AURORA ENERGY RESEARCH

CO_2-free flexibility options for the Dutch power system

Prepared for the Ministry of Economic Affairs and Climate Policy

October 2021

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Based on the requirements of EZK, this report is structured in four chapters

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MEA's requirements

- The Dutch Ministry of Economic Affairs and Climate Policy (EZK) has commissioned Aurora Energy Research to investigate **options for carbon-free flexible power supply in an increasingly decarbonising power market**
- EZK set out to understand
  - **Which sources** of carbon-free flexibility are available
  - How their **economic and technical characteristics** compare
  - Which **contributions they can make in the Dutch power market** medium or longer term
  - **Which policy environment** is needed to ensure the **timely provision** of sufficient carbon-free electricity sources

Approach

This report is divided into four chapters:

1. Identification of the **potential and characteristics** of CO_2-free flexible capacity
   - Development of dashboard with key metrics for technologies in scope
2. Evaluation of the **business cases** of the various flexibility options in 2030
   - Alignment of a Project Base Case[1] with EZK and TenneT
   - Analysis of required income for technologies on a 1 MW basis, revenues achieved in project base case and gap to profitability
   - Sensitivities for different commodity prices and flex in neighboring countries
3. Quantification of the **need for flexibility and determination of the cost-efficient path** to CO_2-free security of supply
   - Calculation of loss of load and need for flexibility in different weather years
   - Implementation of different technology mixes[2] to close the capacity gap
4. Recommendations to **bridge the gap to profitability** for promising technologies
   - Overview of obstacles
   - Proposal for solutions

1) Scenario of the Dutch power market. Aligned were e.g. RES capacities, the amount of flexible demand available and phase out of thermal assets to reach net zero by 2050. For details, see respective section in the report; 2) We set the technology mixes exogenously to take non-financial aspects into account and enhance comparability. For details, see respective section in the report

Sources: Aurora Energy Research

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Executive Summary

1/3

- First, we provide an overview of the most relevant technologies offering flexibility to the system, split into
  - **Dispatchable Production** Technologies (e.g. hydrogen power plant) that dispatch based on their **marginal costs** and are financed through the wholesale market
  - **Storage** Technologies (e.g. Li-ion battery) that buy and sell power on the wholesale market based on **achievable spreads** between high and low power prices– they are also financed through the wholesale market
  - **Demand Flexibility** Technologies (e.g. electric boilers), which offer **flexibility on the demand side** subject to certain constraints. They are not financed through the wholesale market, but investments are made for other purposes (e.g. heating). Thus, their business cases is not quantified here, rather they are an **integral part of our Base Case**
  - **Other** Technologies. **Renewable energy sources** (RES) dispatch **based on the sun / wind** and are financed through the wholesale market, while **interconnection** depends on **prices differences** between markets and is built according to socio-economic cost benefit analysis
- Second, we assess the **business case** of the different technologies for the Dutch power market in 2030. Our Base Case for 2030 is aligned with EZK and TenneT[1]. The analysis shows that **almost none of the assessed technologies** (i.e. excluding Demand Flex) have a **positive business case by 2030**. In that year, the remaining gas capacity, demand flexibility and interconnection offer enough power at moments of low RES production
  - From an abstract cost perspective (i.e. Levelised Cost of Electricity, LCOE), **none of the Dispatchable Production** Technologies have **lower costs than a natural gas CCGT**, given the commodity price scenario for 2030[2]. When running a limited number of hours per year (i.e. 1500 h/year[3]) retrofitted biomass, biogas and H_2 power plants have the lowest LCOE. For higher usage (i.e. 4500 h/year[3]) gas and biomass plants with CCS perform slightly better. Of the **Storage** Technologies, **lithium-ion batteries** and the more experimental vehicle-to-grid **have the lowest cost**, and are even cheaper than new natural gas CCGTs when used for 1500 h/year
  - Testing the **actual profitability** of flexibility assets in the Project Base Case[4] the **best performing** flexibility assets in the 2030 power system are those with **low investment costs, like e-methane, biogas and hydrogen CCGTs.**

1) Numbers from the KEV2020 of PBL, the II3050 study of Gasunie and Tennet and Aurora's own market view were used to construct our Base Case. 2) In our Net Zero scenario, we assume gas prices drop from their high levels in Oct-21 to 21 €/MWh by 2030. 3) These hours – 4500 and 1500 – are taken as examples to facilitate comparison, based on nat. gas CCGT running hours in 2030 and 2040 respectively given business-as-usual. 4) This deviates from LCOE, as technologies run different hours based on their marginal costs.
Source: Aurora Energy Research

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Executive Summary

2/3

- **Demand Flexibility Technologies reduce the need for additional capacity** in the system[1] towards 2050. Heat pumps, electrolysers and other demand flex shift and distribute power demand over time to moments of low prices. However, the **Dutch gas fleet cannot be phased out** and the climate targets cannot be reached **without additional CO_2-free production and storage** entering the market post 2030
  - **Demand Flexibility Technologies** do not only reduce the need for other flexible capacity, but also **improve the business case of renewables**, by concentrating demand at moments of high renewable production. The extra flexible demand prevents capture prices of wind and solar from dropping to zero, even though renewable capacity more than doubles between 2030 and 2050, which makes merchant renewable projects more feasible
  - For **CO_2-free flex production and storage capacity to be profitable** in a decarbonising power system, **price peaks are needed** to make these technologies profitable. When capacities are sufficient to provide **high security margins** even for extreme weather situations (i.e. low renewable production and high demand), technologies will **struggle to generate enough revenue** to break-even. On the other hand, a **tighter system** with less back-up flexibility would lead to **sufficient high-price hours for technologies** to be profitable. In such a tight system, there might be a role for emergency demand response programs.
  - **Retrofitted BECCS plants**[2] (Biomass with Carbon Capture and Storage) and **H_2 CCGTs** are **best positioned to provide long-duration flexibility towards 2050** – even in a scenario with higher security they can be profitable from 2035 and 2042 respectively. Nuclear plants will find it difficult to compete with BECCS and H_2 CCGTs. Even in a tight system, only the lower-cost nuclear SMR can break-even in the 2040s. Similarly Gas CCS can only operate profitably when there is enough scarcity in the system and when retrofitted to existing gas plants.
  - **Back-up and short-duration flex capacity** also **require high-priced hours to operate economically**. When the system is tight, back-up capacity[3] can be profitable by producing only a few hours per year with high prices. **Li-ion batteries** at the estimated cost levels for 2030 are still not profitable when only considering the wholesale market, but if the cost reduction towards 2050 materialises, they **will become profitable in a tighter system.** Also, Li-ion likely profit more from additional revenue streams like balancing markets to enhance their business case than less flexible technologies.

1) We model the system on a national level, and do not model potential local grid restrictions; 2) As negative emissions technology, BECCS plants receive income from selling CO_2; 3) Back-up flex takes up the largest share of added capacity – in the scenario with higher security, it takes up ~2/3 of the total capacity added by 2050

Source: Aurora Energy Research

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Executive Summary

3/3

- In the last part of the study, we provide **an overview of key non-financial[1] hurdles** to market entry and scale-up for a selection of the **most promising flexible CO_2-free technologies**. We also suggest **potential solutions** to these hurdles and provide an **estimate of the lead time** for the first 1 GW of each technology
  - **Lithium-ion** batteries see the fewest non-financial hurdles, with the main two being **high grid tariffs** and **possible scarcity issues** surrounding some of the metals used in their construction
  - For **flexible-demand technologies** – smart EVs, flexible household heat pumps, electrolysers, and industrial power-to-heat – most key hurdles stem from **lacking incentives in price, taxes, and tariffs**.[2] Non-variable energy prices and fees give households little incentive to flexibilise their demand, and electrification is rendered costly for industrial consumers by high grid fees
  - **Fuel-combusting technologies** – biogas, biomass, hydrogen, and e-methane – often suffer from issues related to their fuel source. **Biofuels may be difficult to source sustainably** in sufficient quantities. **Carbon-free hydrogen and e-methane** are as of yet only commercially available in **small quantities**; production will likely be scaled up quickly, but sufficient renewable electricity, electricity infrastructure, and hydrogen infrastructure are required
  - **For nuclear fission plants, long construction times and potential delays** risk stalling CO_2 abatement. High CAPEX and long lifetimes risk large write-offs in later years, when more than expected RES capacities or other competing technologies are built
  - Furthermore, a number of **overarching uncertainties and infrastructural prerequisites** would benefit from **national coordination.** For instance, power grid reinforcement and RES build-out need to happen fast for increased electrification, which is a prerequisite for decarbonisation and the deployment of many of the flexible technologies analysed in this report

1) i.e. other than lack of profitability, which is analysed in Chapter 2 and 3; 2) Variable tariffs and taxes are primarily important to stimulate demand-response to issues of grid congestion, unlike variable prices, which stimulate response to electricity supply. Nonetheless, both incentivise flexible demand, which is important for solving both issues.

Source: Aurora Energy Research

Aurora Energy Research crafted this study together with a core team from EZK and TenneT, receiving input from an extended stakeholder group

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Study authors and core team

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Ministry of Economic Affairs and Climate Policy

TenneT

Extended stakeholder group

- Utilities
- Industry
- Network Operators
- Environmental Organizations

- Aurora Energy Research has crafted this study with close supervision of a core team from the Ministry of Economic Affairs and Climate Policy (EZK) as well as TenneT, while Dr. Laurens de Vries and Prof. Rick van der Ploeg acted as academic advisors
- Additionally, an extended stakeholder group consisting of representatives from the utilities, industry, network operators and environmental organizations gave valuable input and feedback to this study

Source: Aurora Energy Research

The report is based on current research and input from the core team, but is subject to future technological and policy developments

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- One important driver of future development is the technological progress of the CO_2-free sources covered in this report
  - Some technologies might not live up to their current expected potential. For instance, different types of nuclear Small Modular Reactors (SMRs) have varying technology readiness levels and have not been deployed on a commercial scale. If their introduction runs into delays and cost-escalation this would threaten future deployment
  - On the other hand, cost reductions for several technologies could come quicker than expected. This could for instance be the case for the above mentioned SMRs – but also for Li-Ion batteries, a cost break-through could make their business case profitable much earlier
- Beyond developments for technologies covered in this report, there could be other break-through technologies
  - As one example, a US-based start-up recently secured funding to commercialize iron-air batteries. They claim the battery will be a multi-day storage, with up to 100h of duration and 10% of the cost levels of Lithium-ion. Should such a technology be available at scale in the 2030s, it would not only have a strong impact on storage / short-term flexibility technologies, but also on long-term flexibility options
  - In a high-RES system, it is increasingly important to predict the weather. Efforts exist to enhance predictions using artificial intelligence. This could help to take pressure of the system and reduce scarce hours, when they are known in advance
- The timelines and capacity development of renewables and demand flexibility technologies as well as the demand for electricity and hydrogen will strongly depend on the strength of the push for net zero by policy
  - Assumptions and timelines in this study have been aligned with EZK and TenneT, and are partially based on the KEV2020 and II3050
  - If governments decides to set a net zero target for 2040 instead of 2050, expansion of renewables, (flexible) electrification and hydrogen usage should be pushed forward and the transition from conventional to CO_2-free flexibility technologies is required earlier

Source: Aurora Energy Research

Abbreviations used throughout the report are listed here for reference

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Abbreviation	Meaning
BECCS	Bioenergy with carbon capture and storage
CAPEX	Capital expenditure
CCGT	Combined cycle gas turbine
CCS	Carbon capture and storage
CHP	Combined heat and power
DSR	Demand-side response
EV	Electric vehicle
FLH	Full load hours
HHV	Higher heating value
Li-ion	Lithium-ion
LCOE	Levelised cost of electricity
LCOS	Levelised cost of storage
LOLE	Loss of load expectation
NIMBY	Not-in-my-backyard
O&M	Operation and maintenance
OCGT	Open cycle gas turbine

Abbreviation	Meaning
P2H	Power-to-heat
RES	Renewable Energy Sources
SMR	Small modular reactor (nuclear plant)
V2G	Vehicle-to-grid
VOM	Variable operation and maintenance
WY	Weather Year

Source: Aurora Energy Research

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Based on economics and the role of different technologies in the power market, we distinguish four categories of technologies

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A Dispatchable Prod. Technologies

- Technologies that can freely dispatch to the market and can be characterized by their **levelised costs of electricity** (LCOE)
- Assets are **financed** through the **wholesale market** – they will dispatch against **their marginal costs** and depend on the **absolute height of power prices** to recover their costs

B Storage Technologies

- Technologies that buy power from the market in low price hours and then later sell it again at higher prices – an adjusted version of the **levelised cost of electricity** (LCOE) can be used to characterize them
- Assets are **financed** through the **wholesale market** – they depend on the **spread between high and low-price hours** (not on the absolute level) in order to recover their costs

C Demand flexibility Technologies

- Technologies do not supply electricity but can **adjust their demand subject to certain constraints,** e.g. storage size, degradation, consumption patterns
- Assets are **not financed through the wholesale market** – investments mostly made for other purposes (e.g. heating) but assets can contribute flexibility and hence to security of supply

D Other Technologies

- **Renewable assets** also are characterized by their **levelised costs of electricity** (LCOE) and financed through the **wholesale market**, but **cannot freely dispatch power**
- **Interconnectors** are built based on **socio-economic cost-benefit** analysis – their economics depend on **prices differences** between markets

Technologies *— see Appendix for dashboards for each individual technology*

- *Biomass*
- *BECCS*
- *Biogas*
- *Gas CCS*
- *Hydrogen*
- *E-methane*
- *Metal fuels*
- *Nuclear energy*

- *Batteries – Li-ion*
- *Batteries – Redox-Flow*
- *Compressed Air*
- *Vehicle to grid*

- *Heat Pumps*
- *Hybrid Heat Pumps*
- *Electric Boilers*
- *EV Smart Charging*
- *Industrial DSR*
- *Electrolysers*

- *Additional RES Capacity*
- *Interconnection*

Note: Plant efficiencies in this report are denoted in higher heating value (HHV), while in other publications for some types of plants lower heating value (LHV) might be used. Plant efficiencies expressed in LHV are higher than in HHV. This distinction does not impact our calculations, as we consistently apply HHV in the Aurora Power Market Model.

Source: Aurora Energy Research

Dispatchable production technologies provide long-term flexibility – they dispatch to the market based on their marginal cost

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A Dispatchable Prod. Technologies

- Technologies that can freely dispatch to the market and can be characterized by their **levelised costs of electricity** (LCOE)
- Assets are **financed** through the **wholesale market** – they will dispatch against **their marginal costs** and depend on the **absolute height of power prices** to recover their costs

Technologies

- *Biomass*
- *BECCS* — Special case: income from negative emissions
- *Biogas*
- *Gas CCS*
- *Hydrogen*
- *E-methane*
- *Metal fuels*
- *Nuclear energy*

B Storage Technologies

C Demand flexibility Technologies

- *Industrial DSR*
- *Electrolysers*

D Other Technologies

- **Renewable assets** also are characterized by their **levelised costs of electricity** (LCOE) and financed through the **wholesale market**, but **cannot freely dispatch power**
- **Interconnectors** are built based on **socio-economic cost-benefit** analysis – their economics depend on **prices differences** between markets

- *Additional RES Capacity*
- *Interconnection*

Remarks:

- We show detailed plant characteristics and include the technologies with 1 MW into the model to test their profitability
- As part of the project, we determine which capacities of these technologies could provide flexibility to the power market
  - We present information on expected build-out and / or pilots in order to calibrate at which point in time and how these technologies can provide flexibility
- A plant will dispatch to the market when the power price exceeds its marginal cost
- Our power market model takes into account ramping behavior of plants (e.g. ramping cost) and thus also reflect the cost of these plants operating flexibly
- The technologies in this section are well suited to replace assets in the current power system that provide baseload power, given they are not constrained by their duration – they can provide long-term flexibility

Note: Plant efficiencies in this report are denoted in higher heating value (HHV), while in other publications for some types of plants lower heating value (LHV) might be used. Plant efficiencies expressed in LHV are higher than in HHV. This distinction does not impact our calculations, as we consistently apply HHV in the Aurora Power Market Model.

Source: Aurora Energy Research

Storage technologies can provide short-term flexibility – they buy and sell power, taking advantage of price spreads in the market

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A Dispatchable Prod. Technologies

- Technologies that can freely dispatch to the market and can be characterized by their **levelised costs of electricity** (LCOE)
- Assets are **financed** through the **wholesale market** – they will dispatch against **their marginal costs** and depend on the **absolute height of power prices** to recover their costs

Technologies

- *Biomass*
- *BECCS*
- *Biogas*
- *Gas CCS*
- *Hydrogen*
- *E-methane*
- *Metal fuels*
- *Nuclear energy*

B Storage Technologies

- Technologies that buy power from the market in low price hours and then later sell it again at higher prices – an adjusted version of the **levelised cost of electricity** (LCOE) can be used to characterize them
- Assets are **financed** through the **wholesale market** – they depend on the **spread between high and low-price hours** (not on the absolute level) in order to recover their costs

- *Batteries – Li-ion*
- *Batteries – Redox-Flow*
- *Compressed Air*
- *Vehicle to grid*

C Demand flexibility Technologies

- *Industrial DSR*
- *Electrolysers*

D Other Technologies

Remarks:

- We show detailed plant characteristics and include the technologies with 1 MW into the model to test their profitability
- As part of the project, we determine which capacities of these technologies could provide flexibility to the power market
  - We present information on expected build-out and / or pilots in order to calibrate at which point in time and how these technologies can provide flexibility
- A battery asset will buy power at low prices and dispatch at peak prices
- Technologies in this section are constrained by their duration – they can only supply the amount of power that has previously been stored
  - They will rather provide additional power in hours of high demand, consume power where demand was low before and thus shave peaks – they can provide short-term flexibility

Note: Plant efficiencies in this report are denoted in higher heating value (HHV), while in other publications for some types of plants lower heating value (LHV) might be used. Plant efficiencies expressed in LHV are higher than in HHV. This distinction does not impact our calculations, as we consistently apply HHV in the Aurora Power Market Model.

Source: Aurora Energy Research

Demand flexibility technologies can adjust their demand based on price signals – we assume their capacity exogenously

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A Dispatchable Prod. Technologies

B Storage Technologies

Remarks:

- Given demand flexibility technologies are not financed through the wholesale market, we assume their capacity exogenously in our modelling
- Thus, we present the magnitude of flexible demand that we have assumed in the Project Base Case alongside information on maturity and potential pilot projects
  - The Project Base Case is a combination of Aurora's Dutch Net Zero scenario that has been aligned with EZK and TenneT based on the PBL's Climate and Energy Outlook, TenneT's Security of Supply Monitor and the Integrale Infrastructuurverkenning 2030-2050
- The demand flexibility technologies will have a certain base demand of power, but are able to provide flexibility by adjusting their demand in reaction to price signals

- *Hydrogen*
- *E-methane*
- *Metal fuels*
- *Nuclear energy*

C Demand flexibility Technologies

- Technologies do not supply electricity but can **adjust their demand subject to certain constraints,** e.g. storage size, degradation, consumption patterns
- Assets are **not financed through the wholesale market** – investments mostly made for other purposes (e.g. heating) but assets can contribute flexibility and hence to security of supply

- *Heat Pumps*
- *Hybrid Heat Pumps*
- *Electric Boilers*
- *EV Smart Charging*
- *Industrial DSR*
- *Electrolysers*

D Other Technologies

- **Renewable assets** also are characterized by their **levelised costs of electricity** (LCOE) and financed through the **wholesale market**, but **cannot freely dispatch power**
- **Interconnectors** are built based on **socio-economic cost-benefit** analysis – their economics depend on **prices differences** between markets

- *Additional RES Capacity*
- *Interconnection*

Note: Plant efficiencies in this report are denoted in higher heating value (HHV), while in other publications for some types of plants lower heating value (LHV) might be used. Plant efficiencies expressed in LHV are higher than in HHV. This distinction does not impact our calculations, as we consistently apply HHV in the Aurora Power Market Model. 1) Based on Aurora's Dutch Net Zero scenario, includes adjustments and alignments made during the project

Source: Aurora Energy Research

Renewables are characterized by intermittent power production, interconnection can help balance peaks between countries

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A Dispatchable Prod. Technologies

- Technologies that can freely dispatch to the market and can be characterized by their **levelised costs of electricity** (LCOE)
- Assets are **financed** through the **wholesale market** – they will dispatch against **their marginal costs** and depend on the **absolute height of power prices** to recover their costs

Technologies

- *Biomass*
- *BECCS*
- *Biogas*
- *Gas CCS*
- *Hydrogen*
- *E-methane*
- *Metal fuels*
- *Nuclear energy*

B Storage Technologies

C Demand flexibility Technologies

- *Industrial DSR*
- *Electrolysers*

Remarks:

- For RES assets and interconnection capacity, we assume an existing buildout timeline to cater to the reality of these assets already being in the market
  - The Project Base Case is a combination of Aurora's Dutch Net Zero scenario that has been aligned with EZK and TenneT based on the PBL's Climate and Energy Outlook, TenneT's Security of Supply Monitor and the Integrale Infrastructuurverkenning 2030-2050
- We can, however, assess the economics of marginally adding more assets
  - For RES assets, this will be standard model output
  - For interconnection, we will calculate the interconnector rents
- The model curtails generation from wind and solar when RES production exceeds demand to avoid negative prices and balance supply (taking into account inter-country flows)

D Other Technologies

- **Renewable assets** also are characterized by their **levelised costs of electricity** (LCOE) and financed through the **wholesale market**, but **cannot freely dispatch power**
- **Interconnectors** are built based on **socio-economic cost-benefit** analysis – their economics depend on **prices differences** between markets

- *Additional RES Capacity*
- *Interconnection*

Note: Plant efficiencies in this report are denoted in higher heating value (HHV), while in other publications for some types of plants lower heating value (LHV) might be used. Plant efficiencies expressed in LHV are higher than in HHV. This distinction does not impact our calculations, as we consistently apply HHV in the Aurora Power Market Model.

Source: Aurora Energy Research

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In Chapter 2, we establish a Base Case on which other analyses of this report are based and assess the economics of technologies in 2030

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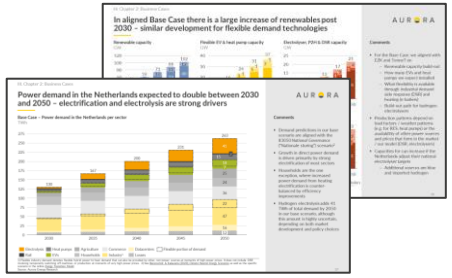
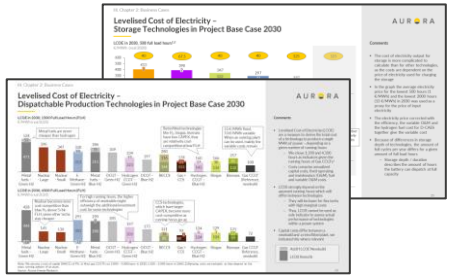
Approach

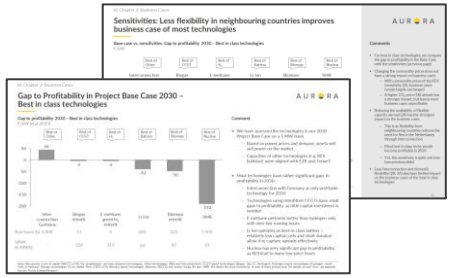
Establishing a Base Case of the Dutch power market



Assessing Levelised Cost of Electricity (LCOE)



Testing profitability in Base Case in 2030



Explanation

- With TenneT and EZK we first aligned on a Base Case for the Dutch power market
  - This comprises development of thermal capacities, buildout of RES, assumptions on hydrogen and (flexible) electricity demand until 2050
  - Also assumptions on neighbouring countries and interconnection are included
- As natural gas capacity is phased out in this Base Case, there will a capacity gap post 2030 that will later be filled with CO_2-free flexible technologies (Chapter 3)
- Within the above Base Case, we calculate the Levelised Cost of Electricity in 2030 for different running hours[1]
  - LCOE give a good indication of the total cost of producing one MWh of power for a technology, if it runs a pre-specified number of hours
  - In the market, technologies will run different number of hours, as their marginal costs differ, making LCOE an imperfect measure
- To test actual profitability of the technologies in 2030, we enter 1 MW of each technology to the Base Case
  - For each technology, we observe run hours and revenues that can be achieved in the Dutch power market in 2030
- Combining information on actual profitability with LCOE and the capacity gap in the Base Case serves as input for which capacities to add to the system post 2030

1) Using running hours of natural gas plants as a reference

Sources: Aurora Energy Research

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Power demand in the Netherlands expected to double between 2030 and 2050 – electrification and electrolysis are strong drivers

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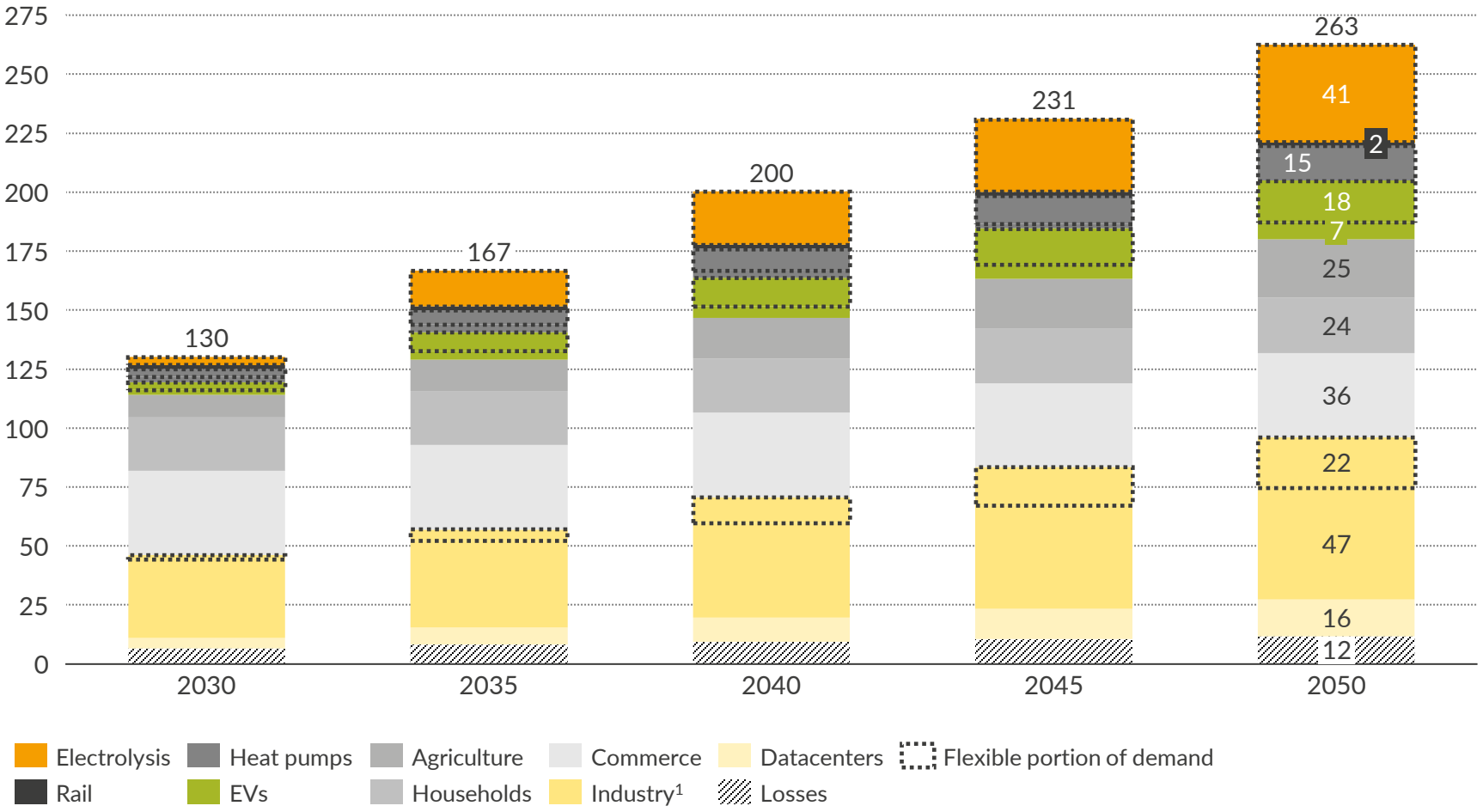
Base Case – Power demand in the Netherlands per sector
TWh



1) Flexible industry demand denotes flexible hybrid power-to-heat demand that can also be provided by other, non-power sources at moments of high power prices. It does not include DSR involving temporarily switching off machines or production at moments of very high power prices. 2) See Berenschot & Kalavasta (2020), *Climate Neutral Energy Scenarios* as well as the specific scenario in the online *Energy Transition Model*.
Source: Aurora Energy Research

Comments

- Demand predictions in our base scenario are aligned with the II3050 *National Governance* ("Nationale sturing") scenario[2]
- Growth in direct power demand is driven primarily by strong electrification of most sectors
- Households are the one exception, where increased power demand from heating electrification is counter-balanced by efficiency improvements
- Hydrogen electrolysis adds 41 TWh of total demand by 2050 in our base scenario, although this amount is highly uncertain, depending on both market development and policy choices

Aligned phase out of thermal capacities by 2050 in Base Case leads to an emissions-free power system in the Netherlands

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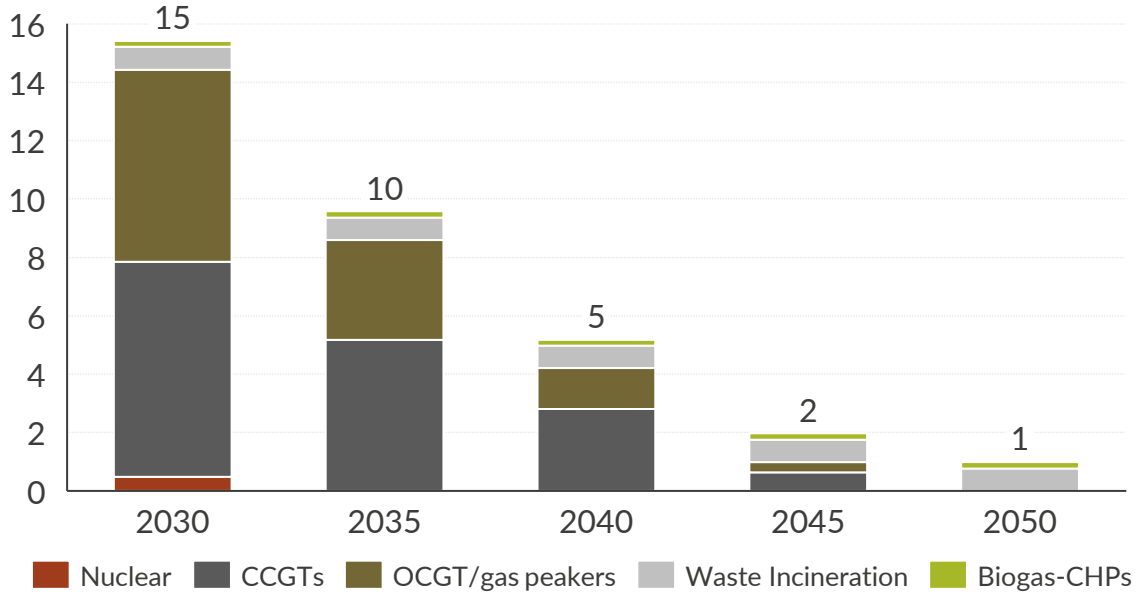
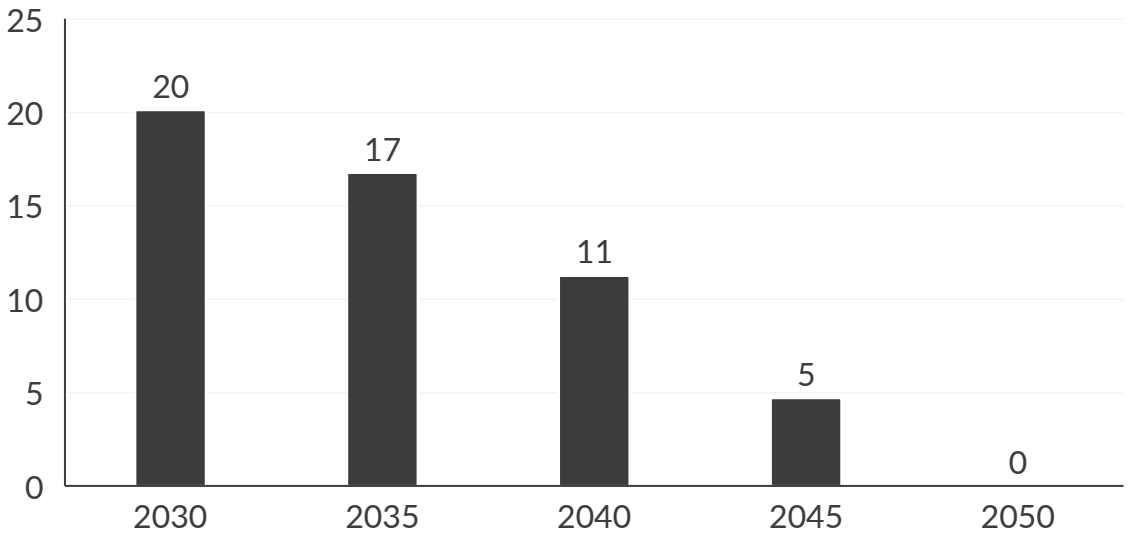
Base Case - Thermal capacities over time
GW



CO_2 emissions over time[1,2]
Mt



Comments

- In our project Base Case, of ~15 GW thermal capacity in 2030, ~14 GW are carbon-emitting gas assets
  - These are phased out, such that only ~4 GW of gas plants are left in 2040, and they are completely phased out by 2050
  - The capacity drop in gas assets results from a combination of plants coming to the end of their lifetime and capacity restrictions to meet CO_2-targets[3]

Comments

- With the phase-out of natural gas, carbon emissions in the base case drop by 50% until 2040 in the project base case – power system would be entirely emission-free by 2050
- In 2030 emissions are higher in our model than PBL's estimate for the Climate Agreement, primarily due to our higher electricity demand (113 TWh vs ~130 TWh) because of further electrification in other sectors

Note: Base Case aligned with EZK and TenneT; 1) Assumes waste incineration uses CCS starting 2030; 2) Includes emissions from heat produced by CHPs; 3) This reduction can result from different factors. On the one hand, this could be due to market dynamics, should natural gas plants become unprofitable with rising carbon prices, on the other hand it could be due to market interventions. We do not specify the exact mechanism but outline what needs to happen to reach Net Zero by 2050.
Sources: Aurora Energy Research, PBL

In aligned Base Case there is a large increase of renewables post 2030 – similar development for flexible demand technologies

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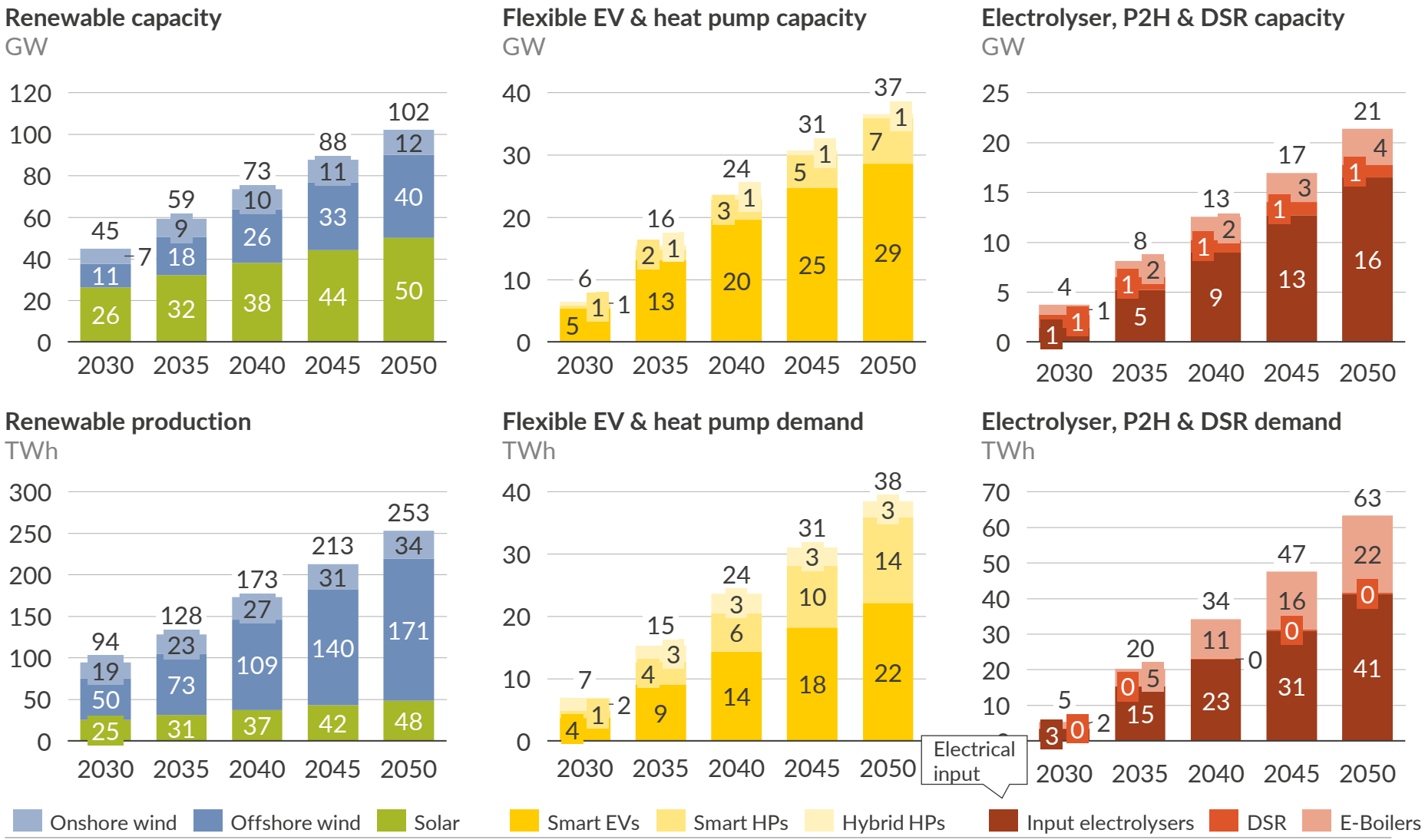

Note: Base Case aligned with EZK and TenneT, based on KEV2020 and II3050.

