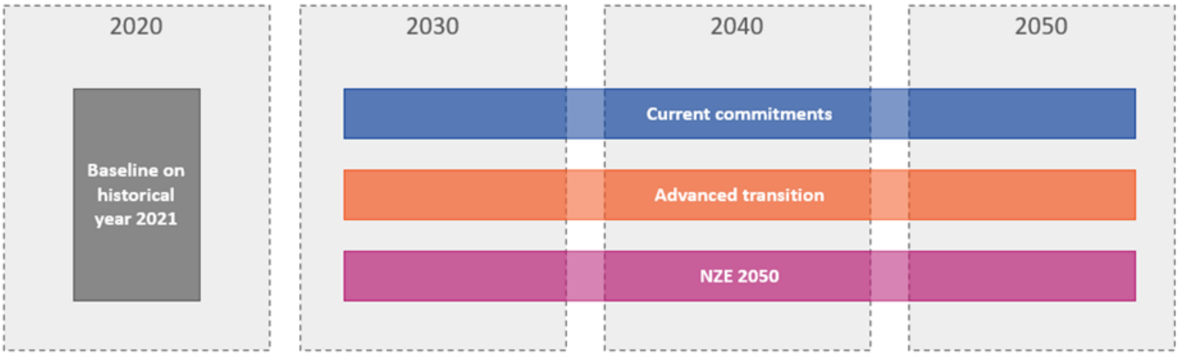

Figure 10: Modelled pathways

The model in Super Grid aims at minimizing the costs for electricity and hydrogen generation in Argentina to satisfy the electricity and hydrogen demand at an hourly rate, with the possibility of exporting hydrogen.

[9] "Current commitments": Energy transition measures allow compliance with the NDC 2030 and NZE 2050 uncertain. "Advanced transition": Energy transition measures allow compliance with the NDC 2030 and NZE after 2050. "NZE 2050": Energy transition measures allow compliance with the NDC 2030 and NZE 2050.
The three pathways are further described in chapter 4.

3.1.2 General presentation of Artelys Crystal Super Grid

The modelling software Artelys Crystal Super Grid (ACSG) is used to simulate the electricity/hydrogen system of Argentina at an hourly time-step, taking into account techno-economic asset constraints accounting for policy objectives and environmental limitations. It minimizes the costs for generating the electricity and hydrogen demand of Argentina, with the possibility to export hydrogen abroad. The model does not include a cost comparison for the application of hydrogen derivatives in different industry sectors (e.g. steel or chemistry).

Typical inputs of the model include:

- Final demand for electricity and hydrogen (which does not include electricity consumption for PtX and hydrogen consumption for electricity, both of which are endogenous, optimized in the model)
- Final demand for electricity and hydrogen (which does not include electricity consumption for PtX and hydrogen consumption for electricity, both of which are endogenous, optimized in the model)
- Installed capacities of production assets which are not economically optimized (such as nuclear and hydro)
- Costs related to the installation and operation of the economically optimized assets
- Assumption on the commodity costs for the years 2030, 2040 and 2050
- Maximum wind and solar installation rates (based on industrial production rates)

Typical elements of the model when simulating system operations include:

- Consumption and variable renewable generation patterns,
- Generation of Hydropower, accounting for seasonal storage and run-off-river,
- Conventional thermal generation with typical minimal load and gradient constraints,
- Storage (batteries, PHS) and demand-side flexibilities (EV, heat pumps, etc.),
- Power-to-gas,
- Energy infrastructure and interconnections,
- Transport of electricity and hydrogen (interconnectors and pipelines)

Super Grid also optimises investments by simultaneously minimising the investment and operation costs of the system while satisfying a target energy demand.

It identifies the cost-optimal system alongside different horizons accounting for different sets of framework assumptions (e.g., H_2 exports, technology costs, RES potentials), while respecting varying levels of carbon emission targets (cf. the different scenarios). This provides meaningful insights for future technology and investment requirements, their optimal operation, and the benefits of regional cooperation.

Typical outputs of the pathway optimisations (which was used in this study) include:

- Investments in each technology at each step (year) of the pathway
- System operation for each pathway year, including hourly generation for the modelled producer, hourly imports and exports between the modelled zones, hourly storage usage and PtX solutions, amount of hydrogen exported to the rest of the world
- Costs for investments and operation of the system

With these outputs, a large set of key performance indicators (KPIs) are computed and further analysed.

Figure 11: Synthetic description of Artelys Crystal Super Grid

3.1.3 Geographical scope

Argentina is modelled as 9 power zones defined by CAMMESA (system operator and administrator), linked by interconnections capacities (NTCs – Net Transfer Capacities). The current transmission capacities are used as a baseline and included in the model for year 2021. For the future pathway's milestones (2030, 2040 and 2050) the NTC between the regions are optimized.

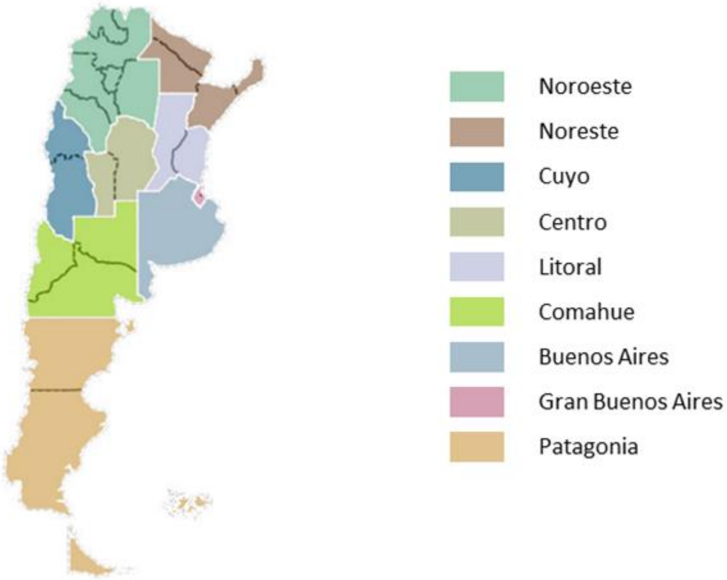

Figure 12: Power regions of Argentina

NB: CAMMESA regions include groups of Argentinian provinces, except for "Gran Buenos Aires", which includes the perimeter of the distribution companies EDENOR and EDESUR, i.e. CABA and a small portion of Buenos Aires province.

The neighbouring countries with which Argentina is currently interconnected (Chile, Paraguay, Brazil, Uruguay)[10] is not modelled explicitly, but electricity imports and exports from/to these neighbouring countries are considered as an hourly profile. Electricity exports and imports come only from three regions, namely Noroeste, Noreste and Litoral.

[10] Electricity imports and exports in Argentina represent a very small share of total supply and demand (less than 3%) and are thus modelled in a simplified manner. An electrical interconnection (132kV line) between Bolivia and Argentina of 120MW has recently started operation, however, it is not specifically modelled for its limited size and expected impact on national electricity balance.
Gas imports from Bolivia are taken into account in the short-term through the regional assumptions on price and availability of gas in Argentina. Gas infrastructure is not modelled in this study.

3.1.4 Modelling of the electricity system

3.1.4.1 Consumption

The **electricity demand** is set per region in Argentina. Yearly consumption targets from the scenario definition are translated into hourly demand profiles for the total electricity demand (apart from PtHeat and transport demand).

The consumption of heat pumps for **electrical heating** is modelled separately and has a specific thermosensitive pattern, which is generated with historic temperatures and calibrated to obtain a target consumption in TWh/year.

The consumption of **electric vehicles** is also modelled specifically, accounting for their main characteristics and based on international experiences.

3.1.4.2 Generation, storage and transport

The following capacities are accounted for in the model, at a regional level. All technologies highlighted below are considered in the scenario development, however only the underlined technologies have their capacity optimised during this exercise: the rest of them included exogenously using expert criteria:

- **Renewables**: hydro run-of-the-river and reservoirs, solar (PV and concentrated), wind onshore, biomass, biogas, waste;
- **Non-renewable**: nuclear, gas OCGT and CCGT, hydrogen OCGT and CCGT, coal;
- **Storage and conversion**: batteries, pumped hydro; power-to-hydrogen
- **Transport:** NTCs between zones, NTC with neighbours.

3.1.4.3 Optimisation of the expansion of the fleet and operation of the system

The optimisation of the expansion of the fleet is done to minimise the total costs of the system while ensuring the supply/demand equilibrium of electricity at each time. As such, the optimisation does not evaluate optimal capacities based on their LCOE (Levelized Cost of Electricity), but also based on their generation patterns adequacy with consumption, the potential needs for storage or transmission across regions.

The parameters that are accounted for in the model for each asset are:

- CAPEX

- OPEX
- Production costs (fuel costs, variable costs and CO_2 costs if relevant, accounting efficiency)
- WACC (Weighted Average Cost of Capital)
- Life time
- Hourly availability of the technology
- Other technology-specific technical characteristics (gradients for thermal generation, ...)

The simulated system operation follows an optimal dispatch of power production assets and use of flexibilities in order to respond as efficiently as possible to the consumption. The results of the dispatch and the related marginal costs correspond to the functioning of a typical day ahead, pay as clear wholesale competitive market assumption.

3.1.5 Modelling of the hydrogen system

3.1.5.1 Consumption

The **hydrogen demand** is set per region in Argentina and considered constant over the year, except for the endogenous consumption of hydrogen for electricity generation which is a result of optimisation and can vary during the year. Currently, the consumption of H_2 in Argentina corresponds to uses in industrial processes only.

Hydrogen exports are considered as an additional elastic consumption of hydrogen and concern only green hydrogen (it was assumed that production of grey and blue hydrogen cannot be exported). The profile of exports at any given time is initially unconstrained (meaning that the exports profile can vary depending on the season and time of day), and exports are valued at a given price. This price is set based on the review of exogenous sources. In practice, Argentina will export PtX products from Hydrogen such as green ammonia, methanol, e-fuels. However, the model does not specifically represent these processes nor the electricity demand corresponding to them. The yearly volume of exports is limited by the installation potential of electrolysers and renewables for each pathway and time horizon. The candidate regions to produce and export PtX products are Patagonia, Comahue and Buenos Aires, thanks to their large renewable potential, high wind load factors and existing export infrastructure (vicinity to port). Therefore, electricity or hydrogen must be transported to these regions to be transformed and exported.

3.1.5.2 Production and transport

Regarding hydrogen production, the decommissioning of current capacities of SMR (Steam Methane Reforming) is scenarized. To replace these capacities, installed capacities of **electrolysis,** and **SMR + CCS** (SMR equipped with a carbon capture storage) is optimized in each region to minimize the total system costs to satisfy regional consumption, additionally to the **hydrogen and/or power transport capacities** between regions. Technology costs and characteristics are set for each of these investment options which are potentially decreasing over time (e.g., for electrolysis). The storage and transport costs of CO_2 are not directly modelled, only extra costs in CAPEX and OPEX are considered.

Off-grid electrolysis is considered outside of the model as a scenario for green hydrogen production. Only then is it linked to the model by deducting it from the final demand of hydrogen as well as simultaneously adjusting for the maximum potential of wind in regions (for example Patagonia) where off-grid capacities are installed. In turn, off-grid electrolysis assumptions are divided into off-grid electrolysis dedicated to local demand and off-grid electrolysis for exports.

3.1.5.3 Storage

Gaseous hydrogen storage at moderate pressures and liquid storage under cryogenic conditions are the two major mature hydrogen storage technologies that have reached commercial scale so far. Gaseous storage is dedicated to stationary uses only because it requires large volumes of space (due to the low hydrogen density). The cryogenic storage in turn, requires energy and of concern is the persistent evaporation of hydrogen if it is stored for long periods of time.

International underground (geological) experiences of hydrogen storage is so far only restricted to salt caverns, a good that is limited in Argentina. Furthermore, the storage of hydrogen in depleted oil and gas reservoirs has only been tested for gas mixtures, and a massive adoption of this technology is doubtful[11].

As a consequence, we have considered short-term storages in Argentina, accounting for the storage capacity of pipelines and production means. This storage capacity is designed to ensure average daily demand storage, with charging/injection capacity being equal to the average hourly hydrogen demand.

[11] In this regard, it is worth mentioning that there is a small-scale facility in Argentina (Hychico) that produces green hydrogen. It is composed by two electrolysers with a total capacity of 120 Nm3/h of hydrogen and 60 Nm3/h of oxygen. The high purity hydrogen is mixed with natural gas to feed a 1.4 MW genset equipped with an internal combustion engine especially adapted to operate with rich and/or poor gas mixed with hydrogen.

3.1.5.4 Optimisation of the expansion of the fleet and operation of the system

The capacity expansion of hydrogen assets is done in parallel of the electricity capacity expansion. The fleet parameters used for the optimisation are the following:

- CAPEX
- OPEX
- Production costs (fuel and electricity costs, variable costs and CO_2 costs if relevant)
- WACC (Weighted Average Cost of Capital)
- Life time
- Hourly availability of the technology

Similarly to electricity, (storage and transport are also considered by the optimisation), LCOH (Levelized Cost of Hydrogen) is not the only factor determining investment decisions in green or blue hydrogen.

The operation of all the hydrogen assets (generation, storage, exports, transport) are unconstrained and economically optimised from the perspective of a perfect planner controlling all the energy assets in Argentina.

For **electrolysers**, this corresponds to a flexible, electricity market-driven operation as it produces mostly when electricity prices are low and is not forced to produce in baseload periods. Indeed, the model avoids producing hydrogen through electrolysis when it is simultaneously generating electricity using gas or hydrogen in OCGT/CCGTs, as it results in a net energy loss, and relies as much as possible on SMR in this configuration.

For the **exports of PtX products produced from on-grid electrolysis**, the model optimizes economically a volume of green H_2 at a given price. This means, that exports at a given hour in a given region can only occur if the 3 conditions are verified:

- The final Argentinian green H_2 demand is supplied
- There is still some unused capacity of electrolysis
- The electricity price is low enough to have a marginal cost of production below the export price of H_2

Note that the export price also affects the investment in VRES-e (wind, solar) capacities.
In parallel, exports of PtX products produced from off-grid electrolysis rely on scenarized capacities of electrolysers and wind, dedicated only to these exports.

3.1.6 Summary of the modelling set-up

The modelling set-up is summarized in the following chart:

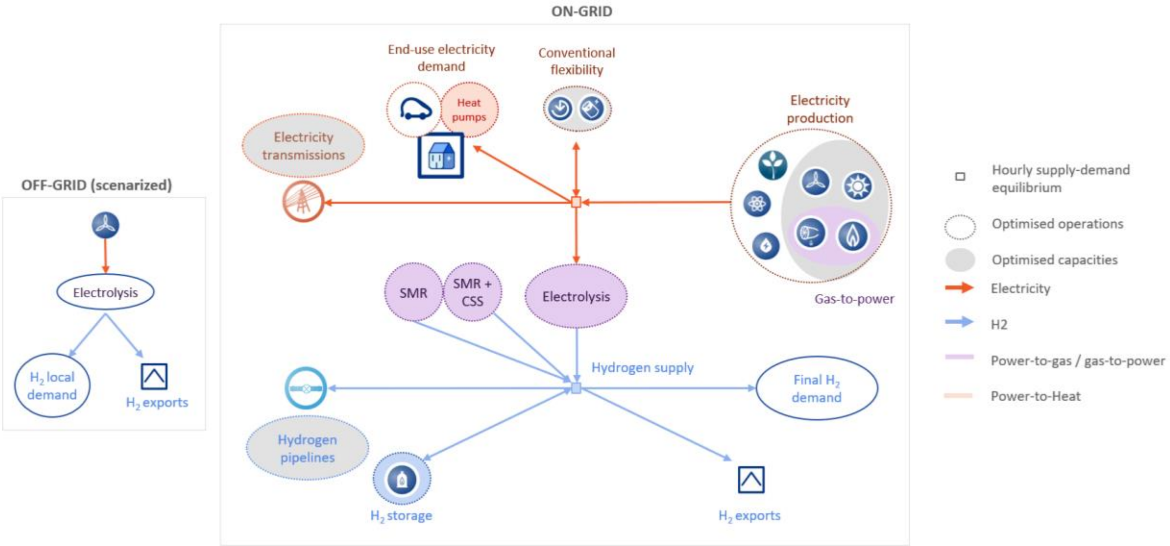

Figure 13: Description of technologies modelled in Artelys Crystal Super Grid for this assignment

3.2 Data collection and preparation

In this chapter, we describe the main data sources and how input data have been elaborated/calculated for the Baseline year simulation and for future pathways.

3.2.1 Baseline (2021): Data collection and preparation

In order to properly calibrate the model and ensure that the geographical representation via 9 nodes adequately represents the current state and dispatch of the electricity system[12], a set of input data to run the Baseline year was elaborated.

The Baseline year is set to be the year 2021, as it most adequately represents the current installed capacity per technology in Argentina. Although 2021 contains some specificities in terms of electricity generation dispatch (low level of hydro production due to dryness, high level of fuel-oil

[12] The hydrogen system is not specifically modelled for the Baseline.

consumption, etc.), it is not an impediment for future pathways as the “Base Year” is only used to initially calibrate the model. For future pathways, average conditions (in terms of hydropower, for example) are used.

The **data used for year 2021** is elaborated based on operational statistics (monthly reports[13], post-operative data[14]) and seasonal programming[15] by the system operator (**CAMMESA**), publicly available on its website.

3.2.1.1 Baseline (2021): Electricity supply data

The following data have been prepared, for each production technology:

- **Wind and Solar PV power plants**: Electricity generation capacities and hourly timeseries of production by technology and by region.
- **Hydroelectric power plants**:
    - Hydro power plants with monthly seasonal reservoirs (around 40% of total hydro installed capacity, mainly located in Comahue):
        - Water storage volume (based on tables of Volume/level per power plant),
        - Water inflows over the year,
        - Technical parameters of the plant (installed capacity, min and max storage level, mean efficiency, useful volume, etc…).
    - Rest of the power plants: A classification system differentiates: Small hydro (<50MW), Large hydro (>50MW) along the following characteristics: run-of-river, daily reservoir, weekly reservoir, pumping. For each category and each region, hourly time series and installed capacities are calculated.
- **Thermal and nuclear power plants:** The analysis of historical data on thermal plants accounts for both the technology and the fuel consumed.
    - Technical parameters such as: Installed capacity, Specific consumption (calculated based on historical generation and consumption per fuel type), Availability rate (historical average), emission factors,

[13] https://cammesaweb.cammesa.com/informe-sintesis-mensual/
[14] https://cammesaweb.cammesa.com/parte-post-operativo/
[15] https://cammesaweb.cammesa.com/programacion-estacional/

- Economic parameters such as: O&M costs (as defined in the seasonal programming), fuel costs per region (as defined in the seasonal programming),
- Historical monthly production rates per technology and fuel use.

3.2.1.2 Baseline (2021): Electricity demand, Import/Export, grid capacities

The following data have been prepared:

- **Hourly electricity consumption by region:** Calculated based on the sum of hourly demand per province (for Buenos Aires province, a monthly repartition between GBA and BAS is used on a pro-rata basis). Losses and pumping demands are accounted separately as they are published at national level. Demand for pumping only applies to regions where pumping hydro plants do exist (Cuyo and Centro) and is optimized, while losses are assumed to be proportional to the regional demand.
- **Hourly timeseries of electricity imports and exports with neighbour countries**: Based on hourly timeseries of total electricity imports and exports as well as monthly timeseries of electricity imports and exports per country. Imports and exports in Argentina represent a very small share of total supply and demand (less than 3%), thus limiting their impact on the national electricity dispatch.
- **Net transfer capacities (NTC) between Argentina and neighbouring countries**: Based on operational data from CAMMESA (seasonal programming) and the min/max hourly historical exchanges between countries. In the specific case of Paraguay, although the country is not interconnected to Argentina through a specific transmission line, Paraguay sells electricity to Argentina via the binational hydro power plant Yacyreta.
- **Net transfer capacities (NTC) between Argentina's regions**: Based on the operational data from CAMMESA (seasonal programming) and the physical limits of the interconnection lines or the specific operational constraints identified in the seasonal programing between regions (substation, capacitors, tension, etc…).

3.2.2 Pathways (2030, 2040 and 2050): Data requirement, part of the scenario definition

In this paragraph, we present the methodology and the data needed for each pathway. A part of the input data depends on the scenario definition, which is not treated in detail in this chapter. The type of data is identified via the following color code:

- Purple data: data is part of the scenario definition. In particular, it can vary between the modelled scenarios. Its elaboration is not further treated in this chapter.
- Orange data: data is not scenarized. The consultant has access to a direct and reliable source of data or has made some educated guesstimate.

The data is organized in two subchapters on the supply and demand of electricity and H_2.

3.2.2.1 Pathways: Electricity and H_2 supply data

3.2.2.1.1 Electricity: Required data for non-optimized power plants

- **Hydroelectricity power plants**:
  - For hydro power plants with monthly seasonal reservoirs: Water inflows corresponding to an average hydraulicity[16], based on CAMMESA data for the year 2019 or other historically similar years.
  - For the other hydro power plants: Hourly timeseries of the average hydraulicity, derived from CAMMESA data for the year 2019 or another similar historical year.
  - For new non-optimized hydro capacity: installed capacity per region and type of reservoir.

- **Nuclear power plants**:
  - For new non-optimized nuclear capacity, installed capacity per region and technical characteristics (efficiency, availability rate, etc…).

3.2.2.1.2 Electricity: Data needed for the optimization of new electricity capacities

- **Costs**:
  - Commodity prices (gas, oil, CO_2 etc.): Commodity prices are assumed to be identical for the 3 pathways, only CO_2 price differing. The CO_2 price impacts the relative competitiveness of electricity and H_2 production options (measured indirectly by their LCOE and LCOH).
  - Investment costs for new power plants (CAPEX, \$/MW) & Fixed operating costs (\$/MW/year) & Variable operating costs & Lifetime (year) & WACC (%) per pathway and per milestone: Based on international publication from IRENA, NREL, IEA and other international sources, as agreed with the PtX hub
  - CAPEX and OPEX of building new electric lines between regions (\$/ additional MW): Based on unitary costs per km of new 500 kV lines and costs per substations, estimating the distance of such project between regions, the necessary number of substations (additional substations are needed for larger distances).

[16] As a first step, pathways are simulated with an average hydraulicity condition, which is the best proxy for long-term studies.

- **Wind and Solar (PV and concentrated power plants) optimization**:
  - Non-optimised installed output capacity (Baseline, MW)
  - Installation potentials -min/max limit per period of 10 years (MW), based on own assumption from resources, geography and sector capacity development (rhythm constraints).
  - Hourly timeseries of production by technology and by region (based on historical data from CAMMESA for regions with existing projects, and Renewables Ninja and PtX Atlas (Fraunhofer), for the regions without current installed projects.
- **Batteries optimization**:
  - Technical characteristics of batteries - 2h and 4h Li-ion batteries.

3.2.2.1.3 H_2: Data for modelling and optimizing the H_2 sector

- **Existing facilities (2021 data)**: Own data elaboration based on data from "Instituto petroquimico argentino"
  - Hydrogen production capacities (SMR, Electrolysers)[17] by region,
  - Actual hydrogen consumption in Argentina
  - Actual hydrogen production in Argentina
- **Costs**:
  - Investment costs for new hydrogen generation capacities (CAPEX, $/MW) & Fixed operating costs ($/MW/year) & Variable O&M costs & Lifetime (year) & WACC (%): Based on international publications from IEA[18], IRENA, and other international sources
  - Cost of developing new hydrogen pipelines and storage facilities: own estimates based on international data from EU TSO[19]
- **Technical parameters**: Efficiency, others. Based on international publications from IEA and own assumptions.
- **Potentials for electrolysis**:
  - Installation potentials for Green H_2 exports -min/max limit per period of 10 years (MW), based on international references such as IEA, IRENA, Hydrogen Council and

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[17] SMR, SMR + CCS and Electrolysers will be the options modeled, as future options for hydrogen production.
[18] Global Hydrogen Review 2021, Assumptions Annex, https://iea.blob.core.windows.net/assets/2ceb17b8-474f-4154-aab5-4d898f735c17/IEAGHRassumptions_final.pdf#page=7
[19] European Hydrogen Backbone https://ehb.eu/

own assumptions considering resources, geography and sector development capacities.

- **For the optimization of Green H_2 exports**:
  - Netback price of Green H_2 exports

3.2.2.2 Pathways: Electricity and H_2 demand, Import/Export, grid capacities

- Electricity and H_2 demand by region:

Type of demand	Data needed
Power demand, apart from space heating and transport demand	• Annual volume & Hourly normalised timeseries of electricity demand, based on historical regional profiles from CAMMESA (assuming negligible historical use of electrical heating and electrical car).
Power demand for space heating	• Annual volume & Hourly normalised timeseries of electricity demand (MWh) for heating, based on a typical heat pump profile proportional to temperature, from the Consultant database. • Temperature (°C), based on historical series of daily regional temperature (SMN, Servicio Meteorológico Nacional)
Power demand for transports	• Annual electricity demand volume for transport (electric vehicles) (MWh) or number of electric vehicles • Typical characteristics (daily charging energy, EV battery capacity, charger capacity, arrival and departure patterns), according to international experience (data cannot be collected locally since there is practically no EV penetration presently). • Share of dumb charging, smart charging and V2G (in %)
Hydrogen demand	• Annual volume (H_2 demand assumed to be flat for the industrial sector). The geographical repartition of H_2 industrial demand in future scenarios is similar to the current repartition.

- **Electricity imports and exports** and **Net transfer capacities (NTC)** between Argentina and neighbouring countries: Equal to the Baseline.
- **Net transfer capacities (NTC) between Argentina's regions**: Data optimised by the model.

4 Scenario definition

4.1 General context and objectives

The Work Package 2 aims to:

- propose three envisaged scenarios (or pathways) reflecting different levels of ambition for total CO_2e emissions reduction[20],
- elaborate a set of detailed hypotheses for each pathway and time horizon (2030, 2040, 2050).

First, the current CO_2e emissions per sector were analysed together with, current energy and electricity balances and energy sector specificities. Based on this analysis, a range of detailed energy transition pathways/scenarios for Argentina towards 2050 were developed, with a special focus on the domestic use and export of renewable electricity-based molecules (PtX).

4.2 Current situation: CO_2e emissions and the Energy sector

4.2.1 Historical CO_2e emissions and commitments

According to the National GHG inventory, total emissions in 2018 amounted to 366 MtCO_2e, of which 51% corresponded to the Energy sector (i.e. emissions corresponding to fuel combustion and fugitive emissions corresponding to fuel leakage) and 39% to Agriculture, Land-Use, Land-Use Change and Forestry. The emissions linked to the current production and use of grey hydrogen as raw material[21] (non-energetic use of fuels) are included in the category Industrial processes and Product Use sector, corresponding only to 6% of the total emissions (see Figure 6).

20 Argentina does not have yet an official detailed roadmap towards 2050 nor a clear legislation to achieve its long-term decarbonisation targets. For the energy sector, the time horizon of the official energy scenarios is until 2030 (Resolution 1036, Oct-2021).

[21] Although most of the gas consumed in SMR is methane used as feedstock, a limited amount of natural gas is also used for heat supply. Emissions resulting from the combustion of natural gas for heat supply are included in the category "Energy".

Supported by: Federal Ministry for Economic Affairs and Climate Action
on the basis of a decision by the German Bundestag
International Climate Initiative
Implemented by Deutsche Gesellschaft für Internationale Zusammenarbeit (GIZ) GmbH
Conducted by Artelys Optimization Solutions

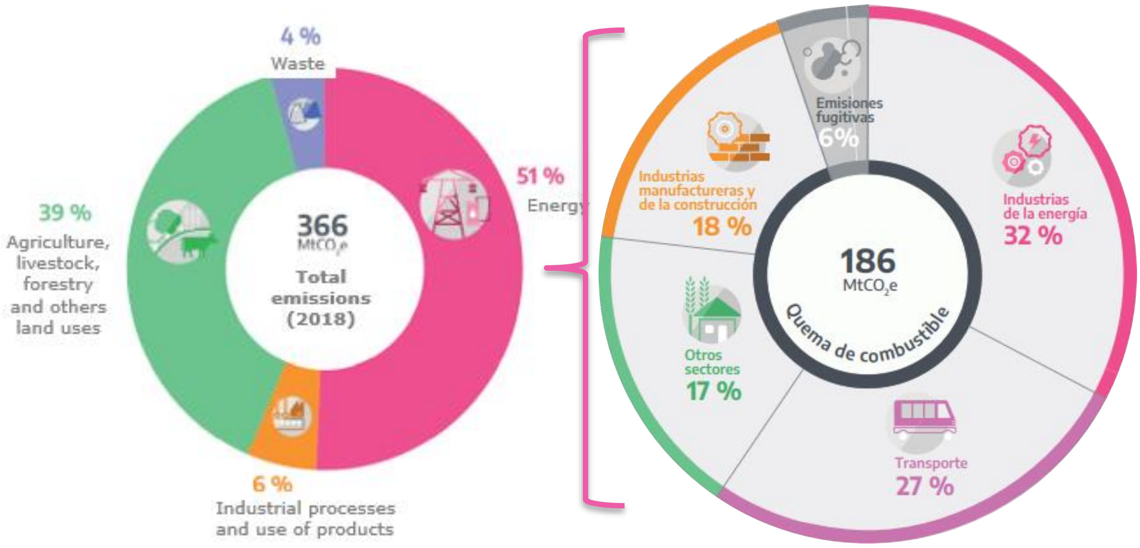


Figure 14: CO2e emissions per sector and subsector energy, 2018, MtCO2e. Source: National GHG Inventory

Taking a closer look at the Energy sector (figure 6, right circle), 32% of the total emissions correspond to the category "Energy Industries", most of which coming from electricity generation. The CO2e emissions from the transport sector come next (27%). CO2e emissions from the Energy sector have remained rather stable in the last decade in absolute terms, however, their share of the total is higher than in the 1990s.

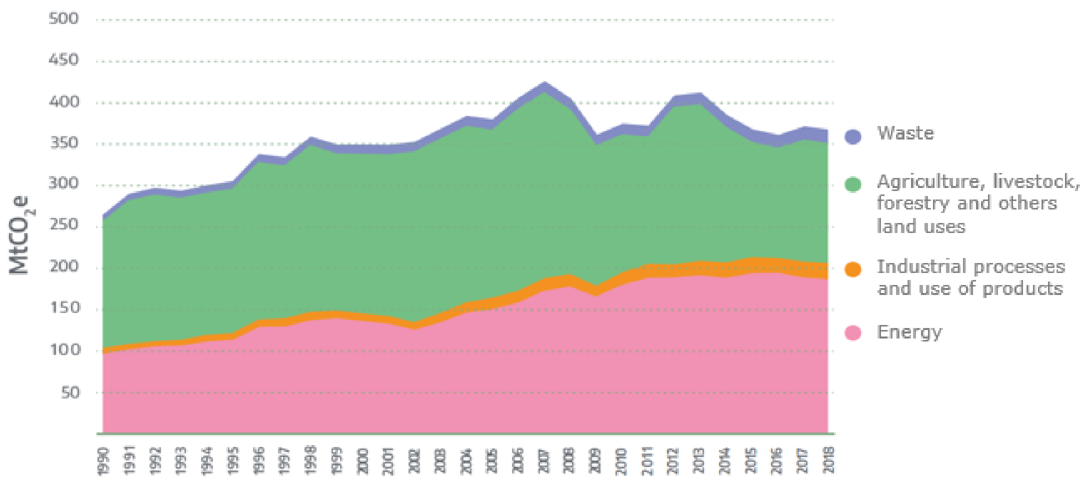


Figure 15: Historical evolution of CO2e emissions per sector, 1990-2018, MtCO2e. Source: National GHG Inventory

Argentina has committed to reduce its CO2 emissions in the medium term, reaching 349MtCO2e by 2030, in line with its NDC. In the long term, Argentina is aligned with the Paris Agreement aiming to achieve "net zero" emissions by 2050[22]. Figure 8 below depicts the different decarbonisation pathways.

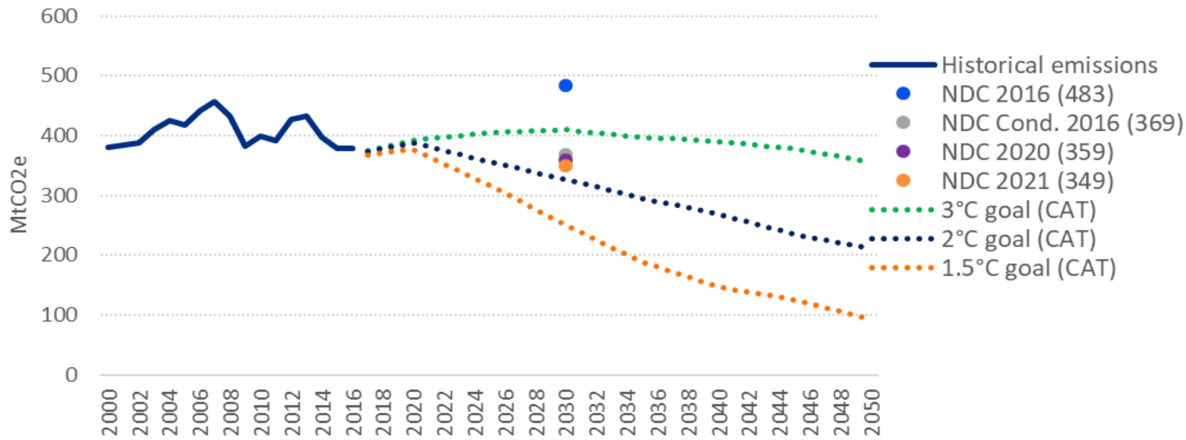


Figure 16: Historical CO2e emissions, commitments and trajectories, MtCO2e. Source: Own elaboration based on Climate Action Tracker[23] (CAT)

The analysis of decarbonisation pathways will focus on the emissions related to the Energy sector[24].

4.2.2 Characteristics of the energy and electricity matrix

Natural gas is a strategic primary energy source for Argentina. It is both its main energy and electricity source as of today (55% of the energy mix and 55% of the electricity supply in 2020).

Argentina has the second largest shale gas reserves in the world and has long been a producer of natural gas (conventional gas historically), which explains the penetration of gas in final uses and sectors such as heating, hot water, cooking for residential and commercial sectors, cars, etc. This specificity must be considered when elaborating decarbonisation scenarios.

[22] Although the mid-term objectives do not represent a significant decrease of current CO_2e emissions, the pathway towards net zero emissions in 2050 will require significant efforts in all sectors and processes, equivalent to dividing current emissions by about four.

[23] CAT analysis does not include emissions from LULUCF (Land-Use, Land-Use Change and Forestry). Although CO_2e proposed trajectory does not reach zero emissions, this trajectory is compatible with net zero emissions objectives, assuming the remaining emissions will be absorbed by the sector LULUCF or other sectors.

[24] Future evolution of the emissions from the rest of the sectors is not studied in details. We assume that all the sectors will contribute to the global emissions reduction objectives in the same proportion.

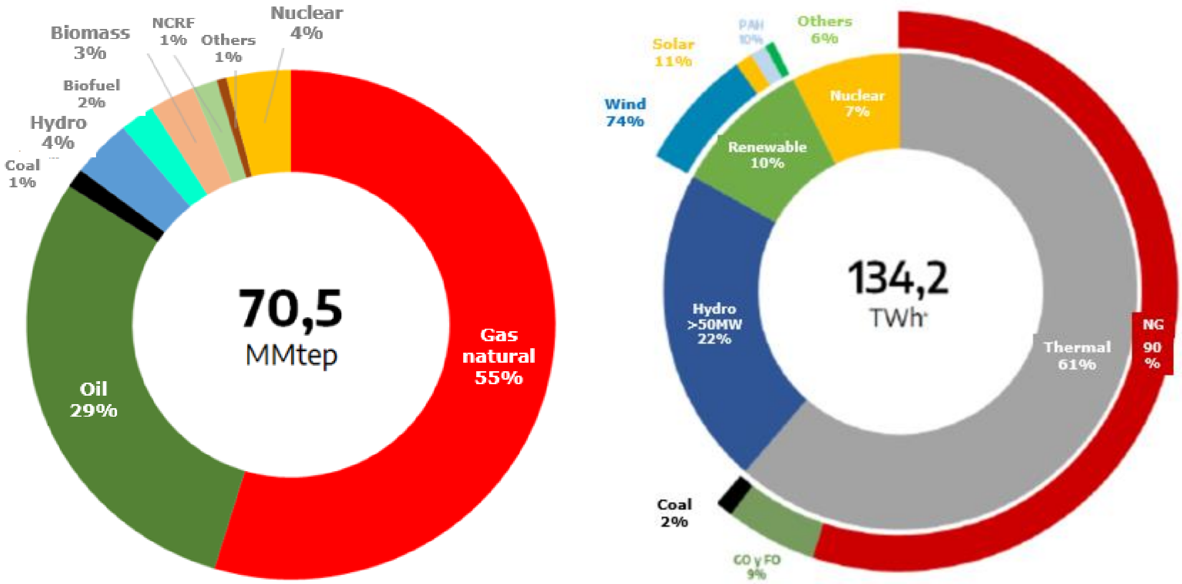


Figure 17: Primary Energy Matrix and Electricity Supply 2020, MMtoe, TWh. Source: Res. 1036 - 2021

Additionally, **Argentina has a great potential for renewable energies**. It harbours large renewable resources at high capacity factors and has significant land availabilities, especially in terms of Wind in the South (Patagonia, Comahue and South of Buenos Aires region) and Solar resources in the North West and Cuyo regions. This potential has so far only been barely used.

4.2.3 Methodology of scenarios

Demand scenarios are built via:

- The analysis of historical tendencies of final sector and fuel consumption[25],and their correlated key indicators (GDP, population, etc…).
- A Baseline scenario corresponding to the projection of historical trends, without applying additional decarbonisation policies.
- The application of decarbonisation policies for three pathways, according to the following pillars:

[25] The National Energy Balance Matrix presents the final consumption in 5 main sectors: Residential, Commercial and public, Industrial, Agriculture and Transport. A 6th sector corresponds to non-energetic final consumption.

- Energy efficiency and Behavioural changes in energy consumption, as the first pillars for energy savings;
- Electrification of uses (performance improvement), with a greener electricity generation mix;
- Temporary and partial use of gas in the transport sector to replace liquid fuels, complementary to the development of the electro-mobility.
- Use of a low carbon H_2 for non-directly electrifiable sectors and the replacement of existing grey H_2 usage in the industrial sector[26].

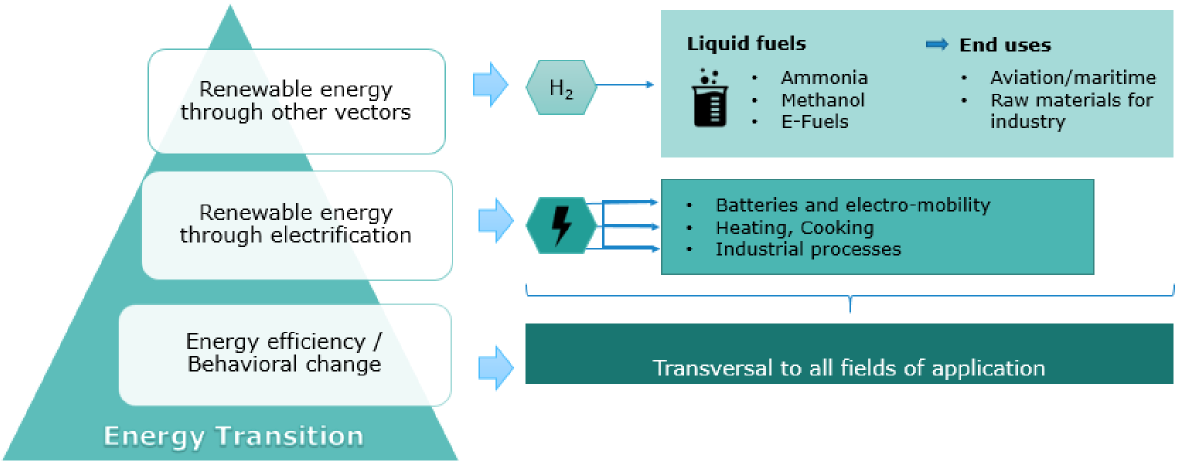


Figure 18: Pillars of the energy transition, at international level

In practice, the three pathways consist of a combination of parameters having different impacts on total CO2e emissions, including:

- GDP growth,
- penetration of electrification rates for specific uses (heating, cooking, hot water, light and heavy vehicles, etc…),
- penetration of other fuels in transport and agriculture (CNG/LNG, H_2, etc.),
- penetration of energy efficiency and behavioural change rates per sector,
- transformation of the electricity mix towards low-carbon emissions sources.

[26] In particular, the renewable hydrogen exports, in the form of X (NH_3, mainly), have a role to play and an impact on the decarbonisation of the industrial sector.

4.3 High-level description of the three pathways

The envisioned scenarios reflect different levels of ambition in terms of total emissions reduction, underpinned by a set of specific targets aiming to transition from current fossil-based production technologies to low carbon technologies in each sector. The main characteristics and parameters for each pathway are described below as well as further described in the subsequent chapters.

Current commitments	• Energy transition measures that allow compliance with the NDC 2030. • From 2030 onwards, stabilization of the level of emissions (the increase in emissions due to growth in demand is offset by EE measures and moderate use conversions).
Advanced transition	• Compliance with the NDC 2030 goal and acceleration of energy efficiency measures and the process of conversion of uses with respect to the "Current commitments" scenario. • From 2040 onwards, final energy consumption remains constant (reduction of energy intensity).
Net zero 2050	• Transformation of the energy sector to achieve the goals of net zero emissions in 2050. • Very significant measures to be implemented in all sectors to limit the growth in demand (energy efficiency), the consumption of fossil fuels (electrification of uses, transformation of the electrical matrix, development of low-carbon H2 production for specific uses).

Figure 19: High-level description of the three pathways

Category	Factor	Current Commitments	Advanced Transition	Net Zero 2050
GHG emissions	Climate GHG mitigation commitments	NDC and NZE uncertain	NDC and NZE after 2050	NDC and NetZero 2050
Economic	Economic growth	2%	2.5%	3%
	Fossil fuels + carbon tax	Low	Average	High
	Reduction of costs of electrolysers	Low	Average	High
Energy demand	Energy efficiency	Low	Average	High
	Electrification of uses	Low	Average	High
Power system	Non-fossil technologies (% of TWh)	65% in 2050	90% in 2050	100% in 2050 or CCUS
H_{2LC}	1st step: Current uses (raw material for the industry)	Driven by economic growth, imports substitution and progressive goals to replace existing processes.		
	2nd step: Penetration in subsectors that are difficult to electrify (aviation)	Low	Average	High
International integration	Exports of PtX products	To the extent that PtX products are competitive at international level.		

Figure 20: High-level description of the main parameters characterizing the three pathways

The three pathways reflect different levels of energy efficiency measures implementation, behavioural changes, electrification of uses (which results in a decrease of energy consumption for a given use). Energy demand is expected to grow in all three scenarios at a similar rate until 2030, while in the long-term, the evolution of final energy consumption being very different from one pathway to one other (increasing, stabilizing or decreasing energy consumption). In all three pathways, the reduction of energy intensity (units of energy per unit of GDP) is significant in the long-term.

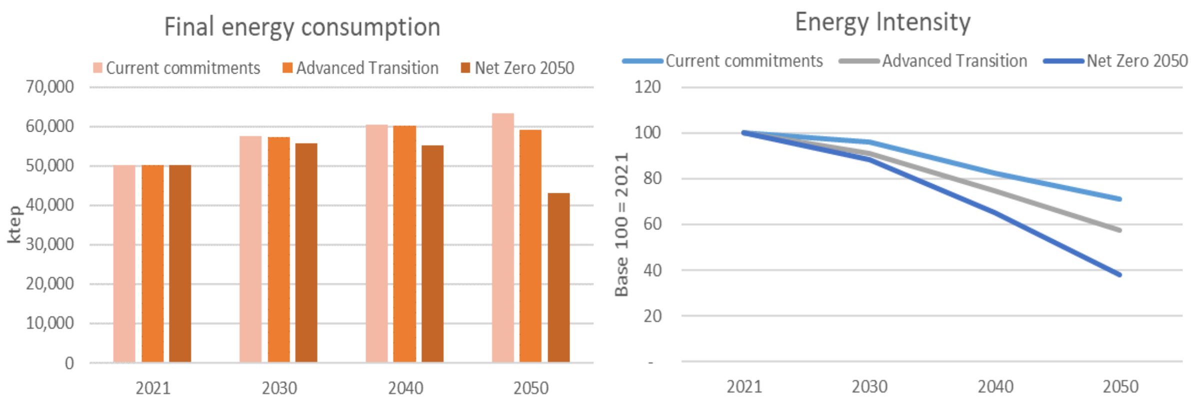


Figure 21: Final energy consumption, ktoe, and Energy intensity, ktoe/MUSD (base 100=2021), per pathway. NB: Final demand for non-energetic consumption is not represented

Electrification of final consumption plays a vital role in decarbonizing the energy sector, provided that it is accompanied by a diverse and predominantly non-fossil electricity production mix[27].

In the NZE 2050 pathway, electricity accounts for almost 60% of total final energy consumption and electricity supply consists of100% low carbon energy.

[27] If the electrification of end- uses leads to a rise in fossil fuel combustion in power plants to meet the growing electricity demand, there is a possibility that the resulting CO_2 emissions will not be lower than the initial levels.

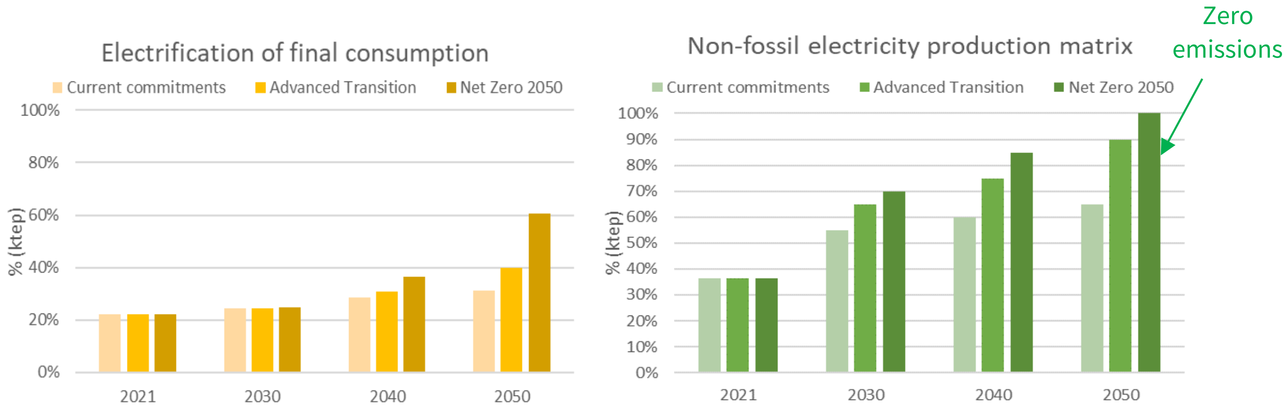


Figure 22: Electrification of final consumption (%) and share of non-fossil electricity production mix (%), per pathway

The combination of assumptions for each parameter and each pathway are compatible with the NDC in 2030 and with net zero emissions in 2050, for the 3rd pathway.

