# System value of V2G under slower EV diffusion

Update on the study "Potential of a full EV-power-system-integration in Europe & how to realise it" by Fraunhofer ISI & Fraunhofer ISE

on behalf of Transport & Environment

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# Imprint

## System value of V2G under slower EV diffusion - Update on the study “Potential of a full EV-power-system-integration in Europe and how to realise it”

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# Contents

# List of abbreviations

| **Abbreviations** | |
|---|---|
| aFRR | Automatic Frequency Restoration Reserve |
| BEV | Battery electric vehicle |
| CC | Controlled Charging |
| CSP | Concentrated solar power |
| DSO | Distribution system operator |
| EU | European Union |
| EU27 | European Union (27 member states) |
| EV | Electric vehicle |
| EVSE | Electric vehicle supply equipment |
| FCEV | Fuel cell electric vehicle |
| FCR | Frequency containment reserve |
| ICE | Internal combustion engine |
| NGV | Natural gas vehicle |
| PHEV | Plug-in hybrid electric vehicle |
| PV | Photovoltaic |
| PVC | Polyvinyl chloride |
| SOC | State of charge |
| TCO | Total cost of ownership |
| ToU | Time-of-use |
| TSO | Transmission system operator |
| V1G | Vehicle-1-grid, smart charging from the grid |
| V2H | Vehicle-to-home |
| V2G | Vehicle-to-grid |
| V2L | Vehicle-to-load |
| V2X | Vehicle-to-everything |
| DSO | Distribution system operator |

# Executive Summary

### Electric vehicles flexibility value is limited in worst-case EV diffusion scenario

Europe’s power system is rapidly becoming dominated by wind and solar. While this reduces emissions, it sharply increases the need for short-term flexibility to balance daily and weather-driven fluctuations: Europe’s transition to a renewables-based power system will require large amounts of cost-effective flexibility. The 2026 update of the Fraunhofer study “Potential of a full EV-power-system-integration in Europe & how to realise it” confirms that electric vehicles (EVs)—through smart charging and especially bidirectional Vehicle-to-Grid (V2G/V2X)—are substantial and lowest-cost flexibility resources available to the EU with substantial benefits for system costs, infrastructure needs, and renewable integration.

### Delaying electrification and slow down EV uptake raises total system costs

Smart charging and V2X are essential enablers of an affordable, secure and renewable-based Europe power system[1], capable of saving tens of billions annually while improving resilience and accelerating decarbonisation. Weakening the ICE phase-out directly reduces available EV flexibility and lowers power-system efficiency gains.

- EV flexibility value is reduced by €4,0 billion per year by 2040 if the lower EV diffusion of the worst-case occurs.
  - Across Europe V2G flexibility value in the base EV diffusion scenario reaches €11.7 billion per year compared to only €7.7 billion per year in the worst-case EV diffusion scenario.
  - Flexibility value for each battery electric vehicle increases from €150 to €240 per BEV under V2G conditions from 2030 to 2040 indicating the marginal value of each additional BEV that would be added to the power system.
- Replacement of large parts of stationary batteries is reduced by one third resp. 93 GWh in the worst-case diffusion scenario.
  - In the worst-case EV diffusion scenario, vehicle batteries substitute only 191 GWh of stationary battery parks capacity compared to 284 GWh in the base EV diffusion scenario.
  - Still more than 94% of stationary battery capacity can be avoided at EU level in both diffusion scenarios.
  - EV flexibility also reduces the need for gas and hydrogen peaking plants. The avoided backup capacity in the worst-case scenario is only 26 GW compared to 39 GW in the base EV diffusion scenario. In the worst-case scenario 13 GW less peaking capacity is avoided.
- Renewable integration, especially for solar PV, is slowed down with lower EV diffusion. The lower diffusion of EVs results in 51 GW less PV capacity enabled by V2G.
  - By 2040, EV flexibility from V2G would allow up to 139 GW of additional PV at EU level in the base EV diffusion scenario compared to dumb charging. This value of additional PV would be reduced to only 88 GW of additional PV enabled by V2G in the worst-case EV diffusion scenario.
  - The capability to absorb midday solar generation and shift it to evening demand is substantially reduced.

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[1] All EU-level results refer to EU27 + United Kingdom + Norway + Switzerland  unless stated otherwise

Next to the impacts on flexibility, slower or weaker EV uptake slightly reduces overall power-sector investment needs—but dramatically increases oil use and emissions costs. By 2040, delayed electrification could raise overall system costs by up to €25 billion per year.

The updated calculation regarding grid impacts shows: In the base-case, the cost saving potential for grid reinforcement totals €8.3 billion for the EU-27. In the worst-case scenario, this is reduced to €4.8 billion, meaning that under worst-case EV uptake conditions, grid reinforcement costs would be €3.5 billion higher than in the currently expected base-case.

# 1 Introduction

Europe's energy system is undergoing a profound transformation as the continent accelerates the transition toward climate neutrality. Driven by rapidly increasing shares of variable renewable energy sources—particularly wind and photovoltaics—Europe faces growing challenges in balancing supply and demand on hourly, daily, and seasonal timescales. This shift demands new forms of system flexibility that are scalable, cost-efficient, and socially acceptable. Electric vehicles (EVs), when integrated intelligently into the power system, are emerging as one of the most promising flexibility resources available to Europe over the next two decades. The future power system is characterised by increasing shares of weather-dependent renewable electricity sources that results in curtailment of high co-generation of wind and PV, the need for hydrogen backup power plants, especially in winter and intensified storage usage to shift especially PV (see Figure 1).

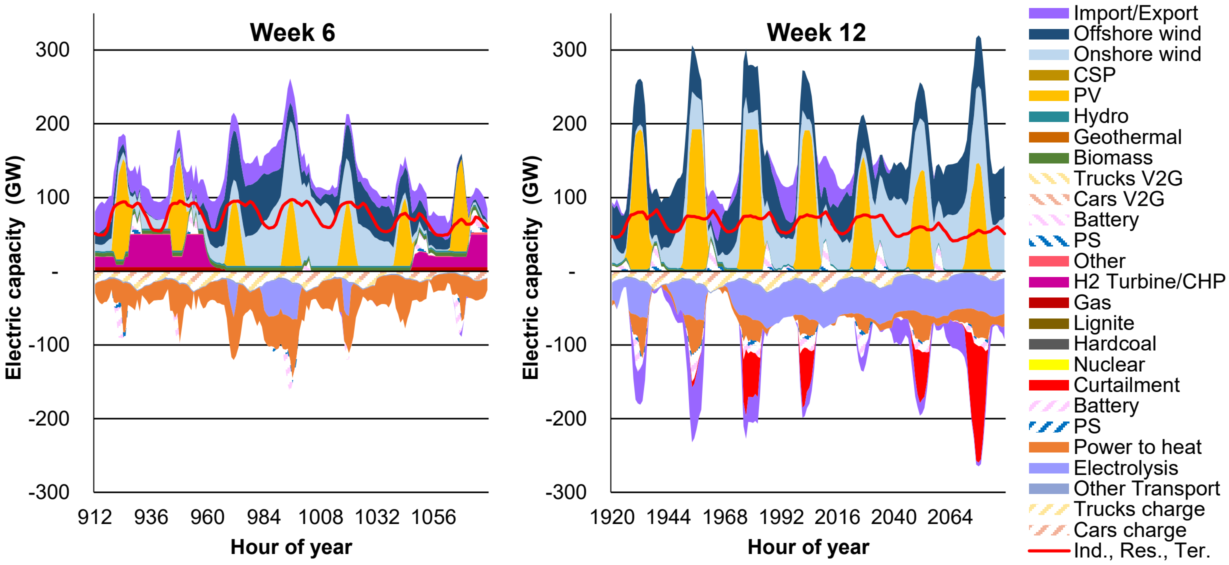


**Figure 1: Future electric power system hourly dispatch in Germany for two weeks in 2040. Electric capacity of generation, demand and storage technologies.**

At the same time, the EU's 2035 phase-out of the internal combustion engine has come under political pressure, raising uncertainty about the pace of electric-vehicle (EV) adoption. This uncertainty directly affects the availability of mobile battery capacity that can contribute to system flexibility through smart charging and bidirectional vehicle-to-grid (V2G) operation.

The previous 2024 analyses by Fraunhofer ISI and ISE (Kuehnbach et al. 2024) demonstrate that EVs—when intelligently integrated—can become a major flexibility resource for Europe's power system by 2030 and 2040. Smart charging already reduces system costs, curtails renewable energy losses, and lowers the need for stationary batteries and hydrogen-fired backup plants. Bidirectional charging goes further: by enabling EVs to discharge electricity back to the grid, V2G can substitute most stationary storage, support significantly higher solar PV deployment, and cut annual system costs by several billion euros.

The current discussion on slower EV uptake—triggered by delays or weakening of the 2035 combustion-engine phase-out—reduces the volume of mobile storage available to the system. This raises the question to what extent the economic and technical advantages of smart charging and V2G change, and which impacts on other investments like stationary storage and peaking technologies occur. This study is updating earlier assessments and re-evaluates the system-level benefits of EV flexibility under reduced EV diffusion, using updated data for the uptake of electric mobility and detailed modelling based on the Enertile framework.

This report synthesizes these updated findings. It quantifies how EV-based flexibility—both unidirectional and bidirectional—affects system costs, renewable integration, infrastructure needs, and grid impacts under alternative EV diffusion pathways. The results show the impacts of a reduced diffusion pathway compared to the initial evaluation.

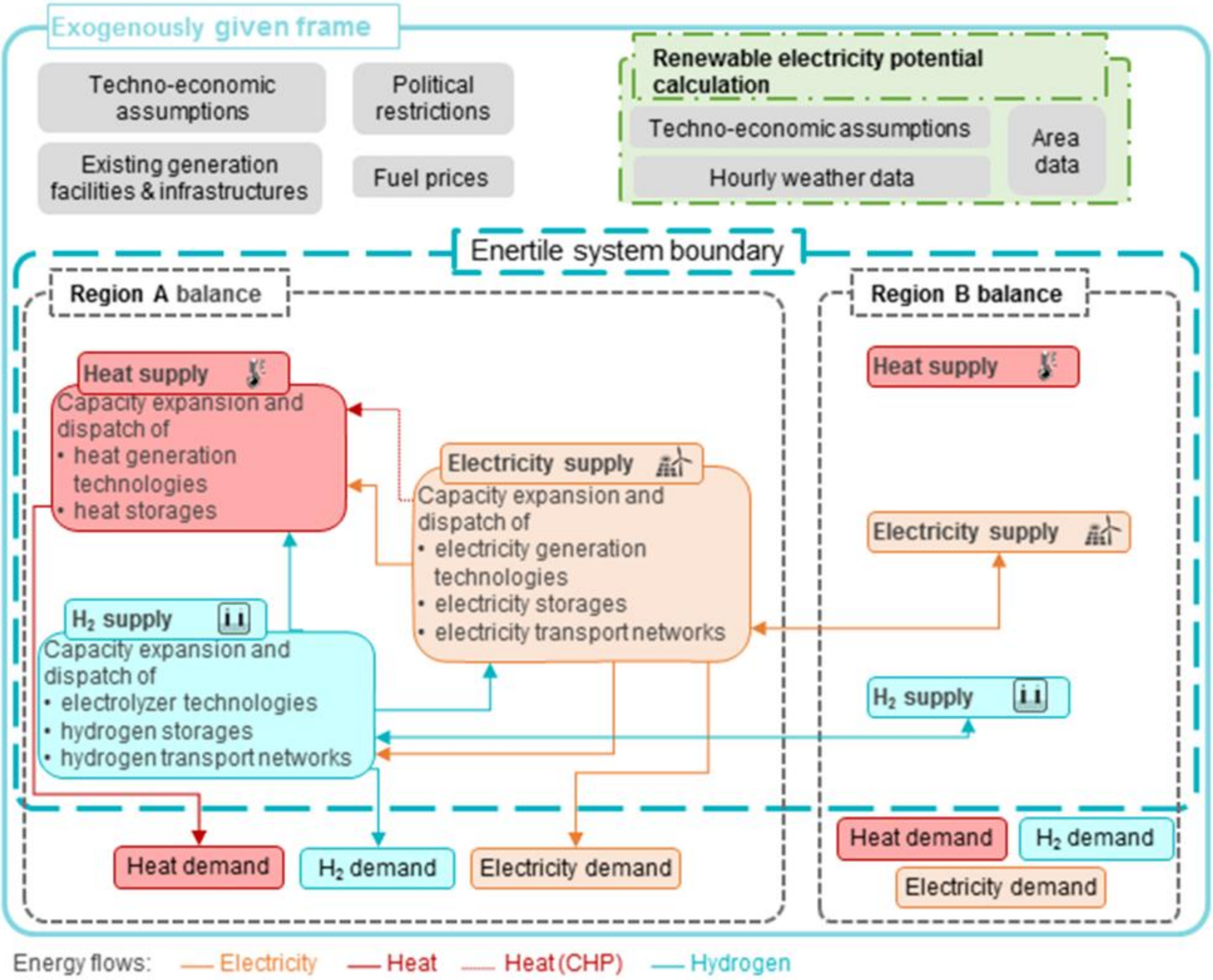
# 2 Modelling approaches

The quantitative assessment in this study is based on the long-term energy system optimisation model Enertile. Figure 2 shows its structural layout. A detailed description of the mode is given Lux (2023). Enertile is a bottom-up, supply-side model with a detailed representation of renewable electricity potentials. It jointly minimises the total cost of electricity, district heat and hydrogen supply, subject to technical, resource and policy constraints, within a framework that is consistent with a greenhouse-gas-neutral European energy system by 2050. The model covers the EU-27 at country level and explicitly includes the United Kingdom, Norway and Switzerland. For each optimisation year, Enertile is run at hourly resolution over a full year under perfect foresight, capturing the temporal variability of wind and solar generation and the resulting flexibility needs. Capacity expansion and dispatch of conversion, storage and transport technologies are determined endogenously.

Bidirectional charging of EVs is modelled as a flexibility option with three core characteristics.

- First, all battery-electric vehicles in a model region are aggregated into a single mobile battery storage system. Driving is represented as an hourly, exogenous battery-discharging process derived from aggregated driving profiles.
- Second, the minimum and maximum state of charge (SOC) of this aggregated battery in each hour are derived from real driving and parking profiles under two contrasting charging strategies: an “upper-bound” strategy, in which vehicles charge as quickly and as much as possible whenever they are connected to a power source, and a “lower-bound” strategy, in which vehicles only charge the minimum amount required to complete the next trip(s), as late as possible, given the subsequent driving schedule and available charging options.
- Third, the hourly charging and system-beneficial discharging capacities of the mobile storage system are restricted by the vehicles’ driving and parking times.

Within these SOC envelopes and power limits, Enertile optimises charging and discharging in conjunction with all other flexibility options in order to minimise total system costs.



Source: Lux et al. (2022)

**Figure 2:** **Detailed bottom-up optimisation model Enertile for energy supply.**

In addition to the power-system optimisation, this study updates the estimated grid impacts of EVs and V2G. These updates build on the preceding study (Kuehnbach et al. 2024), in which grid-reinforcement costs for 2030 and 2040 were calculated using synthetically generated representative grids, including the demand for materials such as copper, steel, aluminium, and PVC. The aim of that analysis was to estimate how much grid reinforcement could be avoided through grid-friendly operation of bidirectional-charging EVs. For the present study, those results were updated by interpolating them in proportion to the revised number of EVs, since a lower penetration of bidirectional-charging EVs reduces the potential savings in grid reinforcement accordingly.

# 3 Scenario definition and input data

## 3.1 Scenario definition

The scenario framework is defined along **two independent dimensions**:

1. **EV market diffusion** (how many BEVs are on the road), and
2. **Use of EV flexibility** (how those BEVs charge and whether they can discharge).

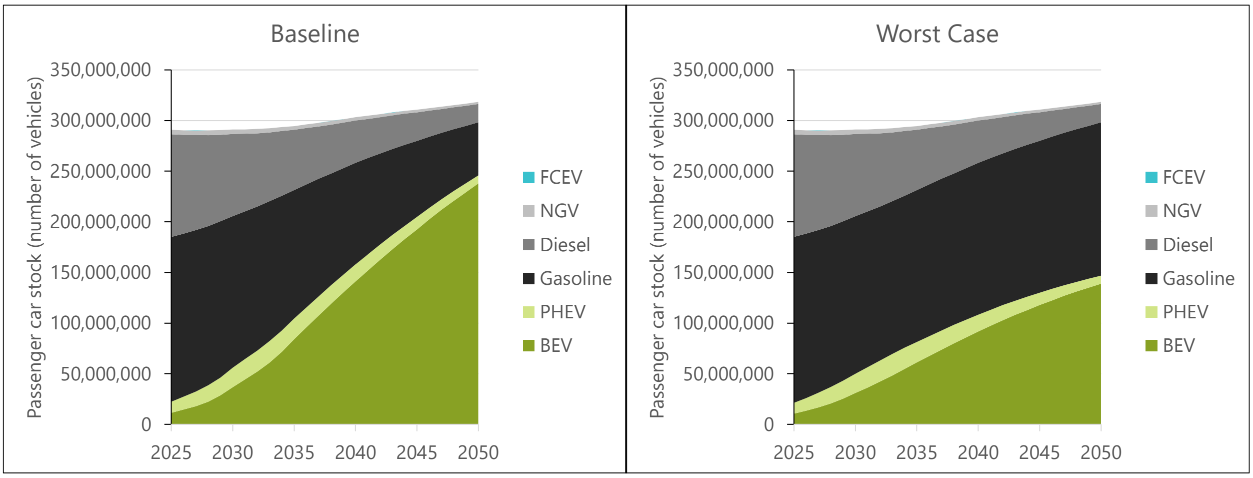
For each model year (2030 and 2040) we run the **cross-product of both dimensions**, yielding six core power-system scenarios shown in Table 1.

**Table 1: Scenario matrix for the power system analysis (evaluated for 2030 and 2040).**

| | | **EV market diffusion** | |
|---|---|---|---|
| | | **Base** | **Worst-case** |
| **V2X diffusion** | **Reference** (i.e. uncontrolled charging) | Reference Base | Reference Worst-case |
| | **Controlled Charging** (i.e. smart unidirectional charging) | CC Base | CC Worst-case |
| | **V2X** (i.e. smart and bidirectional charging) | V2X Base | V2X Worst-case |

### 3.1.1 EV market diffusion and associated energy demand

Figure 3 shows the two pathways considered for the future development of the passenger car stock in the European Union, the United Kingdom, Norway, and Switzerland. Both scenarios assume a modest increase in total vehicle stock, reaching 291 million passenger cars on European roads by 2030 and 305 million by 2040. The baseline scenario assumes steady adoption of battery electric vehicles (BEVs), with projected stocks of 37 million in 2030 and 141 million in 2040. In contrast, the worst-case scenario assumes a slower BEV uptake in the EU member states, resulting in lower stocks of 31 million in 2030 and 92 million in 2040. Plug-in hybrid electric vehicle (PHEV) projections are consistent across both scenarios: 19 million vehicles in 2030, declining to 17 million by 2040.



Source: T&E

**Figure 3:** **Passenger car stock development in Europe (EU27, UK, NO, CH) in baseline and worst-case scenarios**

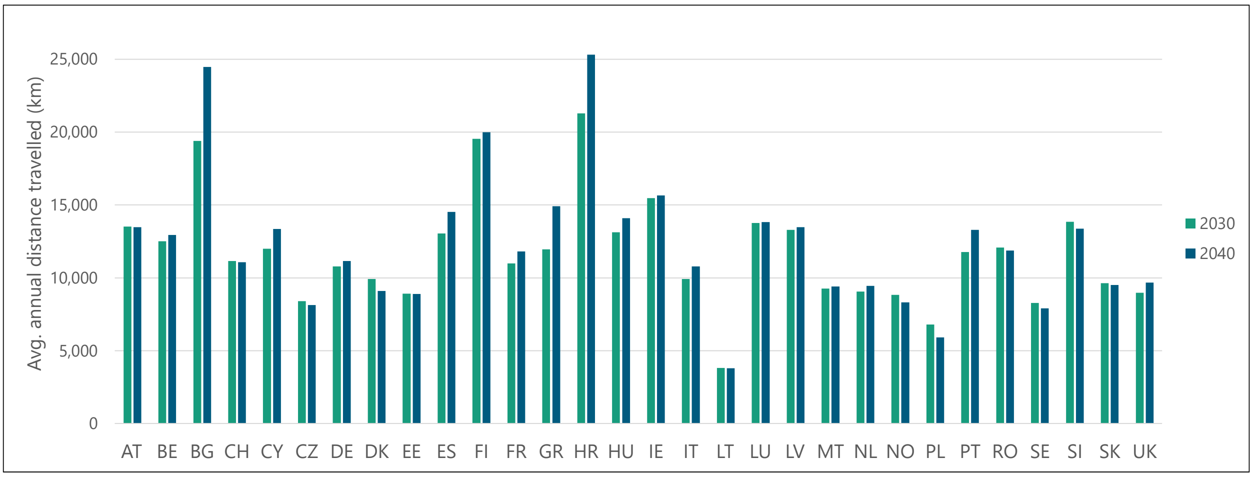
We derive final energy demands for passenger cars from the considered stock scenarios, accounting for the age structure and the segmentation of the national vehicle fleets. Therefore, we make assumptions on the energy efficiency of cars (depending on powertrain, size segment and registration year, see Table 2) and their annual mileage (depending on country and year, see Figure 4). We assume today's country-specific distribution of the car fleet on three size classes (small/medium/large) to remain stable in the future, and the segmentation of BEVs to increasingly align with the overall segmentation of the national car fleets. We model PHEVs to cover half their mileage using electricity.

