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PROJECT

REPORT

Contribution of Electric Vehicle Chargepoints to the Flexibility of the Luxembourgish Energy System and the Absorption of Renewable Energy

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Contents

Abbreviations

AC	Alternating Current
ACEA	European Automobile Manufacturers Association
AFIR	Alternative Fuels Infrastructure Regulation
aFRR	Automatic Frequency Restoration Reserve
BEV	Battery Electric Vehicle
BRP	Balancing Responsible Party
BSP	Balancing Service Provider
DC	Direct Current
DSO	Distribution System Operator
EAFO	European Alternative Fuels Observatory
ENTSO-E	European Network of Transmission System Operators for Electricity
EMSP	eMobility Service Provider
EU	European Union
EV	Electric Vehicle
EVI	Electric Vehicle Infrastructure
EVSE	Electric Vehicle Supply Equipment
FCR	Frequency Containment Reserve
HGV	Heavy Goods Vehicles
ILR	Institut Luxembourgeois de Régulation
kW	Kilowatt
kWh	Kilowatt-hours
LFC	Load Frequency Control
mFRR	Manual Frequency Restoration Reserve
MHDVs	Medium and Heavy Duty Vehicles
MoU	Memorandum of Understanding
MW	Megawatt
NECP	National Energy and Climate Plan
PHEV	Plug-in Hybrid Electric Vehicle
PINC	Plugged-in Not Charging
PV	Photovoltaic
RFG	Requirements for Generators
RTO	Research and Technology Organisation
SOC	State Of Charge
TRL	Technology Readiness Level
TSO	Transmission System Operator
V2G	Vehicle to Grid

Executive Summary

Introduction

This report has been prepared at the request of Institut Luxembourgeois de Régulation (ILR) in response to obligations under the European Union's (EU) Alternative Fuels Infrastructure Regulation (AFIR) Articles 15(3) and 15(4). Article 15(3) requires EU Member States to assess how the deployment and operation of electric vehicle (EV) chargepoints could enable EVs to contribute more to the flexibility of the energy system, including their participation in the balancing market, and to a better absorption of renewable electricity. Article 15(4) requires the regulator to assess the potential contribution of bidirectional charging to reducing the costs of the electricity system and users and to increasing the share of renewable electricity in the electricity system.

Method

Data was collected from publicly available sources in addition to data provided by ILR and Creos. A perfect foresight optimisation model was used to simulate typical days of electricity demand both nationally and regionally for Luxembourg. This method assumes a perfect knowledge of future events and efficient dispatch of flexibility, so results presented are idealised and should be viewed as an upper bound on what is possible. Winter and summer days of both high and low renewables generation output were selected from historical data to provide a variety of conditions in which EV charging flexibility could operate within. The model was applied to a current scenario in 2023 and a forecast scenario in 2030. EV uptake rates, EV plug-in behaviour, and renewable generation capacities were varied within the forecast scenario. EV plug-in profiles for cars, vans and heavy goods vehicles (HGVs) were created, with plug-in events at home, workplace, destination, or high powered (e.g. en route) locations. The electricity demand profile for 2030 was forecast using a combination of historical demand shapes and the Creos scenario report. Electricity prices for 2030 were forecast with a 9 EUR/MWh reduction from 2023 in line with the results of a literature review on price forecasts.

Key insights

In 2030 the connected charging power (for the incentivised plug-in scenario) peaks at around 1.700 MW. A maximum discharge power of around 370 MW is also available. Figure 1 shows the corresponding average charging power and discharging power of all connected vehicles in each hour of the day. This metric is based on the rated charger power for each vehicle and does not account for the State of Charge (SOC) present in each vehicle battery at the time of connection.

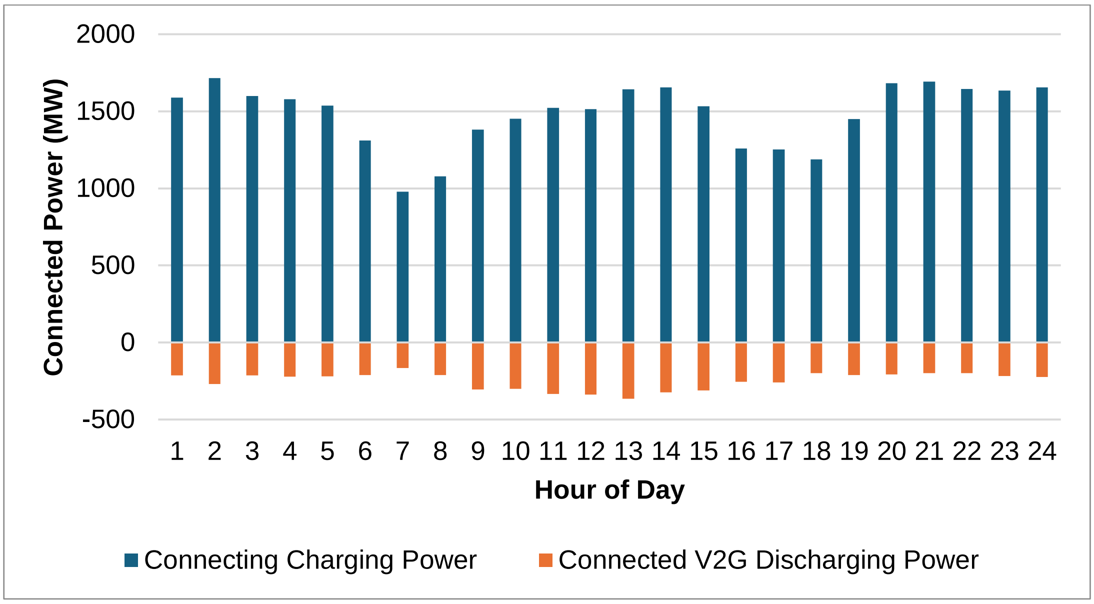


Figure 1: Sum of Charger Power of all Connected Vehicles per Hour of the Day, 2030 Incentivised Weekday Profile

In 2023 based on the current number of EVs and current plug-in behaviours, up to 88 MW of EV charging demand could be shifted from the times of day with the highest EV charging demand to other times of the day. In 2030 with the incentivised plug-in behaviour this rises to 878 MW.

In 2030 if EV charging is optimised for day ahead wholesale energy prices, they could provide daily energy cost savings of up to 299k EUR for smart charging alone. 403k EUR if vehicle to grid (V2G) is included, and 427k EUR if V2G and grid services are included.

Table 1: Summary of Potential Savings against Unmanaged Charging in EUR, 2030 Incentivised

Reference Day	Winter High-Generation 13 January	Winter Low-Generation 25 January	Summer High-Generation 02 August	Summer Low-Generation 28 August
Baseline National Consumption Costs at Day-Ahead Pricing (Unmanaged EV Charging)	**1650k EUR**	**4677k EUR**	**1417k EUR**	**2532k EUR**
Saving Cost-Optimised Smart Charge	299k EUR	256k EUR	141k EUR	235k EUR
Saving Cost-Optimised V2G	403k EUR	291k EUR	195k EUR	280k EUR
Saving Combined Grid Services & Cost Optimised V2G	427k EUR	322k EUR	249k EUR	326k EUR

In 2030 an EV fleet could be expected to contribute to automatic frequency restoration reserve (aFRR) and frequency containment reserve (FCR) grid services, based upon existing technical demonstrations of the technology and an expected technology readiness level (TRL) of 9 in 2030. Modelling of 2030 suggests that, with the incentivised plug-in scenario, the EV charging portfolio can offer close to and sometimes more than the transmission system operator (TSO) grid services requirement.

There is potential for the optimisation of EV charging to contribute to network reinforcement postponement. Modelling demonstrates that in 2030, if EV charging is used solely for the purpose of reducing network peak capacity, then network reinforcements that would otherwise be required can be postponed. All regions within Luxembourg, with the exception of Southeast and Southwest, could keep the maximum network demand below 2023 capacity levels on the typical days simulated, resulting in a deferral of 566M EUR of reinforcement costs.

If the 2030 costs savings above are split equally across all residents this results in the following daily savings per resident depending on the source:

- Day ahead wholesale energy price optimisation: between 0,19 EUR and 0,61 EUR
- Additional savings from grid service provision: between 0,03 EUR and 0,08 EUR
- From network reinforcement postponement: 0,17 EUR

EV charging can be optimised to facilitate increasing the share of renewables in electricity consumption by supporting increases to renewable capacity build. However, where there is no renewables export or spill (due to grid congestion), EV charging is not required to assist (as is the case in 2023). In 2030 and assuming an incentivised plug-in behaviour, the share of renewable electricity in final consumption on the highest generation day (summer high generation day) is 39,6% at National Energy and Climate Plan (NECP) target scenario renewables level. In this scenario, since all renewable energy is absorbed, EV charging cannot contribute to increasing absorption. Therefore, a simulation was performed with EV charging optimised to absorb renewables, and renewable installed capacity increased to the point where renewable energy export first occurs at the national level (whilst observing regional grid capacity levels). This resulted in an additional 1.198 MW of installed renewables capacity (an 80% increase compared to the NECP target scenario), and 73,5% share of renewables in electricity consumption on the highest generation day (summer high generation day). With unmanaged EV charging a renewable electricity consumption share of only 64,5% could be obtained on the same day (assuming the same installed renewables capacity). This means that EV charging can contribute to a 9% additional absorption of renewable electricity on the summer high generation day (1.959 MWh).

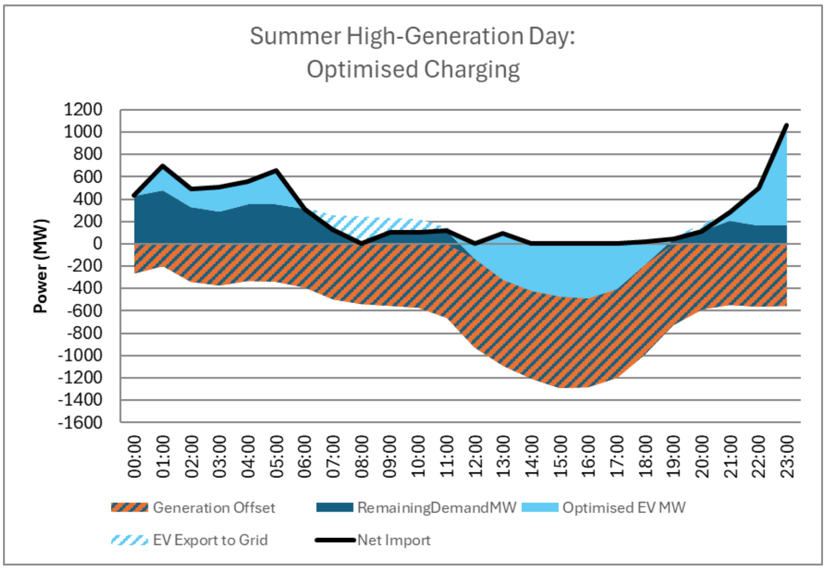


Figure 2: EV Charging Optimised for Increased Renewables Installation, 2030

Recommendations

There are clear benefits to optimised EV charging for the Luxembourg electricity system, including cost optimisation, reducing peak demand and renewables integration. **We recommend pursuing optimised EV charging due to the multiple possible benefits for the electricity system.**

The incremental benefit of V2G charging above smart charging is such that it could pay for itself within 1 to 4 years. **We recommend that V2G charging is pursued as it can contribute a net benefit to the electricity system.**

Grid services (specifically aFRR and FCR) could be considered within an optimised EV charging solution. However additional hardware, monitoring and integration costs to facilitate grid service provision may challenge economic viability.

Energy cost optimisation alone from EV charging could put additional strain on the grid during the cheapest priced periods. **We recommend that such effects are avoided by initiatives such as diversification of price signals to EV charging, differing charging objectives, or explicit capacity costing for users.** Optimising EV charging for day ahead wholesale electricity prices will sometimes compete against shaving peaks in electricity demand profiles. Co-optimising both is out of the scope of this project, but peaks from cost optimisation need to be carefully watched in the future.

Incentivised plug-in behaviour for EV charging could increase savings (from day ahead optimisation and grid services in 2030) from between 6% and 18% each day compared to the current plug in behaviour. **We recommend that actions are taken to encourage EV owners to plug-in EVs more frequently where a dedicated charger for the EV exists. This could be done via the customer value proposition to EV/chargepoint users.** Examples of this proposition include rewarding users for the time EVs are plugged in and available, cheaper EV charging during certain windows, passing through a portion of grid services revenue (via aggregator) to EV users, or gamification to earn rewards and compete with friends.

As it currently stands it is not yet clear which technology, between alternating and direct current (AC and DC) V2G, will win out, as this is still dependent upon vehicle OEMs and how interoperable different solutions become. **There are no clear recommendations currently between AC and DC V2G technology solutions.**

1 Introduction & Background to the Work

1.1 Introduction to Cenex

Cenex was established as the UK's Centre of Excellence for Low Carbon and Fuel Cell technologies in 2005.

Today, Cenex lowers emissions through innovation in transport & associated energy infrastructure and operates as an independent, not-for-profit research and technology organisation (RTO) and consultancy, specialising in the project delivery, innovation support and market development.

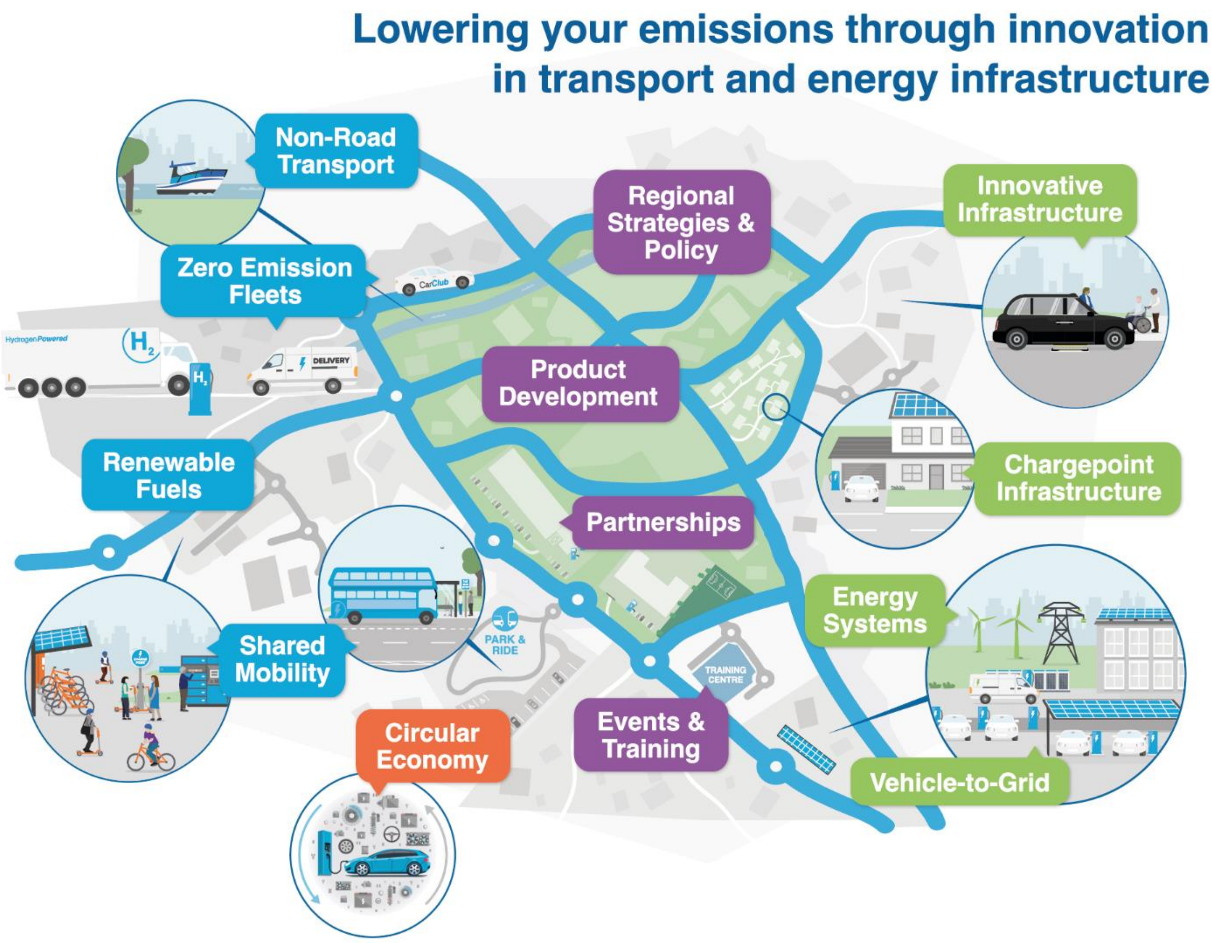
Employing around 50 people, the Cenex head office is in Loughborough, with additional bases in Belfast, Northern Ireland, as well as a sister company Cenex Nederland, based in Amsterdam. The Cenex group of companies (both Cenex and Cenex Consultancy Services in the UK and Cenex Nederland in Amsterdam) are all non-profit mission-led organisations.

We also organise Cenex-Expo, the UK's premier transport decarbonisation and Connected and Automated Mobility event comprising three exhibition halls and a two-day seminar programme demonstrating the latest technology and innovation.

Cenex's independence ensures impartial, trustworthy advice, and as a not-for-profit we are driven by the outcomes that are right for you, your industry and your environment, not by the work which pays the most or favours one technology.

As trusted advisors with expert knowledge, Cenex are the go-to source of guidance and support for public and private sector organisations along their transition to a zero-carbon future and will always provide you with the insights and solutions that reduce pollution, increase efficiency and lower costs.

To find out more about our recent work and expertise, visit: www.cenex.co.uk



1.2 Introduction to the Project

The EU Alternative Fuels Infrastructure Regulation (AFIR) has two main objectives. On the one hand, to set minimum targets for alternative fuels infrastructure for each Member State. On the other hand, to further detail the provisions to be complied with by these infrastructures.

Article 15(3) of the AFIR requires Member States to assess how the deployment and operation of electric vehicle (EV) chargepoints could enable EVs to contribute more to the flexibility of the energy system, including their participation in the balancing market, and to a better absorption of renewable electricity. This assessment considers all types of chargepoints, including those that offer bidirectional and smart charging, and all power outputs, whether open to the public or private.

Article 15(4) of the AFIR requires the regulator to assess the potential contribution of bidirectional charging to reducing the costs of the electricity system and users and to increasing the share of renewable electricity in the electricity system.

Considering these two articles of the AFIR, the Luxembourgish Ministry of Mobility and Public Works and the Ministry of the Economy (responsible for national energy policy) entrusted this task to the Institut Luxembourgeois de Régulation (ILR), who in turn contracted Cenex to conduct this study. This report and the data derived from it will be used by the Luxembourgish Government to take measures to adjust the geographical distribution and availability of chargepoints and take any relevant related measures.

1.3 Scope of Work

The summarised scope of the project was to analyse the potential contribution of the charging infrastructure to:

A. the flexibility of the electricity system, including participation in the balancing market, and reducing user and system costs;

B. increasing the absorption and share of renewable electricity in the electricity system.

This analysis was carried out considering all relevant input parameters for both a current reference scenario and a forecast 2030 scenario. Recommendations for the deployment and operation of charging infrastructure were also in scope.

ILR framed the above requirements within 7 questions:

1) What is the estimated power and energy volume stored in the batteries of grid-connected electric cars for each hour of a reference day in summer and winter?
2) What is the potential impact of charging and discharging these vehicles on the grid at the local and national level?
3) To what extent and how could the EV fleet contribute to the flexibility of the electricity system, react to price signals from the wholesale market (dynamic prices) and participate in the balancing market and ancillary services, such as frequency and voltage control?
4) Could network reinforcements or extensions be avoided or postponed? In what order of magnitude?
5) What would be the financial impact on network users (simplified analysis)?
6) Depending on the assumptions made, what savings for the system and network users would be possible by shifting electricity consumption from high-priced periods to lower-priced periods and by storing electricity produced during low-price periods?
7) Depending on the different assumptions made, in what order of magnitude can the share of renewable electricity in the electricity system be increased?

1.4 Structure of the report

Firstly, in chapter 2, a literature review on the electricity markets relevant to EVs in Luxembourg was carried out. Then, in chapter 3, the assessment of a current reference scenario was performed, including a description of our modelling assumptions and methodology, the data fed into our model, and its outcomes regarding flexibility and renewable energy absorption. Chapter 4 has a similar structure to the previous section albeit focussing on the 2030 scenario, describing the forecast methodology for all model inputs and showcasing the model outcomes regarding flexibility and renewables. Our model outcomes were then discussed in chapter 5, indicating the implications on the technical and financial aspects of EV smart and/or bidirectional charging. Finally, in chapter 6 recommendations on deployment and operation of EV charging infrastructure in Luxembourg was provided.

The report structure is in line with the way the project was scoped, as per the work package diagram in Figure 3.

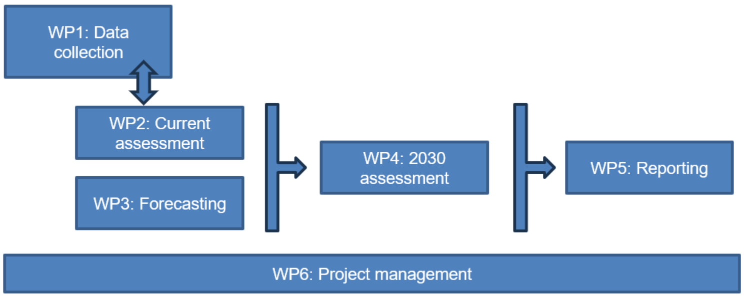


Figure 3: Project structure

2 Luxembourgish Electricity Markets Relevant to Electric Vehicles

This chapter is a literature review on the electricity markets relevant to EVs in Luxembourg, to ensure the analysis focus is on the correct markets and balancing services.

2.1 Arrangement of electricity markets

Luxembourg falls under the load frequency control (LFC) area Amprion / Creos. As such, balancing processes and markets in Luxembourg are covered by both German and Luxembourgish regulations. As shown in Figure 4, Amprion is one of Germany's four transmission system operators (TSOs): Amprion, 50Hertz, TenneT and TransnetBW.

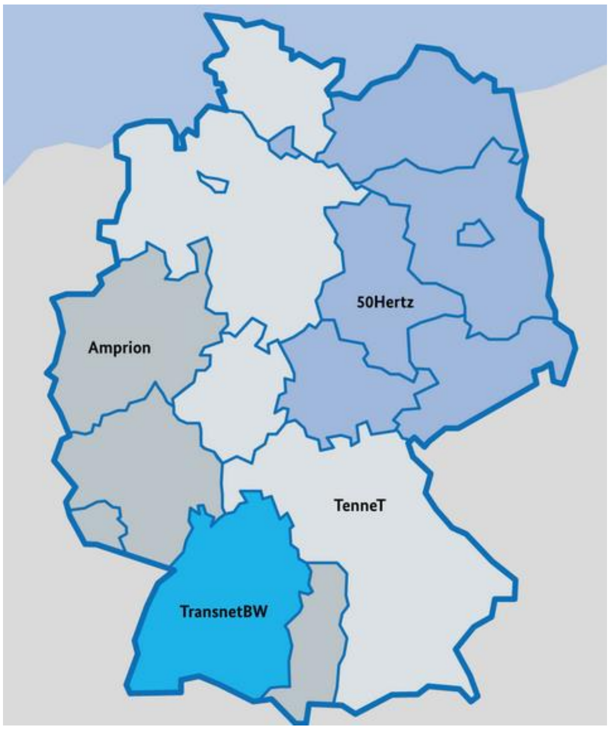


Figure 4: Amprion coverage in Germany includes Nordrhein Westfalen, Rheinland Pfalz and Saarland, in addition to Luxembourg.

The Luxembourgish market follows European Union (EU) Regulation 2017/2195/EU, published in 2017, which provided guidelines for establishing a cross-zonal internal market. Each TSO is responsible for balancing electricity within a specified LFC area. Electricity suppliers and traders within an LFC area form balancing groups, and all feed-in, withdrawal and traded volume is assigned to a balancing group. Each balancing group has balancing responsible parties (BRPs): producers, large users, energy suppliers or energy traders, responsible for management of the balancing group. BRPs are typically registered with the TSO.

Creos is responsible for balancing energy settlement with the Luxembourg balance responsible parties but Amprion is responsible for procuring and deploying balancing reserves. Balancing service providers (BSPs) are generators, demand response facilities or storage operators who can offer balancing services (capacity and/or energy) to the TSOs, who in turn use these services to balance the system within a balancing group. This arrangement is depicted in Figure 5.

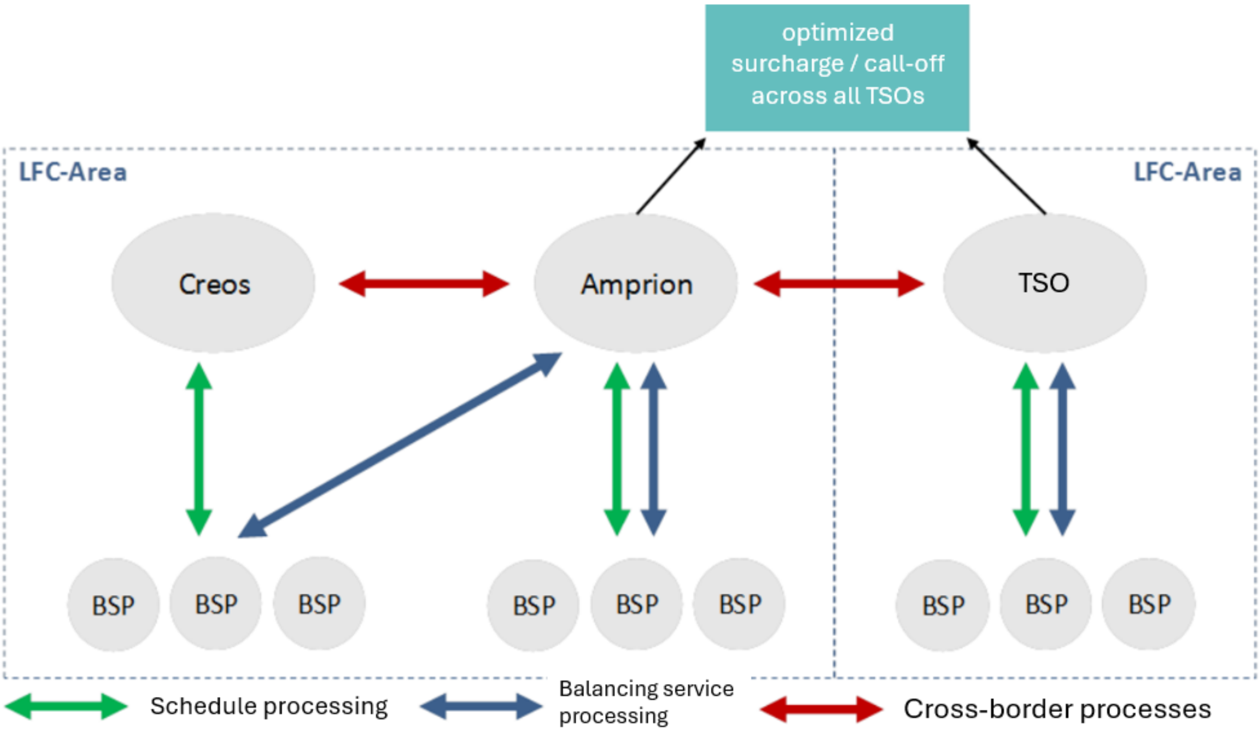


Figure 5: Exchange of information between BSPs, Creos and Amprion in Luxembourg

The liberalisation of the European electricity sector led to the unbundling of several electricity monopolistic utilities. They then transitioned to either distribution system operator (DSO) – Creos Luxembourg, Ville d'Ettelbruck, Ville de Diekirch and Sudstroum – or energy supplier roles – Ville de Dudelange and Sudenergie.

As in all countries in the EU, the electricity markets in Luxembourg involve the forward, day-ahead, intra-day and balancing markets. The forward markets involve purchasing electricity years in advance to enable hedging against short term uncertainty and are not relevant for flexibility.

EVs have been involved in the day-ahead and intraday markets in Germany for many years. Companies like Entelios, Lichtblick and Markt E currently offer this service to large customers with electric vehicle charging[1]. Companies like Jedlix (part of Kraken group) also offer this service to e-mobility service providers (EMSPs) in addition to EV drivers and are active in Germany[2].

2.2 Balancing services

The balancing markets involve the purchase and delivery of the three balancing services in Germany and Luxembourg:

1) **Frequency containment reserve (FCR):** FCR involves proportional (to deviation from 50 Hz) and rapid (complete activation in 30 s) response to stabilise the frequency. It is typically activated in the LFC area where the imbalance is caused/ detected.
2) **Automatic frequency restoration reserve (aFRR):** FRRs have the function of minimizing the deviation i.e. returning the frequency to the target value: 50 Hz. aFRR is automatically deployed within the LFC area where the imbalance is caused/detected. The response provided is slower than FCR, with full activation required within 5 minutes, and replaces FCR as quickly as possible.
3) **Manual frequency restoration reserve (mFRR):** mFRR is the manually deployed FRR and is deployed to replace aFRR for longer time periods. This enables the aFRR to be

[1] Chapter 5 - Aggregators today and tomorrow: from intermediaries to local orchestrators? Poplavskaya et al. Behind and Beyond the Meter, Academic Press, 2020.

[2] https://www.jedlix.com/

made available for balancing that is needed at short notice. Activation of mFRR in Germany is now carried out electronically.

An overview of the key service features is provided below.

	combined market	balancing capacity market		balancing energy market	
	FCR	aFRR	mFRR	aFRR	mFRR
tender period	daily D-1 (8 a.m.)[18]	daily D-1 (9 a.m.)	daily D-1 (10 a.m.)	daily 25 minutes before delivery period	
product duration	6 x 4-hour blocks[19]				
product differentiation	none (symmetric product)	positive and negative			
minimum bid size	1 MW[20]				
bid increment	1 MW				
tendering	capacity price merit order	capacity price merit order		energy price merit order	
remuneration	pay-as-cleared (capacity price)	pay-as-bid (capacity price)		pay-as-bid (energy price)	

Figure 6: Product features of different balancing services in Germany

All BSPs must prove that they fulfil the technical requirements for providing each of the balancing services through a process called pre-qualification. Pre-qualification is carried out by the TSO and typically takes around 3 months to complete.

