Decarbonising the Dutch gas-fired power fleet

Note on the assessment of policy options

October 12, 2023 – Prepared by Aurora Energy Research

This study has been developed by Aurora Energy Research, in close alignment with six study participants

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The findings of this study are a result of the in-house modelling methodology, assumptions, and data of Aurora Energy Research

Sources: Aurora Energy Research

Agenda

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Executive Summary

(1/3)

1 Preparing for a CO_2-neutral and secure power system by 2035 requires 10 GW of additional[1,2] carbon-free flexible capacity.

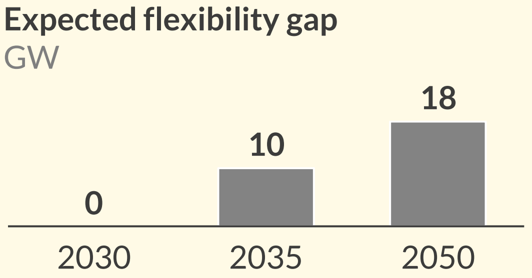
- After coal exits the system by 2030, there can be no more net emissions of natural gas by 2035, to reach a CO_2-neutral power sector in line with government ambitions.
- Due to a growing share of intermittent wind and solar production, additional flexible capacity that can quickly ramp up and down is needed– up to 10 GW by 2035 and 18 GW by 2050.

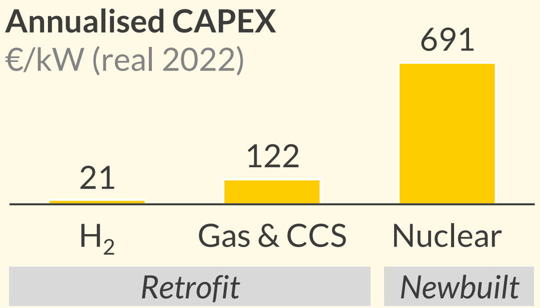
2 Among options to fill the flexibility gap, retrofitting the current natural gas fleet to H_2 requires the least additional investment.

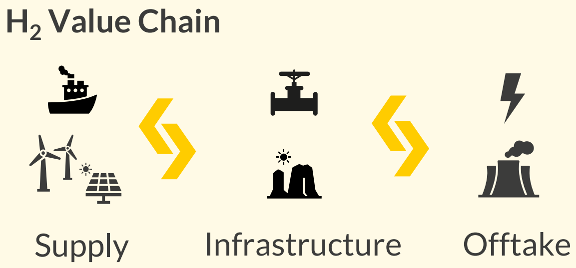
- Batteries and flexible demand are cornerstones of a secure, CO_2-neutral power system, but dispatchable plants will still be needed.
- Retrofitted H_2 CCGTs utilise existing infrastructure and are a cost-effective option to provide low carbon dispatchable power.
- Gas & CCS could be apt to complement this as next most cost-effective choice and newbuilt H_2 plants could play a long-term role.

3 To ensure enough access to H_2, coordinated policy action between supply, infrastructure, and power sector offtake is required.

- Electrolyser production is expected to grow strongly, but imports and/or blue H_2 production will be required to meet rising demand.
- Plant operators must be able to plan long-term offtake volumes, and access the national H_2 network & off-site storage facilities.
- Efforts should start early as developing the needed infrastructure will require sufficient time.







1) On top of existing firm capacity, DSR, and interconnection; 2) Can be realised by retrofitting plants, not only with newbuilt capacity

Sources: Aurora Energy Research

Executive Summary

(2/3)

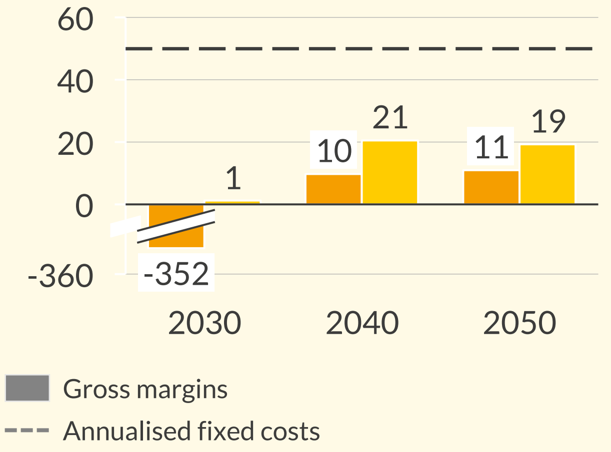
4 Retrofitting the natural gas fleet to H_2 is technically feasible, but without further support plants will be priced out of the merit order due to high fuel costs.

- Plants can be retrofitted to blend 30% H_2 volume relatively cheaply (~€70/kW), but emission savings are limited (~10%), while 100% retrofits (~€195/kW) decarbonise stronger.
- The high price of H_2, relative to natural gas, increases marginal costs of CCGTs, pricing them out of the merit order in most hours. H_2 plants are profitable in limited hours and margins remain low.
- Low running hours lead to difficult and costly H_2 sourcing and storage contracting. Storage requirements are significant and should be developed in a timely manner.

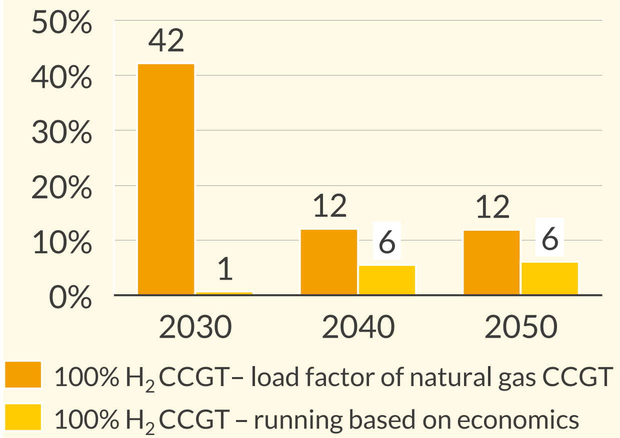
5 To stimulate power production based on H_2, both the fixed and variable components need support through new policy.

- Additional support is needed to incentivise the conversion of natural gas plants to run on hydrogen.
- The government is already planning to compensate for fixed costs, by budgeting €1 bln for plant conversion CAPEX.
- CAPEX and OPEX support ensures proper de-risking, whilst also increasing security of supply and lowering import dependency.
- No additional support could lead to a delayed roll-out, especially as H_2 supply chain, including storage, may be a limiting factor.

Gross margins & fixed costs H_2 retrofit[1]
€/kW (real 2022)



Load factor H_2 retrofit[1]
%



1) In Aurora Net Zero scenario

Sources: Aurora Energy Research

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Executive Summary

(3/3)

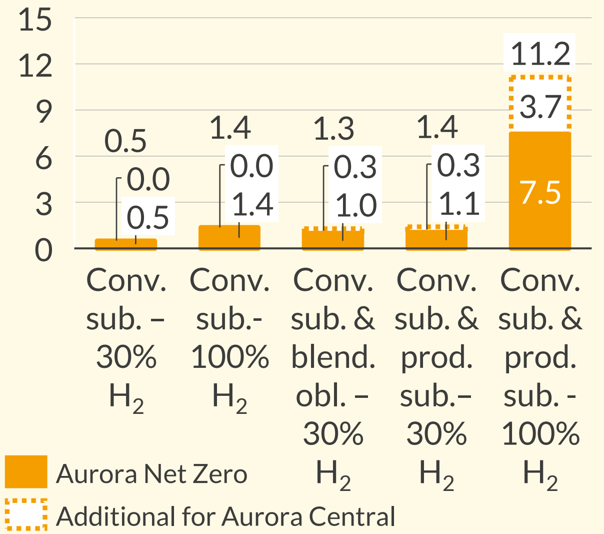
6 **While budget costs for a 100% H_2 production subsidy are high, CO_2-savings are high & abatement costs low, compared to blending.**

- A conversion subsidy with a 100% H_2 production subsidy would be a relatively cost-efficient option, as emissions are reduced strongly and there will be less carbon leakage than with other options.
- A stand-alone conversion subsidy has the lowest budget costs, but CO_2-savings are uncertain & abatement costs are hard to quantify.

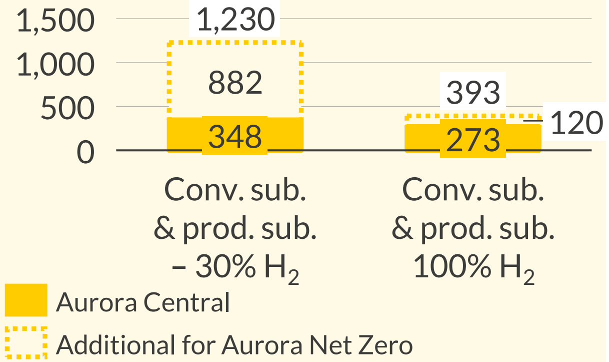
7 **A policy to stimulate decarbonisation and H_2 use, will also need to balance security of supply and import dependence considerations.**

- Forcing out natural gas without stimulating alternatives, or raising the CO_2 price in the Netherlands unilaterally, will increase import dependence, impact security of supply, and drive up prices.
- A stand-alone conversion subsidy, or combined with subsidised blending, will not have a strong decarbonising effect, but will create the optionality of using H_2 and help with a timely transition.
- On the other hand, enforcing an obligation to blend would have a negative effect on security of supply.
- Adding a 100% H_2 production subsidy will strongly decarbonise, stimulate a timely development of a liquid H_2 market in the Netherlands, and lower the risk of H_2 plants not running. Yet, with H_2 supply potentially constrained strongly, it could reduce availability of H_2 to hard to abate sectors, impacting overall CO_2 reduction and/or making action in other sectors more costly[1].
- EU-ETS prices are an efficient tool to decarbonise but could be insufficient to incentivise clean H_2 use in the power sector.

