Long Duration Energy Storage in Spain

Public Report

July 2023

Commissioned by Breakthrough Energy

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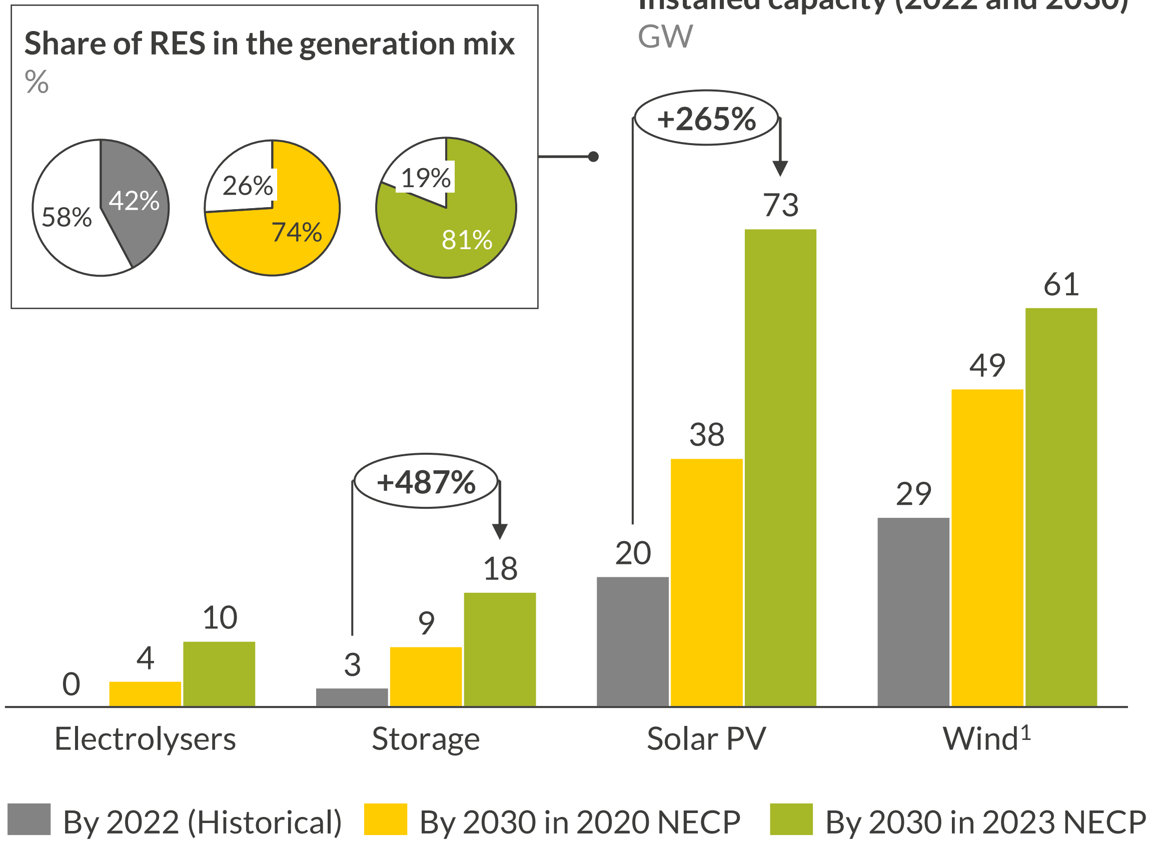
Enabling integration of renewables in the power system will be key to achieve higher electrification and decarbonisation goals set in the revised NECP

1

2023 National Energy Climate Plan (NECP) is significantly more ambitious in terms of renewable, storage and electrolyser deployment; renewables expected to represent 81% of the generation mix by 2030



Share of RES in the generation mix

%

Installed capacity (2022 and 2030)

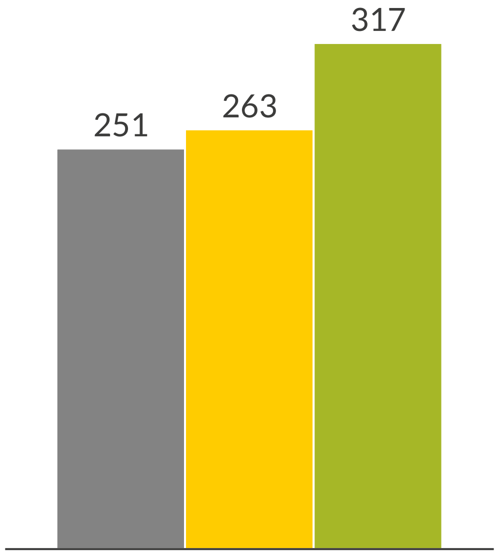
GW

2

The revised plan includes higher electrification and decarbonisation goals; technologies shifting renewable generation to when needed while ensuring security of supply and providing grid services will be vital

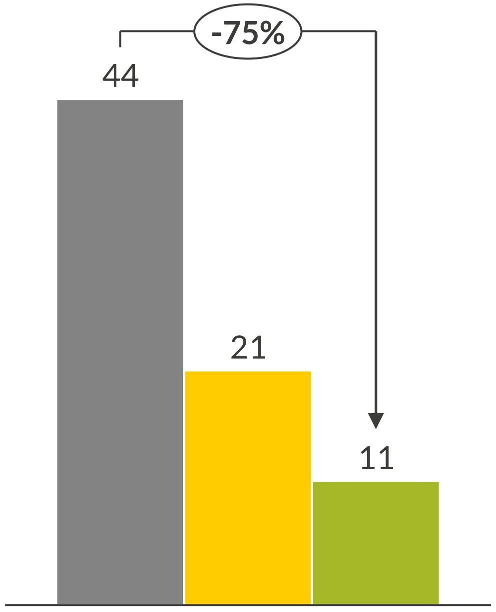
Electricity demand (2022 and 2030)

TWh



Power sector CO_2 emissions (2022 and 2030)

MtCO2e



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1) Onshore and offshore wind.

Sources: Red Eléctrica, 2020 NECP, 2023 NECP

LDES is a cost-efficient way to reduce reliance on gas while avoiding renewable curtailment, but there are still challenges for its deployment

AURORA

The 2023 NECP proposes a 173% increase (or 85 GW) in renewable capacity by 2030 from current capacities[1]; storage[2] is expected to increase by 487%, or 15 GW from installed capacity. Long Duration Energy Storage (LDES) can ensure renewable energy is utilised in the system while decreasing reliance on CO_2 emitting technologies

Key results of modelling the use of Long Duration Energy Storage (LDES) in the Spanish power system

1	**Lower power system costs**	A power system with 15 GW of Long Duration Energy Storage (LDES) by 2050 accumulates a total system **cost advantage of around 1 Bn €** (2025-2060) compared to a scenario without LDES
2	**Higher utilisation of renewable energy**	LDES absorb renewable electricity by charging in hours in which renewables (RES) production exceeds demand; **economic curtailment is eliminated by 2035**
3	**Lower natural gas use**	LDES replaces thermal generation and ensures security of supply; Net Zero in the power sector is **achieved 5 years earlier**
4	**Decarbonising industry**	By 2025, some thermal storage assets are already competitive with existing technologies like gas boilers, **avoiding CO_2 emissions in the industrial sector**
5	**Increasing profitability of LDES technologies**	The **need for storage in Spain is recognised by policymakers**, targeting 18 GW of storage[2] by 2030 and allocating subsidies under PERTE ERHA; however, the calls' design is not suitable for LDES
		LDES cannot rely on near-term price signals for investment; **contracted revenue confidence** and **addressing missing markets for system and grid services'** not procured individually are necessary

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1) Solar PV and onshore and offshore wind combined. 2) Draft 2023 NECP "daily, weekly, seasonal" storage. Peninsular target. Does not include solar thermal. National target including solar thermal sums up to 22 GW.

Overview of the study

Overview of the study

1. Aurora modelled a **Baseline scenario** aligned with ambitious EU policies for upcoming NECP targets by 2030 and a long-term view for a Net Zero power system by 2050
2. Aurora modelled a **Long Duration Energy Storage (LDES) scenario** built on top of the Baseline scenario, including thermal storage deployment in industrial process heat and electricity storage in the power system
3. Aurora evaluated the **asset economics for thermal and electrical storage** under the LDES scenario and outlined policy, regulatory and private sector intervention to ensure LDES successful deployment

- Aurora sought for feedback from the Advisory Group, LDES Innovators, and Peer-reviewers through workshops during the development of the study, from **March to July 2023.** Our findings and policy conclusions are based on our own independent analysis and do not necessarily reflect the views of the participating stakeholders
- Key workstreams and sections of the report covering them can be found in **slide 6.** This study does **not** include combined heat and power, co-located[1] storage, nodal network modelling and locational analysis, and Innovators data[2]

Participants

Advisory Group

- Breakthrough Energy
- MITECO
- IDAE
- Red Eléctrica
- MINCOTUR
- CNMC

LDES Innovators

- LDES Council
- Silbat
- Malta
- Elestor
- Rondo
- Antora
- Form Energy
- Quidnet
- Kraftblock
- Energy Dome
- Highview Power
- Build to Zero
- Kyoto Group
- Future Clean Architects
- EASE
- Energy Storage Coalition
- Cell Cube
- RedoxBlox
- Sumitomo
- ENERGYNEST
- ASEALEN

Peer-reviewers

- Iberdrola
- Enel
- Acciona
- EDF
- EDP
- Orsted
- Comillas IIT

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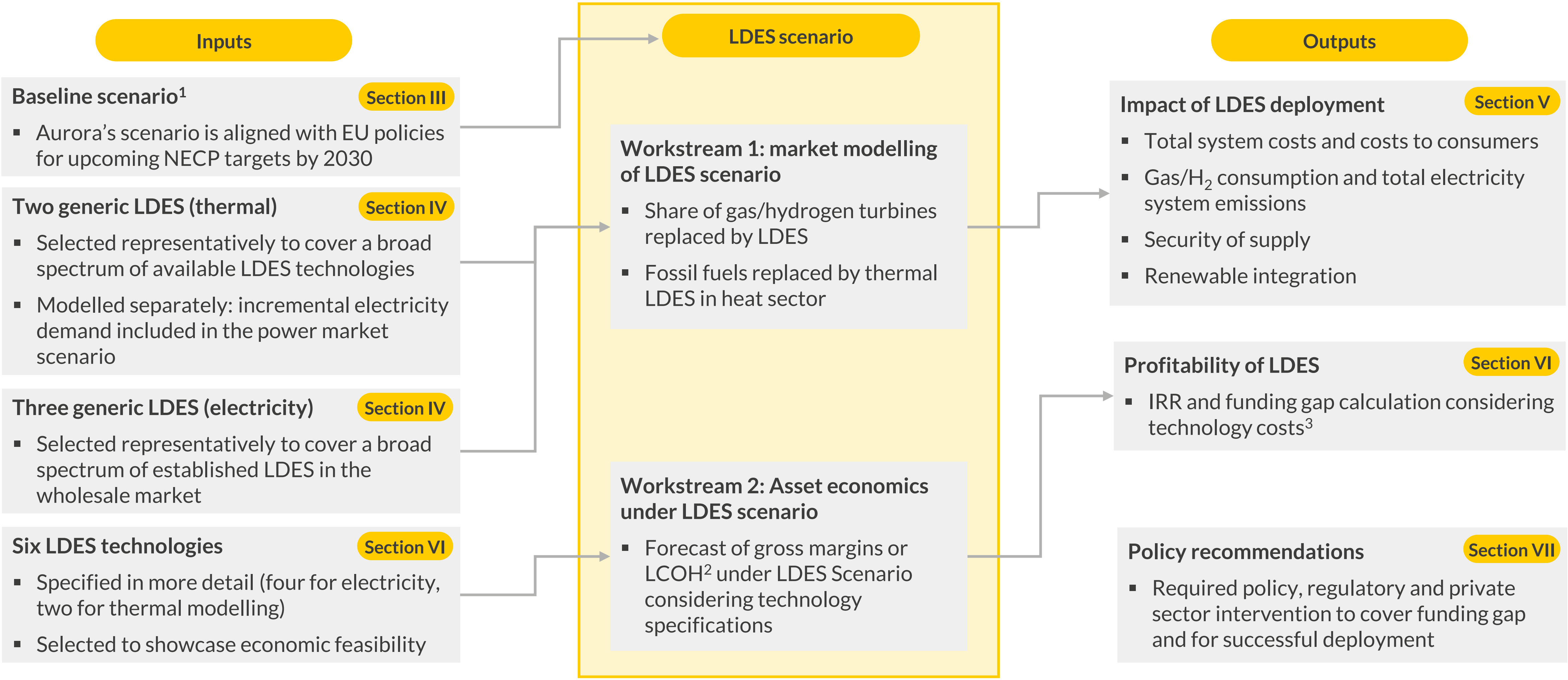
1) For power-to-heat storage we include a deep dive on RES PPAs (solar and co-located solar and wind). 2) To maintain data confidentially, Innovator's data has been withheld from this report. This includes data points referring to optimal operation, specifications and investment costs. We include representative data based on literature and Innovators' feedback.

The study quantifies the economic benefits and business opportunities of deploying LDES in the Spanish power system



Inputs

Baseline scenario[1] **Section III**

- Aurora's scenario is aligned with EU policies for upcoming NECP targets by 2030

Two generic LDES (thermal) **Section IV**

- Selected representatively to cover a broad spectrum of available LDES technologies
- Modelled separately: incremental electricity demand included in the power market scenario

Three generic LDES (electricity) **Section IV**

- Selected representatively to cover a broad spectrum of established LDES in the wholesale market

Six LDES technologies **Section VI**

- Specified in more detail (four for electricity, two for thermal modelling)
- Selected to showcase economic feasibility

LDES scenario

Workstream 1: market modelling of LDES scenario

- Share of gas/hydrogen turbines replaced by LDES
- Fossil fuels replaced by thermal LDES in heat sector

Workstream 2: Asset economics under LDES scenario

- Forecast of gross margins or LCOH[2] under LDES Scenario considering technology specifications

Outputs

Impact of LDES deployment **Section V**

- Total system costs and costs to consumers
- Gas/H_2 consumption and total electricity system emissions
- Security of supply
- Renewable integration

Profitability of LDES **Section VI**

- IRR and funding gap calculation considering technology costs[3]

Policy recommendations **Section VII**

- Required policy, regulatory and private sector intervention to cover funding gap and for successful deployment

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1) Modelling of the scenarios took place from March to May 2023, before the release of the NECP (June 29). We have included qualitative commentary on the impact of the differences between the updated NECP and Aurora Baseline scenario. 2) For thermal storage technologies, our analysis will focus on a comparison of Levelised Cost of Heat against competing technologies. 3) Data points shown in this document are representative, preserving data confidentiality from Innovators.

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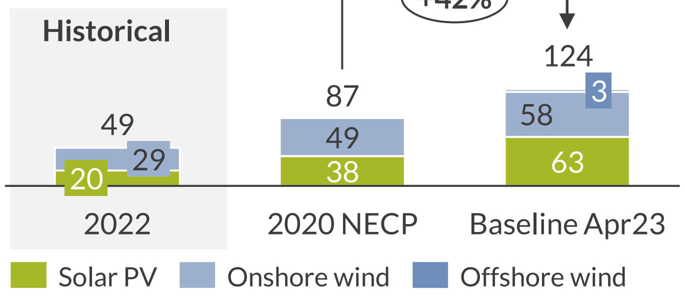
Executive Summary

- In this study, Aurora modelled two scenarios: a Baseline and a Long Duration Energy Storage (LDES) scenario
- The Baseline scenario is aligned with ambitious EU policies for upcoming NECP targets by 2030[1] and a long-term view for a Net Zero power system by 2050
- The LDES Scenario is built on the Baseline scenario but includes LDES deployment:
  - i. Thermal storage in industrial process heat, replacing fossil fuels
  - ii. Electricity storage in the power system, replacing gas and hydrogen plants
- This study shows that LDES is an effective and cost-efficient way to lower the amount of gas required for the power and industry sectors while avoiding renewables curtailment and increasing their profitability

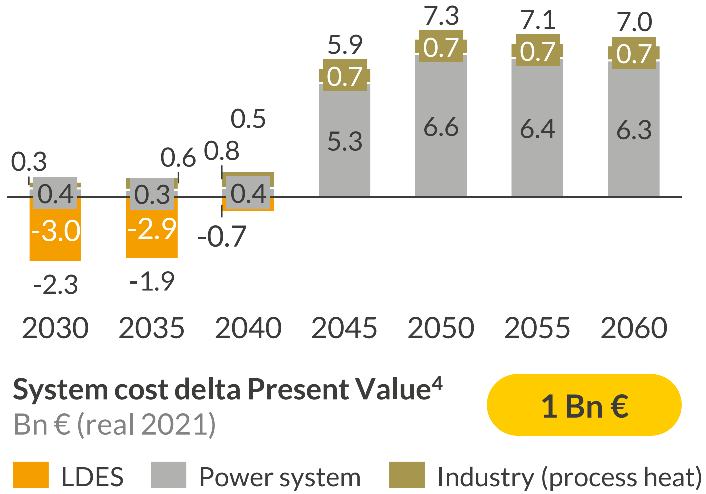
Baseline scenario


Installed capacity target by 2030

GW

- **Ambitious renewable targets:** In the Baseline scenario, renewable capacity target by 2030 is ~40% higher than 2020 NECP target[1], driven by ambitious EU policies. Such deployment leads to a share of renewables in the generation mix of 88% by 2030, surpassing the 2020 NECP target of 74%
- **Significant economic curtailment:** Economic curtailment rises significantly with up to 18 TWh of solar, onshore and offshore wind generation curtailed in 2029
- **Renewables do not recover costs:** Capture prices show large discount to baseload, resulting in buildout unable to recover their costs. Solar is the most impacted with capture prices ~45% below LCOE[2]

LDES scenario


System cost delta compared with Baseline[3]

Bn € (real 2021)

System cost delta Present Value[4]

Bn € (real 2021)

1 Bn €

- **LDES replaces fossil fuels in industry and power system:** By 2050, in the LDES scenario, 15 GW of storage are deployed in the power system and 40% of process heat in industry is met by thermal storage
- **Net Zero is achieved 5 years earlier:** 44 TWh of natural gas are saved between 2027 and 2050, with storage replacing gas generation and ensuring security of supply; the Net Zero in the power sector is achieved by 2045 (5 years earlier than in the Baseline scenario)
- **Integrating renewable generation:** LDES absorbs renewable electricity by charging in hours in which renewable production exceeds demand. Between 2023 and 2060, LDES avoids economic curtailment of 232 TWh of renewables
- **Deployment of LDES leads to 1 Bn € of savings:** Alongside with these benefits, LDES would lower total system costs by 1 billion € in net present value until 2060, compared with the Baseline scenario

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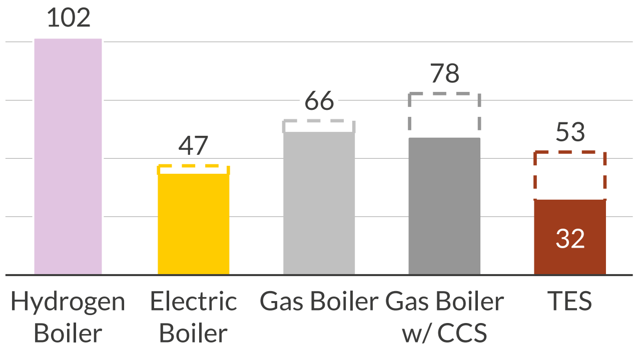
1) Modelling of the scenarios took place from March to May 2023, before the release of the draft NECP (June 29). We have included qualitative commentary on the impact of the differences between the updated 2023 NECP and Aurora Baseline scenario. 2) For a merchant asset, discounted at 10.5%. 3) Savings in positive numbers, costs in negative numbers. Not discounted. 4) 5% discount rate for system-wide assessment.

Executive Summary

- Under the LDES scenario, Aurora selected power-to-heat and power-to-power LDES to showcase the economic feasibility and analyse specific business cases to understand the funding gap
- High upfront costs of emerging technologies, combined with a lack of revenue certainty and missing market signals, would lead to underinvestment. To bridge the gap and incentivise LDES, policy support through direct mechanisms and/or other market reforms recognising the value and the need for LDES is required
- Recommendations are outlined in the final section of the study. Lack of investment in low-carbon technologies would result in higher power sector costs and higher emissions in power and industry

Power-to-heat

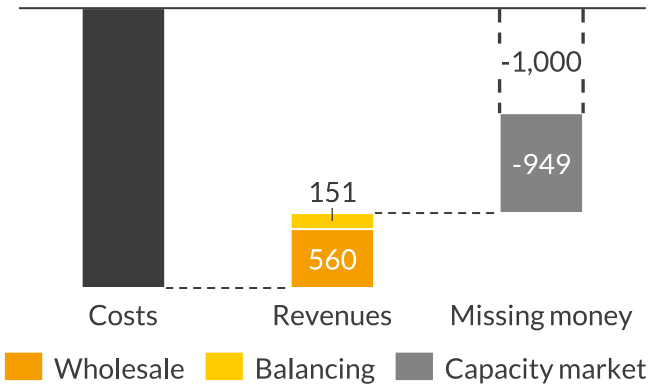
Levelised cost of heat (LCOH) for COD 2025[1]
€/MWh (real 2021)



- **Thermal storage can be competitive by 2025:** By 2025, there are thermal energy storage (TES) assets already competitive with existing technologies by only charging in the hours of lowest price each day (reducing variable costs), resulting in LCOH of ~32 €/MWh
- **High capital costs:** Despite TES effectively benefiting from market volatility, investment costs[2] are still higher than that of an electric boiler; thus, some TES configurations require a subsidy to compete
- **Current retail charges framework worsens the business case:** co-location of TES was assessed as a route to minimise variable costs and retail charges. In a scenario with capture prices below LCOE, benefits of signing PPAs by 2025 are only seen if TES pay retail charges (current design penalises consumption in the middle of the day)

Power-to-power

12h storage deep dive[3]: present value of cashflows for COD 2025, €/kW (real 2021)



- **LDES cannot rely on near-term price signals:** By 2025, considering existing revenue streams in Spain (wholesale and balancing markets) under the LDES scenario, there is a funding gap dependent on the configuration[4]
- **Contracted long-term revenue can help bridge the gap:** To achieve a 7% IRR, all assets would require a subsidy ensuring between 73% and 88% of its investment costs[2] . Other revenue streams like the proposed Spanish capacity market would not be enough to bridge the missing money gap
- **Address missing markets:** Since LDES is suitable to fulfil the system's requirements, missing money could be recovered via the provision of auxiliary services; however, these services are not procured individually
- **Cost declines expected to improve business case:** Costs are anticipated to fall significantly over time, improving the business case by 2030; however, cost decline rates will depend on level of deployment and learning rate

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1) Range of configurations tested (min in full, max in dashed). 2) Investment costs include capital and operational expenditure. 3) Business case and results shown here for a 12h asset with certain technical parameters and costs. Results differ for each asset modelled. See slide 67 for results for 4 LDES assets with different parameters and costs. 4) Different technical parameters and costs.

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    - iii. Commodities
    - iv. Hydrogen
  - c. Results
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    - ii. Baseload price
    - iii. Capture prices
    - iv. Curtailment
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In the Baseline scenario, Aurora revised demand, renewables, storage and interconnections compared to the 2020 NECP, aligned with EU ambitious policies

Demand

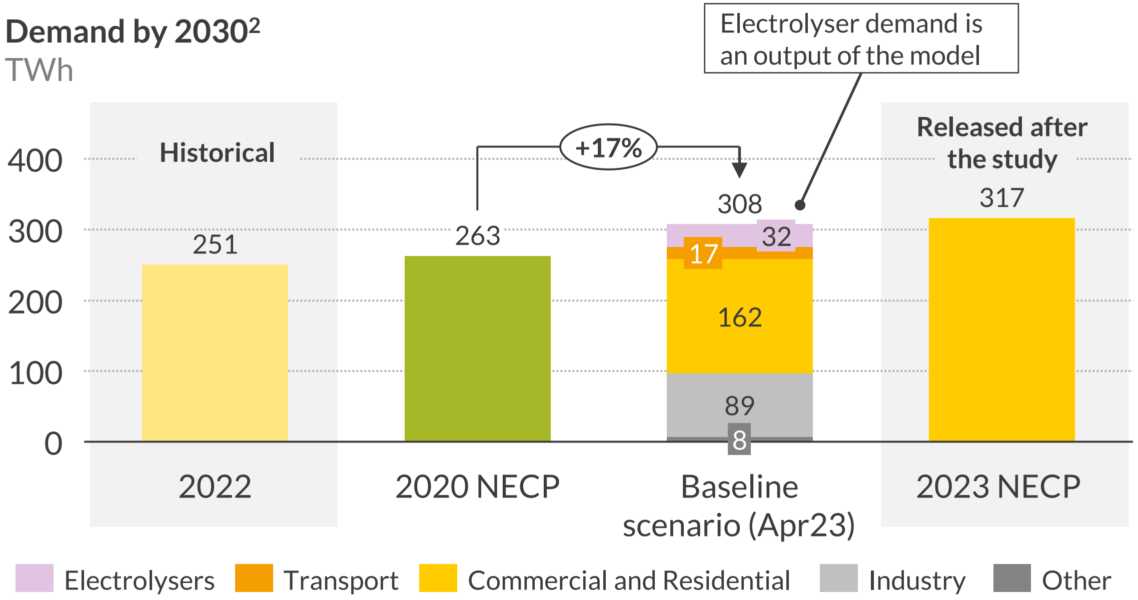
1. Aurora updated the Baseline demand to reflect REPowerEU heat pump uptake targets in space heating (R&C and industry) and in low temperature processes (industry). The new targets lead to an increasing electrification of these sectors, increasing demand by 5% compared to 2020 NECP
2. Aurora revised EV uptake given historical adoption in Spain. In the Baseline, EVs are consistent with 2020 NECP target of 5 million units by 2030[1]
3. Aurora included maritime electricity demand under Transport, following FF55 electrification targets for the sector

Power system

1. In the Baseline scenario, renewable capacity target by 2030 is ~40% higher than 2020 NECP target, driven by ambitious EU policies announced in 2022. This means that 72 GW of onshore wind and solar PV must come online in the next 7 years
2. Regarding storage, Aurora doubled the installed battery capacity in the Baseline scenario. For pumped-hydro, Aurora updated the target in line with projects in the pipeline expected to be operational by 2030
3. Aurora updated interconnector capacities with France and Portugal, according to the latest ENTSO-E TYNDP[3] 2022

Demand by 2030[2]

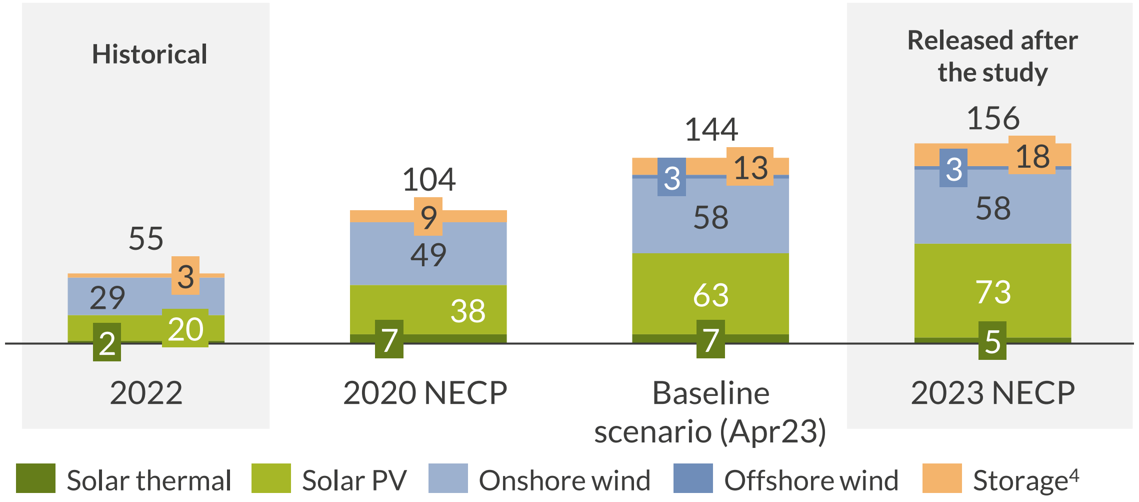
TWh



Electrolyser demand is an output of the model

Installed capacity by 2030

GW



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1) Updated to 5.5 million in the revised 2023 NECP. Modelling of the scenarios took place from March to May 2023, before the release of the NECP (June 29). We have included qualitative commentary on the impact of the differences between the updated NECP and Aurora Baseline scenario. 2) Does not include demand from electrolysers, which will be an output of the model. It will be added on top of the sectorial demand.3) Ten-Year Network Development Plan. 4) Storage for 2022 only pumped-hydro storage, for 2020 NECP and Baseline scenario is pumped-hydro and batteries. For 2023 NECP is "daily, weekly, seasonal" storage, including batteries, pumped-hydro as well as other types.

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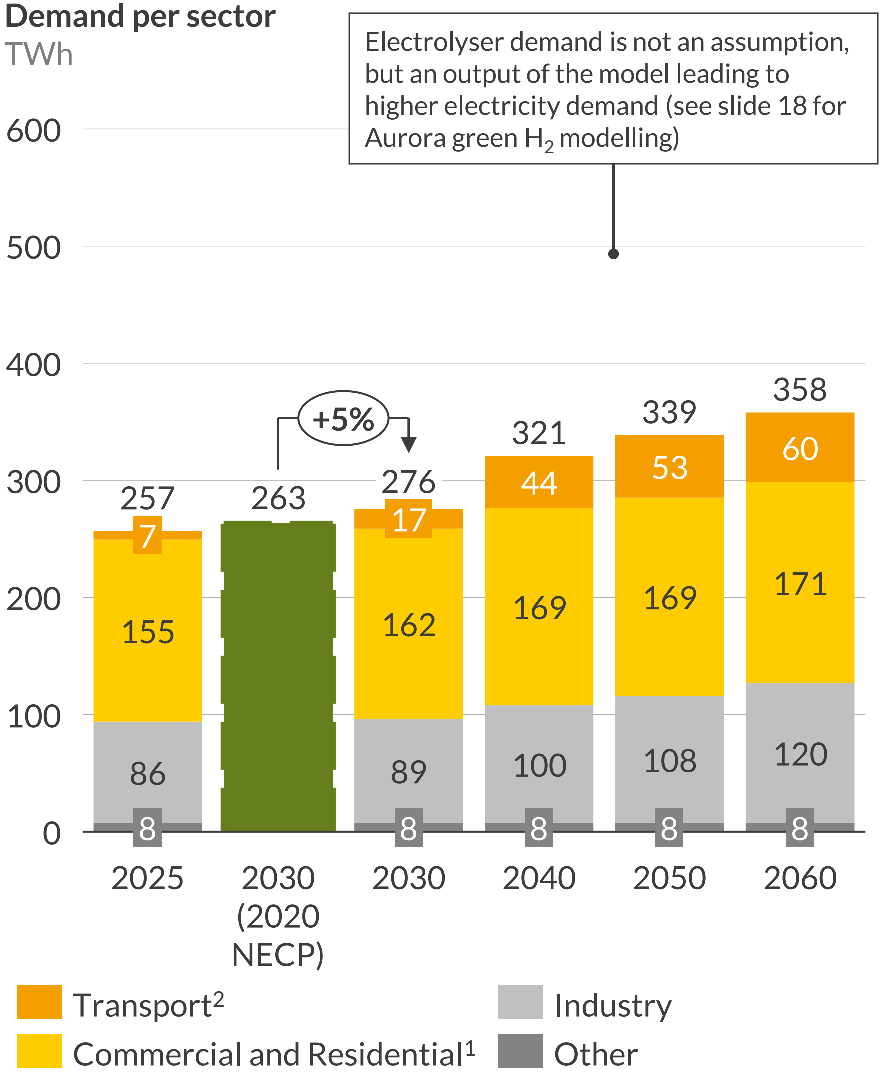
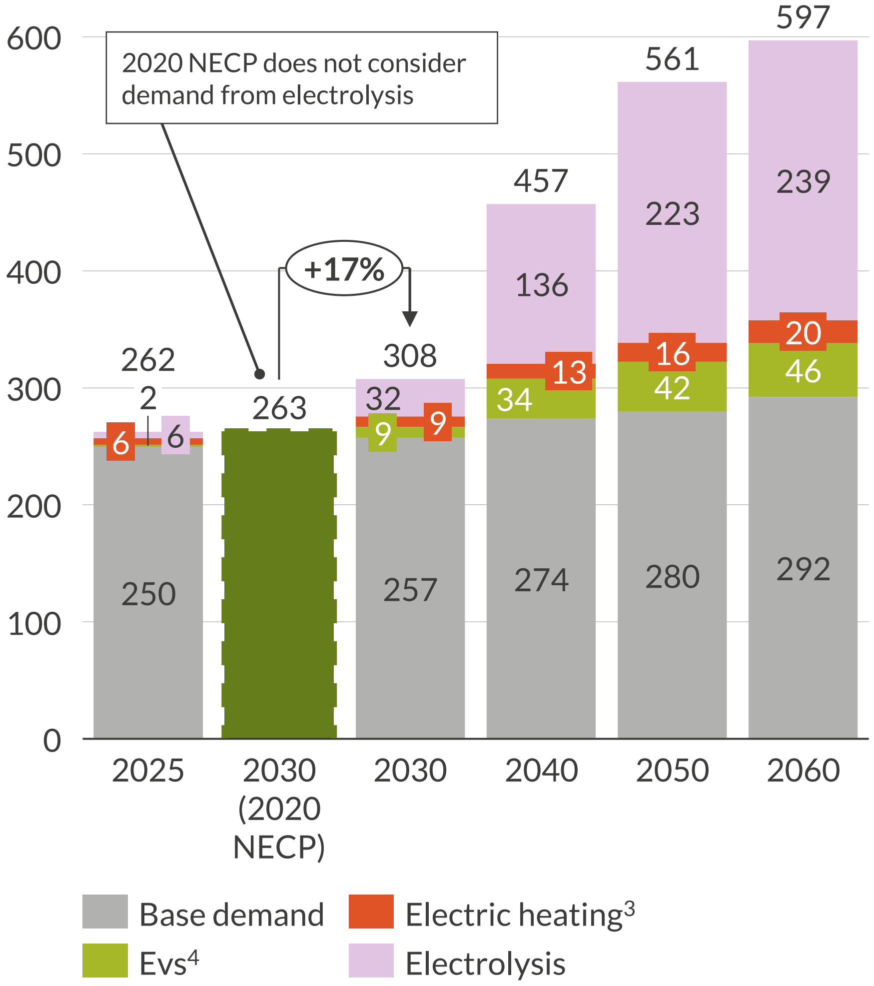
Ambitious REPowerEU and FitFor55 targets lead to an increasing electrification of the sectors compared with the 2020 NECP

Demand per sector
TWh



Electrolyser demand is not an assumption, but an output of the model leading to higher electricity demand (see slide 18 for Aurora green H_2 modelling)

Demand by technology (inc. electrolysis)
TWh



2020 NECP does not consider demand from electrolysis

Industry:

- Aurora has revised demand to include ambitious REPowerEU and FF55 targets regarding heat pumps uptake in space heating (in line with the EC's JRC[5]) and low temperature processes

Commercial and Residential:

- We assume a higher share of adoption for heat pumps use in space heating for this sector, inline with JRC[5]

Transport:

- EV projections are aligned with 2020 NECP targets until 2030 given historical adoption in Spain; after 2035, following the EU ban on ICEs[6], EV adoption accelerates. By 2060, 95% of the fleet is electrified
- Maritime demand includes OPS[7] facilities, ship plug-in and hybrid batteries' deployment following FF55 targets[8]

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1) Includes C&R heat pumps 2) Includes EVs, road, rail and maritime 3) Only C&R heat pumps included, industrial heat pumps are considered base demand 4) Includes passenger and heavy vehicles 5) Joint Research Centre "Heat pumps in the European Union 2022 – Status report" 6) Internal combustion engine 7) Onshore power supply 8) "Fit for 55 package: Fuel EU Maritime"

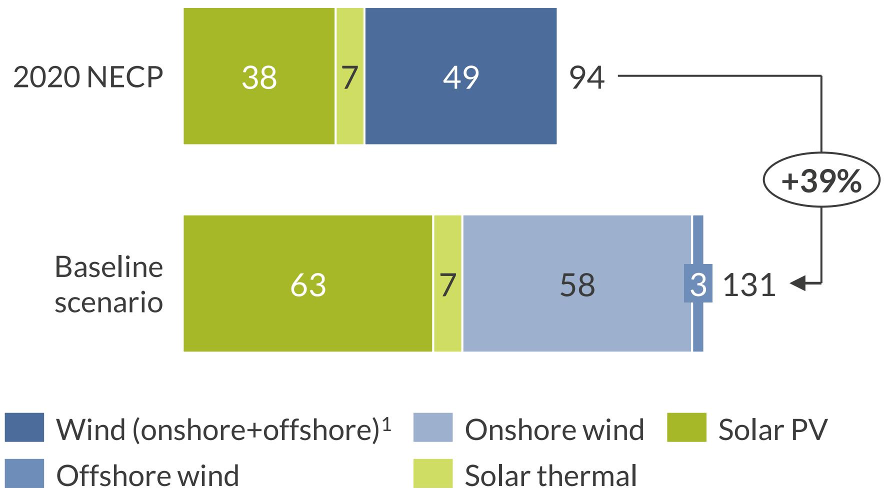
Sources: Aurora Energy Research, National Energy and Climate Plan, RepowerEU, Joint Research Centre – European Commission, IEA Net Zero

Aurora Baseline scenario is characterised by ambitious Government targets, adding 37 GW of new build RES to the 2020 NECP target

- In the Baseline, RES target by 2030 is 39% higher than 2020 NECP target, driven by ambitious EU policies announced in 2022
- Baseline scenario's solar target is 63 GW by 2030, compared to 38 GW in the 2020 NECP (+64% increase, or 25 GW)
- Overall, the updated wind target is 61 GW, compared to 49 GW in the 2020 NECP
    - For offshore, Aurora assumes 3 GW (in line with the Marine Roadmap)
    - For onshore, new target of 58 GW represents a +27% increase, or 12 GW

Spain solar and wind installed capacity by 2030

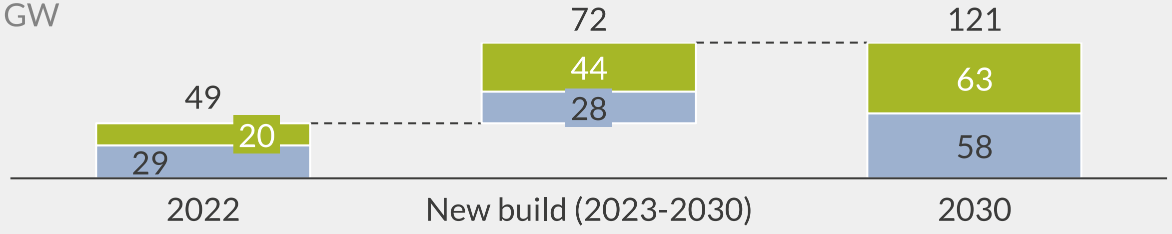
GW



Methodology to update 2030 Spanish target (*see Appendix*)

Spain solar and wind installed capacity

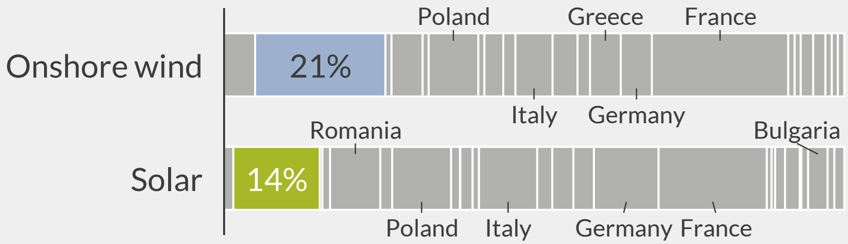
GW



- New build is based on "IEA main case", which foresees average annual additions at EU level of 39 GW and 17 GW for solar and onshore wind
- Assuming these annual additions, this sums up to 312 GW of new solar and 136 GW of new onshore wind across the EU. This assumption still falls short compared to REPowerEU target (**see Appendix for details**[2])
- According to the potential maps developed by the JRC[3], we allocate the EU level IEA main case additions based on Spain's contribution to the EU target. For solar capacity, Spain's share would be 14% while for wind it would be 21%

Spain share of RES additions at EU level (REPowerEU)

%



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1) 2020 NECP does not disclose target for offshore and onshore wind. 2) IEA main case assumes 2022-2027 additions, Aurora assumes that rate of additions 2022-2030. This would still be below REPowerEU target to achieve a total installed capacity 592 GW of solar PV and 510 GW of wind by 2030 at EU level. See Appendix for further details. 3) Joint Research Centre.

