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Feed-in grid charge – policy assessment update

September 2025 | 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 updated assessment of two potential designs of feed-in grid charges for producers, based on new numbers from ACM. Scenario modelling is based on Aurora's 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. Updated proposals for feed-in network charges with higher fee levels 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, retroactively disadvantaging renewables that were granted subsidies based on lower cost levels.
4. In the long term, feed-in charges **slow down renewable buildout**, can reduce renewable generation by more than 15TWh annually, and put government decarbonisation ambitions at risk.
5. **To maintain the Net Zero renewable buildout, additional subsidies of up to 1,427 mn €/year are needed** to offset the extra costs of feed-in grid tariffs, which would still need to be distributed and could impact consumers.
6. Lower renewable generation leads to higher utilisation of EU thermal assets, **pushing up electricity prices and the costs for end-consumers,** although Dutch thermal asset utilisation could reduce pending the fee design.
7. Even **after correcting for second order effects** such as rising electricity prices, already **commissioned assets are still negatively impacted,** with IRRs for solar PV projects reducing by as much as 1.2 p.p.
8. While higher prices allow for some additional power plant buildout, it is not sufficient to cover demand, **increasing import dependency**, with up to 16TWh more net imports annually and significant financial flows leaving the country.
9. **Security of supply is further at risk**, as higher costs from feed-in charges may lead to early natural gas power plant closures for Dutch assets.
10. Higher electricity prices outweigh the reduced grid fees for offtakers on the medium to long term, **increasing total end-consumer bills** by up to 7 mn €[1] annually in the 2030s.

1) For a typical 100MW industrial baseload offtaker

Source: Aurora Energy Research

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

Proposals being explored by the regulator

1 kWmax tariff

A fixed component based on asset capacity adjusted for monthly peak injection into the grid

2 kWh tariff

A variable component based on asset production injected into the grid

i

We used the average level of grid fees from 2021 to 2023 as calculated by the ACM to create our feed-in network charge scenarios, based on Aurora's Net Zero scenario – see slide 15.

As a simplification, we consider assets to be connected to the offshore grid[2], the HV grid[3] and the MS grid[4].

Grid fees ACM[1]

Voltage level grid	1 kWmax grid fee	2 kWh grid fee
	EUR/kWmax	EUR/MWh
Offshore grid[2]	[redacted]	
EHV grid[5]	[redacted]	
HV grid[3]	[redacted]	
TS grid	[redacted]	
Trafo HS + TS/MS	[redacted]	
MS[4]	[redacted]	
Trafo MS/LS	[redacted]	
LS	[redacted]	

- Currently, the regulator is exploring the implementation of feed-in network charges, which would distribute grid costs between consumers and producers. Fee levels are higher than the previous proposal.
- The goal of this is to establish better cost-reflectivity, distributing costs to the parties that are responsible for incurring these costs.
- Informed by the 2021-2023 values assessed by the ACM, we update scenarios on two feed-in network charge design options. This yields a view on the effects that feed-in network charges could have on the system.
- There is still a level of uncertainty on how these tariffs would develop over time, which we do not capture. We only consider inflation for components not capped by EU legislation.

1) Average of 2021, 2022 and 2023 values. 2) Offshore wind assets. 3) Thermal assets including gas, hydrogen, biomass; nuclear plants and batteries. 4) Solar and onshore wind assets. 5) We assume all large assets are connected to the HV grid, excluding the EHV grid that has higher fees. This means that the overall negative impact on the system is underestimated.

Sources: Aurora Energy Research, ACM

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 2030. – Decisions on feed-in grid fees would not be made before Q4 2025.	**1 Projected effects for capacity buildout and prices could be exacerbated if the investment climate worsened through increased uncertainty.** ▪ Policy on feed-in charges, and potentially the discussion on it, will likely raise the cost of capital and hurdle rates due to increased uncertainty[2]. ▪ Depending on the speed and kind of policy implementation, this could also imply capacity buildout changes before 2030.
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.**
7 Impact on grid expansion plans is not included in this assessment.	**7 The impact on the system could reduce investments in the grid, which could have a reducing effect on grid fees.**
8 Net zero targets for the power market and wider economy are achieved	**8 Lower prices but higher emission if this is not achieved, due to gas plants.**

1) Security of Supply; 2) Not reflected in the results of this analysis

Source: Aurora Energy Research

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.

Assessment	Design options: No fee[1]	Design options: kWmax fee	Design options: kWh fee
1 Renewable investment	+	− −	−
2 Security of supply	+	−	− −
3 End consumer electricity bill	+	− −	−
Complexity of implementation[2]	+ +	−	+
Cost reflectivity	−	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 decarbonisation targets are achieved. 2) Complexity of implementation into plant management and trading strategies for asset owners.

Source: Aurora Energy Research

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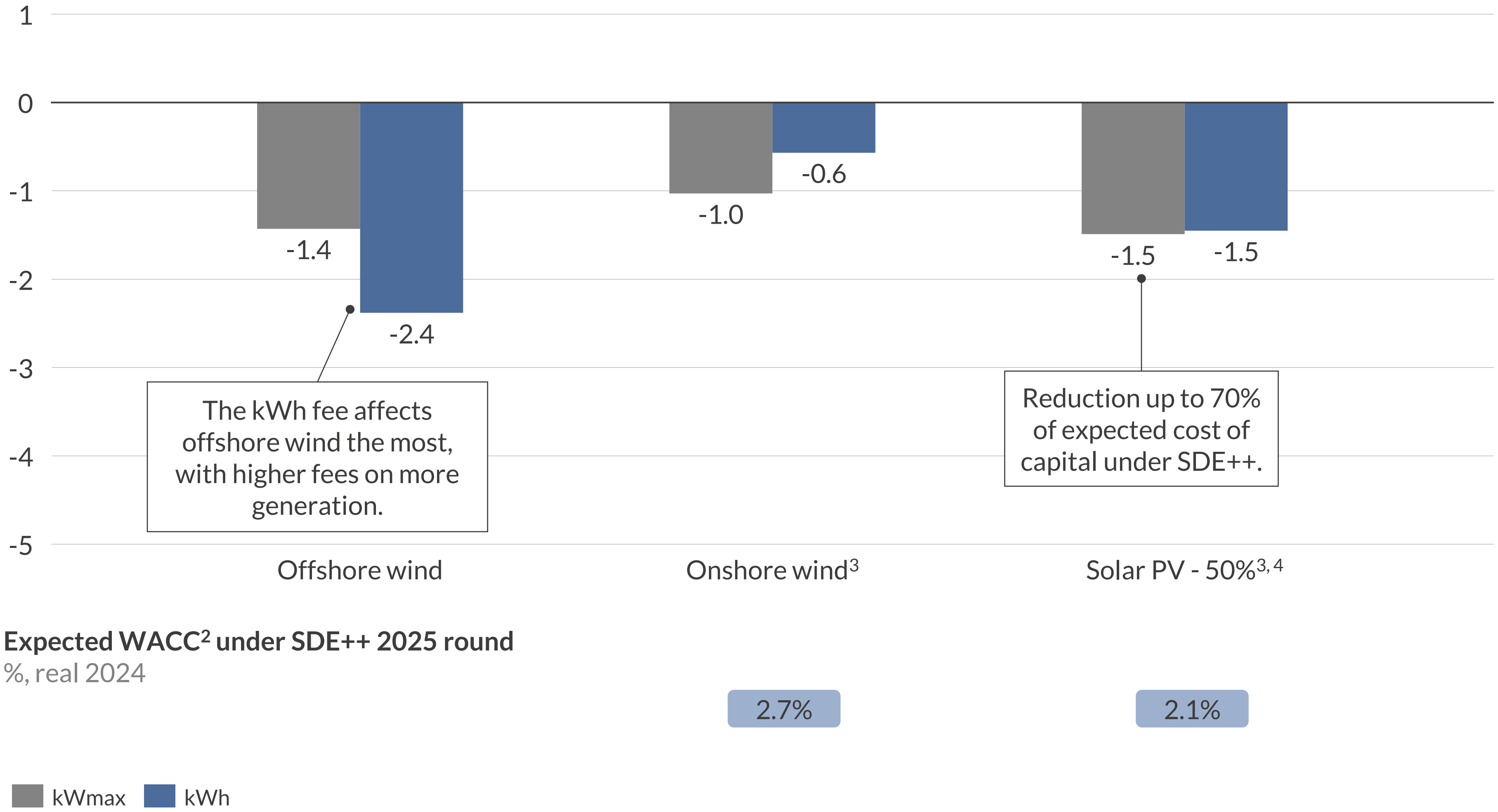
In the short term, feed-in network charges negatively affect already commissioned renewable projects, especially if all else is held equal