Total subsidy cost 2030 to 2050
Bln €



Average abatement cost 2030 - 2050
€/tCO_2e (real 2022)



1) This effect has not been analysed in this study

Sources: Aurora Energy Research

Demand is expected to rise significantly, while baseload generation is replaced by intermittent sources, resulting in an increased need for flexibility

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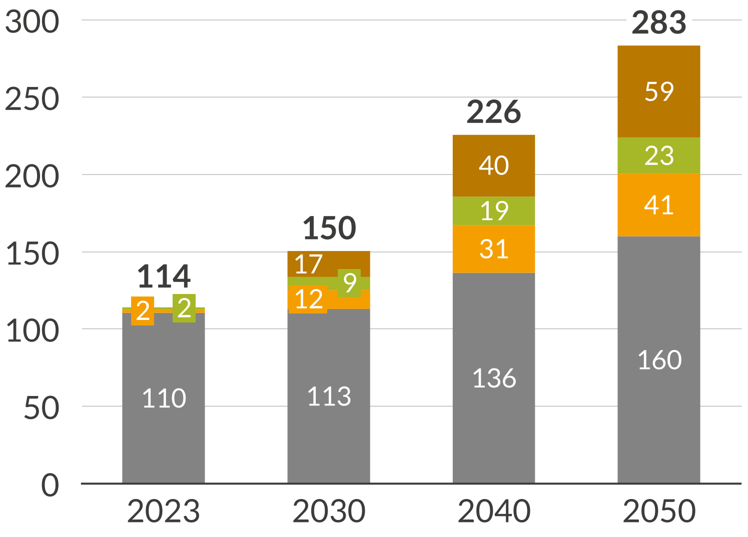
Net electricity demand[1] – Aurora Net Zero

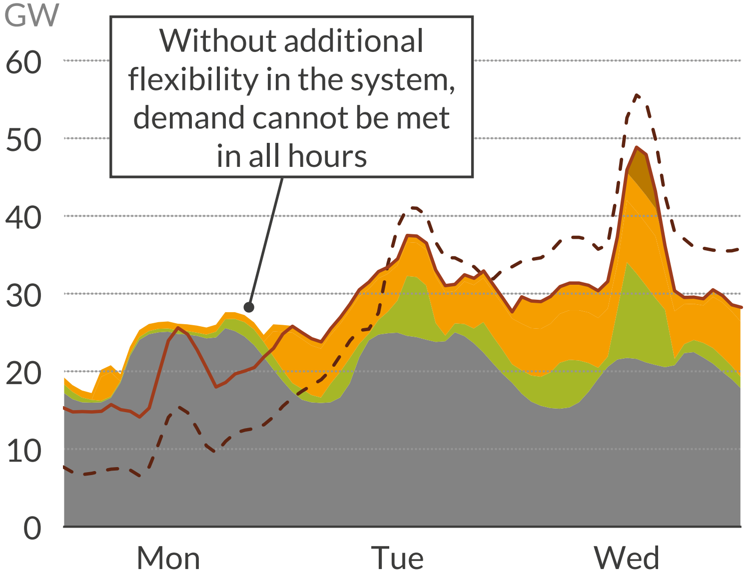
TWh



- Power demand is expected to more than double between now (114 TWh) and 2050 (283 TWh), in our target-driven Net Zero scenario.
- While this demand will become increasingly more flexible, the base demand in the Netherlands will continuously increase over the years as well.

Example generation 2050 – No added flex – Winter[4]

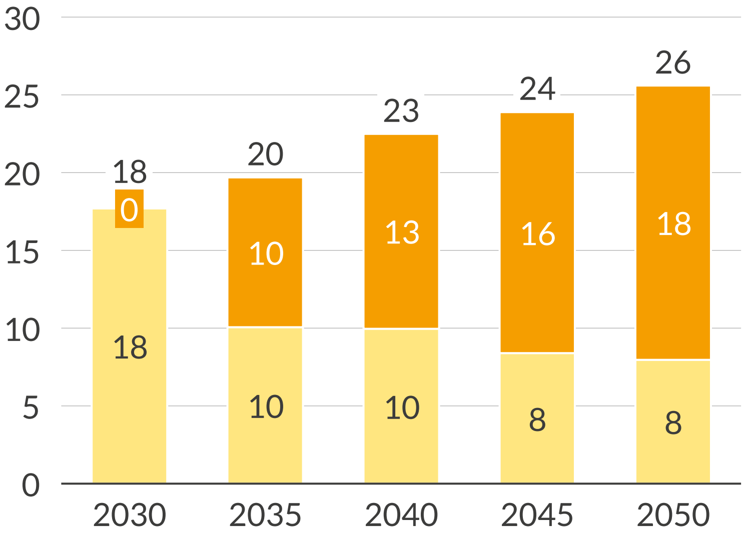
GW



- Due to the increased share of wind and solar production, peak demand will occur, especially in winter, where generation without additional flexibility in the system is insufficient.
- Technologies that can quickly ramp up and down are needed, to ensure this peak demand is met in a cost-efficient manner.

Need for flexibility[5] – Aurora Net Zero

GW



- Due to this, the need for flexible capacity rapidly increases, from 18 GW in 2030 to 26 GW in 2050 in our Net Zero scenario.
- There is a need of up to 18 GW of flexible capacity, on top of existing firm capacity, DSR, and interconnection, due to natural gas plants required to transform to ensure a CO_2-neutral power system by 2035.

- - RES-generation — Total generation incl. net imports

Base power demand[2] Heat pumps & P2H EVs Hydrogen[3]

Derated existing flexible capacity, DSR & Interconnection[6]

Potential flexibility gap

1) Including sectoral demand & transmission losses, but excluding power plant self-consumption & demand from efficiency losses of storage; 2) Underlying demand excluding heat pumps, Evs, and electrolysis; 3) Demand for H_2 production from electrolysis; 4) From Aurora study for EZK on carbon free flexible alternatives; 5) Excluding a security margin; 6) Adjusted for the share of capacity that is expected to contribute to peak demand, excluding RES

Sources: Aurora Energy Research; Oxford economics; IMF

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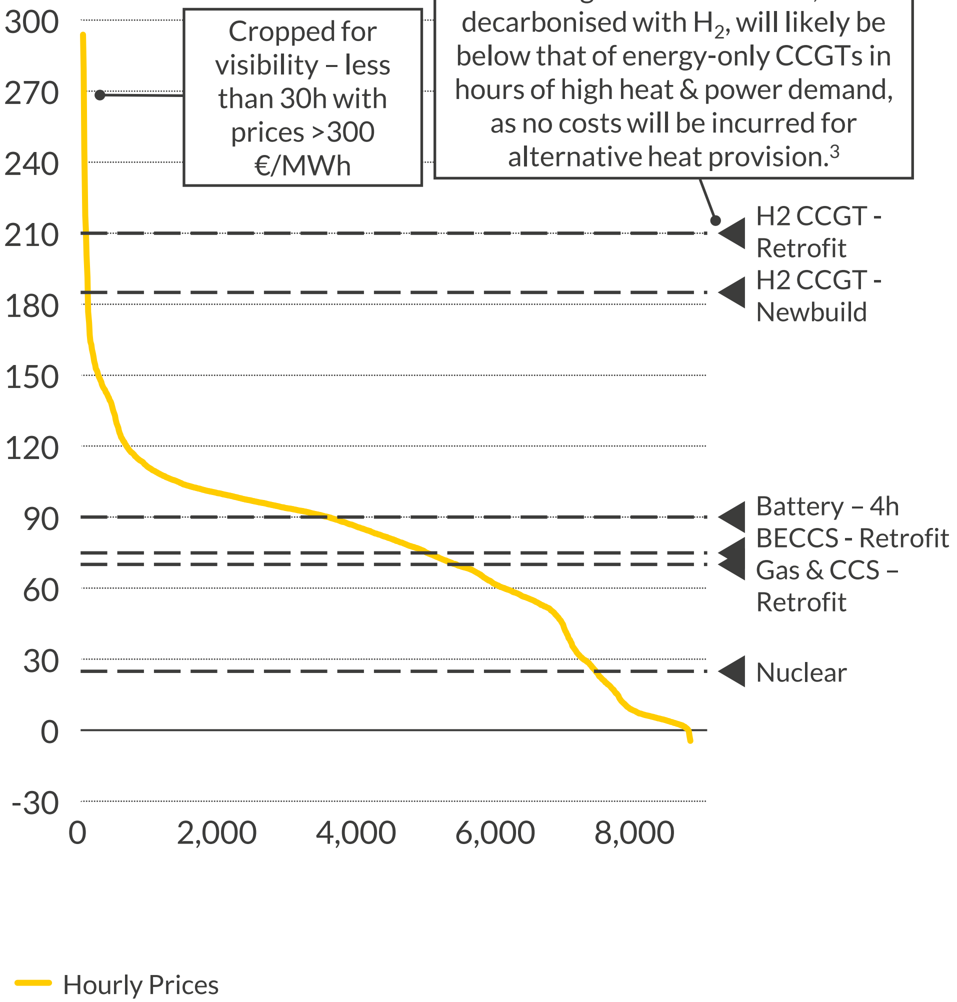
Compared to several flexible low carbon alternatives, H_2 CCGTs are characterised by low investment costs but high marginal costs

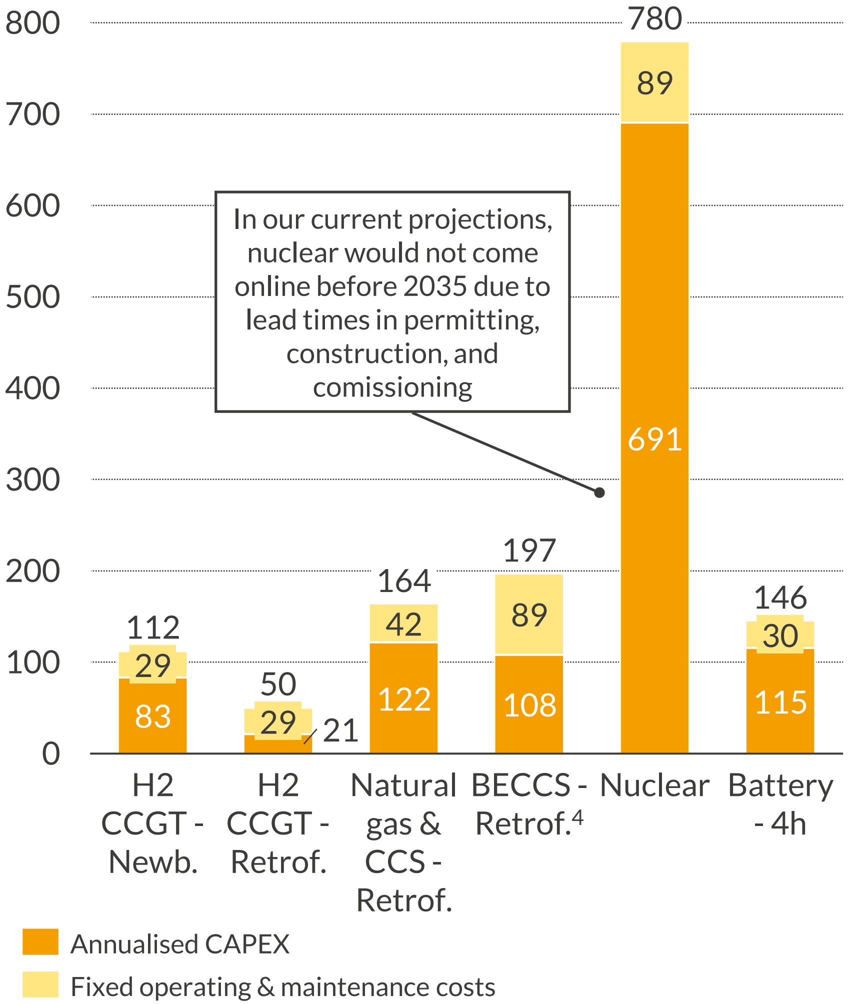
Price duration curve & marginal costs in 2030 – Aurora Net Zero

