Feed-in grid charges - policy assessment

Policy note | Prepared for Energie Nederland

Executive Summary

Aurora Energy Research is a leading global provider of power market forecasting and analytics for critical investment and financing decisions. Our mission is to facilitate the global energy transition through widely trusted quantitative analysis and high-quality decision support.

This report contains our assessment of several potential designs of feed-in grid charges for producers, based on our target-driven Net Zero scenario. This scenario represents a world where the net-zero target is reached by 2050 and a carbon-neutral power sector is realised in 2035, in line with governmental ambitions.

This report is commissioned by Energie Nederland.

1. Currently, proposals for feed-in network charges are being explored by the regulator (ACM), aiming to achieve **higher system cost-reflectivity**.
2. Our study indicates that these charges have **the opposite effect, including significantly increasing costs for end consumers**, impacting renewable investment, and security of supply.
3. In the short term, feed-in network charges negatively **affect already commissioned renewable projects**, especially if all else is held equal.
4. In the long term, feed-in charges **slow down renewable buildout** and put government decarbonisation ambitions at risk.
5. Lower renewable generation leads to higher utilisation of EU thermal assets, **pushing up electricity prices and the costs for end-consumers.**
6. Even **after correcting for second order effects** (i.e. rising electricity prices), already **commissioned assets are still negatively impacted.**
7. While higher prices allow for some additional hydrogen power plant buildout, it is not sufficient to cover demand, **increasing import dependency**.
8. **Security of supply is further at risk**, as higher costs from feed-in charges may lead to early natural gas power plant closures.
9. Higher electricity prices outweigh the reduced grid fees for offtakers on the medium to long term, **increasing total end-consumer bills.**

Sources: Aurora Energy Research

Currently, proposals for feed-in network charges are being explored by the regulator, aiming to achieve higher system cost-reflectivity

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Proposals being explored by the regulator

1. **Standard tariff – fixed component based on capacity**
2. **Peak-use tariff – fixed component based on capacity adjusted for peak hour injection into grid**
3. **Volume based tariff – variable component based on production**
4. **Locational tariff – fixed component based on capacity and location in feed-in, offtake or mixed area**
5. **Deep connection costs – one-off CAPEX increase based on grid connection size**

i To make the results from our study more comparable, we used the level of charges of the CE Delft study when creating our feed-in network charge scenarios.

- Currently, the regulator is exploring the implementation of feed-in network charges, which would distribute grid costs between consumers and producers.
- The goal of this is to establish better cost-reflectivity, distributing costs to the parties that are responsible for incurring these costs.
- To assess potential effects, CE Delft is conducting a study on design options for feed-in network charges.
- Informed by the study by CE Delft, we create scenarios on five proposed feed-in network charge design options. This yields a second view on the effects that feed-in network charges could have.

Sources: Aurora Energy Research, CE Delt

Our study indicates that these charges have the opposite effect, significantly increasing costs for end consumers, and impacting renewable investment

We assessed the feed-in network charges using criteria of impact on renewable investment, security of supply (SoS), and end consumer bills, as well as regarding complexity of implementation, cost reflectivity and investment security. The assessment criteria are further elaborated on in the appendix.

Design options

Assessment	No fee[1]	Flat-fixed fee scenario	Peak-use fixed fee scenario	Flat variable fee scenario	Locational difference scenario	CAPEX scenario[2]
1 Renewable investment	+	−	−	−	−	− −
2 Security of supply	+	−	−	− −	−	− −
3 End consumer electricity bill	+	−	−	− −	−	− −
Complexity of implementation	+ +	−	− −	+	− −	+
Cost reflectivity	−	Neutral	+	Neutral	+	Neutral
Investment security	+ +	− −	− −	Neutral	− −	+

+ Positive ○ Neutral − Negative Deep-dive Qualitative assessment

1) Based on Aurora Net Zero, Aurora's best view on a system in which government decarbonisaiton targets are achieved; 2) One-off CAPEX assumptions, from CE Delft, are high compared to connection costs in other countries. With lower CAPEX assumptions the effects will be less negative.

Sources: Aurora Energy Research

In the short term, feed-in network charges negatively affect already commissioned renewable projects, especially if all else is held equal

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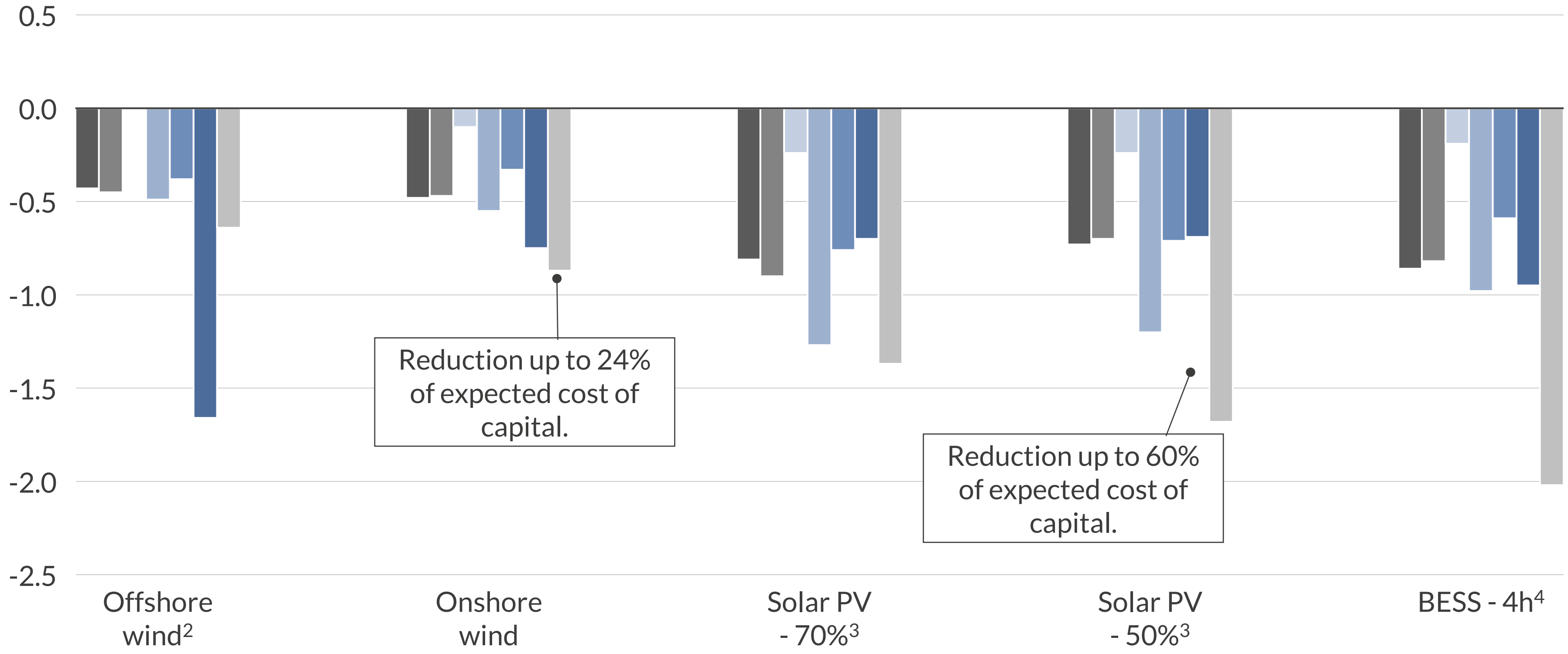
IRR delta to Aurora Net Zero, reference asset with construction starting in 2024 – excluding second order effects[1]

%, pre-tax real 2023



Expected WACC under SDE++ 2024 round[5]

%, real 2023

3.7% (Onshore wind) | 2.8% (Solar PV - 50%)

Flat fixed | Peak-use | Locational - offtake | Locational - feedin | Locational - combi | Flat variable | CAPEX

- These deltas, as in the study by CE Delft, do not yet reflect second order effects of the introduction of a feed-in network charge on renewable buildout, power prices, and system composition.
- The implementation of a feed-in network charge would negatively affect already commissioned renewable assets, reducing their returns.
  - Based on a reference asset starting construction in 2024.
- Compared to Aurora Net Zero, IRRs for renewables would drop by as much as 1.7 percentage points, and by up to 2 percentage points for batteries.
- However, it can be expected that investment decisions would change in response to the introduction of feed-in network charges; therefore, we also assessed second order effects.