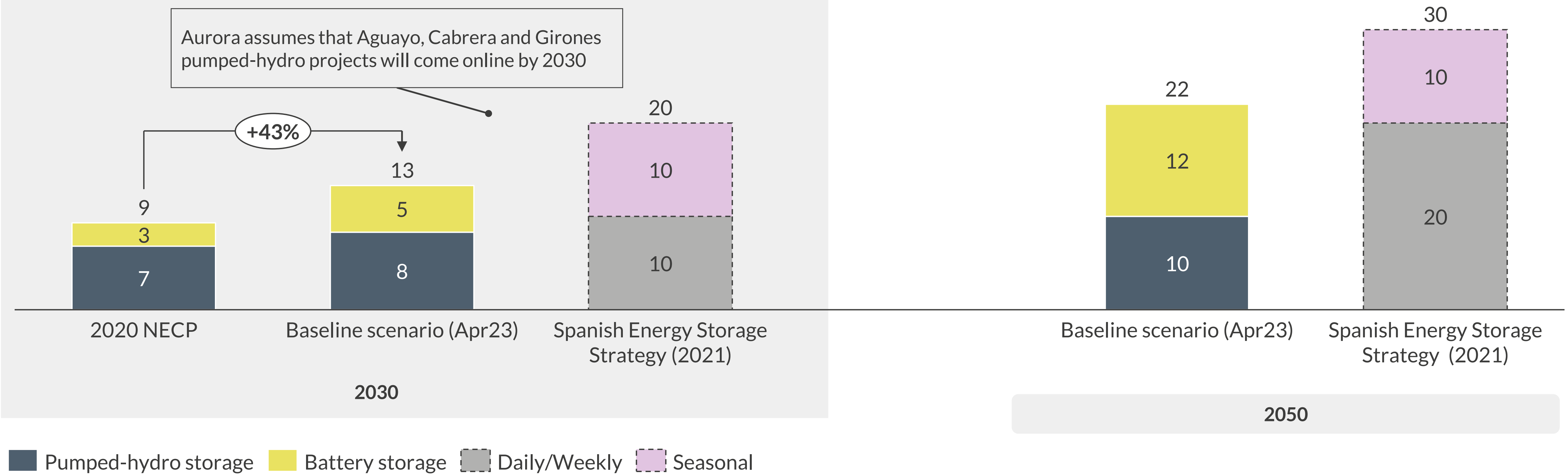
Sources: IEA "Renewables 2022" (main case), Energy and Industry Geography Lab (EU Joint Research Centre), REPowerEU Annexes, NECP 2021-2030

By 2030, battery and pumped-storage in the Baseline scenario sum to 13 GW; Aurora doubled the 2020 NECP target for batteries of 2.5 GW

- Regarding storage targets, Aurora doubled the battery installed capacity to 5 GW compared to 2020 NECP target of 2.5 GW of battery storage by 2030
- For pumped-hydro storage, Aurora also updated the target to 8 GW by 2030, in line with projects in the pipeline expected to be operational by 2030
- These assumptions are in line with the Spanish Energy Storage Strategy[1] and assume that these technologies will fulfil the daily-weekly target completely. Seasonal storage could be covered by other types of storage (e.g., different long-duration storage technologies and/or hydrogen)

Storage installed capacity

GW



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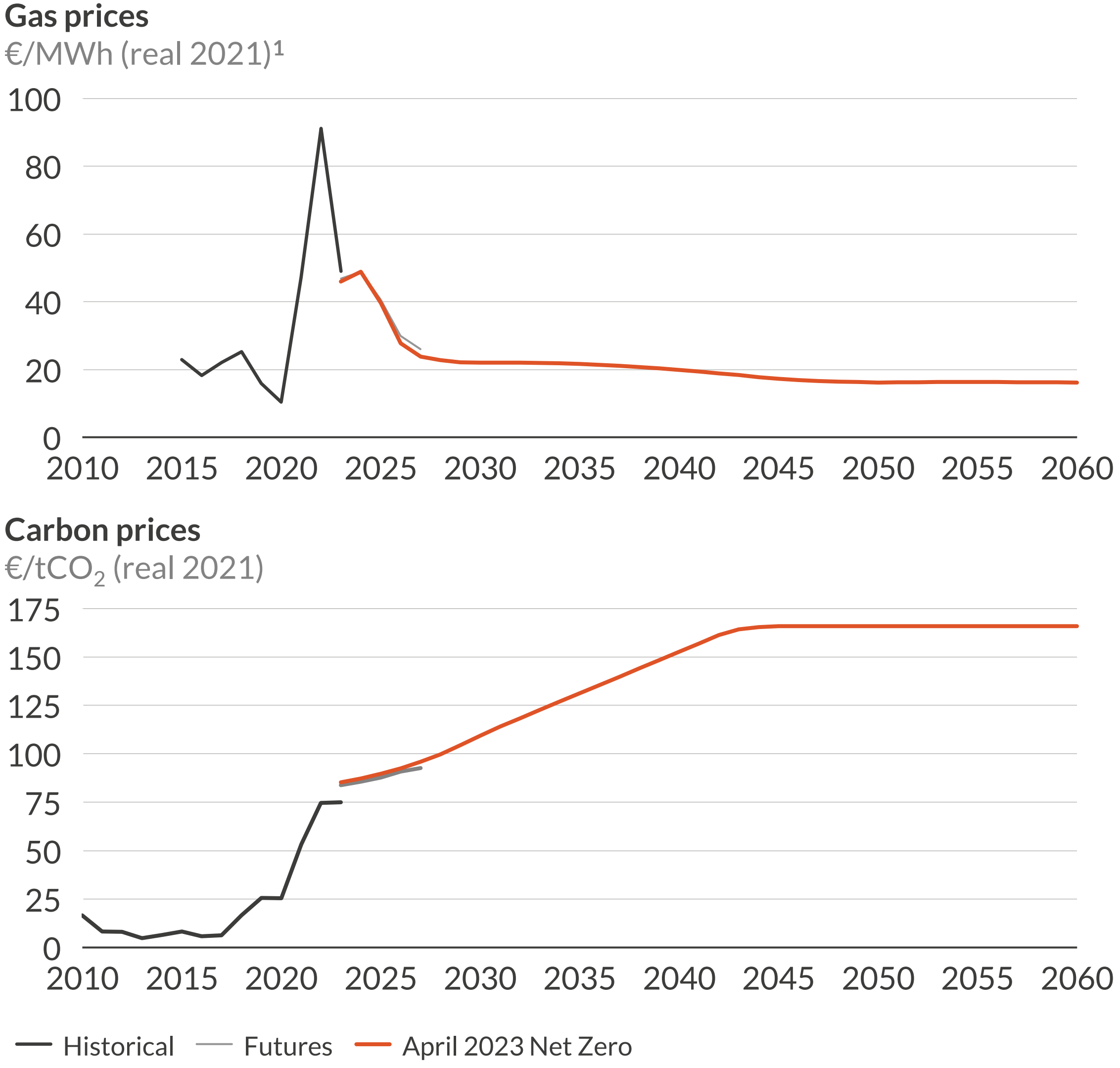
[1] Energy Storage Strategy targets of 20 GW and 30 GW distinguish between daily/weekly and seasonal storage and includes pumped-storage, batteries, behind-the-meter batteries, thermal storage, electric vehicles, hydrogen, etc. Even though all those technologies can be considering, there are no specific targets per technology and deployment will depend on its technological status.

Sources: Spanish Energy Storage Strategy. ENTEC "Study on Energy Storage". NECP 2021-2030

Commodity prices in the Baseline are based on Aurora Net Zero; in this scenario, global GHG emissions are limited to hit 2°C of global warming



The commodity prices used in the Baseline scenario are consistent with the commodity prices for the latest Aurora Net Zero, released in April 2023

- **Short term (2023 - 2024)**
  - Net zero **gas prices** average 47.4 €/MWh
  - The **carbon price** averages 86.3 €/tCO_2 in this period. This is in part the result of an aggressive European policy to keep the flow of investment in low-emissions technology across the continent
- **Medium term (2025 - 2027)**
  - While net zero **gas prices** average 30.4 €/MWh, the carbon price average in this period 92.7 €/MWh
- **Long term (2028 - 2060)**
  - Net Zero **gas prices** average 18.7 €/MWh in the period
  - The **carbon price** averages 150 €/tCO_2 in this period
  - Our Net Zero scenario assumes commodity prices consistent with a scenario where global GHG emissions are limited in order to hit a maximum of 2 degrees of global warming

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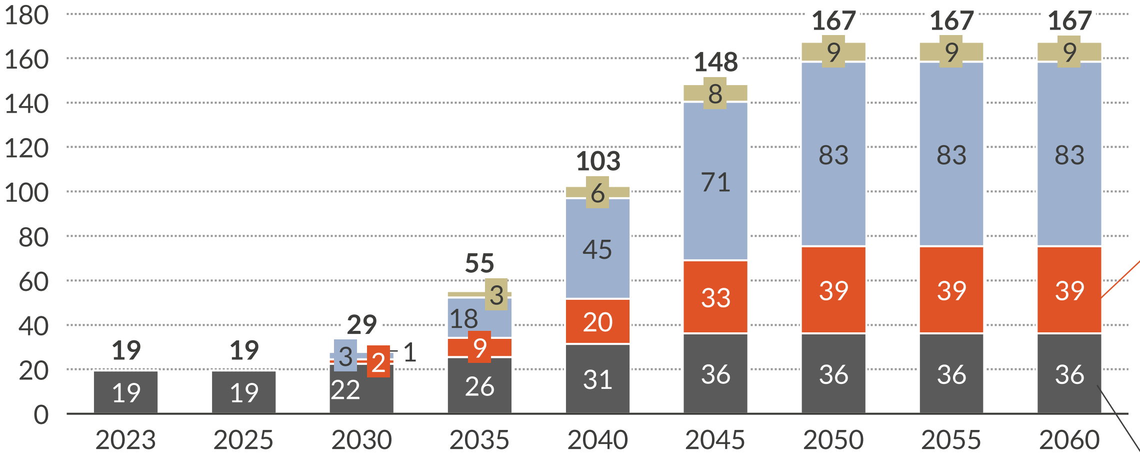
1) For years 2023-2028, the prices shown take into account current futures prices for the years in question, with declining weights. Forecast gas prices account for the price cap on gas for power introduced by Spain and Portugal until the end of 2023. 2) A rolling 14-day average as of 01/03/2023. 2) TTF day ahead gas EU reference prices.

Sources: Aurora Energy Research, EIKON

Hydrogen demand grows exponentially from 2030, due to decarbonisation of the transport sector and industrial process heating

Hydrogen demand by sector

TWh

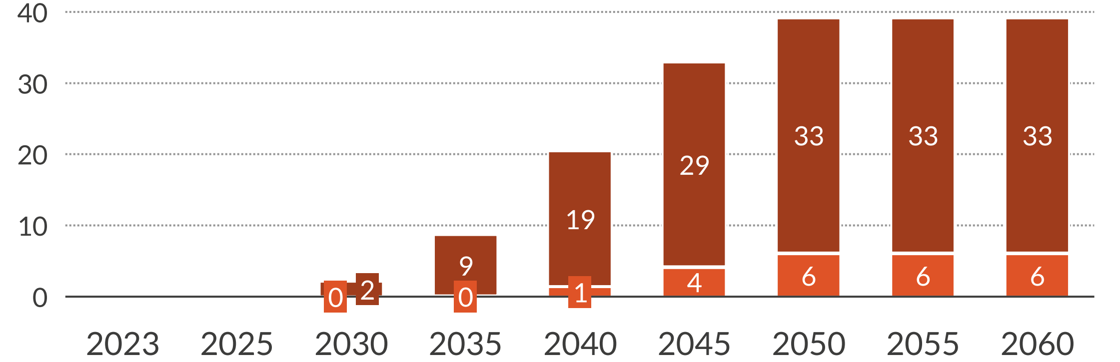


- We assume a deployment of electrolysers in line with Government goals, but we allow non-renewable hydrogen supply to compete with green hydrogen for production decisions[1]
- Until 2030, industrial feedstock is the sole source of hydrogen demand across all sectors
- Demand for hydrogen for industry process heating is also expected to grow, amounting to 39 TWh by 2050. In the LDES scenario, process heating demand in industry will also be covered by LDES technologies
- Demand from transport (aviation and maritime sectors) is the main growth driver of hydrogen demand as of 2030, reaching 83 TWh by 2050

🟫 Space heating 🟦 Transport 🟧 Industry - process heating ⬛ Industry - feedstock

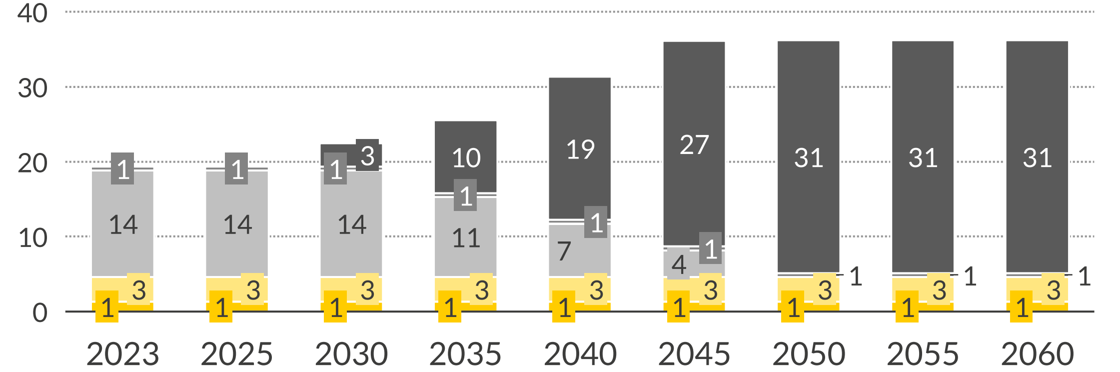
Process heat hydrogen demand by industrial sector

TWh



Feedstock hydrogen demand by industrial sector

TWh



⬛ Steel
⬛ Other chemicals
⬜ Methanol
⬜ Refinery
🟨 Ammonia
🟨 Other industries
🟥 High-grade process heat
🟧 Low-grade process heat
🟧 Medium-grade process heat

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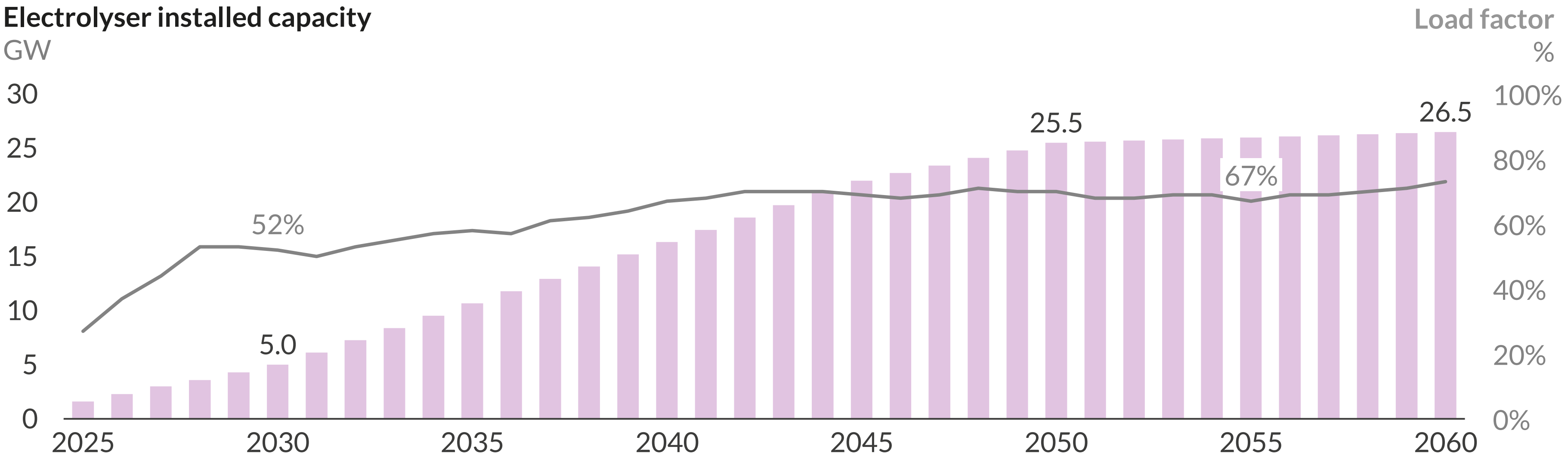
1) Assumes that the existing capacity for production of grey hydrogen will remain constant, but in the future it will be a combination of grey, blue and imported hydrogen. 2) Low temperature process heat defined as >100°C. 3) Medium temperature process heat defined as 100-500°C. 4) Space heating include heat for residential, commercial and industrial buildings

Sources: Aurora Energy Research

Aurora assumes 5 GW of electrolysers by 2030; on average, electrolysers show a 60% load factor in the Baseline scenario

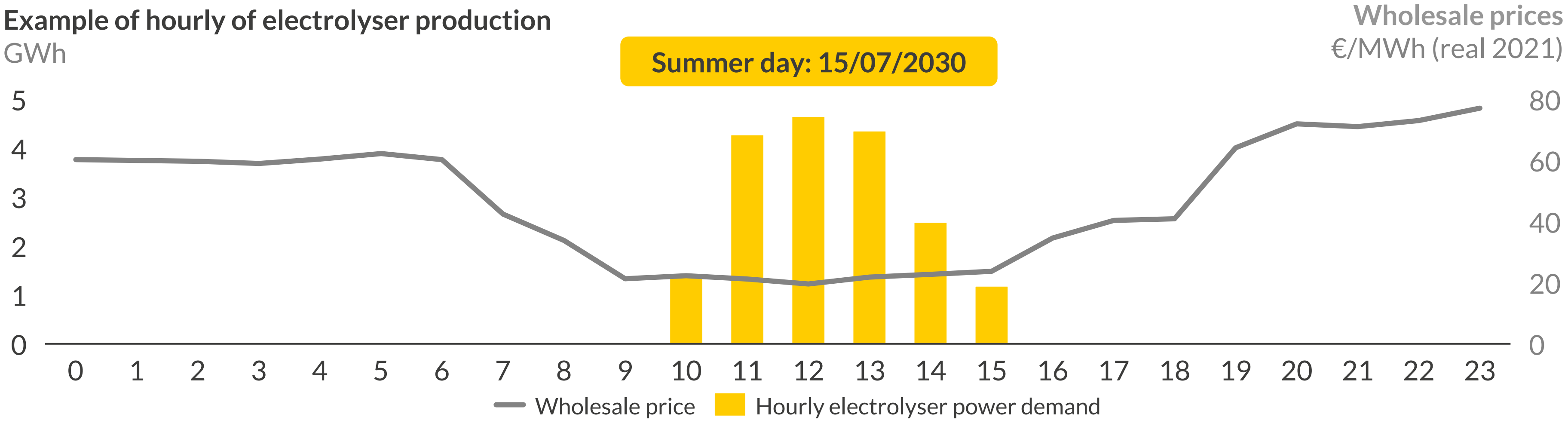
Electrolyser installed capacity

GW



Example of hourly of electrolyser production

GWh



Aurora methodology: hydrogen production from electrolysers

- We assume a deployment of electrolysers in line with Government goals by 2030, although their utilisation will depend on the economics of hydrogen production
- The introduction of electrolyser capacity[1] in the system serves as a load sink: electrolysers will consume electricity to produce hydrogen when power prices are low and expected hydrogen prices are high
- Electrolyser deployment (and consequently, green hydrogen production) prevents negative or zero priced hours, allowing further renewable deployment
- On average, electrolysers have load factors of ~60% between 2023 and 2060 in the Baseline scenario

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1) Same applies to other types of flexible demand, like smart charging electric vehicles.

Sources: Aurora Energy Research

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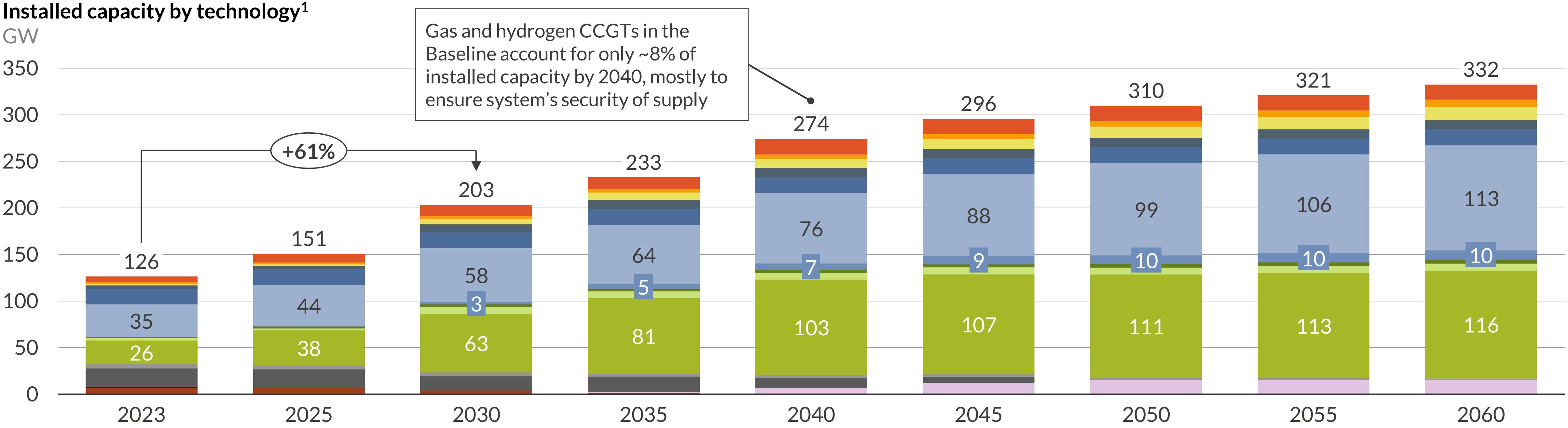
Renewables account for 74% of the installed capacity by 2030 in the Baseline scenario, with solar PV representing ~50% of new capacity

Installed capacity by technology[1]

GW



Gas and hydrogen CCGTs in the Baseline account for only ~8% of installed capacity by 2040, mostly to ensure system's security of supply

- In the Baseline scenario, Aurora followed the REPowerEU targets for renewable deployment and revised electricity demand. Electricity demand revision includes higher heat pump uptake in space heating (commercial, residential and industry) and in industrial low temperature processes, following REPowerEU announcements. Maritime electricity demand has also been included, following FitFor55 targets
- From 2023 to 2030, the total installed capacity increases by 78 GW, or 61%, in Spain. This increase is mostly driven by the growth in intermittent renewables with solar and wind installed capacity additions summing up to 63 GW
- From 2023 to 2060, the total installed capacity increases by 207 GW, or 165%, with solar and onshore and offshore wind additions accounting for 178 GW of new installed capacity

🟥 Interconnectors
🟧 DSR
🟨 Battery storage
🟫 Peaking
⬛ Pumped storage
🟦 Hydro
🟦 Onshore wind
🟦 Floating Offshore wind
🟩 Other RES[2]
🟩 Solar CSP
🟩 Solar PV[3]
⬜ Other thermal[4]
⬛ Gas CCGT
🟪 Hydrogen CCGT
🟫 Coal
🟥 Nuclear

---

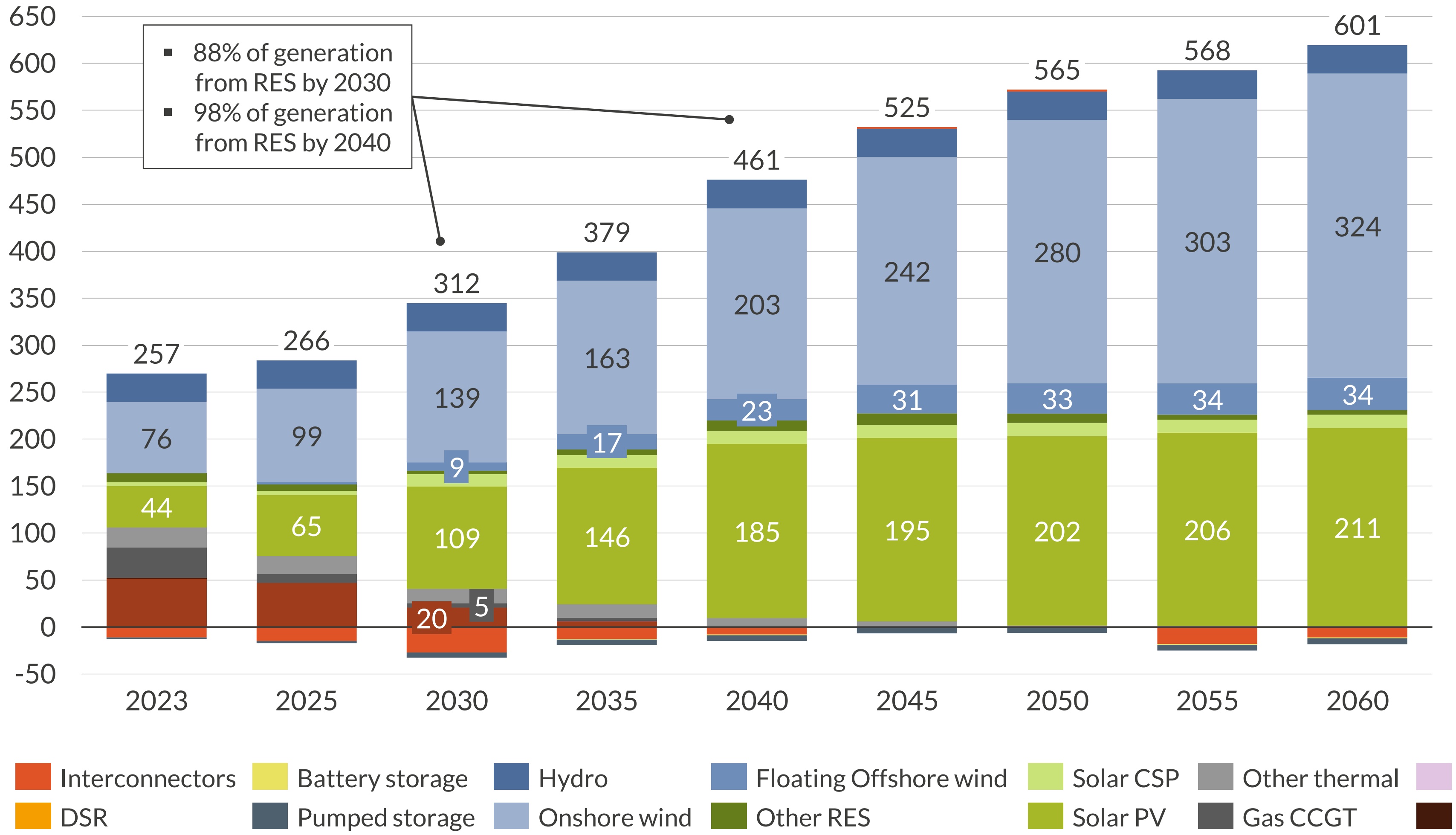
1) At a system level, we only consider stand-alone assets. 2) Other RES includes biomass, renewable cogeneration, run-of-river, and hydro reservoir. 3) Includes solar rooftop PV, solar ground-mounted PV. 4) Other thermal includes fossil fueled cogeneration.

Sources: Aurora Energy Research

In the Baseline scenario, the share of renewables in the generation mix is 88%, surpassing the 2020 NECP target of 74%

Generation by technology[1]

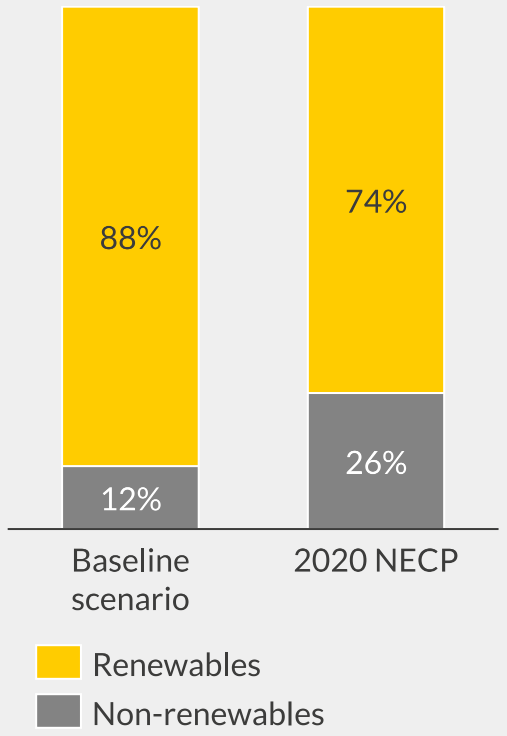
TWh



- 88% of generation from RES by 2030
- 98% of generation from RES by 2040

Deep dive: share of RES

Share of RES in the generation mix by 2030, %



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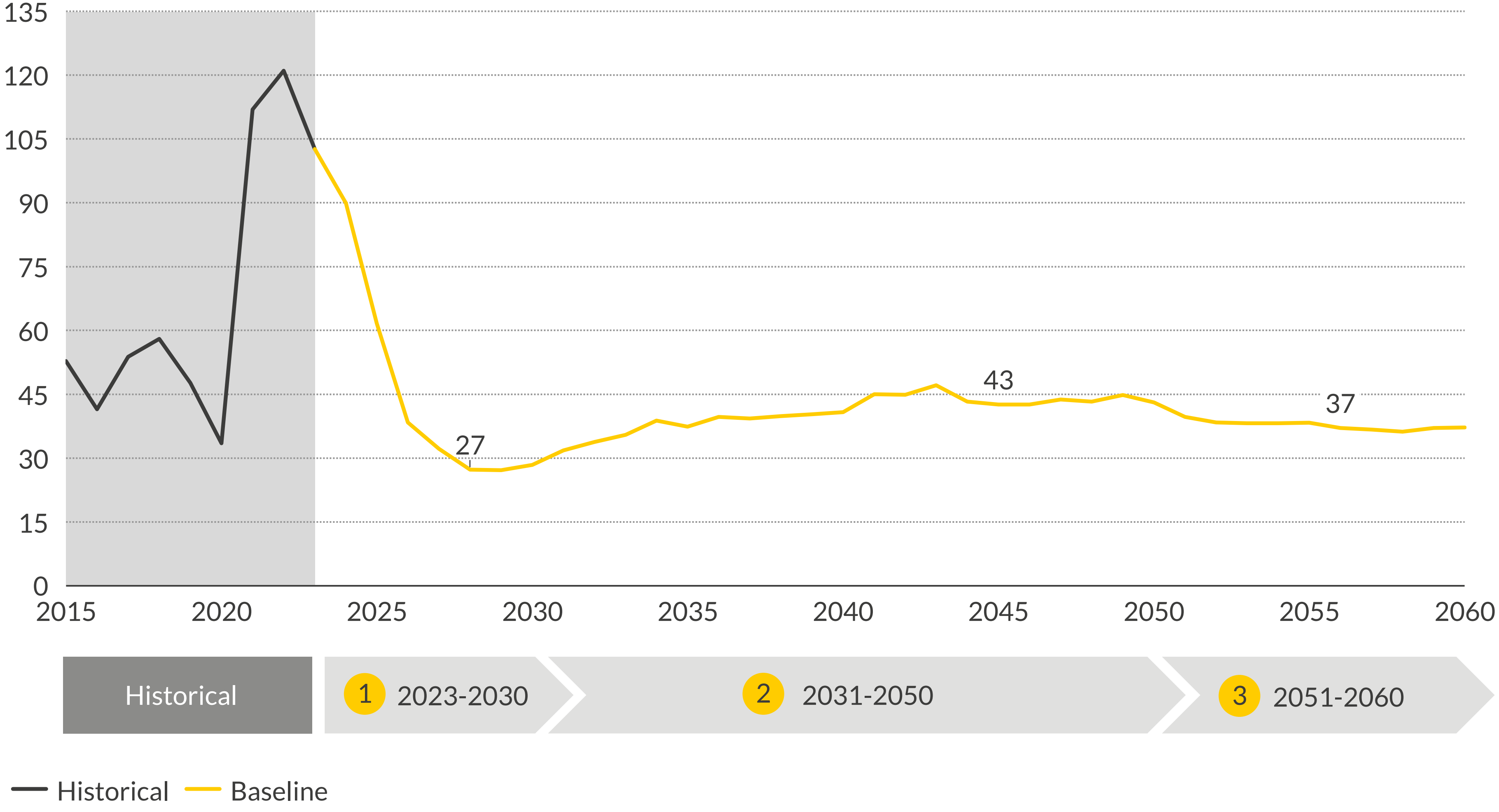
1) At a system level, we only consider stand-alone assets.

Sources: Aurora Energy Research

Baseline scenario sees a dip in prices by 2030 due to accelerated renewable buildout

Baseload wholesale electricity price[1]

€/MWh (real 2021)



Outlook for baseload prices

1. As commodity prices decline from their current high and renewables buildout accelerates driven by REPowerEU targets, power prices fall significantly, reaching a minimum of 27 €/MWh by 2029
2. In the 2030s, deployment of storage, electrolyser capacity and flexible demand starts picking up, reducing the frequency of zero price hours and enabling the integration of renewable capacity. This leads to an increase in baseload prices averaging at ~40 €/MWh between 2030 and 2050
3. In the last years of the forecast, baseload prices decrease slightly due to declining hydrogen prices

---

1) Prices are inclusive of the generation tax from 2024 onwards (inclusive), which we assume to continue throughout the forecast horizon.