**Table 2:** **Specific energy consumption (kWh/km) by powertrain, segment, and registration year**

Size classification: S – small (EC segments A, B), M – medium (C, D), L – large (E, F). PHEV consumption by operation mode: electric vs. internal combustion engine (ICE). Years in between interpolated.

| | **2020** | | | **2030** | | | **2040** | | |
|---|---|---|---|---|---|---|---|---|---|
| | **S** | **M** | **L** | **S** | **M** | **L** | **S** | **M** | **L** |
| Gasoline | 0.55 | 0.66 | 0.89 | 0.53 | 0.59 | 0.76 | 0.50 | 0.56 | 0.73 |
| Diesel | 0.42 | 0.51 | 0.63 | 0.53 | 0.59 | 0.76 | 0.50 | 0.56 | 0.73 |
| PHEV (elec.) | 0.16 | 0.20 | 0.21 | 0.15 | 0.18 | 0.20 | 0.14 | 0.17 | 0.19 |
| PHEV (ICE) | 0.50 | 0.61 | 0.78 | 0.53 | 0.59 | 0.76 | 0.50 | 0.56 | 0.73 |
| BEV | 0.17 | 0.21 | 0.23 | 0.16 | 0.19 | 0.21 | 0.15 | 0.18 | 0.20 |
| NGV | 0.61 | 0.70 | 0.87 | 0.53 | 0.59 | 0.76 | 0.50 | 0.56 | 0.73 |
| FCEV | 0.30 | 0.32 | 0.34 | 0.29 | 0.31 | 0.32 | 0.27 | 0.29 | 0.31 |

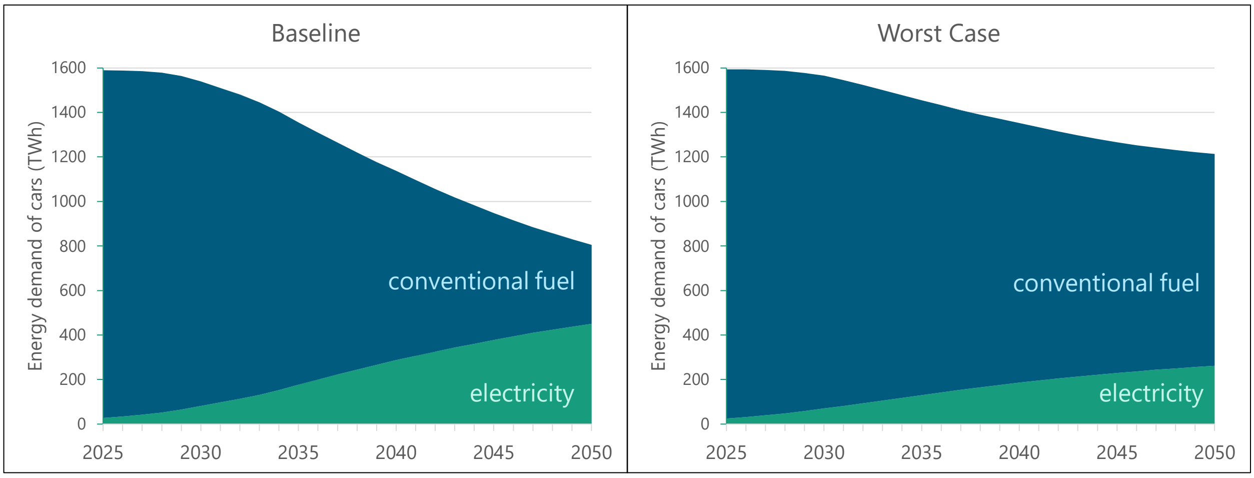
Source: Fraunhofer ISI, own assumptions



Source: T&E

**Figure 4:** **Assumed average annual mileage of passenger cars by country**

Figure 5 shows the final energy demand of the vehicle fleet under consideration. The baseline scenario results in electricity demand of 82 TWh in 2030 and 287 TWh in 2040. This is accompanied by a decline in demand for hydrocarbon fuels used in internal combustion engines. Due to efficiency gains from electrification, the total energy demand of the European passenger car fleet decreases significantly to 1,540 TWh in 2030 and 1,137 TWh in 2040. The worst-case scenario shows a slower transition, reaching an electricity demand of 70 TWh in 2030 and 186 TWh in 2040, and consequently exhibits higher total energy demand (1,565 TWh in 2030 and 1353 TWh in 2040) for the same total fleet size, as fewer efficiency gains are realised through electrification.

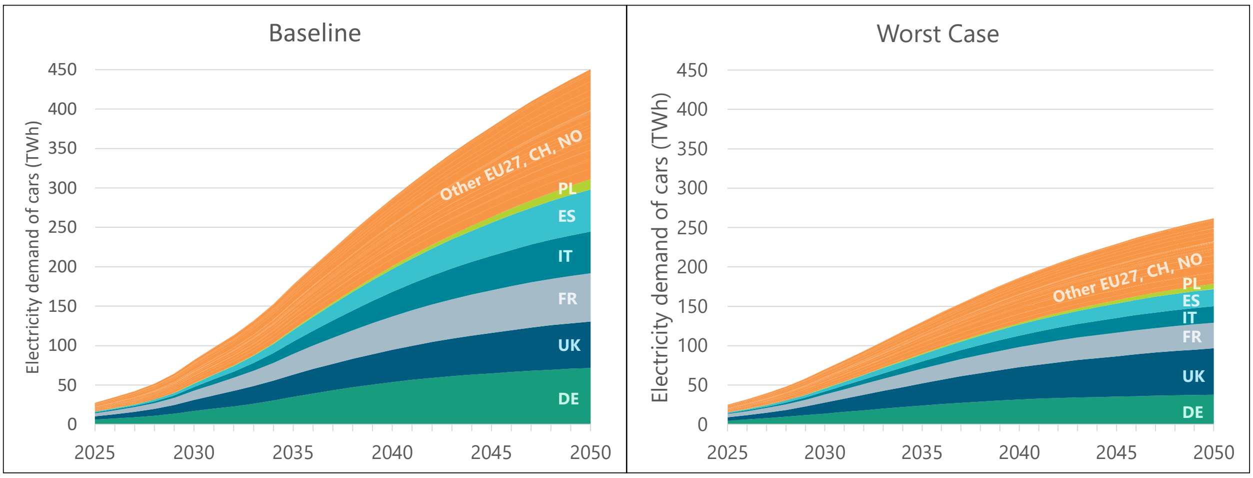


Conventional fuel aggregates diesel fuel, gasoline, and natural gas.
Source: Fraunhofer ISI, own calculation based on T&E input and own assumptions

**Figure 5:** **Final energy demand (TWh) of passenger cars in Europe (EU27, UK, NO, CH) in baseline and worst-case scenarios**

Figure 6 outlines the distribution of EV energy demand on the most important European car markets. In the long term, five markets – Germany, the United Kingdom, France, Italy, and Spain – combined make up about two thirds of the electricity demand. Up to the mid-2030s, Germany, France, and the United Kingdom combined account for half of it, as Italy and Spain see a delayed uptake in comparison.

Despite being expected to have the largest overall car stock in the long term, Poland only has a relatively small electricity demand from cars as it lags behind the other large markets in terms of fleet electrification in the scenarios.



Source: Fraunhofer ISI, own calculation based on T&E input and own assumptions

**Figure 6:** **Final electric energy demand (TWh) of passenger cars in Europe (EU27, UK, NO, CH) in the baseline and worst-case scenarios, by country**

## 3.1.2 Use of EV flexibility (charging modes)

The second scenario dimension defines how the BEV fleet interacts with the power system. Three charging modes are distinguished, each representing a progressively higher level of power-system integration:

**Reference (inflexible charging).** Every BEV starts charging as soon as it is plugged in and only stops charging when its battery is fully charged (or when the subsequent trip begins). The resulting load profile is dictated entirely by travel patterns and provides no flexibility to the power system. This mode serves as the counterfactual against which the value of managed charging is measured.

**Controlled charging (CC).** Charging is shifted in time within the constraints imposed by each vehicle's next departure and required state of charge. An optimiser allocates charging to hours with low residual load (i.e., high renewable output or low demand), thereby reducing peak loads and curtailment. Energy flows are unidirectional: the vehicle can only draw from the grid, not feed back into it.

**Bidirectional charging (V2X).** In addition to smart charging, BEVs can discharge electricity back to the grid (vehicle-to-grid, V2G) or to local loads (vehicle-to-building, V2H). Each vehicle thus operates as a mobile storage unit whose charge and discharge are co-optimised with the rest of the power system, subject to the constraint that the vehicle's driving needs must be met at all times.

**Participation shares.** Not all BEVs in the fleet are assumed to participate in managed charging or bidirectional use. The share of BEVs that are enabled for CC or V2X is taken from the optimised smart-charging and V2G participation trajectories of FfE's BDL scenario (FfE, 2023). In 2030, 25 % of the BEV stock is assumed to participate in managed charging (CC or V2X); by 2040 this share rises to 35 % (Table 3). The same participation shares apply to both the CC and V2X modes: in the CC scenarios, 25 % / 35 % of BEVs charge in an optimised, unidirectional manner while the remainder charges inflexibly; in the V2X scenarios, the same 25 % / 35 % additionally provide bidirectional discharge capability. PHEV are not considered to be relevant for V2X

**Table 3: Assumed shares* of the BEV fleet participating in managed charging, based on FfE (2023), BDL scenario.**

| | 2030 | 2040 |
|---|---|---|
| Share of BEV stock participating in CC/V2X<br>(PHEV are not considered to be relevant for V2X) | 25% | 35% |

* Share is related to the energy demand of BEV that can be charged in a smart resp. bidirectional way. Optimization considers also driving profiles and battery restrictions.

Source: FfE (2023), BDL scenario.

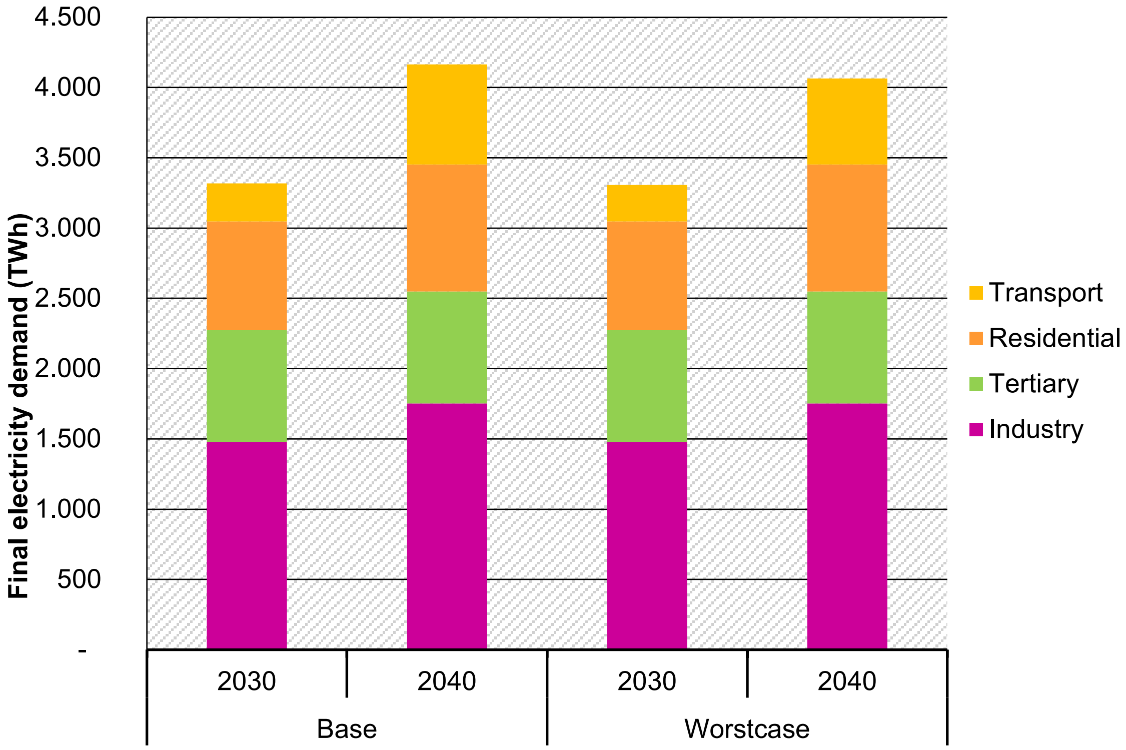
## 3.2 Key assumptions

The power system scenarios build on a harmonised set of exogenous assumptions regarding technology characteristics, energy demand and fuel and $CO_2$ prices.

### 3.2.1 Final electricity demand

Final electricity demand trajectories are taken from the S2 scenario of the TransHyDe project, which is consistent with achieving greenhouse-gas neutrality in Europe by 2050. This scenario provides sector-specific projections of electricity use in industry, the tertiary sector and households for the EU-27, the United Kingdom, Norway and Switzerland (Figure 7). Electricity demand from passenger cars is based on new market penetration scenarios; a distinction is made between a base and a worst-case scenario (see section 3.1). The remaining electricity demand from the transportation sector also corresponds to the S2 scenario from the TransHyDe project.

The phase-out of fossil fuels and the electrification of end-use sectors lead to a substantial increase in electricity demand over time. European electricity demand in 2030 increases to 3 318 TWh in the base scenario and 3 306 TWh in the worst-case scenario. In 2040, electricity demand is projected to reach 4 166 TWh in the base scenario and 4 064 TWh in the worst-case scenario. The transport sector’s share of total electricity demand accounts for around 8% in 2030 and 17% in 2040 in the base scenario, and 15% in the worst-case scenario.



Source: All except passenger cars: Alibas et al (2024). Passenger cars: own calculation based on T&E input

**Figure 7:** **Assumed final electricity demand in the EU27, UK, Norway, and Switzerland.**

### 3.2.2 Fuel and $CO_2$ prices

Assumptions on fuel and $CO_2$ prices are aligned with established international scenarios. Fossil-fuel price paths for coal, oil and natural gas are taken from the International Energy Agency's World Energy Outlook 2025 (IEA 2025), using the Net Zero Emissions by 2050 scenario for Europe (see Table 4). Values between milestone years are interpolated. All prices are expressed in real terms, i.e. adjusted for inflation. These trajectories feed into the Enertile model as exogenous inputs for generation-cost calculations and investment decisions.

**Table 4:** **Assumed fuel and $CO_2$ prices**

| | **Unit** | **2030** | **2040** |
|---|---|---|---|
| Natural gas | EUR/MWh | 22 | 13 |
| Coal | EUR/MWh | 9 | 5 |
| Oil | EUR/MWh | 31 | 17 |
| | USD/barrel | 54 | 30 |
| $CO_2$ | EUR/t | 183 | 365 |

Source: Fossil Fuels: IEA (2025), Net Zero Emissions by 2050 Scenario for Europe Linear interpolation.

### 3.2.3 Driving behaviour and BEV charging flexibility

Temporal load profiles as well as hourly SOC and (dis)charging power constraints for BEV charging used in the optimisation of the European energy system are derived from a simulation of 7,000 real-world vehicle driving profiles from Germany. The methodology is described in detail in Frank et al. (2025). A summary is provided below, along with the key technical assumptions.

**Driving consumption profile**. Each driving profile contains the start and end times of each trip as well as the trip's distance. We derive a normalised driving consumption profile for the entire BEV fleet from aggregating the consumption patterns of the simulated driving profiles.

**Uncontrolled charging load profile.** If charging is uncontrolled, the charging process starts when the EV is connected and only ends when the battery is fully charged or when the user unplugs the EV. Here, we assume that users plug in their EV as soon as they arrive at a charging location and unplug it when they leave. We calculate the stock's uncontrolled load profile by aggregating the individual location-specific charging power (cf. Table 5) of all charging vehicles at a time.

**Table 5: Assumed charging infrastructure availability and power, by location and year**

| Location | Charging option availability | | Average charging power (kW) | |
|---|---|---|---|---|
| | 2030 | 2040 | 2030 | 2040 |
| Home | 100 % | 100 % | 6.1 | 8.6 |
| Workplace | 20 % | 50 % | 6.1 | 8.6 |

Source: Gnann et al. (2024)

**Availability of car batteries as flexibility resource.** The available load (or in case of V2G, generation) of the BEV fleet is limited by the number of BEVs connected to the grid and the charging power at their locations. We calculate the upper boundary for the power that can be drawn from (or fed into) the system by the managed BEV stock by summing up the location-specific power of all potentially plugged-in BEVs at a time. This limit varies over time, depending on how many BEVs are parked and where. We assume that private vehicles and company cars can potentially be plugged in when their user is at home, and that commercial fleet vehicles can do so when they are parked at their home location. We assume workplace charging to be increasingly available to BEV users (cf. Table 5). We do not consider public charging as flexible in this study.

**Battery capacity and SOC boundaries.** Battery capacity of BEVs differs within BEV segments from 25 kWh for small cars to 73 kWh for large cars. After 2030 battery capacity further increase due to cost reduction of batteries making them more affordable for users. The assumption on capacity is increased to 38 kWh for small cars and 100 kWh for large cars (see Table 6).

We calculate individual upper and lower boundaries for the SOC of each driving profile by employing SOC-minimizing and SOC-maximizing charging strategies in the battery simulation. The SOC-maximizing strategy corresponds to the uncontrolled pattern, in which charging starts at arrival and only ends when the battery is fully charged or when the next trip begins. The SOC-minimizing strategy is characterised by charging as late and as little as possible given the location-specific charging power. Charging starts when the remaining parking time is exactly sufficient to charge the minimum energy required at departure.

**Table 6:** **Assumed battery capacity (kWh) of BEVs by segment and registration year**

90% usable capacity. Interpolated for years in between; constant from 2030.

| BEV segment | 2020 | 2030 onwards |
|---|---|---|
| Small | 25 | 38 |
| Medium | 45 | 69 |
| Large | 73 | 100 |

Source: Gnann et al. (2024)

We then calculate upper and lower boundaries for the cumulative energy stored in the managed BEV stock's batteries by aggregating the individual minimum and maximum SOC boundaries. Finally, we add a safety margin of 30 % to the lower technical limit. We withhold 30 % of the usable battery capacity, which is reserved for the users (in addition to the energy required to realise their driving profiles) for unforeseen trips or to account for battery health considerations or range anxiety. Only the reduced capacity is available for the optimisation.

Conclusion:

The scenario framework deliberately separates two fundamental drivers of future outcomes: the pace of passenger-car electrification and the way in which EV batteries are integrated into the power system. By combining base- and worst-case EV diffusion pathways with three distinct charging regimes—uncontrolled charging, controlled charging, and bidirectional vehicle-to-grid (V2X)—the analysis isolates the flexibility effect of EVs from the effect of higher electricity demand alone.
EV market projections are translated into electricity demand using detailed assumptions on vehicle stock composition, mileage and efficiency. EV batteries are represented as aggregated mobile storage units whose charging and discharging behaviour is constrained by empirically derived driving patterns. This ensures that the provision of system services never compromises mobility needs. Importantly, the analysis focuses exclusively on passenger cars as a source of flexibility, providing a conservative and clearly attributable estimate of V2G impacts.
The power system response to these inputs is determined endogenously using a cost-minimising, hourly-resolved optimisation model with perfect foresight. Generation, storage and backup capacities are not prescribed but emerge from the optimisation, given consistent techno-economic assumptions on fuel prices, $CO_2$ prices and technology costs. Demand developments in industry, buildings and appliances are held constant across scenarios, ensuring that observed differences in system outcomes can be attributed directly to EV diffusion and charging behaviour.

# 4 Power system impacts

## 4.1 Overview electricity balance and capacity

**Reference system.** By 2030, the modelled European (EU27, UK, Norway, and Switzerland.) power system is already dominated by variable renewable energy sources. Onshore wind, photovoltaics (PV) and offshore wind together generate more than 2 280 TWh, complemented by approximately 684 TWh of nuclear output and roughly 209 TWh from gas-fired plants. Stationary batteries and pumped-hydro storage provide the bulk of short-term flexibility, with system-wide curtailment reaching approximately 58 TWh. Inflexible passenger-car charging adds a load of about 92 TWh in the Baseline EV-diffusion scenario (80 TWh in the worst-case). By 2040, wind and solar output nearly doubles, nuclear generation declines to approximately 441 TWh, and annual curtailment rises to roughly 152 TWh. Stationary battery discharge increases to about 88 TWh, illustrating how the flexibility challenge scales with renewable penetration (Figure 8).

**Controlled charging (CC).** Shifting EV charging to hours of high renewable output – without enabling feed-back to the grid – produces effects that grow markedly between 2030 and 2040. In 2030, CC already reduces gas-fired generation by approximately 5–6 TWh and curtailment by around 3 TWh. By 2040, the impact extends principally to stationary batteries, whose discharge falls by roughly 30 TWh, and to hydrogen power plants, whose output declines by about 4 TWh. On the capacity side, stationary battery power decreases from approximately 148 GW to 96 GW (−52 GW), while the renewable generation mix and installed capacities show only small changes (Figure 9). CC thus optimises the dispatch of an already renewables-dominated system rather than altering its structural composition.

**Bidirectional charging (V2X).** V2X converts the passenger-car fleet into a major distributed storage resource and triggers a structural re-optimisation of the generation portfolio. By 2040, car-to-grid feed-in reaches approximately 204 TWh in the Baseline scenario. This nearly eliminates stationary battery operation (discharge falls from 88 TWh to approximately 2 TWh) and substantially reduces hydrogen power plant generation (−12 TWh relative to the Reference). Curtailment declines by approximately 23 TWh, despite the system installing significantly more PV capacity.

The capacity shifts under V2X are equally pronounced. In 2040, stationary battery power drops from approximately 148 GW to about 6 GW, hydrogen-turbine capacity from roughly 110 GW to 71 GW (−39 GW), and electrolyser capacity by about 19 GW. Simultaneously, PV capacity rises by approximately 139 GW, while CSP and some onshore wind are partially displaced. The result is a more solar-intensive and less infrastructure-intensive system architecture.

**Worst-Case EV diffusion.** The worst-case diffusion scenario reproduces these patterns at a reduced scale. In 2040, V2X still provides approximately 133 TWh of car-to-grid feed-in, reduces stationary battery discharge from 60 TWh to about 3 TWh, and lowers stationary battery power capacity by roughly 96 GW. The qualitative conclusions are robust across both EV-uptake pathways: CC delivers meaningful operational benefits, while V2X enables a step change in which vehicle batteries become the dominant source of short-term flexibility and support a structurally more solar-centric European power system.