1) Excluding cost increase due to the feed-in network charge but excluding the second order effects, negative effect on renewable buildout and increasing power prices; 2) No offshore wind assumed in offtake areas; 3) Inverter & grid connection size share of peak capacity; 4) No change in battery behaviour compared to Aurora Net Zero is assumed; 5) Post-tax

Sources: Aurora Energy Research

In the long term, feed-in charges slow down renewable buildout and put government decarbonisation ambitions at risk

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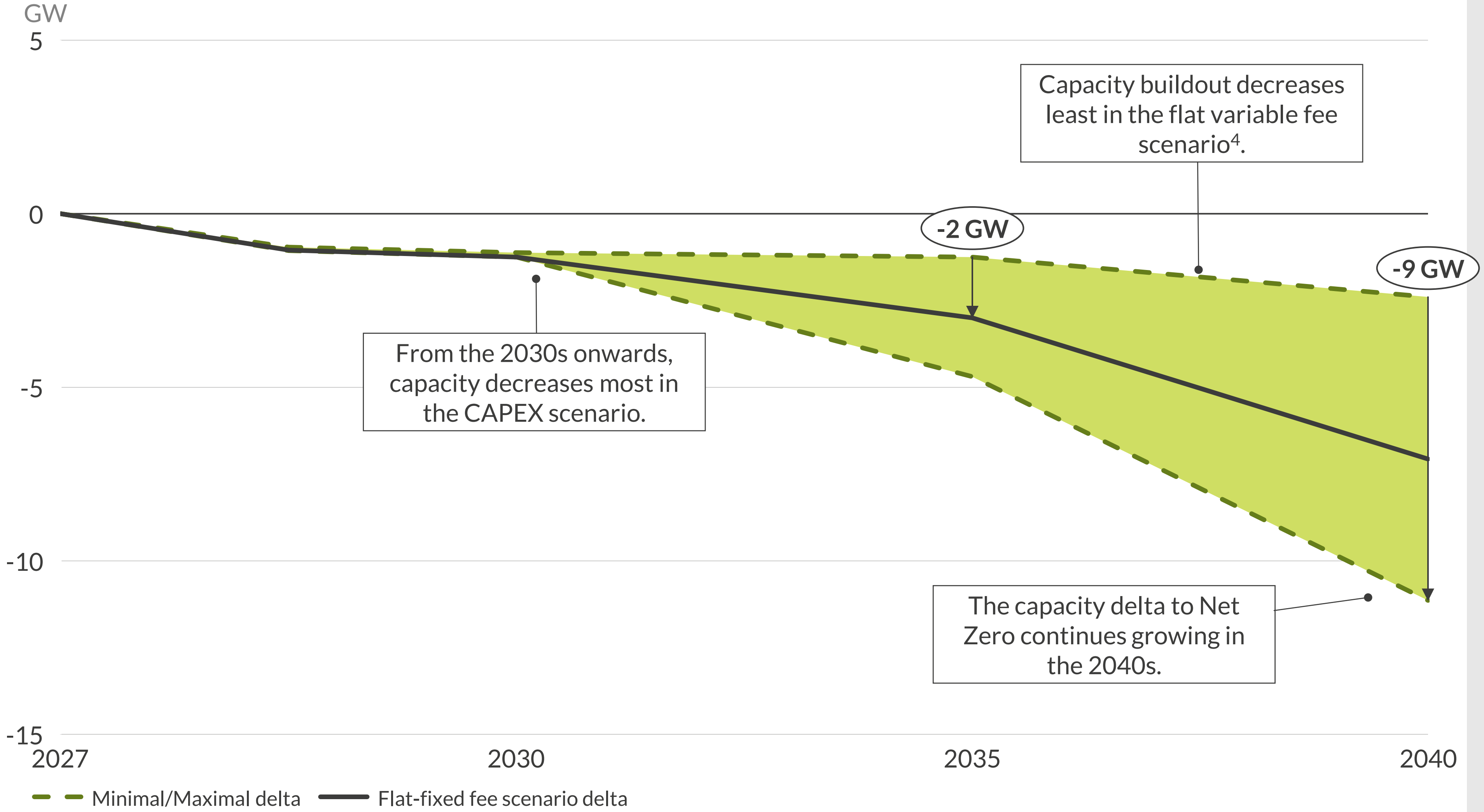
Range of renewable buildout deltas to Aurora Net Zero across all scenarios[1,2]



1) Onshore wind, offshore wind, and solar PV; 2) Displaying 2nde order effects; 3) We assume the producers tariff is implemented in 2027 and impacts investment decisions from 2028 onwards; 4) Impact on net generation is similair to other scenarios, as mainly offshore wind is affected in this scenario, compared to solar PV in other scenarios., where offshore wind produces more p.a..

Sources: Aurora Energy Research, Rijksoverheid

- Accounting for 2nd order effects, increased costs from feed-in network charges lead to reduced renewable capacity buildout in all scenarios[3].
- The lower build out of renewables will make it harder to reach decarbonisation targets.
  - In the CAPEX scenario, the target of 70% renewable generation might be missed.
  - Electrification in industry, and other sectors may slow down as less cheap electricity from renewables is available.
- To still make targets, further investments via subsidy may be needed, increasing societal cost.
- Imports may not always be available or there may be regulation on fossil-based imports, endangering security of supply (SoS).