€/MWh (real 2022)



Annual fixed costs in 2030 – Aurora Net Zero[1,2]

€/kW (real 2022)



- Retrofitted hydrogen CCGTs have the lowest annual fixed costs of the alternatives considered in this study, but the high marginal costs, determined by the price of hydrogen, hinder these plants from running.
- Nuclear runs a very large share of the year due to its low marginal costs, although its high fixed costs make it hard to remain profitable, and reduces potential for renewables.
- Natural gas & CCS and BECCS[4] have comparable marginal costs, although negative emissions provide an additional revenue stream for BECCS[4], which may benefit from rising carbon prices.
- Batteries can help reduce renewable curtailment, but have dispatch constraints due to their limited storage & discharge potential, and cannot fill the flexibility gap on their own.

1) Fixed costs of retrofit plants are dependent on over how many years the CAPEX can be spread, lifetime of 20 years assumed for H_2 retrofits; 2) Considering costs due to the time needed for construction; 3) Depending on specific efficiency of CHP and alternative heat provision in portfolio; 4) Bioenergy & CCS

Sources: Aurora Energy Research

In 2030, in our Net Zero scenario, retrofit H_2 CCGTs have the lowest gap to profitability, but still need support to become a viable option

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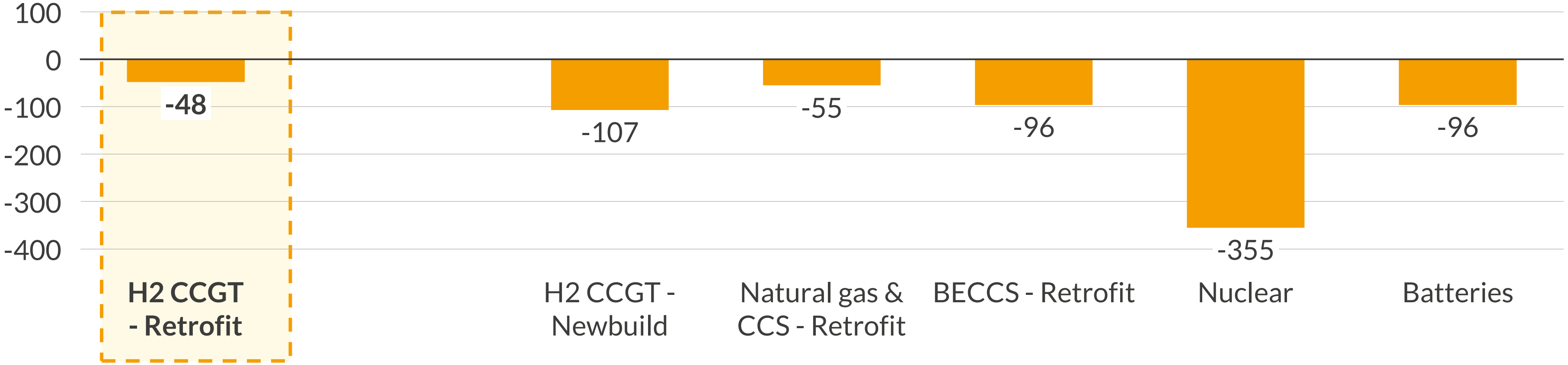
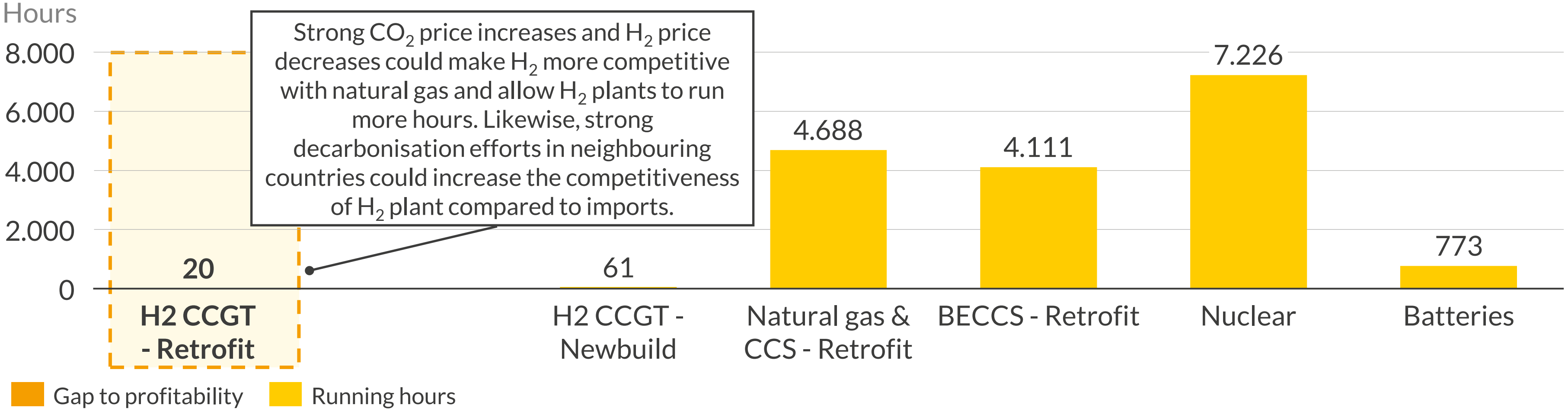
Gap to profitability in 2030[1,2,3] – Aurora Net Zero
€/kW (real 2022)



Full load hours in 2030 – Aurora Net Zero
Hours



1) Profitability of retrofit plants is dependent on spread of CAPEX over years, lifetime of 20 years assumed for H_2 retrofits; 2) Considering costs due to the time needed for construction; 3) This does not reflect emission reduction effectiveness. 4) Batteries might have an overall positive business case through revenue stacking with ancillary services – not focus of this study

Sources: Aurora Energy Research

- Retrofit hydrogen CCGTs have lowest gap to profitability, as retrofit requires low fixed costs.
  - Yet, high marginal costs keep them from running outside of peak hours without support.
- Technologies with CCS display high run hours in 2030.
  - BECCS running hours will depend on carbon markets and revenue from negative emissions.
  - Natural gas & CCS provides low gap to profitability with high run hours, reducing risk. Over time, profitability declines with uncaptured emissions and rising carbon prices.
- Nuclear is very capital-intensive, but will run most hours due to low variable cost and limited ramping.
- Batteries will only be able to run limited hours based on wholesale prices[4], as charging depth is limited.

CHP CCGTs could provide carbon free power & heat in challenging peak demand hours, but are excluded from the current policy proposal

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Benefits of CHPs

- CHPs can support both the power and heat markets in decarbonising, contributing during the most challenging (winter) hours with a shortage of electricity and high heat demand
  - Using hydrogen they could support with flexible low carbon power generation
  - CHPs could help reduce the need to run e-boilers or heat pumps during hours of shortage, avoiding additional electricity consumption, and instead provide both heat and electricity
- CHPs are characterised by being located relatively close to end-users, and can play a more decentralised role in providing power & heat

Challenges of converting CHPs to run on H_2

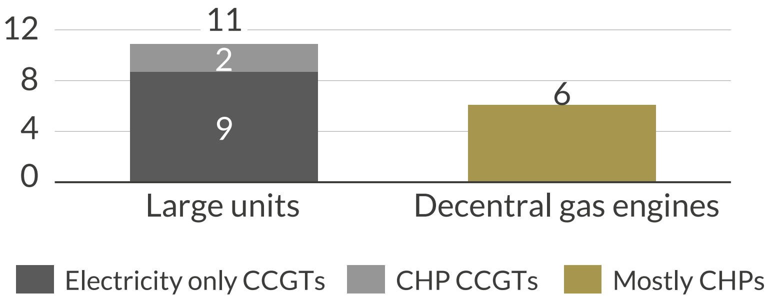
- Generally, CHPs face the same technical challenges as electricity only plants in the transition to hydrogen fuelled power generation
- However, there are a couple of characteristics that set them apart
  - Dispatch behaviour is not solely based on spark spreads, but also on revenue streams of heat or obligations to run, due to long term contracts
  - Some CHPs are integrated in industrial heating processes, which can increase the risk on capacity loss due to space constraints
  - Dutch CHPs are on average much older than the electricity-only CCGTs

Reflection on the currently proposed subsidy

- The currently proposed subsidy to retrofit natural gas plants is aimed at retrofitting existing large electricity-only CCGTs, and includes an obligation to blend a CO_2-free energy carrier
- In the current proposal, for the first round of this subsidy, the government communicates to exclude CHPs
- A solution for decarbonising CHPs must be found, as they can play a role in the decarbonisation of both the power & heat markets
  - If CHPs are fully decarbonised using hydrogen, a lot of hours with higher costs could occur due to contractual obligations to provide heat