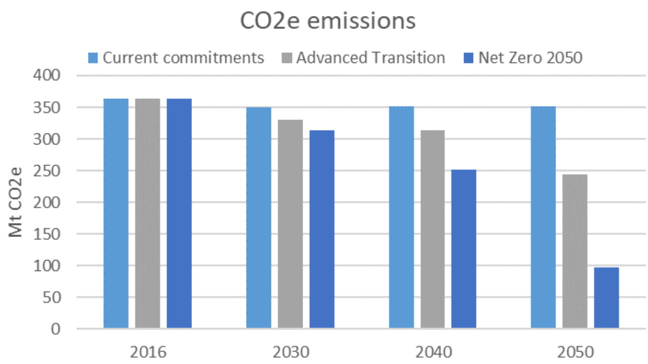
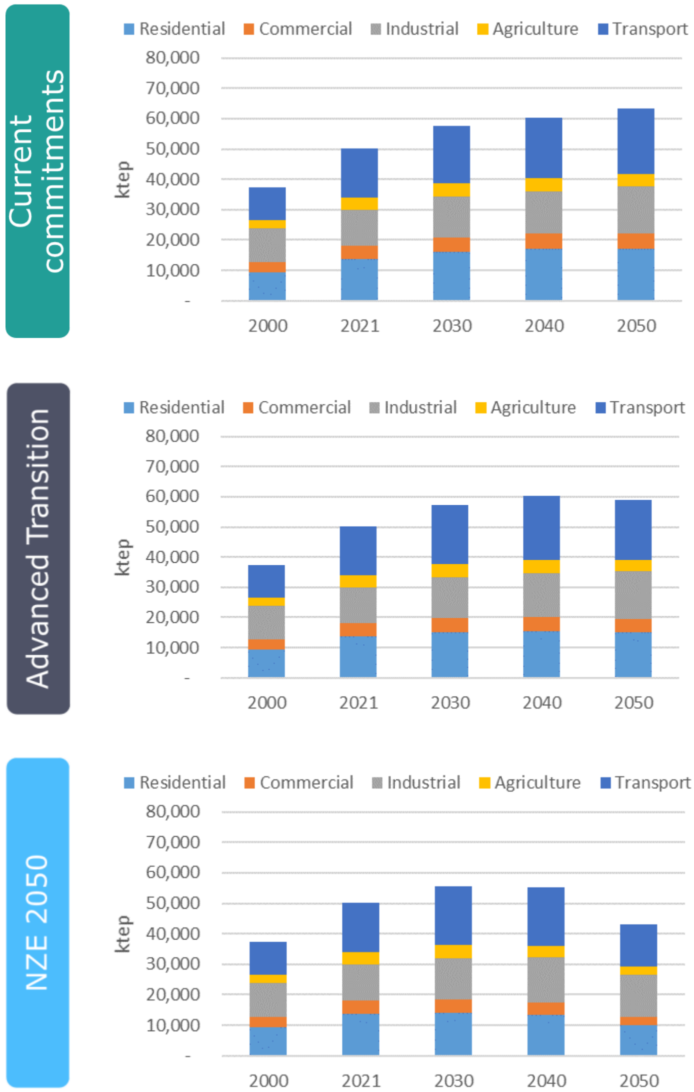


Figure 23: CO_2e emissions, MtCO_2e, per pathway

4.4 Deep dive on final energy consumption by sector and fuel

4.4.1 Final energy consumption by sector

NB: In the following figures, final consumption for non-energetic uses is not represented.



- Demand growth over the period;
- Energy transition measures partially offset GDP growth;
- Relative participation by sector remains stable.

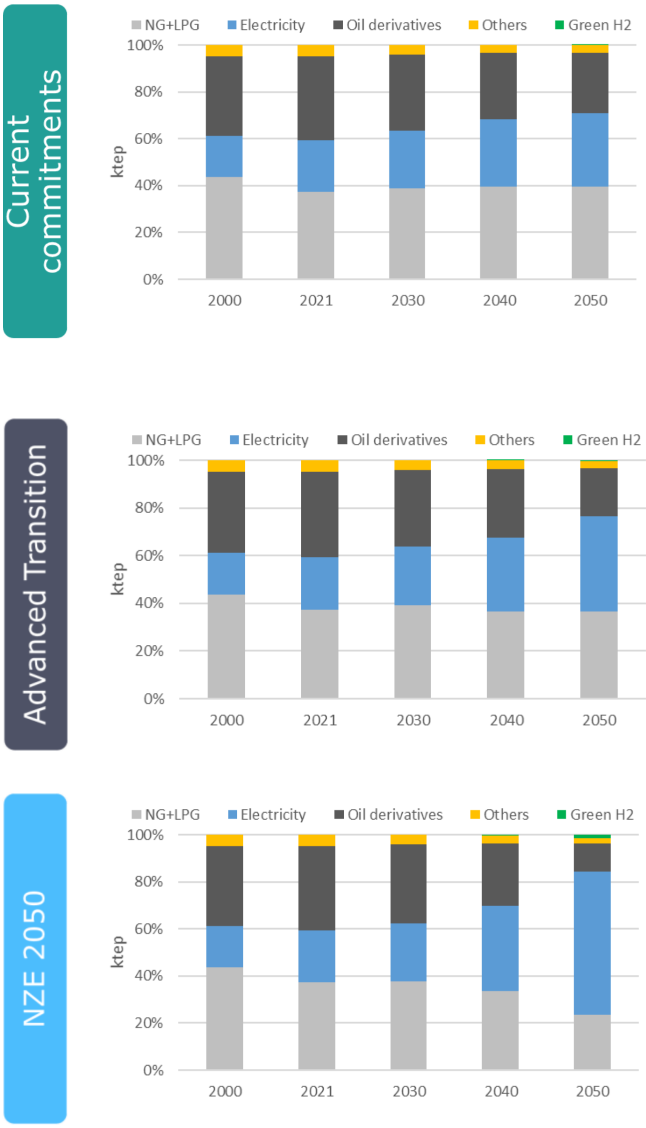
- Demand growth until 2040;
- Energy transition measures offset GDP growth after 2040;
- Relative participation by sector remains stable.

- Final demand reduction from 2030 onwards;
- Conversions of uses, mass electrification, behavioural changes;
- The relative participation of the residential and transport sectors decreases, in favour of the industrial sector.

Figure 24: Final consumption by sector, in ktoe, per pathway

4.4.2 Final energy consumption by fuel

NB: In the following figures, non-energetic uses are not represented. This is the case for H_2 consumed as feedstock for industrial processes. H_2 demand for industrial processes is described in the chapter 4.6. Green H_2 demand in the following figures corresponds to the transport sector (aviation).



- Stable share for natural gas (partial electrification of the residential sector and partial reconversion of the transportation sector towards NG);
- Growing share of electricity, squeezing out oil derivatives.
- Green H_2: incipient substitute in the transport sector (aviation).

- Stronger electrification implying a reduction of the use of oil and gas derivatives (partial);
- Green H_2: limited replacement in the transport sector (aviation).

- Massive electrification of all uses, particularly in the transport and residential sectors;
- Green H_2: partial replacement for transport sector (aviation and martime).

Figure 25: Final consumption by fuel, % of ktoe, per pathway

4.4.3 Final electricity demand

As seen in the previous section, the growth of electricity demand in each pathway is influenced by the underlying assumptions concerning the electrification of end-use sectors, energy efficiency measures and changes in consumption behavior. In all three scenarios, most of the electricity consumption corresponds to current uses of electricity (without account for electric heating and electric vehicles).

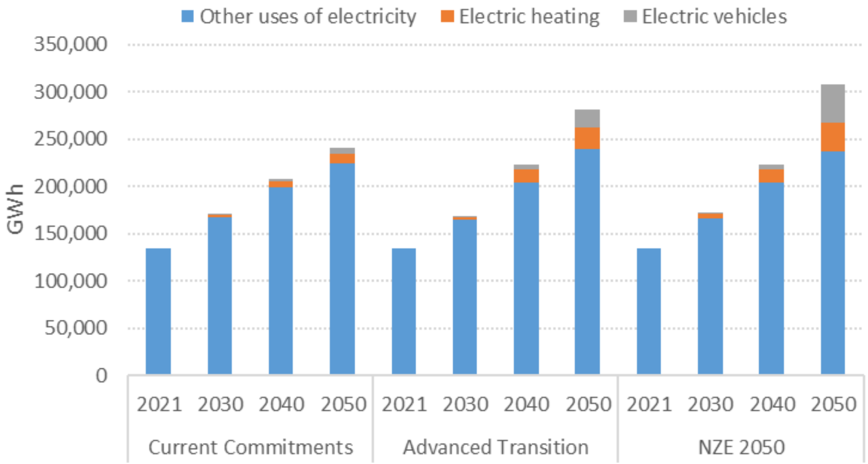


Figure 26: Electricity demand per scenario, GWh

Electricity demand on an annual basis is then converted to hourly load profiles by region, using the following assumptions:

- Electric **vehicles (EV)**: The regionalization of the corresponding electricity demand is based on current repartition of cars per region. The load shape accounts for typical arrival/departures of EVs to charging stations.
- Electric **heating**: The regionalization of the corresponding electricity demand is based on current residential and commercial thermo-sensitive gas consumption per region. The load shape of electric heating depends on daily temperature profiles and Heat Pumps efficiency.
- **Other uses** of electricity: Based on current consumption per region and current load shapes.

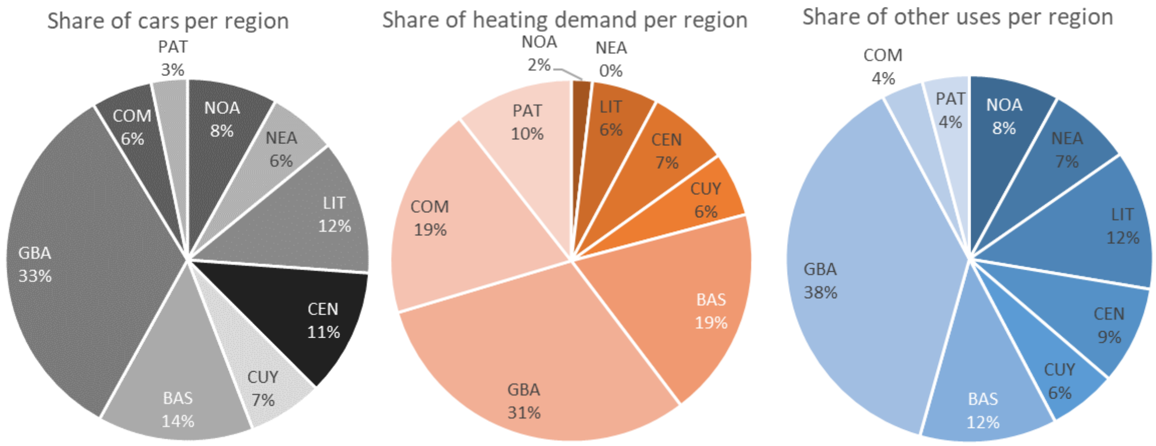


Figure 27: Main assumptions for regionalization of the electricity demand

The resulting load profiles per region show that:

- Buenos Aires (BAS) and Gran Buenos Aires (GBA) concentrate around half of the country's electricity demand.
- The development of electric heating and electric vehicles add **volatility to the current hourly demand profiles**, in particular, for the coldest days of winter (high peak demands).
- Maximum peak electricity demand (in GW) grows faster than annual electricity production (in GWh).

4.5 Deep dive on Energy Supply assumptions

4.5.1 Fuel prices and CO_2 price

Fuel prices are assumed to remain constant (in real terms) over the 2030-2050 period and stay identical for the three pathways. The values in Figure 27 show he fuel costs at plant site (including transport costs).

USD/MMBtu	Fuel cost at plant site, avg.
Natural Gas	5.8[28]
Fuel Oil	22.5
Gas Oil	30.9
Coal	18.2

Figure 28: Fuel price at plant site, USD/MMBtu. Source: Own assumptions. Note: the share of coal in the electricity generation mix is negligible

The values of the carbon tax are assumed to vary depending on the chosen pathway, as it is used as a tool to promote and allow competitiveness of transition technologies, both for electricity and hydrogen production.

(US$/t CO2)	Current commitments	Advanced transition	NZE 2050
Carbon tax	Current price already included in fuel prices	60	120

[28] A cost of production of natural gas in Vaca Muerta of around 5 USD/MMBtu is considered.

Figure 29: Carbon tax price projection, USD/t CO_2

4.5.2 Fossil fuels availability

The assumptions on fossil fuels availability for the three pathways are presented below.

- **Natural gas**: The three pathways consider full availability of gas from Vaca Muerta to cover national demand. During the peak demand months in wintertime, a small share of the natural gas demand may be covered by LNG imports or the use of other fuels (dual fuel power plants in the electricity sector), as already observed today.
- **Liquid fuels:** Liquid fuels are considered as fully available, either from local production, or imported.

Natural gas and liquid fuels Supply	Current commitments 2030	2040	2050	Advanced transition 2030	2040	2050	Net zero 2050 2030	2040	2050
Local production	Function of local demand								
Exports	Export of surpluses to neighbouring countries								

Figure 30: Hypotheses on Natural gas and Liquid fuels supply

4.5.3 Electricity supply assumptions

In the following tables, we present the assumptions related to electricity supply for each of the three paths.

- **Electricity**: The three pathways are characterized by:
  - different ambition levels regarding low-carbon technologies production,

Electricity Supply	Current commitments 2030	2040	2050	Advanced transition 2030	2040	2050	Net zero 2050 2030	2040	2050
Low Carbon Technologies (% of TWh)	**55%**	**60%**	**65%**	**65%**	**75%**	**90%**	**70%** (1)	**85%**	**100%**

  - large hydro and nuclear expansion capacities (these technologies are not optimized, they are part of the scenario definition), as shown in the following figure,
  - a menu of candidate technologies (and their associated costs) to expand the power system in the context of the energy transition: Solar, Wind, CSP, CCGT and GT fuelled by gas or hydrogen.

Electricity Supply	Current commitments 2030	2040	2050	Advanced transition 2030	2040	2050	Net zero 2050 2030	2040	2050
Large hydro, MW (2)	1806	2577	1540	1806	2577	1540	1806	2577	1540

Small hydro (< 50MW), MW [3]	50	150	150	50	150	150	50	150	150
Nuclear (Atucha III), MW [4]		1200			1200		1200		
Modular reactors (CAREM), MW [5]	32	100	100	32	# commercial scale modules (100MW) to be defined to achieve goals		32	# commercial scale modules (100MW) to be defined to achieve goals	
CCUS	no	no	no	no	no	available	no	available	
Storage [6]	Storage additions will be optimized (need for flexibility).								

Figure 31: Hypotheses on Electricity supply

(1) Source: based on the "Guidelines for an Energy Transition Plan for 2030" (Res. 1036 – 2021)
(2) Based on "Guidelines 2030" (Res. 1036 – 2021), with updates based on the progress of projects. From 2030 onwards, selected projects based on the consultant's experience.
(3) Source: consultant's experience
(4) Source: Nucleoelectrica Argentina S.A. (https://www.na-sa.com.ar/es/nuevosproyectos)
(5) Source: https://www.argentina.gob.ar/cnea/carem
(6) In modules to be defined based on the supply and demand balance; and need to provide additional firmness of supply.

The following table details the assumptions considered in terms of expansion of hydro power plants.

Hydro power plant name	Region	Installed Capacity (MW)	Objective year
Aña Cuá	NEA	276	2030
Gobernador Jorge Cepernic	PAT	360	2030
Nestor Kirchner	PAT	950	2030
El Tambolar	CUY	70	2030
El Baqueano (Río Diamante)	CUY	116	2030
Chihuido I	COM	637	2040
Piedra del Aguila, expansion	COM	700	2040
Other projects (small-sized hydro)	COM	734	2040
Cordon del Plata I and II	CUY	1,061	2040
La Invernada	COM	540	2040
Cerro Rayoso	COM	540	2050
Small Hydros	CUY	50	2030
Small Hydros	COM-CUY	150	2040
Small Hydros	CEN-NOA-CUY	150	2050
Total		**6,334**	

Figure 32: List of hydroelectricity power plants, considered in the three Pathways

The assumptions on the decommissioning year of existing power plants based on their commissioning date (COD) are: 60 years for nuclear power plants, 45 years for thermal power plants.

4.5.4 Techno-economic assumptions of Solar and Wind

This section focusses on the main techno-economic assumptions used by the model for the optimization of the generation mix expansion. The hypotheses for the other technologies are presented in Annex 2.

4.5.4.1 LCOE of Solar and Wind

The LCOE for solar and wind power plants in promising regions or regions with already installed projects, is based on the following set of assumptions: WACC (7.5%), lifetime (20 years), Capacity factor per region and technology (based on past data from CAMMESA), CAPEX for each time horizon and OPEX expressed as a percentage of CAPEX (1.7% solar, 2.7% wind).

CAPEX per Technology (USD/kW)	2030	2040	2050
Solar PV[29]	726	669	617
Wind onshore	1,300[30]	1,150	1,000

Figure 33: CAPEX per technology, USD/kW

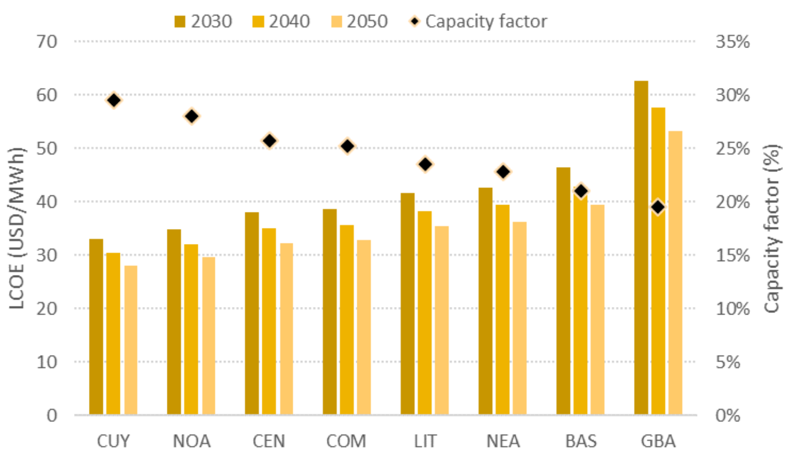


Figure 34: Solar capacity factor (%) and LCOE (USD/MWh) per region

[29] For GBA, CAPEX and OPEX are assumed to be 25% higher than for the rest of the regions as they correspond to Residential PV (in opposition to Utility scale PV for the rest of the regions).
[30] In line with the document "Escenarios Energéticos 2030", 2019.

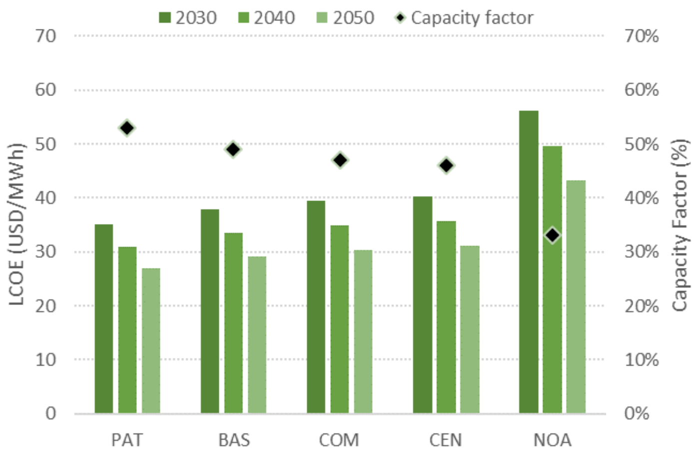


Figure 35: Wind capacity factor (%) and LCOE (USD/MWh) per region

LCOE values for both solar and wind projects are very competitive for most of the regions and time horizons. The regions with the highest capacity factors in solar (energy above 28% in Noroeste and Cuyo) and wind (energy above 45% in Patagonia, Buenos Aires, and Comahue) show the lowest LCOE.

4.5.4.2 The development potential for renewable energy

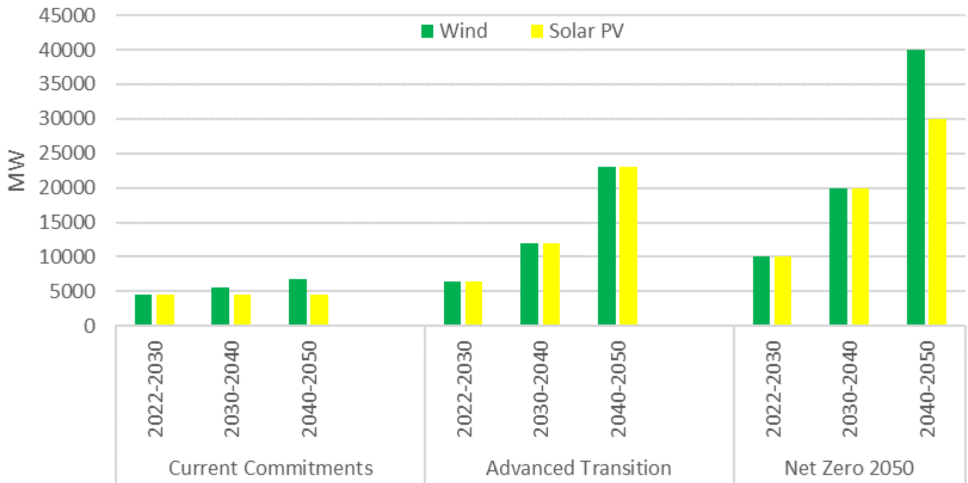
The expansion of the electricity system mainly depends on the theoretical potential for renewable energy technology (function of resources and geographical characteristics) and on the possibilities for the sector development (rhythm constraints).

- **Renewable resources**: With wind and solar energy production potential estimated[31] at 700 GW and 6,000 GW, Argentina has a significant theoretical potential.
- **Regional characteristics**: Development of wind power projects is expected to take place primarily in Patagonia, Buenos Aires, and Comahue, where both wind resources and land availability are favorable. A significant amount of solar potential can be found in most of the regions, but the potential is greatest in Noroeste and Cuyo.
- **Limits from the industry**: It is estimated that the theoretical potential of solar and wind energy is well beyond the capacities that could be installed within the next 30 years. A

[31] The calculation of the maximum theoretical potential refers exclusively to the quality of the energy resource (solar, wind), with only orographic and environmental limitations. This analysis does not contemplate restrictions linked to the impossibility of alternative uses of the land (this applies in particular to the solar resource), or the distance to consumption centers. This potential only considers areas with high production factors.

realistic scenario should then take into account both the rhythm constraints associated with each technology and the maximum demand for green electricity and H_2:

- One of the consideration in the pathways is related to the logistics of the supply chain, at the national level (including the capacity for producing green H_2 from wind for exports) and the pace of project development, which may be influenced by the speed of obtaining permits, among other aspects.
- An additional aspect to consider is the consistency of the scenario definitions[32]. These limits are indeed in line with the share of low carbon technologies for supplying local electricity demand and the potential for green H_2 (local demand and exports).



	Current Commitments			Advanced Transition			Net Zero 2050		
	2020-2030	2030-2040	2040-2050	2022-2030	2030-2040	2040-2050	2022-2030	2030-2040	2040-2050
Wind	450	567	684	650	1200	2300	1000	2000	4000
Solar PV	450	450	450	650	1200	2300	1000	2000	3000

Figure 36: Maximal installation capacity per technology, MW

[32] The proposed assumptions for the Net Zero scenario facilitate the attainment of precise targets regarding the share of green electricity and the volume of locally produced and exported green H_2. As the model does not include a maximum limit for green H_2. exports, nor does it simulates competitors or global demand for green H_2, this approach indirectly ensures consistency with the assumptions related to electricity and H_2 demand. To capture three distinct pathways, the assumptions for the remaining scenarios reflect slower rates of development.

4.6 Deep dive on H_2: Possible PtX development pathways

4.6.1 Key findings for the construction of the Argentinian scenarios

This section presents the key conclusions of the first Workshop supporting the scenario definition[33].

Key findings and Conclusions from the first Workshop:

1. **There isn´t a "Hydrogen Pathway" nor a H_2 promotion policy** in place, in Argentina. Thus, future H_2 scenarios will be based on projections outside of the existing policy framework.
2. "Green certifications" are not yet uniformly used in the world, notwithstanding the efforts conducted in different developed countries (see Germany, Japan, Australia and USA) and international regional organizations (like European Union). Some necessary conditions for the development of the sector are:
   (a) international regulations and certifications,
   (b) verified access to international green markets (for X),
   (c) "**Green Products" preference** (due to carbon tax and other incentives).
3. With **significant natural gas resources**, Argentina is able to provide sufficient energy, as well as having a long-standing experience in the production and use of natural gas. The country also has a competitive biofuels industry. In this context, Argentina has the **potential to develop a Blue Hydrogen industry** at a competitive cost.
4. A green H_2 industry could be developed for local demand but its role in the decarbonisation process of the country will be limited. The **decarbonisation** process in Argentina will be driven primarily by **sustainable electricity generation and electro-mobility**; with a previous path that involves CNG and LNG in the short and medium-term. Energy consumption, **behavioural change** and more **energy efficient** technologies will also play a significant role.

   Nonetheless, the Green H_2 industry could lead to the development of green exports due to the growth of international markets.
5. **GH_2 domestic use vs GH_2 Exports**: Participants showed different point of views on the development steps of the Green H_2 industry:
   (a) Green H_2 for exports (PtX) as a first step of Green H_2 industry development,
   (b) Or gradual substitution of domestic uses by Green H_2, before developing projects for exports (PtX).

[33] The opinions of the Workshop participants do not necessarily represent the opinion of the author of this study in all aspects, but the conclusions, to a certain extent, have been considered in the scenario definition.

6. End-uses for Green H_2:
    (a) Industrial sector: Potential for domestic uses substitution and PtX export, if there is access to international markets and an effective preference for "Green Products".
    (b) Transport sector: Mainly CNG/LNG and electricity as future transition instrument. Limited role of green H_2.
    (c) Blending doesn´t seem economically and technically viable.

7. Development of e-fuels is possible provided that the incentives for decarbonisation (international and then domestic) justify their preference over bio-fuels.

8. Preferred locations for producing and consuming H_2: Due to the high cost of transporting H_2, **local hubs** should be preferred, located in lower cost electricity nodes (for GH_2) **or existing grey H_2 facilities** which could be converted to blue H_2 (since they already use natural gas).

4.6.2 Main assumed drivers for H_2 demand forecast

4.6.2.1 Base year 2022

Hydrogen is currently used primarily as a feedstock in the industrial sector in Argentina[34]. As of 2021, the local production of H_2 was approximately 331 thousand tons[35], with the majority being generated by four industrial sectors:

- Ammonia (NH_3) production, mainly used to produce nitrogen fertilizers (urea),
- Methanol production, mainly used in the biodiesel industry and petrochemical sector,
- Refining sector (H_2 used in the process of hydrotreating, HDT),
- Production of sponge iron.

[34] H_2 is also produced as a by-product of some industrial processes.
[35] Excluding H_2 production as a by-product.

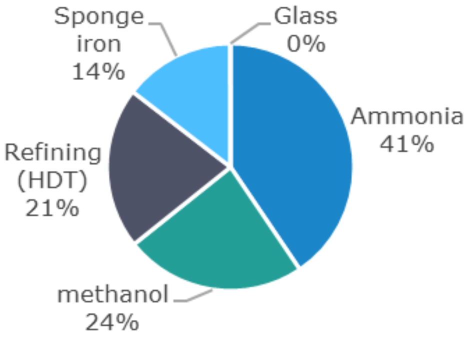


Figure 37: H_2 Production of per demand sector (% of thousand tons of H_2).
Source: Own elaboration based on data from the "Instituto Petroquímico Argentino"

In terms of geographical repartition, most of the local H_2 production is located in the Buenos Aires region. Sector-wise, the production of methanol and ammonia is primarily located in the province of Buenos Aires, while the steel industry, which consumes H_2, is located primarily in the Litoral province and the refinery in Cuyo.

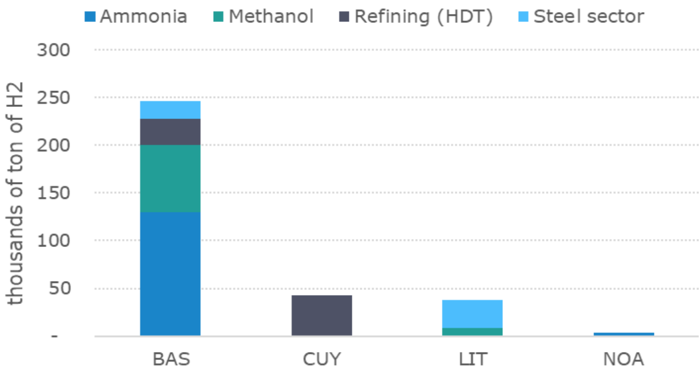


Figure 38: Production of H_2 per region and demand sector (thousand tons of H_2).
Source: Own elaboration based on data from the "Instituto Petroquímico Argentino"

Furthermore, Argentina imports a number of products for which hydrogen is an important component, such as ammonia (NH_3) or steel products. According to the current estimate, 366 thousand tons of H_2 could be substituted for NH_3 and steel products ("translated to H_2")[36], most of which would replace current imports of nitrogen fertilizers.

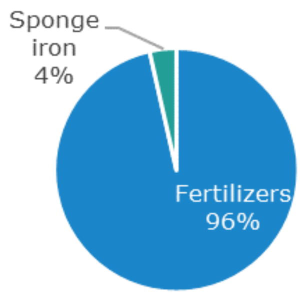
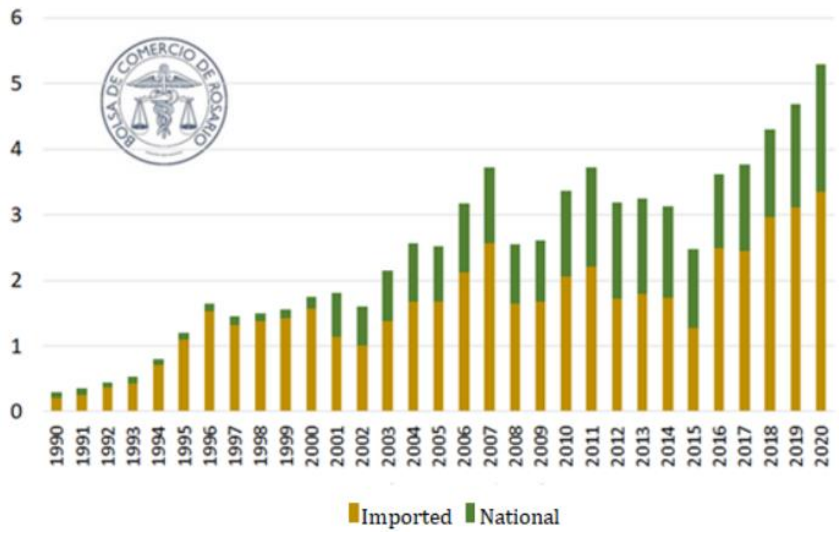


Figure 39: Potential for imports substitution (% of thousand tons of H_2). Source: Own elaboration based on data from the Stock Exchange of the City of Rosario and the Argentine chamber of steel

As such, one must recall that local fertilizer demand in Argentina has grown consistently since the 1990s, rising from around 300,000 tons in 1990 to 3 Mt in 2010 and almost 6 Mt in 2021 (55% of which are nitrogen fertilizers). Demand for fertilizers is expected to continue growing.



[36] Corresponding to 353 thousand tons of H_2 for the production of 2.4 million tons of NH_3 and 13 thousand tons of H_2 for the production of 270 thousand ton of sponge iron. The conversion rate is based on the current values from Argentinian industries (0.15 t H_2/t NH_3 and 0.05 t H_2/t sponge iron).

Figure 40: Evolution of fertilizer consumption in Argentina by origin (million tons). Source: Stock Exchange of the City of Rosario

Additionally, the share of national fertilizers production (as compared to total consumption) has grown significantly since the beginning of the 2000s. In 2021, approximately 30% of the fertilizers consumption came from the national industry, the remaining 70% being imported.

In terms of production technology, hydrogen is produced mainly from natural gas (grey hydrogen) and as a by-product of other industrial processes. The main technology used to produce grey hydrogen is steam methane reforming (SMR). In a more incipient form and at a very low percentage (pilot scale), green hydrogen is produced via water electrolysis.

4.6.2.2 Drivers for future H_2 demand growth

H_2 demand is expected to grow in the future, both for local uses and for exports, in line with worldwide decarbonisation scenarios. Hydrogen offers opportunities to decarbonise a range of sectors which are not suitable for direct electrification, such as some industry processes (NH_3, steelmaking, …) and in the maritime and aviation transport. The main drivers of future H_2 demand are presented by sector. In general, existing uses[37] of hydrogen (industrial sector) are expected to keep dominating the hydrogen demand in Argentina.

- **Industrial sector**: Presently, hydrogen is used in oil refining and industrial key sectors such as ammonia and methanol production, as well as in the steel sector. Existing hydrogen applications in various industrial sectors are expected to continue existing and growing in volume:
  - **Fertilizer industry, Steel and Methanol**: H_2 demand will grow with the GDP for the three pathways.
  - **Refining**: H_2 demand for refining depends on the growth of internal demand for liquid fuels expected for each of the three pathways.
  - **Imports substitution** (especially fertilizers and steel products): All the three pathways take place in a global context where most of the countries worldwide are also undertaking a transition towards a green economy. The need to decarbonise industrial processes worldwide implies that products will become more expensive.

[37] In line with IEA study: https://www.iea.org/reports/hydrogen-in-latin-america

This, in turn, will influence the pace at which local production replaces imports of ammonia and steel, depending on the pathway.

- **Use of H_2 for High temperature heating**: The deployment of hydrogen-based heating technologies for high-temperature industrial applications is still in its early stages and there are some controversies regarding the readiness and efficiency of these technologies, as well as their long-term reliability and scalability. As such, it is not considered as a "no-regret" option for Argentina´s decarbonisation pathways. This assumption is in line with the findings from Agora Energiewende[38].

- **Transport sector**: Shipping and aviation have limited available low-carbon fuel options and represent an opportunity for green hydrogen-based fuels. The light passenger transport (cars) sector has already started the transition towards electric vehicles, thus It is not foreseen room for hydrogen demand in this segment. As part of heavy transportation, electric heavy-duty trucks are also gaining market share, which, according to IEA[39], is "driven by an increase in available models in those markets, policy support, rapidly improving technical viability and economic competitiveness". In that context and in the understanding that hydrogen will primarily be used in sectors not suitable for direct electrification, the three pathways suggest that electricity (and LNG) would be the preferred options for converting heavy trucks towards greener options in the long-term.
- **Blending**: Demand of hydrogen for blending is not considered in any of the three pathways, due to the technical and financial barriers accompanying such option in Argentina (average age of gas infrastructure, risk of degradation, etc.). This assumption is in line with the findings by the Fraunhofer Institute and the experience of the Consultant.
- **Power generation**: When used in gas turbines, hydrogen can enhance the flexibility of power systems and represents a storage option for renewable energy. Based on the output from the pathways, the model will optimize the corresponding volume.
- **Exports**: As a result of global decarbonisation strategies, Argentina will have an opportunity to export PtX-products, such as ammonia or steel, which are already traded internationally and may benefit from carbon adjustment mechanisms in some markets in the coming years.

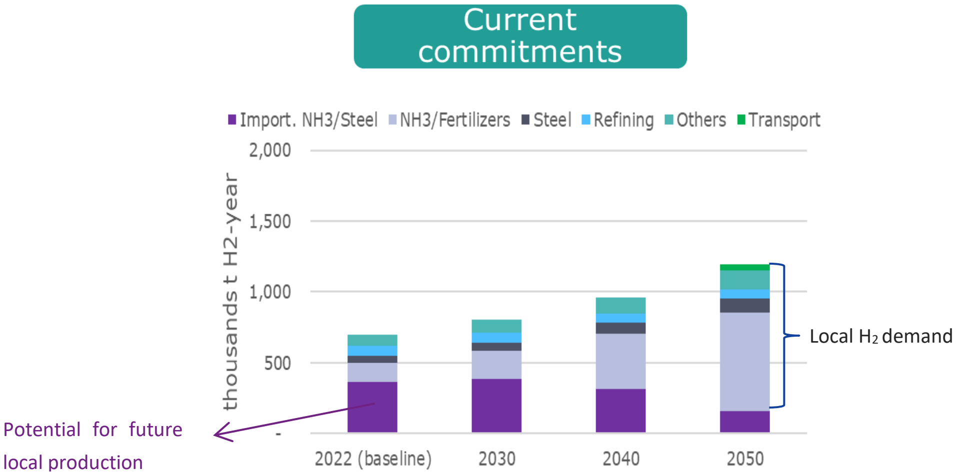
4.6.2.3 Local H_2 demand scenarios for "X"

In this chapter, the H_2 demand per sector is presented for each pathway.

[38] https://www.agora-energiewende.de/en/publications/12-insights-on-hydrogen-argentina-edition/ p15
[39] https://www.iea.org/reports/global-ev-outlook-2022/trends-in-electric-heavy-duty-vehicles

4.6.2.3.1 Current commitments Pathway

Local and Global context: The GDP growth in Argentina is 2%, implying a moderate growth of H_2 demand for existing industrial uses as the world is gradually transitioning to a green economy. Consequently, Argentina gradually substitutes imports of NH_3/Steel by local production, although only partially (see remaining imports in purple, in the figure below on the right).



H2 demand per sector	2022 (Base)	2030	2040	2050
NH3/Fertilizers	134	198	393	695
Steel	48	58	76	101
Refining	70	72	66	63
Others	79	92	112	137
Transport	-	-	-	40
Total Local demand	**331**	**421**	**647**	**1,035**
Share of imports substitution	-	10%	40%	75%
Import. NH3/Steel	366	386	314	159

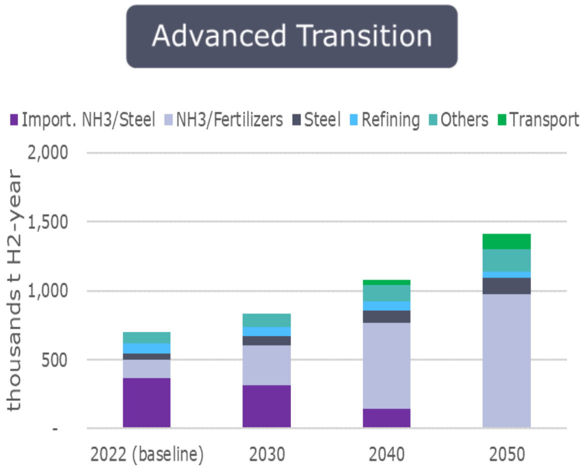
Figure 41: H_2 internal demand projection and NH_3/Steel imports (million tons)

H_2 demand per type (grey, blue, green):

- Industrial sector: The assumption underlying this pathway of moderate transition is the continuation of existing processes (grey H_2) until they have no further purpose. For the additional H_2 demand (expansions and imports substitutions), the choice between green, blue and grey H_2 is optimized depending on their relative competitiveness.
- Transport sector and exports of PtX products: Only Green H_2 is an option.

4.6.2.3.2 Advanced Transition Pathway

General context: The GDP in Argentina growths at a rate of 2.5%, implying a moderate growth of H_2 demand for existing industrial uses and the world transitions towards a green economy dynamically. In this context, Argentina progressively substitutes all its NH_3/Steel imports with local production.



H2 demand per sector	2022 (Base)	2030	2040	2050
NH3/Fertilizers	134	292	622	973
Steel	48	63	90	122
Refining	70	71	67	47
Others	79	96	123	157
Transport	-	-	36	114
Total Local demand	**331**	**523**	**938**	**1,412**
Share of imports substitution	-	30%	75%	100%
Import. NH3/Steel	366	312	143	-

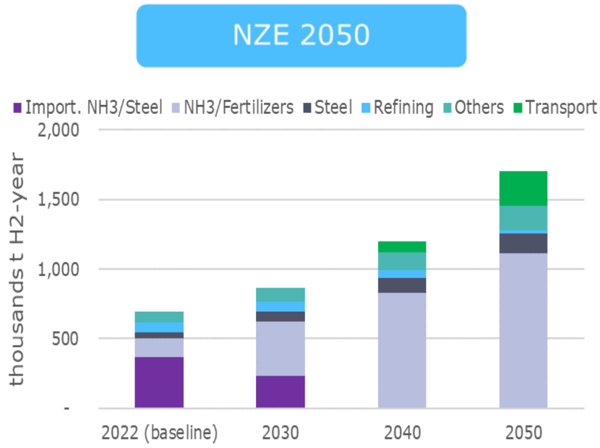
Figure 42: H_2 internal demand projection and NH_3/Steel imports (million tons)

H_2 demand per type (grey, blue, green):

- Industrial sector: Existing processes (grey H_2) are replaced progressively, leaving more space for transitioning towards blue and green H_2. For the additional H_2 demand, low emissions technologies become competitive, in particular Blue H_2.
- Transport sector and exports from PtX products: Green H_2 as the only option.

4.6.2.3.3 Net Zero 2050 Pathway

General context: The GDP growth in Argentina is 3%, implying a higher growth of H_2 demand for existing industrial uses. The world is moving towards NZE 2050 and Argentina substitute all its NH_3/Steel imports with local production by 2040.



H2 demand per sector	2022 (Base)	2030	2040	2050
NH3/Fertilizers	134	393	830	1,115
Steel	48	69	104	139
Refining	70	72	57	21
Others	79	100	134	180
Transport	-	-	77	250
Total Local demand	**331**	**634**	**1,201**	**1,706**
Share of imports substitution	-	50%	100%	100%
Import. NH3/Steel	366	232	-	-

Figure 43: H_2 internal demand projection and NH_3/Steel imports (million tons)

H_2 demand per type (grey, blue, green):

- Industrial sector: Existing processes (grey H_2) are replaced progressively, leaving more space for transitioning towards blue and green H_2. For the additional H_2 demand, low emissions technologies become competitive, in particular Green H_2.
- Transport sector and exports from PtX products: Only Green H_2 is an option.

4.6.2.3.4 Geographic repartition of H_2 local demand

In all the scenarios, past patterns of H_2 demand per sector and per region are considered. Future local H_2 demand is assumed to be mainly located in the province of Buenos Aires, as observed historically.

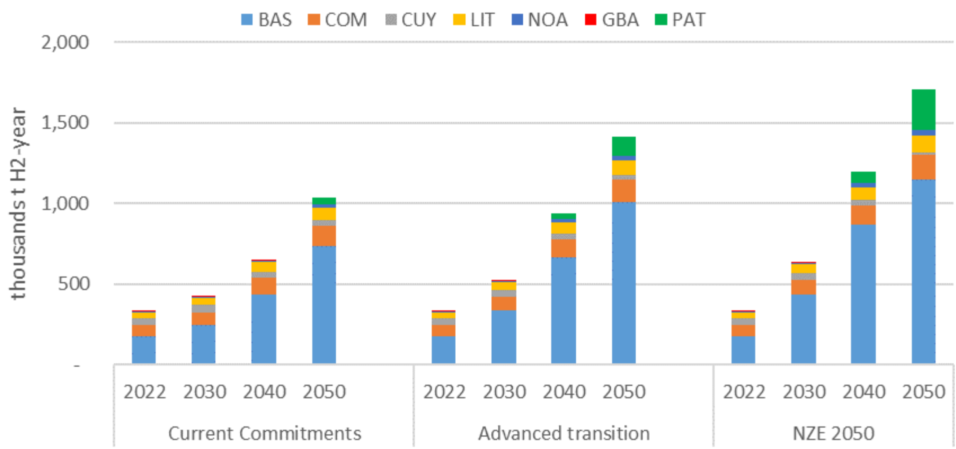


Figure 44: Geographic repartition of H_2 local demand

4.6.3 LCOH and LCOA

4.6.3.1 LCOH for grey, blue and green H_2

The levelized cost of hydrogen (LCOH) represents the revenue required per unit of product (H_2) over a specified period (lifetime usage) to recover all the costs incurred to build and operate the plant (capital and operating costs) while obtaining a reasonable return on investment.

The main drivers of the LCOH of grey, blue and green H_2 are:

- **Grey H_2** mainly depends on NG price and CO_2 cost
- **Blue H_2** mainly depends on NG price and CAPEX from the CCS

Green H_2 is highly CAPEX intensive and depends on electricity cost (wind power plants CAPEX) and electrolizers CAPEX. Both wind and electrolyzers CAPEX are assumed to decrease in time (Wind: 1300-1000 USD/kW, Electrolyzer: 595-420 USD/kWelec in the period 2030-2050).The following figures present the LCOH for each pathway and the relative competitiveness between grey, blue and green H_2. In each scenario, different assumptions on CO_2 price (0 USD/tCO_2[40], 60 USD/tCO_2, 120 USD/tCO_2) are considered, modifying the LCOH for grey and blue H_2 and their relative competitiveness with green off-grid LCOH. In the CO_2 emissions are included the upstream GHG emissions[41]., i.e. fugitive

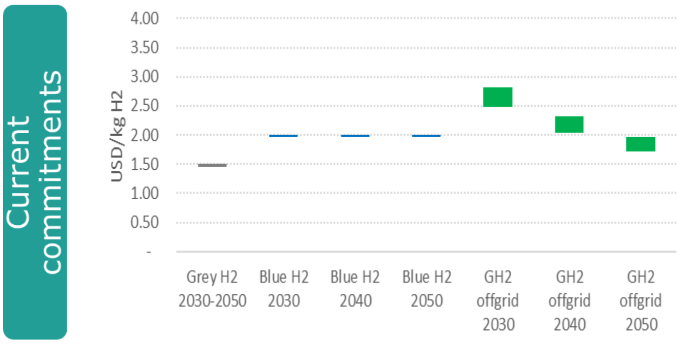
[40] A carbon tax is already in place in Argentina, however, it does not apply to gas natural.
[41] https://iea.blob.core.windows.net/assets/c5bc75b1-9e4d-460d-9056-6e8e626a11c4/GlobalHydrogenReview2022.pdf#page=89 (low upstream GHG emissions assumed)

emissions from gas natural production. The LCOH for green H_2 is estimated for off-grid projects and differs depending on the region considered.