Lower renewable generation leads to higher utilisation of EU thermal assets, pushing up electricity prices and the costs for end-consumers

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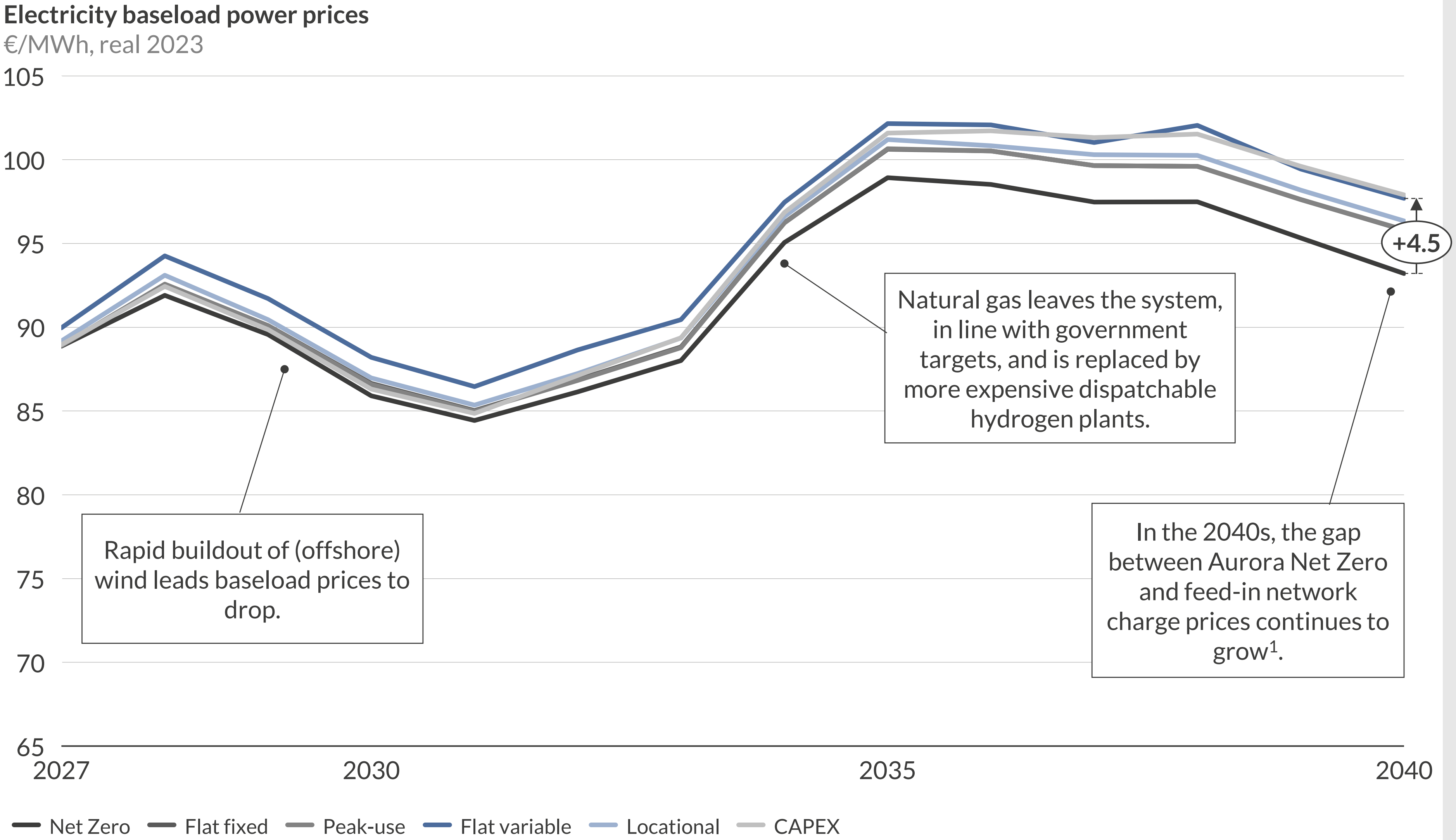


1) In our modelling, we made projections for up to 2050.

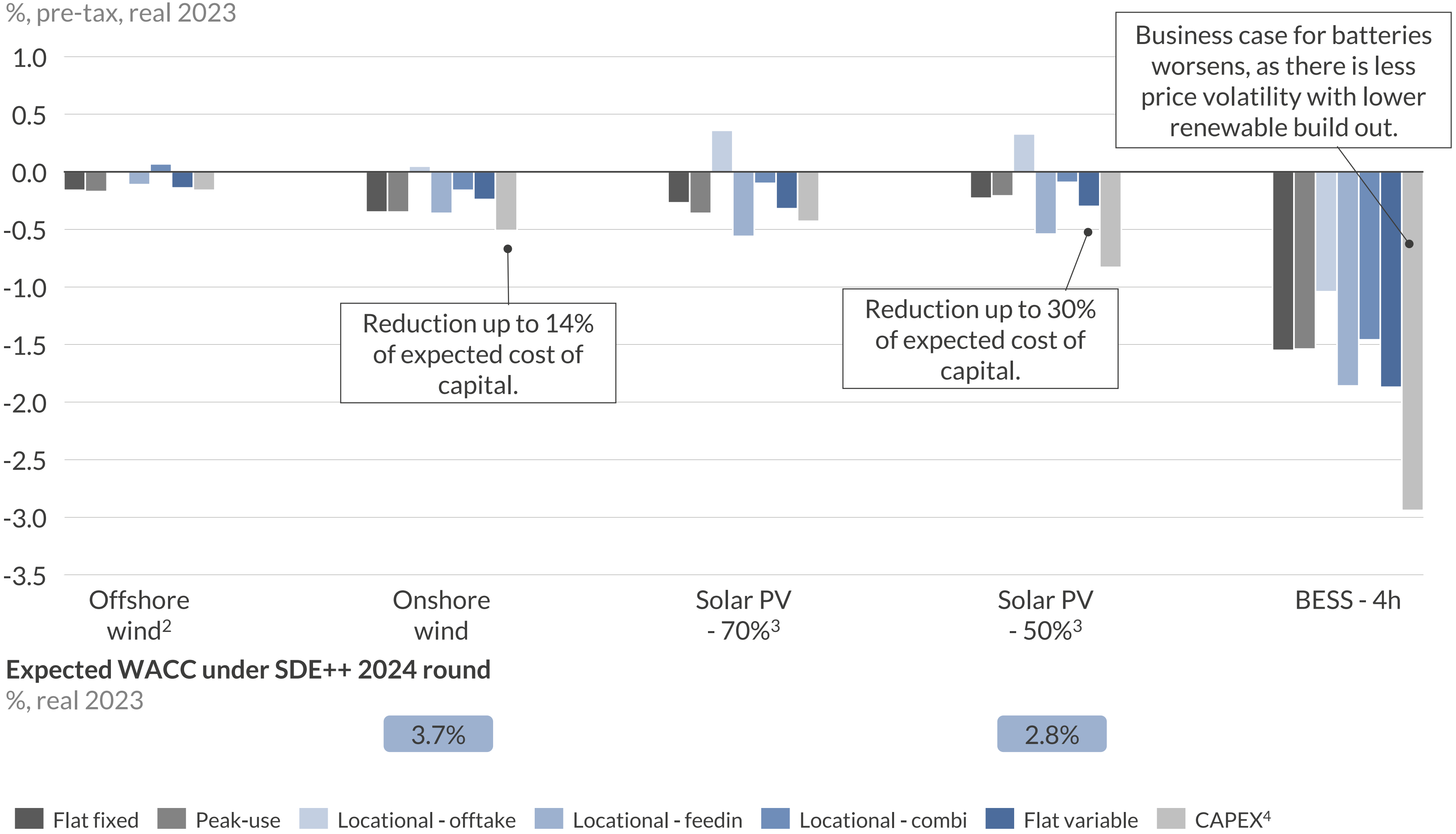
Sources: Aurora Energy Research

- Introducing a feed-in network charge leads to higher baseload prices, whose delta to Aurora Net Zero increases over time.
  - In the short term, prices increase mostly in the flat variable fee scenario, as asset dispatch is directly affected by the additional fees.
  - In the capacity-based scenarios, differences show from ~2028 onwards, when reduced buildout in response to the charges set in.
- Decreased renewable capacity buildout leads to:
  - Higher prices due to increased reliance on dispatchable plants; hydrogen CCGTs and OCGTs from the mid-2030s onwards.
  - Higer prices due to increased reliance on imports, including higher imports from EU thermal assets.