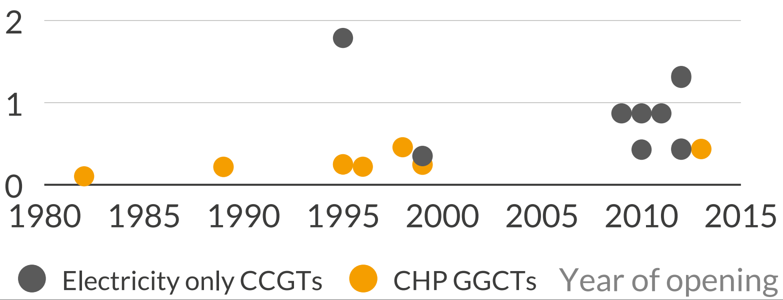
Installed capacity per type of natural gas plant

GW

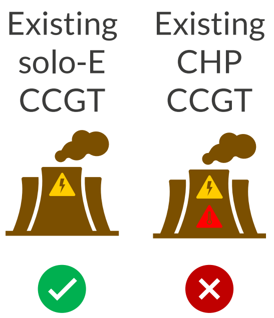


Dutch CCGTs (CHPs & electricity-only plants)

Capacity - GW



Scope of proposed first round of subsidy



Note: No in-depth dispatch modelling on a plant level has been done for CHP CCGTs in the course of this study

To effectively decarbonise the Dutch gas fleet, policy action needs to reflect risks for players along the entire H_2 value chain

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The H_2 value chain …

…needs to be reflected for policies for converting the Dutch gas plants to H_2

A **H_2 Generation and Supply**

- Buildout of renewables must be supported for local generation of green H_2. Dutch supply needs to be supplemented by blue H_2 in the medium term and imports even in the long-term.
- Before a liquid market forms, multi-year offtake agreements with sufficient flexibility are needed for generators.
- Subsidising the production of H_2 could help with the predictability of price levels, but does not address the uncertainty of needed volumes.

B **Infrastructure and Storage**

- For offtaker and supplier to close agreements, transport infrastructure needs to be ready and plannable – government commitment to certain timelines can ensure credibility.
- For higher H_2 volumes over the course of the 2030s, additional large-scale storage and pipeline infrastructure will be required to support offtake in power and other sectors. Efforts need to be undertaken to access practical onshore storage potential in the Netherlands.

C **Offtake and power generation**

- Offtake and use of hydrogen in the power sector need to be supported by clear policies, for generators to coordinate with suppliers and infrastructure providers.
- As we expect an undersupply of hydrogen in the Netherlands, only with clear foresight of support schemes and obligations, generators will be able to convert their plants and secure offtake agreements for a timely transition in the power sector.

- Policies in EU and neighbouring countries.
- Cross-border flows and connecting infrastructure.

Sources: Aurora Energy Research

A quick ramp-up of domestic hydrogen production, imports, and storage capacity is needed to meet domestic H_2 demand

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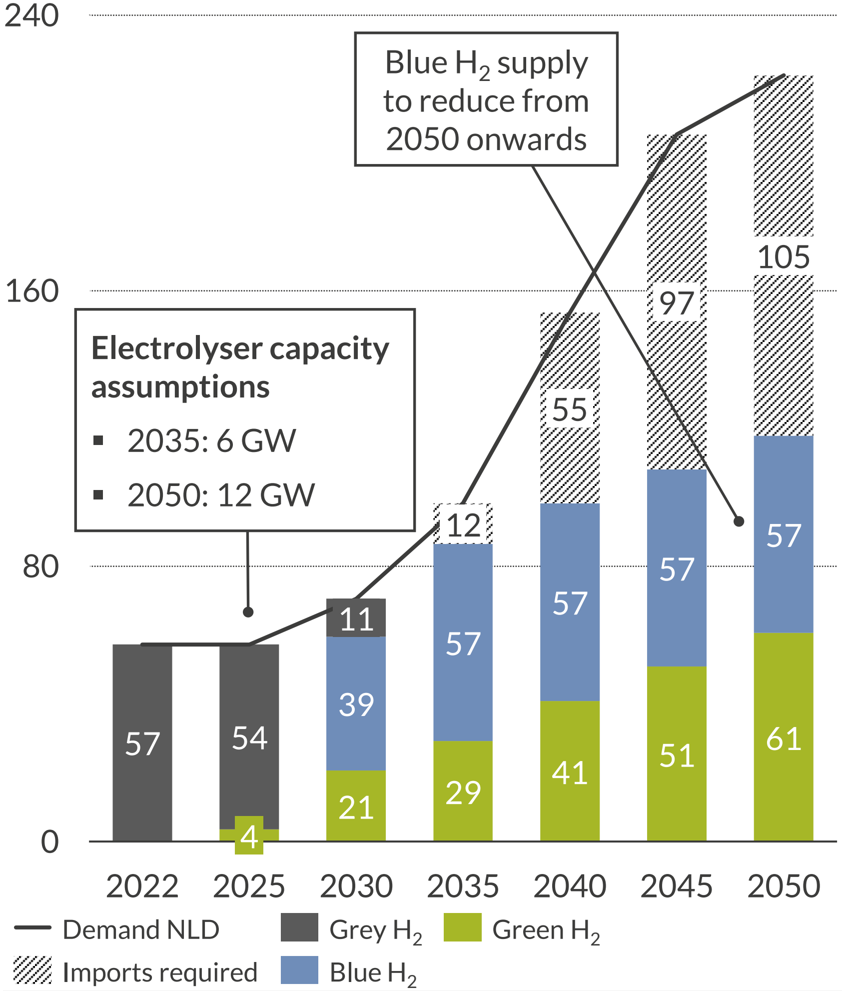
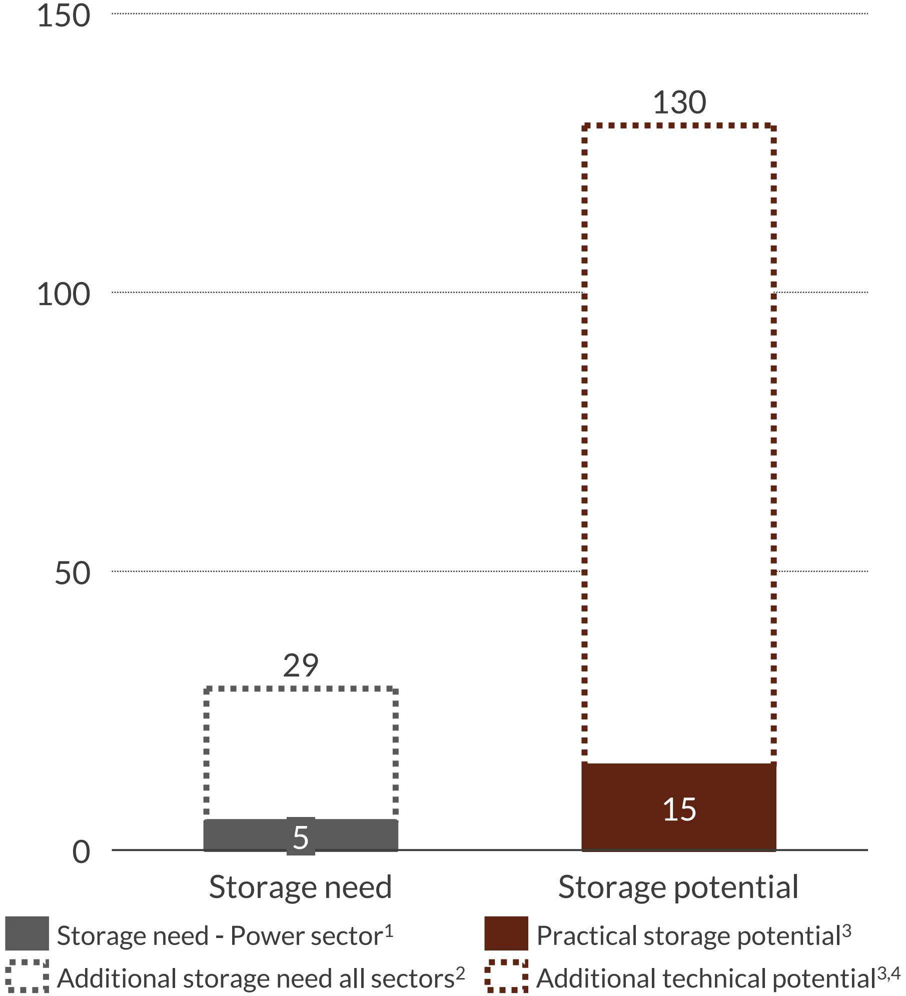
A Illustrative hydrogen supply mix – Aurora Net Zero

TWh, final energy consumption



B Salt cavern H_2 storage need & potential

TWh



- The Netherlands supports the production of both green and blue[5] hydrogen by the SDE++ subsidy scheme.
- We expect electrolyser capacity to increase significantly to 6 GW in 2035 & 12 GW in 2050.
- Despite the significant ramp-up of low-carbon H_2 technologies, the country will heavily rely on imports quite early in the time horizon.
  - But different sectors might compete for H_2 supply.
- Storage is necessary to ensure sufficient H_2 supply and domestic onshore storage potential might not suffice for the total system demand.
- Alternatives to onshore salt cavern storage in the Netherlands could be:
  - Outsourcing to facilities in Germany
  - Offshore storage in the Northsea

1) Based on a strategic reserve needed to cover a month of highest demand in the Net Zero scenario in 2045; 2) According to the Roadmap Energy Storage; 3) Only considering onshore storage potential; 4) Based on techno-economic modelling of salt caverns by the RWTH Aachen; 5) Mainly through support for CCS

Sources: Aurora Energy Research; Hystock; RWTH Aachen; Ministerie van Economische Zaken en Klimaat; TNO