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

%, pre-tax real 2024



Expected WACC[2] under SDE++ 2025 round

%, real 2024

	Offshore wind	Onshore wind	Solar PV - 50%
Expected WACC		2.7%	2.1%

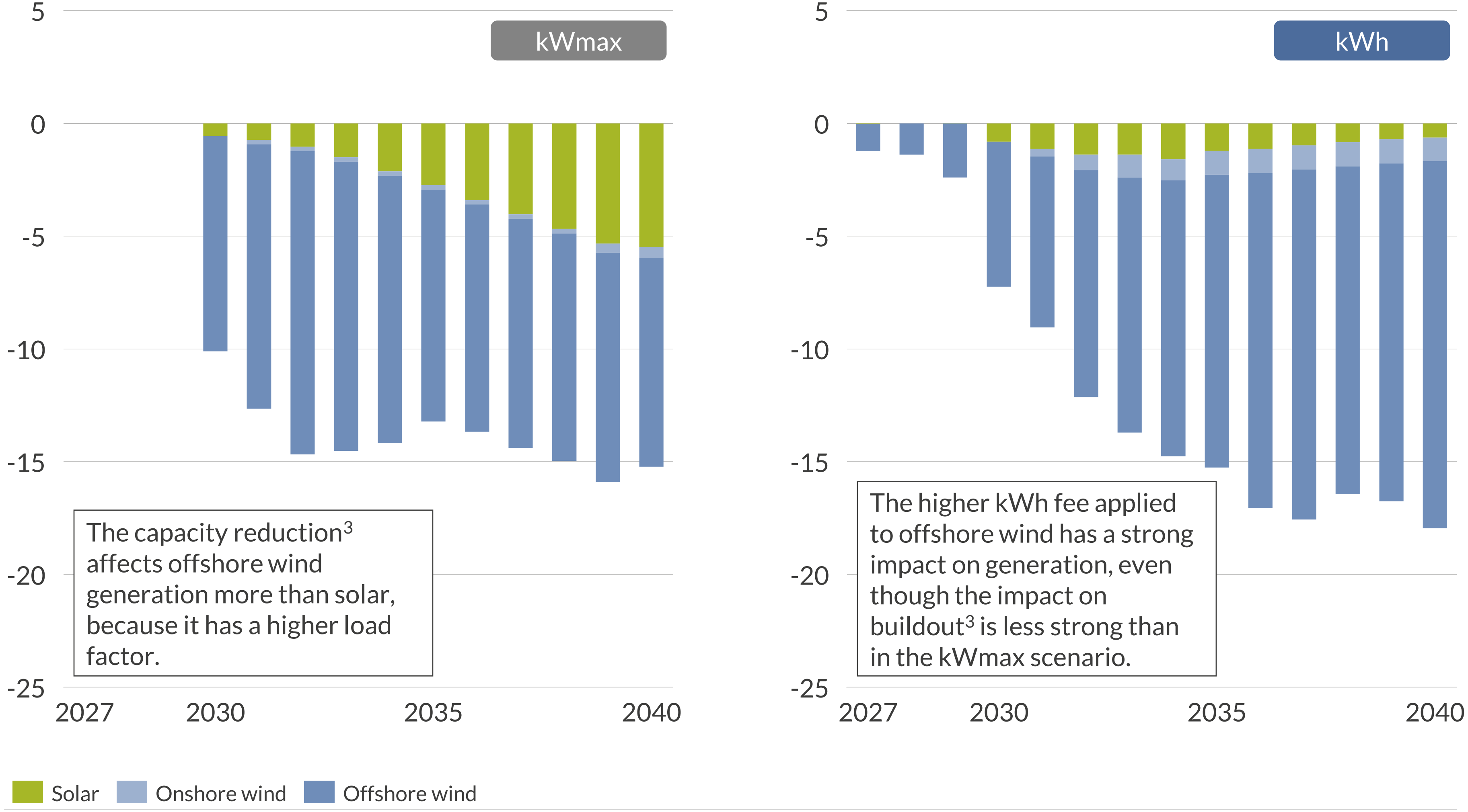
- These deltas do not yet reflect second order effects of the introduction of a feed-in network charge on renewable buildout, power prices, and system composition.
- The implementation of a feed-in network charge would negatively affect already commissioned renewable assets, reducing their returns.
  - Based on a reference asset starting construction in 2024.
- Compared to Aurora Net Zero, IRRs for renewables would drop by as much as 2.4 p.p.
- 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 in the next slides.

1) Including 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) Post-tax. 3) Subsidised asset. 4) Inverter & grid connection size share of peak capacity.

Source: Aurora Energy Research

Renewable generation is reduced by slower buildout and impact on dispatch decisions, putting decarbonisation ambitions at risk

Renewable generation deltas to Aurora Net Zero[1,2]
TWh



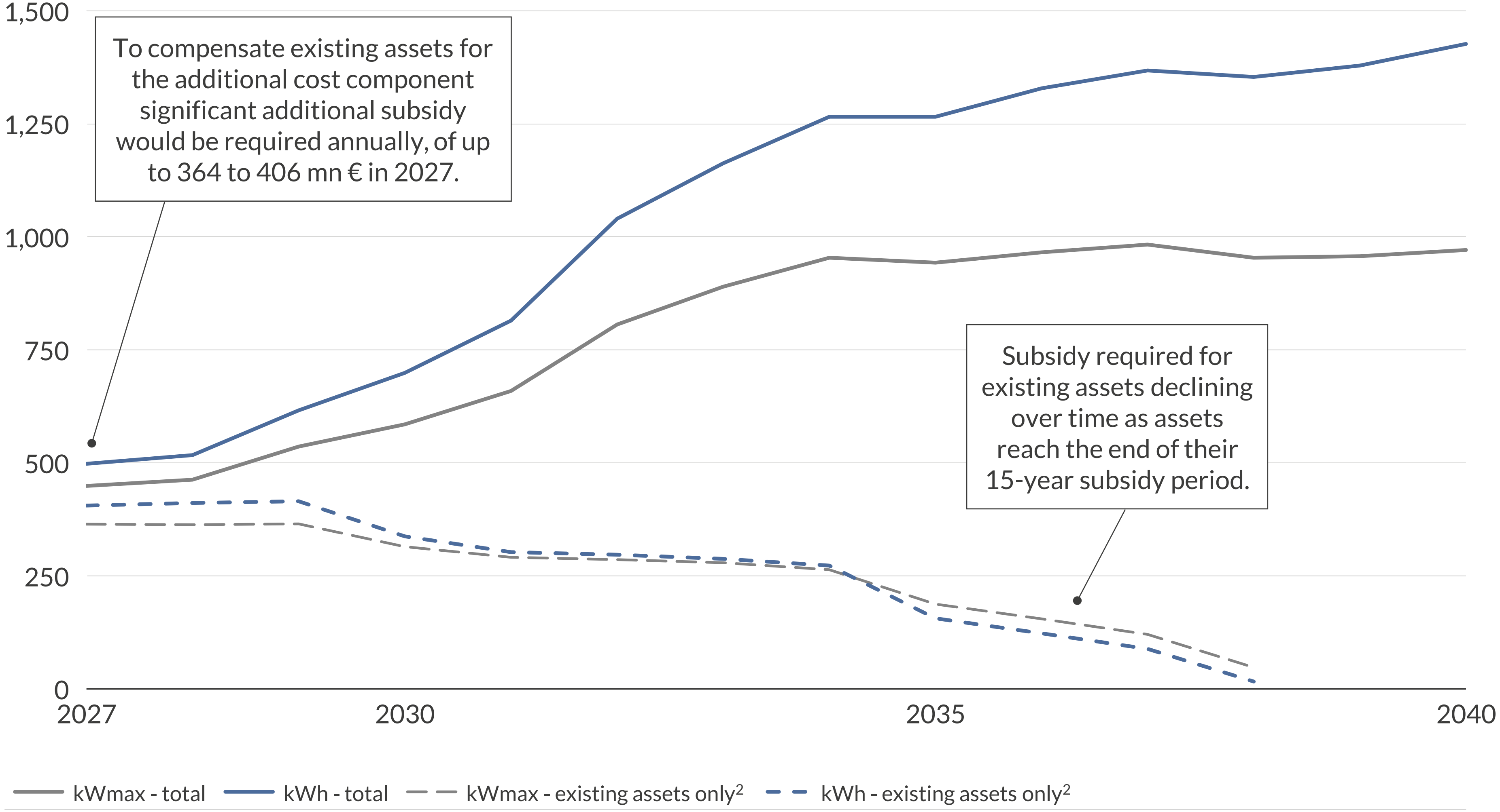
- The negative impact on total renewable generation starts earlier in the kWh fee scenario and worsens over time with offshore wind buildout.
- Lower renewable generation makes decarbonisation targets harder to reach.
  - Renewable generation can drop more than 15TWh from 2030 onwards, leading to delayed Net Zero targets.
  - Electrification in industry, and other sectors may slow down as less cheap electricity from renewables is available.
- To still meet targets, further investments via subsidy may be needed, increasing societal cost.
- Imports may be limited by availability or regulation on fossil-based imports, endangering security of supply.