Even after correcting for second order effects (i.e. rising electricity prices), already commissioned assets are still negatively impacted

IRR delta to Aurora Net Zero, reference asset with construction starting in 2024 – including second order effects[1]

%, pre-tax, real 2023



1) Including cost increase due to the fee but excluding the 2nd order effects, negative effect on renewable buildout and increasing prices; 2) No offshore wind assumed in offtake areas; 3) Inverter & grid connection size share of peak capacity; 4) Assumption on distribution taken from CE Delft; 5) One-off CAPEX assumptions CE Delft are high compared to current one-off fee & other countries

Sources: Aurora Energy Research

- The introduction of feed-in network charges leads to a decrease in renewable buildout.
  - Decreased cannibalisation among renewable assets leads to higher capture prices.
  - Medium- to long term higher running hours of hydrogen plants further increases power prices.
- However, the returns of already commissioned projects would still be negatively impacted.
- Additionally, existing assets with long-term PPA contracts will not benefit from 2nd order effects and will be affected more significantly.
- While IRRs for renewable assets in electricity offtake areas increase, most renewable assets would be negatively affected as they are located in other areas[4].

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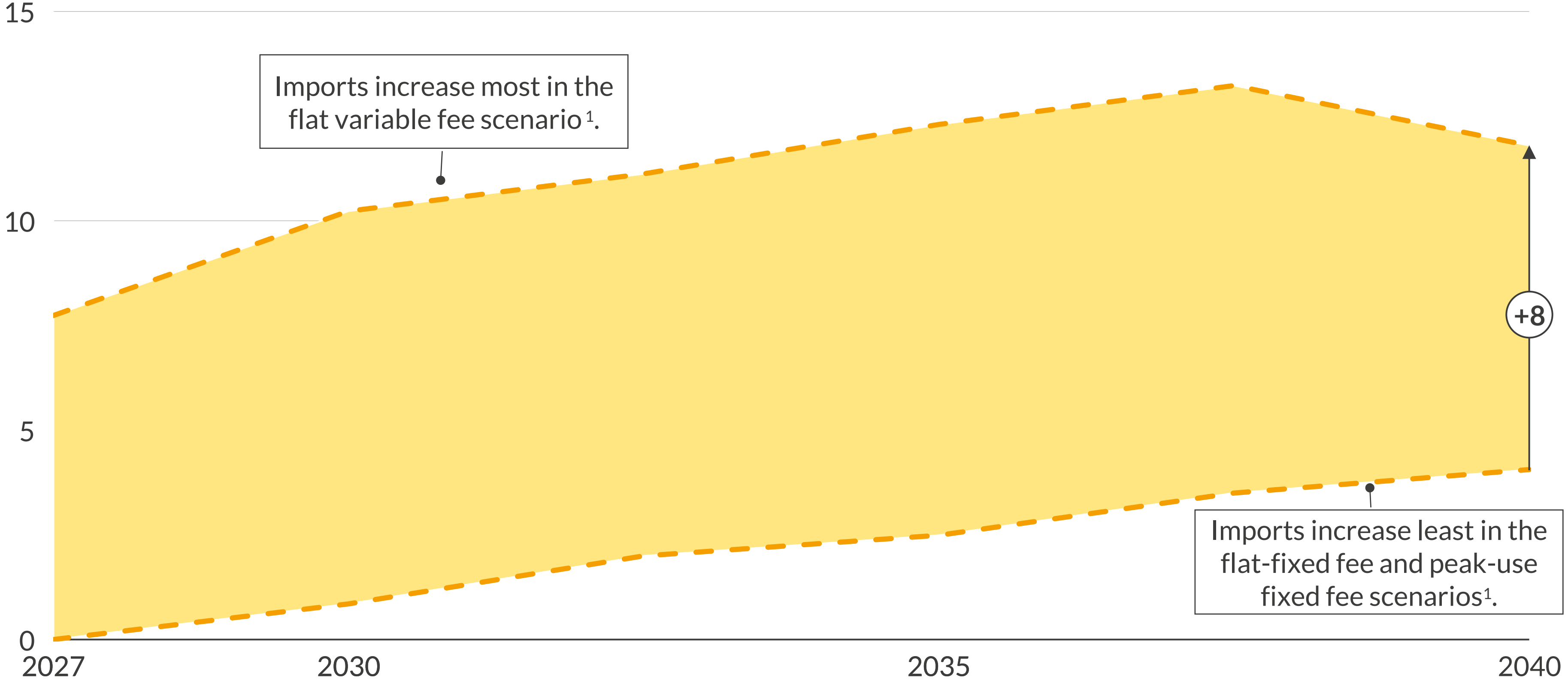
While higher prices allow for some additional H_2 CCGT buildout, it is not sufficient to cover demand, increasing import dependency

Range of deltas in imports compared to Aurora Net Zero
TWh



Maximum increase in imports as a share of total imports in Aurora Net Zero
%

2030	2035	2040
93.4%	86.8%	149%

1) In the 2040s, imports increase further in all scenarios.

Sources: Aurora Energy Research

Comments

- As power prices increase, imports become cheaper than building additional assets inside the country. Import dependency increases across all scenarios.
- In the scenario with the highest increases, the flat variable fee scenario, imports increase by up to ~13TWh.
  - This is largely driven by a reduction in thermal running hours due to the increased production costs in the short term and less offshore buildout in the long term.
  - There is not sufficient additional dispatchable capacity to compensate this.
- In the flat-fixed fee and peak-use fixed fee scenarios, imports increase the least, reaching a delta of 4TWh in 2040.

Short- to medium-term security of supply is further at risk as higher costs from feed-in charges may lead to early natural gas power plant closures