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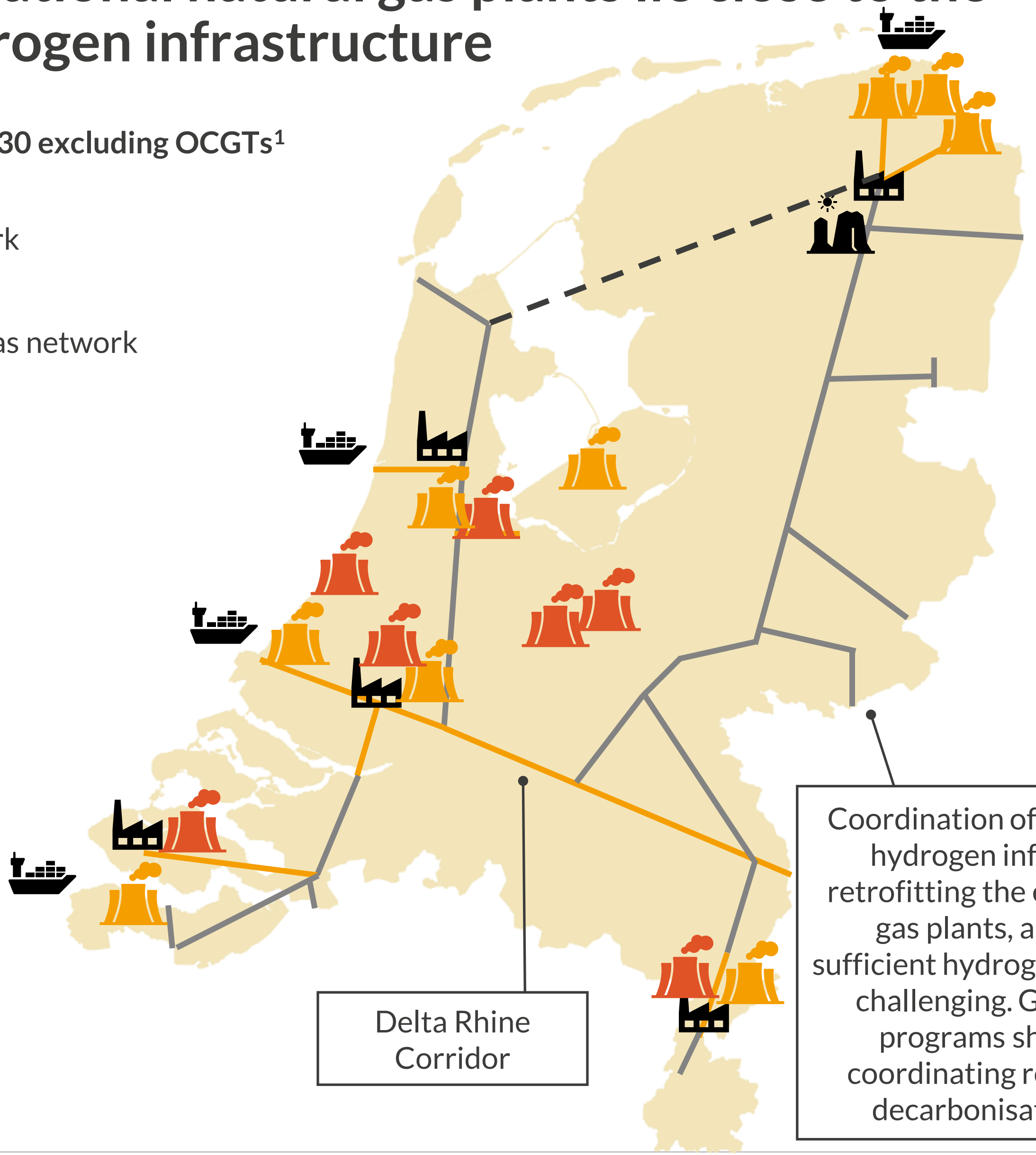
Not all currently operational natural gas plants lie close to the planned national hydrogen infrastructure

B Planned national hydrogen network 2030 excluding OCGTs[1]

- New pipelines hydrogen network
- Repurposed pipelines natural gas network
- Potential pipeline route
- Industrial cluster
- Import
- Salt cavern storage
- CCGTs
- CHPs



Coordination of developing the hydrogen infrastructure, retrofitting the existing natural gas plants, and ensuring sufficient hydrogen supply is very challenging. Governmental programs should take a coordinating role to support decarbonisation targets.

- The future hydrogen network, as currently planned, is located near most CCGTs and CHPs in the Netherlands.
- However, there are several plants that do not lie close to the planned national network.
- Local grid operators could potentially play a role in bridging this gap, or private pipelines could be built.
- Still, the availability of hydrogen for these plants in 2030/2035 is for a large part dependent on further governmental plans for development of the grid.
- The need for early connection of plants further away from the planned national network could lead to higher costs for HyNetwork Services.

1) Positions of all elements on the map are indicative

Sources: Aurora Energy Research; Gasunie; Hystock; Hynetwork

A conversion subsidy supports retrofits at low cost; A production subsidy is costly, but could help decarbonise the power market & stimulate a H_2 market

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Design options

Assessment	A Conversion subsidy	B Conversion subsidy with a 30% H_2[1] blending requirement	C Conversion subsidy with a 100% H_2 production subsidy	D Obligation to phase out natural gas	E National carbon price
Budget cost of policy 2030 - 2050[2]	Positive	Positive	Negative	Neutral	Neutral
Decarbonisation in the NLD by 2035	Neutral	Neutral	Positive	Positive	Positive
Security of Supply	Positive	Negative	Positive	Negative	Negative
Electricity import dependency	Neutral	Negative	Positive	Negative	Negative
Hydrogen consumption power sector	Neutral	Neutral	Positive	Negative	Negative

A more detailed breakdown of this scoring can be found in the Appendix, section V

If a lower share of H_2 in the fuel mix is subsidised, budget costs will reduce, as well as the contribution to decarbonisation

Positive Neutral Negative Extensive quantitative analysis Concise assessment

1) Volume based; 2) Obligation to phase out natural gas & national carbon price have low 'direct' budget costs, but can bear higher indirect costs (e.g., societal costs, indirect costs for compensation of missed revenues)

Sources: Aurora Energy Research

Subsidy cost levels are determined based on the goal of a policy option, depending on initial investment costs and increased operating costs

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A Conversion subsidy

- The purpose of a conversion subsidy is to incentivise the retrofitting of natural gas plants
- Compensation from the government is needed for:
  - The capital expenditure of the retrofitting[1]

Cost calculation

Cost of conversion of natural gas plant × Total capacity of natural gas plant

B Conversion subsidy with a blending obligation

- The purpose of adding a blending obligation to the conversion subsidy, is to stimulate production with H_2 in the fuel mix, to be able to cover peak power demand
- Compensation is needed for:
  - The capital expenditure of the retrofitting
  - The difference in margins between a gas and 30% volume blended hydrogen plant, **running based on economics**[2]

Cost calculation

Cost of conversion of natural gas plant × Total capacity of natural gas plant

AND

Gross margin reference natural gas plant − Gross margin reference 30% H_2 blended plant

C Conversion subsidy with a production subsidy

- The purpose of a adding a production subsidy to the conversion subsidy, is to stimulate production with hydrogen to the level of a mid-merit gas plant
- Compensation is needed for:
  - The capital expenditure of the retrofitting
  - The difference in margins of a natural gas and a hydrogen plant (30% or 100% H_2 volume), **running at the load of a natural gas plant**[2]

Cost calculation

Cost of conversion of natural gas plant × Total capacity of natural gas plant

AND

Gross margin reference natural gas plant − Gross margin reference H_2 plant

1) Cost level dependent on whether the retrofitting to a blended or 100% H_2 plant is compensated; 2) This will mostly coincide with the difference in fuel cost between a natural gas plant and hydrogen plant, as this is the largest cost component, and takes into account running hours risk as compensation is offered for the load similar to that of a natural gas plant

Sources: Aurora Energy Research

Implementing a 100% H_2 production subsidy has higher budget costs than other policy options, between €7.5 & €11.2 bln

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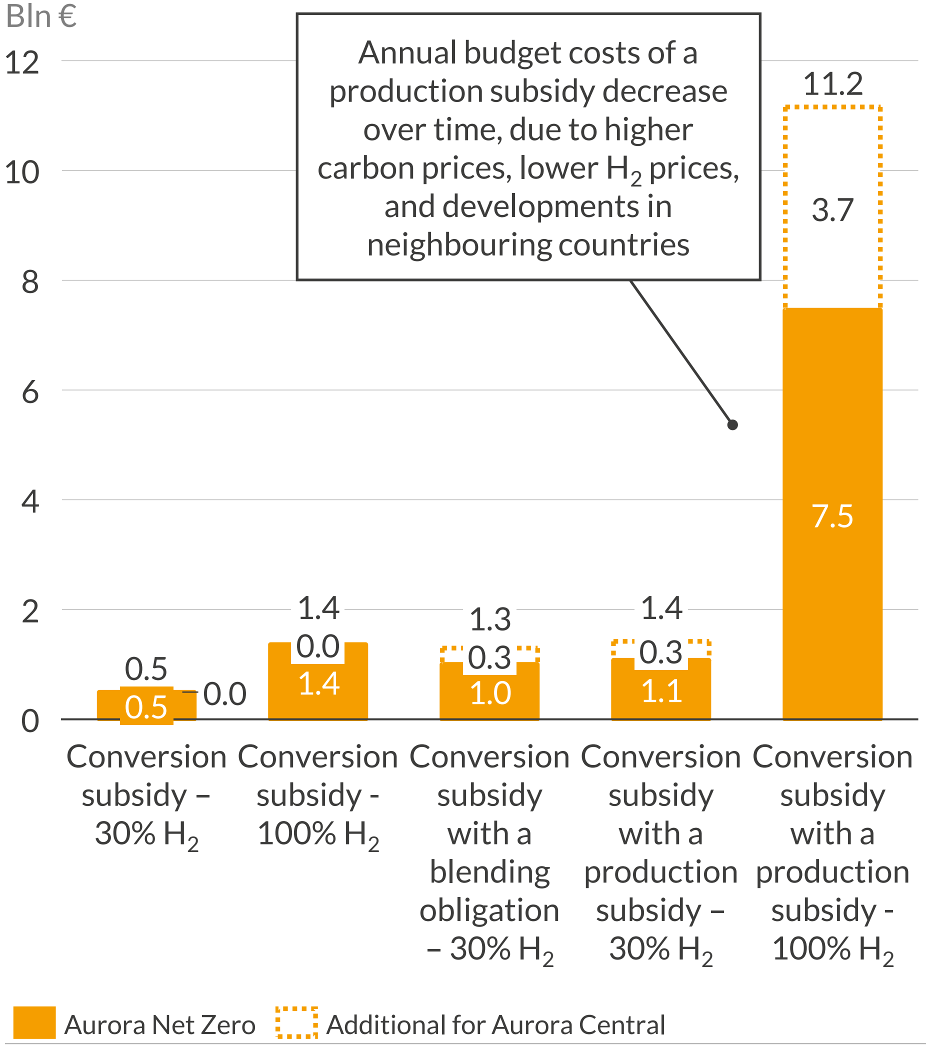
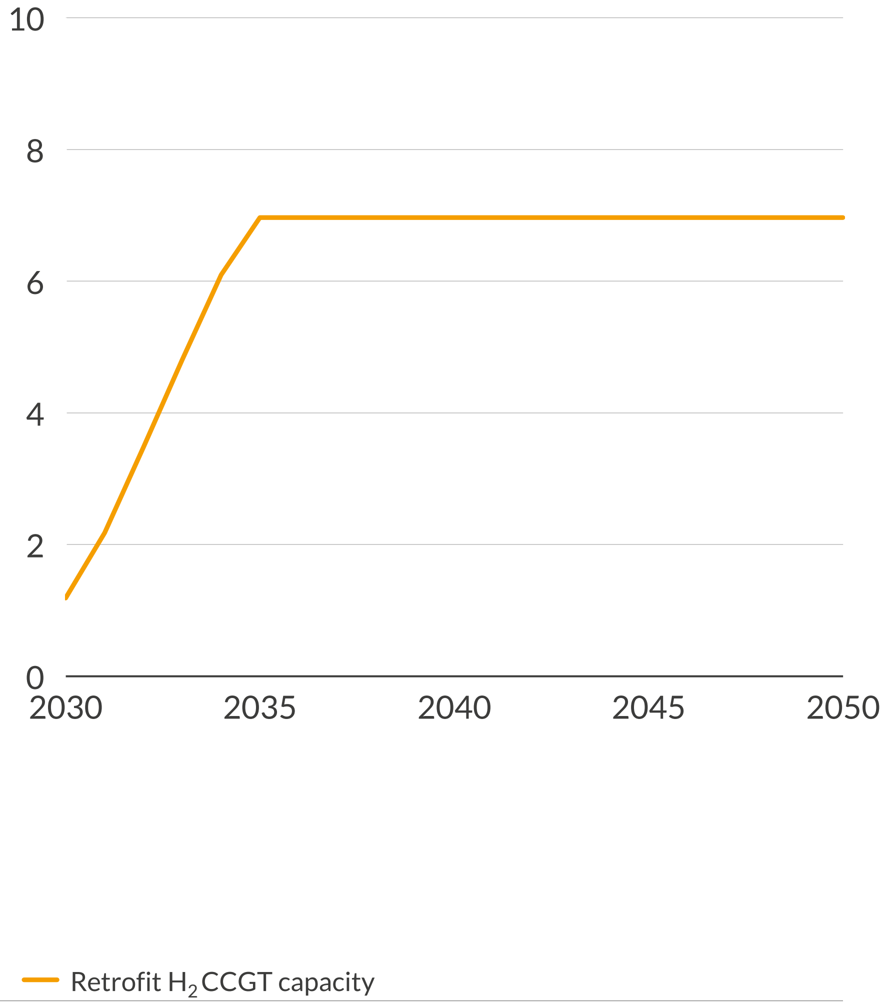
Total subsidy cost 2030 to 2050 – Central H_2 price scenario