Aggregation of assets is permitted in the Amprion area, and earlier pilots have set precedents for the use of EVs to provide balancing services. During trials in 2022 by the BSP Next Kraftwerke, EVs were aggregated as part of a virtual powerplant of 14.000 assets for provision of FCR to Amprion[3]. Six 'Honda e' EVs and six Honda Power Manager bidirectional CCS chargers were used in the trial and met the prequalification requirements.

In another project in the same year, Next Kraftwerke used 'Hyundai IONIQ 5s' for providing aFRR to Amprion. The EVs together with wallboxes and home batteries provided by LG met the prequalification requirements for aFRR.

No similar precedents have been found for mFRR, likely because the characteristics (manual control, long duration, emergency/n-2 contingence) make EVs less suitable for this service. Therefore, mFRR was omitted from this study.

[3] https://www.next-kraftwerke.com/news/control-reserve-honda

In 2025 EV flexibility services are beyond the stage of trials that show that the technology works in practice. The recent developments have occurred mainly in the topics of regulation, standardization, cross-border harmonization, interoperability and integration with the energy grid, which are all pre-requisites for scaling. Delays in the publication of ISO 15118:20 (first published in 2022, and now expecting amendment), and the updating of the European regulations on Requirements for Generators (RFG, still in draft phase as of March 2025) have slowed down scaled adoption.

2.3 Selection of relevant EV electricity markets

Based on a DNV report assessing regulatory frameworks for vehicle to grid (V2G) across Europe[4], only Great Britain, the Netherlands and France have local flexibility markets where EVs can offer flexibility to DSOs through market-based procurement. Market based procurement of flexibility is not supported in Germany, and DSOs rely on Redispatch 2.0, a cost-based generation dispatch approach for managing congestion. As such, the TSO services with precedence, i.e. those governed by rules that determine which flexibility providers are prioritized when multiple providers offer the same service to a network operator, represent opportunities which are closer to market.

While the market and regulatory development over the 2030 horizon remains uncertain, the flexibility services that EVs could offer in Luxembourg along with their technology readiness level (TRL) have been listed below:

Table 2: Summary of EV Flexibility TRL

Flexibility service	Current TRL	Expected TRL in 2030
Day-ahead Markets	TRL 9	TRL 9
Intra Day Markets	TRL 9	TRL 9
FCR	TRL 6/7 - Technically demonstrated with TSO Amprion with EVs on the market	TRL 9
aFRR	TRL 6/7 - Technically demonstrated with TSO Amprion with EVs on the market	TRL9
Congestion / DSO markets	TRL 4/5 – tested in other countries	TRL 6 – demonstration in relevant environment

Within this project, congestion / DSO markets were excluded as they are not expected to be a sufficiently high TRL for the modelled years. Only some trial projects have demonstrated these markets so far, such as FlexPower in the Netherlands and My Electric Avenue in the UK. However, when applied in normal operation, DSOs need to follow the European directive 2019/944 on the common rules for the internal market for electricity[5]: article 33 states that "*distribution system operators shall not own, develop, manage or operate recharging points for electric vehicles*". While DSOs can procure such a service according to article 32, congestion / DSO markets for EV charging are not expected to be mature enough in 2030 to have a significant impact on the results of this study.

Only one wholesale market was included in this study (the day-ahead market), as including both would only add a small value but a lot more complexity. In summary, the markets included for analysis within this project were:

- **Day-ahead Market**
- **FCR**
- **aFRR**

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[4] V2X-Enables-and-Barriers-Study_11-2023_DIGITAL.pdf

[5] https://eur-lex.europa.eu/legal-content/EN/TXT/PDF/?uri=CELEX:02019L0944-20240716

3 Current Assessment of Flexibility from Electric Vehicles

This chapter describes the methodology for modelling the contribution of EVs to the Luxembourg grid, including the optimisation approach and the assumptions and inputs collected for our model. Then the simulation results for the current reference scenario were shown regarding flexibility and renewables absorption.

3.1 Outline of the modelling approach

To address the questions proposed by ILR for the study the Cenex REVOLVE model was applied to the problem. REVOLVE is a perfect foresight EV charging optimisation model, meaning that the model assumes a complete and accurate knowledge of future events, including energy demand, prices and vehicle movements. This is representative of a scenario where the actors controlling and dispatching the EV charging can perfectly predict future events and price. This allows for the most efficient possible EV resource allocation (for further details see Appendix A – The REVOLVE Model). And as such, results provided by the model should be viewed as an upper bound of what is possible. The model is also a 'Price Taker' meaning that prices are assumed fixed and the actions within the model of changing the times and magnitude of demand do not have an impact on electricity prices. This will only be correct when the demand being changed within the model is relatively small when compared with the overall electricity market. In the case of modelling large numbers of EVs in Luxembourg in 2030 as part of the DE-LU price area, this may not be true. It is however, a necessary simplification since modelling the entirety of the electricity market (including generation assets) is beyond the scope of this study. The model was adapted to simulate the Luxembourg electricity system at an hourly level. This involved:

- Inclusion of current photovoltaic (PV) and wind generation capacities.
- Current electricity demand profile for Luxembourg, with EV charging removed from it.
- EV charging demand: representations of all electric cars, vans and heavy goods vehicles (HGVs) resident in or regularly visiting Luxembourg, aggregated into 'mega vehicle' blocks[6].
- Inclusion of day-ahead electricity prices, from historical data.
- Inclusion of FCR and aFRR prices.
- Modelling of typical days only.

The REVOLVE model was set up for four typical days within the year. These were.

1. Winter High Renewables Output
2. Winter Low Renewables Output
3. Summer High Renewables Output
4. Summer Low Renewables Output

This combination of days was chosen to provide a spread of possible market conditions in which EV flexibility could be demonstrated. On high renewables output days, the flexibility can be tested to see how much renewable generation can be absorbed. On low renewables output days, the impact of flexibility on price optimisation and grid service provision can be tested without the need for renewables absorption.

Scenarios were set up within the model for the 'current situation' and for a forecast of 2030. For the current situation, the year 2023 was chosen as this was the most recent year with a complete set of EV parc, electric vehicle supply equipment (EVSE), price and electricity system data. Although some data was available for 2024, the year 2023 was selected for consistency of the whole input dataset.

Much of the analysis was done by running a scenario at the national level. This provided results for total impact of EV charging and EV flexibility. However, to address issues of regional capacity

[6] This step was required to reduce computational complexity of the problem in the model.

constraints or renewables absorption, regional versions of the model were run. These regional versions were based on the six grid zones in Luxembourg (Figure 7). In these regional scenarios, demand and generation capacity was split down into these zones using demographic data for the regions fed by the transmission grid in each zone. The electricity transmission capacity (data obtained from Creos) was modelled as a single import constraint for each grid zone.

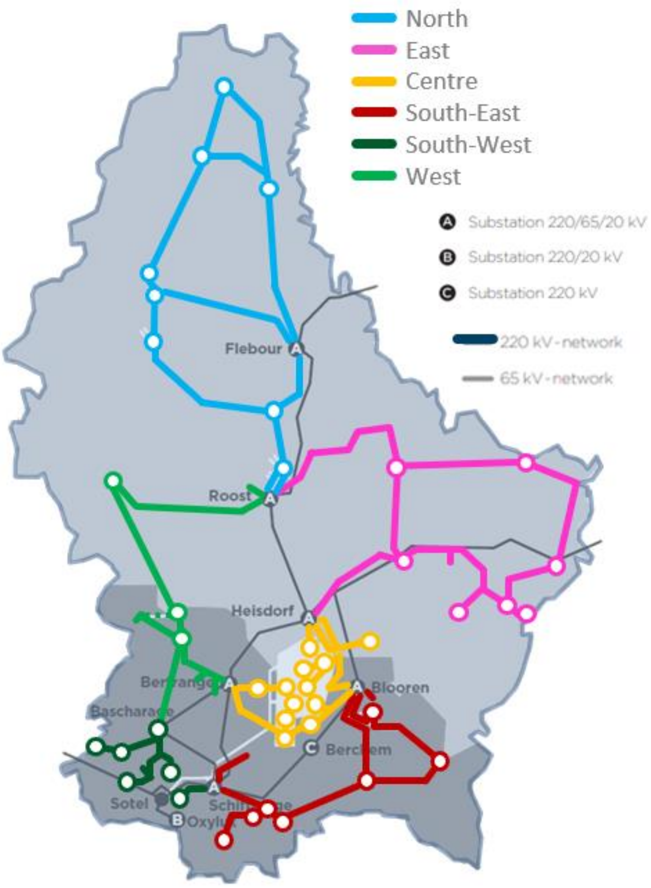

Figure 7: Luxembourg grid zones (source: Creos)

3.2 Model inputs

A preliminary data collection and processing exercise was carried out to prepare the correct inputs for our model, which is described in this section.

3.2.1 EV & EVSE data

At the end of 2023, there were 22.626 battery electric vehicle (BEV) cars, 15.126 plug-in hybrid electric vehicle (PHEV) cars and 873 BEV vans in Luxembourg[7]. Not all vehicles have V2G capabilities. Currently, around 6% of vehicle models have this capability[8], and this percentage was used to estimate how many vehicles are currently able to provide this service in Luxembourg (1.358 cars and 70 vans). Their corresponding chargepoints were assumed to be V2G-capable, even though there are currently very few V2G chargepoints installed. This assumption was made because the simulations for the 2023 scenario represent the extent of the possibilities if all V2G-capable vehicles present now actually performed V2G.

Data was provided by ILR on HGV vehicle registration in Luxembourg showing 12 eHGVs in 2023 (semi-trailer trucks), whilst data from the European Automobile Manufacturers Association[9] (ACEA)

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[7] Stock of road vehicles registered by type of vehicle and fuel (STATEC/SNCA)

[8] https://www.mobilityhouse.com/int_en/knowledge-center/article/which-cars-are-v2g-capable

[9] ACEA-Report-Vehicles-on-European-roads-.pdf

reported 42 eHGVs in 2023 (this includes special purpose HGVs). Given these negligible numbers and current limitations for bi-directional charging of eHGVs, they were excluded from the analysis for 2023.

To support these vehicles, there were a total of 12.769 chargepoints at the end of 2023[10], of which 1.521 are 'public' and 93 are direct current (DC). Data from Chargy[11] indicates that on average at end of 2023, alternating current (AC) chargers had 2 charging sessions per day, outputting 18 kWh each session; DC chargers had 4 sessions per day, outputting 24 kWh per session.

3.2.2 EV plug-in profile methodology

A plug-in profile is defined as the combination of

a) vehicle energy requirements,

b) likely times during the day when charging sessions begin,

c) likely charging locations and their typical power rates

d) typical dwell times at each charging location, and

e) plug-in frequency (described in this report as 'charging scenarios').

These four attributes are described below.

Vehicle archetypes

The energy requirements were calculated from their average annual distance and a typical efficiency value, based on the National Energy and Climate Plan (NECP) "target scenario" defined in the Creos 2040 scenario report[12]. Battery capacity is representative of current technology status averaged across different types of cars and vans.

Table 2: 2023 vehicle archetype attributes

Vehicle type	Annual km	kWh/km	kWh per day	Battery capacity (kWh)
Car	16.000	0,2	8,4	45
Van	20.000	0,29	15,7	75
HGV	N/A: negligible number of vehicles in 2023			

Charging times

For cars and vans, data from the Luxmobil 2017 survey[13] was used to estimate the times when vehicles move from home to work or destination and back again. Data from the quality of work report[14] was used to estimate the duration between arriving at work and leaving, and data from the "Parkraum Strategie" document[15] was used to estimate how long vehicles remained at a destination location (e.g. hotels, shopping malls, sports centres). To match these timings, profiles were

[10] Existing Charging Infrastructure (connectors); (data from ILR at https://www.ilr.lu/espace-statistiques/les-statistiques-par-secteur/le-secteur-electricite/)

[11] Chargy data supplied by ILR

[12] Creos; *Electricity Transmission Grid Scenario Report 2040,* 2023

[13] https://transports.public.lu/dam-assets/publications/contexte/situation-actuelle/20171207-enquete-mobilite-luxmobil-2017-premiers-resultats-presse-v2.pdf

[14] Quality of Work Luxembourg; infas Institut für angewandte Sozialwissenschaft GmbH; 2023

[15] Nationale Parkraumstrategie Luxemburg; Ministère de la Mobilité et des Travaux publics; 2021

generated for travelling to and from work, and to and from destinations. Vehicles were added to these profiles based on the total number of journeys in each type in the travel survey.

Charging locations

Each vehicle was assigned to a charging type: *Workplace*, *Destination*, *High Power* (e.g. motorway service stations) and *Residential*. These charging types all have different dwell times and charging powers (Table 3), which influence how suitable they are for EV flexibility services.

Table 3: Charging type specifications

Charging Type	Typical dwell time (hours)	Power (kW)
Workplace	7-10	22
Destination	1-8	22
High Power	1-2	50
Residential	12-22	7

Using the National Mobility Plan[16], 73% of Luxembourg residents have access to private parking, and the assumption was that most of them had access to private charging at these locations. 94%[17] of these vehicles were assigned to the *Home* locations, where they charged on private chargepoints. The remaining 6% was allocated to the *Out* locations, representing those who either do not have private charging, or have private charging but charged on the public network (e.g. they were working away from home, travelling long distances etc.). This proportion (6% of 73% = 4%), plus the 27% who do not have private parking (totalling 31% of vehicles) were split across the three *Out* charging profiles (*Workplace*, *Destination*, and *High Power*), based on the distribution of journeys in the travel survey. The method used in this project to calculate public charging proportions aligns very well with the proportions published by the European Alternative Fuels Observatory (EAFO)[18].

Frontier workers were also considered. There are assumed to be around 223.800 frontier workers[19]. 83% of them drive to work by car[20], and the average car occupancy is 1,1, which resulted in around 169.000 cars. Using the same EV ratios and driveway likelihood as Luxembourg, this results in 2.700 BEVs that will charge on the public network in 2023 and 18.000 BEVs in 2030. These are all added to the *Workplace – Out* group.

The charging demand was then allocated to the six regions defined in section 3.1. *Workplace* and *Destination* demand was allocated based on the number of employees in each region[21], and *Residential* and *High Power* was allocated based on population in each region[22].

16 Plan national de mobilité 2035; 2022

17 This is a correction factor used in Cenex's previous modelling in the UK, based on chargepoint numbers, chargepoint utilisation and off-street parking data. While this may still seem like a high number, note that the 2023 scenario is simulating the extent of the possibilities, e.g. if currently there was widespread deployment of private chargepoints.

18 [2024 EAFO Consumer Monitor survey]

19 https://lustat.statec.lu/vis?pg=0&df[ds]=ds-release&df[id]=DF_B3107&df[ag]=LU1&df[vs]=1.0&pd=2015%2C2023&dq=.A&lc=en

20 https://delano.lu/article/insee-five-figures-on-the-comm

21 A Growing Polarization of Home-Work Travel in Luxembourg; Ferro et al. 2021

22 "Population par canton et commune". www.statistiques.public.lu. Statistics portal of the Grand-Duchy of Luxembourg. Retrieved 25 April 2023.

The final EV allocations for cars, in 2023, by region, plug-in profile, and charging type are shown in Table 4. The same proportions were used for vans, and for all the 2030 scenarios.

For example, those in the first column (*Workplace – Home*) go to work (on average between 8am and 6pm), they do not charge at work and then return home to charge. Those in the second column (*Workplace – Out*) can charge at work and do not charge at home.

Table 4: BEV car allocations for plug-in profiles.

Charging type	Workplace	Workplace	Destination	Destination	Residential	High Power
Location	Home	Out	Home	Out	Home	Out
Central	2.673	4.211	2.005	1.654	1.064	800
Southwest	1.901	1.119	1.426	439	757	212
Southeast	1.419	859	1.064	337	565	163
West	829	604	622	237	330	115
East	909	562	682	221	362	107
North	1.110	879	833	345	442	167
Total	**8.842**	**8.234**	**6.632**	**3.233**	**3.519**	**1.563**

Charging scenarios

Three charging scenarios were used to test the sensitivity of how frequently vehicles plug-in, reflecting the availability of V2G and incentivisation of users to plug-in, when possible, even if they do not need to charge. These are shown in Table 5 below.

Table 5: Charging scenario attributes

Scenario	Description	Plug-in frequency (days elapsed between charges)	
		Cars	Vans
Necessary	The vehicles only plug-in strictly when required, based on their daily energy needs and battery size	4,8	4,4
Current	Vehicles maintain their current plug-in behaviour based on current average energy per charge (e.g. 15 kWh for cars[23])	1,9	1
Incentivised	Vehicles plug-in every day	1	1

3.2.3 Selection of typical renewable energy days

The four typical or representative days for the model simulations were selected from historical 2023 data: winter high renewables, winter low renewables, summer high renewables, and summer low renewables. The process followed was:

1. Add up the daily generation of solar PV and wind for each day of 2023[24].
2. Sort the addition of daily PV and wind from highest to lowest generation, separately for the summer and winter months.

[23] Chargy data supplied by ILR

[24] Data provided by ILR

3. Remove weekends and national holidays to ensure the corresponding energy demand for those days is consistent with a typical weekday. For example, the high frequency spikes in energy demand from steel factories need to be present.
4. Select the four representative days as per Figure 8 and Figure 9 below:
    a) High (PV + wind) summer day: 2nd August 2023.
    b) Low (PV+ wind) summer day: 28th August 2023.
    c) High (PV + wind) winter day: 13th January 2023.
    d) Low (PV+ wind) winter day: 25th January 2023.

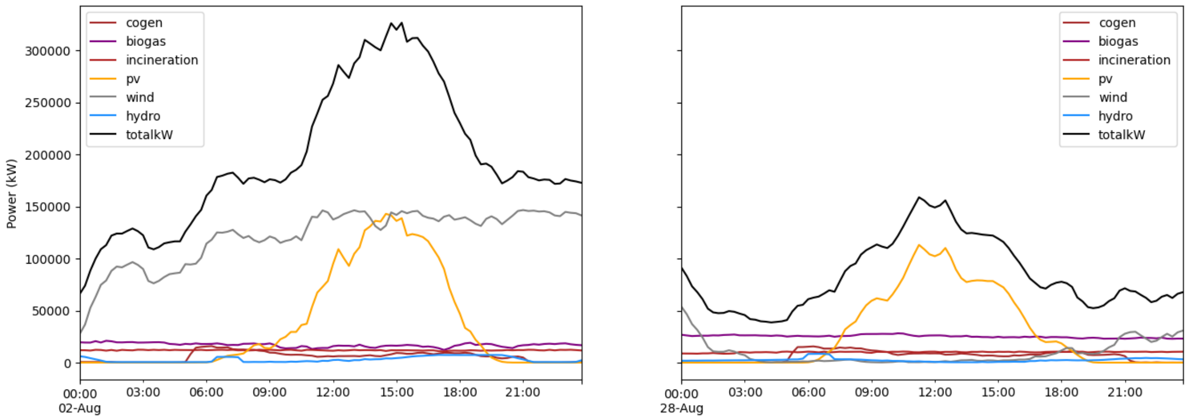

Figure 8: Typical summer days, high renewables (left) and low renewables (right).

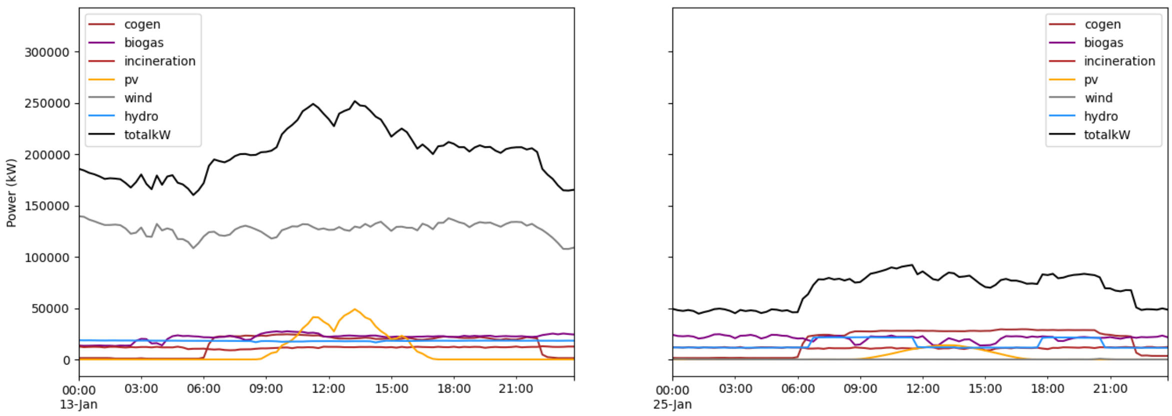

Figure 9: Typical winter days, high renewables (left) and low renewables (right).

3.2.4 Electricity demand

The granular data for electricity demand[25] corresponding to the four typical days is shown in Figure 10. It includes data from 2023 for both the Creos as well as the Sotel grids.

[25] Data provided by ILR.

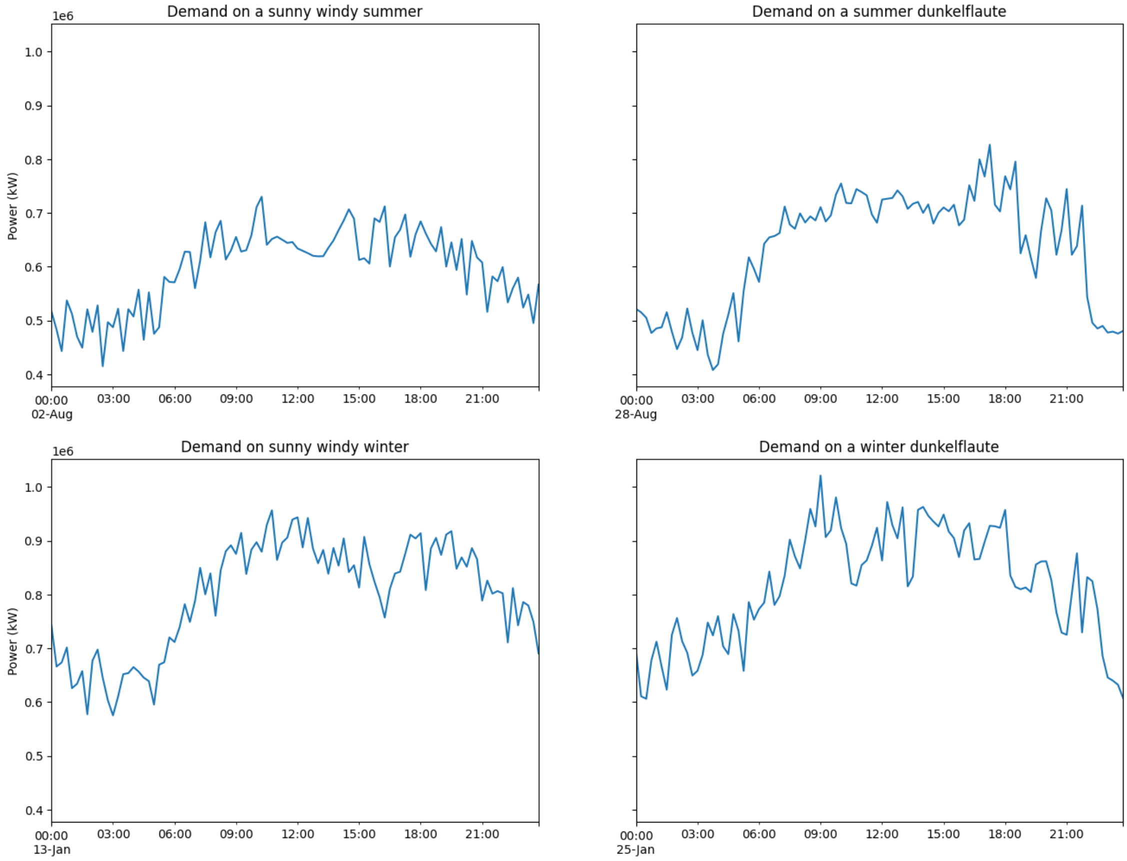

Figure 10: Electricity demand for the four reference days. “Dunkelflaute” refers to periods of low wind and minimal sunshine.

The electricity demand data used was provided at a national level, meaning that assumptions were needed to assign portions of this demand to each grid region for regional-level simulations. It was assumed that the national demand profile could be split between each grid region in proportion to the grid peak power in each region as defined in Figure 11.

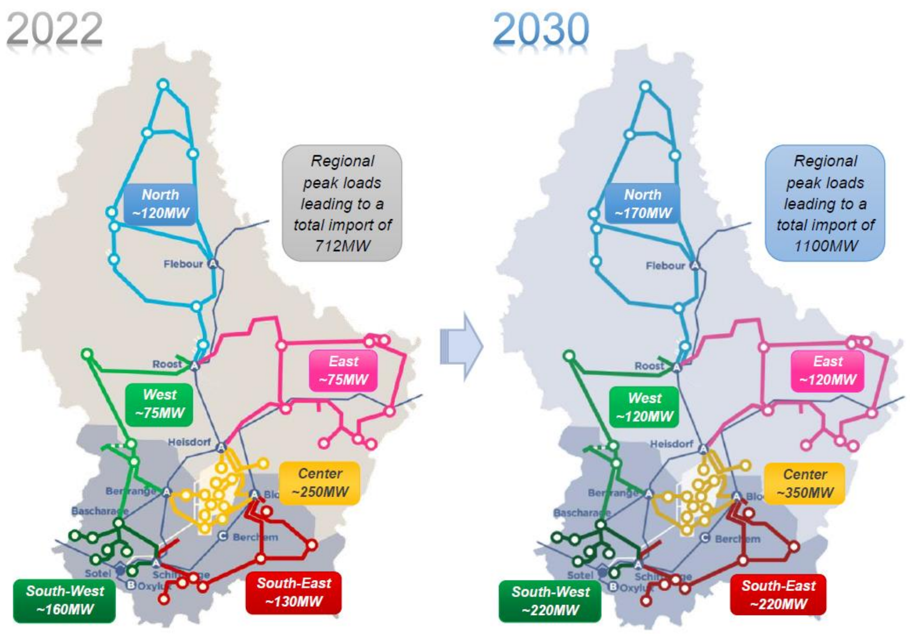

Figure 11: Expected peak power in each grid region[26]

[26] Creos, Network Development Plan 2024 - 2034

3.2.5 Electricity prices

The day-ahead electricity prices were sourced from the European Network of Transmission System Operators for Electricity (ENTSO-E) transparency platform for the DE-LU region. The prices are shown below in Figure 12, describing the price development over the previous decade since 2015 and the prices in the year 2023, used as the baseline in this work.

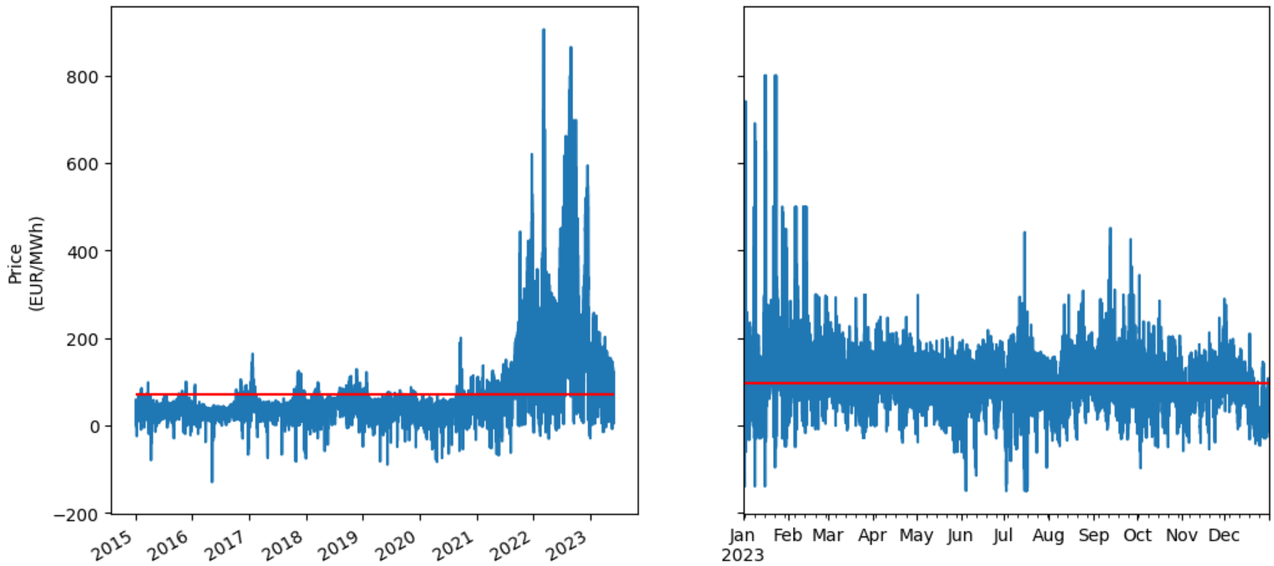

Figure 12: Historic day-ahead electricity prices for the DE-LU region (Source: ENTSO-E transparency platform)

The day-ahead prices reveal the significant influence of the Russia-Ukraine war on electricity prices in 2022 and subsequent years. The effects of the price shock is also seen in the high price volatility seen in the early parts of 2023 as well as in the higher average electricity price than in the pre-war years. The electricity price profiles for each of the four reference days is shown in Figure 13.