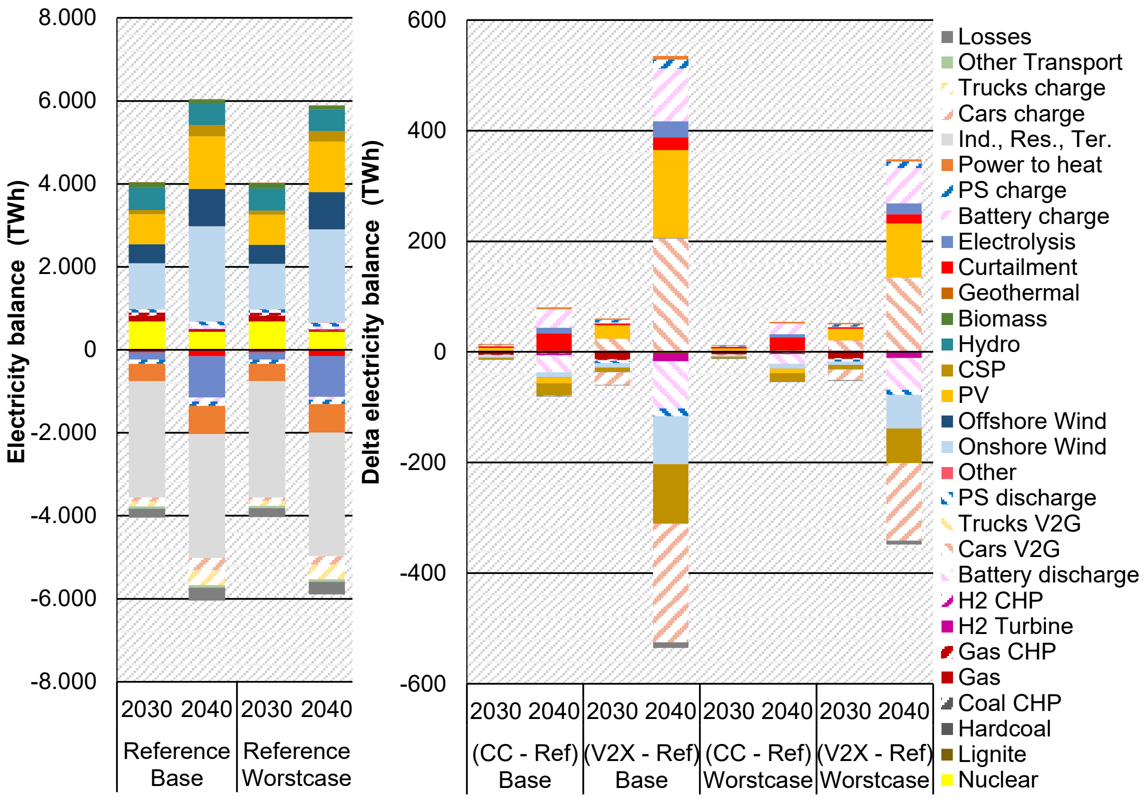


**Figure 8:** Joint electricity balances and changes in the scenario variants for the EU27, UK, Norway, and Switzerland.

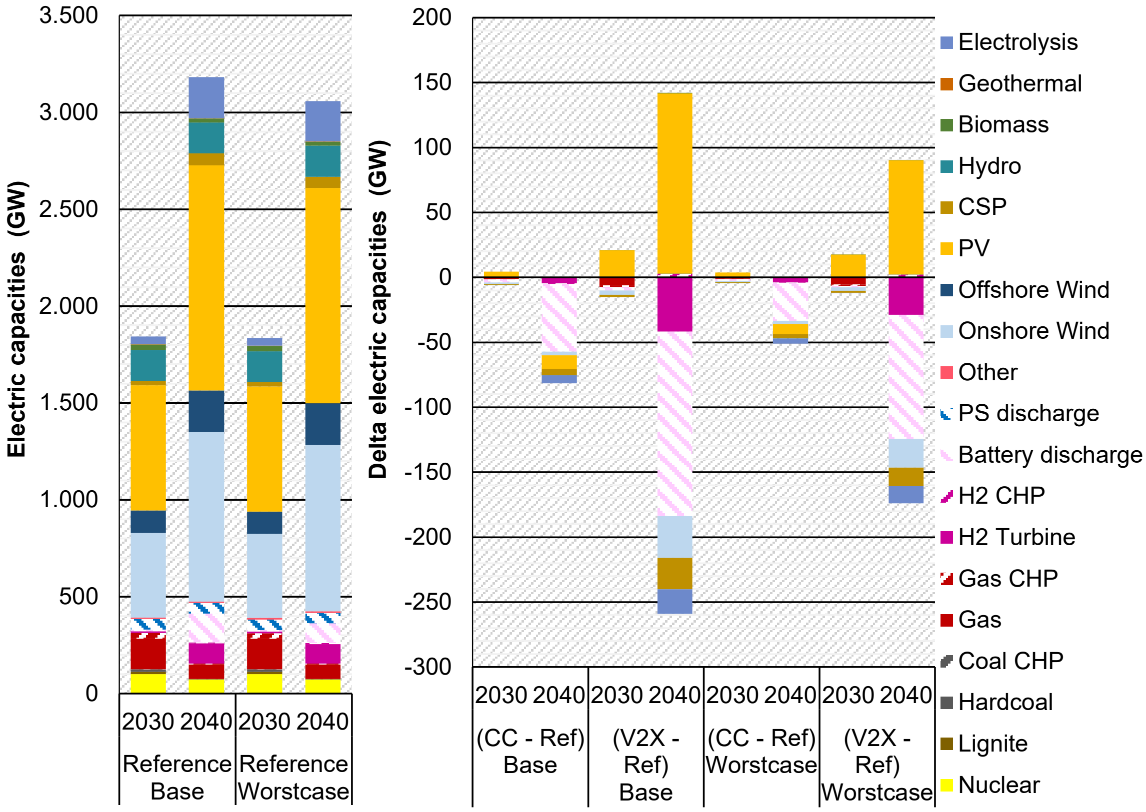


**Figure 9:** Electric capacities and changes in the scenario variants for the EU27, UK, Norway, and Switzerland.

## 4.2 Back-up capacities

The capacity mix required to ensure system adequacy in a renewables-dominated system changes substantially once EV flexibility is activated (Figure 9). In the Baseline Reference scenario for 2040, the European system (EU27, UK, Norway, and Switzerland) maintains a large fleet of short-duration flexibility and peaking assets: approximately 80 GW of gas capacity, about 110 GW of hydrogen power plants, and approximately 148 GW of stationary batteries, complemented by some 54 GW of pumped-hydro storage.

**Effect of CC.** Controlled charging primarily reduces the need for the most expensive short-duration flexibility assets. By 2040 in the Baseline scenario, stationary battery power falls from approximately 148 GW to about 96 GW (−52 GW), while hydrogen power plant capacity declines marginally from roughly 110 GW to 105 GW (−5 GW). Gas capacities remain essentially unchanged, indicating that CC optimises the utilisation of existing peaking plant rather than substituting it outright. In the worst-case diffusion, the same qualitative pattern is observed: stationary battery power drops from approximately 102 GW to about 72 GW, and hydrogen power plants from about 106 GW to 102 GW.

**Effect of V2X.** Bidirectional charging fundamentally reshapes the back-up stack. In the Baseline 2040 scenario, stationary battery power falls from approximately 148 GW in the Reference to only about 6 GW – essentially eliminating the need for a large centralised battery fleet. Hydrogen power plant capacity falls from about 110 GW to about 71 GW (−39 GW), as vehicle batteries increasingly cover residual peak demand. Gas capacities are only marginally reduced in absolute terms but are dispatched less frequently; their role narrows to residual back-up during extended low-renewable periods. In the V2X Worst-Case scenario, stationary battery power falls to about 6 GW and hydrogen power plant capacity from approximately 106 GW to 79 GW (Figure 10).

**Implications.** These results suggest that CC, and especially V2X, can maintain system reliability with a significantly smaller fleet of dedicated peaking plants and stationary batteries. The adequacy function is increasingly provided by a coordinated, distributed storage resource – the vehicle fleet – rather than by capital-intensive centralised assets.

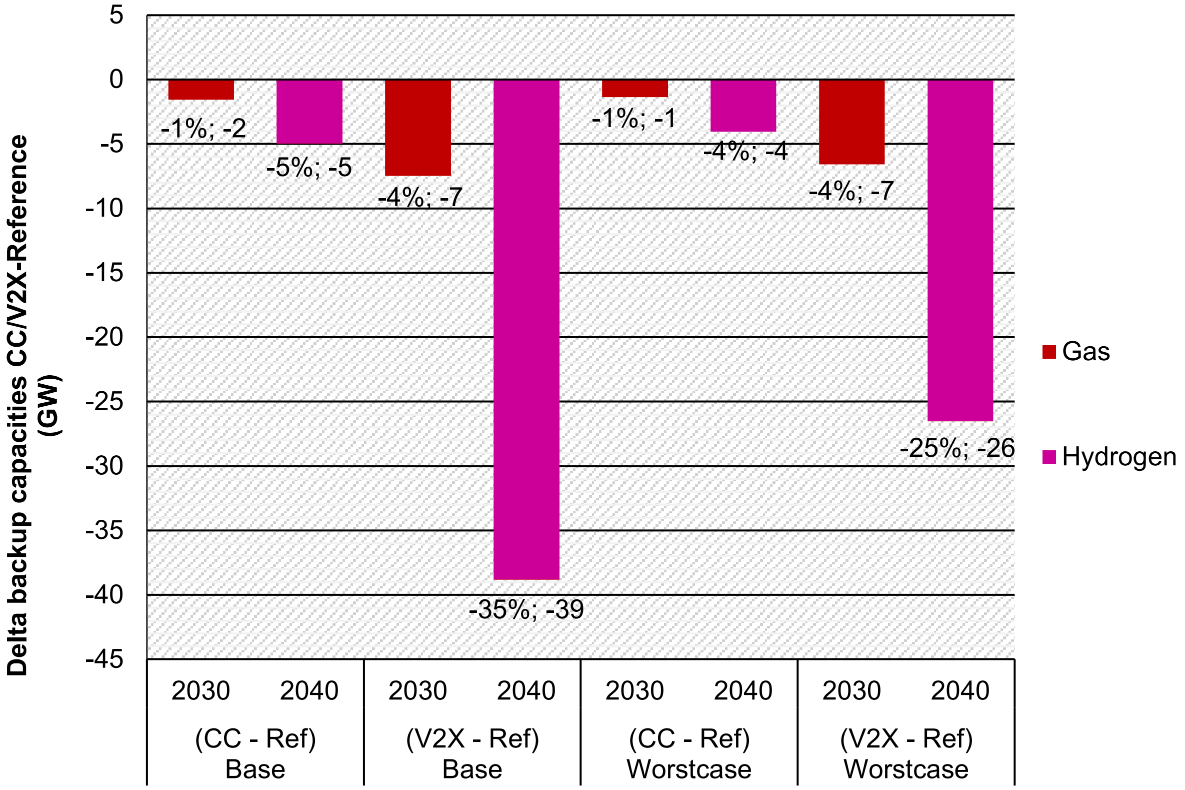


**Figure 10:** **Changes in back up capacities in the scenario variants for the EU27, UK, Norway, and Switzerland.**

## 4.3 Stationary Batteries

The evolution of stationary battery energy capacity further illustrates the substitution potential of EV flexibility (Figure 11). Results in this subsection refer to EU27, UK, Norway and Switzerland combined.

**Reference.** In the Baseline Reference scenario, stationary batteries provide approximately 17 GWh of energy storage capacity in 2030 and close to 296 GWh by 2040. In the Worst-Case Reference, lower EV electricity demand permits somewhat smaller battery volumes – about 15 GWh in 2030 and 203 GWh in 2040 – but the overall system architecture remains similar: stationary batteries act as a key buffer for short-term variability and peak demand.

**CC.** Controlled charging reduces these requirements substantially. In the Baseline, battery energy capacity in 2030 falls from approximately 17 GWh to about 13 GWh, and by 2040 from roughly 296 GWh to about 192 GWh – a reduction of approximately 5 GWh and 104 GWh, respectively, corresponding to roughly one-third of the Reference battery volume in 2040. The Worst-case diffusion exhibits smaller but significant reductions: about 2 GWh less in 2030 and approximately 59 GWh less in 2040.

**V2X.** Bidirectional charging reduces stationary battery requirements far more drastically. In the Baseline, stationary battery volume in 2040 falls from nearly 296 GWh under inflexible charging to approximately 12 GWh – a reduction of roughly 96 %. The Worst-case scenario shows the same structure: battery volume declines from about 203 GWh to approximately 12 GWh (−191 GWh, or 94 %).

In a power system with widespread V2X, stationary batteries thus become a niche technology rather than a central pillar of short-term flexibility. CC already reduces stationary battery energy needs by about one-third relative to inflexible charging; V2X removes almost the entire residual requirement.

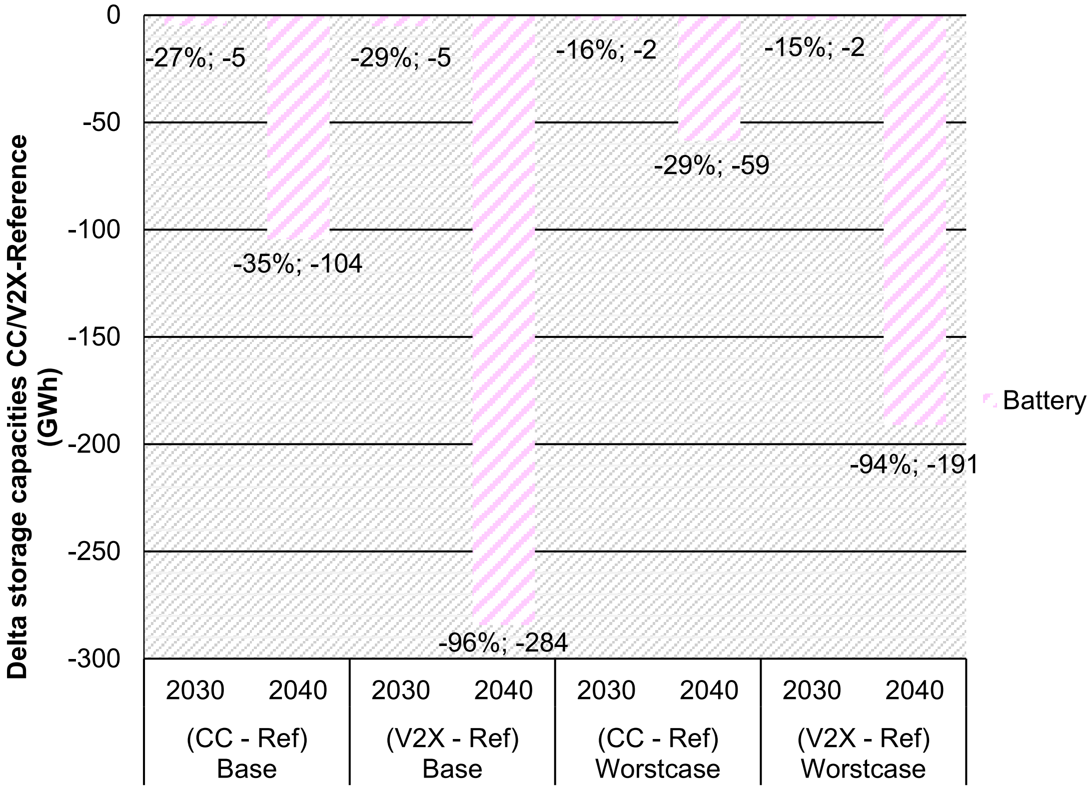


**Figure 11:** **Changes in stationary battery capacities in the scenario variants for the EU27, UK, Norway, and Switzerland.**

## 4.4 Renewables Capacities and Curtailment

Controlled and bidirectional charging both act as enablers of renewable integration, particularly for solar photovoltaics. All figures in this subsection refer to EU27, UK, Norway and Switzerland unless otherwise noted.

**CC effects.** In the Baseline EV scenario for 2030, CC increases installed PV capacity by approximately 4 GW (around 1 % above the Reference) and reduces renewable curtailment by about 3 TWh (about 5 % below the Reference) relative to inflexible charging . By shifting charging to hours with high solar output, CC modestly improves the effective utilisation of existing PV and makes incremental PV capacity economic. The Worstcase diffusion shows a very similar effect, with PV capacity up by roughly 4 GW (around 1 %) and curtailment down by about 3 TWh (about 5 %). By 2040, CC reduces curtailment by approximately 31 TWh (about 20 % of the Reference level) in the Baseline and around 23 TWh (about 16 %) in the Worstcase. At the same time, the model slightly reduces optimal PV capacity with CC in 2040 (around 1 % below the Reference in both Baseline and Worstcase), indicating that CC's long-term contribution is primarily through more efficient operation rather than a large structural increase in PV capacity.

**V2X effects.** V2X amplifies these effects substantially, especially by 2040. In 2030, PV capacity rises by approximately 21 GW in the Baseline scenario relative to the Reference (around 3 % higher PV capacity), while curtailment declines by about 3 TWh (around 5 % lower). In 2040, the system takes considerably greater advantage of bidirectional charging: V2X supports an additional approximately 139 GW of installed PV capacity in the Baseline scenario (around 12 % above the Reference), while curtailment still declines by approximately 23 TWh (about 15 %). In the Worstcase scenario, additional PV capacity amounts to about 18 GW in 2030 (around 3 %) and 88 GW in 2040 (about 8 %), with curtailment reductions of approximately 3 TWh in 2030 (about 5 %) and 17 TWh in 2040 (around 11 %).

**Mechanisms.** These results reflect two complementary mechanisms. First, both CC and V2X reduce curtailment for a given renewable fleet by better aligning EV demand (and, in the case of V2X, discharge) with renewable availability. Second, and quantitatively more important, V2X changes the cost-optimal generation mix: because vehicle batteries can absorb midday solar peaks and shift energy to evening and night-time hours, the system invests heavily in additional PV capacity while maintaining curtailment at manageable levels. The additional PV capacity enabled by V2X is an order of magnitude larger (in GW) than the reduction in curtailment suggests, demonstrating that the principal value lies not only in absorbing surplus generation but in making a substantially more solar-intensive portfolio economically attractive.

The comparison between Baseline and Worst-case EV diffusion indicates that these qualitative effects are robust. With fewer EVs, less flexibility is available and the absolute increase in PV capacity is smaller, but both CC and V2X consistently shift the system in the same direction: higher PV deployment, lower curtailment, and a clearer trend towards a solar-rich generation mix (Figure 12 and Figure 13).

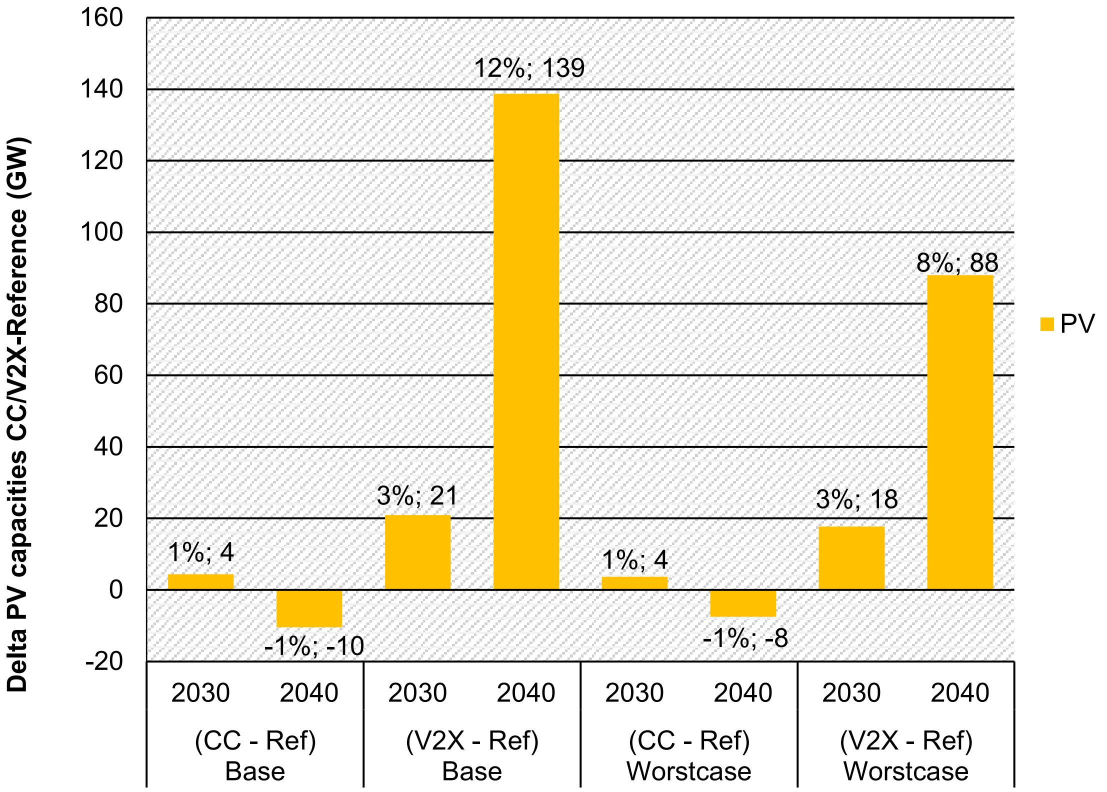


**Figure 12:** Changes in PV capacities in the scenario variants for the EU27, UK, Norway, and Switzerland.

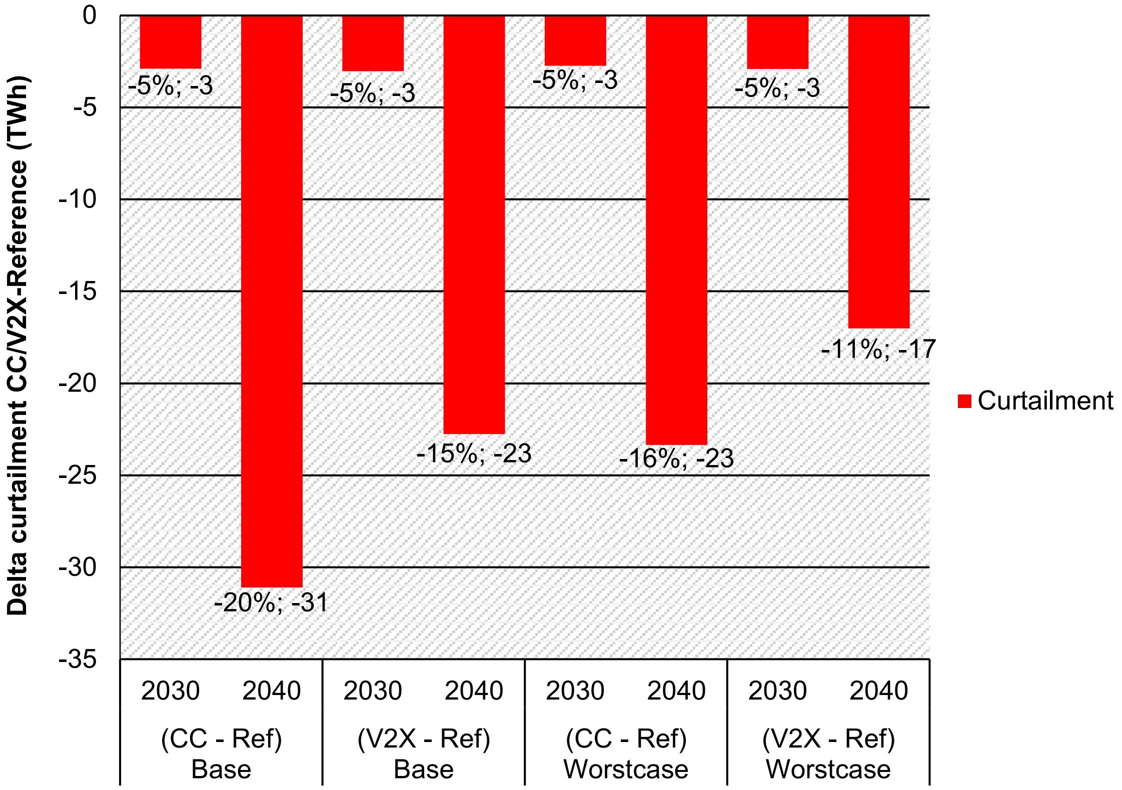


**Figure 13:** Changes in curtailment in the scenario variants for the EU27, UK, Norway, and Switzerland.

## 4.5 Vehicle-to-Grid feed-in

Vehicle-to-grid (V2G) transforms the passenger car fleet into a major distributed energy storage resource. In the EU27 plus Norway, Switzerland, and the UK, car-to-grid feed-in reaches about 19 TWh in the Worstcase scenario and 21 TWh in the Baseline scenario by 2030. By 2040, these values increase substantially, with approximately 133 TWh in the Worstcase scenario and 204 TWh in the Baseline scenario. Figure 14 provides an overview of vehicle-to-grid feed-in by country, year, and scenario.