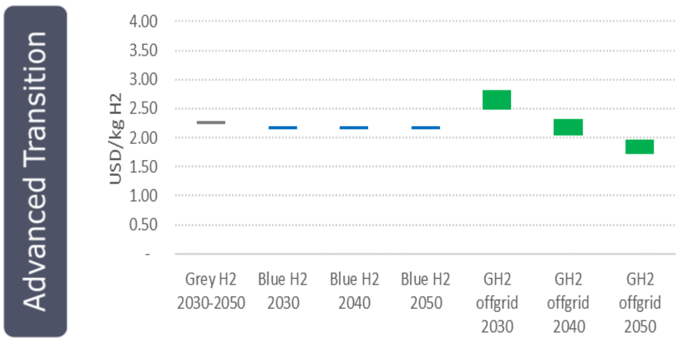
Detailed assumptions for LCOH calculation are presented in Annex 2.

The boundaries for LCOH calculation for grey and blue H_2 are the following:

- CO_2 emission includes upstream GHG emissions (low upstream emission data from IEA). Accounting for fugitive emissions in LCOH calculation is a way of evaluating global impact of grey and blue H_2 production and better assess their competitiveness compared to green H_2.
- CO_2 storage costs and transport (from production site to storage location) are not considered in the calculation[42]. This tends to favour blue H_2 compared to green H_2.

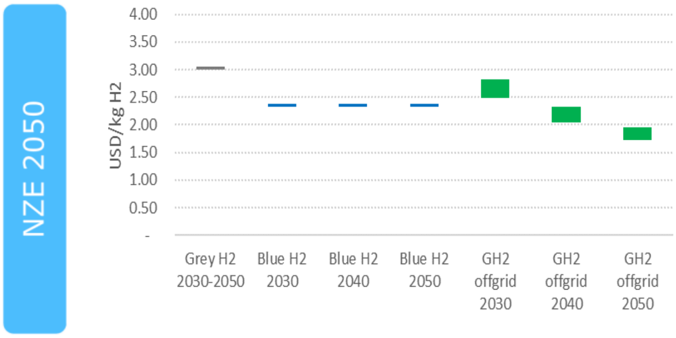


- Carbon tax: 0 USD/tCO_2
- **Grey H2** is the most competitive option.
- Existing processes (grey H_2) continue until the end of their operatingl life.
- Blue and green H_2 projects are developed for specific demand sectors through targeted policies.



- Carbon tax: 60 USD/tCO_2
- **Blue H2** is the most competitive option in **2030**. In **2040 and 2050**, **Off-grid Green H2** is cheaper in parts of the regions.
- Grey H_2 is progressively replaced.

[42] By including those costs, blue H_2 would become slightly more expensive. For instance, a 10 USD/tCO_2 cost for transport and storage would add 0.13 USD/kg to the LCOH of blue H_2. Globally, this assumption tends to favor blue H_2 compared to green H_2.



- Carbon tax: 120 USD/tCO_2
- **Blue H2** is the most competitive option in **2030**. In **2040 and 2050**, **Off-grid Green H2** is cheaper, in the three analysed regions.
- Grey H_2 is replaced rapidly.

Figure 45: LCOH for grey, blue and green off-grid and on-grid H_2, USD/kg H_2 LHV

NB: The min and max values for green H2 correspond to the estimate for Patagonia (lowest value) and Comahue (highest value) of the three potential studied regions (Patagonia, Comahue, Buenos Aires).

4.6.3.2 LCOA for green NH_3

The levelized cost of ammonia (LCOA) accounts for all the capital and operating costs of ammonia production. The resulting LCOA depends on the time horizon and region and lies within the range of 420-620 USD/t NH_3.

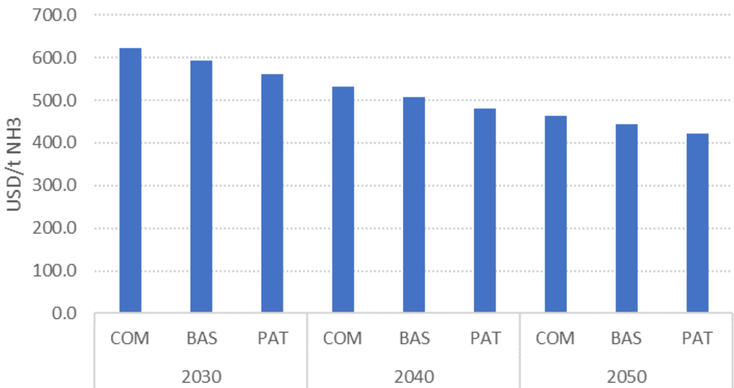


Figure 46: LCOA Estimation for off-grid wind projects per region, USD/kg and USD/t NH_3

The main cost driver is the electricity cost to produce green hydrogen (around 70% to 85% of total cost)[43].

[43] Therefore, for a high level estimation of the cost of producing green ammonia (LCOA), it can also be assumed that 178 kg of hydrogen are necessary to produce 1 ton of NH_3 (on a mass balance).

Once the LCOA is estimated, typical NH_3 shipping costs from Argentina to Europe are considered in order to calculate the total export price. Typical NH_3 shipping costs are estimated to be within the range of 0.3-0.4 USD/kg H_2 (≈50-70 USD/t NH_3).

4.6.4 H_2 export demand

It is expected that future global trade of green H_2 will be largely polarized, with LATAM, Australia, the Middle East and North Africa aiming to be green H_2 exporters, while the European Union and Japan/South Korea are expected to become net importers.

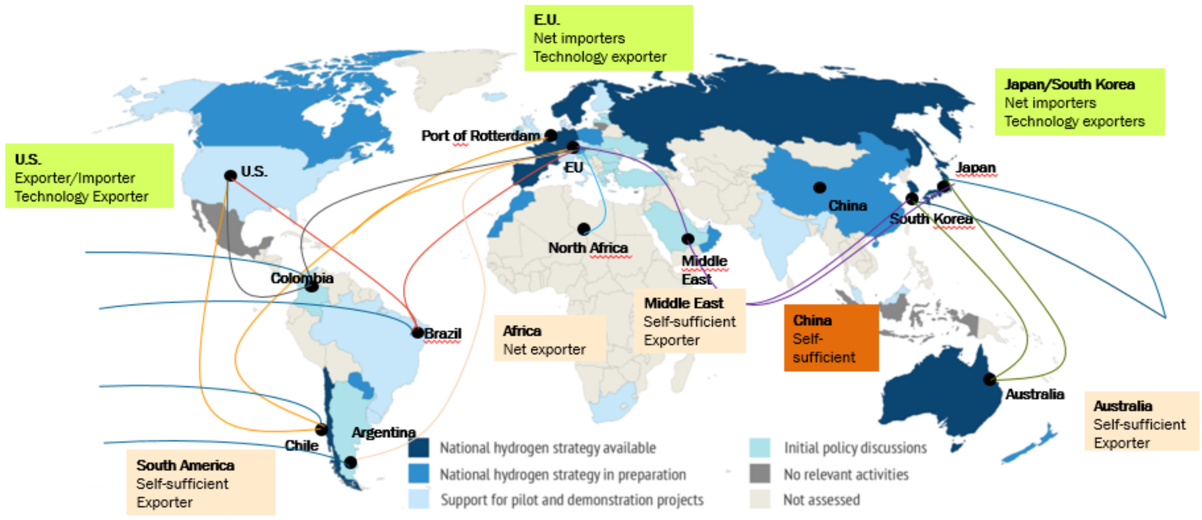


Figure 47: Global H_2 trade

In this context, and in light of the cost analysis of the value chain involved in the transformation and shipment of H_2 products from Argentina, it is apparent that:

- exports towards Europe (Port of Rotterdam) are cheaper than exports towards Japan (Port of Kobe),
- NH_3 exports are cheaper than liquid H_2 exports, globally (as of now, NH_3 is the most competitive carrier for transporting H_2).

To enable the export of green products, Argentina will have to be competitive with other key green H_2 producers such as Chile, Australia or Middle-East countries.

Assumptions behind green H_2 derivatives export:

The volume of green H_2 derivatives exported depends on the time horizons and pathways. Additionally, the green H_2 can be produced either off grid or on grid. The volume of exports associated with green H_2 production, which is subsequently used in the production of green H_2 derivatives like NH_3, is determined based on the following set of assumptions:

- First, there is an international price threshold, if hydrogen production costs are below that threshold, it is possible to export (production costs decrease every decade). This international price threshold has been set as 2.3 USD/kg in 2030, 2.05 USD/kg in 2040, and 1.8 USD/kg in 2050. To this production price must be added the carrier conversion cost (NH_3), plus the storage and transport to the import terminal; these costs being calculated at 1 to 1.2 USD/kg H_2. With these hypotheses, the landed cost of green NH_3 at port of Rotterdam should be within the range of 2.8 to 3.5 USD/kg H_2 (i.e. ≈500-620 USD/t NH_3). This value does not include the cost for Cracking (transformation of NH_3 into H_2).
- Second, there is a maximum international market share that Argentina is supposed to be able to take. The maximum volume of green H_2 exports was estimated as a percentage of the total volume of global demand in importing countries.

    - For the global demand scenario, IEA NZE was adopted for the pathway NZE 2050. For the two other pathways, global demand for H_2 is assumed to be lower due to a slower pace of the energy transition worldwide;
    - A share of that demand comes from international trade. That share depends on the scenario and the year, and lies under 25%;

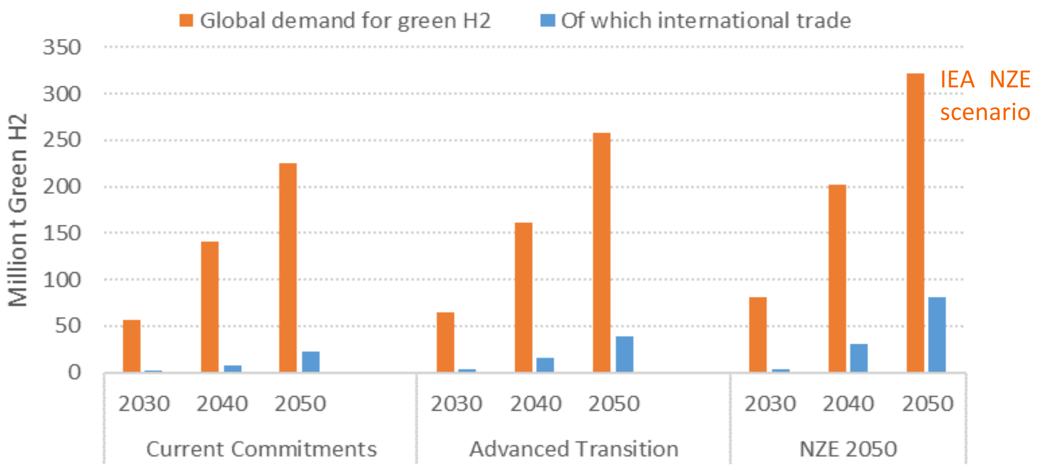


Figure 48: Global demand for green H_2 of which international trade, Mt GH_2

    - A share of 3 to 5% of the international trade is assumed to come from Argentina (according to a benchmark of studies).

- Third, the installation of renewable capacity to produce hydrogen is restricted by the renewable installation rate limit, defined in section 4.2.

The exports volume corresponding to on-grid H_2 production (later used to produce PtX products such as NH_3) is optimized by the model. The candidate regions to produce and export PtX products are Patagonia, Comahue and Buenos Aires, thanks to their large renewable potential, high wind load factors and existing export infrastructure (vicinity to port).

A portion of the maximum export demand is compatible with the amount of off-grid projects included in the scenario definition. The corresponding off-grid electrolysers and wind capacities are estimated based on assumptions on electrolyser efficiencies and wind load factors and are located in Patagonia region.

Assumptions for off-grid projects development per pathway and time horizon:

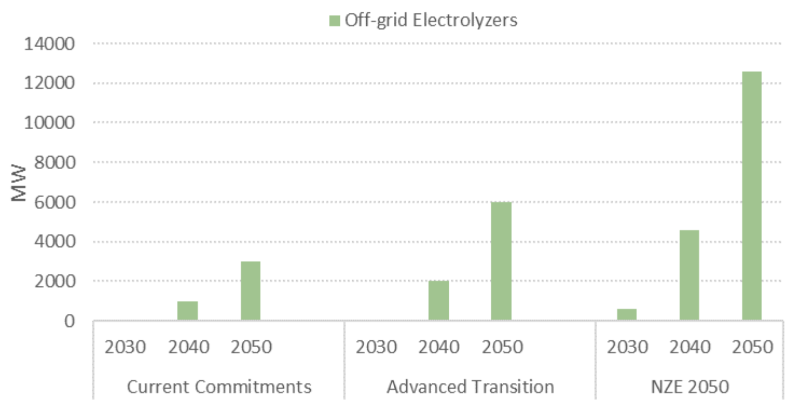


Figure 49: Off-grid electrolysers capacity, MW

5 Analysis of energy transition pathways

5.1 Results for the three baseline pathways

5.1.1 Introduction

The following section details the results of pathway optimization for the three baseline pathways: Current Commitments, Advanced Transition and Net Zero Emissions 2050. As described in the previous sections, these three pathways vary from each other along a few parameters in the consumption and production of electricity and hydrogen in Argentina.

As it is detailed on the section 3.1, the modelling of the pathway includes a scenarized evolution of installed capacities such as coal, nuclear and hydro power plants. The rest of the production is optimized: renewables (wind and solar), CCGT and OCGT capacities, power-to-hydrogen systems, batteries, hydrogen pipelines and inter-regional electricity interconnections. The investments in each of these technologies are variables of the optimization problem, which consists in minimizing investment and operational costs of the system under different operational constraints.

The results are presented in the next sections in the following order: power system, hydrogen production and exports, costs for the three different pathways and finally on the quantities of CO_2 emitted for each pathway.

5.1.2 Electricity System

In the modelling results of the three baseline scenarios, the increase of power demand is mostly met by additional renewable capacity.

The share of low carbon energy (including RES and nuclear – the latter being scenarized) differs between scenarios: when the share reaches 98% for Net Zero 2050 in 2050, it only totals 73% for Current Commitments.

Scenario	Current Commitments	Advanced Transition	Net Zero 2050
2030	55%	64%	73%
2050	73%	96%	98%

Figure 50: Low carbon energy shares for electricity production

In the three pathways, renewable production is mainly based on on-grid wind power, which reaches up to 255 TWh in 2050, mainly installed in Patagonia (40%). Regarding gas-based production, it decreases by almost 90% in Net Zero 2050 while it only reduces by 15% in Current Commitments.

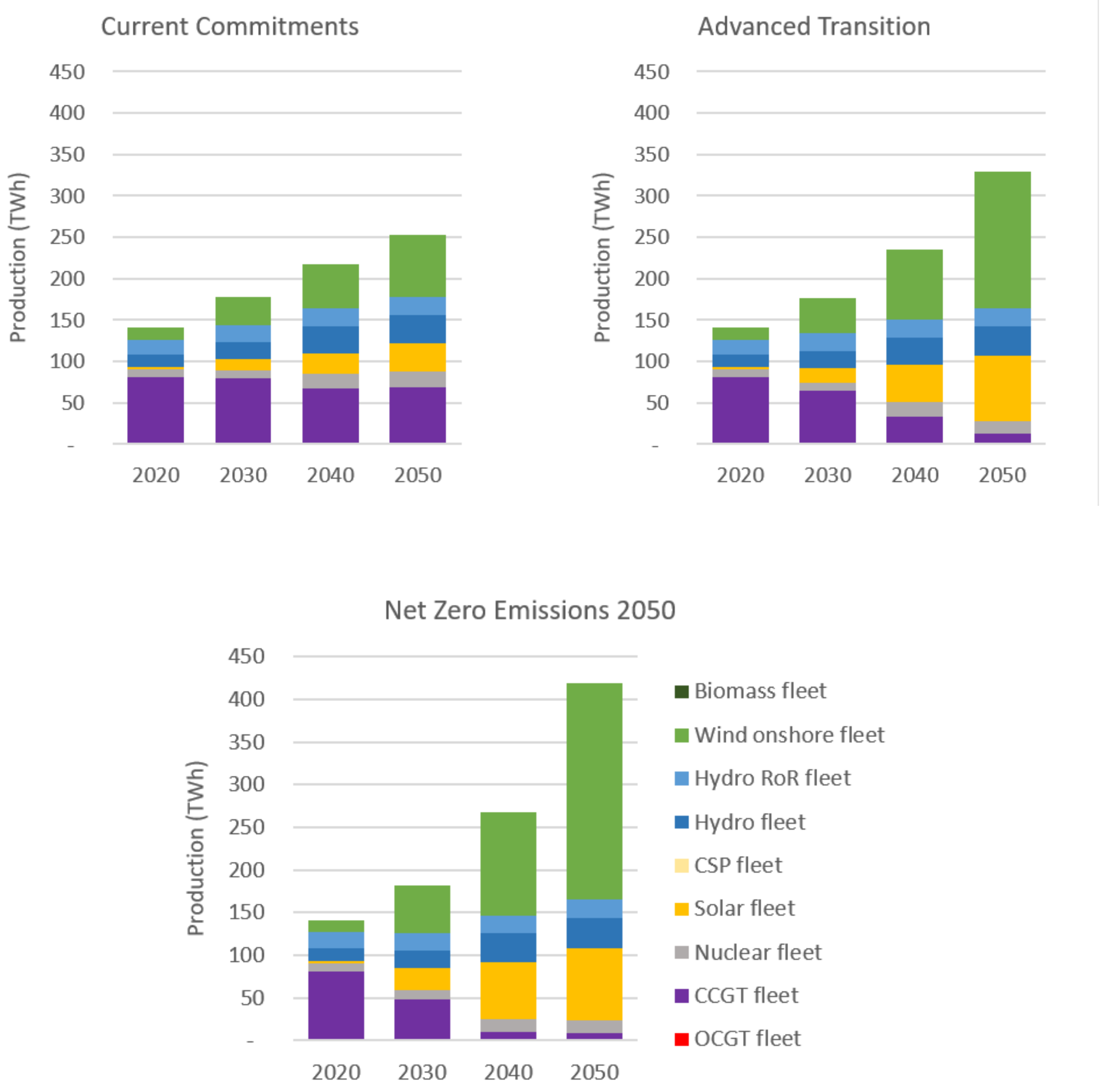


Figure 51: Yearly electrical production in the three pathways

The results highlight that RES (especially wind) is more competitive than gas-based electricity generation in all scenarios from 2030 onwards, as underlined by the calculations of the LCOEs of these technologies (see Figure 52 below), despite the intrinsic variability of RES generation[44]. This accounts for potential costs in network, storage and flexibility linked to RES, as the model optimizes the whole system simultaneously, with an hourly resolution. In the end, the optimal solution is to install in priority renewables capacities compared to gas power plants because of their cheaper overall costs.

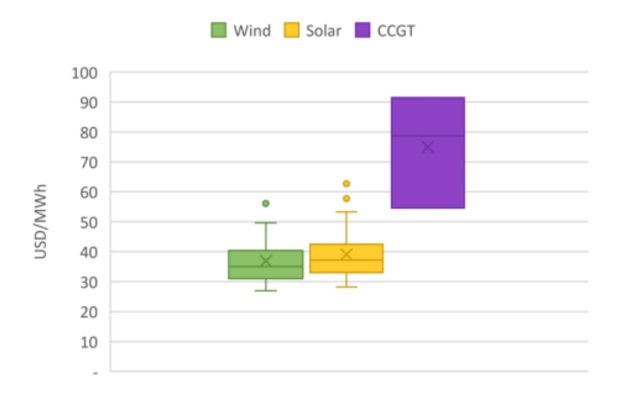


Figure 52: LCOEs of CCGT, Solar and Wind electricity production

The optimal investments in renewable capacities obtained in the three pathways also vary because of the maximum wind and solar capacity installation rates set for each pathway. These maximum installation rates are set as assumption in the model, translating the industrial capacity of the country to develop new RES.

[44] As a reminder, the LCOE of CCGT varies depending on the scenario because of the carbon tax considered, different in the three scenarios. The LCOE of RES considered in the optimization varies depending on the year (learning curves) and region (various load factors per region).

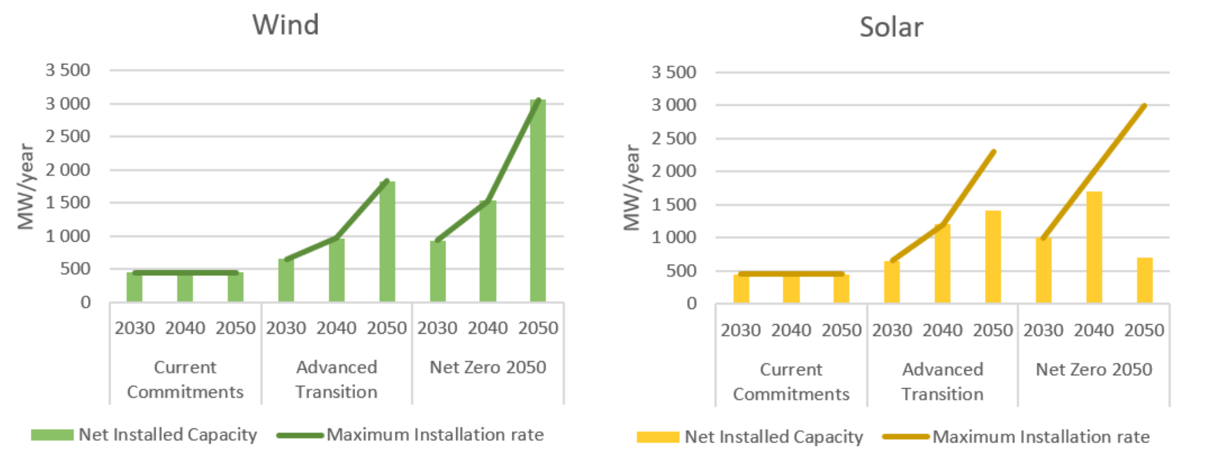


Figure 53: Maximum and optimized on-grid wind and solar installation rhythms

In the three pathways, on-grid wind installation rates reach the maximum fixed for each time-step of the pathway, going up to more than 3 GW/year for Net Zero 2050 with more than 1GW/year in Patagonia in 2050, compared to 1.3 GW/year for off-grid rates (0.9 GW/year in Patagonia and the remaining part in Buenos Aires). For solar capacities, maximum capacities are only reached in the Current Commitments scenario. Solar capacities however do not reach their maximum potential in Advanced Transition and Net Zero 2050. The solar installed capacity is actually the same in 2050 for these two scenarios (around 35 GW).

Figure 54: Renewable installed capacities

These results tend to show that solar power plants have a decreasing value for the system as the development of solar capacities increase. As more solar power plants are added to the grid, they generate surplus electricity during peak sunlight hours, leading to a decrease in the value of electricity during those hours. This well-known effect is usually called “cannibalization” because the new solar power plants "eat away" the revenue streams of existing solar power plants. Therefore, the value of adding new solar capacity for the system is highly reduced. This phenomenon can be mitigated with the use and development of flexibilities in the system, such as hydro reservoir, batteries, demand-side flexibility (e.g. for electric vehicles charging during the day), network, etc.

These high deployments of decentralized renewables require reinforcements in the inter-regional transport network of electricity as we can see in the results. As a reminder, the inter-regional network is optimized with specific costs per border, without constraints of maximum development of the network. The other types of networks, for instance distribution, are not modelled.

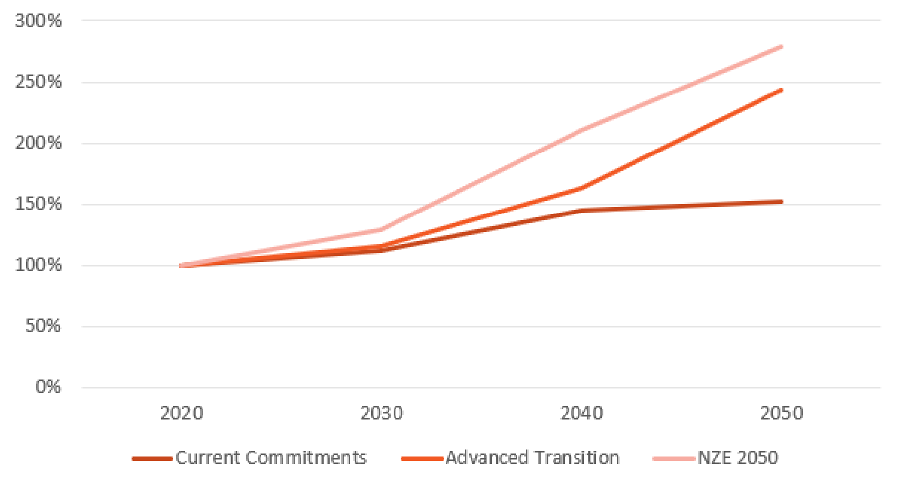
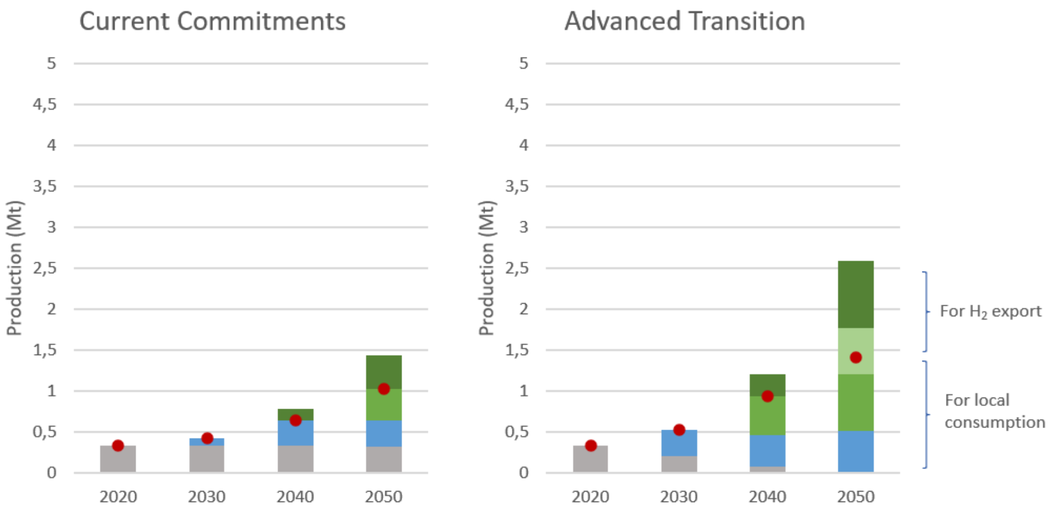


Figure 55: Inter-regional transmission capacities expansion compared to the current network

Because of the various deployments of renewables, the network reinforcements differ between pathways, from +50% compared to the current network for Current Commitments to +180% for Net Zero 2050. The increased in transmission capacity is particularly strong on the Buenos Aires – Comahue - Patagonia axis.

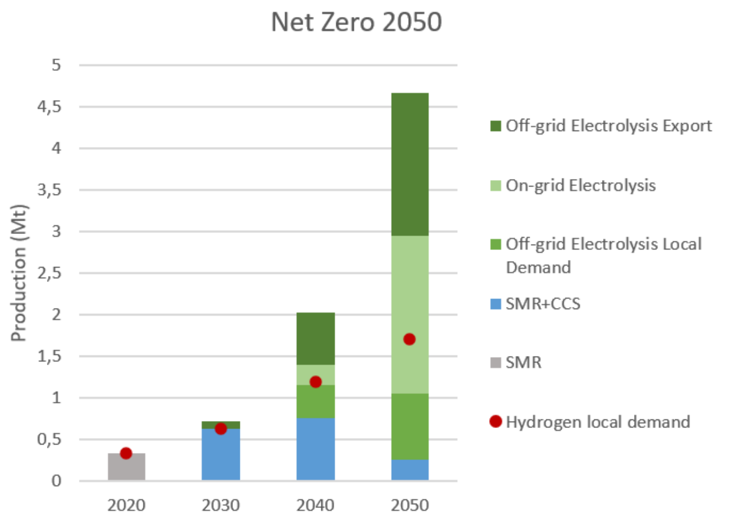
5.1.3 Hydrogen System

In all the baseline pathways, not only the electricity but also the hydrogen demand increases significantly. To supply this growing demand (both local and global, with a potential development of hydrogen exports) the hydrogen production is shifting from a SMR-based production to a low-carbon hydrogen production from SMR with CCS and from electrolysers.



Hydrogen Production CC (Mt)				
Technology	2020	2030	2040	2050
On-grid Electrolysis	0,0	0,0	0,0	0,0
Off-grid Electrolysis Export	-	-	0,1	0,4
Off-grid Electrolysis Local Demand	-	-	-	0,4
SMR+CCS	-	0,1	0,3	0,3
SMR	0,3	0,3	0,3	0,3
Hydrogen local demand	0,3	0,4	0,6	1,0

Hydrogen Production AT (Mt)				
Technology	2020	2030	2040	2050
On-grid Electrolysis	-	0,0	0,0	0,6
Off-grid Electrolysis Export	-	-	0,3	0,8
Off-grid Electrolysis Local Demand	-	-	0,5	0,7
SMR+CCS	-	0,3	0,4	0,5
SMR	0,3	0,2	0,1	-
Hydrogen local demand	0,3	0,5	0,9	1,4



Hydrogen Production NZE (Mt)				
Technology	2020	2030	2040	2050
On-grid Electrolysis	-	0,0	0,2	1,9
Off-grid Electrolysis Export	-	0,1	0,6	1,7
Off-grid Electrolysis Local Demand	-	-	0,4	0,8
SMR+CCS	-	0,6	0,8	0,3
SMR	0,3	0,0	-	-
Hydrogen local demand	0,3	0,6	1,2	1,7

Figure 56: Yearly hydrogen production in the three pathways

The production of hydrogen is done only with SRM (steam methane reforming, i.e. grey hydrogen) in 2020 and shifts towards SMR+CCS by 2030 (blue hydrogen) and electrolysis (green hydrogen, if electricity comes from low-carbon electricity sources). Note that SMR capacities without CCS are an input of simulation and assumed to decrease in all scenarios.

When the renewable share and the CO_2 tax are sufficient, from 2040 onwards in Net Zero 2050 and in 2050 in Advanced Transition, on-grid electrolysis become competitive and is deployed to replace SMR. This on-grid electrolysis supplies both a portion of the local demand and of the exports. On-grid exports are optimized based on costs for electrolysis, RES and RES potentials, assuming an evolving price for selling H_2 (2.3 USD/kg_{H2} in 2030[45], 2.05 USD/kg_{H2} in 2040 and 1.8 USD/kg_{H2} in 2050).

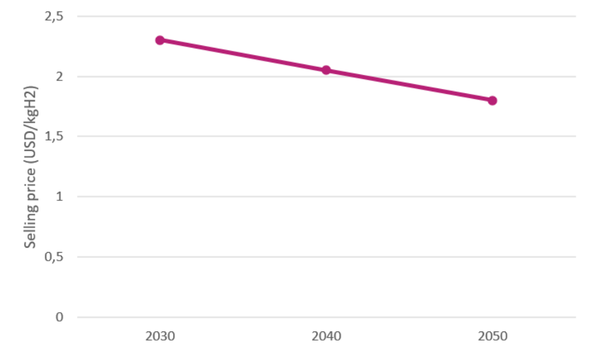


Figure 57: Hydrogen selling price (USD/kgH_2)

On-grid electrolysis is preferably developed in Patagonia where the wind resources are the best (Patagonia has the highest wind capacity load factor), reaching 1.4 Mt H_2 in 2050 in Net Zero 2050 (over 1.9 Mt H_2 of on-grid green hydrogen production). In Current Commitments, the conditions for profitability are not met and therefore no on-grid green hydrogen is produced: using RES production directly as final demand of electricity to replace gas fired power plant is more suitable than using it to produce green H_2.

This development of on-grid electrolysis is accompanied with a scenarized development of off-grid production of green hydrogen, which includes investments in electrolysers and in dedicated wind capacities that are only connected to these electrolysers. Part of this production is allocated to local

[45] This price can be seen as a maximum production costs for H2 to be exported. Computing a final cost for an importer country would require adding costs for transport (from the production facility to the port, through the oceans and from the H2 hub to the importer) and potential conversion and reconversion to another H2-based carrier.

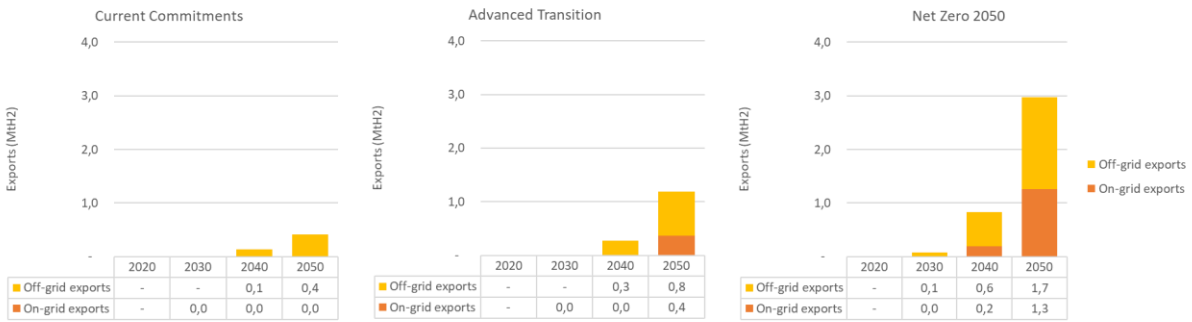
demand (“Off-grid Electrolysis Local Demand”) while the remaining is allocated to exports (“Off-grid Electrolysis Export”).

In 2050, the exports (from off-grid and on-grid production) reach levels between 0.4 and 2.9 Mt depending on the scenario.

Scenario	Current Commitments	Advanced Transition	Net Zero 2050
H_2 exports in 2050 (MtH_2)	0.4	1.2	2.9

Figure 58: Hydrogen exports in 2050

In Current Commitments, since on-grid electrolysis is not competitive, there are no on-grid exports. In contrast, on-grid exports reach 30% (0.35 MtH_2) in 2050 in Advanced Transition, and respectively 24% in 2040 (0.2MtH_2) and 42% (1.25MtH_2) in 2050, in the Net Zero 2050 scenario.



Current Commitments	2020	2030	2040	2050
Off-grid exports	-	-	0,1	0,4
On-grid exports	-	0,0	0,0	0,0

Advanced Transition	2020	2030	2040	2050
Off-grid exports	-	-	0,3	0,8
On-grid exports	-	0,0	0,0	0,4

Net Zero 2050	2020	2030	2040	2050
Off-grid exports	-	0,1	0,6	1,7
On-grid exports	-	0,0	0,2	1,3

Figure 59: Yearly hydrogen exports in the three pathways

Finally, in all three scenarios, investments in hydrogen transmission pipelines are negligible: these investments are suboptimal compared to a situation where the electricity is transmitted to the regions where the electrolysis needs to be done.

Additionally, in all three scenarios, hydrogen-based electricity production does not develop. While this technology could be a low carbon alternative to gas peakers (high load factors on this technology would not be competitive vs RES or nuclear), the gas price is too low, even while accounting for a potential CO2 tax, to make hydrogen-based electricity competitive.

There are also no investments in CSP fleets (Concentrated Solar Power) as their LCOE is too high compared to solar PV.

5.1.4 Pathway costs

5.1.4.1 Contents and scope

Pathway costs presented in the report account for costs for the whole electricity and hydrogen system from 2020 to 2050 and are computed accounting for actualization and presented in USD2020. They are limited to the perimeter of the study and include the components described in the following table.

Components of costs and revenues for the system	Details
Gas supply costs	Costs of gas purchases linked to the gas consumption in gas-fired electricity generation and SMR (with and without CCS)
CAPEX	Investment costs related to the investments in electricity and hydrogen production, network, storages. For the sake of comparison between pathways only the optimized assets are accounted for in this computation.
Fixed Operation & Maintenance	Fixed operation and maintenance costs related to the investments in electricity and hydrogen production, network, storages. For the sake of comparison between pathways only the optimized assets are accounted for in this computation.
Variable costs	Variable operation cost of production capacities, proportional to the production of each asset.
Exports revenues	Source of **revenues** for the Argentinian system, thus accounted as a reduction of pathway costs. This corresponds to the revenues from the sales of hydrogen for exports. Since the price of hydrogen considered does not account for its potential transformation, this does not account for potential added value from downstream processes.
CO2 tax	This is not a cost nor a revenue for the Argentinian system but is still displayed in the following graph for information purpose. This corresponds to the potential CO2 taxes paid by gas-based electricity producers or SMR owners to the Argentinian state. As such they are neutral for the overall system: they are a transfer of money between two actors of

	the Argentinian economy. While this does not play in a role in the total costs for Argentina, these CO2 taxes are used in the modelling to account for the negative externality of gas-based producers and affect their relative value and competitiveness versus low-carbon alternatives. As a reminder, CO2 tax is zero in Current Commitments, 60 USD/tCO2 in Advanced Transition and 120 USD/tCO2 in Net Zero 2050

Figure 60: Components of costs and revenues for the system

As these pathway costs only consider what is included in the perimeter of the model, they do not include:

- Costs of the gas systems beyond the gas consumption for electricity and hydrogen production. These should be significantly higher in Current Commitments, given it has lower electrification than the two other pathways
- Costs related to the electrification of usages, which should be proportionally higher in both Advanced Transition and Net Zero 2050 given their higher electrification than Current Commitments.
- Costs related to hydrogen transformation (proportionally higher in AT and NZE than in CC)
- Costs of electricity and hydrogen distribution networks
- Investment and fixed O&M costs of the existing and scenarized generation technologies (hydro, nuclear, …).

5.1.4.2 Costs and revenues of the baseline scenarios

Pathways costs are displayed below for the three baseline scenarios along with a reminder of the overall demand to be satisfied along the pathway.

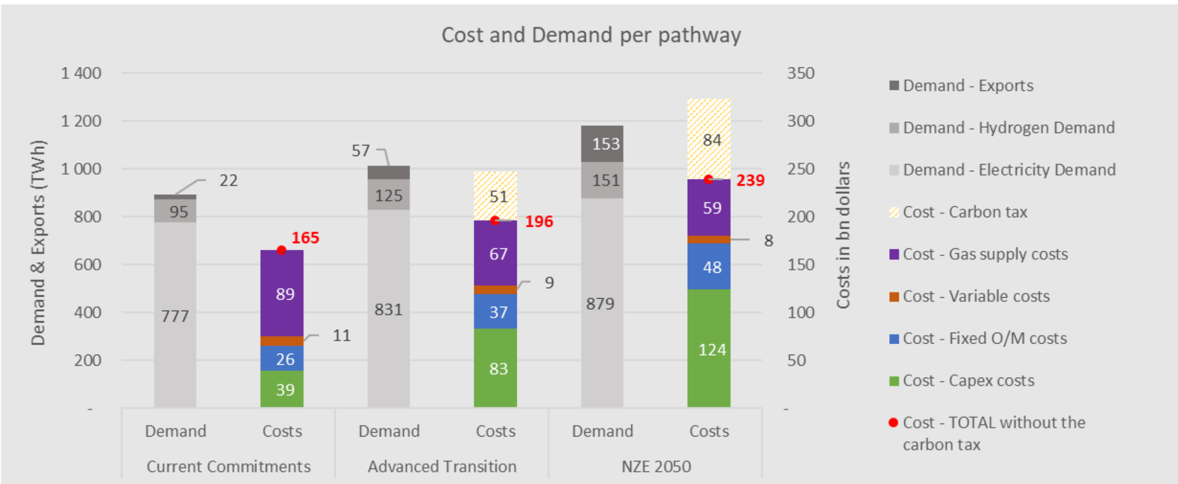


Figure 61: Pathway total costs from 2020 to 2050 (in billion dollars)

With higher electricity and H2 consumptions, pathway costs in Advanced Transition and in Net Zero Emissions 2050 are higher than in Current Commitments of respectively 19% and 45%.

The increase of costs mostly come from additional capex and fixed O&M costs due to the higher investments in electricity and hydrogen production, network and storage. These investments costs are mostly driven by the increase in RES capacities in all scenarios which counts for 59% of CAPEX costs in Current Commitments, 56% in Advanced Transition and 54% in Net Zero 2050. Power network and batteries, installed mostly to harness the full value of RES variable production, account for 11-12 % of the investments. Finally, Investments in H_2 production represent a significant share of investments, proportionally bigger in NZE 2050 (29%) than in CC (20%) as exports are far more significant in this scenario.

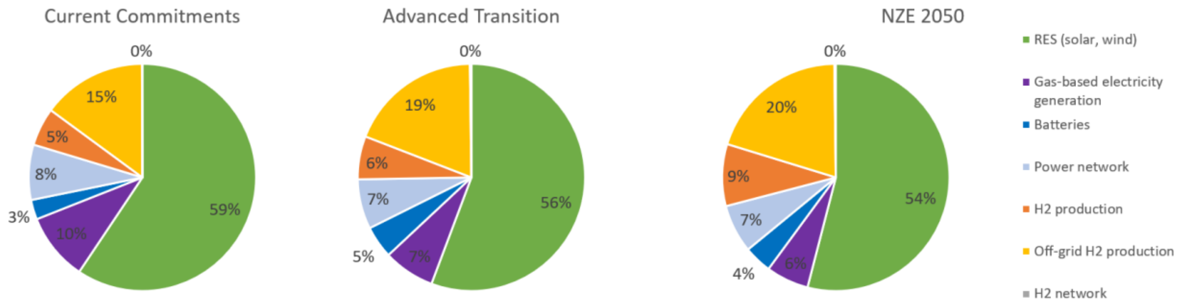


Figure 62: Distribution of investment costs in the three pathways

This increase in investment costs is partly compensated by a reduction of the purchase of gas (reduction of gas supply costs).

While this is not part of costs and revenues for the Argentinian system, it is worth noting the carbon tax, paid by Argentinian producers to the Argentinian state, would increase significantly in NZE2050, even with a lower gas consumption, and that this could be used to finance energy infrastructure projects that could favour electricity and hydrogen production.

With the development of hydrogen or hydrogen-based molecules, the revenues from exports also increase in Advanced Transition and in Net Zero Emission 2050, as displayed below, which compensate the off-grid installations costs (electrolysers and associated wind power) and a share of the on-grid installations costs. As a reminder, these revenues are computed as the product between hydrogen price (as presented above) and the volume of hydrogen exports

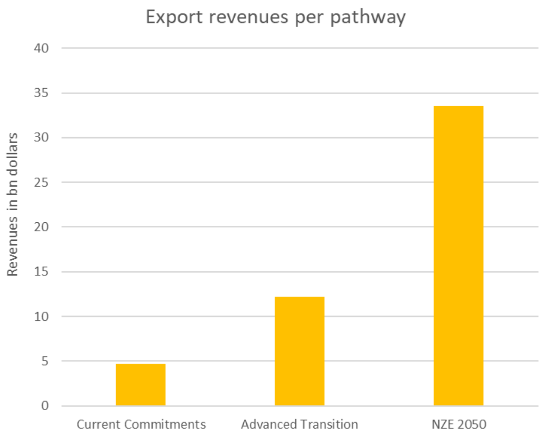


Figure 63: Revenues from hydrogen exports over the period 2020-2050 (in billion dollars)

While pathway costs in NZE2050 and AT appear higher than those of CC, it is important to recall that the costs of what is not electrified is not accounted for in this calculation, which means that **AT and NZE are not necessarily more expensive overall**.

For example, in AT and NZE, the adoption of heat pumps is driving an increase in electricity demand which requires additional production on the electricity system. However, this electrification of heat also contributes to reduce the needs in gas for heating, and thus the costs of the gas system overall (less consumption, less needs for imports) which are not accounted for in this analysis.

To compare this, we display below the system costs divided by the total final demand (which is higher in NZE and AT compared to CC). The average supply price of 1 MWh of final demand varies between 30.8 in CC and 35.6 in NZE, which shows that the difference between the scenarios remains limited (note that this is without accounting for benefits from exports, counting the hydrogen consumption for exports as a final consumption).

Scenario	Current Commitments	Advanced Transition	Net Zero 2050
Average supply price (USD/MWh)	30.8	33.2	35.6

Figure 64: Average supply cost of hydrogen and electricity

5.1.5 CO_2 emissions

Finally, one of the key indicators that differentiates the three pathways is the CO_2 emissions.

The scope of this analysis is limited to the power and hydrogen sectors which represents around 15% of the total emissions of Argentina. This evaluation only integrates direct emissions in CO2eq *for electricity and hydrogen production (scope 1), i.e. emissions from gas-based electricity generation (CCGT, OCGT) and gas-based hydrogen generation (SMR, SMR with CCS). This evaluation is not a life cycle assessment, in the sense that it does not account for emissions from the whole lifetime of generation assets or networks.*

The CO_2 emissions decrease in all three scenarios with the decrease of gas power plant production. The degree of reduction varies according to the scenarios (see Figure 65 below).

Despite larger hydrogen and electricity demand, the decrease is steeper in the scenario Net Zero 2050 with the fastest and largest development of RES capacities, reaching 6 $MtCO_2$ in 2050 (-88% relatively to 2020 emissions), compared to 8.5$MtCO_2$ for Advanced Transition (-82%) and 43 $MtCO_2$ for Current Commitments (-11%).

Taking the gross amount of CO_2 emissions, It could be considered that the improvement in CO_2 emissions in the scenario Current Commitments is quite limited. Nevertheless, if these emissions are compared to the total electricity and hydrogen produced, emissions per MWh decrease by 55% for Current Commitments between 2020 and 2050.