Retrofit build out assumption[1,2]



- To compare the impact of the subsidy schemes in different pricing scenarios, we assume a retrofit buildout pattern reaching 7 GW in the long term in both scenarios, due to economic lifetimes and potential capacity losses.
- This is consistent with the buildout pattern in the Aurora Net Zero scenario, but does not reflect the actual retrofit buildout in the Aurora Central scenario.
- Compared to other policy options, implementing a 100% H_2 production subsidy is much more expensive.
- However, enforcing a blending requirement, or subsidising 30% H_2 blended production, is not sufficient to reach a carbon-neutral power sector by 2035, as not all emission of natural gas plants will be replaced.

1) Used throughout this policy note to calculate total subsidy costs

Sources: Aurora Energy Research

While a 100% production subsidy has high budget costs, it leads to high emission savings in NLD, with limited cost per tonne CO_2 abated

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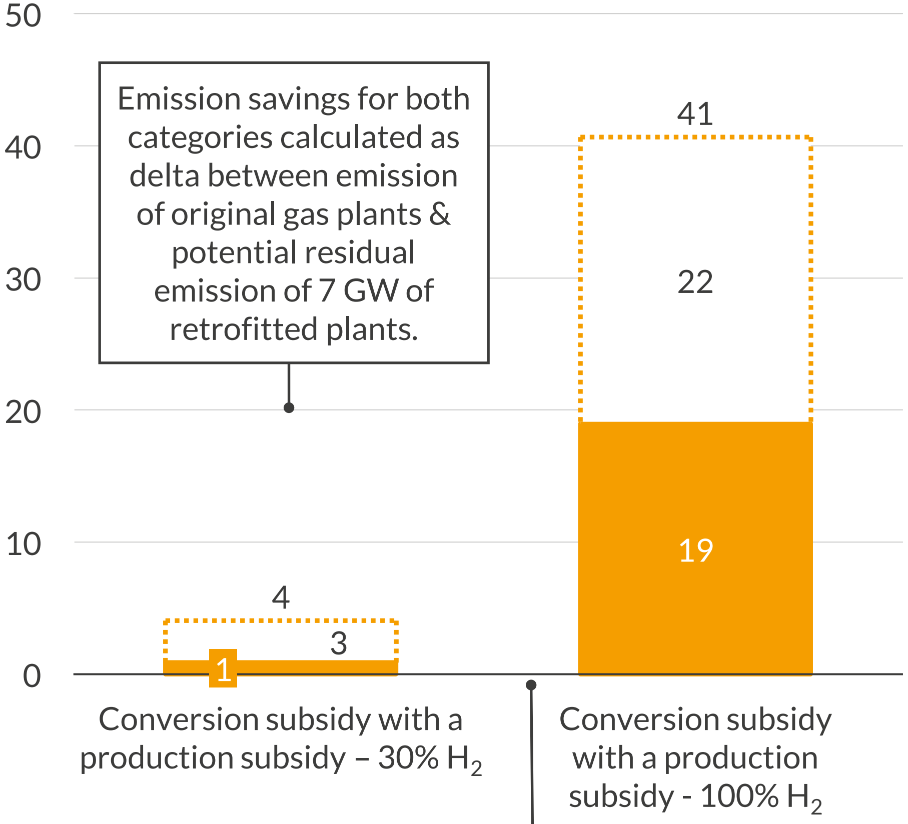
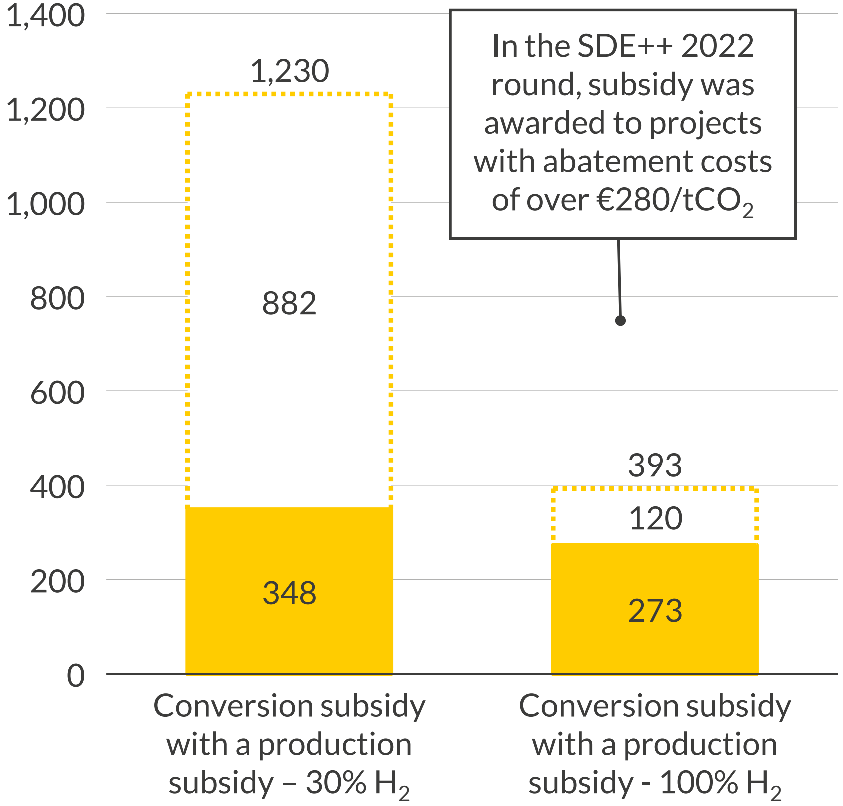
Total emission savings NLD 2030 - 2050[1]

$MtonneCO_2e$



Average abatement cost 2030 - 2050[4]

€/tCO_2e (real 2022)



Emission savings in the Netherlands not reflecting total emission savings on the EU level, as the EU-ETS mechanism covers the entire power sector.

Aurora Net Zero[2] | Additional for Aurora Central[3] | Aurora Central | Addditional for Aurora Net Zero

- A conversion subsidy & 100% production subsidy is cost-efficient, especially in the Central scenario, as natural gas remains in the system longer than in Net Zero and potential for emission savings is higher.
- A conversion subsidy & 30% production subsidy is less cost-efficient, as a larger share of H_2 exponentially saves more emissions[5], and will not result in a CO_2-neutral power sector without additional policy.
- Emission savings of a stand-alone conversion subsidy and one with a 30% blending obligation are uncertain
  - Stand-alone: as this provides the optionality to run on H_2.
  - Blending obligation: as the share of natural gas remaining in the system is uncertain. Assuming 45% – 55%, abatement costs could range between ~€270 & ~€1440/tCO2e.