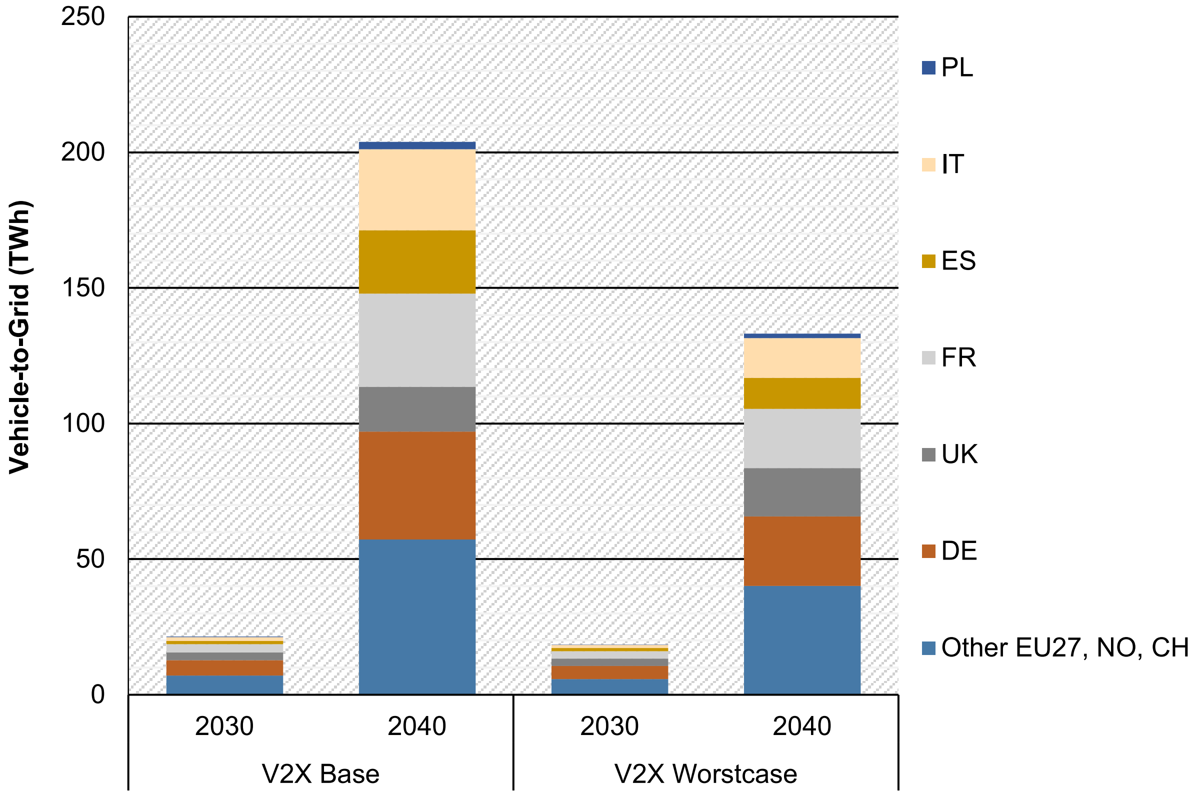


**Figure 14:** **Vehicle-to-grid feed-in by country, year and scenario.**

## 4.6 System Costs and Emissions

### 4.6.1 The value of flexibility by battery electric vehicles

*Flexibility value*

**Definition**

The flexibility value measures how much controlled charging (CC) or bidirectional charging (V2X) reduces annual power-sector supply system cost compared with a Reference case with inflexible charging, for the same EV diffusion and model year. It can be reported in absolute terms (€/year) and per battery-electric vehicle (€/BEV).

**Notation**

- $c_{sup}^{Ref/CC/V2X}(y) = annual\ supply\ system\ cost\ in\ the\ Reference/Controlled\ charging/V2X\ case\ in\ year\ y$
- $N_{BEV}(y) = BEV\ stock\ in\ year\ y$

**Absolute flexibility value (per year)**

$$FV_{CC/V2X}(y) = c_{sup}^{Ref}(y) - c_{sup}^{CC/V2X}(y)$$

A positive value means that CC or V2X reduces supply system cost relative to inflexible charging.

**Flexibility value per BEV**

$$FV_{CC/V2X\ per\ BEV}(y) = \frac{FV_{CC/V2X}(y)}{N_{BEV}(y)}$$

The flexibility gains from CC and V2X can be expressed as explicit cost savings relative to inflexible charging for a given EV fleet size. These savings capture the value of improved intra-day flexibility and are computed as the difference in annual EU-wide supply-system costs (EU27, UK, Norway and Switzerland) between the Reference and the respective managed-charging scenario, holding total passenger-car electricity consumption essentially constant (Figure 15).

In the Baseline diffusion, CC reduces annual supply-system costs by approximately €0.8 billion in 2030 and €4.6 billion in 2040. Moving from the Reference to V2X yields savings of roughly €1.4 billion and €11.7 billion, respectively.

**Per-vehicle value.** As described in section 2.2.2, not all BEVs in the fleet participate in managed charging. Relating the total system savings to the number of participating vehicles (25 % of the BEV stock in 2030, 35 % in 2040) yields the average flexibility value per participating BEV. In the Baseline scenario, the BEV stock comprises approximately 37 million vehicles in 2030 and 141 million in 2040, of which roughly 9.2 million and 49.4 million, respectively, participate in CC or V2X. The resulting average flexibility value per participating BEV is approximately €85 in 2030 and €93 in 2040 for CC, and roughly €150 and €237, respectively, for V2X (Figure 16).

In the Worst-Case diffusion, the BEV fleet is smaller (approximately 31 million in 2030 and 92 million in 2040), so each participating vehicle's flexibility is marginally scarcer. The average value per participating BEV is correspondingly slightly higher: about €85–95 for CC and approximately €150–241 for V2X. The similarity of these ranges across diffusion scenarios indicates that the per-vehicle benefit is determined primarily by the characteristics of the surrounding high-renewables system rather than by the exact size of the BEV fleet. Investing in smart-charging capabilities thus yields robust system benefits per participating vehicle, with the additional step to V2X roughly doubling to tripling the value relative to CC alone.

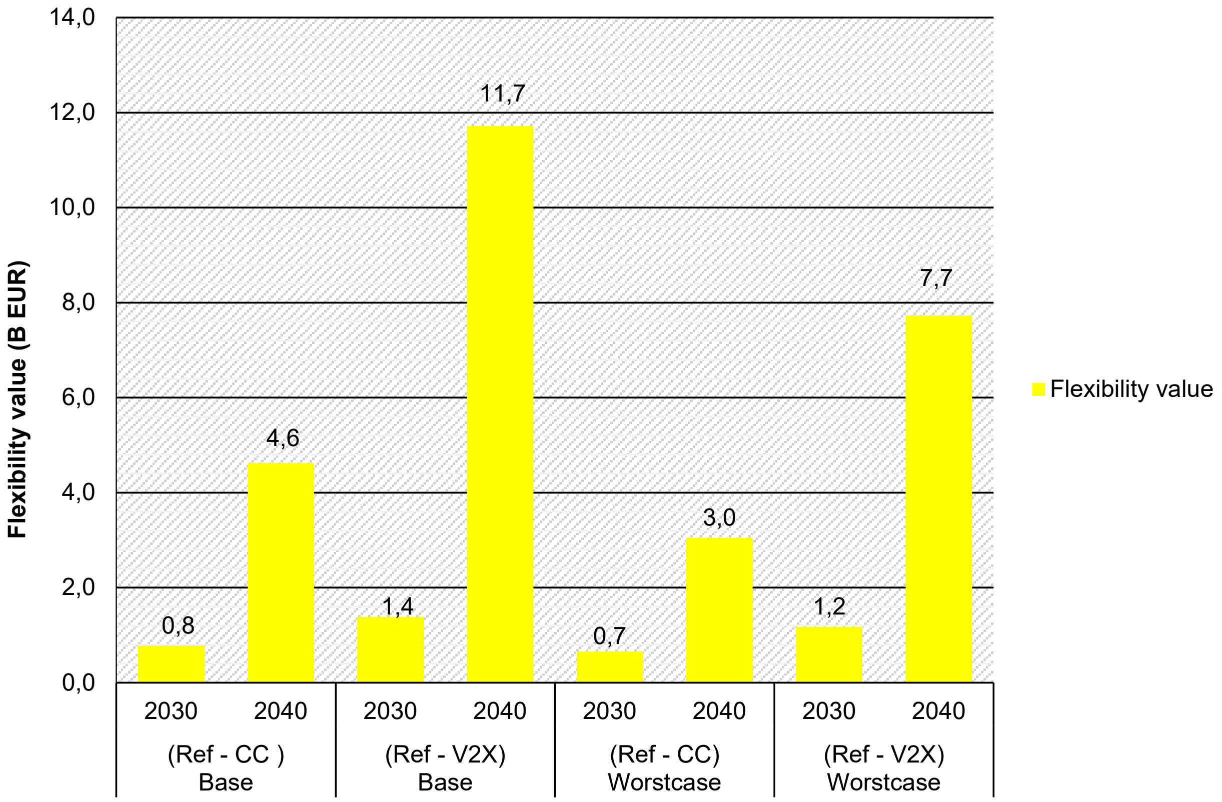


**Figure 15:** **Flexibility value of battery electric vehicles in the EU27, UK, Norway, and Switzerland.**

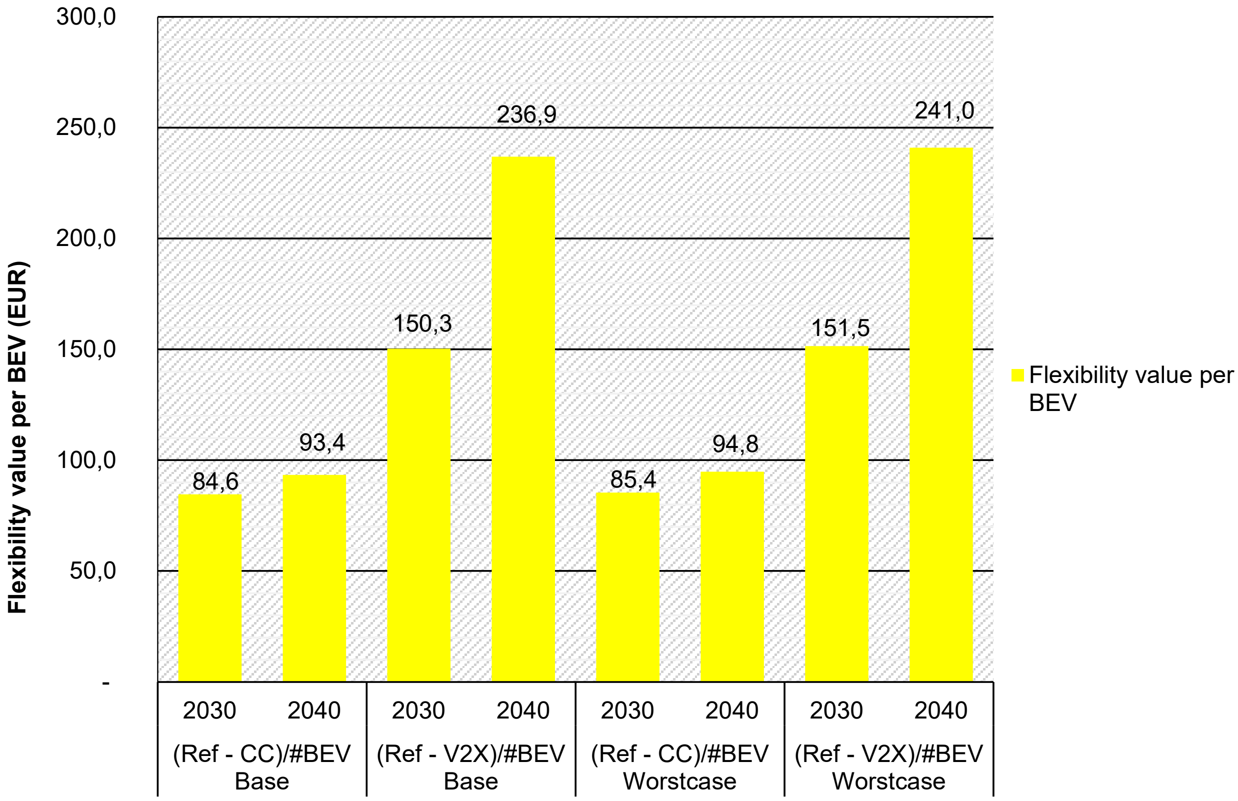


**Figure 16:** **Flexibility value per battery electric vehicle.**

### 4.6.2 The value of faster battery electric vehicle diffusion

*Difference in system cost*

**Definition**

The "difference in system cost" compares total annual system cost between the Base and Worst-case EV diffusion scenarios for a given charging option $s \in \{Reference, CC, V2X\}$. Total system cost is defined as the sum of power-sector supply system cost and car fuel cost. Both components include associated $CO_2$ costs.

**Notation**

- $c_{sup}^{s,e}(y) = annual\ supply\ system\ cost\ in\ year\ y$
- $c_{fuel}^{s,e}(y) = fossil\ car\ fuel\ cost\ cost\ in\ year\ y$
- $e \in \{Base, Worstcase\}$

**Total system cost**

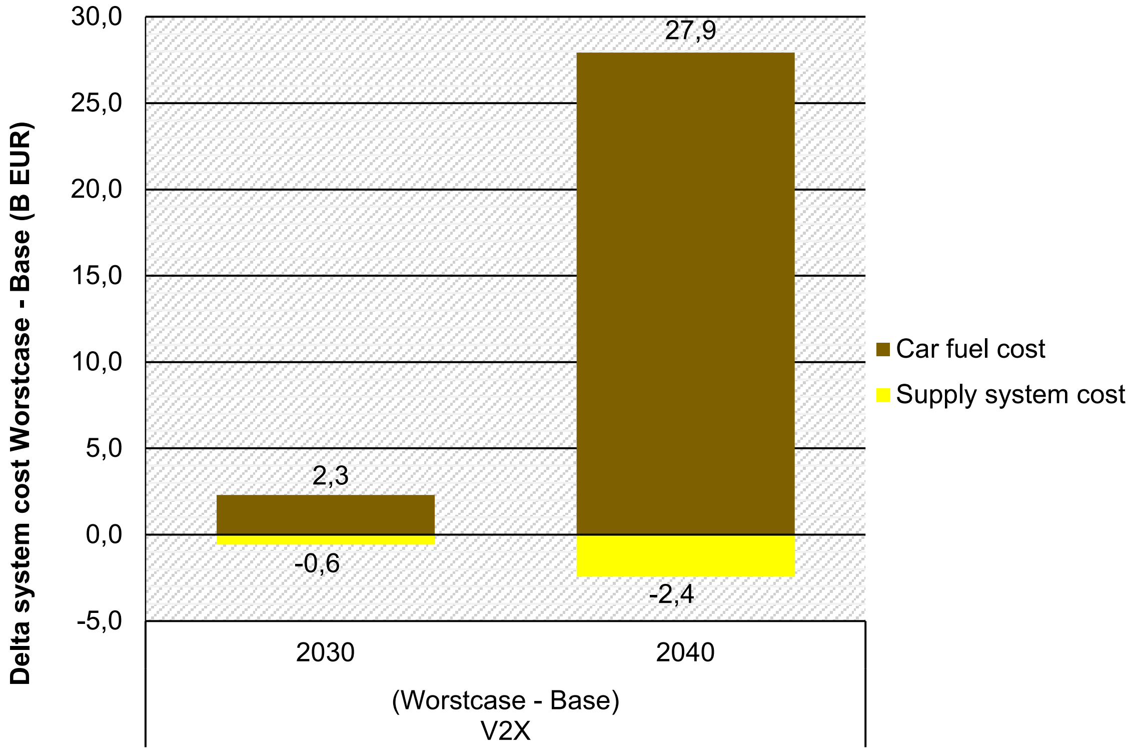
$$c_{tot}^{s,e}(y) = c_{sup}^{s,e}(y) + c_{fuel}^{s,e}(y)$$

**Difference Worst-case – Base (for a fixed charging option $s$**

$$\Delta c_{tot}^{s}(y) = c_{tot}^{s,Worstcase}(y) - c_{tot}^{s,Base}(y)$$

A positive $\Delta c_{tot}^{s}(y)$ means the more conservative EV diffusion (Worst-case) is more expensive than the Base EV pathway under charging option $s$, including all $CO_2$-related costs in both the power and transport sectors.

**Total system cost including vehicle fuel.** When conventional car-fuel expenditure is added to the supply-system cost, slower electrification in the Worst-Case scenario unambiguously increases overall system cost. In 2030, higher expenditure on liquid fuels (approximately €2.3 billion) outweighs the €0.6 billion of power-supply savings, raising total system cost by about €1.7 billion per year. By 2040, the effect is substantially larger: total system cost in the Worst-Case exceeds that of the Baseline by approximately €25 billion per year. Figure 17 shows the differences in system cost between the Baseline and Worst-case EV market diffusion when V2X is enabled.



Car fuel costs shown consist of oil and CO2 cost. Taxes, excise duties, or profit margins not included, and no admixture of non-fossil fuel considered.

**Figure 17:** **Differences in system cost in the scenario variants for the EU27, UK, Norway, and Switzerland.**

Conclusion:
By 2030, passenger-car electrification is already large enough to shape the European power system. Under inflexible charging, EVs are an additional load of about 70 TWh in the Base scenario, served by a wind- and solar-dominated system with growing fleets of hydrogen turbines and stationary batteries. Introducing controlled charging (CC) keeps electricity demand unchanged but reduces gas-fired generation, hydrogen-turbine output and stationery-battery cycling and cuts curtailment by around 2 TWh. Bidirectional charging (V2X) adds roughly 18 TWh of car-to-grid output and further reduces stationary-battery use and hydrogen storage needs.
By 2040, the structural role of EV flexibility becomes clear. In the Reference Base scenario, short-term flexibility is provided mainly by hydrogen turbines and stationary batteries, with significant renewable curtailment. CC lowers stationary battery power capacity by roughly one-third and reduces hydrogen-turbine use and curtailment by about 20–25 %, without materially changing the renewable mix. Allowing V2X fundamentally re-optimises the system: vehicle batteries become the dominant short-term storage, stationary battery power falls from around 130 GW to about 6 GW, hydrogen-turbine capacity from around 95 GW to roughly 63 GW, and electrolyser capacity is also reduced. At the same time, additional PV capacity (on the order of 125–140 GW) becomes economical, while CSP and some onshore wind are partially crowded out. The system becomes more PV-heavy, with fewer dedicated peakers and almost no stationary batteries.
These technical changes translate into substantial cost savings. In the Base EV diffusion, CC reduces EU-wide supply system costs by about €0.8 bn/year in 2030 and €4.6 bn/year in 2040; V2X yields around €1.4 bn/year and €11.7 bn/year, respectively. On a per-vehicle basis, smart charging delivers roughly €85–95 per BEV per year, while V2X provides about €150–240 per BEV per year, with only a modest decline at higher BEV shares. When conventional fuel costs for cars are added, slower electrification (Worst-case) clearly raises overall system costs: by around €1.7 bn/year in 2030 and €25 bn/year in 2040, compared with the Base diffusion. Overall, the analysis shows that high EV uptake combined with smart charging and V2X is a cost-efficient flexibility strategy in a renewables-based European power system.

# 5 Power System Country Results

## 5.1 Germany

Germany's 2040 Reference Baseline power system is, in the model results, dominated by renewables. In all German scenarios, the expansion of onshore wind, offshore wind and photovoltaics is constrained such that at least the statutory minimum deployment targets defined in the Renewable Energy Act (Erneuerbare-Energien-Gesetz, EEG) are achieved in each model year; additional renewable capacity can be built endogenously where this is cost-effective. Onshore wind produces approximately 386 TWh from 160 GW of installed capacity, offshore wind contributes roughly 308 TWh from 70 GW, and photovoltaics generate about 361 TWh from 400 GW. Together, these three sources account for more than 95 % of gross domestic generation. Dispatchable thermal sources play only a residual role: natural-gas plants supply about 5 TWh, hydrogen power plants contribute approximately 14 TWh. The associated capacities are, however, substantial – roughly 7 GW of gas and 49 GW of hydrogen power plants – indicating that these assets are maintained primarily for security of supply during extended low-renewable periods rather than for regular dispatch. Stationary batteries discharge approximately 25 TWh per year from about 47 GW of installed power. Renewable curtailment is among the highest in Europe at roughly 41 TWh. Passenger-car charging absorbs approximately 55 TWh per year in the Baseline EV-diffusion scenario (33 TWh in the Worst-case). The system's flexibility challenge is thus defined by large volumes of variable renewable output, modest thermal back-up, and a heavy reliance on stationary batteries and hydrogen peaking plants for short-term balancing (Figure 18 and Figure 19).