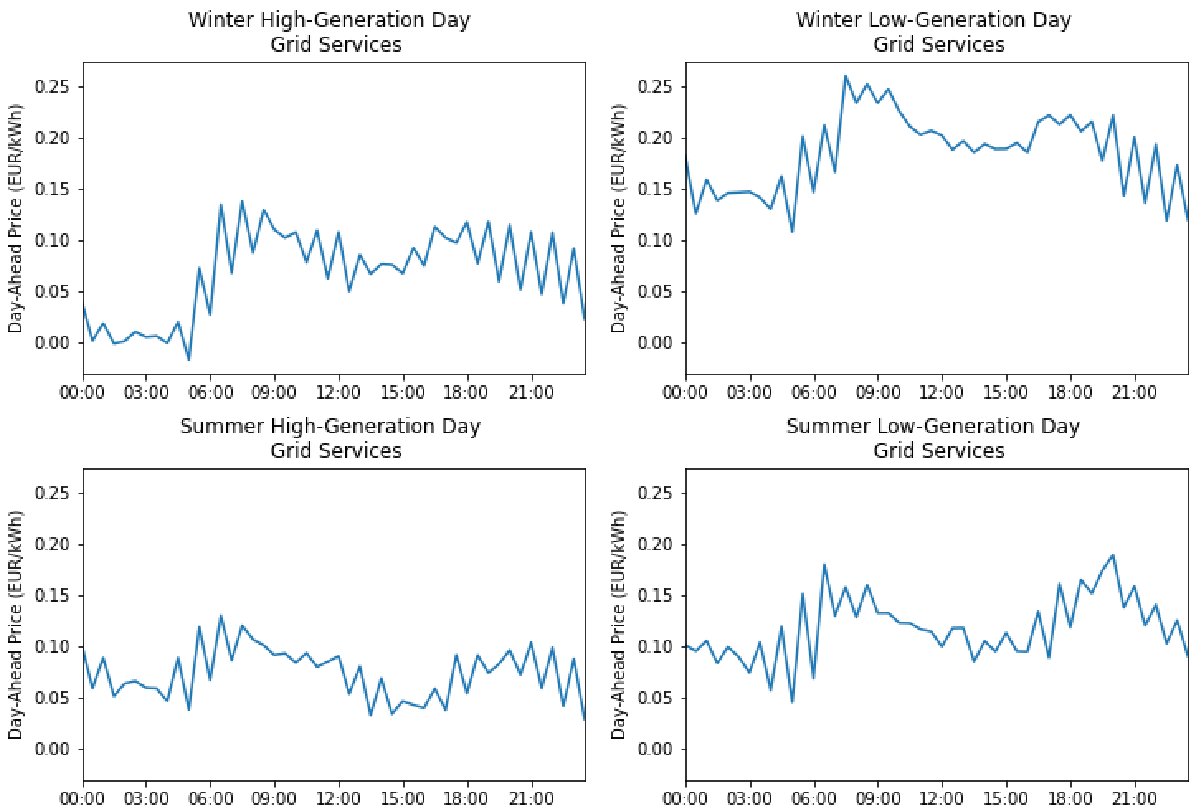

Figure 13: Day-Ahead electricity import prices for the four reference days

3.2.6 Flexibility prices

The aFRR 2023 prices were sourced from the ENTSO-E transparency platform for the DE-LU region. These were separated by upwards and downwards regulation prices. Upwards regulation means an increase in active power output or a decrease in active power consumption, while downwards regulation means a decrease in active power output or an increase in active power consumption.

FCR price data for Germany (and by extension, Luxembourg) for the year 2023 was obtained from the platform for balancing services operated by the four German TSOs[27].

Where utilisation prices were also available for the products (i.e. aFRR), simulations have assumed a utilisation rate of 5%[28] for both 2023 and 2030. Utilisation is defined as the reserved flexibility that is activated (i.e. dispatched as energy generation or consumption) by the grid operator. Hence in this case an offered aFRR service will receive 5% of possible balancing energy revenue whilst retaining 100% of balancing capacity revenue.

3.3 Contribution to the flexibility of the electricity system

Several scenarios were tested to estimate the contribution of electric vehicles to the flexibility of the energy system. These included three charging behavioural patterns as described in Section 3.2.2, and the following optimization scenarios:

- Cost optimisation: EV charging and discharging is optimised against day-ahead pricing without the inclusion of grid services.
- Combined cost optimization and grid services: EV charging is optimised to maximise the combined saving from day-ahead pricing and grid services income.
- Peak reduction: EV charging is used to first support reducing the demand peak within the four reference days, with any remaining flexibility used for cost optimisation and grid services.
- Renewables absorption: Renewable generation capacity is increased and EV charging is used to support increased absorption of renewables, with any remaining flexibility used for cost optimisation and grid services.

The current/recent year scenario uses the reference year of 2023. It is assumed for the purpose of these tests that any V2G-capable vehicle operating during this year is able to plug-in to a V2G-capable chargepoint.

3.3.1 Available Power and Energy Storage for Flexibility

Results are first presented on the factors that are independent of the reference day, as all reference days fall on relatively normal weekdays with similar driver charging behaviours. In this section, the available power and energy storage is presented for an incentivised charging scenario, where it is assumed that all vehicle users will plug-in their vehicle every day. This represents a best-case scenario for flexibility, with the impact of different charging behaviours detailed in Section 3.3.4.

The average simulated number of vehicles plugged in during each hour of the day is shown in Figure 14.

[27] Datacenter FCR/aFRR/mFRR/ABLA

[28] Previous simulations of similar products in the UK by Cenex resulted in 10% utilisation. This was reduced down to 5% to compensate for a more stable continental grid.

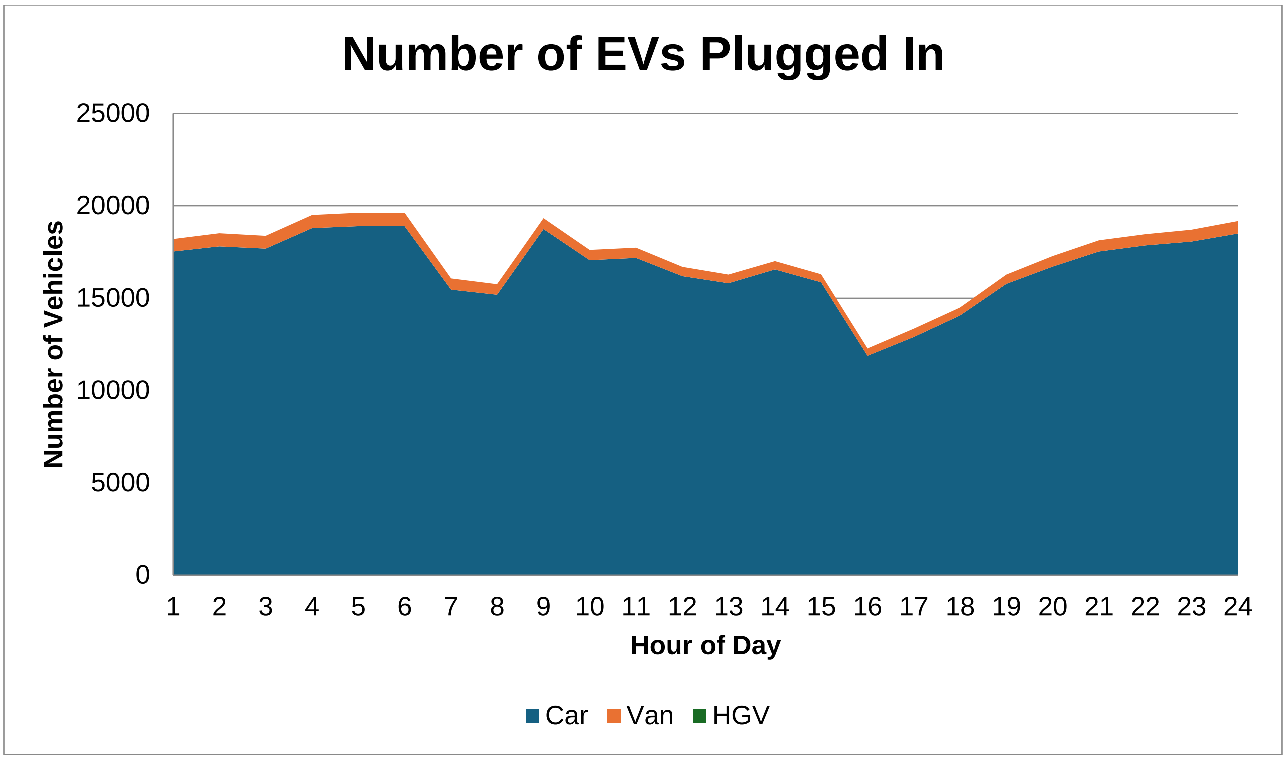

Figure 14: Connected Number of Vehicles per Hour of the Day, 2023 Incentivised Weekday Profile

From a total of approximately 33 thousand electric cars and vans estimated to operate within Luxembourg in 2023, the number of vehicles connected to chargers is expected to peak overnight, reaching a maximum of around 19,6 thousand in the Incentivised scenario. The minimum number of connected vehicles is expected to occur around typical commuting times during the morning and evening.

Cars and vans were simulated to plug in to different charger powers according to their vehicle type, plug-in location, and plug-in schedule. Figure 15 shows the corresponding average charging power and discharging power of all connected vehicles in each hour of the day. This metric is based on the rated charger power for each vehicle and does not account for the State of Charge present in each vehicle battery at the time of connection.

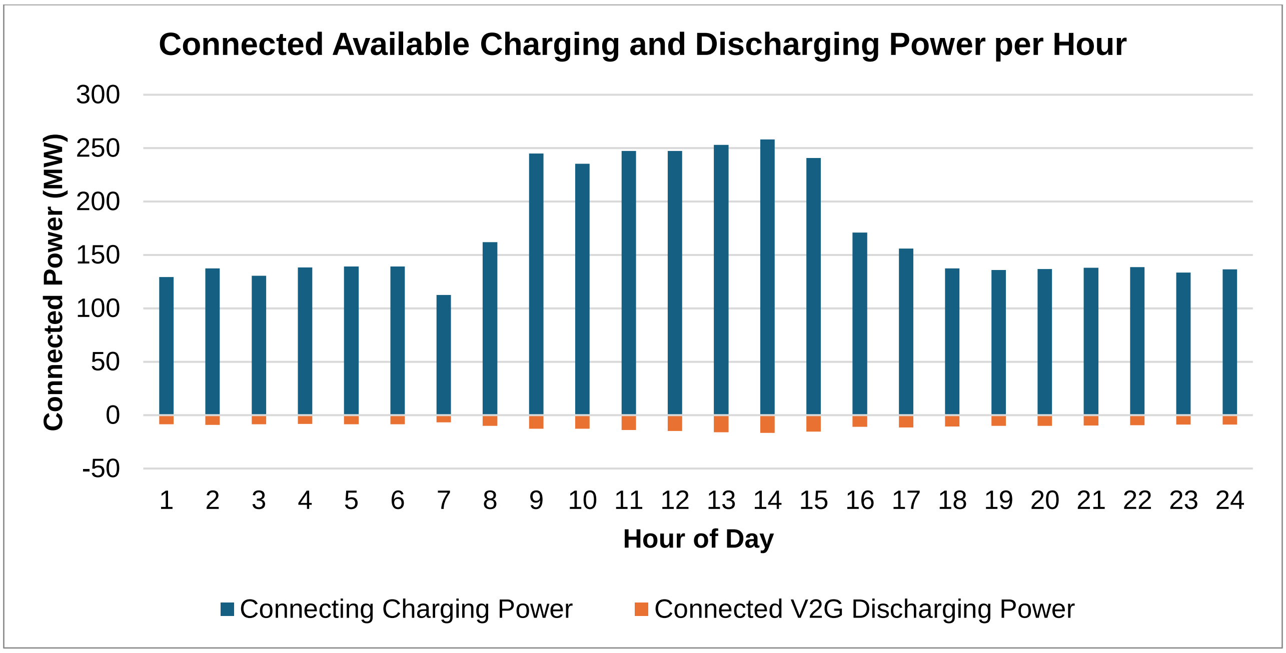

Figure 15: Sum of Charger Power of all Connected Vehicles per Hour of the Day, 2023 Incentivised Weekday Profile

As shown in the figure, the relatively low number of V2G-capable vehicles means that the capacity for discharging is significantly lower than charging for 2023. Connected charging power is estimated to peak between the hours of 09:00-15:00, corresponding to vehicles plugging in at higher-powered chargers at workplaces or other destinations during the day.

Finally, the available connected energy stored (footroom) within all plugged-in vehicle batteries per hour of the day is shown in Figure 16, minus 20% state of charge (SOC) to consider that users would not allow their batteries to discharge under that value. The SOC at each hour of the day was considered to plot this graph, and it was also assumed that vehicles charge in an unmanaged way: charging at the chargepoint's rated power from the time of plug-in, until the battery is full.

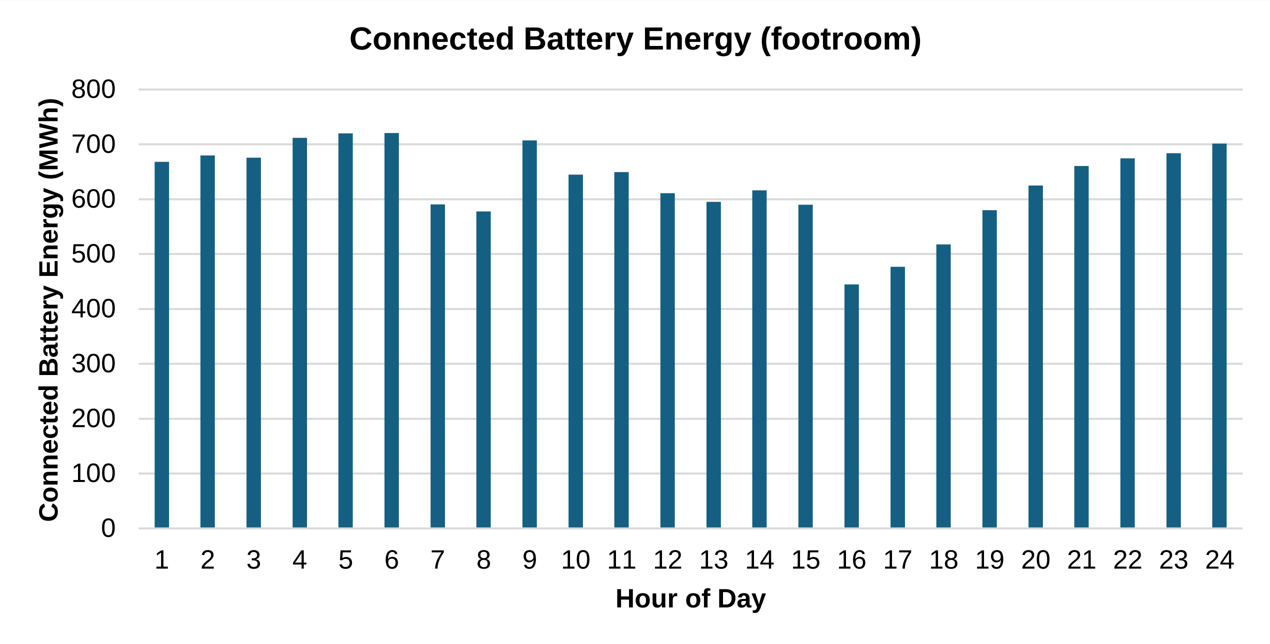

Figure 16: Sum of Connected Battery Capacity per Hour of the Day, 2023 Incentivised Weekday Profile

The connected battery capacity is expected to peak during the early hours of the morning, with approximately 720 MWh connected. The minimum connected battery capacity is expected to occur at approximately 16:00, with 440 MWh connected. This corresponds to both the minimum number of connected vehicles, and potentially the impact of use of the vehicles during the day depleting the battery.

3.3.2 Cost Optimisation: Maximised Savings from Day-Ahead Pricing and Grid Services

An optimised use of the available flexibility of the vehicle parc was simulated for each of the four reference days using the REVOLVE model as described in Appendix A – The REVOLVE Model. To show the maximum possible potential for the current EV parc, the incentivized plug-in behaviour is presented in this section. As a baseline, the impact of unmanaged charging on imports at the national level is shown for each reference day in Figure 17. This figure shows the amount of national electricity demand that is met by national electricity generation (orange/blue hatched area), the amount of remaining demand that must be met by electricity import (dark blue), and the estimated demand of EV charging (light blue). Please note that electricity generation is represented as an offset to the total import requirement, and so is shown in this graph as a negative value.

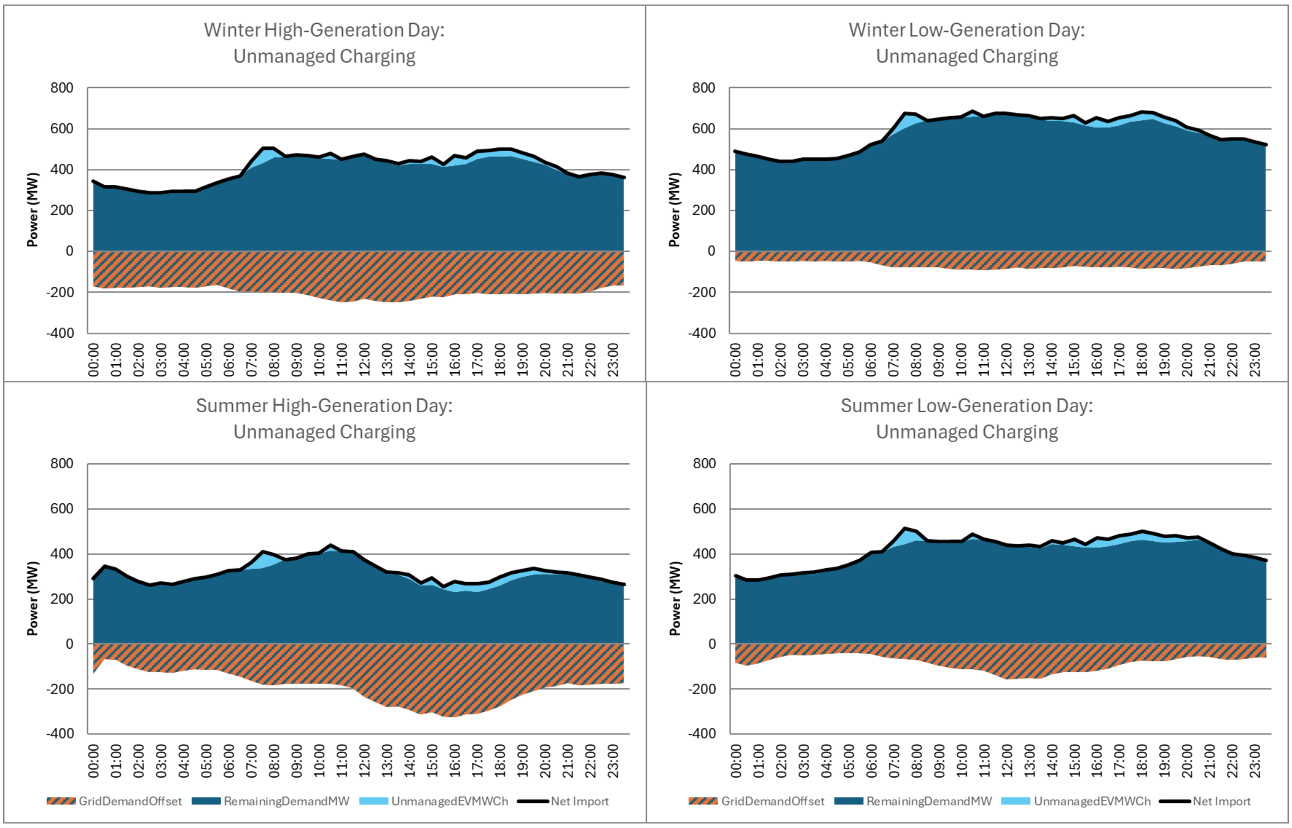

Figure 17: 2023 Unmanaged Demand, Generation and Charging Profiles per Reference Day

As the EV parc represents a small portion of the overall national demand in 2023, an unmanaged charging profile does not make a large difference to the daily peak import relative to the existing non-EV demand. However, by deferring EV charging to different times of day for cost optimization, cost savings can be achieved. Using the day-ahead electricity prices described in Section 3.2.5, a baseline of total consumption costs for the combined demand of the Creos grid and unmanaged EV charging was calculated at day-ahead pricing. Optimisation was then run for the EV charging against day-ahead pricing with three different assumptions:

- Day-ahead pricing optimisation with smart (unidirectional) charging only for all vehicles
- Day-ahead pricing optimisation with V2G charging for capable vehicles, smart charging for non-capable vehicles
- Pricing/income optimisation balancing grid services offering and day-ahead pricing to maximise the combined saving from grid services and price offset.

The total baseline national consumption costs and relative savings of each optimization run are described in Table 6 and Table 7.

Table 6: Summary of Potential Savings against Unmanaged Charging in EUR

Plug-in behaviour	Reference Day	Winter High-Generation 13 January 2023	Winter Low-Generation 25 January 2023	Summer High-Generation 02 August 2023	Summer Low-Generation 28 August 2023
Incentivised	**Baseline National Consumption Costs at Day-Ahead Pricing (Unmanaged EV Charging)**	**1071k EUR**	**2976k EUR**	**913k EUR**	**1450k EUR**

	Saving Cost-Optimised Smart Charge	24k EUR	22k EUR	13k EUR	18k EUR
	Saving Cost-Optimised V2G	28k EUR	24k EUR	15k EUR	20k EUR
	Saving Combined Grid Services & Cost Optimised V2G	36k EUR	30k EUR	32k EUR	28k EUR

Table 7: Summary of Potential Savings against Unmanaged Charging as a percentage of Cost of National Consumption

Plug-in behaviour	**Reference Day**	Winter High-Generation **13 January 2023**	Winter Low-Generation **25 January 2023**	Summer High-Generation **02 August 2023**	Summer Low-Generation **28 August 2023**
Incentivised	**Baseline National Consumption Costs (Unmanaged EV Charging)**	**1071k EUR**	**2976k EUR**	**913k EUR**	**1450k EUR**
	Saving Cost-Optimised Smart Charge	2,2%	0,7%	1,5%	1,2%
	Saving Cost-Optimised V2G	2,6%	0,8%	1,7%	1,4%
	Saving Combined Grid Services & Cost Optimised V2G	3,3%	1,0%	3,5%	1,9%

The savings described in the tables above represent total possible savings available from day ahead wholesale price optimisation and selected grid services. The REVOLVE model is a price-taker and perfect foresight optimisation model. Hence actual savings would be reduced depending on price and plug-in behaviour forecast errors and bid acceptance rates in wholesale and grid service markets. These savings would also be split between possible stakeholders in the energy value chain (EV users, chargepoint operators, energy suppliers, aggregators). The split itself would be determined by the business model in operation for the provision of flexibility.

The savings presented for the grid services simulations above include the combined effect of cost savings from EV charging and income from grid services. The grid services income is assumed to offset some import costs and so is presented as part of the total savings. A breakdown of the grid services power offered for each reference day in the final optimisation run is shown in Figure 18, with the income from these offers in Table 8. It was assumed that all bids offered by the portfolio are accepted and thus income is received for all grid services offered. Where grid services products also have a separate utilisation price (aFRR), it was assumed that 5%[28] of offered flexibility would be utilised, resulting in an additional utilisation income of 5% of the possible flexibility offered.

For the 2023 simulations, the total power offering does not exceed the TSO requirement (i.e. volumes procured by Amprion) for any product (shown in dashed lines in Figure 18). This effect makes a larger impact when the potential offering can exceed the total TSO requirement and is explained in further detail for the 2030 simulations in Section 4.3.2.

Table 8: Simulated Grid Services Income per 2023 Reference Day

Income	Winter High-Generation 13 January 2023	Winter Low-Generation 25 January 2023	Summer High-Generation 02 August 2023	Summer Low-Generation 28 August 2023
Availability Income from Grid Services	€ 7.753	€ 5.458	€ 16.002	€ 5.672
Utilisation Income from Grid Services at 5% Utilisation	€ 3.452	€ 2.338	€ 4.968	€ 4.474
Total Income	**€ 11.205**	**€ 7.795**	**€ 20.970**	**€ 10.145**

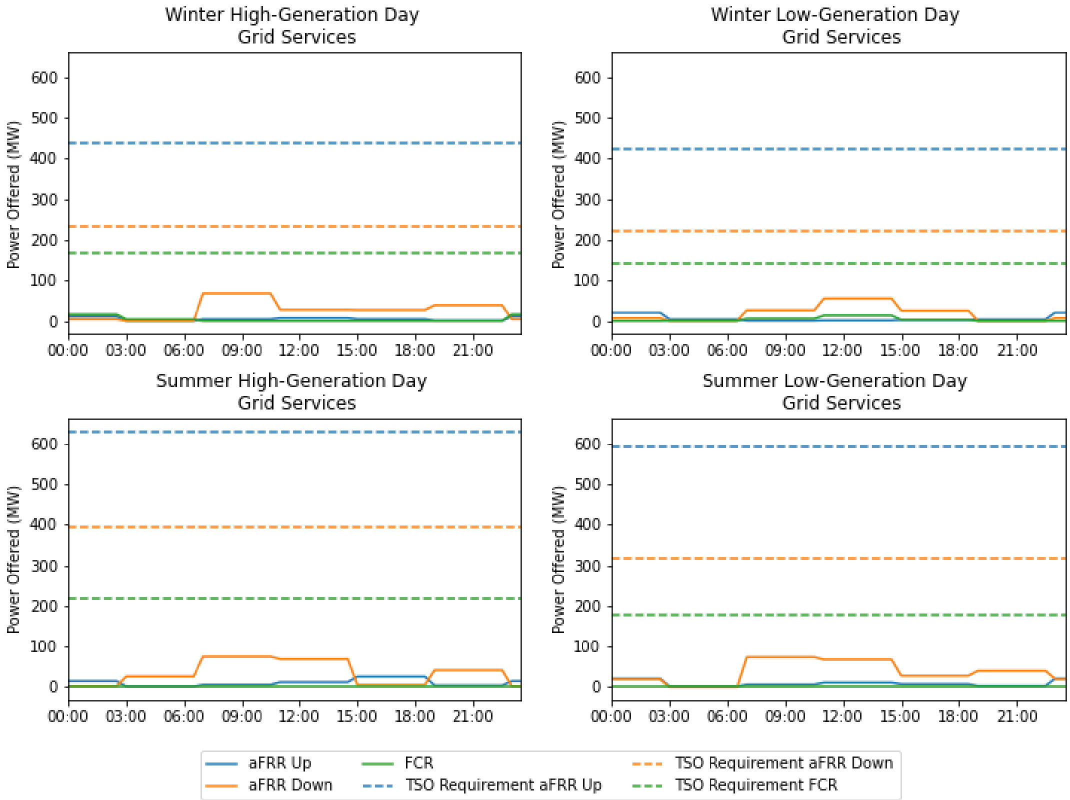

Figure 18: Optimised Hourly Grid-Services Offering, 2023 Reference Days

3.3.3 Influence of V2G vs Smart Charging

The main calculations in this report assume that all V2G capable vehicles within the EV parc can be used for bidirectional charging each time they plug in. To show the difference in potential saving made by the use of V2G beyond the saving that can be achieved by smart charging alone, an additional simulation was run where all vehicles were assumed to only be capable of unidirectional smart charging. A summary of the marginal saving on total national electricity consumption costs between the smart and V2G simulations is shown in Table 9.

Table 9: Additional benefit per V2G-enabled Vehicle in each Reference Day, 2023

	Number of vehicles		Cost-Optimised Smart Charging		Cost-Optimised without Grid Services		Cost-Optimised with Grid Services	
Day	Number Electric Vehicles	Number V2G Vehicles	Marginal Benefit Unmanaged vs Smart Charging (EUR)	Benefit per EV	Marginal Smart vs V2G Saving (EUR)	Benefit per V2G Vehicle	Marginal Smart vs V2G Saving (EUR)	Benefit per V2G Vehicle
13 January 2023	33.092	1.986	23.504	0,71	4.137	2,08	5.444	2,74
25 January 2023	33.092	1.986	22.205	0,67	1.385	0,70	4.336	2,18
02 August 2023	33.092	1.986	13.247	0,40	2.112	1,06	4.489	2,26
28 August 2023	33.092	1.986	17.751	0,54	1.865	0,94	3.738	1,88

3.3.4 Influence of Driver Plug-in Behaviours

This section presents the influence on available flexibility and potential cost savings caused by different assumptions on driver plug-in behaviours. The savings shown in Section 3.3.2 represent a best-case where drivers are incentivised to plug in every day. Figure 19 shows the difference in the hourly total number of EVs connected under the different behaviours described in Table 5.

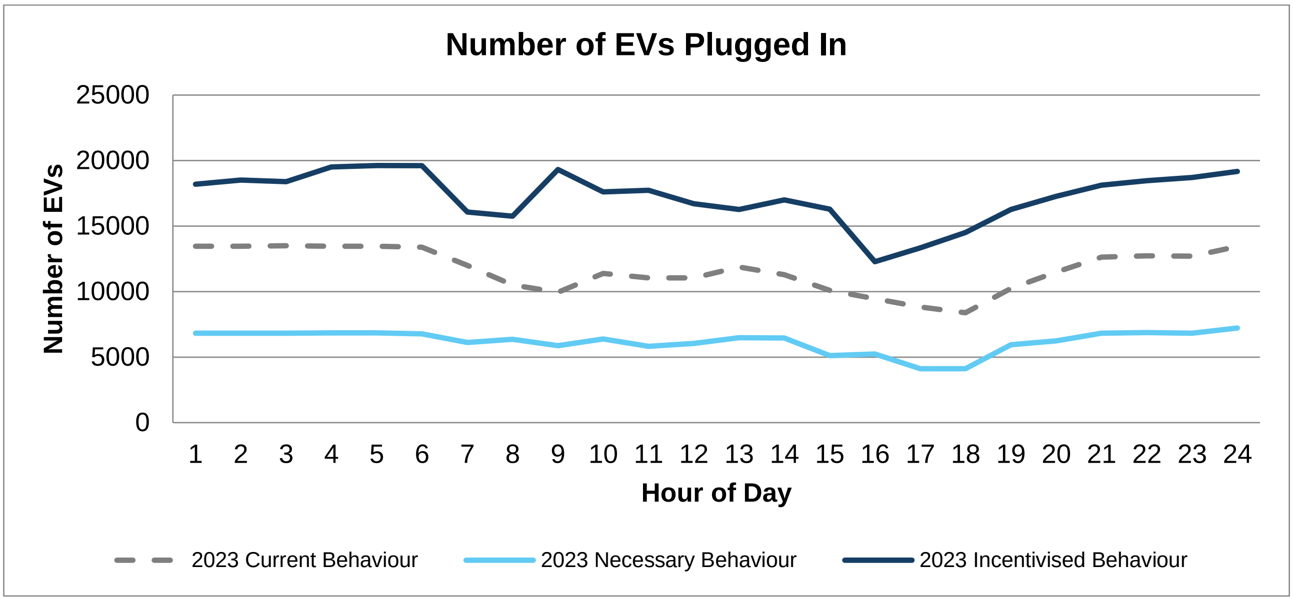

Figure 19: Number of Plugged-in Vehicles under Different Driver Behaviours, 2023

As shown in the figure, the potential available resource for flexibility can be significantly affected by how frequently drivers plug in their vehicles. Under a simulated unmanaged charging strategy (where vehicles charge at full power from the time of plug-in until the battery is full) the PiNC[29] (plugged in, not charging) time is shown in Table 10.

[29] Plugged-In Not Charging (PINC) is a metric that measures the flexibility of EV charging. As a percentage it gives the proportion of the time a vehicle is spent plugged in and not charging. The greater the value the greater the flexibility. An EV charged at home overnight might only charge for 2 hours of a 10 hour plug-in window over a 24 hour period, giving a PINC time of 33%. However, an EV only ever charged at en route rapid chargers might have a PINC time of 0%, indicating no dormant time at a chargepoint.