1) Displaying 2nd order effects. 2) We assume the producer's tariff is implemented in 2027 and impacts investment decisions from 2030 onwards. 3) Impact on capacity buildout can be found in the Appendix.
Sources: Aurora Energy Research, Rijksoverheid

To maintain the Net Zero renewable buildout, additional subsidies are needed to offset the extra costs of feed-in grid tariffs

Maximum potential yearly additional subsidy for existing & newbuild renewables under SDE++[1]

mn €, real 2024



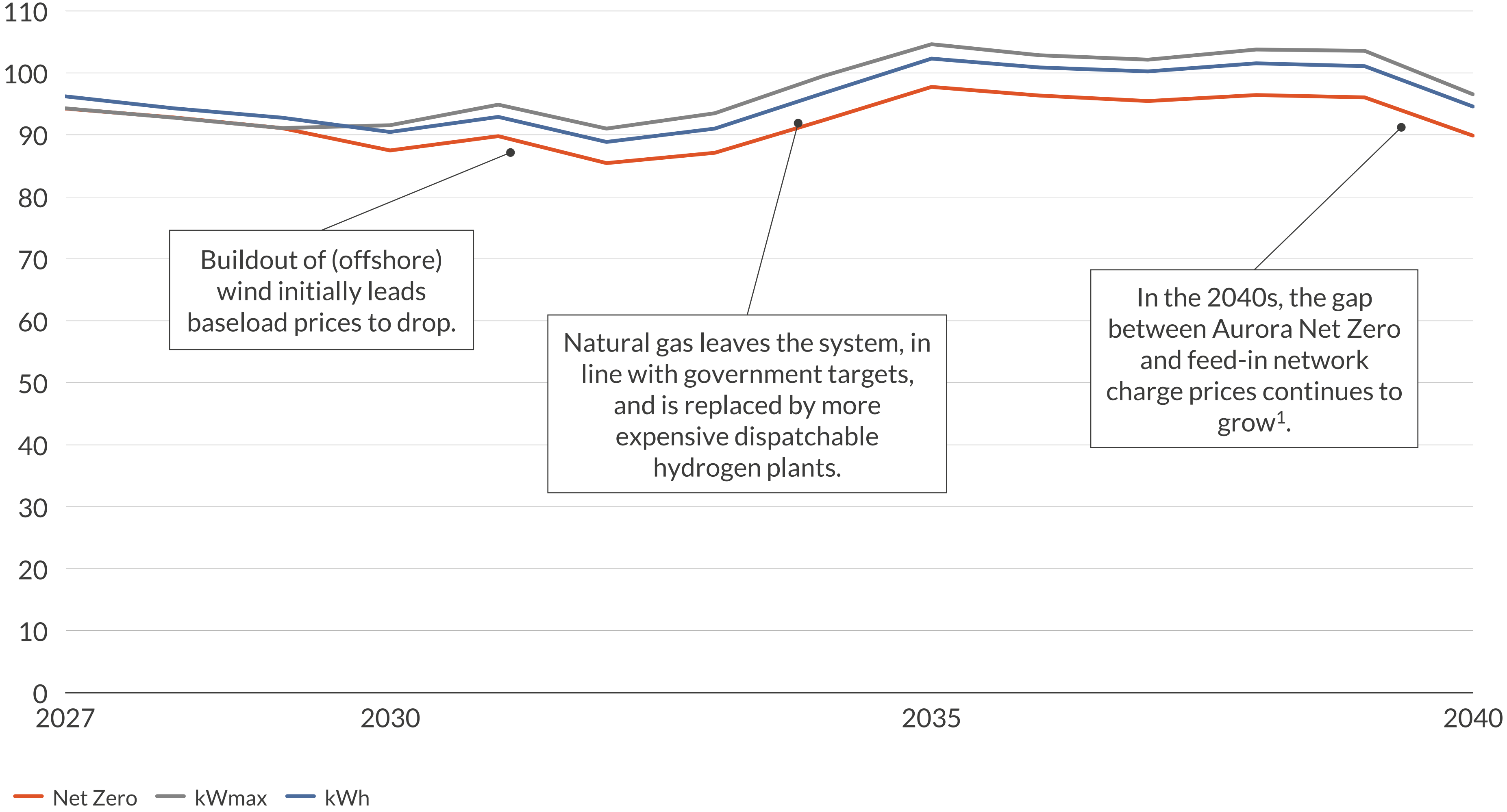
1) Estimation of support needed to maintain Net Zero renewable buildout targets. Calculated as 15-year subsidy to cover additional fee costs, applied to all onshore wind, large scale solar, and offshore wind assets; 2) Assuming projects operational at the start of 2025

Source: Aurora Energy Research

- Additional subsidies through SDE++ could be needed to cover increasing financial gaps and maintain renewable buildout in line with Net Zero targets.
- Currently, offshore wind does not receive SDE++ subsidies, but support might be needed to sustain the buildout to 2040. This is especially important with the kWh fee, which increases offshore wind costs the most.
  - To cover increased costs for both newbuild & existing assets, subsidies for wind and solar would increase by up to 917-1,427 mn €/year in 2040.
- This aid would support wind and solar, but other assets (e.g. thermal power plants) are still affected by tariffs and can have an impact on prices and security of supply.