**Controlled charging.** CC shifts the temporal profile of EV charging without enabling grid feed-back. In 2040, this optimisation significantly reduces the cycling of stationary batteries: their annual discharge falls from approximately 25 TWh to 14 TWh (−11 TWh, or −44 %). Hydrogen power plant output declines from 14 TWh to 12 TWh (−2 TWh). Curtailment is reduced from roughly 41 TWh to 34 TWh (−6 TWh), reflecting a better temporal alignment of EV demand with surplus renewable output. Gas generation declines only marginally, consistent with their already negligible role. On the capacity side, stationary battery power falls from approximately 47 GW to 26 GW (−20 GW) – a substantial reduction in dedicated storage infrastructure. By contrast, hydrogen power plant capacity decreases by only 2 GW. This pattern confirms that CC in Germany operates primarily by optimising the dispatch of existing assets – particularly stationary batteries – rather than by inducing a different investment trajectory in generation or back-up capacity.

**Bidirectional charging (V2X).** V2X transforms the passenger-car fleet into Germany's dominant source of short-term flexibility. By 2040, car-to-grid feed-in reaches approximately 40 TWh in the Baseline scenario. This displaces almost all stationary battery operation: battery discharge falls to approximately 2 TWh, and battery power capacity contracts from 47 GW to 6 GW – a reduction of 87 %. Hydrogen power plant generation drops sharply from 14 TWh to about 7 TWh (−50 %), and hydrogen power plant capacity falls from 48 GW to 35 GW (−13 GW). Curtailment declines by approximately 6 TWh relative to the Reference, a reduction comparable in magnitude to the CC scenario. Vehicle batteries act primarily as a substitute for dedicated storage and hydrogen peaking plants, rather than as an enabler of a structurally different generation mix.

**Worst-case EV diffusion.** The Worst-case scenario reproduces the same qualitative patterns at reduced magnitude. V2X car-to-grid feed-in reaches approximately 26 TWh. Stationary battery power is still reduced to 6 GW, and hydrogen power plant capacity falls from 46 GW to 38 GW (−8 GW). The reduction in hydrogen plant generation is about 5 TWh (compared with 7 TWh in the Baseline). In both diffusion scenarios, CC significantly reduces stationary battery requirements, while V2X largely eliminates them and approximately halves hydrogen power plant dispatch.

Figure 20 shows the cost difference between the Worstcase and Baseline V2X scenarios for Germany. In both 2030 and 2040, higher car-fuel expenditure from slower electrification clearly outweighs the associated power-system savings: the net cost of delayed EV uptake amounts to approximately €0.5 billion per year in 2030 and rises to roughly €5.5 billion per year by 2040.

**Country-specific observations.** The model maintains a very large hydrogen power plant fleet (48 GW) despite its low utilisation (capacity factor ≈ 3 %), highlighting the role of these assets as insurance against extended low-wind, low-solar periods.

**Implications.** In a deeply decarbonised German power system, the principal benefit of EV flexibility is the avoidance of tens of gigawatts of stationary batteries and hydrogen peaking plants. The model results suggest that maintaining high EV uptake and enabling V2X could allow a substantial reallocation of investment from dedicated flexibility assets towards renewables and grid infrastructure, while preserving system adequacy. The persistence of a large (albeit less frequently dispatched) hydrogen-turbine fleet under V2X indicates that long-duration back-up needs remain, even with widespread vehicle-based flexibility.

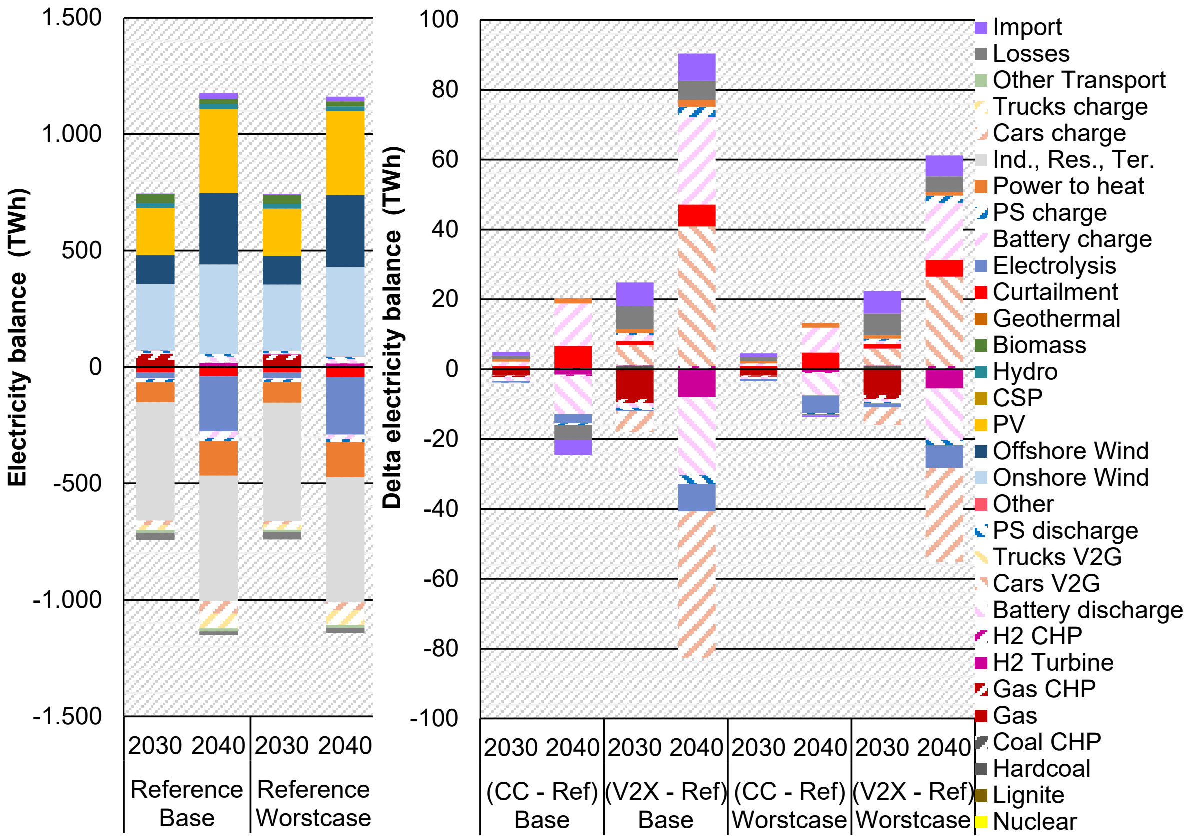


**Figure 18:** **Electricity balances and their changes in the scenario variants for Germany.**

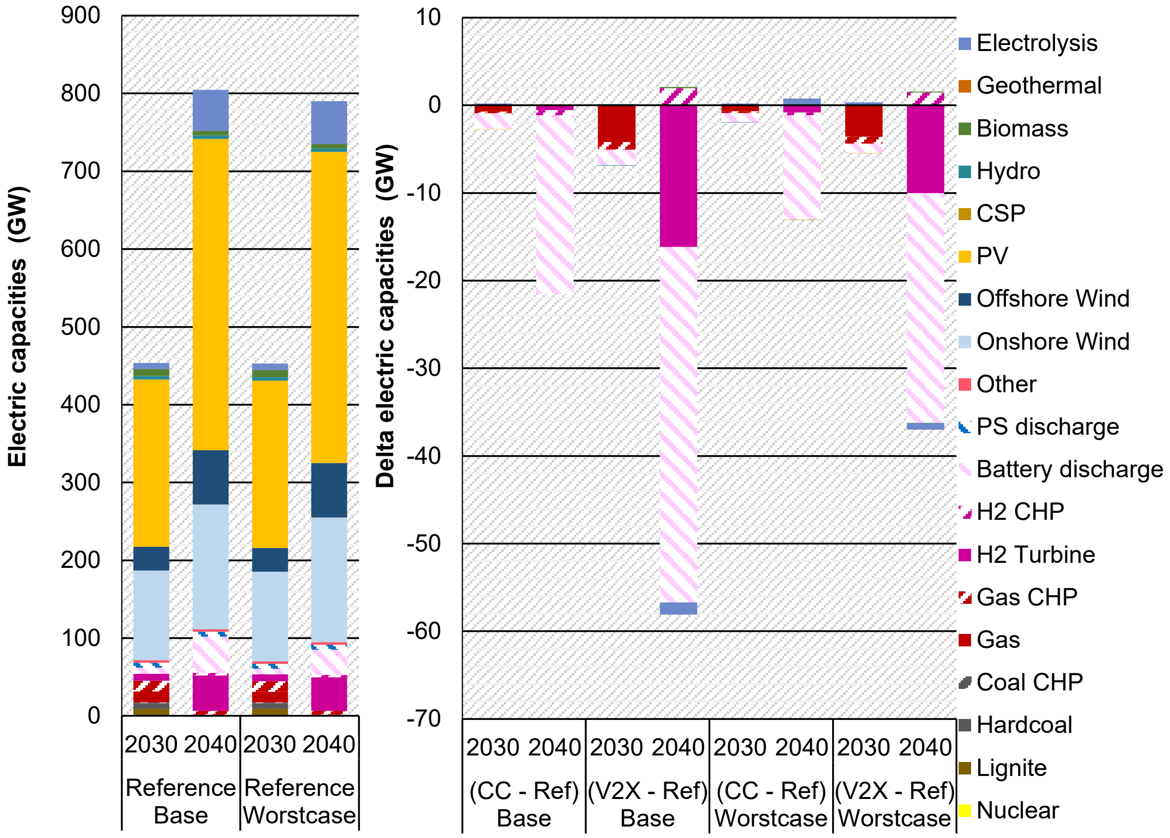


**Figure 19:** **Electric capacities and changes in the scenario variants for Germany.**

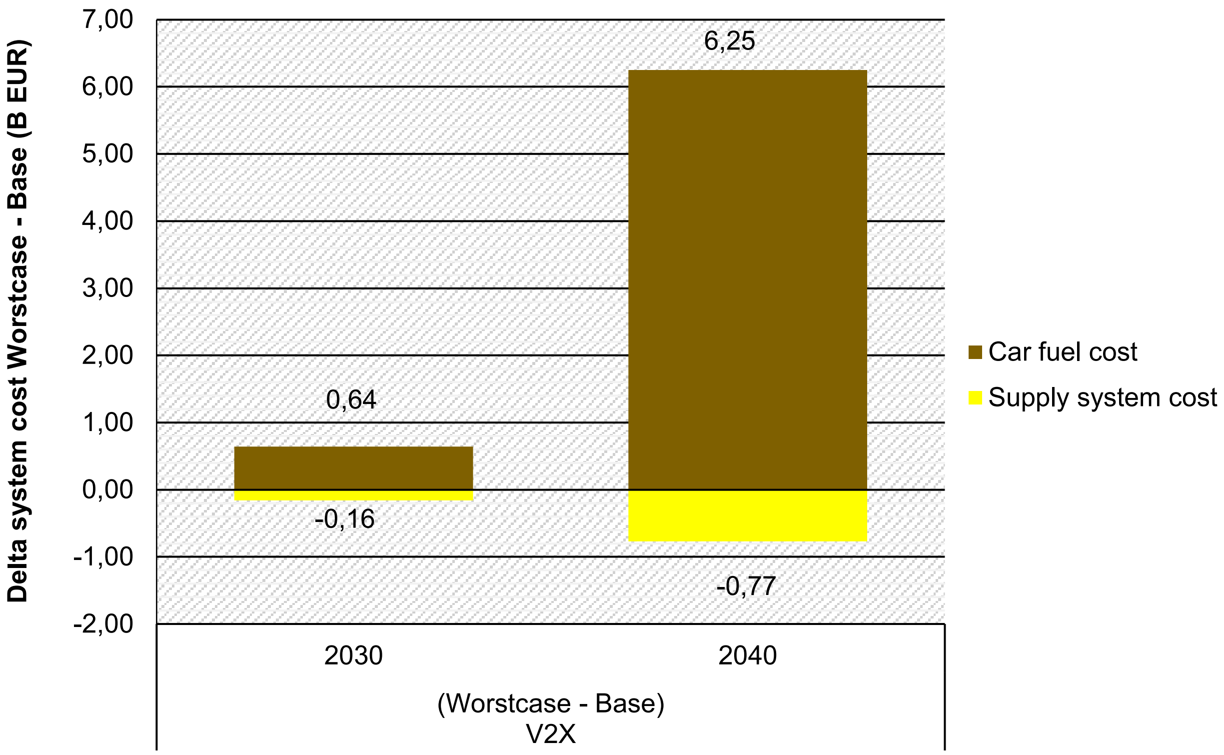


**Figure 20:** **Differences in system cost in the scenario variants for Germany.**

## 5.2 France

France's 2040 Reference Baseline retains the largest nuclear fleet in Europe, generating approximately 200 TWh from 36 GW of installed capacity. This baseload is complemented by a substantial renewable portfolio: onshore wind produces roughly 466 TWh from 175 GW, photovoltaics generate about 170 TWh from 140 GW, offshore wind adds approximately 16 TWh from 5 GW, hydro contributes about 65 TWh from 19 GW, and concentrated solar power (CSP) provides roughly 8 TWh from 2 GW. Thermal back-up plays a minor role: gas plants generate only about 1 TWh, and hydrogen turbines approximately 1 TWh – yet hydrogen-turbine capacity is substantial at 11 GW, implying a capacity factor of less than 1 %. This extreme asymmetry between installed capacity and utilisation illustrates that hydrogen turbines in France serve an adequacy function for rare but severe residual-load events. Stationary batteries are essentially absent in all French scenarios. Pumped-hydro storage discharges about 11 TWh from 7 GW. Curtailment is modest at approximately 10 TWh, and France is a sizeable net electricity exporter (≈ 56 TWh). Passenger-car charging absorbs about 44 TWh per year in the Baseline scenario (27 TWh in the Worst-case) (Figure 21 and Figure 22).

**Controlled charging.** CC delivers moderate but meaningful benefits in France. Curtailment drops from approximately 10 TWh to 8 TWh (−3 TWh), hydrogen-turbine generation decreases slightly, and gas generation falls marginally. Hydrogen-turbine capacity declines modestly from 11 GW to 10 GW (−1 GW). PV generation decreases by approximately 1 TWh, and net exports increase by about 4 TWh. Renewable capacities remain virtually unchanged. CC in France thus primarily improves intra-day scheduling and reduces the waste of wind and solar energy, without triggering structural investment changes.

**Bidirectional charging (V2X).** V2X drives a fundamental shift in France's generation portfolio. Car-to-grid feed-in reaches approximately 34 TWh in 2040. This additional flexibility enables a dramatic expansion of solar PV: generation rises from roughly 170 TWh to 220 TWh (+50 TWh), and installed PV capacity increases from 140 GW to 185 GW (+45 GW). Simultaneously, CSP is nearly eliminated: its output falls from 8 TWh to approximately zero, and its installed capacity from 2 GW to essentially zero. Hydrogen-turbine capacity drops from 11 GW to effectively zero, representing a complete elimination of dedicated hydrogen peaking plants. Hydrogen-turbine generation correspondingly falls from about 1 TWh to approximately zero. Nuclear generation decreases modestly (−3 TWh), reflecting minor dispatch adjustments in response to the larger PV fleet. France becomes a significantly larger net exporter, with exports rising from approximately 56 TWh to 86 TWh (+30 TWh). Curtailment increases slightly (from 10 TWh to 11 TWh), indicating that the much larger PV fleet generates marginally more surplus than the V2X-enabled system can absorb – though the increase is modest relative to the 45 GW of additional PV capacity.

**Worst-case EV diffusion.** Under the Worst-case scenario, annual V2G feed-in reaches approximately 22 TWh. Hydrogen-turbine capacity is reduced from 10 GW to about 4 GW rather than eliminated entirely, and PV capacity increases by approximately 30 GW (compared with 45 GW in the Baseline). The qualitative pattern is preserved – solar expansion at the expense of CSP and hydrogen peakers – but the effects are attenuated.

Figure 23 displays the cost difference between the Worstcase and Baseline V2X scenarios for France. Additional car-fuel spending under slower electrification exceeds the power-system savings in both target years, resulting in a net cost increase of about €0.2 billion per year in 2030 and approximately €4.2 billion per year by 2040.

**Country-specific observations.** France is unique among the six countries in several respects. First, stationary batteries play no role in any scenario (Reference, CC or V2X), because the combination of nuclear baseload, extensive hydro and pumped storage, and moderate curtailment levels obviates the need for short-duration battery cycling. Second, V2X in France acts primarily as a catalyst for solar expansion rather than as a substitute for existing storage: the 45 GW of additional PV is enabled by the intra-day shifting capability of vehicle batteries, which absorb midday solar peaks and discharge in the evening. Third, the elimination of hydrogen-turbine capacity under V2X is complete in the Baseline – a more radical outcome than in any other country studied, reflecting the fact that France's nuclear-hydro backbone provides sufficient long-duration back-up when complemented by vehicle-based short-term flexibility.

**Implications.** The results suggest that France could exploit V2X to expand PV capacity very substantially while reducing or eliminating hydrogen-based peaking capacity.