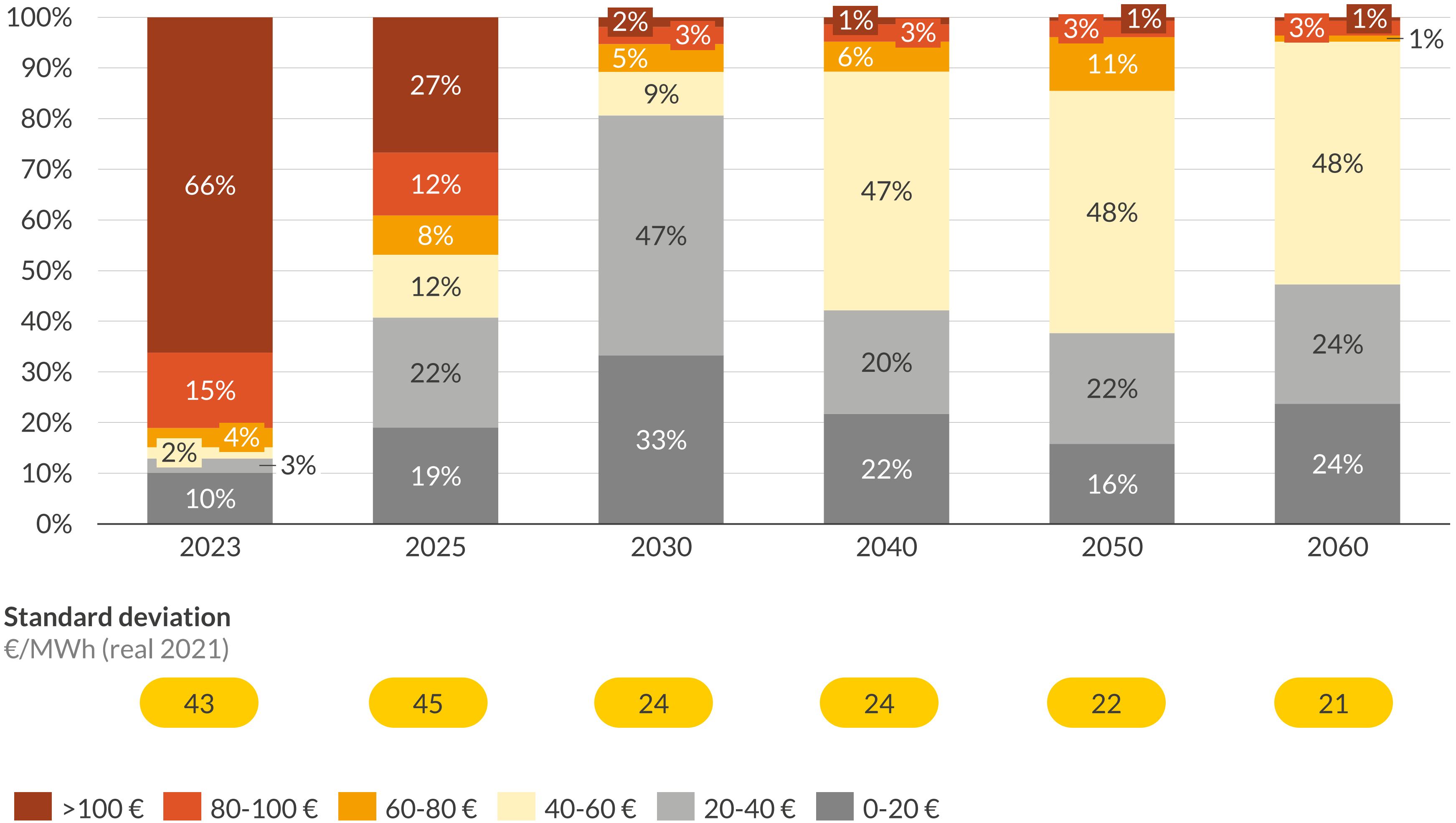
Sources: Aurora Energy Research

Growing renewable penetration increases frequency of low prices; high prices decrease over time driven by dropping commodity prices

AURORA

Frequency distribution of the electricity price

%

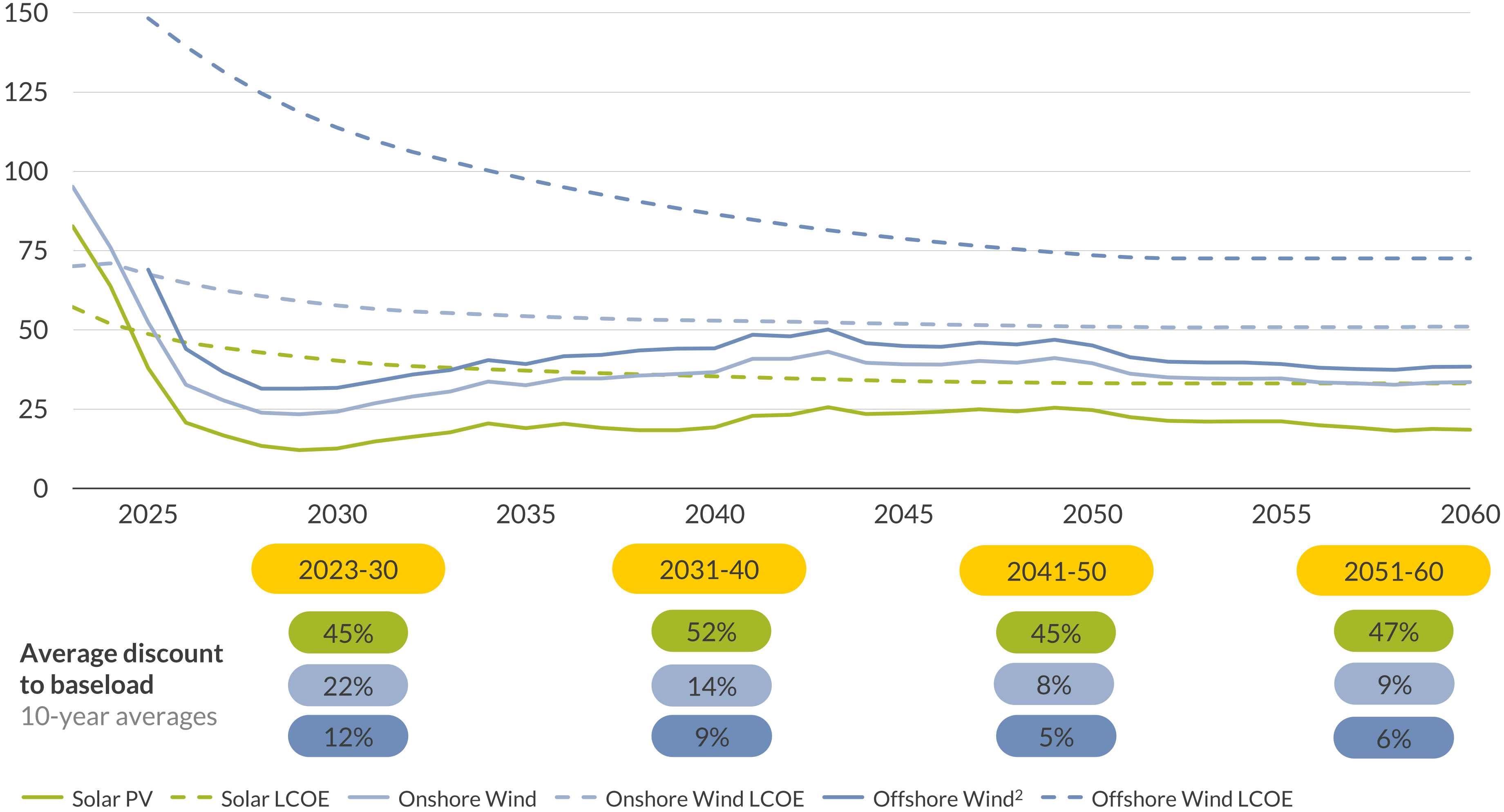


- In 2025, power prices are still high due to the current spike in commodity prices. This is expected to slowly decline over the next years
- The frequency of low prices (<20 €) increases by 23 p.p. between 2023 and 2030 as RES set prices more frequently. In this period, RES is deployed at faster rates than storage and flexible demand
- The frequency of high prices (>80 €) decreases after the late 2020s driven by dropping commodity prices, reducing marginal costs for CCGTs
- In late 2030s, increasing hydrogen and flexible demand reduce frequency of low prices
- Price volatility remains constant after the 2030s as evidenced by the standard deviation (around ~20 €/MWh throughout)

Source: Aurora Energy Research

Capture prices for solar, onshore wind and floating offshore wind in the Baseline scenario are well below LCOE

Uncurtailed capture price and LCOE[1]
€/MWh (real 2021)



Average discount to baseload
10-year averages

	2023-30	2031-40	2041-50	2051-60
Solar PV	45%	52%	45%	47%
Onshore Wind	22%	14%	8%	9%
Offshore Wind	12%	9%	5%	6%

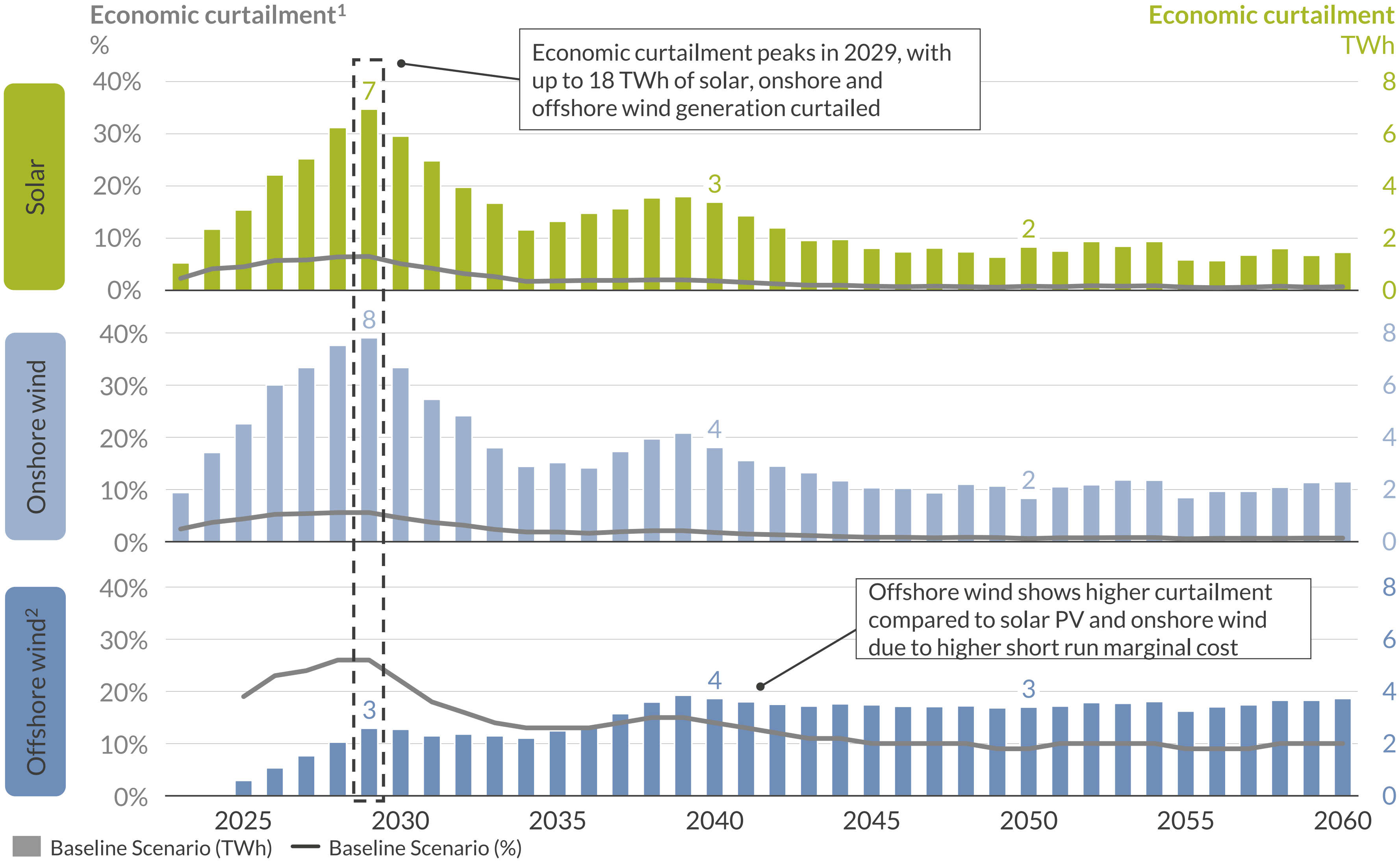
- RES deployment to achieve REPowerEU targets leads to capture prices with significant discount to baseload
- Solar is the most impacted technology due correlation in solar PV production across the peninsula, showing an average discount to baseload of 48% between 2023 and 2060
- Flexible demand (e.g., heat pumps and electrolysers) and storage entering the system partly mitigate cannibalisation
- However, solar capture prices are on average 45% below LCOE between 2026-2060, resulting in solar PV buildout unable to recover their costs
- In order to achieve renewable targets, additional flexible capacity (e.g., in the form of storage or flexible demand) or government support would be required

---

1) Uncurtailed capture prices. See slide 25 for curtailment details. LCOE estimates from April 2023, assuming 10.5% WACC. Considering 30-year lifetime for solar and floating offshore and 27-year for onshore wind.2) Offshore wind refers exclusively to floating offshore wind.

Sources: Aurora Energy Research

Increasing capacity of renewable fleet results in a rise of curtailment across all renewable technologies



Economic curtailment peaks in 2029, with up to 18 TWh of solar, onshore and offshore wind generation curtailed

Offshore wind shows higher curtailment compared to solar PV and onshore wind due to higher short run marginal cost

- Economic curtailment is the self-scheduled curtailment of an asset based on market prices
- Whilst very low prices and grid constraints may coincide, Aurora only considers economic curtailment and does not explicitly include grid constraint-induced curtailment
- Increasing RES penetration and thus low capture prices in late 20s lead to a higher number of periods where short run marginal costs are above market price
- The high curtailment indicates an oversupply of renewable energy and an opportunity for storage options such as LDES
- Across the forecast, average curtailment[3] is

Solar	2%
Onshore wind	2%
Offshore wind[2]	13%

---

1) Percentage of generation that is curtailed economically for intermittent renewables across Spain. Economic curtailment occurs when wholesale prices are below the marginal cost. 2) Offshore wind exclusively refers to floating offshore wind. 3) Offshore wind shows higher curtailment due to higher short run marginal cost.

Sources: Aurora Energy Research

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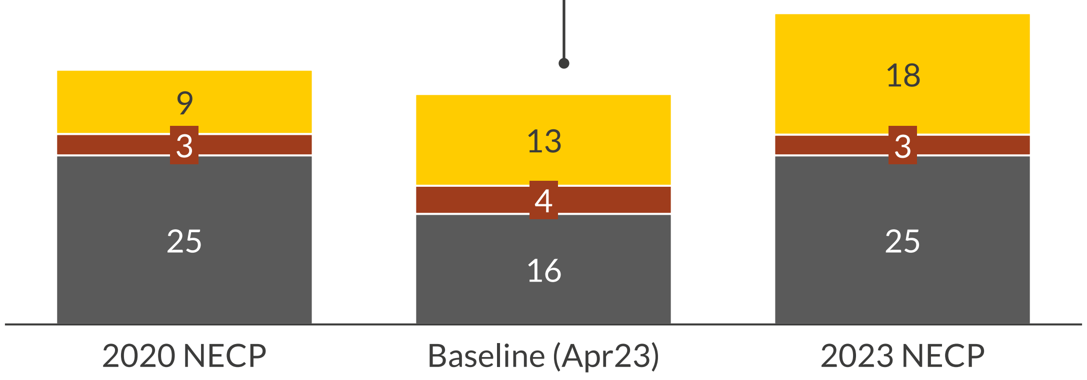
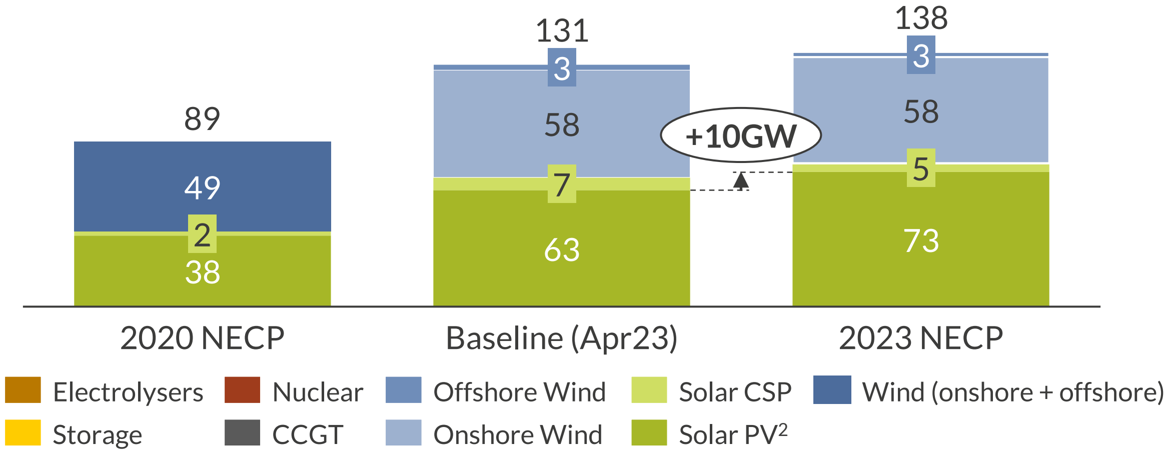
While electrolyser and solar deployment in the 2023 NECP are more ambitious than Baseline, existing CCGT fleet does not retire by 2030

Baseload and flexible capacity[1], GW

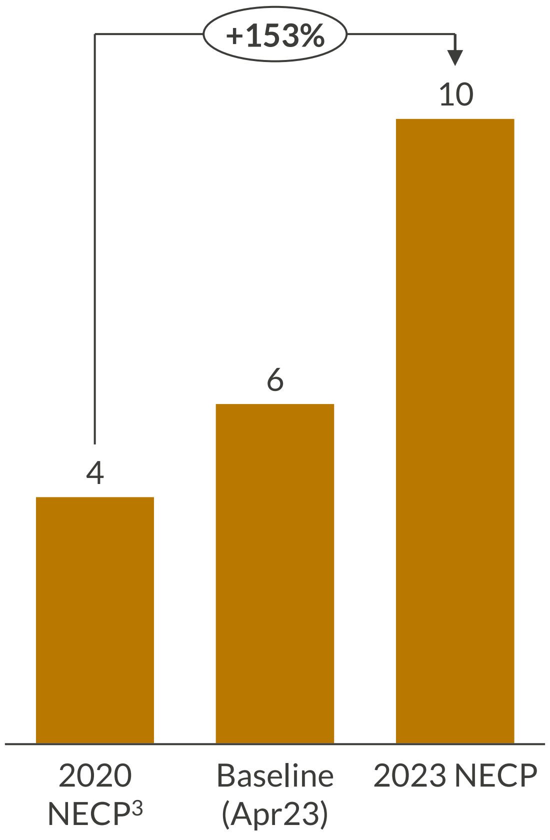
Baseline includes 5 GW of battery and 8 GW of pumped storage while the new NECP does not distinguish between storage technologies



Renewable capacity[1]
GW



Electrolyser capacity[1]
GW



Nuclear

- Despite maintaining phase out of nuclear energy in Spain by 2035, nuclear generation is increased by 9% (+2p.p.) by 2030 between NECPs
- 2023 NECP shows 15 TWh of higher generation compared with Baseline

Gas CCGTs

- CCGT fleet is not assumed to retire in NECPs to ensure security of supply
- 11TWh less CCGT generation (-40%) is seen in the 2023 NECP compared with 2020 NECP, in efforts to meet decarbonisation targets

Renewables

- RES in the generation mix increases in the 2023 NECP vs 2020 NECP (74% vs 81%) but remains below Baseline (88%) despite higher capacity deployment
- Vast majority of solar buildout is solar PV with 10 GW more capacity in the 2023 NECP

Electrolysers

- Electrolyser target even more ambitious than Baseline, aiming to integrate RES and for Spain to become a hydrogen exporter

---

1) Peninsular capacity 2) Includes rooftop solar in Baseline scenario. 3) 2020 NECP contains no electrolyser plan, value taken from Renewable Hydrogen Roadmap (May 2020).

Sources: Aurora Energy Research, MITECO, Renewable Hydrogen Roadmap

Even though RES targets set by 2023 NECP are higher than Baseline, electrolyser targets have also been increased; impact on prices is inconclusive

Variable	Baseline	2023 NECP	Impact
Solar PV capacity, GW	63	73	▪ By increasing solar capacity, baseload price and capture prices will significantly decrease as the deployment occurs, bringing capture price further below LCOE than seen in Aurora's Baseline scenario
Wind capacity, GW	61	61	▪ Identical capacities would reflect similar capture prices for both offshore and onshore wind, if average load factors across different regions of Spain were consistent between Baseline and 2023 NECP; however, Aurora load factors for new build are higher than 2023 NECP
Storage capacity, GW	13	18	▪ Higher storage in the 2023 NECP is expected to decrease frequency of low-price hours, impacting price spreads in wholesale and balancing markets
Electrolyser capacity, GW	5.5	10.1	▪ Higher electrolyser capacity will act as a load sink, decreasing occurrence of zero or low-price hours. Electrolysers function similarly to TES, and could potentially hurt the business case for LDES
CCGT capacity, GW	16	25	▪ 2023 NECP assumes that existing CCGT fleet is kept online to ensure security of supply in the event of high demand periods, no LDES technologies are assumed to provide this type of services in the NECP modelling
Demand, TWh	308	317	▪ Higher electrolyser targets, and thus green hydrogen production leads to higher demand; putting upwards pressure in wholesale prices ▪ 5.5 million EVs in NECP compared with 5 million in the Baseline would also lead to higher demand
CCGT generation, TWh	5	17	▪ Increased carbon intensive generation increases wholesale market costs and represents higher levels of carbon emissions.
Renewable generation %, TWh	88% 275	81% 306	▪ Lower contribution of RES in the generation mix despite similar RES contribution in the capacity mix implies lower load factors considered in the 2023 NECP for both wind and solar (the two primary sources of RES generation). ▪ Aurora assumes different load factors for new-build and existing assets; for new build[1], we assume 22% for solar, 36% for the onshore-wind fleet average while the 2023 NECP considers 20% and 23%, respectively

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1) Assets built after 2023; existing fleet load factors of 20% for solar and 28% for onshore wind.

Sources: Aurora Energy Research, MITECO

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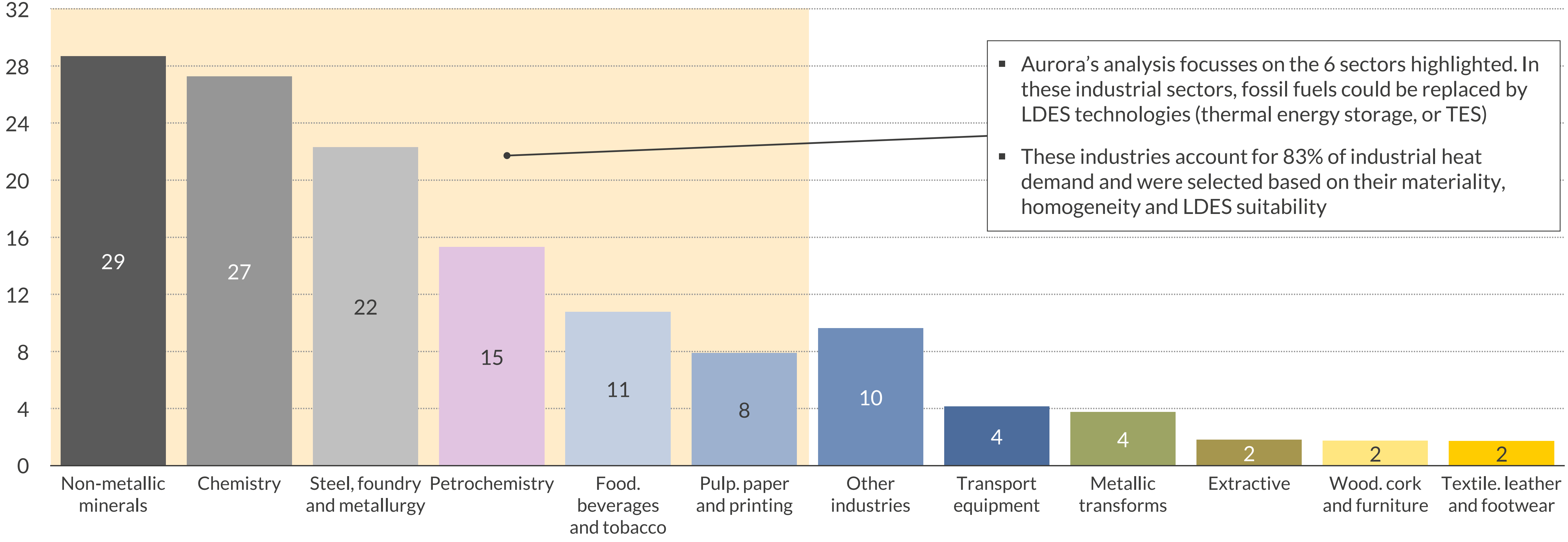
Industry heat demand accounts for 56% of Spanish heat demand; Aurora selected sectors to analyse based on their materiality and LDES suitability

- The industry heat demand in Spain accounts for 135 TWh/year, representing 56% of the total heat demand in Spain. It is made up of a diverse range of sectors and processes using a variety of fuels and heat temperatures

Heat demand by industrial sector[1]

TWh/year



- Aurora's analysis focusses on the 6 sectors highlighted. In these industrial sectors, fossil fuels could be replaced by LDES technologies (thermal energy storage, or TES)
- These industries account for 83% of industrial heat demand and were selected based on their materiality, homogeneity and LDES suitability

---

1) Data retrieved from the 'Mapa de Calor', last published in December 2022.

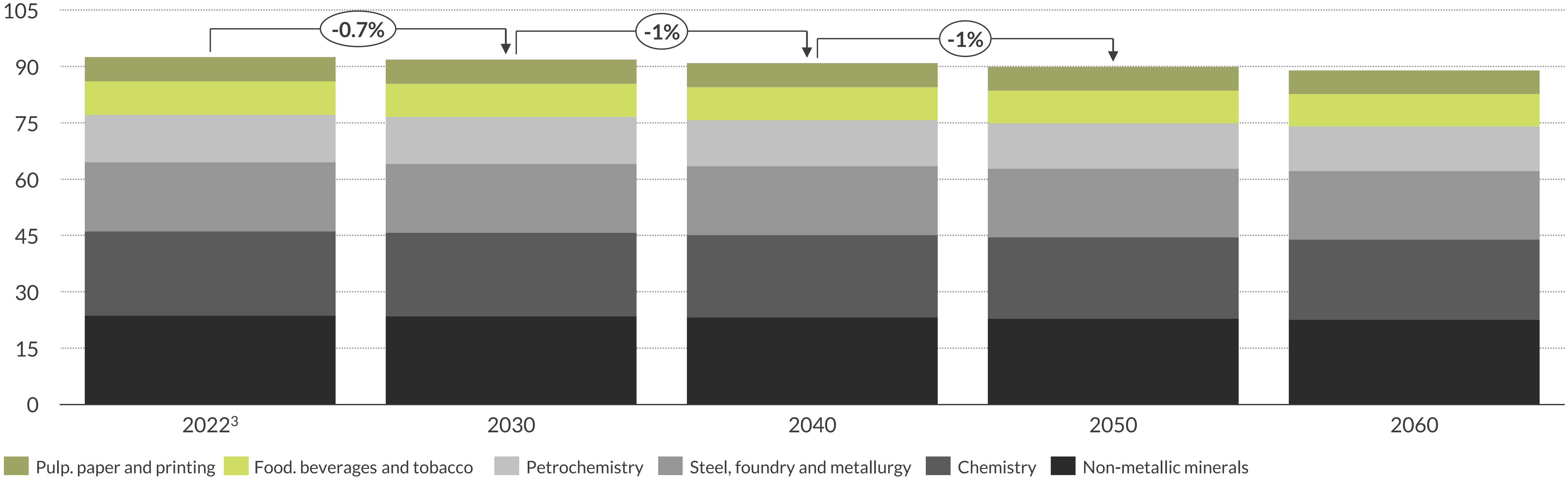
Sources: Aurora Energy Research, IDAE, MITECO

By 2030, Aurora expects process heat demand in the considered sectors to decrease driven by a decrease in energy intensity

- Since heat demand represents two-thirds of the final industrial energy consumption, we have assumed process heat demand to decrease at the same rate as industrial energy consumption
- The main driver of energy reduction initiatives is the EU-ETS (carbon pricing), prompting investments in more efficient technologies and processes
- Aurora assumes a 0.7% from 2022 to 2030 in line with the 2020 NECP forecast[2], and allocates the decrease across industrial sectors following energy consumption changes per industrial sector under the 2020 EU reference scenario

Forecast of process heat (PH) demand in Spain by industrial sector

TWh



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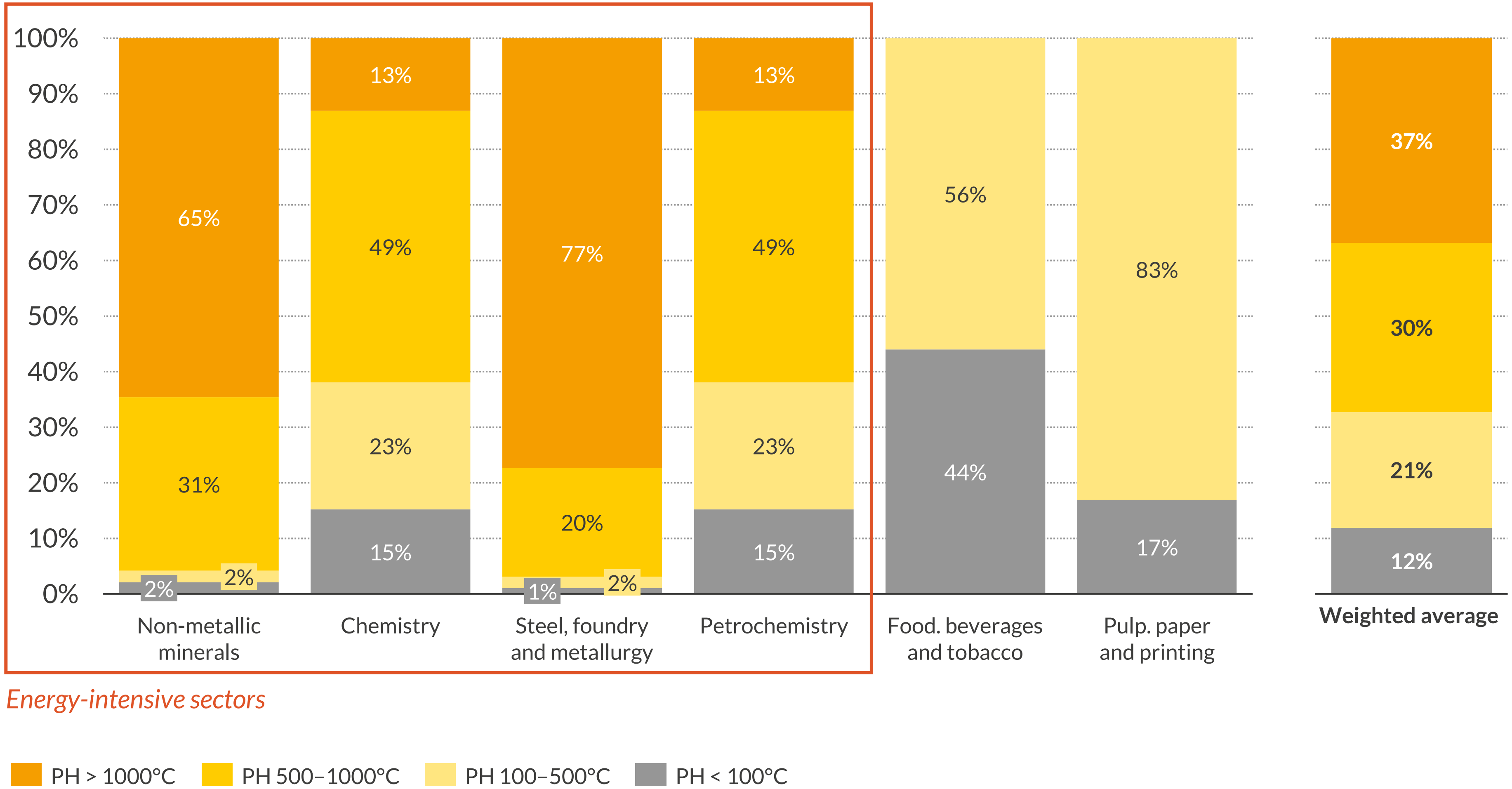
1) Historically, industry demand has remained quite flat (20.6 Mtoe in 2019, 18.8 Mtoe in 2020 – COVID, and 20.6 Mtoe in 2021). 2) While industrial energy consumption decreases by 0.7% by 2030, total energy consumption in Spain decreases by 12% in the 2020 NECP, in line with the "Energy Efficiency Directive" target announced on the 10th of March 2023. 3) The historical 2022 data was retrieved from the IDAE 'Mapa de Calor'.

Sources: Aurora Energy Research, IDAE (Mapa de calor), European Commission (EU Reference Scenario 2020), MITECO

81% of the energy-intensive sectors require temperatures above 500°C, compared to an average of 67% for the six sectors analysed

Share of temperature levels for process heating by analysed industry sectors in Spain
%



- Spain has one of the largest share of high temperature (>500°C) process heat demand in Europe, very similar to Germany
- Even though the share of temperature levels is available for Spanish industry as a whole, there is not a breakdown by sector
- The sectorial process heat demand temperature distribution is based on German data, given the similarity between countries
- For the six sectors displayed, the process heating demand temperature requirement is[2]:
    - 12% below 100°C
    - 21% between 100-500°C
    - 30% between 500-1000°C
    - 37% above 1000°C
- Aurora assumes the same shares per sector throughout the 2023-2060 forecast

---

1) These six sectors account for 83% of industrial heat demand and were selected based on their materiality, homogeneity and LDES suitability. In the surveys shared with Innovators, Aurora also requested for LDES suitability and application in the industrial sector. 2) Shares are calculated based on industrial processes heat demand weighted average

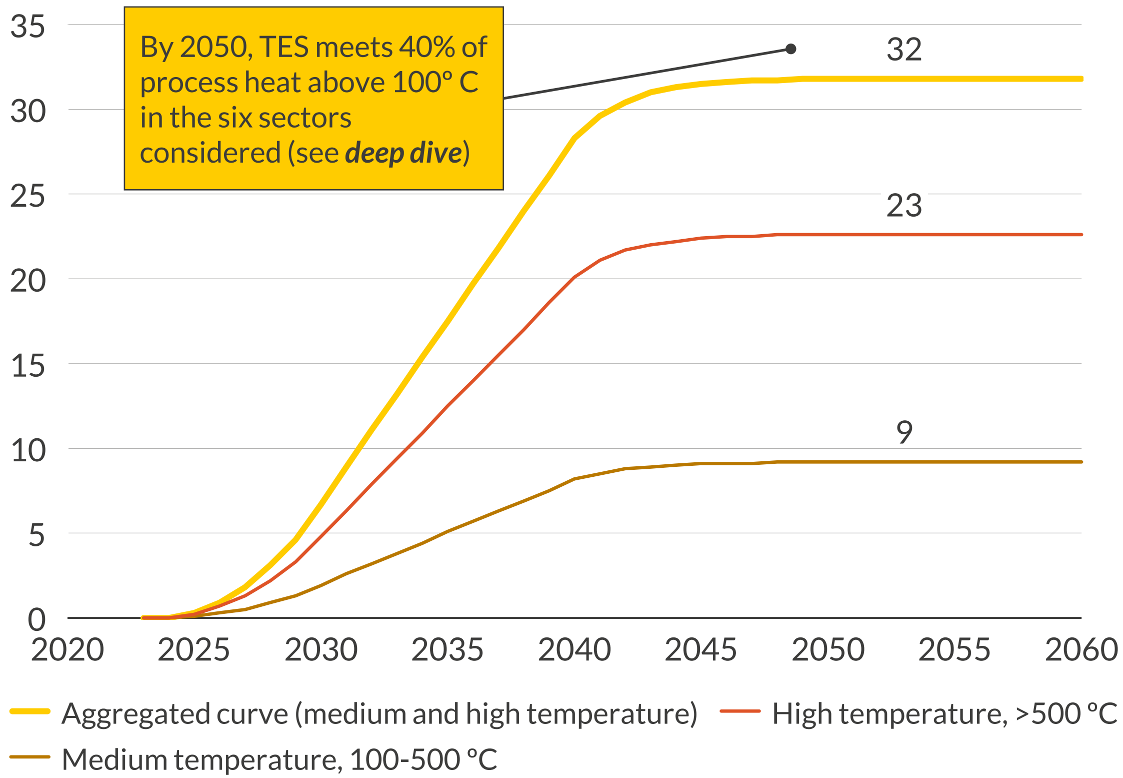
Source: Aurora Energy Research, Mapa de Calor (IDAE), Naegler et al (2015)

Thermal storage meets 40% of industrial process heat demand >100° C by 2050, representing a larger share in the medium temperature range

- Based on the heat demand forecast for the sectors considered[1], we have assumed that thermal storage (TES) is suited to meet a % of industrial process heat demand. We consider three different levels of temperatures (low, medium and high) consistent with LDES Innovators and with Aurora H_2 process heat temperature ranges
- We ensure a maximum uptake for TES considering its suitability and given Aurora H_2 assumptions for the Baseline scenario. We assumed a yearly uptake for TES based on a replacement rate assuming an average 25-year lifetime for existing technologies

Incremental electricity demand from TES (total and per temperature range)

TWh

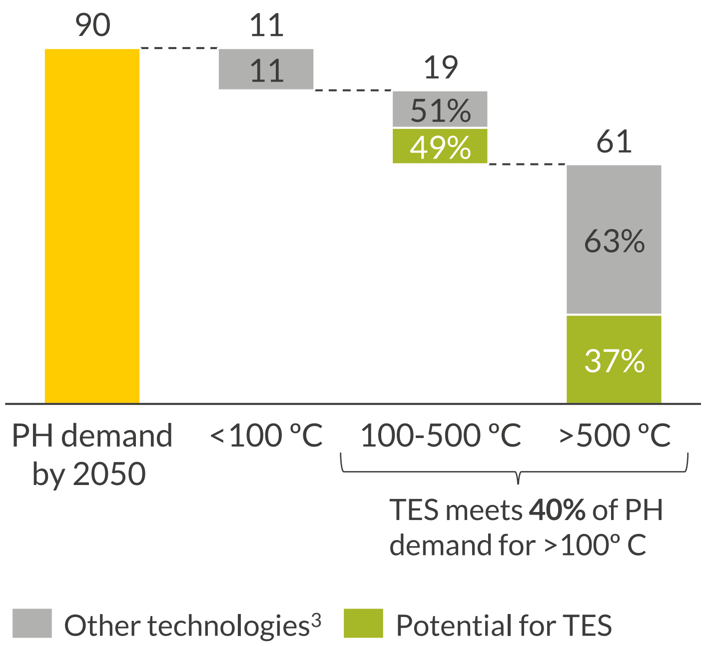


By 2050, TES meets 40% of process heat above 100° C in the six sectors considered (see ***deep dive***)

Deep dive: Thermal energy storage in industrial process heat[1,2]

Process heat demand by 2050 in industrial sectors considered

TWh



TES meets **40%** of PH demand for >100° C

- Aurora considers temperature ranges consistent with applicability of TES technologies (collected in Innovator surveys)
- Aurora assumes that TES uptake will not displace H_2. LDES scenario is consistent with Baseline H_2 assumptions for the same temperature ranges

---

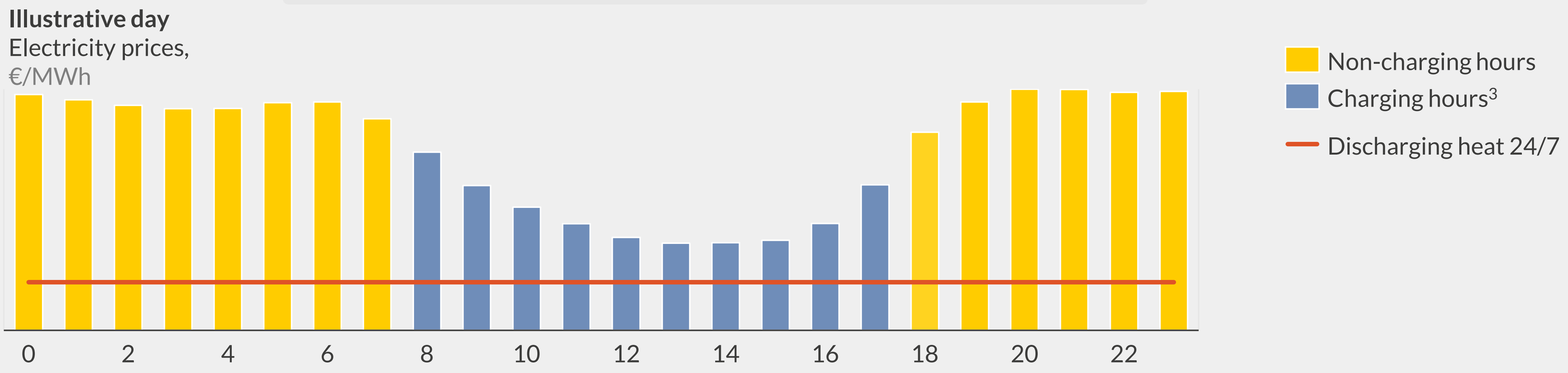
1) The 6 sectors considered represent 86% of total industrial heat demand, namely, i) non-metallic minerals, ii) chemistry, iii) steel, foundry and metallurgy, iv) petrochemistry, v) food, beverages and tobacco, vi) pulp, paper and printing. 2) Based on LDES applicability (mostly energy intensive and high temperature sectors). 3) Other technologies includes heat pumps, other types of electrification (electric boilers), hydrogen boilers.

Sources: Aurora Energy Research

We assume 24/7 year-round delivery of heat for the industry sector, using charging profiles for thermal storage based on LDES Innovators' input

- For our modelling, we assumed a uniform 24-hour daily heat demand as it is a common heat demand profile for energy intensive industry. This implies that the LDES will be discharging heat 24/7
- LDES will charge power during low prices hours; therefore, the incremental demand[1] will be added in low-price hours when renewables are producing, enabling renewable integration and avoiding curtailment
- To model the demand profile in the power market modelling for two generic LDES technologies, we gathered input from LDES Innovators for the range of temperatures considered in the study[2] (duration, thermal efficiency, availability)

Illustrative day: TES charging 10 hours per day while discharging heat 24/7



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1) Incremental demand added in the LDES scenario can be found in slide 33. 2) We consider temperature ranges <100°C, 100-500 °C, 500-1000°C and above 1000°C. We gathered data from LDES Innovators regarding technologies suitable for the temperature levels >=100°C. Below 100°C, heat pump uptake is considered. 3) Charging time = energy storage capacity (MWh) / discharge rate (MW).