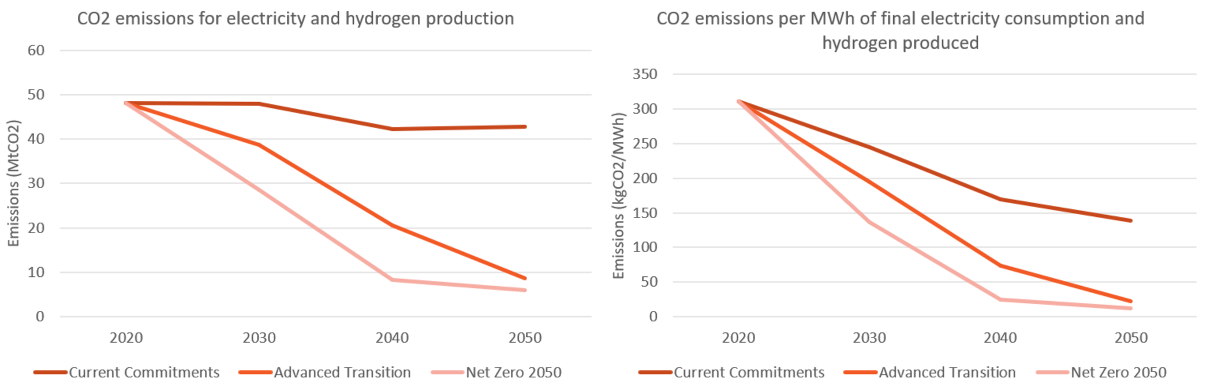


Figure 65: CO_2 emissions of final electricity consumption and hydrogen produced (yearly total and per MWh)

Note that this computed decrease does not account for two aspects that would play in favour of NZE 2050:

- Potential reductions of CO2 emissions linked to increased green H2 exports from Argentina to the rest of the world. Indeed, this increase may help reduce the use of fossil hydrogen in the importer countries and thus their emissions for hydrogen production
- Emissions of what is not electrified (e.g. vehicles relying on fossil fuels, gas-based heating) which are present in a much larger quantity in CC and AT than in NZE 2050.

5.1.6 Conclusion of the main pathway analysis

From all these results, several main messages can be derived:

1. The investment in RES capacities is economically viable in Argentina, even in a context with a low gas price. Gas-based electricity generation should function as intermediate load or as a peaker for an economic operation of the power system.
2. The development of the wind industry is a key point for a quick and significant decarbonisation of the energy system. With the lower LCOE of RES compared to carbon-intensive alternatives, increasing the potential development of RES is key, and the technical potential in Argentina is not constraining due to the available surface for RES development.
3. On-grid electrolysis can be profitable from 2040 onwards, if the RES share and the CO_2 tax are sufficient. It is worth noting that renewables are best used for electricity decarbonisation in a first step and that on-grid electrolysis comes in a second step of the decarbonisation of the system. In other words, the competition will be between blue and green H2, depending on the level of decarbonisation.
4. A significant development of the transmission network is necessary for Argentina to reach high-RES shares in the electricity mix. In average, the network should increase in capacity by a factor 2 or 2.5 in the most ambitious scenarios to harness the full value of RES sources. The increase of the capacity from Patagonia to Buenos Aires is particularly necessary to benefit from the wind potentials in Patagonia.
5. Argentina can become a massive hydrogen exporter with up to 2.9 Mt exported per year in 2050 in an ambitious scenario.
6. Depending on the level of ambition in the scenario, the decarbonisation of the electricity and hydrogen systems reduction varies from 11% to 85%. Depending on the development of RES on the grid, the decarbonisation of hydrogen system will rely on the development of SMR+CSS mostly or of green hydrogen mostly.

5.2 Sensitivity Analyses

Several sensitivity analyses have been led to identify the robustness of the results with regards to different key assumptions of the scenarios. The following table is a summary of all the analyses that have been carried out.

N°	Sensitivity	Scenario	Quantitative Hypothesis
1	Decrease of gas price	Current Commitments	• Reducing gas price from 5.7 to 3.2 USD/MMBtu
2	Increase of gas price	Net Zero Emissions 2050	• Increasing gas price from 5.7 to 8.2 USD/MMBtu • Increasing off-grid hydrogen production • Acceleration of installation rate for wind
3	Decrease of electrolysers costs	Net Zero Emissions 2050	• Reducing electrolysers CAPEX to 99 USD/kW in 2050 (136USD/kW in 2030) which correspond to a 75% decrease (71% in 2030), in line with BloombergNEF forecast for electrolysers CAPEX in China • Higher RES installation rates
4	Optimisation without accounting for fugitive emissions	Net Zero Emissions 2050	• Considering direct emissions from H_2 production process only (no fugitive emissions associated to gas production). It corresponds to a decrease by 16% of CO_2 emissions for a SMR plant (80% for SMR+CCS) • Lower off-grid hydrogen production • Slowing down the installation of wind off-grid capacities for local demand
5	Increased WACC	Current Commitments	• Increasing from 7.5% to 14%
6	Increased Fugitive CO_2 emissions	Net Zero Emissions 2050	• Considering higher fugitive CO_2 emissions. It corresponds to an increase by 16% of CO_2 emissions for a SMR plant (80% for SMR+CCS) • Acceleration of installation rate for wind

7	Decrease of H_2 export price	Net Zero Emissions 2050	• Reducing by 20% the exports price to reach about 1.4 USD/kg in 2050
8	Limitation of electricity network development	Advanced Transition	• Limiting to a 50% increase of inter-regional transmission capacities
9	Increased H_2 export prices	Net Zero Emissions 2050	• Increasing hydrogen exports prices to reach about 2 USD/kg in 2050 • Increase of wind on-grid (+30%) and off-grid for exports (+50%) installation rhythms

5.2.1 Decrease of gas price (S1)

Context and objective

Gas-fired plants are an essential component of Argentina electricity production. Their impact on both CO_2 emissions and total costs is crucial. However, renewable deployment and profitability depends also on the marginal costs of production of these plants. It seems therefore interesting to analyse the impacts on both renewable development, CO_2 emissions and total costs.

Scenario Current Commitments

Quantitative hypothesis

- Reducing gas price from 5.7 to 3.2 USD/MMBtu

Decreasing gas price impacts first gas-based electricity generation. The lower cost of gas-based electricity generation makes the installation of RES less attractive, and even non-competitive before 2050. The investments in RES capacities are therefore much lower.

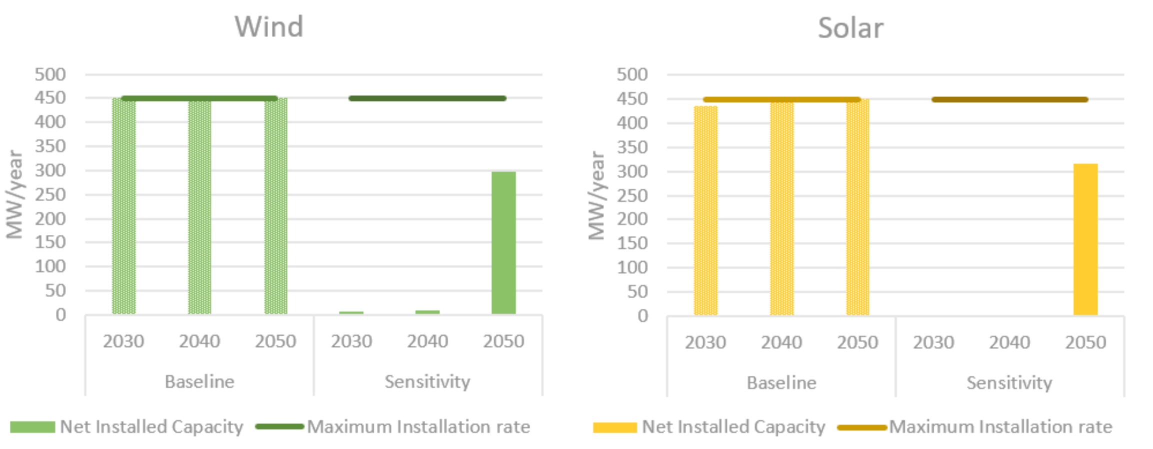


Figure 66: Net and maximum installation rates for wind (on-grid only) and solar capacities – Sensitivity S1

When the installation rhythms for wind (on-grid only) and solar capacities reach the maximum ones in the baseline, they are zero in 2030 and 2040 and significantly inferior to the maximum ones in 2050 in the sensitivity.

Installed capacities in gas power plants are higher by 3.5 GW in 2050, while solar and wind capacities are respectively 10.2 GW and 10.4 GW lower compared to the baseline.

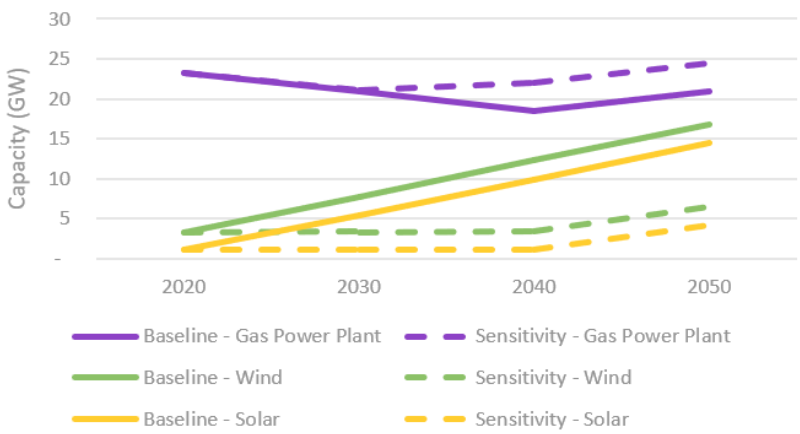


Figure 67: Installed capacities on-grid for gas power plants, solar and wind – Sensitivity S1

Because of these differences in the installation of capacities, the electricity production mix shifts to a lower share of low-carbon energy (RES and nuclear share, the reduction coming from the reduction of RES share), decreasing by 28% in 2050 compared to the baseline. Gas power plant are on their side producing 159 TWh more in 2050 compared to the baseline, and even more than they produce in 2020.

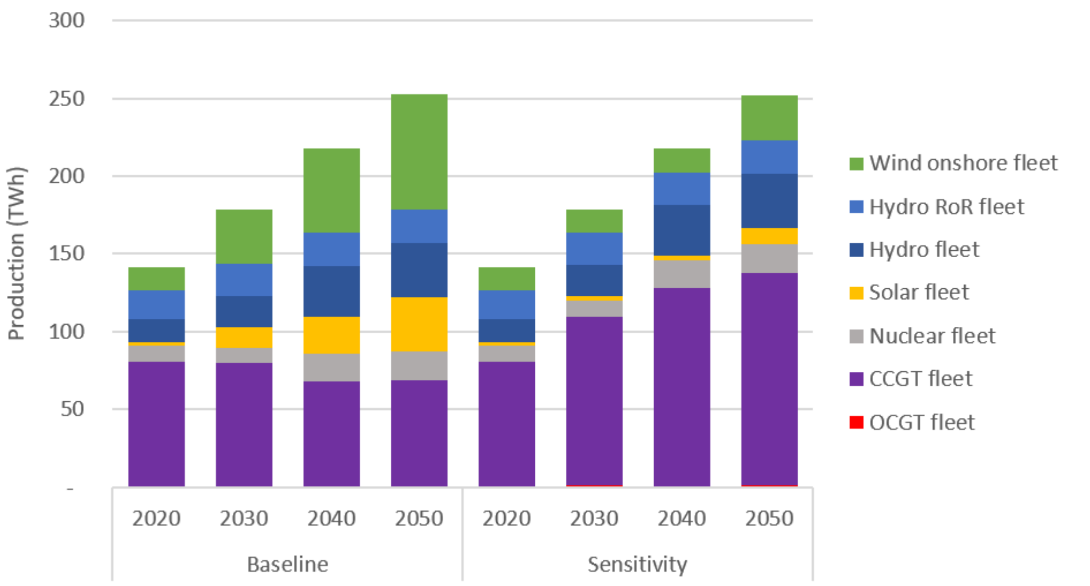


Figure 68: Yearly electricity production – Sensitivity S1

Low carbon energy share (%)	2030	2050
Baseline	55%	73%
Sensitivity	39%	45%

Figure 69: Low carbon energy share comparison – Sensitivity S1

Regarding the hydrogen system, there is no difference in hydrogen production in this sensitivity, as there is no on-grid electrolysis in the baseline and a decrease of gas price makes electrolysis even less competitive. Moreover, while grey hydrogen might become more competitive compared to blue, with this reduction of gas price, there is no additional capacities in SMR without CCS since these capacities were inputs of the model in all scenarios (no possibility of investing in additional grey hydrogen production).

As a reminder, off-grid assumptions are unchanged between the baseline and the sensitivity.

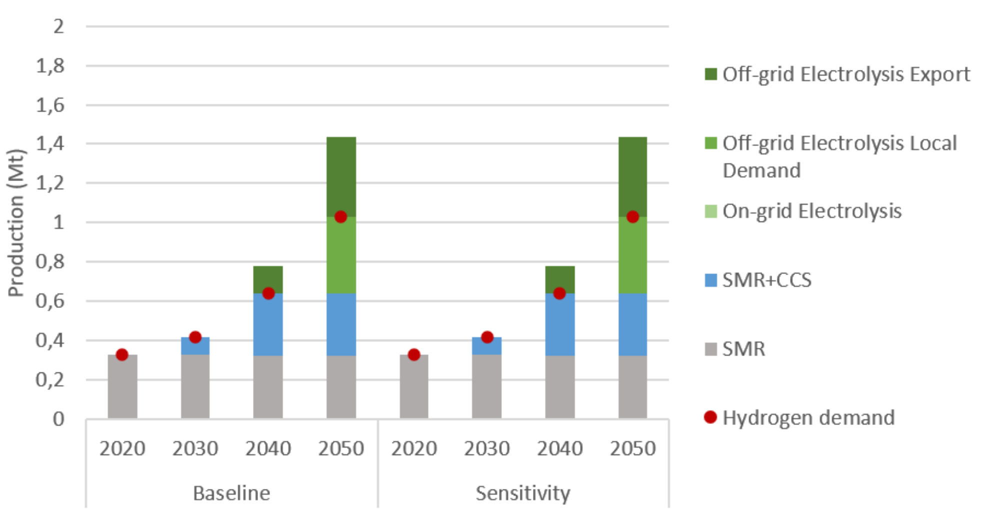


Figure 70: Yearly hydrogen demand and production – Sensitivity S1

The shift of the electricity production mix towards a more gas-based increases significantly CO_2 emissions over the pathway.

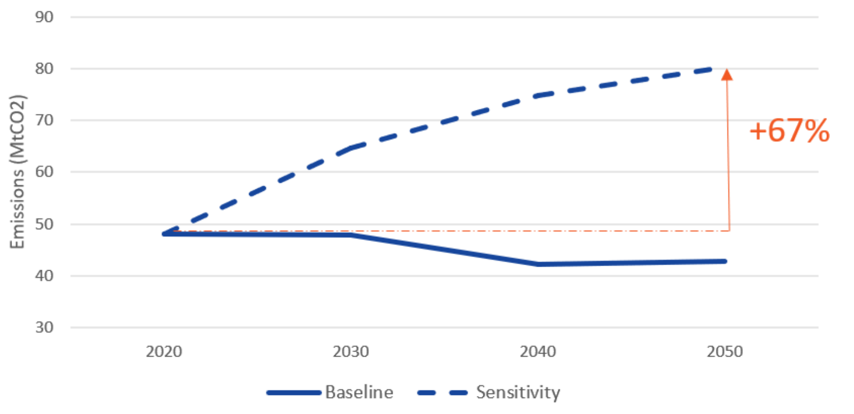


Figure 71: Direct CO2 emissions for electricity and hydrogen production - Sensitivity S1

In the baseline CC scenario, there is an observed 11% reduction in CO2 emissions between 2020 and 2050. However, in this sensitivity analysis, that reduction is no longer present. Instead, due to the higher utilization of gas, CO2 emissions rise by 67% between 2020 and 2050.

NB: All CO_2 emissions computations account for direct emissions only (scope 1) for electricity and hydrogen production. They do not account for emissions from the construction of solar panels or wind turbines (not a life cycle assessment), nor the CO_2 emissions of what is not electrified in current commitments, nor the CO_2 emissions reduction brought by the low carbon H_2 exports.

Moreover, with a lower investment in RES and higher investment in dispatchable capacities near consumption areas, the investments in the electricity inter-regional network are lower, reaching an additional deployment of 12% instead of 53% for the baseline.

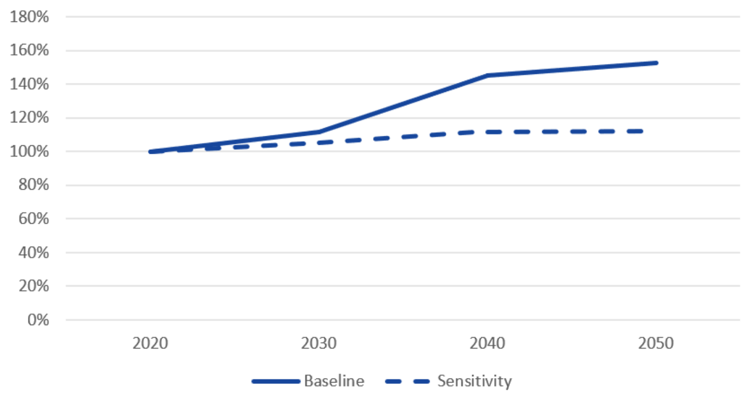


Figure 72: Transmission capacities deployment (electricity) – Sensitivity S1

Regarding the pathway costs, whose calculation is depicted in section 5.1.4, gas supply costs decrease by about 23%, despite the increase in gas-fired electricity production. As the hydrogen production matrix hasn't changed the costs of hydrogen production remain the same in the sensitivity as in the baseline. Additionally, CAPEX and OPEX are reduced because of the decrease of RES installation. Overall, the total cost of the pathway (excluding export revenues), as well as the net total cost (including export revenues) is reduced by 28% driven mainly by the reduction of gas price. Note that the gas system is not included in the scope of the study, meaning that the investment and operation costs of gas infrastructure are not considered.

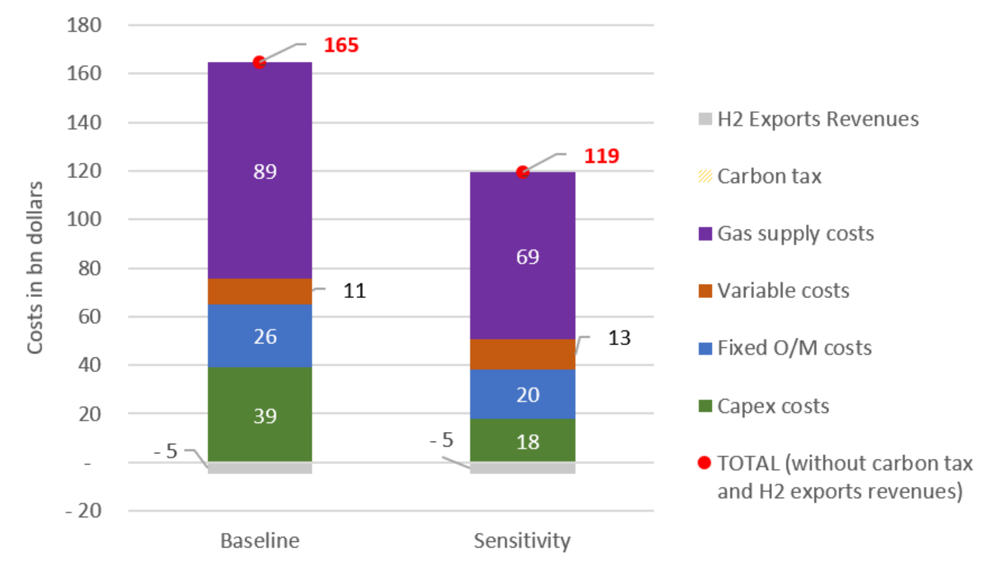


Figure 73: Costs per pathway – Sensitivity S1

KEY FINDINGS

Lower gas costs would affect the competitiveness of renewables, affecting their deployment by 2050. This would have a direct impact of increasing the direct CO_2 emissions of the hydrogen and electricity systems by 67%. Overall, the total cost of the pathway is reduced by 28% (excluding potential increases of gas network costs and fugitive emissions).

5.2.2 Increase of gas price (S2)

Context and objective

This sensitivity aims at analysing the impact of an increase of gas price, reflecting, for example, higher production costs for unconventional gas or influence of international LNG markets. Such a sensitivity could encourage solar and wind installation and reduce SMR production.

Scenario Net Zero Emissions 2050

Quantitative hypothesis

- Increasing gas price from 5.7 to 8.2 USD/MMBtu
- Increase off-grid hydrogen production
- Acceleration of installation rhythm in the beginning of the pathway for wind, as stated on the graph below

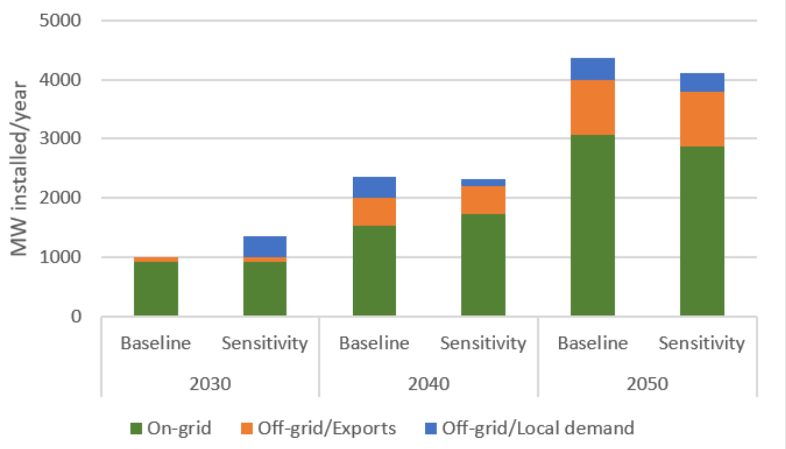


Figure 74: Maximum wind installation rhythms – Sensitivity S2

The changes regarding maximum installation rhythms for wind modifies wind installation rates. Indeed, in the sensibility, on-grid wind capacity can increase at a faster pace in the beginning of the pathway, ultimately reaching the same value as in the Baseline of 59 GW by 2050. Regarding solar installation, maximum rhythms and optimized investments are unchanged.

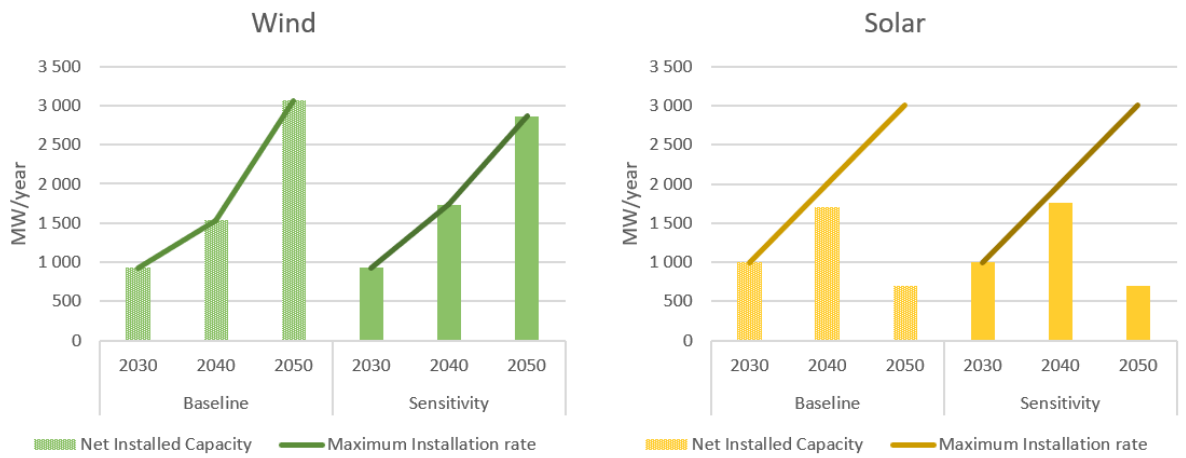


Figure 75: Net and maximum installation rates for wind (on-grid only) and solar capacities – Sensitivity S2

As total wind and solar installed capacities are about equal between the sensitivity and the baseline, so are gas-based electricity production capacities.

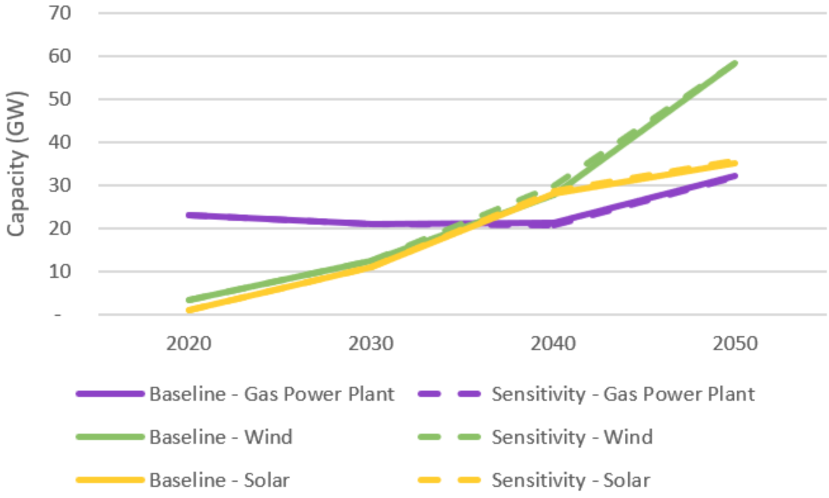


Figure 76: Installed capacities for gas power plants, solar and wind – Sensitivity S2

Because of these capacities, the electricity production mix are similar between the sensitivity and the baseline. Gas-based electricity production decreases by only 2% along the pathway and the share of low carbon electricity remains constant between both cases.

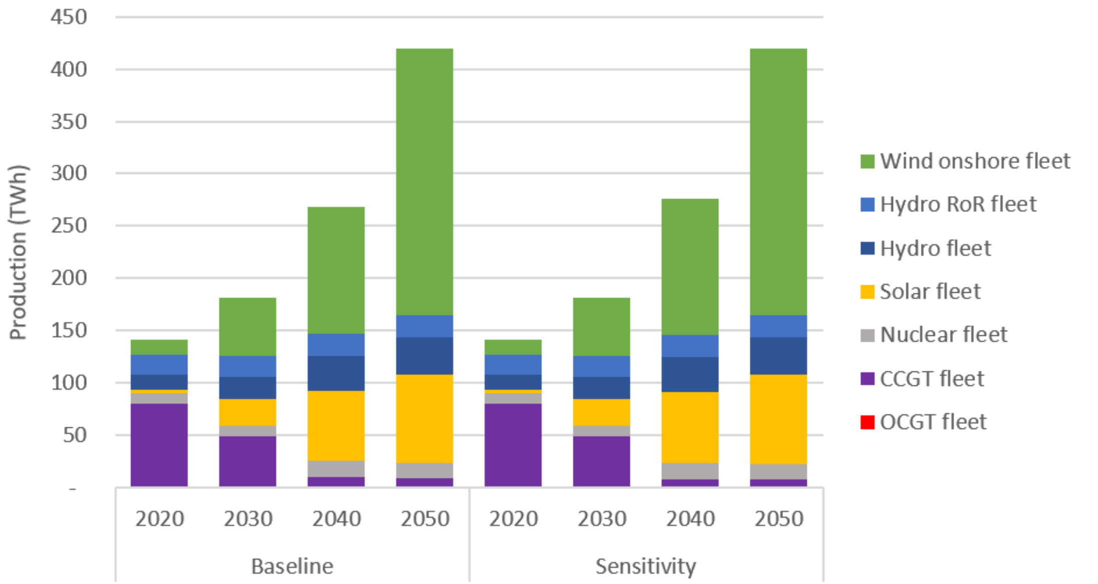


Figure 77: Yearly electricity production – Sensitivity S2

Low carbon energy share (%)	2030	2050
Baseline	73.2%	97.9%

Sensitivity	73.2%	98.1%

Figure 78: Low carbon energy share comparison – Sensitivity S2

Regarding the hydrogen system, green H_2 is made more competitive in 2030 and onward with to the increase in gas prices. In the sensitivity, green H_2 production for local demand appears in 2030 and replaces the production from SMR+CCS (blue hydrogen): the production from SMR+CSS decreases by 62% in 2030 compared to the baseline. In 2050, this production of SMR+CCS is also reduced by 68%. In contrast, the improved competitiveness of electrolysis results in more on-grid green H_2 production, which increases by 64% in 2040 compared to the baseline.

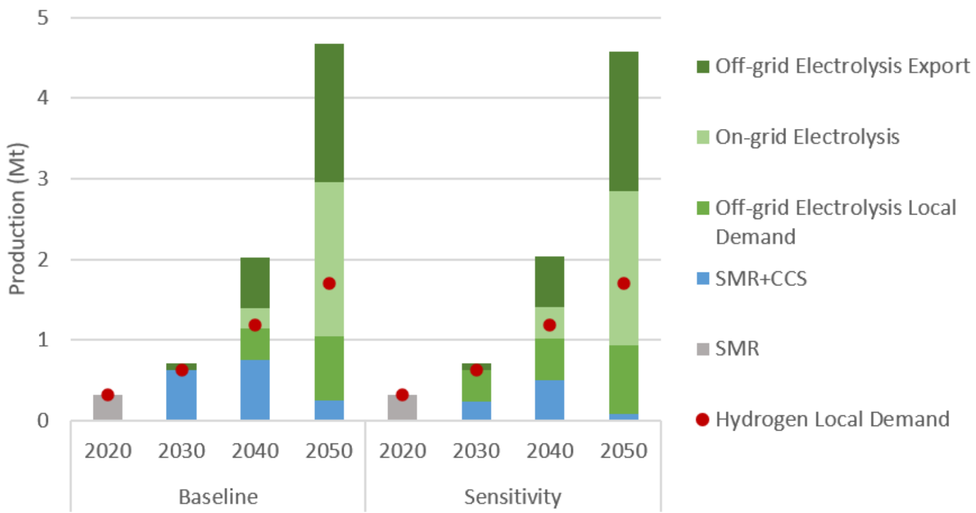


Figure 79: Yearly hydrogen demand and production – Sensitivity S2

As a result of both electricity and hydrogen production mixes, the direct CO_2 emissions for electricity and hydrogen production are similar between the baseline and the sensitivity. The earlier installation of renewables and the lesser use of SMR technology leads to a slightly faster decrease in CO_2, but the difference between the baseline and the sensitivity appears to be negligible. Between 2020 and 2050, emissions are reduced by 90% in the sensitivity compared to 88% for the baseline.

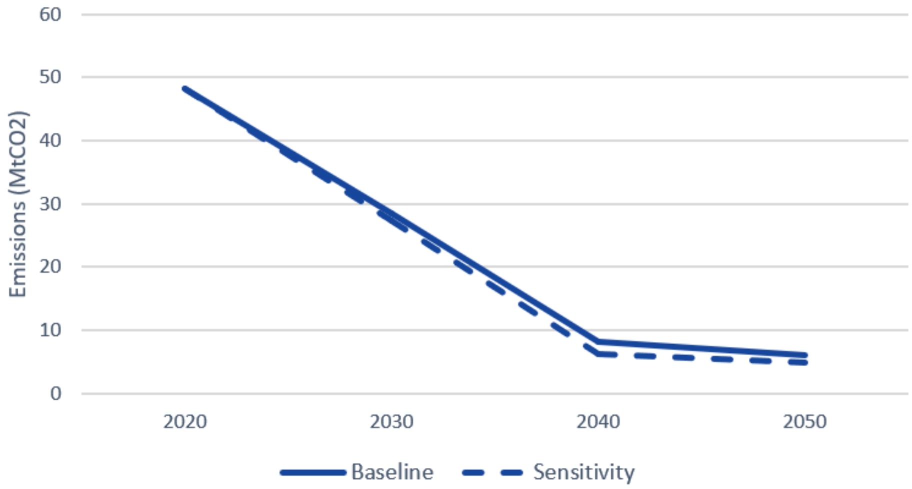


Figure 80: Yearly direct CO_2 emissions for electricity and hydrogen production – Sensitivity S2

Finally, the pathway costs are higher in the sensitivity due to an increase of gas supply costs by about 30%, as a direct consequence of gas price increase, even though gas consumption (mostly for SMR and SMR+CCS) decreases. Overall, the total costs (excluding export revenues) rise by 11% and the net total costs (costs minus exports revenues) rise by 13%.

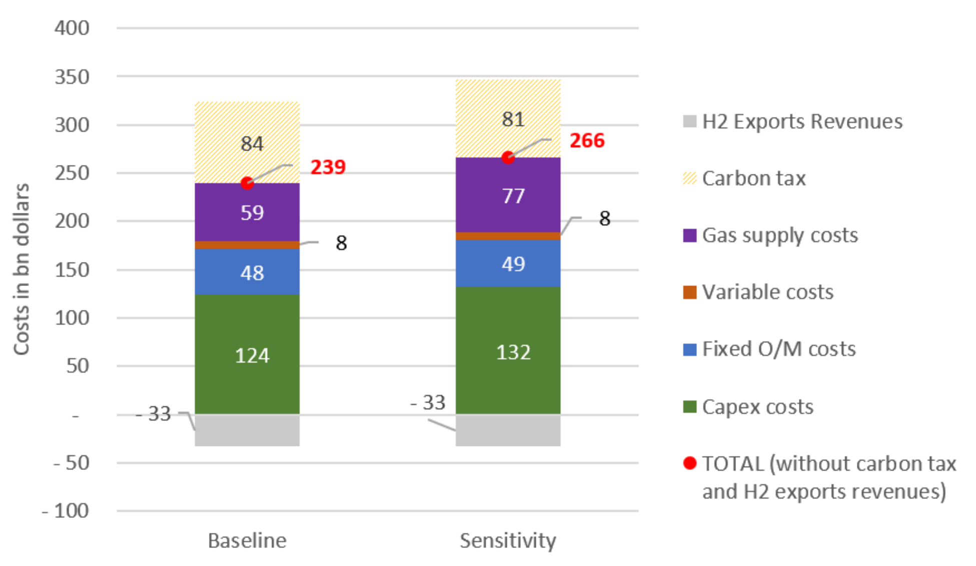


Figure 81: Costs per pathway – Sensitivity S2

KEY FINDINGS

Rising gas prices reduces the competitiveness of gas-based electricity and hydrogen production and make renewables and electrolysis relatively more competitive. In this context, it is more economical to reduce the share of gas and increase the share of electrolysis in hydrogen production. This leads to a 13% increase in total net costs, mainly driven by the increase of gas supply costs.

5.2.3 Decrease of electrolysers costs (S3)

Context and objective

Renewable deployment relies both on competitiveness with gas-based electricity production means and on profitability in combination with electrolysis for H_2 production. The profitability of green H_2 depends on their costs but also on costs of electrolysers. As electrolysers costs remain very uncertain for the following years to come, it seems relevant to analyse the impacts that could be derived from a reduction of electrolyser costs linked with the decreasing costs of Chinese electrolysers.

Scenario Net Zero Emissions 2050

Quantitative hypothesis

- Electrolysers CAPEX reduced to 99 USD/kW in 2050 (136USD/kW in 2030) which correspond to a 75% decrease (71% in 2030) compared to the Baseline and which are forecasts for electrolysers CAPEX in China[46]
- Acceleration of installation rhythm in the beginning of the pathway for wind, as stated below

[46] Source: BloombergNEF

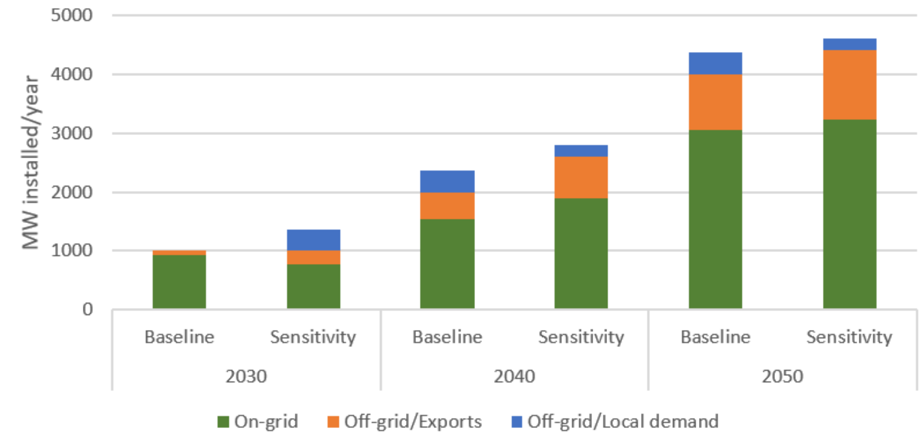


Figure 82: Maximum wind installation rhythms - Sensitivity 3

Both the increase of maximum on-grid wind installation rates and the decrease of electrolyser costs increase wind and solar installed capacities in this sensitivity. In fact, on-grid wind maximum installation rates are higher for 2040 and 2050 in the sensitivity but optimized installation rhythms still reach the maximum rates. In addition, with these electrolysis costs, it also becomes profitable to invest in solar power to produce green hydrogen, which explains the increase of solar installation rates in the sensitivity.

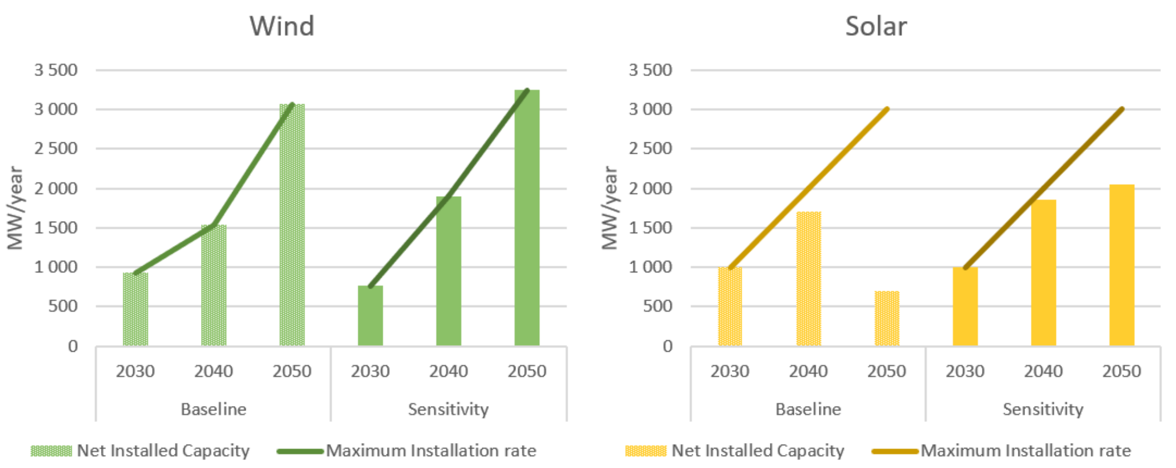


Figure 83: Net and maximum installation rates for wind (on-grid only) and solar capacities – Sensitivity S3

Wind installed capacities are 7% higher (62 GW) in the sensitivity and solar capacities are 43% higher, reaching 50 GW in 2050. Peak gas-based capacities are only marginally affected, since the additional renewable capacity is used mostly for green hydrogen production without much effect on the electricity dispatch.

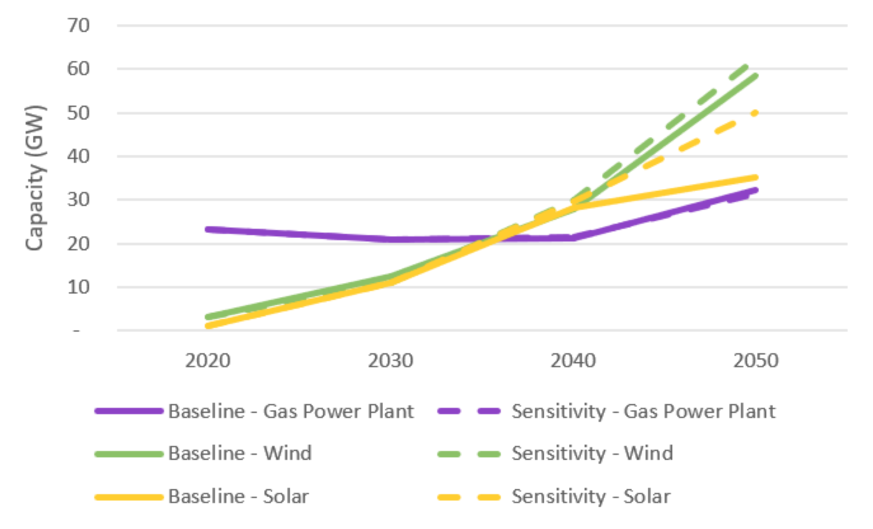


Figure 84: Installed capacities for gas power plants, solar and wind – Sensitivity S3

Because of these installed capacities, renewable production increases by about 10% in the electricity production mix. This additional electricity is fully dedicated to green hydrogen production.

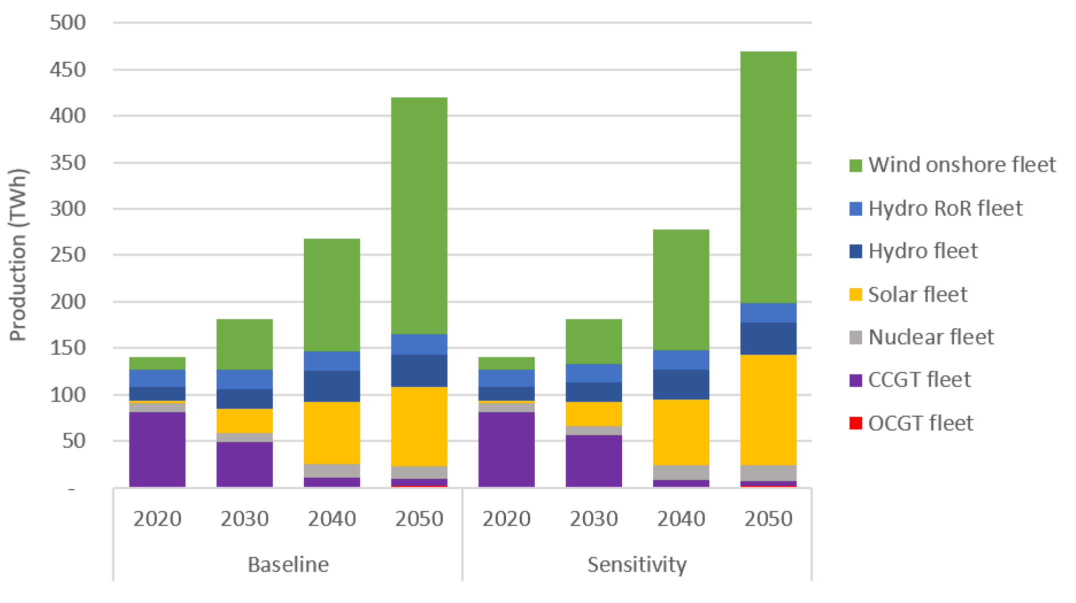


Figure 85: Yearly electricity production mix – Sensitivity S3

Regarding the hydrogen system, off-grid green hydrogen production for local demand appears in 2030 and replaces SMR+CCS production, decreasing this technology's production by 62% in 2030 and by 38% in 2040. As additional wind capacities are installed in the years 2040 and 2050, the surplus energy generated is utilized for increasing the production of on-grid green hydrogen, which increases by 119% in 2040 (67% in 2050) compared to the Baseline.

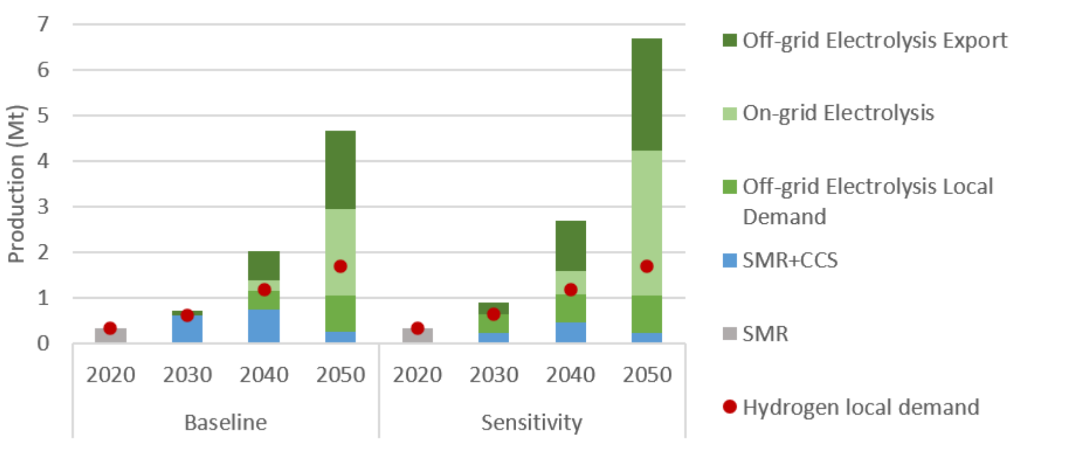


Figure 86: Yearly hydrogen demand and production – Sensitivity S3

Overall, with the increase in on-grid and off-grid H_2 production, the hydrogen exports increase significantly, rising by 82% in 2040, reaching 1.5 MtH_2 and by 68% in 2050, reaching 5 MtH_2.

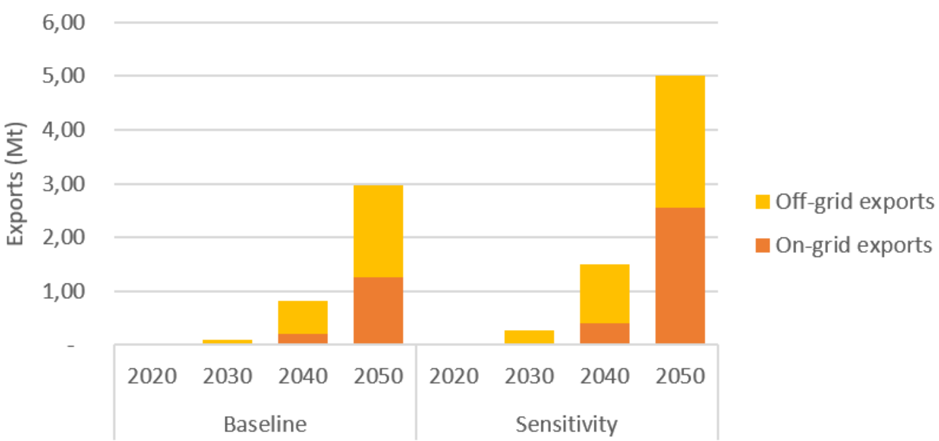


Figure 87: Yearly Off-grid and On-grid hydrogen exports – Sensitivity S3

The reduction of electrolysers costs does not affect in a significant way the network development since the additional RES and electrolysis develop in the same areas and only marginally the CO2 emissions of the system, since this green H2 is used for exports and CO2 benefits from exports are not assessed.