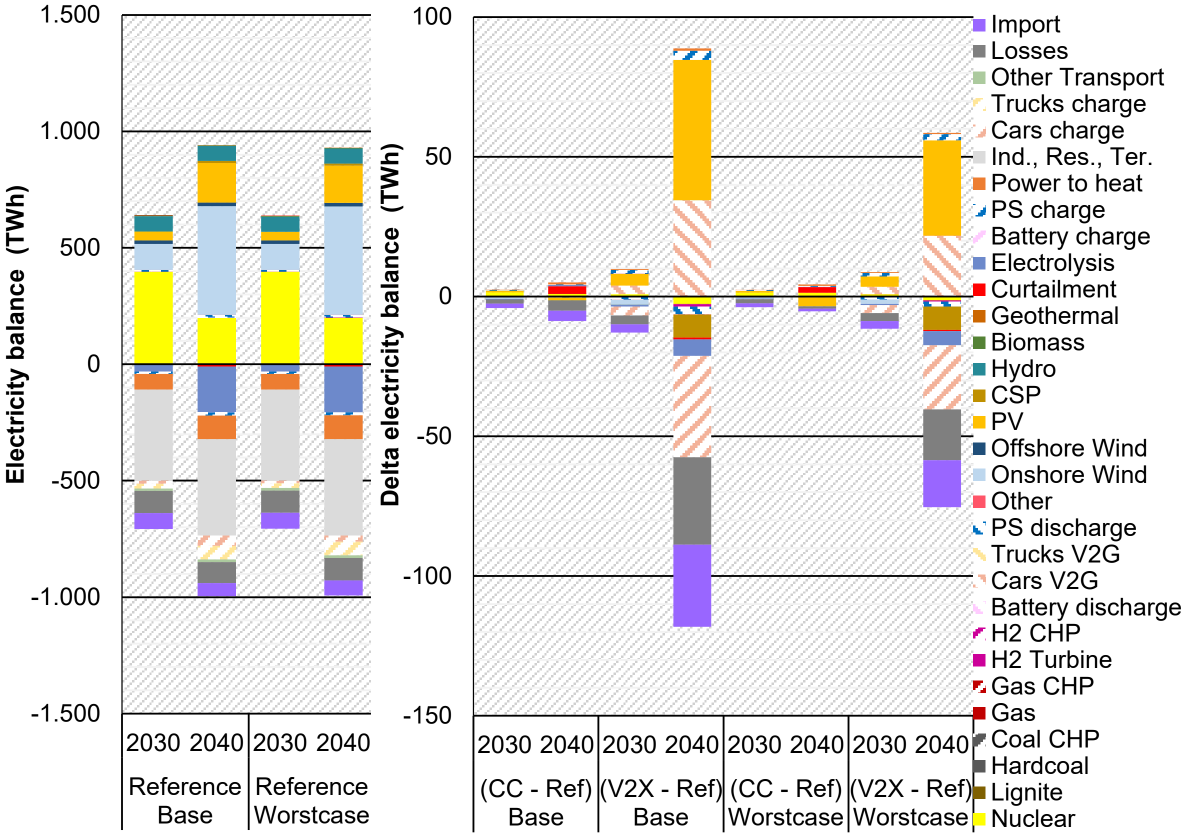


**Figure 21:** **Electricity balances and changes in the scenario variants for France.**

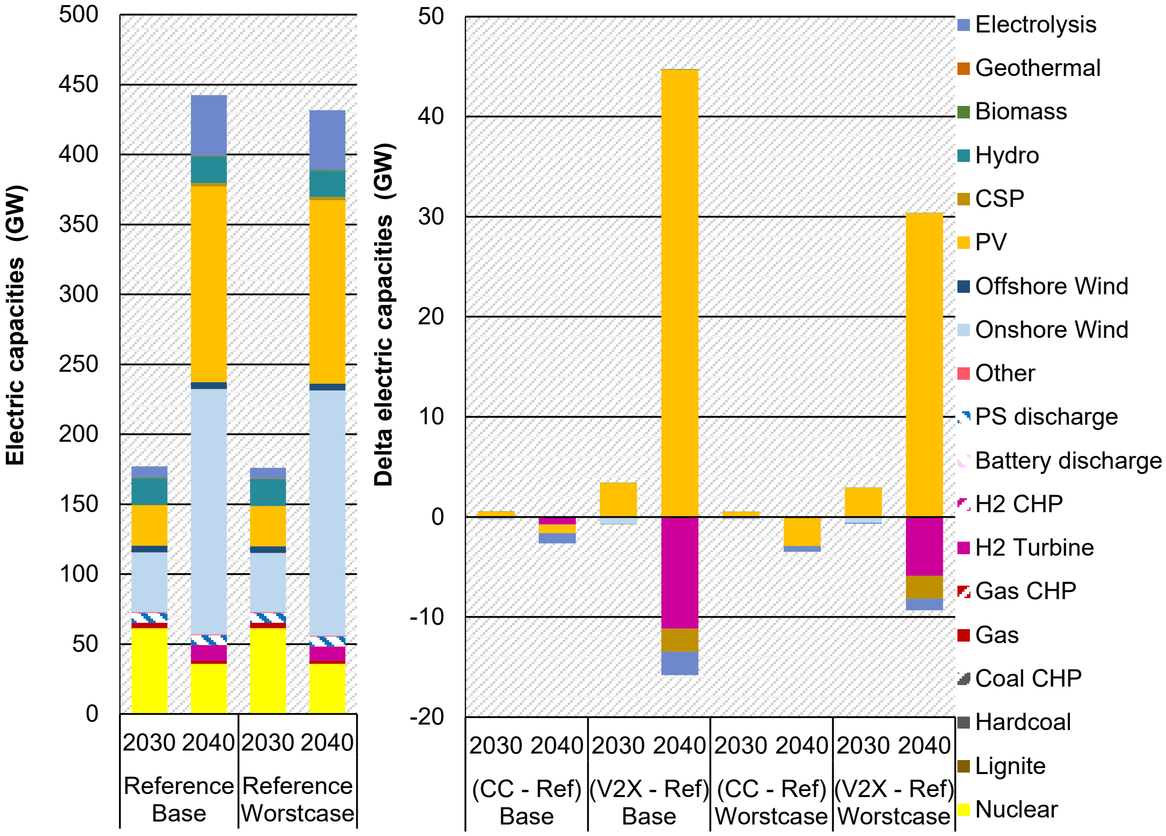


**Figure 22:** **Electric capacities and changes in the scenario variants for France.**

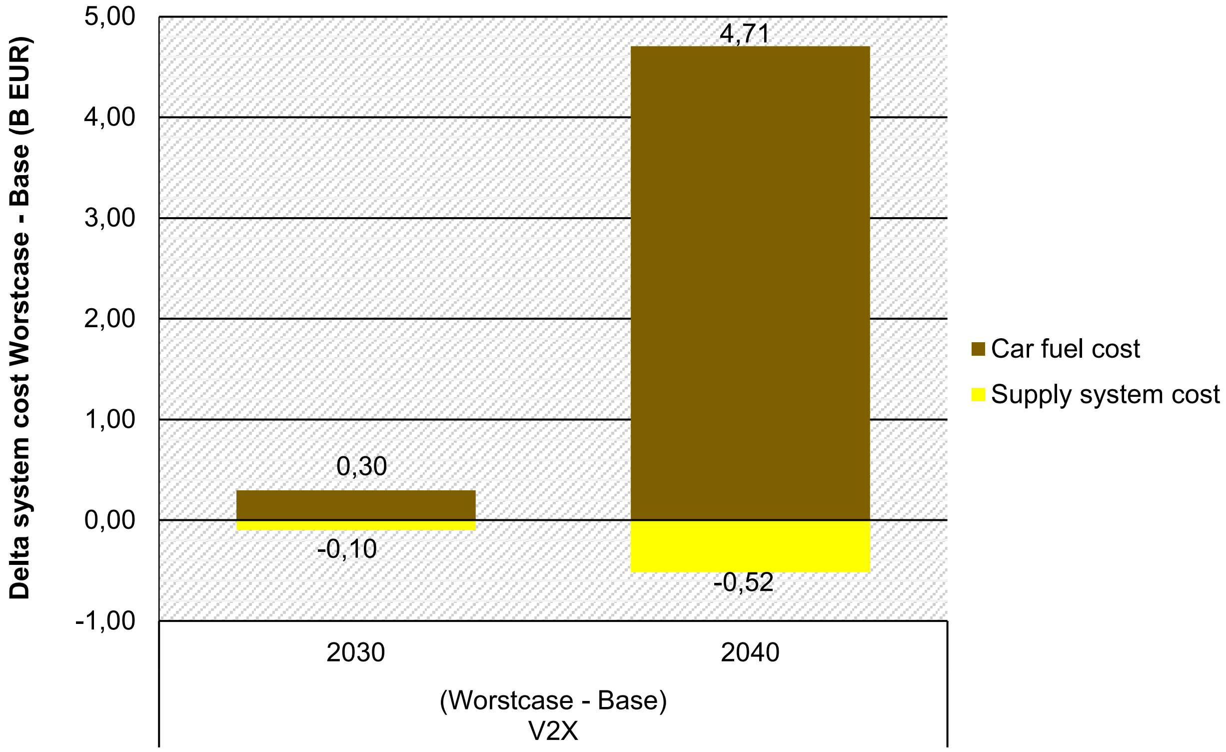


**Figure 23:** **Differences in system cost in the scenario variants for France.**

## 5.3 Italy

Italy's 2040 Reference Baseline is solar-intensive. Photovoltaics generate approximately 237 TWh from 188 GW of installed capacity, CSP adds about 18 TWh from 4 GW, onshore wind contributes roughly 97 TWh from 42 GW, offshore wind provides 2 TWh from 1 GW, and hydro produces approximately 49 TWh from 15 GW. Gas plants generate about 22 TWh from 28 GW, reflecting residual thermal back-up needs. A distinctive feature of Italy's system is the extraordinarily large role of stationary batteries: they discharge approximately 45 TWh per year from about 72 GW of installed power. By contrast, hydrogen power plants play essentially no role in any Italian scenario. Pumped-hydro storage provides about 14 TWh from 7 GW. Curtailment stands at roughly 11 TWh. Italy is a net importer of about 22 TWh per year. Passenger-car charging requires approximately 32 TWh (15 TWh in the Worst-case) (Figure 24 and Figure 25).

**Controlled charging.** CC delivers substantial benefits in Italy, principally by reducing stationary battery cycling and curtailment. Battery discharge falls by approximately 13 TWh (from 45 TWh to 32 TWh, −28 %), and stationary battery power capacity decreases from roughly 72 GW to 51 GW (−21 GW, −29 %). Gas generation declines by about 1 TWh (−5 %), and curtailment drops sharply from 11 TWh to 6 TWh (−5 TWh, −47 %). Net imports increase by approximately 6 TWh, suggesting that CC allows Italy to draw more power from interconnected markets during favourable hours. Notably, PV generation *decreases* by about 11 TWh and installed PV capacity falls by approximately 9 GW. This counterintuitive result arises because, in the Reference scenario, a substantial portion of PV capacity exists specifically to charge stationary batteries during midday hours; once CC reduces the need for this PV-to-battery chain, some PV becomes uneconomic and is no longer deployed by the model.

**Bidirectional charging (V2X).** V2X effectively eliminates stationary batteries from the Italian power system. Car-to-grid feed-in reaches about 30 TWh. Stationary battery discharge drops to a negligible level, and battery power capacity contracts from 72 GW to essentially zero. Gas generation falls by approximately 1 TWh. Curtailment decreases only slightly relative to the Reference, because the system no longer relies on the PV-plus-battery combination that drove high curtailment in the Reference. Net imports increase substantially, rising from 22 TWh to 31 TWh (+9 TWh), as Italy integrates more closely with neighbouring markets. PV capacity decreases by approximately 9 GW – a result that, like the CC case, reflects the elimination of the PV-to-battery pathway rather than a reduction in solar competitiveness per se.

**Worst-case EV diffusion.** Under the Worst-case scenario, V2X car-to-grid feed-in reaches approximately 15 TWh from 14 GW of discharge capability. Stationary battery power is again reduced to essentially zero (from 50 GW in the Worstcase Reference). PV capacity decreases by about 12 GW, and net imports rise by approximately 13 TWh. The qualitative conclusions are robust across both diffusion pathways.

As shown in Figure 26, slower EV diffusion in Italy reduces power-system costs but raises car-fuel expenditure by a considerably larger margin. The net cost of delayed electrification is roughly €0.1 billion per year in 2030 and approximately €4.3 billion per year by 2040.

**Country-specific observations.** Italy differs from all other countries examined in three fundamental respects. First, hydrogen turbines play no role in any scenario – neither the Reference nor the managed-charging variants deploy any meaningful hydrogen peaking capacity. Italy's adequacy challenge is met entirely by gas plants, stationary batteries and imports. Second, PV capacity *falls* rather than rises with V2X, in stark contrast to Germany (neutral), France (+45 GW) and Spain (+30 GW). This reflects Italy's unique system architecture, in which the primary role of PV in the Reference is to feed stationary batteries rather than serve load directly; once V2X makes these batteries redundant, the associated PV capacity is no longer needed. Third, imports increase substantially under V2X (by up to 13 TWh in the worst-case), indicating that the optimised system relies on cross-border trade to a greater extent when domestic battery flexibility is replaced by vehicle-based flexibility plus interconnection.

**Implications.** The results indicate that Italy could operate its PV-dominated system without a dedicated stationary battery fleet if V2X is widely deployed. The scale of avoided stationary battery investment is striking: approximately 72 GW of battery power and the associated energy capacity are eliminated in the Baseline scenario. However, the increasing reliance on imports under V2X underscores the importance of adequate cross-border interconnection capacity. Italy's system-value proposition for V2X is thus twofold: avoiding very large stationary battery investments while leveraging deeper market integration with neighbouring countries.

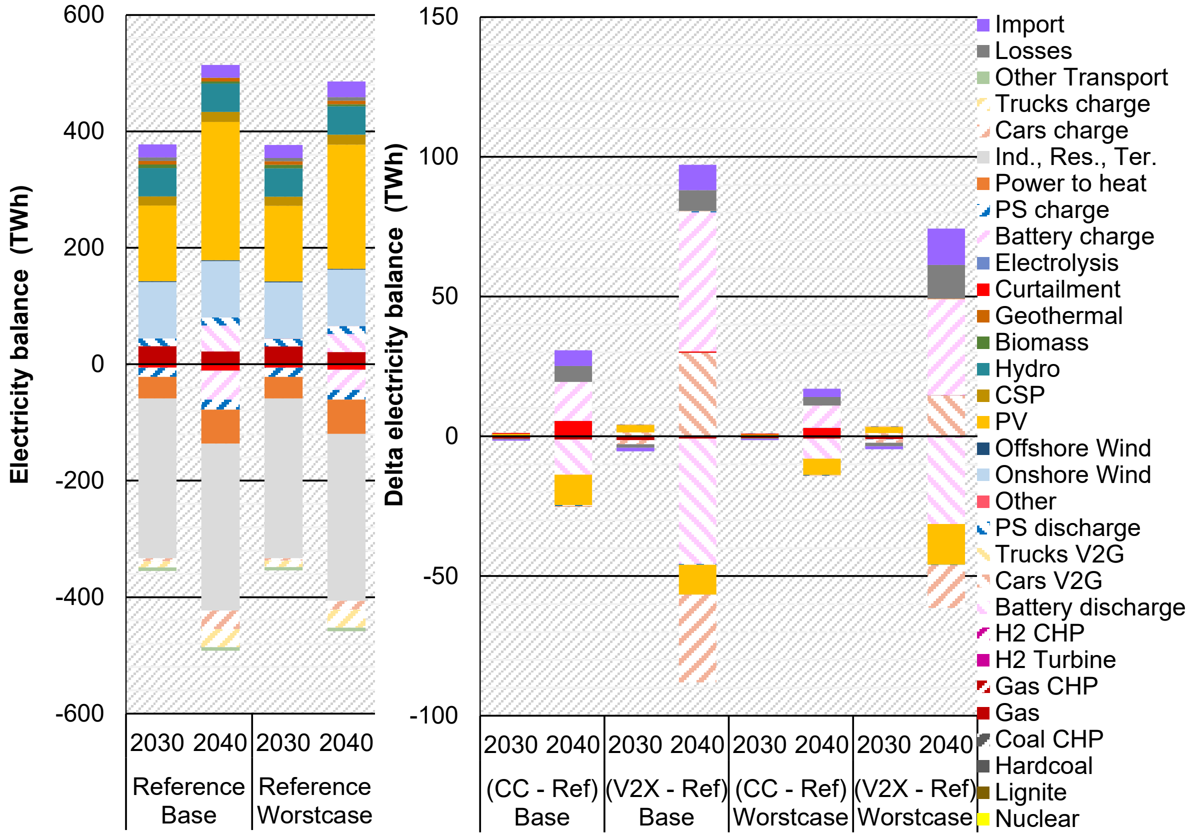


**Figure 24:** Electricity balances and changes in the scenario variants for Italy.

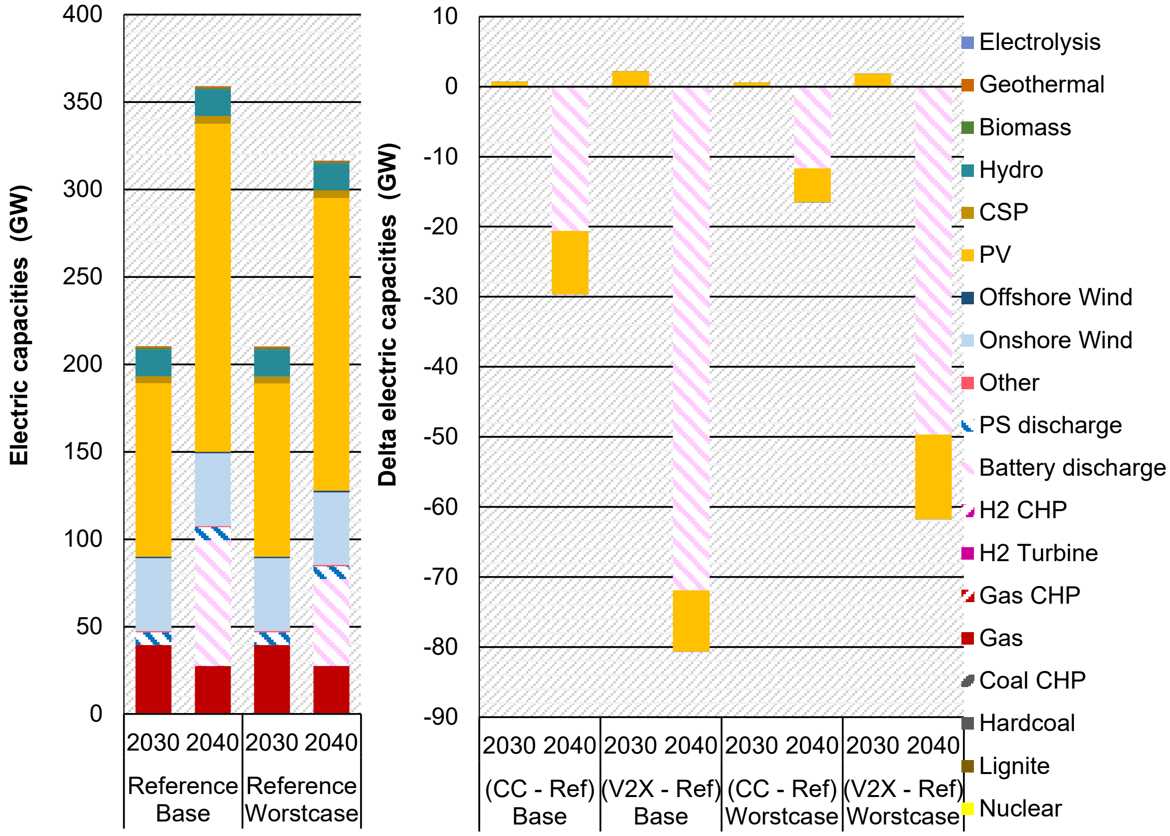


**Figure 25:** Electric capacities and changes in the scenario variants for Italy.

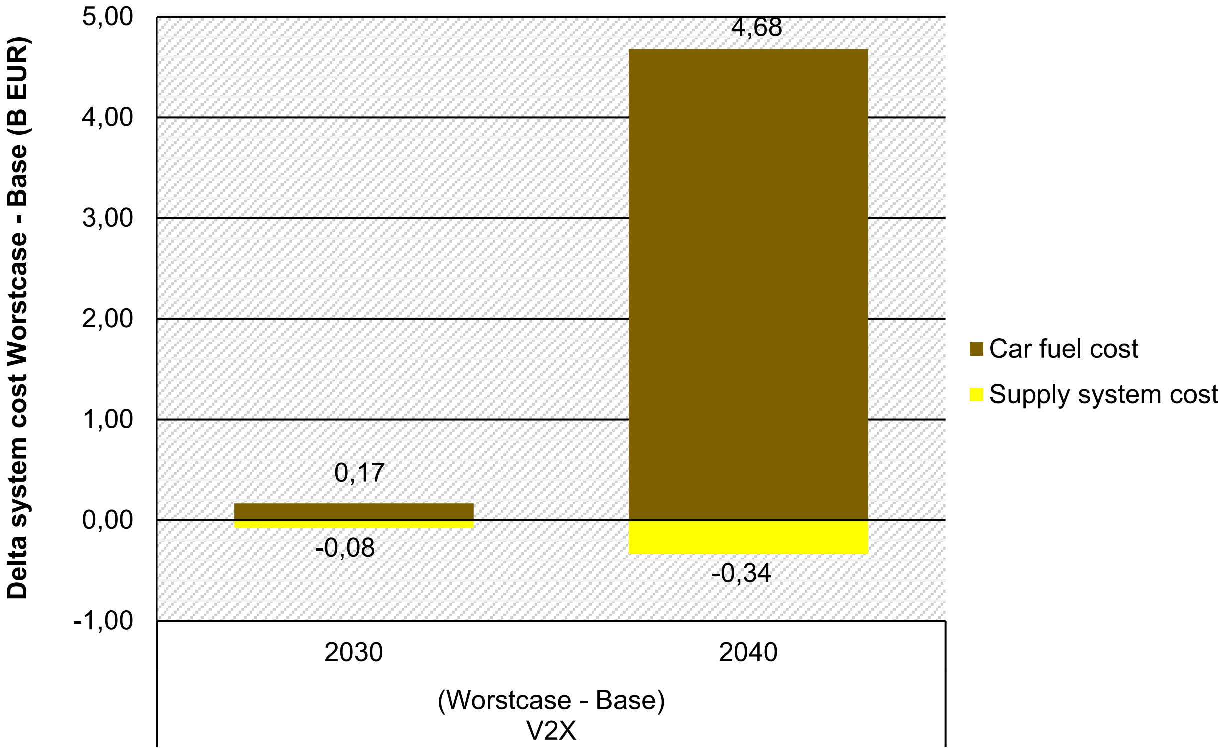


**Figure 26:** **Differences in system cost in the scenario variants for Italy.**

## 5.4 Spain

Spain's 2040 Reference Baseline exploits the country's exceptional solar resources through a distinctive portfolio dominated by concentrated solar power. CSP generates approximately 210 TWh from 46 GW of installed capacity – by far the highest CSP deployment in Europe. Photovoltaics contribute about 112 TWh from 77 GW, onshore wind adds roughly 98 TWh from 41 GW, and hydro produces approximately 29 TWh from 17 GW. Gas plants generate only about 2 TWh from 21 GW, and hydrogen turbines as well as stationary batteries are essentially absent. Pumped-hydro storage provides about 10 TWh from 6 GW. Curtailment is moderate at approximately 18 TWh. Spain is a sizeable net electricity exporter (≈ 37 TWh). Passenger-car charging requires approximately 30 TWh per year (15 TWh in the Worst-case). The dominance of CSP is a defining feature of Spain's Reference system: CSP's built-in thermal storage provides intra-day and short-term flexibility that would otherwise have to come from batteries or hydrogen peakers. This makes Spain's system architecture particularly sensitive to the introduction of an alternative short-term flexibility source—the vehicle battery fleet (Figure 27 and Figure 28).

**Controlled charging.** CC shifts EV demand into hours of high solar output and reduces the system's reliance on CSP's thermal storage. CSP generation falls by approximately 18 TWh (−9 %), while onshore-wind generation increases by about 5 TWh and onshore-wind capacity rises by roughly 2 GW. Curtailment drops from 18 TWh to 12 TWh (−7 TWh, −36 %) – one of the largest relative reductions among the six countries studied. CSP capacity decreases by about 4 GW, while PV capacity and generation are essentially unchanged. Gas generation also declines slightly. Net exports decrease by about 4 TWh. These results show that even unidirectional smart charging begins to erode CSP's competitive advantage by providing an alternative mechanism for shifting solar energy across hours—namely, charging EVs during midday rather than storing heat in CSP plants.

**Bidirectional charging (V2X).** V2X fundamentally rebalances Spain's solar portfolio. Car-to-grid feed-in reaches approximately 23 TWh. PV generation rises sharply from 112 TWh to 153 TWh (+40 TWh), and installed PV capacity expands from 77 GW to 107 GW (+30 GW). Conversely, CSP output falls dramatically from 210 TWh to 129 TWh (−80 TWh), and CSP capacity contracts from 46 GW to 28 GW (−18 GW). Onshore-wind generation also increases (+11 TWh) and wind capacity rises by about 5 GW. Curtailment declines from 18 TWh to 11 TWh (−8 TWh). Notably, gas generation *increases* slightly (+1 TWh), suggesting that some residual back-up is redirected to gas plants as CSP's thermal-storage function is reduced. Net exports decline substantially from 37 TWh to 16 TWh (−21 TWh), as the system absorbs more renewable output domestically through vehicle batteries rather than exporting surplus.

The result is a solar portfolio dominated by PV rather than CSP, with vehicle batteries providing the intra-day flexibility that CSP's built-in thermal storage previously offered.

**Worstcase EV diffusion.** Under the Worst-Case scenario, V2X car-to-grid feed-in reaches approximately 12 TWh. PV capacity increases by about 10 GW (compared with 30 GW in the Baseline), while CSP capacity falls by roughly 10 GW (compared with 18 GW). Curtailment is reduced by approximately 6 TWh. The qualitative finding – a shift from CSP to PV enabled by vehicle-based flexibility – is robust, but the magnitude is substantially attenuated with fewer EVs.

Figure 29 illustrates the cost difference between the Worstcase and Baseline V2X scenarios for Spain. Although power-system savings are noticeable, they are far exceeded by higher car-fuel costs, particularly by 2040. The net cost of slower EV uptake is close to cost-neutral in 2030 (approximately €0.04 billion) but rises to roughly €4.0 billion per year by 2040.

**Country-specific observations.** Spain is unique among the six countries in that the main effect of V2X is not the avoidance of stationary batteries (which are absent in all scenarios) or hydrogen peakers (also absent), but rather a substitution between two solar technologies: capital-intensive CSP with thermal storage is partially replaced by lower-cost PV combined with vehicle-battery storage. This makes Spain the country where the *generation-mix* effect of V2X is most pronounced,. Spain is also distinctive in that net exports decline under V2X, whereas in France they increase; this reflects the fact that Spain's V2X-enabled system absorbs more energy domestically (via vehicle charging and discharge) rather than exporting surplus.

**Implications.** V2X enables Spain to shift from capital-intensive CSP to lower-cost PV, with vehicle batteries substituting for CSP's thermal storage function.