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

Electricity baseload power prices
€/MWh, real 2024

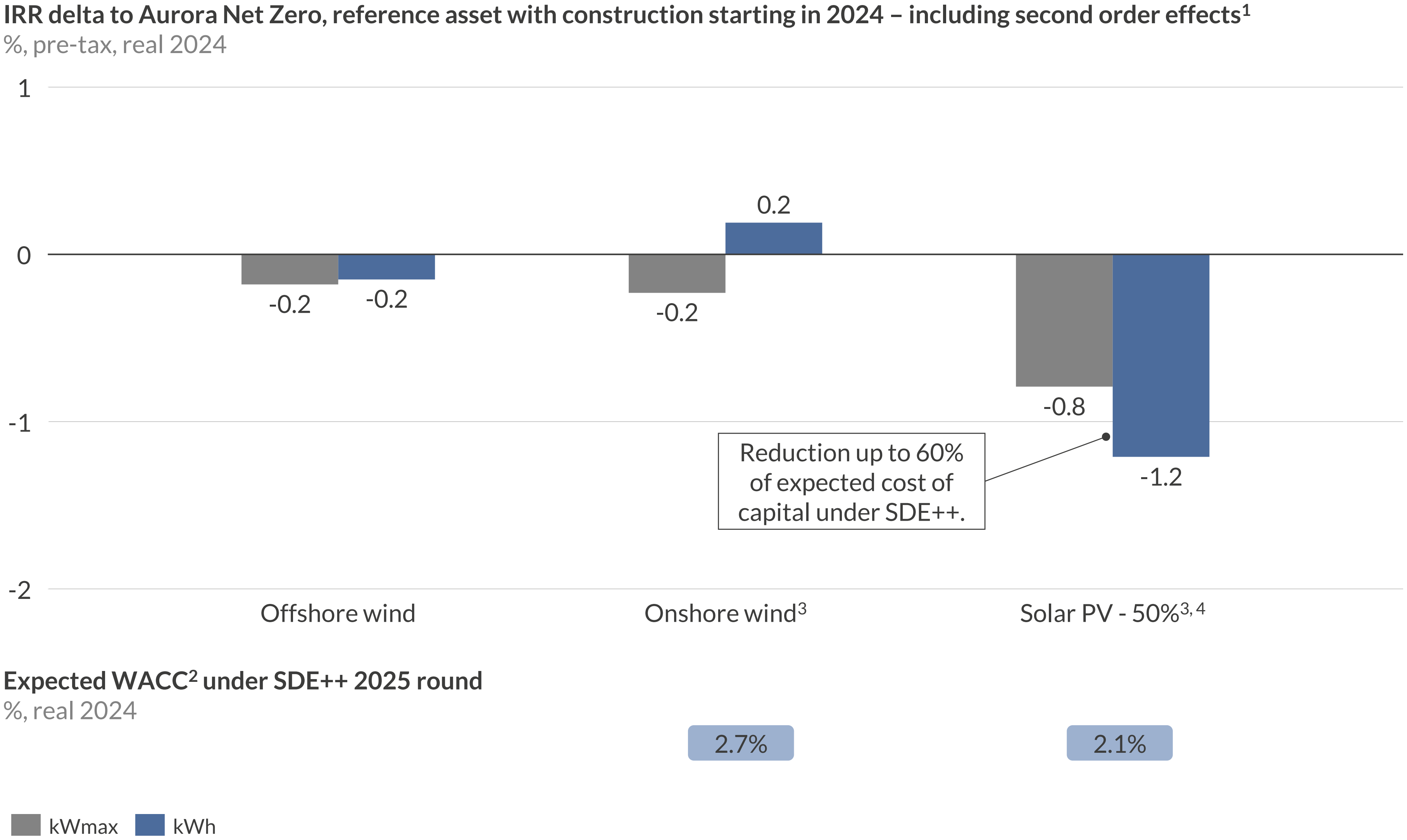


1) In our modelling, we made projections for up to 2050.

Source: Aurora Energy Research

- Introducing a feed-in network charge leads to higher baseload prices, whose delta to Aurora Net Zero widens over time.
  - In the short term, prices increase in the kWh fee scenario, as kWh fees directly affect asset dispatch.
  - kWmax fees slow down renewable buildout from ~2030, also increasing prices.
- Decreased renewable capacity and generation leads to:
  - Higher prices due to increased reliance on dispatchable plants; hydrogen CCGTs and OCGTs from the mid-2030s onwards.
  - Higher prices due to increased reliance on imports, including higher imports from EU thermal assets.

Even after correcting for 2nd order effects, such as rising electricity prices, already commissioned assets are still negatively impacted



- 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. This is especially noticeable for solar assets, as there is already more existing capacity in the system that cannot react to cost changes.
- Additionally, existing assets with long-term PPA contracts or subsidy levels above projected electricity prices will not benefit from 2nd order effects and will be affected more significantly.

1) Including 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) Post-tax. 3) Subsidised asset. 4) Inverter & grid connection size share of peak capacity.
Source: Aurora Energy Research

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

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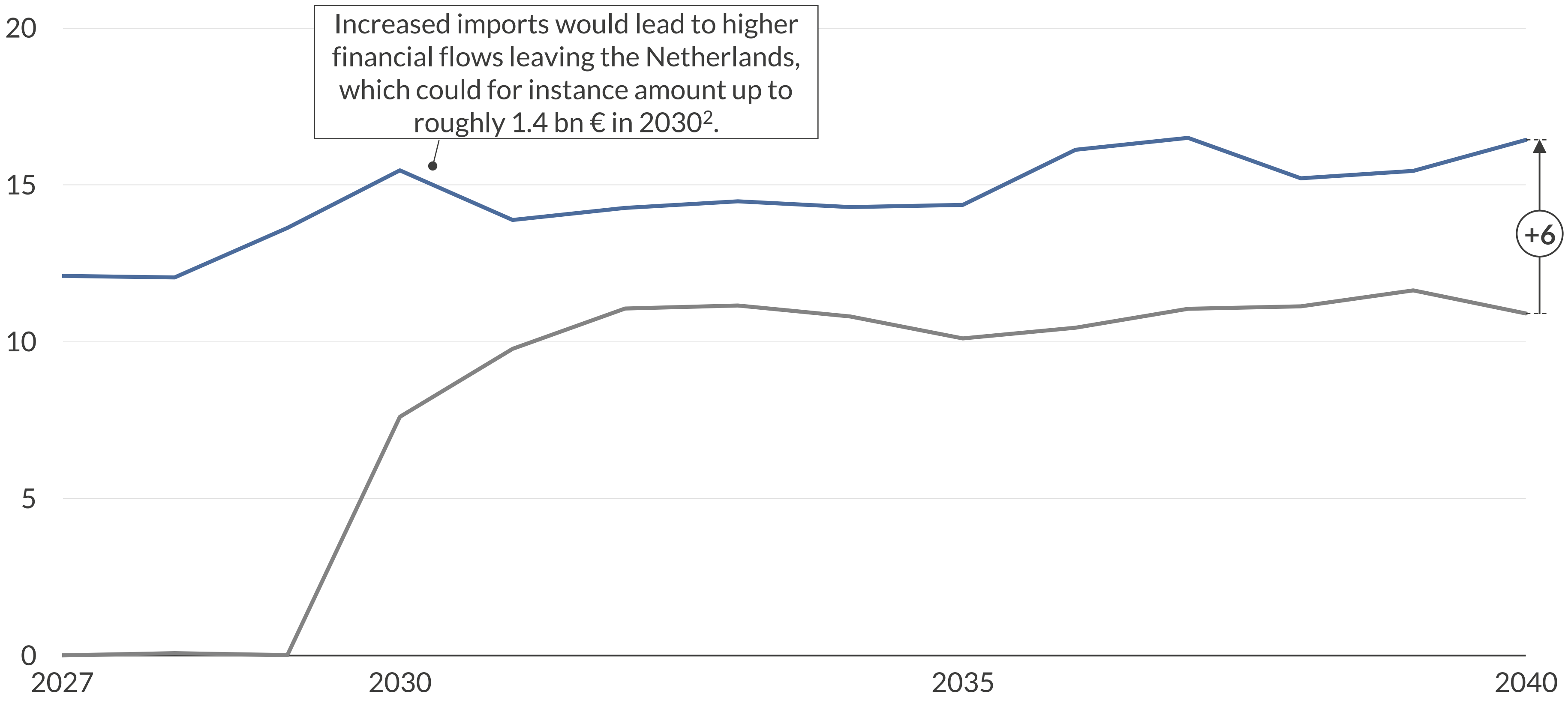
Deltas of net imports compared to Aurora Net Zero
TWh



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

2030	2035	2040
118%	74%	185%

kWmax — kWh

- With rising power prices, imports become cheaper than building additional domestic assets, and exports decrease. Import dependency increases across all scenarios[1].
- The impact on the kWh fee scenario starts as soon as the fees are implemented in 2027, with 12TWh more net imports. This rises by up to 16TWh in 2040.
  - Drivers are reduced thermal running hours due to higher production costs in the short term, and lower renewable buildout and generation in the long term.
  - There is not sufficient additional dispatchable capacity to compensate this.
- In the kWmax fee scenario, net imports reach deltas of 11TWh.