Table 10: Summary of Plugged-in-Not-Charging Time as a Percentage of Total Vehicle Hours

	Necessary (Minimum) Plug-in	Current (Medium) Plug-in	Incentivised (Maximum) Plug-in
Percentage of Total Vehicle Hours	14%	31%	48%
Average PiNC Total Daily Vehicle-Hours	113.345	243.159	377.299

For each behavioural scenario, a separate cost optimisation was simulated. The potential savings against unmanaged charging in each scenario are presented in Table 11 and Table 12.

Table 11: Summary of Potential Savings against Unmanaged Charging in EUR for different Plug-in Behaviours

	Reference Day	Winter High-Generation 13 January 2023	Winter Low-Generation 25 January 2023	Summer High-Generation 02 August 2023	Summer Low-Generation 28 August 2023
Incentivised	**Baseline National Consumption Costs (Unmanaged EV Charging)**	**1071k EUR**	**2976k EUR**	**913k EUR**	**1450k EUR**
	Saving Cost-Optimised Smart Charge	24k EUR	22k EUR	13k EUR	18k EUR
	Saving Cost-Optimised V2G	28k EUR	24k EUR	15k EUR	20k EUR
	Saving Combined Grid Services & Cost Optimised V2G	36k EUR	30k EUR	32k EUR	28k EUR
Current	Saving Cost-Optimised Smart Charge	23k EUR	22k EUR	14k EUR	14k EUR
	Saving Cost-Optimised V2G	25k EUR	22k EUR	15k EUR	15k EUR
	Saving Combined Grid Services & Cost Optimised V2G	31k EUR	26k EUR	27k EUR	21k EUR
Necessary	Saving Cost-Optimised Smart Charge	17k EUR	15k EUR	11k EUR	10k EUR
	Saving Cost-Optimised V2G	18k EUR	15k EUR	11k EUR	10k EUR
	Saving Combined Grid Services & Cost Optimised V2G	23k EUR	20k EUR	18k EUR	14k EUR

Table 12: Summary of Potential Savings against Unmanaged Charging as a Percentage for different Plug-in Behaviours

	Reference Day	Winter High-Generation	Winter Low-Generation	Summer High-Generation	Summer Low-Generation
Incentivised	**Baseline National Consumption Costs (Unmanaged EV Charging)**	**1071k EUR**	**2976k EUR**	**913k EUR**	**1450k EUR**
	Saving Cost-Optimised Smart Charge	2,2%	0,7%	1,5%	1,2%
	Saving Cost-Optimised V2G	2,6%	0,8%	1,7%	1,4%
	Saving Combined Grid Services & Cost Optimised V2G	3,3%	1,0%	3,5%	1,9%
Current	Saving Cost-Optimised Smart Charge	2,1%	0,7%	1,5%	1,0%
	Saving Cost-Optimised V2G	2,4%	0,8%	1,6%	1,1%

	Saving Combined Grid Services & Cost Optimised V2G	2,9%	0,9%	3,0%	1,5%
Necessary	Saving Cost-Optimised Smart Charge	1,6%	0,5%	1,2%	0,7%
	Saving Cost-Optimised V2G	1,7%	0,5%	1,2%	0,7%
	Saving Combined Grid Services & Cost Optimised V2G	2,1%	0,7%	2,0%	1,0%

3.4 Contribution to the increase in the share of renewable energy

Luxembourg currently imports a majority of its energy, with generation never exceeding existing demand within the 2023 reference year. Due to this, the use of EV flexibility would not be needed to support an increased self-consumption of renewable energy at a national level. However, the existing EV parc could be used to help absorb an expanded renewable generation installation. This section details the maximum potential renewable generation that could be supported by the current grid demand and EV parc, based on the four selected reference days.

The constraints applied to this assessment were:

- National level: no export of renewable generation. It is assumed that if Luxembourg is generating enough excess energy to export, that this may also be true of neighbouring countries, or at least prices will be extremely low which could result in subsequent renewable generation build becoming uneconomic.
- Grid region level: each region must not exceed its current grid capacity in export to other regions.

The calculations were completed using the following method:

- Renewable energy is maximised by simulating a proportionate increase in the installed capacity of PV and Wind until national-level export is reached on at least one of the reference days. This calculation gives a national-level multiplier for renewables.
- Applying the national-level multiplier to each region individually to check that the export from any individual region does not exceed its planned grid capacity.
- If any region is exceeded on one or more of the reference days, the multiplier for that region is decreased until maximum export falls below the grid capacity of the region.

There are challenges with where to set the limit of increasing the installed capacity of renewables. The aim of this part of the analysis is to understand how much flexibility from the EV parc can increase the renewable share of the energy consumed within Luxembourg. It is true that the highest share of renewables in final consumption would happen when the installed renewables capacity has reached theoretical limits of what could be installed in the country. However, this would result in network constraints causing large volumes of energy to be spilt and consequently renewables that are uneconomic to build. Therefore, a limit to renewable capacity must be set lower than theoretical maximum levels. Calculating a limit based on the addition of a marginally economic renewable generator is beyond the scope of this work. So, a simple limit was chosen where renewable energy capacity was increased until renewable energy export can no longer be avoided. This simple limit provides an approximate, though likely conservative, estimate of when the grid begins to fail to fully absorb renewable energy.

It was assumed that hydroelectric power is already making maximum use of potential resource due to the minimal difference in planned hydroelectric installation between 2020 and 2030[30]. Hydroelectric is therefore not considered for increase. Similarly, other generation sources such as biomass were also excluded from this calculation and were assumed to stay constant. PV and wind installations were increased proportionately to the current installed capacity within each grid region

[30] Electricity Transmission Grid Scenario Report 2040; Version 2022; p.75

of Luxembourg. It is beyond the scope of this study to verify whether such an increase is feasible in each region, or if the relative proportion of installed energy in each region is likely to change.

The results of this process are presented in Table 13, showing that the PV and wind capacity within the country could be approximately doubled before reaching the point of exporting energy within the reference days tested. Please note that the assumed current installed capacity was taken from the only data source that provided both an installation date and location for each installation, which was filtered to include only installations marked as having an active contract at some point within the year 2023[31]. In the results table, the maximised installed capacity for 2023 represents the highest upscale factor for PV and Wind that could be supported by the current demand/EV parc before the described local and national export conditions are met.

A visualisation of the hourly profile of generation, demand, and EV charging is shown in Figure 20. Here it can be seen that the limiting day is the summer high-generation day, where peak generation of the increased installation matches demand during the afternoon.

Table 13: Current Installed Capacity vs Maximised Installed PV and Wind Renewables Capacity in Each Region

	Current Installed Capacity 2023 PV (MW)	Current Installed Capacity 2023 Wind (MW)	Assumed Grid Capacity Limit in 2023 (MW)[32]	Renewable Installed Multiplier	2023 Maximised Installed Capacity PV (MW)	2023 Maximised Installed Capacity Wind (MW)
Total	**371**	**198**	**n/a**	**1,95**	**723**	**331**
Central	28	0	330	2,16	60	0
North	117	145	140	1,50	176	217
East	66	16	120	2,16	143	34
Southeast	51	26	140	2,16	110	56
Southwest	49	4	180	2,16	107	9
West	59	7	140	2,16	127	15

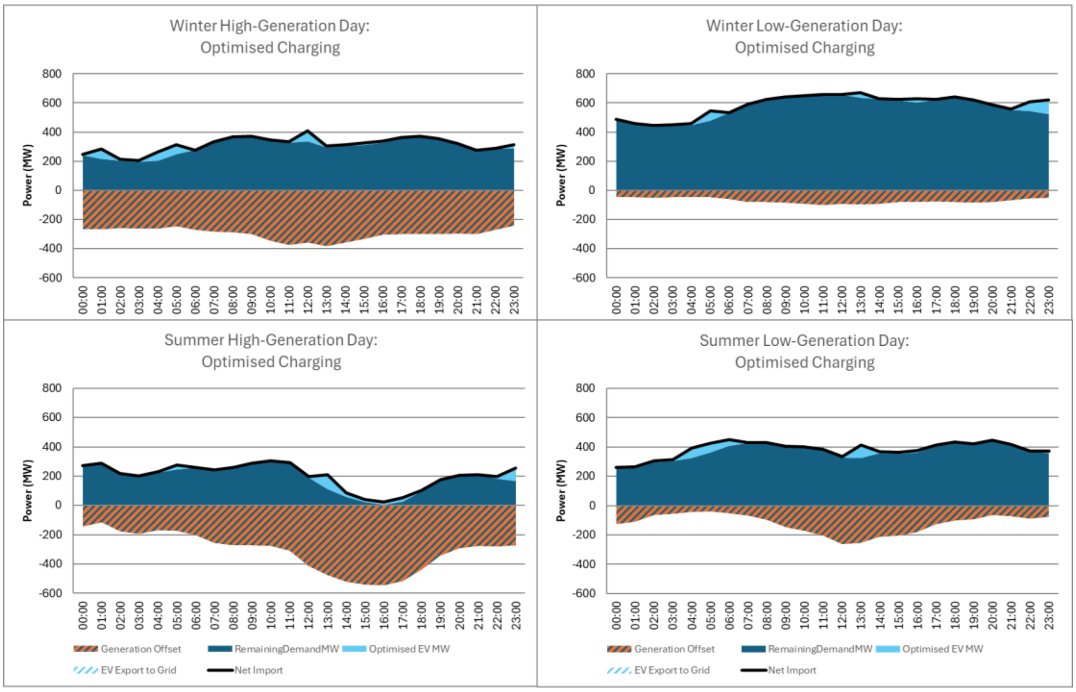

Figure 20: EV Charging Optimised for Increased Renewables Installation, 2023 Reference Days

[31] "Installed generation capacity", ILR data

[32] Creos Grid Upgrade Data; Creos 2024

The above analysis aims to increase the percentage of national demand that is met by renewable generation sources. For each of the four reference days, the total daily energy demand was calculated. Renewable generation was assumed to comprise total generation from PV, wind, hydroelectric and biomass installations, where hydroelectric and biomass generation were taken directly from the 2023 transmission network load data and PV/wind were simulated based on energy per installed capacity in the reference year. A summary of the share of both baseline and increased renewables for each of the reference days is shown in Table 14. As the EV parc represents a small proportion of the overall demand, optimised charging patterns do not contribute significantly to an overall increase in renewable share for the 2023 reference year.

Table 14: Current and Maximised Renewables Share for 2023 Reference Days

Scenario	Summer Low Generation 28/08/2023	Summer High Generation 02/08/2023	Winter Low Generation 25/01/2023	Winter High Generation 13/01/2023
Daily Total Demand (Creos Grid + EV Charging) MWh	**12.086**	**12.340**	**15.710**	**14.658**
Current Renewables, Unmanaged	13,3%	33,2%	5,9%	29,1%
Increased Renewables, Unmanaged[33]	20,0%	55,2%	6,3%	45,0%
Increased Renewables, Optimised for Absorption	20,0%	55,2%	6,3%	45,0%

[33] Note that this calculation uses the same installed renewables capacity as the optimised case, as described in Table 13.

4 2030 Assessment of Flexibility from Electric Vehicle Infrastructure

This chapter describes the methodology for modelling the contribution of EVs to the Luxembourg grid in 2030, including the forecasting of the data required to create the scenarios.

Then the simulation results for the 2030 scenario are shown regarding flexibility and renewables absorption.

4.1 Modelling approach

The fundamental modelling approach compared to the 2023 scenario remained unchanged for consistency. The four typical days described previously were used, the geographical division into the six grid zones was maintained, and 2030 forecasts for EV parc, EV charging demand, non-EV electricity demand, renewable energy generation, prices of electricity and prices of flexibility services were used. The forecast methodology is described in the following section.

4.2 Model inputs: forecasts for 2030

4.2.1 EV data

Three EV uptake rates were determined, with the low scenario aligning to the NECP reference scenario[34], the high scenario aligning to the NECP target scenario, and the mid scenario halfway between them. These can be seen in Figure 21. New PHEVs are added each year at a consistent proportion to the current ratio of PHEVs to BEVs (40%).

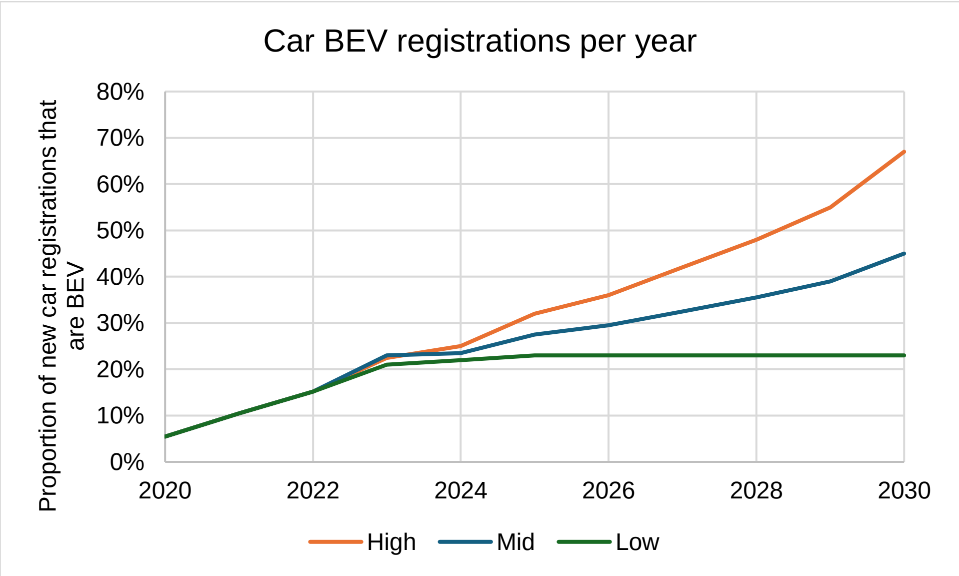

Figure 21: EV uptake scenarios

These new vehicles were added to the vehicle parc each year, and old vehicles were removed. Regarding frontier workers, the same EV uptake rates and private charging likelihood as for the whole of Luxembourg were assumed, resulting in 33.400 additional frontier EVs in 2030 that will charge at *workplaces* in the high scenario (27.900 in mid and 22.400 in low). The total number of EVs in 2030 are shown in Table 15.

[34] Plan national intégré en matière d'énergie et de climat du Luxembourg pour la période 2021-2030; July 2024

Table 15: 2030 forecast for electric cars and vans.

	2023	2030 - Low	2030 - Mid	2030 - High
Car - BEV	22.636	102.184	127.434	152.684
Car - PHEV	15.126	41.932	55.432	75.432
Van - BEV	650	4.316	6.293	8.271

Building on the assumed 6% of vehicles which have V2G capability in 2023[35], it is assumed that 100% of new vehicles sold will be V2G capable in 2035. An exponential curve is fitted to these two points and included in the vehicle uptake model, which results in 22% of the total cars and vans being V2G capable in 2030.

Earlier Cenex work[36] for the Luxembourg Ministry of Energy and Regional Planning was used for future estimations of the number of electric HGVs in Luxembourg. The forecasts on number of HGVs in Luxembourg in 2030 are shown in Figure 22, where the two developed scenarios for eHGV forecasts were the Memorandum of Understanding (MoU) scenario and the German scenario.

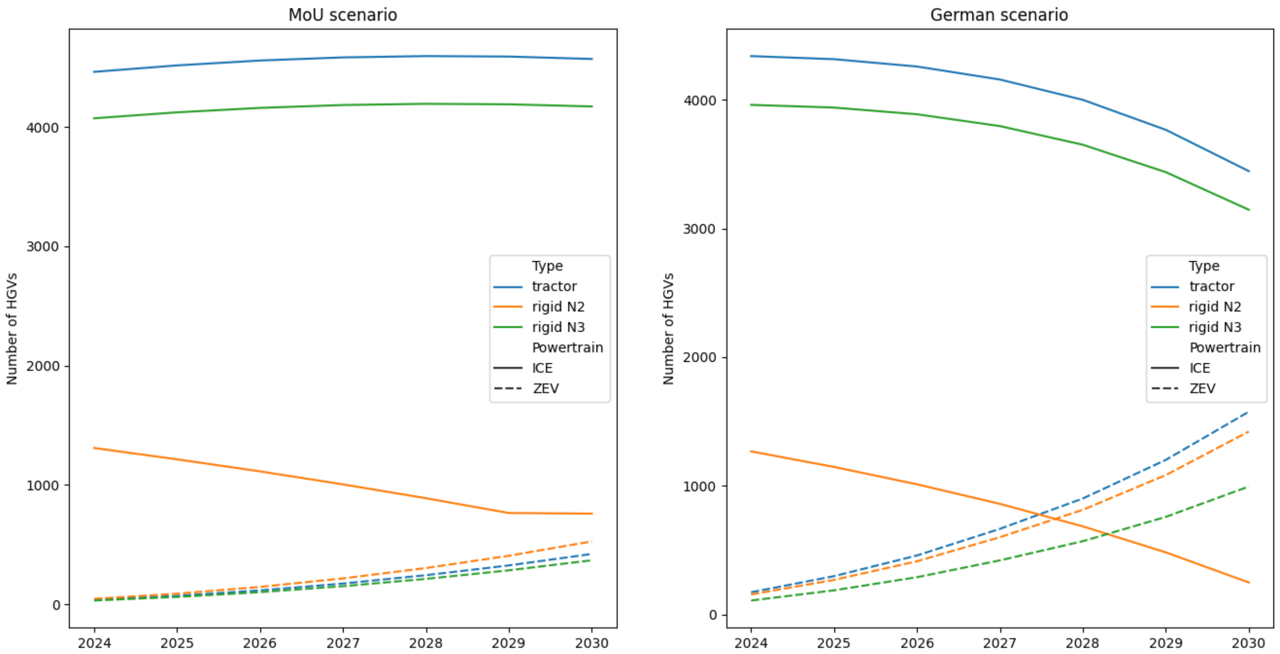

Figure 22: The two forecast scenarios for the number of HGVs in Luxembourg in 2030. Tractor stands for articulated tractor-trailer HGVs with usually a maximum mass of 44 tonnes. N2 rigid HGVs have a maximum mass between 3.5 and 12 tonnes, and N3 rigid HGVs higher than 12 tonnes. ICE stands for internal combustion engine and ZEV stands for Zero Emission Vehicle.

The MoU scenario was based on the MoU signed by countries that are leading the process of electrification, including Luxembourg. This MoU committed to a target for all new medium and heavy duty vehicles (MHDVs) sold to be zero emission by 2040 with an interim target of 30% by 2030. The German scenario on the other hand, was based on the target of 33% of the fleet being zero emission vehicles by 2030. These scenarios differed on both the final number as well as the rate of adoption of electric HGVs in Luxembourg in 2030. This work uses the MoU scenario, since it is based on Luxembourg's stated policy and targets.

[35] https://www.mobilityhouse.com/int_en/knowledge-center/article/which-cars-are-v2g-capable

[36] Transport durable - Klima an Energie - Portail de l'environnement - emwelt.lu - Luxembourg

V2G-enabled HGVs are still in a technology demonstrator stage currently, and it is uncertain if and when this technology will be widely adopted. In this analysis, it was assumed that 10% of the trucks in 2030 will have V2G capability.

4.2.2 EV plug-in profiles

Vehicle archetypes

For cars and vans, the only difference with 2023 was an assumed increase in battery capacity of 20% by extrapolating historic data on average capacity across different vehicle sizes. HGV archetypes were created based on the cited earlier Cenex work.

Table 16: 2030 vehicle archetype attributes

Vehicle type	Annual km	kWh/km	kWh per day	Battery capacity (kWh)
Car	16.000	0,2	8,4	54
Van	20.000	0,29	15,7	90
HGV – N2 rigid	15.000	0,4	24	200
HGV – N3 rigid	35.000	1,32	185	330
HGV – N3 tractor	110.000	1,65	602	650

Charging times

For cars and vans, there were no changes in charging times compared to 2023.

For HGVs, based on the three archetypes and the estimated number of trucks per grid region, charging profiles were built up. For HGVs, the typical times and durations of operation were based on the data obtained during surveys earlier conducted among fleet operators in Luxembourg based on the cited earlier Cenex work. Times of operation obtained from the sample size were assumed to be representative of all fleet operators in Luxembourg.

Charging locations

For cars and vans, there are no changes in charging locations compared to 2023, i.e. the proportion of regional grid zone distribution and charging type were maintained.

For HGVs, all charging was assumed to take place at depots, i.e. there was no explicit modelling of en route charging. Given the lower prices for depot charging in comparison with en route charging and the still-developing infrastructure for high power charging along highways, almost all charging for urban and regional use cases is expected to happen at depots. While long haul vehicles are expected to use en route charging for intercity trips, this share (estimated in Cenex's earlier work at around 18% of all energy consumption of long haul trucks) is expected to be a small fraction of the total energy use at the grid region level, and has local rather than regional level impact. Further, the location of these high power charging stations is yet uncertain. For these reasons, en route charging demand has been neglected in this study.

Data from the earlier Cenex report gave the distribution of trucks (of all powertrains) across Luxembourg by canton. The data focused on depot charging. In this study, the distribution of trucks in Luxembourg in 2030 was assumed to remain similar to that in 2023 i.e. there would be no major movement of depots across the country. The distribution of depots by canton was then aggregated across the country by grid region. Applying the HGV forecasts from the earlier work and the distribution of trucks by grid region, the total number of trucks per grid region in 2030 was obtained.

Charging scenarios

There was no change compared to the 2023 scenarios.

4.2.3 Renewable generation forecasts

The forecasts for renewable energy generation in the Luxembourgish electricity grid in 2030 were taken from the NECP report. The report has two scenarios - the Reference and the Target scenarios - shown below in **Error! Reference source not found.**.

Table 17: Reference and target scenarios for installed capacity in Luxembourg until 2040 based on the National Energy and Climate Plan

All units in MW	NECP Reference scenario			NECP Target scenario		
	2020	2030	2040	2020	2030	2040
Solar PV	175	608	857	175	984	1.800
Wind	146	400	500	146	400	550
Hydro	34	42	43	34	37	40
Biogas and biomass	47	75	100	47	75	110
Waste burning	21	21	21	21	21	21
Cogeneration	63	69	79	63	29	14
Total installed capacity	**487**	**1.215**	**1.600**	**487**	**1.546**	**2.535**

As seen in the table, the difference in the two scenarios for 2030 from each other is primarily in terms of the amount of solar PV installed. The differences in other generation technologies are much smaller in comparison. In early 2025 (midway between 2020 and 2030), Luxembourg had an installed solar PV capacity of 486 MW, which was 80% the 2030 Reference value and 52% of the Target value. As such, it seems very likely that by 2030, the Target value for solar PV will be achieved, and the final capacity mix will be closer to the Target scenario than the Reference one. As such, for renewable energy modelling, the Target scenario was used to inform our estimates for installed capacity in Luxembourg in 2030.

Solar PV and wind energy installations are distributed unequally across the grid regions of Luxembourg, as shown in Figure 23. This distribution was assumed to remain the same, i.e. areas which are currently suitable for wind and solar development continue to remain so until 2030.

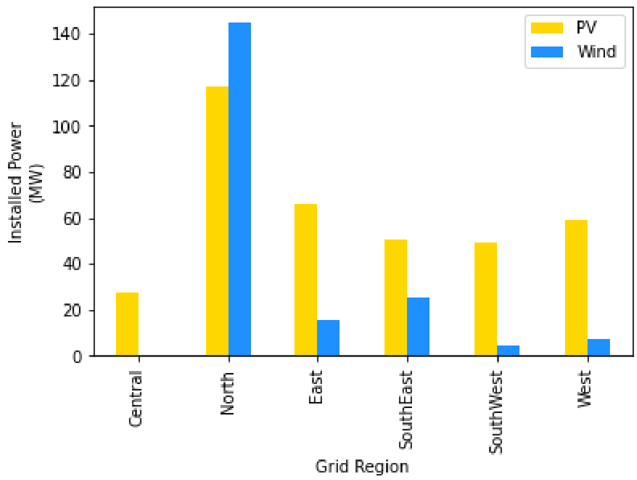

Figure 23: 2023 distribution of solar PV and wind energy installations across the grid regions of Luxembourg

Applying the increase in generation capacity from the NECP, the total generation profile of the country was calculated. Figure 24 shows the difference between the generation profiles over the year in 2023 and 2030. This difference is mainly caused by the increase in installed capacity of solar PV and wind from 371 MW and 198 MW to 984 MW and 400 MW, respectively. Similar weather conditions and performance of technology in 2030 were assumed, along with the distribution of installed capacity across the grid regions. Our four typical days for renewables were then selected from this dataset, being the same as described previously.

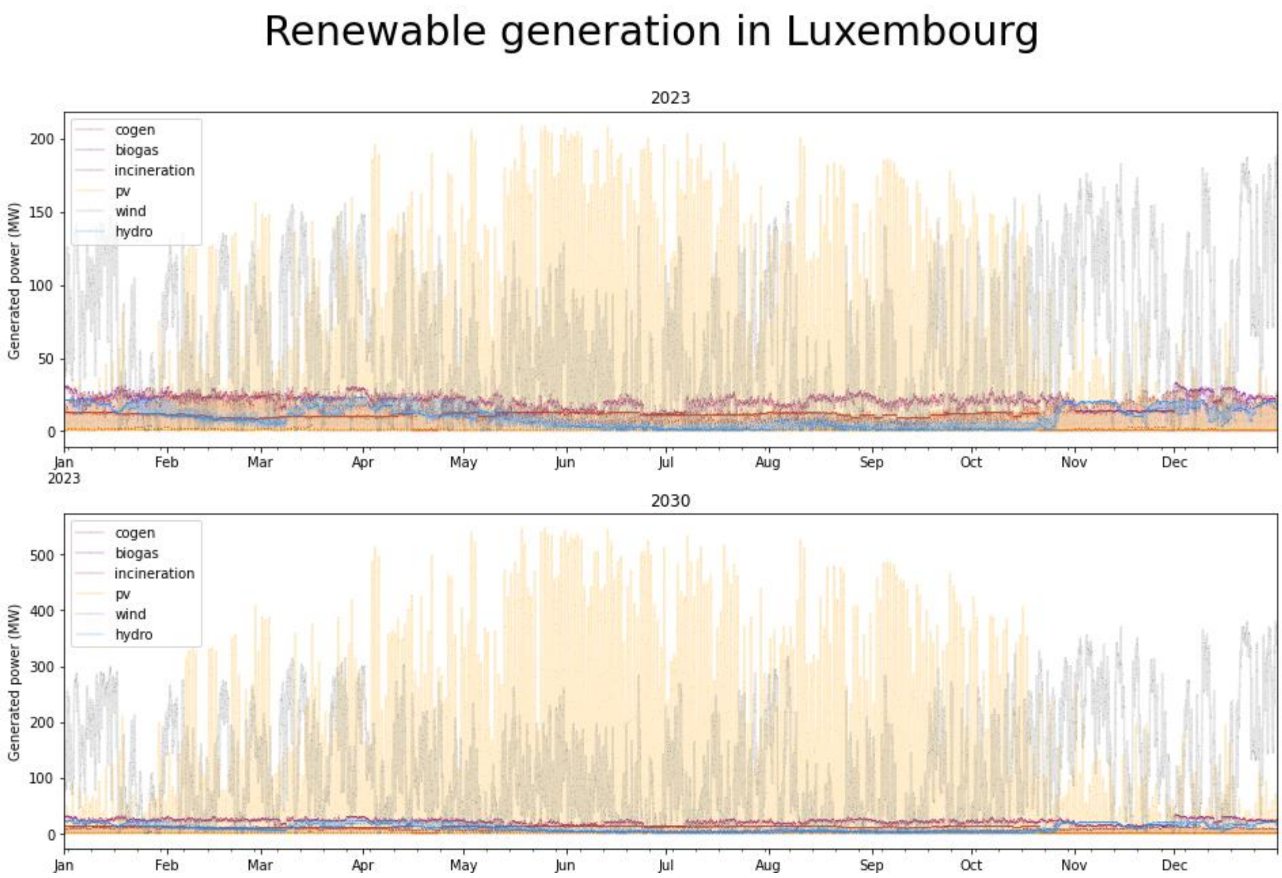

Figure 24: Annual power profile of different generation technologies (top) in 2023 and (bottom) in 2030

4.2.4 Electricity demand forecasts

The forecast for electricity demand in 2030 followed this process:

1. EV demand for both 2023 and 2030 was calculated as explained in previous sections.
2. The total 2023 EV demand was subtracted from the total 2023 electricity demand curve of the Creos grid. This resulted in the 2023 Creos demand profile without EVs.
3. The Sotel grid was assumed to be integrated into Creos by 2030. This comprises mainly an industrial demand in the South of Luxembourg (an equal distribution between South West and South East was assumed).
4. The 2030 EV peak and annual demands were calculated as explained in previous sections.
5. These were then subtracted from the 2030 peak and annual demand of the Creos plus Sotel grids, which were obtained from the NECP and Creos 2040 scenario reports as per Table 18.
6. The 2023 Creos curve from step 2 was then upscaled subject to the conditions that both
   a. the peak electricity demand matched the 2030 forecast and
   b. the total annual electricity demand matched the 2030 forecast.

7. This resulted in the 2030 Creos and Sotel demand profile without EVs, in a way that was consistent with our own EV predictions and also the NECP. The result for the four typical days is shown in Figure 25.

The regional forecast demand was divided by region using the same process as described in Section 3.2.4, but with the upscaled Sotel demand added only to the Southeast and Southwest regions.

Table 18: Upscaling factors used for the 2030 energy demand predictions.