However, in terms of costs, the increase in exports results in an increase in revenues by a factor of 2 (33bn$ over the pathway in the baseline and 60bn$ in the sensitivity). In addition, the rise in wind installed capacities is compensated by the decrease of electrolysers CAPEX: the total CAPEX costs increase is limited to 5%. Therefore, overall, the system costs (excluding export revenues) increase by about 2%. However, with a 78% increase of H2 exports revenues, net costs decrease by 10%.

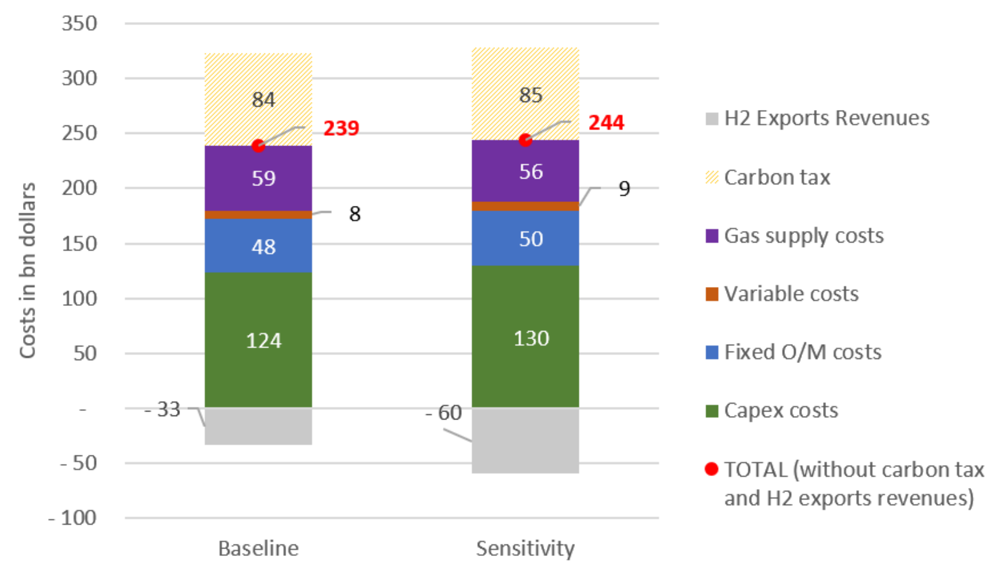


Figure 88: Costs per pathway – Sensitivity S3

KEY FINDINGS

The evolution of the international costs of production of electrolysers can reduce the production costs of green hydrogen in Argentina and provide an opportunity for Argentina to increase its hydrogen exports.

Such a reduction in the cost of electrolysers encourages greater installation of RES capacities and electrolysers dedicated to hydrogen exports, especially as green hydrogen from solar PV becomes competitive. This results in an additional 2 Mt of hydrogen produced for export, a doubling of hydrogen export revenues and an overall 10% reduction in the total net cost of the pathway, mainly related to these additional export revenues.

5.2.4 Optimisation without accounting for fugitive emissions (S4)

Context and objective

Taking into account fugitive emissions in the estimation of the LCOH may have an impact on the relative competitiveness of grey, blue and green H_2. However, as those emissions are not directly related with the process of H_2 production (i.e. direct emissions), it is not clear how they would impact on price. In that context, this sensitivity aims at analysing the impact of considering only direct emissions for the optimization process.

Scenario Advanced Transition

Quantitative hypothesis

- Considering direct emissions only (i.e., no fugitive emissions associated to gas consumption), both for H_2 production by SMR, and for electricity production by CCGT.
- Removing fugitive emissions from the analysis decreases CO_2 emissions by 16% for a SMR plant, and 80% for SMR+CCS.
- Lower off-grid hydrogen production, slowing down the installation of wind off-grid capacities for local demand as stated on the graph below.

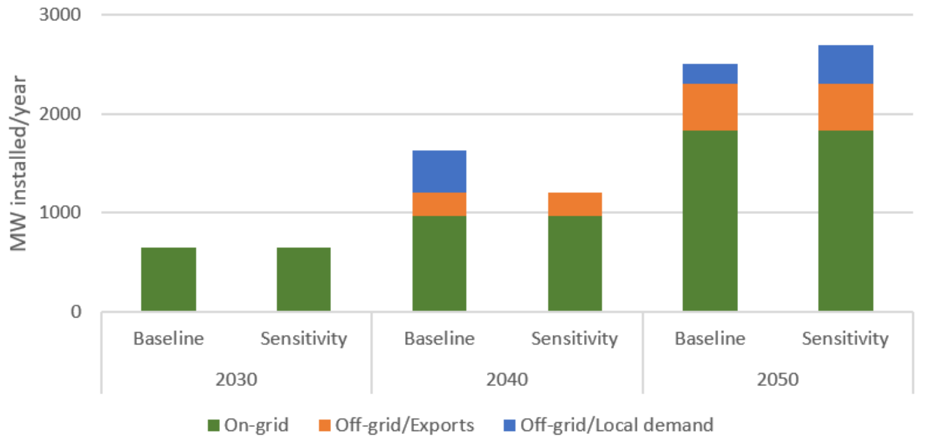


Figure 89: Maximum wind installation rhythms – Sensitivity S4

Considering only direct emissions for electricity and hydrogen production (instead of including fugitive emissions in the calculations) may affect the competition between fossil fuel-based technologies and their renewable alternatives. In the case of Argentina, excluding fugitive emissions reduces both the CO2 emissions and marginal production costs for CCGTs, SMR and SMR+CCS.

In the case of gas-fired **electricity** generation, this favours CCGTs but does not drastically affect the competition between CCGTs and vRES-e : the LCOE of gas-fired power plants remains higher than the LCOE of vRES with and without taking fugitive emissions into account (see Figure 52).

Note that this is due to the high competitiveness of RES in Argentina, which benefits from high solar and wind load factors and may not be the case elsewhere.

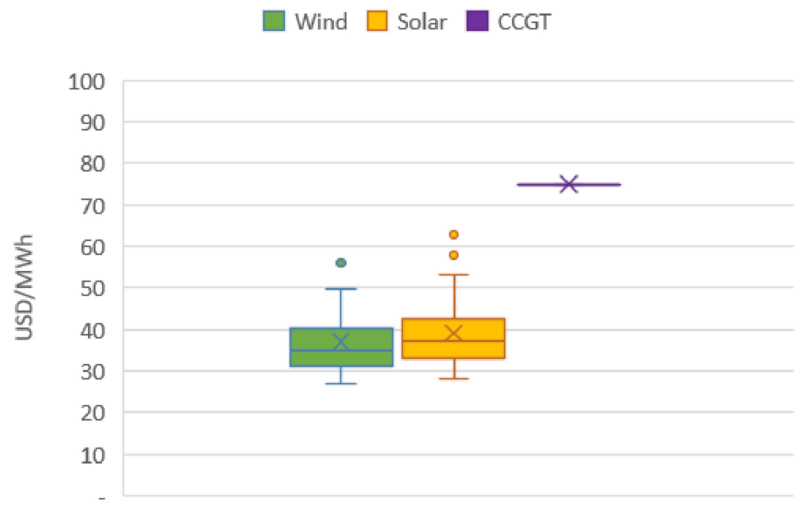


Figure 90: LCOEs of CCGT, Solar and Wind electricity production – Sensitivity S4

As a result, in the simulations performed, the electricity generation mix is only marginally affected by this change, with slightly more gas-fired electricity production in Argentina.

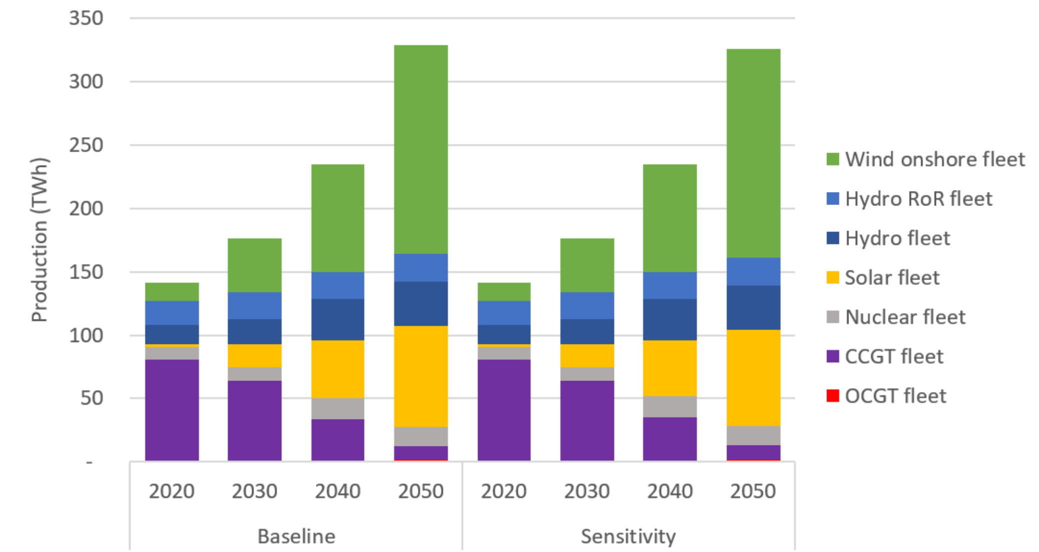


Figure 91: Yearly electricity production mix – Sensitivity S4

For the **hydrogen** system, not considering fugitive emissions makes SMR and SMR+CCS more competitive overall. Therefore, before 2050, the local demand is met exclusively by SMR and SMR+CCS and off-grid green hydrogen production only becomes competitive for local demand in 2050, whereas in the baseline it was competitive in 2040. The amount of hydrogen produced by

SMR+CCS is almost doubled in 2050. However, in the simulations performed, ignoring fugitive emissions does not affect the development of on-grid electrolysis.

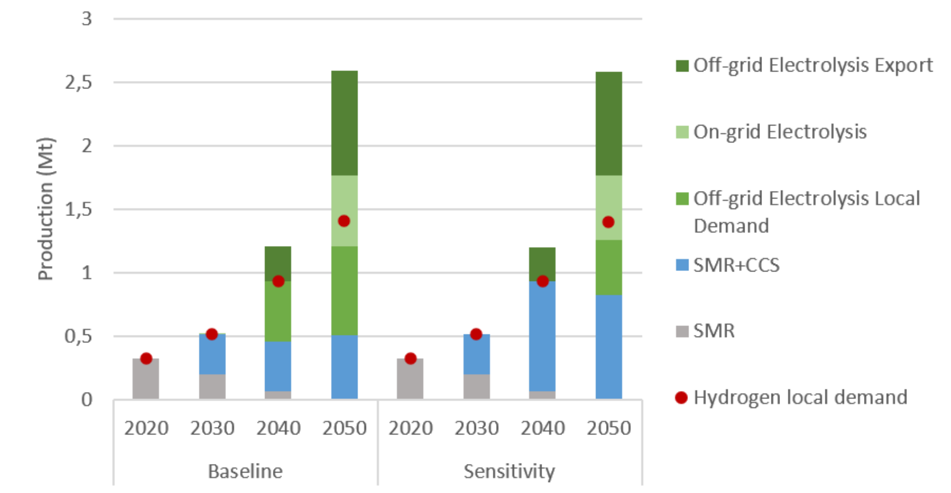


Figure 92: Yearly hydrogen demand and production – Sensitivity S4

When it comes to CO_2 emissions, it is possible to compare the CO_2 emissions in the sensitivity analysis to those in the baseline scenario, with emission factors consistent with the baseline. Anticipating for the fugitive emissions in the investment decision leads to a slight reduction of CO2 emissions overall, mostly in 2040 and 2050 as displayed in the figure below.

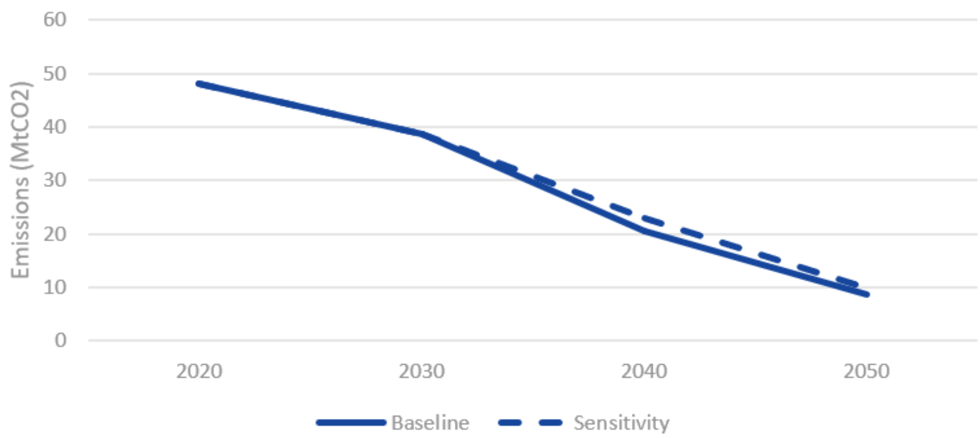


Figure 93: Yearly direct CO_2 emissions for electricity and hydrogen production – Sensitivity S4

Moreover, because of the increase of blue hydrogen production, gas supply costs are higher in the sensitivity. However, less electrolysers are installed as SMR+CCS is more competitive. Overall, the total pathway costs (excluding export revenues), as well as the net total costs, are equivalent.

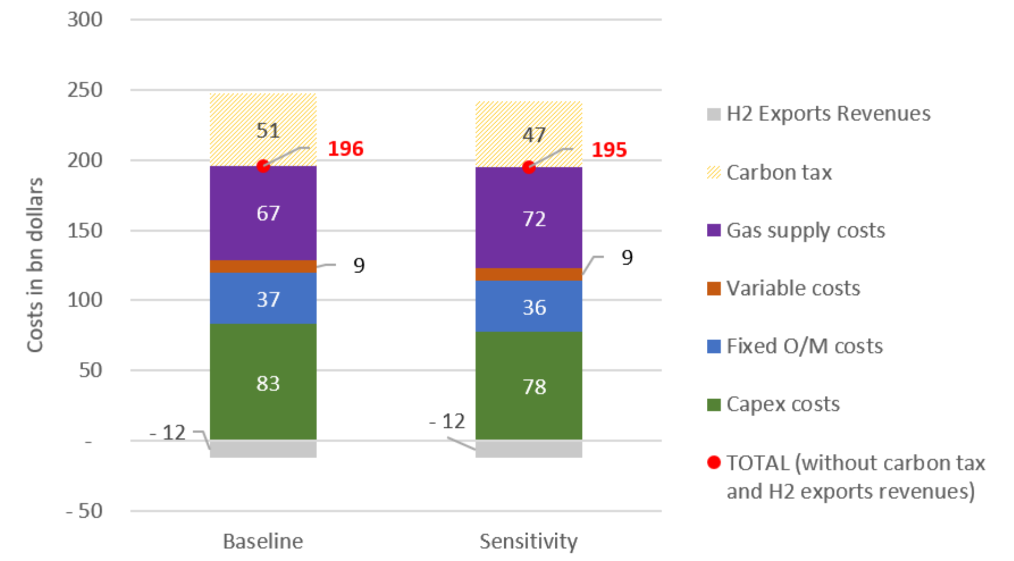


Figure 94: Costs per pathway – Sensitivity S4

KEY FINDINGS

Fugitive emissions can play an important role in the assessment of CO2 emissions, especially when considering the gas system as a whole.

Taking them into account for gas-based electricity and hydrogen production as in the simulations carried out does not significantly affect the role of CCGTs for electricity generation, as vRES-e remains more competitive than gas even in this case, but it does affect investment in SMR+CCS, which almost doubles its share in the mix in 2050 at the expense of off-grid RES and electrolysis.

Overall, ignoring fugitive emissions in the investment planning slightly increases the CO2 emissions of the resulting system, while the total costs do not change, making fugitive emissions an issue worth considering.

5.2.5 Increased WACC (S5)

Context and objective

One key parameter when optimizing investment decisions is the Weighted Average Costs of Capital (WACC). WACC is the average rate that a company expects to pay to finance its assets. This rate has been considered relatively optimistic in the baseline, being equal to 7.5%. This sensitivity aims to understand the impacts of a more unfavourable WACC, taking it equal to 14%.

Scenario Current Commitments

Quantitative hypothesis

- Increase from 7.5% to 14%, affecting investment in power production (RES, peakers and batteries) in hydrogen production (SMR+CCS and electrolysers) and in network (transmission lines and hydrogen pipelines)

WACC crucially impacts electricity production costs of technologies, especially for CAPEX-intensive technologies such as renewables and nuclear (it would also affect investments in natural gas infrastructure but these are outside of the scope of the study). As a reference, the cost of a project of 25 years of lifetime (such as wind turbines for instance) increase by 60% when the WACC changes from 7.5% to 14%.

In the sensitivity, the increase of WACC and decreased competitiveness of RES result in a significant reduction in wind and solar investments.

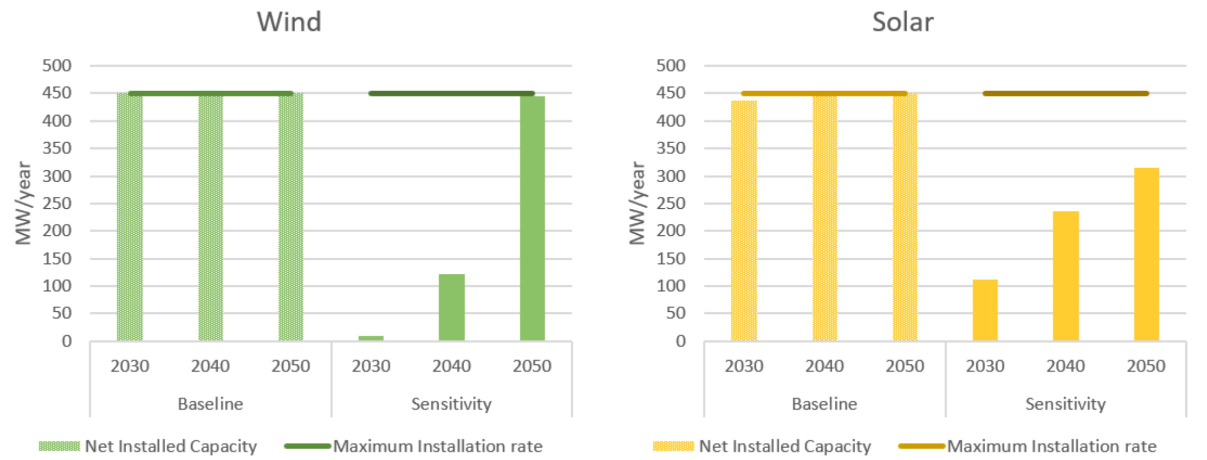


Figure 95: Net and maximum installation rates for wind (on-grid only) and solar capacities – Sensitivity S5

There are about 45% less installed capacities of for both solar and wind in 2050 compared to the baseline. On the contrary, it leads to greater investments in gas power plants, which are less affected by a WACC increase, CAPEX representing only a small share of their total costs. Overall, there is 10% more installed capacities of gas power plant in 2050, reaching 23GW.

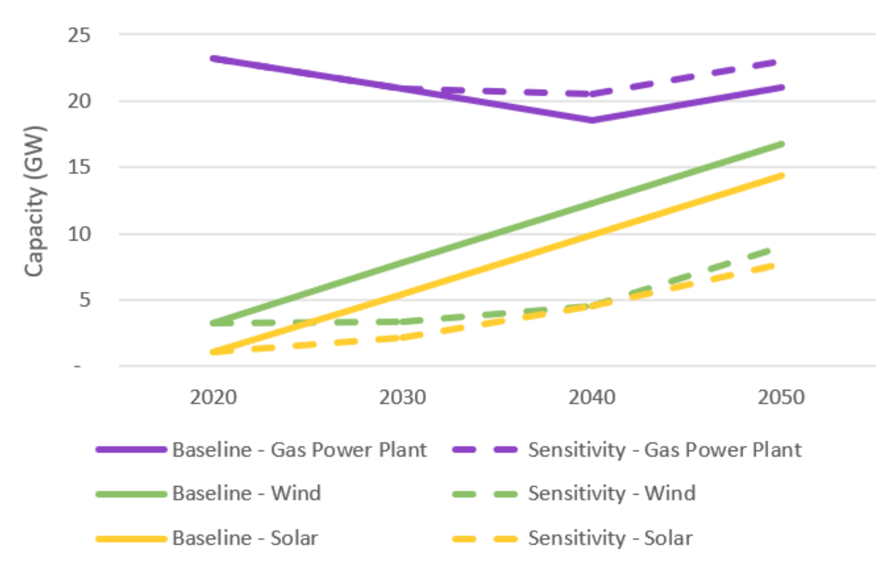


Figure 96: Installed capacities for gas power plants, solar and wind – Sensitivity S5

The electricity production mix is deeply impacted by the change of WACC: gas-based electricity production increases by 72% (about 50TWh) compared to the baseline in 2050 with the RES production decrease. Consequently, the share of low carbon energy is 53% in 2050, compared to the 73% in the baseline.

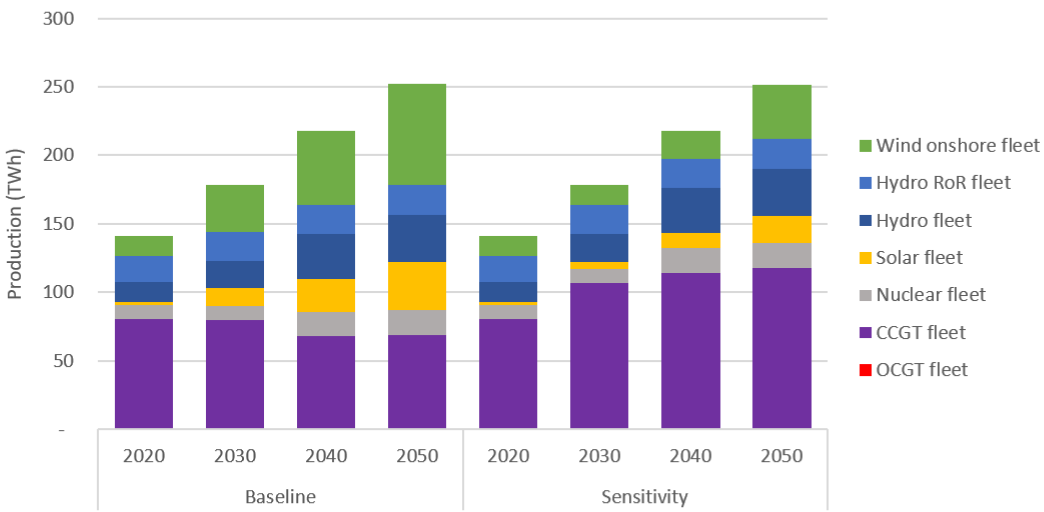


Figure 97: Yearly electricity production – Sensitivity S5

Low carbon energy share (%)	2030	2050
Baseline	55%	73%

Sensitivity	40%	53%

Figure 98: Low carbon energy share comparison – Sensitivity S5

The competitiveness of green hydrogen is also affected by the increase of WACC, but this does not affect the hydrogen mix in Current Commitments which already does not include green hydrogen from on-grid electrolysis (due to low RES potentials and the absence of CO2 tax).

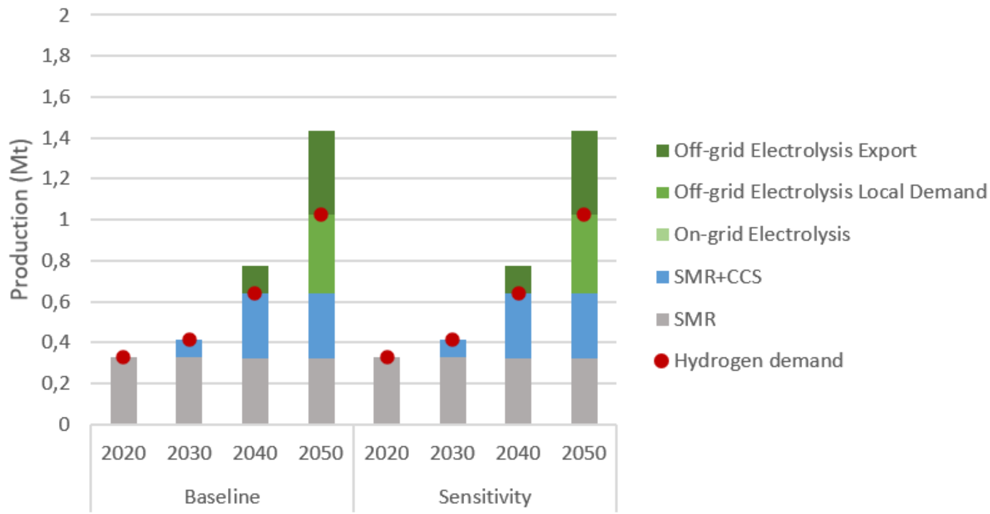


Figure 99: Yearly hydrogen production and demand – Sensitivity S5

Compared to the baseline which sees an 11% decrease in CO_2 emissions between 2020 and 2050, the sensitivity shows a significant 30% increase in CO_2 emissions due to the high carbon intensity of its electricity mix.

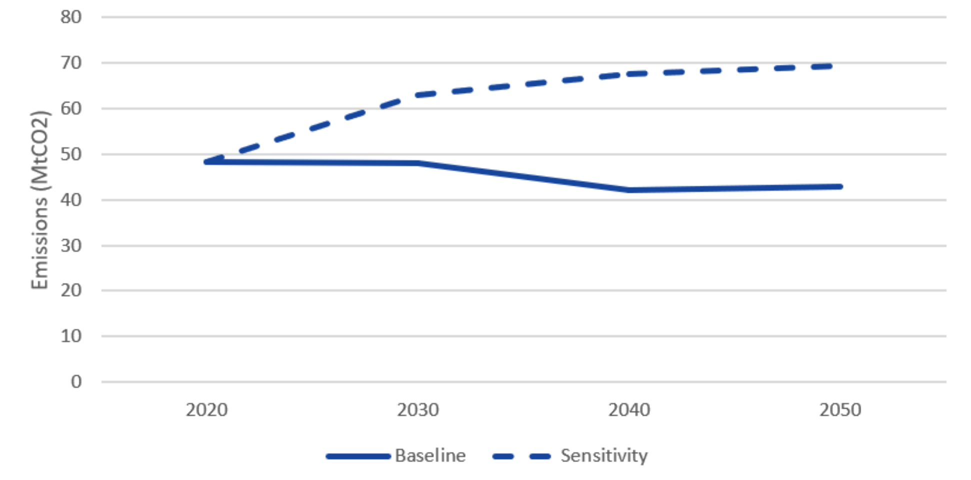


Figure 100: Yearly direct CO_2 emissions for electricity and hydrogen production – Sensitivity S5

With the lower deployment of RES and the increased capacities of gas-based electricity generation, the investments in the inter-regional electricity network are lower in this sensitivity: the additional deployment of the network reaches only 17% in 2050 (in comparison to 2020) compared to +50% in the baseline.

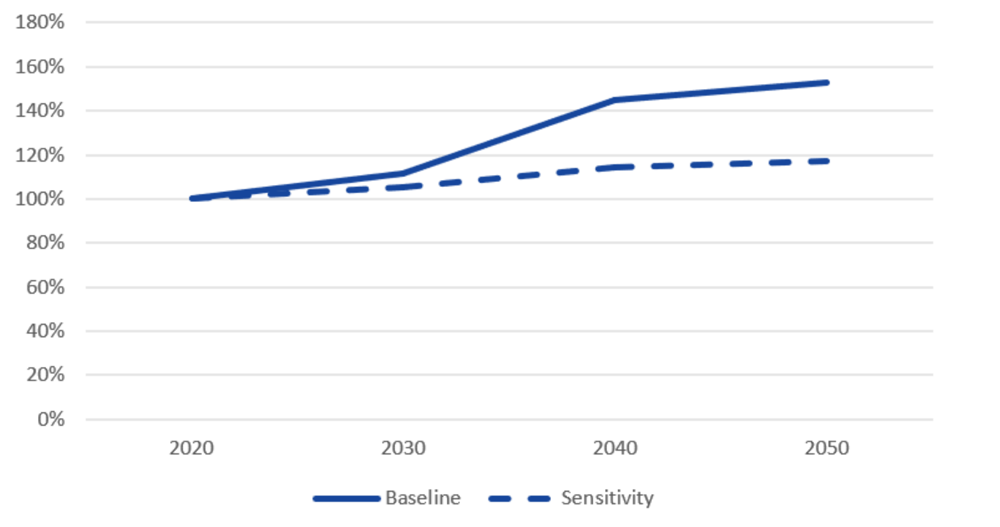


Figure 101: Transmission capacities deployment (electricity) – Sensitivity S5

When it comes to costs, gas supply costs increase by about 29%, as a consequence of gas-fired electricity production increase. Moreover, as investments in renewable are reduced, CAPEX decrease by 13% and O/M costs by 19%. Overall, the total pathway costs (excluding export revenues) and net total costs increase by 11%.

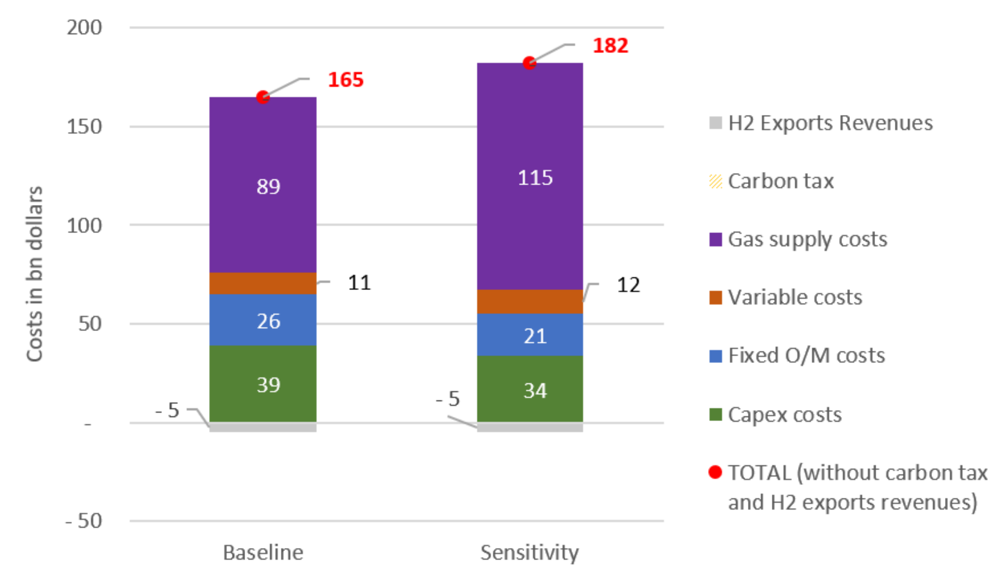


Figure 102: Costs per pathway – Sensitivity S5

KEY FINDINGS

The WACC is a very sensitive financial parameter for investments in CAPEX-intensive projects. If RES and electrolysis projects are exposed to a higher WACC (14% in the sensitivity compared to 7.5% in the baseline), the decarbonisation of the mix could be much slower or even absent.

Indeed, the development of RES installations is slowed down (RES capacities in 2050 are 45% lower in the sensitivity than in the baseline), and gas-fired electricity generation therefore increases by 72% (about 50 TWh more than in the baseline in 2050), leading to a 30% increase in CO2 emissions from electricity and hydrogen production between 2020 and 2050 (instead of the much-needed 10% reduction over the same period in the baseline). Overall, the path is also 11% more expensive than the baseline, even with fewer RES installations, mainly due to the increase in fuel consumption.

5.2.6 Increased Fugitive CO_2 emissions (S6)

Context and objective

There is an increasing awareness of fugitive emissions when considering the CO2 emissions from the gas system. There are many uncertainties in estimating these fugitive emissions, especially when they come from unconventional gas production. In this context, and in contrast to sensitivity S4, it could be interesting to understand how the consideration of higher fugitive emissions affects investment decisions.

Scenario Net Zero Emissions 2050

Quantitative hypothesis

- Considering higher fugitive CO_2 emissions. It corresponds to an increase by 16% of CO_2 emissions for a SMR plant and 80% for SMR+CCS.
- Acceleration of installation rhythm for wind, as stated on the graph below

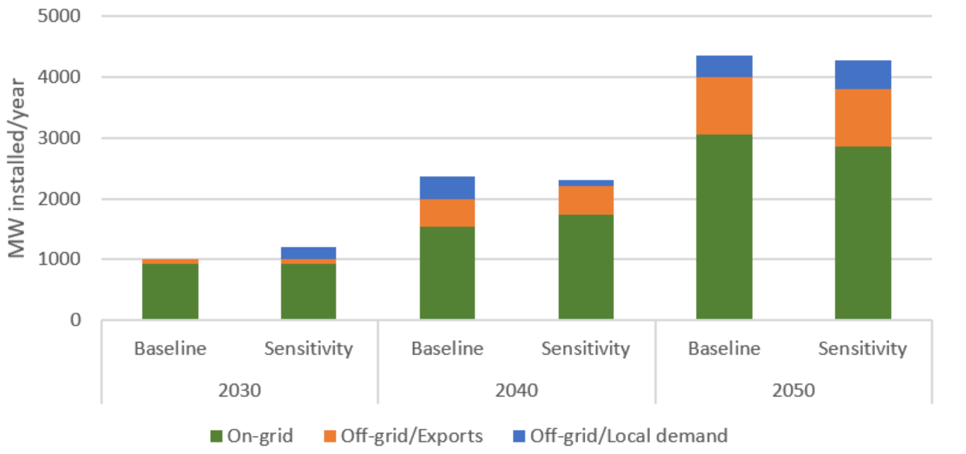


Figure 103: Maximum wind installation rhythms for – Sensitivity S6

The higher emission factors for SMR and SMR+CCS lead to an increase of LCOH and a decrease of competitiveness of these technologies compared to green hydrogen. This leads to an increase of wind and solar deployment: on-grid wind capacity increases at a faster pace, ultimately reaching the same value of 59 GW by 2050, following the maximum installation rate imposed. Moreover, maximum rhythms and optimized investments for solar are unchanged.

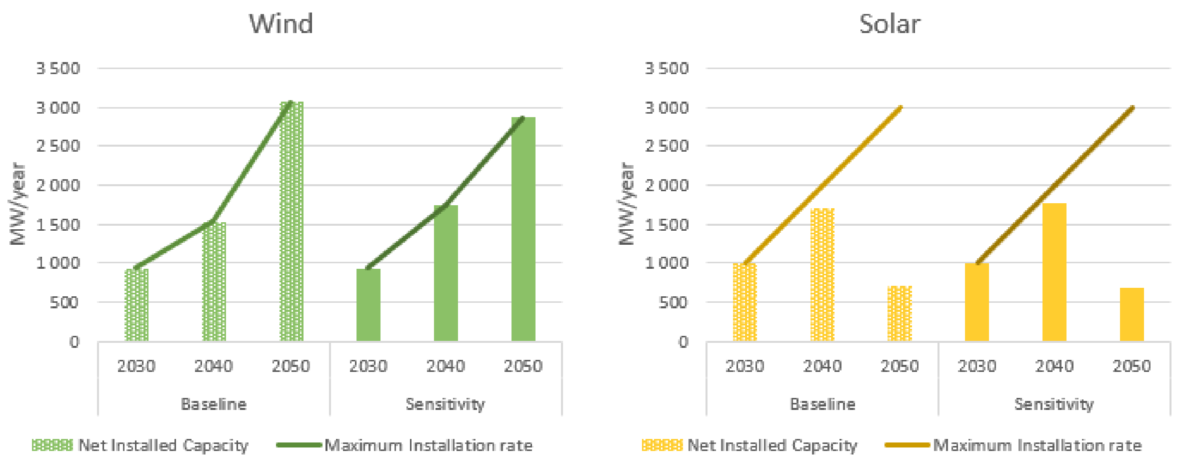


Figure 104: Net and maximum installation rates for wind (on-grid only) and solar capacities – Sensitivity S6

As a consequence, installed capacities remain globally the same between the baseline and the sensitivity. Then, the electricity production mix is also very close to the baseline one, so is the electrical network.

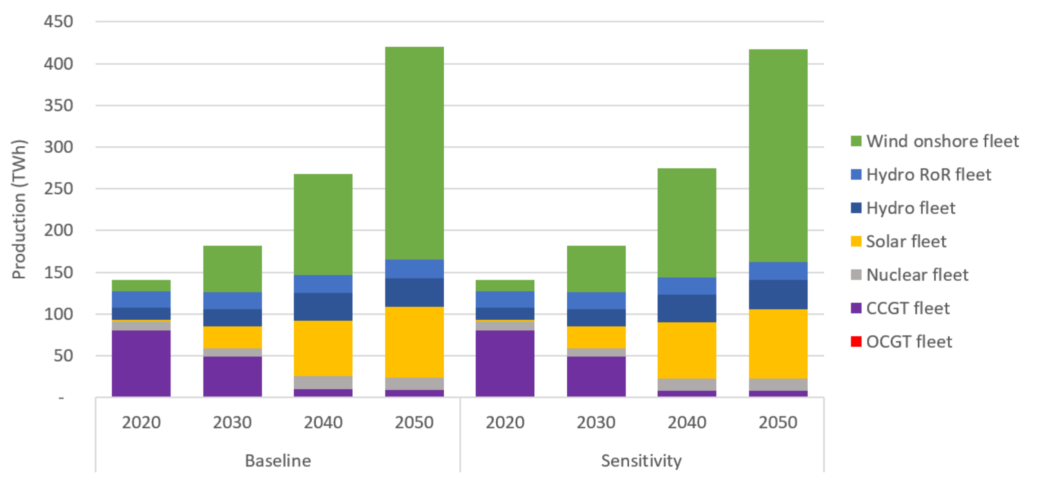


Figure 105: Yearly electricity production – Sensitivity S6

When it comes to the hydrogen production mix, since the LCOH of SMR + CCS is increased by 2.5% (2.4 USD/kgH_2) in this sensitivity, the development of off-grid green hydrogen is assumed to be faster: it starts developing in 2030 (instead of 2040 in the baseline) for local demand. Additionally, higher investments in RES and electrolysis on-grid enable more on-grid green hydrogen production, which increases by 54% in 2040.

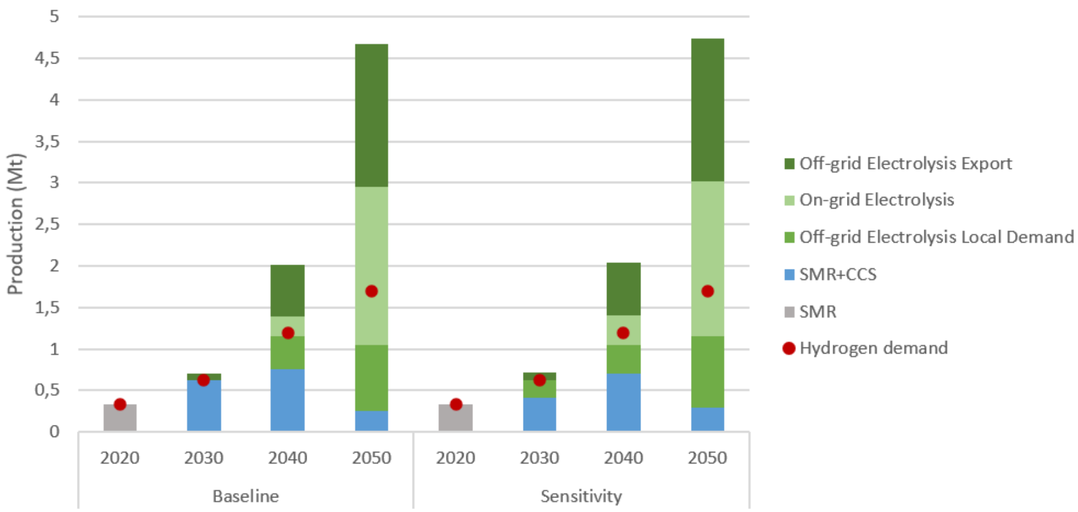


Figure 106: Yearly hydrogen production and demand – Sensitivity S6

Regarding CO_2 emissions, recomputing the emissions of the sensitivity and the baseline with the emission factors of the sensitivity, shows that emissions in the sensitivity are slightly lower. The inclusion of a higher emission factor for fugitive emissions in the investment decision tends to reduce slightly the actual CO_2 emissions of the modelled system.

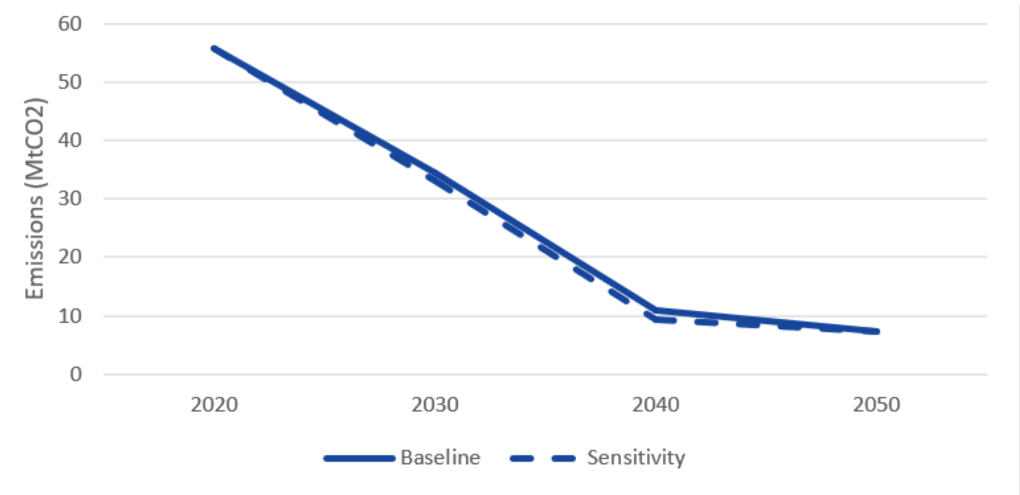


Figure 107: Yearly direct CO_2 emissions for electricity and hydrogen production (same emissions factors) – Sensitivity S6

Finally, while the competition between off-grid RES + electrolysis and SMR+CCS is affected, the resulting total costs (excluding exports revenues) of the sensitivity are very similar to those of the baseline, with a little more investment costs due to earlier investments in renewable capacities (although total capacities are the same in 2050), a little higher for off-grid green hydrogen production, and a little less gas supply costs in 2030. As export revenues are equivalent, net total pathway costs are also almost identical.

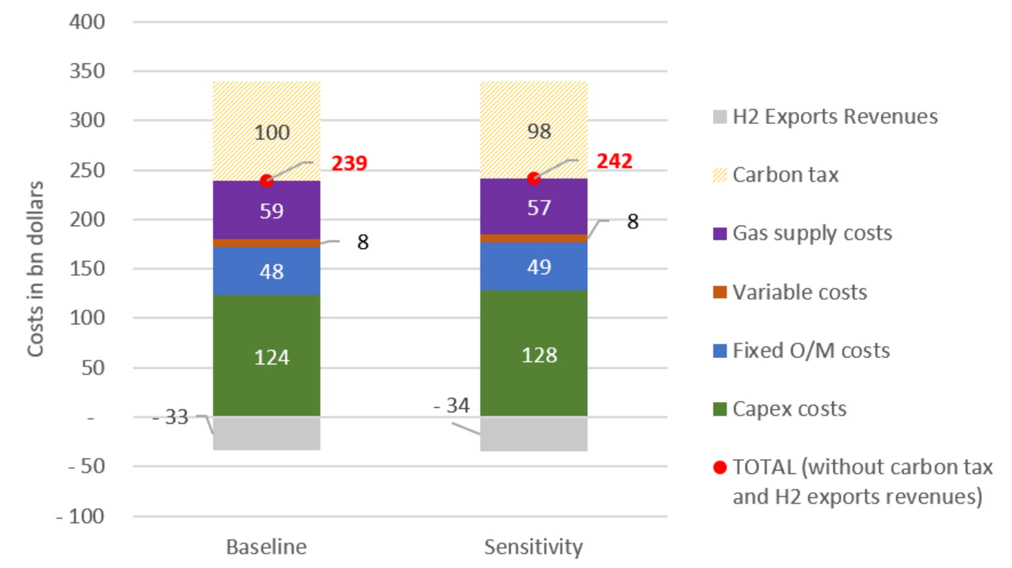


Figure 108: Costs per pathway – Sensitivity S6

KEY FINDINGS

Fugitive emissions can play an important role in the assessment of CO2 emissions, especially when considering the gas system as a whole.

In the optimisations carried out, considering a higher emission factor for fugitive emissions affects the competition between blue hydrogen and electrolysis, and leads to a faster development of off-grid RES and electrolysis especially in 2030, without significantly affecting the overall cost of the system.

Overall, taking into account higher fugitive emissions in the investment planning slightly reduces the CO2 emissions of the resulting system, while the total cost does not change much, making fugitive emissions an issue worth considering.

5.2.7 Decrease of H2 Exports Price (H_2)

Context and objective

Hydrogen export prices depend on global trade and thus on the relative competitiveness of countries exporting hydrogen and prices that importing countries are willing to pay. Viewed from today, prices therefore suffer from a high uncertainty. However, these prices are essential in the investment decisions in electrolyser capacities and additional renewable capacities. It thus seems crucial to analyse the impact of a decrease of hydrogen sold prices on these capacities.

Scenario Net Zero Emissions 2050

Quantitative hypothesis

- Reducing by 20% the exports price to reach about 1.4 USD/kg in 2050

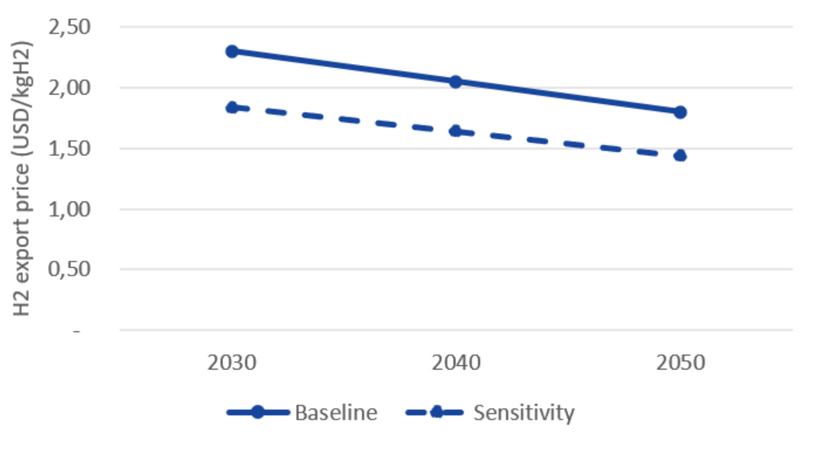


Figure 109: Hydrogen export price evolution – Sensitivity S7

The reduction of hydrogen export prices affects the economic potential of green hydrogen in Argentina (and in the world). The production costs of green hydrogen have indeed to be lower to be able to remain competitive on the global market, which is only possible with the best wind resources in Argentina. Some projects that are built in the baseline scenario can thus become economically irrelevant for exports in the sensitivity.