1) In the 2040s, imports increase further in all scenarios; 2) Considering 15.46 TWh additional net imports in 2030 and assuming these imports all come at the average baseload price in 2030

Source: Aurora Energy Research

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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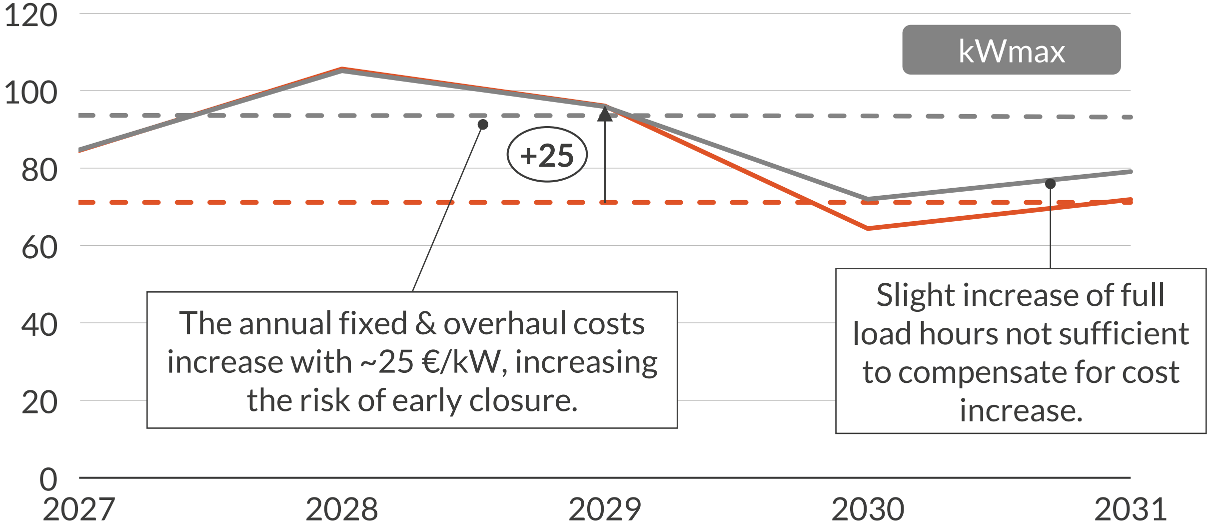
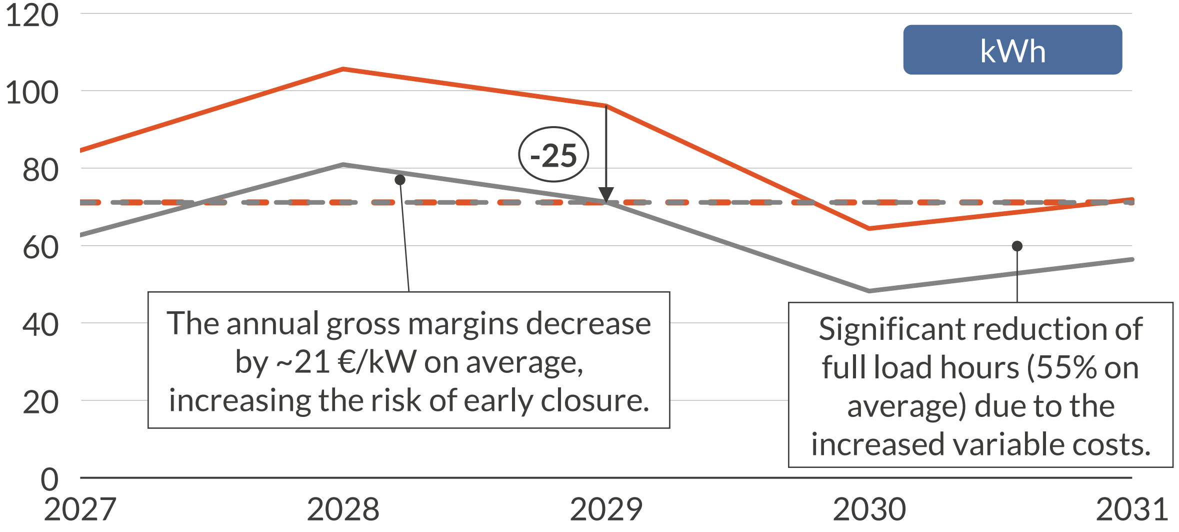
Gross margins v. costs – kWmax fee scenario
€/kW, real 2024



Gross margins v. costs – kWh fee scenario
€/kW, real 2024



In both the capacity-based and the dispatch-based feed-in network charge scenarios, charges could lead to 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].
- The reference gas CCGT plant is at risk of closing from ~2029 onwards in both the kWmax fee and in the kWh fee scenarios, 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.

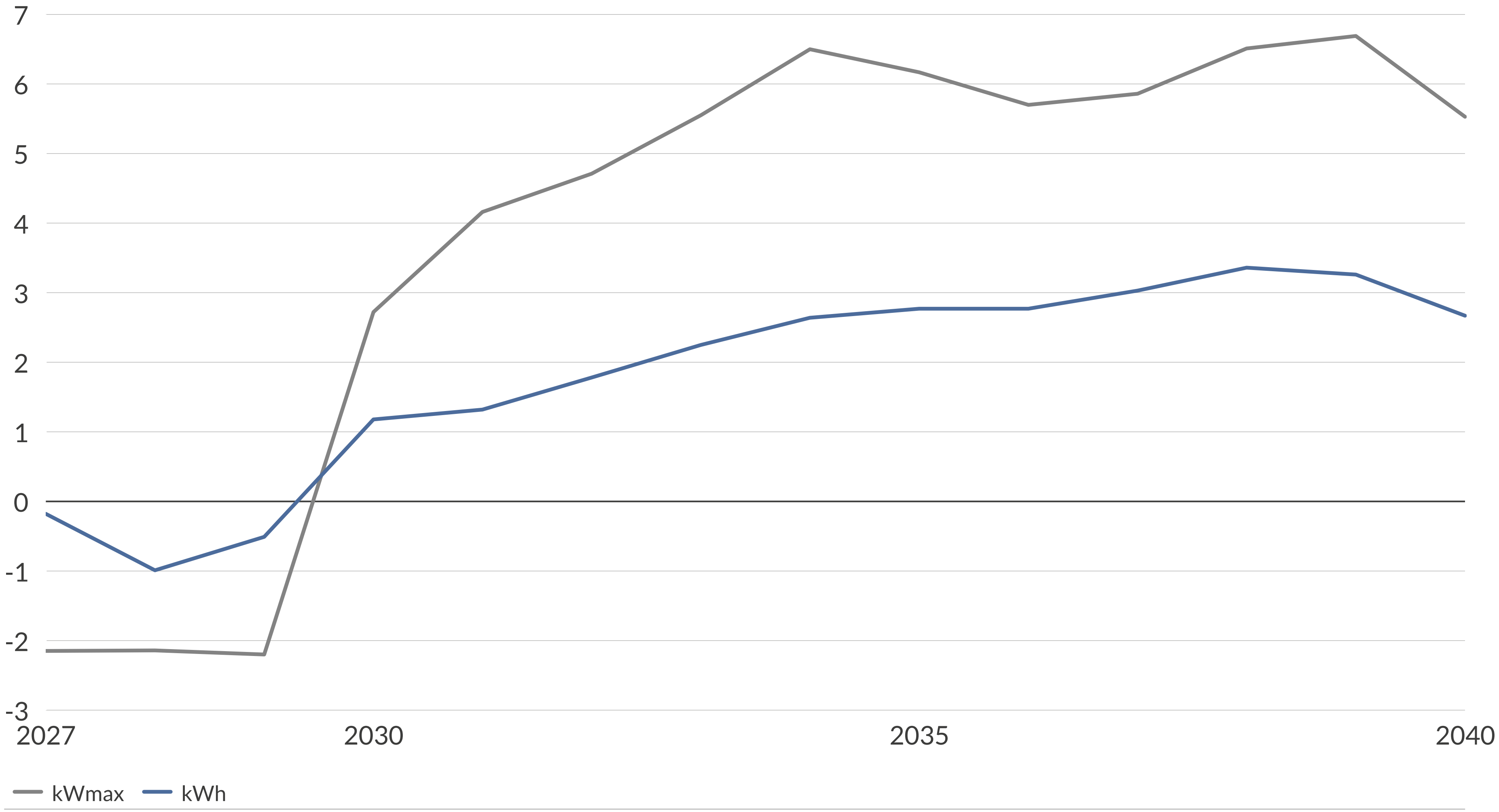
Net Zero: annual gross margins — Net Zero: annual fixed & overhaul costs — Scenario: annual gross margins — Scenario: annual fixed & overhaul costs