	Creos		Sotel		Creos + Sotel		Scaled EV Charging		(Creos + Sotel) - Scaled EV Charging Curve		
	2023 (Actual)	2030 (Estimate)	2023 (Actual)	2030 (Estimate)	2023 (Actual)	2030 (Estimate)	2023 (Estimate)	2030 (Estimate)	2023 (Estimate)	2030 (Estimate)	% Change
Annual GWh Demand	4719	n/a	1289	n/a	6008	8122	**90,99**	906	**5917**	**7216**	**22%**
Annual Peak MW Demand	807	860	307	n/a	1057	1550	**22,98**	430	**1048**	**1120**	**7%**

Source:	Historical Demand Data	NECP Report	Creos Scenario Report	Cenex EV Uptake figures	**Calculation**

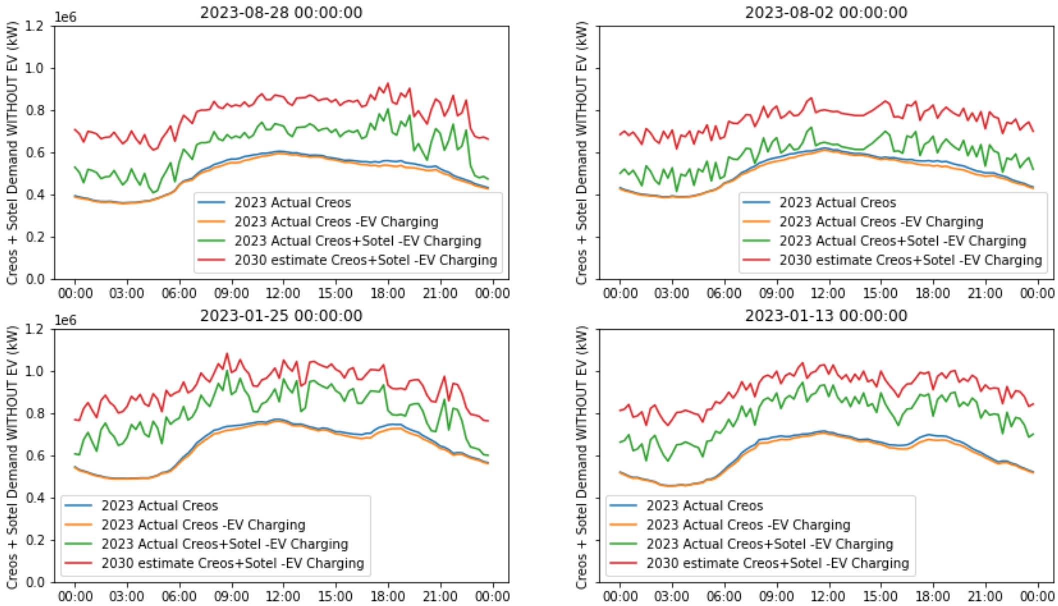

Figure 25: Result for 2030 non-EV electricity demand forecast for four typical days.

4.2.5 Electricity price forecast

A literature review was conducted to find the best available forecasts of German day-ahead electricity prices for 2030. Due to the detailed methods, recent publication (therefore considering the war effects), and the variety of scenarios and influencing factors, the forecasts from Liebensteiner et al.[37] were used, as shown below in Figure 26Figure 26.

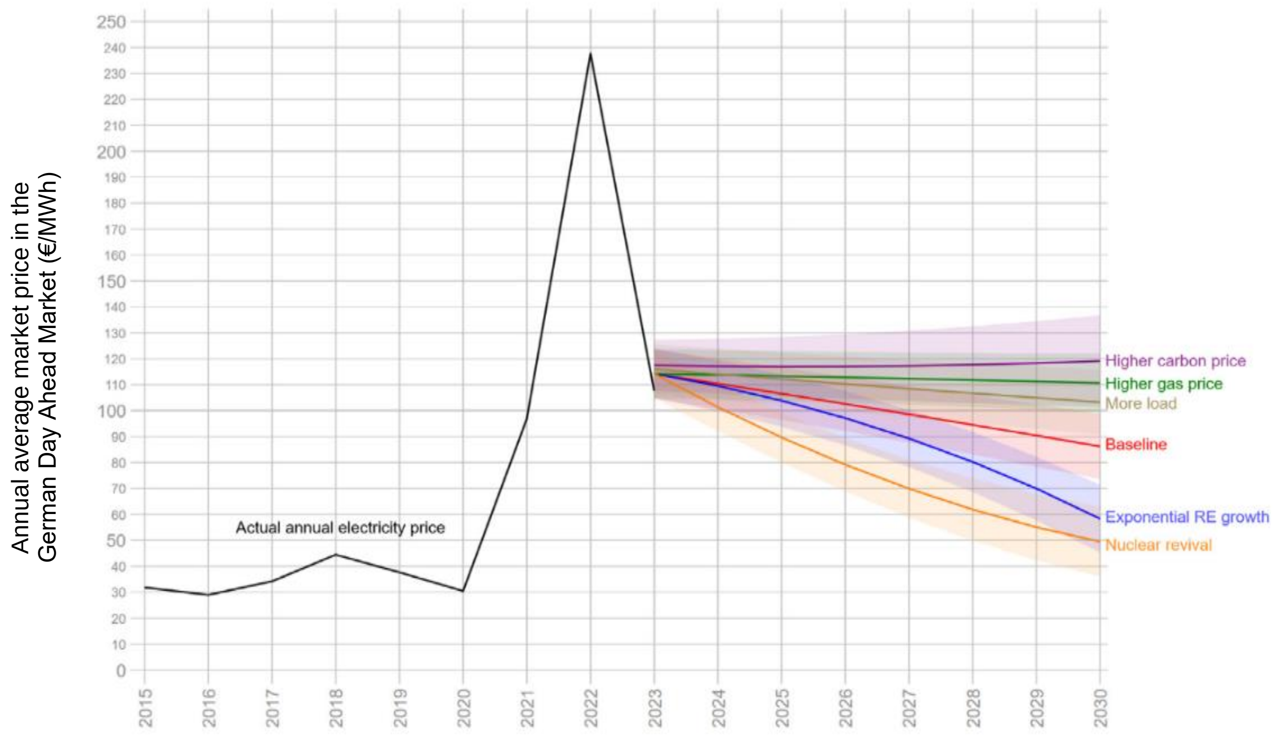

Figure 26: Development of day-ahead electricity prices in €/MWh in Germany, forecast to 2030

The lead author was contacted for the source data, from which the Baseline scenario was used, with a forecast annual mean price of 86 EUR/MWh. The forecast expects a reduction of prices from the average in 2023 (95 EUR/MWh) by 9 EUR/MWh.

Retaining the distribution of electricity prices from 2023, a uniform reduction of 9 EUR/MWh was applied to each hour in 2023 to obtain hourly values for day-ahead market prices for the year 2030, shown in Figure 27.

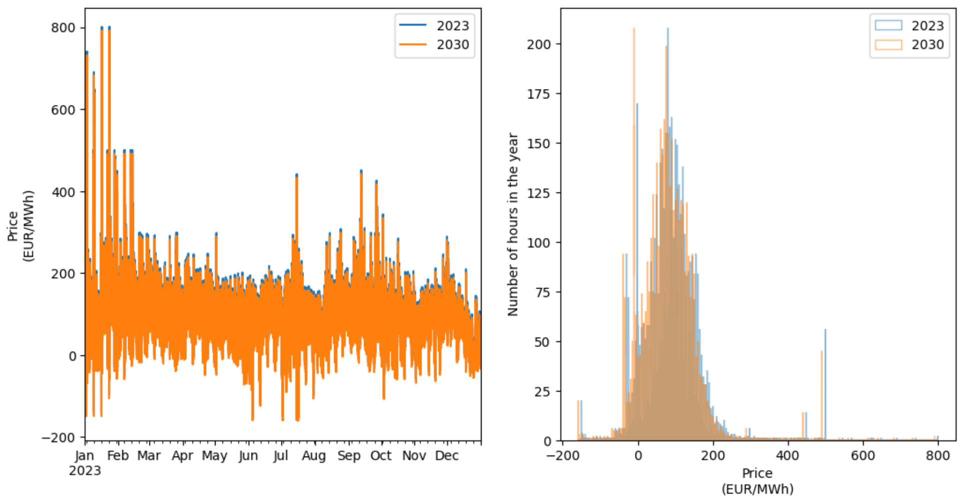

Figure 27: Hourly prices in 2023 and 2030: Timeseries (left) and distribution (right)

[37] High electricity price despite expansion in renewables: How market trends shape Germany's power market in the coming years. Liebensteiner et al., Energy Policy, Volume 198, 2025.

Higher volatility was hence retained (resulting from the effects of the war on electricity prices) while lowering the mean price. Higher price volatility and lower prices on average are both common expectations of future electricity prices, resulting from high shares of variable renewable energy in the grid. The resulting electricity price profiles for the four reference days are shown in Figure 28.

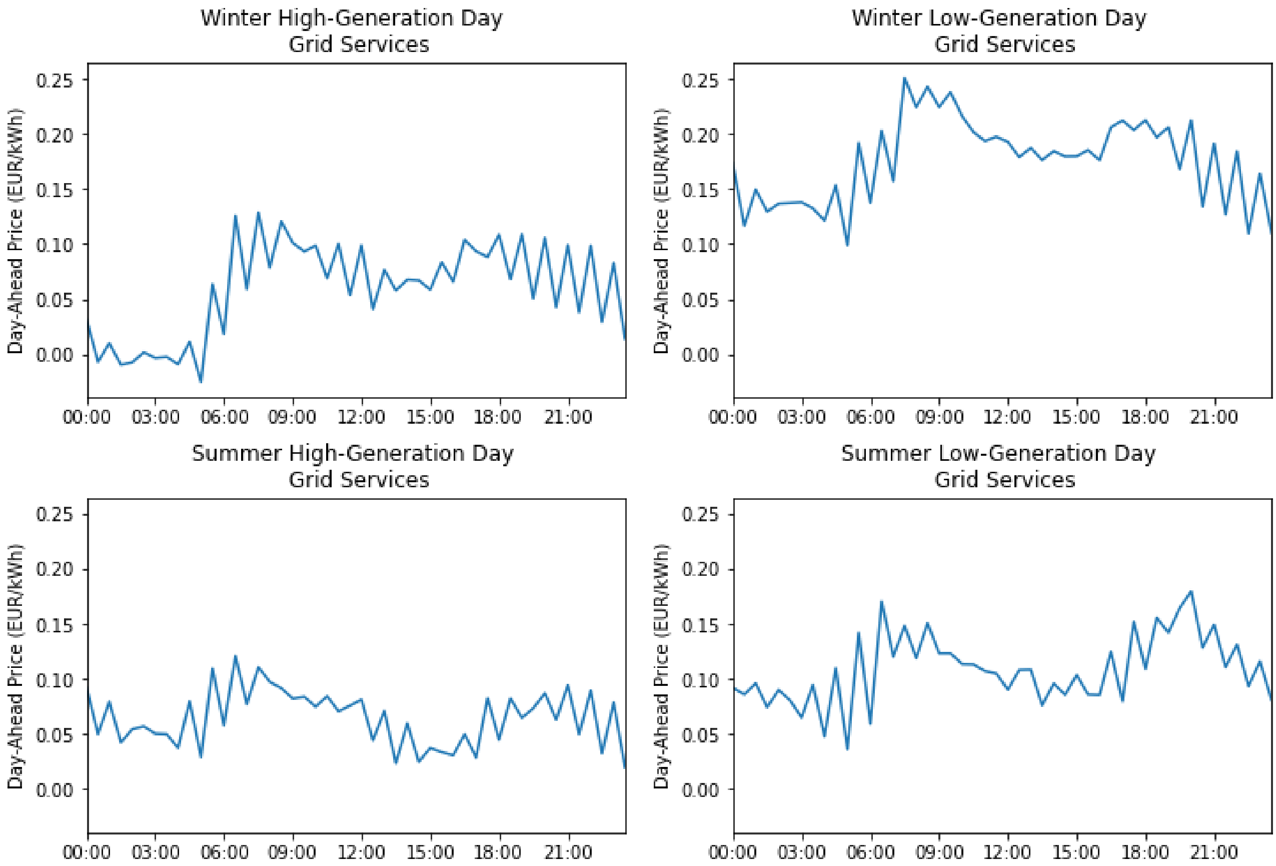

Figure 28: Forecast day-ahead electricity import prices in 2030

4.2.6 Flexibility price forecasts

FCR and aFRR prices were kept constant from 2023 due to lack of available information and uncertainty on their values. Additionally, the total demand from Amprion for grid services was assumed to be the same for our typical days in 2030 as it was in the 2023 historical days.

4.3 Contribution to the flexibility of the energy system

Throughout this section, it is important to note that a central reference scenario was picked assuming both a high uptake of EVs on track with the NECP 'Target' scenario, and user behaviours incentivised to plug in every day. The incentivised behaviour has been used to demonstrate the potential of what smart charging and V2G can achieve in terms of flexibility.

4.3.1 Available Power, Energy Storage for Flexibility

Similarly to the 2023 assessment year, the available number of connected EVs during each hour of the modelled typical weekday is presented in Figure 29.

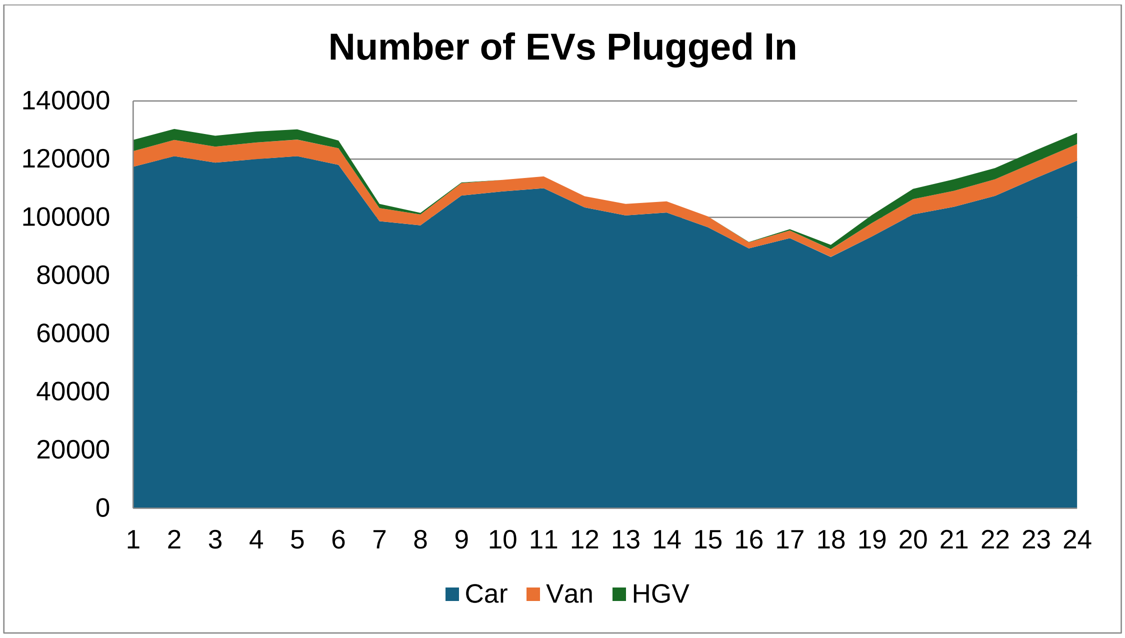

Figure 29: Connected Number of Vehicles per Hour of the Day, 2030 Incentivised Weekday Profile

From a total of approximately 218 thousand electric cars, vans and HGVs estimated to operate within Luxembourg in 2030, the number of vehicles connected to chargers is expected to peak overnight, reaching a maximum of around 130 thousand in the Incentivised scenario. The minimum number of connected vehicles is expected to occur around typical commuting times during the morning and evening, similarly to the 2023 simulation.

Cars, vans, and HGVs were simulated to plug in to different charger powers according to their vehicle type, plug-in location, and plug-in schedule. Figure 30 shows the corresponding average charging power and discharging power of all connected vehicles in each hour of the day. This metric is based on the rated charger power for each vehicle and does not account for the State of Charge (SOC) present in each vehicle battery at the time of connection. The connected charging power peaks at 1.716 MW and the maximum discharge power peaks at 365 MW.

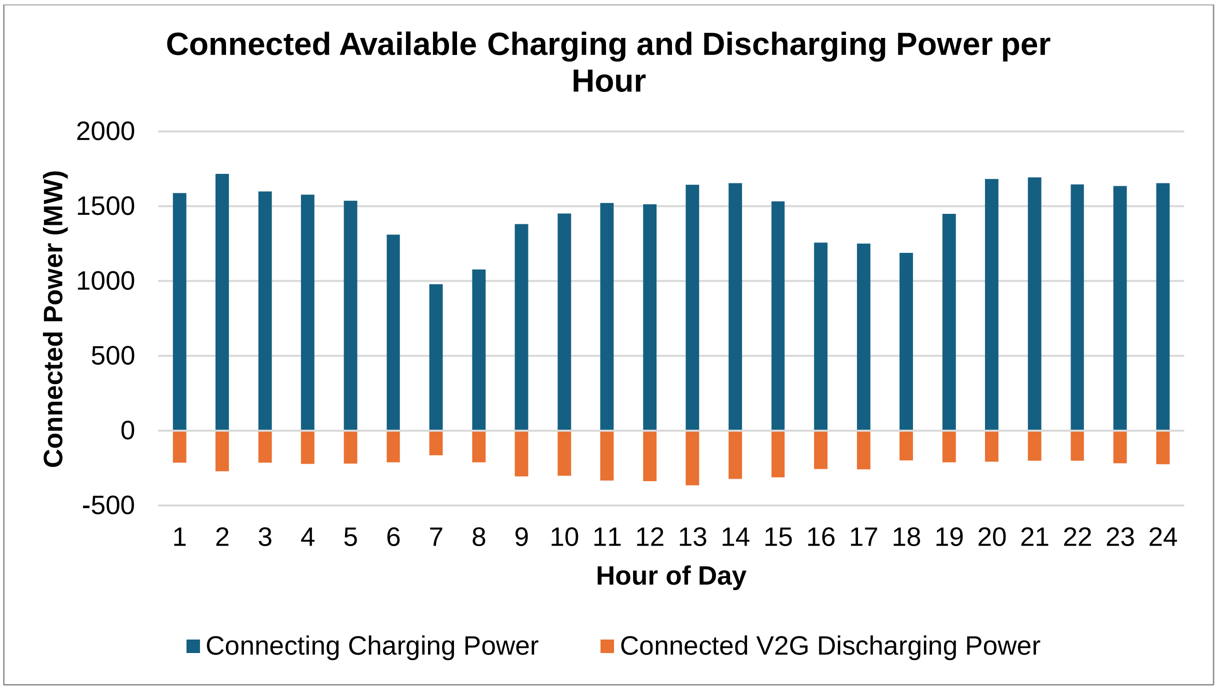

Figure 30: Sum of Charger Power of all Connected Vehicles per Hour of the Day, 2030 Incentivised Weekday Profile

In contrast to the 2023 estimates, the number of V2G capable vehicles is now estimated to make up a greater proportion of the total EV parc, meaning that a larger amount of potential discharging power is connected throughout the day. Due to the impact of depot-based HGVs connecting overnight, the estimated peak connected charging power occurs both during the day due to vehicles plugging in at higher-powered chargers at workplaces or other destinations, and during the night due to HGV depots.

Finally, the available connected energy stored (footroom) within all plugged-in vehicle batteries per hour of the day is shown in Figure 31, minus 20% SOC to consider that users would not allow their batteries to discharge under that value. The SOC at each hour of the day was considered to plot this graph, and it was assumed that vehicles charge in an unmanaged way: charging at the chargepoint's rated power from the time of plug-in, until the battery is full. Note that it was also assumed that the average car and van battery capacity will increase by 20% between 2023 and 2030, based on the evolution of the last 7 years.

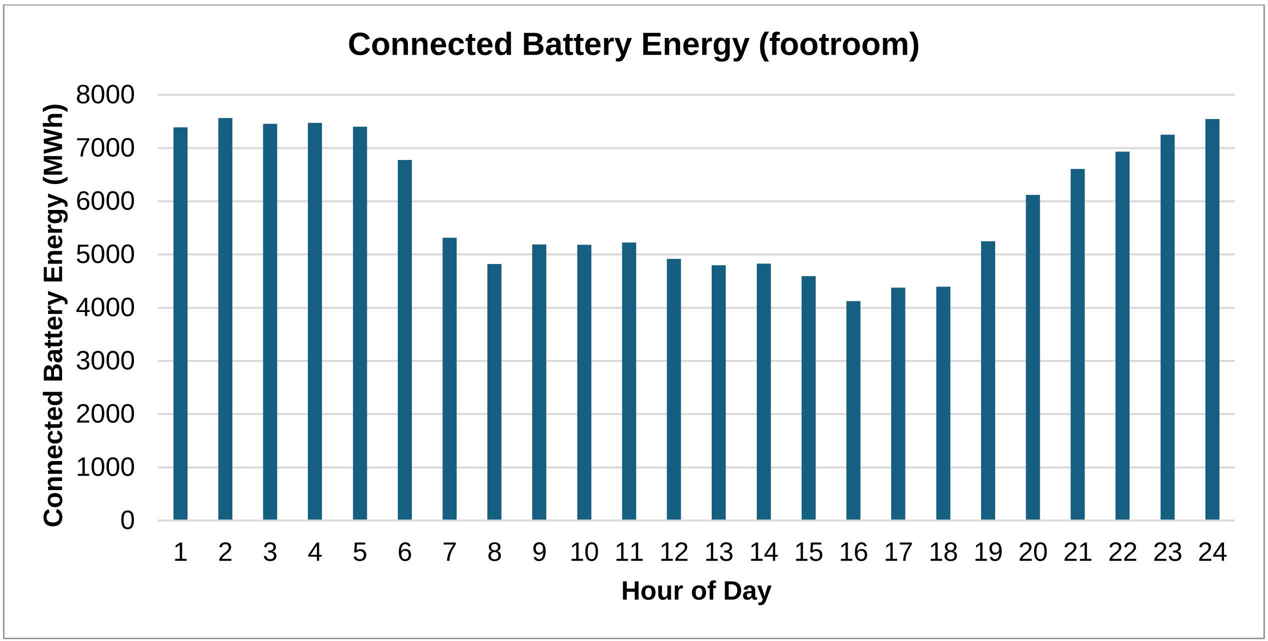

Figure 31: Sum of Connected Battery Capacity per Hour of the Day, 2030 Incentivised Weekday Profile

4.3.2 Cost Optimisation: Maximised Savings from Day-Ahead Pricing and Grid Services

An optimisation process was completed for the 2030 forecast year to best use EV charging for cost minimised smart charging, cost minimised V2G charging, and cost minimised V2G charging with grid services. As with the 2023 simulations, charging profiles for incentivised plug-in behaviour are presented here as an estimate of the maximum possible impact of the EV parc. The influence of different charging behaviours and uptake rates are detailed in Section 4.3.5 and Section 4.3.6.The simulated unmanaged charging profiles for 2030 are shown in Figure 32.

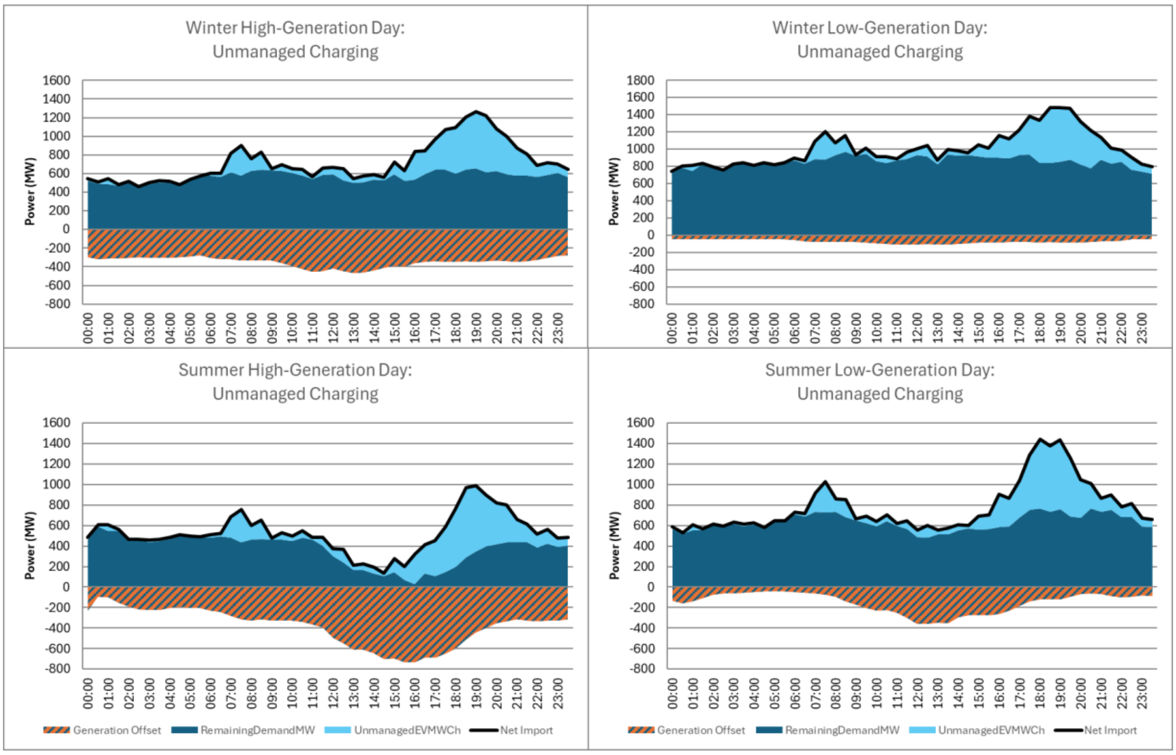

Figure 32: 2030 Unmanaged Demand, Generation and Charging Profiles per Reference Day

As shown in the figures above, the relative contribution of the EV parc to the overall country's demand is significantly larger than in the 2023 reference year. Unmanaged charging would significantly increase the peak demand on the grid as large numbers of vehicles return from daily use and plug in. However, it is reasonable to expect that some vehicle charging would be managed at the charger level by 2030, meaning that the figures above would present a worst-case estimate.

Figure 33 shows the equivalent demand, generation and EV charging for the cost-optimised V2G simulation, where all vehicles are charged during the periods with the lowest day-ahead electricity prices, and V2G-capable vehicles are discharged during periods with the highest prices.

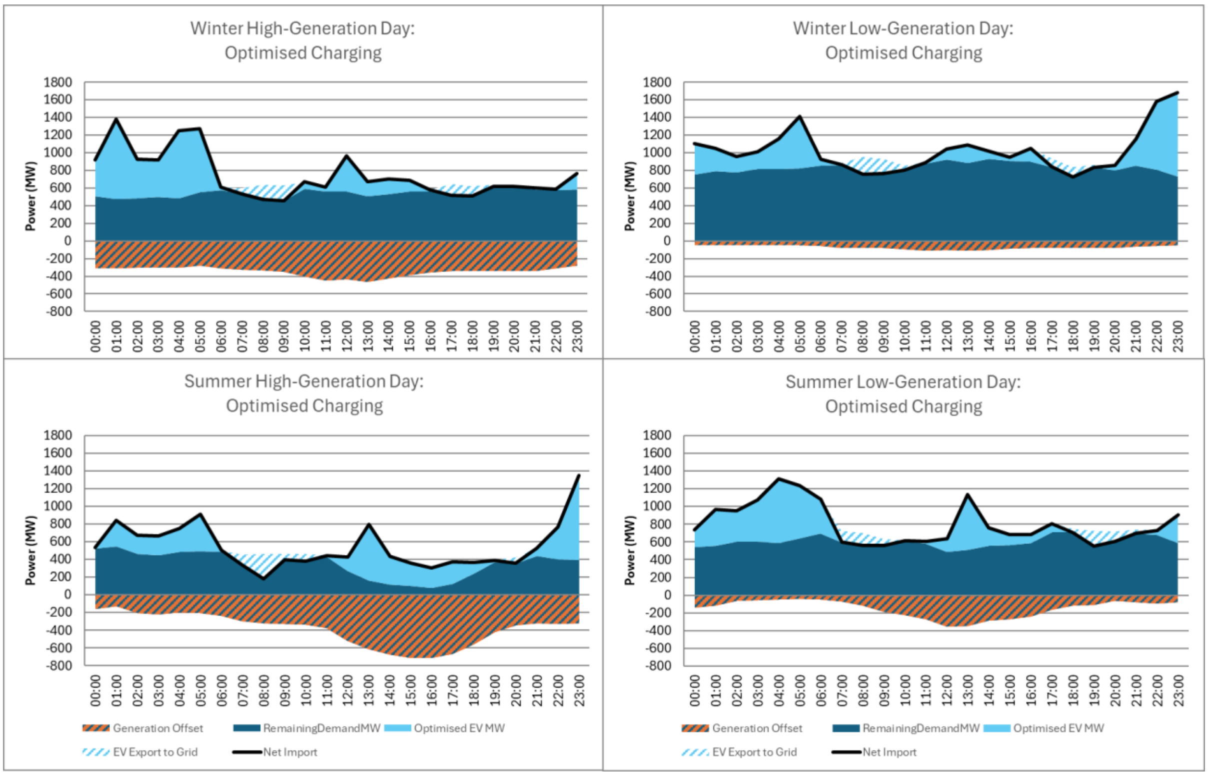

Figure 33: 2030 Cost-Optimised Demand, Generation and Charging Profiles per Reference Day

cenex

The cost-optimised charging has the effect of moving the peak load of EV charge to cheaper times of the day, particularly overnight. However, as each vehicle individually is optimising its charging times against costs, this can lead to spikes in charging power where prices are low for a short time period. For example, the peak power reached at 23:00 in the cost-optimised winter low-generation day is greater than the unmanaged peak power for the same reference day. In reality, such a movement could impact prices (increasing prices in the cheapest periods) and so tempering this effect. However, as discussed in section 3.1 the impact of moving charging demand on prices is outside of the scope of this work.

The total baseline national consumption costs and relative savings of each optimisation run are described in Table 19 and Table 20 respectively.

Table 19: Summary of Potential Savings against Unmanaged Charging in EUR, 2030 Incentivised

	Reference Day	**Winter High-Generation** 13 January	**Winter Low-Generation** 25 January	**Summer High-Generation** 02 August	**Summer Low-Generation** 28 August
Incentivised	**Baseline National Consumption Costs at Day-Ahead Pricing (Unmanaged EV Charging)**	**1650k EUR**	**4677k EUR**	**1417k EUR**	**2532k EUR**
	Saving Cost-Optimised Smart Charge	299k EUR	256k EUR	141k EUR	235k EUR
	Saving Cost-Optimised V2G	403k EUR	291k EUR	195k EUR	280k EUR
	Saving Combined Grid Services & Cost Optimised V2G	427k EUR	322k EUR	249k EUR	326k EUR

Table 20: Summary of Potential Savings against Unmanaged Charging as a percentage of Cost of National Consumption with Unmanaged Charging, 2030 Incentivised

	Reference Day	**Winter High-Generation**	**Winter Low-Generation**	**Summer High-Generation**	**Summer Low-Generation**
Incentivised	**Baseline National Consumption Costs at Day-Ahead Pricing (Unmanaged EV Charging)**	**1650k EUR**	**4677k EUR**	**1417k EUR**	**2532k EUR**
	Saving Cost-Optimised Smart Charge	18,1%	5,5%	10,0%	9,3%
	Saving Cost-Optimised V2G	24,4%	6,2%	13,7%	11,0%
	Saving Combined Grid Services & Cost Optimised V2G	25,9%	6,9%	17,6%	12,9%

As in the reference year simulations, the savings presented for the grid services simulations above include the combined effect of cost savings from EV charging and income from grid services. The grid services income is assumed to offset some import costs and so is presented as part of the total saving. Table 21 presents a breakdown of the estimated income from grid services offered across all products. It was assumed that the bid income is received for all offers made, provided that the TSO requirement is not exceeded. Where grid services products also have a separate utilisation price (aFRR), it was assumed that 5%[28] of offered flexibility would be utilised, resulting in an additional utilisation income of 5% of the possible flexibility offered. Figure 34 shows the hourly flexibility offered to each grid services product on each reference day.