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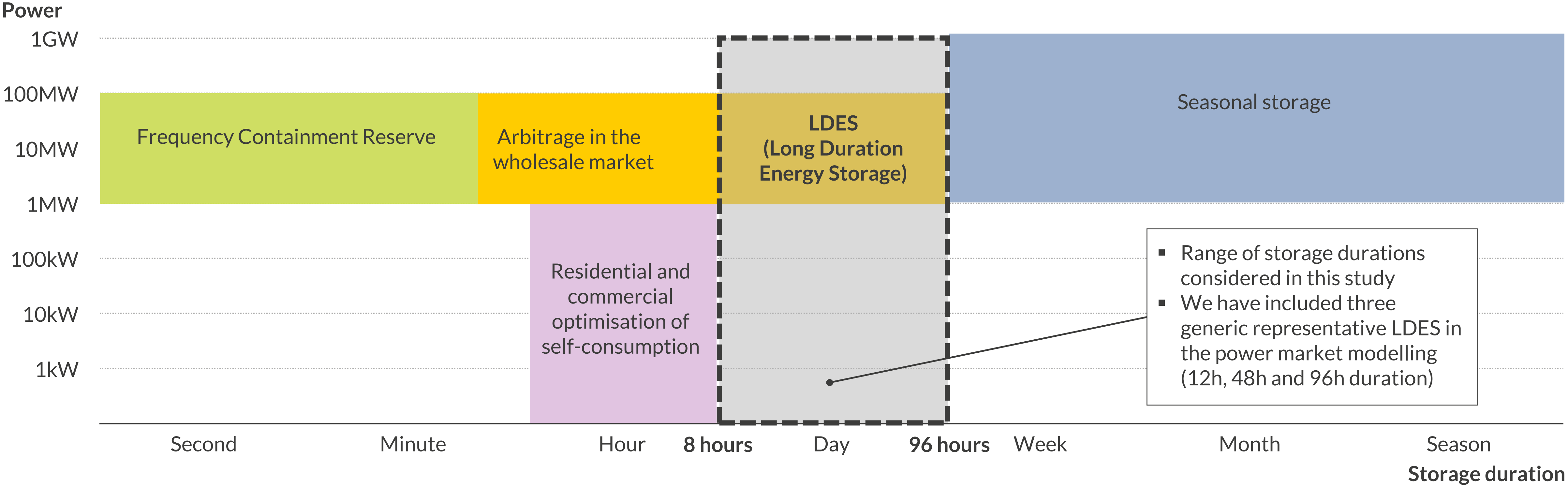
Long Duration Energy Storage fills the gap between short-term and seasonal storage by saving energy for above 8 hours up to a few days

Use cases of energy storage technologies



- Range of storage durations considered in this study
- We have included three generic representative LDES in the power market modelling (12h, 48h and 96h duration)

- Long Duration Energy Storage (LDES) technologies are able to respond to supply and demand variations caused by daily peaks and weather events as well as multiday variations in renewable electricity generation
- The focus of our analysis lies on storage technologies with **durations above 8 hours and up to 96 hours**. Generic technologies are implemented in the model to simulate the system-level effect of LDES deployment
- Longer durations spanning across multiple weeks or months are considered seasonal storage, which we expect to be primarily provided by hydrogen-based solutions

Source: Aurora Energy Research

Various LDES technologies are in the spotlight to be commercial deployable in the near-term; we included generic LDES in the power system modelling

1 **Various emerging LDES technologies are in the spotlight to be commercially deployed in the near-term, fulfilling system requirements with regards to congestion relief and ancillary services**

Overview of Long Duration Energy Storage technologies (non-exhaustive, based on surveys)[1]

Power-to-Power	**Flow Batteries (Electro-chemical)**
	Metal-Air Batteries (Electro-chemical)
	Novel pumped hydropower (Mechanical)
	Compressed Air (Mechanical)
	Thermal as power-to-power[3] ***(Details for types below)***
Power-to-Heat	**Sensible heat (Thermal)**
	Latent heat (Thermal)
	Thermo-chemical heat (Thermal)

2 **In the power system modelling, we have included generic representative technologies to capture the potential that each LDES technology can bring to the system given its different technical parameters**

- LDES technologies have different specifications and allow different system needs to be fulfilled
- LDES can differ in typical size, duration, costs, lifetime, efficiency and response times. Additionally, for thermal storage, technologies differ in temperature (delivered and operational)
- **Power-to-Power**
  - We have included three generic representative LDES in the power market modelling
  - Assets have different duration, lifetime, efficiency and costs
  - We model 12h, 48h and 96h duration to cover a span of different durations
- **Power-to-Heat**
  - We have included two generic representative LDES in the power market modelling
  - Likewise, assets differ in technical parameters. The two generic thermal assets considered fulfil the needs for different temperature ranges required for process heat in the industry sector (medium and high temperature)[2]
  - Assets are modelled separately by adding incremental electricity demand in the power market scenario

---

1) Based on LDES Innovators surveys. For the values used in the asset economics analysis, please refer to the “Asset Economics” section. All LDES considered in this study provide a more energy efficient solution for power storage than a power – H_2 – power cycle. For thermal technologies outputting both power and heat simultaneously, we only consider power output for the power-to-power workstream. For the power-to-heat workstream, we only consider heat output. 2) Further details in slides 30-34.

Sources: Aurora Energy Research, IRENA, European Association for Storage of Energy, Innovator’s surveys

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Aurora and the Advisory Group defined a set of metrics to determine the LDES scenario maximising system cost savings compared with the Baseline

Baseline scenario

- Scenario aligned with EU policies for upcoming NECP targets[1] by 2030 for electricity and hydrogen demand, renewables, storage and hydrogen
- Basis for the **multiple** LDES scenarios

LDES scenario

- Aurora modelled **multiple** scenarios of LDES deployment (TES and electricity storage); the more the LDES capacity in the system, the higher the required investment, but there are savings in other components
- To determine the scenario maximising system cost savings compared with the Baseline, Aurora analysed a set of metrics across scenarios

Key metrics to compare scenarios with different LDES deployment

1 Power system

- Investment costs[2]:
  - LDES : daily, weekly and seasonal electricity storage (12h, 48h, 96h)
  - Thermal (CCGTs, peakers) plants
  - H_2 CCGT plants
  - Renewables
- Gas and CO_2 savings
- Grid investment costs[3]
- Renewable curtailment

2 Industry

- Investment costs:
  - TES for medium and high temperature processes
  - Competing technologies (electric boilers, H_2 boilers and gas boilers with CCS), including variable operation costs[4]
- CO_2 emissions

3 H_2 infrastructure

- Investment costs:
  - Electrolysers capacity
  - Storage capacity
- Imports costs:
  - (Transport) infrastructure
  - H_2 import costs[5]

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1) Modelling of the scenarios took place from March to May 2023, before the release of the draft NECP (June 29). 2) We do not consider power market imports since we are not modelling an equivalent LDES Scenario for neighbouring countries. 3) Aurora high-level assessment based on historical data available at a national level. A more detailed nodal analysis would be needed to more accurately assess the impact of LDES, as recommended by Red Eléctrica. 4) Aurora prices for electricity, gas, and H_2 used in the analysis. 5) Intranational H_2 distribution costs assumed to be the same across scenarios. For more details on the assumptions, refer to the appendix. Services that can be provided by LDES can be found in slide 46 and 71.

Agenda

I. Overview of the study

II. Executive summary

III. Baseline scenario

IV. LDES scenario

V. Scenario comparison: LDES vs Baseline

- a. System cost delta
- b. Incremental demand from thermal storage
- c. Capacity and generation
- d. Gas generation and CO_2 emissions
- e. Renewable curtailment
- f. Grid investment
- g. Baseload price and spreads
- h. Capture prices

VI. Asset economics under LDES scenario

VII. Policy considerations

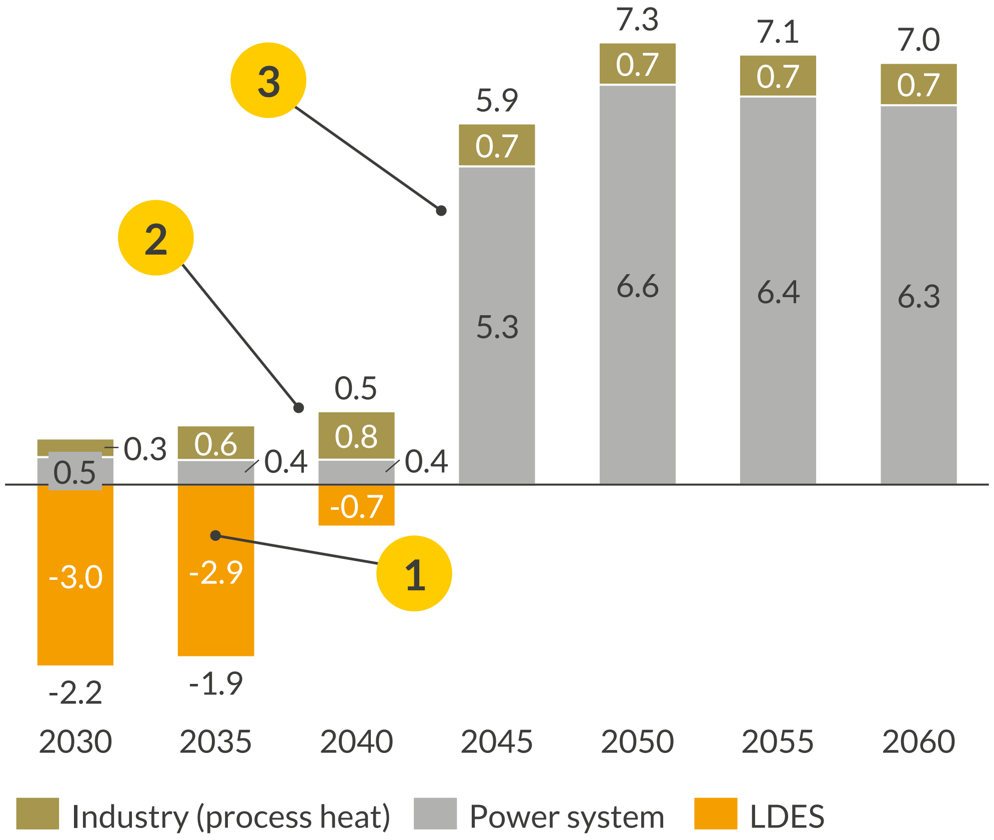
VIII. Appendix

Integrating LDES into the power system would lower total system costs by 1 billion Euros in net present value until 2060

Aurora modelled **multiple** scenarios of LDES deployment (power-to-power and power-to-heat): the more the LDES capacity, the higher the required investment, but there are savings / costs in other components. To determine the scenario maximising system cost savings compared with the Baseline, Aurora assessed a set of metrics[1]

System cost delta compared with the Baseline scenario[2]

Bn € (real 2021)



Present Value[3] of system cost delta with Baseline

Bn € (real 2021)

1 Bn €

1

- Investment costs in LDES technologies in the power system (12h, 48h and 96h power-to-power) and industry (power-to-heat for medium and high temperature process heat) happen in the 2030s

2

- Investment in thermal energy storage (TES) for process heat in industry means that competing technologies (electric, hydrogen and gas boilers) are displaced
- The variable operating costs, CAPEX and OPEX of the displaced technologies are savings relative to the Baseline scenario, in which TES is not deployed

3

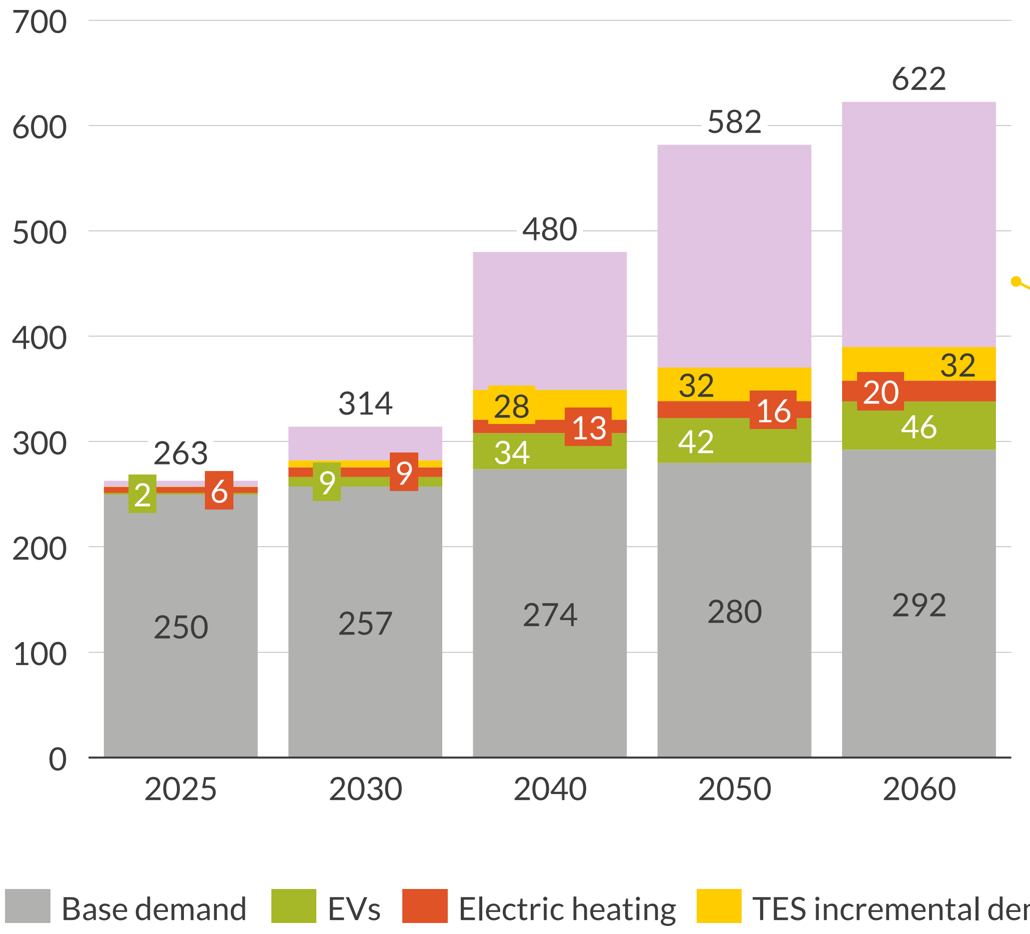
- In the power system, LDES displaces thermal, gas and H_2 CCGTs:
  - There will be lower thermal generation, leading to gas and CO_2 economic savings
  - LDES can provide grid services that would otherwise rely on carbon-intensive technologies like CCGTs with higher running and ramping costs
  - In medium and long-term, LDES deployment ensures system's security of supply standards. This leads to lower costs in maintaining gas CCGTs and other thermal assets online, and/or in investing in H_2 CCGTs
- However, incremental demand from TES reduces the frequency of low prices, leading to lower domestic electrolyser production and higher hydrogen import costs[4]

---

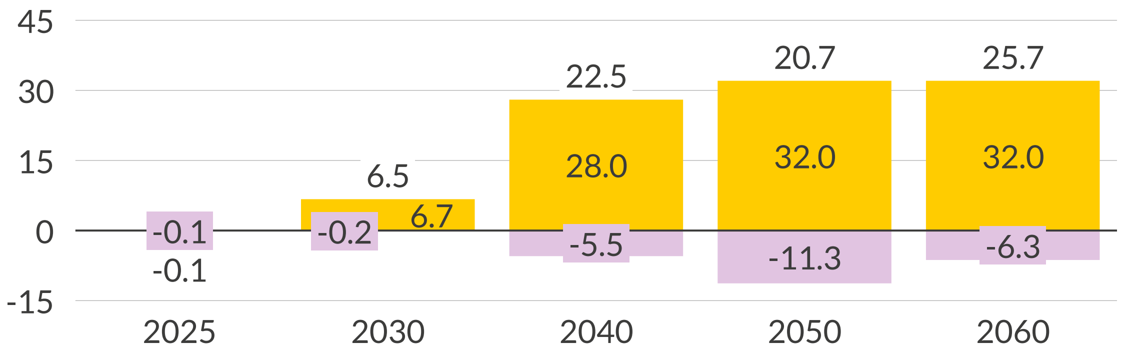
1) Economic metrics assessed were investment costs in power sector (EES, thermal plants, H_2 plants, RES), grid investment savings, gas and CO_2 savings; investment costs in industry (TES for medium and high process heat and competing technologies), investment costs in H_2 infrastructure (electrolysers, storage, transport infrastructure, H_2 import costs). 2) Savings in positive numbers, costs in negative numbers. Not discounted. 3) 5% discount rate. 4) Import costs include infrastructure and H_2 price imports. Details on electrolyser production in slide 42.

Incremental demand from thermal storage for industry process heat is added on top of Baseline demand, increasing it by up to 9% by 2050

Demand by technology (inc. electrolysis)
TWh



Demand: LDES vs Baseline scenario
TWh



- Incremental TES demand[1] (see section IV for details) is added on top of Baseline demand, increasing it by up to 9% by 2050. TES flattens the price curve and reduces the frequency of low prices, integrating renewable generation, but also negatively affecting electrolysis (see slide 48)
- This leads to a marginal reduction in electrolyser load factor from 65% (in the Baseline) to 63% (in LDES scenario), on average, from 2030 to 2060
- Domestic electrolyser production decreases by up to 5% by 2050. The cost of required yearly imports was included in the overall system costs assessment. As reduction is domestic production is marginal, electrolyser capacity required is the same as in the Baseline

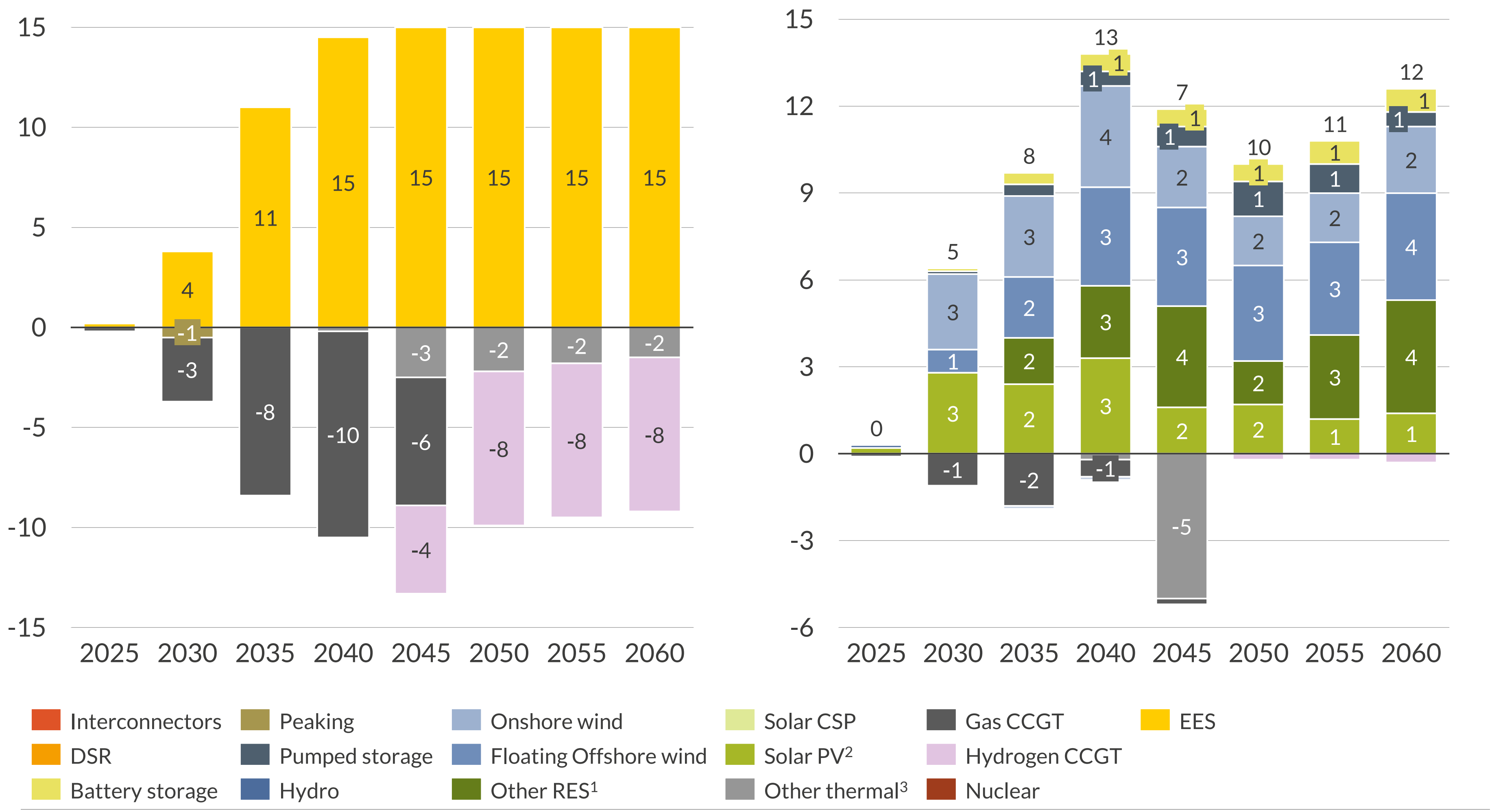
---

[1] Incremental TES demand considered to provide 24/7 medium and high temperature process heat for industry would represent ~4 GW of TES, assuming 95% efficiency and 98% load factor.

In the LDES scenario, storage replaces thermal and H_2 CCGTs, while integrating up to 13 TWh of renewable generation

Capacity: LDES vs Baseline scenario
GW

Generation: LDES vs Baseline scenario
TWh

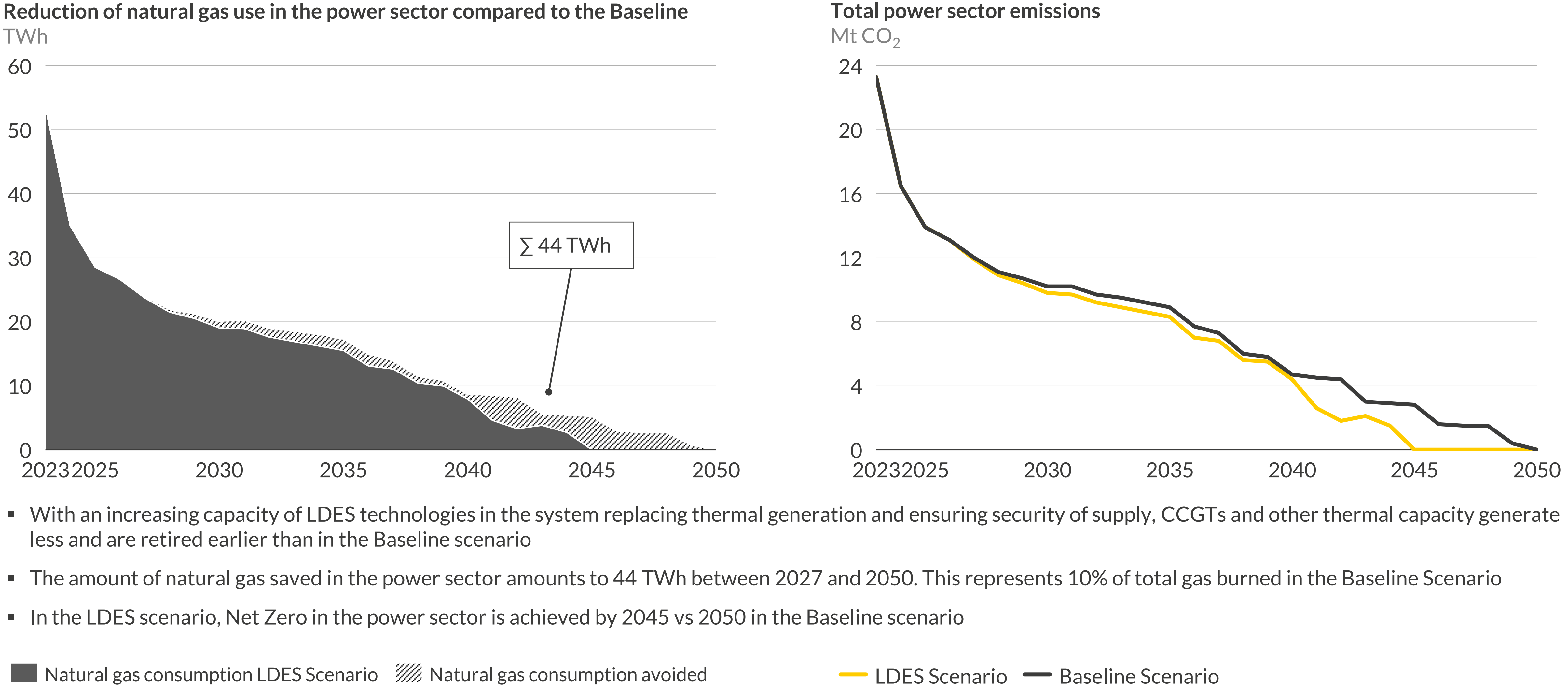


- In the LDES scenario which optimises system cost savings, 15 GW of EES[4] are deployed
- In this scenario, there is lower need for thermal and hydrogen installed capacity to ensure security of supply levels in the Spanish power system
- Given that EES discharge in high price hours, there is lower natural gas use, reducing the amount of electricity generated by conventional gas plants and consequently CO_2 emissions in the power sector
- LDES absorb renewable electricity by charging in hours in which renewable production exceeds demand, enabling integration of up to 13 TWh of renewable generation that would have been curtailed

---

1) Other RES includes biomass and renewable cogeneration. 2) Solar includes solar rooftop PV and solar ground-mounted PV. 3) Other thermal includes fossil fueled cogeneration. 4) Three generic electricity storage assets of 12h, 48h and 96h based on Innovators' surveys specifications. Incremental TES demand considered (see slide 33) would represent ~4 GW of TES, assuming 95% efficiency and 98% load factor.

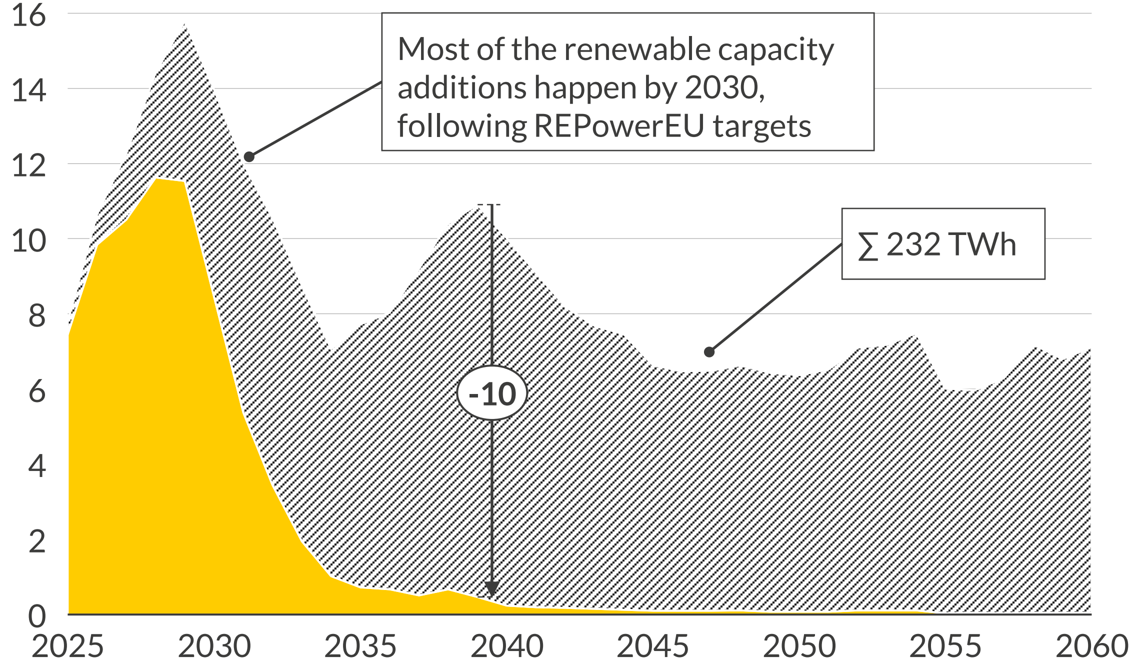
Net Zero in the power sector is achieved 5 years earlier in the LDES scenario, with 44 TWh of natural gas saved between 2027 and 2050



- With an increasing capacity of LDES technologies in the system replacing thermal generation and ensuring security of supply, CCGTs and other thermal capacity generate less and are retired earlier than in the Baseline scenario
- The amount of natural gas saved in the power sector amounts to 44 TWh between 2027 and 2050. This represents 10% of total gas burned in the Baseline Scenario
- In the LDES scenario, Net Zero in the power sector is achieved by 2045 vs 2050 in the Baseline scenario

Source: Aurora Energy Research

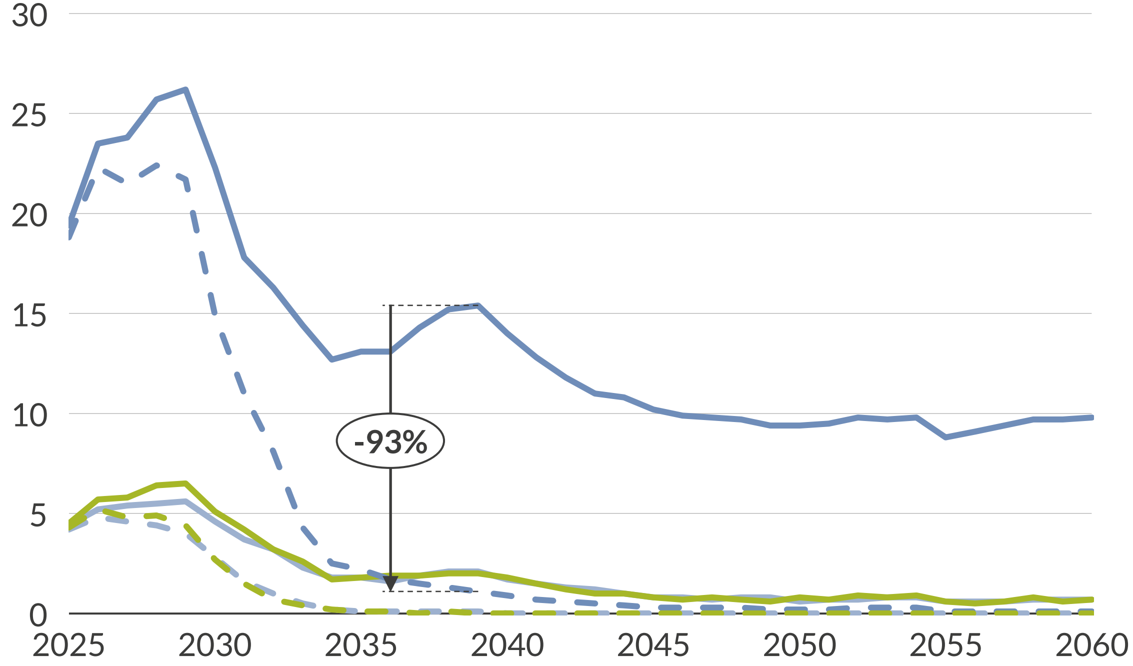
Additional flexibility provided by LDES eliminates renewable economic curtailment by 2035



Reduction of renewables' economic curtailment compared to Baseline Scenario

- Between 2025 and 2060, LDES deployment increases generation from renewable energy sources by 232 TWh by limiting curtailment of excess production
- The most significant impact happens in the late 2030s and 2040s when most of the LDES capacity enters the system

🟨 Curtailment LDES Scenario ▨ Curtailment avoided compared to Baseline Scenario



Renewable economic curtailment

- The largest decrease in curtailment is seen for floating offshore wind, reduced by up to 93 p.p. in the LDES scenario compared to the Baseline
- In the LDES scenario, economic curtailment is reduced to ~0% by the early 30s for solar PV and onshore wind compared to 5% in the Baseline scenario

Onshore wind - Baseline
Floating offshore wind - Baseline
Solar PV - Baseline
Onshore wind - LDES
Floating offshore wind - LDES
Solar PV - LDES

Source: Aurora Energy Research

LDES can replace carbon-intensive and more expensive technologies to provide ancillary services, resulting in additional system savings

Service	Typical technologies that can provide service	
	Baseline scenario	LDES scenario[2]
Voltage control	Gas and H_2 CCGTs, battery storage, and RES (curtail)	Battery storage, LDES and H_2 CCGTs
Thermal constraints	Gas and H_2 CCGTs, battery storage and RES (curtail)	Battery storage, LDES and H_2 CCGTs
Inertia[1]	Thermal, gas and H_2 CCGTs, pumped storage and battery storage	Battery storage, LDES and H_2 CCGTs
Black start	Gas and H_2 CCGTs	LDES and H_2 CCGTs

In the Baseline scenario:

- The main technologies providing most of ancillary services are gas and hydrogen CCGTs
- Another approach to address certain ancillary services is through RES curtailment. This measure would be recurrent in the Baseline, due to the high levels of renewable penetration
- Batteries are able to provide most ancillary services reducing the pressure in the grid during peak hours and providing synthetic inertia[3]

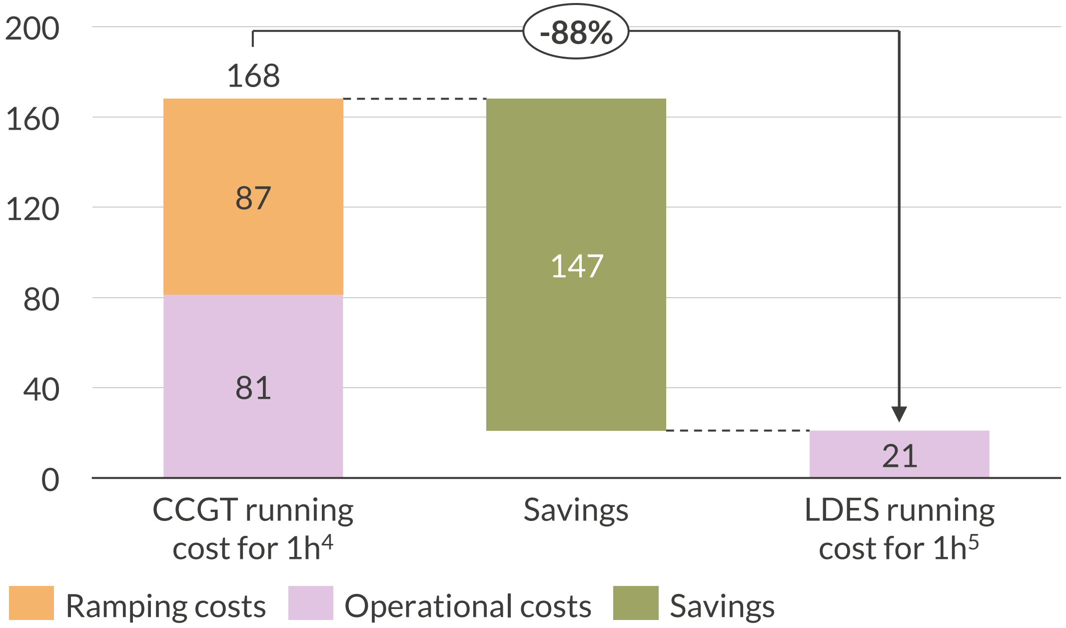
In the LDES scenario:

- Most LDES technologies are able to generate synchronously with low ramping constraints, providing voltage control and congestion relief
- As LDES have lower running and ramping costs while providing security of supply, they would replace more expensive technologies, like gas and H_2 CCGTs
- LDES would also enable renewable integration, avoiding its curtailment and replacing investment in the network, if properly located

- As LDES charges from the grid, the energy generated only depends on market prices; therefore, their cost to provide these services is the opportunity cost of not selling that energy in an alternative market
- Traditional generators have operating costs that are directly tied to fuel costs, influenced by international markets and regulation
- In addition to running costs, thermal plants have ramping costs; those are more representative when running for short periods which is usually the case to solve ancillary services

Deep dive: cost to run a gas CCGT and a generic LDES for 1h by 2030

€/MWh (real 2021)



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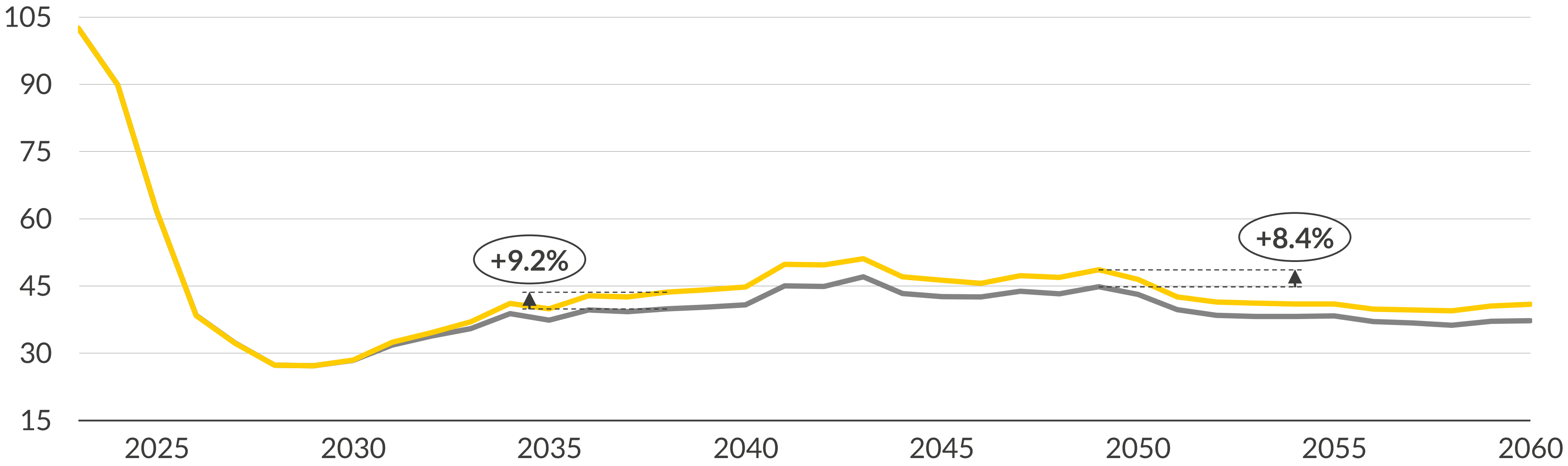
1) Other synchronous generators such as nuclear provide inertia but, due to ramping constraints, cannot be called to provide this service. 2) Gas CCGT retires earlier in LDES scenario reducing their contribution on ancillary services. 3) Also applicable to LDES scenario. Battery duration considered below 4h, thus limited duration when compared to LDES. 4) Accounting for fixed and variable operation costs, fuel costs, efficiency, ramping rate, ramping fixed costs and ramping fuel cost. 5) Accounting for fixed operation and maintenance costs, efficiency and wholesale and balancing average price.