As a result, the on-grid wind installation rate does not reach the maximum installation rhythms in 2050 and 2040 (while it did in the baseline) and 2050 solar installation rates are also lower.

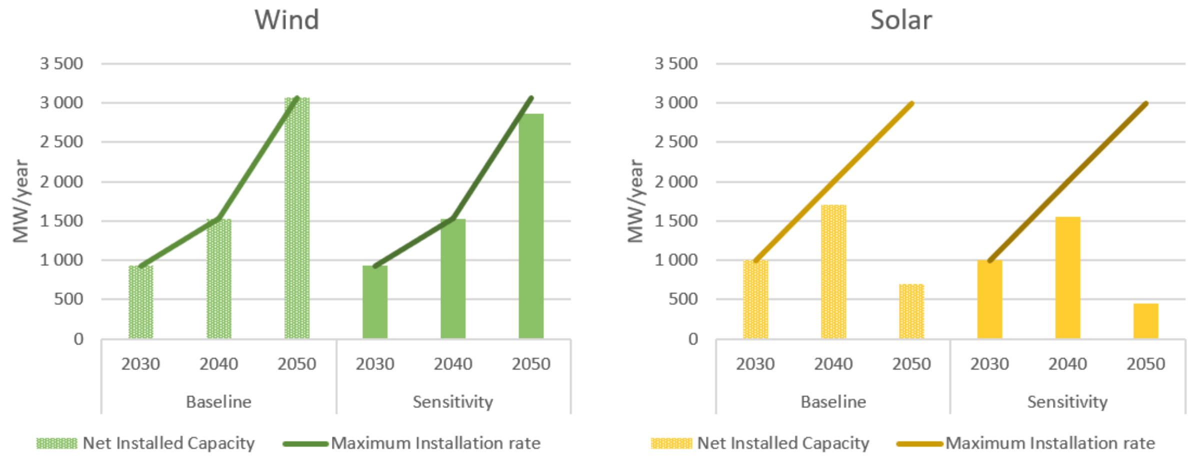


Figure 110: Net and maximum installation rates for wind (on-grid only) and solar capacities – Sensitivity S7

This results in 4% less installed capacity for wind and 12% for solar in 2050 in the sensitivity compared to the baseline. On the other hand, gas-based capacities remain constant.

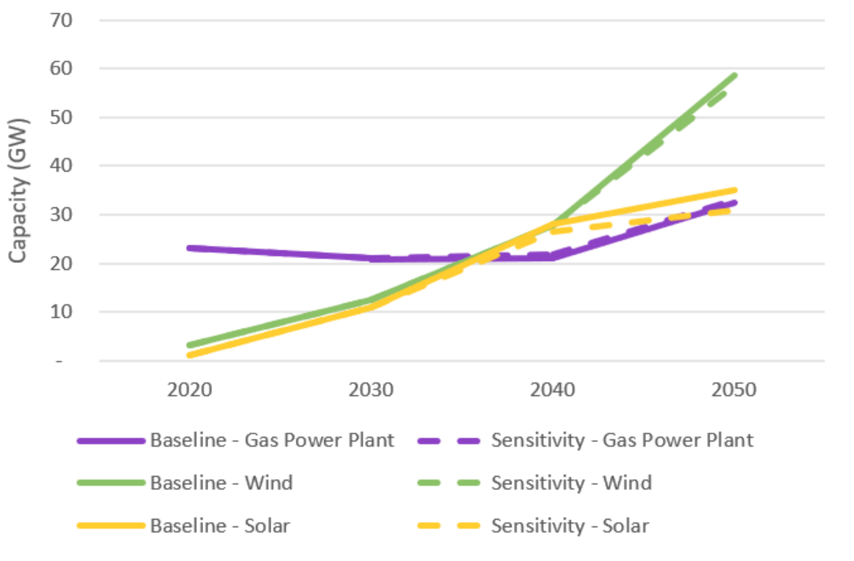


Figure 111: Installed capacities for gas power plants, solar and wind – Sensitivity S7

As a consequence, electricity production of solar and wind decrease, by about 20 TWh in 2050 compared to the baseline. Gas-based electricity production is constant each year between both scenarios and differences of share of low carbon energy is then negligible.

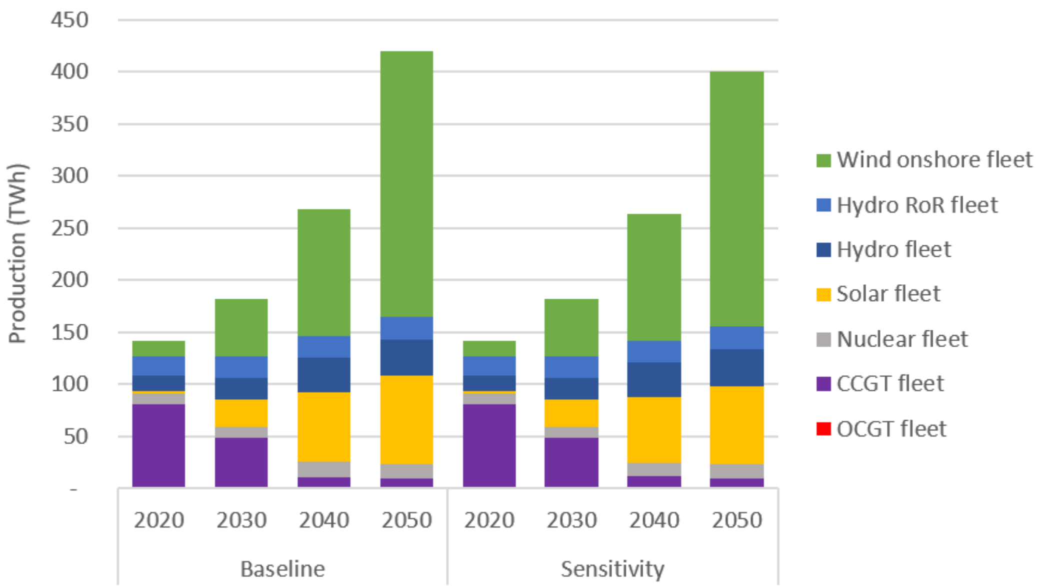


Figure 112: Yearly electricity production – Sensivity S7

Low carbon energy share (%)	2030	2050
Baseline	73%	97.5%
Sensitivity	73%	97.9%

Figure 113: Low carbon energy share comparison – Sensitivity S7

The fact that gas-based electricity production is constant underlines that the 20TWh decrease of renewable was only dedicated to electrolysis.

On-grid hydrogen production is indeed modified by this amount. In fact, on-grid hydrogen exports decrease by 55% in 2040 and 40% in 2050, and the expected revenues from its sale are lower.

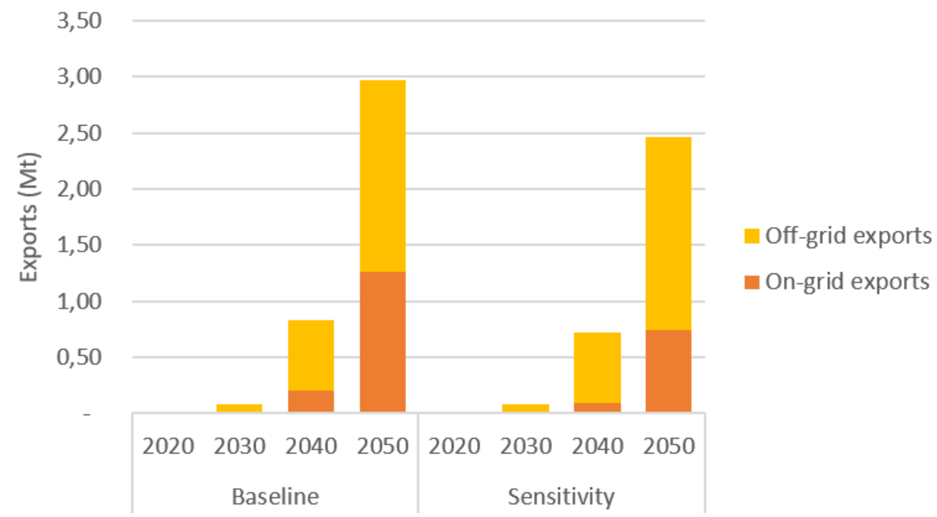


Figure 114: Yearly hydrogen exports – Sensitivity S7

Additionally, the 2050 SMR+CCS production is replaced (in a very moderate volume) by on-grid electrolysers redirected from export production. In the meantime, off-grid electrolysis production remains identical as it is a fixed hypothesis.

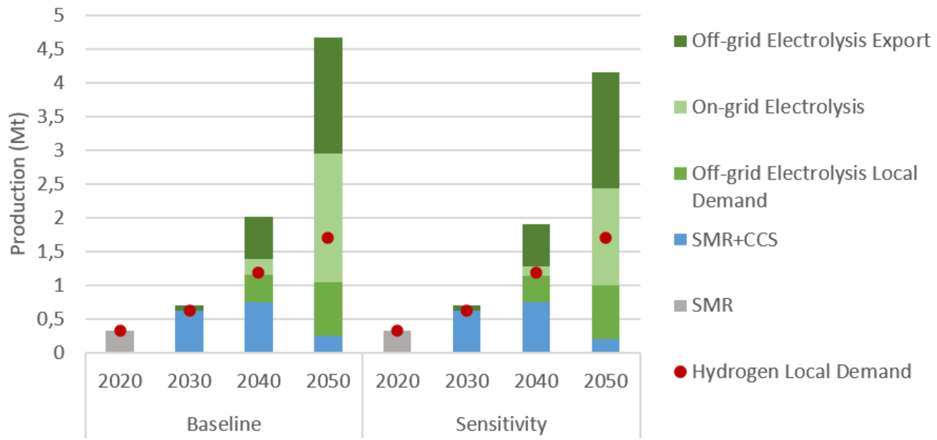


Figure 115: Hydrogen production and demand

Network transmission deployment remains very similar (since projects that are not built in this sensitivity were dedicated to exports, without need for network reinforcements) and since the production of electricity from fossil fuels has remained stable between the sensitivity and baseline scenarios, the levels of CO_2 emissions have also remained constant.

Note however that CO_2 emissions that could be avoided with green hydrogen exports are not taken into account and could differentiate both scenarios in terms of emissions.

Finally, as green hydrogen export volumes are lower in the sensitivity, their associated revenues decrease: they fall down by 32%. However, reduction of wind and solar installed capacities leads to a little reduction of CAPEX.

Overall, the total pathway cost (excluding export revenues) decreases by 2%, but since export revenues decrease by 30%, net total costs and the net total costs increase by 2.5%.

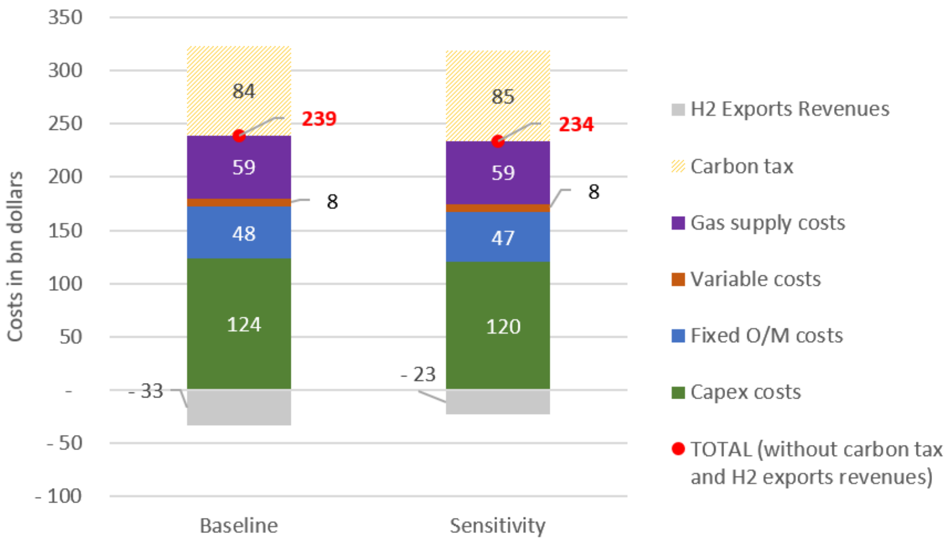


Figure 116: Costs per pathway

KEY FINDINGS

Decreasing H2 exports price makes the export of H2 and PtX from Argentina less competitive. This leads to a reduction in RES installations and green H2 production for export. This also reduces export revenues and increases the overall net cost of the system for Argentina (who could have more added value if export prices were higher).

Although this has not been calculated, this could also lead to an overall increase in global CO2 emissions, as these green hydrogen exports could be used to replace other sources of hydrogen, possibly produced by SMRs.

5.2.8 Limitation of Electricity Network Development (S8)

Context and objective

When network development can be done at a relatively cheap cost, the development of renewable capacities tends to be focused first in areas with the better load factors and LCOE. This can be seen for instance in the baseline scenarios were wind capacities in Patagonia (region which benefits from the best load factors in Argentina) are the most developed. Indeed, the development of the network can in this case enable to effectively reach these LCOE with only minimal curtailment of renewable generation.

In this sensitivity we consider a case where the network development is limited, and we analyse the effect it has on renewable deployment, on electricity and hydrogen mixes.

As a reminder, in the baseline scenarios, no limitations have been put on the deployment of the electricity transmission network, and the inter-regional network is thus an investment option, at a moderate cost.

Scenario Advanced Transition

Quantitative hypothesis

- Limiting to a 50% increase of inter-regional transmission capacities. Equivalent to consider that each corridor between region can be increased by 50% max but no new corridor can be created.

In this sensitivity, the limitation set on network development naturally leads to a lower development of inter-regional interconnections. The inter-regional network development even falls short of the 50% target as the reinforcement of certain interconnections corridors are not economically relevant. In particular axis between Gran Buenos Aires and Buenos Aires are the most affected by this change.

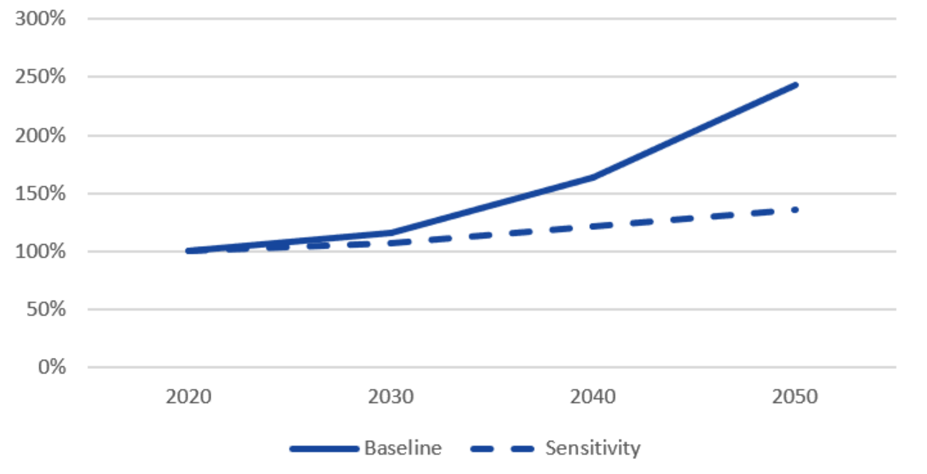


Figure 117: Transmission capacities deployment (electricity) – Sensitivity S8

The restriction to the extension of the grid limits the installation of RES. Solar installation rates are lower in 2050 when wind ones are lower in 2030 and 2040. This highlights the importance of having additional transmission capacities to transport electricity from regions with the highest wind profitability (with the highest capacity factors) to the areas with the highest electricity consumption, which may not necessarily be the same locations. On the contrary, regions with the highest solar capacity factor are near consumption areas and do not require large network deployment to be exploited.

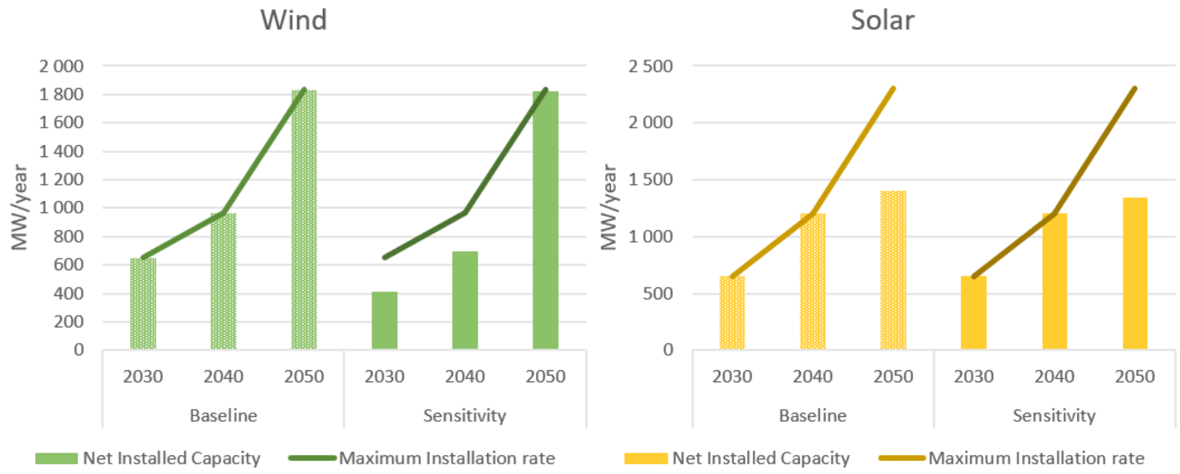


Figure 118: Net and maximum installation rates for wind (on-grid only) and solar capacities – Sensitivity S8

Therefore, there is 14% less wind installed capacities in 2050 and 2% less solar capacities in 2050 in the sensitivity compared to the baseline. On the contrary, there is 10% more gas fired power plant installed to compensate this limitation of sharing RES production between regions.

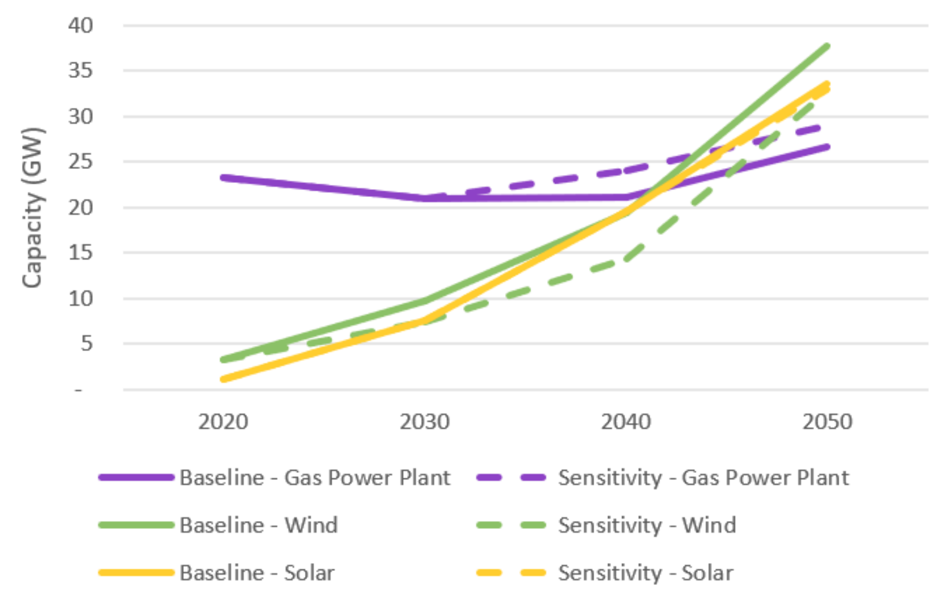


Figure 119: Installed capacities for gas power plants, solar and wind – Sensitivity S8

As a result of these changes in the installed capacities, the electricity production from renewables goes down and gas-based electricity generation increases (by 71% in 2050). The share of low carbon energy is only 84% in 2050 (compared to 96% in the baseline).

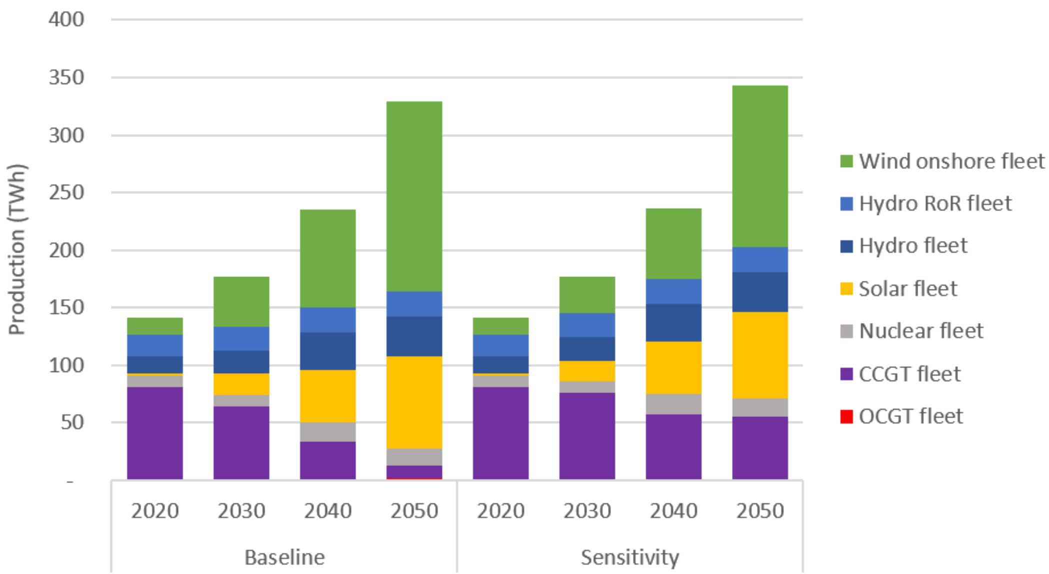


Figure 120: Yearly electricity production – Sensitivity S8

Low carbon energy share (%)	2030	2050

Baseline	64%	96%
Sensitivity	57%	84%

Figure 121: Low carbon energy share comparison – Sensitivity S8

The total electricity production is however higher in the sensitivity than in the baseline. This is due to an additional demand for electrolysis. Indeed, the reduction of network development benefits to hydrogen generation: as there is less competition on RES resources that cannot be shared between regions, they can be used for electrolysis. In fact, production of on-grid green hydrogen even becomes competitive in 2040 and its production is 64% higher than in the baseline in 2050, reaching 0.9 MtH_2. The share of SMR in hydrogen generation for local needs is also lower.

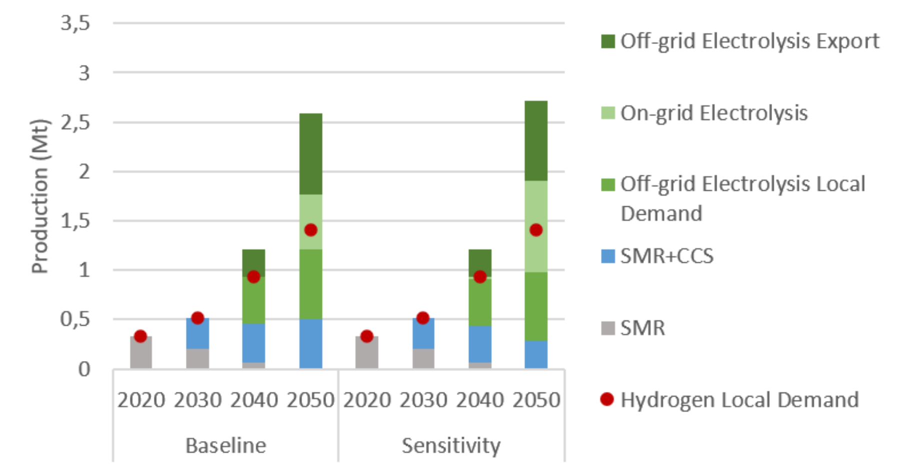


Figure 122: Yearly hydrogen production and demand – Sensitivity S8

Similarly, on-grid green hydrogen exports increase by 11% in 2050, while off-grid exports, which are independent from network development, remain constant.

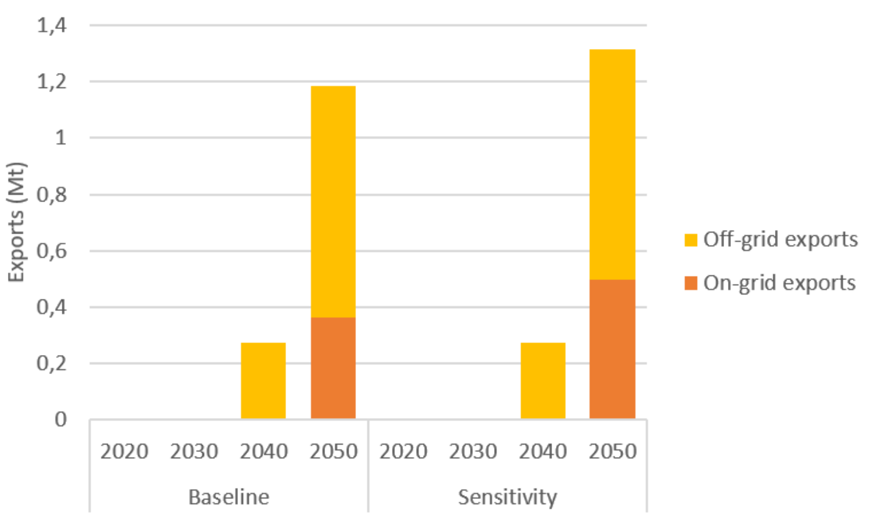


Figure 123: Yearly Off-grid and On-grid hydrogen exports – Sensitivity S8

Moreover, as a higher part of the electrical production is gas-based in the sensitivity, CO_2 emissions increase compared to the baseline. They decrease only by 35% between 2020 and 2050, compared to 82% for the baseline. Note that this is without accounting for the potential additional benefits in terms of CO_2 from exporting more hydrogen (which could help replace grey hydrogen in importer countries for instance). Also note that these potential avoided emissions will in any case be lower than what if the electricity produced by RES was used directly for electricity if the network was developed : direct use of electricity is more economic and better for emissions than indirect use.

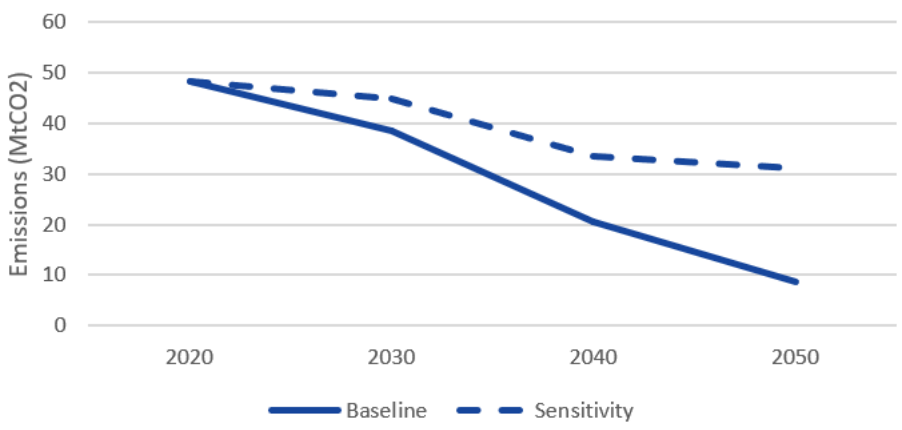


Figure 124: Direct CO_2 emissions for electricity and hydrogen production – Sensitivity S8

Finally, the pathway total costs are higher in this sensitivity than in the baseline.

A key reason for that is that gas supply costs increase by about 21%, as a consequence of gas-fired electricity production since RES is less used for final electricity consumption. This is even after accounting for a decrease of the production of hydrogen via SMR.

In parallel, investment in renewable capacity is reduced, so CAPEX decreases by 12% and O/M costs by 9%. Overall, the total pathway cost (excluding export revenues) and the net pathway costs remain about equal.

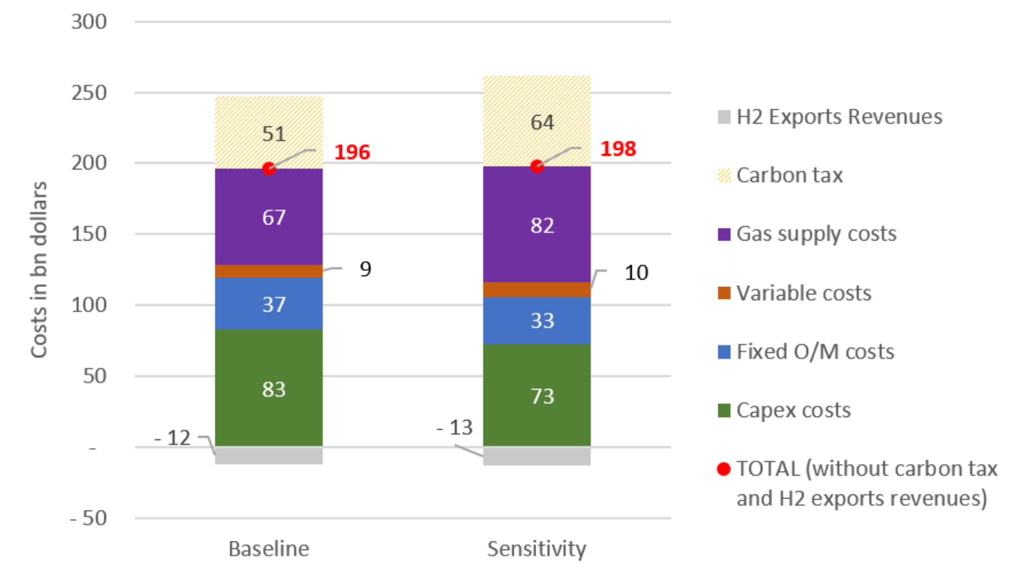


Figure 125: Costs per pathway – Sensitivity S8

KEY FINDINGS

Limiting the electricity network development to a 50% increase does not allow the full use of RES capacities to decarbonize the electricity mix, which increases gas-based electricity production by a factor of 5 in 2050 compared to the baseline. However, this creates an opportunity for on-grid green hydrogen production which is more competitive and increases by 11% in this sensitivity.

Overall, this leads to an increase of CO2 emissions which would be reduced by only 35% between 2020 and 2050 in the sensitivity instead of 82% in the baseline (not taking into account the CO2 avoided by the increase of hydrogen exports) but does not affect the total pathway costs, which are similar in both cases.

Overall, it is worth noting that RES are better used for direct decarbonisation of the electricity mix than for green hydrogen, although green hydrogen production may still be an opportunity for RES projects in the absence of network.

5.2.9 Increased H_2 Exports Price (S9)

Context and objective

As mentioned in the sensitivity S7, viewed from today, future hydrogen export prices are very uncertain. In fact, the pricing of these exports depends largely on the competition between hydrogen exporting countries and the price that importing countries are willing to pay. This sensitivity has shown that reducing these prices had an impact on vRES installation dedicated to exports. Therefore, on the contrary, it seems interesting to analyze if an increase in vRES installation can lead to a further deployment of renewables and a higher volume of hydrogen exported.

Scenario Net Zero Emissions 2050

Quantitative hypothesis

- Increasing hydrogen exports prices to reach about 2 USD/kg in 2050

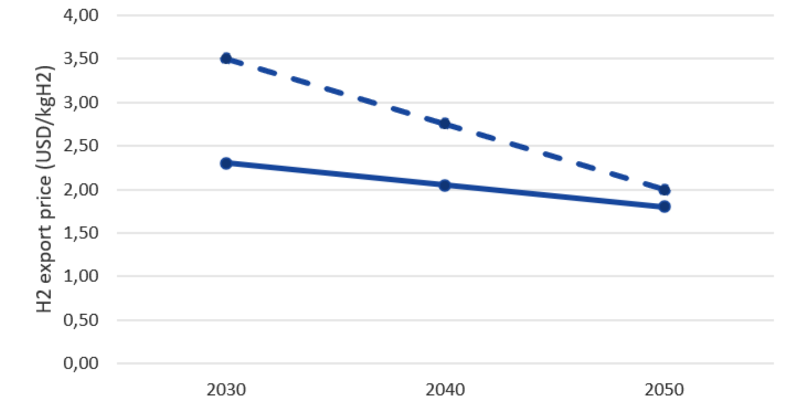


Figure 126: Hydrogen export price evolution – Sensitivity S9

- Increase of wind on-grid (+30%) and off-grid for exports (+50%) installation rhythms, as stated on the graph below

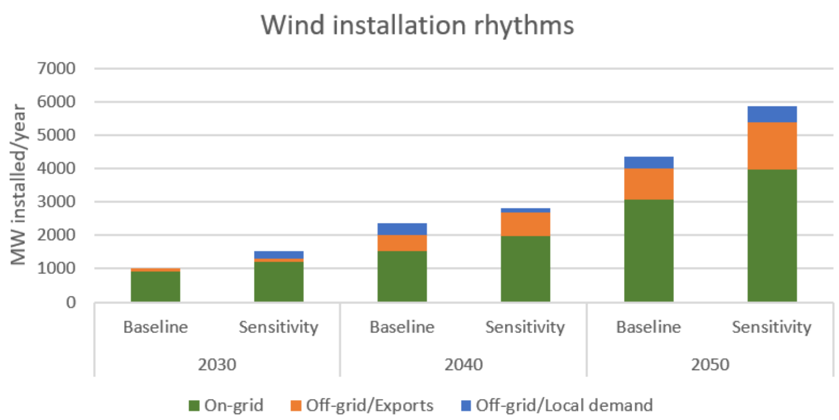


Figure 127: Maximum wind installation rhythms - Sensitivity 9

First, the rise of maximum wind on-grid installation rates, added to the rise of H_2 export prices, leads to an increase of wind on-grid installation by the economic optimization: 30% more wind on-grid capacities are installed in 2050.

Even if solar maximum installation rates are identical for the baseline and the sensitivity, solar installation rhythms increase in the sensitivity: there is 7% more solar installed capacity in 2050 in the sensitivity. This is linked with the additional capacities of on-grid electrolysis, they able to absorb a higher amount of electricity during the solar peak.

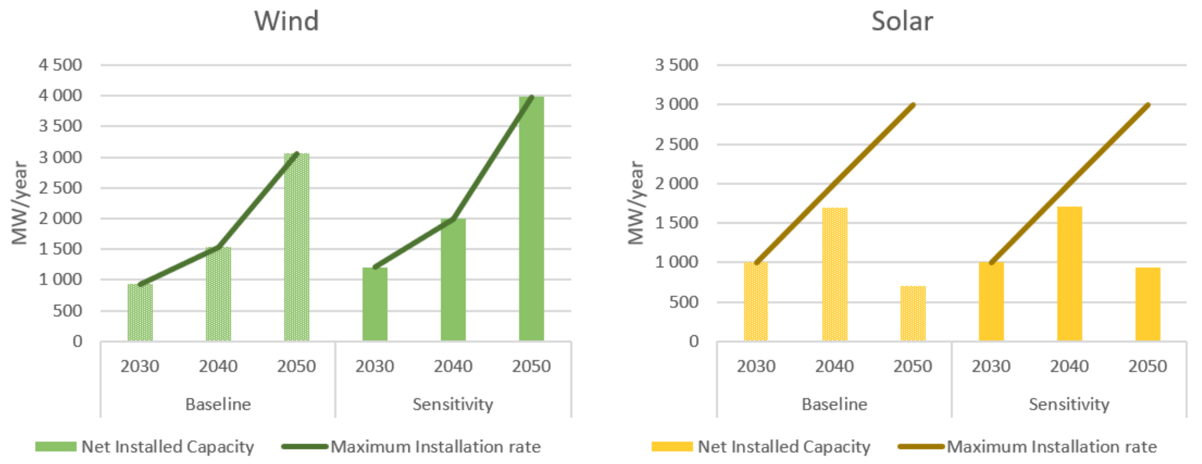


Figure 128: Net and maximum installation rates for wind (on-grid only) and solar capacities – Sensitivity S9

Regarding gas-fired capacities, they are slightly reduced: the total gas-fired capacities only decrease by 5% in 2050 in the sensitivity.

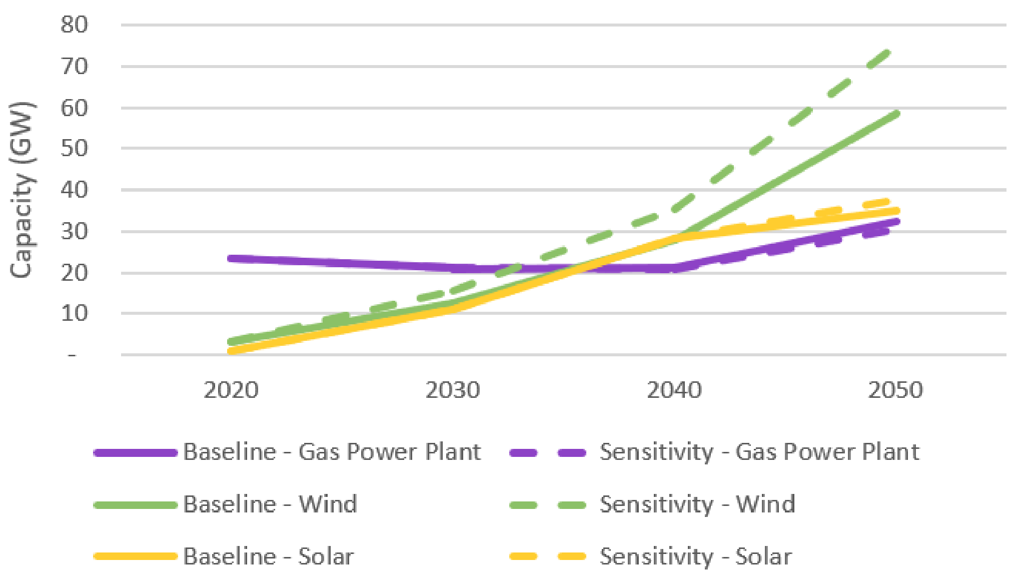


Figure 129: Installed capacities for gas power plants, solar and wind – Sensitivity S9

On-grid wind production increases by 72 TWh in 2050 compared to the baseline (28% increase) when solar production increases by 6 TWh (7% increase). Overall, variable renewable generation in 2050 increases by 20% compared to the baseline.

Gas-based electricity generation decreases by only 2 TWh in 2050 between the baseline and the sensitivity and other means of production are not significantly reduce, this shows that the additional renewable production is mostly dedicated for hydrogen production for exports.

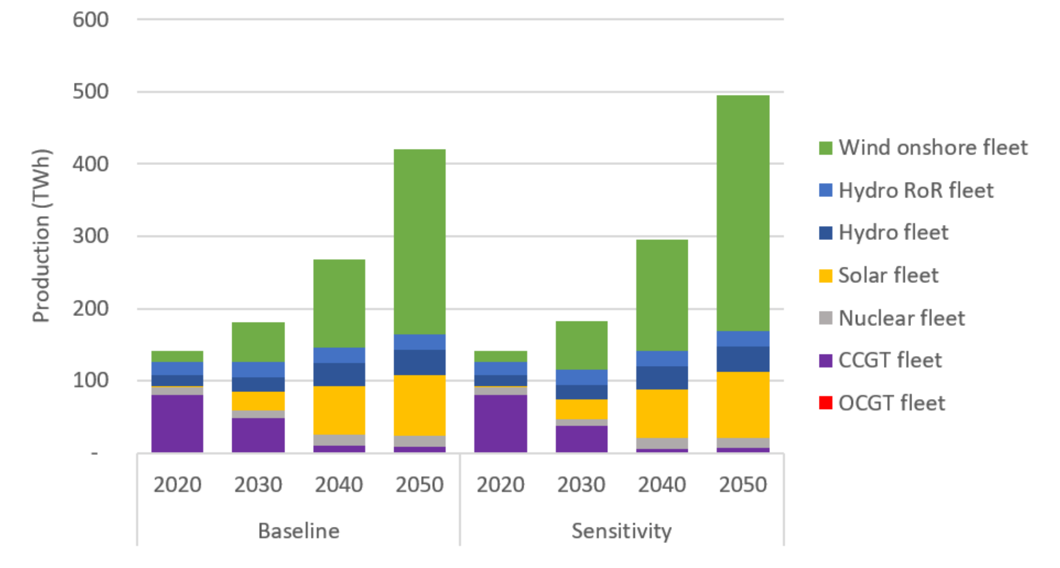


Figure 130: Yearly electricity production – Sensitivity S9

Low carbon energy share (%)	2030	2050
Baseline	73%	98%
Sensitivity	73%	99%

Figure 131 : Low carbon energy share comparison – Sensitivity S9

As it already reaches almost the maximum in the baseline (98%), the share of low carbon energy remains constant.

Regarding the hydrogen system, blue hydrogen production is partly replaced by on-grid produced green hydrogen and decreases then by 12% in 2040 and 15% in 2050.

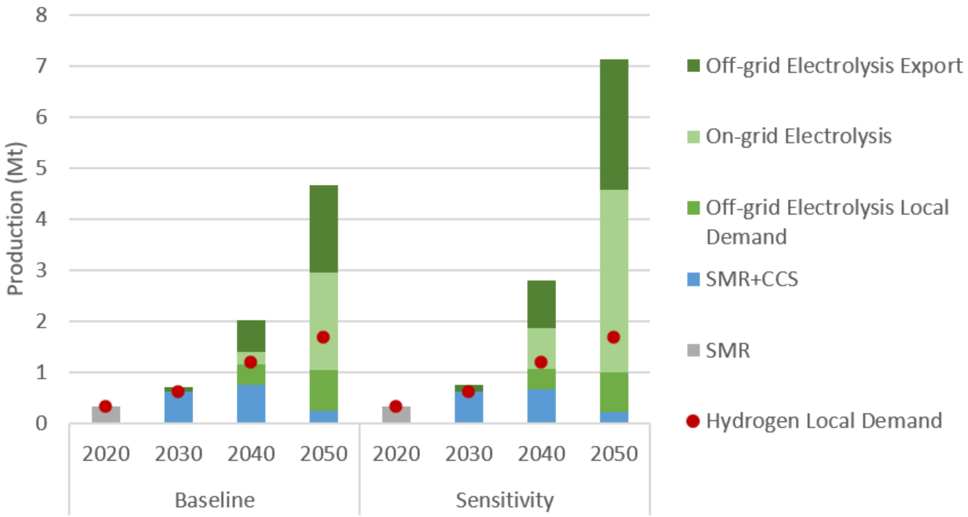


Figure 132: Hydrogen production and demand – Sensitivity S9

Additionally, on-grid and off-grid hydrogen exports increase in the sensitivity. Hydrogen exports increase by 95% in 2040 and 83% in 2050: they reach 5.45 MtH_2 in 2050.

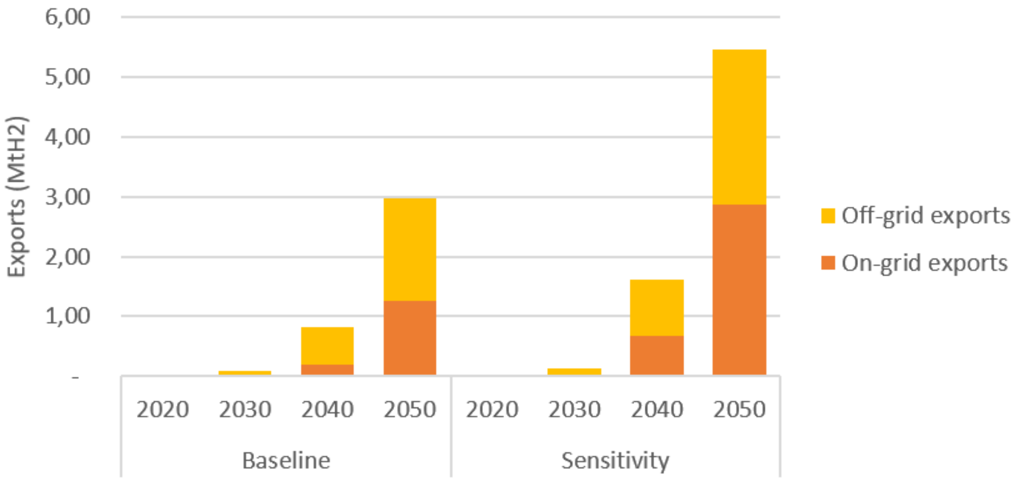


Figure 133: Hydrogen exports – Sensitivity S9

Network transmission deployment remains identical between the baseline and the sensitivity. This means that additional deployment of renewables mainly takes place without the need for additional interconnections, i.e., directly in regions where hydrogen can be produced and exported.

Regarding CO_2 emissions, the decarbonation of the mix is happening earlier in the sensitivity to finally reach a similar level of emission. In fact, CO_2 emissions decrease by 90% between 2020 and 2050, compared to 88% for the baseline.

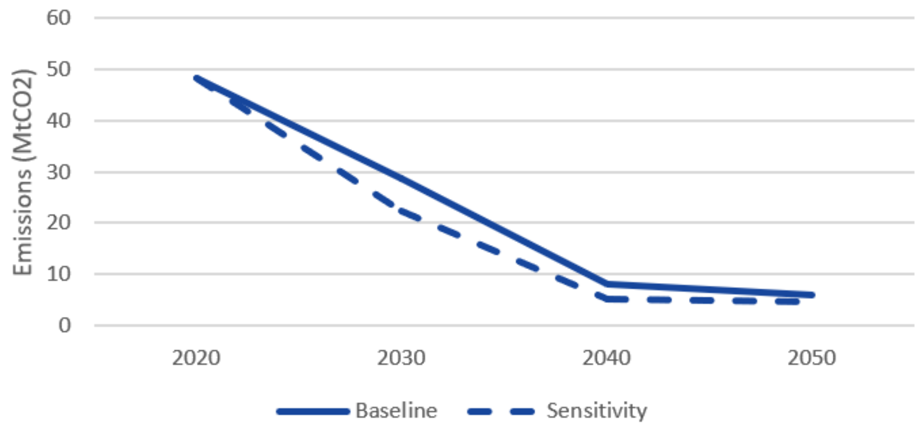


Figure 134: Yearly direct CO_2 emissions for electricity and hydrogen production – Sensitivity S9

Finally, regarding costs, investment costs increase by 22% and operation costs by 14%, as a direct consequence of the additional installation of renewables and electrolysers. However, as export volumes increase and they are more expensive, export revenues are also greater: hydrogen exports revenues increase by 120% over the entire pathway. Overall, total pathway costs (excluding export revenues) are 12% higher. However, with the increase in export revenues, net total pathway costs are 6% lower overall in this sensitivity.