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

Source: Aurora Energy Research

Higher electricity prices outweigh the reduced grid fees for offtakers from 2030, increasing total end-consumer bills

Net delta electricity costs to Net Zero for a 100 MW offtaker[1]
mn €, real 2024



- In the short term, the reduction of grid fee payments reduces end-consumer electricity bills.
- This is because renewable investments are not expected to slow down immediately, with first effects appearing from 2030 onwards.
- In the long term, system changes driven by higher feed-in tariffs lead to a notable rise electricity prices and annual electricity costs.
- The impact of the feed-in grid charge shifts more costs towards end-consumers, which is not in line with its purpose of more cost reflectivity.

1) With stable, full-load consumption profile of 100MW.

Source: Aurora Energy Research

Details and disclaimer

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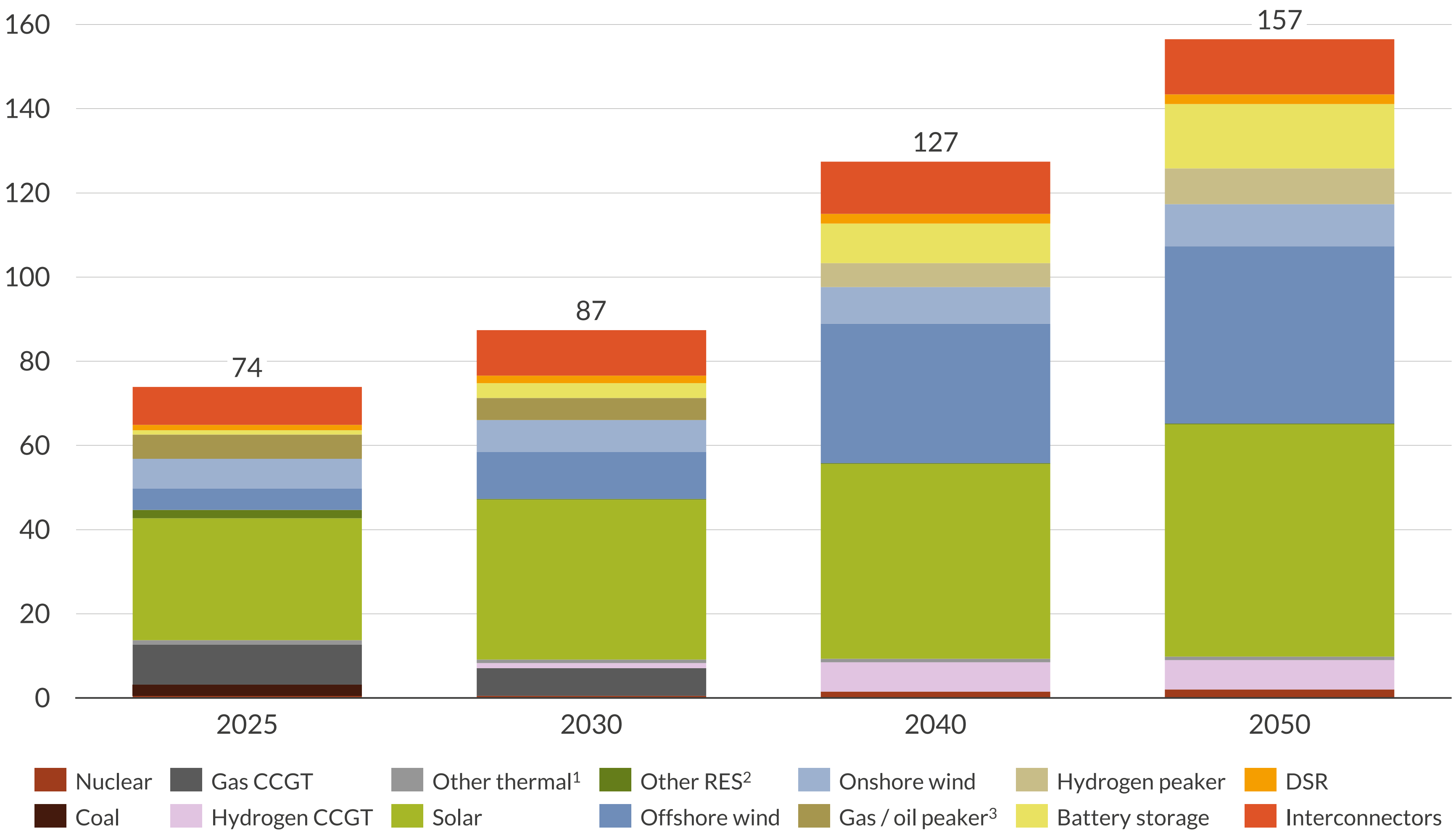
All scenarios are based on Aurora's target driven Net Zero scenario, adjusting asset cost structures to reflect the feed-in grid charges

Total installed capacity in Aurora Net Zero scenario[1]

GW



- Installed capacity increases by 83GW in 2025 -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.

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.

Source: Aurora Energy Research

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

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 fairer distribution of costs.