Baseload power prices increase by 3 €/MWh on average between 2030 and 2060 with the deployment of LDES

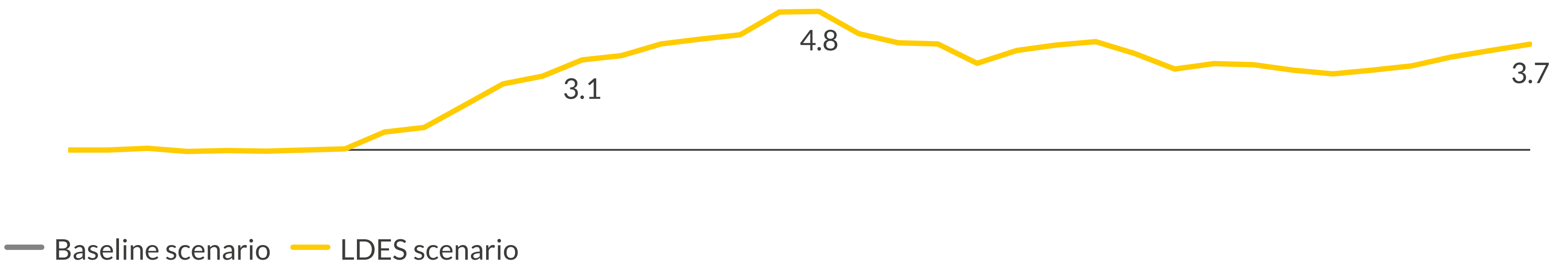
Baseload wholesale electricity prices: LDES and Baseline scenarios

€/MWh (real 2021)



Delta in baseload wholesale electricity prices between LDES and Baseline scenario

€/MWh (real 2021)



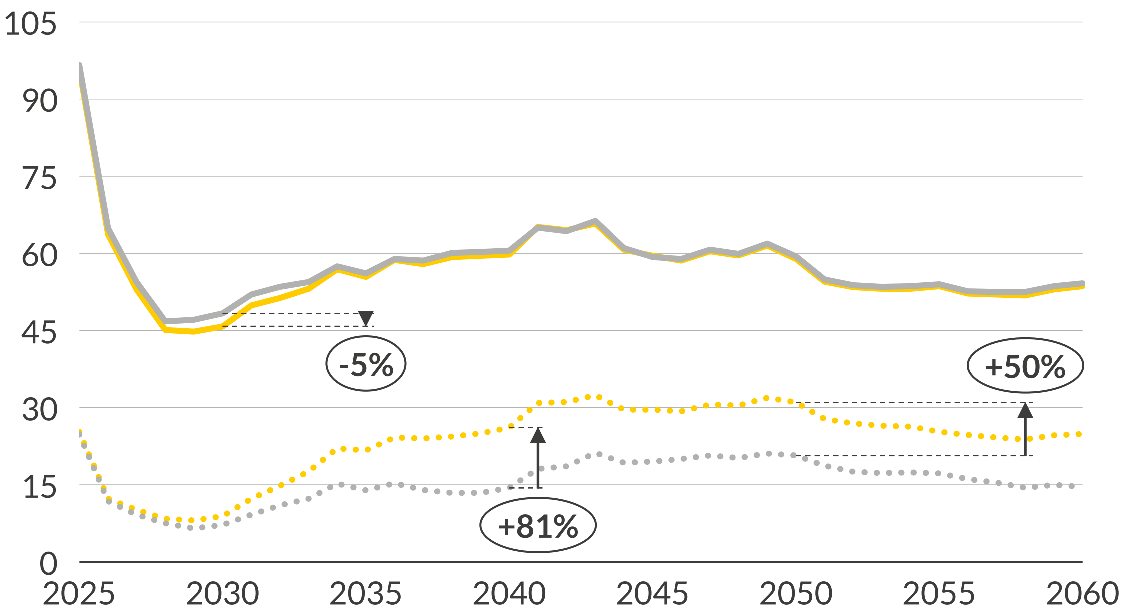
Outlook for baseload prices

- With the introduction of LDES, baseload power prices increase by 8% on average between 2030 and 2060. In 2040 and 2050, power prices are respectively 4 and 3 €/MWh higher with LDES
- The change in average yearly baseload prices is the result of two opposing effects:
  - Incremental power demand from thermal storage in low price hours increases prices in times of high renewable generation
  - The system needs less generation from expensive thermal plants in peak hours. Nonetheless, these technologies are in the system mostly to ensure security of supply
- Overall, the incremental demand in low price hours has a larger impact on baseload prices

LDES decreases daily spreads by 21% on average by reducing frequency of extremely low prices, potentially affecting other flexible technologies

Yearly averages of daily minimum and maximum power prices

€/MWh (real 2021)

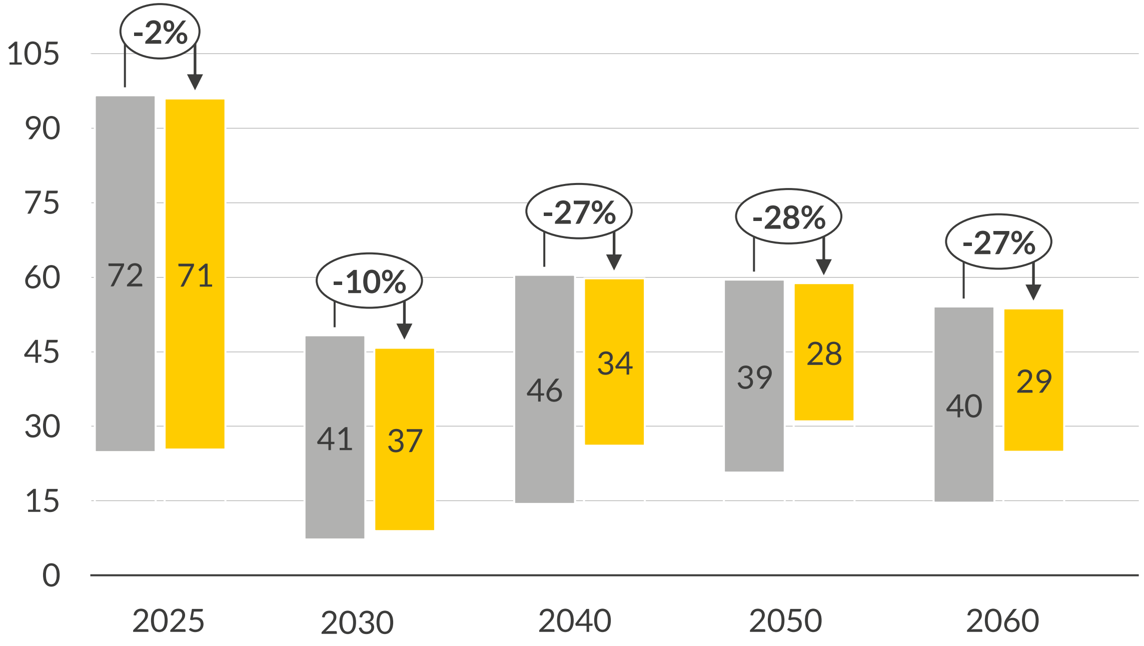


- Incremental demand from TES and EES charging flattens the power price curve and reduces the frequency of extremely low prices
- The significant increase in low power prices past 2030 negatively affects flexible demand technologies, such as electrolysers or electric vehicles

•• Average daily min. price LDES Scenario
•• Average daily min. price Baseline Scenario
― Average daily max. price LDES Scenario
― Average daily max. price Baseline Scenario

Yearly averages of spreads between daily minimum and maximum prices

€/MWh (real 2021)



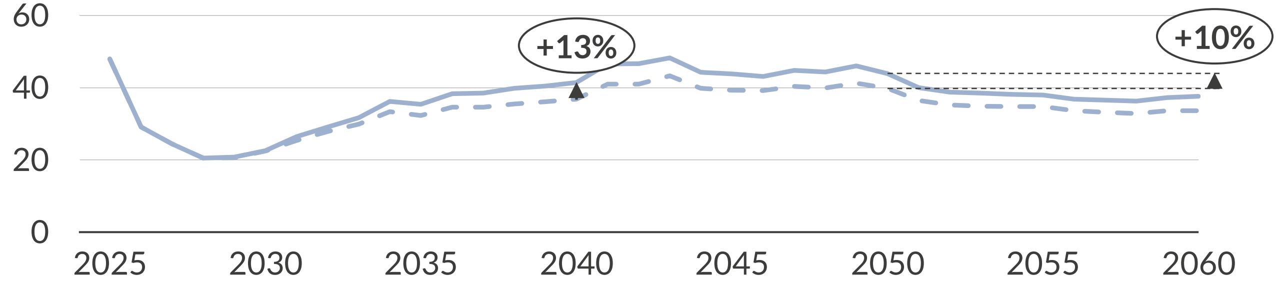
- Daily power price spreads are reduced on average by 21% between 2025 and 2060 when LDES enters the system. The maximum delta reaches 28% in 2050, with an 11 €/MWh difference between scenarios
- The reduced daily spreads have negative implications for short-term storage, which rely on intraday volatility to perform wholesale market arbitrage

▨ Baseline Scenario ▨ LDES Scenario

Source: Aurora Energy Research

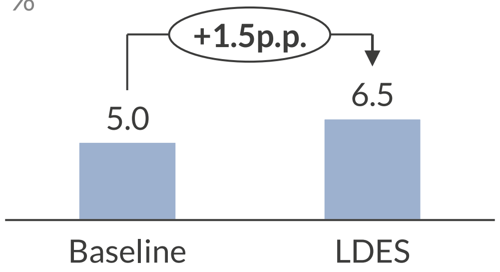
Driven by LDES deployment, renewables' capture prices increase improving profitability, especially for solar PV assets

Onshore wind capture prices[1], €/MWh (real 2021)

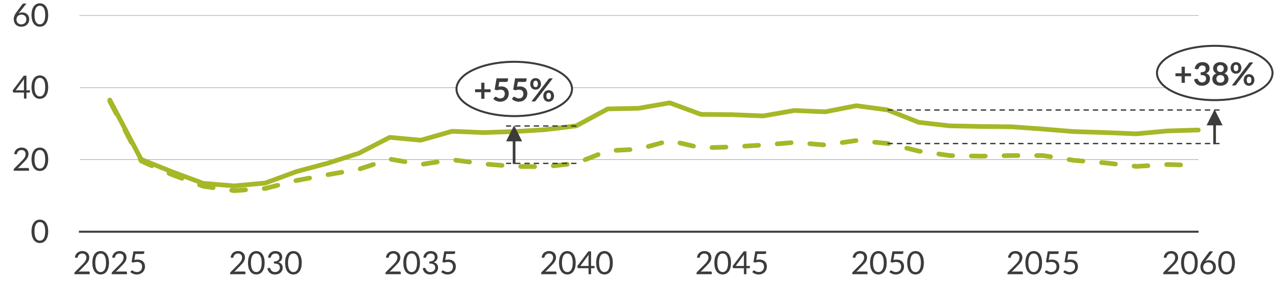


Onshore wind IRR (COD 2030)[2]

%

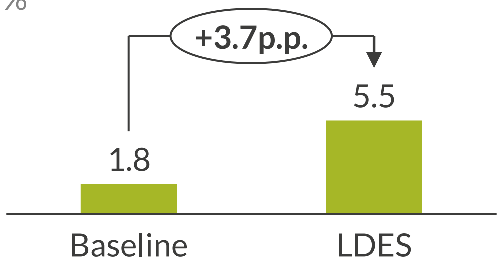


Solar PV capture prices[1], €/MWh (real 2021)

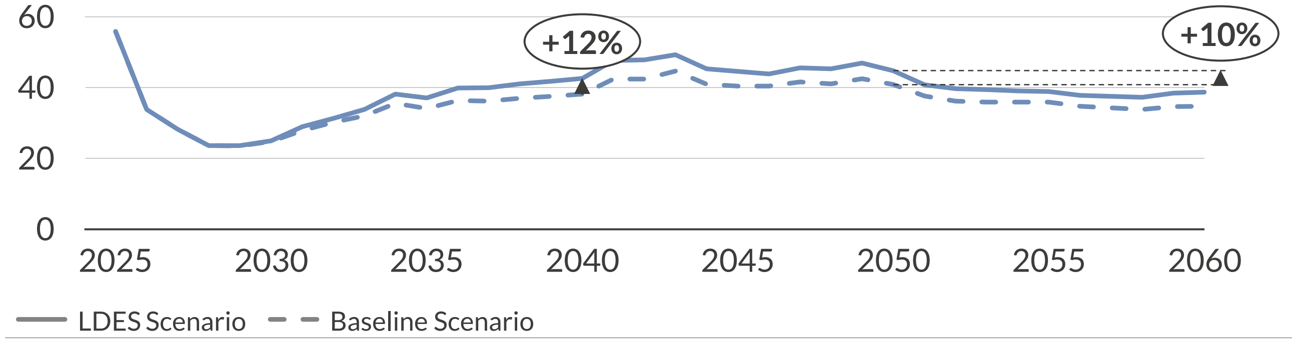


Solar IRR (COD 2030)[2]

%

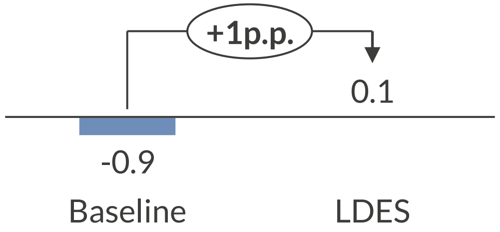


Offshore wind capture prices[1], €/MWh (real 2021)



Offshore wind IRR (COD 2030)[2]

%



Outlook for RES capture prices and asset profitability

- Capture prices go up for all RES when LDES enters the system. Incremental demand from TES uptake in industry and EES charging happens when RES generation is high, reducing cannibalisation
- With an average increase of 39% between 2030 and 2060, solar benefits most from higher capture prices. Solar PV suffers the most from cannibalisation due to high buildout and correlated generation profiles, which is mitigated by the deployment of LDES
- Profitability of renewables assets improves significantly with LDES deployment, especially for solar. As a result, RES deployment would require less subsidies

---

1) Uncurtailed generation-weighted capture prices. 2) Representing merchant asset. IRR numbers are real and pre-tax. Aurora CAPEX and OPEX as of H1 2023. For onshore, load factor is 34% and 27-year lifetime. For solar PV, load factor is 22% and 30-year lifetime. For offshore, load factor assumed is 50% and 30-year lifetime.

Source: Aurora Energy Research

Agenda

- **I. Overview of the study**
- **II. Executive summary**
- **III. Baseline scenario**
- **IV. LDES scenario**
- **V. Scenario comparison: LDES vs Baseline**
- **VI. Asset economics under LDES scenario**
  - a. Power-to-heat LDES
    - i. Assumptions and modelling framework
    - ii. Levelised cost of heat by 2025
    - iii. Impact of retail charges in the business case
    - iv. Thermal storage with PPAs
    - v. Levelised cost of heat by 2030
  - b. Power-to-power LDES
- **VII. Policy considerations**
- **VIII. Appendix**

Aurora compared thermal storage to alternatives based on cost of producing same heat requirements through fossil fuels and electric boilers

AURORA

Power-to-heat

Assumptions for power-to-heat LDES analysis

- Aurora gathered data from LDES Innovators regarding their thermal storage technologies for grid connected assets
- TES will be providing 24/7 heat for process heat; technologies can charge from the grid while simultaneously discharging heat
- Assets will be modelled with the preferable set ups for grid connected TES considering
  - Charging profile
  - Energy storage capacity
  - Thermal efficiency
  - Availability
  - Lifetime
  - Costs (CAPEX, OPEX)
- The generic business case for TES considers that the asset **charges only from the wholesale market**
  - Aurora will not consider secondary, tertiary and replacement reserve markets
  - No foresight on dispatchability in these ancillary service markets and increasing competition (scenario with 17 GW of storage by 2030), would make it a highly risky business model given that TES must provide 24/7 heat for industry process heat

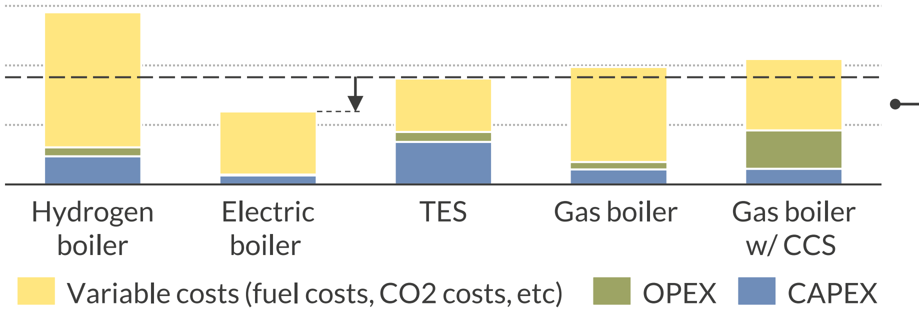
Results: business case for each power-to-heat LDES

- Compare costs to alternatives based on cost of producing **same thermal requirements** through other technologies

Driver of economics	Description
CAPEX	Upfront cost
OPEX	Annual cost associated with regular upkeep of technology[1]
Lifetime	Average number of years before replacement
Efficiency	Average round trip efficiency throughout the year
Variable costs	Annual running cost dependent on demand profile, efficiency (and CO_2 costs, if applicable)
Discount rate	Time valuation (discounting)

Illustrative levelised cost of heat (LCOH) for COD 2025

€/MWh



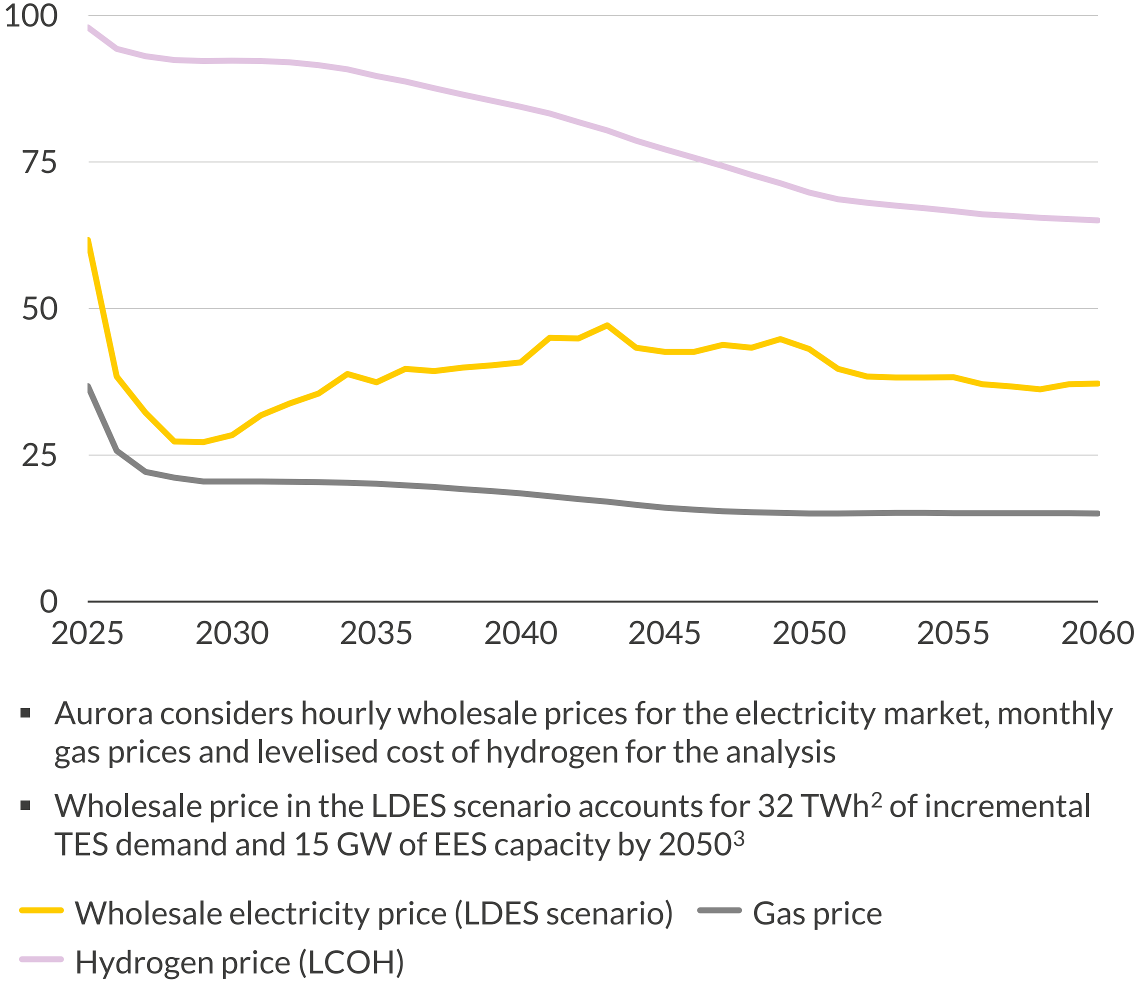
- Funding gap to compete against existing technologies
- **Aurora shared preliminary results with Innovators to gather their feedback**

---

1) For gas boiler with CCS, Aurora includes carbon transport and storage costs on top of OPEX costs (see slide 53).

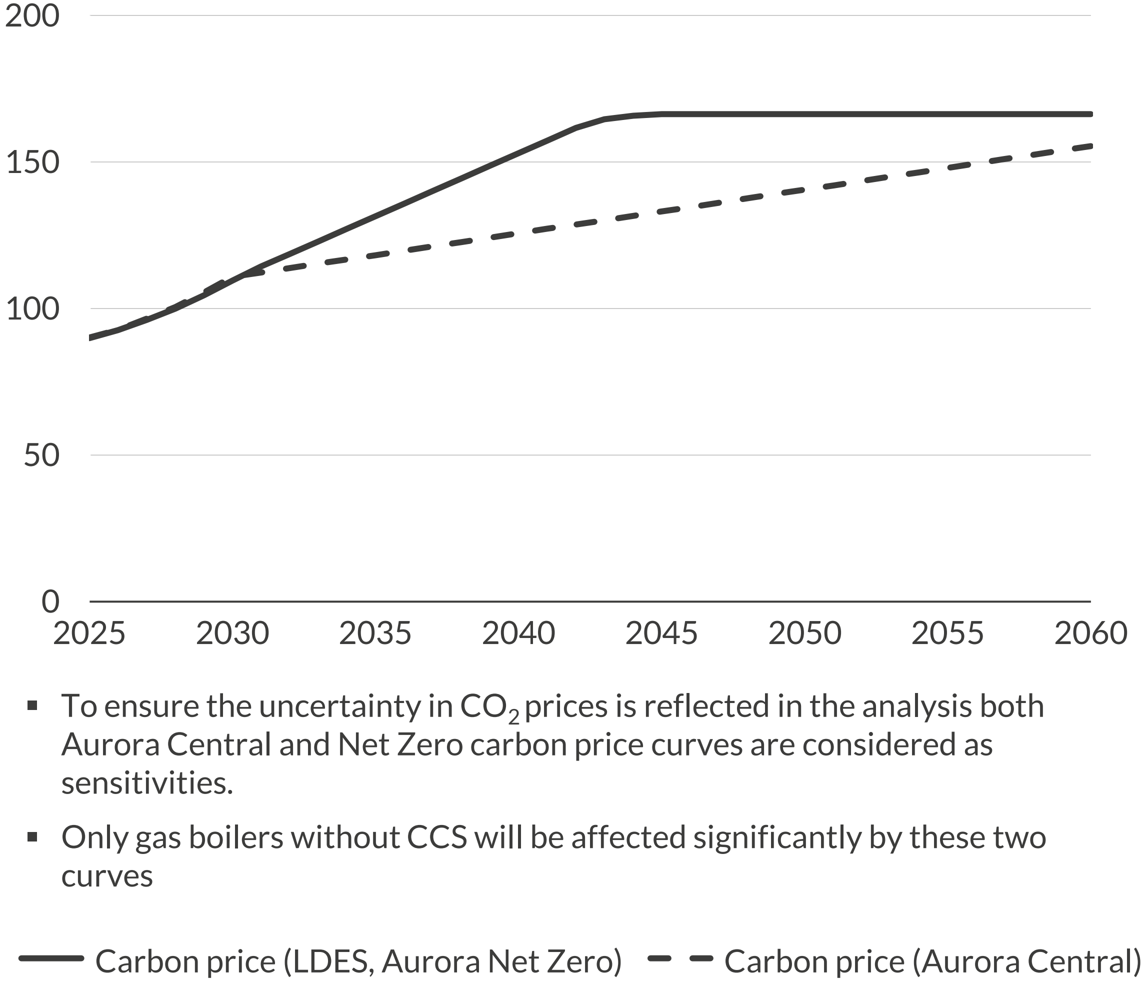
Aurora's power and commodity prices under the LDES scenario are central to accurately reflect variable costs for all technologies

Market prices under LDES Scenario[1]
€/MWh (real 2021)



- Aurora considers hourly wholesale prices for the electricity market, monthly gas prices and levelised cost of hydrogen for the analysis
- Wholesale price in the LDES scenario accounts for 32 TWh[2] of incremental TES demand and 15 GW of EES capacity by 2050[3]

Carbon price
€/tCO_2 (real 2021)



- To ensure the uncertainty in CO_2 prices is reflected in the analysis both Aurora Central and Net Zero carbon price curves are considered as sensitivities.
- Only gas boilers without CCS will be affected significantly by these two curves

---

1) Aurora market price includes 7% generation tax. Aurora prices are based on April 23 release. 2) Modelled as incremental demand, representing 4 GW of thermal capacity. See slide 33. 3) See slide 63 for further detail on the durations.

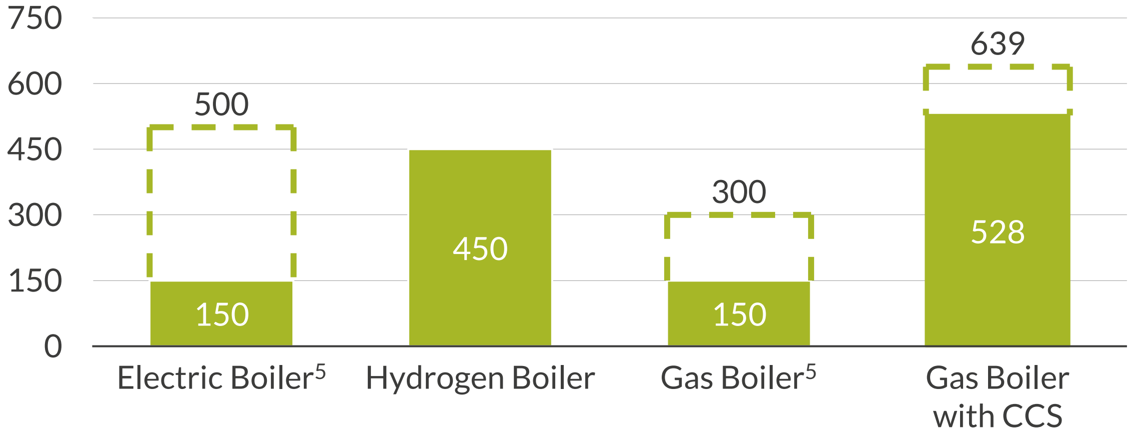
Sources: Aurora Energy Research

Specifications and costs for competing technologies are based on literature while variable costs are determined based on Aurora price curves

Parameter	Electric Boiler	Hydrogen Boiler	Gas Boiler	Gas Boiler with CCS
Efficiency, %	99%	95%[1]	89%	89%[2]
Load Factor, %	98%			
Lifetime, years	25			
Variable Costs (Aurora curves)	Power (wholesale)	Levelised Cost of Hydrogen[3]	Gas + Carbon	Gas + 5% Carbon[4] + Carbon transport and storage
Discount rate, %	7%			

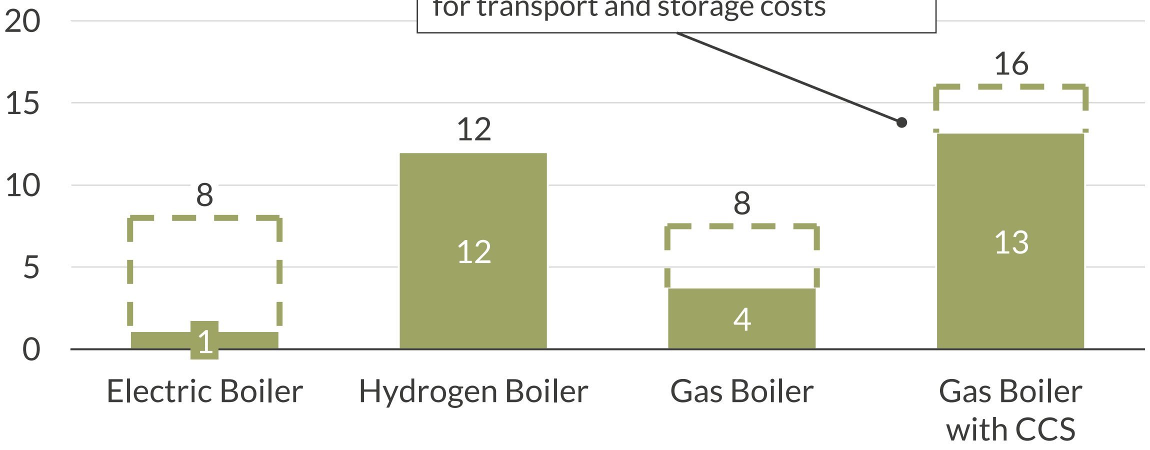
CAPEX

€/kW (real 2021)



OPEX

€/kW/yr (real 2021)



On top of costs shown, we have assumed additional 90[6]-155[7] €/tCO$_2$ for transport and storage costs

---

1) 100% H$_2$ burners reported to be more efficient than gas due to flue gas condensation and recycling. 2) Efficiency only for the heating process. 3) Levelised Cost of Hydrogen for a grid connected electrolyser. 4) Consistent with predicted Longship project CO$_2$ capture 5) Gas and electric boilers present a similar median CAPEX. Higher cost for electric boiler are explained by additional infrastructure costs. 6) IEA predicted cost. 7) In line with published research for industry sectors considered in this study

Sources: Aurora Energy Research, European Technology Platform for Zero Emission, BEIS, Joint Research Centre, Danish Energy Agency, NL PBL, GB household study, Goldman-Sachs, IEA, Energy Strategy Reviews Journal

Aurora analysed thermal storage asset configurations based on input provided through Innovators' surveys

Innovator input

- Values given below are indicative of ranges used to calculate LCOH for given TES temperature range with specific configurations. Data points are representative preserving data confidentiality from LDES Innovators
- Configurations provide 24/7 heat for industrial purposes with a given storage size, charging profile and discharging output provided by Innovators. **Only configurations (profile and respective costs) provided by Innovators were evaluated**
- Annual generation is used to compare costs of competing technologies given the same 24/7 thermal output. **Combined power and heat is not considered in this study**[1]

Parameter	Medium temperature[2] (100-500°C)		High temperature[2] (500-1500°C)	
Technology	Thermal sensible heat energy storage system			
Efficiency, %	92 - 97%		95 - 98%	
Availability, %	95 - 98%		92 - 95%	
Charge Power, MW	Configuration specific – based on Innovators' input. We do not provide more information on set up to preserve data confidentiality			
Storage, MWh				
Charging Profile, hours	6h to 13h		3h to 13h	
Annual Generation, GWh	40 – 60		20 – 50	
Lifetime, years	25[3]		25[3]	
CAPEX[4], €/kWh	2025: 50 – 200[5]	2030: 40 – 160	2025: 30 – 45[6]	2030: 15 - 25
OPEX[4], €/kWh/yr	2025: 0.5 – 0.75[7]	2030: 0.5 - 0.75	2025: 1 – 2[8]	2030: ~1

- Only configurations provided by Innovators were evaluated
- Resulting LCOH must be analysed on a case-by-case basis

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1) Combined power and heat LDES could stack heat revenues, but analysis for the specific case would be required to quantify benefit. 2) Details regarding temperature range and deployment in slides 30-34. 3) Some Innovators could have lifetimes of 30 years. 4) Representative of Innovators' technologies to preserve data confidentiality. All values are real 2021. 5) 650 – 2500 €/kW. 6) 250 – 300 €/kW. 7) 6 – 8 €/kW 8) 9 -12 €/kW.

Sources: Aurora Energy Research, Innovator's surveys

By 2025, some thermal storage assets in the LDES scenario are already competitive with existing technologies, showing LCOH ~32 €/MWh

Power-to-heat

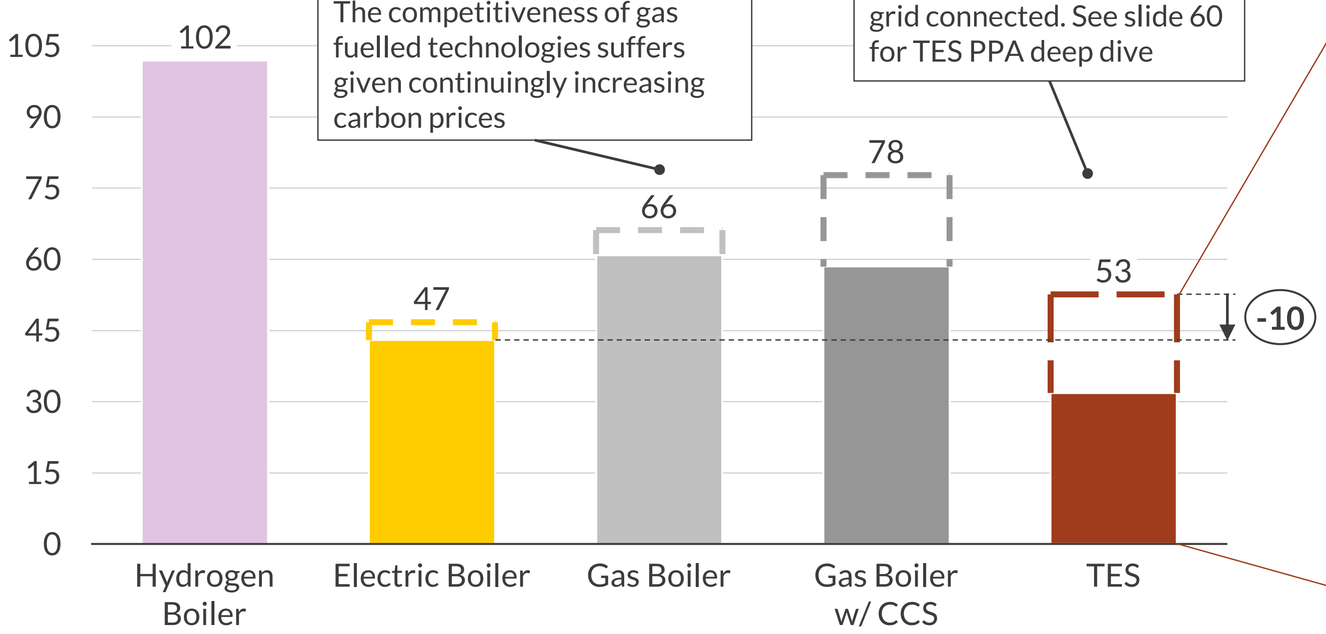
Competing technologies

- Some thermal storage set ups are already competitive with existing technologies by 2025 in the LDES scenario, showing a LCOH as low as 32 €/MWh
- LCOH of H_2 boilers remains above thermal storage due to high hydrogen prices
- For the higher ranges, TES need subsidies to compete with electric boilers

Thermal storage

- Most of the Innovators target industry process heat applications at high temperature (i.e., delivery of heat >500°C)[3]
- Medium and high temperature TES show different LCOHs as a result of different investment and variable costs[2]

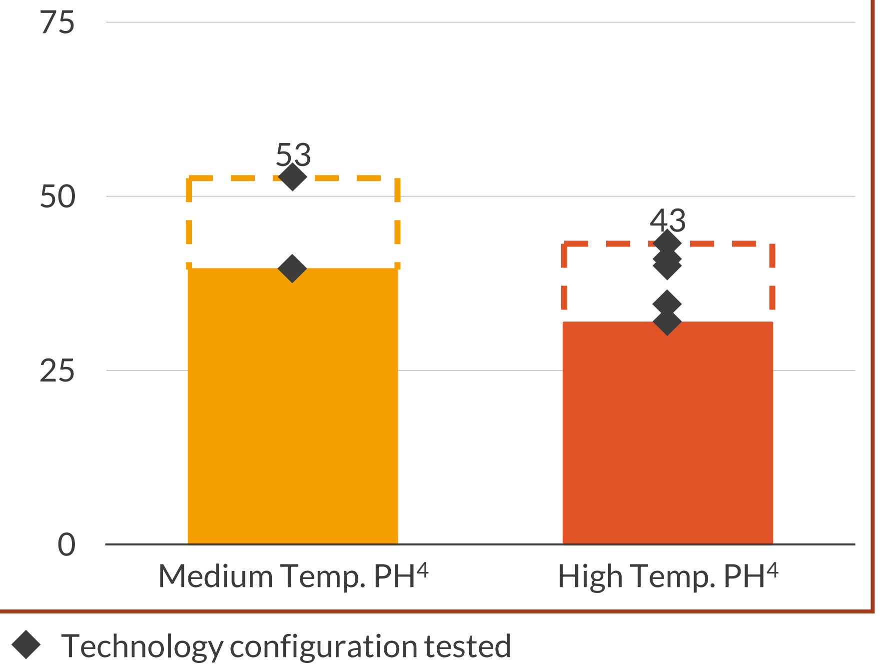
Levelised cost of heat (LCOH) for COD 2025[1,2]
€/MWh



The competitiveness of gas fuelled technologies suffers given continuingly increasing carbon prices

All technologies are assumed to be stand-alone grid connected. See slide 60 for TES PPA deep dive

TES levelised cost of heat (LCOH) for COD 2025[1]
€/MWh



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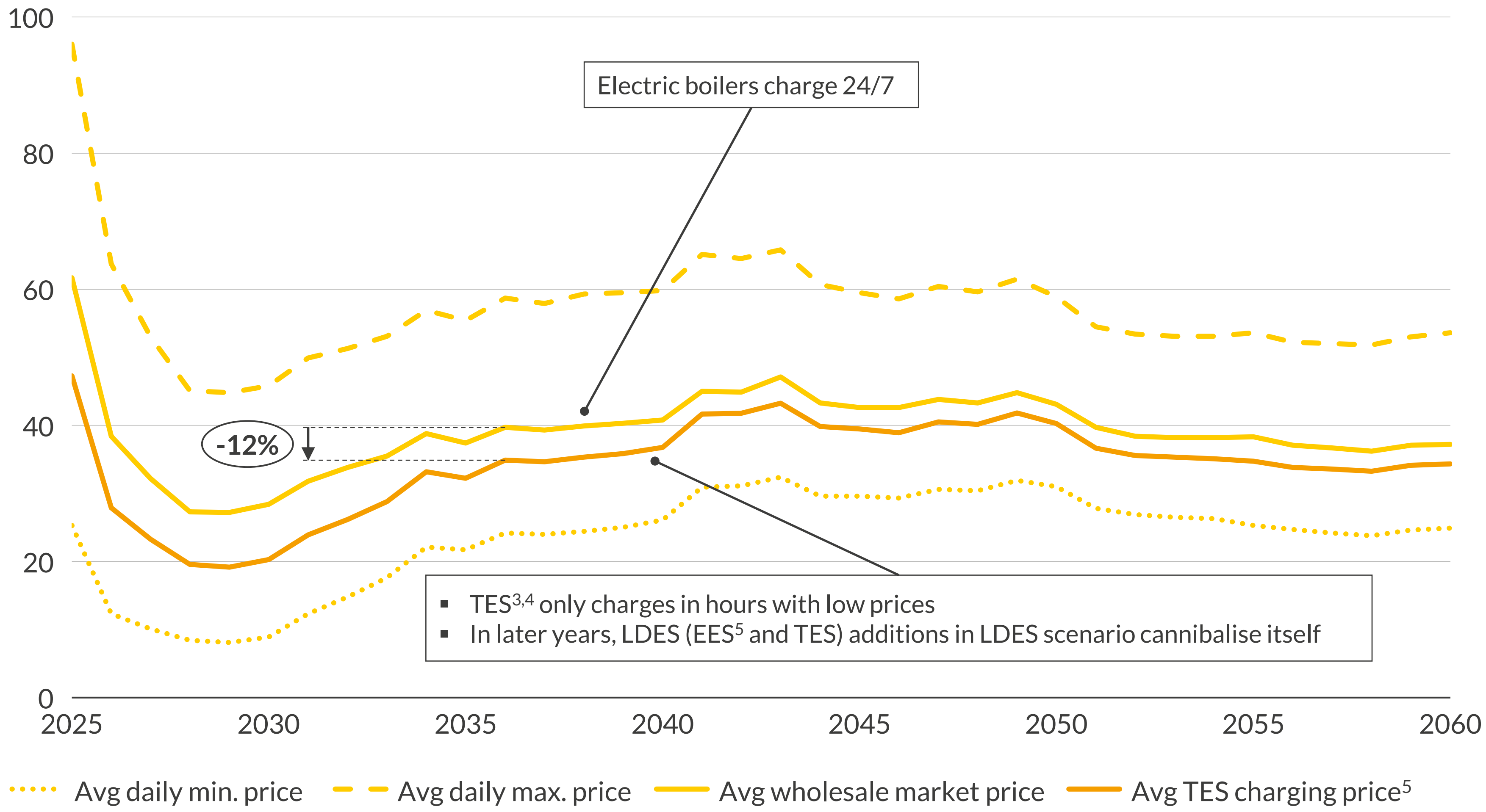
1) Discount rate of 7% . Unless explicitly stated, we consider only "wholesale energy costs", namely "variable costs" in the LCOH analysis. See slides 58-59 for retail charges deep dive. 2) Slides 52 and 56 include Aurora's market prices considered as well as TES variable costs under LDES scenario for one of the configurations. 3) High temperature configurations can deliver both medium and high temperature heat. See LDES section for details on uptake of TES in process heat. 4) Configurations are cycled daily.