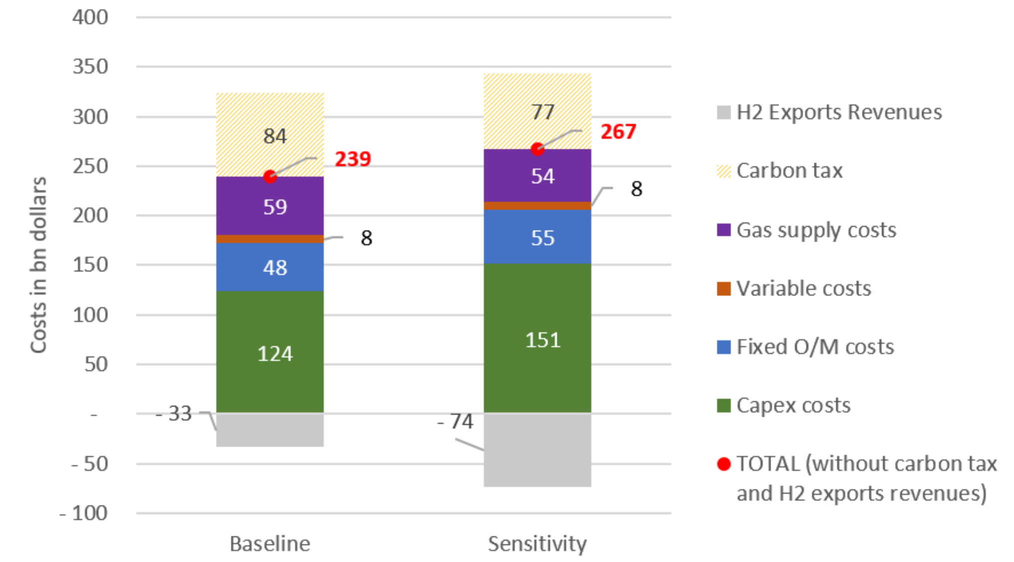


Figure 135: Costs per pathway – Sensitivity S9

KEY FINDINGS

An increase in hydrogen export prices and a more developed wind industry would allow to reach higher RES capacities and higher hydrogen exports (+83%), and even higher revenues from these exports (+120%).

The additional costs associated with the investments in VRES and electrolysers are more than offset by hydrogen sales. In fact, the total net cost of the pathway in the sensitivity is 6% lower than in the baseline scenario.

Overall, if the conditions are right, i.e. if a VRES industry and electrolysers are developed, and if export prices are high enough, Argentina can position itself as a major exporter of green hydrogen by exporting up to 5.45 Mt of hydrogen per year in 2050.

5.3 PtX: Potential exports of ammonia (NH_3)

The previous sections (5.1 and 5.2) have presented the volume of exports of Hydrogen resulting from a set of different scenarios and assumptions. For Argentina, it could be more viable to prioritise exports of PtX products for example green NH_3, methanol, e-fuels, etc. However, the model does not specifically represent these processes nor the electricity demand corresponding to them.

This chapter briefly presents potential quantities of NH_3 exports, assuming that all the quantities of hydrogen which are not dedicated to local demand will be used as feedstock for NH_3 production. . NH_3 is currently considered an easier PtX technology to develop than other options because of:

- established production infrastructure and local expertise: Argentina already produces part of its own NH_3 consumption and the process of synthesizing NH_3 is well-established,
- existing market and applications, as a fertilizer and chemical feedstock,
- versatility and energy carrier potential: NH_3 can be used as an alternative fuel for the maritime sector, and can be readily converted back into H_2 for various applications. It is also the carrier with the lowest costs of storage and transport,
- there is no need of a carbon source.

Note that there are also other carriers that could be developed in Argentina such as e-methanol and green steel.

We present hereafter the volumes of exports of NH_3[47] per scenario and time horizon

NH_3 exports ($Mt\ NH_3$) - derived from H_2 exports				
Scenario	**2030**	**2040**	**2050**	**Sum**
Current Commitments	0.0	0.8	2.3	3.1
Advanced Transition	0.0	1.5	6.6	8.2
Net Zero Emission 2050	0.5	4.6	16.7	21.8
S1	0.0	0.8	2.3	3.1
S2	0.5	4.7	16.1	21.3
S3	1.5	8.4	28.1	38.1
S4	0.0	1.5	6.6	8.1
S5	0.0	0.8	2.3	3.1
S6	0.5	4.8	17.1	22.3
S7	0.5	4.0	13.8	18.3
S8	0.0	1.5	7.4	8.9

Figure 136: NH_3 exports - derived from H_2 exports, Mt NH_3

The sensitivities 1 and 5 are based on the pathway "Current Commitments" and as such, have similar results in terms of NH_3 exports.

The sensitivities 4 and 8 are based on the pathway "Advanced Transition" and as such, have similar results in terms of NH_3 exports.

The rest of the sensitivities correspond to the pathway "Net Zero 2050" and are characterized by higher NH_3 exports. In particular, the Sensitivity 3 benefits from more competitive LCOH and LCOA which allow larger volumes of exports.

[47] The conversion factor considered is 178 kg of hydrogen to produce 1 ton of NH_3 (mass balance): https://dechema.de/dechema_media/Downloads/Positionspapiere/Technology_study_Low_carbon_energy_and_feedstock_for_the_European_chemical_industry.pdf

6 Main conclusions and recommendations

This study aims at developing a range of detailed energy transition pathways/scenarios for Argentina towards 2050, to inform how and which PtX products can contribute to the decarbonisation of the country´s power, heat, transport and industrial sectors, as well as the potential for hydrogen exports, while testing different decarbonisation ambition levels, technology assumptions, infrastructure development levels, etc.

The study relies on the optimization and analysis of three different pathways or scenarios for Argentina. The model optimises the investments and operation costs of the electricity and hydrogen systems while satisfying a target energy demand, and allowing for the potential export of hydrogen.

The three pathways are representative of different levels of energy transition and decarbonisation, being the scenario Net Zero 2050 (NZE 2050) the most ambitious one. The analysis is completed by nine sensitivities on specific parameters, to identify the robustness of the results. These sensitivity analyses are especially relevant as there are lots of uncertainties on the future evolution of techno-economic parameters of the different solutions.

This section presents the key findings, conclusions and recommendations drawn from the analysis.

6.1 Main conclusions

6.1.1 Energy transition

- **Argentina is committed to the energy transition** and has taken several steps to promote the use of renewable energy sources and reduce its greenhouse gas emissions.
- The main objective of the proposed scenarios is to reduce the carbon footprint:
    - The optimal way to achieve this is through:
        - Energy efficiency and behavioural changes in energy consumption, to increase energy savings;
        - Electrification of uses (performance improvement), with a greener electricity generation mix.
    - **H_2 and its derivatives participate in national CO_2 emissions reduction**, however this reduction is not as significant (less than 6% in 2050 in the NZE pathway)**,** as the one of other measures such as energy efficiency and behavioural changes, electrification of uses, and development of a greener electricity generation mix, which have a bigger role to play in the energy transition.

    - Currently, CO_2 emissions from grey H_2 represent around 1% of total national emissions.
    - New application fields such as PtX products for maritime and aviation sectors are expected to develop from 2040 onwards, the rest of the H_2 demand being feedstock for the industrial sector.
    - In the NZE 2050 pathway, the maximum potential CO_2e emissions savings from converting H_2 demand from grey H_2 to green H_2 would be 2% of national CO_2e emissions in 2030, 4% in 2040 and 5% in 2050.
  - **Renewables are best used for electricity decarbonisation in a first step and on-grid electrolysis comes in a second step of the decarbonisation of the system**.
  - Additionally, Argentina is well positioned to export PtX products to importing regions such as European Union, Japan and South Korea, which could also contribute to the global decarbonisation.

- **Favourable economic and financing conditions are needed** to implement the main measures for the Energy Transition: energy efficiency, renewables, behavioural changes, blue and green H_2, development of the electricity grid.
  - Sensitivity 5 (increased WACC) analyses the impact on power production, hydrogen production and network development, of a pessimistic evolution of the WACC[48]. With a WACC of 14%, RES capacities in 2050 are 45% lower than in the baseline, and gas-based electricity production will therefore increase by 72%, leading to an increase in CO_2 emissions by 30% for electricity and hydrogen production between 2020 and 2050. Overall the pathway is also 11% more expensive than the baseline, even with less RES installations mainly due to the increase of fuel consumption.

- In most of the pathways and sensitivities tested, **the development of wind and solar production is expected to be significant** and the conditions of competitiveness of renewables (investments in generation, development of electric transport and flexibility) are met. Argentina benefits of high load factors for solar and wind production. Some of the necessary conditions to support this development in the future are a favourable discount rate, relatively low capex for these technologies and a gas price which reflect future costs (or

[48] The WACC takes into account the cost of both debt and equity capital. It can be calculated based on the Capital Asset Pricing Model (CAPM) method, which takes into account several factors including a risk-free rate, a business-specific risk rate, and a country/region-specific risk rate. There are different views on the current value of the WACC in the energy sector in Argentina. In the long-term, one could also have evaluated the impact of a lower WACC than the one assumed in the pathways (7.5%).

a CO_2 price applied to its cost). These conditions are not currently met in Argentina. Favouring part of them would accelerate the deployment of renewables, especially in the mid-term.

- Sensitivities 1 (decrease gas price) and 5 (increased WACC) are representative of unfavourable conditions for the development of renewables. In Sensitivity 1, installed capacities in solar and wind capacities are respectively 10.2 GW and 10.4 GW lower compared to the baseline. In Sensitivity 5, RES capacities in 2050 are 45% lower than in the baseline.

- The development of the wind industry is a key point for a quick and significant decarbonisation of the energy system. With the lower LCOE of RES compared to carbon-intensive alternatives, increasing the potential development of RES is key, and the technical potential in Argentina is not constraining due to the available surface for RES development.
- As seen in all the pathways and sensitivity analysis (S8), **the expansion of the electricity grid is a necessity to optimize the use of large renewable quantities** and benefit from regional characteristics (strong wind in the South, high solar irradiation in the North). Significant transmission network development is necessary for Argentina to reach high-RES shares in the electricity mix. In average, the network should increase in capacity by a factor 2 or 2.5 in the most ambitious scenarios to harness the full value of RES sources. The increase of the capacity from Patagonia to Buenos Aires is particularly necessary to benefit from the wind potentials in Patagonia.

  - Sensitivity 8 (limitation of Electricity Network Development) is representative of unfavourable conditions for the development of renewables. Limiting the development of interregional transmission capacities (to +50% compared to 2050) as tested in sensitivity S8 would decrease the quantity of renewables installed in the system and increase total costs, although there would be more production of green hydrogen.
  - Even though direct electrification through RES is the best option for decarbonisation, green H_2 production provides an opportunity for RES projects in case of limitations of network capacities. This conclusion is also true in case of the absence of transmission network (off grid H_2 production).

- Depending on the level of ambition in the scenario, the decarbonisation of the electricity and hydrogen systems reduction varies from 11% to 85%.

6.1.2 Hydrogen and PtX

- **PtX production for local demand** includes current uses of hydrogen **in Argentina** such as:

- production of ammonia (NH_3), mainly used to produce nitrogen-based fertilizers (urea),
- production of methanol, mainly used in the biodiesel industry and petrochemical sector,
- refining sector (H_2 used in the process of hydrotreating, HDT),
- and production of sponge iron.

In the future, the **main drivers for local demand for low carbon hydrogen in Argentina** are likely to be the country's commitment to reducing greenhouse gas emissions, its abundance of renewable energy sources, the role of hydrogen as a **feedstock in the industry sector** and the i**nternational regulations regarding the carbon footprint of the products that the country exports**.

- Presently, hydrogen is used in oil refining and industrial key sectors such as NH_3 and methanol production, and the steel sector. The existing uses of hydrogen in different industrial sectors are expected to continue and grow in volume thanks mainly to GDP growth and the potential for imports substitution (especially fertilizers and some steel products).
    - In all three pathways, the future utilization of hydrogen for local demand will primarily focus on NH_3/fertilizers. This usage is expected to increase from the current level of approximately 41% to reach around 65-70% of the total by 2050.
    - The utilization of PtX products for the maritime and aviation sectors (NH_3, e-fuels) is also expected to increase from 2040 onwards and reach 15% in 2050 in the NZE 2050 pathway.
    - Other uses such as methanol production, and the steel sector are expected to increase more slowly, so their relative weight in total H_2 demand is expected to decrease.
    - H_2 used in the process of hydrotreating, HDT, is expected to decrease as energy consumption evolves from liquid fossil fuels to natural gas and electricity.

Competitiveness of green, blue and grey H_2: There is currently a wide price gap between green H_2 compared to grey and blue H_2 in Argentina (mainly because of a relatively low domestic gas price compared to international prices, as well as high CAPEX for both wind and electrolysers).

- Therefore, there is the need of incentives to promote its development (for example by taxing CO_2 emissions).

- The production of green hydrogen could be targeted for new developments or exports, rather than a mandatory replacement of existing technology (grey). The global appetite for green products may also trigger its development.
- The **most promising findings for green hydrogen projects** (in terms of competitiveness) are reached for the **Patagonian region**.
- By implementing a carbon tax, the viability and competitiveness of green H_2 are enhanced at an earlier stage (2040), as observed when comparing the different pathways. A faster reduction of electrolysers capex would accelerate green H_2 development (Sensitivity 3). It would result in 2 Mt of additional hydrogen produced for exports, a doubling of hydrogen export revenues and an overall reduction of the net total costs of the pathway by 10% mainly linked to these additional export revenues.
- An increase on gas price would also ensure a better competitiveness of green H_2 as compared to grey and blue H_2 and an acceleration of its development, from 2030 onwards instead of 2040 onwards(S2). It would lead to an increase in net total costs by 13% mainly driven by the increase of gas supply costs.
- Considering a higher emission factor for fugitive emissions in the investment decision (S6) favour green H_2 development from 2030 onwards. On the other hand, not considering them (S4) may delay the competitiveness of green H_2 in time (2040 to 2050). **Considering fugitive emissions** in the investment decision is a key component, especially when comparing blue and green H_2. This can be a **decisive factor when choosing the technology pathway for H_2 production.**

| Distinction between the development of on-grid and off-grid green H_2:

- On-grid electrolysis is developed only if the electricity generation mix achieves a high share[49] of low carbon technologies.
- The off-grid solution to export PtX products can be deployed independently of the local decarbonisation scenario, if the price conditions are favourable. It can also play a significant role to overcome energy infrastructure challenges.

[49] Based on the results of the pathways, a rough estimate suggests that this share could potentially be around 90-95%. It is important to note that this estimation may be subject to variation based on potential modifications to certain assumptions.

- **Electricity grid expansion tend to be a more competitive option than H_2 pipeline development**, for on-grid electrolysis: it is cheaper to transport electricity than green hydrogen to supply local demand.
  - Another option is the development of local hubs at a small-mid scales in the regions benefiting from both local demand and good renewable resources (south of Buenos Aires province, for example).
- **Argentina can become a massive hydrogen exporter** with up to 2.9 Mt exported per year in 2050 in the NZE 2050 scenario and an accumulated H_2 exports revenue of up to 33 billion USD. In that sense, Argentina has a big trade role to play. In terms of revenues, the analysis of the three pathways shows that the revenues from exports compensates the increase of system costs to produce this additional energy.
  - One of the limitations to its development may come from limitations in the rhythm of installation of renewable projects, which may be related to the supply chain logistics, the duration of permitting and licensing procedures, the need for upgrading and expanding the grid infrastructure (Sensitivity 8). If those limits are exceeded and if a major demand for PtX products does develop, the PtX products´ exports would most probably be higher.
  - The rest of the limitations are related to economic factors which have an impact on the competitiveness of the production of green H_2 such as WACC (Sensitivity 5), CAPEX (Sensitivity 3), etc.
  - If there is a greater development of a RES industry and of electrolysers, Argentina can position itself as a key exporter of green hydrogen. Considering the assumptions of the model, at an export price of 2 USD/kg, Argentina would export 5,45 Mt of hydrogen annually by year 2050.
- **International H_2 and derivatives prices impact significantly the H_2 export amounts (see sensitivity 7).** These market prices are not clear yet, but they should be followed to understand the economic viability of Argentina exports, as higher prices makes exports more attractive.
  - Sensitivity 7 (decreased H_2 exports price) is representative of unfavourable conditions for the green H_2 exports.
- **Currently, in Argentina, one of the PtX product which present lots of interest for future exports is green NH_3**, because it is the carrier with the lowest costs of storage and transport. Besides, Argentina already produces part of its own consumption (and as such, benefits of knowledge and know-how). Therefore, any export project could leverage on the domestic consumption as an initial off taker, at least in the first phases of an export project.

- The main driver of the levelized cost of green NH_3 (LCOA) is the production cost of H_2 (ie. the electricity price).

6.2 SWOT analysis

As a matter of conclusion, we present hereafter a SWOT analysis (Strengths, Weaknesses, Opportunities, and Threats) of the development of the hydrogen economy and PtX in Argentina:

- **Strengths:**
  - Abundance of natural resources: With its abundant wind resources in Patagonia, solar irradiation in the North-West and natural gas reserves in Neuquén, Argentina is positioned as a prime country to produce large amounts of low carbon (green and blue) hydrogen at low cost in the mid and long terms.
  - Existence of local demand hubs (fertilizers, steel, methanol) that can leverage pilot or demonstration projects that ease the learning curve.
  - Longstanding research centers, as well as a solid expertise in H_2, NH_3, methanol, refinery industries. Additionally, a lot of professionals work with complex processes in Oil & Gas and petrochemical industries.
  - Existing ports infrastructure and trading expertise
  - Existing natural gas pipelines: that could be repurposed to transport hydrogen (it requires a thorough analysis on a case-by-case basis).
  - Land availability: in particular, in the southern part of the country with excellent onshore wind resources.
- **Weaknesses:**
  - Constrained investment: The development of a hydrogen economy requires significant investment, which may be difficult to secure in a country such as Argentina, given its current macroeconomic situation.
  - Lack of a hydrogen law, hydrogen strategy and road map, necessary to promote a favourable business environment, although they are currently under development.
  - Lack of a certification of origin scheme for the renewable electricity withdrawn from the grid, to facilitate the development of on-grid green H_2 projects.
  - Lack of technology suppliers: Argentina may face challenges in developing the necessary technology suppliers, for example for electrolysers, wind turbines, etc.
  - Lack of a stable regulatory framework: Political instability in Argentina may deter potential investors and make it difficult to establish a stable regulatory framework. The regulatory framework needs to be stable in time to favour investments.
- **Opportunities:**

- Export potential: Argentina's strategic location and abundance of natural resources make it well-positioned to become a major exporter of low carbon hydrogen.
- Economic growth: The development of a hydrogen economy could stimulate economic growth in Argentina and create new jobs.
- Decreasing cost of green hydrogen production: Argentina can benefit from global cost reduction associated to renewable power plants and electrolysers.
- Increasing global demand for Hydrogen: Most of the countries worldwide are also transitioning towards a green economy, meaning that global demand for PtX products will most probably increase.
- International collaboration: Argentina can collaborate with other countries and international organizations to develop its hydrogen industry, leading to knowledge transfer and the sharing of best practices.

Threats:

- Competition: Other neighbouring countries are developing their hydrogen industries faster than Argentina, leading to increased competition in the global market.
- Uncertainty with respect to potential off-takers and long term contracts: The absence of established global markets for H_2 and PtX products, as well as the lack of clear pricing benchmarks, presents challenges in attracting stable long-term investments and determining pricing levels for long contractual commitments.
- Uncertain H_2 demand: Although there are common agreements of long-term commitments and actions towards energy transition worldwide, there is still uncertainty on whether those commitments will come true and more specifically on the impact of external events such as war, economic crisis, etc...
- Uncertainty with respect to the acceptance of blue H_2 in the external markets, especially regarding exports of industrial goods from Argentina towards other regions. In the model, blue H_2 is considered for local demand.
- Safety concerns: Hydrogen is a highly flammable gas, and there may be safety concerns associated with its production, transportation, and storage.
- Regulatory challenges: The development of a hydrogen economy will require a regulatory framework that balances safety, environmental concerns, and economic considerations.

6.3 Recommendations

As derived from the main conclusions of the studies and the SWOT analysis, one can formulate some key recommendations to support green H_2 development in Argentina, such as:

- Establishing a **clear and stable policy and regulatory framework**, including a hydrogen law and a hydrogen strategy and roadmap, which are currently under development. This is essential given the nature of green H_2 projects, which are high-CAPEX intensive. This regulatory framework should provide certainty and attract investments in the sector. Some of the elements needed within the regulatory framework are:
  - specific targets, timelines, and desired outcomes in order to have a clear understanding of the government's intentions and long-term commitment.
  - project permitting, grid connection, hydrogen quality standards, and environmental impact assessments.
- **Accelerating the development of renewable energy projects**, which is crucial for both decarbonizing the electricity mix and allowing the development of green hydrogen production.
  - Argentina has already implemented several incentives[50] to accelerate renewable development, such as the RenovAr program, the FODER, etc. Additional auctions, supportive policies and financial mechanisms would further boost renewable energy installation.
  - Upgrading and expanding the transmission and distribution networks is also needed to allow for further development of renewable energy.
  - Ensuring that the permitting and licensing procedures for renewable projects are short enough, enabling a timely development of renewable projects.
  - Supply chain logistics need to be well developed in order not to hold that development, both at national and international levels, through:
    - developing and improving current infrastructure, such as transportation networks, port facilities, storage facilities;
    - simplifying customs procedures and regulatory processes to reduce delays for imports of material;
    - eventually developing a national industry to limit the impacts, in case of a global supply chain disruption.
- **Establishing favourable financing mechanisms, incentives, and financial support** programs to attract domestic and international investments in green H_2 projects.

[50] Some of the existing incentives are the RenovAr program (offering long-term PPAs through renewable energy auctions), tax benefits and exemptions on the purchase of equipment and components for renewable energy projects, Net metering policies, the FODER (Fondo para el Desarrollo de Energías Renovables) providing guarantees and funding mechanisms.

- **Fostering the development of domestic and international markets** for green hydrogen and its derivatives and facilitating partnerships and agreements with potential off-takers, industries, and other sectors. In that sense, any export project could leverage on the domestic consumption as an initial off taker, at least in the first phases of the project.
- Collaborating with other countries and market players to exchange knowledge, share best practices, and **promote the development of global hydrogen standards and markets**.

7 Annexes

7.1 Annex 1: Main assumptions on final energy demand per sector and fuels

Energy demand scenarios are built via:

- The analysis of historical tendencies of final sector and fuel consumption, and their correlated key indicators (GDP, population, etc…). The following table shows the underlying assumptions for population and GDP growth.

	Historical	Current Commitments			Advanced Transition			NZE 2050		
Variable	2000-2021	2021-2030	2030-2040	2040-2050	2021-2030	2030-2040	2040-2050	2021-2030	2030-2040	2040-2050
GDP growth (%)	1.7%	2.0%	2.0%	2.0%	2.5%	2.5%	2.5%	2.5%	3.0%	3.0%
Population Growth (%)	1.0%	0.8%	0.7%	0.5%	0.8%	0.7%	0.5%	0.8%	0.7%	0.5%

Figure 137: Assumptions for population and GDP growth (%)

- A Baseline scenario corresponding to the projection of historical trends, without applying additional decarbonisation policies.
- The application of decarbonisation measures for three pathways, with different levels of:
    - penetration of electrification rates for specific uses (heating, cooking, hot water, light and heavy vehicles, etc…),
    - penetration of other fuels in transport and agriculture (CNG/LNG, H_2, etc.),
    - penetration of energy efficiency and behavior change rates per sector.
- The decarbonisation policies prioritized for all the pathways are the ones corresponding to rather mature and economical options (i.e. “no-regret” options).
    - Energy efficiency and behavior changes are the first measures to implement.
    - The electrification of uses is always prioritized, when possible. It allows both a reduction in energy consumption (greater efficiency) and a reduction in CO_2 emissions.
    - Green hydrogen is considered only for those uses where it is the only option for decarbonisation, as it is not energy efficient (a large volume of renewables is needed to produce green H_2). Some of the no-regret options for H_2 are the use as feedstock

and reaction agent in the industry (non-energetic uses[51]) and the maritime and aeronautical sector.

- The underlying assumptions are further described in the following chapters per sector.

7.1.1 Final energy consumption, Transport sector

Presently, the transport sector accounts for 33% of total final energy consumption and is predominantly reliant on oil derivatives (OD) such as gasoil and nafta (which include a portion of biodiesel and bioethanol), as well as CNG. Approximately two-thirds of the road energy demand in the transport sector is attributed to passenger transport, while the remaining portion comes from freight transport. Aviation and maritime transports account for less than 5% of the overall energy demand in the sector.

The main decarbonisation measures considered for the transport sector are:

- Transitioning the current fleet of light passenger transport vehicles to electric or CNG alternatives. For freight transport, the focus is on utilizing electricity or LNG. For aviation and maritime sectors, the decarbonisation option is the use of PtX products.
- Improved energy efficiency in comparison to the existing light vehicles´ fleet.
- Development of modal changes such as remote work, carpooling, and other strategies to promote more sustainable transportation choices.

	Current Commitments			Advanced Transition			NZE 2050		
Variable	**2030**	**2040**	**2050**	**2030**	**2040**	**2050**	**2030**	**2040**	**2050**
Light vehicules: OD -> CNG	10%	20%	20%	15%	20%	20%	10%	10%	0%
Light vehicules: OD-> electricity	1%	10%	20%	2%	15%	50%	5%	40%	100%
Freight: OD-> LNG	10%	20%	30%	10%	20%	30%	10%	20%	20%
Freight: OD-> electricity	0%	5%	10%	1%	5%	25%	1%	15%	60%
Aviation/Maritime -> PtX products	0%	0%	10%	0%	10%	20%	0%	20%	45%
Energy efficiency (depending on the fuel)	1%-5%	2%-10%	3%-15%	1%-5%	2%-10%	3%-15%	1%-5%	2%-10%	3%-15%

[51] In the following figures, non-energetic uses are not represented. This is the case for H_2 consumed as feedstock for industrial processes. H_2 demand for industrial processes is described in the chapter 4.6.

Modal changes (light vehicules)	3%	10%	15%	5%	10%	20%	5%	10%	30%

Figure 138: Global transition assumptions per pathway, Transport sector

Overall, the growing proportion of electricity in the transport sector leads to a substantial reduction in energy consumption, primarily due to the higher efficiency of EVs compared to conventional internal combustion engine vehicles (ICEs), with EVs being approximately five times more efficient.

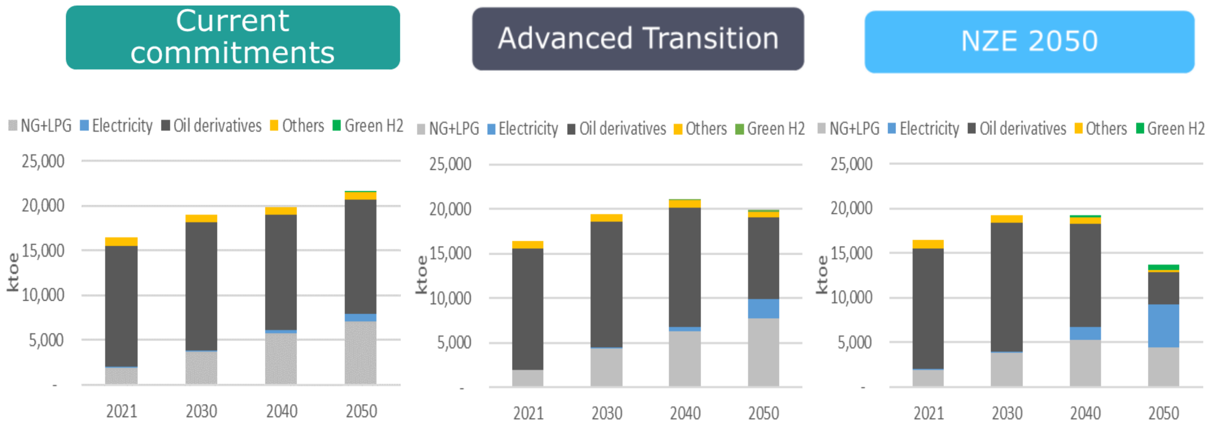


Figure 139: Final energy consumption by fuel and pathway, Transport sector, % of ktoe

7.1.2 Final energy consumption, Industrial sector

Presently, the industrial sector accounts for 23% of total final energy consumption and is predominantly reliant on natural gas, as well as electricity (35%). The projected industrial energy demand depends on GDP growth (which differs in each pathway) and is constrained by decarbonisation measures, such as:

- the electrification of a share of currently non-electrified industrial processes,
- the implementation of energy efficiency measures.

It should be noted that the potential for decarbonisation measures in the industrial sector is comparatively more limited than the ones assumed for other sectors.

	Current Commitments			Advanced Transition			NZE 2050		
Variable	**2030**	**2040**	**2050**	**2030**	**2040**	**2050**	**2030**	**2040**	**2050**
Electrification measures	5%	10%	10%	5%	10%	15%	5%	20%	40%
Energy efficiency impact	5%	10%	10%	5%	10%	15%	7%	10%	30%

Figure 140: Global transition assumptions per pathway, Industrial sector

Overall, the share of electricity in the industrial sector is expected to increase and energy efficiency to have a moderate impact in decarbonisation scenarios.

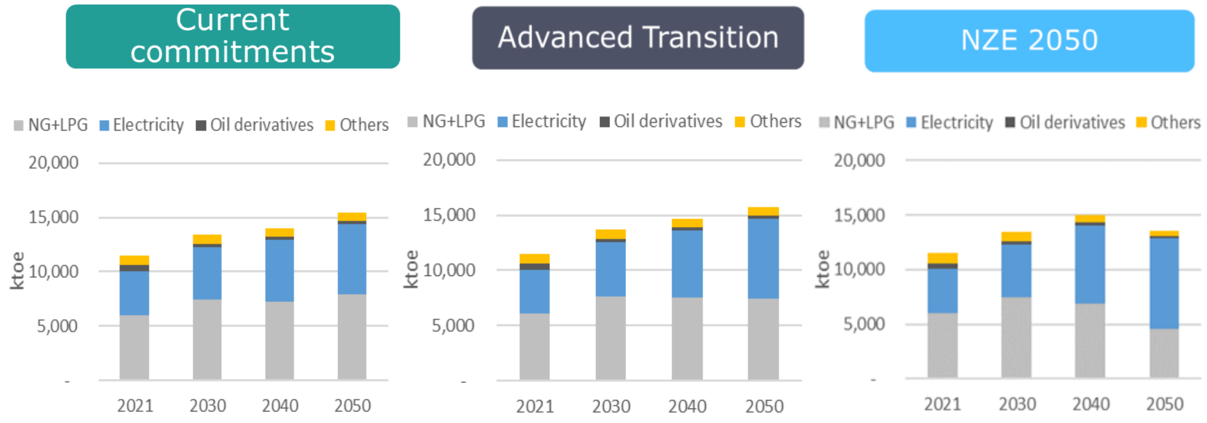


Figure 141: Final energy consumption by fuel and pathway, Industrial sector, % of ktoe

7.1.3 Final energy consumption, Residential sector

Presently, the residential sector accounts for 27% of total final energy consumption and is predominantly reliant on the use of natural gas (almost 70%) and electricity (30%). Natural gas consumption in the residential sector is divided into three primary categories: heating, which constitutes over half of the total natural gas consumption, followed by domestic hot water (DHW) and cooking.

The projected residential energy demand depends on population growth and is constrained by decarbonisation measures, such as:

- the adoption of electric heating, domestic hot water (DHW), and cooking, which in turn leads to a decrease in overall energy consumption,
- the implementation of energy efficiency measures for both new electrical appliances and improved thermal insulation of buildings, offering significant potential for reducing energy consumption.

	Current Commitments			Advanced Transition			NZE 2050		
Variable	**2030**	**2040**	**2050**	**2030**	**2040**	**2050**	**2030**	**2040**	**2050**
Electrification measures	5%	12%	20%	7%	30%	50%	10%	40%	90%
Energy efficiency impact	5%	15%	25%	10%	20%	30%	15%	30%	50%

Figure 142: Global transition assumptions per pathway, Residential sector

Overall, the share of electricity in the residential sector is expected to increase and energy efficiency to have a significant impact in decarbonisation scenarios.

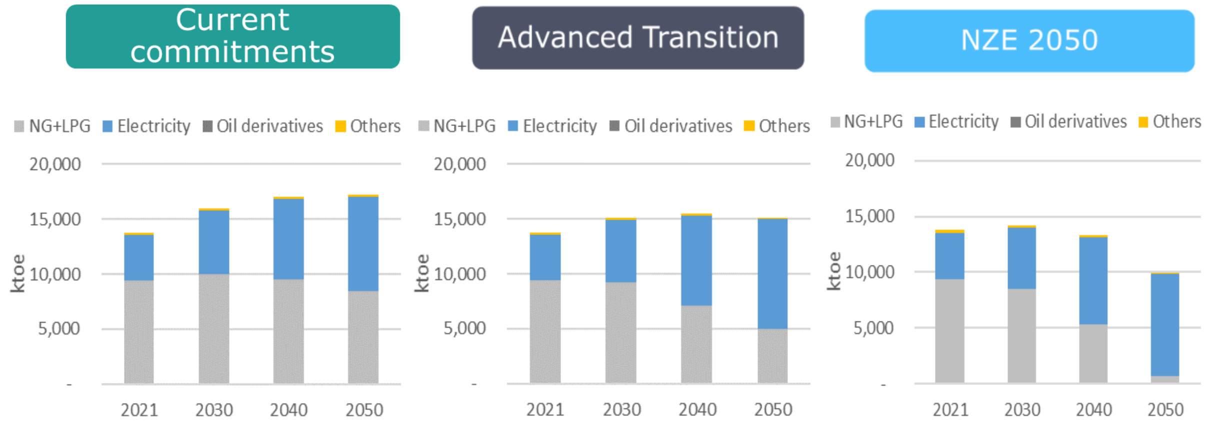


Figure 143: Final energy consumption by fuel and pathway, Residential sector, % of ktoe

7.1.4 Final energy consumption, Commercial sector

Presently, the commercial sector accounts for 9% of total final energy consumption and is predominantly reliant on the use of electricity (64%), followed by NG. The projected commercial energy demand depends on GDP growth (which differs in each pathway) and is constrained by decarbonisation measures, similar to the ones presented for the residential sector.

	Current Commitments			Advanced Transition			NZE 2050		
Variable	**2030**	**2040**	**2050**	**2030**	**2040**	**2050**	**2030**	**2040**	**2050**
Electrification measures	5%	12%	20%	7%	30%	50%	10%	40%	90%
Energy efficiency impact	5%	15%	25%	10%	20%	30%	15%	30%	50%

Figure 144: Global transition assumptions per pathway, Commercial sector

Overall, the share of electricity in the commercial sector is expected to increase and energy efficiency to have a significant impact in decarbonisation scenarios.

Current commitments | Advanced Transition | NZE 2050

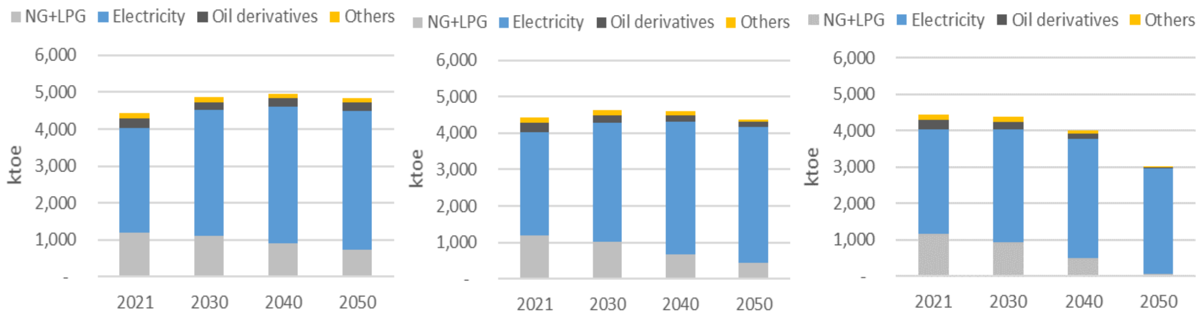


Figure 145: Final energy consumption by fuel and pathway, Commercial sector, % of ktoe

7.1.5 Final energy consumption, Agriculture sector

Presently, the agriculture sector accounts for only 8% of total final energy consumption and is predominantly reliant on oil derivatives. The projected agriculture energy demand depends on GDP growth (which differs in each pathway) and is constrained by decarbonisation measures, such as:

- the technological migration in global agricultural machinery towards electricity (or LNG), which in turn leads to a decrease in overall energy consumption,
- the optimization of agricultural practices, sustainable irrigation, etc.

	Current Commitments			Advanced Transition			NZE 2050		
Variable	2030	2040	2050	2030	2040	2050	2030	2040	2050
Conversion of oil derivatives ->Electricity	0%	5%	15%	0%	10%	25%	0%	30%	60%
Conversion of oil derivatives ->LNG	0%	10%	20%	5%	10%	25%	5%	10%	10%
Impact of optimization of the sector	5%	5%	10%	5%	10%	15%	5%	10%	20%

Figure 146: Global transition assumptions per pathway, Residential sector

Overall, the share of electricity in the agriculture sector remains rather low compared to other sectors.

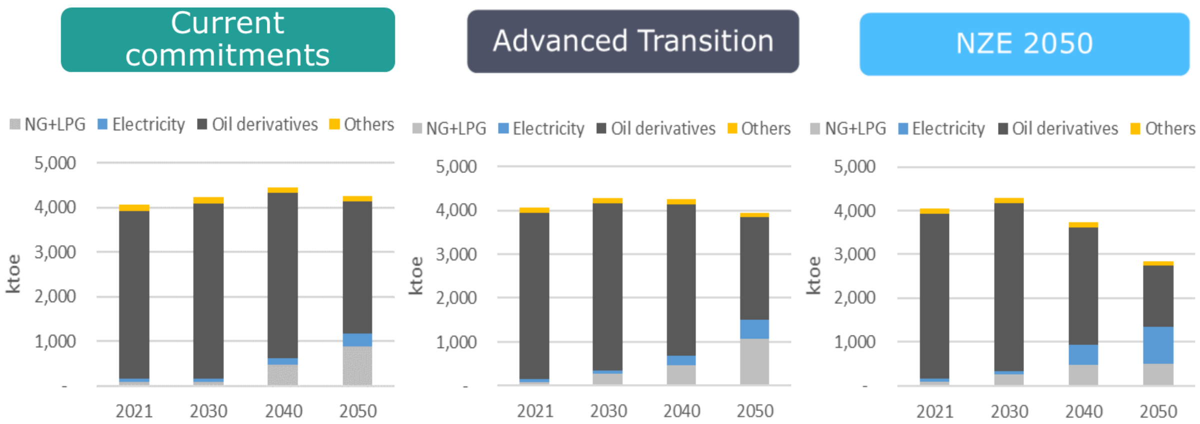


Figure 147: Final energy consumption by fuel and pathway, Agriculture sector, % of ktoe

7.2 Annex 2: Economic assumptions for model optimization

All prices are expressed in USD of the year 2022.

7.2.1 Electricity production and transport: Parameters for the optimizable technologies

7.2.1.1 Electricity production

The following CAPEX and OPEX are considered for the three pathways, based on NREL projections[52], IRENA projections and own assumptions.

CAPEX per Technology	Unit	2030	2040	2050
Solar PV	USD/kW	726	669	617
Wind onshore	USD/kW	1,300[53]	1,150	1,000
Solar CSP	USD/kW	4,000	3,500	3,000
Battery 4h	USD/kWh	170	140	115
Gas OCGT	USD/kW	750	750	750
Gas CCGT	USD/kW	850	850	850
H2 OCGT	USD/kW	750	750	750
H2 CCGT	USD/kW	850	850	850

Figure 148: CAPEX per technology, USD/kW or USD/kWh

OPEX per Technology	Unit	2030-2050
Solar PV	USD/kW-year	1.7%
Wind onshore	USD/kW-year	2.7%
Solar CSP	USD/kW-year	1.4%
Battery 4h	USD/kW-year	11.5%
Gas OCGT	USD/MWh	2
Gas CCGT	USD/MWh	2

[52] https://atb.nrel.gov/electricity/2022/technologies

[53] In line with the document "Escenarios Energéticos 2030", 2019.

H2 OCGT	USD/MWh	2
H2 CCGT	USD/MWh	2

Figure 149: OPEX per technology, USD/kW-year or USD/MWh

7.2.1.2 Electricity transport

The unitary costs for electricity grid expansion are elaborated based on typical costs (for lines, substations) for new 500kV projects of around 1,200 MW of transfer capacity and an estimated distance between regions.

From	To	Millions USD/MW
Patagonia	Comahue	0.35
Comahue	Cuyo	0.38
	Centro	0.46
	Buenos Aires	0.44
Cuyo	Centro	0.26
	NOA	0.39
Centro	Buenos Aires	0.40
	NOA	0.35
	Litoral	0.24
Buenos Aires	Litoral	0.34
	GBA	0.21
NOA	Litoral	0.41
	NEA	0.39
Litoral	GBA	0.25
	NEA	0.34

Figure 150: Unitary cost of grid expansion, Millions USD/MW

7.2.2 Hydrogen production and transport: Parameters for the optimizable technologies

7.2.2.1 Hydrogen production

Hypothesis used come from IEA (Global Hydrogen Review 2021) and are expressed in USD_{2022}:

CAPEX per technology (USD_{2022}/MW)	2030	2040	2050
Electrolysis	595	475	420
SMR	889	889	889
SMR + CCS	1,676	1,676	1,676

Figure 151: Unitary CAPEX for hydrogen production assets

OPEX per technology (USD/kW/yr, % of CAPEX)	2030	2040	2050
Electrolysis	2.0%	2.0%	2.0%
SMR	4.7%	4.7%	4.7%
SMR + CCS	4.0%	4.0%	4.0%

Figure 152: Unitary OPEX for hydrogen production assets

7.2.2.1.1 LCOH estimation

7.2.2.1.1.1 LCOH for grey and blue H_2

The levelized cost of hydrogen (LCOH) for grey and blue H_2 is calculated using the following parameters:

Year	Technoeconomic characteristics						Assumptions on fuel price and use rate		Results
	Overnight CAPEX (USD_{2022}/ kWH_2)	Life time (yr)	WACC (%)	Yearly OPEX (% CAPEX/yr)	Efficiency LHV ($MWhH_2$/ MWhGas)	CO_2 emissions (tCO_2/ MWhGas)	Gas price LHV (USD/MMBtu)	Load factor (%)	LCOH (USD/ kg)
2030	889	20	7.5%	4.7%	76%	0.30	6.3	95%	1.5
2040	889	20	7.5%	4.7%	76%	0.30	6.3	95%	2.2
2050	889	20	7.5%	4.7%	76%	0.30	6.3	95%	3.0

Figure 153: Assumptions for LCOH calculation and results (grey H_2)

Year	Technoeconomic characteristics						Assumptions on fuel price and use rate		Results
	Overnight CAPEX (USD_{2022}/ kWH_2)	Life time (yr)	WACC (%)	Yearly OPEX (% CAPEX/yr)	Efficiency LHV ($MWhH_2$/ MWhGas)	CO_2 emissions (tCO_2/ MWhGas)	Gas price LHV (USD/MMBtu)	Load factor (%)	LCOH (USD/kg)
2030	1,676	20	7.5%	4.0%	69%	0.065	6.3	95%	2.0
2040	1,676	20	7.5%	4.0%	69%	0.065	6.3	95%	2.1
2050	1,676	20	7.5%	4.0%	69%	0.065	6.3	95%	2.3

Figure 154: Assumptions for LCOH calculation and results (blue H_2)

As mentioned before, the source of techno-economic characteristics (CAPEX, OPEX, efficiency, capacity factor) are based on IEA and own assumptions.

Boundaries: CO_2 emission includes upstream GHG emissions (low upstream emission data from IEA)[54]. CO_2 transport and storage costs are not considered in the calculation[55].

7.2.2.1.1.2 LCOH for green H_2

For off-grid projects, the candidate regions are Patagonia, Comahue and Buenos Aires, as these regions have high wind potential and access to ports.

The first step of the calculation is to evaluate the best configuration in terms of MW installed of wind capacities and electrolysers, based on the wind profile in each region and a set of assumptions in terms of investment costs, CAPEX, etc… Off-grid projects are usually characterized by the need of a surplus of wind installed capacity, as well as wind curtailment:

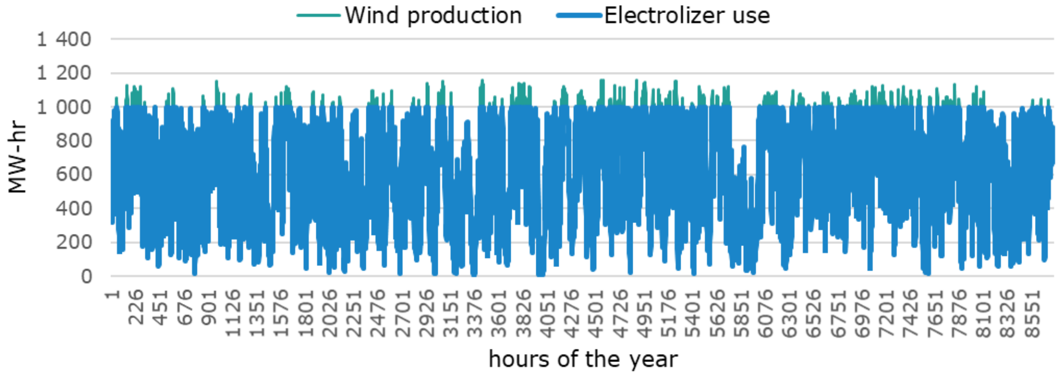


Figure 155: Wind production and Electrolizer use, Patagonia, MWh

Based on the Hourly wind profile for the region under study, and the MW of the generation fleet and MW of electrolizers, we obtain: H_2 production; and running hours of the electrolizers.