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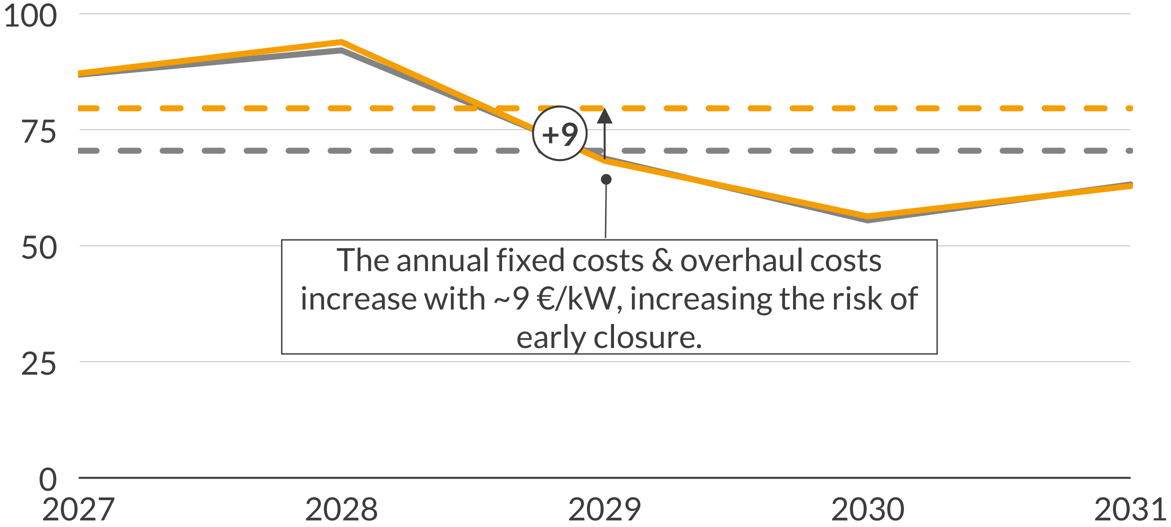
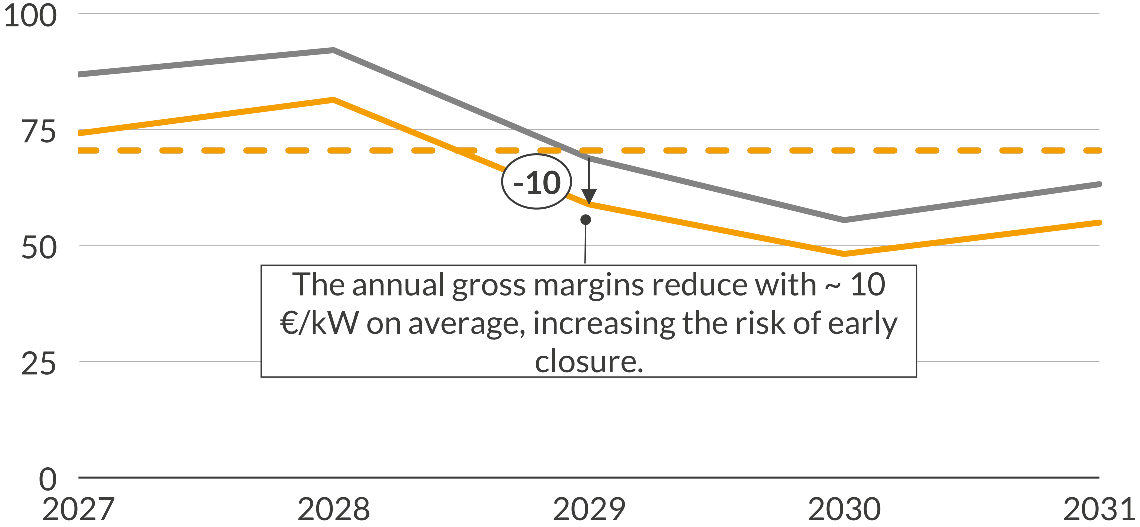
Gross margins v. costs - flat fixed fee scenario
€/kW, real 2023



Gross margins v. costs - flat variable fee scenario
€/kW, real 2023



In both capacity-based feed-in network charge and in dispatch-based feed-in network charge scenarios, charges could imply earlier closure of gas CCGTs.

- Feed-in network charges are an additional cost and could lead operators to close their plants early when other expenses, such as overhaul cost, arise.
  - Overhaul costs are capital investments into gas CCGTs for maintenance and need to be made over the course of the asset's lifetime.
  - Even with fixed cost covered, margins may not be sufficient to cover both overhaul cost and feed-in network charges when assets near closure in the early 2030s[1].
- In the displayed flat fixed fee and flat variable fee scenarios, the reference gas CCGT plant is at risk of closing from ~2028 onwards, with the business case becoming more sensitive to any additional changes in costs or revenues.
- Premature closure of gas CCGT plants would have negative effects on security of supply, increasing reliance on imports, pushing up power prices and societal costs.

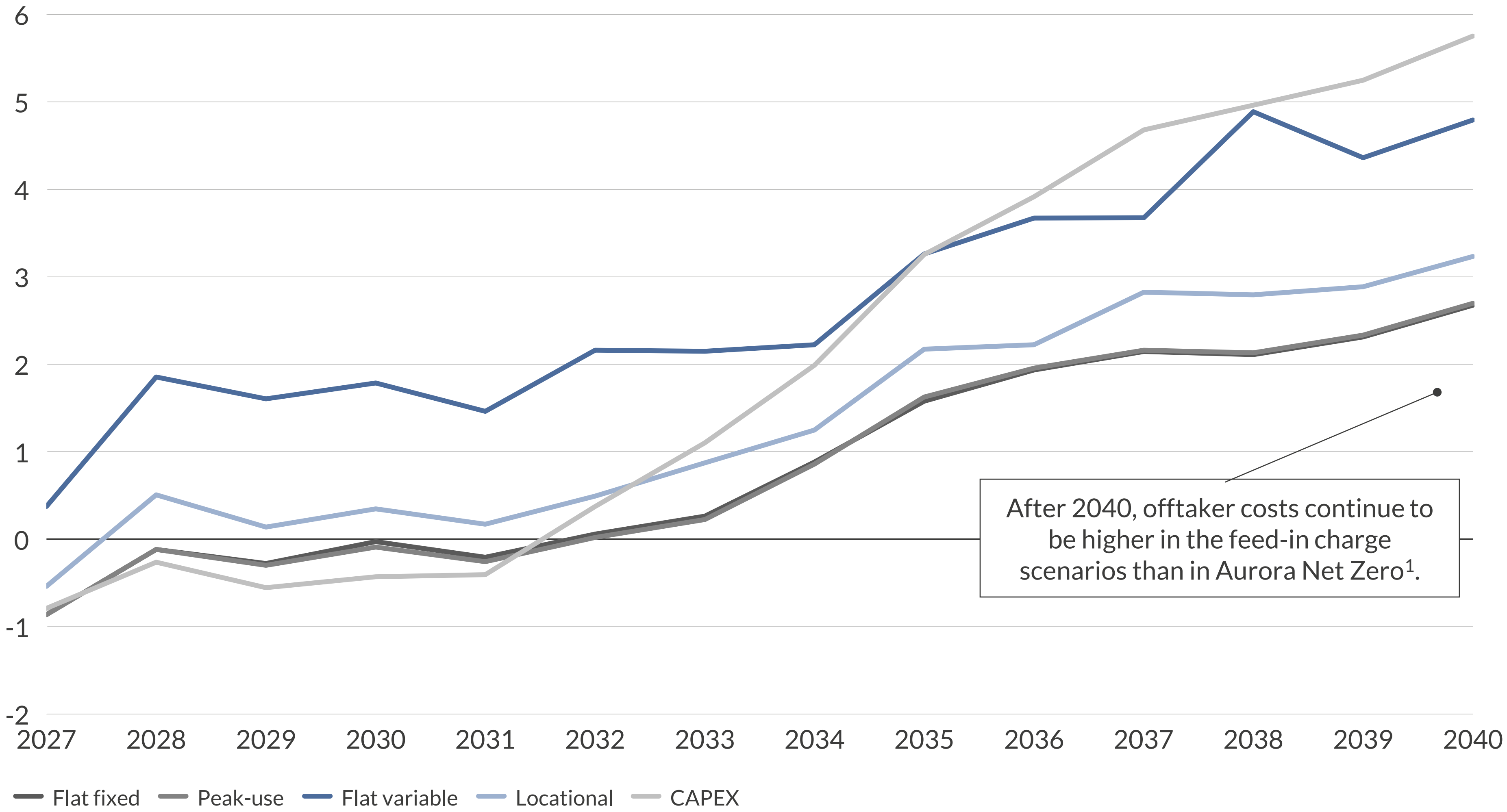
Net Zero: annual gross margins — Net Zero: annual fixed & overhaul costs — Scenario: annual gross margins — Scenario: annual fixed & overhaul costs

1) As per the government's goal of reaching a zero-emissions power sector.