Source: Aurora Energy Research

Comments

- For the Base Case, we aligned with EZK and TenneT on
  - Renewable capacity build-out
  - How many EVs and heat pumps we expect installed
  - What flexibility is available through industrial demand side response (DSR) and heating (e-boilers)
  - Build-out path for hydrogen electrolysers
- Production patterns depend on load factors / weather patterns (e.g. for RES, heat pumps) or the availability of other power sources and prices that form in the market / our model (DSR, electrolysers)
- Capacities for can increase if the Netherlands adjust their national electrolyser targets
  - Additional sources are blue and imported hydrogen

The transition to Net Zero is expected to be accompanied by lower gas and coal prices and higher carbon prices

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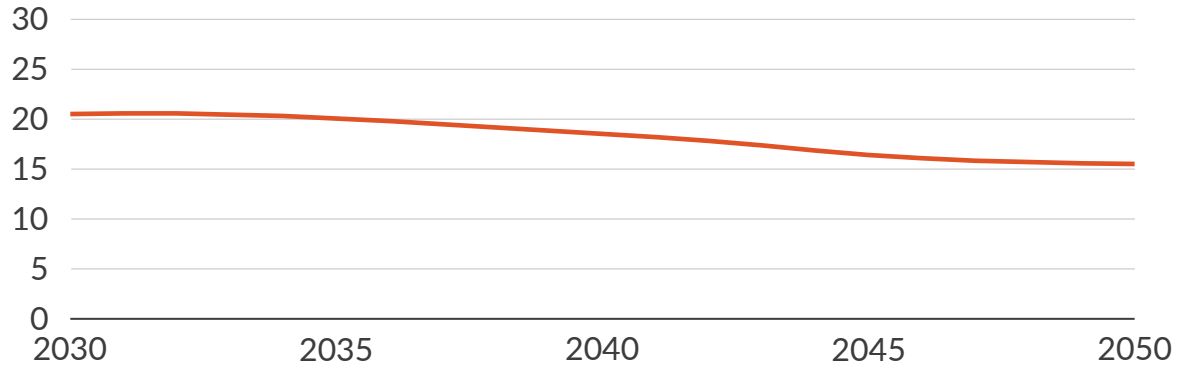
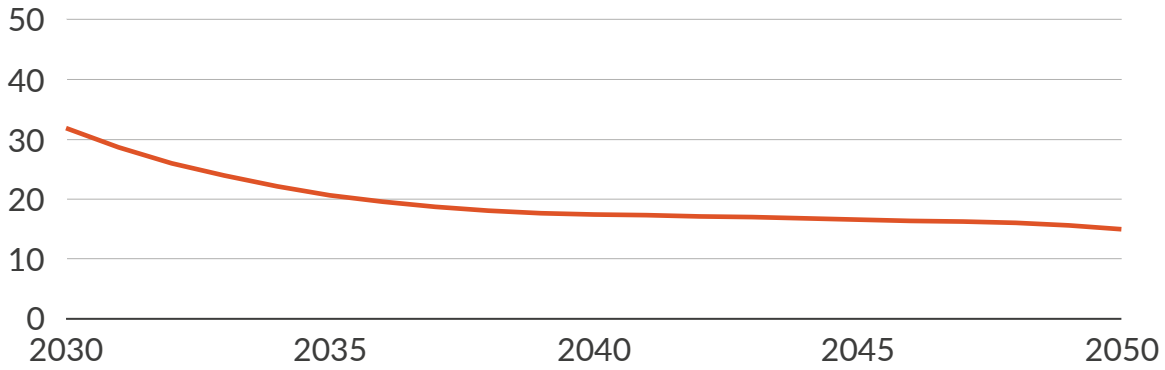
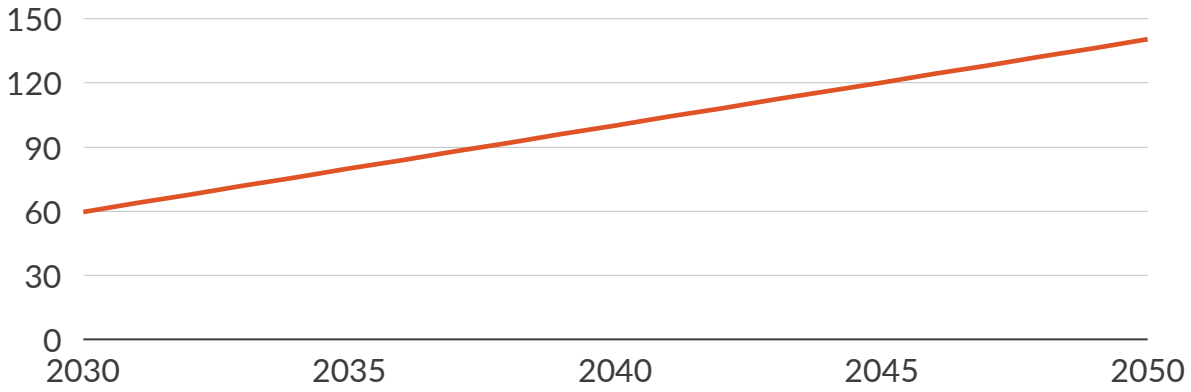
Gas prices
€/MWh (real 2020)



Coal prices
€/tonne (real 2020)



Carbon prices
€/tCO_2 (real 2020)



Aurora's Net Zero price forecast:

- In our Net Zero analysis, the gas price is expected to be around €21/MWh by 2030, driven by coal-to-gas switching and rising global LNG demand. From 2030 onwards prices start to decline, falling to €16/MWh by 2050
- This trend is due to Asian gas demand falling with growing renewable penetration, which drives down the marginal cost of LNG shipments to Europe
- The coal price is expected to plummet to €20/tonne by 2035 as coal is phased out of power, and only the cheapest producers stay online
- We assume a rise in carbon prices to €140/tCO_2 by 2050, reflecting the required marginal CO_2 abatement across most sectors to decarbonise

Note: Base Case aligned with EZK and TenneT

Sources: Aurora Energy Research, EIKON

Due to interconnection to neighbouring countries, developments there need to be taken into account in our Base Case

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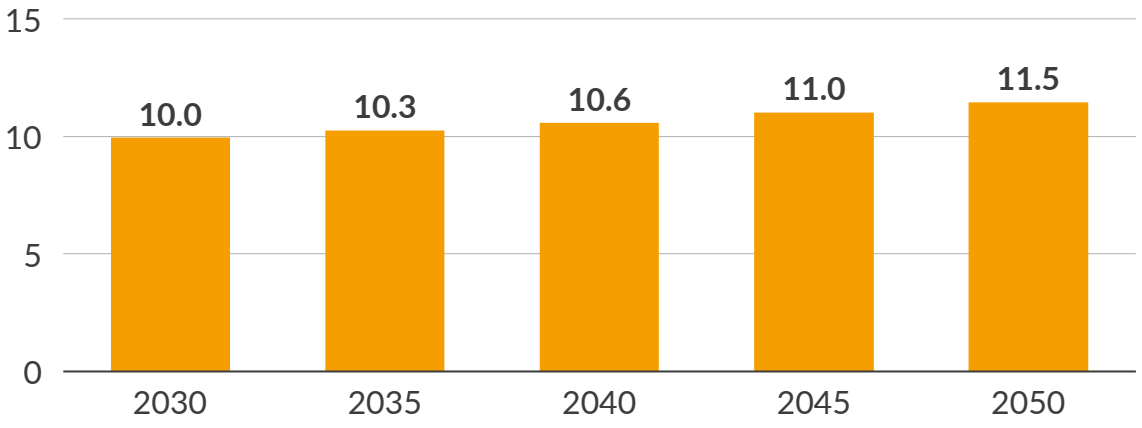
Interconnection capacity Netherlands until 2050[1]
GW



Comments

- The Netherlands are highly interconnected, with ~11.5 GW of interconnection by 2050
  - Direct interconnection capacity with Germany and Belgium
  - Interconnected overseas with Denmark, Great Britain and Norway
- Thus, developments in other countries are highly relevant to business cases of technologies (see right-hand side)

Contrary to Germany and Belgium, we have assumed no batteries for the Netherlands in our Base Case – this is to ensure a level playing field[2]

Assumptions for key neighbouring countries

Based on respective net zero scenarios

Germany

- Nuclear is phased out by 2023, lignite by 2030 and hard coal by 2035
- Gas plants are mostly phased out by 2045 and partially replaced by hydrogen CCGTs and OCGTs
- Renewables are expected to more than triple by 2050 compared to 2021
- Batteries are already part of the mix in 2021 as households combine rooftop solar with home batteries, and are expected to be further build out towards 2050

Belgium

- Nuclear is phased out by 2025 and all coal is already closed since 2016
- Gas plants replace nuclear in the 2020s and 2030s, but are converted or replaced by hydrogen plants
- Renewable build out is limited due to a relatively small sea surface and high population density
  - For onshore and offshore wind, maximum capacity is estimated at 9 GW and 8 GW respectively
  - Solar PV is less limited in potential, as it faces fewer NIMBY issues and rooftop potential is large
- Batteries buildout takes off later than in Germany, but grows faster to accompany the big roll out of solar

Note: Base Case aligned with EZK and TenneT; 1) Interconnection to and from the Netherlands; 2) If we would assume sizeable battery capacities in the market, already, this would cannibalize the business case of flex technologies

Source: Aurora Energy Research

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AURORA

Levelised Cost of Electricity – Dispatchable Production Technologies in Project Base Case 2030

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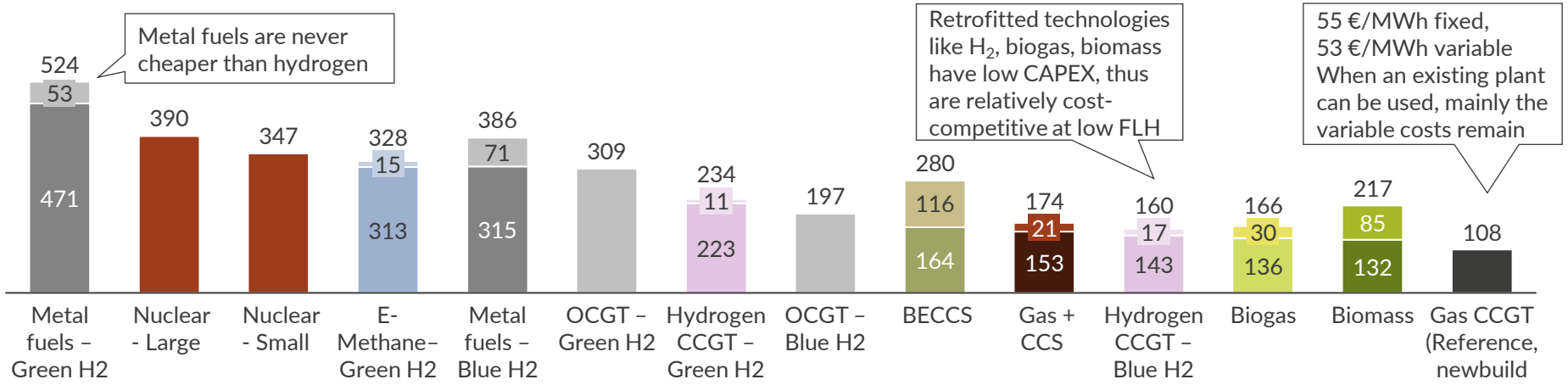
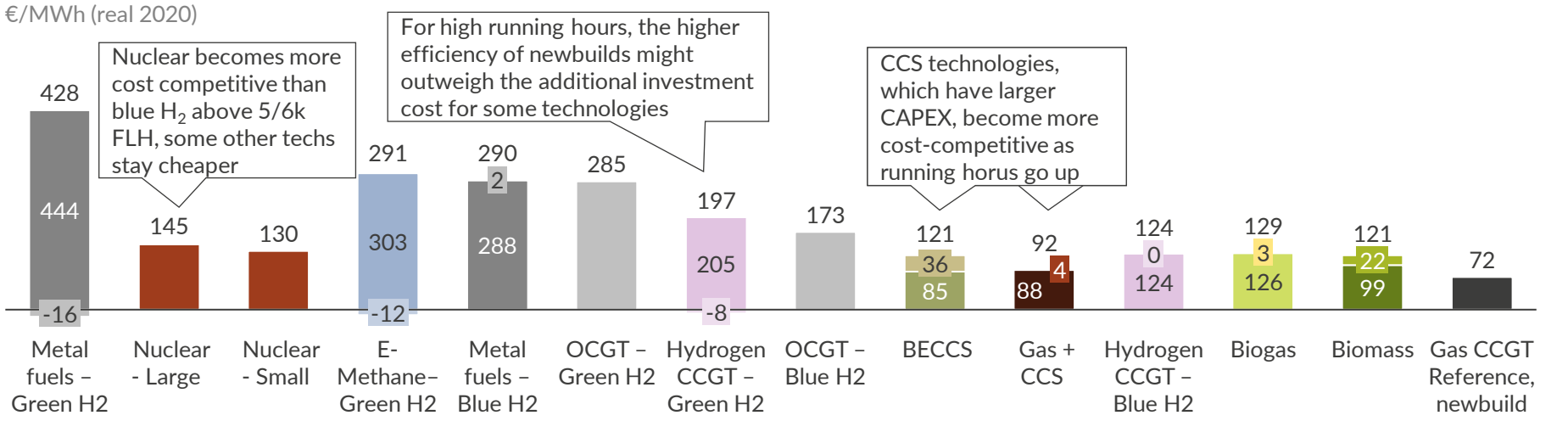
LCOE in 2030, 1500 Full Load Hours (FLH)
€/MWh (real 2020)



LCOE in 2030, 4500 Full Load Hours (FLH)
€/MWh (real 2020)



Note: We assume a cost of capital (WACC) of 9%; 1) Most gas CCGTS run 3,000 – 5,000 hours in 2030, 1,500 – 2,000 hours in 2040; 2) Ramping costs are excluded, as they depend on the exact running pattern of an asset.
Source: Aurora Energy Research

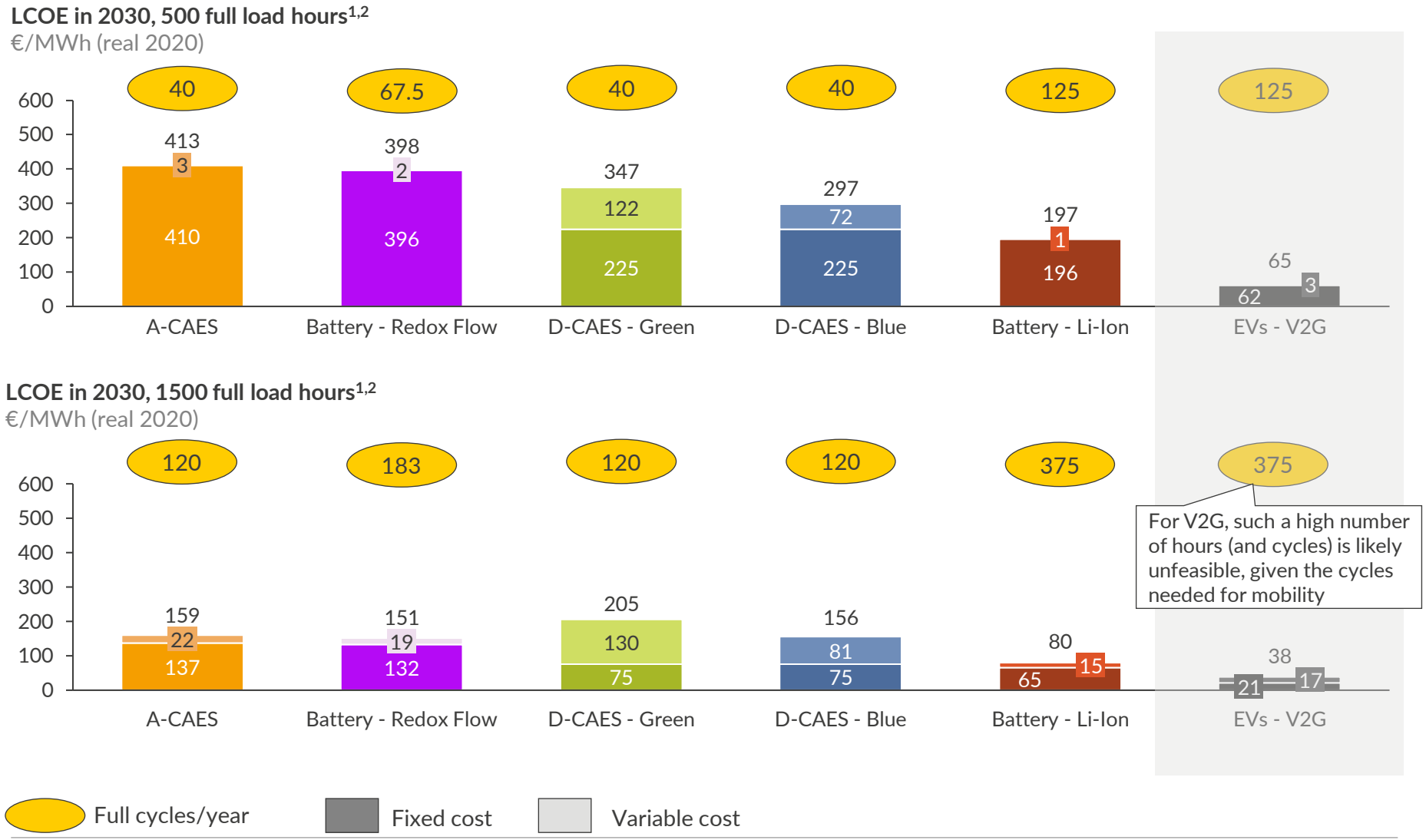
Comments

- Levelised Cost of Electricity (LCOE) are a measure to derive the total cost of a technology to produce a single MWh of power – depending on a given number of running hours
  - We chose 1,500 and 4,500 hours as indicators given the running hours of Gas CCGTs[1]
  - Costs comprise annualized capital costs, fixed operating and maintenance (O&M), fuel and variable O&M costs
- LCOE strongly depend on the assumed running hours which will differ between technologies
  - They will be lower for flex techs with high marginal costs
  - Thus, LCOE cannot be used as sole indicator to assess actual performance of technologies within a power system
- Capital costs differ between a newbuild and a retrofitted plant, we indicated this where relevant

Addt'l LCOE Newbuild
LCOE Retrofit

Levelised Cost of Electricity – Storage Technologies in Project Base Case 2030

AURORA



Note: We assume a cost of capital (WACC) of 9%. 1) Does not include costs for ramping. 2) Discharging hours.

Source: Aurora Energy Research

Comments

- The cost of electricity output for storage is more complicated to calculate than for other technologies, as the costs are dependent on the price of electricity used for charging the storage
- In the graph the average electricity price for the lowest 500 hours (1 €/MWh) and the lowest 2000 hours (13 €/MWh) in 2030 was used as a proxy for the price of input electricity
- The electricity price corrected with the efficiency, the variable O&M and the hydrogen fuel cost for D-CAES together give the variable cost
- Because of differences in storage depth of technologies, the amount of full cycles per year differs for a given amount of full load hours
  - Storage depth / duration describes the amount of hours the battery can dispatch at full capacity

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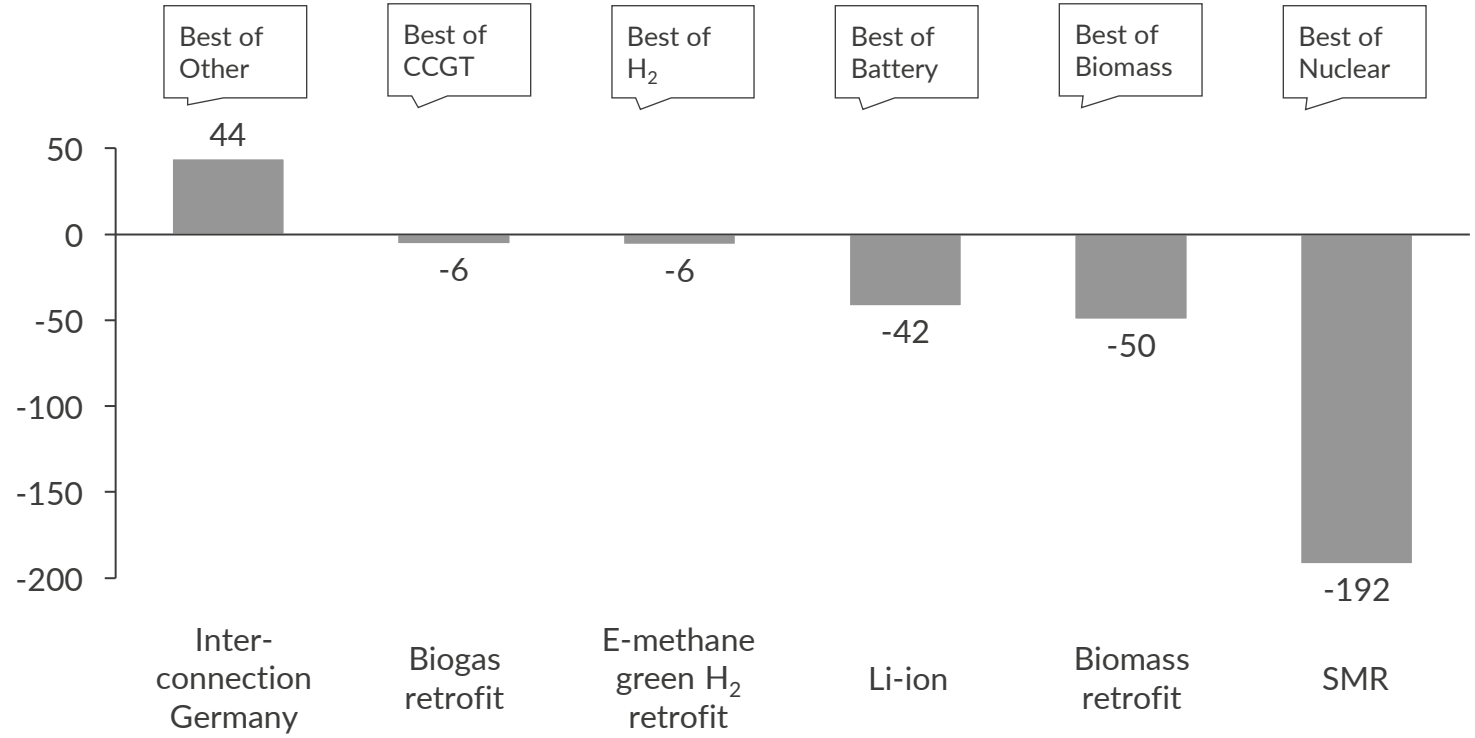
Gap to Profitability in Project Base Case 2030 – Best in class technologies

AURORA

Gap to profitability 2030 – Best in class technologies
€/kW (real 2020)



	Inter-connection Germany	Biogas retrofit	E-methane green H_2 retrofit	Li-ion	Biomass retrofit	SMR
Run hours (h)	4,808	15	6	686	225	7,405
SRMC (€/MWh)	-	128	315	69	87	23

Comment

- We have assessed the technologies in our 2030 Project Base Case on a 1 MW-basis
  - Based on power prices and demand, assets will sell power on the market
  - Capacities of other technologies (e.g. RES buildout) were aligned with EZK and TenneT
- Most technologies have rather significant gaps to profitability in 2030
  - Extra interconnection with Germany is profitable in 2030, mostly driven by the hastened phase out of coal in our Net Zero scenario, leading to a high prices, making exports to Germany attractive
  - Technologies using retrofitted CCGTs have small gaps to profitability, as little capital investment is needed
  - E-methane performs better than hydrogen only with very low running hours
  - Li-ion operates as best-in-class battery – relatively low capital costs and short duration allow it to capture spreads effectively
  - Nuclear has large gap to profitability despite high running hours, as RES build out leads to many low-price hours

Note: We assume a cost of capital (WACC) of 9%. For simplification, we have clustered technologies: Other technologies (RES and Interconnection), CCGT-based technologies (Biogas, Gas CC, Hydrogen), Hydrogen-based technologies (Hydrogen, metal fuels, e-methane), Storage technologies (Li-ion, Redox Flow, CAES, V2G), Biomass-based technologies (Biomass, BECCS) and nuclear (Large III+ gen, SMR). We depict the most economical of each of these groups here. For details on each tech, see appendix.
Source: Aurora Energy Research

We test how sensitive the results for the business cases are to commodity prices and assumptions on flexibility abroad and in the Netherlands

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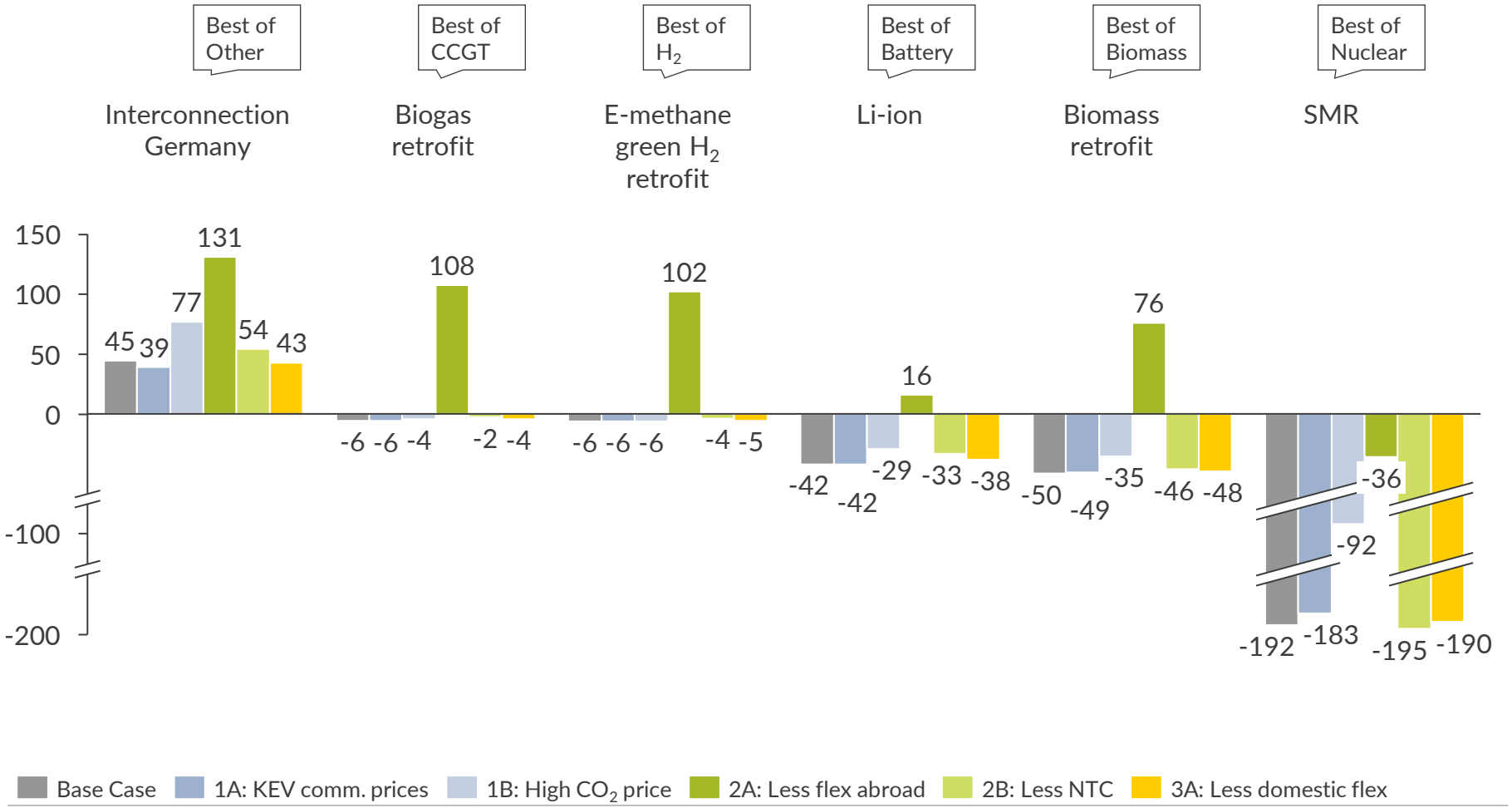
Scenario / Sensitivity	Description	Rationale	Best-performing technologies
Project Base Case	▪ Base Case, as aligned with EZK & TenneT ▪ 2030 prices: Gas: 20.5 €/MWh, Coal: 31.8 €/t, CO_2: 59.7 €/t	▪ -	▪ Interconnection Germany ▪ Biogas retrofit ▪ E-Methane green H_2 retrofit
Sensitivity 1A KEV comm. prices	▪ Commodity prices from KEV 2030 ▪ 2030 prices: Gas: 23.2 €/MWh, Coal: 65.2 €/t, CO_2: 46.2 €/t	▪ Commodity price sensitivity ▪ Impact of higher gas and coal price, but lower CO2 price like in KEV	▪ Interconnection Germany ▪ Biogas retrofit ▪ E-Methane green H_2 retrofit
Sensitivity 1B High CO_2 price	▪ Higher CO_2 price ▪ 2030 CO_2 price: 100 €/t	▪ Commodity price sensitivity ▪ Impact of a much higher CO2 price	▪ Interconnection Germany ▪ BECCS retrofit ▪ Wind offshore
Sensitivity 2A Less flex abroad	▪ Capacity of thermal and battery flex reduced by 25% for Germany, UK and Belgium ▪ The scenario is quite extreme, loss of load occurs in most countries	▪ Sensitivity on flex capacities abroad ▪ Impact of less flexibility in neighbouring countries	▪ Interconnection Germany ▪ Hydrogen blue H_2 retrofit ▪ Biogas retrofit
Sensitivity 2B Less NTC	▪ Interconnection capacity is reduced by 25% for Germany, UK and Belgium	▪ Sensitivity on flex capacities abroad ▪ Impact of less interconnection with neighbouring countries	▪ Interconnection Germany ▪ Biogas retrofit ▪ E-Methane green H_2 retrofit
Sensitivity 3A Less domestic flex	▪ Reduction of flexible demand within the Netherlands by 25%, for: smart EVs, smart heat pumps, industrial DSR and electrolysers	▪ Sensitivity on domestic flex capacities ▪ Impact of less demand flexibility within the Netherlands	▪ Interconnection Germany ▪ Biogas retrofit ▪ E-Methane green H_2 retrofit

Source: Aurora Energy Research

Sensitivities: Less flexibility in neighbouring countries improves business case of most technologies

AURORA

Base case vs. sensitivities: Gap to profitability 2030 – Best in class technologies
€/kW



Note: We assume a cost of capital (WACC) of 9%.

Source: Aurora Energy Research

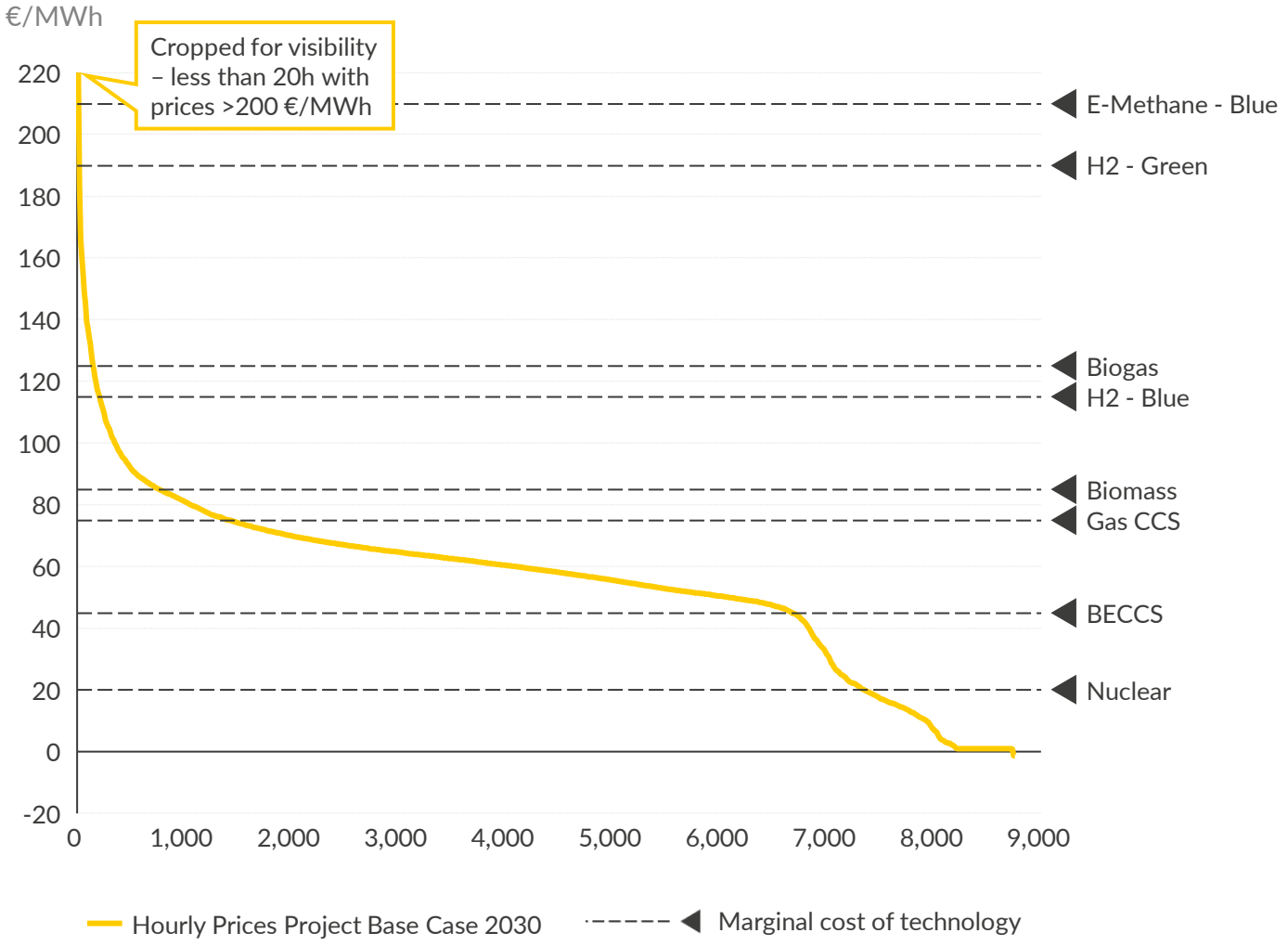
Comments

- For best in class technologies, we compare the gap to profitability in the Base Case with the sensitivities (previous page)
- Changing the commodity prices does not have a strong impact on business cases
  - With commodity prices of the KEV (sensitivity 1A), business cases remain largely unchanged
  - A higher CO_2 price (1B) already has a stronger impact, but leaves most business cases unprofitable
- Reducing the availability of flexible capacity abroad (2A) has the strongest impact on the business cases
  - This is as flexibility from neighbouring countries reduces the need for flex in the Netherlands through interconnection
  - Most best in class techs would become profitable in 2030
  - Yet, this sensitivity is quite extreme (see previous slide)
- Less interconnection and domestic flexibility (2B, 3A) also have limited impact on the business cases of the best in class technologies

The price duration curve of the Base Case in 2030 explains the running hours and profitability of the technologies

AURORA

Price duration curve and Marginal Costs – Base Case, 2030



Comments

- Whenever the price is higher than the marginal cost of a technology, it will produce electricity
- The area between the power price and the marginal cost lines of the respective technology correspond to the gross margins of the technology
- In 2030, power prices are distributed such that
  - For ~7,000 hours, prices are in the range of 20-100 €/MWh
  - Only for ~400 hours, prices rise above 100€/MWh
  - For >500 hours, prices below 1 €/MWh occur
- From this price distribution, the running hours of the different technologies become apparent
  - Technologies with low marginal costs like nuclear or BECCS can run up to 7,000 hours per year already in 2030
  - Technologies with high marginal cost (i.e. high fuel cost or low efficiency) like biogas, hydrogen or e-methane can barely run
- When running hours are low, technologies have limited possibility to earn back their capital costs and / or their fixed operating and maintenance costs
  - With more high price hours in years after 2030, technologies like hydrogen or gas CCS can run significantly more hours and become profitable eventually – see next chapter

Note: While the intersection of marginal costs and price duration curve gives a rough indication of run hours, plants will additionally have to consider ramping in their decision to dispatch. I.e. they will not ramp up for one high price hour, but only if there are enough consecutive high price hours to recover ramping cost. Some technologies (e.g. metal fuels) have such high marginal costs, they are not plotted here.

Source: Aurora Energy Research

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AURORA

Introduction (1/2): To design carbon-free technology mixes for the Dutch power market post 2030, we first assessed the need for flexibility

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In the following section(s), we will present analyses referring to LOLE, the loss of load expectation. Assessing capacities in the power system vs. the demand is key to understanding the behaviour and economics of any production technology in the power market – checking whether and to which magnitude loss of load is expected, is an essential part of any such analysis. However, the **focus on this study is to assess the profitability of and need for carbon-free flexibility sources in the Dutch system.** Our assessment gives a rough indication of required capacity, but conclusions on the exact magnitude of LOLE in a given year cannot be drawn

Scope of the study and treatment of loss of load

- Main goal of this study is to assess the profitability of and need for carbon-free flexibility sources in the Dutch system
- In order to size the capacities that need to be entered into the market from 2030 to 2050, as a first indicator we use the amount of loss of load that arises in this time period once thermal capacities are phased out
  - This analysis is repeated for a set of 10 Weather Years to take into account the variation that arises from different production patterns of wind and solar as well as different demand patterns (e.g. heat demand)
- Taking this as a starting point, iterations were done to identify levels of capacity of carbon-free flex technologies that can operate economically

Outside of study scope

- There are studies, usually conducted by the TSOs, with the sole purpose of assessing security of supply and system adequacy of power markets, which usually include the below aspects to derive estimates of LOLE
  - Analysis of a broad set of weather years (30-40 years)
  - Statistical analysis to quantify the likelihood of extreme events arising
  - Focus on the next 10-15 years, as uncertainties beyond that time increase strongly
- The depth of such an analysis goes beyond the scope of this study on carbon-free flexibility sources – results on loss of load arising in this study should thus only be interpreted in the context of the profitability of technologies

Source: Aurora Energy Research

Introduction (2/2): The aligned Base Case shown in Chapter 2 is the basis for the analysis on required flexibility in this section

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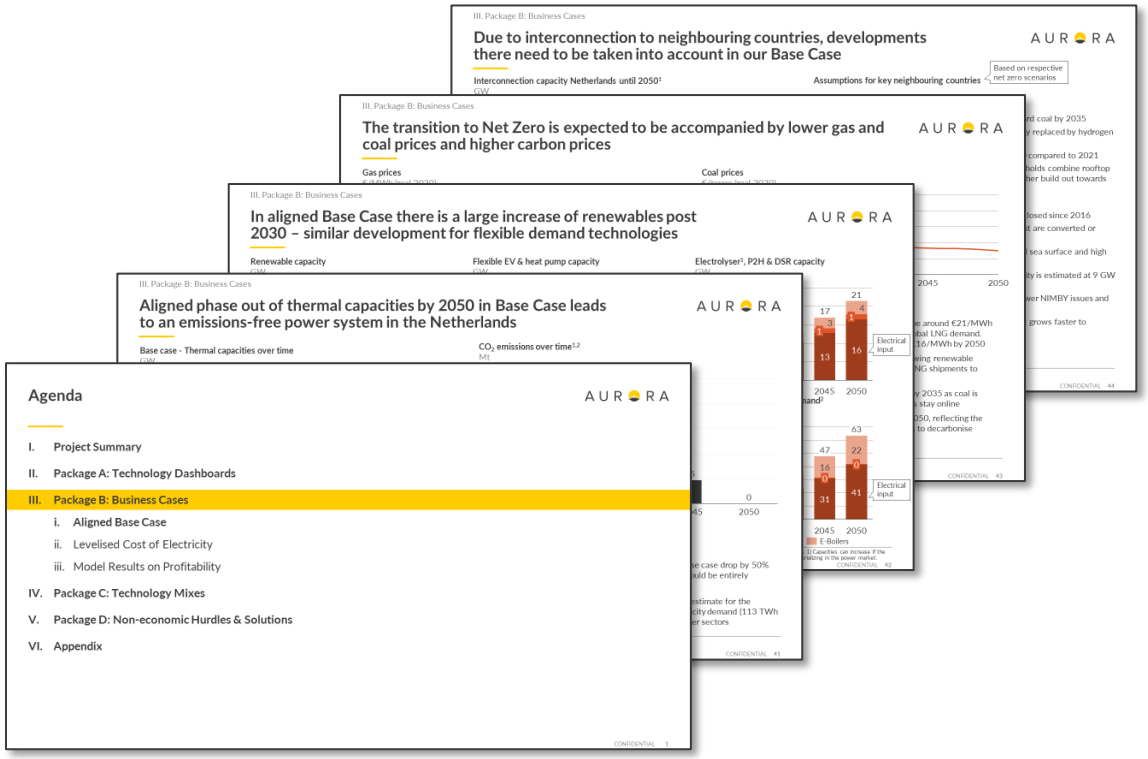
The Base Case aligned with EZK and TenneT in Chapter 2…



… is the basis for the following analysis of required flexibility

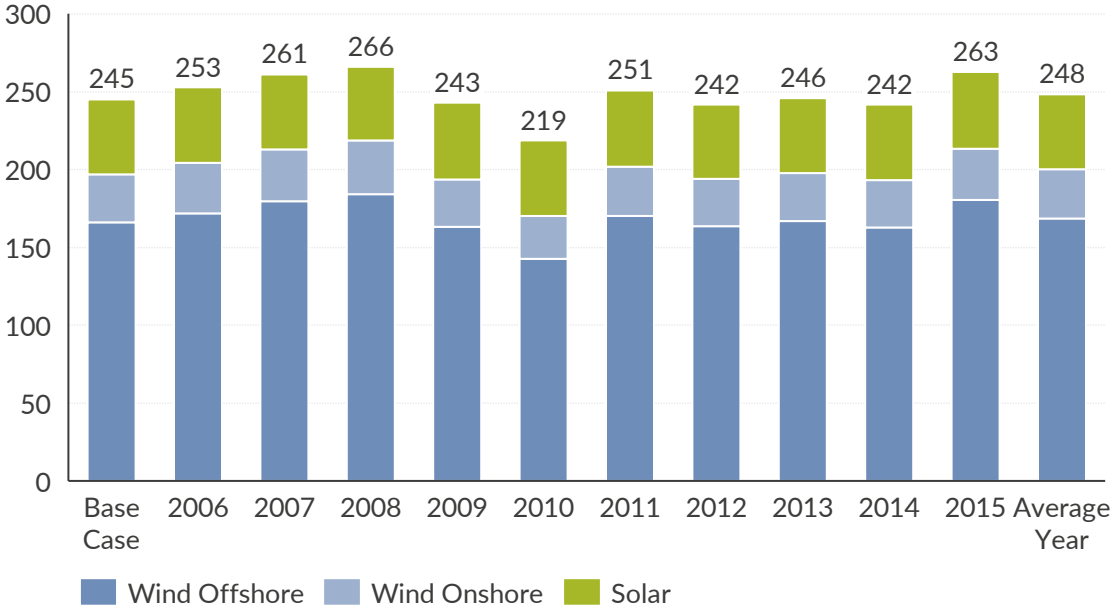
- The analysis of required flexibility uses the same Base Case that has been used to assess the profitability in technologies in Chapter 2
- Importantly, this analysis is based on a system, in which
  - Gas capacities are reduced over time, resulting from a combination of assets coming to the end of their lifetime and capacity restrictions to meet CO_2-targets
  - No flexible production technologies have yet been added on the supply side
  - But flexibility exists on the demand side, e.g. from heat pumps and electrolysers, as well as through interconnection to neighbouring countries
- To understand the market environment in which the analysis of required flexibility is conducted, please consult the respective section in Chapter 2

Source: Aurora Energy Research

We test ten different weather years – load factors lead RES generation to vary by up to ~20%, demand fluctuates too

AURORA

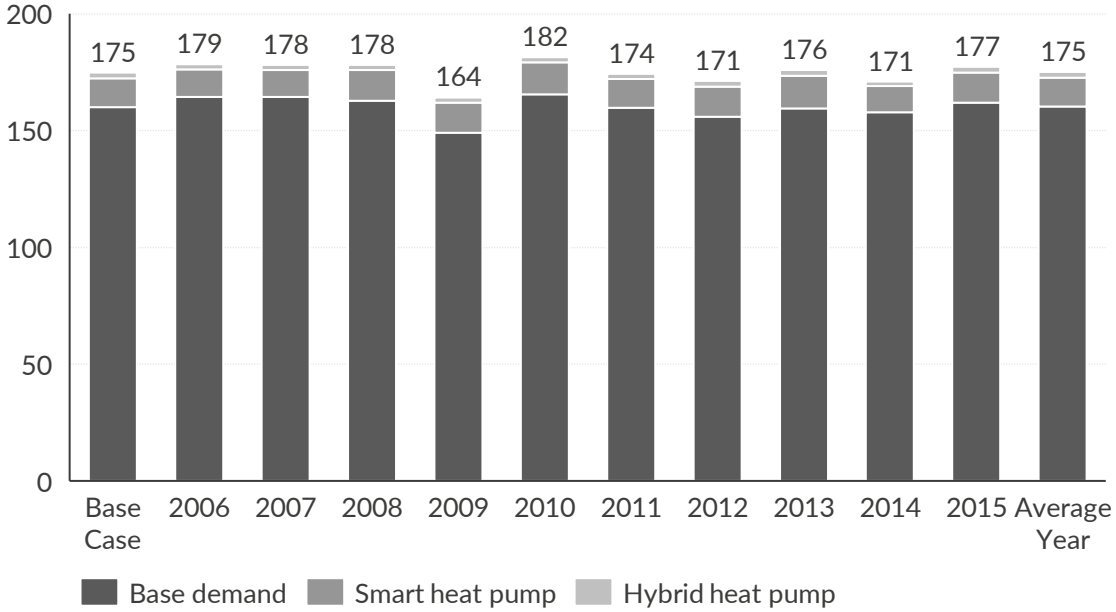
RES Generation – 2050
TWh



Comments

- Given offshore wind is the main RES-source, its fluctuations drive difference in RES generation – difference of >40 TWh between year of highest production (WY 2008) and year of lowest production (WY 2010)
  - Up to ~47 TWh total difference in RES generation between these years

Base demand and heat pump demand – 2050
TWh



Comments

- The weather years have also different inputs on the demand side
  - Base demand is the main driver here, up to ~16 TWh difference between WY 2009 and WY 2010
  - Also heat pump demand differs – up to ~2.5 TWh of additional variation between weather years

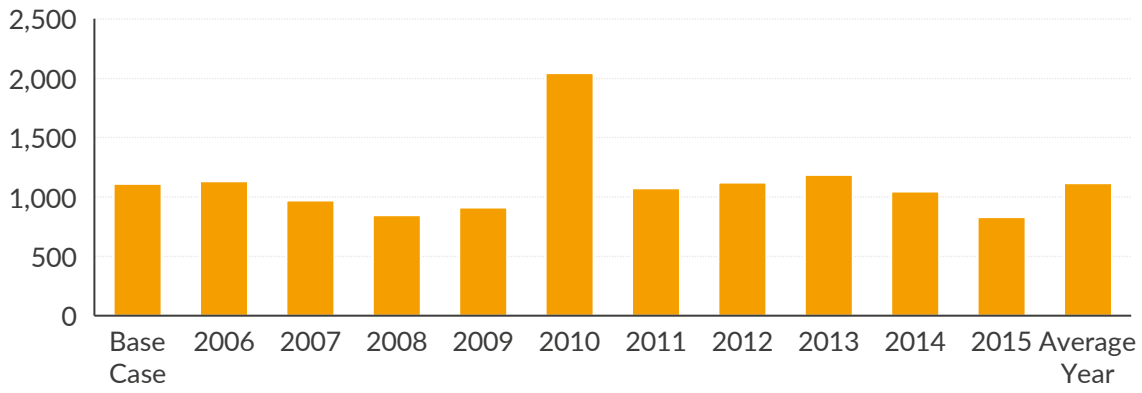
Note: WY = Weather Year

Source: Aurora Energy Research

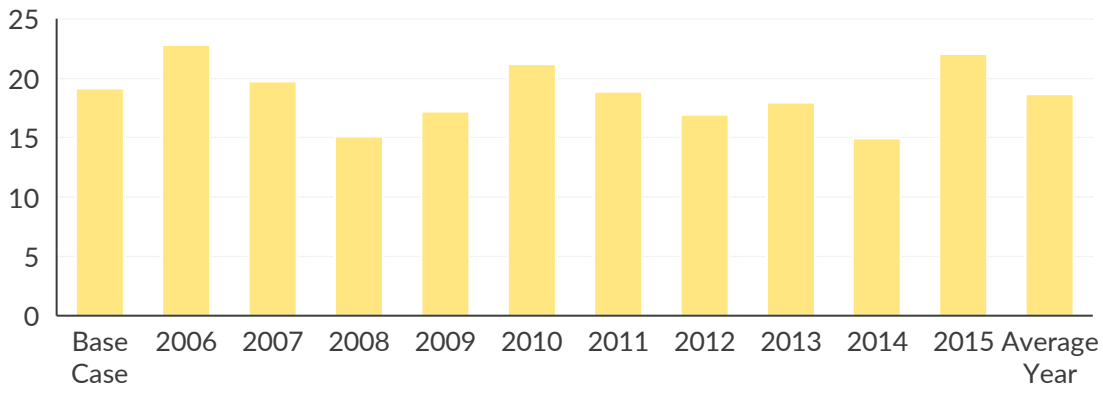
In 2050, depending on weather year, up to ~2,000 hours of loss of load, ~8 TWh of unmet demand and ~23 GW max loss of load