The project cash flow is then calculated for the integrated project ("Wind farm + electrolizers"). The calculation takes into account total CAPEX and OPEX. The capacity factor of the electrolyser (running hours) depends on the dimensioning of the wind and electrolizers.

As for the rest of the calculations, the assumed life time of the project is 20 years and the WACC 7.5%.

[54] https://iea.blob.core.windows.net/assets/c5bc75b1-9e4d-460d-9056-6e8e626a11c4/GlobalHydrogenReview2022.pdf#page=89

[55] By including those costs, blue H_2 would become slightly more expensive. For instance, a 10 USD/tCO_2 cost for transport and storage would add 0.13 USD/kg to the LCOH of blue H_2.

		Electrolizer				Wind				Results
		CAPEX (USD/kWelec)	Stack replacement (% CAPEX)	Yearly OPEX (% CAPEX/yr)	Efficiency LHV (MWhH2/ MWhElec)	Yearly OPEX (USD/kW)	CAPEX (USD/kW)	Ratio Wind/ Electrolizer capacity	Load factor (%)	LCOH (USD/kg)
2030	BAS	595	26%	2%	69%	2.7%	1300	1.25	60%	2.7
	COM	595	26%	2%	69%	2.7%	1300	1.25	57%	2.8
	PAT	595	26%	2%	69%	2.7%	1300	1.17	61%	2.5
2040	BAS	475	24%	2%	71.50%	2.7%	1150	1.25	60%	2.2
	COM	475	24%	2%	71.50%	2.7%	1150	1.25	57%	2.3
	PAT	475	24%	2%	71.50%	2.7%	1150	1.17	61%	2.0
2050	BAS	420	23%	2%	74%	2.7%	1000	1.25	60%	1.8
	COM	420	23%	2%	74%	2.7%	1000	1.25	57%	2.0
	PAT	420	23%	2%	74%	2.7%	1000	1.17	61%	1.7

Figure 156: Assumptions for LCOH calculation (green H_2, offgrid projects) and results

Source of techno-economic characteristics:

- CAPEX and OPEX: IEA, NREL projections[56], IRENA projections and own assumptions,

Boundaries:

- The LCOH is calculated at plant site (off-grid project). Needs for storage are not taken into account.
- CAPEX is depreciated over the operating life of the plant. The interests during construction period are not specifically considered in this simplified approach (a cash flow analysis considering 2 to 3 years of construction would lead to slighter higher results).

7.2.2.2 Hydrogen transport

Hypothesis used come from a European study from GasForClimate[57]

	CAPEX (USD/MW/km)
Hydrogen pipeline	128

Figure 157: Unitary CAPEX for hydrogen pipelines

	OPEX (USD/MW/km/yr)
Hydrogen pipeline	2

Figure 158: Unitary OPEX for Hydrogen pipelines

[56] https://atb.nrel.gov/electricity/2022/technologies
[57] https://gasforclimate2050.eu/gas-for-climate/

7.3 Annex 3: Main results of the pathways by regions

7.3.1 Installed Capacities

7.3.1.1 Current Commitments

Electrical System										
	Installed capacities (GW)	BAS	CEN	COM	CUY	GBA	LIT	NEA	NOA	PAT
2020	Solar	-	0,1	-	0,3	-	-	-	0,7	-
	On-grid Wind	1,2	0,1	0,3	-	-	-	-	0,2	1,6
	Off-grid Wind	-	-	-	-	-	-	-	-	-
	Other RES (hydro+biomass)	0,0	0,2	4,7	0,9	0,0	1,0	2,8	0,2	0,6
	Nuclear	1,1	0,6	-	-	-	-	-	-	-
	Electricity Storage	-	0,8	0,1	0,2	-	-	-	-	-
	Gas-fired	5,1	1,4	2,0	0,6	7,8	2,8	0,0	2,9	0,6
	Other fossil fuels	0,8	0,1	0,1	0,0	0,3	0,3	0,3	0,3	-
2030	Solar	0,2	0,4	0,3	1,4	0,0	0,2	0,2	2,7	-
	On-grid Wind	2,3	0,2	1,2	-	-	-	-	0,2	3,8
	Off-grid Wind	-	-	-	-	-	-	-	-	-
	Other RES (hydro+biomass)	0,0	0,2	4,7	1,2	0,0	1,0	3,1	0,2	1,9
	Nuclear	1,1	0,6	-	-	-	-	-	-	-
	Electricity Storage	0,0	0,8	0,1	0,2	0,0	0,0	0,0	0,0	0,0
	Gas-fired	4,5	1,5	2,0	0,6	6,1	2,8	0,0	2,8	0,6
	Other fossil fuels	0,3	0,1	0,1	0,0	0,3	0,3	0,3	0,3	0,2
2040	Solar	0,4	0,7	0,7	2,6	0,1	0,4	0,4	4,7	-
	On-grid Wind	3,4	0,3	2,2	-	-	-	-	0,2	6,1
	Off-grid Wind	-	-	-	-	-	-	-	-	1,2
	Other RES (hydro+biomass)	0,0	0,2	7,3	2,3	0,0	1,0	3,1	0,2	1,9
	Nuclear	2,1	0,6	-	-	-	-	-	-	-

	Electricity Storage	0,0	0,8	0,1	0,2	1,0	0,0	0,0	0,2	0,0
	Gas-fired	3,5	1,2	1,2	0,4	6,4	2,8	0,0	2,5	0,6
	Other fossil fuels	0,3	0,1	0,1	0,0	0,3	0,3	0,3	0,3	0,2
2050	Solar	0,5	1,1	1,0	3,7	0,3	0,5	0,5	6,8	-
	On-grid Wind	4,6	0,4	3,2	-	-	-	-	0,3	8,3
	Off-grid Wind	3,5	-	-	-	-	-	-	-	3,5
	Other RES (hydro+biomass)	0,0	0,2	7,8	2,4	0,0	1,0	3,1	0,3	1,9
	Nuclear	2,2	0,6	-	-	-	-	-	-	-
	Electricity Storage	0,0	0,8	0,1	0,2	1,0	0,0	0,0	2,5	0,3
	Gas-fired	2,5	1,2	0,7	0,1	10,4	3,7	0,4	1,6	0,6
	Other fossil fuels	0,3	0,1	0,1	0,0	0,3	0,3	0,3	0,3	0,2

Hydrogen System										
Installed capacities (GW)		BAS	CEN	COM	CUY	GBA	LIT	NEA	NOA	PAT
2020	SMR	0,9	-	0,4	0,2	0,0	0,2	-	0,0	-
	SMR+CCS	-	-	-	-	-	-	-	-	-
	On-grid Electrolysis	-	-	-	-	-	-	-	-	-
	Off-grid Electrolysis	-	-	-	-	-	-	-	-	-
	Hydrogen Storage	-	-	-	-	-	-	-	-	-
2030	SMR	0,9	-	0,3	0,2	0,0	0,2	-	0,0	-
	SMR+CCS	0,3	-	0,1	0,0	0,0	0,0	-	0,0	-
	On-grid Electrolysis	0,0	0,0	0,0	0,0	0,0	0,0	0,0	0,0	0,0
	Off-grid Electrolysis	-	-	-	-	-	-	-	-	-
	Hydrogen Storage	1,1	0,0	0,4	0,2	0,0	0,2	0,0	0,0	-
2040	SMR	0,9	-	0,3	0,2	0,0	0,2	-	0,0	-
	SMR+CCS	1,3	-	0,1	0,0	0,0	0,1	-	0,0	-
	On-grid Electrolysis	0,0	0,0	0,0	0,0	0,0	0,0	0,0	0,0	0,0

	Off-grid Electrolysis	-	-	-	-	-	-	-	-	1,0
	Hydrogen Storage	1,9	0,0	0,4	0,2	0,0	0,3	0,0	0,1	-
2050	SMR	0,9	-	0,3	0,2	0,0	0,2	-	0,0	-
	SMR+CCS	1,0	-	0,4	0,0	0,0	0,2	-	0,0	-
	On-grid Electrolysis	0,0	0,0	0,0	0,0	0,0	0,0	0,0	0,0	0,0
	Off-grid Electrolysis	2,8	-	-	-	-	-	-	-	3,0
	Hydrogen Storage	1,6	0,0	0,5	0,2	0,0	0,3	0,0	0,0	0,2

7.3.1.2 Advanced Transition

Electrical System										
Installed capacities (GW)		BAS	CEN	COM	CUY	GBA	LIT	NEA	NOA	PAT
2020	Solar	-	0,1	-	0,3	-	-	-	0,7	-
	On-grid Wind	1,2	0,1	0,3	-	-	-	-	0,2	1,6
	Off-grid Wind	-	-	-	-	-	-	-	-	-
	Other RES (hydro+biomass)	0,0	0,2	4,7	0,9	0,0	1,0	2,8	0,2	0,6
	Nuclear	1,1	0,6	-	-	-	-	-	-	-
	Electricity Storage	-	0,8	0,1	0,2	-	-	-	-	-
	Gas-fired	5,1	1,4	2,0	0,6	7,8	2,8	0,0	2,9	0,6
	Other fossil fuels	0,8	0,1	0,1	0,0	0,3	0,3	0,3	0,3	-
2030	Solar	0,3	0,6	0,6	1,8	0,3	-	-	3,9	-
	On-grid Wind	2,8	0,3	1,7	-	-	-	-	0,2	4,8
	Off-grid Wind	-	-	-	-	-	-	-	-	-
	Other RES (hydro+biomass)	0,0	0,2	4,7	1,2	0,0	1,0	3,1	0,2	1,9
	Nuclear	1,1	0,6	-	-	-	-	-	-	-
	Electricity Storage	0,0	0,8	0,1	0,2	0,0	0,0	0,0	0,0	0,0
	Gas-fired	4,5	1,5	2,0	0,6	6,1	2,8	0,0	2,8	0,6

	Other fossil fuels	0,3	0,1	0,1	0,0	0,3	0,3	0,3	0,3	0,2
2040	Solar	1,2	1,5	1,5	4,8	1,2	0,9	0,9	7,5	-
	On-grid Wind	5,8	0,5	4,3	-	-	-	-	0,3	8,5
	Off-grid Wind	4,3	-	-	-	-	-	-	-	2,3
	Other RES (hydro+biomass)	0,0	0,2	7,3	2,3	0,0	1,0	3,1	0,2	1,9
	Nuclear	2,1	0,6	-	-	-	-	-	-	-
	Electricity Storage	0,8	0,8	0,1	0,9	0,0	0,0	0,0	3,0	0,6
	Gas-fired	3,5	1,2	1,2	0,4	9,0	2,8	0,0	2,5	0,6
	Other fossil fuels	0,3	0,1	0,1	0,0	0,3	0,3	0,3	0,3	0,2
2050	Solar	1,2	1,5	1,5	10,5	1,2	2,6	0,9	14,1	-
	On-grid Wind	11,6	1,0	9,4	-	-	-	-	0,6	15,3
	Off-grid Wind	6,4	-	-	-	-	-	-	-	7,0
	Other RES (hydro+biomass)	0,0	0,2	7,8	2,4	0,0	1,0	3,1	0,3	1,9
	Nuclear	2,2	0,6	-	-	-	-	-	-	-
	Electricity Storage	1,4	1,5	0,1	4,6	0,0	0,0	0,3	5,0	0,6
	Gas-fired	2,5	1,2	0,7	0,1	17,2	2,8	0,0	1,6	0,6
	Other fossil fuels	0,3	0,1	0,1	0,0	0,3	0,3	0,3	0,3	0,2

Hydrogen System										
Installed capacities (GW)		BAS	CEN	COM	CUY	GBA	LIT	NEA	NOA	PAT
2020	SMR	0,9	-	0,4	0,2	0,0	0,2	-	0,0	-
	SMR+CCS	-	-	-	-	-	-	-	-	-
	On-grid Electrolysis	-	-	-	-	-	-	-	-	-
	Off-grid Electrolysis	-	-	-	-	-	-	-	-	-
	Hydrogen Storage	-	-	-	-	-	-	-	-	-
2030	SMR	0,2	-	0,3	0,2	0,0	0,2	-	0,0	-
	SMR+CCS	1,4	-	0,1	0,0	0,0	0,1	-	0,0	-

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	On-grid Electrolysis	0,0	0,0	0,0	0,0	0,0	0,0	0,0	0,0	0,0
	Off-grid Electrolysis	-	-	-	-	-	-	-	-	-
	Hydrogen Storage	1,5	0,0	0,4	0,2	0,0	0,2	0,0	0,0	-
2040	SMR	-	-	-	0,2	-	0,1	-	-	-
	SMR+CCS	1,4	-	0,3	0,0	0,0	0,2	-	0,0	-
	On-grid Electrolysis	0,0	0,0	0,0	0,0	0,0	0,0	0,0	0,0	0,0
	Off-grid Electrolysis	3,5	-	-	-	-	-	-	-	2,0
	Hydrogen Storage	0,9	0,0	0,5	0,2	0,0	0,3	0,0	0,0	0,2
2050	SMR	-	-	-	-	-	-	-	-	-
	SMR+CCS	1,6	-	0,4	0,1	0,0	0,4	-	0,0	-
	On-grid Electrolysis	0,0	0,0	0,9	0,1	0,0	0,0	0,0	0,1	3,3
	Off-grid Electrolysis	5,1	-	-	-	-	-	-	-	6,0
	Hydrogen Storage	1,5	0,0	0,6	0,1	0,0	0,4	0,0	0,0	0,5

7.3.1.3 Net Zero 2050

Electrical System										
Installed capacities (GW)		BAS	CEN	COM	CUY	GBA	LIT	NEA	NOA	PAT
2020	Solar	-	0,1	-	0,3	-	-	-	0,7	-
	On-grid Wind	1,2	0,1	0,3	-	-	-	-	0,2	1,6
	Off-grid Wind	-	-	-	-	-	-	-	-	-
	Other RES (hydro+biomass)	0,0	0,2	4,7	0,9	0,0	1,0	2,8	0,2	0,6
	Nuclear	1,1	0,6	-	-	-	-	-	-	-
	Electricity Storage	-	0,8	0,1	0,2	-	-	-	-	-
	Gas-fired	5,1	1,4	2,0	0,6	7,8	2,8	0,0	2,9	0,6
	Other fossil fuels	0,8	0,1	0,1	0,0	0,3	0,3	0,3	0,3	-
203	Solar	0,5	1,0	0,9	2,6	0,5	-	-	5,6	-

	On-grid Wind	3,7	0,3	2,5	-	-	-	-	0,3	5,9
	Off-grid Wind	-	-	-	-	-	-	-	-	0,7
	Other RES (hydro+biomass)	0,0	0,2	4,7	1,2	0,0	1,0	3,1	0,2	1,9
	Nuclear	1,1	0,6	-	-	-	-	-	-	-
	Electricity Storage	0,0	0,8	0,1	0,2	0,0	0,0	0,0	0,0	0,0
	Gas-fired	4,5	1,5	2,0	0,6	6,1	2,8	0,0	2,8	0,6
	Other fossil fuels	0,3	0,1	0,1	0,0	0,3	0,3	0,3	0,3	0,2
2040	Solar	0,5	2,5	2,4	7,6	0,5	1,5	1,5	11,6	-
	On-grid Wind	8,7	0,7	6,9	-	-	-	-	0,5	11,2
	Off-grid Wind	3,6	-	-	-	-	-	-	-	5,4
	Other RES (hydro+biomass)	0,0	0,2	7,3	2,3	0,0	1,0	3,1	0,2	1,9
	Nuclear	2,1	0,6	-	-	-	-	-	-	-
	Electricity Storage	1,2	1,3	0,1	2,9	0,0	0,0	0,1	5,0	0,2
	Gas-fired	3,5	1,2	1,2	0,4	9,0	2,8	0,0	2,5	0,6
	Other fossil fuels	0,3	0,1	0,1	0,0	0,3	0,3	0,3	0,3	0,2
2050	Solar	0,5	2,5	2,4	12,6	0,5	1,5	1,5	13,6	-
	On-grid Wind	18,7	1,5	15,7	-	-	-	-	0,9	21,8
	Off-grid Wind	7,3	-	-	-	-	-	-	-	14,7
	Other RES (hydro+biomass)	0,0	0,2	7,8	2,4	0,0	1,0	3,1	0,3	1,9
	Nuclear	2,2	0,6	-	-	-	-	-	-	-
	Electricity Storage	1,2	1,3	0,1	2,9	0,0	0,0	0,1	5,0	0,3
	Gas-fired	2,5	1,2	0,7	0,1	22,4	3,3	0,0	1,6	0,6
	Other fossil fuels	0,3	0,1	0,1	0,0	0,3	0,3	0,3	0,3	0,2

Hydrogen System										
Installed capacities (GW)		BAS	CEN	COM	CUY	GBA	LIT	NEA	NOA	PAT
2020	SMR	0,9	-	0,4	0,2	0,0	0,2	-	0,0	-
	SMR+CCS	-	-	-	-	-	-	-	-	-
	On-grid Electrolysis	-	-	-	-	-	-	-	-	-
	Off-grid Electrolysis	-	-	-	-	-	-	-	-	-
	Hydrogen Storage	-	-	-	-	-	-	-	-	-
2030	SMR	0,2	-	0,3	0,2	0,0	0,2	-	0,0	-
	SMR+CCS	2,2	-	0,4	0,2	0,0	0,3	-	0,1	-
	On-grid Electrolysis	0,0	0,0	0,0	0,0	0,0	0,0	0,0	0,0	0,0
	Off-grid Electrolysis	-	-	-	-	-	-	-	-	0,6
	Hydrogen Storage	1,9	0,0	0,4	0,2	0,0	0,2	0,0	0,1	-
2040	SMR	-	-	-	-	-	-	-	-	-
	SMR+CCS	2,4	-	0,7	0,2	0,0	0,4	-	0,1	-
	On-grid Electrolysis	0,0	0,0	0,2	0,0	0,0	0,0	0,0	0,0	2,0
	Off-grid Electrolysis	2,9	-	-	-	-	-	-	-	4,6
	Hydrogen Storage	2,2	0,0	0,5	0,2	0,0	0,3	0,0	0,1	0,3
2050	SMR	-	-	-	-	-	-	-	-	-
	SMR+CCS	0,6	-	0,3	0,0	0,0	0,4	-	0,0	-
	On-grid Electrolysis	0,9	0,0	2,0	0,1	0,0	0,1	0,0	0,2	10,0
	Off-grid Electrolysis	5,8	-	-	-	-	-	-	-	12,6
	Hydrogen Storage	1,7	0,0	0,7	0,1	0,0	0,5	0,0	0,0	1,1

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7.3.2 Yearly Production

7.3.2.1 Current Commitments

Electrical System										
Production (TWh)		BAS	CEN	COM	CUY	GBA	LIT	NEA	NOA	PAT
2020	Solar	-	0,1	-	0,8	-	-	-	1,7	-
	On-grid Wind	5,1	0,5	1,0	-	-	-	-	0,5	7,3
	Hydro	-	0,5	9,3	2,2	-	2,4	16,1	0,7	2,4
	Nuclear	5,3	4,6	-	-	-	-	-	-	-
	Gas-fired	14,3	5,3	0,5	2,7	32,4	15,8	0,0	9,5	0,0
	Other fossil fuels	0,0	0,0	0,0	0,0	0,0	0,0	0,0	0,0	-
	Demand	16,7	12,0	5,1	8,3	52,3	17,0	10,2	11,0	5,7
2030	Solar	0,3	0,9	0,7	3,7	0,0	0,4	0,4	6,7	-
	On-grid Wind	9,9	0,9	5,1	-	-	-	-	0,6	17,8
	Hydro	0,0	0,5	9,3	3,1	0,0	2,4	17,8	0,7	7,4
	Nuclear	5,6	4,6	-	-	-	-	-	-	-
	Gas-fired	11,4	5,6	0,1	1,3	35,5	17,1	0,1	8,3	0,0
	Other fossil fuels	0,0	0,0	0,0	0,0	0,0	0,0	0,0	0,0	0,0
	Demand	21,3	15,1	6,8	10,5	66,1	21,4	12,7	13,8	7,4
2040	Solar	0,7	1,7	1,5	6,6	0,2	0,7	0,7	11,7	-
	On-grid Wind	14,7	1,2	9,2	-	-	-	-	0,7	28,2
	Hydro	0,0	0,5	19,0	6,3	0,0	2,4	17,8	0,7	7,5
	Nuclear	13,5	4,6	-	-	-	-	-	-	-
	Gas-fired	4,5	2,8	0,1	0,5	35,5	16,4	0,1	7,6	0,0
	Other fossil fuels	0,0	0,0	0,0	0,0	0,0	0,0	0,0	0,0	0,0
	Demand	26,4	18,6	8,9	12,8	80,6	26,0	15,3	16,8	9,3
2050	Solar	1,0	2,4	2,2	9,5	0,5	1,1	1,1	16,6	-
	On-grid Wind	19,6	1,6	13,3	-	-	-	-	0,8	38,7
	Hydro	0,0	0,6	20,9	6,4	0,0	2,4	17,8	0,9	7,5
	Nuclear	14,1	4,4	-	-	-	-	-	-	-
	Gas-fired	0,9	2,3	0,1	0,0	39,4	20,1	1,2	4,7	0,0
	Other fossil fuels	0,0	0,0	0,0	0,0	0,0	0,0	0,0	0,0	0,0
	Demand	30,8	21,6	10,8	14,9	93,0	29,9	17,5	19,3	10,9

Hydrogen System										
Production (TWh)		BAS	CEN	COM	CUY	GBA	LIT	NEA	NOA	PAT
2020	SMR	6,9	-	2,7	1,7	0,0	1,5	-	0,2	-
	SMR+CCS	-	-	-	-	-	-	-	-	-
	On-grid Electrolysis	-	-	-	-	-	-	-	-	-
	Off-grid Electrolysis	-	-	-	-	-	-	-	-	-
	Demand	6,9	-	2,7	1,7	0,0	1,5	-	0,2	-
	Exports	-	-	-	-	-	-	-	-	-
2030	SMR	6,9	-	2,7	1,7	0,0	1,5	-	0,2	-
	SMR+CCS	2,6	-	0,5	0,0	0,0	0,3	-	0,1	-
	On-grid Electrolysis	0,0	0,0	0,0	0,0	0,0	0,0	0,0	0,0	0,0
	Off-grid Electrolysis	-	-	-	-	-	-	-	-	-
	Demand	9,5	-	3,2	1,7	0,0	1,7	-	0,2	-
	Exports	0,0	-	0,0	-	-	-	-	-	0,0
2040	SMR	6,8	-	2,7	1,6	0,0	1,5	-	0,2	-
	SMR+CCS	10,2	-	1,2	0,0	0,0	0,8	-	0,3	-
	On-grid Electrolysis	0,0	0,0	0,0	0,0	0,0	0,0	0,0	0,0	0,0
	Off-grid Electrolysis	-	-	-	-	-	-	-	-	5,4
	Demand	17,1	-	3,9	1,6	0,0	2,3	-	0,5	-
	Exports	0,0	-	0,0	-	-	-	-	-	5,4
2050	SMR	6,8	-	2,7	1,5	0,0	1,5	-	0,2	-
	SMR+CCS	7,6	-	3,4	0,0	0,0	1,5	-	0,2	-
	On-grid Electrolysis	0,0	0,0	0,0	0,0	0,0	0,0	0,0	0,0	0,0
	Off-grid Electrolysis	15,2	-	-	-	-	-	-	-	16,1
	Demand	29,4	-	4,8	1,5	0,0	2,9	-	0,4	1,6
	Exports	0,0	-	0,0	-	-	-	-	-	16,1

Hydrogen System										
Production (MtH2)		BAS	CEN	COM	CUY	GBA	LIT	NEA	NOA	PAT
2020	SMR	0,17	-	0,07	0,04	0,00	0,04	-	0,00	-
	SMR+CCS	-	-	-	-	-	-	-	-	-
	On-grid Electrolysis	-	-	-	-	-	-	-	-	-
	Off-grid Electrolysis	-	-	-	-	-	-	-	-	-
	Demand	0,17	-	0,07	0,04	0,00	0,04	-	0,00	-
	Exports	-	-	-	-	-	-	-	-	-
2030	SMR	0,17	-	0,07	0,04	0,00	0,04	-	0,00	-
	SMR+CCS	0,07	-	0,01	0,00	0,00	0,01	-	0,00	-
	On-grid Electrolysis	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00
	Off-grid Electrolysis	-	-	-	-	-	-	-	-	-
	Demand	0,24	-	0,08	0,04	0,00	0,04	-	0,01	-
	Exports	0,00	-	0,00	-	-	-	-	-	0,00
2040	SMR	0,17	-	0,07	0,04	0,00	0,04	-	0,00	-
	SMR+CCS	0,26	-	0,03	0,00	0,00	0,02	-	0,01	-
	On-grid Electrolysis	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00
	Off-grid Electrolysis	-	-	-	-	-	-	-	-	0,14
	Demand	0,43	-	0,10	0,04	0,00	0,06	-	0,01	-
	Exports	0,00	-	0,00	-	-	-	-	-	0,14
2050	SMR	0,17	-	0,07	0,04	0,00	0,04	-	0,00	-
	SMR+CCS	0,19	-	0,09	0,00	0,00	0,04	-	0,01	-
	On-grid Electrolysis	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00
	Off-grid Electrolysis	0,39	-	-	-	-	-	-	-	0,41
	Demand	0,75	-	0,12	0,04	0,00	0,07	-	0,01	0,04
	Exports	0,00	-	0,00	-	-	-	-	-	0,41

7.3.2.2 Advanced Transition

Electrical System										
	Production (TWh)	BAS	CEN	COM	CUY	GBA	LIT	NEA	NOA	PAT
2020	Solar	-	0,1	-	0,8	-	-	-	1,7	-
	On-grid Wind	5,1	0,5	1,0	-	-	-	-	0,5	7,3
	Hydro	-	0,5	9,3	2,2	-	2,4	16,1	0,7	2,4
	Nuclear	5,3	4,6	-	-	-	-	-	-	-
	Gas-fired	14,3	5,3	0,5	2,7	32,4	15,8	0,0	9,5	0,0
	Other fossil fuels	0,0	0,0	0,0	0,0	0,0	0,0	0,0	0,0	-
	Demand	16,7	12,0	5,1	8,3	52,3	17,0	10,2	11,0	5,7
2030	Solar	0,6	1,5	1,3	4,6	0,6	-	-	9,6	-
	On-grid Wind	12,0	1,0	6,9	-	-	-	-	0,6	22,4
	Hydro	0,0	0,5	9,3	3,1	0,0	2,4	17,8	0,7	7,5
	Nuclear	5,6	4,6	-	-	-	-	-	-	-
	Gas-fired	4,3	4,4	0,1	0,6	33,4	14,4	0,1	6,9	0,0
	Other fossil fuels	0,0	0,0	0,0	0,0	0,0	0,0	0,0	0,0	0,0
	Demand	21,2	15,0	6,9	10,4	65,4	21,1	12,5	13,7	7,4
2040	Solar	2,3	3,5	3,3	12,3	2,1	1,9	1,8	18,5	-
	On-grid Wind	24,9	2,0	17,8	-	-	-	-	1,0	39,4
	Hydro	0,0	0,5	19,0	6,3	0,0	2,4	17,8	0,7	7,4
	Nuclear	12,5	4,3	-	-	-	-	-	-	-
	Gas-fired	0,9	0,8	0,1	0,1	16,3	10,0	0,1	5,4	0,0
	Other fossil fuels	0,0	0,0	0,0	0,0	0,0	0,0	0,0	0,0	0,0
	Demand	28,8	19,8	10,7	13,7	85,6	27,3	15,8	17,5	10,4
2050	Solar	2,3	3,5	3,3	27,2	2,1	5,4	1,8	34,7	-
	On-grid Wind	49,7	3,9	38,7	-	-	-	-	1,7	71,1
	Hydro	0,0	0,6	20,9	6,4	0,0	2,4	17,8	0,9	7,5
	Nuclear	11,5	3,6	-	-	-	-	-	-	-
	Gas-fired	0,6	0,4	0,1	0,0	7,9	2,5	0,0	0,8	0,1
	Other fossil fuels	0,0	0,0	0,0	0,0	0,0	0,0	0,0	0,0	0,0
	Demand	36,8	25,2	14,5	17,4	106,9	34,1	19,3	21,7	13,3

Hydrogen System										
Production (TWh)		BAS	CEN	COM	CUY	GBA	LIT	NEA	NOA	PAT
2020	SMR	6,9	-	2,7	1,7	0,0	1,5	-	0,2	-
	SMR+CCS	-	-	-	-	-	-	-	-	-
	On-grid Electrolysis	-	-	-	-	-	-	-	-	-
	Off-grid Electrolysis	-	-	-	-	-	-	-	-	-
	Demand	6,9	-	2,7	1,7	0,0	1,5	-	0,2	-
	Exports	-	-	-	-	-	-	-	-	-
2030	SMR	1,8	-	2,7	1,7	0,0	1,5	-	0,2	-
	SMR+CCS	11,3	-	0,6	0,0	0,0	0,4	-	0,2	-
	On-grid Electrolysis	0,0	0,0	0,0	0,0	0,0	0,0	0,0	0,0	0,0
	Off-grid Electrolysis	-	-	-	-	-	-	-	-	-
	Demand	13,1	-	3,3	1,7	0,0	1,9	-	0,3	-
	Exports	0,0	-	0,0	-	-	-	-	-	0,0
2040	SMR	-	-	-	1,6	-	1,1	-	-	-
	SMR+CCS	11,3	-	2,4	0,0	0,0	1,5	-	0,2	-
	On-grid Electrolysis	0,0	0,0	0,0	0,0	0,0	0,0	0,0	0,0	0,0
	Off-grid Electrolysis	18,6	-	-	-	-	-	-	-	10,8
	Demand	26,7	-	4,3	1,6	0,0	2,6	-	0,2	1,4
	Exports	0,0	-	0,0	-	-	-	-	-	10,8
2050	SMR	-	-	-	-	-	-	-	-	-
	SMR+CCS	12,7	-	2,8	0,8	0,0	3,5	-	0,2	-
	On-grid Electrolysis	0,0	0,0	4,6	0,3	0,0	0,0	0,0	0,3	17,0
	Off-grid Electrolysis	27,5	-	-	-	-	-	-	-	32,3
	Demand	40,5	-	5,5	1,1	0,0	3,5	-	0,3	4,4
	Exports	0,0	-	2,0	-	-	-	-	-	44,5

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Hydrogen System										
Production (MtH2)		BAS	CEN	COM	CUY	GBA	LIT	NEA	NOA	PAT
2020	SMR	0,17	-	0,07	0,04	0,00	0,04	-	0,00	-
	SMR+CCS	-	-	-	-	-	-	-	-	-
	On-grid Electrolysis	-	-	-	-	-	-	-	-	-
	Off-grid Electrolysis	-	-	-	-	-	-	-	-	-
	Demand	0,17	-	0,07	0,04	0,00	0,04	-	0,00	-
	Exports	-	-	-	-	-	-	-	-	-
2030	SMR	0,05	-	0,07	0,04	0,00	0,04	-	0,00	-
	SMR+CCS	0,29	-	0,02	0,00	0,00	0,01	-	0,00	-
	On-grid Electrolysis	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00
	Off-grid Electrolysis	-	-	-	-	-	-	-	-	-
	Demand	0,33	-	0,08	0,04	0,00	0,05	-	0,01	-
	Exports	0,00	-	0,00	-	-	-	-	-	0,00
2040	SMR	-	-	-	0,04	-	0,03	-	-	-
	SMR+CCS	0,29	-	0,06	0,00	0,00	0,04	-	0,00	-
	On-grid Electrolysis	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00
	Off-grid Electrolysis	0,47	-	-	-	-	-	-	-	0,27
	Demand	0,68	-	0,11	0,04	0,00	0,07	-	0,00	0,04
	Exports	0,00	-	0,00	-	-	-	-	-	0,27
2050	SMR	-	-	-	-	-	-	-	-	-
	SMR+CCS	0,32	-	0,07	0,02	0,00	0,09	-	0,00	-
	On-grid Electrolysis	0,00	0,00	0,12	0,01	0,00	0,00	0,00	0,01	0,43
	Off-grid Electrolysis	0,70	-	-	-	-	-	-	-	0,82
	Demand	1,03	-	0,14	0,03	0,00	0,09	-	0,01	0,11
	Exports	0,00	-	0,05	-	-	-	-	-	1,13

7.3.2.3 Net Zero 2050

Electrical System										
	Production (TWh)	BAS	CEN	COM	CUY	GBA	LIT	NEA	NOA	PAT
2020	Solar	-	0,1	-	0,8	-	-	-	1,7	-
	On-grid Wind	5,1	0,5	1,0	-	-	-	-	0,5	7,3
	Hydro	-	0,5	9,3	2,2	-	2,4	16,1	0,7	2,4
	Nuclear	5,3	4,6	-	-	-	-	-	-	-
	Gas-fired	14,3	5,3	0,5	2,7	32,4	15,8	0,0	9,5	0,0
	Other fossil fuels	0,0	0,0	0,0	0,0	0,0	0,0	0,0	0,0	-
	Demand	16,7	12,0	5,1	8,3	52,3	17,0	10,2	11,0	5,7
2030	Solar	0,9	2,2	2,0	6,6	0,9	-	-	13,9	-
	On-grid Wind	15,8	1,3	10,1	-	-	-	-	0,7	27,3
	Hydro	0,0	0,5	9,3	3,1	0,0	2,4	17,8	0,7	7,5
	Nuclear	5,5	4,5	-	-	-	-	-	-	-
	Gas-fired	1,7	3,1	0,1	0,1	26,2	11,3	0,1	6,1	0,0
	Other fossil fuels	0,0	0,0	0,0	0,0	0,0	0,0	0,0	0,0	0,0
	Demand	21,9	15,4	7,3	10,6	66,9	21,6	12,7	13,9	7,7
2040	Solar	0,9	5,5	5,3	19,5	0,9	3,1	3,0	28,6	-
	On-grid Wind	37,3	2,9	28,2	-	-	-	-	1,3	52,0
	Hydro	0,0	0,5	19,0	6,3	0,0	2,4	17,8	0,7	7,5
	Nuclear	11,3	3,9	-	-	-	-	-	-	-
	Gas-fired	0,8	0,3	0,1	0,1	5,3	2,4	0,0	1,2	0,0
	Other fossil fuels	0,0	0,0	0,0	0,0	0,0	0,0	0,0	0,0	0,0
	Demand	31,1	21,5	11,9	14,8	91,4	29,2	16,7	18,7	11,2
2050	Solar	0,9	5,5	5,3	32,6	0,9	3,1	3,0	33,4	-
	On-grid Wind	80,3	6,2	64,5	-	-	-	-	2,5	101,4
	Hydro	0,0	0,6	20,9	6,4	0,0	2,4	17,8	0,9	7,5
	Nuclear	11,1	3,5	-	-	-	-	-	-	-
	Gas-fired	0,4	0,2	0,1	0,0	6,2	1,4	0,0	0,5	0,0
	Other fossil fuels	0,0	0,0	0,0	0,0	0,0	0,0	0,0	0,0	0,0
	Demand	40,9	28,1	16,9	19,1	115,6	36,9	20,5	23,5	14,6

Hydrogen System										
Production (TWh)		BAS	CEN	COM	CUY	GBA	LIT	NEA	NOA	PAT
2020	SMR	6,9	-	2,7	1,7	0,0	1,5	-	0,2	-
	SMR+CCS	-	-	-	-	-	-	-	-	-
	On-grid Electrolysis	-	-	-	-	-	-	-	-	-
	Off-grid Electrolysis	-	-	-	-	-	-	-	-	-
	Demand	6,9	-	2,7	1,7	0,0	1,5	-	0,2	-
	Exports	-	-	-	-	-	-	-	-	-
2030	SMR	0,0	-	0,0	0,0	0,0	0,0	-	0,0	-
	SMR+CCS	17,1	-	3,5	1,7	0,0	2,0	-	0,5	-
	On-grid Electrolysis	0,0	0,0	0,0	0,0	0,0	0,0	0,0	0,0	0,0
	Off-grid Electrolysis	-	-	-	-	-	-	-	-	3,2
	Demand	17,1	-	3,5	1,7	0,0	2,0	-	0,5	-
	Exports	0,0	-	0,0	-	-	-	-	-	3,2
2040	SMR	-	-	-	-	-	-	-	-	-
	SMR+CCS	19,0	-	5,7	1,7	0,0	3,0	-	0,5	-
	On-grid Electrolysis	0,0	0,0	0,9	0,0	0,0	0,0	0,0	0,1	8,4
	Off-grid Electrolysis	15,5	-	-	-	-	-	-	-	24,7
	Demand	34,5	-	4,6	1,3	0,0	3,0	-	0,5	3,0
	Exports	0,0	-	1,5	-	-	-	-	-	31,0
2050	SMR	-	-	-	-	-	-	-	-	-
	SMR+CCS	4,4	-	2,3	0,0	0,0	3,3	-	0,0	-
	On-grid Electrolysis	5,7	0,0	11,7	0,8	0,0	0,3	0,0	0,7	56,1
	Off-grid Electrolysis	31,3	-	-	-	-	-	-	-	67,7
	Demand	45,9	-	6,2	0,5	0,0	4,0	-	0,4	9,8
	Exports	0,0	-	3,8	-	-	-	-	-	113,4

Hydrogen System										
	Production (MtH2)	BAS	CEN	COM	CUY	GBA	LIT	NEA	NOA	PAT
2020	SMR	0,17	-	0,07	0,04	0,00	0,04	-	0,00	-
	SMR+CCS	-	-	-	-	-	-	-	-	-
	On-grid Electrolysis	-	-	-	-	-	-	-	-	-
	Off-grid Electrolysis	-	-	-	-	-	-	-	-	-
	Demand	0,17	-	0,07	0,04	0,00	0,04	-	0,00	-
	Exports	-	-	-	-	-	-	-	-	-
2030	SMR	0,00	-	0,00	0,00	0,00	0,00	-	0,00	-
	SMR+CCS	0,43	-	0,09	0,04	0,00	0,05	-	0,01	-
	On-grid Electrolysis	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00
	Off-grid Electrolysis	-	-	-	-	-	-	-	-	0,08
	Demand	0,43	-	0,09	0,04	0,00	0,05	-	0,01	-
	Exports	0,00	-	0,00	-	-	-	-	-	0,08
2040	SMR	-	-	-	-	-	-	-	-	-
	SMR+CCS	0,48	-	0,15	0,04	0,00	0,08	-	0,01	-
	On-grid Electrolysis	0,00	0,00	0,02	0,00	0,00	0,00	0,00	0,00	0,21
	Off-grid Electrolysis	0,39	-	-	-	-	-	-	-	0,63
	Demand	0,88	-	0,12	0,03	0,00	0,08	-	0,01	0,08
	Exports	0,00	-	0,04	-	-	-	-	-	0,79
2050	SMR	-	-	-	-	-	-	-	-	-
	SMR+CCS	0,11	-	0,06	0,00	0,00	0,08	-	0,00	-
	On-grid Electrolysis	0,14	0,00	0,30	0,02	0,00	0,01	0,00	0,02	1,42
	Off-grid Electrolysis	0,79	-	-	-	-	-	-	-	1,72
	Demand	1,17	-	0,16	0,01	0,00	0,10	-	0,01	0,25
	Exports	0,00	-	0,10	-	-	-	-	-	2,88

7.3.3 Inter-regional Network Expansion

7.3.3.1 Current Commitments

Line capacity (MW)	2020	2030	2040	2050
TRANSMISSION_BAS_CEN	-	0	0	0
TRANSMISSION_BAS_COM	5 300	5 300	7 175	7 175
TRANSMISSION_BAS_GBA	5 300	6 131	8 364	8 364
TRANSMISSION_BAS_LIT	-	0	0	0
TRANSMISSION_CEN_BAS	-	0	0	0
TRANSMISSION_CEN_COM	-	0	1 040	1 040
TRANSMISSION_CEN_CUY	865	892	1 229	1 115
TRANSMISSION_CEN_LIT	850	850	850	850
TRANSMISSION_CEN_NOA	850	850	850	850
TRANSMISSION_COM_BAS	5 300	5 300	7 175	7 175
TRANSMISSION_COM_CEN	-	0	1 040	1 040
TRANSMISSION_COM_CUY	1 600	1 600	1 600	1 600
TRANSMISSION_COM_PAT	850	2 708	4 444	6 010
TRANSMISSION_CUY_CEN	850	877	1 214	1 100
TRANSMISSION_CUY_COM	1 600	1 600	1 600	1 600
TRANSMISSION_CUY_NOA	-	0	577	577
TRANSMISSION_GBA_BAS	5 300	6 131	8 364	8 364
TRANSMISSION_GBA_LIT	3 200	3 200	3 200	3 200
TRANSMISSION_LIT_BAS	-	0	0	0
TRANSMISSION_LIT_CEN	1 200	1 200	1 200	1 200
TRANSMISSION_LIT_GBA	3 200	3 200	3 200	3 200
TRANSMISSION_LIT_NEA	3 550	3 550	3 550	3 550
TRANSMISSION_LIT_NOA	-	0	0	0
TRANSMISSION_NEA_LIT	3 550	3 550	3 550	3 550
TRANSMISSION_NEA_NOA	850	850	850	1 190
TRANSMISSION_NOA_CEN	850	850	850	850
TRANSMISSION_NOA_CUY	-	0	577	577

TRANSMISSION_NOA_LIT	-	0	0	0
TRANSMISSION_NOA_NEA	850	850	850	1 190
TRANSMISSION_PAT_COM	850	2 708	4 444	6 010
Total	**46 765**	**52 196**	**67 794**	**71 378**

7.3.3.2 Advanced Transition

Line capacity (MW)	2020	2030	2040	2050
TRANSMISSION_BAS_CEN	-	0	0	435
TRANSMISSION_BAS_COM	5 300	5 300	7 318	10 338
TRANSMISSION_BAS_GBA	5 300	5 863	9 435	14 377
TRANSMISSION_BAS_LIT	-	0	0	0
TRANSMISSION_CEN_BAS	-	0	0	435
TRANSMISSION_CEN_COM	-	0	1 038	1 359
TRANSMISSION_CEN_CUY	865	865	1 398	2 576
TRANSMISSION_CEN_LIT	850	850	959	1 747
TRANSMISSION_CEN_NOA	850	850	850	899
TRANSMISSION_COM_BAS	5 300	5 300	7 318	10 338
TRANSMISSION_COM_CEN	-	0	1 038	1 359
TRANSMISSION_COM_CUY	1 600	1 600	1 600	3 991
TRANSMISSION_COM_PAT	850	3 627	6 226	9 163
TRANSMISSION_CUY_CEN	850	850	1 383	2 561
TRANSMISSION_CUY_COM	1 600	1 600	1 600	3 991
TRANSMISSION_CUY_NOA	-	304	304	1 229
TRANSMISSION_GBA_BAS	5 300	5 863	9 435	14 377
TRANSMISSION_GBA_LIT	3 200	3 200	3 200	3 200
TRANSMISSION_LIT_BAS	-	0	0	0
TRANSMISSION_LIT_CEN	1 200	1 200	1 309	2 097
TRANSMISSION_LIT_GBA	3 200	3 200	3 200	3 200
TRANSMISSION_LIT_NEA	3 550	3 550	3 550	3 550
TRANSMISSION_LIT_NOA	-	0	184	1 053
TRANSMISSION_NEA_LIT	3 550	3 550	3 550	3 550
TRANSMISSION_NEA_NOA	850	850	1 921	2 850

TRANSMISSION_NOA_CEN	850	850	850	899
TRANSMISSION_NOA_CUY	-	304	304	1 229
TRANSMISSION_NOA_LIT	-	0	184	1 053
TRANSMISSION_NOA_NEA	850	850	1 921	2 850
TRANSMISSION_PAT_COM	850	3 627	6 226	9 163
Total	46 765	54 055	76 301	113 864

7.3.3.3 Net Zero 2050

Line capacity (MW)	2020	2030	2040	2050
TRANSMISSION_BAS_CEN	-	0	536	903
TRANSMISSION_BAS_COM	5 300	5 300	9 150	11 633
TRANSMISSION_BAS_GBA	5 300	6 653	12 037	19 085
TRANSMISSION_BAS_LIT	-	0	0	62
TRANSMISSION_CEN_BAS	-	0	536	903
TRANSMISSION_CEN_COM	-	0	1 350	1 667
TRANSMISSION_CEN_CUY	865	897	2 217	3 792
TRANSMISSION_CEN_LIT	850	850	1 783	2 773
TRANSMISSION_CEN_NOA	850	850	850	850
TRANSMISSION_COM_BAS	5 300	5 300	9 150	11 633
TRANSMISSION_COM_CEN	-	0	1 350	1 667
TRANSMISSION_COM_CUY	1 600	1 600	2 407	5 047
TRANSMISSION_COM_PAT	850	4 580	7 830	7 916
TRANSMISSION_CUY_CEN	850	882	2 202	3 777
TRANSMISSION_CUY_COM	1 600	1 600	2 407	5 047
TRANSMISSION_CUY_NOA	-	351	756	1 064
TRANSMISSION_GBA_BAS	5 300	6 653	12 037	19 085
TRANSMISSION_GBA_LIT	3 200	3 200	3 200	3 200
TRANSMISSION_LIT_BAS	-	0	0	62
TRANSMISSION_LIT_CEN	1 200	1 200	2 133	3 123
TRANSMISSION_LIT_GBA	3 200	3 200	3 200	3 200

TRANSMISSION_LIT_NEA	3 550	3 550	3 550	3 550
TRANSMISSION_LIT_NOA	-	81	1 126	1 163
TRANSMISSION_NEA_LIT	3 550	3 550	3 550	3 550
TRANSMISSION_NEA_NOA	850	2 143	2 143	2 428
TRANSMISSION_NOA_CEN	850	850	850	850
TRANSMISSION_NOA_CUY	-	351	756	1 064
TRANSMISSION_NOA_LIT	-	81	1 126	1 163
TRANSMISSION_NOA_NEA	850	2 143	2 143	2 428
TRANSMISSION_PAT_COM	850	4 580	7 830	7 916
Total	46 765	60 443	98 205	130 600

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