Sources: Aurora Energy Research, European Technology Platform for Zero Emission, BEIS, Joint Research Centre, Danish Energy Agency, NL PBL, GB household study, Goldman-Sachs

Unlike electric boilers, thermal storage takes advantage of market volatility charging only in low price hours of the day

Yearly averages of daily minimum and maximum power market prices under LDES Scenario[1,2]
€/MWh (real 2021)



Electric boilers charge 24/7

- TES[3,4] only charges in hours with low prices
- In later years, LDES (EES[5] and TES) additions in LDES scenario cannibalise itself

- Electric boilers are vulnerable to wholesale price volatility as they charge every hour to ensure delivery of process heat 24/7
  - A trade-off is made by sacrificing flexibility in charging price in favour of very low required capital investment
- On the other hand, TES[3,4] requires a higher investment but benefits from lower variable costs from charging in the hours of the day with lowest prices
- A COD after 2029 (year with the minimum wholesale price) will hurt the business case of TES more than electric boilers in relative terms as there is less price volatility

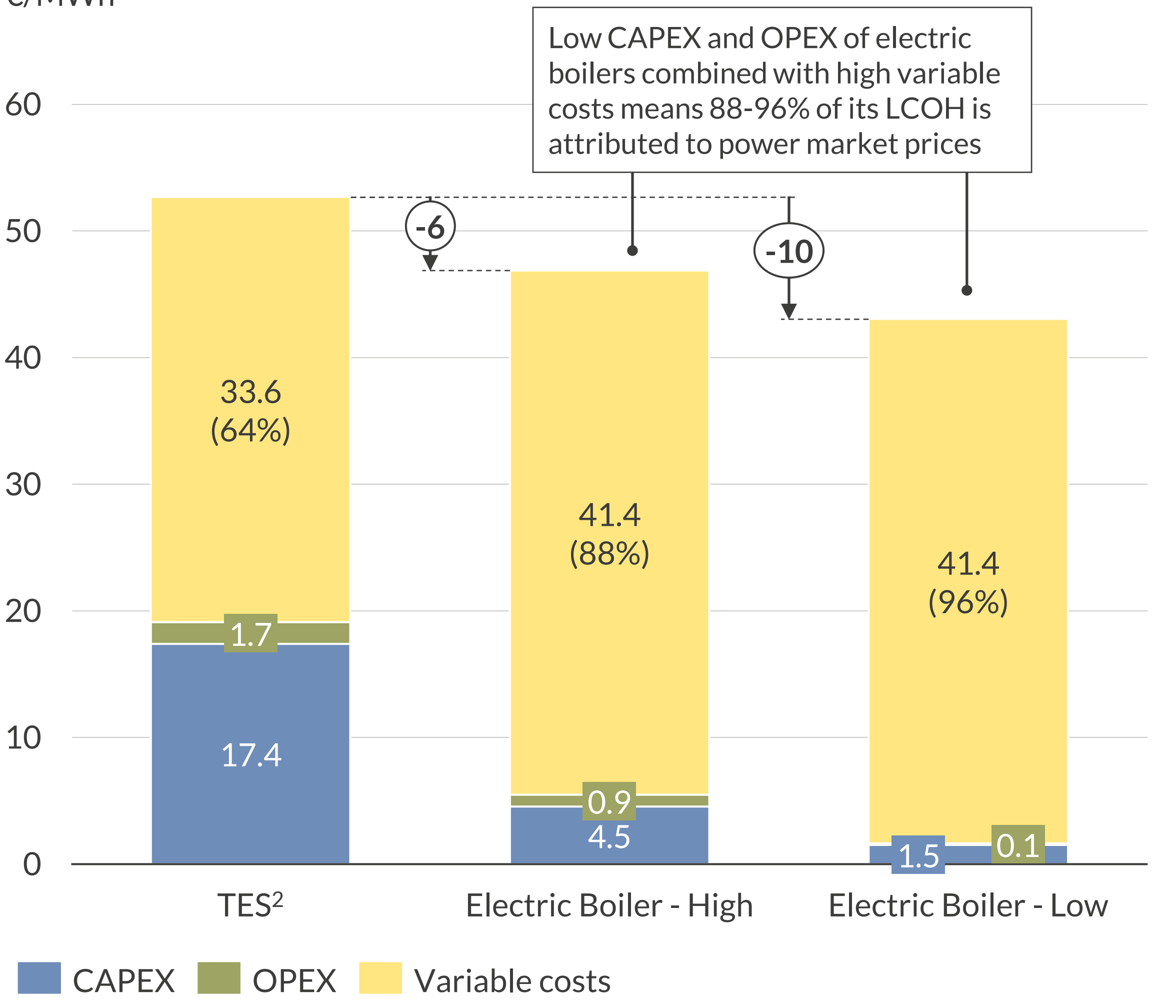
---

1) Aurora market price includes 7% generation tax. Aurora prices are based on April 23 release. 2) See "LDES vs Baseline" section for further detail. 3) Thermal energy storage. Modelled as incremental demand, representing 4 GW of thermal capacity. 4) Charging price is dependent on charging profile, curve shown is specific to a single configuration. 5) Electrical energy storage.

Sources: Aurora Energy Research

Some TES configurations for industrial process heat applications would still require a subsidy of 6-10 €/MWh to compete with electric boilers in 2025

LCOH: bankable funding gap for COD 2025 for upper range TES vs electric boilers[1,2,3]
€/MWh



Required funding gap

- Although some tested configurations are already competitive with alternative technologies, other configurations for industrial process heat applications show a LCOH of 53 €/MWh. Thus, a subsidy would be necessary
- In the upper range case, the funding gap for TES would differ compared with cheapest electric boilers by 10 €/MWh and 6 €/MWh for the most expensive electric boilers
- Some TES configurations would require a subsidy to remain competitive given its higher investment costs compared with electric boilers; the combined CAPEX and OPEX LCOH components for TES is between 4-12x that of an electric boiler
- Variable costs represent the largest component of the LCOH for all technologies, between 64-96%
- TES benefits from charging mostly in low price hours, but can still be exposed to high market prices (see slide 56) and does not offset the high investment cost
- Both technologies charge from the grid operating in an LDES scenario with storage cannibalisation[4]

---

1) Discount rate of 7%. 2) Does not consider retail tariffs for the assets. See slide 59 for retail charges deep dive. 3) Comparing medium temperature TES (up to 500°C) and electric boilers. Electric boilers that can generate industrial heat up to 500 degrees are available. For heat up to 1000°C, it is technologically feasible but not yet commercially available for all applications. 4) We assume 32 TWh of incremental thermal demand in industry and 15 GW of electrical storage in the system by 2050

Sources: Aurora Energy Research, Agora Energiewende and Wuppertal Institut, McKinsey

We assume that thermal storage will be subject to the electricity tariffs for industrial consumers connected at medium-high voltages

Power-to-heat

- For our analysis, we assumed that TES will be subject to the electricity tariffs for industrial consumers connected at medium-high voltages
- The total electricity cost includes several components; we have only considered wholesale energy costs and retail charges
  - We use hourly level wholesale market prices for the LDES scenario[1]
  - We assume the current tariffs (set by Circular 3/2020) throughout the entire period
- Components like ancillary services and elements of the retail charges would be different between the LDES scenario and the Baseline scenario

1 **Ancillary services**:

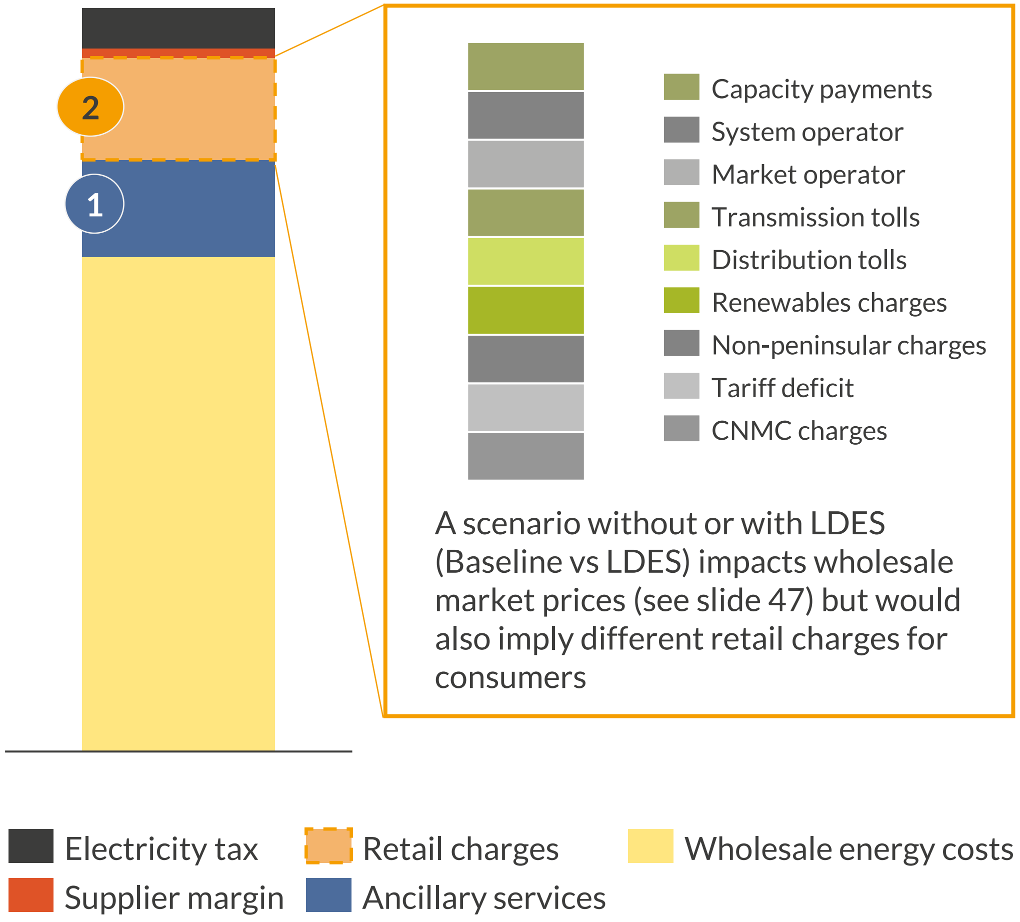
- LDES can provide ancillary services as well as other auxiliary services to grid operators like inertia, congestion relief and voltage control
- In the LDES scenario, participation in these services would replace other CO_2 emitting synchronous technologies and could decrease costs for the consumer. This has not been quantified in this study

2 **Retail charges**:

- Retail charges are divided into two components which vary depending on the time at which energy is consumed, and the maximum capacity contracted in each period
- Retail charges include all regulated costs: network tolls, capacity payments and charges related with promotion of renewables (tariff deficit)
- Regulated costs related with renewables would be linked with the level of subsidy required by each scenario. Given that LDES integrates RES generation, increasing its profitability, RES costs passed on to consumers would be different in a scenario without or with LDES[3]

Electricity cost components for industrial consumers[2]

€/MWh



A scenario without or with LDES (Baseline vs LDES) impacts wholesale market prices (see slide 47) but would also imply different retail charges for consumers

---

1) Unless explicitly stated, we consider only "wholesale energy costs", namely "variable costs" in the LCOH analysis in the previous slides (55-57) and in slide 61. 2) Illustrative example of the breakdown of the electricity cost for an industrial consumer under the retail tariff set by Circular 3/2020. Retail charges that apply to an industrial consumer under tariff 6.2. TD (32-72.5 kV). 3) Analysis for both scenarios would be required to quantify the impact.

Source: Aurora Energy Research

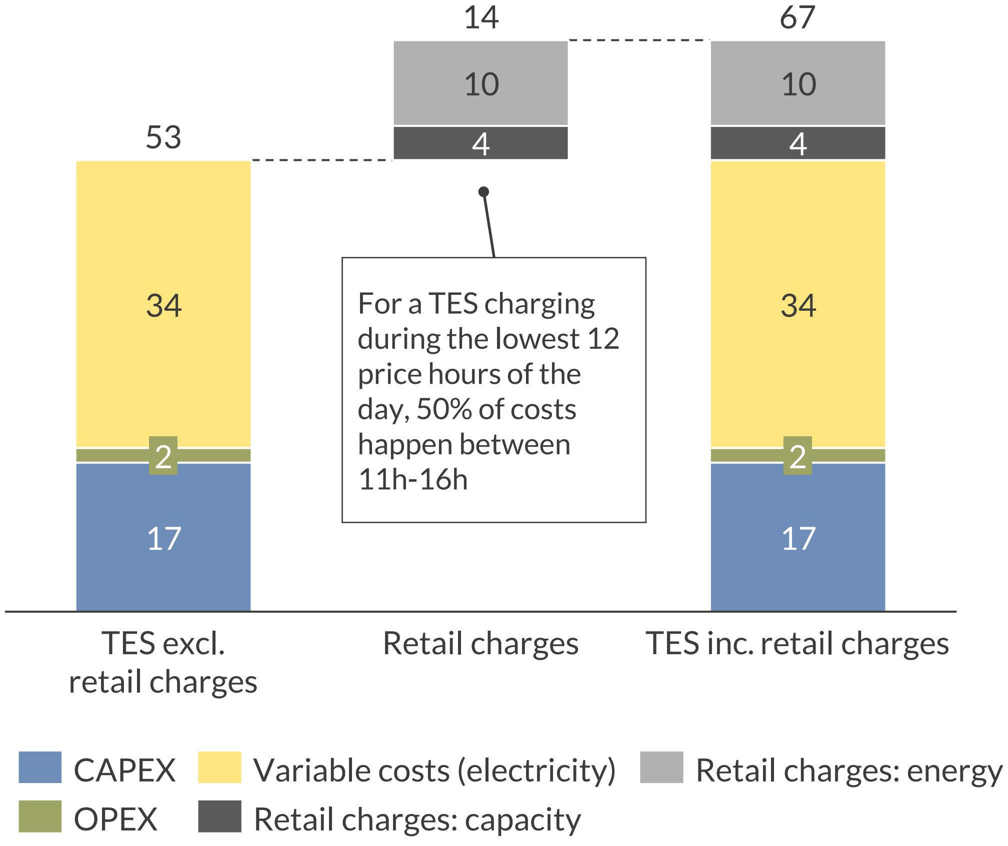
Unless there are regulatory changes, current tariffs penalise TES energy consumption during the middle of the day, worsening the business case

Power-to-heat

In our analysis, we have not accounted for grid charges. Even though Circular 3/2020 exempts storage from grid charges, this only applies if energy is reinjected into the grid. For TES operating as power-to-heat, energy would not be reinjected back; thus, within the regulatory framework, TES would have to pay grid charges[1]

Levelised cost of heat (LCOH) for COD 2025

€/MWh



For a TES charging during the lowest 12 price hours of the day, 50% of costs happen between 11h-16h

- Considering an industrial consumer connected at medium-high voltage, if grid charges were applied to the thermal storage asset, the levelised cost of heat would increase by 28% compared to our base case, or by 14 €/MWh
- Grid charges are divided into two components which vary depending on the time at which energy is consumed, and the maximum capacity contracted in each period
- The current tariff structure penalises capacity and energy consumption in the middle of the day (see Appendix for industrial consumer tariff considered in this study)
- TES charges during the hours of the day with the lowest prices, which are usually in the middle of the day driven by high levels of solar generation
- For a TES charging during the 12 hours of the day with the lowest price, 50% of the retail charges happen between 11h-16h

A Policy section: Impact of retail charges[1] for TES

- This deep dive on the impact of retail charges regulation for TES has been referred in the policy section. Possible measures to incentivise the TES business case could be:
  - Revise tariff structure to reflect lower costs when there is high solar output
  - Exempt TES from grid charges given that is outputting heat (in some cases, TES discharges power and heat), if avoiding CO_2 emissions in the industry sector

X *Included in policy section*

---

1) Retail charges would also apply to electric boilers. For the electric boilers case, providing same thermal output as this TES, LCOH would be increased by 9.5 €/MWh. Namely, from 43 €/MWh (lower case) to 52.5 €/MWh and from 47 €/MWh (high case) to 56.5 €/MWh. This is comparable with the 67 €/MWh LCOH for the TES with retail charges.

TES with solar PPA shows the best LCOH due to complementary TES charging profile and solar generation while benefiting from lower retail charges

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Power-to-heat

A Grid connected stand-alone TES

- For this business case, we consider the TES case shown in slide 59 considering that asset only charges from the grid in a LDES scenario in which renewables are built below LCOE before 2030s

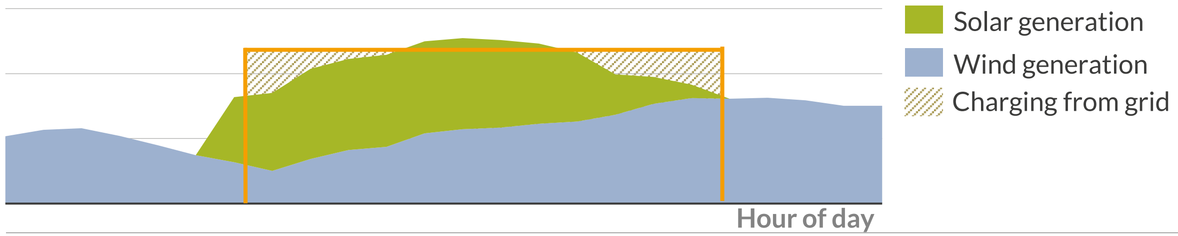
B Grid connected TES with a solar PPA

- RES asset assumed to deliver all generation to TES if within charging hours. Asset is sized such that peak annual generation is 120% of TES charging power demand, meeting 65% of total TES charging needs[1]
- Price paid for charging TES from asset is the respective LCOE discounted at 7%. If outside of this period, sale of excess energy assumed at wholesale price, generating revenue[2]

C Grid connected TES with a co-located solar and wind PPA

- Co-locating with solar and wind aims to increase overlap of charging and RES generating[2]. Assets oversized using the method above (see illustrative day below)
- With both assets, TES charges from RES in all hours but at lower power (shown below), meeting 58% of TES charging needs

Illustrative day of charging operation for a 12h TES

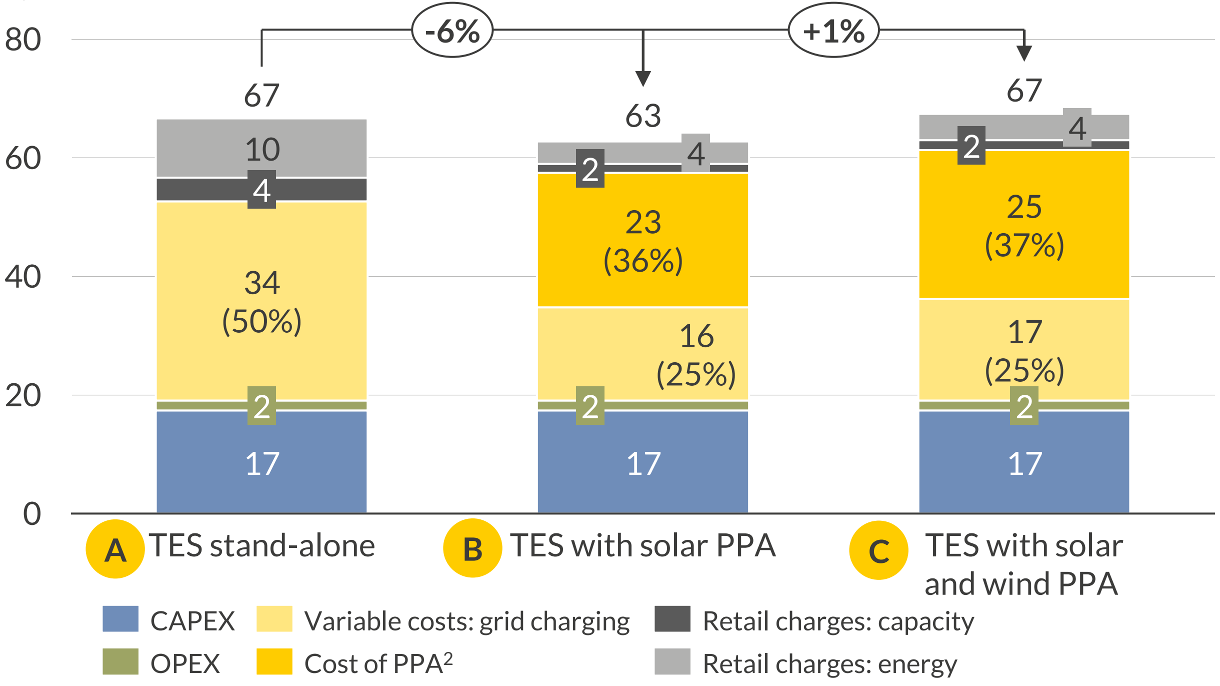


PPA valuation

- A PPA increases variable costs from charging since renewables are built below LCOE in the LDES scenario whereas PPAs are assumed to be signed at LCOE[3]
- TES with solar PPA shows the best LCOH due to complementary TES charging profile and solar generation, while benefiting from lower retail charges
- TES with solar and wind PPA shows worse LCOH due to higher investment costs and less complementary generation and charging profiles

LCOH: bankable funding gap for COD 2025 for high range TES[1,2]

€/MWh



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1) Solar generation in 93% of charging hours. 2) We assume a pay-as-produced PPA. We consider that energy that is not being used to charge the TES is sold to the grid at wholesale market price using this revenue to mitigate PPA cost for the TES. 3) If LCOE is calculated using a 10% discount rate, this is no longer true and LCOH of stand-alone case is below both PPA cases.

Sources: Aurora Energy Research

By 2030, power prices cause an increase in variable costs; TES becomes increasingly competitive with electric boilers as its costs fall

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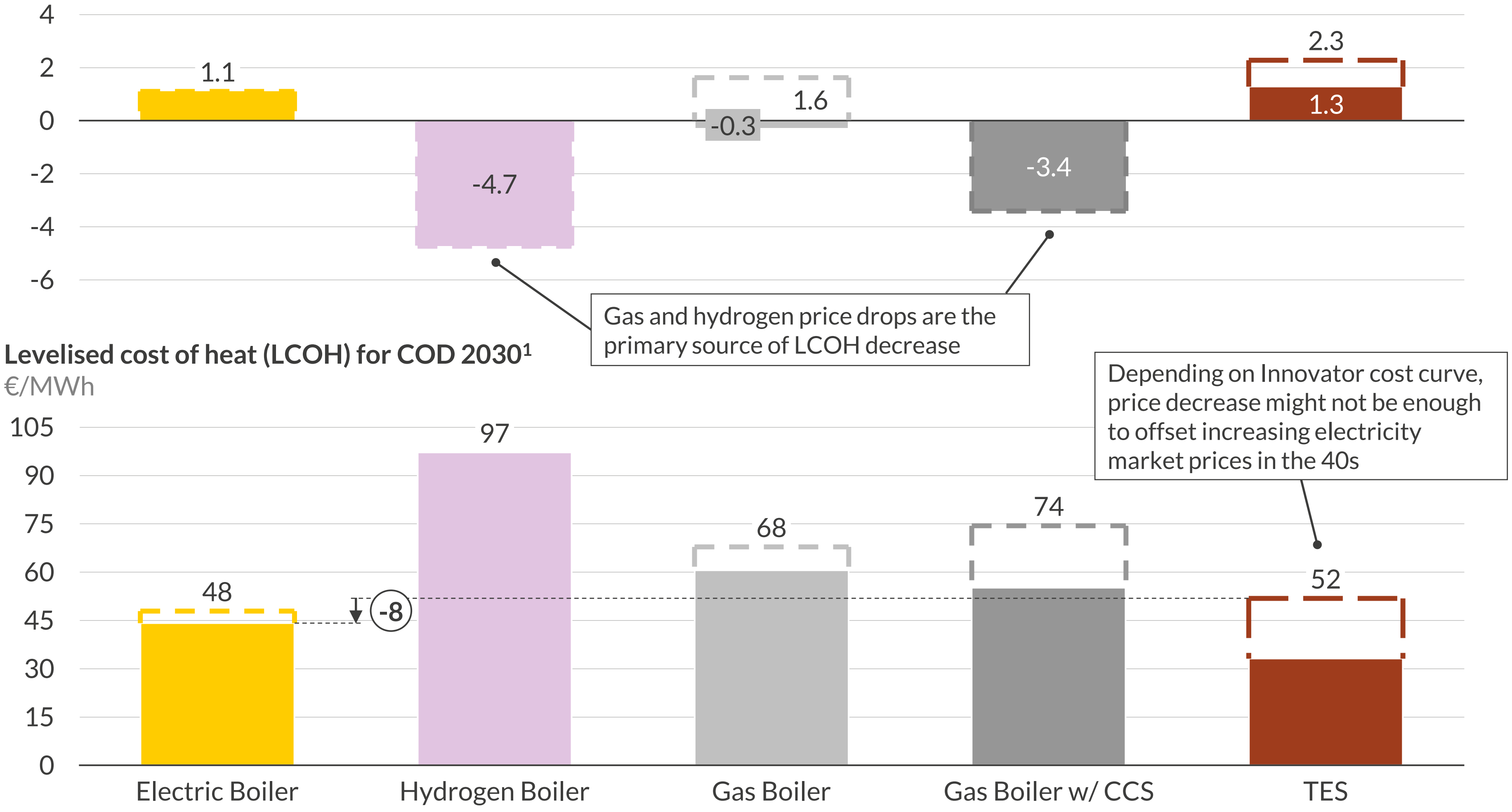
Power-to-heat

Levelised cost of heat (LCOH) delta between COD 2025 and 2030

€/MWh



Gas and hydrogen price drops are the primary source of LCOH decrease

Levelised cost of heat (LCOH) for COD 2030[1]

€/MWh

Depending on Innovator cost curve, price decrease might not be enough to offset increasing electricity market prices in the 40s

- Lower wholesale market spreads by 2030 (see slide 56) lead to higher LCOH for TES and electric boilers
- TES-has a diminished ability to capitalise on high price volatility as the market stabilises with fast storage and lower pace of renewables after late 30s
- Although TES benefits from decreasing costs, this advantage is not enough (in some cases) to decrease LCOH
- Hydrogen benefits greatly from 6% lower hydrogen prices over the hydrogen boiler lifetime
- Gas prices decrease 10% on average over the lifetime of the asset. Given high CO_2 prices, the benefit of low gas prices is outweighed for gas boilers
  - Paying only 5% of the carbon price, CCS gas boilers see the most benefit from low gas price

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1) Discount rate of 7%.

Agenda

I. **Overview of the study**

II. **Executive summary**

III. **Baseline scenario**

IV. **LDES scenario**

V. **Scenario comparison: LDES vs Baseline**

VI. **Asset economics under LDES scenario**

  a. Power-to-heat LDES

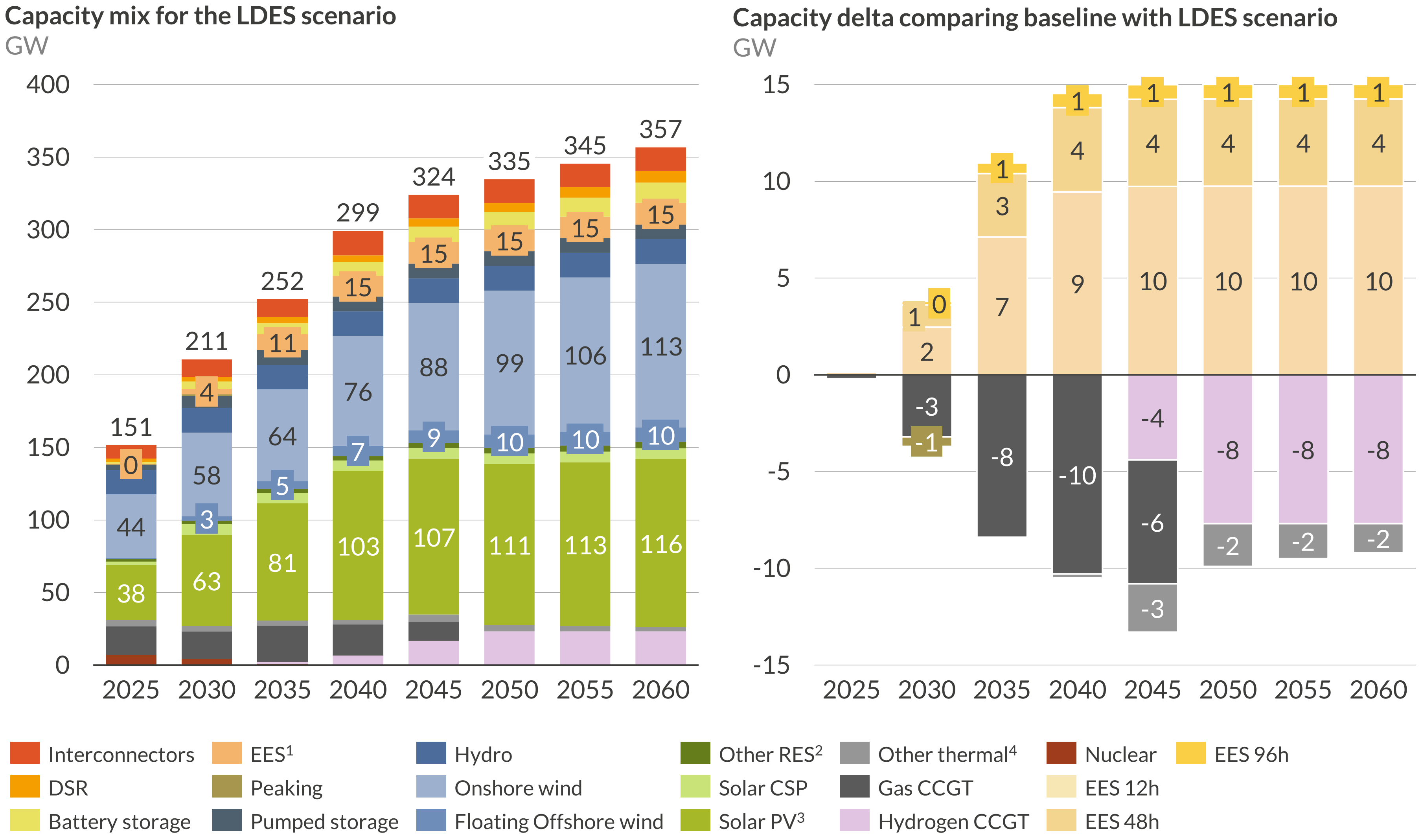
  b. Power-to-power LDES

    i. Assumptions and modelling framework
    ii. Gross margins and IRRs for COD 2025
    iii. Trading strategy across available revenue streams
    iv. Impact of a capacity market and other auxiliary services
    v. Business case for COD 2030
    vi. Subsidies under LDES vs Baseline scenarios

VII. **Policy considerations**

VIII. **Appendix**

In the LDES scenario, 15 GW of EES are deployed by 2045, replacing more expensive CO_2-emitting technologies



- In the LDES scenario which optimises system cost savings, 15 GW of EES[4] are deployed
- In this scenario, there is lower need for thermal and hydrogen installed capacity to ensure security of supply levels in the Spanish power system
- Given that EES discharge in high price hours, there is lower natural gas use, reducing the amount of electricity generated by conventional gas plants and consequently CO_2 emissions in the power sector
- LDES absorb renewable electricity by charging in hours in which renewable production exceeds demand, enabling integration of up to 13 TWh of renewable generation that would have been curtailed

---

1) Three generic electricity storage assets of 12h, 48h and 96h based on Innovators' surveys specifications. 2) Other RES includes biomass and renewable cogeneration. 3) Solar includes solar rooftop PV and solar ground-mounted PV. 4) Other thermal includes fossil fueled cogeneration.

Aurora performed dispatch modelling for 4 power-to-power LDES trading in wholesale and balancing markets

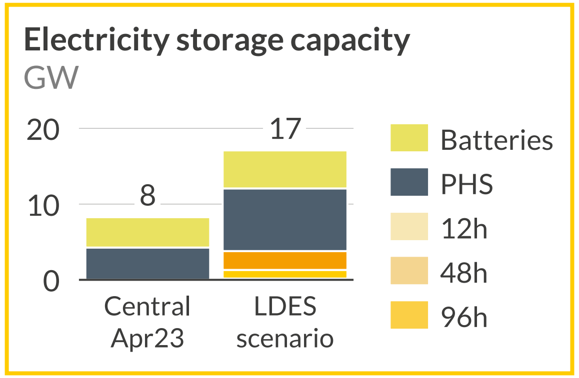
Power-to-power

Assumptions for power-to-power LDES analysis

- Aurora defined **four** power-to-power storage assets based on Innovators' surveys. These will be modelled with the specific set up provided (duration, efficiency, degradation, etc)
- Aurora performed specific dispatch modelling for **COD 2025 and 2030**
- The generic business case for LDES will consider two revenue streams currently accessible for LDES[1]: **wholesale and balancing** (tertiary and replacement reserves) **markets**
- Secondary reserve market will **not** be considered for LDES:

① Secondary reserve is a shallow market with ~700 MW of volumes

- In Aurora Central[2], secondary reserve price is expected to average ~13 €/MW/h from 2030 onwards
- Given the build out in the LDES scenario, increased competition combined with such levels of storage deployment will drive prices close to zero
- LDES might have different response times for charging and discharging, limiting participation to one direction



Electricity storage capacity
GW

② To trade in this market, assets need to be part of a Regulation Zone

③ Required response time is <20 seconds

- Batteries are expected to be more suitable given their faster response
- It will be a highly attractive market for batteries given the possibility to access revenues with reduced cycling, limiting degradation (not a concern for LDES)

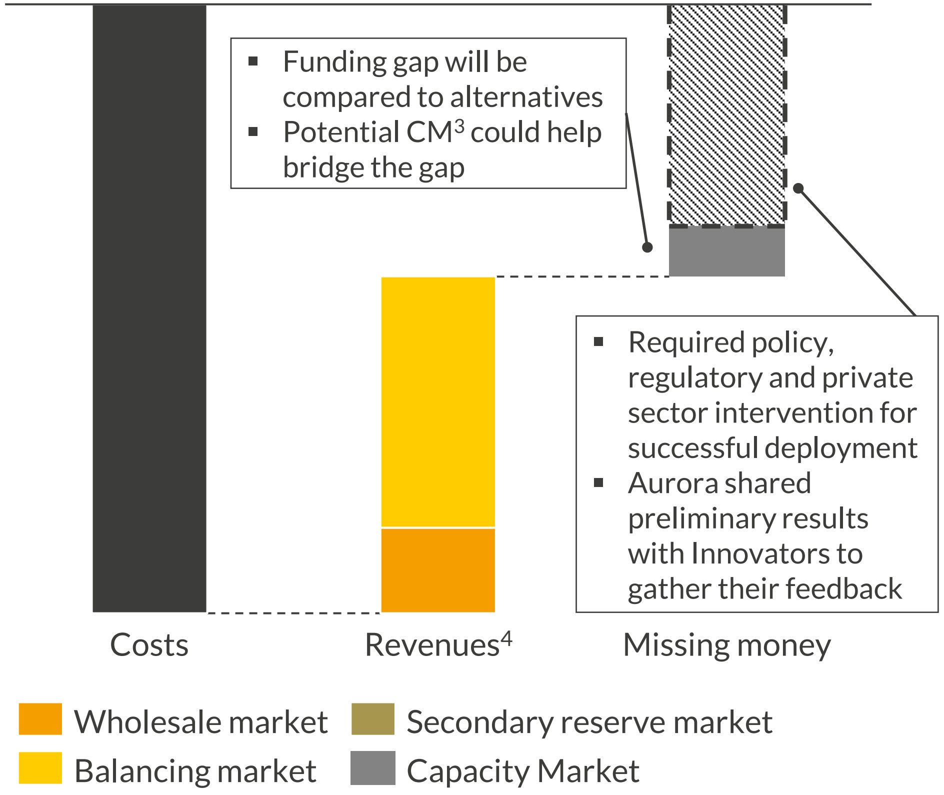
Results: business case for each power-to-power LDES

Generic business case for LDES in Iberia, €/kW

Technology X
(1 out of 4)
COD 2025

- CAPEX, OPEX
- X duration
- X efficiency
- X degradation
- X lifetime

IRR X%



- Funding gap will be compared to alternatives
- Potential CM[3] could help bridge the gap

- Required policy, regulatory and private sector intervention for successful deployment
- Aurora shared preliminary results with Innovators to gather their feedback

---

1) Overview of existing markets in Spain are covered in the Appendix. 2) Aurora Central April 2023. 3) Summary overview of current capacity market proposal can be found in the policy section. 4) Refers to gross margins from charging and discharging in each market.

To quantify missing money, Aurora assumed key parameters in line with the characteristics of each technology

Power-to-power

Innovator input

- Various technologies are currently being developed, mostly differing in costs and commercial maturity. Each technology has different technical parameters, allowing different system needs to be fulfilled. While technologies below could cover a range of durations, Aurora analysed the business case for a specific duration only
- Aurora selected 4 technologies to showcase economic feasibility, based on LDES Innovators' feedback aiming to cover a range of different durations (12h-96h) and efficiencies. **Values given below are representative, preserving data confidentiality from LDES Innovators**
- Assets participate in current revenue streams available for LDES, namely, wholesale and balancing markets (see slide 64 for methodology and appendix for details)

Parameter | Asset	12h Electrochemical Flow Storage	12h Thermal Storage	48h Electrochemical Flow Storage	96h Electrochemical Metal Air Storage
Roundtrip electrical efficiency, %	75%	55%	70%	45%
Availability, %	96%	95%	95%	98%
Lifetime, years	40	30	25	30
Degradation of usable storage capacity, %/yr	Negligible			
CAPEX[1,2], €/kW	2025: 2,300 - 4,000 €/kW 2030: 1,500 - 2,150 €/kW			
OPEX[1,3], €/kW/yr	2025: 12 – 35 €/kW/yr 2030: 6 – 35 €/kW/yr			
Storage duration, hours	12	12	48	96

A discount rate of 7% is applied for the asset level analysis

---

1) Values are real 2021. 2) Investment costs are dependent on the storage duration which varies between the technologies considered. COD 2025: 24 – 292 €/kWh; COD 2030: 18 – 175 €/kWh. 3) OPEX values were not updated for cases where LDES Innovators did not provide values for 2030 or 2035.

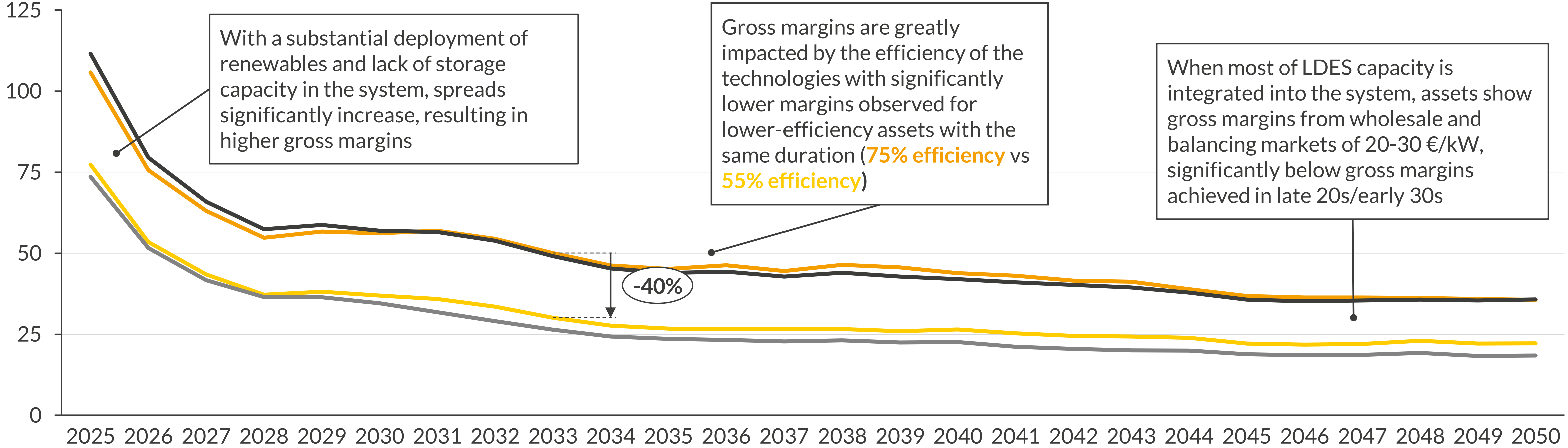
Sources: Aurora Energy Research, IRENA, European Association for Storage of Energy, Innovator's surveys

Gross margins for the different technologies are heavily affected by the spreads of the LDES scenario and by technology's efficiency

Power-to-power

Gross margins of analysed LDES technologies[1]

€/kW (real 2021)



With a substantial deployment of renewables and lack of storage capacity in the system, spreads significantly increase, resulting in higher gross margins

Gross margins are greatly impacted by the efficiency of the technologies with significantly lower margins observed for lower-efficiency assets with the same duration (75% efficiency vs 55% efficiency)

When most of LDES capacity is integrated into the system, assets show gross margins from wholesale and balancing markets of 20-30 €/kW, significantly below gross margins achieved in late 20s/early 30s

2025-2028

The capacity additions of new renewables is larger than LDES deployment

2029-2034

While the pace of new renewables has slowed down, LDES additions continue to increase

2035-2050

Most of the LDES capacity has already been deployed

---

[1] Accounting for 7% generation tax.