1) Under the assumption of 0 CO_2 emission from hydrogen, see Appendix for potential emission levels H_2; 2) 2030 – 2034; 3) 2030 – 2047; 4) EU-ETS costs for burning natural gas included in calculation of subsidy levels, these abatement costs are additional costs on top of regular carbon payments; 5) 30% volume share of H_2, equal to ~10% energy content

Sources: Aurora Energy Research ; Rijksoverheid; Ministerie van Economische Zaken en Klimaat

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Details and disclaimer

Publication
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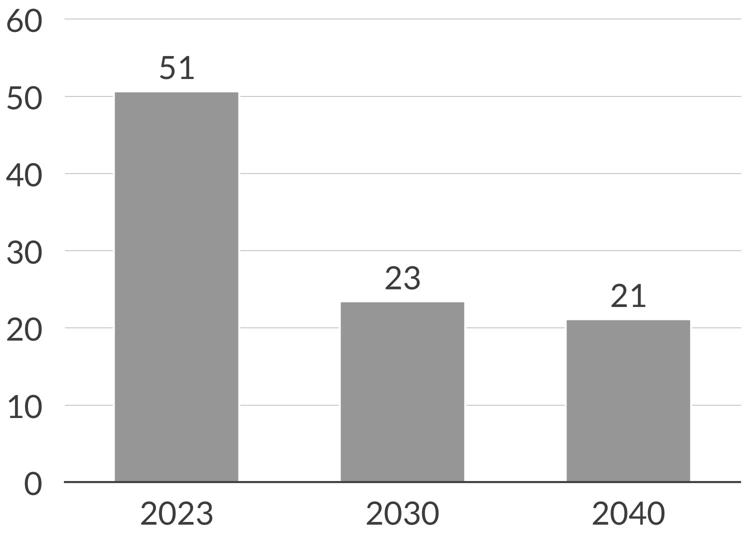
ENERGY RESEARCH

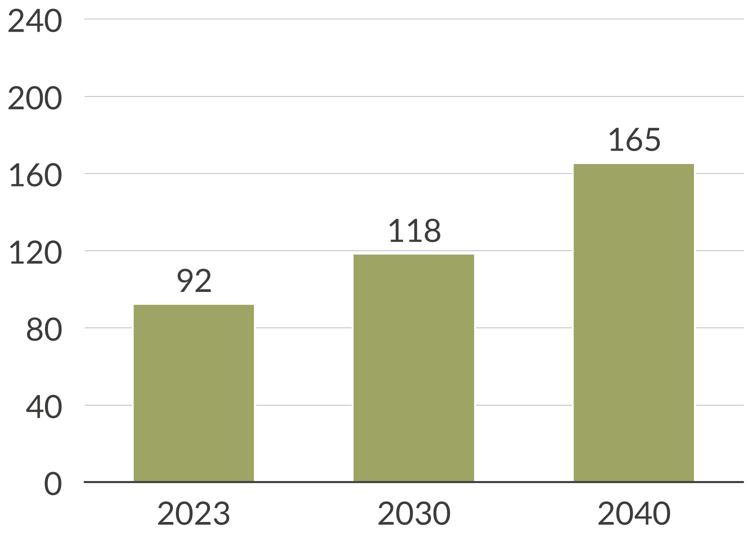
Agenda

In Aurora's Net Zero scenario, natural gas prices are expected to decrease toward 2030, while carbon prices grow strongly over the years

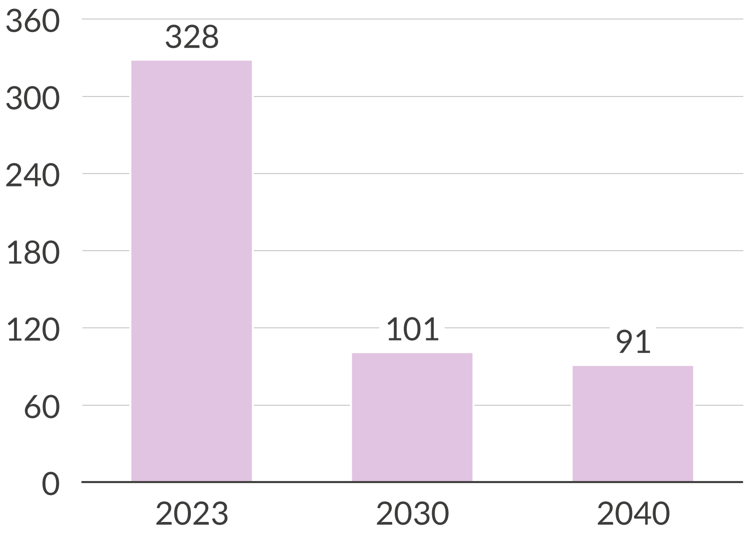
Natural gas prices – Aurora Net Zero
€/MWh (real 2022)[1]



Carbon prices[2] – Aurora Net Zero
€/tCO_2 (real 2022)



Hydrogen prices – Aurora Net Zero
€/MWh HHV (real 2022)



- In Aurora's Central Scenario, natural gas prices are assumed to be higher and carbon prices are assumed to be lower, resulting in a more attractive environment for natural gas plants than in the Net Zero scenario – and higher budget costs for production subsidies.
- If the carbon price increases more strongly than expected in Aurora's Net Zero scenario (e.g., due to very strong competition for EU-ETS certificates by harder to abate industries), hydrogen offtake might be viable without subsidising production due to an increased competitive position compared to natural gas plants.
  - The chance of this happening would further increase with more strongly decreasing hydrogen prices than expected in Aurora's Net Zero scenario.

1) For years 2023-2028, the prices shown take into account current futures prices for the years in question, with declining weights; 2) 2023 price is a mix of historical price and forecast YTD as of February 2023. For years 2023-2027 the prices shown consider current futures prices with declining weights

Sources: Aurora Energy Research

The EU-ETS price could be insufficient to stimulate retrofitting, as transitioning to H_2 comes with high switching costs

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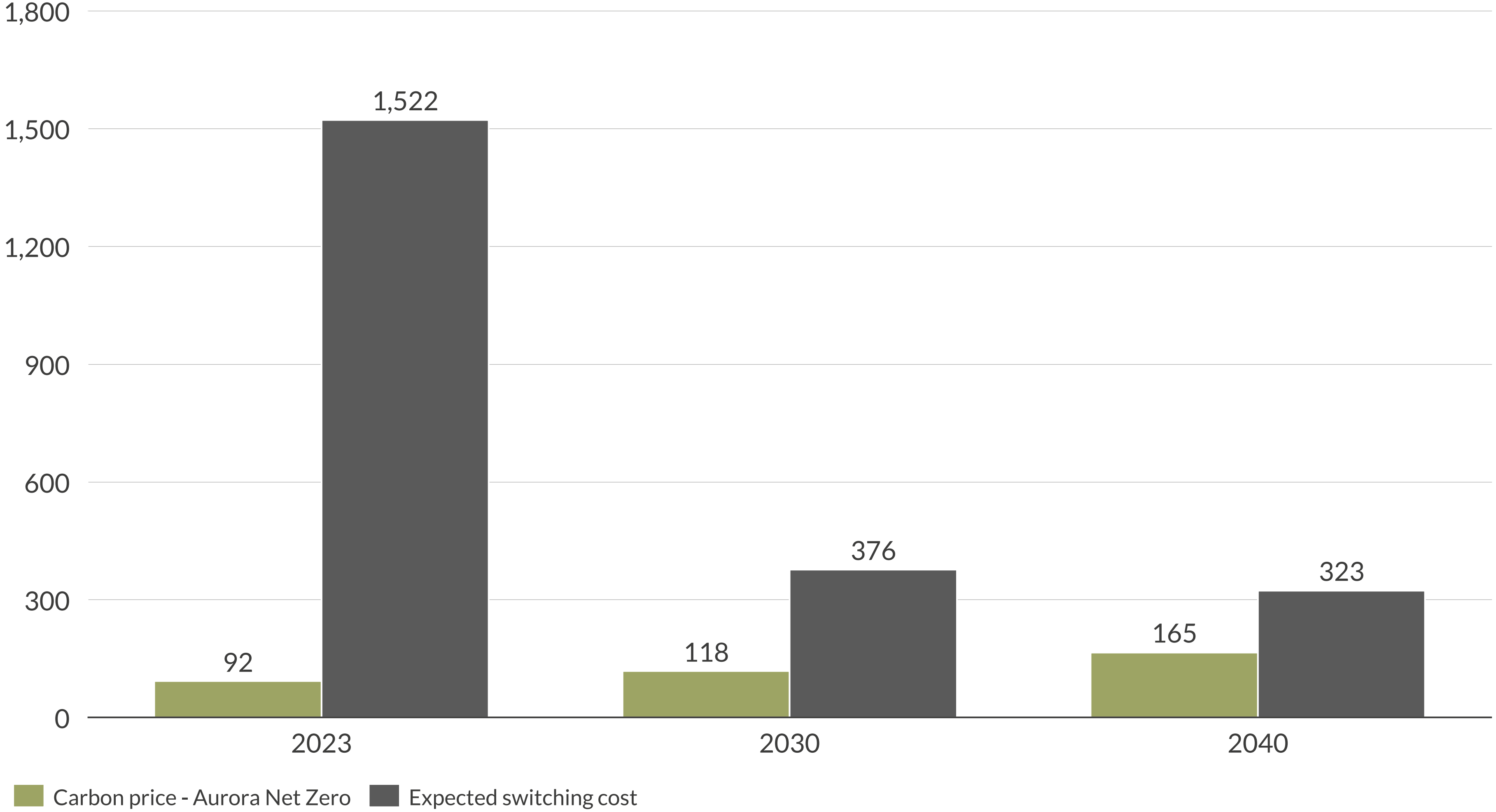
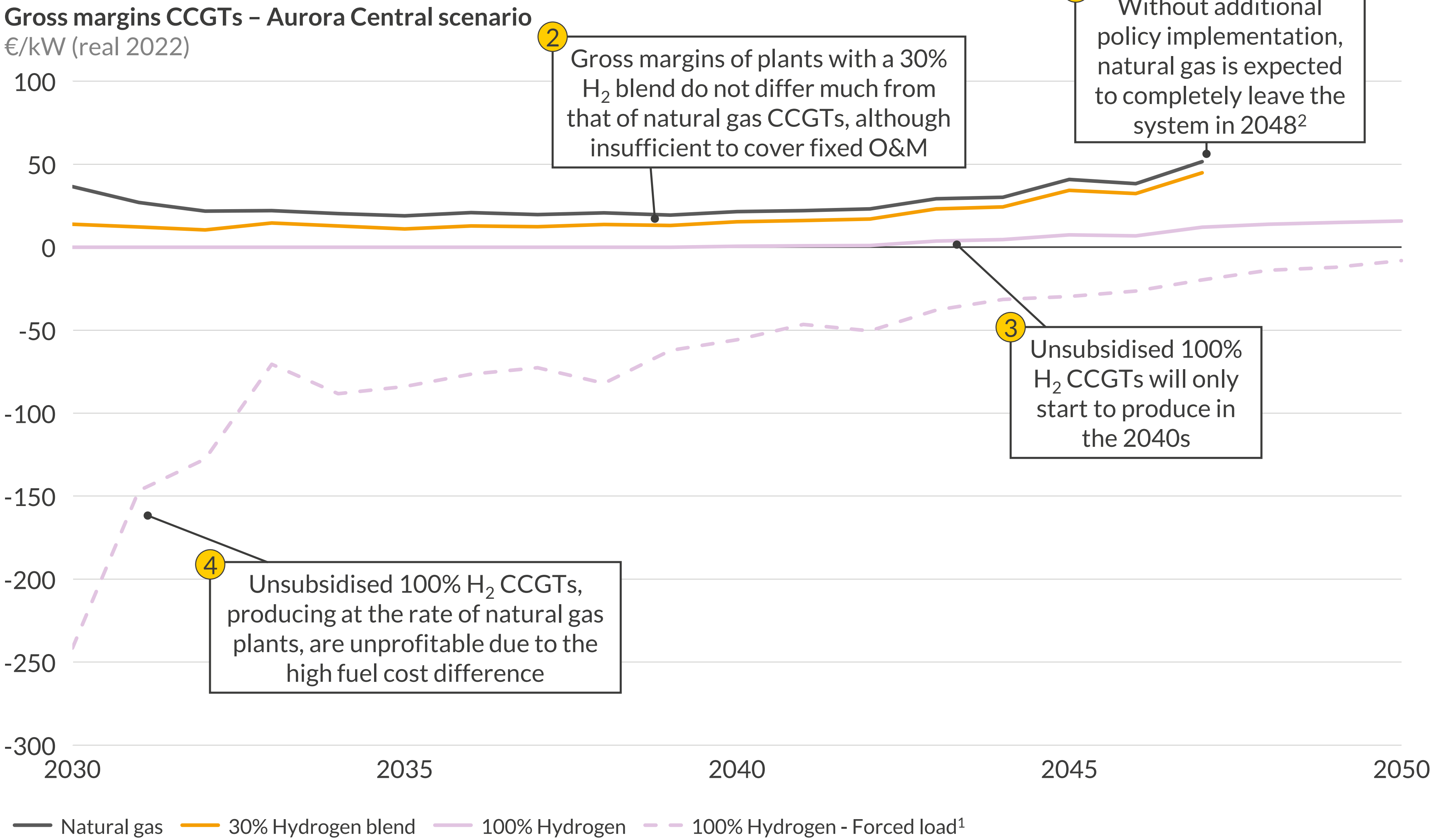
Carbon prices & expected switching costs natural gas to H_2
€/tCO_2e (real 2022)