AURORA

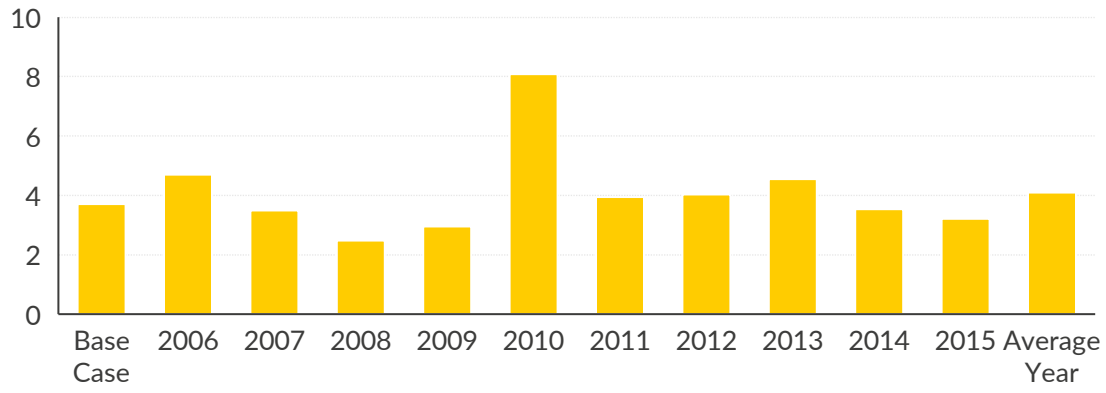
Loss of load numbers of hours – 2050
h



Maximum loss of load – 2050
GW



Loss of load depth – 2050
TWh



Comments

- WY 2010 is most extreme weather year
  - Leads to ~2000 hours where loss of load occurs as well as ~8 TWh of unmet demand by 2050
  - Not the highest WY in terms of maximum loss of load
- WY 2006 leads to highest maximum loss of load in 2050, amounting to ~23 GW of loss of load in the most extreme hour
- WY 2008 with very little loss of load over all categories

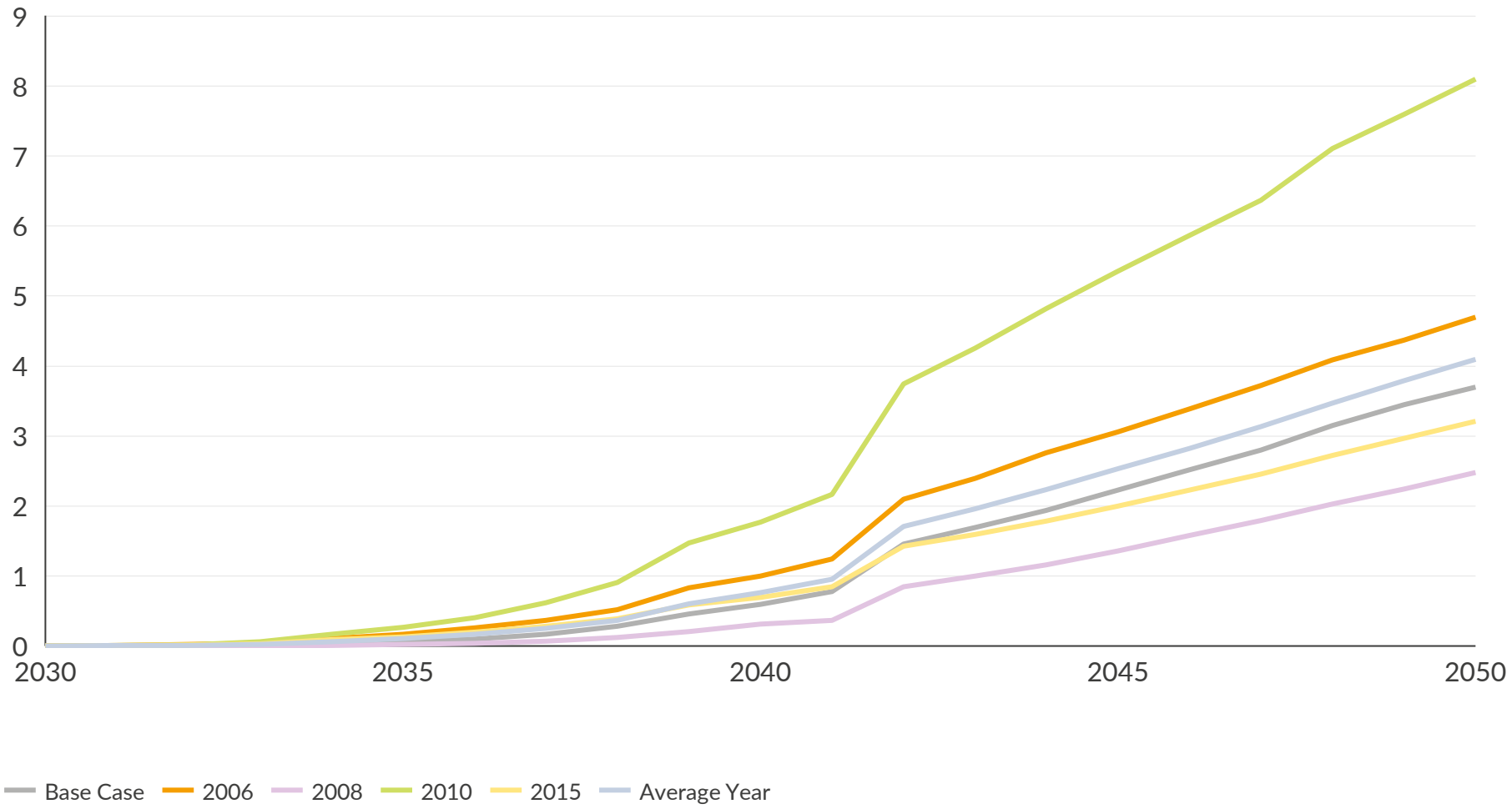
While these results are a theoretical analysis with no flex technologies added, it is important to point out that with such a high number of loss of load and associated extreme prices, likely additional demand response (e.g. from new industrial electrification) would come online to prevent these outcomes. Compare e.g. emergency load response programs in some US states.

Note: This section covers loss of load and prices in the Base Case when only considering RES and the remaining thermal assets - without having added the flex production technologies.

Source: Aurora Energy Research

Average weather year with ~4 TWh of unmet demand by 2050 – wide range from 2.5 TWh to 8 TWh

Loss of load depth
TWh



Note: This section covers loss of load and prices in the Base Case when only considering RES and the remaining thermal assets - without having added the flex production technologies.

Source: Aurora Energy Research

AURORA

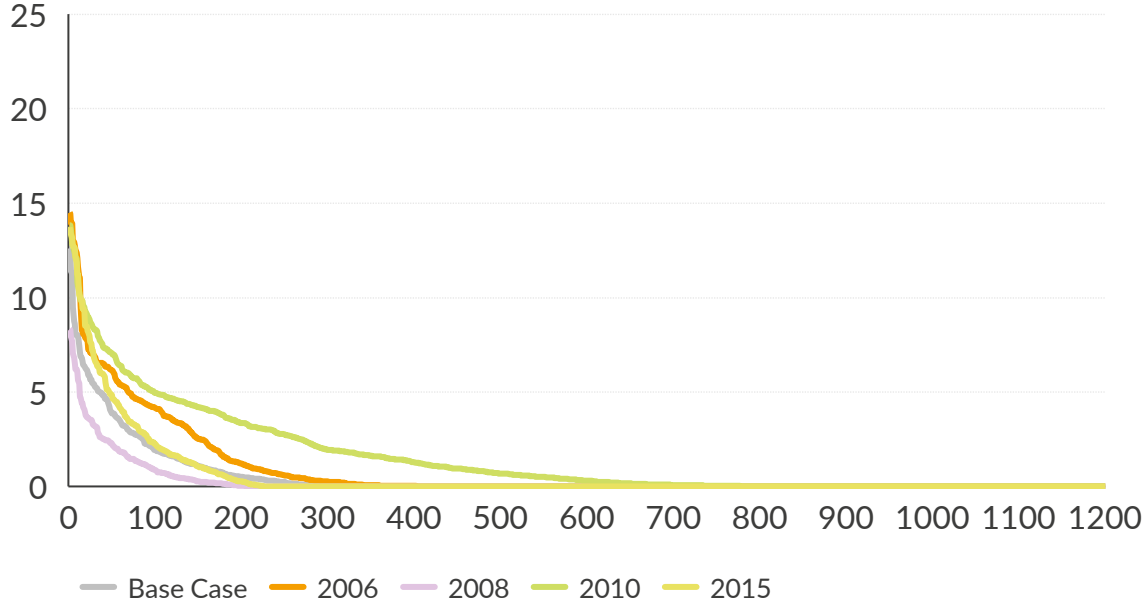
Comments

- Outside of the base case and the average year, we only present select weather years to keep visibility high:
  - WY 2006: Highest max loss of load
  - WY 2008: Fewest problems with loss of load
  - WY 2010: Highest number of loss of load hours and depth of loss of load
  - WY 2015: High peak loss, but limited number of hours and max loss of load

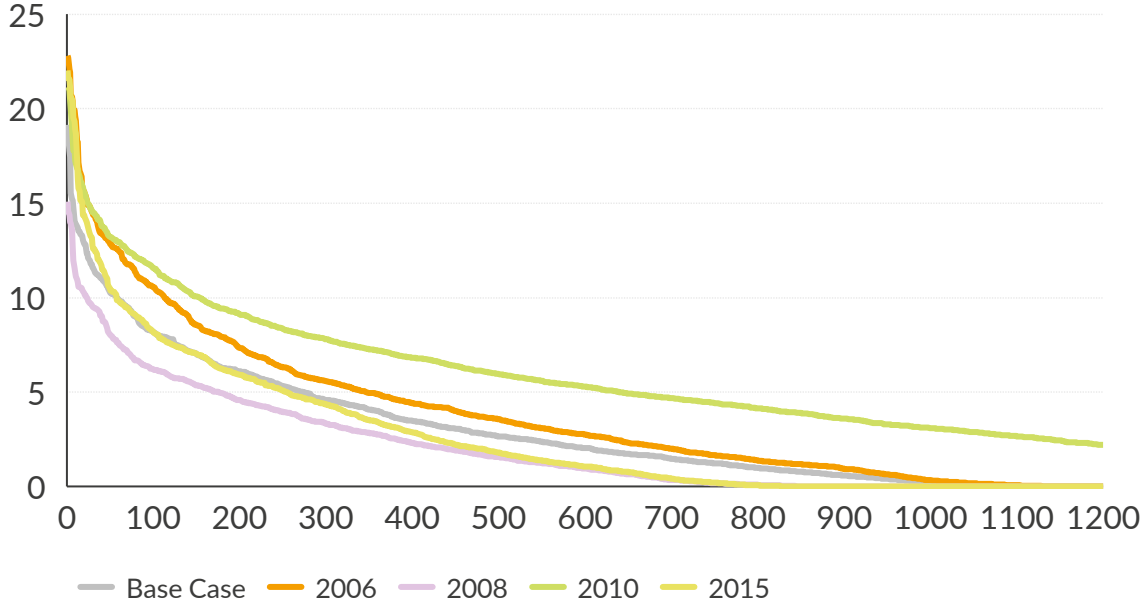
While hours of extreme loss of load already occur in 2040, their number increases strongly within the ten years up to 2050

AURORA

Loss of load duration curve top 1200 hours – 2040
GW (sorted)



Loss of load duration curve top 1200 hours – 2050
GW (sorted)



Comments

- In 2040, for most weather years only a small number of hours exhibit high loss of load – usually fewer than 300 hours
- WY 2010 again is the exception, where more than twice that many hours show significant loss of load

Comments

- By 2050, the picture has changed – in all weather years there are many hours with high loss of load
- Still, between WY 2008 (least hours) and WY 2010 (most hours) the difference is stark – e.g. three times as many hours with 5 GW loss of load

Note: This section covers loss of load and prices in the Base Case when only considering RES and the remaining thermal assets - without having added the flex production technologies.

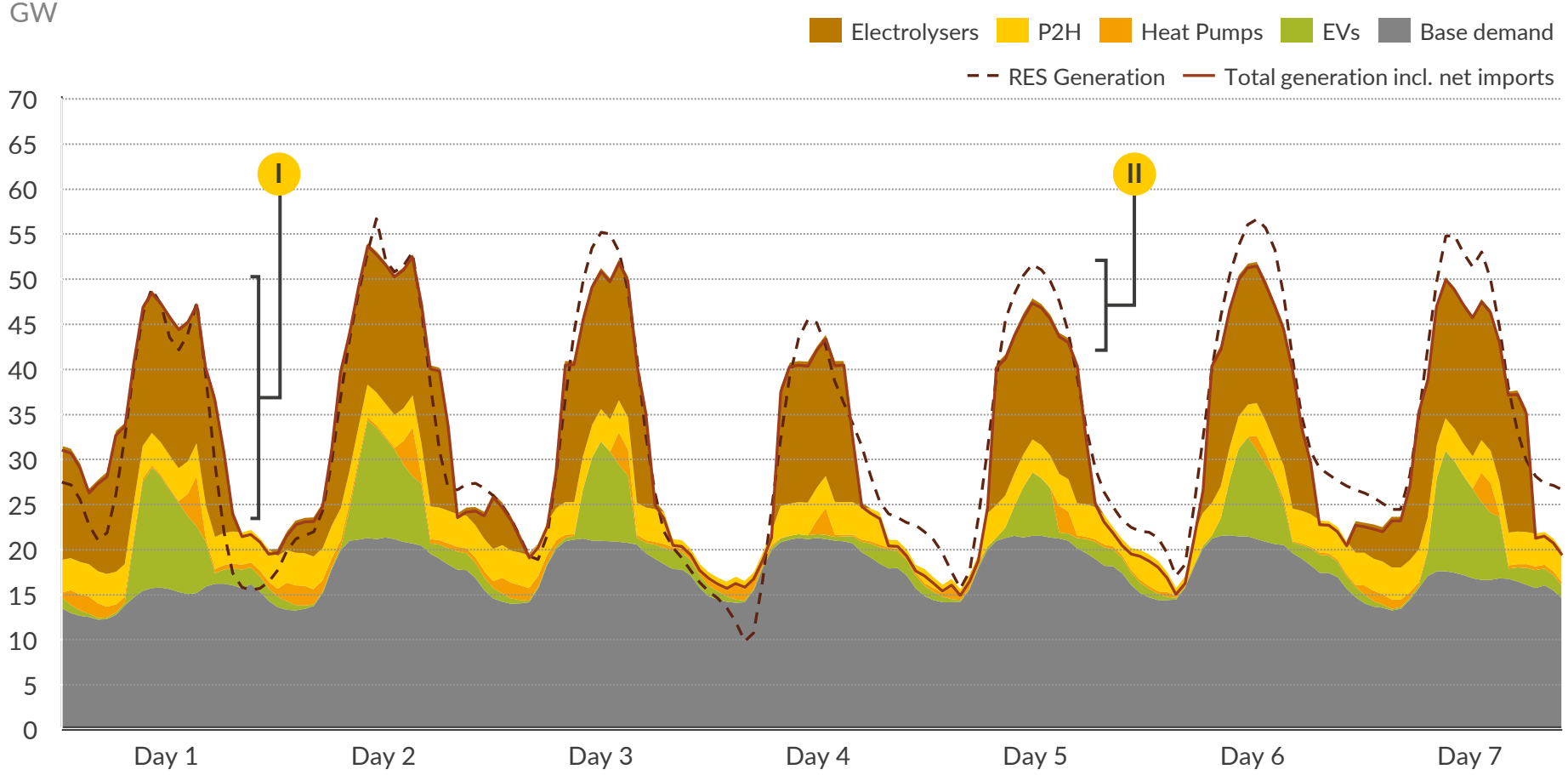
Source: Aurora Energy Research

Flexible demand technologies take advantage of the high production and volatile patterns of renewable power sources in summer

AURORA

Generation and Demand – Typical Summer Week 2050, Base Case

GW



Explanation

- On the left, power generation and demand in the Dutch power market in our model in 2050 for an exemplary week in summer are shown
  - It shows the interplay of demand flexibility and interconnection with volatile power production

I EVs, Heat pumps, P2H (E-Boilers) and Hydrogen-Electrolysers provide an enormous amount of flexible demand, allowing effective use of renewables' generation curves
  - In winter, heat pump demand flexibility plays a much more significant role

II When there is not enough demand to consume all the RES generation domestically, surplus power gets exported to neighboring countries

- As depicted, flexible demand technologies are well able to shift demand in times where sufficient RES generation is available during the day

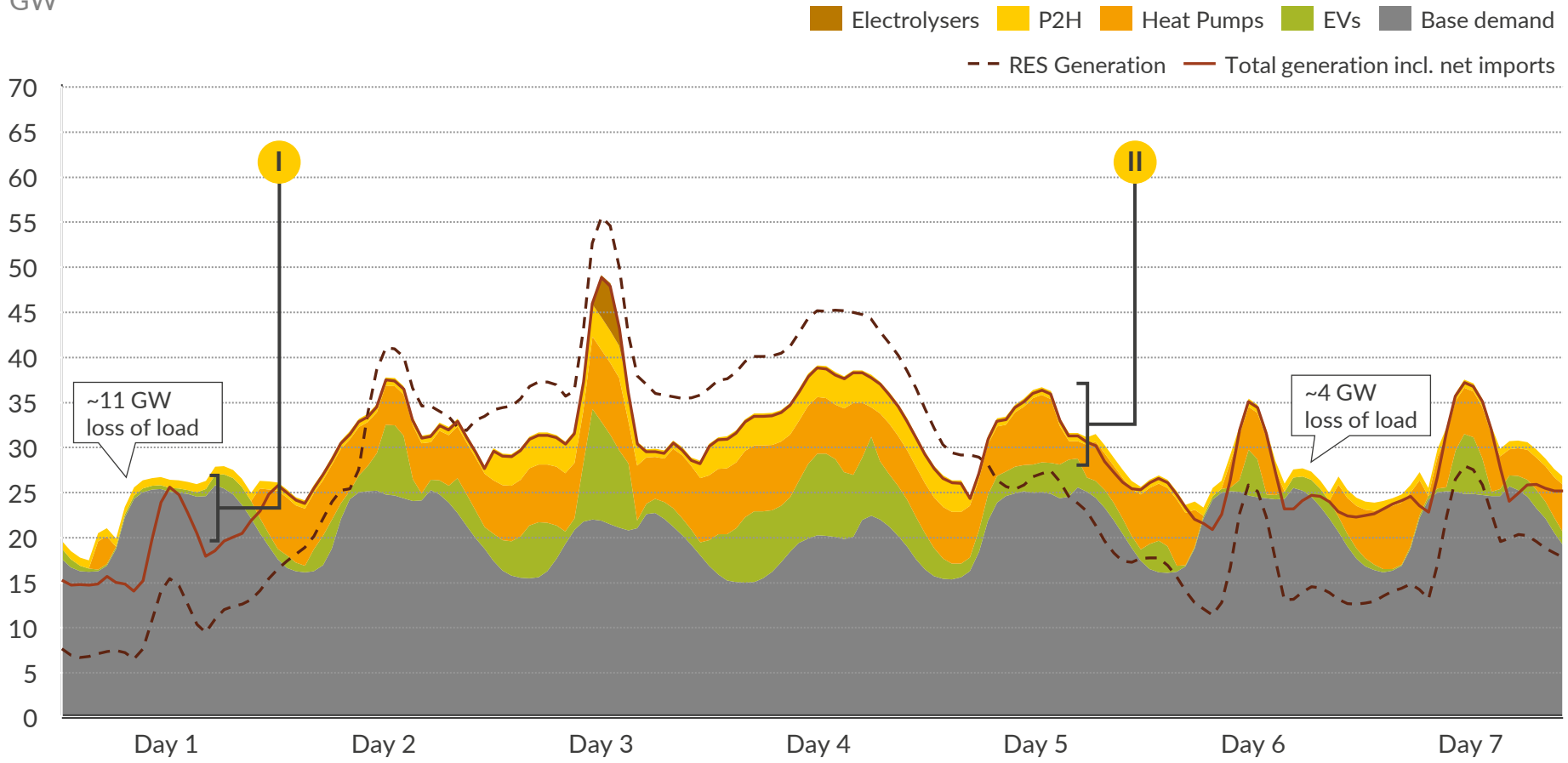
Note: This section covers loss of load and prices in the Base Case when only considering RES and the remaining thermal assets - without having added the flex production technologies.

Source: Aurora Energy Research

During winter, RES generation and imports will not always be enough to cover demand – loss of load occurs frequently

Generation and Demand – Typical Winter Week 2050, Base Case

GW



Note: This section covers loss of load and prices in the Base Case when only considering RES and the remaining thermal assets - without having added the flex production technologies.

Source: Aurora Energy Research

AURORA

Explanation

I Even with imports, the generation from wind and solar alone will not be sufficient to cover demand

- This is where loss of load occurs in our base case. In this instance, ~9 GW occur

II In winter, heat pumps provide increased flexibility during hours of high RES production

- They will shift (smart electric HP) or adjust (hybrid HP) to avoid / reduce loss of load

- When there is insufficient RES generation during the day and increased demand (e.g. strong heating demand in winter), additional capacities are needed to ensure sufficient power provision at any time
  - Different options are explored in the next chapter

Table of contents

Starting off with the analysis of required flexibility, we determined which capacities of long-duration, short-duration and back-up flex are added

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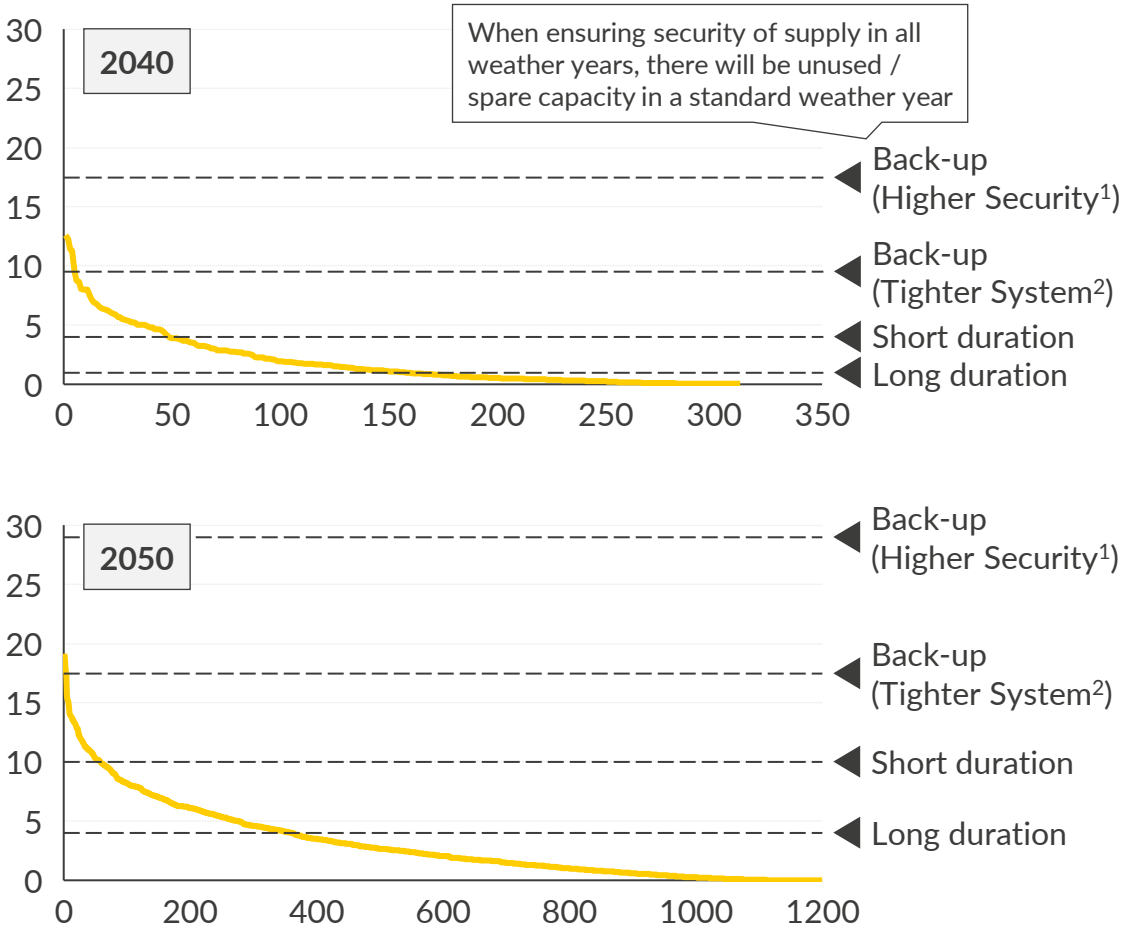
Approach for Capacity Sizing

- The analysis of required flexibility gives a good indication of how much capacity is needed for a certain amount of load hours (graphs on the right)
  - I.e. in 2050, there are ~400 hours where at least 5 GW production capacity is missing in the system
  - This we used to form an initial sizing of the different types of flexibility, where long duration flex is meant to cover many hours a year, short duration / storage is meant to shift demand / supply within a day and back-up flex is meant to run only in very few hours where production capacity is still insufficient after adding the other types of flexibility
- From there, we iterated and tested different capacities, taking into account
  - How tight is the system / does loss of load occur in the standard weather year and / or in more extreme weather years
  - How high are baseload prices and total system costs
  - What is the profitability of the technologies added
- When more capacity is added, the profitability of each technology usually declines, as the system becomes less tight
  - Short-duration flex / batteries in particular will contribute to peak shaving and thus cannibalize their own business case, as they depend on spreads
- As we tested three different technology mixes, we kept the capacity of long duration / short duration / back-up flex constant between them, to enhance comparability

Loss of load duration curve Base Case – Standard Weather Year (WY)

GW (sorted)



1) Ensures no loss of load occurs – details on following slides; 2) Enhances profitability of technologies – details on following slides

Source: Aurora Energy Research

Three different technology mixes were developed – they mainly differ by the technology that is used to offer long-duration flex

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Flex Techs	Technology Mix 1	Technology Mix 2	Technology Mix 3
Long-duration	▪ Hydrogen CCGTs	▪ Nuclear Small Modular Reactors (SMRs)	▪ BECCS, Gas CCS
Short-duration	▪ Lithium-Ion Batteries	▪ Lithium-Ion Batteries	▪ Lithium-Ion Batteries
Back-up	▪ Hydrogen OCGTs	▪ E-Methane OCGTs	▪ Hydrogen OCGTs
Rationale	▪ Hydrogen CCGTs are a very effective option to offer long-duration flexibility in a high-RES system – While their business case in 2030 is worse than for E-Methane CCGTs, Hydrogen CCGTs have lower LCOE already for a few hundred running hours – as the number of high price hours increases over time, hydrogen CCGTs are the cheaper option – Price of hydrogen will decline over time and increase the competitiveness further – Retrofitting existing assets is possible, reducing CAPEX need vs. Nuclear SMRs ▪ Lithium-Ion batteries can provide flexibility within the day and help balance short-term fluctuations – Besides V2G, Lithium-Ion is the cheapest storage technology, given its high round-trip efficiency – see LCOE calculations – V2G is a rather experimental technology – it is unclear whether implementation hurdles (technical, acceptance) can be overcome	▪ Nuclear SMRs are an alternative to ensure security of supply that differs from hydrogen CCGTs – Nuclear power plants are less flexible than CCGTs, as ramping is slower and more expensive – still, they can provide flexibility to the system – Also, having them operate as baseload, demand flex and storage can take advantage of shifting demand and supply – Nuclear SMRs will still run >7k hours and be in the merit order right behind RES ▪ In the most extreme hours, only back-up will be able to ensure security of supply – for OCGTs, e-methane could be used as a fuel, given the low running hours of back-up – E-Methane can more easily be used in existing infrastructure compared to H_2 – Yet, due to efficiency losses, the fuel is more expensive than hydrogen	▪ BECCS can play an important role as one pillar to ensure the security of supply – Like nuclear SMRs, BECCS plants can provide some flexibility themselves and combining them with batteries and flexible demand enhances the overall flexibility of the power system effectively – Rising carbon prices make it a highly profitable option, additionally existing coal plants can be retrofitted ▪ Gas CCS represents an effective supplement for BECCS, which is limited by the availability of biomass – CCGTs ramp more flexibly than the coal plants, offer high efficiency and low marginal costs – even considering the additional cost for carbon capture ▪ Running OCGTs on Hydrogen is the alternative, taking advantage of the lower fuel cost compared with e-methane

Note: As the Aurora Power Market Model features an investment module, we could let the model decide which technologies and capacities to build economically in the market. Yet, system choices are not solely based on economics but also depend on other factors (e.g. availability of fuel). To take these into account and make the outcomes comparable, we set the technology mixes externally, taking our analysis on profitability and LOLE as a basis and aiming for a balance between system cost and profitability.

Source: Aurora Energy Research

Tech Mix 1 uses H_2 CCGTs for long-duration, Tech Mix 2 Nuclear SMRs and Tech Mix 3 BECCS and Gas CCS – we test two scenarios for each

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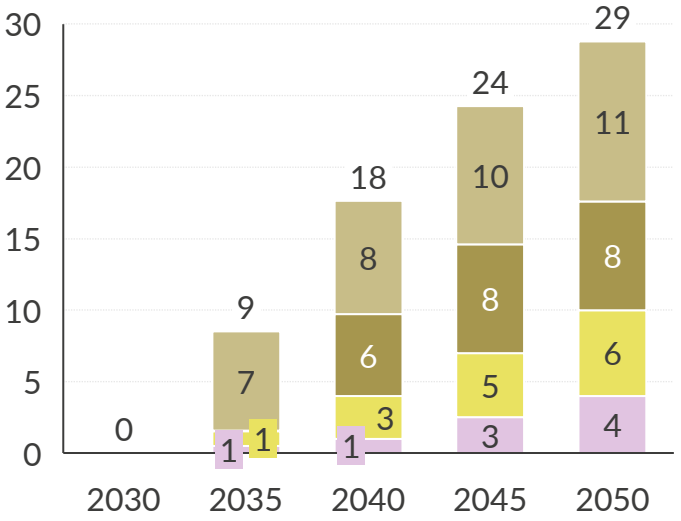
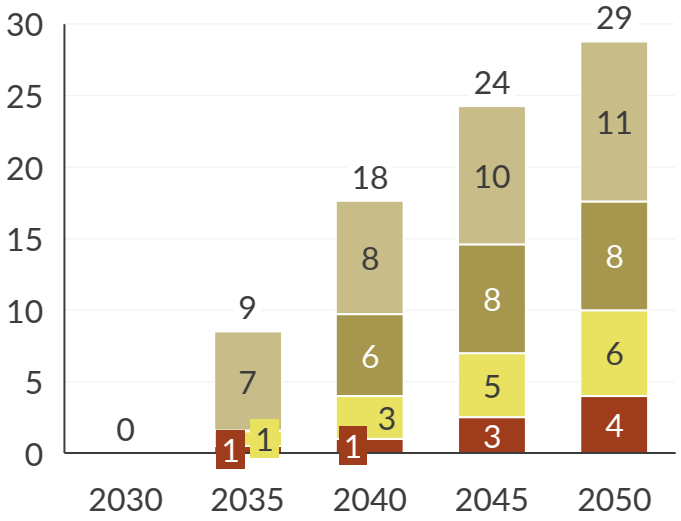
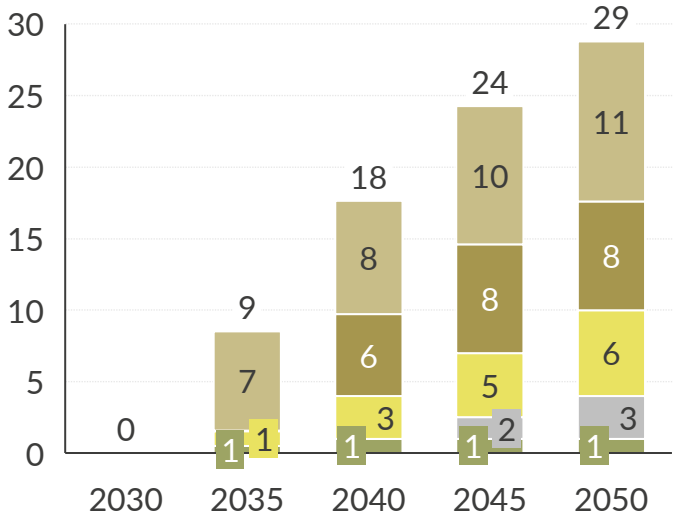
CO_2 free flexible capacities – Tech Mix 1



CO_2 free flexible capacities – Tech Mix 2



CO_2 free flexible capacities – Tech Mix 3



H2 CCGTs | Nuclear SMRs | BECCS | Gas CCS | Li-ion | Back-up - Tighter System | Additional Back-up - Higher Security

Retrofitted

Comments

- For each technology mix, we created one scenario that **ensures security of supply ("higher security scenario")** and one scenario that **increases the profitability of the technologies added ("tighter system scenario")**
  - They differ only by the amount of back-up capacity that is added to the system: In the higher security scenario 19 GW back-up flex is added by 2050, in the tighter system scenario it is only 8 GW
- In both scenarios and all technology mixes, 4 GW of long duration and 6 GW of short duration flex is built by 2050

Note: The above graphs shows the capacities that were added to the base case in the course of creating the technology mixes. All scenarios still have nuclear power plant Borssele operating until 2033.

Source: Aurora Energy Research

For technologies to operate profitably, the market needs to be tight – up to 10 hours of loss of load and a maximum of 7 GW peak LOLE

No LOLE in Higher Security Scenario

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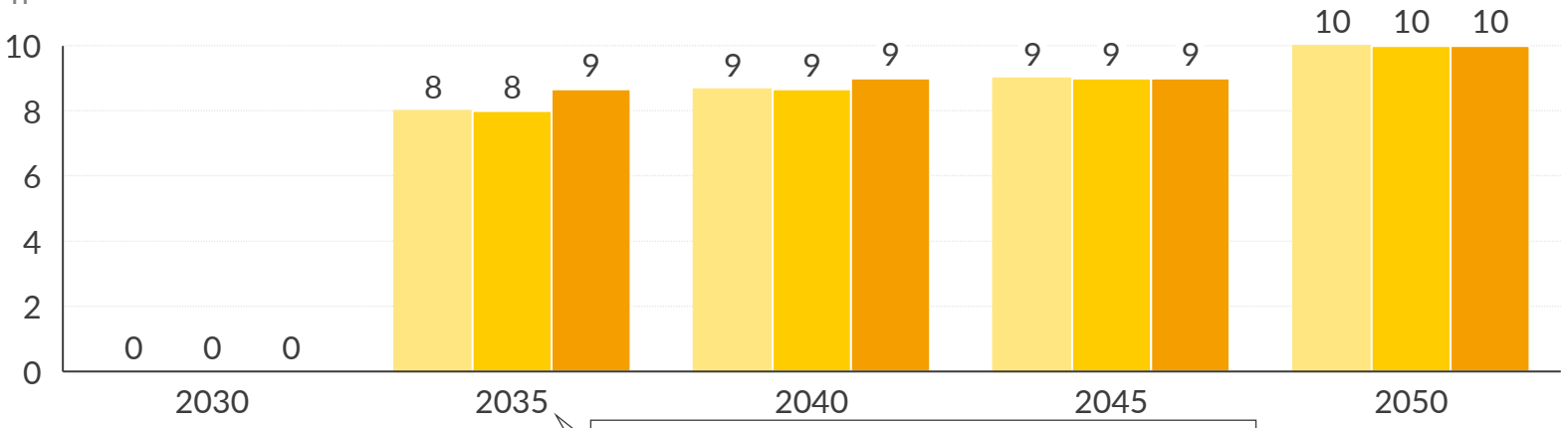
TIGHTER SYSTEM SCENARIO

Hours of Loss of Load per year

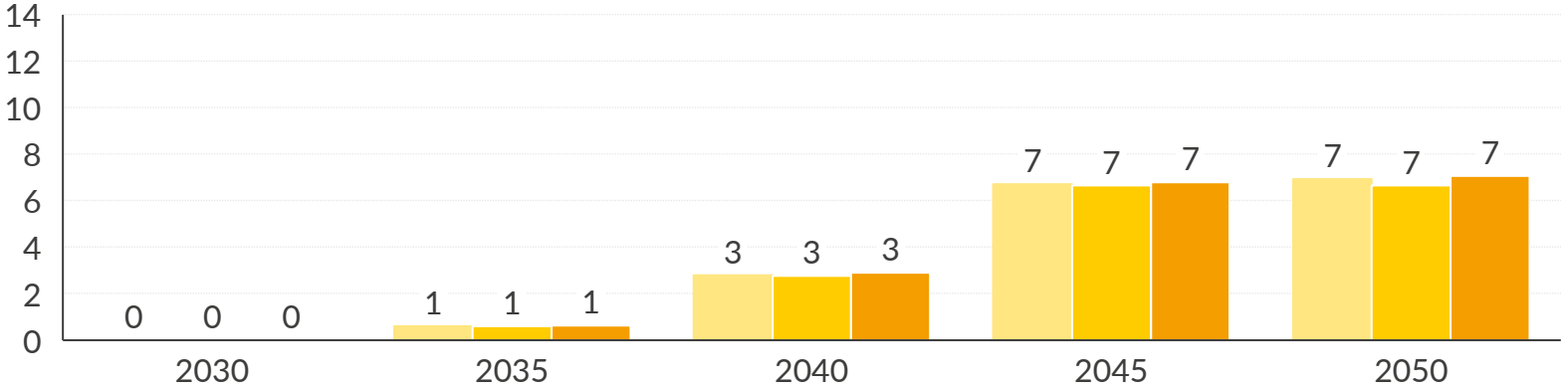
h



Hours of loss of load rise quickly already in the 2030s, as the base case assumes phase out of thermal capacities, e.g. restriction of gas plants to meet CO_2 targets on top of lifetimes of some plants ending

Maximum Loss of Load in a given year

GW



Tech Mix 1 Tech Mix 2 Tech Mix 3

Comments

- By 2030, no loss of load occurs for either of the technology mixes
- The number of hours quickly rises for all technology mixes to ~8-9 hours of loss of load by 2035 – after that it only rises slightly to ~10 hours by 2050
- The maximum peak loss of load rises steadily from ~1 GW by 2035 to ~3 GW and stabilises around ~7 GW by 2045
  - While the number of hours stay constant, the missing capacity in these hours rises over time, as thermal capacities are removed
- The analysis is conducted with a maximum market price of ~3k €/MWh that arises when loss of load occurs – with a higher price of e.g. ~10k €/MWh a different result might occur[1]
  - Given the increased prices, more capacities could operate profitably or more demand would have incentive to flexibilise, which would lower loss of load

1) A dynamic system is currently in place: While the starting maximum price is 3k €/MWh, if in one European day-ahead market the price exceeds 60% of the maximum (i.e. 1.8 k €/MWh), the maximum increases by 1k €/MWh and applies for five weeks in all coupled markets. This principle can be repeated, leading to prices of several thousand euros. As this dynamic would require several consecutive days with loss of load and additional investigation to model it, we refrain from addressing it in this report.

Source: Aurora Energy Research

To achieve scenarios where assets can operate profitably, higher baseload prices need to be incurred – while system costs remain lower

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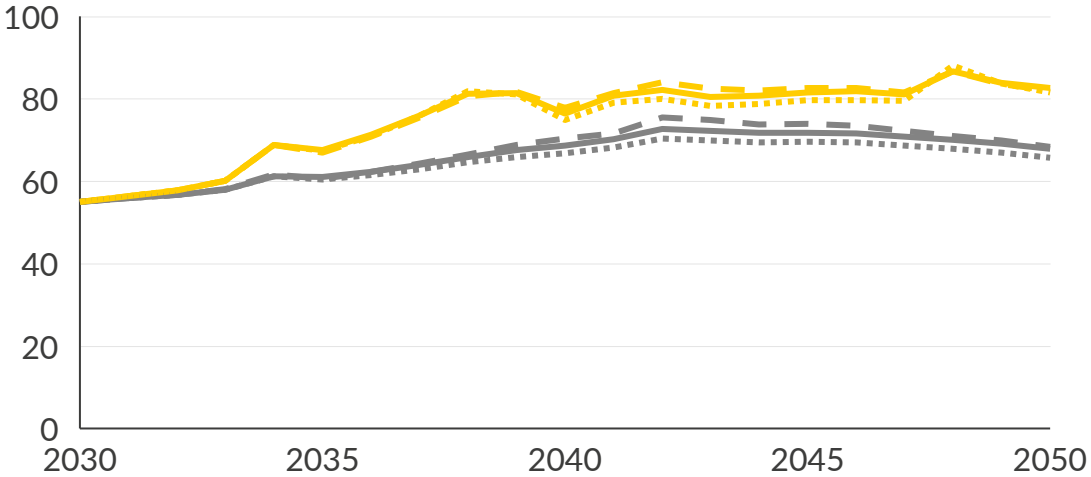
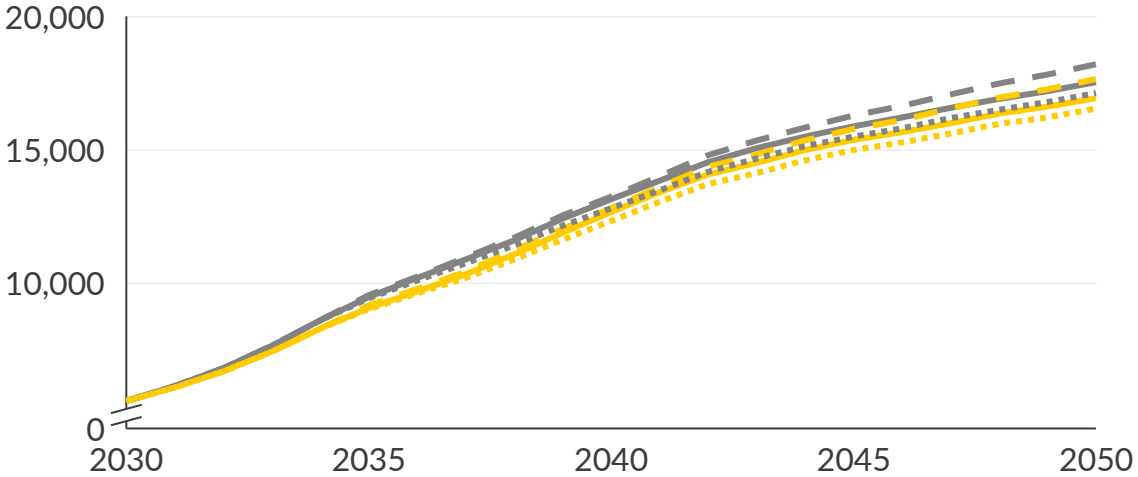
Baseload prices
€/MWh (real 2020)



- Baseload prices are strongly affected by the amount of back-up capacity in the system; when the capacity is tight prices go further up in high priced hours and sometimes get to the maximum market cap of 3000 €/MWh.
- Price deltas between technology mixes are less strong. They are driven by differences in variable cost of long duration capacity and back-up. Tech mix 3 has lowest prices, as BECCS is highly profitable to operate, with negative variable costs. Tech Mix 2 has highest prices, even though nuclear has lower variable costs than H_2 CCGT, which is driven by the higher variable costs of its E-methane OCGTs vs H_2 OCGTs.