In 2030 the model was able to offer more flexibility in the form of grid services than the potential need of the electricity system. This can be seen in Figure 34 with the solid lines (potential offered flexibility) being higher than the dashed lines (Amprion TSO requirement) for many of the periods. So that the resulting income is not overstated, grid service income was capped at the maximum TSO requirement for each service and day. Furthermore, the price obtained by offering grid services was reduced depending on how much of the service was offered (see Figure 35). The first MW of grid service offered by the model would obtain the clearing price for the relevant grid service. Each subsequent MW would obtain a lower price declining to zero once the TSO requirement was met. This simplified approach captures some of the impact of altering the clearing price of the market when offering significant volumes into the market.

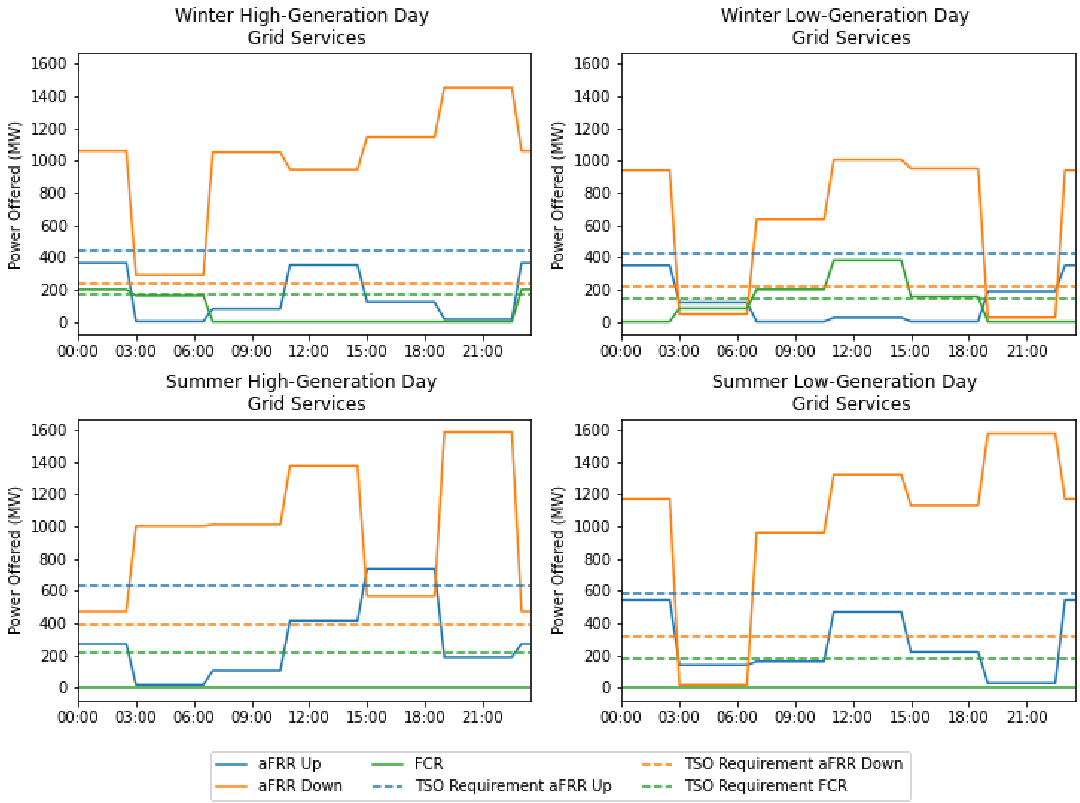

Figure 34: Optimised Hourly Grid-Services Offering, 2030 Reference Days

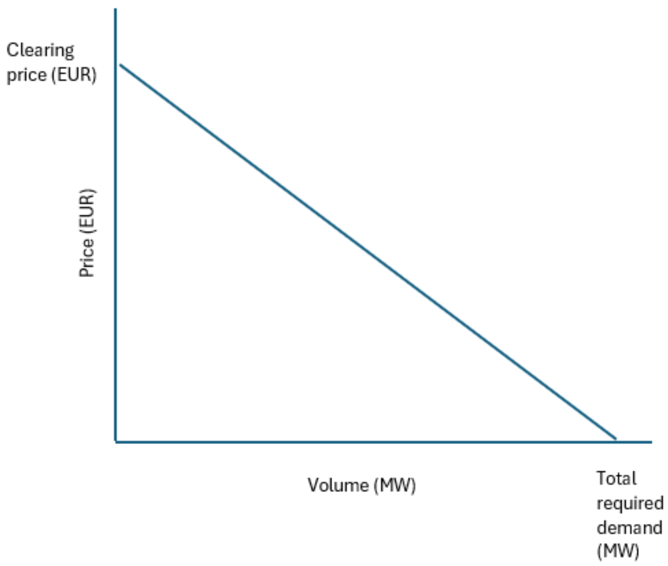

Figure 35 Declining price for increased volume of grid services offered

Table 21: Simulated Grid Services Income per 2030 Reference Day

	Winter High-Generation 13 January	**Winter Low-Generation** 25 January	**Summer High-Generation** 02 August	**Summer Low-Generation** 28 August
Availability Income from Grid Services	€29.170	€ 26.342	€ 49.716	€ 15.324
Utilisation Income from Grid Services at 5% Utilisation	€ 40.813	€ 28.551	€ 70.739	€ 66.307
Total Income	**€ 69.983**	**€ 54.893**	**€ 120.455**	**€ 81.631**

4.3.3 Peak Optimisation: Avoided cost from grid reinforcement.

The previous section shows that cost optimisation may cause an increase in peak power demand where beneficial price differences occur for short periods of the day, concentrating charging power within a short time window. A separate optimisation was run to investigate the best case for peak reduction using the available EV flexibility. The primary goal of this optimisation process is to use the available charging and discharging power of the EV parc to minimise any increase to the daily peak load, with cost optimisation and offers to grid services as a secondary goal where this can align with the primary objective of peak reduction. This simulation was run at a national level and at the level of each grid region (2030, incentivised plug-in behaviour).

For each region, and each typical day, the peak loading for the unmanaged and peak-optimised scenarios was extracted. The hourly profile for the peak-optimised EV charging at a national level for each reference day is shown in Figure 36. The EV parc provides sufficient flexibility to entirely flatten the demand curve on each typical day. The highest daily peak is seen on the winter low-generation reference day, where less of the demand is offset by generation.

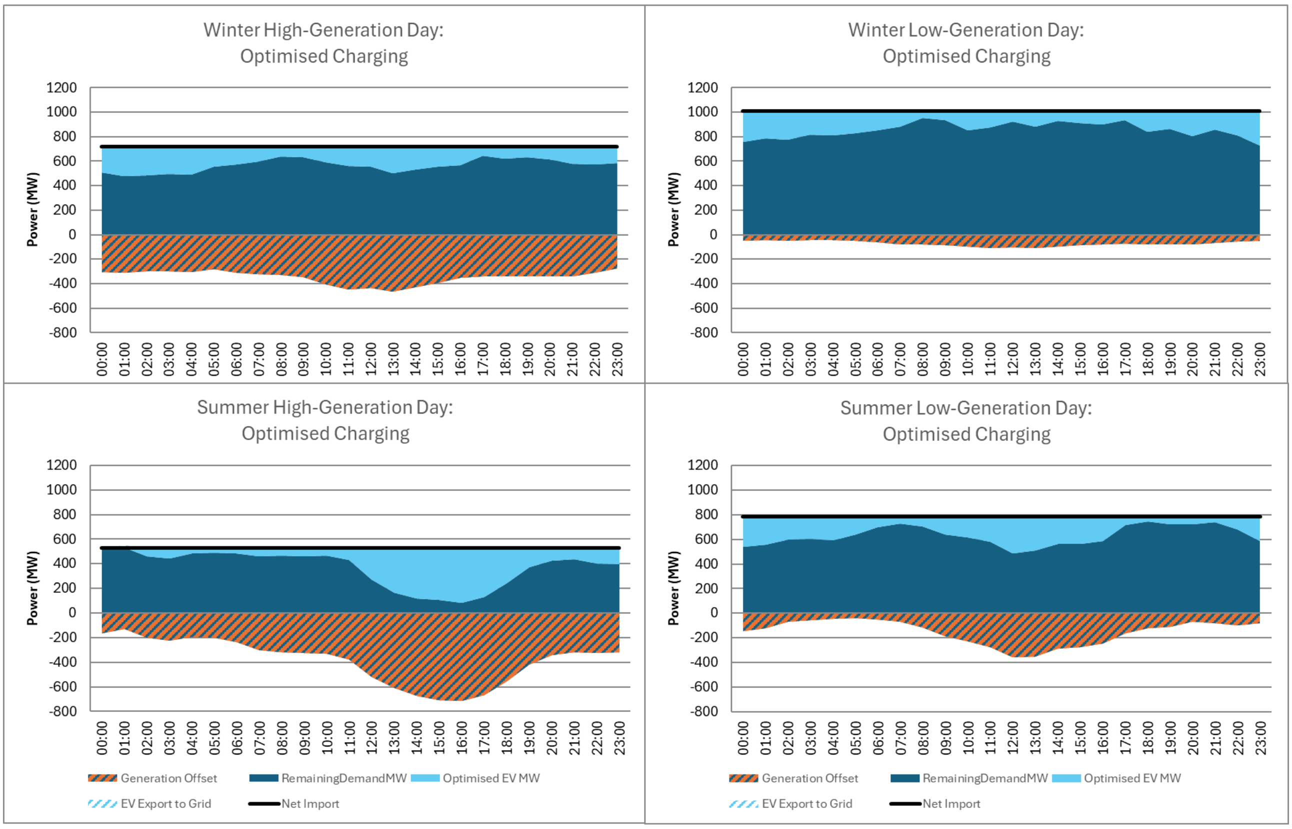

Figure 36: 2030 Peak-Optimised Demand, Generation and Charging Profiles per Reference Day

For each grid region, the required reinforcement cost (if any) was determined from Creos supplied data on planned upgrade to the grid by 2030[38]. It was assumed that the Creos supplied plans also include the addition of the Sotel grid demand to the Southwest and Southeast regions, in line with the 2030 demand forecasting data used in this report.

The savings for the optimised case vs unmanaged was then calculated, and to give an indication of savings to the population from deferring this reinforcement, divided by the population in the area[39]. These results are shown in Table 22.

The Central, North, East and West regions are all able to defer their planned reinforcement costs by following the peak-optimised scenario, with their peak loading reducing up to 50% against an unmanaged EV charging simulation. Whilst reinforcement may still be required in the future, being able to defer that investment and better accommodate the growth in power demand is highly favourable. From this work we are unable to say for how many years the investment may be deferred. To more easily compare these savings with other savings for residents it can be converted into a daily value per resident. Thus, we assume this cost is spread over 20 years (of customers' bills) at 4% discount rate, equating to 0.17 EUR per day per resident (if applied equally to all residents).

Table 22: Grid reinforcement costs per region, and potential savings from avoiding this reinforcement.

Region	Assumed Grid Capacity		Unmanaged Case		Optimised Case		**Total Savings (MEUR)**	Residents	**Savings per Resident (EUR)**
	Current 2023 Capacity (MW)	Planned 2030 Upgrade (MW)	Peak Load (MW)	Reinforcement Cost (MEUR)	Peak Load (MW)	Reinforcement Cost (MEUR)			
Central	330	500	464	221	248	None	**221**	199.526	**€ 1.108**
North	140	400	200	184	103	None	**184**	82.896	**€ 2.220**
East	120	250	144	138	75	None	**138**	67.888	**€ 2.033**
Southeast	140	320	381	51	254	51	**None**	105.922	**€ -**
West	140	250	141	23	83	None	**23**	61.909	**€ 372**
Southwest	180	320	260	101	225	101	**None**	141.923	**€ -**
Total				**718**		**152**	**566**	**660.065**	**€ 857**

4.3.4 Influence of V2G vs Smart Charging

The main calculations in this report assume that all V2G capable vehicles within the EV parc can be used for bidirectional charging each time they plug in. To show the difference in potential saving made by the use of V2G beyond the saving that can be achieved by smart charging alone, an additional simulation was run where all vehicles were operated using unidirectional smart charging. A summary of the marginal savings between the smart and V2G simulations is shown in Table 23 (2030, incentivised plug-in behaviour). Note that:

- to calculate the total savings of V2G without grid services compared to unmanaged charging, the savings in columns A and B would need to be summed. This results in daily savings ranging between 4,21 and 8,72 EUR per V2G vehicle.
- Likewise, to calculate the total savings of V2G with grid services compared to unmanaged charging, the savings in columns A and C would need to be summed. This results in daily savings ranging between 4,98 and 9,38 EUR per V2G vehicle.

[38] Creos Supplied data on grid reinforcement plans and costs

[39] "Population par canton et commune". www.statistiques.public.lu. Statistics portal of the Grand-Duchy of Luxembourg. Retrieved 25 April 2023.

Table 23: Additional benefit per V2G-enabled Vehicle in each Reference Day, 2030 incentivised behaviour

			A. Cost-Optimised Smart Charging without Grid Services		B. Cost-Optimised V2G without Grid Services		C. Cost-Optimised V2G with Grid Services	
Day	Number Electric Vehicles	Number V2G Vehicles	Marginal Saving Smart vs Unmanaged (EUR)	Saving per EV (EUR)	Marginal Saving V2G vs Smart (EUR)	Saving per V2G Vehicle (EUR)	Marginal Saving V2G vs Smart (EUR)	Saving per V2G Vehicle (EUR)
13 January	217.841	46.191	299.426	1,37	103.208	2,23	133.784	2,90
25 January	217.841	46.191	256.350	1,18	34.972	0,76	65.404	1,42
02 August	217.841	46.191	141.009	0,65	53.551	1,16	88.816	1,92
28 August	217.841	46.191	234.685	1,08	45.037	0,98	83.501	1,81

4.3.5 Influence of User Plug-in Behaviours

The impact of different driving behaviour assumptions is presented in this section, similarly to the 2023 reference year. Figure 37 shows the difference in the total number of EVs plugged in per hour of the day in each behavioural scenario. As in 2023, the behaviours of drivers has a significant impact on the available resource for flexibility.

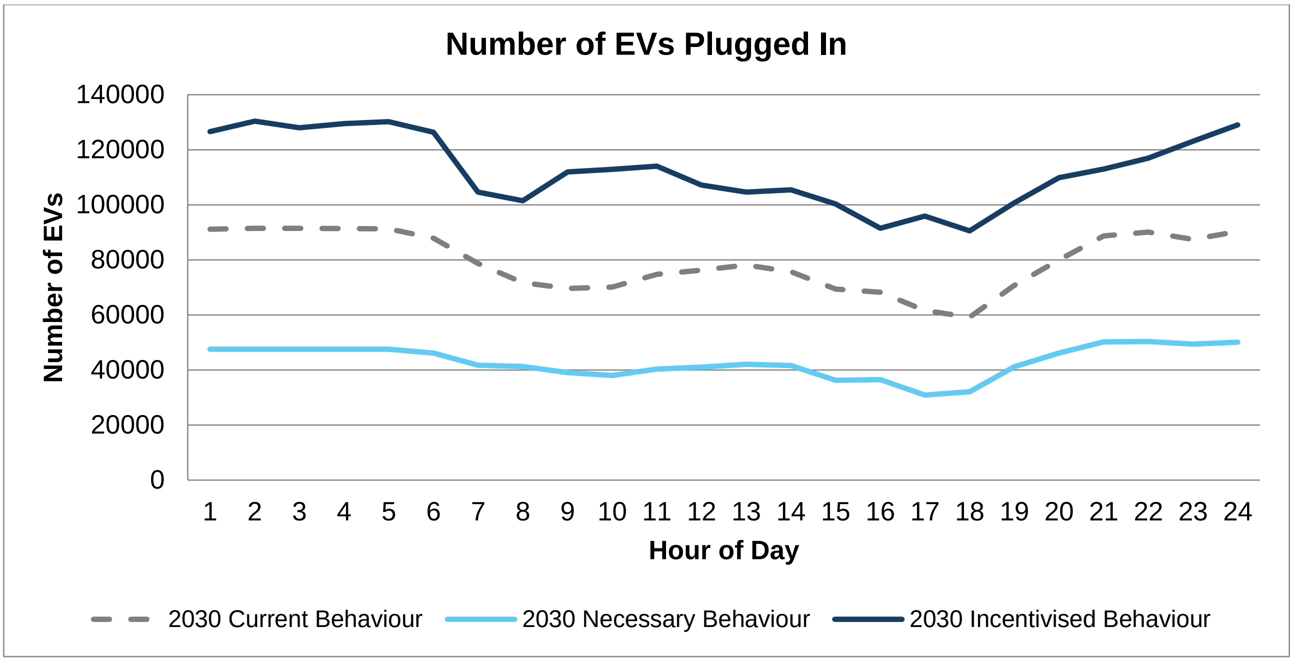

Figure 37: Number of Plugged-in Vehicles under Different Driver Behaviours, 2030

The equivalent PiNC (plugged in, not charging) time under unmanaged charging is shown in Table 24, following similar patterns to the 2023 simulation as the underlying driving behaviours are assumed to be consistent between 2023 and 2030. Note that the percentage of total vehicle hours is similar to the 2023 estimate due to the same plug-in behaviours used in both simulations, with the addition of electric HGVs in 2030 causing a slight variation. The total number of available vehicle hours across the entire EV parc is significantly higher, due to the increase in the total number of vehicles

Table 24: Summary of Plugged-in-Not-Charging Time as a Percentage of Total Vehicle Hours

Scenario	Necessary (Minimum) Plug-in	Current (Medium) Plug-in	Incentivised (Maximum) Plug-in
Percentage of Total Vehicle Hours	15%	32%	47%
Average PiNC Total Daily Vehicle-Hours	792.500	1.657.744	2.452.466

Further cost optimisation simulations were completed for each behavioural scenario, with the potential saving in each case presented in Table 25 and Table 26.

Table 25: Summary of Potential Savings against Unmanaged Charging in EUR for different Plug-in Behaviours, 2030

	Reference Day	Winter High-Generation 13 January	Winter Low-Generation 25 January	Summer High-Generation 02 August	Summer Low-Generation 28 August
Incentivised	**Baseline National Consumption Costs at Day-Ahead Pricing (Unmanaged EV Charging)**	**1650k EUR**	**4677k EUR**	**1417k EUR**	**2532k EUR**
	Saving Cost-Optimised Smart Charge	299k EUR	256k EUR	141k EUR	235k EUR
	Saving Cost-Optimised V2G	403k EUR	291k EUR	195k EUR	280k EUR
	Saving Combined Grid Services & Cost Optimised V2G	427k EUR	322k EUR	249k EUR	326k EUR
Current	Saving Cost-Optimised Smart Charge	297k EUR	253k EUR	147k EUR	210k EUR
	Saving Cost-Optimised V2G	367k EUR	274k EUR	182k EUR	238k EUR
	Saving Combined Grid Services & Cost Optimised V2G	389k EUR	303k EUR	232k EUR	277k EUR
Necessary	Saving Cost-Optimised Smart Charge	267k EUR	216k EUR	127k EUR	187k EUR
	Saving Cost-Optimised V2G	295k EUR	225k EUR	141k EUR	197k EUR
	Saving Combined Grid Services & Cost Optimised V2G	317k EUR	262k EUR	188k EUR	234k EUR

Table 26: Summary of Potential Savings against Unmanaged Charging as a Percentage for different Plug-in Behaviours, 2030

	Reference Day	Winter High-Generation	Winter Low-Generation	Summer High-Generation	Summer Low-Generation
Incentivised	**Baseline National Consumption Costs at Day-Ahead Pricing (Unmanaged EV Charging)**	**1650k EUR**	**4677k EUR**	**1417k EUR**	**2532k EUR**
	Saving Cost-Optimised Smart Charge	18,1%	5,5%	10,0%	9,3%
	Saving Cost-Optimised V2G	24,4%	6,2%	13,7%	11,0%
	Saving Combined Grid Services & Cost Optimised V2G	25,9%	6,9%	17,6%	12,9%
Current	Saving Cost-Optimised Smart Charge	18,0%	5,4%	10,3%	8,3%

	Saving Cost-Optimised V2G	22,3%	5,9%	12,8%	9,4%
	Saving Combined Grid Services & Cost Optimised V2G	23,6%	6,5%	16,4%	10,9%
Necessary	Saving Cost-Optimised Smart Charge	16,2%	4,6%	9,0%	7,4%
	Saving Cost-Optimised V2G	17,9%	4,8%	10,0%	7,8%
	Saving Combined Grid Services & Cost Optimised V2G	19,2%	5,6%	13,3%	9,2%

4.3.6 Influence of Vehicle Uptake Rate

For the 2030 forecast, additional assumptions were made on the uptake rate of EVs between the reference year and 2030. The main results for the forecast are presented for the high EV uptake scenario, as current EV ownership suggests that the country is on track to meet this target. However, the potential available resource under the medium and low uptake scenarios is presented in Figure 38 for comparison, assuming an incentivised plug-in behaviour.

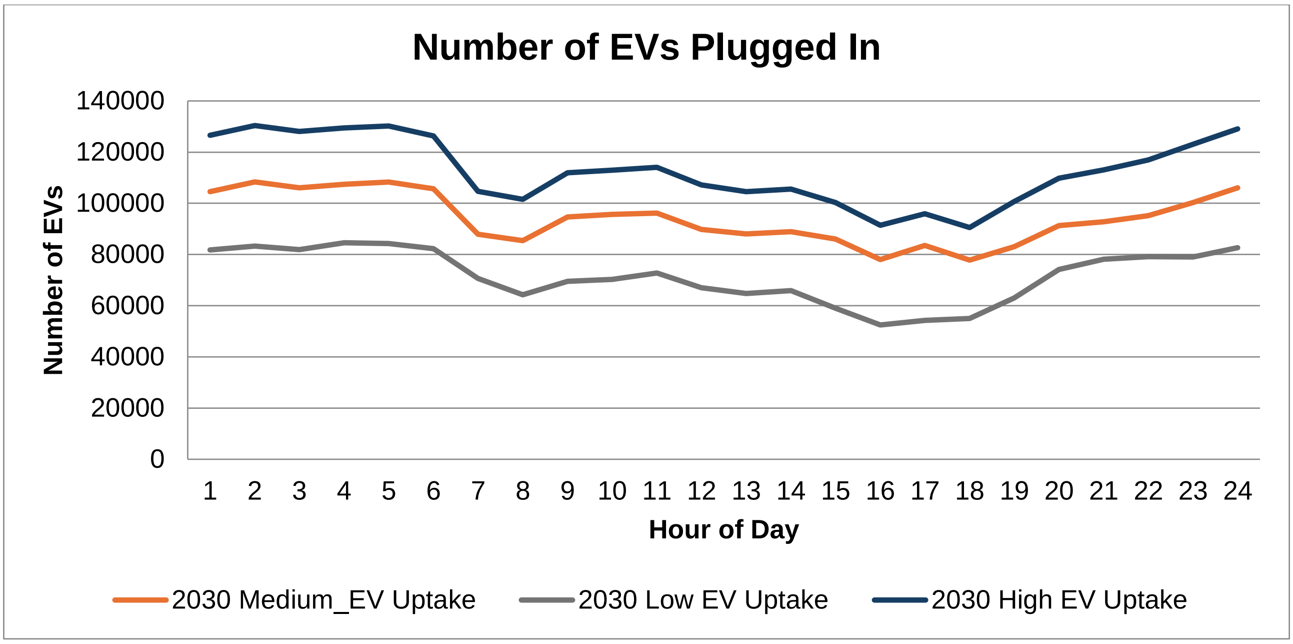

Figure 38: Number of Plugged-in Vehicles under Different EV Uptake Scenarios, 2030

Potential savings from cost optimisation under different uptake scenarios is presented in Table 27 and Table 28.

Table 27: Summary of Potential Savings against Unmanaged Charging in EUR for different Uptake Rates, 2030

	Reference Day	Winter High-Generation 13 January	Winter Low-Generation 25 January	Summer High-Generation 02 August	Summer Low-Generation 28 August
High Uptake	**Baseline National Consumption Costs at Day-Ahead Pricing (Unmanaged EV Charging)**	**1650k EUR**	**4677k EUR**	**1417k EUR**	**2532k EUR**
	Saving Cost-Optimised V2G	403k EUR	291k EUR	195k EUR	280k EUR
	Saving Combined Grid Services & Cost Optimised V2G	427k EUR	322k EUR	249k EUR	326k EUR
Medium Uptake	Saving Cost-Optimised V2G	314k EUR	225k EUR	154k EUR	217k EUR
	Saving Combined Grid Services & Cost Optimised V2G	340k EUR	254k EUR	212k EUR	258k EUR
	Saving Cost-Optimised V2G	226k EUR	161k EUR	115k EUR	154k EUR

Low Uptake	Saving Combined Grid Services & Cost Optimised V2G	252k EUR	189k EUR	169k EUR	189k EUR

Table 28: Summary of Potential Savings against Unmanaged Charging as a Percentage for different Uptake Rates, 2030

	Reference Day	**Winter High-Generation** 13 January	**Winter Low-Generation** 25 January	**Summer High-Generation** 02 August	**Summer Low-Generation** 28 August
High Uptake	**Baseline National Consumption Costs at Day-Ahead Pricing (Unmanaged EV Charging)**	**1650k EUR**	**4677k EUR**	**1417k EUR**	**2532k EUR**
	Saving Cost-Optimised V2G	24,4%	6,2%	13,7%	11,0%
	Saving Combined Grid Services & Cost Optimised V2G	25,9%	6,9%	17,6%	12,9%
Medium Uptake	Saving Cost-Optimised V2G	19,0%	4,8%	10,9%	8,6%
	Saving Combined Grid Services & Cost Optimised V2G	20,6%	5,4%	15,0%	10,2%
Low Uptake	Saving Cost-Optimised V2G	13,7%	3,4%	8,1%	6,1%
	Saving Combined Grid Services & Cost Optimised V2G	15,3%	4,0%	11,9%	7,5%

4.4 Contribution to the increase in the share of renewable energy

The 2030 forecast year incorporates changes to grid demand, renewable generation, and the number of EVs charging within the country. To assess the potential for increasing the share of renewable energy using EV flexibility, a separate optimisation simulation was run using the same method described in Section 3.4, where the installed renewable energy capacity is increased until set limits are reached, to show the potential upper limit of renewable share.

Some assumptions applied to this calculation were:

- The planned 2030 upgrades to the grid capacity per region were assumed to have been completed for this calculation, with the upgraded capacities used as the capacity limit of export from each grid zone. Note that this provides a separate, and mutually exclusive, result to the cost-optimised and peak-optimised simulations presented in the previous sections of this report.
- Only PV and wind generation were considered for increase in this calculation.
- The combined generation from other electricity generation sources was estimated to be equal to that of the 2023 reference year due to the similarity in planned installed capacity between 2023 and 2030.

A summary of the resulting potential installed capacity of renewables in each region is presented in Table 29, with a visualisation of the hourly generation, demand and optimised EV charging on each reference day shown in Figure 39. As with the 2023 simulation, the limiting day for generation is the summer high-generation day, during which the optimised EV parc is used to absorb excess generation during the peak hours of the day, which would not be possible without targeted use of EV charging. Please note that, at a national level, some excess capacity remains during the hours 12:00-19:00 while export is being offset, due to the limits on the maximum renewables possible to install in the North region while respecting local export limits. During this time, if the energy price is advantageous, the remaining vehicles may charge above the base level required for export avoidance.