- A large role in the decarbonisation of gas assets is given to the EU-ETS mechanism.
- However, due to the high fuel costs associated with hydrogen, the switching cost associated with retrofitting natural gas plants to burn H_2 are high.
- Comparing switching costs to the carbon price in Aurora's Net Zero scenario, the CO_2 price, by itself, is not expected to incentivise switching behaviour in the foreseeable future.
- Depending on the development of the carbon price, additional support could be needed to stimulate the timely conversion of natural gas plants to run on hydrogen.

Sources: Aurora Energy Research

Plants running on 100% H_2 are less profitable than natural gas CCGTs, and will not run until the 2040s without additional subsidy



1) Forced to run at the level of a mid-merit natural gas CCGT; 2) No new EU-ETS certificates issued from 2040 onward, but assumed trading of banked certificates until the period 2045-2050 on secondary markets, leaving some room for natural gas plants to operate, although other harder to abate industries will be competing for EU-ETS certificates

Sources: Aurora Energy Research

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1. In our Central scenario that represents a world where no additional policy is implemented, natural gas is expected to completely leave the system in 2048, strongly driven by expected carbon price developments.
2. Plants running on a 30% H_2 volume blend generate slightly lower margins, even when forced to run as a mid-merit gas plant, driven by the natural gas in the fuel mix, although not enough to cover fixed O&M.
3. However, plants running on 100% H_2 are pushed to the back of the merit order, due to their high fuel costs, and will only start to produce in the 2040s.
4. To support these plants to produce at the same rate of a mid-merit gas CCGTS, high subsidy levels will be needed.

Policy assessment (1/3): While a conversion subsidy creates the optionality to use H_2, including a production subsidy will more strongly help to decarbonise

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Design options

Assessment	A Conversion subsidy	B Conversion subsidy with a 30% H_2[1] blending requirement	C Conversion subsidy with a 100% H_2 production subsidy	D Obligation to phase out natural gas	E National carbon price
Budget cost of policy 2030 - 2050	⊕	⊕	⊖	●	●
	▪ Total budget costs for 7 GW fleet between €0.5 & €1.4 bln. ▪ Depending on compensation for full or partial retrofit.	▪ Limited H_2 use has little impact on fuel costs and power price. ▪ Total costs for 7 GW fleet between €1.1 & €1.3 bln.	▪ Large fuel price delta to compensate. ▪ Total costs for 7 GW fleet between €7.5 & €11.2 bln[2,3].	▪ Depending on compensation for lost revenues[4]. ▪ Missed revenue potential >€10 bln, compared to 'business-as-usual'.	▪ High additional cost of carbon[4]. ▪ Carbon levy up to ~€265/tonne CO_2.
Decarbonisation in the NLD by 2035	●	●	⊕	⊕	⊕
	▪ Emission savings are uncertain, but creates optionality of using H_2. ▪ Incentivises to retrofit early and helps preparing to decarbonise by 2035.	▪ Supporting natural gas retrofits helps preparing to decarbonise by 2035. ▪ Emission savings are limited, up to ~10% per MWh, as only part of the natural gas is replaced.	▪ Can contribute to a CO_2 neutral power system by 2035, as all natural gas production will be replaced by H_2, although supply chain risks remain[5].	▪ Enforcing an obligation to phase out gas would ensure there will be no direct carbon emission from natural gas in the Netherlands by 2035.	▪ Enforcing a national carbon price, on top of the EU-ETS, would provide a high incentive to save emissions by 2035.

⊕ Positive ● Neutral ⊖ Negative ▪ Extensive quantitative analysis (A–C) ▪ Concise assessment (D–E)

1) Volume based; 2) High level of uncertainty due to the uncertainty surrounding future H_2, natural gas, and carbon prices; 3) Budget will reduce if lower share of H_2 is subsidised 4) Obligation to phase out natural gas & national carbon price have low 'direct' budget costs, but can bear higher indirect costs (e.g., societal costs, indirect costs for compensation of missed revenues); 5) Contribution to decarbonisation will reduce if lower share of H_2 is subsidised

Sources: Aurora Energy Research

Policy assessment (2/3): A production subsidy can decrease dependency on other countries, while other options can negatively impact security of supply

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Design options

Assessment	A. Conversion subsidy	B. Conversion subsidy with a 30% H_2[1] blending requirement	C. Conversion subsidy with a 100% H_2 production subsidy	D. Obligation to phase out natural gas	E. National carbon price
Security of Supply	+	−	+	−	−
	▪ A conversion subsidy could realise more low carbon back-up capacity, while keeping the option open to burn with natural gas if needed.	▪ Plants potentially leaving the system due to running hour risk, as blended production is not fully subsidised.	▪ Stimulates use of H_2, resulting in more running hours, with the optionality of using natural gas if H_2 is undersupplied and peak demand must be covered.	▪ Forced exit of a conventional technology, without incentive for replacement technology. ▪ Risk of capacity & security of supply 'cliff-edge'[2].	▪ Natural gas plants could remain available, although getting less competitive. ▪ This could also lead to plants leaving the system, due to less strong business cases.
Electricity import dependency	●	−	+	−	−
	▪ A conversion subsidy does not target the high marginal costs of producing with H_2, but creates optionality to burn H_2.	▪ If plants would leave the system, due to running hour risk, dependency on neighbouring countries for power imports could increase.	▪ Import dependency would not increase or even decrease, as national carbon-free production is subsidised.	▪ Import dependency will increase, as insufficient flexible capacity is available due to the exit of natural gas, potentially leading to carbon leakage in the EU[3].	▪ Increasing marginal cost of conventional plants, without supporting alternatives, increases reliance on imports, potentially leading to carbon leakage in the EU[3].

+ Positive ● Neutral − Negative ■ Extensive quantitative analysis ■ Concise assessment

1) Volume based; 2) If existing plants cannot be run after a certain date, and market conditions have not been strong enough to incentivize sufficient low-carbon alternatives, can lead to a sudden reduction in production capacity. 2) Emission reduction in the Netherlands could lead to slower decarbonisation in other countries, depending on policy implementation in those countries, as the specified policy options aim to realise decarbonisation ahead of EU-ETS mechanism

Sources: Aurora Energy Research

Policy assessment (3/3): A production subsidy could de-risk hydrogen offtake, and help realise a CO_2-neutral power system by 2035

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Design options

Assessment	A: Conversion subsidy	B: Conversion subsidy with a 30% H_2[1] blending requirement	C: Conversion subsidy with a 100% H_2 production subsidy	D: Obligation to phase out natural gas	E: National carbon price
Hydrogen consumption power sector[2]	Neutral	Neutral	Positive	Negative	Negative
	▪ A subsidy for conversion only targets CAPEX, while it does not provide more certainty about fuel use. ▪ It does create the optionality to burn H_2.	▪ Slightly increases H_2 use, and slightly supports market liquidity & predictability of demand. ▪ First experience with H_2 combustion can be gained.	▪ Strongly increases H_2 use, market liquidity & predictability of demand. ▪ However, could reduce the availability of H_2 to hard to abate sectors reducing overall decarbonisation[3].	▪ Forcing out natural gas, without supporting H_2 production, does not de-risk H_2 offtake while forcing the need for gas alternatives.	▪ Increasing the marginal costs of natural gas, without supporting H_2 production, does not de-risk H_2 offtake while increasing the need for gas alternatives.

Positive · Neutral · Negative · Extensive quantitative analysis · Concise assessment

1) Volume based; 2) For this category, no change in hydrogen consumption is seen as negative as this can have high H_2 offtake risks for the power sector as a result, which could lead to delayed investment decisions; 3) This effect has not been analysed in this study

Sources: Aurora Energy Research