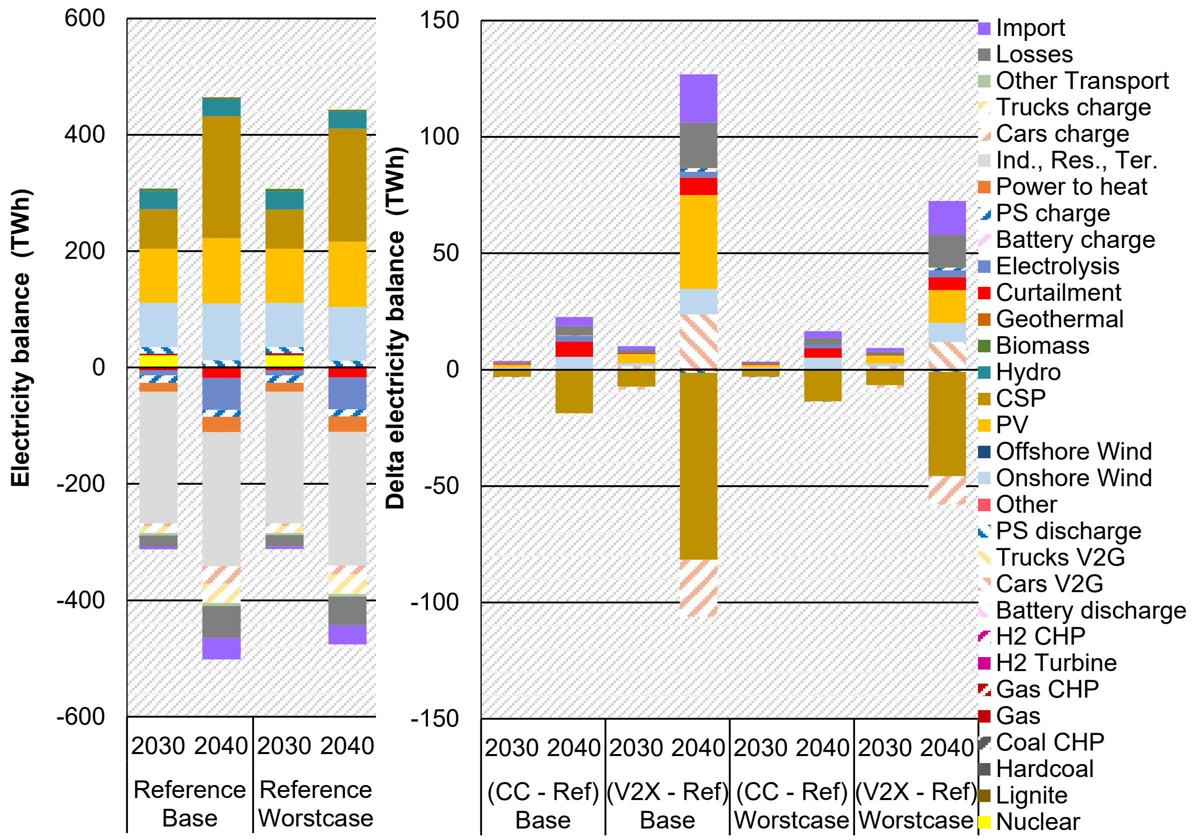


**Figure 27:** Electricity balances and changes in the scenario variants for Spain.

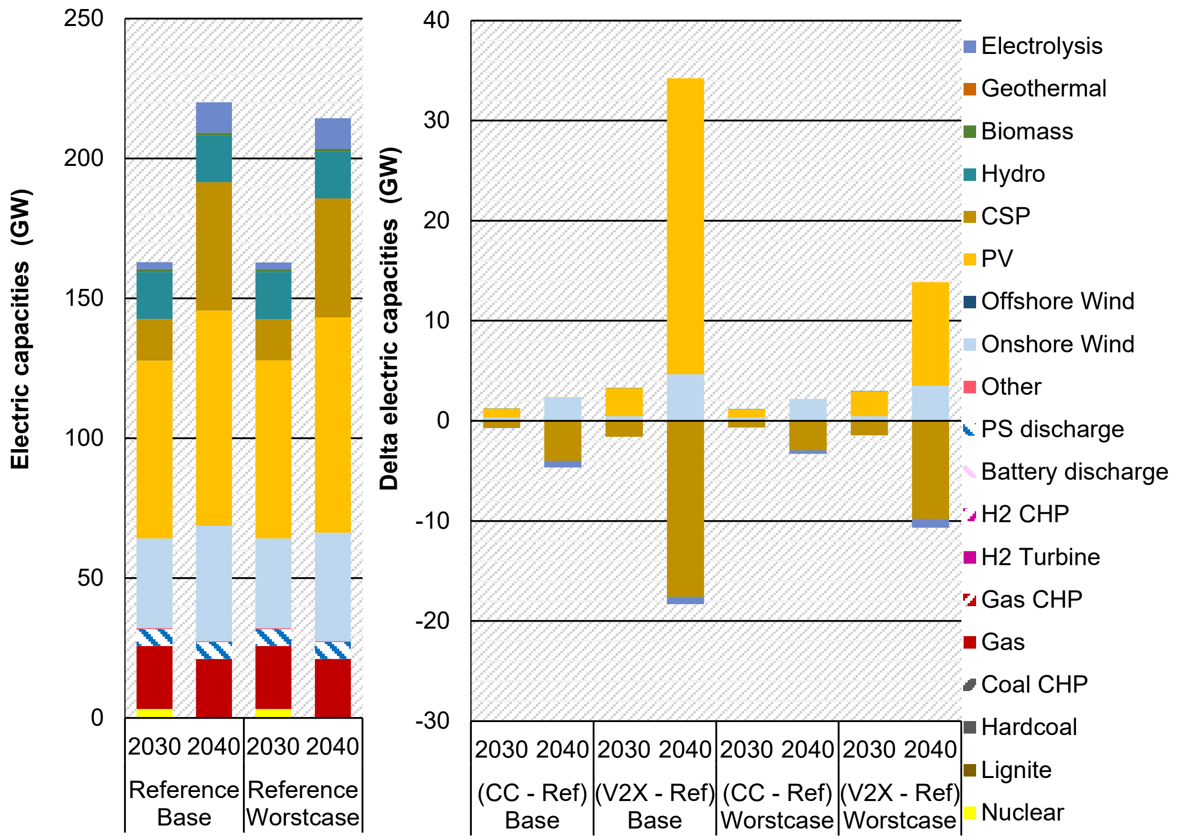


**Figure 28:** Electric capacities and changes in the scenario variants for Spain.

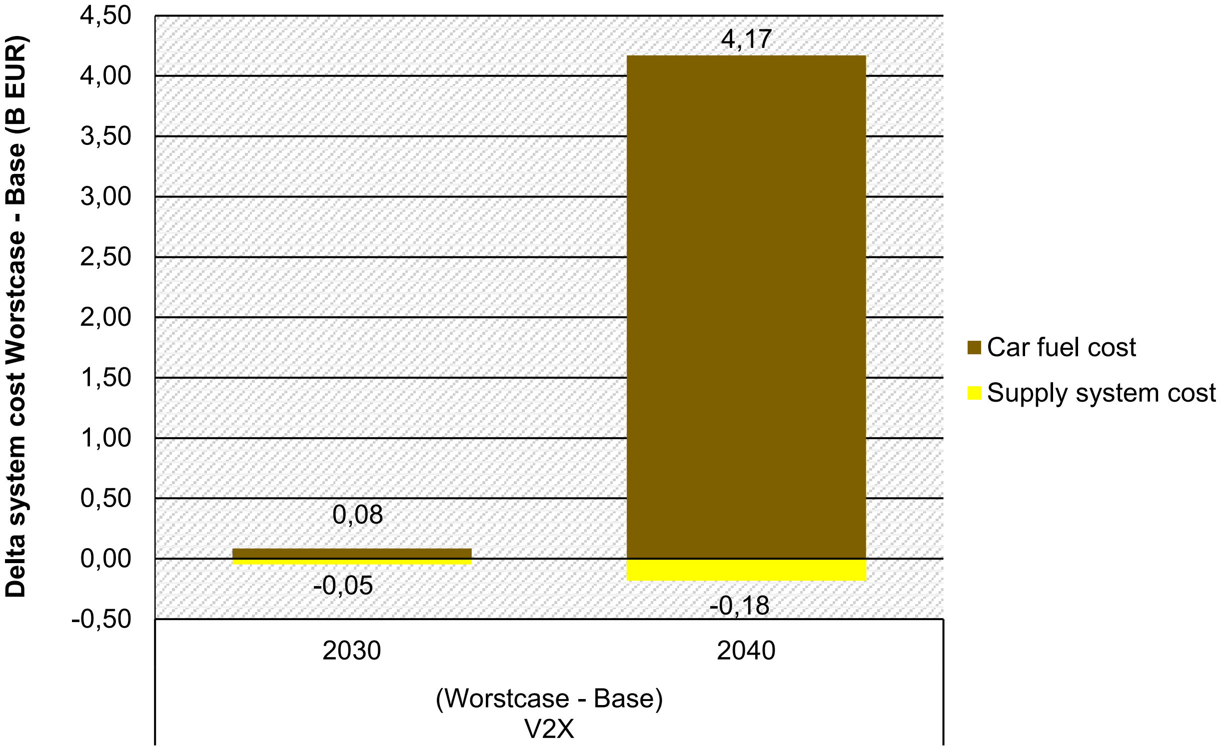


**Figure 29:** **Differences in system cost in the scenario variants for Spain.**

## 5.5 Poland

Poland's 2040 Reference Baseline represents a transitional power system that combines a newly built nuclear fleet with extensive wind and growing solar capacity, while nearly completing the phase-out of coal. Nuclear plants generate approximately 32 TWh from 5 GW, onshore wind produces roughly 184 TWh from 71 GW, offshore wind adds about 14 TWh from 4 GW, and photovoltaics contribute approximately 45 TWh from 46 GW. Residual fossil generation is very small: gas produces less than 1 TWh, and lignite and hard coal together less than 1 TWh, with the associated capacities maintained as reserve. Hydrogen turbines generate approximately 1 TWh. Stationary batteries are essentially absent in all Polish scenarios. Curtailment is modest at approximately 3 TWh. Poland is a substantial net importer, drawing roughly 32 TWh from interconnected markets. The EV fleet is the smallest among the six countries: passenger-car charging requires only about 4 TWh per year (2 TWh in the Worst-case). Electrolysis consumes about 50 TWh, reflecting significant domestic hydrogen production (Figure 30 and Figure 31).

**Controlled charging.** Given the small EV fleet, CC delivers modest but clearly visible benefits. Curtailment is reduced by about 1 TWh (−18 %). Electrolysis consumption declines by approximately 3 TWh (−5 %). Onshore-wind capacity decreases slightly (−2 GW) while PV capacity also falls marginally (−1 GW), suggesting minor reoptimisation of the generation mix. Stationary battery operation, already negligible, is further reduced.

**Bidirectional charging (V2X).** V2X strengthens these effects markedly relative to the fleet size. Car-to-grid feed-in reaches approximately 3 TWh in the Baseline scenario. Hydrogen-turbine capacity drops from 5 GW to 3 GW (−3 GW, −53 %). PV capacity increases by roughly 4 GW (from 46 GW to 50 GW), and PV generation rises by about 4 TWh. Conversely, onshore-wind capacity decreases by approximately 9 GW (from 71 GW to 61 GW), and wind generation falls by about 23 TWh. This represents a notable wind-to-solar shift enabled by vehicle-based flexibility: the ability to store midday solar output in car batteries and discharge it later makes PV relatively more valuable and reduces the system's need for wind capacity. Electrolysis consumption falls substantially by approximately 13 TWh (−27 %), reflecting a reduced need for hydrogen-based energy conversion when vehicle batteries provide short-term flexibility. Net imports increase by about 4 TWh. Curtailment declines by approximately 1 TWh.

**Worstcase EV diffusion.** Under the Worstcase scenario, V2X car-to-grid feed-in reaches approximately 2 TWh. Hydrogen-turbine capacity is reduced from 5 GW to 3 GW (−2 GW). The wind-to-solar shift is still present but attenuated: PV capacity increases by about 5 GW while onshore-wind capacity falls by approximately 5 GW. The effects are proportionally smaller but qualitatively consistent.

Figure 32 presents the cost comparison for Poland. Owing to Poland's comparatively small EV fleet, both power-system savings and additional car-fuel costs under slower diffusion are modest. In 2030 the two effects nearly cancel out, leaving the system roughly cost-neutral. By 2040 a small net cost of about €0.07 billion per year emerges, as car-fuel expenditure begins to marginally exceed power-system savings.

**Country-specific observations.** Poland's results illustrate that even comparatively small EV fleets can deliver meaningful system benefits. First, the wind-to-solar shift under: onshore-wind capacity falls by roughly 9 GW while PV increases by 4 GW, representing a rebalancing of about 13 % of Poland's wind fleet. Second, the reduction in electrolysis consumption (−13 TWh, or 27 %), suggesting that vehicle-based flexibility directly substitutes for hydrogen as a flexibility option. Third, Poland's large import dependency (≈ 32 TWh) persists across all scenarios, confirming the importance of cross-border interconnection for Polish supply security regardless of the charging mode.

**Implications.** Even with the smallest EV fleet among the six countries, Poland can use V2X to reduce back-up power plant requirements by more than half and support a modest but cost-effective shift from wind to solar generation. EV flexibility complements the ongoing investments in nuclear capacity and renewables and may facilitate a smoother transition away from coal.

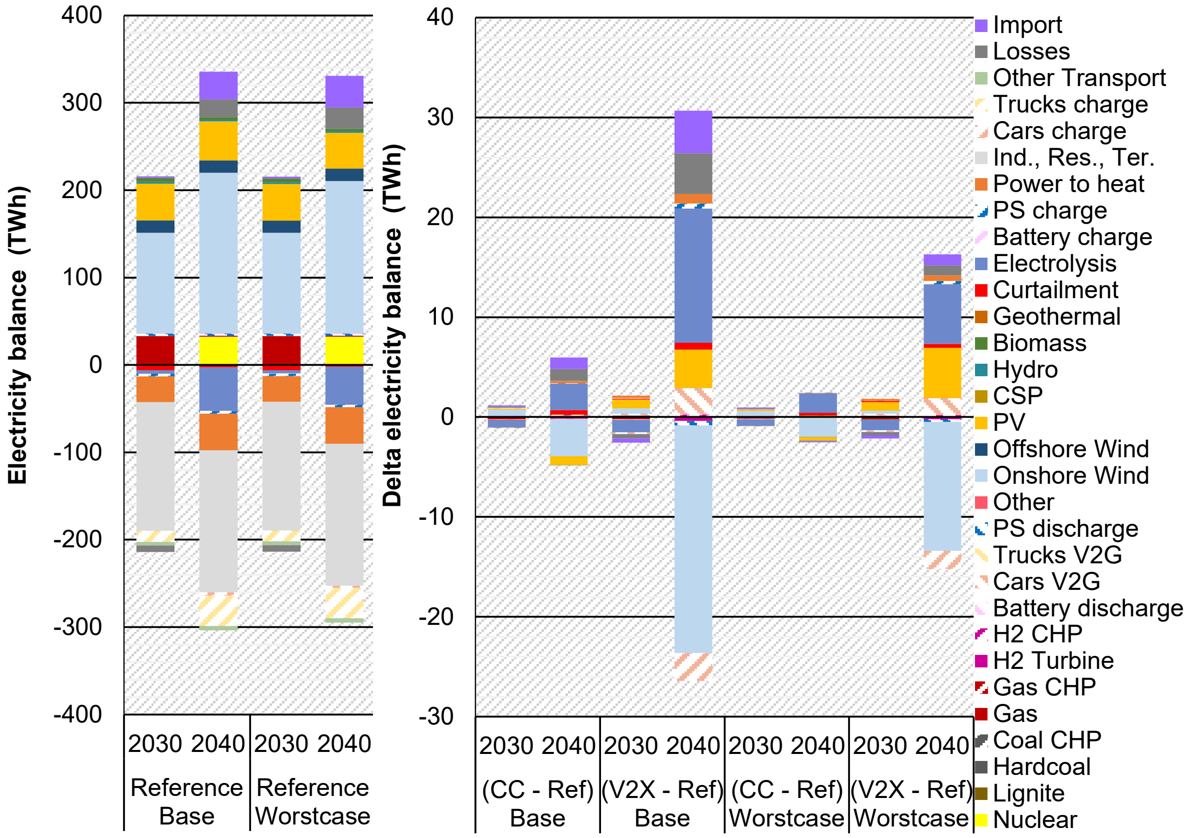


**Figure 30:** **Electricity balances and changes in the scenario variants for Poland.**

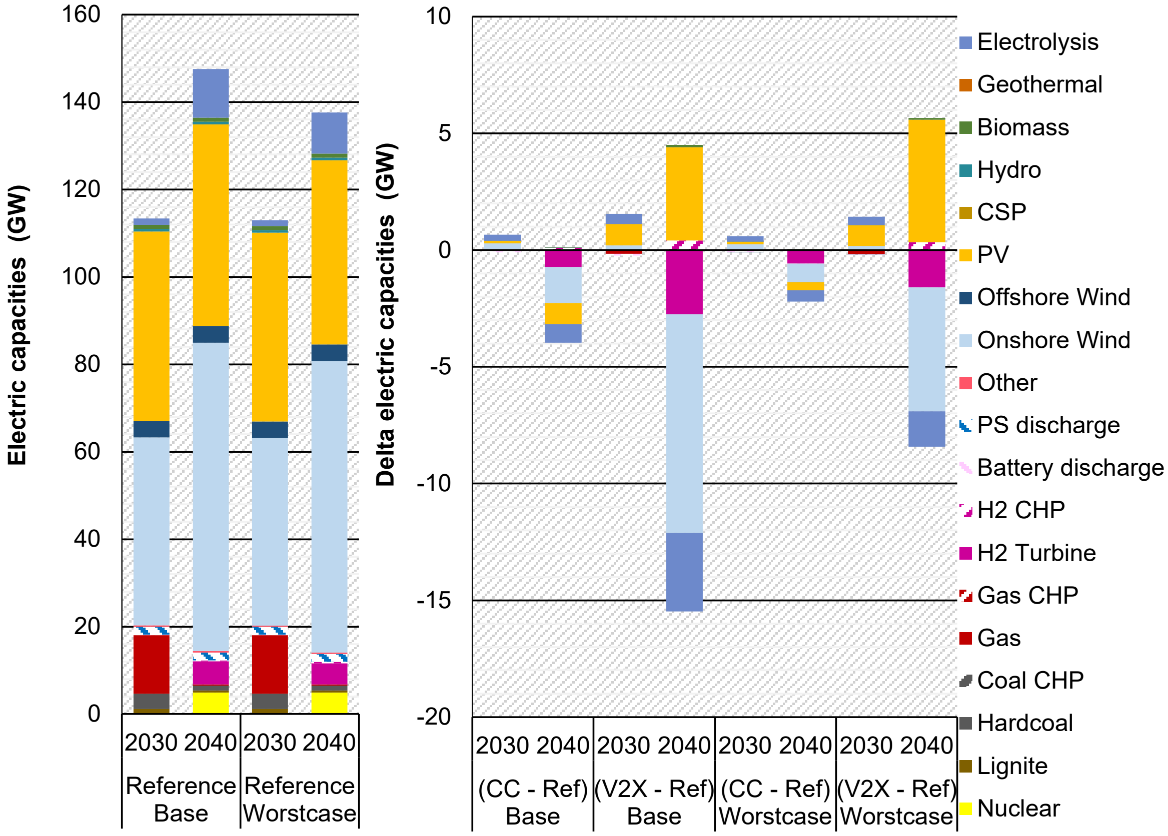


**Figure 31:** **Electric capacities and changes in the scenario variants for Poland.**

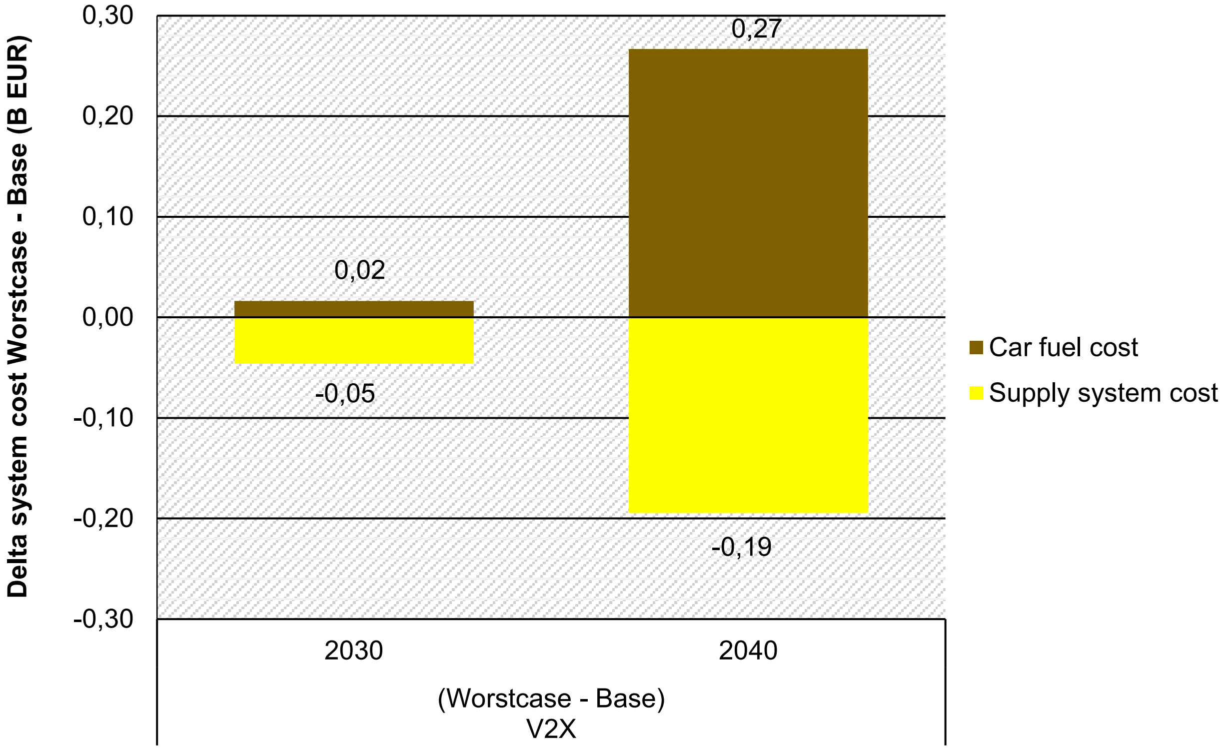


**Figure 32:** **Differences in system cost in the scenario variants for Poland.**

## 5.6 UK

The United Kingdom's 2040 Reference Baseline power system is wind-dominated. Onshore wind generates approximately 371 TWh from 125 GW of installed capacity, and offshore wind contributes roughly 173 TWh from 40 GW – together accounting for about 80 % of total generation. Photovoltaics produce approximately 65 TWh from 67 GW, nuclear power adds about 26 TWh from 4 GW, biomass generates roughly 21 TWh from 4 GW, and hydro provides about 5 TWh from 2 GW. Gas plants generate approximately 4 TWh from 6 GW. Hydrogen turbines are installed with a substantial capacity of 10 GW but produce only about 1 TWh – an implied capacity factor of roughly 1 %, meaning these expensive assets stand idle more than 98 % of the time. Their role is purely one of adequacy insurance for extreme residual-load events. Stationary batteries are essentially absent in all UK scenarios. Pumped-hydro storage provides about 3 TWh from 3 GW. Curtailment is high at approximately 30 TWh, reflecting the system's very high variable-renewable penetration and the limited domestic flexibility options. The UK is a net exporter of about 30 TWh. Passenger-car charging requires approximately 42 TWh (Figure 33 and Figure 34).