Table 29: NECP Target vs Maximised Installed PV and Wind Renewables Capacity in Each Region

Region	Assumed Installed Capacity 2030 PV (MW)	Assumed Installed Capacity 2030 Wind (MW)	Upgraded Grid Export Capacity Limit (MW)[40]	Renewable Installed Multiplier	Maximised Installed Capacity PV (MW)	Maximised Installed Capacity Wind (MW)
Total	**984**	**400**	**n/a**	**1,80**	**1862**	**720**
Central	73	0	500	2,01	146	0
North	308	293	400	1,73	531	506
East	173	32	250	2,01	347	64
Southeast	133	52	320	2,01	268	105
Southwest	130	8	320	2,01	260	17
West	154	14	250	2,01	310	28

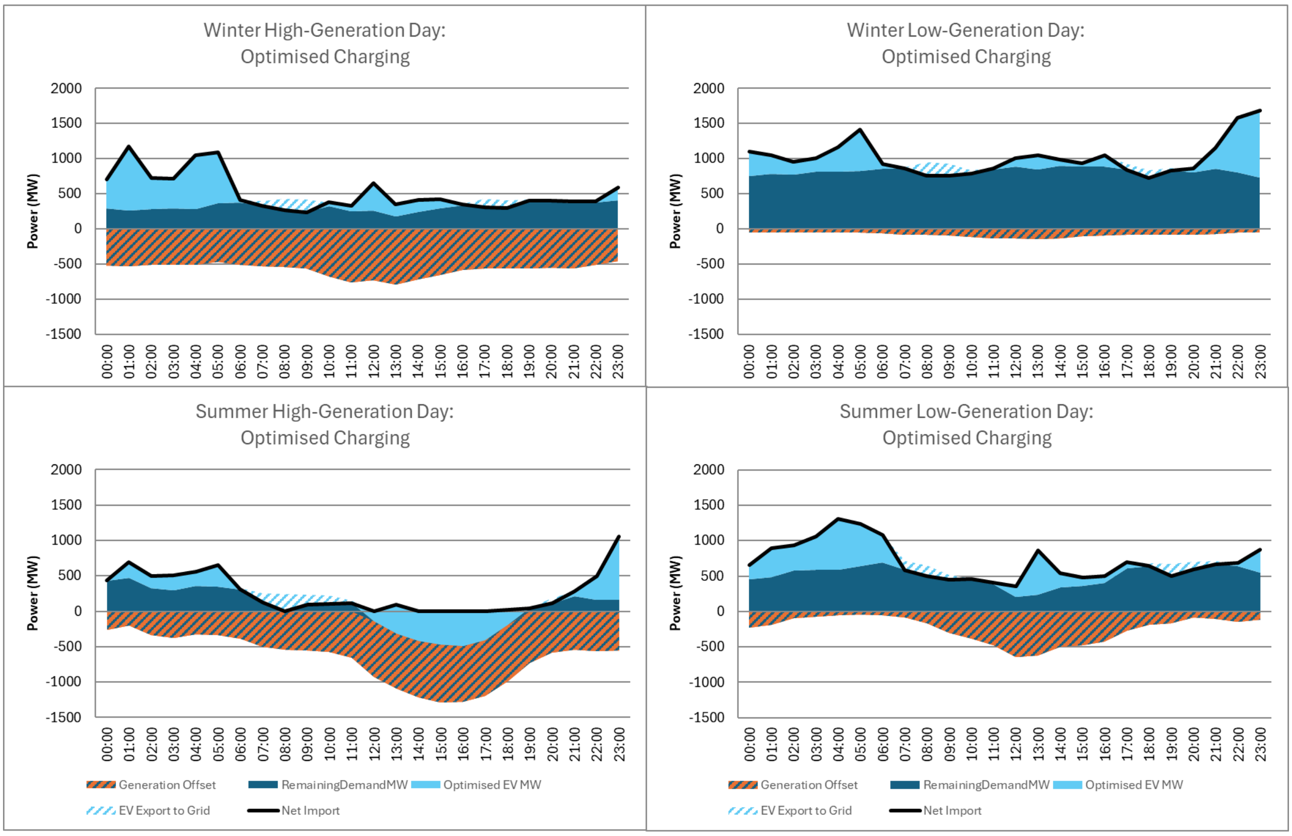

Figure 39: EV Charging Optimised for Increased Renewables Installation, 2030 Reference Days

To assess the renewable share on each reference day, the total estimated daily energy demand was calculated. Renewable generation was assumed to comprise total generation from PV, wind, hydroelectric and biomass installations, where hydroelectric and biomass generation were taken directly from the reference year transmission network load data and PV/wind were simulated based on energy per installed capacity in the reference year. A summary of the share of both baseline and increased renewables for each of the reference days is shown in Table 30. For the 2030 forecast year, an optimised use of the EV parc could allow for a greater share of renewables, raising the

[40] Creos Grid Upgrade Data; Creos 2024

renewables share to 73,5% of estimated demand on the highest generation reference day[41]. EV charging is used to absorb generated energy that would otherwise have been exported or otherwise curtailed.

Table 30: NECP Target and Maximised Renewables Share for 2030 Reference Days

	Summer Low Generation 28/08	Summer High Generation 02/08	Winter Low Generation 25/01	Winter High Generation 13/01
Daily Total Demand (Upscaled Creos + Sotel Grid + EV Charging) MWh	**22.408**	**21.767**	**25.984**	**25.631**
NECP Target Renewables, Unmanaged	14,6%	39,6%	4,1%	31,1%
Increased Renewables, Unmanaged[42]	24,6%	64,5%	4,7%	53,1%
Increased Renewables, Optimised for Absorption	25,4%	73,5%	4,9%	55,6%

[41] Note that minor differences in the renewable percentage on other days are due to differences in the total import energy due to different ending battery State of Charge in unmanaged vs optimised simulations.

[42] Note that this calculation uses the same installed renewables capacity as the optimised case, as described in Table 29.

5 Discussion

This chapter provides a brief commentary on the results of the scenario modelling, and then addresses the seven questions listed in the ILR tender, drawing from the analysis in the previous chapters

In chapter 3 and 4 of this report results from simulating EV charging across Luxembourg have been presented. As a result of the modelling approach taken (i.e. perfect foresight optimisation, meaning that the model has a complete and accurate knowledge of future events, including energy demand, prices and vehicle movements), all results should be viewed as indicating the upper bound of what is possible within the scenarios and typical days simulated. In reality there will be a reduction in the value of optimisation possible due to forecast errors of prices, vehicle availability and user engagement. Furthermore, when simulating the provision of grid services, our model is based on a ‘price taker’ approach. This makes the assumption that, in all offers to provide grid services that the model makes, it is successful. Due to the large volume of grid services potentially offered in 2030, we have made some simple adjustments to the grid services price calculations to account for price decreases that the flexibility portfolio may cause. So, when larger volumes of flexibility are offered, a lower price is obtained. However, the full dynamics of the market have not been simulated, and so grid service income results should be taken as indicative.

The model was run in 2030 with three separate objectives. These were

- Cost optimisation: maximised savings from day-ahead pricing and grid services
- Peak power optimisation: avoided cost from grid reinforcement
- Increase the absorption of renewable energy

The objectives in each of these runs are different and at times will be competing. As such, the savings from the individual objectives are not additive. In a fully optimised system, these three objectives should be co-optimised, however this is outside of the scope of this project.

The remainder of this chapter explicitly addresses the seven questions listed in the tender, drawing from the analysis in the previous chapters.

1. **What is the estimated power and energy volume stored in the batteries of grid-connected electric cars for each hour of a reference day in summer and winter?**
    - We modelled a typical winter and summer day to represent different seasonal driver behaviours. In 2030 we forecast a peak of 130.000 vehicles plugged in between midnight and 6 am, representing about 7.500 MWh.
    - In 2030 the forecast peak connected power is around 1.700 MW for charging and 350 MW for discharging.
2. **What is the potential impact of charging and discharging these vehicles on the grid at the national level?**
    - In 2023 the impacts of charging vehicles on the grid are relatively small. However, in 2030 unmanaged charging of EVs creates significant peaks in demand in the early morning and the evening. Optimisation of this charging results in a shifting of the demand to cheaper periods (primarily overnight). This could cause overnight peaks that are higher than in the unmanaged EV charging scenario in three of the four reference days, but if these are mitigated then EV charging could potentially be used to defer grid reinforcement.

- The PINC time[43] is about 12 hours per vehicle and day in the incentivised charging behavioural scenario, 7,4 hours in the current scenario and 3,4 hours in the necessary charging behavioural scenarios.
- The impact of optimisation against day ahead prices on the daily power profile at national level is shown in Figure 40 and Figure 41.

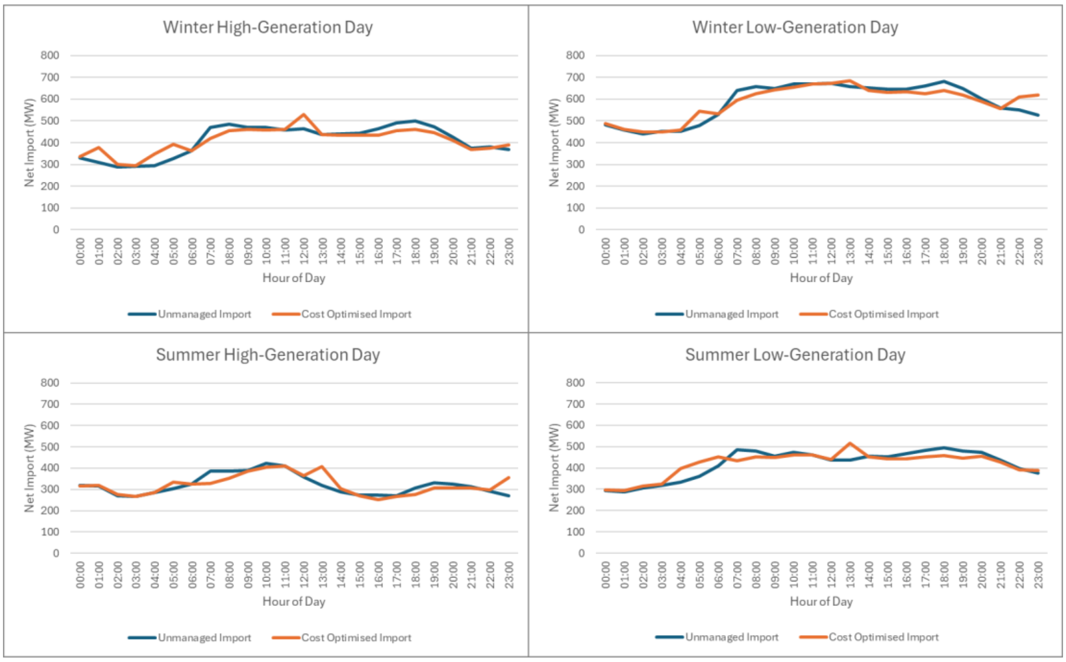

Figure 40 Impact on national demand profile in 2023 for Cost Optimised charging

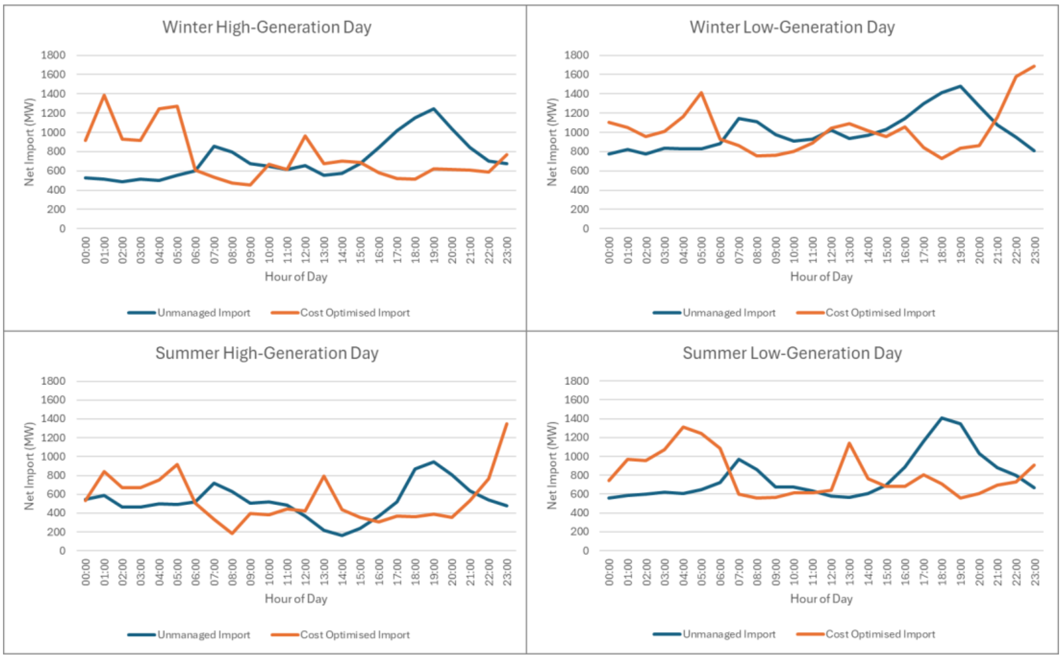

Figure 41 Impact on national demand profile in 2030 for Cost Optimised charging

[43] Plugged-In Not Charging (PINC) is a metric that measures the flexibility of EV charging. As a percentage it gives the proportion of the time a vehicle is spent plugged in and not charging. The greater the value the greater the flexibility. An EV charged at home overnight might only charge for 2 hours of a 10-hour plug-in window over a 24-hour period, giving a PINC time of 33%. However, an EV only ever charged at en route rapid chargers might have a PINC time of 0%, indicating no dormant time at a chargepoint.

3. **To what extent and how could the EV fleet contribute to the flexibility of the electricity system, react to price signals from the wholesale market (dynamic prices) and participate in the balancing market and ancillary services, such as frequency and voltage control?**
    - The extent that the EV fleet could contribute to the flexibility of the electricity system is primarily dependent upon the uptake of EVs and the charging behavioural scenario. In addition to this, the uptake of smart and V2G charging with integrated and aggregated control is required. Assuming that these are in place, the scenarios modelled in this report demonstrate that in 2023 with the current plug-in behaviour a maximum of 88 MW can be shifted (Winter low generation).
    - In 2030 with the incentivised plug-in behaviour 878 MW can be shifted (Winter low generation). This flexibility could result in a maximum daily saving from wholesale electricity costs of around 28k EUR in 2023 and 403k EUR in 2030.
    - In 2030 an EV fleet could be expected to contribute to aFRR and FCR grid services (based upon existing technical demonstrations of the technology and an expected TRL of 9 in 2030). Modelling of 2030 suggests that with the incentivised plug-in scenario the EV charging portfolio can offer close to and sometimes more than the TSO grid services requirement. In a single day, the portfolio could offer up to 6.967 MW*h[44] of aFRR Up (versus a requirement of 15.120 MWh), 24.750 MW*h of aFRR Down (versus a requirement of 7.608 MWh) and 3.299 MW*h of FCR (versus a requirement of 3.360 MWh).
4. **Could network reinforcements or extensions be avoided or postponed? In what order of magnitude?**
    - There is potential for the optimisation of EV charging to contribute to network reinforcement postponement. Our modelling demonstrates that in 2030, if EV charging is used solely for the purpose of reducing network peak capacity, then network reinforcements that would otherwise be required can be postponed. All regions within Luxembourg, with the exception of Southeast and Southwest, could keep the maximum network demand below 2023 capacity levels on the typical days simulated. This results in a cumulative deferral of 566M EUR, although grid capacity investments would still need to be made in the Southeast and Southwest regions by 2030. From this analysis we are unable to say for how long the cost can be deferred since only 2030 has been simulated. It should also be noted that this is a simplified analysis with a single transmission level grid constraint modelled in each region.
5. **What would be the financial impact on network users (simplified analysis)?**
    - Transmission reinforcement that would have been carried out by 2030 can be postponed up to the value of 566M EUR, which is 857 EUR per resident. If we assume this cost is spread over 20 years (of customers' bills) at 4% discount rate, this equates to 0,17 EUR per day **per resident** discount (if applied equally to all residents).
    - Daily wholesale energy cost savings due to day-ahead price optimisation in 2030 range from 127k EUR (necessary plug-in behaviour, summer high generation day, smart charging only) to 403k EUR (incentivised plug-in behaviour, winter high generation day, V2G). This gives a daily saving of between 0,19 EUR and 0,61 EUR **per resident** if applied equally.

[44] The * in MW*h is used to denote that volume of flexibility is being measured. That is a quantity of MWs over a period of hours. This notation is used to differentiate between flexibility (MW*h) and a volume of energy (MWh).

- Additional daily savings from grid service provision in 2030 (compared to V2G without grid services) range from 22k EUR (necessary plug-in behaviour, winter high generation day) to 54k EUR (incentivised plug-in behaviour, summer high generation day). This gives a daily saving of between 0,03 EUR and 0,08 EUR **per resident** if applied equally.
- Wholesale energy costs savings are the most significant savings, followed by transmission reinforcement deferral and finally grid service provision. However, transmission reinforcement deferral savings cannot be fully stacked with the other two savings (due to the competing optimisation objectives used when simulating the savings).

6. **Depending on the assumptions made, what savings for the system and network users would be possible by shifting electricity consumption from high-priced periods to lower-priced periods and by storing electricity produced during low-price periods?**
    - In 2030 the daily savings from smart charging (compared with unmanaged charging) range between 0.58 EUR/vehicle/day (Necessary behaviour, Summer high generation day) and 1.37 EUR/vehicle/day (Incentivised behaviour, Winter high generation). The additional value of V2G charging (compared with smart charging) ranges between 0.19 EUR/vehicle/day (Necessary behaviour, Winter low generation day) and 2.23 EUR/vehicle/day (Incentivised behaviour, Winter high generation).
7. **Depending on the different assumptions made, in what order of magnitude can the share of renewable electricity in the electricity system be increased?**
    - In 2023 the flexibility from current EV charging has a negligible impact on increasing the share of renewable energy in the electricity system. The share of renewable energy in final consumption of the electricity system on the highest generation day (Summer High) is 33,2%. A simulation was performed with EV charging optimised to absorb renewables, and renewable installed capacity increased to the point where renewable energy export first occurs at the national level (whilst observing regional grid capacity levels). This resulted in an additional 485 MW of installed renewables capacity. In this scenario, it makes no difference to the share of renewables in electricity consumption whether EV charging is optimised for renewables absorption or left as unmanaged, with 55,2% in each case. This is because the EV parc represents a very small proportion of the overall electricity demand.
    - In 2030 and assuming an incentivised plug-in behaviour, the share of renewable electricity in final consumption on the highest generation day (summer high generation day) is 39,6% at National Energy and Climate Plan (NECP) target scenario renewables level. In this scenario, since all renewable energy is absorbed, EV charging cannot contribute to increasing absorption. Therefore, a simulation was performed with EV charging optimised to absorb renewables, and renewable installed capacity increased to the point where renewable energy export first occurs at the national level (whilst observing regional grid capacity levels). This resulted in an additional 1.198 MW of installed renewables capacity (an 80% increase compared to the NECP target scenario), and 73,5% share of renewables in electricity consumption on the highest generation day (summer high generation day). With unmanaged EV charging a renewable electricity consumption share of only 64,5% could be obtained on the same day (assuming the same installed renewables capacity). This means that EV charging can contribute to a 9% additional absorption of renewable electricity on the summer high generation day (1.959 MWh).

6 Recommendations for Deployment and Operation of Charging Infrastructure

This chapter provides a list of recommendations for deployment and operation of EV charging infrastructure drawn from the results and analysis in this report.

There are clear benefits to optimised EV charging for the Luxembourg electricity system. In 2030 for the incentivised scenario this ranges between 0,7 EUR and 1,4 EUR per vehicle per day (cost optimised without grid services from smart charging alone). There are also benefits from using EV charging optimisation to reduce peak demand and integrate more renewable generation. **We recommend pursuing optimised EV charging due to the multiple possible benefits for the electricity system.**

The incremental benefit of V2G charging above smart charging is in the order of 1,2 EUR to 2,2 EUR per day per V2G-enabled vehicle[45] (2030, incentivised, excluding grid services). This gives total benefits of between 1,9 EUR and 3,6 EUR per day per V2G-enabled vehicle. The price difference between unidirectional and bidirectional chargepoints is unclear at this stage due to the lack of V2G units commercially available. Previous research[46] has suggested that the difference could be around 1000EUR by 2030. This being the case, the V2G charge could pay for itself within 1 to 4 years. **We recommend that V2G charging is pursued as it can contribute a net benefit to the electricity system.** Note that in this study we assumed that en route (high powered) charging is not V2G enabled, due to the low flexibility of this type of charging.

Our modelling suggests that in 2030 revenue from grid services of between 0,1 EUR and 0,25 EUR per vehicle per day can be obtained (with V2G vehicles contributing more than smart charging vehicles). Although this is significantly less than cost optimisation income **grid services (specifically aFRR and FCR) could be considered within an optimised EV charging solution. However additional hardware, monitoring and integration costs to facilitate grid service provision may challenge economic viability.**

The greatest savings come from a wholesale cost optimisation of EV charging. Transmission reinforcement deferral is in second place (on a per resident basis), whilst grid services offer a relatively small additional value[47]. **Therefore, we recommend that an optimisation of EV charging combining wholesale energy costs and minimising peak capacity is prioritised as the likely highest value solution.**

In this work we performed cost optimisation, peak capacity optimisation and renewables absorption independently. However, in the cost optimisation scenario EV charging could put additional strain on the grid during the cheapest priced periods (see Figure 33 Winter low generation). **We recommend that such effects are avoided by initiatives such as diversification of price signals to EV charging, differing charging objectives, or explicit capacity costing for users.** Optimising EV charging for day ahead wholesale electricity prices will sometimes compete against shaving peaks in electricity demand profiles. Co-optimising both is out of the scope of this project, but peaks from cost optimisation need to be carefully watched in the future.

EV charging plug-in behaviour differs from what would be strictly necessary to charge EVs for their upcoming journeys. With current plug-in behaviour EVs are plugged in for 32% of the time. In an incentivised scenario, this increase to 47%. In 2030 this leads to an increase in savings (from day ahead optimisation and grid services) of between 6% and 18% for each day. In some contexts,

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[45] 22% of EVs assumed to be V2G-capable by 2030

[46] V2GB-Public-Report.pdf

[47] See question 5 in section 5 for the savings per resident from all sources

incentivised plug-ins require more charging infrastructure (such as work), however where a dedicated charger already exists it wouldn't. **We recommend that actions are taken to encourage EV owners to plug-in EVs more frequently where a dedicated charger for the EV exists. This could be done via the proposition to EV/chargepoint users.** Examples include: rewarding users for the time EVs are plugged in and available, cheaper EV charging during certain windows, passing through a portion grid services revenue (via aggregator) to EV users, gamification to earn rewards and compete with friends.

The EVSE requirements of a vehicle parc can be met in a variety of ways. Aspects such as cost, environmental impact, user preferences, accessibility and impact on the electricity grid all need to be taken into account when designing a solution. Within this investigation we have not varied the overall EVSE solution but rather carried forward the current spilt of charging powers. However, it is important to note that the longer EVs spend plugged in to chargepoints the greater the flexibility that could be offered to the electricity system. Rapid charging, where vehicles stop (often en route) to charge and then move on, offer very little flexibility. However, destination or home charging where vehicles could be plugged in for 8 hours at a time offer more flexibility since the required charging is often completed within just a few hours. **We recommend that flexible EV charging solutions (both smart and V2G) are focused on the use cases where EVs spend long plugged in and not charging. These are likely to be firstly residential private charging, and then residential low powered public charging and then workplace charging.**

AC Versus DC Charging

For unidirectional charging, the choice between AC and DC is made primarily based on power requirements/charging speed. Since AC charging requires on-vehicle rectification of the AC power to DC, AC charging speeds are limited by individual vehicles. Whilst DC charging limits are also limited by vehicles, these limits are typically significantly higher. DC charging currently offers the advantage that the chargepoint can often read the state of charge of the EV battery (whilst AC chargers cannot), which can lead to simpler charging optimisation via the chargepoint. However, future standards will close this gap enabling new AC chargers to read SOC from the vehicle. In fact, both public and private, AC and DC chargers installed or renovated from 1 January 2027 shall comply with ISO 15118-20:2022[48], which defines the communication messages and sequence requirements for bidirectional power transfer (incl. reading SOC).

In an AC Vehicle-to-grid (V2G) system the power conversion takes place in the vehicle and power transfer between the vehicle and chargepoint is via AC. Renault and Nissan have both made recent press releases announcing the imminent launch of V2G propositions in Europe between 2024 and 2026[49,50,51]. Both are based around an AC V2G arrangement and involve all-inclusive packages with a vehicle, a chargepoint and an electricity contract.

In a DC V2G system the power conversion takes place off-board in the chargepoint and the connection between the car and chargepoint is in DC. DC V2G systems have been used in most previous trials and demonstrators and have several advantages. In a DC V2G system the generator part is within the chargepoint, therefore it is part of the fixed installation and so can be regarded as a more traditional generator in terms of management of type approval and grid codes. In general, the downside to DC V2G is that the chargepoint is bigger and much more expensive than a standard

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[48] ANNEX to the Commission Delegated Regulation (EU) amending Regulation (EU) 2023/1804 of the European Parliament and of the Council as regards standards for wireless recharging, electric road system, vehicle-to-grid communication and hydrogen supply for road transport vehicles (link)

[49] Charge for Free – Renault, Mobilize, and TMH launch V2G

[50] Renault Group, We Drive Solar and MyWheels join forces with the city of Utrecht to launch Europe's first V2G enabled car-sharing service - Site media global de Renault Group

[51] Driving the Future of Energy: Welcome to the World of V2G

AC chargepoint. The marginal cost difference has historically been significant acting as a barrier to the value of V2G, although with time this has reduced.

As it currently stands it is not yet clear which technology between AC and DC V2G will win out, as this is still dependent upon vehicle OEMs and how interoperable different solutions become. **There are no clear recommendations currently between AC and DC V2G technology solutions.**

Appendixes

Appendix A – The REVOLVE Model

The modelling for this project has been performed using the Cenex REVOLVE model. REVOLVE is a perfect foresight optimisation model capable of simulating the charging/discharging behaviour of large numbers of EVs at half hourly granularity over a year. Perfect foresight models have a complete and accurate knowledge of future events, including energy demand, prices and vehicle movements. This is representative of a scenario where the actors controlling and dispatching the EV charging can perfectly predict future events and price. This allows for the most efficient possible EV resource allocation.

Key Features:

- Simulates charging/discharging of a fleet of EVs
- Customisable constraints on max charging/discharging power to allow modelling of specific or generic V2G units
- Customisable constraints on max/min storage capacity of EVs to allow modelling of specific or generic vehicles
- Constraints on EV availability (plug-in times) and requirement to make journeys (energy demand)
- Modelling of:
    - charging/discharging losses
    - half-hourly varying import and export tariffs
    - flexibility of charging/discharging for the provision of grid services
- Simulation of local PV or Wind generation
- Optimises EV charging/discharging against time varying tariff value streams and grid services
- Customisable warranty constraint modelling through optional limiting of maximum kWh of V2G provision per vehicle per day

The model optimises the charging/discharging behaviour of individual EVs on a minimum cost basis using the import and export tariffs available to the EV. Whilst the model can cover an entire year, it does this by optimising weekly blocks one at a time. Each EV in the model has an associated driving energy and plug-in availability data set for the year. It also includes the local electricity demand for the site or building(s) the chargepoint is connected to. For this project the model has been used in Site mode, and so all EVs have been modelled at the same site (or Node) with an associate local electricity demand. This local demand can be offset by discharging the EVs.

The chargepoints in the model can also be aggregated up and offered to provide grid services. The model stacks the available flexibility inherent in the chargepoints to build up the grid service product window requirements. To provide a grid service, a minimum capacity (in MW) must be held in either an upwards or downwards (or both) direction, for the specified grid service periods. During the entire service periods, the model must also hold sufficient stored energy/demand reduction (or battery headroom) to meet a minimum length of call of the grid service product. Note that whilst this headroom/footroom is held, the model does not currently simulate the actual calls due to the additional modelling complication this adds. This means that the actual energy position of the asset at the end of the offered grid service period could differ from the simulated energy position in the model, however the impact of this is relatively small. Note that remuneration from calls (utilisation) is included in the model at average utilisation rates.

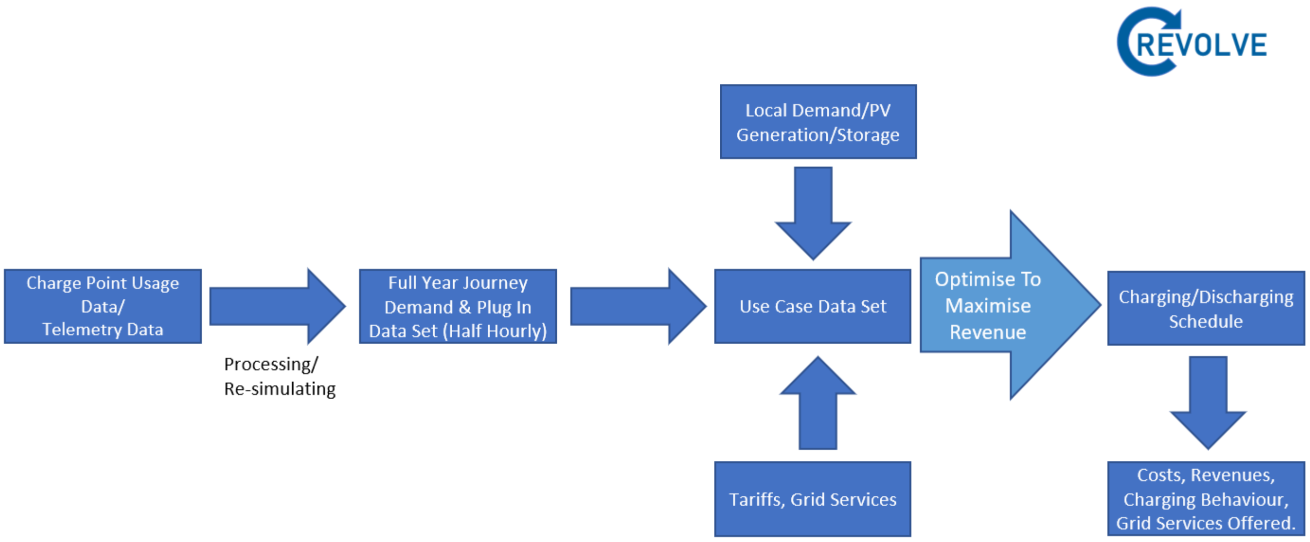


Figure 42: Cenex REVOLVE Model Diagram

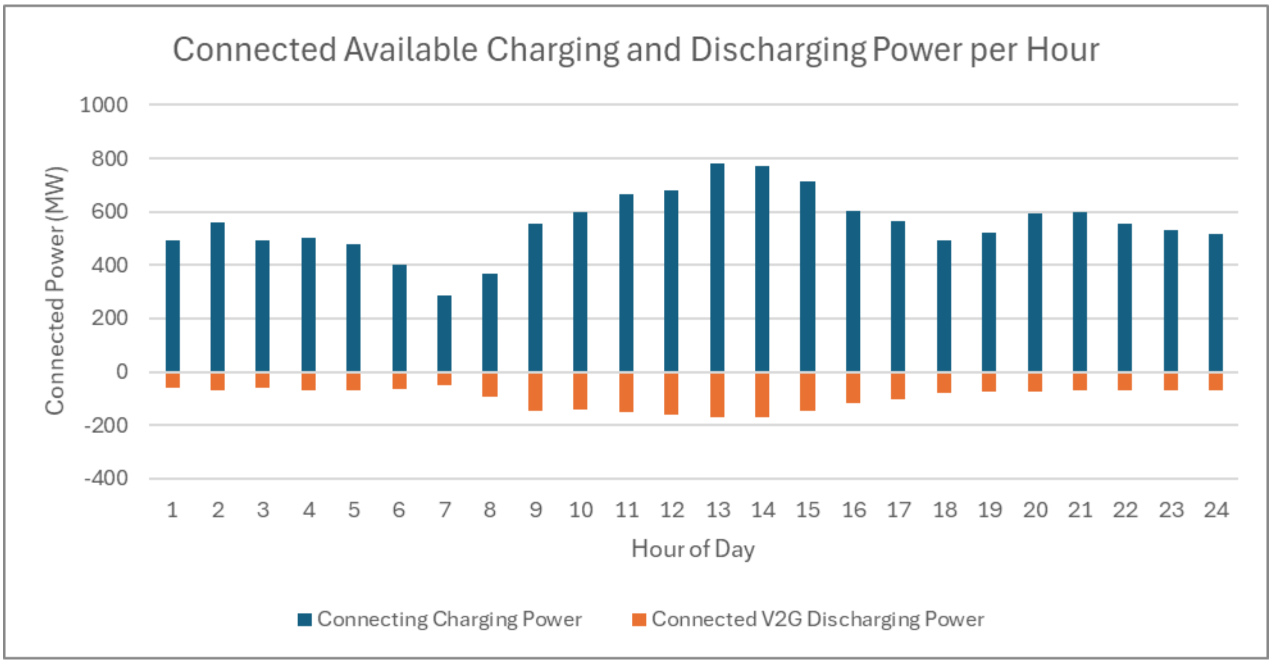
Because the model is a perfect foresight model, it provides an upper bound on the revenue that can be earned through the V2G options modelled. In reality there will be deteriorations in the value through EV availability forecasting error and potentially price forecasting error.