Sources: Aurora Energy Research

Higher electricity prices outweigh the reduced grid fees for offtakers on the medium to long term, increasing total end-consumer bills

Net delta electricity costs to Net Zero for a 100 MW offtaker[2]
mn €, real 2023



1) In our modelling, we made projections for up to 2050. 2) with stable, full-load consumption profile

Sources: Aurora Energy Research

- CE Delft estimates annual reductions of grid fee payments of 100 MW large-scale industrial offtakers at 0.9 mn €.
- Short term, this has a slight positive effect on the electricity bill of the end-consumer.
  - This is because renewable investments are not expected to slow down immediately.
  - The first effects are seen from 2028 onwards.
- In the long term, changes in the system driven by the new feed-in network charges lead to significantly higher electricity prices and total annual electricity costs.
- As we see more costs shifting towards end-consumers, the impact of the feed-in network charge is not in line with its purpose, which is to realise more cost reflectivity.

The assumptions used in our modelling are relatively optimistic, in practice the negative impact on consumer bills and security of supply could be exacerbated

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Assumption	Impact of change in assumption
1 While we include second-order effects, investment conditions such as capital cost remain unchanged. ▪ WACC and hurdle rates are the same as in the Aurora Net Zero scenario. ▪ We include second-order effects of feed-in network charges, where differences in capacity buildout in the Netherlands start in 2028. – Decisions on feed-in network charges would not be made before 2025, with implementation and feedback effects taking longer.	**1 Projected effects for capacity buildout and prices could be exacerbated if the investment climate worsened through increased uncertainty.** ▪ The policy on feed-in charges, and potentially even the discussion on it, will likely raise the cost of capital and hurdle rates due to increased uncertainty. ▪ Depending on the speed and kind of policy implementation, this could also imply capacity buildout changes before 2028.
2 There are capacity payments to cover H_2 thermal investment gaps. ▪ We assume capacity payment which fill the gap to financing hydrogen CCGTs and OCGTs in the long term, to avoid loss of load.	**2 Without capacity payments, long-term electricity prices would be more volatile, likely increasing the negative impact of feed-in charges.** ▪ This is due to insufficient dispatchable capacity from thermal plants, which could lead to unacceptable hours of loss of load and impact SoS[1].
3 Gas CCGT plants only need to recover fixed O&M costs to keep running. ▪ In our modelling, gas CCGTs make the decision to decommission by comparing gross margins to fixed operation and maintenance costs.	**3 Considering the cost for major overhauls, which are not unlikely to be needed for some plants, could lead gas CCGTs to close early, putting more pressure on security of supply and increasing prices.**
4 The impact of feed-in charges on demand growth is limited. ▪ Base demand is the same as in Aurora Net Zero. Flexible demand technology buildout (e.g., electrolyser capacity) remain unchanged. The offtake hours of the demand sources do react to changes in prices.	**4 Base demand and the buildout of flexible demand technologies could be affected by increased prices.** ▪ Decarbonisation targets could be missed through reduced electrification due to higher prices.
5 In the model, emissions goals are reached according to current emissions goals, with imports available.	**5 Imported electricity may not be carbon free or available, increasing system emissions and risks on security of supply.**
6 In the model we assume no additional nuclear buildout.	**6 Additional nuclear capacity would decrease imports but also renewable capacity buildout as it worsens renewable business cases.**

1) Security of Supply

Sources: Aurora Energy Research

Details and disclaimer

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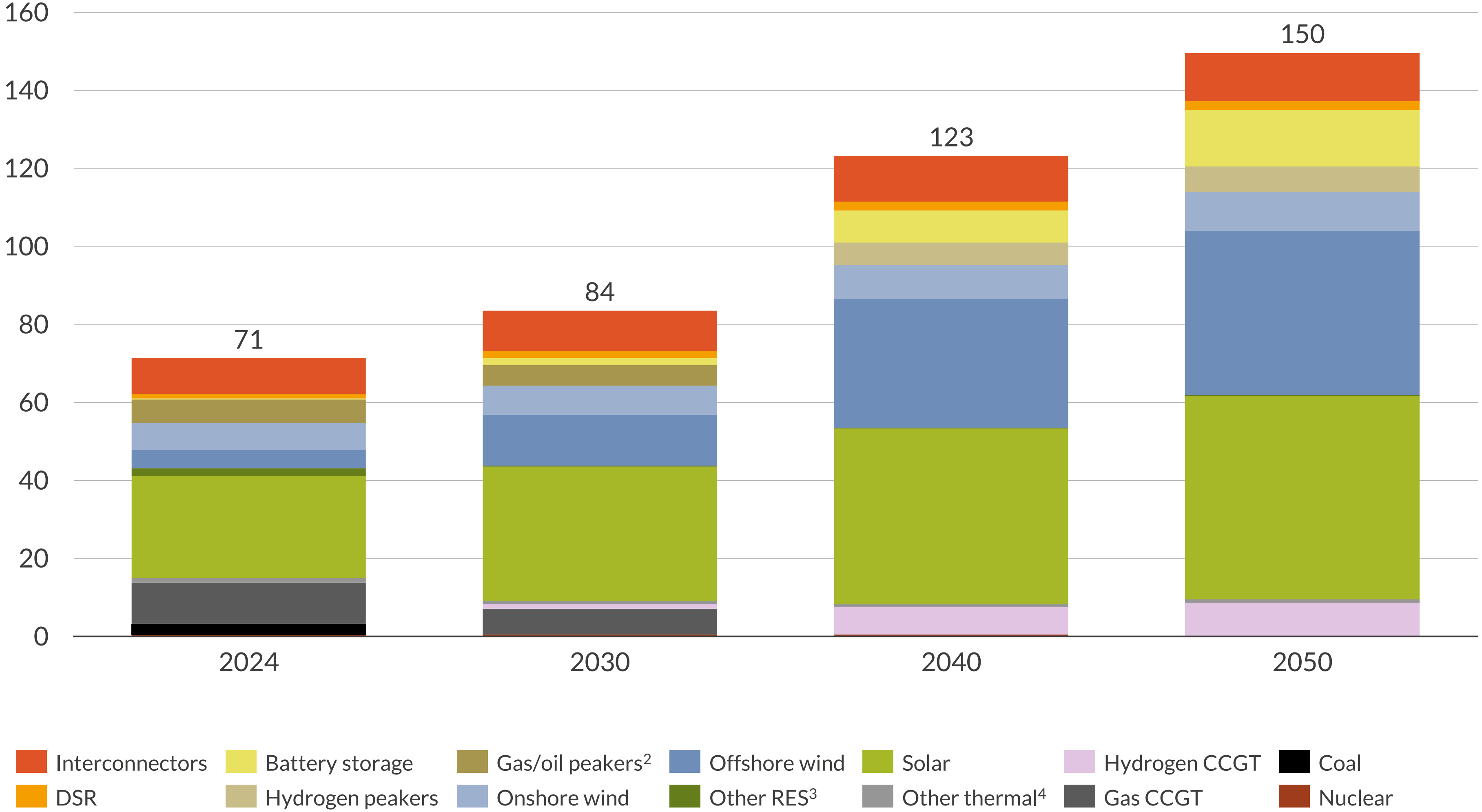
All scenarios are based on Aurora's target driven Net Zero scenario, adjusting asset cost structures to reflect the feed-in grid charges

Total installed capacity in Aurora Net Zero scenario[1]

GW



1) Excluding offshore wind that is developed for direct delivery for hydrogen production. 2) Peaking includes OCGTs and reciprocating engines; 3) Other RES is exclusively biomass in the Netherlands; 4) Other thermal are waste to energy plants, which are assumed to be combined with CCS from 2030 onwards.