**Controlled charging.** CC reduces gas generation by less than 1 TWh, hydrogen-turbine output by less than 1 TWh, and curtailment from roughly 30 TWh to 25 TWh (−5 TWh, −15 %). Hydrogen-turbine capacity declines from 10 GW to approximately 7 GW (−3 GW). PV generation increases slightly, and onshore-wind generation decreases by about 4 TWh, accompanied by a modest decline in wind capacity (−2 GW). Electrolysis consumption falls by approximately 6 TWh, and net exports increase by about 4 TWh. The generation mix and remaining installed capacities are otherwise nearly unchanged, confirming that CC in the UK primarily optimises dispatch and reduces curtailment without structural changes.

**Bidirectional charging (V2X).** V2X largely eliminates fuel-based peaking in the UK. Car-to-grid feed-in reaches approximately 16 TWh. Hydrogen-turbine generation drops from 1 TWh to essentially zero, and hydrogen-turbine capacity falls from 10 GW to approximately zero – a complete elimination of dedicated hydrogen peaking plants. Gas generation declines by less than 1 TWh. Curtailment is reduced from 30 TWh to 23 TWh (−7 TWh, −23 %). PV capacity increases from 67 GW to 81 GW (+14 GW), and PV generation rises by about 13 TWh. Onshore-wind capacity decreases by approximately 12 GW (from 125 GW to 113 GW), and wind generation falls by about 34 TWh. Offshore wind remains essentially stable at 40 GW and approximately 171 TWh. Electrolysis consumption falls substantially by approximately 20 TWh (−11 %), indicating a major reduction in hydrogen-based energy conversion. Net exports decrease by about 2 TWh.

**Country-specific observations.** The UK stands out in several respects. First, the complete elimination of hydrogen-turbine capacity under V2X is achieved despite the system's extreme wind dependence and high curtailment levels. This demonstrates that vehicle batteries, combined with pumped hydro and cross-border trade, can provide sufficient adequacy even in a system prone to extended low-wind periods. Second, the wind-to-solar shift under V2X (−12 GW onshore wind, +14 GW PV) is proportionally significant, suggesting that vehicle-based flexibility makes solar more competitive even in a relatively northern, wind-rich market.

**Implications.** In the UK's wind-dominated system, V2X is a particularly effective tool for managing wind variability and displacing hydrogen peaking plants that would otherwise operate at extremely low capacity factors (< 2 %). The results suggest that investment in V2X-ready charging infrastructure and appropriate market mechanisms rewarding bidirectional flexibility could yield substantial cost savings relative to building 10 GW of hydrogen peaker fleets.

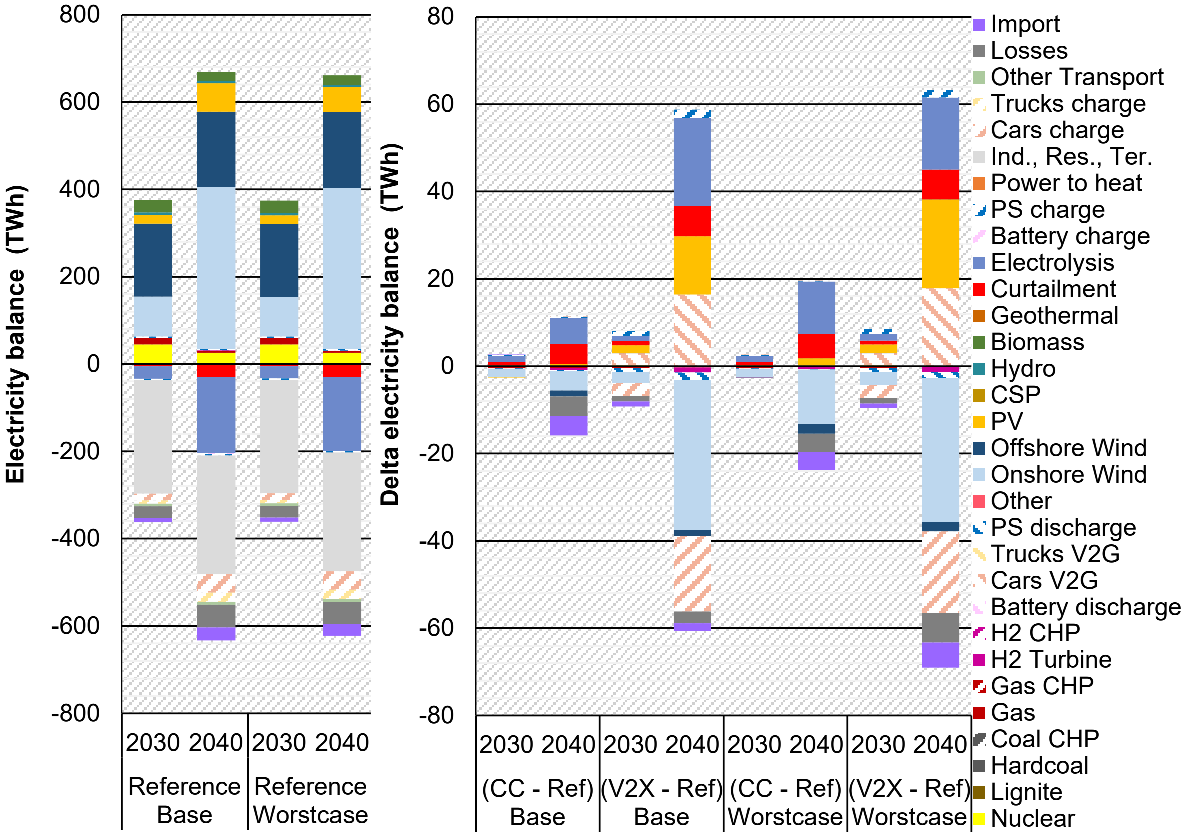


**Figure 33:** Electricity balances and changes in the scenario variants for the UK.

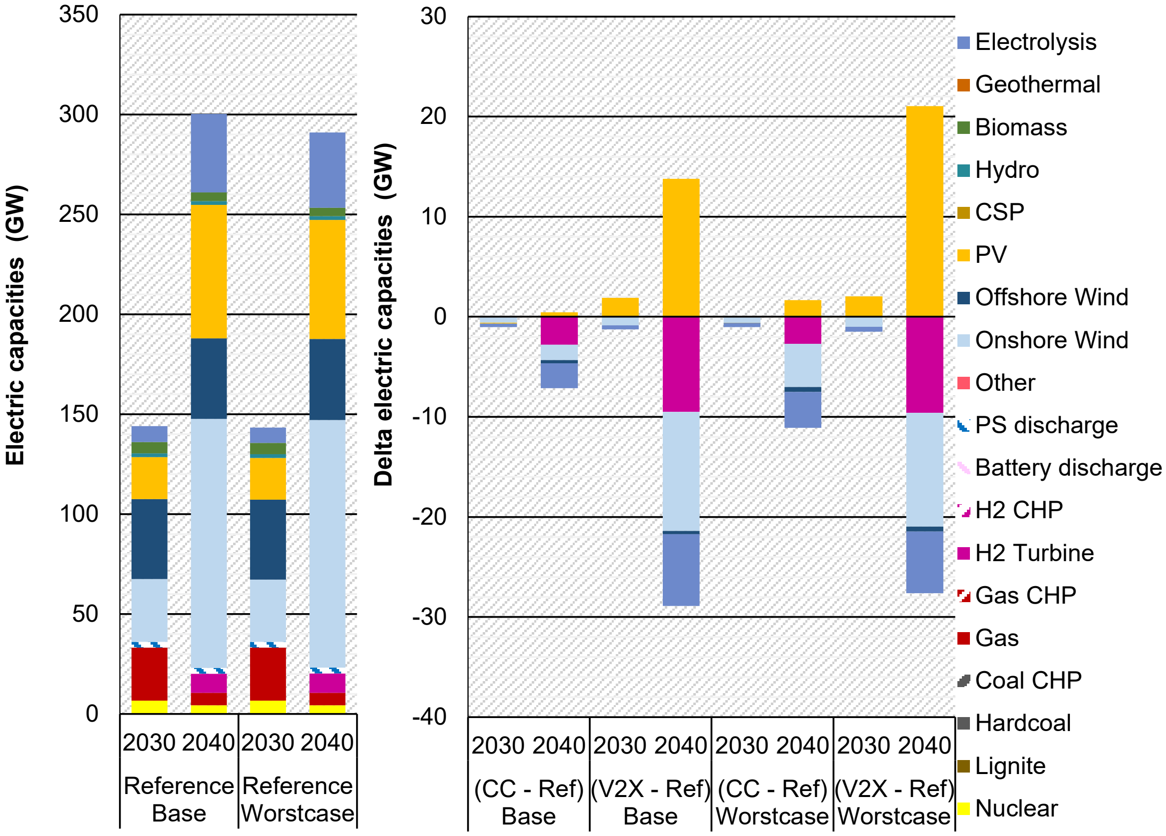


**Figure 34:** Electric capacities and changes in the scenario variants for the UK.

Conclusion:
The country-level analysis confirms that EV flexibility is beneficial across very different power system archetypes, but the **nature of the benefit varies**:

- In **Germany**, a largely renewable system uses EV flexibility mainly to replace stationary batteries and hydrogen turbines. Smart charging and especially V2X greatly reduce the need for these assets.
- In **France**, where nuclear remains strong, EV flexibility is used to support an expansion of solar PV. V2X allows the near elimination of hydrogen peakers and stationary batteries and enables a shift from CSP and marginal wind additions towards cheaper PV, while nuclear and hydro continue to provide firm capacity.
- In **Spain and Italy**, with excellent solar resources, EV flexibility underpins a strongly PV-oriented pathway. Smart charging already cuts storage needs and curtailment; V2X enables a pronounced shift from CSP to PV in Spain and stabilises a PV-heavy system in Italy with limited gas backup.
- In **Poland**, EV flexibility reduces the need for back-up power plants and stationary batteries and allows a modest rebalancing towards more solar, even though effects are smaller in absolute terms due to lower EV numbers.
- In the **United Kingdom**, a wind-dominated system, EV flexibility is particularly valuable for balancing wind variability. Smart charging reduces gas and hydrogen-turbine dispatch and curtailment; V2X almost completely replaces hydrogen peakers and supports additional PV deployment.

Across all six countries, a consistent pattern emerges: **controlled charging delivers a first tranche of system benefits** by reducing curtailment and the need for stationary storage, while **V2X provides a second, larger tranche** by allowing vehicle batteries to substitute hydrogen turbines and central batteries on a large scale. Countries with larger EV fleets (Germany, France, UK) obtain particularly large reductions in backup and storage capacities, while solar-rich countries (Italy, Spain) primarily use V2X to support a more PV-heavy expansion. These results confirm that maintaining high EV uptake and enabling smart/V2X charging is a robust, low-cost strategy for the EU across a wide range of national system configurations.

# 6 Grid impacts update

The main benefits of V2G can be realised at the system level, particularly for integrating PV generation and reducing the need for back-up capacity from hydrogen- and gas-driven power plants (see Chapter 4). Additional impacts on power grids have been shown in the initial study, but with a higher diffusion of EVs until 2030 and 2040.

This section examines V2G impacts from the perspective of electricity grids with a slower uptake of EVs. The preceding study conducted a detailed grid analysis, including: an overview of current European network codes regarding electric vehicles and V2G; analyses of the effects of various EV and V2G operational management strategies on low-voltage grids and necessary grid expansion; and—of particular importance—the question of what grid extension costs occur and whether V2G can reduce these costs through grid-friendly charging behaviour.

Up to 2030, the grid reinforcement costs for all three investigated cases—uncontrolled, economically optimised, and grid-friendly—were approximately equal. However, up to 2040, cost savings of €9.7 billion through grid-friendly EV operation appear possible for EU-27. Along with these financial savings come reductions in material consumption (PVC, aluminium, and steel) as well as potentially reduced PV curtailment. Reduced PV curtailment is possible as bidirectional charging EV may discharge their batteries to store expected overproduction of PV plants.

The goal of the current study is to update these cost savings estimates by accounting for reduced EV penetration rates. The results of the former study were interpolated based on the reduced EV penetration assumptions for 2040, as discussed above. This study investigates a base-case and a worst-case for future EV penetration. In the base-case, the cost saving potential for grid reinforcement totals €8.3 billion for the EU-27. In the worst-case scenario, this is reduced to €4.8 billion—meaning that under worst-case EV uptake conditions, grid reinforcement costs would be €3.5 billion higher than in the currently expected base-case.

Figure 35 depicts low-voltage grid expenditures resulting from reduced EV penetration, comparing the base-case to the worst-case. Beyond direct costs, the analysis accounts for PV generation curtailment and materials required for transformers and cables, including PVC, aluminium, and steel. The countries analysed are France, Germany, Italy, Poland, Spain, and the UK.

**France:** Lower bidirectional charging EV penetration leads to increased PV curtailment of 1 GWh per year in rural areas. Cable reinforcement requires an additional 1.4 kt of PVC, 10 kt of aluminium, and 4.2 kt of steel, resulting in €516 million in additional expenses.

**Germany:** Worst-case EV development implies additional annual PV curtailment of 1.4 GWh. Increased cable reinforcement necessitates 2.3 kt of PVC, 5.8 kt of aluminium, and 9 kt of steel, with associated additional costs of €624 million.

**Italy:** With its high share of people living in intermediately populated areas, Italy faces PV curtailment increases of 1 GWh annually. Approximately 2 kt of PVC, 4 kt of aluminium, and 5 kt of steel are required additionally, corresponding to a cost increase of €432 million.

**Poland:** With a high proportion of inhabitants living in thinly populated areas, Poland must contend with 0.9 GWh of additional PV curtailment. Material requirements increase by 1 kt of PVC, 3 kt of aluminium, and 6.1 kt of steel, translating to €337 million in additional expenses.

**Spain:** With its population primarily concentrated in densely populated areas, Spain faces additional PV curtailment of 0.7 GWh per year. An additional 1 kt of PVC, 2 kt of aluminium, and 3.2 kt of steel are needed, resulting in €254 million in additional grid-related costs.

**United Kingdom:** With a population even more concentrated in densely populated areas than Spain, the UK experiences additional annual PV curtailment of 0.8 GWh. To compensate for reduced grid-supporting V2G capabilities through added grid reinforcement, 1.6 kt of PVC, 2.4 kt of aluminium, and 2.7 kt of steel are required, with additional costs totalling €302 million.

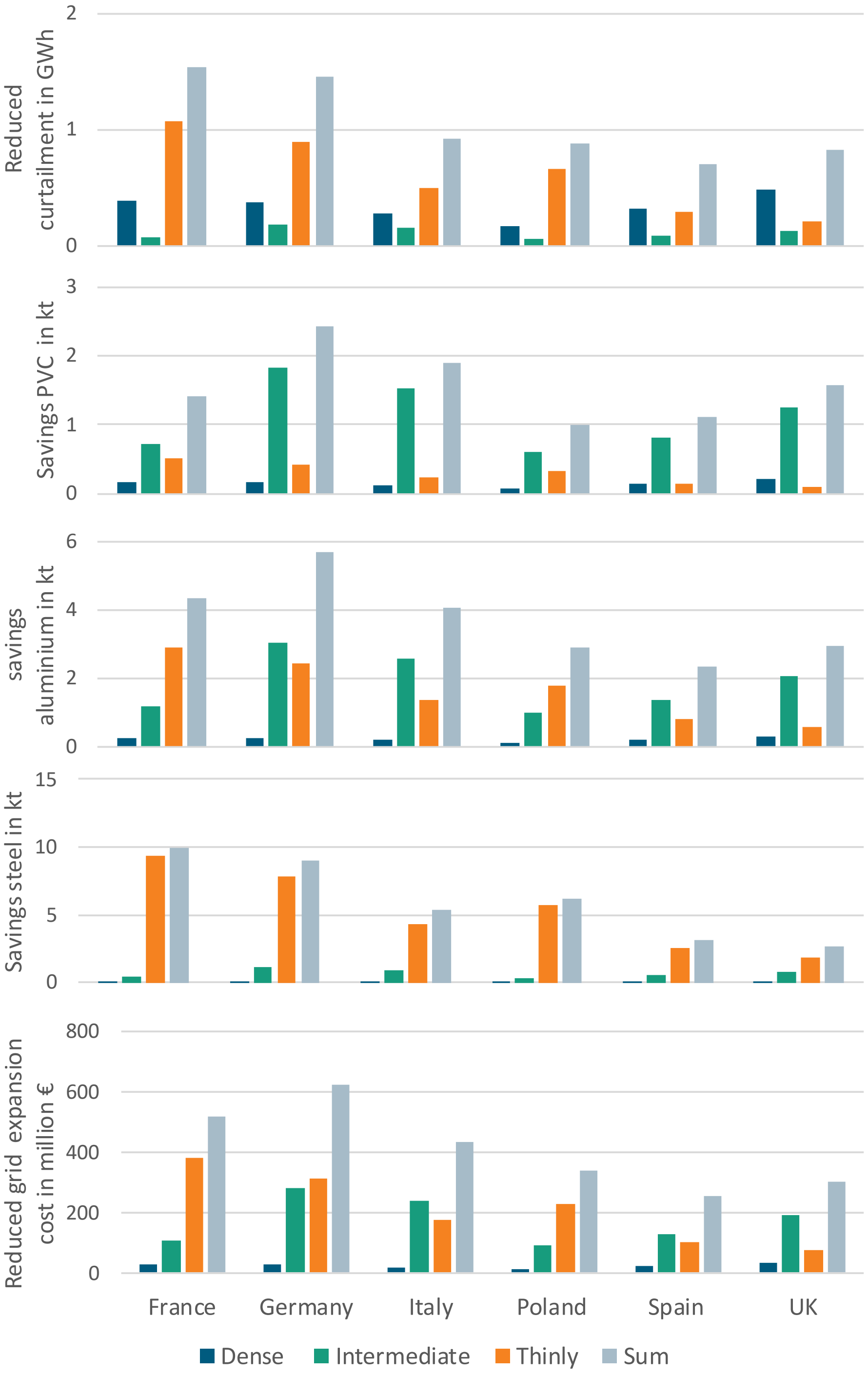


**Figure 35:** **Additional grid related expenditures due to reduced V2G.**

# 7 Conclusions

### Key findings of major benefits for the European Power System (2030 – 2040)

The study shows that electric vehicles can become a central flexibility resource for Europe's future power system if smart charging and especially bidirectional charging are widely enabled. As wind and solar generation expand rapidly towards 2030 and 2040, the European power system increasingly faces short-term flexibility challenges, including rising curtailment and growing reliance on gas and hydrogen-fired backup plants. How electric vehicles are charged determines whether they aggravate these challenges or help solve them. Founded on a base scenario and a worst-case scenario related to the diffusion of EVs, system costs are analysed and show that benefits are strongly linked to the available EV numbers.

Even without feeding electricity back to the grid, **controlled (smart) charging** already delivers meaningful system benefits in the base scenario. By shifting charging to hours with high renewable output, smart charging reduces renewable curtailment, lowers the operation of gas and hydrogen turbines, and significantly cuts the need for stationary battery storage. These effects become much stronger by 2040, when renewable shares are higher and flexibility needs are larger. Smart charging already delivers sizeable savings by shifting demand to hours with abundant renewable generation. EV batteries provide substantial distributed storage potential of up to 5 TWh and saves up to €4.6 billion per year across Europe by 2040. Smart charging therefore optimises the operation of a renewables-dominated system still allowing current mobility patterns. In the worst-case scenario the benefit is reduced to only €3.0 billion per year, if the diffusion of EVs is slower.

**Bidirectional charging (V2X)** goes one decisive step further. Allowing EVs to discharge electricity turns the passenger-car fleet into a large, distributed storage resource. By 2040, vehicle batteries provide hundreds of gigawatts of discharge capacity across Europe. This fundamentally reshapes the power system: most stationary battery capacity becomes unnecessary, hydrogen backup turbines are strongly reduced, and residual peaks can largely be covered by vehicle batteries. By 2040, up to 96 % of stationary battery capacity can be avoided at EU level. EV flexibility also reduces the need for gas and hydrogen peaking plants, cutting backup capacity by up to 39 GW.

At the same time, V2X enables a more solar-heavy and less infrastructure-intensive generation mix. Because EV batteries can absorb midday solar peaks and shift energy to evening and night hours, the system can economically deploy much more photovoltaic capacity while keeping curtailment under control. Across the EU, this leads to substantial additional PV deployment, lower curtailment, and reduced dependence on expensive alternatives such as hydrogen peakers or concentrated solar power. These flexibility effects translate into clear economic benefits of up to €11.7 billion per year in the base scenario. The economic benefit in the worst-case scenario is reduced to only €7.7 billion per year. Each battery electric vehicle provides €150 per year of system value under V2G conditions in 2030, which increases to €240 per year in 2040. The value per vehicle increases over time and stays at a similar level in the base and worst-case scenario. This indicates that also with a larger number of EVs in the power system they still provide a high value for the system in 2040.

### Benefits are robust across European power systems

EV flexibility delivers systemic benefits across wind-rich (UK), solar-rich (Spain, Italy), nuclear-supported (France) and mixed systems (Germany, Poland). V2X consistently reduces peaker requirements, supports PV expansion and lowers operating costs.

The results are robust across different national power-system archetypes. Countries with large EV fleets gain particularly large reductions in stationary storage and backup capacity, solar-rich countries use EV flexibility to support PV-dominated systems, and wind-dominated systems benefit strongly from reduced curtailment and the near elimination of hydrogen peakers. Across all cases, the core conclusion remains the same: controlled charging provides a first tranche of system benefits, while bidirectional charging unlocks a much larger, structural value.

**Delaying electrification increases total system costs**

Overall, the study confirms that maintaining high EV uptake and enabling smart and bidirectional charging is a no-regret strategy for Europe. Delaying electrification or failing to enable V2X directly reduces available system flexibility and leads to higher infrastructure needs and higher total system costs. Delayed electrification reduces the amount of mobile battery capacity available to the power system, leading to higher renewable curtailment, greater reliance on stationary storage and backup plants, and higher overall system costs. When higher fossil fuel use in the transport sector is taken into account, slower electrification clearly increases total system costs by the 2030s and even more so by 2040.

# 8 List of figures

# 9 List of tables

# 10 References

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