System cost proxy[1,2]
mio€ (real 2020)



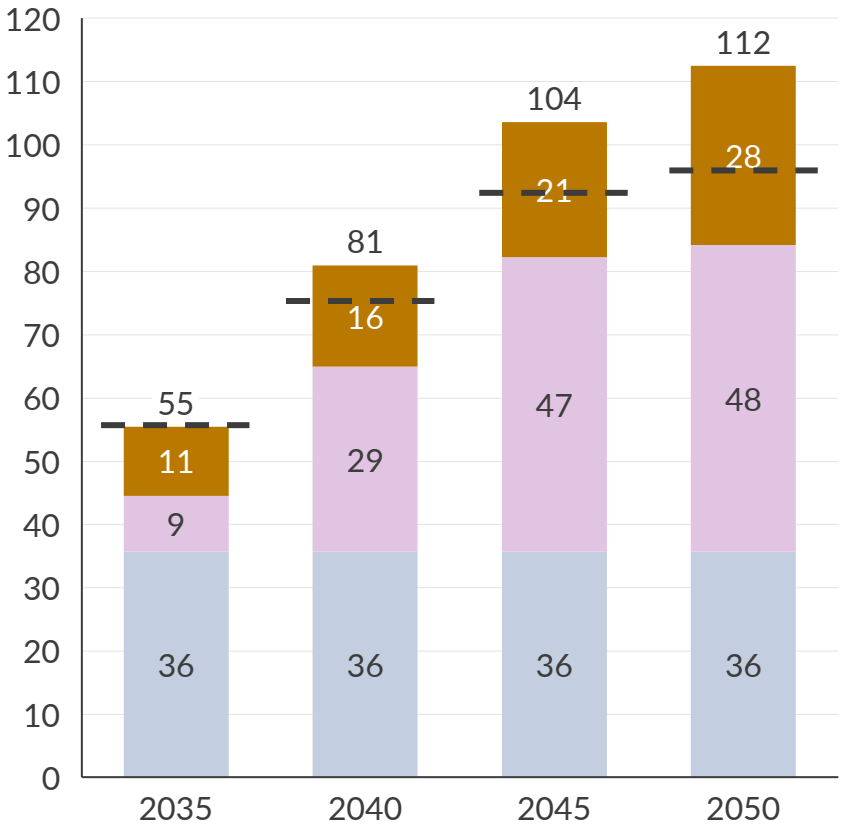
- System costs are higher for the higher security scenario, as more back-up capacity drives up CAPEX and fixed O&M costs, explaining the yearly delta of up to ~590 mio€/year in 2050 with the tighter system scenario
- Loss of Load costs of 3000€/MWh are added to the tighter system scenario which reduces the delta between both scenarios[3]
- From the technology mixes, TM 2 with nuclear is the most expensive one, mostly driven by the high CAPEX of nuclear plants compared to the other long duration technologies, which the low variable costs do not fully make up for
- The strong performance of Tech Mix 3 arises from the high profitability of BECCS, which is further covered in the next slides

TM1 - Higher Security | TM1 - Tighter System | TM2 - Higher Security | TM2 - Tighter System | TM3 - Higher Security | TM3 - Tighter System

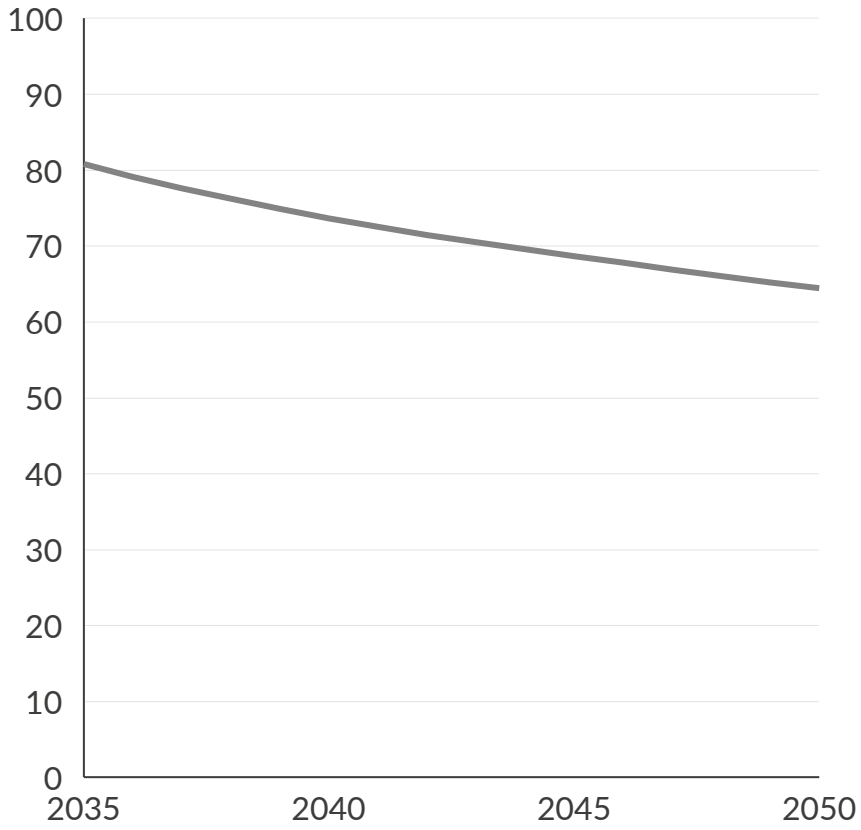
1) System Costs means the sum of Capital Costs, Finance Costs, Operation and Maintenance Costs, and Commodity Costs. CAPEX from before 2030 are not taken into account here. 2) Annualized costs for the respective year 3) ~300 GWh of loss of load occur over the whole period in the tighter system scenario. That is 900 mio€ using 3k €/MWh as cost, or 45 mio€/year

Hydrogen supply consists of domestic green and blue as well as imported hydrogen – green imports from North-Africa price-setting

Hydrogen production mix and base demand
TWh H_2



Hydrogen Price
€/MWh



Blue H_2 | H_2 Imports | H_2 Electrolysis[1] | Hydrogen base demand[2]

Note: Based on Technology Mix 1, Higher security scenario; 1) Electrolyser capacity aligned with EZK and TenneT, based on the KEV2020 and II3050. Capacities can increase if the Netherlands adjust their national electrolyser targets. 2) Demand for H_2 from industry, transport and heating
Source: Aurora Energy Research

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Comments

- In our model, there is a specific hydrogen module allowing for a hydrogen price to form
  - It takes into account hydrogen demand, the marginal cost of H_2 plants and electrolyser dispatch
- Hydrogen is imported on a cost basis – in the 2040s in the majority of hours, imported hydrogen is price setting, thus the impact of blue H_2 and H_2 electrolysers on hydrogen price is limited
- In 2050, ~16 GW of hydrogen electrolysers are installed, demanding ~41 TWh of power to produce hydrogen

With less back-up flex capacity, more loss of load and higher baseload prices, capture prices for RES are higher in the tighter system scenario

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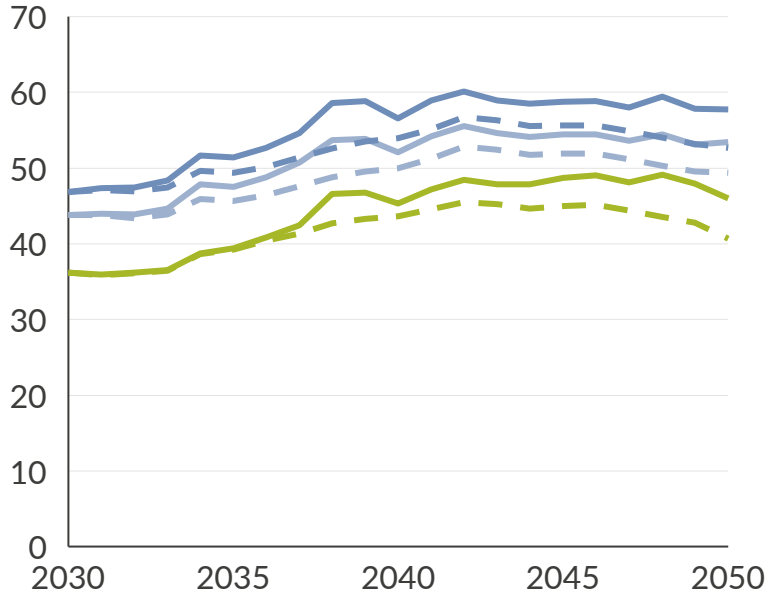
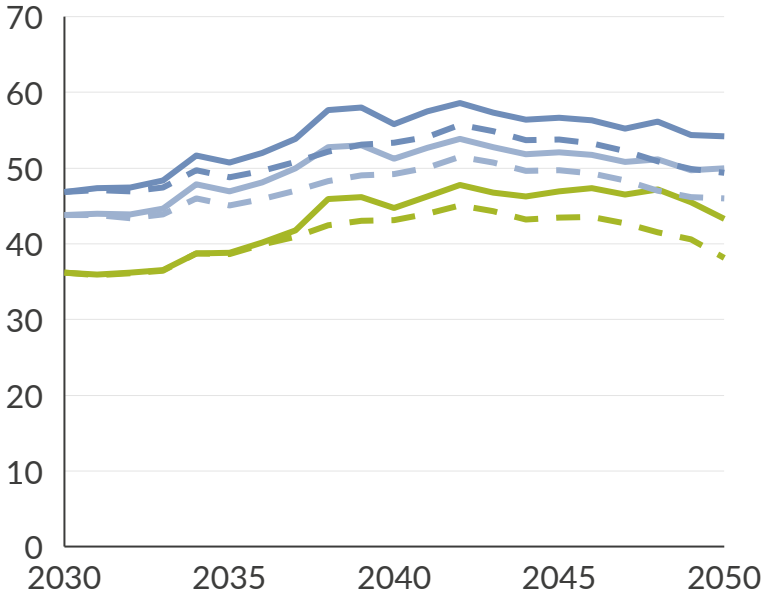
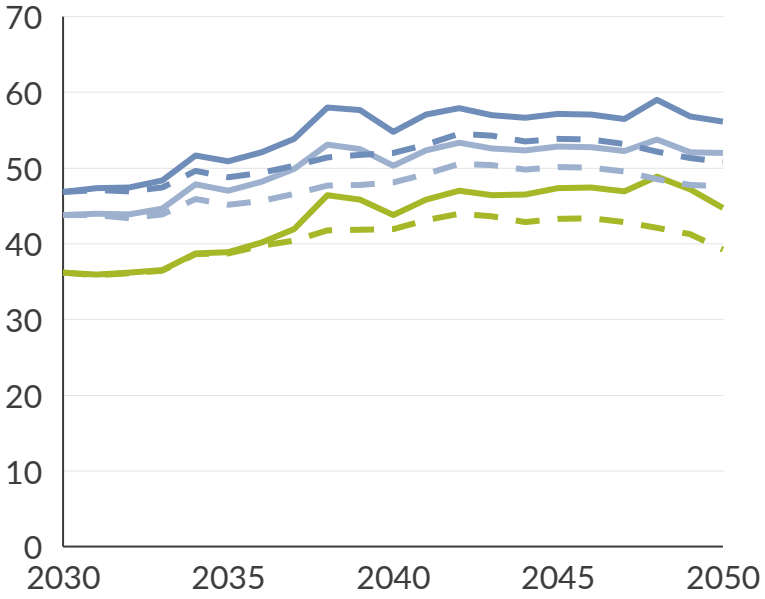
Capture prices[1] – Tech Mix 1
€/MWh (real 2020)



Capture prices[1] – Tech Mix 2
€/MWh (real 2020)



Capture prices[1] – Tech Mix 3
€/MWh (real 2020)



- Renewable capture prices are relatively low around 2030, as RES capacity is build out faster than electricity demand increases.
- In the 2030s, capture prices go up, as the (flexible) demand rises. Flexible demand technologies like electrolysers and P2H have a particular positive effect on renewable capture prices, as their power offtake is concentrated at moments of high renewable production, where prices are usually depressed
- Adding Li-ion batteries as part of the technology mixes also improves capture prices, as they push up demand at moments of low power prices, which correlate strongly with high RES production
- The impact of the differences between technology mixes is rather small. The tightness of the system, however, has a stronger impact on capture prices, as renewable energy sources also benefit from moments with high priced hours

Offshore Wind | Onshore Wind | Solar | Higher Security | Tighter System

1) Generation weighted power price dependent on plant or technology

Source: Aurora Energy Research

For Tech Mix 1, no technology can achieve profitability in the higher security scenario – with less back-up, most plants are profitable starting 2037

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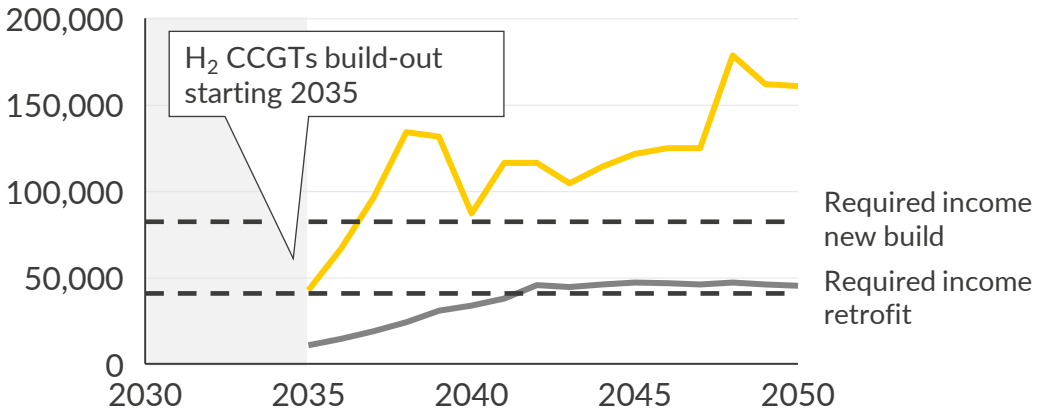
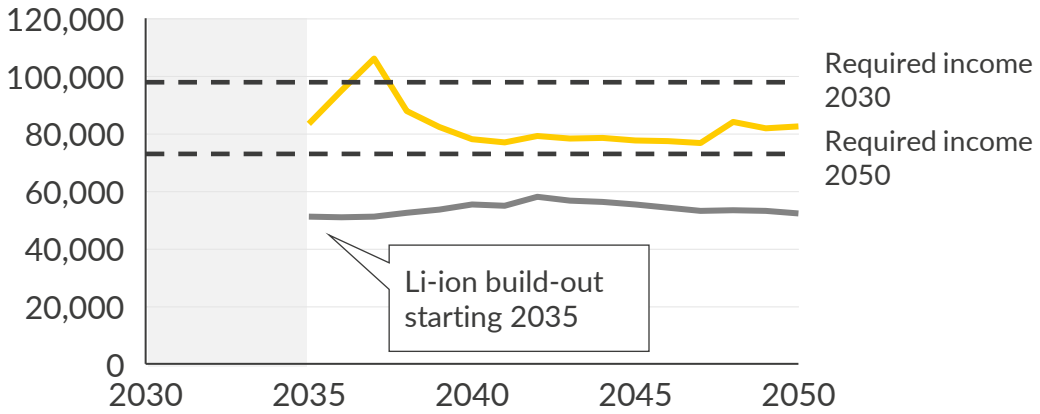
H_2 CCGT Gross margins – Tech Mix 1
€/MW/year (real 2020)



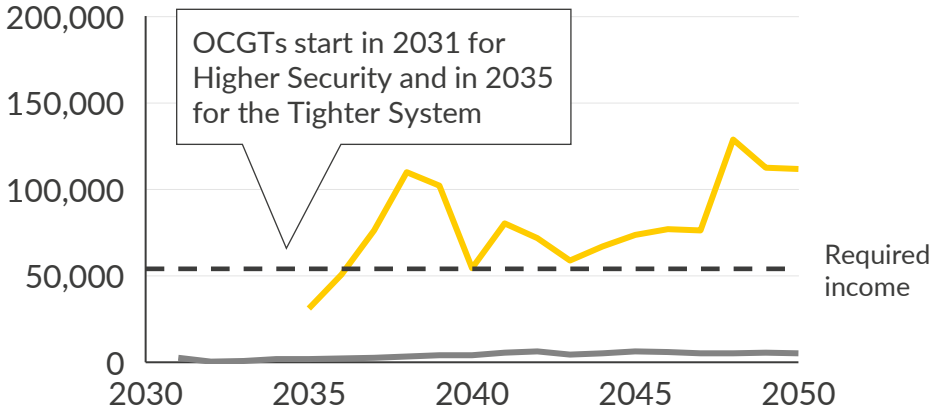
Li-ion (newbuild) Gross margins – Tech Mix 1
€/MW/year (real 2020)



Comments

- Tighter system scenario:
  - H_2 CCGTS become profitable by 2037– from then on their margins are consistently above the income a newbuild CCGT needs to earn, by 2050 their margins are even twice as high
  - Li-ion becomes profitable only in the 2040s – this is as cost improvements lower the required income, while margins stay nearly constant
  - H_2 OCGTs follow CCGTS – they break-even in 2037 and remain profitable
- When aiming for higher security of supply, no technologies can achieve the required incomes for newbuild assets

H_2 OCGT (newbuild) Gross margins – Tech Mix 1
€/MW/year (real 2020)



Higher Security Tighter System

Note: These gross margins reflect the difference between revenues and variable costs on the wholesale market. Yet, this does not exhaust the income opportunities of the technologies. Balancing markets offer an additional income source for many technologies. While a detailed analysis is beyond the scope of this study, we approximate an additional potential of ~5,000 €/MW/year for CCGTs, and ~10,000 €/MW/year for Li-Ion and OCGTs to be derived from balancing markets.

Source: Aurora Energy Research

For Tech Mix 2, when SoS is ensured, the technologies cannot operate profitably – first technologies break-even in 2037 with less back-up

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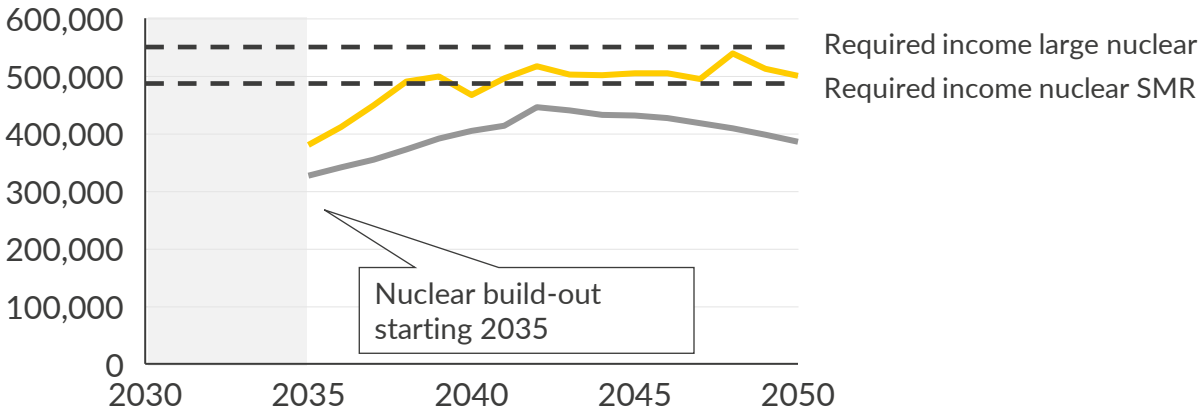
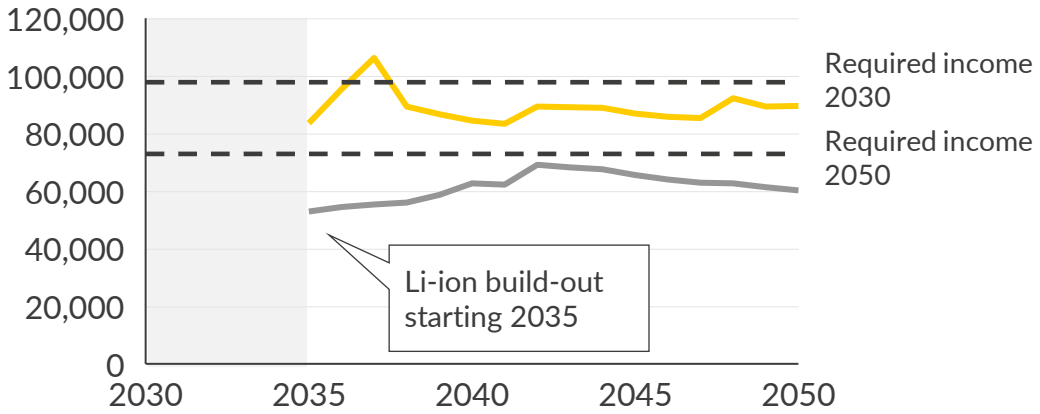
Nuclear (newbuild) Gross margins – Tech Mix 2
€/MW/year (real 2020)



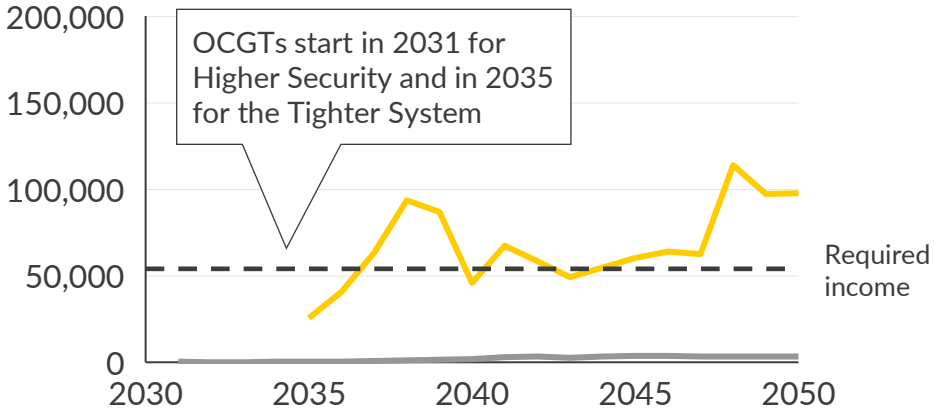
Li-ion (newbuild) Gross margins – Tech Mix 2
€/MW/year (real 2020)



Comments

- Tighter system scenario:
  - Nuclear SMRs become profitable by 2037 and from 2041 on their margins are consistently above the income
  - Li-ion becomes profitable only in the 2040s – this is as cost improvements lower the required income, while margins stay nearly constant
  - E-Methane OCGTs break-even by 2037 – after 2045 their margins stay consistently above the required income
- When aiming for higher security of supply, no technologies can achieve the required incomes

E-methane OCGT (newbuild) Gross margins – Tech Mix 2
€/MW/year (real 2020)



Higher Security Tighter System

Note: These gross margins reflect the difference between revenues and variable costs on the wholesale market. Yet, this does not exhaust the income opportunities of the technologies. Balancing markets offer an additional income source for many technologies. While a detailed analysis is beyond the scope of this study, we approximate an additional potential of ~10,000 €/MW/year for Li-Ion and OCGTs to be derived from balancing markets. Nuclear plants are less dependant on balancing markets.

Source: Aurora Energy Research

For Tech Mix 3, rising carbon prices let BECCS becomes profitable in both scenarios – batteries and back-up perform similarly as in other Tech Mixes

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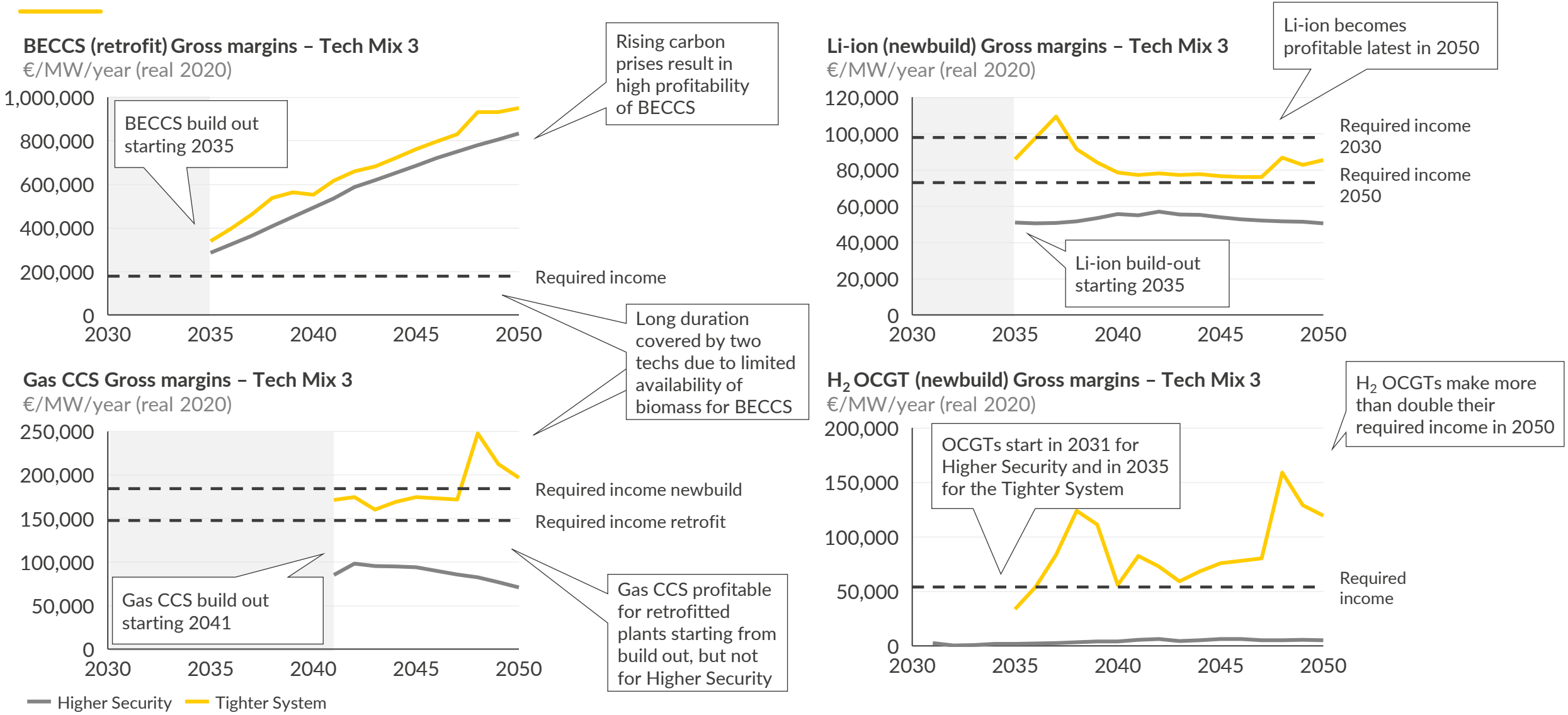

Note: These gross margins reflect the difference between revenues and variable costs on the wholesale market. Yet, this does not exhaust the income opportunities of the technologies. Balancing markets offer an additional income source for many technologies. While a detailed analysis is beyond the scope of this study, we approximate an additional potential of ~5,000 €/MW/year for CCGTs, and ~10,000 €/MW/year for Li-Ion and OCGTs to be derived from balancing markets.

Source: Aurora Energy Research

(1/2): The tighter system scenario deviates from the higher security scenario mainly in the most expensive hours…

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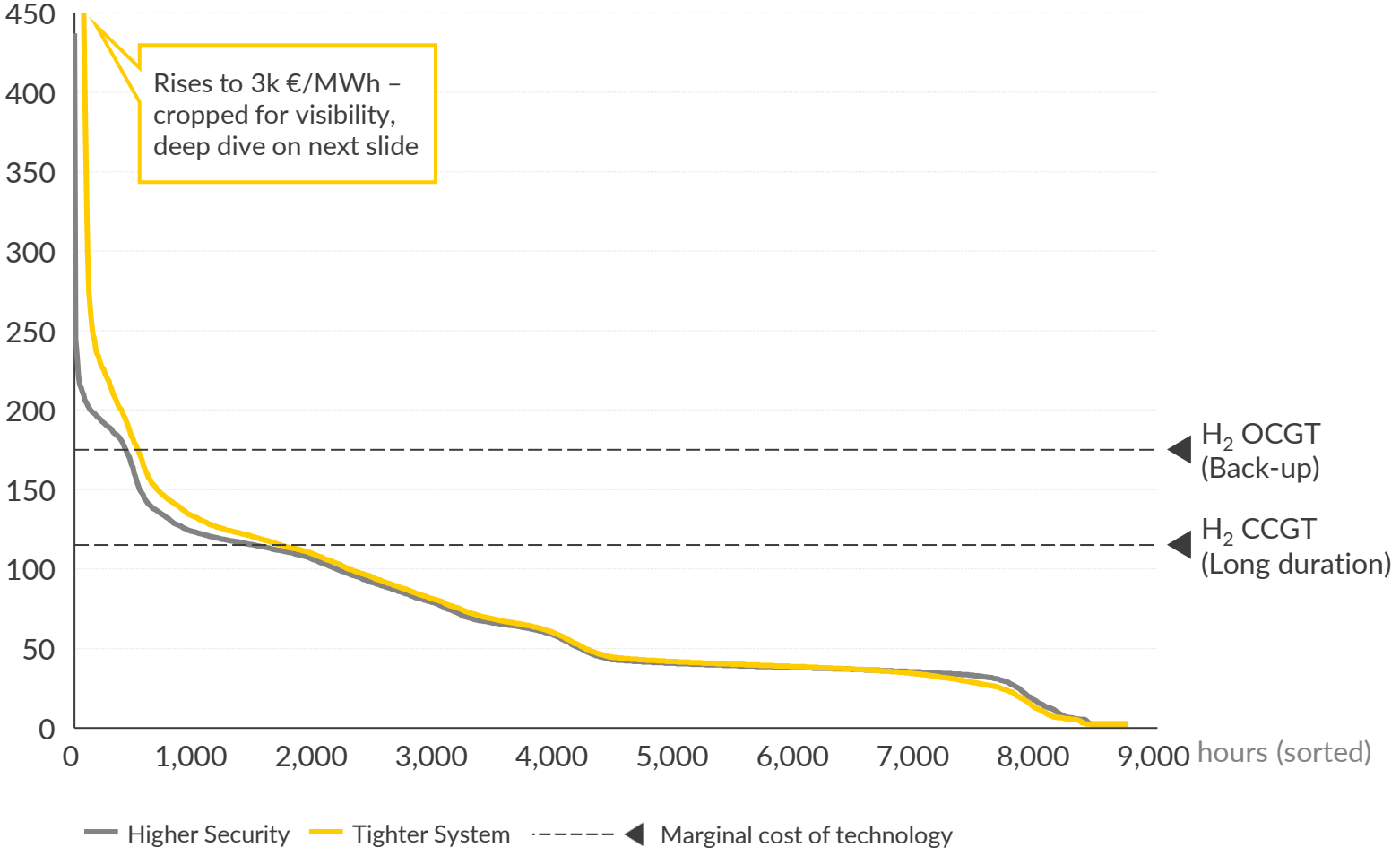
Tech Mix 1

Price duration curve in 2050 – Full year
€/MWh



Comments

- Sorting hourly prices from most to least expensive, the two scenarios exhibit fairly similar power prices – except for the most expensive 2,000 hours
- The tighter system scenario then deviates and starts to show much higher power prices, as expensive DSR becomes active and loss of load occurs
- Whenever the price is higher than the marginal cost of a technology, the plant will produce electricity in this hour
- The area between the power price and the marginal cost lines of the respective technology correspond to the gross margins of the technology
- Especially long-duration flex with high marginal costs and back-up flex strongly benefit from the additional revenues that can be achieved in the few hundred high-price hours
- Technologies with low marginal costs (e.g. nuclear SMRs with ~23 €/MWh, BECCS with ~-46 €/MWh) can produce most hours of the year – not shown for simplification

Note: Prices taken exemplary from Tech Mix 1

Source: Aurora Energy Research

(2/2): … which have a strong impact on technology profitability: Taking back-up flex as an example, its gross margins rise visibly

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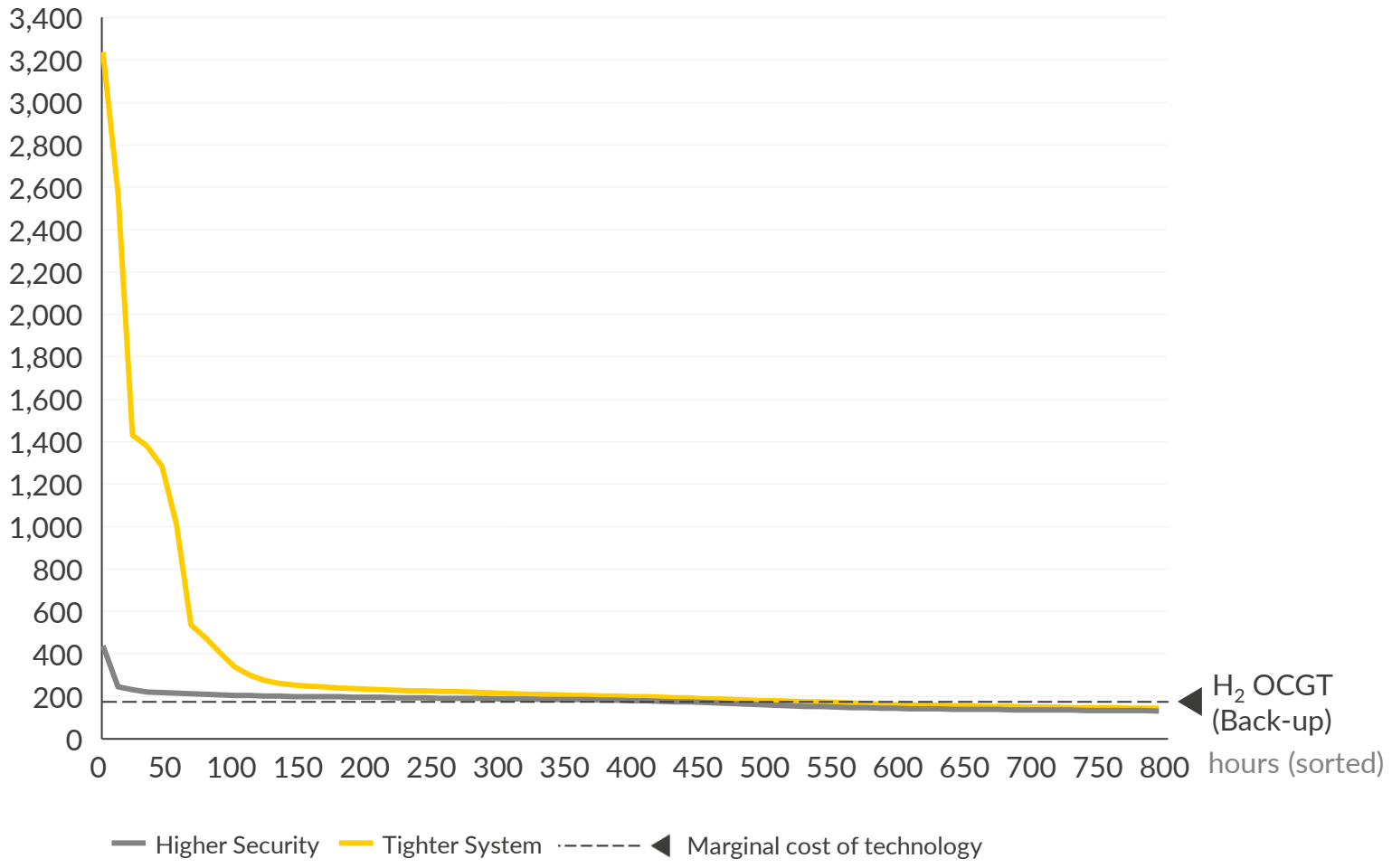
Tech Mix 1

Price duration curve in 2050 – Most expensive 800 hours
€/MWh



Comments

- Compared to the previous slide, only the most expensive 800 hours for both scenarios are shown here – also, for simplicity, only back-up (H_2 OCGT) is shown
- Again taking the area between marginal costs and prices as an approximation for gross margins, it gets clear why there is a strong margin increase with the tighter system scenario
  - In the higher security scenario, the back-up mostly produces when it is price-setting itself
  - This leaves barely any margins
  - With the tighter system scenario, more expensive technologies (DSR) switch on or loss of load occurs – even the expensive back-up now can generate high gross margins
- The same effect occurs for long-duration flex technologies – yet it is relatively less important, as they were already generating sizeable gross margins before

Note: Prices taken exemplary from Tech Mix 1

Source: Aurora Energy Research

Due to persistence in prices and limited storage duration, batteries cannot fully exploit price volatility and achieve a better business case

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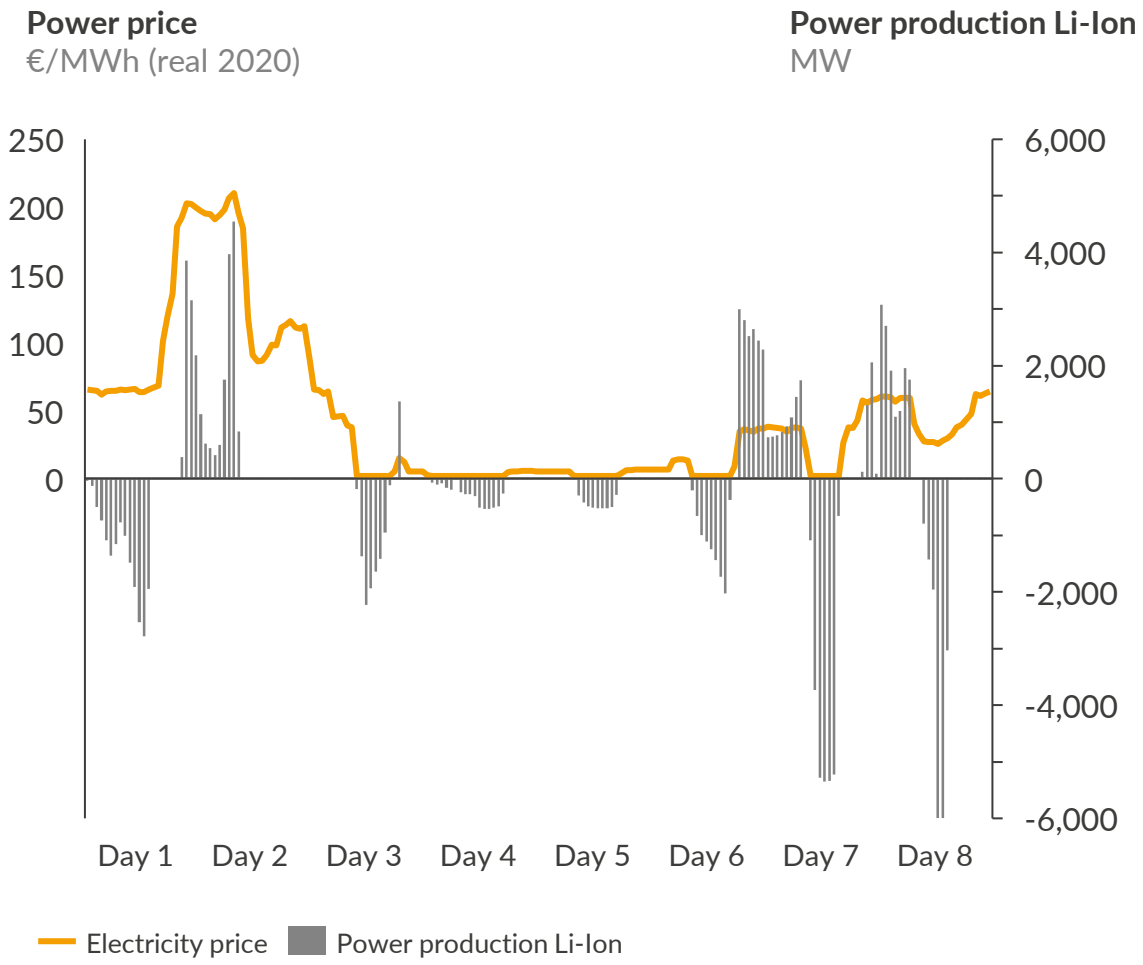
Tech Mix 1

Battery behavior – Example Week March 2050



Comments

- Due to high price fluctuations, one could expect business cases for storage technologies to be much better in 2050
- Yet, given the limited storage duration of batteries as well as the actual price patterns (prices do no oscillate from low to high from hour to hour), there is a limit of how much of these price fluctuation batteries can capture
- On average, batteries lose a spread of ~100 €/MWh versus the theoretical optimum – that means versus a situation where they could exploit the combination of the least and most expensive hours, without being restricted by finite storage depth

2050 Full Year	Charging	Discharging
Full load hours h	834	750
Average Price €/MWh	36 *("average buy")*	110 *("average sell")*
Theoretical Optimum €/MWh	7 *("least expensive hours")*	177 *("most expensive hours")*
Delta €/MWh	*29* *("overpaid")*	*67* *("undersold")*

Note: Based on Tech Mix 1, Higher Security scenario

Source: Aurora Energy Research

Our aligned Base Case assumes Net Zero by 2050 – moving this target to 2040 would require a drastic acceleration of build-out

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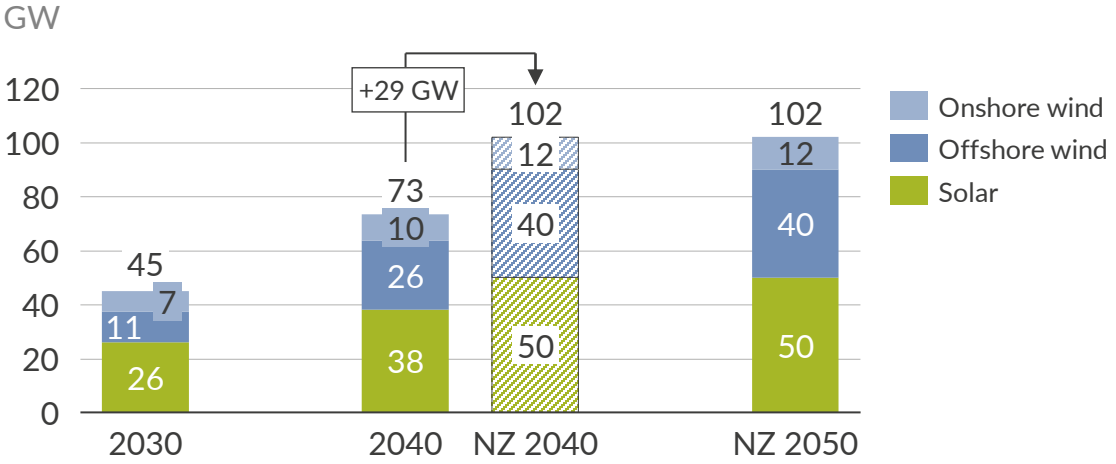
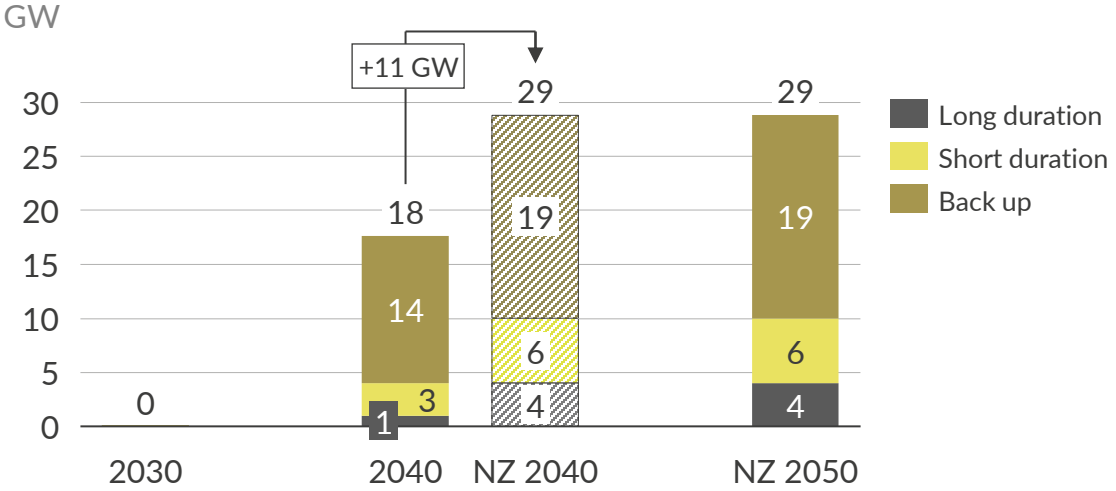
Impact of an earlier Net Zero

- While our Base Case assumes Net Zero (NZ) in the Netherlands by 2050, recent policy developments indicate the possibility of an earlier date
  - The European Climate Law entered into force July 2021, which specifies much stricter emission reduction targets for the EU and establishes monitoring systems to ensure targets are reached
  - To make national targets compatible with updated EU law, the Netherlands might need to aim for Net Zero in the power sector before 2050
- A 2040 Net Zero target for the Dutch power sector would require to accelerate key build-out targets[1]
  - The phaseout of ~14 GW natural gas plants (Base Case in 2030) would need to be completed by 2040 – currently we assume ~4GW to be still active by 2040
  - RES capacities would need to be added at a much higher pace. By 2040, 102 GW of RES would need to be built, 29 GW or ~40% more compared to the assumptions underlying our Base Case
  - Also CO_2-free flex capacities would need to be added more recently –an additional 11 GW or 60% more than our current assumptions for 2040
  - Beyond what is depicted on the right, the electrification and hydrogen use in other sectors would also accelerate, including demand flexibility (EVs, Heat Pumps, Electrolysers, DSR)
- An earlier Net Zero would also affect the business case of the flexibility technologies. Substituting thermal capacities at a faster pace would make the business case for additional CO_2 flex capacities profitable earlier in time

Renewable capacity – Impact of Net Zero by 2040



CO_2 free flexible capacities[2] – Impact of Net Zero in 2040



Note: Base Case aligned with EZK and TenneT, based on KEV2020 and II3050; 1) Numbers indicative – an entire re-modelling of the Dutch power market and its neighbouring countries would be required to arrive at precise estimates; 2) Capacities taken from Higher Security Scenario

Sources: Aurora Energy Research, European Commission

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Introduction: Chapter 4 — an overview of non-financial hurdles for low-carbon flex technologies

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This section, *Chapter 4*, serves to provide an **overview** of the **non-financial hurdles** (i.e. all hurdles not directly related to wholesale market revenues or technology cost) for the most promising CO_2-free flexible technologies identified in *Chapter 2*, as well as **suggested potential high-level solutions**[1] to these hurdles and **estimated lead times** for implementation of the first ~1 GW of each technology. Hurdles are identified per technology, as well as a number of overarching issues relevant no nearly all technologies presented on the next slide.