6 Investment security

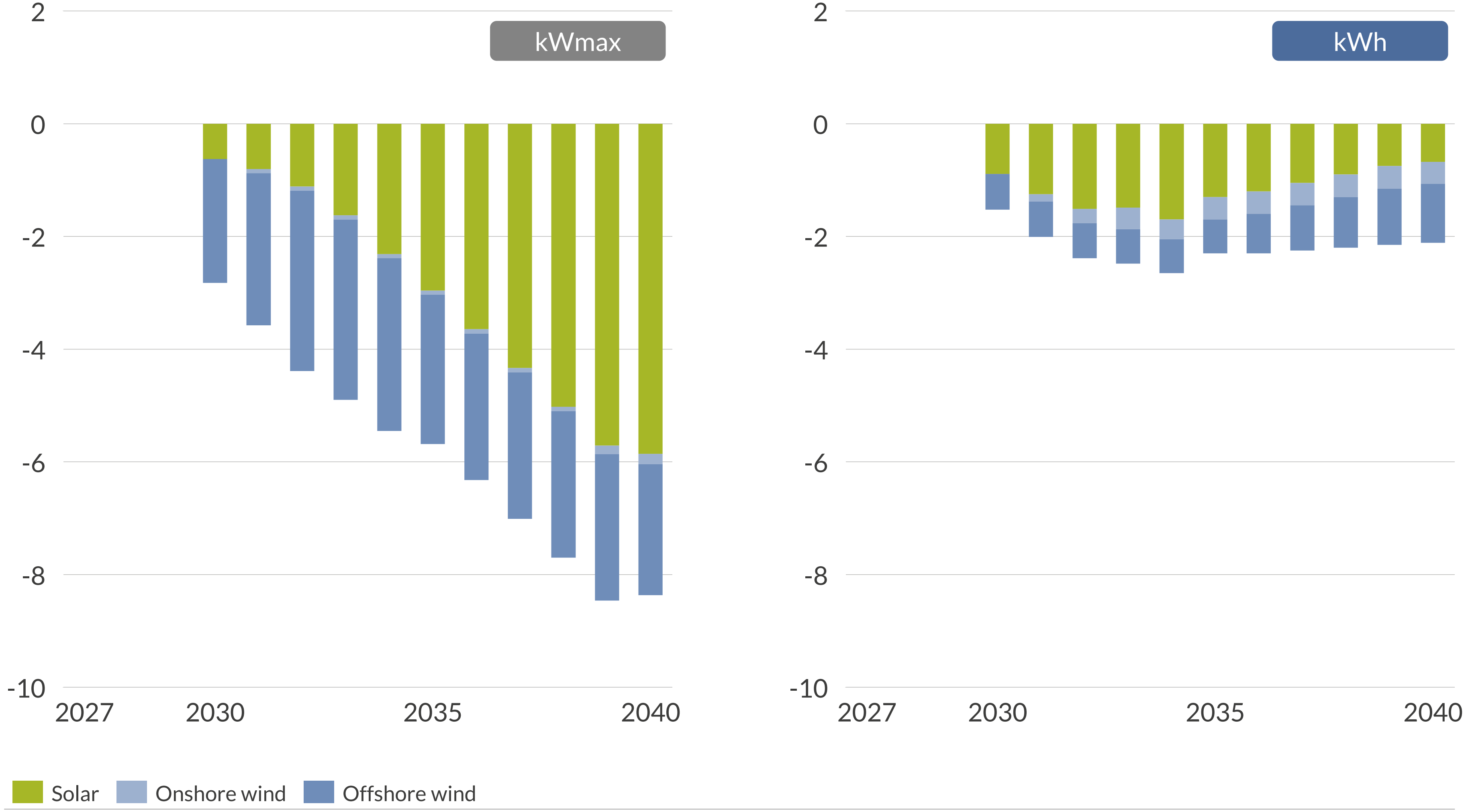
- **Definition:** The level of retroactive disadvantages and transparency about the impact on asset business cases.
- **Relevance:** Retroactive changes lead to a more challenging investment climate, which might undermine future investments.

Source: Aurora Energy Research

In the long term, feed-in charges slow down renewable buildout, with the kWmax tariff causing a reduction of up to 8GW in 2040

Renewable buildout deltas to Aurora Net Zero[1,2]

GW



- Accounting for 2nd order effects, increased costs from feed-in network charges lead to reduced renewable capacity buildout in all scenarios[2].
- Renewable buildout is most affected by the kWmax fee.
  - Solar is strongly affected because it has a lower utilization compared to its peak generation. There reduction is approximately 6GW in 2040.
  - Offshore wind is also affected, because it has a higher fee per kWmax.
- Projected effects of new feed-in tariffs could be worsened as projects become riskier and more uncertain, due to more complex and higher costs. This would lead to higher hurdles and even lower buildout.

1) Displaying 2nd order effects. 2) We assume the producers' tariff is implemented in 2027 and impacts investment decisions from 2030 onwards.

Sources: Aurora Energy Research, Rijksoverheid

Total system capacity payments of up to 1.7bn € will be needed to ensure SoS as gas plants phase out, increasing with the new grid fees

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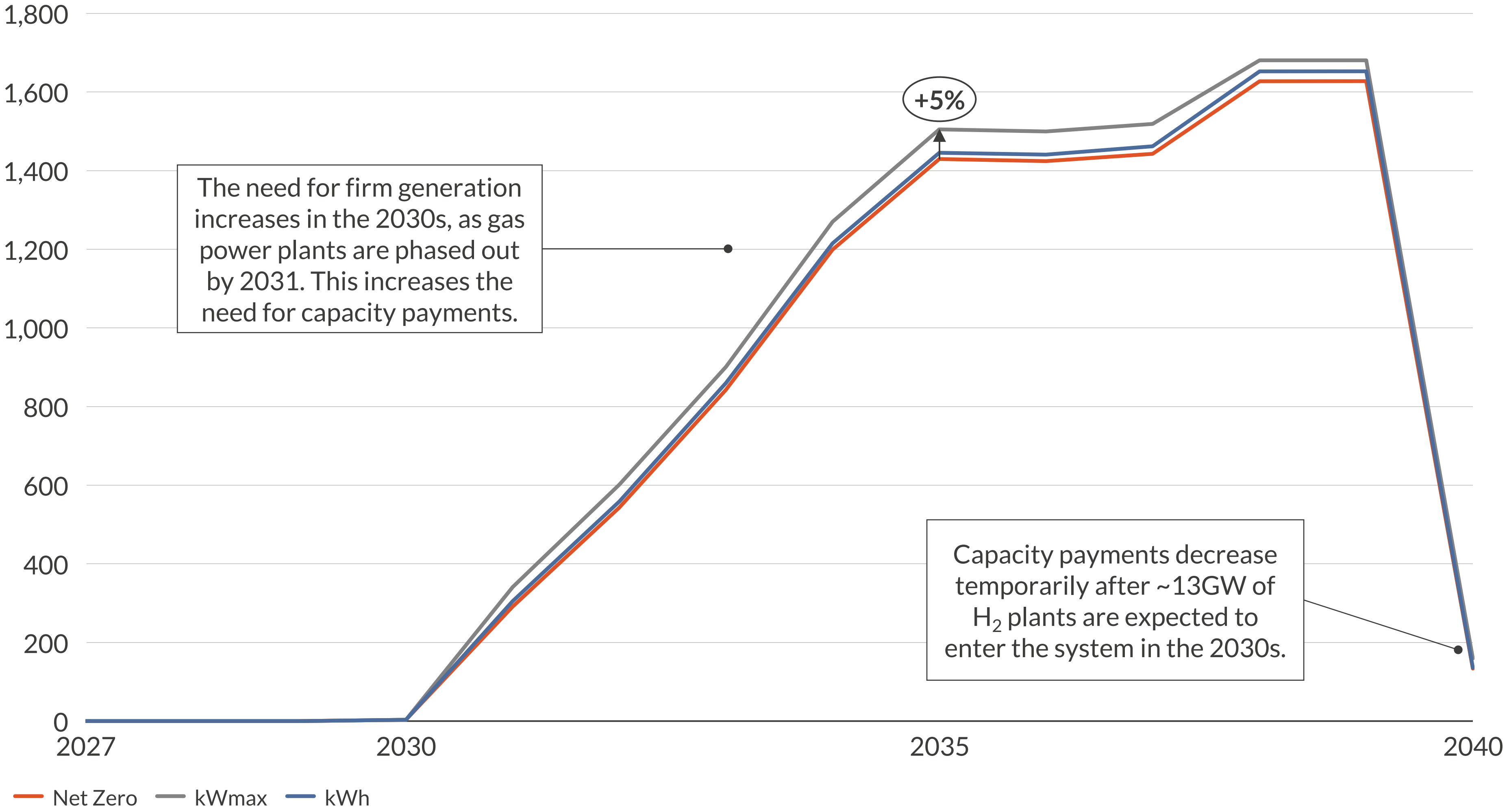
Total system societal capacity payment[2]
mn €, real 2024



- Lower renewable generation, especially during peak demand hours, leads to more demand from other sources of energy.
- In line with Net Zero targets, demand for firm generation will be met by more expensive sources like H_2 CCGTs.
  - We assume some form of capacity payments or support to ensure there is enough supply in the system.
- We expect these payments to be borne by consumers and to be equally distributed between all offtakers.
  - In the kWmax fee scenario, which has a bigger renewable capacity drop, costs in the late 2030s increase by 5% compared to Net Zero.