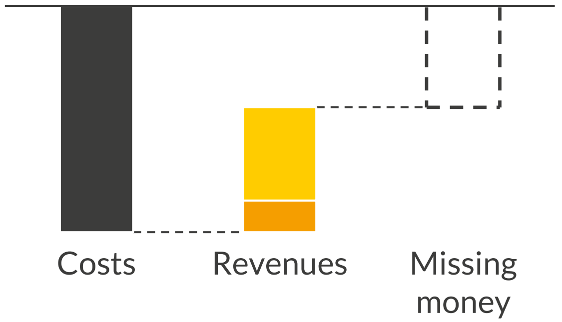
To achieve an 7% IRR, long duration storage assets would require a subsidy ensuring 73-88% of the costs incurred over its lifetime, depending on asset

Power-to-power

COD 2025, 7% target IRR

Illustrative present value of cashflows[1,2]

€/kW, real 2021



- We show the missing money to achieve a target IRR of **7%**
- Participation in other markets (e.g., potential capacity market) would reduce the missing money gap for LDES

🟧 Wholesale market

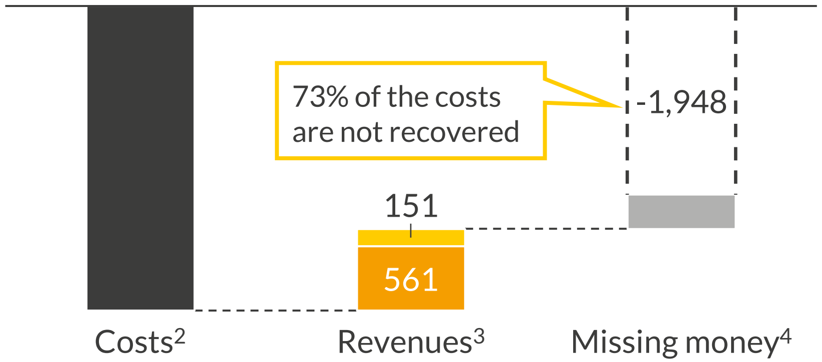
🟨 Balancing market

⬛ Capacity market[5]

1 12h 75% efficiency flow storage

Present value of cashflows[1]

€/kW, real 2021

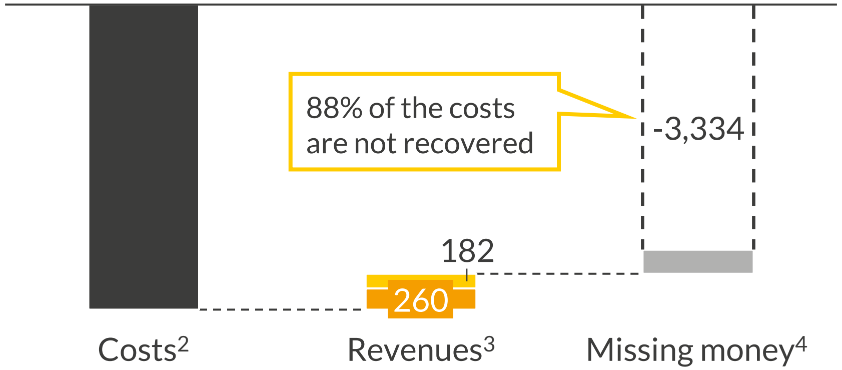


73% of the costs are not recovered

2 12h 55% efficiency thermal storage

Present value of cashflows[1]

€/kW, real 2021

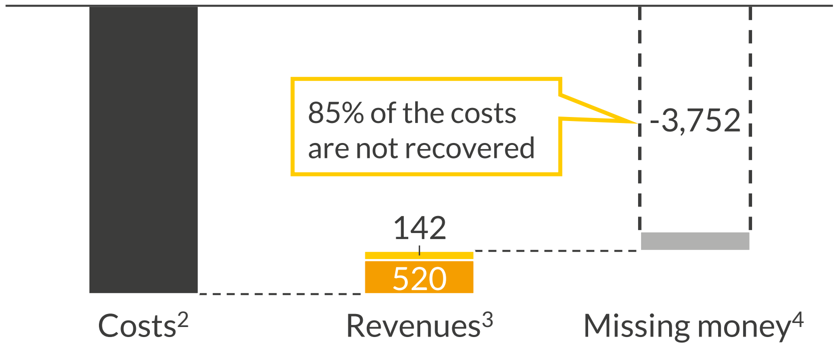


88% of the costs are not recovered

3 48h 70% efficiency flow storage

Present value of cashflows[1]

€/kW, real 2021

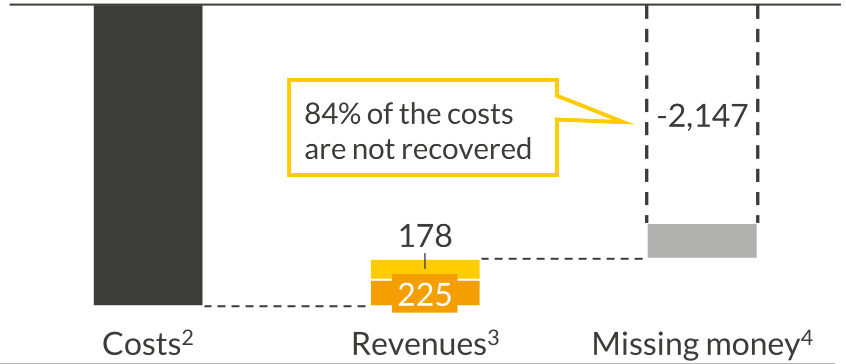


85% of the costs are not recovered

4 96h 45% efficiency metal air storage

Present value of cashflows[1]

€/kW, real 2021



84% of the costs are not recovered

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1) Accounting for 7% generation tax. 2) Considers CAPEX and OPEX costs over each asset lifetime discounted at 7%. 3) Considers yearly average gross margins over each asset lifetime discounted at 7%. 4) Participation in other markets would reduce the missing money gap. 5) Current details for the capacity market proposal can be found in the policy section.

Sources: Aurora Energy Research

Duration and efficiency are key to maximise revenues from the wholesale market, shifting value to a more reliable source of revenues

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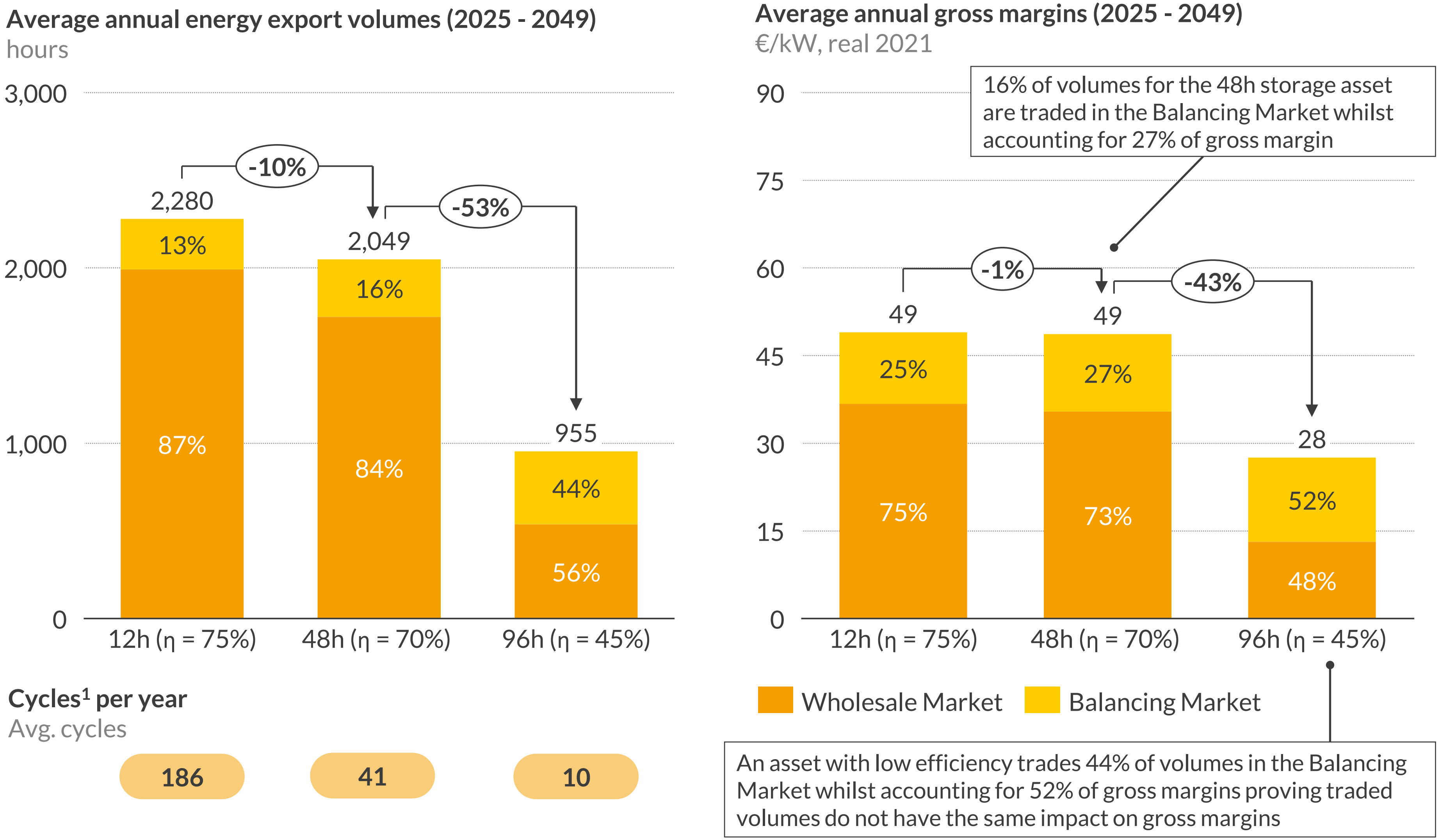
Power-to-power



16% of volumes for the 48h storage asset are traded in the Balancing Market whilst accounting for 27% of gross margin

An asset with low efficiency trades 44% of volumes in the Balancing Market whilst accounting for 52% of gross margins proving traded volumes do not have the same impact on gross margins

- An asset with lower efficiency relies on larger required spreads to trade. This favours trading in the Balancing Market instead of Wholesale Market due to its larger price spread (lower charging and higher discharging prices)
- Lower duration LDES typically benefits from higher efficiencies
- A high efficiency asset maximises revenues captured from the Wholesale Market, obtaining ~73-75% of its revenues from this market while still benefitting from Balancing Market spreads

---

1) Defined as one full charge and discharge cycle. 2) η = electrical round trip efficiency

Participation in more than one market allows for a more optimal trading strategy leading to higher expected revenues

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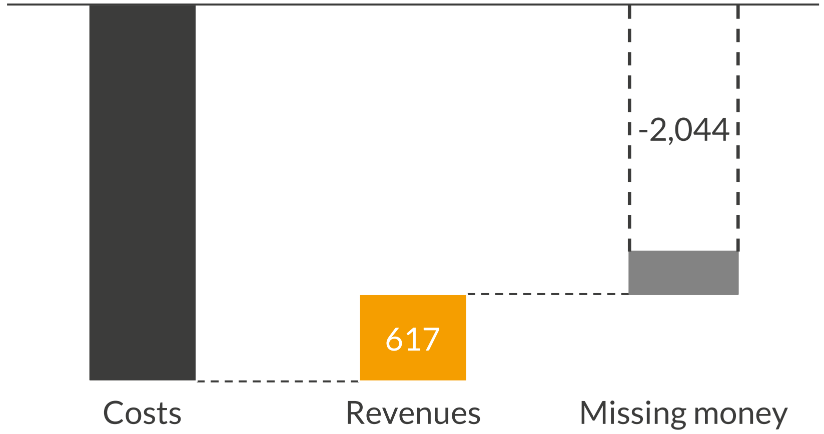
Power-to-power

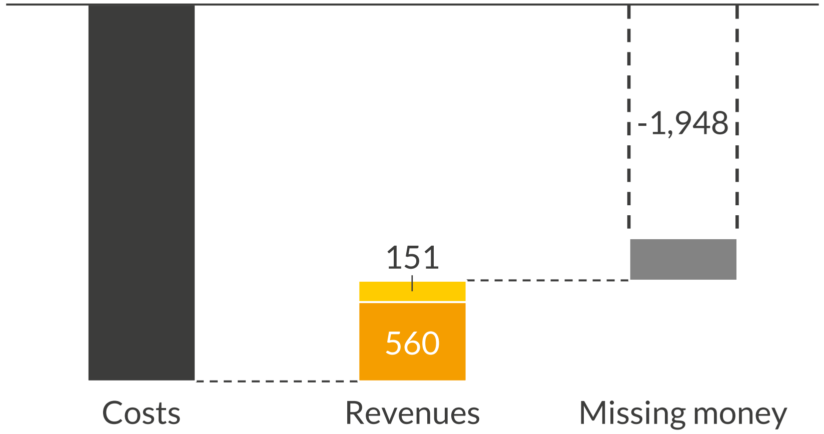
Present value of cashflows[1] for COD 2025 - 12h duration flow storage, €/kW

1 Wholesale Market arbitrage[2]



- Wholesale market gross margins decrease from 36 €/kW, covering 23% of costs over the 40 years lifetime of the asset, to 32 €/kW when including the participation in the Balancing Market
- This asset would only recover 23% of its costs if only participating in the wholesale market due to storage cannibalisation in this scenario (details on wholesale market prices and spreads in slides 47-48)

2 Arbitrage between Wholesale and Balancing Markets[3]



- When LDES participates in Wholesale and Balancing Markets, total revenues increase by 15% reducing the missing money by 5%
- LDES participation in the BM is limited by a fail rate, considering the overall volumes traded in the BM
- As a result, LDES participation in the BM represents a share of the total imbalance volumes, with other flexible technologies also participating in this market

🟧 WM margins 🟨 BM margins ⬛ Capacity market

X *Included in policy section*

---

1) 7% discount rate 2)The asset is constrained to only participate in the wholesale market. 3) The asset participates in wholesale and balancing markets. 4) In GB 95% de-rating factors for >4.5h duration while in Italy 90% de-rating factor for 8h. 5) Our analysis does not include Technical Restrictions given the locational characteristics of this market. 6) Some Innovators are approved to operate in other markets already as synchronous generators. Combined power and heat LDES could stack heat revenues, but analysis for the specific case would be required to quantify benefit.

Other possible revenue streams:

B Capacity Market

- LDES can be competitive in the capacity market if appropriate incentives and parameters are defined[4]. In GB, storage has risen to over 12 GW, with increasingly longer durations being procured
- This increases investor confidence but has not been sufficient: GB has implemented specific tenders for LDES; in Italy, a proposed auction scheme will ensure the deployment of ~9 GW of LDES - deep dives on the specific measures in GB and Italy in the policy section

C Other Markets or services[5]

- LDES can provide inertia, congestion relief, voltage control, short circuit level, and black start depending on the technology and could benefit from additional revenues from locational markets[6]

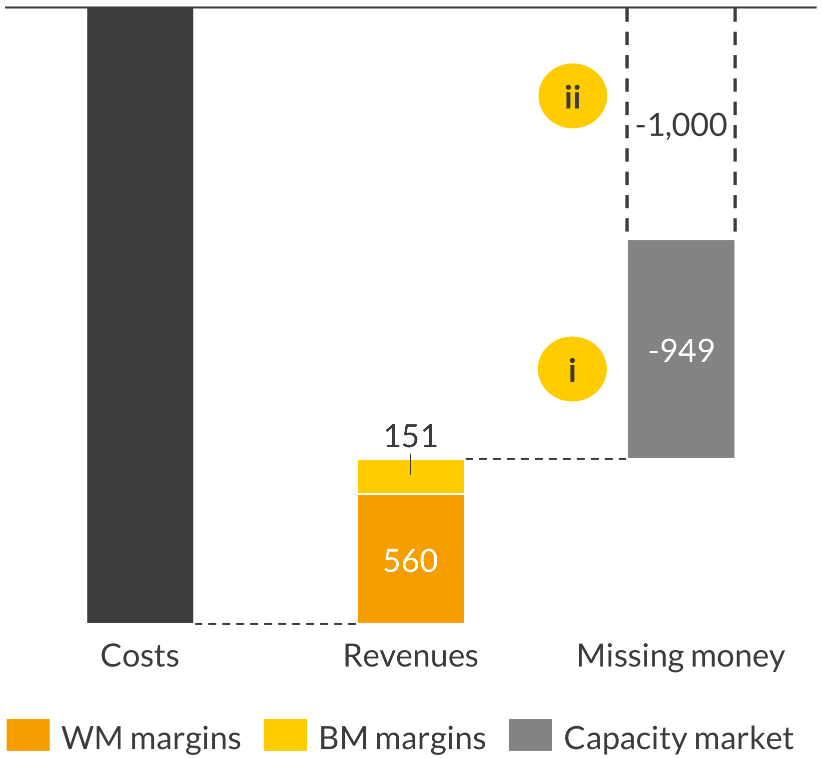
When including capacity market payments, the funding gap for a 12h LDES with COD 2025 is reduced by 49%, reaching a 3% IRR

Power-to-power

B Policy section: Impact of the capacity market

Present value of cashflows[1] for COD 2025 - 12h flow storage with 40 years lifetime, €/kW

IRR[2] = 3%



X *Included in policy section*

i We calculated the capacity market payment for the LDES scenario considering procurement target requirements[3] and when new capacity would be needed in the system

- For this analysis, the first capacity market contract for new build is awarded in the asset's commercial operation date for 5-years, and then renewed yearly on a rolling-basis until the end of its lifetime, as it is existing capacity
- Based on the current installed capacity in the LDES scenario and considering the rise in electricity demand resulting from TES, the need for new-built capacity arises as early as 2026
- In 2025, as there is no need for new installed capacity to meet the procurement target, capacity market prices will be defined by fixed operating costs of gas CCGTs
- From 2026 to 2034, the capacity market price will be determined by new-built batteries[4], with a price averaging at 110 €/kW considering 15-years lifetime and a de-rated factor of 60%
- As battery costs decrease and hydrogen CCGTs enter the system, these assets show a larger missing money gap[5]. Therefore, hydrogen CCGTS will be the price-setting assets at 94 €/kW for the CM. We assume 25 years lifetime[6] and 90% de-rating factor in line with gas CCGTs

ii Even though a capacity market could help bridge the gap, it would not be enough; LDES would require a higher payment than other technologies due to its high investment costs[7]

- Since the Spanish proposal defines the upcoming CM as pay-as-bid, LDES would need to compete with other technologies such as pumped hydro, shorter-duration lithium-ion batteries, hydrogen CCGTs and peaking technologies
- Aurora analysis finds that the capacity market could reduce the funding gap from 21% to 49% for the different LDES technologies for COD 2025 within their lifetimes

---

1) Accounting for 7% generation tax. 2) IRR calculated based on each asset's timeline. It includes capacity market payments. 3) The procurement target considered is 10% higher than the maximum peak demand for each year. De-rating factor for LDES assumed to be 90% in line with gas ccgts. 4) 4h duration lithium-ion batteries considered. 5) Costs assumptions are based on Aurora's assumptions; all discounted at 7% rate. 6) Lifetime assumption based on GB Decarbonisation Readiness - Technical Studies 7) For a deep dive of various options to address the missing money gap, please refer to the policy section. Combined power and heat LDES could stack heat revenues, but analysis for the specific case would be required to quantify benefit.

LDES assets are expected to derive a significant proportion of their value via the provision of non-frequency auxiliary services

Power-to-power

C Policy section: Other services

- Whilst revenues from energy trading in the wholesale and balancing market will make up some of the value for LDES assets, a significant proportion of their value would come from the provision of other auxiliary services that are currently provided by CO_2 emitting synchronous plants
- CNMC has already approved the conditions for non-frequency and other ancillary services for the operation of the Spanish system[1], but current Operating Procedures will need to be adapted for the conditions to apply

Service	Opportunities
Thermal constraints	▪ Thermal constraints are currently managed through technical restrictions ▪ Constraint management issues are expected to grow as more renewable capacity is built in; LDES could potentially defer the cost of network reinforcements[2]
Inertia	▪ Requirement for inertia service will increase over time due to the declining of thermal generation, which traditionally provides system inertia, and the growth of renewables generation
Voltage control	▪ Voltage control is currently managed through technical restrictions, but it will be remunerated under a new service ▪ Requirement for reactive energy is likely to increase as network loading becomes more volatile with baseload generators running less predictably, opening up new revenue streams
Black Start	▪ Increasing opportunity due to decline of traditional generators

- Even though these services present a great opportunity for LDES, there is also the risk of competing with shorter-duration less capital-intensive technologies like batteries, especially in services like thermal constraints and voltage control

X *Included in policy section*

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1) CNMC, Resolución del 8 de septiembre de 2022. 2) LDES benefit for the system can be found in section IV “Scenario comparison: LDES vs Baseline ”

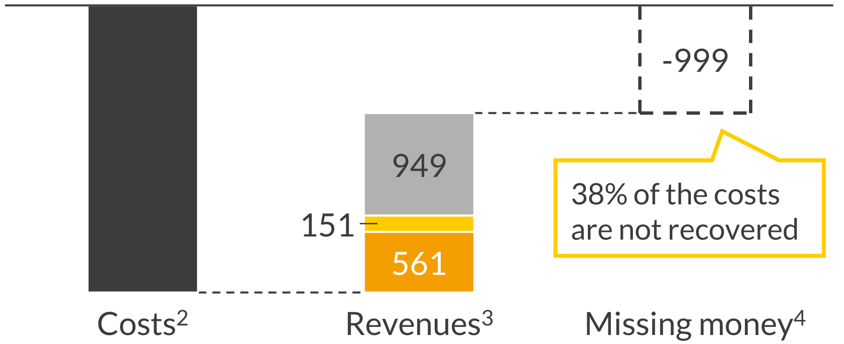
By 2030, an average 38% cost reduction for LDES significantly decreases revenue needed to recover costs, improving the business cases

Power-to-power

1 **Cost for a 12h LDES built in 2030 would have decreased significantly compared with 2025; asset would also benefit from higher revenues from CM as new-built capacity is needed, recovering its costs**

PV of cashflows[1], €/kW, real 2021

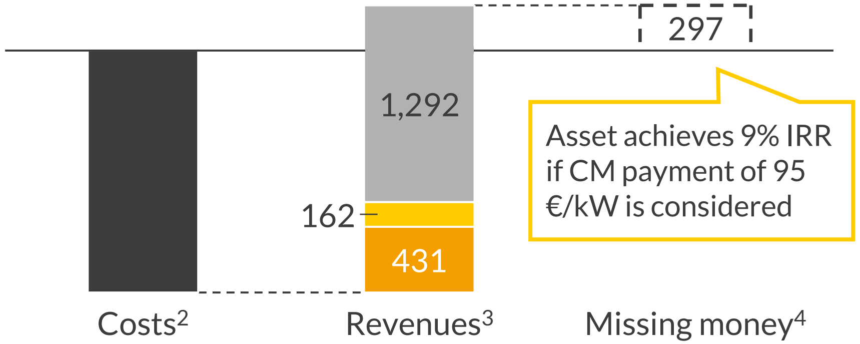
COD 2025



38% of the costs are not recovered

PV of cashflows[1] €/kW, real 2021

COD 2030

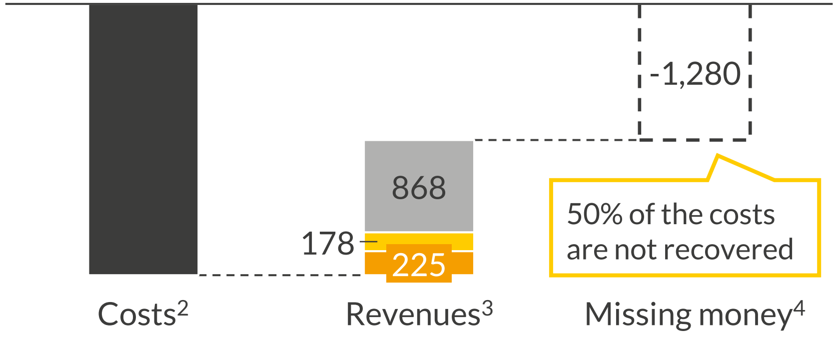


Asset achieves 9% IRR if CM payment of 95 €/kW is considered

4 **Reduction of spreads in WM and BM markets by 2030 impacts revenues for a 96h storage more significantly, leading the asset to not fully recover its costs, even considering a CM payment**

PV of cashflows[1] €/kW, real 2021

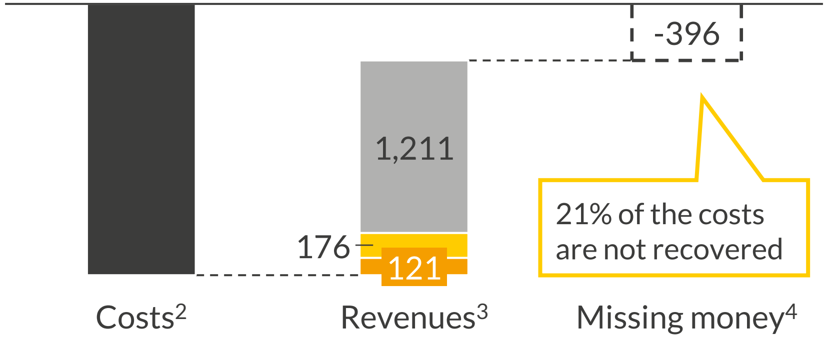
COD 2025



50% of the costs are not recovered

PV of cashflows[1] €/kW, real 2021

COD 2030



21% of the costs are not recovered

- By 2030, we see counteracting effects for the LDES economics:
- **Investment costs:** As LDES technologies are in the early stages of their learning curve, we expect them to experience a significant reduction in CAPEX. However, the reduction assumed is only possible if a certain capacity deployment happens during previous years, following a learning curve trend
- **CM contracts:** CM payment increases from 2025 to 2030. In early years, existing CCGTs set the price based on their running costs. By 2026, new capacity is needed in the LDES scenario; CM payment is set by newly built batteries bidding based on their investment costs
- **Revenues:** on the other hand, by 2030, gross margins decline by 17-26% as a result of the reduced spreads due to increasing storage cannibalisation

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1) Accounting for 7% generation tax. 2) Considers CAPEX and OPEX costs over each asset lifetime discounted at 7%. 3) Considers yearly average gross margins over each asset lifetime discounted at 7%. 4) Participation in other markets would reduce the missing money gap.

Sources: Aurora Energy Research

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IV. LDES scenario

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VI. Asset economics under LDES scenario

VII. Policy considerations

  a. Overview of regulatory aspects

  b. Spanish proposed capacity market

  c. Italy and GB capacity market

  d. Italy storage auction scheme

  e. GB BEIS tenders for LDES

  f. GB potential cap & floor mechanism

  g. PERTE subsidies in Spain

VIII. Appendix

While Spain has storage capacity target of 20 GW by 2030, there are no specific regulatory policies targeting deployment of long-duration storage

Regulatory aspect	What has been done in Spain	Policy considerations and lessons learnt from other countries
Taxes and levies	- Circular 3/2020 exempts storage from grid charges if energy is reinjected back into the grid	A - TES operating as power-to-heat would not reinject energy back to grid and would have to pay grid charges, increasing LCOH. Possible measures could be a tariff structure revision or exemption for thermal storage (slide 59)
Provision of other non-frequency services	- CNMC has approved the conditions for non-frequency and other ancillary services for the operation of the Spanish system - Voltage control will no longer be a service within technical restrictions and will be separately remunerated	C - A significant proportion of LDES value would come from the provision of other grid auxiliary services currently provided by synchronous generators. However, current Operating Procedures still need to be adapted for the conditions to apply (slide 71)
Access to electricity markets	- Energy storage assets can participate in day-ahead and balancing markets D - The proposal for the introduction of a capacity market foresees the participation of storage (slide 75); however, current proposal only foresees 5-year contracts and de-rating factors have not been defined yet	B - The introduction of capacity markets is beneficial for storage since capacity contracts offer a predictable income stream and it would improve the business case (slide 70) D - In Italy and the United Kingdom latest auctions storage got awarded 29% and 60% of the contracts respectively. Even though the duration of LDES presents an advantage compared to shorter-duration lithium-ion batteries for security of supply, CM has not proven enough to incentivise LDES in other geographies (slide 76)
Storage direct subsidies	G - In 2021, the government announced to allocate funds to support the development of storage with a commercial operation date until 2026 under PERTE-ERHA[1] (slide 80) - In the first phase, at least 620mn € were allocated to storage, flexible technologies, and new business models. In 2023, PERTE-ERHA funding for storage and for industry decarbonisation were increase by 5.5 bn € - Nevertheless, subsidies' design does not target LDES	E - Italy recently published an auction scheme for the procurement of storage capacity. It is a capacity-based remuneration for the entire investment horizon in exchange for the obligation to make the capacity available to market operators through a centralised platform (slide 77) F - In GB, £6m of funding have been awarded to new LDES technologies through tenders. BEIS published a consultation in 2021 emphasising the importance of LDES in which the government gathered responses on grid support, deployment barriers and possible mechanisms (for instance, cap & floor) to support investment (slides 78 & 79)

X *Deep dive in "Policy considerations" section*

X *Deep dive in "Asset economics under LDES scenario" section*

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1) Proyecto Estratégico para la Recuperación y Transformación Económica (PERTE) de Energías Renovables, H_2 Renovable y Almacenamiento (ERHA).

The proposed capacity market mechanism will be pay-as-bid and foresees the participation of storage, key parameters are still undefined

Main features of the proposed capacity market

Auction design	▪ Pay-as-bid auction ▪ **Product:** Firm capacity in MW ▪ **Offer unit:** Price per unit of firm capacity in €/MW-year
Settlement	▪ Fixed monthly payment (1/12 of yearly contract) without inflation adjustment
Contract period[1]	▪ Existing capacity: 12 months ▪ **New capacity: five years**
Eligible technologies	▪ Generation technologies, including renewables ▪ Storage technologies ▪ Demand-side response
Participation constraints	▪ Maximum emission rate of 550g CO$_2$/kWh for existing assets ▪ New generators must accredit net zero CO$_2$ emissions ▪ Participating demand (DSR) must not have associated generation under Specific Remuneration Regime

In the UK and Italy, contract length for new-build is 15 years

- If new capacity is needed, as the CM is carbon neutral, we expect a combination of battery storage, brownfield pumped hydro and DSR to compete for new build firm capacity requirements.
- Intermittent renewables are unlikely to receive substantial support due to their limitations in providing firm capacity, leading to low derating factors.

Undefined parameters

- Definition of a "stress event"
- Methodology to define de-rating factors for eligible technologies, including renewables, storage and demand-side response
- Capacity requirements for the peninsula, accounting for uncertainty in:
  - Peak demand
  - Renewable generation contribution to security of supply
  - Availability of the thermal fleet
  - Interconnection participation and derating factors
- Contract obligations for capacity contract holders
- Penalties and testing regime
- Bid guarantees and development milestones

- Red Eléctrica will have a critical role establishing operating procedures and capacity requirements
- Further clarity around key parameters like the target capacity for the auction, as well as the **de-rating factors** applicable to different technologies, will dictate how important this market is for new storage projects

In Italy, de-rating for 8h storage is 90% which is the same de-rating as for a new thermal plant

---

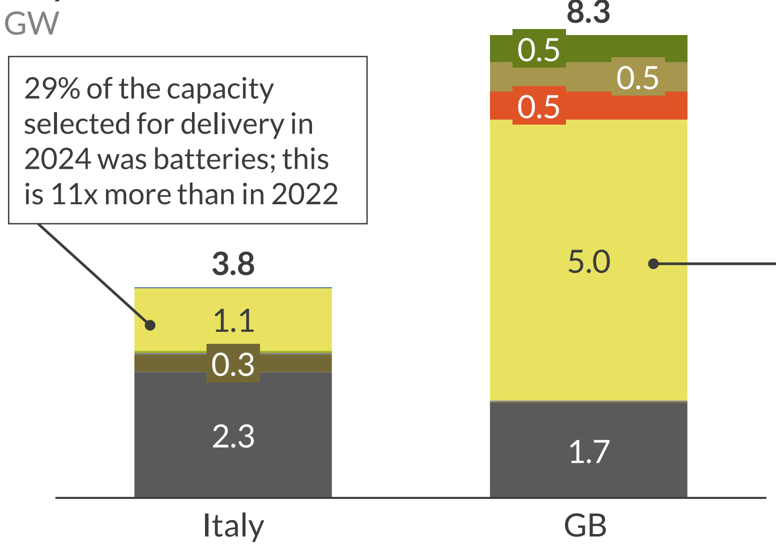
1) For the main auction; there will also be adjustment and extraordinary auctions both for 12 months contracts.

D

Contracted storage capacity has increased significantly in GB and Italy, but capacity markets have incentivised mostly short-duration technologies

New available capacity selected in CM last auctions in Italy and GB

GW

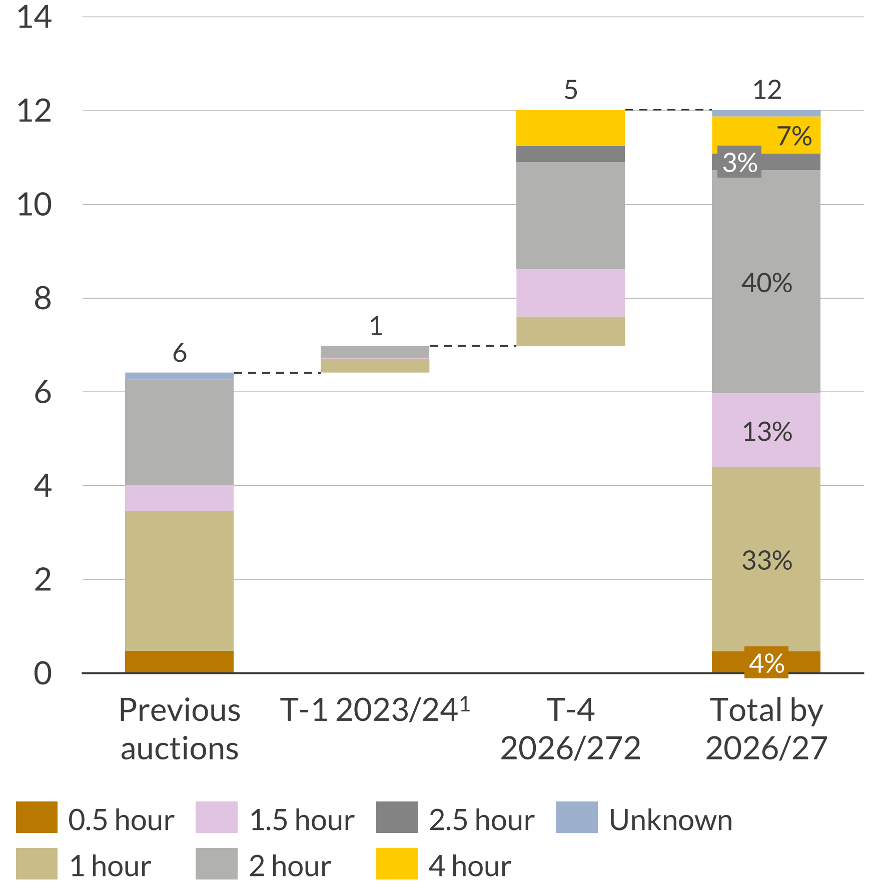


29% of the capacity selected for delivery in 2024 was batteries; this is 11x more than in 2022

- The third auction for delivery in 2024 in Italy saw a change in the trend set by previous auctions and a strong participation from batteries getting contracts for 1.1 GW of capacity, or 11x more than in 2022
- Contracted battery capacity in GB has risen to over 12 GW as a result of the last auction, with increasingly long durations being procured, and larger sites entering the pipeline

Deep dive on CM-procured battery capacity in GB

GW



- In recent years, batteries have become the clear winners of the auctions with their ability to bid low due to lucrative ancillary service revenues in these geographies
- In the latest auctions for GB, typical storage duration was is 2h; however, there has not been any contract awarded to storage with longer duration than 4h
- The GB LDES mix is currently comprised entirely of pumped storage, a long-established technology, although new sites have not been built for the last 3 decades
- New LDES projects in both Italy and GB will need additional support, with established technologies needing reforms to exiting markets, and new technologies still emerging

Sources: Aurora Energy Research, BEIS, UK Government REPD, TERNA

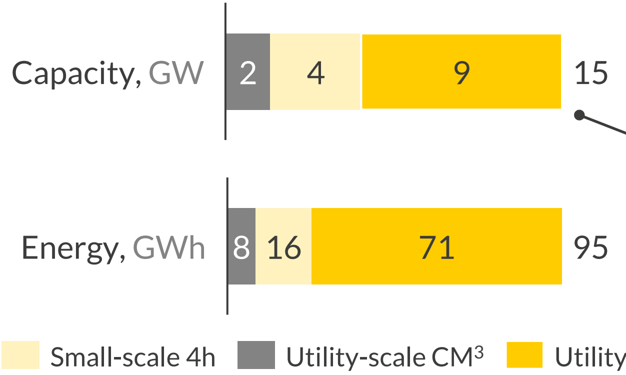
In Italy, a new auction scheme for the procurement of storage will focus on time-shifting capabilities of longer-duration assets

Decree 2021/210[1], defines the next steps for the development of storage in Italy, including periodical dedicated auctions

1 Storage requirements and rules to participate in the scheme

- Only new-build capacity can participate, and it will not be stackable with capacity market participation
- The awarded capacity receives annual capacity payments throughout the investment horizon, covering all costs, including capital and operational expenses
- In return for the capacity payment, the storage capacity is made available to market operators through a centralised platform
- Authorisation is necessary to participate, including all permits from grid access to operation permit
- Following the auction outcomes, if the awarded capacity is below the target envisaged by Terna, the TSO will directly develop the missing capacity

Storage requirements by 2030[2]



- New subsidy scheme will need to support the development of 9 GW of average 8h storage by 2030
- 75% of the energy required comes from storage with average 8h duration

2 Storage scheme focuses on time-shifting while providing ancillary services

- Scheme targets longer-duration storage since ARERA[4] expects the awarded storage capacity to primarily provide a time shifting service
    - Procurement of the target storage capacity is achieved through periodical competitive auctions, but the design of these auctions is yet to be defined
- Terna has the right to reserve capacity for frequency regulation, in particular fast reserve and primary reserve, as well as in emergency situations, without any additional payments
    - Any profits gained through ancillary services[5] trading will be used to finance the scheme and decrease the cost to the end consumer

3 Auction design to be analysed by October 2023 must follow some principles

- **Technological neutrality:**
    - Terna will study potential participating technologies, categorise them based on their profiles (construction period, lifetime, degradation) and define standard contracts
    - Given differences between battery and pumped storage, separate procurement processes are being considered
- **Capacity must be awarded through paid-as-bid auctions**
- **Minimising the cost for consumers:** Terna will periodically calculate the total cost of the scheme. These costs will be proportionally allocated to end consumers based on the energy extracted from the grid

---

1) Signed on 8th November 2021 and transposing EU Directive 2019/9441 on common rules for the internal electricity market; 2) Capacities do not include existing pumped storage; 3) Batteries with Capacity Market contracts, mostly with duration of 4h. 4)Italian Regulatory Authority for Energy, Networks and Environment (Autorita di Regolazione per Energia Reti e Ambiente) . 5) Ancillary Services Market also known as MSD