Promising CO_2-free flexible technologies (per category)

Technologies were identified as 'promising' if they fulfilled at least one of the following criteria[2]:

a) Steep predicted cost-reduction curve
b) Small step to profitability (or already profitable)
c) High suitability to the system's needs, e.g. in terms of duration, flexibility

		Criteria a	Criteria b	Criteria c
Biofuel power plants	▪ Biogas power plants ▪ Biomass power plants		●	●
			●	
Carbon Capture	▪ BECCS ▪ CCS		●	3
			●	
New-fuel power plants	▪ Hydrogen power plants ▪ E-methane power plants	●	●	●
		●	●	●
Nuclear fission	▪ Conventional large-scale ▪ Small Modular Reactors (SMR)			●
		●		
Li-ion batteries		●	●	●
Flexible household demand	▪ Flexible EV charging ▪ Flexible heat pumps ▪ Bidirectional EV charging ('V2G')		●	●
			●	●
			●	●
Flexible industrial demand	▪ Flexible power-to-heat (electric boilers) ▪ Flexible electrolysis		●	●
		●	●	●

Categories of non-financial hurdles

Four main hurdle categories were identified, which are treated separately for each technology group in the group's respective deep-dive. Of the *Market design and regulations* category, the *Tariffs and taxes* subcategory was sufficiently substantial to name its respective hurdles separately in the overview section.

The hurdles named are relevant to current deployment, such that they also include necessary developments that are already planned or very likely to occur.

Political support & market coordination	▪ Public or political concerns or unpopularity ▪ Uncertainty surrounding the direction other market participants, incl. gov't, will take
Availability constraints	▪ Poor fuel availability ▪ Insufficient or lacking infrastructure ▪ Actual or possible resource shortages
Market design & regulations	▪ Inefficient incentives from regulations or market for the technology in question ▪ Missing market structures or definition
↳ Tariffs & taxation	▪ Inefficient incentives from regulations or market for the technology in question
Technological market readiness	▪ Technological immaturity for full commercial deployment, or lack of availability

1) The potential solutions suggested per technology group are presented as ideas to further the debate pertaining to CO_2-free flexible energy technologies, not as concrete proposals for stimulating their uptake. The suggested solutions are in no way binding and do not necessarily represent the opinion of the Dutch Ministry of Economic Affairs and Climate ('EZK') or any of the other stakeholders involved in this project. Aurora does not guarantee completeness of the list of potential solutions, nor that implementation of any of the solutions, alone or in combination, will solve the problem at hand. 2) This identification is primarily the result of *Chapter 2*. 3) By providing negative CO2 emissions, BECCS is highly suited to the system's decarbonisation needs.

Alongside technology specific hurdles, a number of overarching uncertainties exist

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Will the technology options also satisfy other societally important criteria (e.g. environment, resource competition, safety)?

Zero-carbon technologies may have other societal impacts or risks, such as radioactive waste and the low-probability but high-impact risk of a nuclear explosion (nuclear fission), competition for agricultural resources (biofuels), the risk of methane leakage (e-methane), or local hazardous and odorous emissions (biogas).

How large a role will hydrogen play in the future Dutch economy? When will there be a hydrogen transportation grid?

For market participants to invest in hydrogen, certainty is needed that and when a hydrogen ecosystem will come into existence with sufficient supply, demand, and transportation capacity, and sufficient renewables generation to power the necessary electrolysis. Otherwise, a coordinative 'chicken and egg' problem may arise, as all parties wait to see whether the market will shift substantially to hydrogen or opt for other solutions, such as gas with CCS or electrification.

Further uncertainty surrounds the evolution of hydrogen in other countries, with imports and exports poised to play a large role should they become available.

To what extent will the electricity grid be reinforced? How will grid congestion and its costs be managed?

The practical feasibility of multiple aspects of decarbonisation – increased RES generation and electrification in particular – depends on the capacity of the electricity grid to handle them. Although flexibilisation of electricity demand can help reduce congestion, the success of the electrification that enables much of such flexibilization – e.g. electric industrial boilers – depends nonetheless on increased grid capacity.

How will the regulatory landscape develop?

Unadapted grid tariffs and taxes still form a hindrance to the deployment of certain decarbonisation and flexibility technologies. How the structure of markets, tariffs, taxes, and regulations develop will play an important role in shaping the future energy system.

Will the necessary energy carriers (fuels, electricity, organic matter) be available?

For many of the technologies analysed, the availability of the necessary energetic inputs is uncertain. This is true for new-fuel CCGTs (both low-carbon H_2 and e-methane currently have little production in the Netherlands), electrolysers (low-carbon generation demands high levels of renewable electricity generation), and for biofuels (concerns on sufficient sourcing of sustainable biomass).

Source: Aurora Energy Research

All of the promising technologies also face technology specific non-financial hurdles, which differ substantially in severity

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	Biogas power plant	Biomass power plant	BECCS and CCS	H_2 power plant	E-methane power plant	Nuclear fission plant	Li-ion batteries	Flexible household demand[1]	Flexible power-to-heat	Flexible electrolysis
Market design & regulations			Negative emissions not reimbursed	No H_2 market	No e-methane market	High CAPEX and long lifetimes risk large write-offs with system change		Static household electricity prices; no third-party access guidelines		No H_2 market
Tariffs & taxation							Inflexible grid fees	Static household electricity fees	Inflexible grid fees	Inflexible grid fees
Infrastructure, fuel, and space availability	Limited production facilities	Uncertainty of sufficient sustainable sourcing	Possible spatial constraint due to demand from other countries	Low CO_2 free H_2 availability; limited H_2 infrastructure	Low e-methane availability	NIMBY concerns	Rare earth metal scarcity	Possible grid congestion		Little RES; no H_2 infrastructure
Technological market readiness						High lead times; SMR not yet available; few parties with know-how		Technologies exist at small scale; no integrated solutions yet available		PEM electrolysers not yet scaled up
Political support & coordinative uncertainty	Odour concerns	Limited political support	Lack of long-term political commitment	Uncertainty on future hydrogen system setup	Uncertainty on future hydrogen system setup	Safety concerns	Dependent on other sources for providing CO_2 free electricity to charge	Potential unpopularity of flexible price and tariff models		Uncertainty on future hydrogen system setup

Severity of hurdle: Mild | Intermediate | Severe | Currently being (partially) addressed

1) Includes: (i) smart / flexible EV charging, (ii) smart / flexible heat pumps, (iii) bidirectional EV charging, i.e. vehicle-to-grid. 2) For many of the future hurdles (e.g., hydrogen infrastructure development), plans to address them are already being made.

Source: Aurora Energy Research

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The uncertainty around fuel availability for biomass and biogas installations could be resolved through political commitment

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Infrastructure, fuel, and space availability

The potential for increased availability of biogas and biomass is uncertain and likely limited. This is due both to physical limitations themselves and to political and public opinion pertaining to these limitations and the acceptability of the use of certain resources.

Biogas[1]

- **Few production facilities for biogas** are available in the Netherlands
- **Suitability of low-pressure gas grids** for the injection of large volumes of biogas is limited in some cases
- **The biofuels analysed in this study – wood-based and biogas, which is usually made from farming waste – generally do not directly compete with agricultural resources,** however, such competition – both for land and for the use of feed crops – can be a concern for other biofuels, due to its potential to drive up food prices
  - Concerns surrounding the possibility of competition, as well as stringent EU rules, limit the amount of resources considered acceptable to divert to biofuels

Biomass

- **Future / increased availability of biomass may be restricted** by sustainability and environmental criteria pertaining to forests, domestic forestry policy of biomass producers, increased demand across the board from decarbonising countries, and the Netherlands' willingness to import large amounts

Potential solutions

Biogas

- **EU regulations already limit resource competition** by biofuels with agriculture and other sectors
- **Priority should be given to by-product or waste biogas** — e.g. from agricultural or domestic waste streams – as these do not compete with other demands
- **Clear allocation of space** for biogas production could resolve the problem of spatial competition
- **A gas grid upgrade** may be needed for the widespread use of biogas. An alternative could be local conversion of the gas to electricity.

Biomass

- **International coordination on environmental standards and** should be made pertaining to the admissibility of biomass and the environmental standards to be applied

1) To date, most biogas plants are either engine-based or steam turbines.

Sources: Aurora Energy Research, Energeia

Biogas is subject to availability concerns, which could be allayed through research and planning

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Technological market readiness

Biogas[1] and biomass assets are technologically mature

Biogas

- **The technology is viable**[2] but has not been rolled out at scale

Potential solutions

Biogas

- **Increased efficiency of conversion**, through improvement of existing technologies or the development of yet-immature options such as supercritical gasification, could help with resource constraints

Political support & coordinative uncertainty

Evolving political sustainability requirements and low support remain a concern for both biomass and biogas

Biogas

- **Leakages of this greenhouse gas** carry the risk of negating carbon emission reductions through their impact on global warming, as noted for *e-methane*
- **Acceptance of biogas production** is low due to its smell, especially in densely populated areas

Biomass

- **Public concerns** exist about the sustainability of biomass as well as particulate matter emissions, which can damage people's health
- **The proposed RED II revision bans member states from supporting non-CCS electricity from biomass after 2026**[3]

Potential solutions

Biogas

- **Prevention and reparation of methane leaks** is already governed by rules in the Netherlands. Applying the Dutch methane rules to companies exporting to the European Union could be the next step.
- In the **planning of biogas production facilities**, it should be acknowledged that they have the greatest chance of success in rural areas

Biomass

- The **sourcing of biomass** should be made more transparent
- **Much more stringent criteria for biomass sustainability** are included in the EU's proposed revision to RED II

Expected lead time: 0 years

The technologies are market-ready: their success depends on continued political support

1) To date, biogas assets are mainly either steam turbines or engine-based. 2) For example, one neighbourhood in Breda is heated through a biogas CHP. 3) See directive 2021/0218(COD) , Article 1(2)(b)

Sources: Aurora Energy Research, Energeia

For CCS, negative emissions are currently not reimbursed and storage potential might be too limited for international ambitions

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Market design and regulations

- **There is a 'ceiling' to the amount of CCS that can be subsidised** through the SDE++. Recently the ceiling has been raised from 7.2 Mt to 9.7 Mt
- **Utilised CO_2 in CCU technologies sometimes still ends up in the atmosphere**, limiting its contribution to carbon abatement
- There is currently **no legal basis for CO_2 removal** (e.g. through BECCS) **in the EU ETS**

Potential solutions

- **A further increase of the ceiling** (or removal thereof) would help the rollout of CCS projects
- **Clear monitoring of CCU** on how much of the CO_2 is permanently stored would help quantify the actual impact of different CCU technologies on carbon abatement
- **CO_2 removal could be integrated in the EU ETS** to allow for appropriate reimbursement for negative emissions

Infrastructure, fuel, and space availability

- **Spatial constraints** may arise from the political undesirability of CCS in Germany, driving up storage needs in the Dutch part of the North Sea. Germany is not against CCS as such, but does not wish to store CO_2 under German waters. Storage under Dutch or Norwegian waters is commonly viewed as the solution, but political coordination surrounding spatial constraints seems to be lacking

Potential solutions

- **An EU-wide plan of the designated areas** for CO_2 storage would shed more light on storage availability and country targets

Sources: Aurora Energy Research, Energeia

CCS is technologically mature, but the lack of long-term political commitment might impact investors' appetite

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Technological market readiness

- **CCS using exhaust CO_2 is technologically mature enough** to already be (nearly) economically viable
- **Air-capture CCS is possible but still requires significant development** to be widely market-deployable

Potential solutions

- **The government could support CCS by further facilitating** infrastructure projects to **transport CO_2** to optimal locations for storage

Political support & coordinative uncertainty

- **Political support could be volatile.** In contrast to a fully decarbonised system, CCS is not viewed as an 'end-game' technology, as it does not mitigate the reliance on fossil fuels and production of CO_2, and CO_2 storage capacity is not unlimited
- **Investing in CCS could result in high opportunity costs, stranded assets, or technological lock-in**, due to e.g. the abovementioned factors or if later investment non-CCS based technology proves necessary that could already be made now
- **Safety concerns** around offshore storage of CO_2 include leaks and their impact on ecosystems
  - However, onshore CCS is forbidden since the cancellation of the Barendrecht project due to local pressure

Potential solutions

- **Long-term plans or commitments pertaining to CCS** could help market parties decide whether investments in CCS are worthwhile
- **The safety of carbon storage** could be improved through further research and stringent standards pertaining to its application

Expected lead time: 5 years

Carbon capture and storage is nearly market-ready. The estimated five years would be needed for infrastructure buildout. The eventual success for CCS depends on continued political support

Source: Aurora Energy Research

H_2 and e-methane power plants[1] are primarily hampered by fuel and infrastructure unavailability

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Market design & regulations

- **No hydrogen market** is yet defined in the Netherlands – *see Industrial DSR*

Potential solutions

- *See Industrial DSR for Potential solutions pertaining to a hydrogen market definition*

Infrastructure, fuel, and space availability

- **Little yet exists in the way of hydrogen transportation and storage infrastructure** outside of a few industrial clusters: pipelines, conversion / compression stations for shipping, salt caverns for storage, etc.
- **E-methane only makes sense to synthesise from green hydrogen**, as synthesis from blue hydrogen would amount to an effective methane-to-methane conversion with double conversion losses. However, to green hydrogen most hurdles for flexible electrolysis apply, including:
  - Insufficient renewable electricity generation
  - Limited H_2 availability for conversion to e-methane
- **E-methane synthesis requires a high-concentration CO_2 source**, as direct air capture is still prohibitively expensive and technologically immature
- **Suitability of low-pressure gas grids** for the injection of large volumes of e-methane may be limited in some cases (see section on *Biogas*), placing constraints on the possible locations available for synthesis relative to the gas grid

Potential solutions

- **Hydrogen infrastructure and storage buildout should be prioritised and accelerated** by the government and grid operator, including definition of long-term plans with hard financial backing. To this end, the outgoing government has reserved 750 million € for the creation of a hydrogen backbone[4]
- **Methanation co-location with an electrolyser and RES source[5]** could help avoid many of the issues pertaining to electrolysis for e-methane. Both electricity and hydrogen infrastructure shortcomings could then be avoided, as the product could be injected into the natural gas grid. However, proximity to a CO_2 emitter is also necessary, placing restraints on options
- See Potential solutions for *Technological maturity*

1) CCGTs and OCGTs; fuel cells were not considered. 2) See *Chapter 2* of this study, where we estimate the profitability of multiple flex technologies in 2030 in a net zero scenario. 3) Such measures are taken by the Electric Reliability Council of Texas (ERCOT). 4) The idea is for Gasunie to invest this amount and recoup it from the market. The govt. covers the risk that demand will not keep pace with supply. 5) Electrolyser co-location may lead to overall system inefficiency, as described in the *Political support & coordinative uncertainty* section pertaining to flexible electrolysers. It is also made more difficult by the need for a cost-effective and climate-neutral source of CO_2, implying colocation with a CO_2 emitter.

Sources: Aurora Energy Research, Energeia

H_2 turbine lead times are 5-10 years due to the need for new infrastructure, whereas e-methane face efficiency concerns

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Technological market readiness

- **Gas turbine power plants are a mature technology** for which adaptations for burning hydrogen or e-methane are currently commercially available
  - New-build natural gas turbines now often come 'hydrogen-ready', meaning a conversion would require minimal marginal investment
  - Utilities may need time to build up know-how pertaining to an H_2 supply chain
- **Methanation is a known and demonstrated technology**, provided sources of H_2 and (waste) CO_2, and pilot plants exist for synthesising medium amounts of e-methane[1]
  - However, production would need to be scaled up for sufficient amounts to be available for a power plant
  - The potential for e-methane synthesis depends on H_2 electrolysis

Potential solutions

- **A forum for knowledge transfer** from industry players already knowledgeable in H_2 supply chain logistics (e.g. those using the Port of Rotterdam's H_2 grid) to utilities may help speed up scale-up and learning times
- **Support for scale-up projects for e-methane** synthesis as well as coordinative support for co-location could help to speed up the process

Political support & coordinative uncertainty

- **For uncertainties surrounding a future H_2 market** and ecosystem, see *Industrial DSR*
- **Market coordination around e-methane may risk a technological lock-in** onto a fuel less efficient and likely more expensive than hydrogen (due to the additional synthesis step involved, conversion losses, and the need for a CO_2 source)
- **H2 or e-methane may provide more efficient CO_2 abatement in non-power sectors**

Potential solutions

- **Long-term policy, plans, and financial and infrastructural commitments** pertaining to hydrogen and methane would be helpful to address market uncertainties

Expected lead time: 5 - 10 years

E-methane synthesis could be scaled up relatively quickly, as it is mature and has already been demonstrated and researched in multiple projects.[1] lead times for hydrogen power plants may be slightly longer, due to the time necessary to create a hydrogen transportation and storage infrastructure as well as a hydrogen market. However, Gasunie plans to have a national H_2 grid ready by 2027, and an H_2 power plant could feasibly function without such a grid and simply be co-located with its H_2 source.

1) See e.g. Audi's e-gas plant in Emsland and the EU27's Store&Go project, part of the Horizon 2020 programme

Sources: Aurora Energy Research, European Commission

Political commitment to nuclear power is necessary for investors and national support needs to be accompanied with local backing

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Market design and regulations

- **Political support for nuclear has been fluctuating in the Netherlands** and neighbouring countries. The threat of forced phase-out as in Germany and Belgium might deter investors.
- **High CAPEX and long lifetimes risk large write-offs in later years**, when phase-out would be implemented at some point, or more than expected RES capacities or other competing technologies are built

Potential solutions

- **The government could guarantee not to impose a nuclear phase-out** within the lifetime of new nuclear units.

Infrastructure, fuel, and space availability

- **Uranium is no longer mined in any significant amount in Western Europe**, making supplies dependent on overseas or long land-route shipment and thus potentially sensitive to geopolitical or trade disruptions
- Up to now **only Borssele (Zeeland) has emerged as a possible location**, with Noord-Brabant 'willing to negotiate under certain conditions', limiting locations for new nuclear plants

Potential solutions

- **More certainty around the political climate for nuclear power** could help to stabilise the uranium market
- For a large build out of nuclear capacity, it would be beneficial for the grid to have plants in multiple provinces, so **national support should be coupled with provincial and local commitment**

Sources, Aurora Energy Research, Energeia

Nuclear power plants have long lead times and public concerns have to be addressed to prevent further delays

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Technological market readiness

- **The cost evolution potential of conventional nuclear power plants is limited**; these have, in fact, become more expensive over the past decades due to increasingly stringent safety requirements
  - Small modular reactor (SMR) technology may change this, but these are still experimental and not yet market-ready
- **Lead times for development and permitting are long** (10-15 years)
- **High dismantling costs** form a downside to investors
- **Few companies worldwide have the technical capabilities** for construction and maintenance of a nuclear plant

Potential solutions

- **Contracting multiple reactors simultaneously**, or partnering with other countries to this end, may help reduce costs and lead time
- **R&D support for SMRs** may help bring these to market

Political support & coordinative uncertainty

- **Public concerns on nuclear waste, the risk of accidents, and the threat of the use of uranium in nuclear weapons** persist and might lead to further delays in the development of nuclear plants and limited investor appetite
- **Decentralised distribution of SMRs** (which could be beneficial for grid support and other reasons) **could bring additional concerns**

Potential solutions

- **Stringent regulations of waste and security will be necessary**, and an information campaign could help the public put the risk into perspective.
- **For SMRs, additional regulatory, logistic, and security adaptations will be necessary** to allow for more decentralised production

Expected lead time: 15 years

The realisation of a larger reactor can be expected to take at least 15 years.
For small modular reactors, these might be faster in development, but time to reach commercial deployment needs to be added to the development time.

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Lithium-ion batteries' contribution can be enhanced through contracted congestion management and smarter taxation

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Market design and regulations

- **Batteries with a grid connection are still subject to double taxation as of 2021**: power is taxed when the batteries charge and when provided to the end consumer; the government has announced to eliminate this taxation (see below)
- **The tax abolishment will not affect home batteries,** which still face taxes over electricity stored from the grid
- **High grid tariffs** pose a discouragement to battery owners and distort the market, especially given the lack of tariffs levied on generators

Potential solutions

- **Electricity storage will no longer be taxed as of 2022**[1], but could also be extended to co-located batteries, which are currently exempted from the new rule
- **Abolishing energy taxes over stored energy for households** would further incentivise storage at moments of system need
- **Grid tariffs could be lowered or abolished** for batteries, to level the playing field with power plants (which pay only limited electricity grid fees)

Infrastructure, fuel, and space availability

- **The demand for lithium and other rare earth metals** is expected to rise significantly due to the global investment in batteries. Lithium already features on the list of raw materials the EU considers 'critical'
- **The Netherlands (and the EU) are dependent on imports** of these materials
- **Abundant renewable generation is needed** to ensure batteries' proper functioning

Potential solutions

- **Recycling capacity for these materials needs to be built up** and should be considered part of climate policy
- **More support for alternative battery technologies**, such as iron oxide, could reduce the risk of a run on lithium[2]

Political support & coordinative uncertainty

- **Lithium batteries on their own cannot provide all the flexible capacity needed for a high-renewable-generation system**, as their limited depth of charge makes them unable to cover longer periods with low RES generation or to act as seasonal storage

Potential solutions

- **Lithium batteries will have to be combined in an optimal way with other flexible technologies** that can provide longer-duration generation
- **Alternative battery technologies may be better able to provide longer-duration generation and storage**, such as iron oxide
  - These are still in the R&D phase, however, making it uncertain whether such technologies will ultimately come to market at a competitive price point

1) This change is part of the Tax Plan 2022, published on *Prinsjesdag* 2021. 2) A competitive prototype has been demonstrated by US start-up Form Energy.

Source: Aurora Energy Research

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Households currently have little to no incentive to flexibilise their demand, as they pay a fixed unit price for electricity[1]

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Market design and regulations

- **Households have no economic incentive to flexibilise their demand** (shift to low-load hours), as they generally see a uniform per-unit price for their electricity bill (alongside an equally unvarying fixed component)
  - Households generally prefer such low-risk (predictable, hedged) pricing, with the possibility of opting-in on flexibility when convenient
- **The interaction of third parties with household flexibility is not well-governed by guidelines** pertaining to e.g. privacy and control[2]

Potential solutions

- **Flexible pricing contracts could provide households with an incentive** to flexibilise their demand, by passing on price signals from the wholesale market. Utilities could play a role here in stimulating households to switch to such contracts
- **The regulator is advised to set grid fees and / or taxes to rise and fall** with grid congestion, renewable generation, etc.[3] (c.f. United Kingdom), thereby adding an additional incentive for demand flexibilisation and relieving the grid, which can help reduce RES curtailment
  - A regionally variable tariff system would be the most economically efficient method of reflecting (local) grid congestion, but it would require sufficient smart grid and meter infrastructure, and may be impeded by antidiscrimination laws (see *Political support*)[5]
- **Household grid fees and / or taxes could be set to depend on connection capacity**, incentivising households to flatten their demand profile (c.f. Spain) and adding more predictability than e.g. wholesale price signals
- **The government is advised to set up guidelines on third-party access / control** of household demand (e.g. EV (dis)charging behaviour, data privacy standards)

Infrastructure, fuel, and space availability

- **It may be a technical challenge for the TSO and DSOs to coordinate** amongst a large number of small third parties which control and aggregate household demand (and, in the case of V2G[3], generation) flexibility[3]
  - Predicting electricity demand may become more challenging – at least in the short term during a learning period – if a large portion of consumers partially flexibilise demand based on power prices
  - This may be exacerbated by large amounts of consumer discharging to the grid through V2G
- **The development of grid infrastructure** (notably safe and secure data sharing from and control via smart meters) would present a further challenge[3]

Potential solutions

- **Flexible household prices and grid tariffs, especially if region-specific,** would offload some of the grid operators' management burden onto households reacting to these signals
- **The TSO, DSOs** and the government could start to discuss the planning of sufficient smart meter infrastructure
- **Third parties functioning as aggregating intermediaries** between consumers, the DSOs, and the TSO can help coordinate between and simplify the complexity for both consumers and the grid operators[4]
  - Note that such aggregators currently exist and are already likely to play a large role in future flexible demand coordination

1) N.B. The focus here is on stimulating flexible demand relative to non-flexible EV and heat-pump usage; not on stimulating uptake of EVs and heat pumps per se, which is a separate issue. 2) E.g., what insights and control they may be allowed over household energy consumption and timing. 3) 'V2G': Vehicle to Grid, i.e. bidirectional EV-charging. 3) See PwC's 2019 report on regulatory barriers for EV smart charging, notably slides 7-8; 4) E.g. utilities or EV service providers which contract and regulate a certain amount of flexibility from households aggregate this flexibility, and bid as a single entity on the electricity market; 5) *See footnote on next slide*

Source: Aurora Energy Research, PwC

Flexible heat pumps and smart EV charging are market-ready, although insufficient household insulation may prove a hurdle

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Technological market readiness

- **Flexible and bidirectional EV charging technologies are close to being market-ready**, although the know-how and infrastructure for coordinating household flexibility and vehicle-to-grid may still need development and alignment
- **Flexible heat-pump operation is technically uncomplicated and market-ready**; however, such flexible heat-production may be made more complicated where it necessitates thermal storage or improvements in house insulation
  - Well-insulated houses can, themselves, act as a heat buffer, but at current no more than one in five homes in the Netherlands reach this standard
  - Thermal storage, coupled with a heat-pump, can also provide a heat-buffer and enable a large amount of flexibility; however, this adds another up-front cost to consumers

Potential solutions

- For coordination, see *Infrastructure, fuel, and space availability*
- **To improve the flexibilisation of household heat pump systems**, e.g. for the installation of thermal storage in combination with smart heat-pump control, the government could set incentives, provide subsidies, or even set requirements
- **Significantly increasing the number of houses insulated well enough to enable thermal buffering** would enable the deployment of more flexible heat-pumps, which could be achieved by setting incentives or subsidising high-level home insulation

Political support & coordinative uncertainty

- **Flexible prices and grid tariffs may be unpopular with the public**, as they shift some of the risks and costs related to price fluctuation and grid congestion onto households
  - Regionally varying grid tariffs – which could reflect local grid congestion – may run into additional opposition due to fairness concerns and hitherto unforeseen hikes in electricity bills for some households, and might conflict with antidiscrimination law

Potential solutions

- **The government and grid operators could commission a transparent study** on the relative costs, (long-term) benefits, effects on demand-response management by TSO & DSOs, and wealth-distribution consequences of implementing different systems of flexible prices and tariffs versus the current model[5]
  - This could help open an informed public debate on the relative merits of the different models and their acceptability
- **Mechanisms could be put in place to cap or redistribute the costs and benefits** of variable systems, such as an upper limit to the wholesale price that may be passed on to households, or a fixed rebate to households facing higher tariffs due to local grid congestion (thereby keeping the incentive to shift demand but cushioning the costs)

Expected lead time: 1-5 years (EVs); 5-10 years (flexible heat pumps)

Flexible and bidirectional EV charging is technologically mature and, beyond cost, limited primarily by maladapted grid fees and the necessary learning time for implementation. The implementation of flexible heat-pumps is limited not only by abovementioned unvarying grid fees, but by the number of sufficiently well-insulated houses.

5) It can be expected that a system where households are exposed to varying electricity prices and / or grid tariffs / taxes will lead to more efficient use of generation and grid capacity respectively and, as a result, overall lower energy system costs. This is because it incentivises households to shift their demand to hours when cheaper (renewable) generation capacity is available and demand on the grid is lower. The economic efficiency would likely be higher still if the tariffs varied not only with time, but also by region based on local grid congestion. This latter system would, however, lead to effective regional discrimination, which may be unacceptable for various reasons. Not varying tariffs by region favours equity between households, but likely also less efficient capacity usage and overall higher energy system costs.

Sources: Aurora Energy Research, *Centraal Bureau voor de Statistiek*

High grid fees and insufficient infrastructure present obstacles to industrial DSR, alongside general hurdles for electrolysis

AURORA

Market design and regulations

- **High grid connection fees constitute significant costs** for large consumers of electricity (and thus for electrification), such as electrolysers or e-boilers
- **Demand flexibility is further disincentivised by the *volumecorrectiefactor* ("VCF"):** an electricity transportation tariff discount of up to 90% in the case of stable[1] demand[2]
- **No hydrogen wholesale market yet exists in the Netherlands** (in the form of e.g. the TTF), adding uncertainty for parties interested in participating in such a future market
  - This is currently only a minor issue, however, as the nascent electrolysis industry can benefit from the security of a long-term bilateral contract with consumers
- **SDE++ subsidies are not linked directly times of high RES generation**, but only indirectly via a maximum number of hours per year

Potential solutions

- **The regulator is advised to lower and restructure grid tariffs** to better incentivise electrification and large-scale flexibility, e.g. by (i) providing lower tariffs for electrification that benefits decarbonisation; (ii) granting a reduction for flexible-demand installations that respond to price or certain signals from the TSO; or (iii) varying grid tariffs with grid congestion (thereby further incentivising flexibilisation, which would also benefit demand-side response to generation)
- **The VCF or its successor could be adapted** to allow or stimulate flexible demand
- **The government could commence designing the Netherlands' future hydrogen market[2]**, bringing investment security and enabling its direct implementation once infrastructure becomes sufficient
- **CO_2 abatement subsidies could be more directly linked to electricity consumption** only during moments of RES generation

Infrastructure, fuel, and space availability

- **Currently, renewable electricity generation is not sufficient** to make (flexible) electrification environmentally sensible
- **Little exists in the way of H_2 transportation and storage infrastructure**: pipelines, conversion / compression stations for shipping, salt caverns etc.
  - Storage, especially, is a prerequisite for flex. electrolysis, and is only cheap on a large scale in salt caverns
- **The electricity grid is likely to experience congestion issues** if electric boilers and electrolysers are grid-connected
- **It may be a technical challenge for the TSO to coordinate** amongst a large number of small, flexible third parties

Potential solutions

- **The amount of RES generation should be increased** significantly to enable low-carbon electrification
  - Simultaneously, increased (flexible) electrification is necessary to improve RES' and low-carbon flex generation's business cases, meaning that RES build-out and electrification should proceed in tandem
- **The government and grid operator should accelerate hydrogen infrastructure** and storage buildout, including definition of long-term plans with hard financial backing
- **The government and grid operator may need to accelerate electricity grid reinforcement**, potentially combining this with incentives place large power offtakers at grid-optimal locations

1) Flat-profile, high load-factor, >5700 hrs/y 2) A recent proposal for the new energy law (likely to come in to force in 2022) scrapped this correction factor, supposed to be replaced by a new, general regulation, of which the timeline is currently unclear 2) Such a design should include the future availability of hydrogen and the future rules for its wholesale trading.

Source: Aurora Energy Research

Further development is needed to bring fully-flexible electrolysis to market, and much depends on future infrastructure developments

AURORA

Technological market readiness

- **Large-scale electrolysis is technologically mature**, but the traditional and best-developed technology, alkaline electrolysis, is somewhat less flexible than alternatives[1]
  - The scaling up of more flexible technologies (primarily PEM) is underway, but these are as of yet more expensive than alkaline electrolysis
  - Alkaline electrolysis is simultaneously being further developed to improve flexibility[1]
- **Flexible electric boilers are technically uncomplicated** and currently commercially available

Potential solutions

- **The government could provide a boost to the development and cost-reduction of more flexible electrolysis technologies** (which is superior in other aspects, too), such as PEM and solid oxide, by providing support for scale-up projects. Current support mechanisms focus on pilot projects (DEI+) and actual implementation (SDE++), but leave a gap for projects / technologies in between these two stages
  - The government could develop a subsidy scheme specifically focused on flexible technologies[2]

Political support & coordinative uncertainty

- **Many large (coordinative) uncertainties surrounding hydrogen exist** that are highly pertinent for the development of a hydrogen system in the Netherlands, including whether and when large-scale imports will be feasible, and a what price
- **The efficiency of electrolyser co-location versus a direct grid connection is unsure** and depends partly on the future development and capacity of the electricity grid. Hydrogen production may not always be the most efficient use of renewably generated electricity, and, inversely, stopping hydrogen production need not be the most societally efficient way to curb demand during moments of lower renewable generation.[3]

Potential solutions

- **The government is advised to create stable long-term hydrogen policy, plans, financial and infrastructural commitments** to lend investor certainty
- **The government could engage the TSO, electrolyser and renewable developers to find the socially optimal configuration for electrolyser connection** (colocation or grid connection, or both)

Expected lead time: 2-5 years[4]

Small- and mid-size PEM electrolysis projects already exist in multiple European countries.

1) See e.g. Brauns, Turek (2020); 2) Although the SDE++ does only subsidise a limited no. of hours per year, with the aim of only supporting production in hours of high RES generation, its direct focus is on CO_2 abatement and only indirectly on flexibility. Less flexible but cheaper technologies therefore have an implicit advantage over flexible but nascent ones, such as alkaline vs. PEM electrolysers. 3) However, for a grid-connected electrolyser to be possible and provide higher societal efficiency, sufficient power grid capacity to avoid congestion is a prerequisite. 4) A large-scale rollout would likely take 10-20 years. The main limiting hurdles are the lack of hydrogen infrastructure and RES deployment.

Source: Aurora Energy Research

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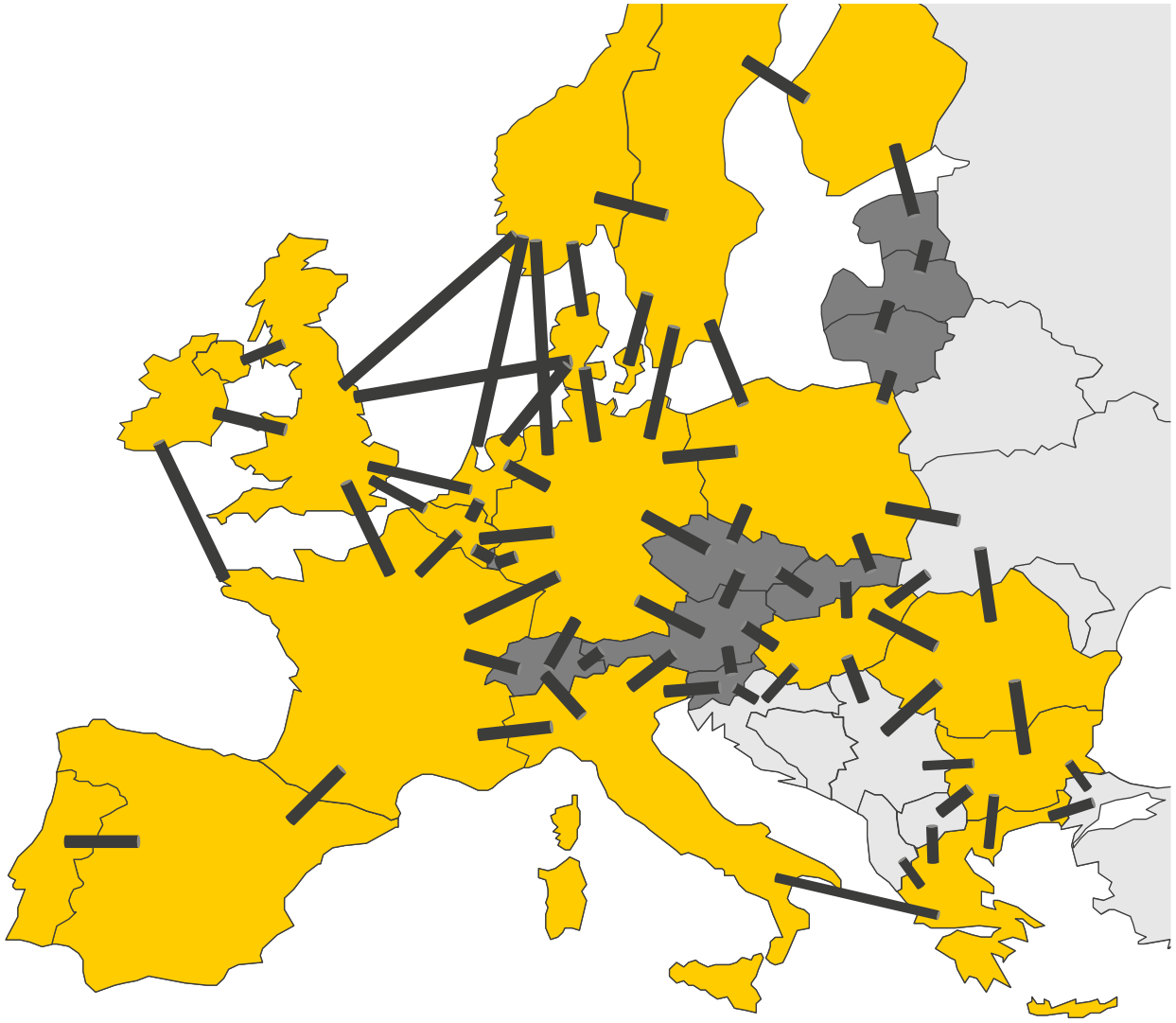
We model the whole of Europe in an integrated manner

AURORA

Endogenous interconnector flows based on price differentials

Interdependence of prices and capacities in different regions

High granularity right down to individual plant level



Key

- Individual plant
- Plant aggregation
- Higher aggregation

Modelling granularity

- Interconnector[1]

1) Sizes, locations and lengths of interconnectors are for visual representation only, illustrative and are not to scale

Source: Aurora Energy Research

Unique, proprietary, in-house modelling capabilities underpin Aurora's superior analysis

AURORA

3 Integrated Models

Gas (AER-GAS) ↔ Power markets (AER-ES) ↔ Global Commodities (AER-GLO)

INPUTS

- Technology
- Policy
- Demand
- Commodity prices[1)]
- Weather patterns

Dispatch model

- Hourly
- Iterative modelling
- Dynamic dispatch of plant
- Endogenous interconnector flows

Continuous iteration until an equilibrium is reached

Investment decisions module[2]

- Capacity market modelling
- Capacity build / exit / mothballing
- IRR / NPV driven
- Detailed technology assessments

OUTPUTS

- Capacity mix
- Generation mix
- Wholesale & imbalance prices
- Capacity market prices
- Profit / Loss and NPV
- Electric vehicle charging

Up to 70	c. 85k	~10k	30+
specifications modelled for each plant	investment hours on modelling capabilities	model runs per week	strength of modelling team globally

1) Gas, coal, oil and carbon prices fundamentally modelled in-house with fully integrated commodities and gas market model; 2) We disabled the investment decisions module for the purpose of this study, in order to explore different and comparable scenarios of flexible capacities added to the system. For more details, see the report section on Technology Mixes.

Source: Aurora Energy Research

Advantages of Aurora approach

- Flexible and nimble because we own the code
- Transparent results
- State-of-the-art infrastructure
- Zero dependence on black-box third-party software (e.g. Plexos)
- Constantly up to date through subscription research
- Ability to model complex policy changes very quickly

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AURORA

Dispatchable production technologies provide long-term flexibility – they dispatch to the market based on their marginal cost

AURORA

A Dispatchable Prod. Technologies

- Technologies that can freely dispatch to the market and can be characterized by their **levelised costs of electricity** (LCOE)
- Assets are **financed** through the **wholesale market** – they will dispatch against **their marginal costs** and depend on the **absolute height of power prices** to recover their costs

Technologies

- *Biomass*
- *BECCS*
- *Biogas*
- *Gas CCS*
- *Hydrogen*
- *E-methane*
- *Metal fuels*
- *Nuclear energy*

B Storage Technologies

C Demand flexibility Technologies

- *Industrial DSR*
- *Electrolysers*

D Other Technologies

- **Renewable assets** also are characterized by their **levelised costs of electricity** (LCOE) and financed through the **wholesale market**, but **cannot freely dispatch power**
- **Interconnectors** are built based on **socio-economic cost-benefit** analysis – their economics depend on **prices differences** between markets

- *Additional RES Capacity*
- *Interconnection*

Remarks for the following section:

- We show detailed plant characteristics and include the technologies with 1 MW into the model to test their profitability
- As part of the project, we determine which capacities of these technologies could provide flexibility to the power market
  - We present information on expected build-out and / or pilots in order to calibrate at which point in time and how these technologies can provide flexibility
- A plant will dispatch to the market when the power price exceeds its marginal cost
- Our power market model takes into account ramping behavior of plants (e.g. ramping cost) and thus also reflect the cost of these plants operating flexibly
- The technologies in this section are well suited to replace assets in the current power system that provide baseload power, given they are not constrained by their duration – they can provide long-term flexibility

Note: Plant efficiencies in this report are denoted in higher heating value (HHV), while in other publications for some types of plants lower heating value (LHV) might be used. Plant efficiencies expressed in LHV are higher than in HHV. This distinction does not impact our calculations, as we consistently apply HHV in the Aurora Power Market Model.