Sources: Aurora Energy Research

- Installed capacity increases by 79GW in 2024 -2050, driven by the strong growth of renewables: solar PV (+26GW), onshore wind (+3GW) and offshore wind (+37GW).
- The government's target of a net zero power system in 2035 is achieved through a complete replacement of gas plants by hydrogen plants by 2035 and additional solar and offshore wind capacity.

To assess the different feed-in network designs, they are scored on 6 criteria reflecting the impact on the system

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1 Renewable investment

- **Definition:** The impact on investment decisions & renewable buildout.
- **Relevance:** Capturing the impact on governmental decarbonisation targets.

2 Security of supply

- **Definition:** The impact on import dependence and risk of blackouts.
- **Relevance:** Capturing the societal impact on energy security.

3 End consumer electricity bill

- **Definition:** The impact on the total electricity costs for an end consumer.
- **Relevance:** Capturing any additional burden on end consumers and the risk of slowing down electrification efforts.

4 Complexity of implementation

- **Definition:** The level of effort and additional costs due to implementation for an asset operator.
- **Relevance:** A feed-in network charge raises the complexity of an asset's dispatch, which might lead to sub-optimal decisions

5 Cost reflectivity

- **Definition:** The level in which fees are charged to the parties responsible for costs of the grid.
- **Relevance:** ACM's objective of the feed-in network charge is a more fair distribution of costs.

6 Investment security

- **Definition:** The level of retroactive disadvantages and transparency about the impact on asset business cases.
- **Relevance:** Retroactive changes lead to a more challenging investment climate, which might undermine future investments.

Sources: Aurora Energy Research

The implementation of feed-in network charges would negatively affect end consumer bills, renewable investment, and security of supply

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Design options

Assessment	No fee [1]	Flat-fixed fee scenario	Peak-use fixed fee scenario	Flat variable fee scenario	Locational difference scenario	CAPEX scenario
Renewable investment	▪ Renewable buildout according to reaching decarbonisation targets. (+)	▪ Renewable capacity buildout is slowed down. ▪ Solar PV most strongly affected. (−)	▪ Renewable capacity buildout is slowed down. ▪ Solar PV most strongly affected. (−)	▪ Renewable capacity buildout is slowed down. ▪ Offshore wind most strongly affected. (−)	▪ Renewable capacity buildout is slowed down. ▪ Solar PV most strongly affected. (−)	▪ Renewable buildout is slowed down, solar PV buildout stops almost fully. (− −)
Security of supply	▪ No impact on installed capacity expected if no fee is implemented. (+)	▪ Lower renewable generation increases reliance on imports. ▪ Gas CCGTs may close early. (−)	▪ Lower renewable generation increases reliance on imports. ▪ Gas CCGTs may close early. (−)	▪ Relatively higher increase in reliance on imports. ▪ Gas CCGTs may close early. (− −)	▪ Lower renewable generation increases reliance on imports. ▪ Gas CCGTs may close early. (−)	▪ Relatively higher increase in reliance on imports. ▪ Gas CCGTs may close early. (− −)
End consumer electricity bill	▪ No additional impact on the electricity bill of an end consumer. (+)	▪ Increased fees are handed down to the end consumer, increasing consumer bills. (−)	▪ Increased fees are handed down to the end consumer, increasing consumer bills. (−)	▪ Relatively higher increase in end consumer bills due to stronger system effects of fee. (− −)	▪ Increased fees are handed down to the end consumer, increasing consumer bills. (−)	▪ Relatively higher increase in end consumer bills due to stronger system effects of fee. (− −)

Positive Neutral Negative

1) Based on Aurora Net Zero, Aurora's best view on a system in which government decarbonisation targets are achieved.

Sources: Aurora Energy Research

Further, the implementation of such charges would increase complexity of dispatch and investments, while risking not being cost reflective

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Design options

Assessment	No fee [1]	Flat-fixed fee scenario	Peak-use fixed fee scenario	Flat variable fee scenario	Locational difference scenario	CAPEX scenario
Complexity of implementation	▪ Not applicable (Positive, Positive)	▪ Weighting by generation and capacity may be difficult to assess and anticipate. (Negative)	▪ Increased complexity for energy management if producers want to adjust their behaviour to benefit from proposal. (Negative, Negative)	▪ Additional cost to dispatch decision, relatively simple to include. (Positive)	▪ Anticipation of cost based on area, next to potential uncertainties on whether areas are fixed, increases complexity. (Negative, Negative)	▪ Additional capital expenditure, relatively simple to include. (Positive)
Cost reflectivity	▪ Limited reflectivity through unequal distribution of cost among consumers and producers. (Negative)	▪ Costs are more distributed over all grid users. ▪ On the other hand, the costs for consumers increase even further. (Neutral)	▪ Favours dispatch in non-peak hours. ▪ On the other hand, the costs for consumers increase even further. (Positive)	▪ Costs are more distributed over all grid users, and production cost is generation based. ▪ On the other hand, the costs for consumers increase even further. (Neutral)	▪ Location-based fees concentrate cost where they are incurred. ▪ On the other hand, the costs for consumers increase even further. (Positive)	▪ Costs are more distributed over all grid users. ▪ Feed-in charge is not linked to actual use of the grid and costs of consumers increase even further. (Neutral)

Positive Neutral Negative

1) Based on Aurora Net Zero, Aurora's best view on a system in which government decarbonisation targets are achieved.

Sources: Aurora Energy Research

Finally, the impact on investments can be hard to assess and assets may be retroactively impacted

Design options

Assessment	No fee [1]	Flat-fixed fee scenario	Peak-use fixed fee scenario	Flat variable fee scenario	Locational difference scenario	CAPEX scenario
Investment security	▪ No additional impact on business cases of investments. (Positive, Positive)	▪ Retroactive impact on projects that have already been realised. ▪ Impact on business case complex to determine as it is difficult to adjust dispatch based on monthly capacity-based fees. (Negative, Negative)	▪ Retroactive impact on projects that have already been realised. ▪ Impact on business case complex to determine as the fees do not directly impact dispatch. (Negative, Negative)	▪ Retroactive impact on projects that have already been realised. ▪ Impact somewhat transparent as fee can be taken into account in dispatch decisions. (Neutral)	▪ Retroactive impact on projects that have already been realised. ▪ Risk of increasing impact over time if classification of location changes. (Negative, Negative)	▪ No retroactive disadvantages for already commissioned projects. ▪ Impact on business case of new projects is transparent. (Positive)

Positive Neutral Negative

1) Based on Aurora Net Zero, Aurora's best view on a system in which government decarbonisation targets are achieved.