Sources: Aurora Energy Research

In GB, BEIS has awarded about £6m of funding through tenders for commercial prototypes of new emerging LDES technologies

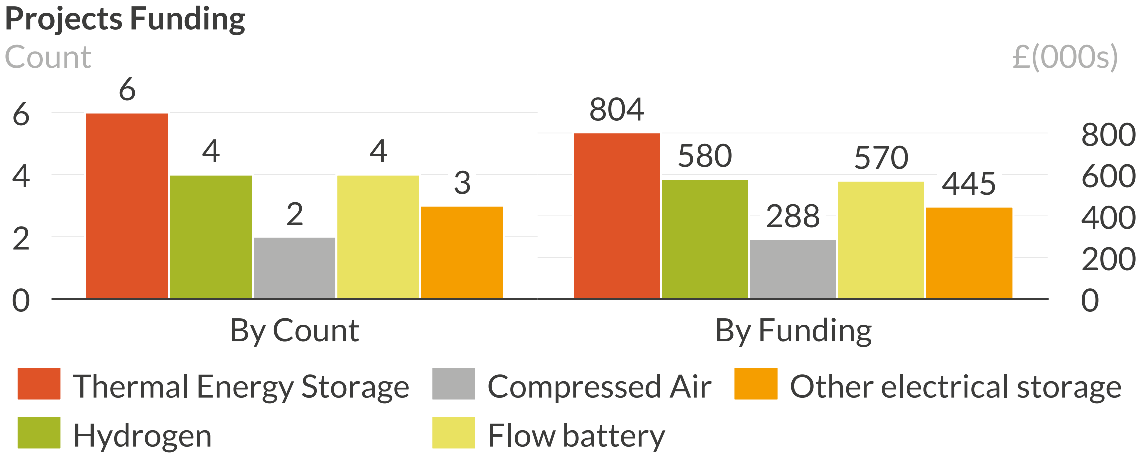
F

The Longer Duration Energy Storage Demonstration Programme published in July 2021 has been the first LDES-specific opportunity with 2 funding streams covering electricity, thermal and power-to-x categories and encompassing preparatory and build & commission phases

Stream 1[2] has awarded 5 projects with over £3m of funding to develop projects through to actual demonstration sites

	Technology
Ballylumford power-to-X	Hydrogen Electrolyser
GraviSTORE	Gravity Storage
Long Duration Offshore Storage Bundle	Compressed Air (& pressurised water)
Vanadium Flow Battery Longer Duration Energy Asset Demonstrator	Vanadium Flow Battery
Cheshire Energy Storage Centre	Compressed Air

Stream 2[2] has allocated over £800k of funding to thermal storage, which was the most successful technology in this tender



- BEIS recognition of the need for LDES led to a public consultation[1] between July to September 2021, seeking feedback regarding the benefits of LDES, its potential grid support capabilities, the reasons behind its limited deployment, and the specific types of support required to promote its adoption
- Financing of LDES has been pointed out as one of the barriers for its deployment: respondents[2] point out that there is risk associated with being the first projects to deploy and that equity available is very expensive, small scale and difficult to obtain. One of the many suggestions was the implementation of a **cap and floor mechanism**

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1) "Facilitating the deployment of large-scale and long-duration electricity storage " - BEIS , July 2021. "Government response" – BEIS, August 2022. 2) Stream 1 projects are for demonstration projects of technologies considered close to commercialisation. Stream 2 projects are expected to develop "first-of-a-kind" prototypes, rather than prepare for immediate deployment

Sources: Aurora Energy Research, BEIS

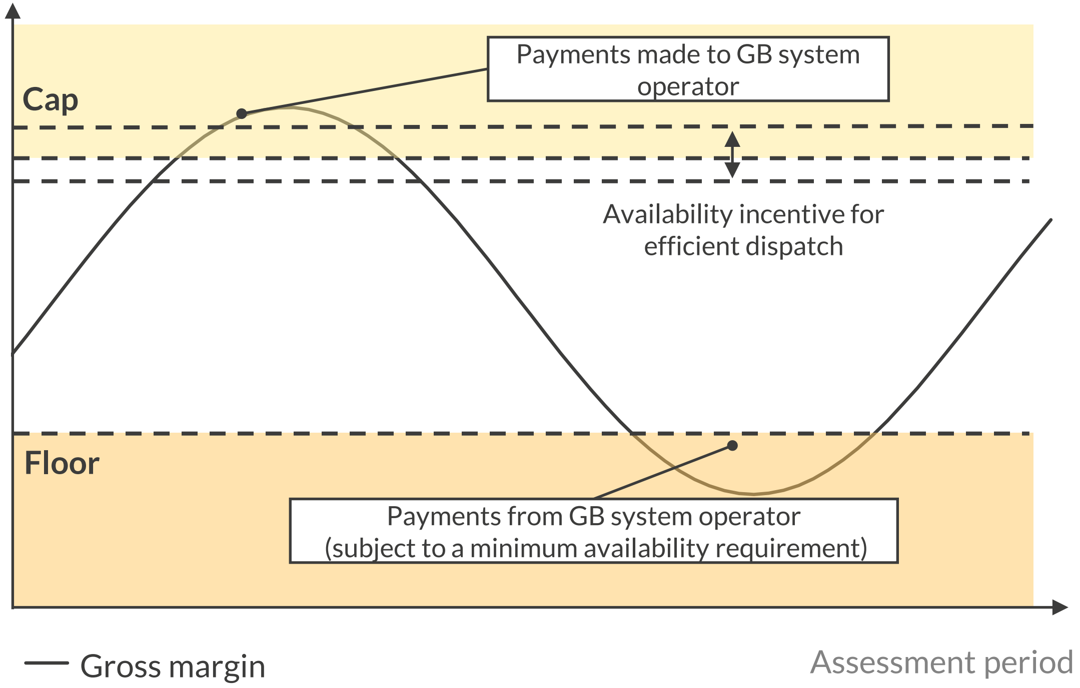
A Cap & Floor mechanism is best positioned to support the deployment of LDES, however additional signals may be needed

F

Among other options outlined in the consultation (Regulated Asset Base mechanism, Contract for Differences and Reformed Capacity Market), the Cap and Floor mechanism is currently the best positioned to support investment in LDES, however there are several limitations and potential modifications that should be considered

Cap and Floor mechanism

Gross Margin £/kW/yr



1 Cap and Floor policy limitations

- **Does not fully incentivise optimal dispatch to benefit the grid**
- **May not support equity investment into LDES projects**

2 Potential considerations and modifications

- **Forecasted returns from energy and system actions –** LDES provides services that are not currently contracted in separated markets; a cap & floor scheme should consider recognising value from all services contributing to grid operation (such as inertia, SCL, constraint relief)
- **Length of contracts and timing of revenues assessment –** contract length should be considered to reflect LDES lifespans and could be combined with revenue assessments to ensure fairness for developers and consumers
- **Contract awarding –** contracts will likely need to be decided on a case by case basis initially but a move towards a competitive auction should be considered
- **Cap and floor prices -** Policymakers should consider whether the cap & floor is set: a) to be technology agnostic, such as only based on market signals and revenues (assuming reforms can provide these), or; b) set for individual assets based more granularly on their locational benefit and grid services provided
- **Hard floor and flexible cap –** projects should have to maintain a minimum level of performance to receive the floor price. A flexible cap would incentivise further output when needed by the grid if the cap is reached, this should be set to ensure services continue to be provided
- **Support to debt & equity –** price floors will need to be high enough to reduce merchant risk, to secure debt and operational costs. Better market signals may be needed to avoid revenues staying at the floor, to attract equity investors
- **Other reforms** – A cap & floor mechanism could be implemented in conjunction with further market reforms to improve market signals

Source: Aurora Energy Research

Storage is eligible for subsidies under PERTE ERHA in Spain, but the design of the calls is not suitable for emerging technologies

G

- **In Spain, at least 350 mn € of subsidies for storage will be granted through four calls under the PERTE ERHA[1] scheme. The PERTE ERHA includes storage, renewables and hydrogen and it is funded by the European Union**
- **In June 2023, funding for PERTE ERHA and PERTE industrial decarbonisation have been increased from 6.6 bn€ to 12 bn€ and from 540 mn€ to 3.1 bn€, respectively**

1 PERTE-ERHA calls support storage projects and new business models and could represent an opportunity for LDES

PERTE ERHA call	Status
Innovative R&D storage projects	Final resolution published in Feb 2023
Innovative co-located energy projects with electricity generation from renewable sources	Applications opened from Jan to Mar 2023
New business models in the energy transition	Regulatory framework approved in Dec 2022
Innovative stand-alone storage	Expected Q4 2022; no updates on timeline

- Calls aim to be technologically neutral, available for all technologies
- Subsidies are allocated based on a point-based system, based on different criteria (i) economic feasibility, ii) enabling renewable penetration, iii) project feasibility and iv) social and environmental impact of the project)
- Some of the calls (for instance, hybrid call) differentiate assets that can provide inertia, short circuit levels, voltage control, and other grid services. These assets achieve better scores, thus a higher position in the ranking, increasing the probability of getting the subsidy

2 However, the design of the calls is not suitable for emerging long-duration competing with more mature short-duration technologies

- For the three calls which have already took place or with approved framework, projects must be built by 2026 and there is a limit of 15 mn € per project
- In the innovative R&D call:
  - Even though technology readiness level (TRL) between 6-8 is eligible, project must be TRL 9 when finished
  - Economic viability and quick completion are criteria to rank projects
- In the hybrid call:
  - Even though there is distinction between durations, projects with longer duration than 8h are all awarded the same score
  - Projects with efficiencies below 65% (inc. losses from all elements associated with storage system) score 0 in efficiency criteria
- In both calls, a preference towards mature well-established technologies that can more easily achieve better scores might result in no LDES projects to apply given that their benefits are not quantified by the calls' criteria
- As reported by respondents in the BEIS consultation[2], one of the key barriers for LDES are high upfront costs, but a near-term investment in LDES can reduce costs and long-term risk to security of the system's decarbonisation

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1) Proyecto Estratégico para la Recuperación y Transformación Económica (PERTE) de Energías Renovables, H_2 Renovable y Almacenamiento (ERHA). 2) See slide 78.

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a) Aurora methodology to update renewable capacity target for 2023 NECP

b) Aurora methodology for impact of LDES in grid investment costs

c) Retail charges for industrial consumer

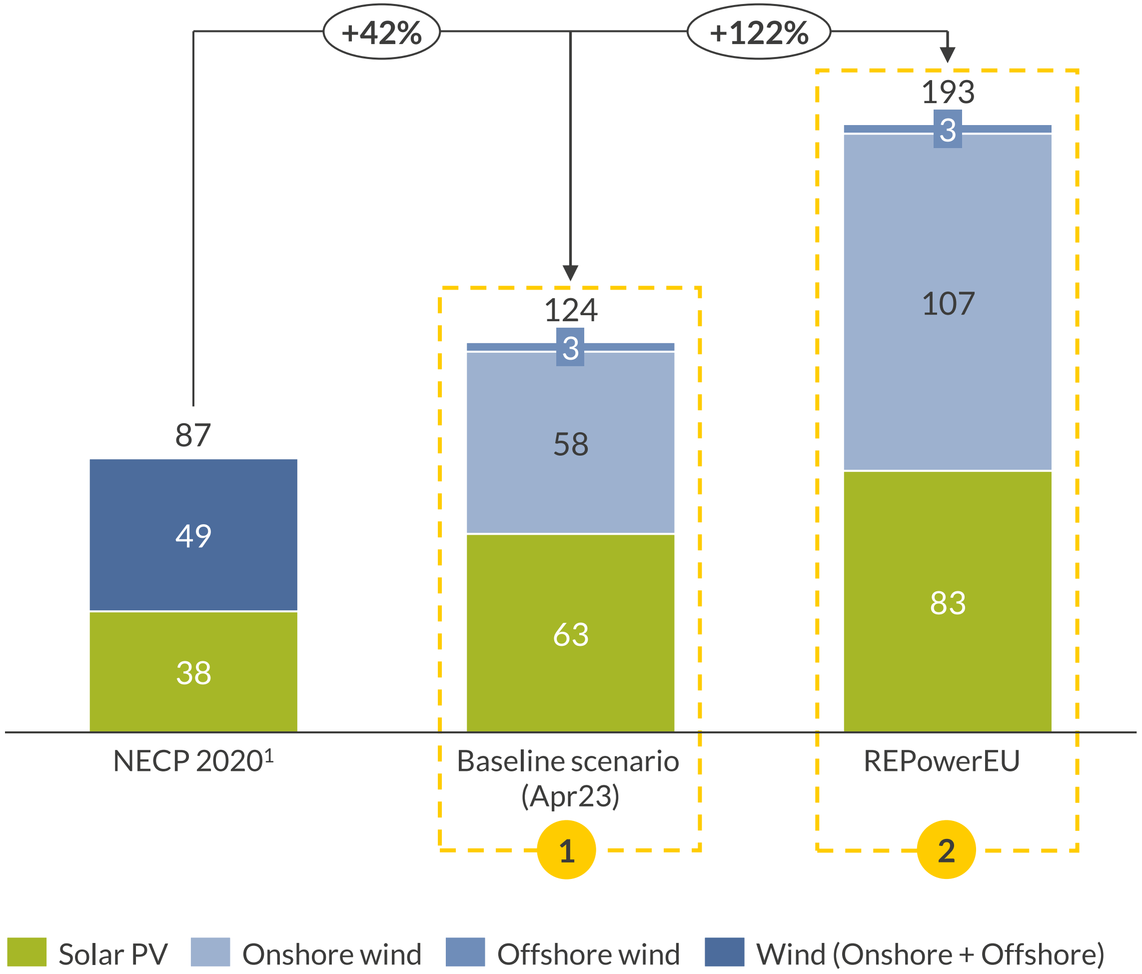
d) Existing markets and ancillary services in Spain

e) Aurora power-to-power dispatch optimisation model

If Aurora were to assume REPowerEU target, 144 GW of solar and wind would have to be added to the system by 2030

AURORA

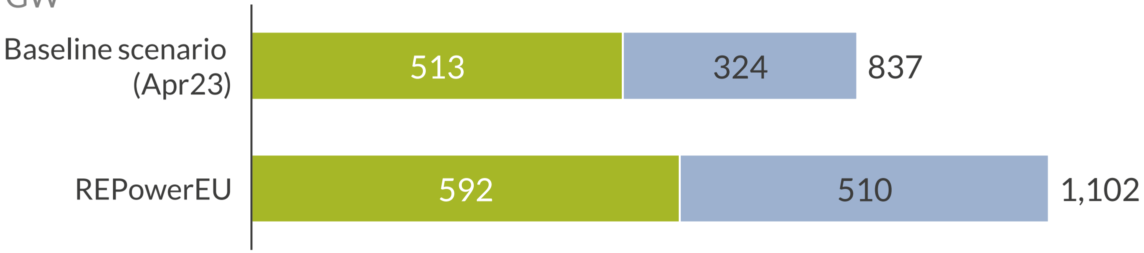
Spain solar and wind installed capacity by 2030
GW



1
- In the Baseline scenario, renewable target by 2030 is ~40% higher than 2020 NECP target, leading to 124 GW of installed solar and wind. This scenario uses the IEA main scenario as basis[2]
- By using the IEA main scenario as reference, the total installed capacity at EU level will fall short compared to the REPowerEU target[3]
- Considering IRENA installed capacity for the EU 27 by 2022[4], at EU-level, the Baseline scenario would reach 513 GW of solar and 324 GW of wind by 2030 while the REPowerEU target is 592 GW and 510 GW

2
- If Aurora were to assume the REPowerEU target[3], the increase would have been 122% compared to 2020 NECP target (including solar PV, onshore and floating offshore wind). **This would mean an additional 144 GW by 2030, compared to today's capacity**
- This would lead to 193 GW of total solar and wind installed capacity in the Spanish system by 2030

EU level solar and wind installed capacity by 2030
GW



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1) NECP announced in 2020 does not disclose onshore and floating offshore wind targets, both included under 49 GW target. Aurora prepared this analysis before the release of the updated NECP by 29th June 2023. 2) Basis to our assumption is IEA "Renewables 2022" (main case) together with potential maps developed by EU Joint Research Centre. 3) Directly using REPowerEU target. 4) IRENA renewable energy capacity statistics 2023.

Sources: IEA "Renewables 2022" (main case), Energy and Industry Geography Lab (EU Joint Research Centre), REPowerEU, REPowerEU Annexes, NECP 2021-2030, IRENA Renewables 2023

Aurora's high-level estimation grid investment is based on Spanish National Development Plans, focusing on RES deployment and RES-to-storage ratio

AURORA

Data collected from Spanish National Development Plan

- Based on the National Development Plan[1] (2021-2026) we selected the categories where LDES could reduce grid investments

Red Eléctrica 2021-2026	Total	Yearly
Total investment (mn €)	5,703	1,141
Not considered (mn €)	2,697	539
Considered (mn €)	3,006	601

Considered

- Security of supply

- Operational needs

- Renewables and TRs

- This investment aims for an installed capacity of 65.6 GW for wind and solar by 2026, starting from 43.9 GW in 2021
- We extrapolated future yearly investment based on the cost of the underlying RES and storage deployment (see data comparison table below)
- Assuming a RES-to-storage ratio of 13.2, it is estimated that each new MW of RES will require an investment of 0.14 million euros

Comparison: National Development Plan and Baseline and LDES scenarios

Installed capacity	National Development Plan		Baseline	LDES
Year	2021	2026	2026	2026
RES (MW)	43,882	65,583	91,800	91,800
Storage (MW)	3,331	4,655	5,700	6,235
Yearly RES deployment[1] (MW)	4,340	4,340	8,600	8,600
RES-to-Storage	13.2	14.1	16.1	14.7

Calculation process to forecast grid investment savings

1 Baseline scenario

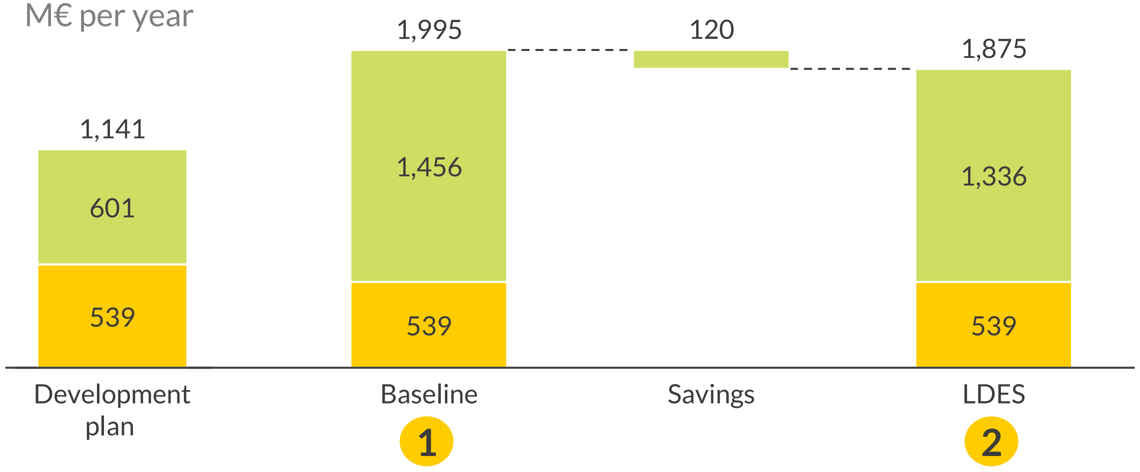
- First, we estimate grid investment costs per MW of RES deployed in the grid development plan. Using this estimate, we calculate the Baseline's yearly grid investment cost based on its RES deployment
- We adjust the cost per MW of RES if the RES-to-storage ratio changes[2]

2 LDES scenario

- In the LDES scenario, RES deployment is the same as in the Baseline. Thus, we adjust grid investments costs (including savings) with the resulting RES-to-storage ratio
- Storage additions have a diminishing effect: the more storage capacity, the less impactful storage additions will be on savings

Example: grid investment costs for the year 2026,

M€ per year



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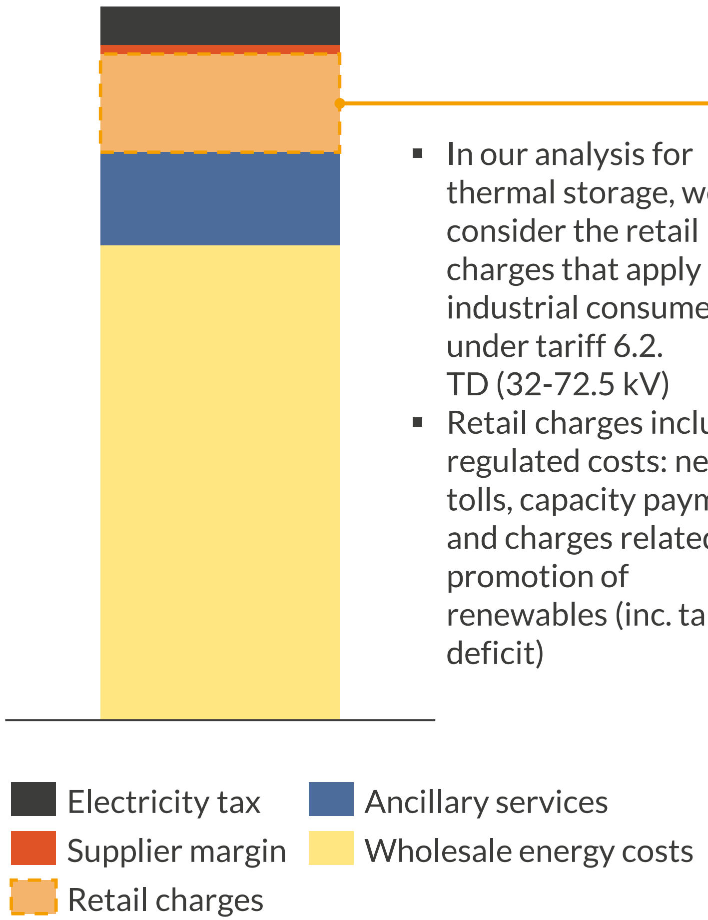
1) Spanish National Development Plan submitted by MITECO to the Council of Ministers for referral to the Congress of Deputies prior to its approval by the Government. Red Electrica acts only as technical support. 2) Higher RES-to-storage ratio results in a higher grid investment costs per MW of RES deployed. Conversely, a lower RES-to-storage ratio results in a lower grid investment costs per MW of RES deployed. We assume that savings from storage additions have a diminishing impact: the more storage capacity, the less impactful storage additions will be on savings.

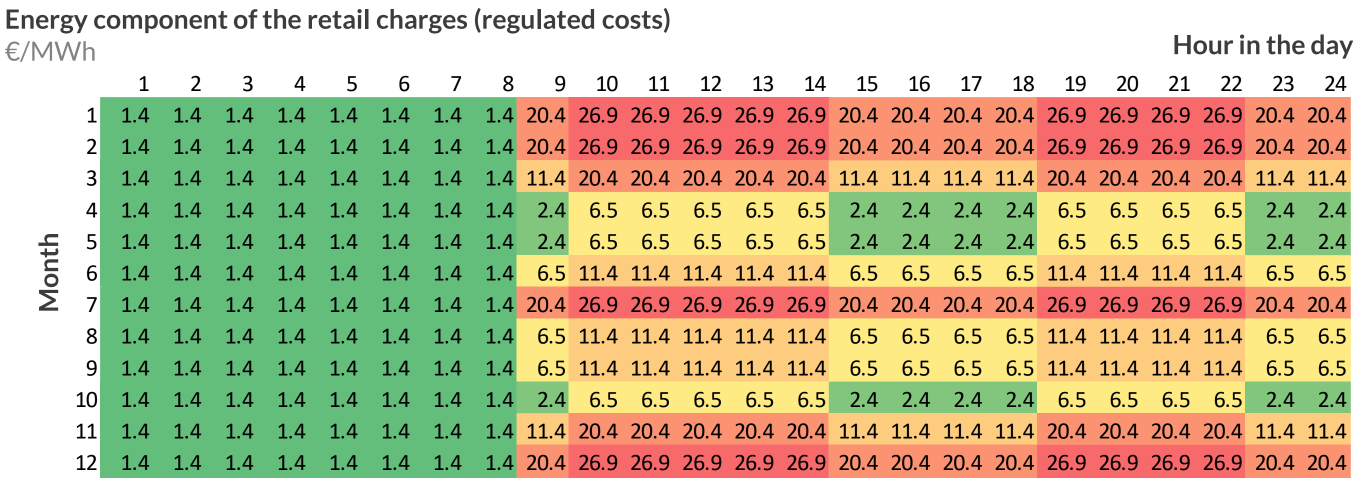
Current tariffs penalise energy consumption during the middle of the day, when solar output is at its peak

Electricity cost components for industrial consumers[1], €/MWh



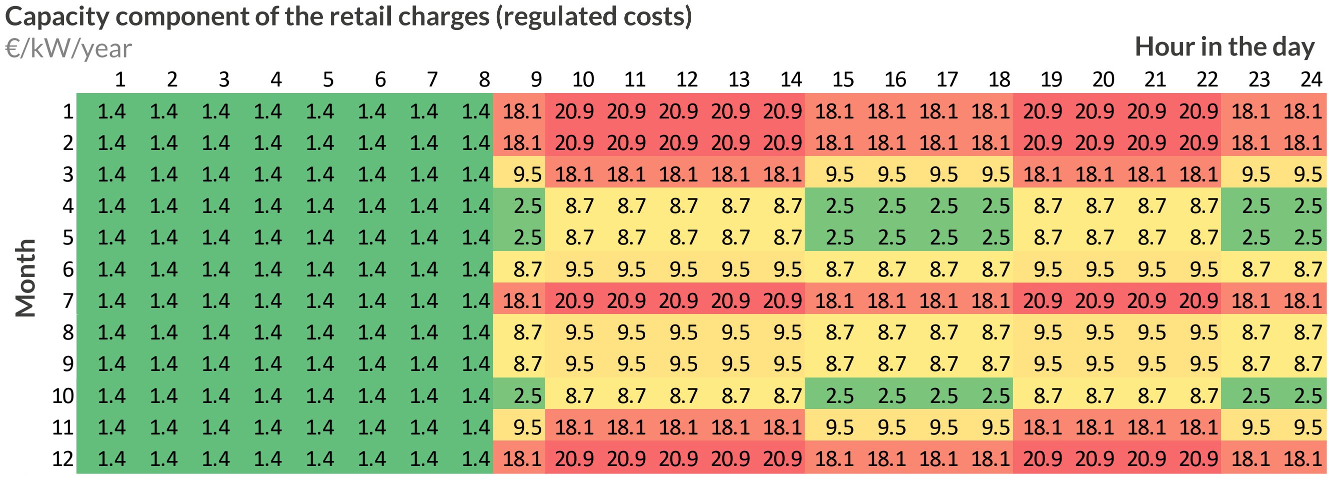
- In our analysis for thermal storage, we consider the retail charges that apply to an industrial consumer under tariff 6.2. TD (32-72.5 kV)
- Retail charges include all regulated costs: network tolls, capacity payments and charges related with promotion of renewables (inc. tariff deficit)

Energy component of the retail charges (regulated costs)
€/MWh



	Hour in the day																							
Month	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
1	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	20.4	26.9	26.9	26.9	26.9	26.9	20.4	20.4	20.4	20.4	26.9	26.9	26.9	26.9	20.4	20.4
2	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	20.4	26.9	26.9	26.9	26.9	26.9	20.4	20.4	20.4	20.4	26.9	26.9	26.9	26.9	20.4	20.4
3	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	11.4	20.4	20.4	20.4	20.4	20.4	11.4	11.4	11.4	11.4	20.4	20.4	20.4	20.4	11.4	11.4
4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	2.4	6.5	6.5	6.5	6.5	6.5	2.4	2.4	2.4	2.4	6.5	6.5	6.5	6.5	2.4	2.4
5	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	2.4	6.5	6.5	6.5	6.5	6.5	2.4	2.4	2.4	2.4	6.5	6.5	6.5	6.5	2.4	2.4
6	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	6.5	11.4	11.4	11.4	11.4	11.4	6.5	6.5	6.5	6.5	11.4	11.4	11.4	11.4	6.5	6.5
7	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	20.4	26.9	26.9	26.9	26.9	26.9	20.4	20.4	20.4	20.4	26.9	26.9	26.9	26.9	20.4	20.4
8	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	6.5	11.4	11.4	11.4	11.4	11.4	6.5	6.5	6.5	6.5	11.4	11.4	11.4	11.4	6.5	6.5
9	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	6.5	11.4	11.4	11.4	11.4	11.4	6.5	6.5	6.5	6.5	11.4	11.4	11.4	11.4	6.5	6.5
10	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	2.4	6.5	6.5	6.5	6.5	6.5	2.4	2.4	2.4	2.4	6.5	6.5	6.5	6.5	2.4	2.4
11	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	11.4	20.4	20.4	20.4	20.4	20.4	11.4	11.4	11.4	11.4	20.4	20.4	20.4	20.4	11.4	11.4
12	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	20.4	26.9	26.9	26.9	26.9	26.9	20.4	20.4	20.4	20.4	26.9	26.9	26.9	26.9	20.4	20.4

Capacity component of the retail charges (regulated costs)
€/kW/year



	Hour in the day																							
Month	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
1	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	18.1	20.9	20.9	20.9	20.9	20.9	18.1	18.1	18.1	18.1	20.9	20.9	20.9	20.9	18.1	18.1
2	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	18.1	20.9	20.9	20.9	20.9	20.9	18.1	18.1	18.1	18.1	20.9	20.9	20.9	20.9	18.1	18.1
3	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	9.5	18.1	18.1	18.1	18.1	18.1	9.5	9.5	9.5	9.5	18.1	18.1	18.1	18.1	9.5	9.5
4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	2.5	8.7	8.7	8.7	8.7	8.7	2.5	2.5	2.5	2.5	8.7	8.7	8.7	8.7	2.5	2.5
5	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	2.5	8.7	8.7	8.7	8.7	8.7	2.5	2.5	2.5	2.5	8.7	8.7	8.7	8.7	2.5	2.5
6	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	8.7	9.5	9.5	9.5	9.5	9.5	8.7	8.7	8.7	8.7	9.5	9.5	9.5	9.5	8.7	8.7
7	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	18.1	20.9	20.9	20.9	20.9	20.9	18.1	18.1	18.1	18.1	20.9	20.9	20.9	20.9	18.1	18.1
8	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	8.7	9.5	9.5	9.5	9.5	9.5	8.7	8.7	8.7	8.7	9.5	9.5	9.5	9.5	8.7	8.7
9	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	8.7	9.5	9.5	9.5	9.5	9.5	8.7	8.7	8.7	8.7	9.5	9.5	9.5	9.5	8.7	8.7
10	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	2.5	8.7	8.7	8.7	8.7	8.7	2.5	2.5	2.5	2.5	8.7	8.7	8.7	8.7	2.5	2.5
11	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	9.5	18.1	18.1	18.1	18.1	18.1	9.5	9.5	9.5	9.5	18.1	18.1	18.1	18.1	9.5	9.5
12	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	18.1	20.9	20.9	20.9	20.9	20.9	18.1	18.1	18.1	18.1	20.9	20.9	20.9	20.9	18.1	18.1

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[1] Illustrative example of the breakdown of the electricity cost for an industrial consumer under the retail tariff set by Circular 3/2020..

Source: Aurora Energy Research, Circular 3/2020

Wholesale and ancillary markets will be the key sources of revenues for storage, although other revenue streams could open up

Time prior to delivery

✦ *Currently available markets*

Years → Days → Hours → Minutes → Seconds → Delivery

CM

Capacity Market

- Ensures sufficient reliable capacity and security of supply in the long term.
- MITECO has published a draft proposal for a capacity market in Spain, but implementation timeline is uncertain.
- Storage will be allowed to participate, but with a de-rating factor reflecting its contribution to security of supply.
- Longer-duration storage can typically benefit from higher de-rating factors.

WM

Wholesale Market ✦

- Market to buy and sell power to **meet demand** on an hourly basis.
- Contracted **from years ahead to up to one hour ahead.**
- Market participants can trade in day-ahead and intraday markets.
- Two intra-day market modalities in Iberia: explicit auction sessions every six hours and a continuous intraday market up to 1 hour ahead.

AS

Ancillary services ✦

- Maintains operational grid requirements and balances demand and generation in real time.
- Contract tenors can vary widely by country, but moving to shorter term contracts.
- Key ancillary markets in Iberia:
  - Primary Reserve (non-remunerated)
  - Secondary Reserve
  - Tertiary Reserve
  - Replacement Reserves

TR

Technical Restrictions Markets (Day-ahead and Real-Time)[1]

- Storage can also help **alleviate grid constraints,** which needs to be analysed locally and procured through local markets.

- Currently, storage can participate in two main markets: the wholesale market and the ancillary services market
- With a draft capacity market proposal now available in Spain, and a storage roadmap highlighting the need for local flexibility, we expect a more diverse spectrum of markets going forward
- To be competitive in a capacity market auction, storage assets will have to carefully consider the revenue opportunities across other markets

---

[1] Red Eléctrica officially defines Technical Restrictions Markets as ancillary services, however, as this markets' objective is to solve grid constraints and is location dependent, we separate this market.

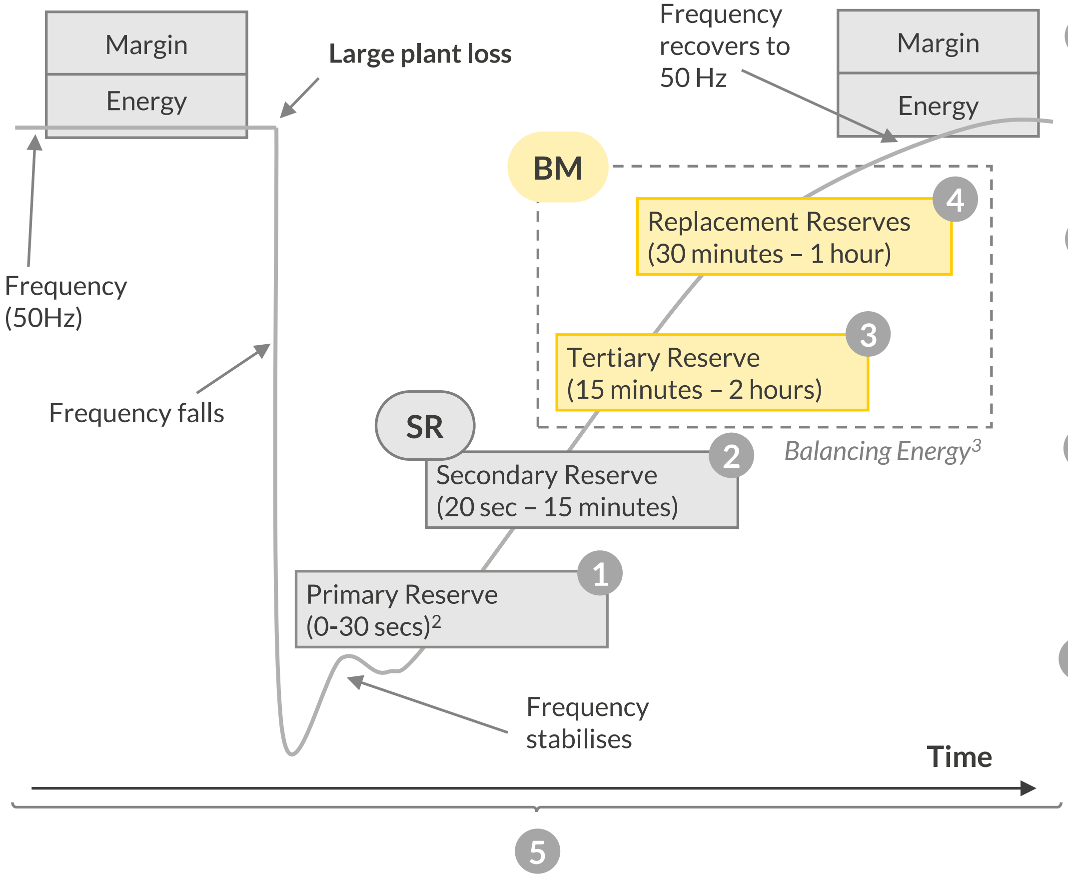
Source: Aurora Energy Research

System operability challenges are managed by ancillary services; from those, our analysis for LDES covers the Balancing Markets

AURORA

Red Eléctrica Ancillary Services

Illustrative case study example of response to a major outage[1]



① **Primary Reserve**
- Obligatory/ non-remunerated
- Automatic response of up to 30 seconds

② **Secondary Reserve (aFRR)**
- Voluntary service
- Remuneration based on two components: available capacity and dispatched energy

③ **Tertiary Reserve (mFRR)**
- Mandatory offers for generators who opted in
- Remuneration based on dispatched energy

④ **Replacement Reserve (RR)**
- Previously called deviation management
- Remuneration based on dispatched energy

⑤ **Technical Restrictions[4]**
- Service to solve grid constraints arising from programmed generation
- Managed through the re-dispatching of market units

- Unforeseen generation or demand levels need to be managed to ensure the operability of the system.
- The Primary Reserve is not explicitly remunerated through market mechanisms by Red Eléctrica.
- Expected imbalances and the solving of grid constraints are managed at the day-ahead stage through Secondary Reserves and the Technical Restrictions markets respectively.
- Close to real time imbalances in demand and supply (after gate closure) are met through Tertiary Reserves and Replacement Reserves.

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1) Some services excluded for simplicity. 2) The first value represents the allowed full activation time while the second value represents the maximum duration of the delivery period. 3) The Balancing Market combines Tertiary Reserve and Replacement Reserve. 4) Our analysis does not include Technical Restrictions given the locational characteristics of this market.

Sources: Aurora Energy Research

We model the different markets in which power-to-power storage can participate; the economics are based on a dispatch optimisation model

AURORA

Power-to-power

Markets

Aurora has an integrated energy system framework

We model the different markets in which storage can participate:

WM **Wholesale market**

- Hourly granularity
- Iterative modelling with dispatch and capacity investment decisions
- Dynamic dispatch of plants
- Endogenous interconnector flows

BM **Balancing market**[1]

- Integrates balancing energy requirements from Tertiary Reserve, Replacement Reserve and Secondary Reserve
- Stochastic estimate of imbalances
- Opportunity cost based on the wholesale market operations
- Hourly resolution of prices and energy in upward and downward reserve

SR **Secondary regulation band (not included in this analysis)**

- Price forecast based on an econometric regression
- Calibration based on historical data, including the negative correlation of regulation band prices with CCGT availability and price spike occurrences
- Accounts for the increasing competition from the participation of flexible technologies i.e. batteries, pumped hydro, etc.

Storage

Dispatch optimisation model

- Aurora's dispatch model optimises the operations of storage across multiple markets in order to maximise profits
- Our methodology assume that the storage asset has limited foresight into the wholesale market and secondary regulation band prices[2]. Based on these prices, wholesale and secondary reserve market participation is decided simultaneously. In this analysis, we did not consider secondary reserve participation
- Optimisation is constrained by no foresight in the balancing market. When trading, the storage system can act in this market if prices are more attractive than planned wholesale or secondary reserve actions. However:
  - The asset will be subject to penalties if it does not have enough available capacity to comply with secondary reserve actions
  - The asset will also be subject to penalties if it does not have enough energy to comply with day-ahead wholesale market commitments
- The asset is assumed to be available for energy trading 24/7 each month. The modelled storage system can differ in terms of availability for energy trading, duration, cycling rates, efficiency and degradation

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1) Balancing market is the combination of tertiary and replacement reserves. 2) We perform a dispatch optimisation and therefore, there are both band and energy remuneration for the secondary reserve market. Conservatively, we assume a maximum of 12-hours per day of secondary reserve participation.

Sources: Aurora Energy Research

Details and disclaimer

Publication
Long Duration Energy Storage in Spain

Date
July 2023

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