Source: Aurora Energy Research

Sustainable wood pellets are a proven technology to provide carbon-free power – policy debate on biomass ongoing, supply limited

AURORA

Description

- Biomass can be used for electricity production, heat production, or both (in a CHP)
- Due to the short carbon cycle, the burning of biomass for electricity and heat production is considered CO_2-free
- An effective use of biomass is the burning of wood pellets in large plants (e.g. former coal plants), as they have high efficiencies and require low capital investment

Price for wood pellets

Key parameters for 2030

Currencies in real 2020

Burning of wood pellets in coal plants

Parameter	Retrofit Coal	Newbuild	Unit
Lifetime	30	40	Years
Typical unit size	700-1,100	Similar	MW
Cost – CAPEX	450,000	2,000,000	€/MW
Cost – Fixed O&M	30,000	Similar	€/MW/a
Cost – Variable O&M	3	Similar	€/MWh
Cost – Fuel[2]	~28-35	Similar	€/MWh
Efficiency (HHV)	~35-40	~40-45	%

Potential barriers for adoption

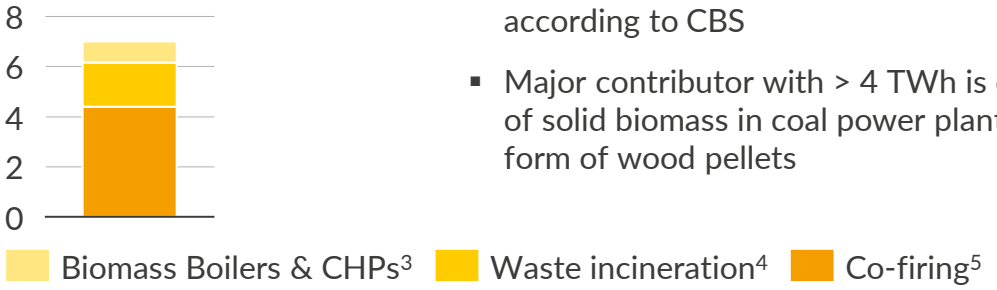
- The use of biomass in the Netherlands is becoming increasingly controversial
  - The predominant concern is that the import of biomass will do irreversible damage to nature abroad, e.g. in Latvia and Estonia
  - These concerns persist despite the obligation to burn only sustainably harvested biomass where subsidies are received[1] – certification of sustainability might need to be improved
- Consensus in parliament regarding wood-based biomass for energy has shifted such that parliamentary majority is currently opposing – but policy debate is ongoing
- On an EU level, biomass demand will likely exceed supply – at least without putting additional pressure on the environment

Maturity, Buildout, Pilots (Focus Netherlands, other markets where relevant)

Commercial Maturity: High

Electricity Output NLD 2020

TWh



- Biomass as proven technology that can provide carbon-free power – ~7 TWh of electricity output from non-gaseous biomass in the Netherlands in 2020 according to CBS
- Major contributor with > 4 TWh is co-firing of solid biomass in coal power plants in form of wood pellets

1) Sustainable wood pellets in installations of up to 100 MW el. and at least 5 MWh were subsidized in the SDE++ autumn 2020. With the new RED regulation, support for use of woody biomass in electricity installations needs to be phased out from 2026.
2) Price for 1 MWh fuel; 3) Combustion of solid / liquid biomass for decentralized production, with / without simultaneous heat production; 4) From plants and animals combusted as part of municipal waste; 5) Wood pellets in coal power plants

Sources: Aurora Energy Research; Ipsos; Pricewise; CE Delft; CBS; Tweede Kamer; Material Economics

BECCS could become a large-scale negative emissions technology – similar constraints as for biomass and high costs prevail

AURORA

Description

- BECCS is a combination of the use of bioenergy and carbon capture and storage (CCS) – it could remove CO_2 from the atmosphere and serve as carbon sink
- For instance, CCS could be added to large former coal plants that have been converted to the burning of biomass
- BECCS is seen as an element in the energy transition that could compensate for overshooting emission targets in other hard-to-abate sectors

We will add the cost of carbon as a negative item in the VOM, reflecting BECCS being a negative emissions technology

Based on efficiency for biomass plants, includes 7% efficiency penalty for CCS

Potential barriers for adoption

- The net carbon balance of BECCS is yet to be determined
  - The carbon capture efficiency of CCS is only at 80-95%
  - The direct and indirect emissions of the biomass production, including process, transport, and effects on the ecosystem
- BECCS relies on sufficient availability of sustainable biomass – *see respective slide*
- Infrastructure for storage and transport of CO_2 is required for the successful implementation of BECCS – policies and governance around CCS in early stage

Key parameters for 2030

Currencies in real 2020

Parameter	Retrofit Coal	Newbuild	Unit
Lifetime	30	40	Years
Typical unit size	700-1,100	Similar	MW
Cost – CAPEX	1,000,000	3,000,000	€/MW
Cost – Fixed O&M	80,000	Similar	€/MW/a
Cost – Variable O&M	3	Similar	€/MWh
Cost – Transport & storage	11	Similar	€/MWh
Cost – Fuel[1]	~28-35	Similar	€/MWh
Efficiency (HHV)	~28-33	~33-38	%

Maturity, Buildout, Pilots (Focus Netherlands, other markets where relevant)

Commercial Maturity: Low - Medium

- A BECCS pilot project has been launched at the Drax Power Station, in the UK
  - Drax has invested £400,000 in the pilot, and claims that BECCS could capture 8 million t CO2/year by 2030 – high level of subsidies required according to think tank Ember for power station to operate
- The first large scale BECCS project is in Illinois
  - It produces ethanol from corn, while the CCS facility captures 1 million t CO_2/year and stores it in a dedicated geological storage site under the facility

1) Fuel price before plant efficiency – price for 1 MWh fuel

Sources: Aurora Energy Research; RVO; PBL; Global CCS Institute; Chalmers University Gothenburg, EMBER

Biogas could be used to replace methane in existing gas assets – availability eventually limited, fuel costs higher than natural gas

AURORA

When adding higher-cost fuels to gas assets, CCGTs have a cost advantage over OCGTs, as the lower efficiencies of OCGTs lead to worse economics already for very low running hours[2]

Description

- Natural biogas is produced through fermentation of biomass
- Biogas could be used to replace methane in current gas plants
- Two more experimental gasification processes (thermal & supercritical gasification) are currently being tested

Key parameters for 2030

Currencies in real 2020

Parameter	Retrofit CCGT	Newbuild	Unit
Lifetime	20	30	Years
Typical unit size	500–1,500	Similar	MW
Cost – CAPEX	26,000	650,000	€/MW
Cost – Fixed O&M	19,000	Similar	€/MW/a
Cost – Variable O&M	2	Similar	€/MWh
Cost – Fuel[3,4]	~66	Similar	€/MWh
Efficiency (HHV)	~50-55	~55-60	%

Potential barriers for adoption

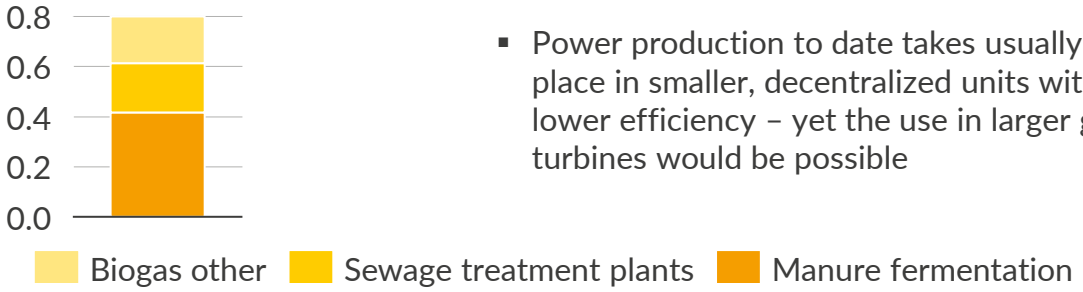
- Sources of natural biogas are limited
  - Potential estimated at ~8 TWh in 2020 and ~22 TWh in 2030 for fermentation for the Netherlands by RVO
  - Agricultural collectives are starting to initiate joint biogas production from manure[1] but as the government plans to move to circular agriculture and thus smaller size of livestock, the future availability of manure could affect the biogas supply
- The use of biogas for power production is also subject to debate, as biogas could be used for processes which are harder to decarbonize

Maturity, Buildout, Pilots (Focus Netherlands, other markets where relevant)

Commercial Maturity: High

Electricity Output NLD 2020

TWh



- Biogas also is a commercially mature technology, but with a small contribution - ~0.8 TWh of electricity output in 2020 in the Netherlands
- Power production to date takes usually place in smaller, decentralized units with lower efficiency – yet the use in larger gas turbines would be possible

1) RVO, *Vergisting and vergassing*, as of July 2021; 2) OCGTs can be relevant, however, as plants that do run in some years but not in others. We assume ~450,000 €/MW CAPEX, ~10,000 €/MW/a Fixed O&M, 2 €/MWh Variable O&M and ~35-40% efficiency for new OCGTs; 3) Fuel price before plant efficiency – price for 1 MWh fuel; 4) SDE++ Basisbedrag 2021;

Sources: Aurora Energy Research; RVO

CCS can be added to gas assets to strongly reduce carbon footprint – infrastructure for transport / storage and storage space required

AURORA

Description

- In a conventional gas asset (retro-) fitted with carbon capture and storage (CCS), the emitted CO_2 is captured post-combustion, compressed and thereafter stored
- Post-combustion CCS is thus seen as a technology that allows the use of existing gas assets, while making them CO_2 neutral[1]

Based on efficiency for gas turbines, includes 7% efficiency penalty for CCS

Key parameters for 2030

Currencies in real 2020

Parameter	Retrofit CCGT	Newbuild	Unit
Lifetime	20	30	Years
Typical unit size	500-1,500	Similar	MW
Cost – CAPEX	1,000,000	1,500,000	€/MW
Cost – Fixed O&M	38,000	Similar	€/MW/a
Cost – Variable O&M	2	Similar	€/MWh
Cost – Transport & storage	11	Similar	€/MWh
Cost – Fuel[2,3]	21	Similar	€/MWh
Efficiency (HHV)	~43-48	~48-53	%

Potential barriers for adoption

- The carbon capture efficiency of CCS is 80-95%, so even the best-in-class assets are not fully carbon-neutral
- Support and / or space for CO_2 storage may eventually prove limited – technologies beyond geological storage (e.g. ocean storage) are still in early phases
- Infrastructure for storage and transport of CO_2 is required for the successful implementation of CCS – policies and governance around CCS in early stage

Maturity, Buildout, Pilots (Focus Netherlands, other markets where relevant)

Commercial Maturity: Medium

- In Europe ten large-scale CCS facilities are being developed and are intended to be operational in the 2020s
- In Ireland, a post combustion CCS project is being developed by ERVIA, the CCS-equipped CCGTs and refinery shall start operation in 2028
  - The project is expected to capture 2 Mt CO_2 per year, then transport and store in the Celtic Sea
- In the UK, for the two ~900 MW CCGTs Peterhead and Keadby 3, Equinor and SSE Thermal plan to retrofit them with CCS and install infrastructure to transport and store CO_2

1) Subsidies for CCS under the current SDE++ framework do not apply to electricity production; 2) Fuel price before plant efficiency – price for 1 MWh fuel; 3) Natural gas

Sources: Aurora Energy Research; IPCC; Eurometal

Hydrogen-burning assets can provide seasonal storage – high fuel cost by 2030, infrastructure for transport required

AURORA

Description

- While hydrogen has applications of its own in industry, transport and heating, it can also be used to produce power
- Purpose-built CCGTs[1] or OCGTs[2] could be used, or existing gas-firing assets could be converted
- Hydrogen can be used for seasonal storage, making it a potentially powerful contributor to system flexibility
- Subsidies for both blue and green hydrogen are in place in the SDE++ framework

Depending on type of low carbon H_2: In 2030, green H2 expected to be most expensive, followed by imported H_2 and blue H_2 – but cost of blue H_2 rather constant, while the other two will decline over time

Potential barriers for adoption

- Hydrogen is expected to be still an expensive fuel by 2030, leading to high variable costs
- Domestic production of green hydrogen in the Netherlands might not be cost-competitive 2030, while imports (e.g. from North Africa) might be politically contentious
- There is a need to develop an infrastructure system: large-scale application of hydrogen-powered plants would require dedicated pipelines and a storage system

Key parameters for 2030

Currencies in real 2020

Parameter	Retrofit CCGT	Newbuild	Unit
Lifetime	20	30	Years
Typical unit size	500–1,500	Similar	MW
Cost – CAPEX[3]	200,000	650,000	€/MW
Cost – Fixed O&M	19,000	Similar	€/MW/a
Cost – Variable O&M	2	Similar	€/MWh
Cost – Fuel[4]	~65-110	Similar	€/MWh
Efficiency (HHV)	~50-55	~55-60	%

Maturity, Buildout, Pilots (Focus Netherlands, other markets where relevant)

Commercial Maturity: Medium - Low

- Engie has announced plans to modernize its Maxima plant (a CCGT) in Lelystad to enable the co-firing of hydrogen
  - The efficiency will be increased to over 60% and 35 MW will be added to the 440 MW-unit - the overhaul should be completed by 2023
- The Magnum plant in Eemshaven has been adapted to be 'hydrogen ready' and a battolyser will be installed for combined hydrogen production and electricity storage

1) Combined cycle gas turbine; 2) Open cycle gas turbine; 3) Our cost estimates assume the presence of a large scale H_2 infrastructure (transport & storage); 4) Fuel price before plant efficiency – price for 1 MWh fuel

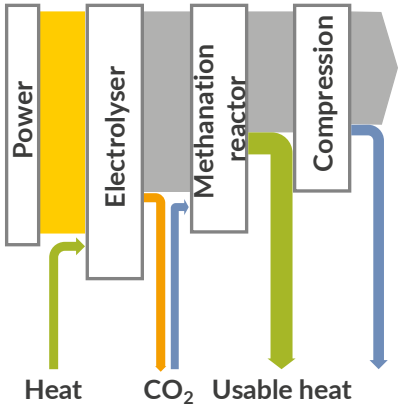
Sources: Aurora Energy Research; Energeia

E-methane could be burned in existing gas assets without additional investment – efficiency losses in process drive high fuel costs

AURORA

Description

- E-methane, or 'green methane' has the same chemical structure as natural gas: CH_4
- Green methane can be produced from hydrogen and carbon dioxide, making its use CO_2-neutral
- A gas-burning CCGT[1] or OCGT[2] could run entirely or partly on e-methane
- Existing gas infrastructure (e.g. distribution grid) does not need to be repurposed for the use of e-methane



Key parameters for 2030

Currencies in real 2020

Parameter	Retrofit CCGT	Newbuild	Unit
Lifetime	20	30	Years
Typical unit size	500–1,500	Similar	MW
Cost – CAPEX	26,000	650,000	€/MW
Cost – Fixed O&M	19,000	Similar	€/MW/a
Cost – Variable O&M	2	Similar	€/MWh
Cost – Fuel[3,4]	~158[5]	Similar	€/MWh
Efficiency (HHV)	~50-55	~55-60	%

Potential barriers for adoption

- E-methane is produced using hydrogen and CO_2 – supply / storage infrastructures for both inputs need to be created and maintained (e.g. co-location with BECCS)
- Efficiency losses in the production of e-methane are a key concern – costs for e-methane are ~50% higher than for H_2, ~20% of H_2 is lost in the process
  - While the gas turbine burning methane eventually is highly efficient, final 'power-to-power' efficiency is only around 30%

Maturity, Buildout, Pilots (Focus Netherlands, other markets where relevant)

Commercial Maturity: Medium - Low

- In principle, all gas-fired units in the Netherlands could be run on e-methane, which means a potential fleet of over 10 GW is already in place
- There are no ongoing pilots, although Engie mentioned co-firing hydrogen and e-methane in its Maxima plant as a possibility

Electric power | Chemical power | Losses | Thermal power

1) Combined cycle gas turbine; 2) Open cycle gas turbine; 3) Fuel price before plant efficiency – price for 1 MWh fuel; 4) Based on 80% efficiency of H_2 to CH_4 conversion as well as other costs for methanation, e.g. for carbon; 5) only based on green H_2

Source: Aurora Energy Research

Metal fuels are being developed as a possible alternative to hydrogen for seasonal storage –technological / commercial maturity still low

AURORA

Description

- Metal powder is a carbon-free fuel that could be used in existing coal assets
- After combustion, iron oxide (rust powder) remains
- Using hydrogen, the iron oxide can be reduced back to iron, releasing only water
- As such, iron powder can serve as seasonal storage of renewable energy

Key parameters for 2030[1]

Currencies in real 2020

Parameter	Retrofit Coal	Newbuild	Unit
Lifetime	30	40	Years
Typical unit size	700-1,100	Similar	MW
Cost – CAPEX	316,000	2,000,000	€/MW
Cost – Fixed O&M	30,000	Similar	€/MW/a
Cost – Variable O&M	3	Similar	€/MWh
Cost – Fuel[2,3]	~110-173	Similar	€/MWh
Efficiency (HHV)	~35-40	~40-45	%

Potential barriers for adoption

- The lower energy density and higher variable costs that go with the combination of iron with hydrogen form a potential roadblock to commercial viability
- Combustion systems that can efficiently burn the metal fuels have to be developed on a larger scale – the technology readiness level of the technology is still low

Maturity, Buildout, Pilots (Focus Netherlands, other markets where relevant)

Commercial Maturity: Low

- Eindhoven University of Technology aims to scale up the development of iron powder as an alternative fuel for power plants
  - Burning of iron powder has been applied at a brewery in Lieshout using a 100 kW installation
  - Goal is to scale to 1 MW next, 10 MW by 2024 and be able to convert a full fired power station by 2030 (through follow-up project SOLID); scale-up supported by EU funds

1) Asset-specific parameters based on a typical coal-burning asset; efficiency and variable costs specific to the iron oxidation-reduction cycle; 2) Fuel price before plant efficiency – price for 1 MWh fuel; 3) Based on 72% efficiency of H_2 (re-) conversion as well as other fixed process costs

Sources: Aurora Energy Research; Energeia; Eindhoven University of Technology

High investment cost and lifetime of require long-term commitment to nuclear – SMRs yet to prove commercial viability

AURORA

Description

- Nuclear power is the use of nuclear reactions to produce electricity, mostly through nuclear fission
- While typically nuclear reactors have been built in larger unit sizes (>500 MW), small modular reactors (SMR) could lead to a breakthrough
  - They are expected to have capacities of up to 300 MW
  - Their construction is assumed to be more standardized which shall help to reduce investment cost

Potential barriers for adoption

- Capital expenses are high and lead times for constructing nuclear power plants are long (10-15 years), which implies high project risks – cost escalation after start of construction has often been observed in the past
- Because of high CAPEX and lifetime, long term commitment are among the main conditions for realizing a new nuclear power plant
- Location-wise, only Borssele in the province of Zeeland persists as a relevant candidate for new plants in the Netherlands – two new reactors proposed close to current site by EPZ in 2020
- Long-term treatment of radioactive waste remains a concern both from an environmental and an economic perspective
- As they ramp slowly, nuclear plants are not well suited to flexible production

Key parameters for 2030

Currencies in real 2020

No commercial maturity at this point

Parameter	Large unit (Gen. III+)[2]	Small Modular Unit (Gen. III+)	Unit
Lifetime	60	Similar	Years
Typical unit size	~1,600-1,800	<300	MW
Cost – CAPEX	5,200,000	4,500,000	€/MW
Cost – Fixed O&M	80,000	Similar	€/MW/a
Cost – Variable O&M	14	Similar	€/MWh
Cost – Fuel[3]	4	Similar	€/MWh
Efficiency (HHV)	40	45	%

Maturity, Buildout, Pilots (Focus Netherlands, other markets where relevant)

Commercial Maturity: High for large units, unproven for small modular reactors

- 485 MW plant in Borssele as only nuclear power plant in the Netherlands, its license to operate is set to expire by 2033 according to the *'Kernenergiewet'* – it belongs to the Generation II reactors, built between the 1960s and 1990s
- For Small Modular Reactors (SMRs), a multitude of different designs and concepts exist that have yet to prove their technical / commercial readiness – most advanced versions are constructed in Argentina, Russia and China[3]
- Third generation reactors are being built in Olkiluoto (Finland), Flamanville (France) and Hinkley Point (United Kingdom) at this point

1) KPMG, *Marktconsultatie kernenergie*; 2) Costs based on EPR third generation type reactor (European Pressurised Reactor) third; 3) Fuel price before plant efficiency – price for 1 MWh fuel

Sources: Aurora Energy Research; KPMG; Lucyd Catalyst; DIW; International Atomic Energy Agency

Storage technologies can provide short-term flexibility – they buy and sell power, taking advantage of price spreads in the market

AURORA

A Dispatchable Prod. Technologies

- Technologies that can freely dispatch to the market and can be characterized by their **levelised costs of electricity** (LCOE)
- Assets are **financed** through the **wholesale market** – they will dispatch against **their marginal costs** and depend on the **absolute height of power prices** to recover their costs

Technologies

- *Biomass*
- *BECCS*
- *Biogas*
- *Gas CCS*
- *Hydrogen*
- *E-methane*
- *Metal fuels*
- *Nuclear energy*

B Storage Technologies

- Technologies that buy power from the market in low price hours and then later sell it again at higher prices – an adjusted version of the **levelised cost of electricity** (LCOE) can be used to characterize them
- Assets are **financed** through the **wholesale market** – they depend on the **spread between high and low-price hours** (not on the absolute level) in order to recover their costs

- *Batteries – Li-ion*
- *Batteries – Redox-Flow*
- *Compressed Air*
- *Vehicle to grid*

C Demand flexibility Technologies

- *Industrial DSR*
- *Electrolysers*

D Other Technologies

Remarks for the following section:

- We show detailed plant characteristics and include the technologies with 1 MW into the model to test their profitability
- As part of the project, we determine which capacities of these technologies could provide flexibility to the power market
  - We present information on expected build-out and / or pilots in order to calibrate at which point in time and how these technologies can provide flexibility
- A battery asset will buy power at low prices and dispatch at peak prices
- Technologies in this section are constrained by their duration – they can only supply the amount of power that has previously been stored
  - They will rather provide additional power in hours of high demand, consume power where demand was low before and thus shave peaks – they can provide short-term flexibility

Note: Plant efficiencies in this report are denoted in higher heating value (HHV), while in other publications for some types of plants lower heating value (LHV) might be used. Plant efficiencies expressed in LHV are higher than in HHV. This distinction does not impact our calculations, as we consistently apply HHV in the Aurora Power Market Model.

Source: Aurora Energy Research

Lithium-ion batteries provide short-duration flexibility at low cost – increasing number of industrial-size projects realised

AURORA

Description

- Li-ion batteries have high roundtrip efficiency and are a proven technology to store power for shorter durations
  - Could store for longer durations, but cost increases strongly
  - Also, the longer the duration, the more difficult it is for batteries to capture high-enough spreads
- Industrial scale projects offer durations of up to 4h, for which Li-ion is highly cost competitive

If the technology is profitable for 4 hours, we may assess it for longer durations

Potential barriers for adoption

- Mineral resources may eventually prove a limiting factor to the widespread adoption of lithium-ion batteries
- Not only the availability, also the extraction of lithium may up for debate: the mining operations associated with extracting lithium are considered dirty and have strong negative environmental impacts, at least on the local level
- Given the cost of Li-ion rises strongly with duration, the technology is economically limited in the numbers of hours it provides flexibility

Key parameters for 2030

Currencies in real 2020

Parameter	Value	Unit
Lifetime	15	Years
Typical unit size	>100	MW
Cost – CAPEX[1]	720,000	€/MW
Cost – Fixed O&M[1]	8,500	€/MW/a
Cost – Variable O&M	0.5	€/MWh
Round trip efficiency	90	%
Cycles	5,000	-
Discharge duration	4	h

Maturity, Buildout, Pilots (Focus Netherlands, other markets where relevant)

Commercial Maturity: Medium - High

- In the Netherlands, several Li-ion projects of smaller scale exist, for instance:
  - AES Netherlands Advancion Energy Storage Array: 10 MW
  - Amsterdam ArenA: 3 MW
- A Li-ion facility with 48 MW / 50 MWh has been built in Jardelund, Germany, by Eneco in cooperation with Mitsubishi
- Globally, the largest project with 300 MW and 4 hours of duration is the Moss Landing Energy Storage System in California

1) We assess CAPEX and Fixed O&M also for the storage technologies based on Cost/MW in order to make them comparable to the other technologies and to assess need and cost for flexible capacity

Source: Aurora Energy Research

With increasing duration, redox-flow batteries gain in cost-effectiveness versus Li-ion but have lower roundtrip efficiency

AURORA

Description

- Redox-flow batteries are a storage technology based on electrochemical processes occurring between a positive and negative electrode
- Power output and storage depth of a redox-flow battery can be scaled independently as the energy is stored in tanks outside the energy conversion unit
- Another feature of this type of batteries is that they do not exhibit significant degradation

Key parameters for 2030

Currencies in real 2020

Parameter	Value	Unit
Lifetime	15	Years
Typical unit size	>100	MW
Cost – CAPEX	1,500,000	€/MW
Cost – Fixed O&M	12,000	€/MW/a
Cost – Variable O&M	0.5	€/MWh
Round trip efficiency	~70-75	%
Cycles	Unlimited	-
Discharge duration	8	h

Potential barriers for adoption

- Redox-flow batteries still achieve lower roundtrip efficiencies, thus they require larger spreads in the power market to achieve profitability
- The initial investment cost for the flow system is quite high – yet, the additional cost for increasing storage depth is lower compared to Li-ion
- The technology is less standardized and has mostly been proven at a smaller scale

Maturity, Buildout, Pilots (Focus Netherlands, other markets where relevant)

Commercial Maturity: Medium

- The EU has recently awarded funds to the MELODY consortium, lead by TU Delft, in order to develop sustainable redox-flow batteries and reduce the costs of the technology
- In Dalian (China), a facility with 200 MW / 800 MWh facility is constructed and planned to be operational by the end of the year which would be the largest operational unit – thus could serve as commercial reference

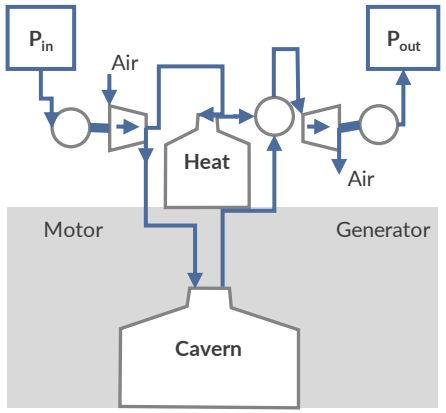
Sources: Aurora Energy Research; IRENA; European Association for Storage of Energy; Fraunhofer ICT; TU Delft; RWE

D-CAES is a proven technology, while pilots for carbon-free A-CAES systems are ongoing – caverns required for storage

AURORA

Description

- A compressed air energy storage system (CAES) is based on air compression and storage in an underground cavern
- Electricity is used to compress air, for an adiabatic plant (A-CAES) the heat of compression is stored separately
- To retrieve the energy, the compressed air is used to generate power in a turbine
- For diabatic plants (D-CAES) systems , additional fuel is used to release power – with H_2 as fuel it becomes carbon-free



Depiction of A-CAES plant

Potential barriers for adoption

- In order to construct / install CAES systems, underground caverns are required as storage locations
  - Research is ongoing on whether the Dutch underground is suitable and offers sufficient opportunities for the development of large-scale compressed air energy storage
- A-CAES systems are not yet widespread – the technology still has to prove its commercial potential (while for D-CAES systems several plants have been in operation since >20 years)

Key parameters for 2030

Currencies in real 2020

Parameter	A-CAES	D-CAES	Unit
Lifetime	30	Similar	Years
Typical unit size	~100-500	Similar	MW
Cost – CAPEX	1,900,000	950,000	€/MW
Cost – Fixed O&M	20,000	Similar	€/MW/a
Cost – Variable O&M	2	Similar	€/MWh
Cost – Fuel	0	~65-110[1]	€/MWh
Round trip efficiency	65	54[2]	%
Cycles	Unlimited	Similar	-
Discharge duration	~10-15	Similar	h

Maturity, Buildout, Pilots (Focus Netherlands, other markets where relevant)

Commercial Maturity: Medium - High

- Corre Energy together with Infracapital is developing a D-CAES plant in Zuidwending, Groningen
  - Capacity of 320 MW, daily dispatch of up to 3-4 GWh
  - Use of hydrogen as fuel for releasing the compressed air – carbon-free
  - Planned to be operational by 2025
- As for A-CAES plants, two 500 MW / 5 GWh projects have been announced in California by Hydrostor, offering ~10 h of duration

1) Fuel price for a set-up using hydrogen; price for 1 MWh fuel; 2) Efficiency based on the combined input of electricity and hydrogen

Sources: Aurora Energy Research; European Association for Storage of Energy; TNO; Energeia; Recharge News

Vehicle-to-grid charging still in early phase – implementation depends on readiness of grid and overcoming acceptance roadblocks

AURORA

Description

- Vehicle-to-grid (V2G), or bidirectional charging, means that a car's battery can both charge and discharge at a charging station
- Next to the direction of charging, the (dis-) charging rate can be varied in response to power prices
- If combined with smart meters, vehicles could receive compensation for their peak shaving services

CAPEX based on cost of technical installation for V2G charging at home – going forward likely to become standard for EVs and thus no additional CAPEX required

Key parameters for 2030

Currencies in real 2020

Parameter	Value	Unit
Lifetime	10	Years
Typical unit size	12	kW
Cost – CAPEX	200,000	€/MW
Cost – Fixed O&M	0	€/MW/a
Cost – Variable O&M	0	€/MWh
Round trip efficiency	90	%
Cycles	100–150	#/a
Discharge duration[1]	4	h

Potential barriers for adoption

- Even more so than for regular electric vehicles, range anxiety is a roadblock to consumer acceptance
- Since batteries have a finite number of cycles, customers could be concerned that vehicle-to-grid could shorten a batteries lifetime
  - Pilots show that there is no considerable effect on battery life, as long as it is charged within 20%-80% of battery range
- DSOs will need to prepare for additional grid load and aggregate EVs to effectively provide flexibility from bidirectional charging
- As such, the technical readiness level of V2G is still quite low

Maturity, Buildout, Pilots (Focus Netherlands, other markets where relevant)

Commercial Maturity: Low

- At present vehicle-to-grid is virtually non-existent, mainly because the electric cars currently on the market are not suitable for it
- However, Utrecht-based shared car company We Drive Solar and car manufacturer Hyundai have signed an agreement to conduct a large-scale test of bidirectional charging in the Utrecht region
  - By early 2022, some 150 electric shared cars that can feed electricity back into the grid should be driving around in Utrecht
- In July 2021 Fiat and Engine have launched the largest existing pilot project in Turin, Italy with 64 EVs

1) When charging and dis-charging between 20% and 80% of battery storage level, degradation is so low that it can be ignored. Assumes 75 kWh storage depth and 12 kW charging capacity.

Sources: Aurora Energy Research; We Drive Solar; Aston University

Heat pumps can contribute to security of supply when they can react to power prices and store heat – flex potential rising over time

AURORA

Description

- Heat pumps are an alternative to the ubiquitous gas boilers to heat homes
- Electric heat pumps provide both heat and hot water, eliminating the need for a gas connection
- Heat pumps with storage and the ability to react to prices can decouple heat and power demand and thus provide flexibility
- An average household could shower for two weeks with one full storage cycle of a heat battery

Aurora's modelling approach

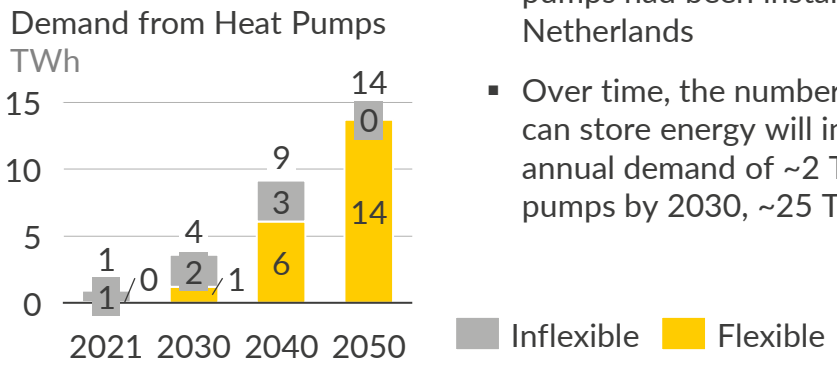
- Aurora's model features a heat-specific electricity demand forecast with seasonal variation
- We model different types of heat pumps: Some heat pumps cannot react to power prices (~2/3 in 2030) and thus not provide flexibility, while we assume the other ~1/3 of heat pumps to be smart by 2030
- Smart heat pumps will react to power prices: they start producing heat when conditions are favorable and store it (e.g. heat battery, hot water cylinder) – reduce their demand when prices and demand from other market participants are high
  - In our modelling, we assume a duration of 2h at full discharging power[1]

Potential barriers for adoption

- Not all heat pumps can flexibly respond to variable power prices and have storage options – retrofitting possible, but will not happen for all units
- Due to high insulation requirements, heat pumps are best suited to newly built homes
- The spread of heat pumps depends on the public – high upfront costs, low awareness and a lack of understanding of costs and benefits might hamper uptake
- Heat pumps could increase the peak demand for electricity, investments in electrical grid infrastructures may be needed

Maturity, Demand Size Netherlands (Project Base Case), Pilots

Commercial Maturity: High



- By 2018, according to CBS 200,000 heat pumps had been installed in the Netherlands
- Over time, the number of heat pumps that can store energy will increase - we expect annual demand of ~2 TWh from these heat pumps by 2030, ~25 TWh by 2050

1) In situation of max heat demand, the battery could provide heat for two hours without any need for power – in other situations much longer. In reality this will also be highly dependent on housing insulation

Sources: Aurora Energy Research; TNO; CBS

Demand flexibility technologies can adjust their demand based on price signals – we assume their capacity exogenously

AURORA

A Dispatchable Prod. Technologies

B Storage Technologies

Remarks for the following section:

- Given demand flexibility technologies are not financed through the wholesale market, we assume their capacity exogenously in our modelling
- Thus, we present the magnitude of flexible demand that we have assumed in the Project Base Case alongside information on maturity and potential pilot projects
  - The Project Base Case is a combination of Aurora's Dutch Net Zero scenario that has been aligned with EZK and TenneT based on the PBL's Climate and Energy Outlook, TenneT's Security of Supply Monitor and the Integrale Infrastructuurverkenning 2030-2050
- The demand flexibility technologies will have a certain base demand of power, but are able to provide flexibility by adjusting their demand in reaction to price signals

- *Hydrogen*
- *E-methane*
- *Metal fuels*
- *Nuclear energy*

C Demand flexibility Technologies

- Technologies do not supply electricity but can **adjust their demand subject to certain constraints,** e.g. storage size, degradation, consumption patterns
- Assets are **not financed through the wholesale market** – investments mostly made for other purposes (e.g. heating) but assets can contribute flexibility and hence to security of supply

- *Heat Pumps*
- *Hybrid Heat Pumps*
- *Electric Boilers*
- *EV Smart Charging*
- *Industrial DSR*
- *Electrolysers*

D Other Technologies

- **Renewable assets** also are characterized by their **levelised costs of electricity** (LCOE) and financed through the **wholesale market**, but **cannot freely dispatch power**
- **Interconnectors** are built based on **socio-economic cost-benefit** analysis – their economics depend on **prices differences** between markets

- *Additional RES Capacity*
- *Interconnection*

Note: Plant efficiencies in this report are denoted in higher heating value (HHV), while in other publications for some types of plants lower heating value (LHV) might be used. Plant efficiencies expressed in LHV are higher than in HHV. This distinction does not impact our calculations, as we consistently apply HHV in the Aurora Power Market Model. 1) Based on Aurora's Dutch Net Zero scenario, includes adjustments and alignments made during the project

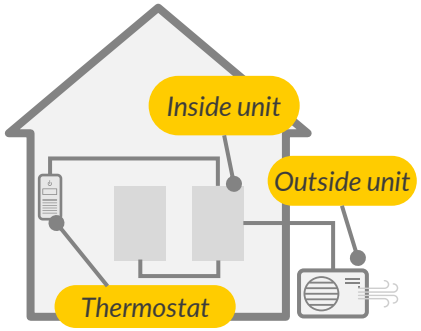
Source: Aurora Energy Research

Hybrid heating systems are an alternative way to decouple heat and power demand – participation depends on alternative fuel price

AURORA

Description

- A hybrid heating system ('hybrid heat pump') is a combination of an electric heat pump and a boiler[1]
- The heat pump uses outside air as a heat source, generated heat is transferred to the central heating system
- The boiler produces additional heat at peak demand moments, when the efficiency of the heat pump drops
- An advantage vs. an all-electric heat pump is that no minimum level of insulation is required, the boiler can always top heat production up



Potential barriers for adoption

- The combination of an electric heat pump and a gas boiler is not CO_2-free – hybrid heat pumps might rather be a transition technology
  - Alternatively, installing a hydrogen boiler and heating with hydrogen as alternative source would be expensive and cost are a main consideration for rapid uptake
- Some existing radiators may not be suited to the lower temperatures (45-55 °C) at which a heat pump works compared to a traditional boiler (60-80 °C)

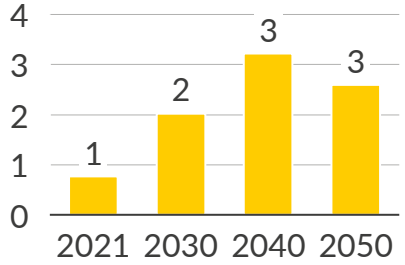
Aurora's modelling approach

- Hybrid heat pumps are bought by households for the primary purpose of heating – thus they do not need to be financed through the wholesale market
- We model hybrid heat pumps like heat pumps on the demand side, compared to normal heat pumps they however have less peak demand
- The hybrid system will optimize its consumption throughout the day (like other smart heat pumps), taking into account the price of the alternative fuel (e.g. clean gas price, price of hydrogen)[2]
- Initially these hybrid systems will mostly run using natural gas, but over time switch towards hydrogen

Maturity, Demand Size Netherlands (Project Base Case), Pilots

Commercial Maturity: High

Demand from Hybrid HPs
TWh



- Low penetration of hybrid heat pumps to date in most markets – 'HR-Hybrid Coalition' (including TenneT) demands for installation of up to 2 million heat pumps (with gas as alternative fuel) by 2030

1) Fuels could be natural gas, hydrogen or the combination of a solar panel and battery; 2) This also depends on the efficiency of the alternative boiler

Sources: Aurora Energy Research; ECN; TNO; Techniek Nederland; II3050

Electric boilers can produce clean and flexible industry heat – activation of the hybrid systems depends on alternative fuel price

AURORA

Description

- Electric boilers can be used to generate heat for businesses
- Industrial applications typically deploy hybrid boilers, which use a boilers with alternative fuel (gas, hydrogen) as a back-up source of heat
- Electricity is used to generate heat when prices are low, the alternative boiler[1] is used in the remaining hours

Aurora's modelling approach

- Like hybrid heat pumps, e-boilers react to power prices by comparing them to the cost of running on their alternative fuel, which serves as the activation cost[2]
  - Over time, more and more boilers in our model will switch from natural gas (activation cost: clean gas price) to hydrogen (activation cost: import price of hydrogen), reflecting the transition to carbon-free industry heat
- We expect more strong growth of direct electricity demand in industry, most of which will arise from the electrification of heat – by 2050, ~3.6 GW of e-boilers to be in the system and provide flexibility in industry heating

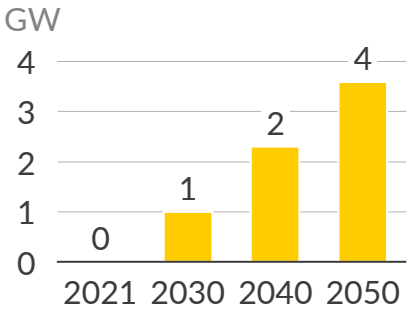
Potential barriers for adoption

- If gas is used as the alternative power source (at least initially), the system would still lead to carbon emissions
- Cost would be the main hurdle for fast and widespread adoption of electric boilers in industry
  - Replacing the boilers by hydrogen-based alternatives would additionally add to this factor

Maturity, Demand Size Netherlands (Project Base Case), Pilots

Commercial Maturity: High

Capacity of E-Boilers



- Electric boilers are a new category in the SDE++ subsidy scheme
- In the autumn round of 2020, nine projects received subsidies, totalling 249 million euros for a capacity of 310 MW
- Some projects with subsidy locked in:
  - USG Industrial Utilities (Chemelot), industrial boiler: 20 MW
  - Vattenfall, district heating in Amsterdam, Almere and Diemen: 50 MW each

1) Also for district heating systems the alternative power source would be a gas boiler, as the efficiency of e-boilers is too low to push out baseload sources like CHPs; 2) Boiler efficiency taken into account

Sources: Aurora Energy Research; PBL; Energeia; RVO

Electric vehicles will increasingly offer demand flexibility, as penetration of EVs and availability of smart charging rises

AURORA

Description

- An electric vehicle (EV) is propelled by an electric motor, using power stored in a lithium-ion battery
- EVs are charged at a dedicated charging station: at home, at work (e.g. corporate fleets) or at a public charging point
- The driving range varies, but lies between 150 and 400 km for passenger cars
- Besides cars, there are also electric (mini-) buses in operation

Aurora's modelling approach

- Aurora's model takes annual demand specific to smartly charging EVs as input, which accounts for quarterly variations: for instance, more travel during the summer due to vacation
- Part of this demand is flexible ('smart EVs'), part is inflexible – increasing share of smart EVs over time
  - Smart EVs observe the wholesale power price and optimize charging cost to the consumer, leveraging the duration of their battery of ~4-5h[1]
  - They are subject to the following constraints: EVs cannot charge at the same time as driving (charging availability) and EVs must have sufficient charging levels to drive

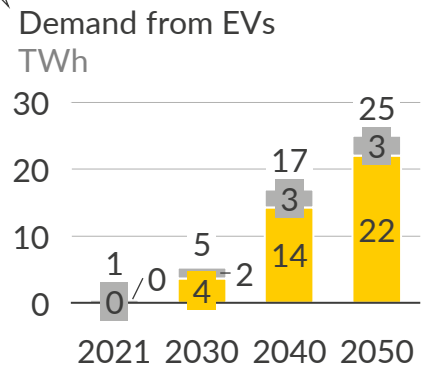
Potential barriers for adoption

- Total cost of ownership (TCO) of EVs still much higher than of petrol cars - pricing of EVs and thus adoption happens outside of wholesale market
- Infrastructure for charging (i.e. charging point density) needs to be available for widespread use
- Range anxiety by consumers poses an acceptance problem – for EVs in general, but potentially also for smart charging
  - Consumers could be sceptic of postponing the charging of their car for grid purposes
- Disposal of batteries as potential environmental concern

Includes heavy vehicles, electric buses etc.