Sources: Aurora Energy Research

Locational choices are strictly regulated by a set of policies, which will limit the potential of locational feed-in tariff to steer capacity

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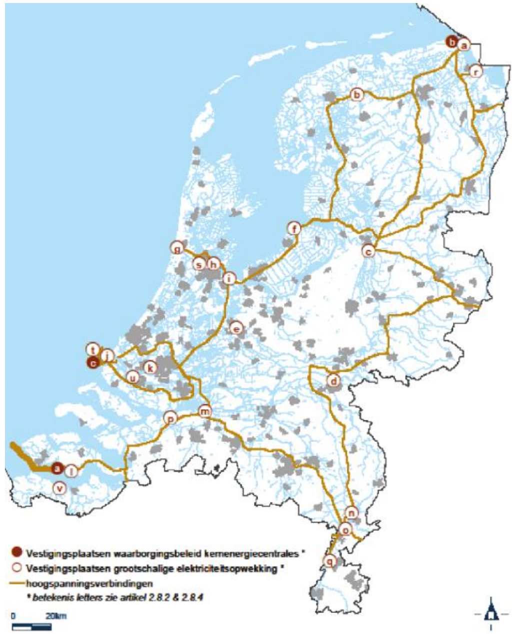
Policy driven impact on power plant locations

- The locational difference scenario for the feed-in tariffs has the intention to make certain locations more attractive for newbuild assets.
- However, change in location will likely be minimal as possible locations are restricted by policy and land-use plans. The most important policies on this are:
  - **Besluit algemene regels ruimtelijke ordening (barro)**: lists the possible locations for large-scale electricity production (larger than 500 MW), excluding wind, and including nuclear plants of any size.
  - **Programma Energie Hoofdstructuur:** includes the restrictions from barro, and outlines policy for locations for offshore wind and large-scale batteries that are connected to the high voltage grid.
  - **Nationale omgevingsvisie:** includes the '*zonneladder*' which indicates the order in which different types of locations should be used for solar PV, starting with unused rooftops, and ending with agricultural sites.
  - **Provinciale omgevingsvisie:** differs per province, most include site requirements for solar PV and designated sites for onshore wind.
- No newbuild gas CCGTs and OCGTs are expected, and already built assets will not change their location. Therefore, gas assets have no potential for locational change.
- The locational difference feed-in network charges have the most potential to influence solar PV asset location choices (more information see appendix).

Expected expansion of network towards 2030, Programma Energie Hoofdstructuur



Locations of large-scale electricity generation, Besluit algemene regels ruimtelijke ordening

In terms of choice of asset location and operation, solar PV has the most potential to be impacted, but effects are still expected to be limited

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Locational changes are most feasible for Solar PV plants, but these are still subject to site requirements

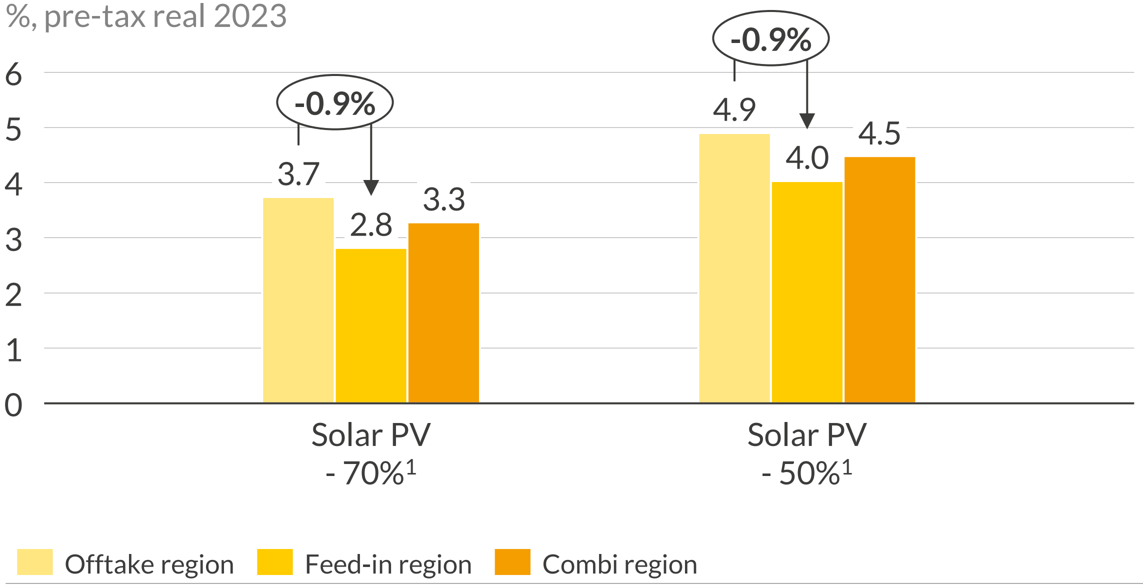
- Newbuild solar PV plants would be able to take the locational feed-in tariff into account when choosing a location. However, they are subject to many site requirements, so the feed-in tariff would not be the only consideration, and only a limited amount of newbuild plants would be expected to change their behaviour.
- The largest difference in locational feed-in tariffs is between the offtake region and the feed-in region. However, buildout potential in offtake regions might be more limited due to other site requirements.

Solar PV plants benefit from limiting their grid connection size, subsidy payments may make higher connection reductions more profitable

- In all scenarios, solar PV plants are incentivised to limit their connection size, this is mainly due to lower CAPEX costs for the grid connection and inverter, although they also benefit from lower grid fees.
- Within SDE++, plants will be required to limit their grid and inverter connection size to 50% of peak capacity. However, the subsidies will allow for gross margins to increase, potentially making them more profitable than assets with a larger grid connection size.

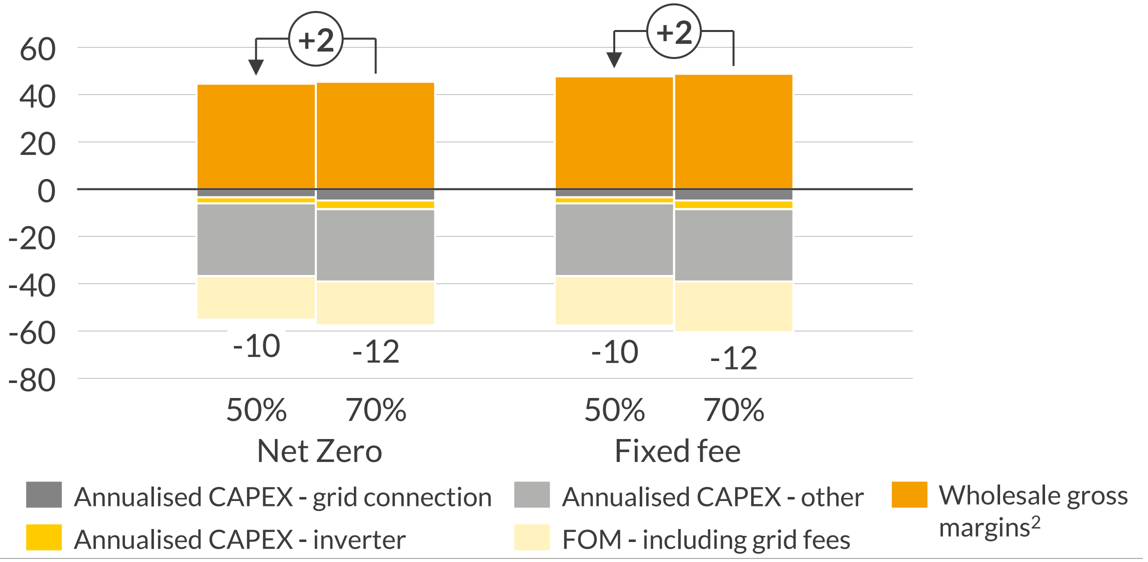
IRR of a reference asset with construction starting in 2024

%, pre-tax real 2023



Annual costs / revenues of solar PV plants, excluding subsidies[1]

€/kW, real 2023



1) Inverter & grid connection size share of peak capacity; 2) Average wholesale gross margins over lifetime.

Sources: Aurora Energy Research