1) In our modelling, we made projections for up to 2050. 2) Assuming this will be distributed across consumers.

Source: Aurora Energy Research

Introduction of feed-in grid fee tariffs result in a shift in costs and a reduction of grid fee payments for consumers

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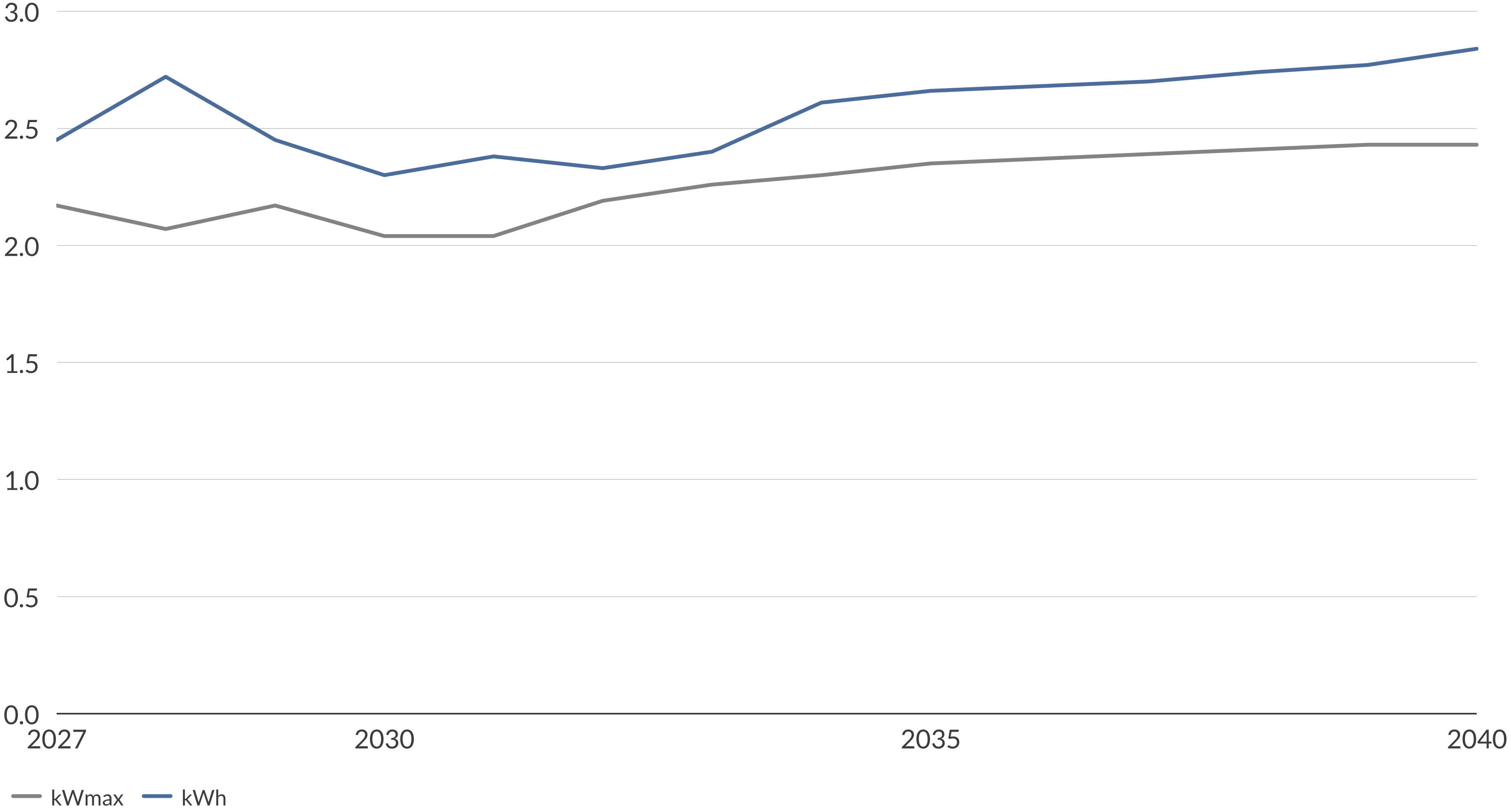
Annual reductions of grid fee payments for a 100 MW offtaker[1]
mn €, real 2024



- The payment of feed-in grid tariffs by generators results in cost shifts in the system, reducing grid payments for consumers.
- The total amount paid by generators is calculated by combining annual generation / peak capacity with the grid fee from the corresponding voltage level.
- This amount is a cost reduction for the offtakers, which is distributed evenly between all connected consumers[2].
- For a large-scale industrial offtaker[1], this results in a reduction of 2-3 mn € per year of grid fee payments.

1) With stable, full-load consumption profile of 100MW; 2) Incorporating the development of the consumer base over time, scaling this by expected demand development

Sources: Aurora Energy Research, CE Delft

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]	kWmax fee	kWh fee
Renewable investment	▪ Renewable buildout according to reaching decarbonisation targets. (+)	▪ Renewable capacity buildout is slowed down. ▪ Solar PV capacity is most strongly affected due to its low load factor. Solar capacity delta reaches -5.8 GW in 2040. (− −)	▪ Renewable capacity buildout is slowed down. ▪ Offshore wind most strongly affected, as it has a higher fee and more generation. In 2040 there are 16TWh less of offshore wind generation. (−)
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, as fees increased their fixed costs above gross margin levels. (−)	▪ High decrease in offshore wind generation greatly increases reliance on imports. ▪ Gas CCGTs may close much earlier as kWh fees greatly reduce gross margins below fixed and overhaul costs. (− −)
End consumer electricity bill	▪ No additional impact on the electricity bill of an end consumer. (+)	▪ System changes driven by kWmax feed-in tariffs greatly increase electricity prices and annual electricity costs. ▪ This outweighs reduced fees for offtakers, increasing end consumer bills. (− −)	▪ Increased fees are handed down to end consumers through higher electricity prices, increasing consumer bills. ▪ The reduction in grid fees for offtakers is relatively smaller. (−)

(+) Positive (○) Neutral (−) Negative

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

Source: Aurora Energy Research

Further, feed-in charges add complexity to dispatch decisions, may impact investment decisions and can retroactively affect existing assets

Design options

Assessment	No fee[1]	kWmax fee	kWh fee
Complexity of implementation	▪ Not applicable (Positive, Positive)	▪ Increased complexity for energy management if producers want to adjust their behaviour to reduce peak-use and benefit from the proposal. (Negative)	▪ Fee represents an additional cost to dispatch decision, relatively simple to include in the asset operation. (Positive)
Cost reflectivity	▪ Limited reflectivity through unequal distribution of cost among consumers and producers. (Negative)	▪ Grid costs are distributed among actual capacity use of the grid. ▪ However, the costs for consumers increase greatly due to strong system changes. (Neutral)	▪ Grid costs are distributed over all grid users, with feed-in costs being generation based. ▪ However, the costs for consumers increase due to system changes. (Neutral)
Investment security	▪ No additional impact on business cases of investments. (Positive, Positive)	▪ Can have retroactive impact on projects that have already been realised. ▪ The impact on business case is complex to determine as the fees do not directly impact dispatch. (Negative, Negative)	▪ Can have retroactive impact on projects that have already been realised. ▪ The impact on business case is somewhat transparent as fees can be considered in dispatch decisions. (Neutral)

Positive Neutral Negative

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

Source: Aurora Energy Research