Maturity, Demand Size Netherlands (Project Base Case), Pilots

Commercial Maturity: Medium



- Penetration of car market with EVs expected to pick up fast – many new cars will be technically ready for smart charging
- NewMotion, owned by Shell, has been licensed in the Netherlands to provide grid balancing services through smart charging – slowing the charging rate of a fleet of vehicles when frequency is too low and vice versa

1) This means the battery charges in ~4-5 hours at an average charger. However, this allows to drive much longer than that on average.

Sources: Aurora Energy Research; New Motion

Industrial flexibility is a potentially potent source of demand-side response in the Netherlands that can be activated at higher prices

AURORA

Description

- Industrial demand-side response (DSR) is a mechanism whereby end-users adjust their demand based on price signals
- Dutch industry is already contributing to balancing the grid
- Currently, only ~20% of the theoretical potential is actively participating in the market
- Companies with substantial electricity demand and non-continuous processes are best placed to participate in the DSR market

Aurora's modelling approach

- Demand can be reduced when a certain activation power price is reached – i.e. the price is high enough to compensate for shifting / shedding production
  - This activation price differs between industries
- For the timeline of industrial DSR, we relied on external sources – we enter an exogenous timeline in our model based on market analysis, not allowing the technology to change its capacity
- DSR can only be active a limited amount of hours per year

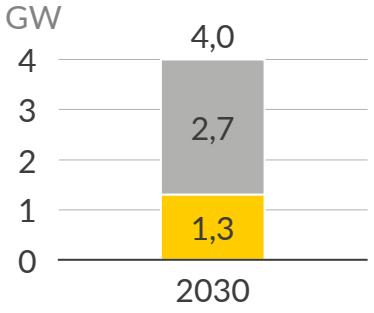
Potential barriers for adoption

- Low awareness of the (economic) potential of DSR for industry seems to hinder participation
  - Comprehensive information and easy regulatory / administrative implementation could reduce hurdles for industrial players
- According to DNV, 40% of the potential for DSR comes at a cost of over 3,000 €/MWh, the current maximum price on the day-ahead market
  - This likely sets un upper ceiling on the potential that will eventually be unlocked

Maturity, Demand Size Netherlands (Project Base Case), Pilots

Commercial Maturity: High

Industrial DSR Capacity



- By 2030, the theoretical potential of DSR in the Netherlands is expected to be ~4 GW
- We expect up to 1.3 GW of industrial DSR to regularly and simultaneously participate in the market
  - Variable cost for activation start at 67 €/MWh, but quickly rise to over 800 €/MWh, final capacities to come online at 2,000 €/MWh

Active DSR Remaining Potential

Sources: Aurora Energy Research; DNV GL; TenneT; Strategy &

Electrolysers can serve as a flexible demand source at large scale in the Dutch power market

AURORA

Description

- Through the chemical process of electrolysis, the molecules of water (hydrogen, oxygen) are separated using electricity
- When using green power as an input, electrolysers thus can produce carbon-free hydrogen
- At the same time, electrolysers can serve as a flexible demand source in the power market, when deployed at a large scale

Potential barriers for adoption

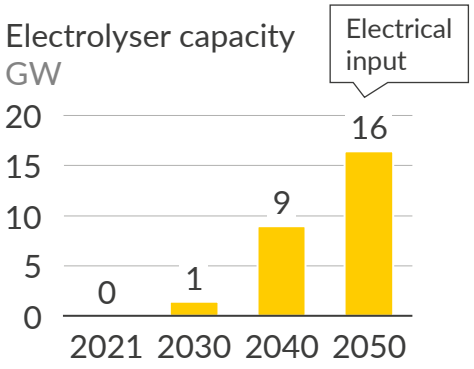
- Currently electrolysers are still only tested at MW-scale, projects with several hundred MW are planned to be operational in the next 2-5 years
  - To supply green H_2 in sufficient quantities, GW-scale is necessary
- The contribution of electrolysers to reduction of CO_2 emissions in the Netherlands depends on the successful RES build-out
- Sufficient demand for H_2 and the willingness to pay for CO_2-free hydrogen will determine the need for electrolysers
  - Depending on the structure of the future hydrogen economy, hydrogen produced in the Netherlands will likely compete with cheaper imports (e.g. from North Africa) and blue hydrogen

Aurora's modelling approach

- Aurora's power market module features an integrated hydrogen module, in which a hydrogen prices forms, taking into account hydrogen demand, the marginal cost of H_2 plants and electrolyser dispatch – thus, electrolysers have an impact on the power demand as well as hydrogen price
- Hydrogen electrolysers will respond flexibly to power prices and thus can serve as flexible demand source
  - At moments that the marginal cost of electrolysers is lower than other sources of hydrogen (e.g. blue or imports), the electrolysers are dispatched
  - Thus, when power is cheap, they will consume power and produce hydrogen and they will shut down when power is expensive

Maturity, Demand Size Netherlands (Project Base Case), Pilots

Commercial Maturity: Medium



- In the port of Rotterdam, Shell plans a 200 MW hydrogen electrolyser plant by 2023
  - Powered by an offshore windfarm
  - Estimation of production of up to 60t of green hydrogen per day
- In Eemshaven, RWE plans to build a 50 MW electrolyser next to a wind park, with the production of green hydrogen expected to start in 2024

Sources: Aurora Energy Research

Renewables are characterized by intermittent power production, interconnection can help balance peaks between countries

AURORA

A Dispatchable Prod. Technologies

- Technologies that can freely dispatch to the market and can be characterized by their **levelised costs of electricity** (LCOE)
- Assets are **financed** through the **wholesale market** – they will dispatch against **their marginal costs** and depend on the **absolute height of power prices** to recover their costs

Technologies

- *Biomass*
- *BECCS*
- *Biogas*
- *Gas CCS*
- *Hydrogen*
- *E-methane*
- *Metal fuels*
- *Nuclear energy*

B Storage Technologies

C Demand flexibility Technologies

- *Industrial DSR*
- *Electrolysers*

Remarks for the following section:

- For RES assets and interconnection capacity, we assume an existing buildout timeline to cater to the reality of these assets already being in the market
  - The Project Base Case is a combination of Aurora's Dutch Net Zero scenario that has been aligned with EZK and TenneT based on the PBL's Climate and Energy Outlook, TenneT's Security of Supply Monitor and the Integrale Infrastructuurverkenning 2030-2050
- We can, however, assess the economics of marginally adding more assets
  - For RES assets, this will be standard model output
  - For interconnection, we will calculate the interconnector rents
- The model curtails generation from wind and solar when RES production exceeds demand to avoid negative prices and balance supply (taking into account inter-country flows)

D Other Technologies

- **Renewable assets** also are characterized by their **levelised costs of electricity** (LCOE) and financed through the **wholesale market**, but **cannot freely dispatch power**
- **Interconnectors** are built based on **socio-economic cost-benefit** analysis – their economics depend on **prices differences** between markets

- *Additional RES Capacity*
- *Interconnection*

Note: Plant efficiencies in this report are denoted in higher heating value (HHV), while in other publications for some types of plants lower heating value (LHV) might be used. Plant efficiencies expressed in LHV are higher than in HHV. This distinction does not impact our calculations, as we consistently apply HHV in the Aurora Power Market Model.

Source: Aurora Energy Research

Interconnection with other countries can contribute to security of supply in Netherlands – further buildout until 2050 expected

AURORA

Description

- The European electrical grid supplies power at a frequency of 50 Hz and is operated by TSOs, which together form ENTSO-E[1]
- The Netherlands became a net exporter in 2020 – net exports to UK and Belgium and net imports from Norway and Denmark – balance with Germany[2]
- European interconnection is expected to increase, e.g. NordLink, between Germany and Norway, operational as of May 2021

- Demand, outages and RES generation are imperfectly correlated across countries – additional interconnection can contribute to security of supply
- Also a mitigating effect on price volatility is expected

Potential barriers for adoption

- International cooperation is required to complete interconnection projects, which usually leads to long lead times
- Politics need to be closely considered – dependance on other countries can be a contentious topic
- The closer the area of RES production is located to the Netherlands, the closer the RES production patters are correlated – reduces contribution to security of supply and viability of business case, as price differences are depressed
- Tariff-hindrances can additionally contribute to the uncertainty of the business case – also considering the large investments necessary

Key parameters for 2030

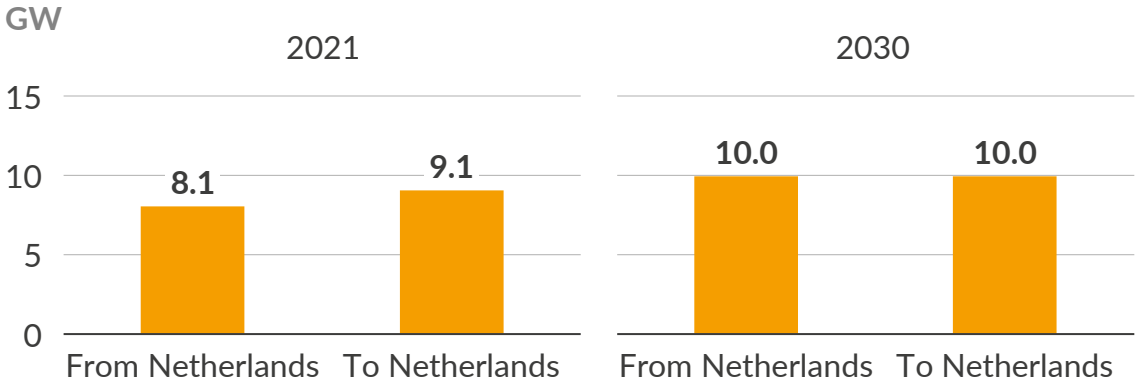
Currencies in real 2020

High CAPEX for converter stations – length of connection not main cost driver

Parameter	Value[3]	Unit
Typical capacity	~500 – 2,000	MW
Length	~100 – 1,000	km
Cost – CAPEX	~750,000 – 1,500,000	€/MW
Cost – Fixed O&M	~4,000 – 17,000	€/MW/a

We model interconnector economics by assessing when the interconnectors are marginal and taking the price delta between the connected countries for these hours

Capacities in aligned Project Base Case[4]



1) European Network of Transmission System Operators for Electricity; 2) Based on physical flows in 2020; 3) Ranges based on cost data from ENTSO-E on select interconnection projects, e.g. including COBRA cable, North Sea Link; 4) Based on TYNDP 2020 for concrete projects until 2030, after 2030 based on System Needs analysis and historical comparison of system needs versus buildout

Sources: Aurora Energy Research; ENTSO-E; Statnett

Offshore wind buildout is expected to grow strongly by 2050 – additional capacities in North Sea to be explored

AURORA

Description

- Offshore wind is an important source of renewable power in the Netherlands
- The government pipeline runs until 2030 and adds up to 11 GW
- Offshore wind buildout has been realised through zero-bid tenders since 2017
- Extra areas in the North Sea need to be designated with sufficient space for an additional 27 GW offshore wind by 2050

Key parameters for 2030

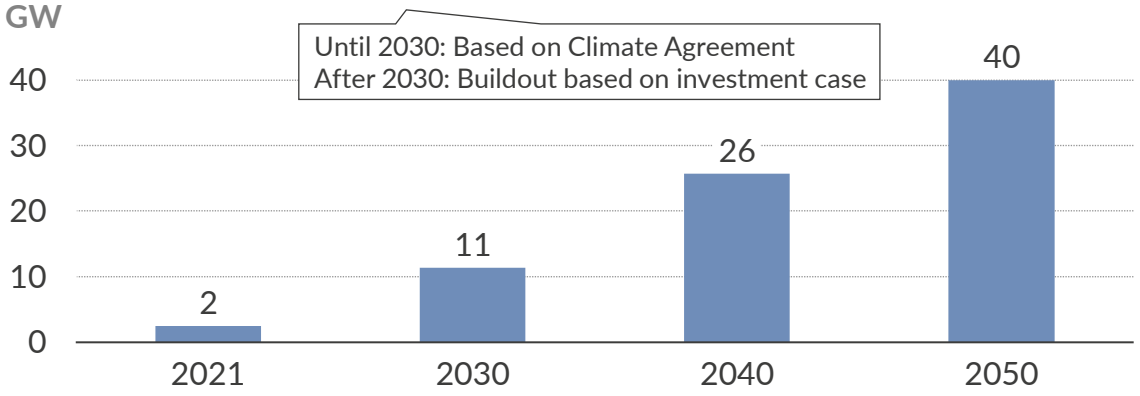
Currencies in real 2020

Parameter	Value	Unit
Lifetime	25	Years
Typical unit size	700	MW
Cost – CAPEX	1,742,000	€/MW
Cost – Fixed O&M	48,000	€/MW/a
Cost – Variable O&M	2	€/MWh
Average load factor	49.1	%

Potential barriers for adoption

- Weather-dependent power generation from wind will place increasing demands on grid infrastructure – otherwise congestion might arise in peak wind production hours
- Extensive buildout of offshore wind impacts nature conservation and fishing.

Capacities in aligned Project Base Case



Sources: Aurora Energy Research; Rijkswaterstaat

While 5 GW of onshore wind buildout has already been realised, newbuilds are facing additional hurdles

AURORA

Description

- Like their offshore counterparts, onshore wind turbines transform the kinetic energy in air motion into electricity
- Onshore wind buildout is planned in the Regional Energy Strategies (RES), in which 30 regions plan their solar and onshore wind buildout
- The latest Monitor Wind on Land found that an additional 2,488 MW onshore wind could be realised by 2023

Key parameters for 2030

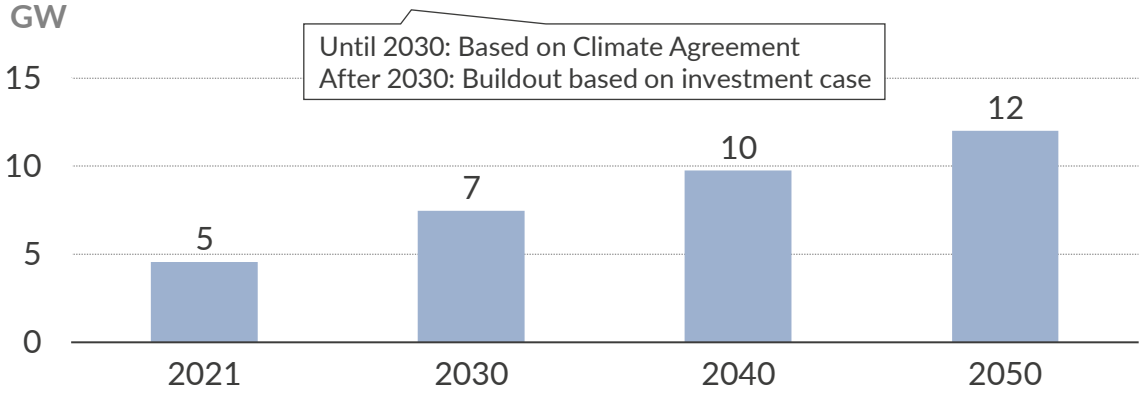
Currencies in real 2020

Parameter	Value	Unit
Lifetime	25	Years
Typical unit size	120	MW
Cost – CAPEX	1,073,000	€/MW
Cost – Fixed O&M	51,000	€/MW/a
Cost – Variable O&M	2	€/MWh
Average load factor	36.5	%

Potential barriers for adoption

- Like in many countries, build-out of onshore wind in the Netherlands is hindered by not-in-my-backyard (NIMBY) concerns
  - While consumers demand green power, there is low acceptance for wind turbines close to the own property
- Wind turbines impact birds and bats – habitats have to be considered during planning

Capacities in aligned Project Base Case



Sources: Aurora Energy Research; Rijksoverheid

Strong increase in solar capacity expected – public preferences are leaning towards rooftop panels

AURORA

Description

- Solar panels produce an electrical current through light absorption
- Together with onshore wind, solar buildout is planned in the Regional Energy Strategies
- While households cannot access the subsidy regime SDE++, rooftop solar can profit from the *salderingsregeling*, allowing them to sell part of their power to the grid
  - Starting 2023 the program is slowly phased out until 2031
- The public preference is for rooftop panels

Key parameters for 2030

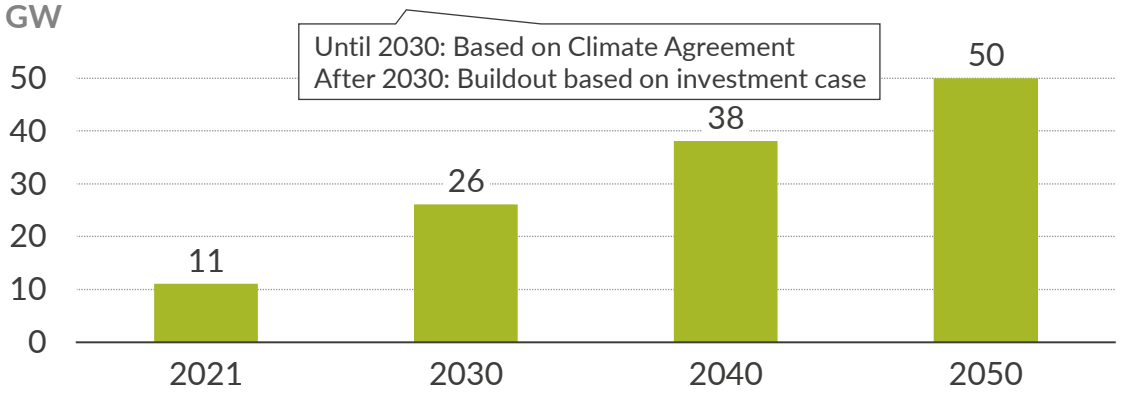
Currencies in real 2020

Parameter	Value	Unit
Lifetime	30	Years
Typical unit size	20	MW
Cost – CAPEX	447,000	€/MW
Cost – Fixed O&M	12,000	€/MW/a
Cost – Variable O&M	0	€/MWh
Average load factor	11	%

Potential barriers for adoption

- Based on the 35 TWh of green power production by 2030 as aligned in the Climate Agreement, Netbeheer Nederland has pointed towards grid connection all these new RES assets as a potential hurdle that might lead to delays
- The use of arable land for solar panels might be subject of increased resistance
- High demand for materials for the manufacturing of solar cells in the short term and production of hazardous waste from old solar panels - infrastructure to recycle end-of-life solar panels needs to be developed

Capacities in aligned Project Base Case



Sources: Aurora Energy Research; Netbeheer Nederland

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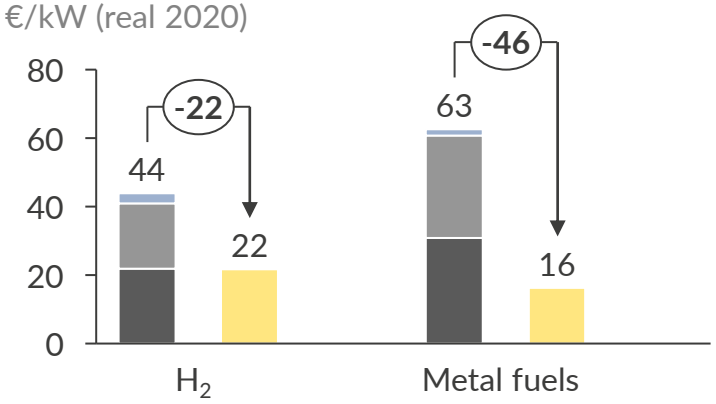
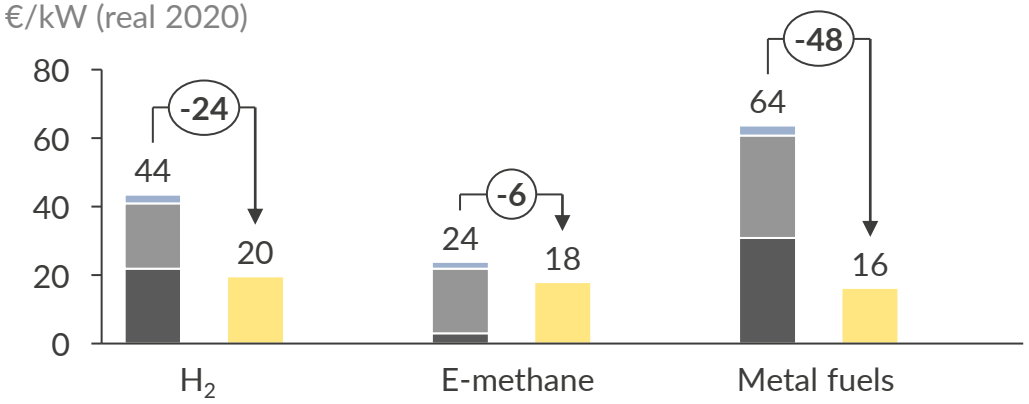
Economics of Technologies in Project Base Case 2030 – Hydrogen technologies

AURORA

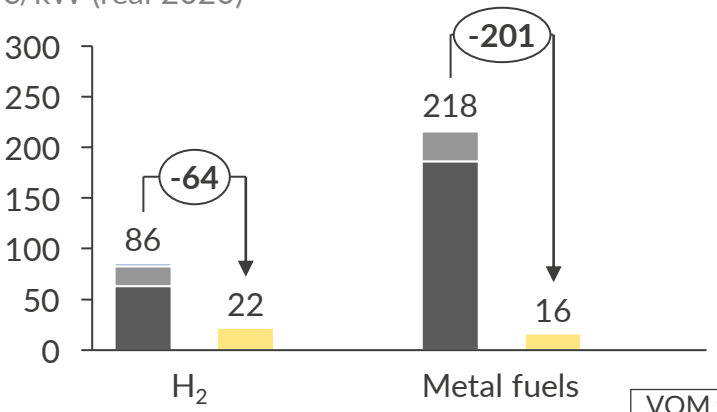
Business Case 2030 – Blue H_2 technologies[1], Retrofit
€/kW (real 2020)



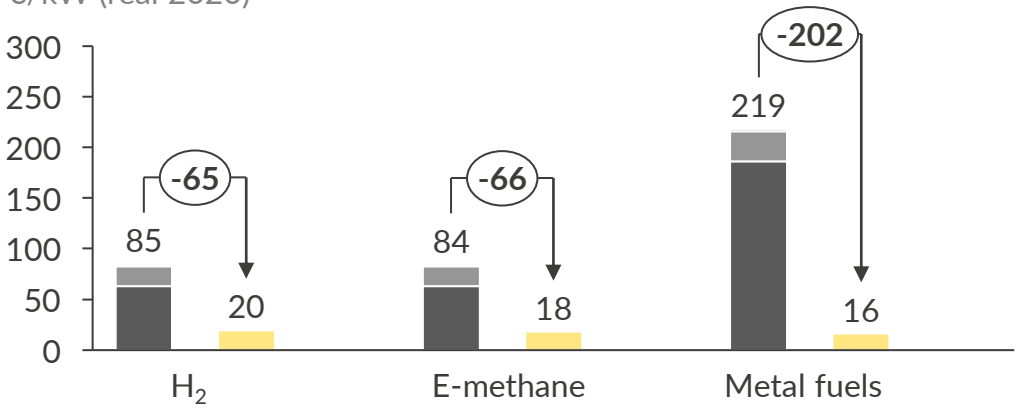
Business Case 2030 – Green H2 technologies, Retrofit
€/kW (real 2020)



Business Case 2030 – Blue H_2 technologies[1], Newbuild
€/kW (real 2020)



Business Case 2030 – Green H2 technologies, Newbuild
€/kW (real 2020)



VOM for some technologies are so low that they do not show

Capex | Fixed O&M | Variable Fuel | Variable O&M | Revenues | -X Gap to profitability

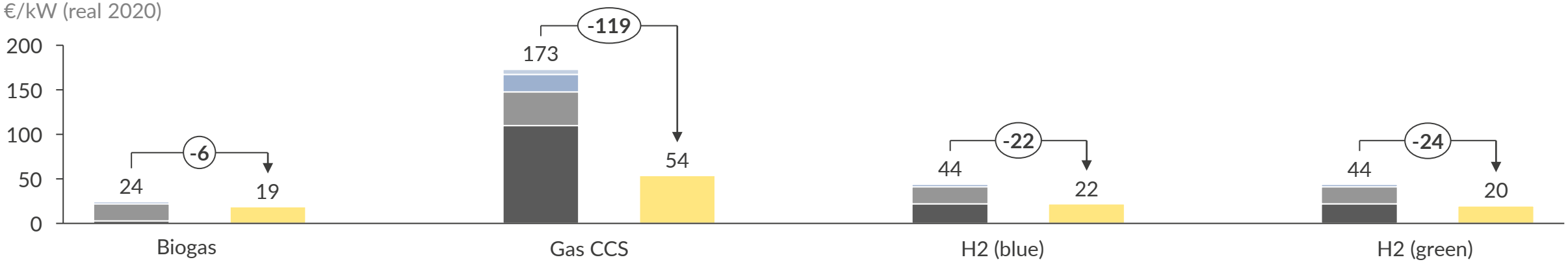
1) E-methane only included using green H_2, as E-methane based on methane is no logical option; instead of blue E-methane one could better store the CO2 capture at the SMR and burn methane in the turbine

Source: Aurora Energy Research

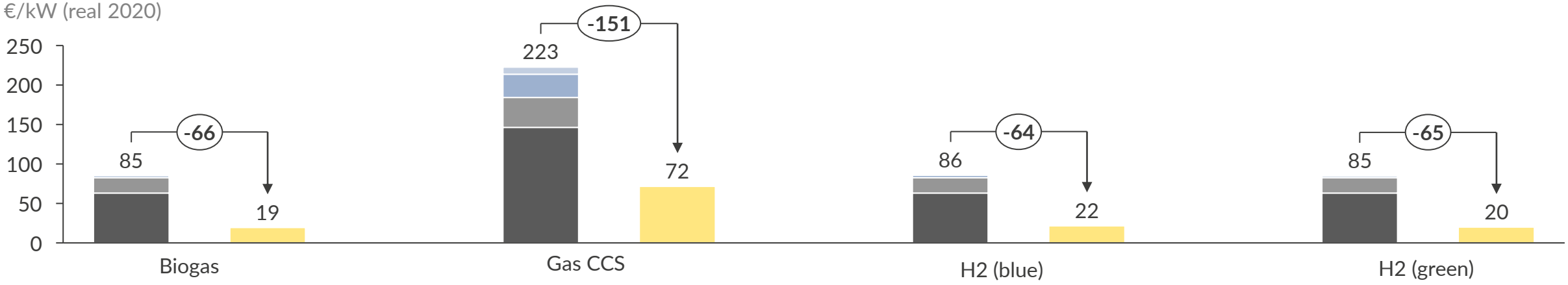
Economics of Technologies in Project Base Case 2030 – CCGTs

AURORA

Business Case 2030 – CCGT, Retrofit
€/kW (real 2020)



Business Case 2030 – CCGT, Newbuild
€/kW (real 2020)



Capex | Fixed O&M | Variable Fuel | Variable O&M | Revenues | -X Gap to profitability

VOM for some technologies are so low that they do not show

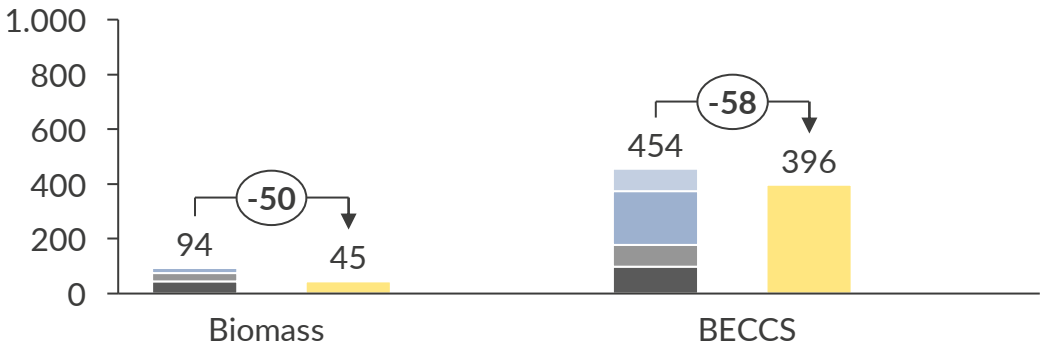
Source: Aurora Energy Research

Economics of Technologies in Project Base Case 2030 – Biomass, Nuclear and Interconnections

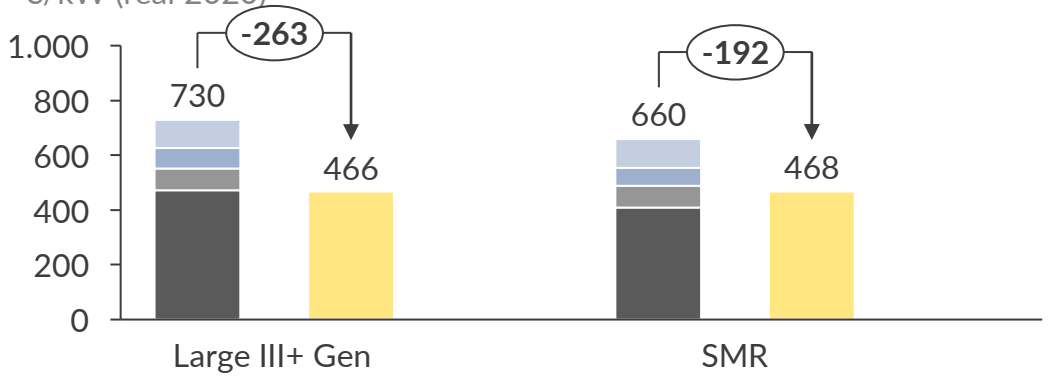
AURORA

In a system with high share of renewables, there are many low-price hours that make it difficult for nuclear to earn back the high fixed cost

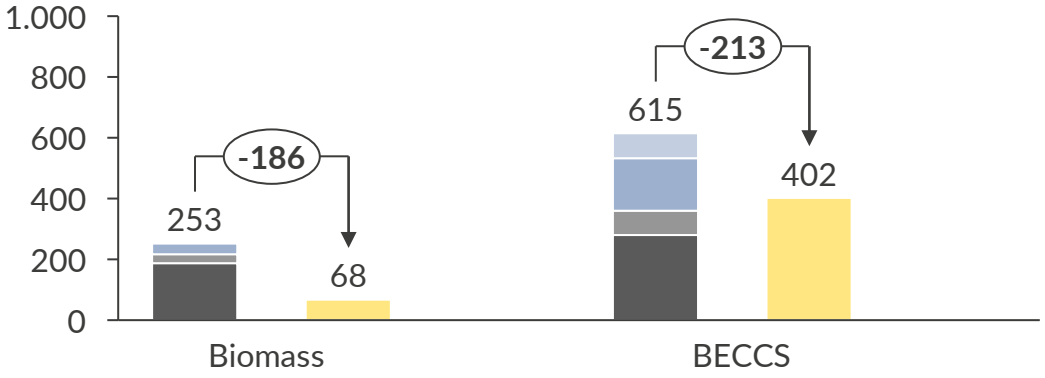
Business Case 2030 – Biomass, Retrofit
€/kW (real 2020)



Business Case 2030 – Nuclear, Newbuild
€/kW (real 2020)



Business Case 2030 – Biomass, Newbuild
€/kW (real 2020)



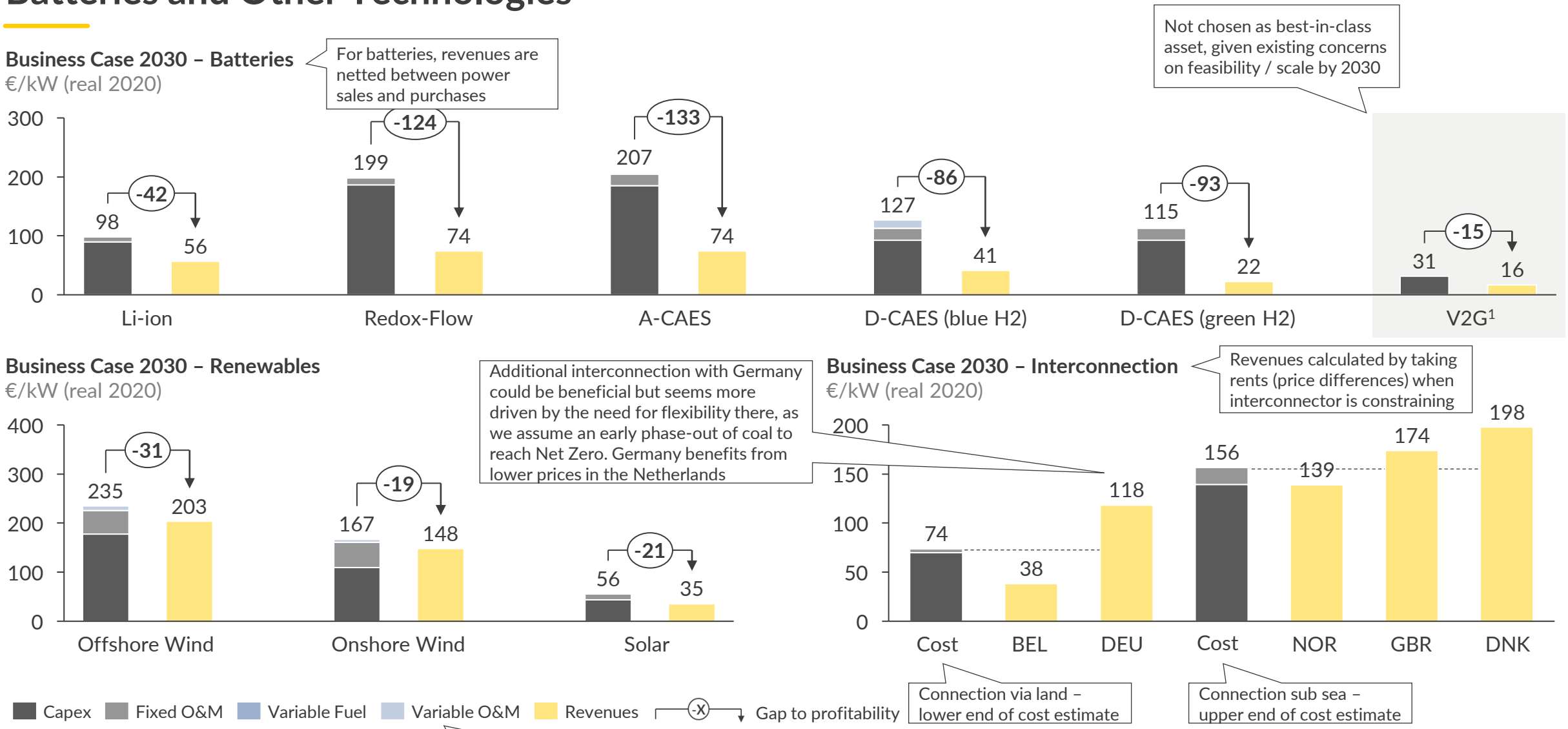
Capex | Fixed O&M | Variable Fuel | Variable O&M | Revenues | -X Gap to profitability

VOM for some technologies are so low that they do not show

Source: Aurora Energy Research

Economics of Technologies in Project Base Case 2030 – Batteries and Other Technologies

AURORA



1) Cost based on CAPEX for wall charger supporting bi-directional charging

Source: Aurora Energy Research

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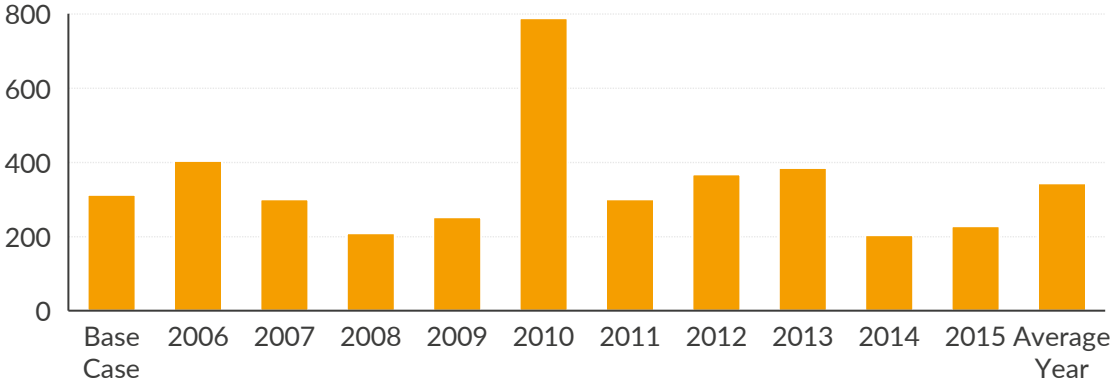
AURORA

In 2040, depending on weather year, up to ~800 hours of loss of load, ~2 TWh of unmet demand and ~14 GW max loss of load occur

AURORA

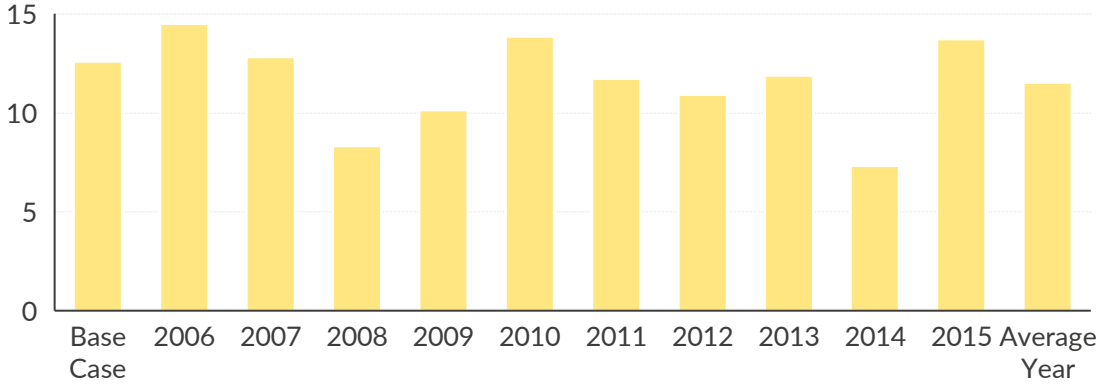
Loss of load numbers of hours – 2040

h



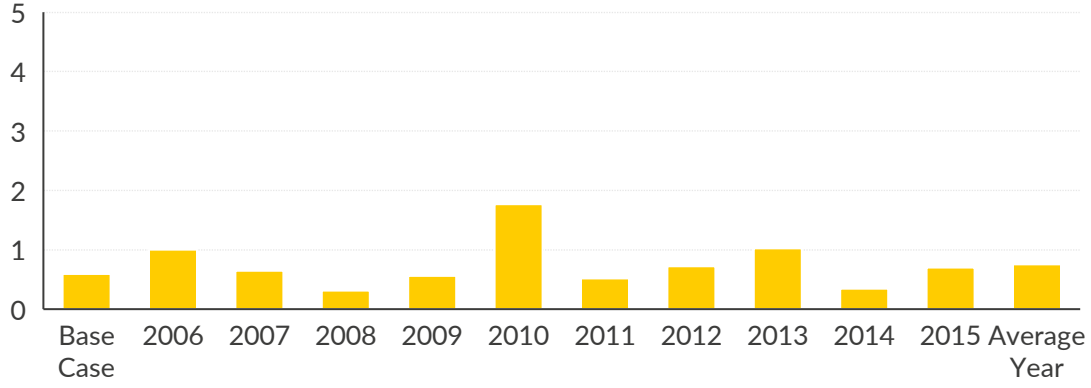
Maximum loss of load – 2040

GW



Loss of load depth – 2040

TWh



Comments

- WY 2010 is most extreme weather year
  - Leads to ~800 hours where loss of load occurs as well as nearly 2 TWh of unmet demand by 2050
  - Not the highest WY in terms of maximum loss of load
- WY 2006 leads to highest maximum loss of load in 2050, amounting to ~14 GW of loss of load in the most extreme hour
- WY 2008 and WY 2014 with very little loss of load over all categories

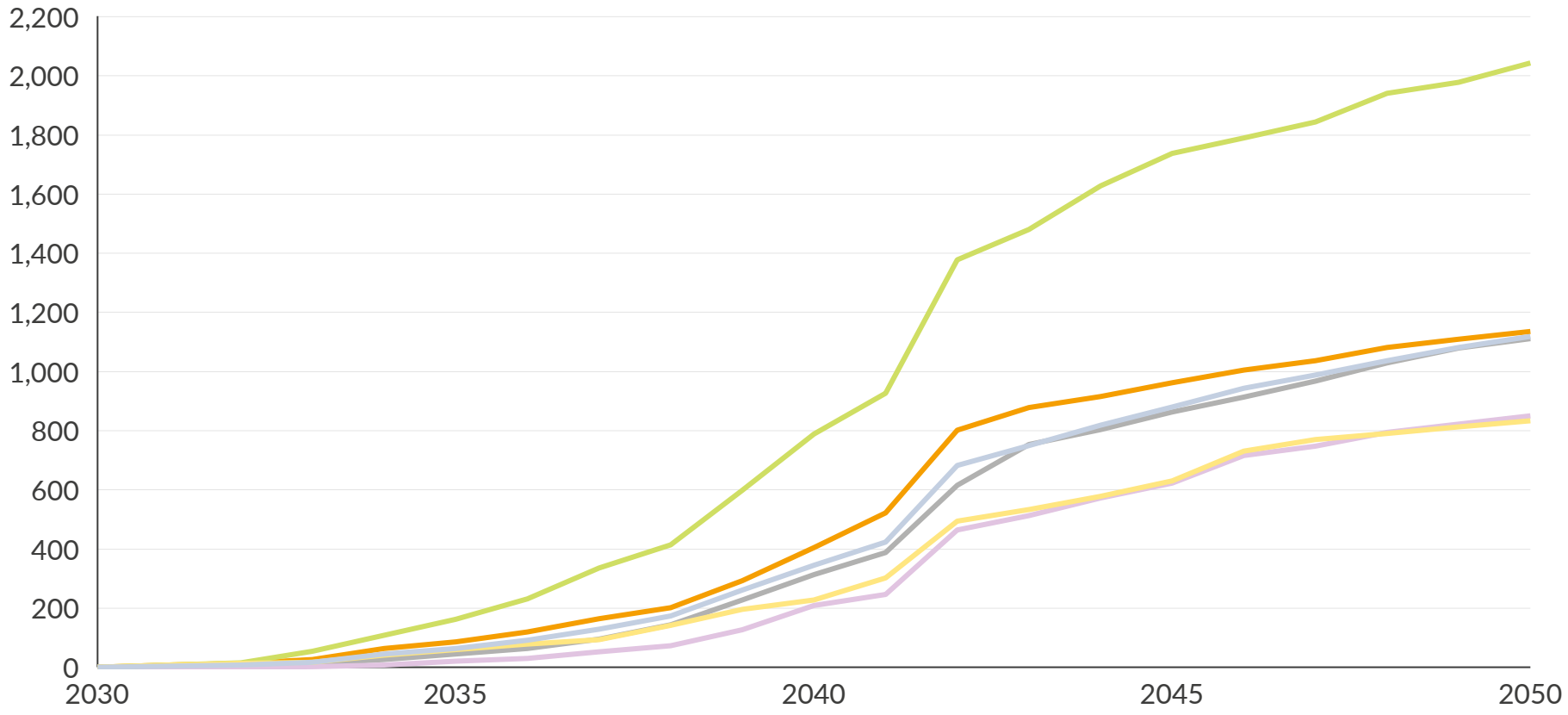
Note: This section covers loss of load and prices in the Base Case when only considering RES and the remaining thermal assets - without having added the flex production technologies.

Source: Aurora Energy Research

Strong increase of the numbers of hours with loss of load over time – most scenarios with 800 – 1,200 hours by 2050

AURORA

Loss of Load number of hours
h



Note: This section covers loss of load and prices in the Base Case when only considering RES and the remaining thermal assets - without having added the flex production technologies.

Source: Aurora Energy Research

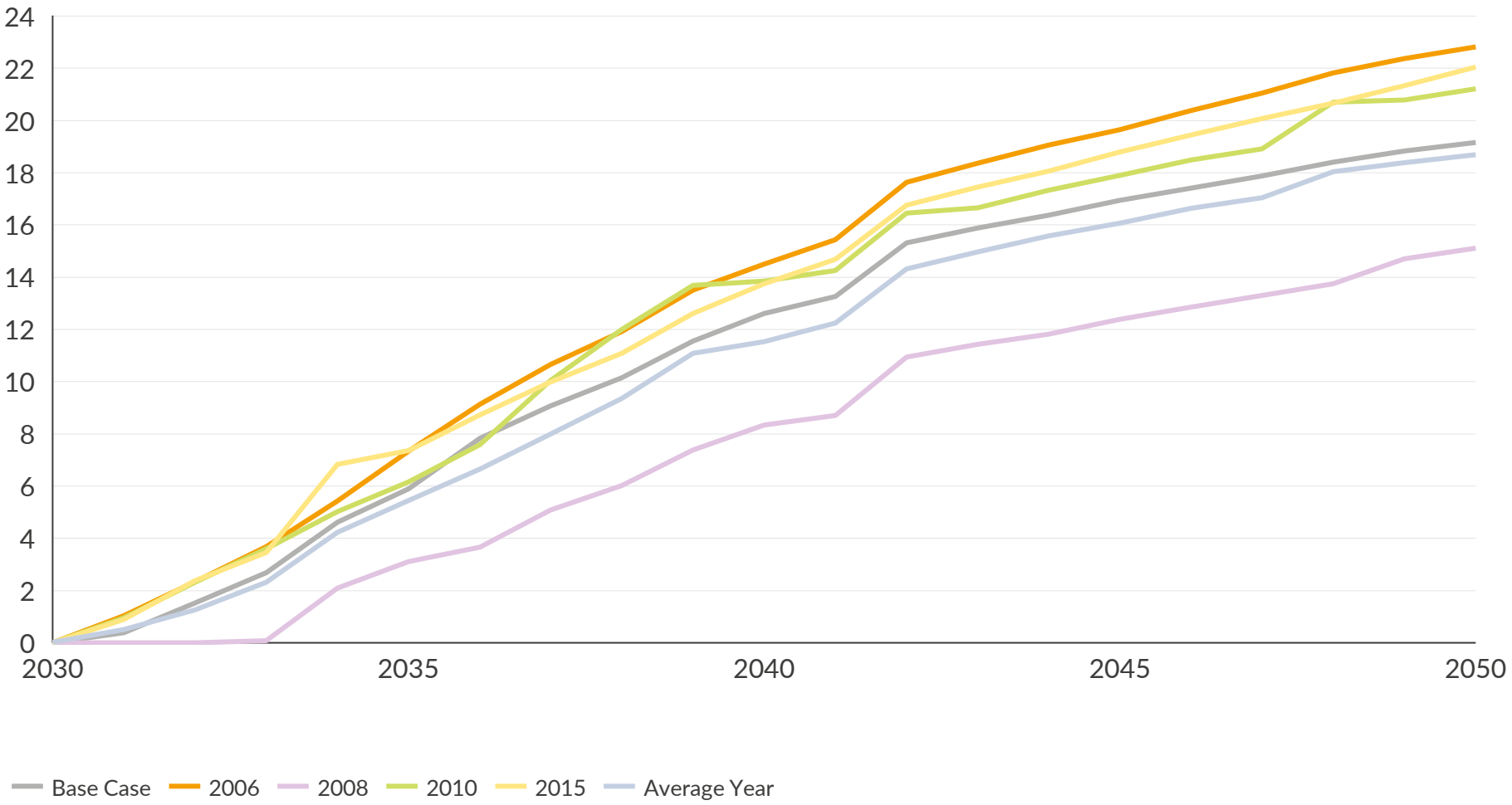
Comments

- Outside of the base case and the average year, we only present select weather years to keep visibility high:
  - WY 2006: Highest max loss of load
  - WY 2008: Fewest problems with loss of load
  - WY 2010: Highest number of loss of load hours and depth of loss of load
  - WY 2015: High peak loss, but limited number of hours and max loss of load

Several years with loss of load of >20 GW by 2020 – even least drastic WY 2008 with >15 GW in most extreme hour

AURORA

Maximum Loss of Load
GW



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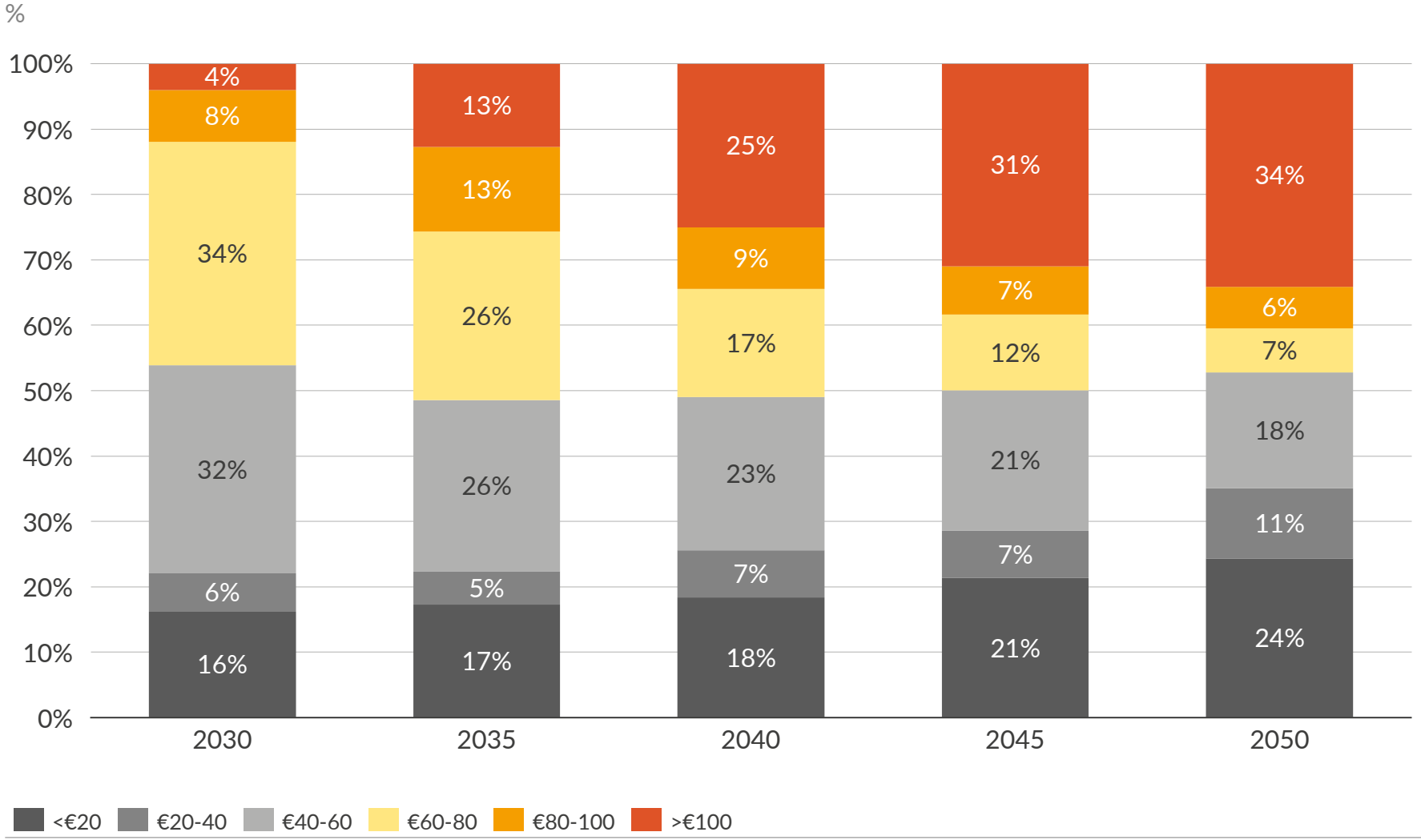
  - WY 2010: Highest number of loss of load hours and depth of loss of load
  - WY 2015: High peak loss, but limited number of hours and max loss of load

Share of hours >100 €/MWh and <20 €/MWh increases by factor 3 from 2030 to 2050 in Base Case – very high volatility

AURORA

Frequency distribution of the electricity price



Note: This section covers loss of load and prices in the Base Case when only considering RES and the remaining thermal assets - without having added the flex production technologies.

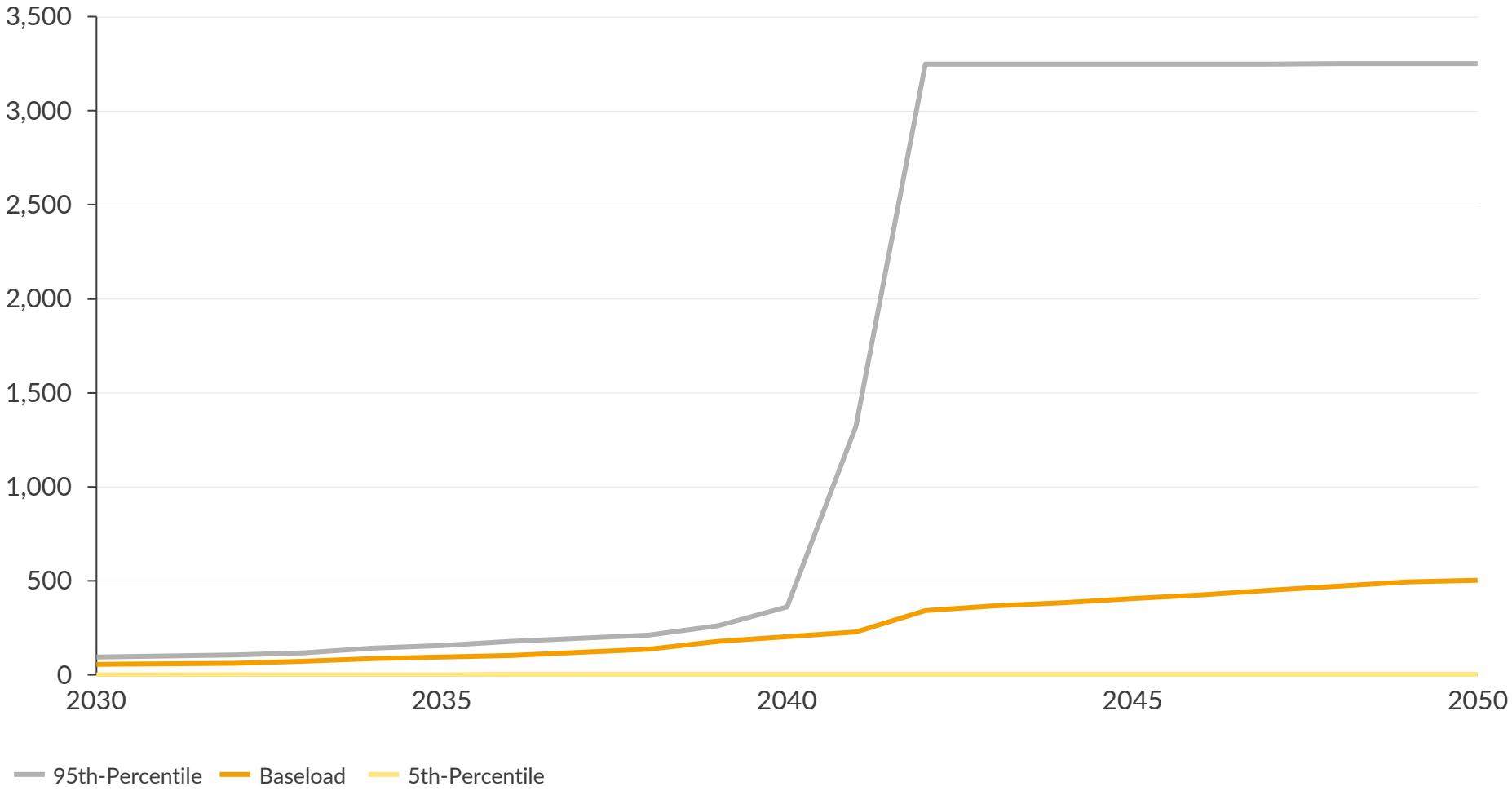
Source: Aurora Energy Research

Comments

- Wholesale prices are expected to become increasingly volatile, as gas is phased out and the buildout of renewables progresses fast
- The frequency of high prices (>100 €/MWh) increases by 30 p.p. between 2030 and 2050, as loss of load situations become more frequent where prices skyrocket
- The frequency of low prices (<20 €/MWh) increases by 8 p.p. between 2030 and 2050 as renewables set prices more frequently

Without thermal capacities, prevalence of loss of load situations leads to wholesale prices of >500 €/MWh by 2050 in Base Case

Wholesale price and percentiles
€/MWh



Note: This section covers loss of load and prices in the Base Case when only considering RES and the remaining thermal assets - without having added the flex production technologies.

Source: Aurora Energy Research

AURORA

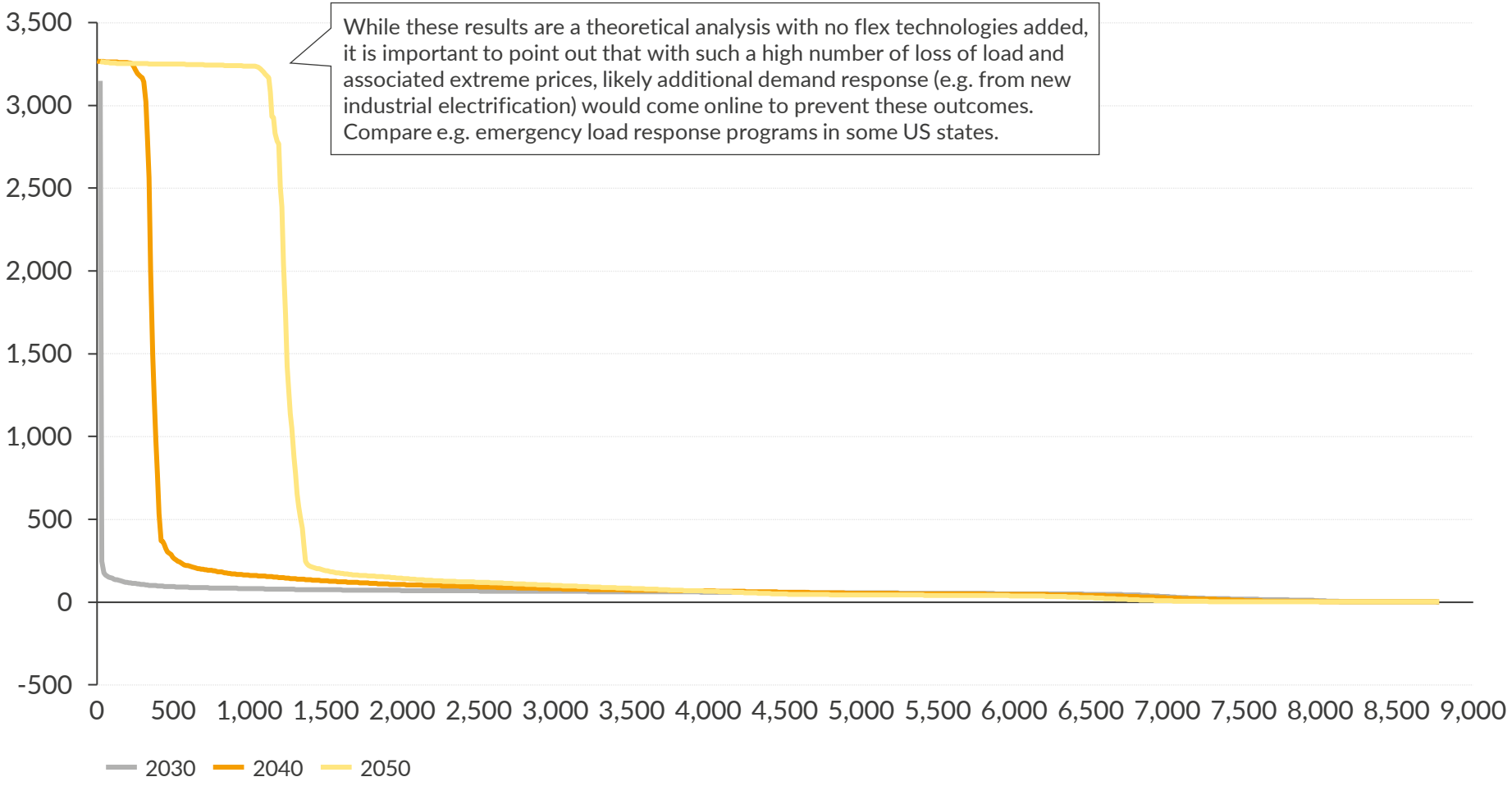
Comments

- Average wholesale price rises from ~60 €/MWh in 2030 to ~200 €/MWh by 2040 and ~500 €/MWh by 2050
  - This is because there are plenty of situations where loss of load occurs and prices skyrocket to >3k €/MWh
- The most expensive prices (95th -percentile) rise from ~400 €/MWh in 2040 to ~3,330 € in 2050, driving up the average wholesale price
- On the other hand, the movement of cheap prices is very limited – the 5th-percentile moves from ~1 €/MWh to ~2 €/MWh over the 20 year horizon

Price distribution curve (1/2): Number of extreme price hours (>1k €/MWh) increases strongly to over ~1,000 hours in 2050

AURORA

Price distribution curve
€/MWh



Comments

- In 2030, there are very few hours with extreme prices
  - Only very few hours with prices over 1k €/MWh
  - In ~700 hours, prices are below 5 €/MWh
- In 2040, more hours with extreme prices emerge – both on the high and on the low end
- By 2050, many hours in the year are characterized by extreme prices
  - In over 1,000 hours, prices top 1k €/MWh
  - In >1,500 hours, prices stay below 5 €/MWh

Note: This section covers loss of load and prices in the Base Case when only considering RES and the remaining thermal assets - without having added the flex production technologies.

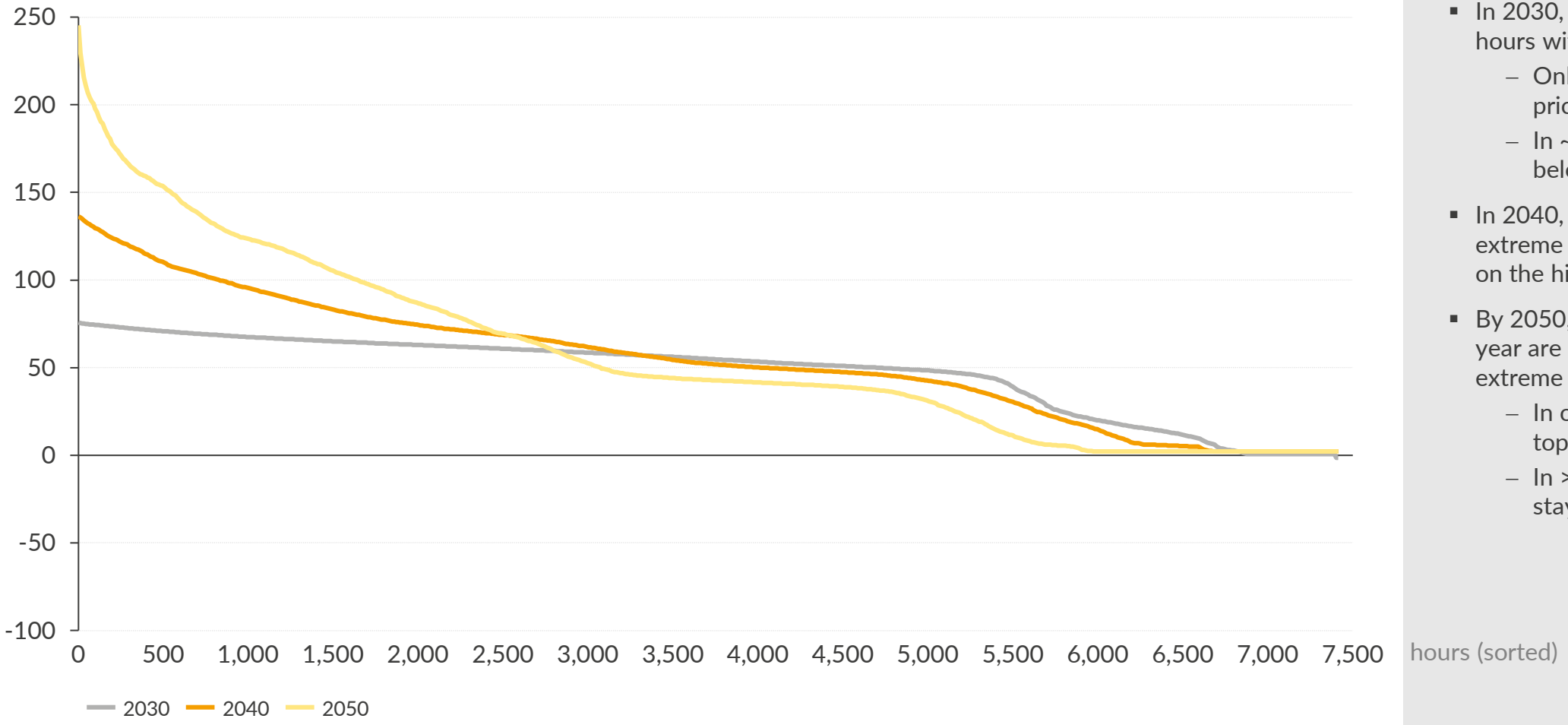
Source. Aurora Energy Research

Price distribution curve (2/2): With more RES-generation, also the number of extremely low-priced hours increases towards 2050

AURORA

Price distribution curve
€/MWh

Zoom-in from previous slide to make differences in lower-priced hours visible



Comments

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  - Only very few hours with prices over 1k €/MWh
  - In ~700 hours, prices are below 5 €/MWh
- In 2040, more hours with extreme prices emerge – both on the high and on the low end
- By 2050, many hours in the year are characterized by extreme prices
  - In over 1,000 hours, prices top 1k €/MWh
  - In >1,500 hours, prices stay below 5 €/MWh

Note: This section covers loss of load and prices in the Base Case when only considering RES and the remaining thermal assets - without having added the flex production technologies.

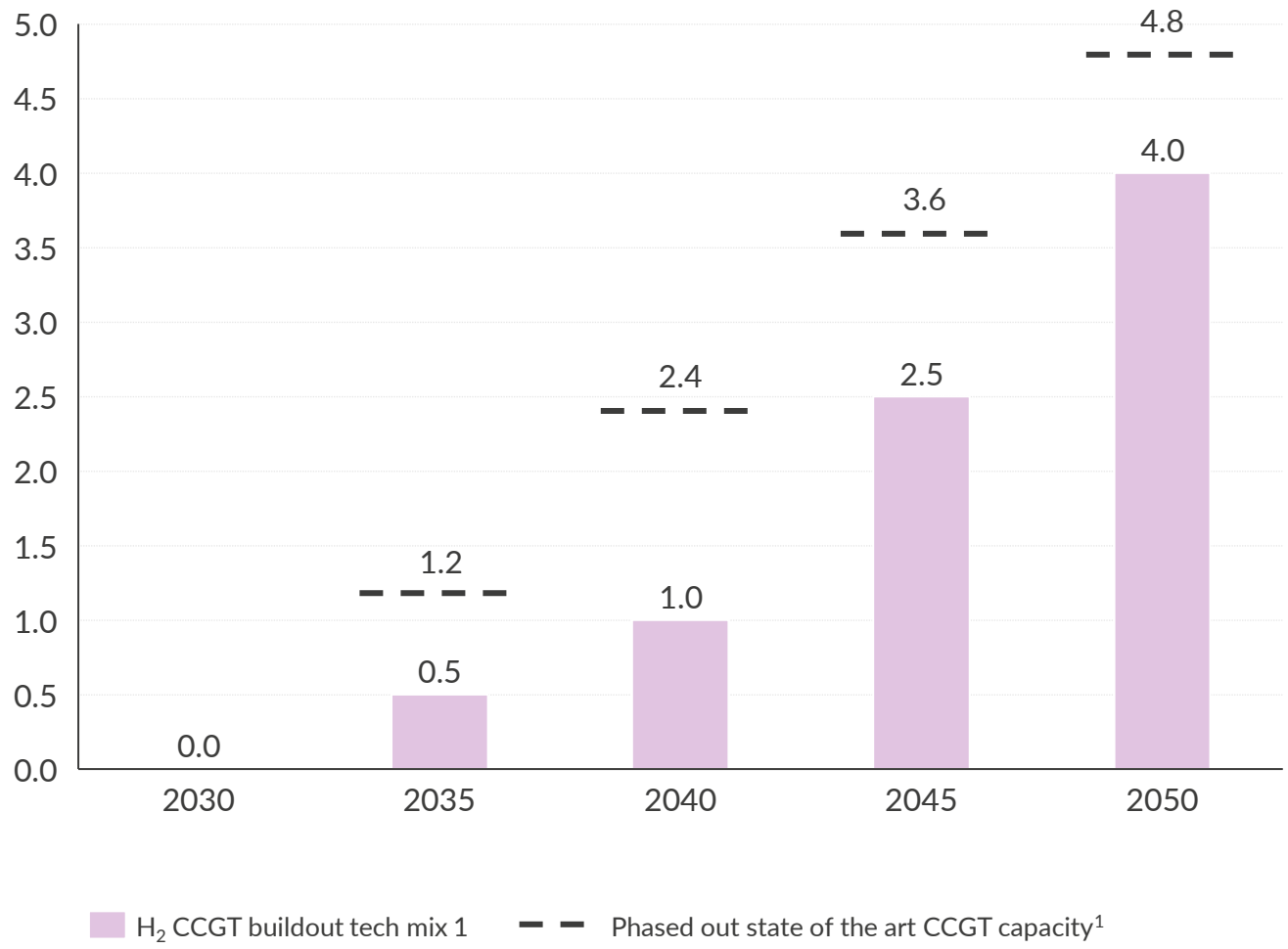
Source. Aurora Energy Research

There is enough CCGT capacity in the Netherlands to cover the H_2 CCGT build of Tech Mix 1 through retrofitting

AURORA

Tech Mix 1

H_2 CCGT build out in tech mix 1 vs. phased out state of the art CCGT capacity[1]
GW



Comments

- In Technology Mix 1, the long duration flex is provided by hydrogen CCGTs, which build up to 4 GW of capacity
- In the higher security scenario, the margins for the plants are high enough to support retrofitted H_2 CCGTs from 2040 onwards, but to be able to do so enough gas CCGT capacity needs to be available for retrofitting
- In the Netherlands there is currently a total of 4.8 GW of CCGT capacity that was built after 2010, which could potentially be suitable for retrofitting
- To reach Net Zero in 2050 and intermediate targets, the capacity is restricted with the capacity as show above
- It is enough to allow all build out in Tech Mix 1 to be based on retrofitted plants, however, the lifetime of these plants would be limited

1) State of the art defined as all CCGT capacity built after 2010, phased out to reach Net Zero.

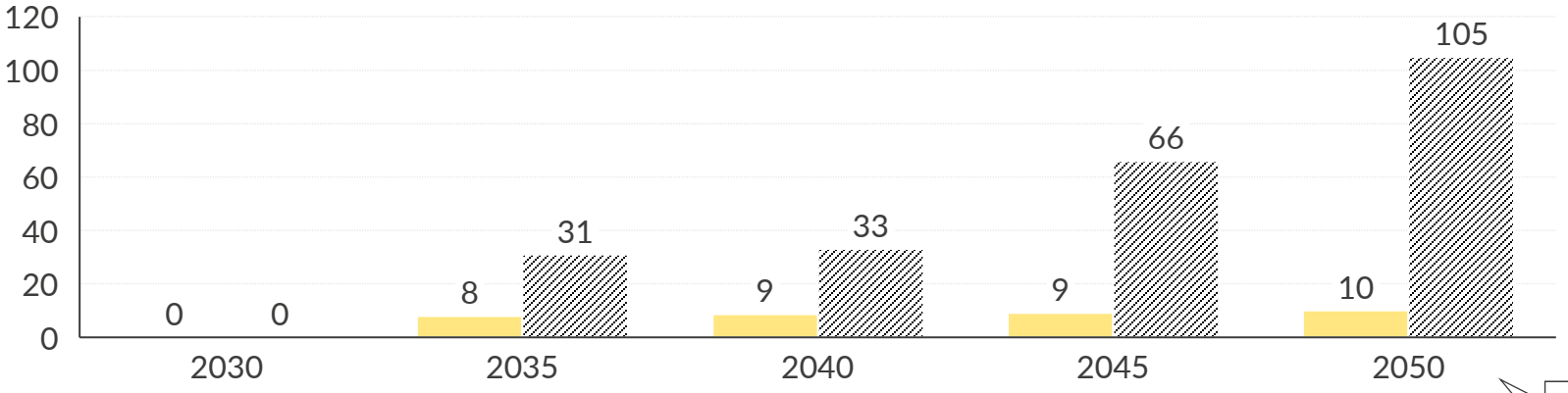
Source: Aurora Energy Research

Hours of loss of load (~10x) and maximum loss of load (~2x) rise strongly, when switching to an extreme weather year

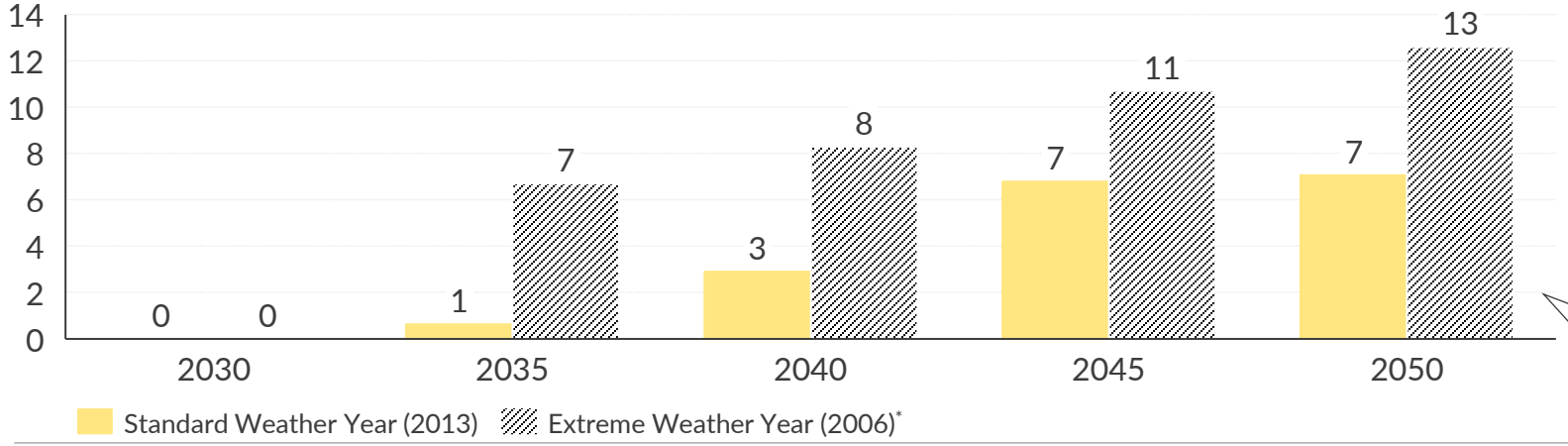
AURORA

Tech Mix 1 | **TIGHTER SYSTEM SCENARIO**

Hours of Loss of Load[1]
h



Maximum Loss of Load[1]
GW



Comments

- Hours of loss of load rise strongly when switching from the standard weather year (2013) to a more extreme weather year (2006)
  - Already in 2035, they are ~4 times higher at 31 hours
  - By 2050, with 105 hours of loss of load, they would rise by >10

Example data for Tech Mix 1 – development in Tech Mix 2 and 3 similar

- Also the maximum peak loss of load rises, even though not in the same magnitude
  - While in 2035 the maximum peak is already much higher at ~7 GW, the value stabilises at ~2 times what it was before and ~13 GW maximum peak loss of load in 2050

It is important to point out that with such a high number of loss of load and associated extreme prices, likely additional demand response (e.g. from new industrial electrification) would come online to prevent these outcomes. Compare e.g. emergency load response programs in some US states.

1) Assumes ~3k €/MWh as price when loss of load occurs; 2) Chosen as WY 2006 exhibited the highest maximum peak loss of load

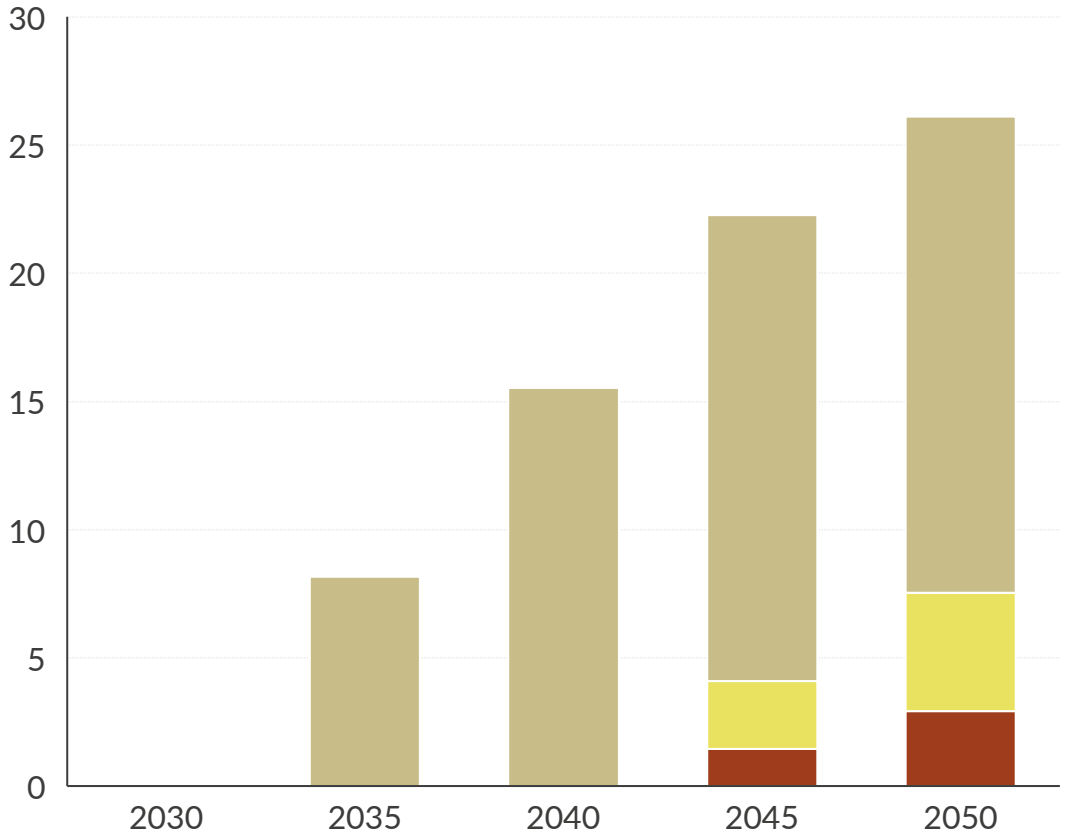
Source: Aurora Energy Research

To quantify what would happen with a much higher capacity build out of long duration, an extra high nuclear scenario was created

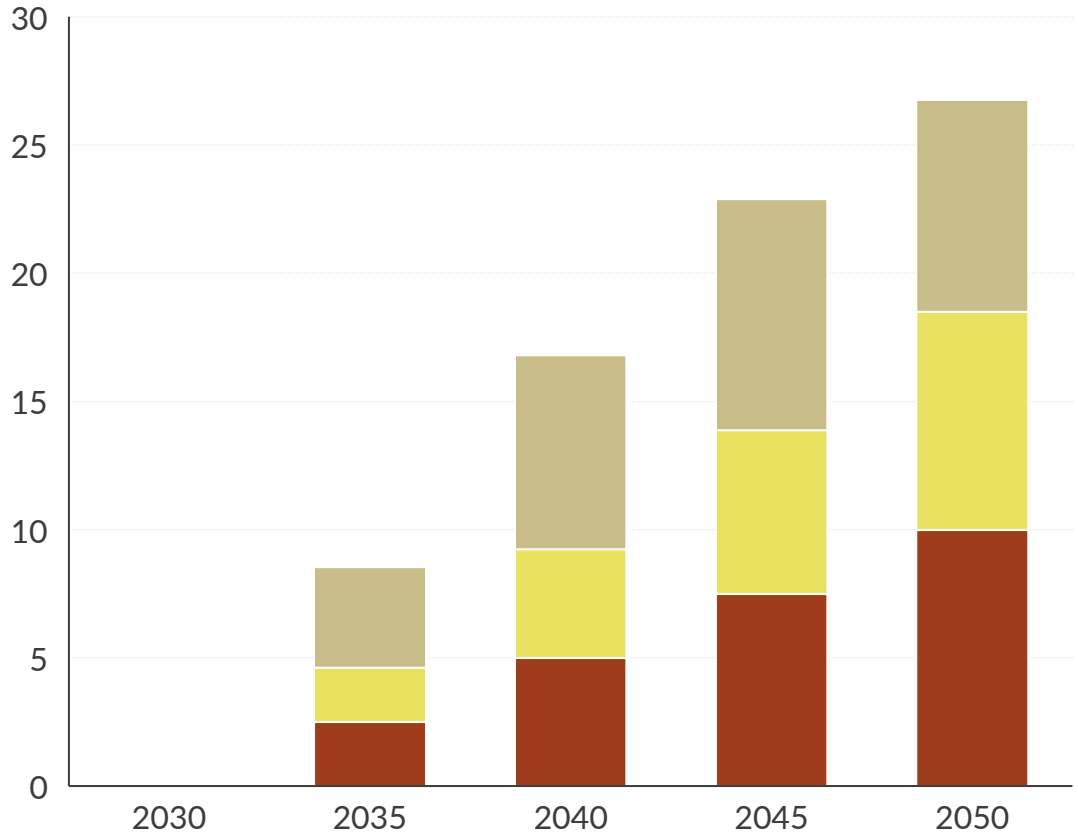
AURORA

SENSITIVITY

CO_2 free flexible capacities – Tech Mix 2 – Higher security
GW



CO_2 free flexible capacities – Tech Mix 2 – High Nuclear Sensitivity
GW



Nuclear SMRs | H2 CCGTs | Li-ion | Back-up

Note: This was an interim analysis / sensitivity to check the impact of increasing the capacity of nuclear power. Numbers for Tech Mix 2 higher security do not reflect final capacities and prices as shown in the main section for Chapter 3.

Source: Aurora Energy Research

A high nuclear scenario leads to strong cannibalisation of margins for flex technologies and low baseload prices

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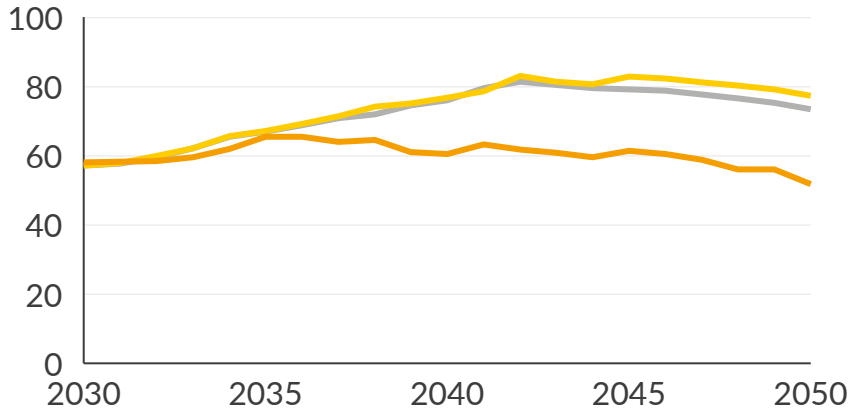
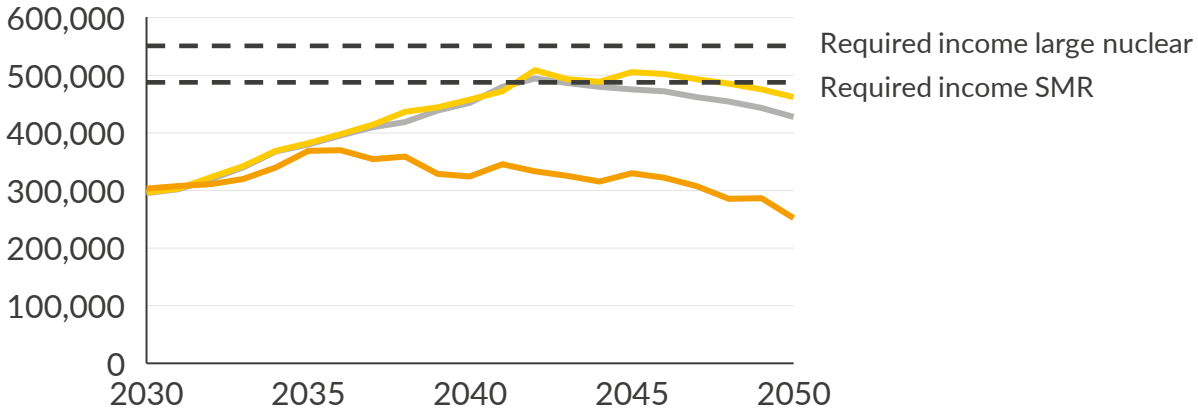
SENSITIVITY

Interim sensitivity – see note on previous slide for more information

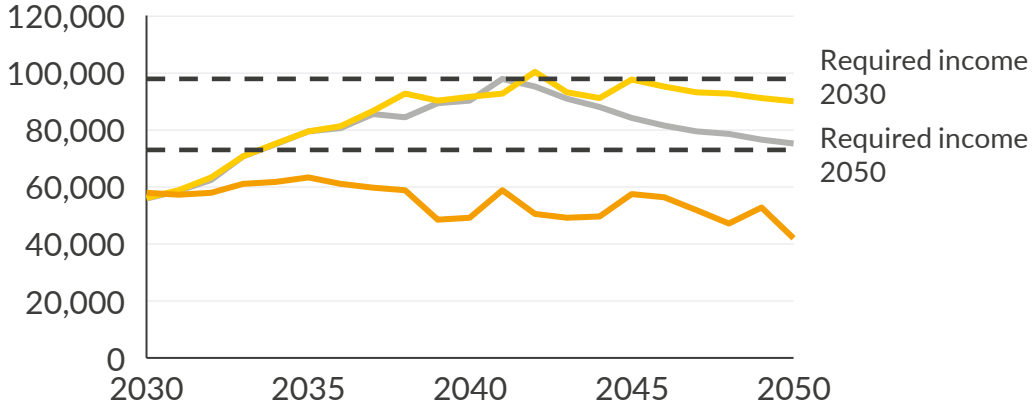
Baseload prices – Tech mix 2
€/MWh (real 2020)



Nuclear margins[1] – tech mix 2
€/MW/year (real 2020)



Li-ion margins[1] – tech mix 2
€/MW/year (real 2020)



Full security of supply — Optimal profitability — High Nuclear Sensitivity

1) The margin reflects the net result from of revenue minus variable cost on the wholesale market.

Source: Aurora Energy Research

Details and disclaimer

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