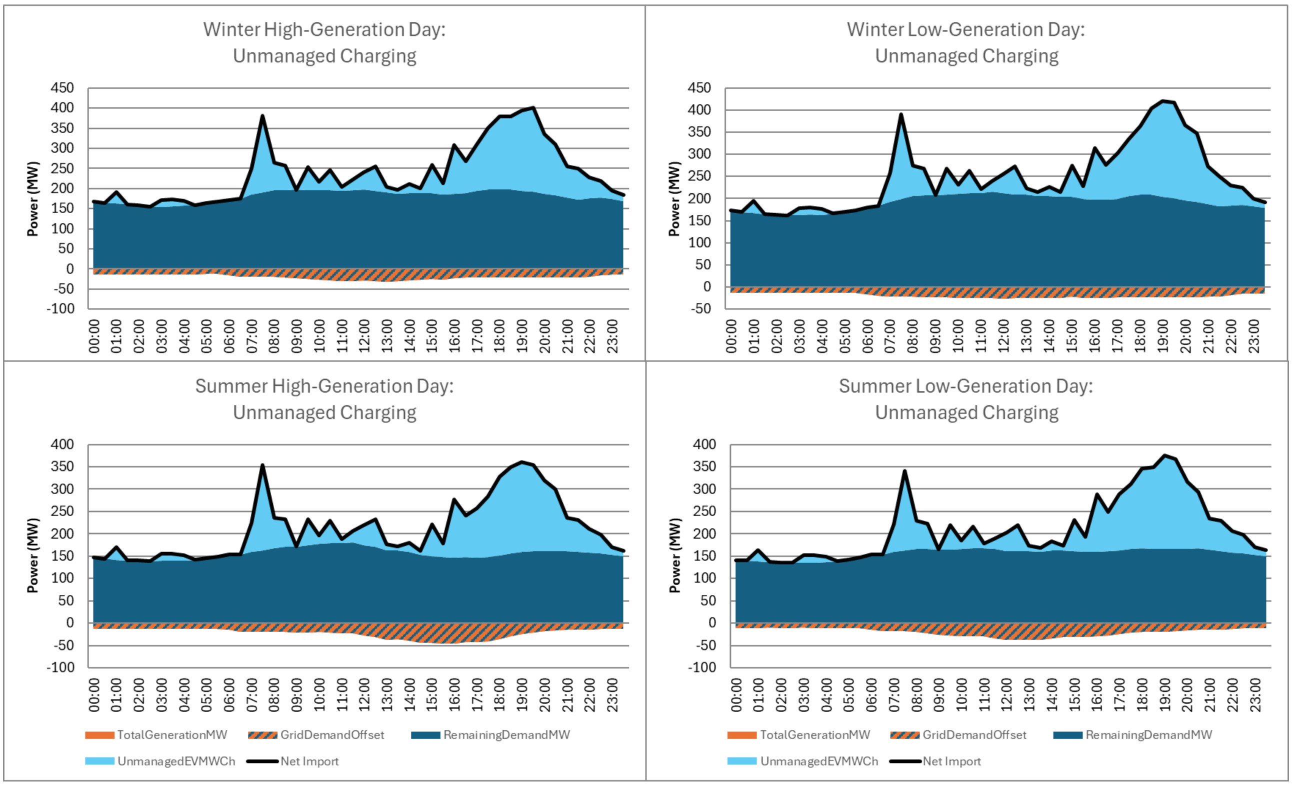
In order to quantify the value provided by V2G, the model first performs an Unmanaged run. In this, all EVs charge up to full as soon as they are plugged in. This run is used to create an energy cost baseline. Subsequently, an Optimised run is performed. In this run the charging and discharging behaviour is optimised on the basis of minimum cost.

Appendix B – Regional Unmanaged Charging

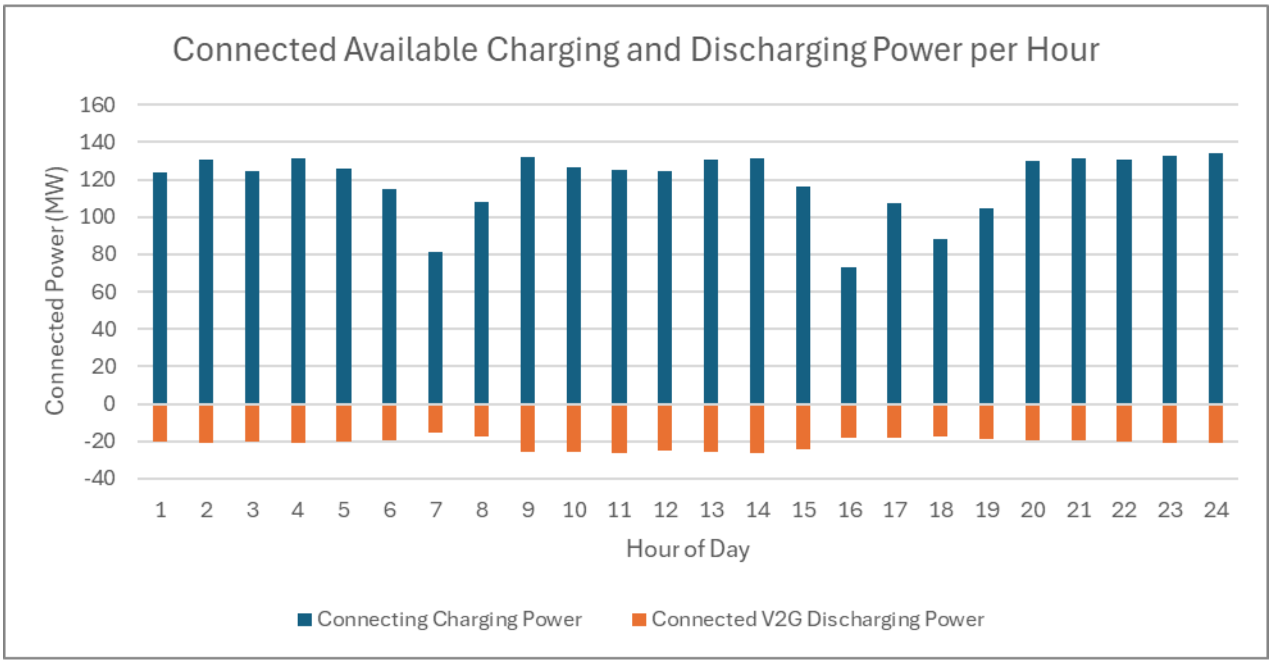
Below are the connected charging power and unmanaged charging/demand/generation profiles for each grid region. Please note the higher availability of charging power during the daytime in the Central region due to a higher proportion of commuter vehicles, and the net export in the North region during high-generation days due to the proportionately larger wind installation in this region.

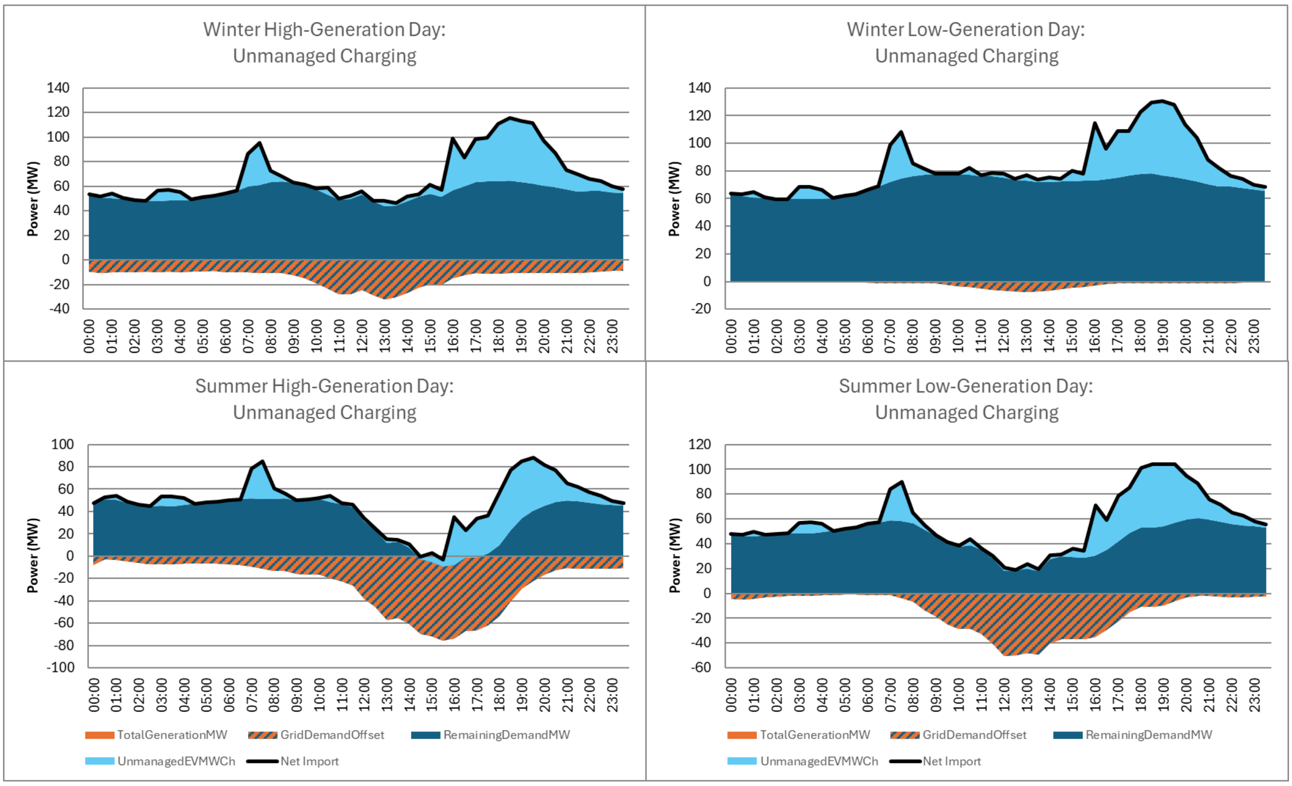
Central





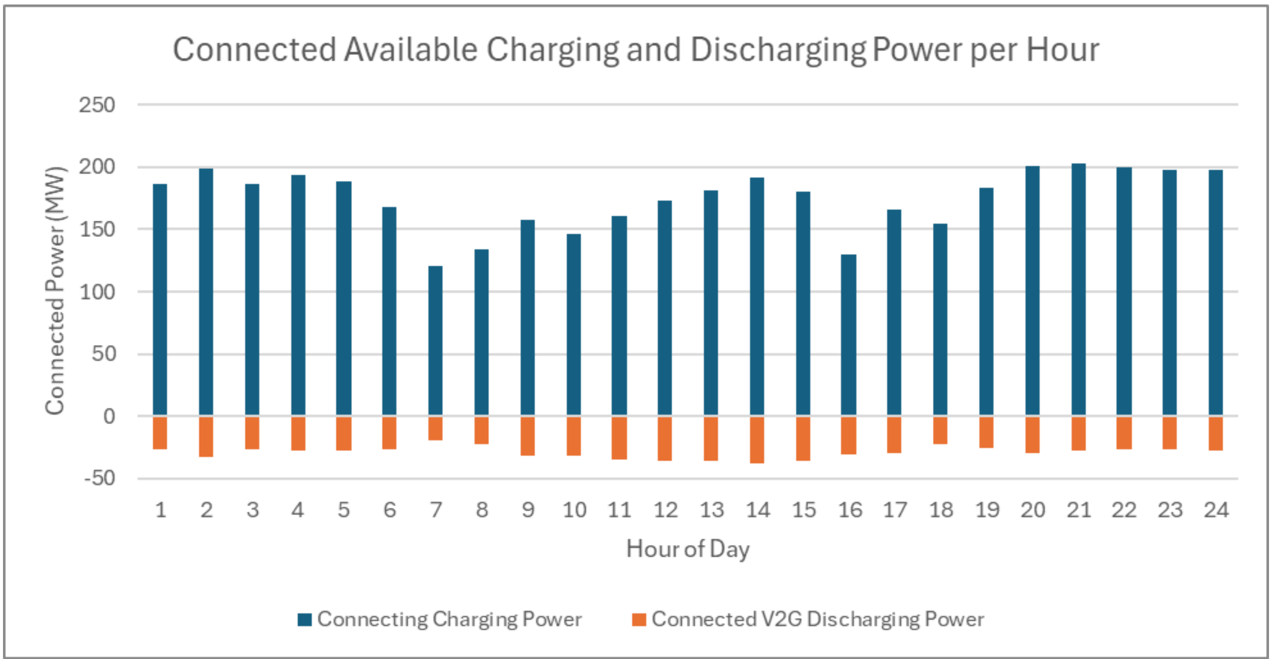
West


Connected Available Charging and Discharging Power per Hour
Connected Power (MW)
160
140
120
100
80
60
40
20
0
-20
-40
1 2 3 4 5 6 7 8 9 10 11 12 13 14 15 16 17 18 19 20 21 22 23 24
Hour of Day
Connecting Charging Power
Connected V2G Discharging Power

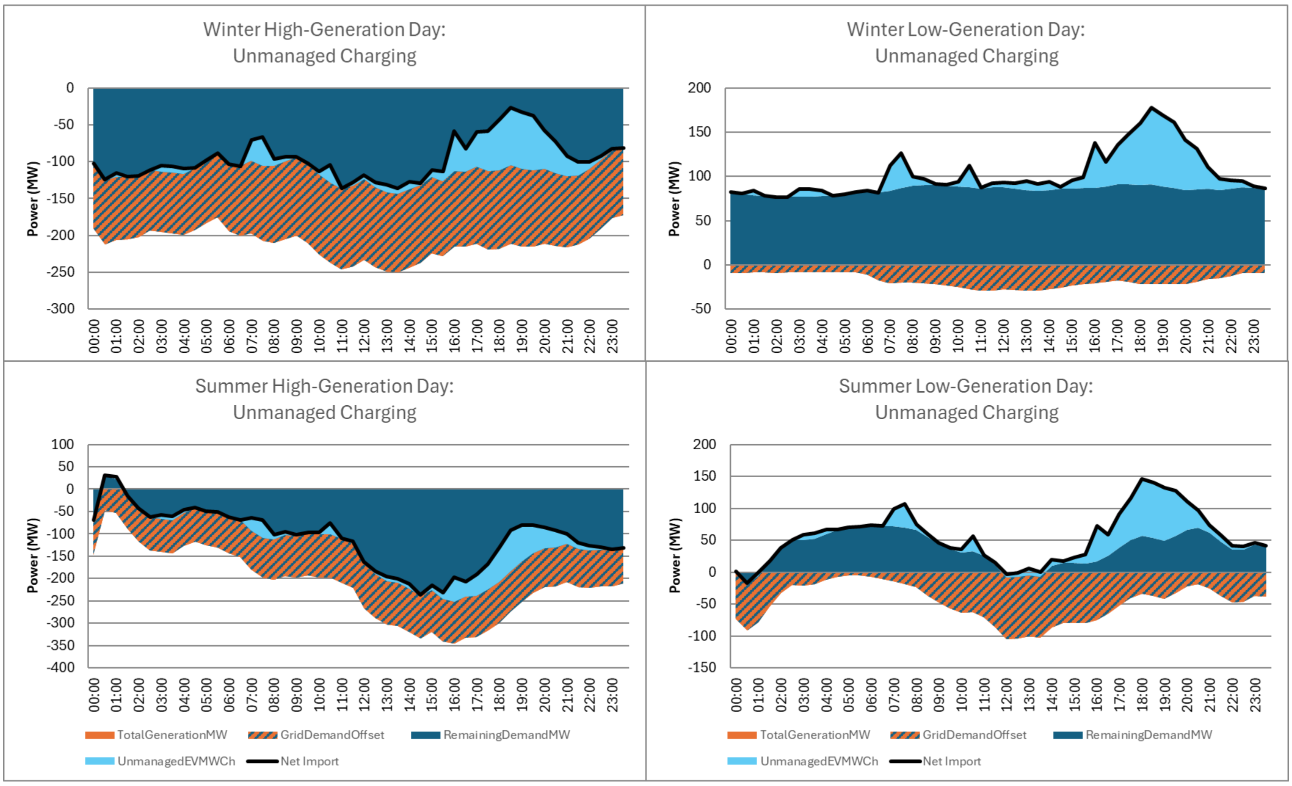

Winter High-Generation Day: Unmanaged Charging
Winter Low-Generation Day: Unmanaged Charging
Summer High-Generation Day: Unmanaged Charging
Summer Low-Generation Day: Unmanaged Charging
Power (MW)
00:00 01:00 02:00 03:00 04:00 05:00 06:00 07:00 08:00 09:00 10:00 11:00 12:00 13:00 14:00 15:00 16:00 17:00 18:00 19:00 20:00 21:00 22:00 23:00
TotalGenerationMW
GridDemandOffset
RemainingDemandMW
UnmanagedEVMWCh
Net Import

cenex

North

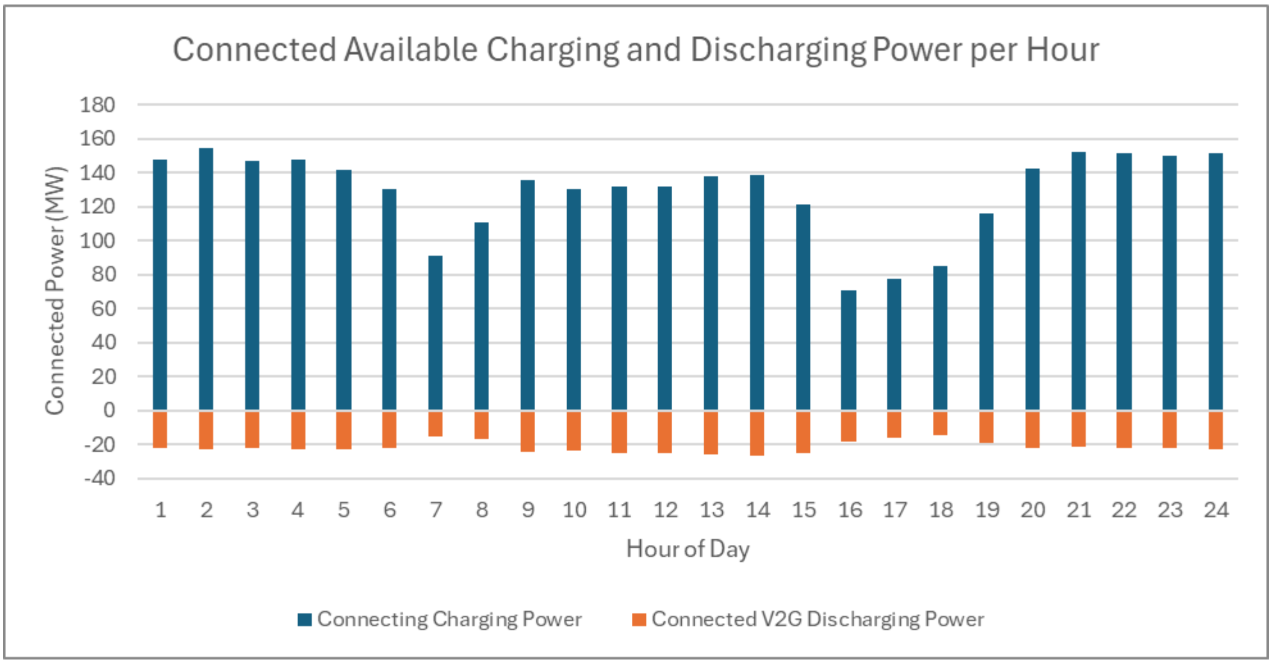


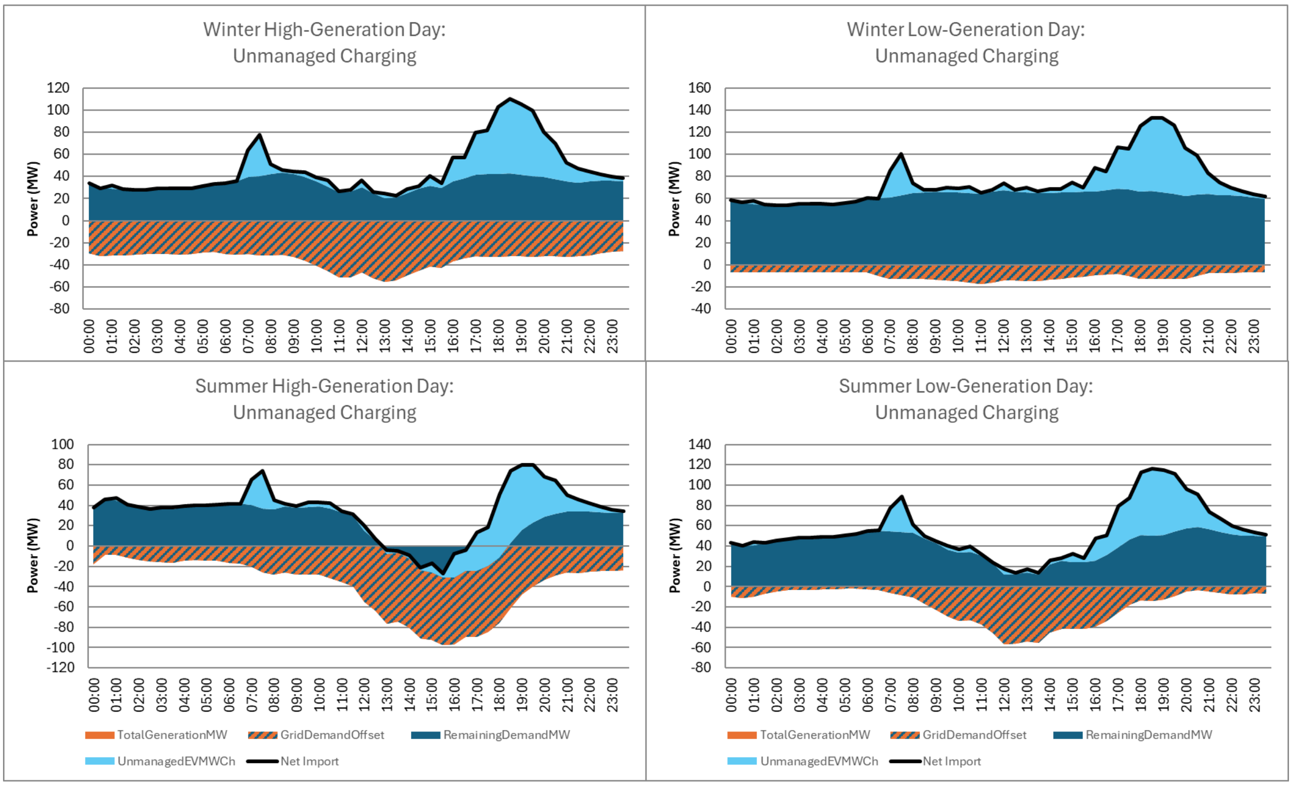
Connected Available Charging and Discharging Power per Hour
Connected Power (MW)
Hour of Day
Connecting Charging Power
Connected V2G Discharging Power



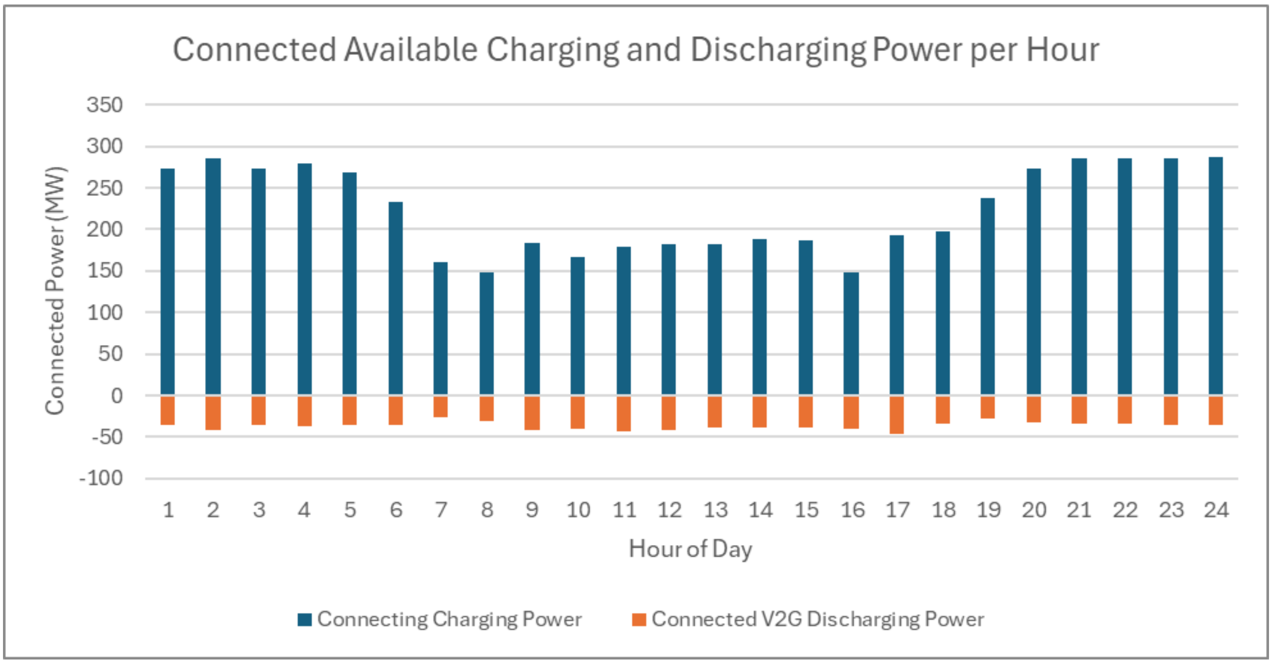
Winter High-Generation Day: Unmanaged Charging
Winter Low-Generation Day: Unmanaged Charging
Summer High-Generation Day: Unmanaged Charging
Summer Low-Generation Day: Unmanaged Charging
Power (MW)
TotalGenerationMW
GridDemandOffset
RemainingDemandMW
UnmanagedEVMWCh
Net Import

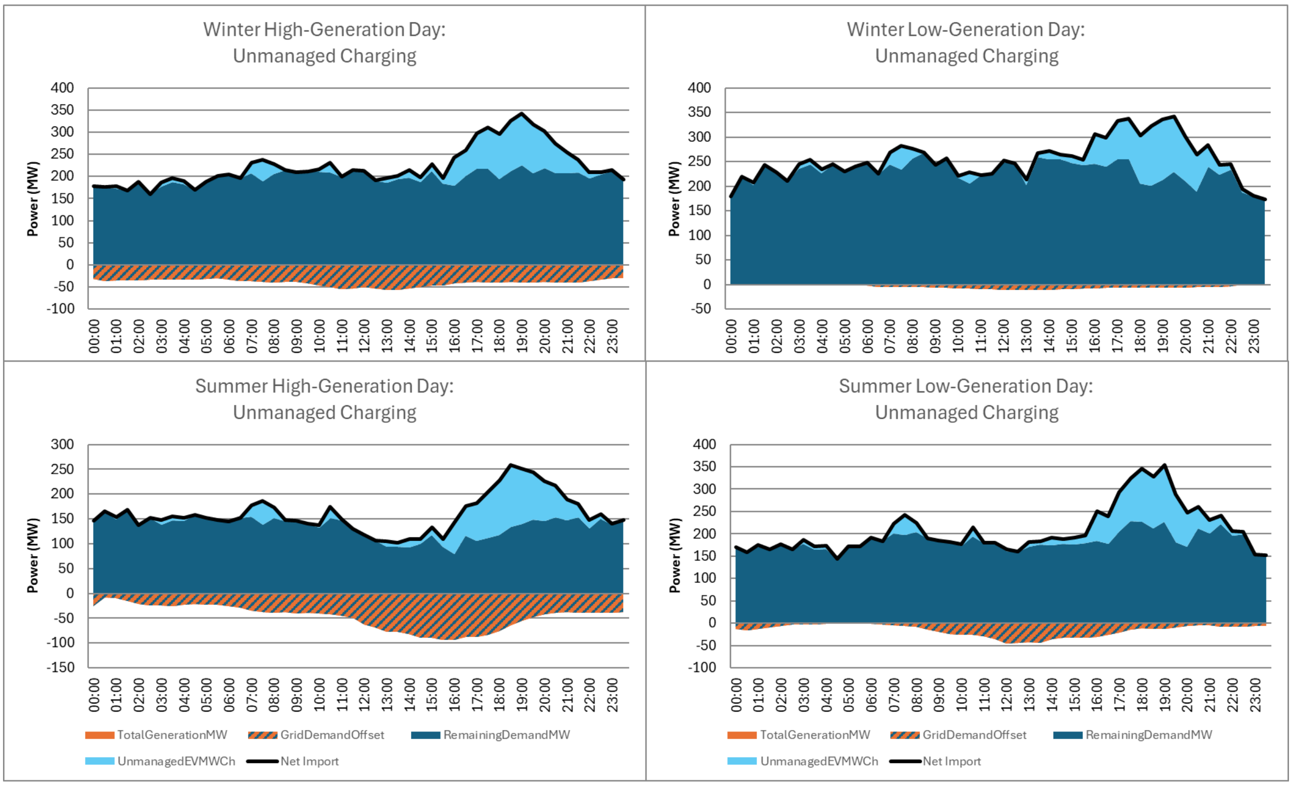
East


Connected Available Charging and Discharging Power per Hour
Connected Power (MW)
180
160
140
120
100
80
60
40
20
0
-20
-40
1 2 3 4 5 6 7 8 9 10 11 12 13 14 15 16 17 18 19 20 21 22 23 24
Hour of Day
Connecting Charging Power
Connected V2G Discharging Power

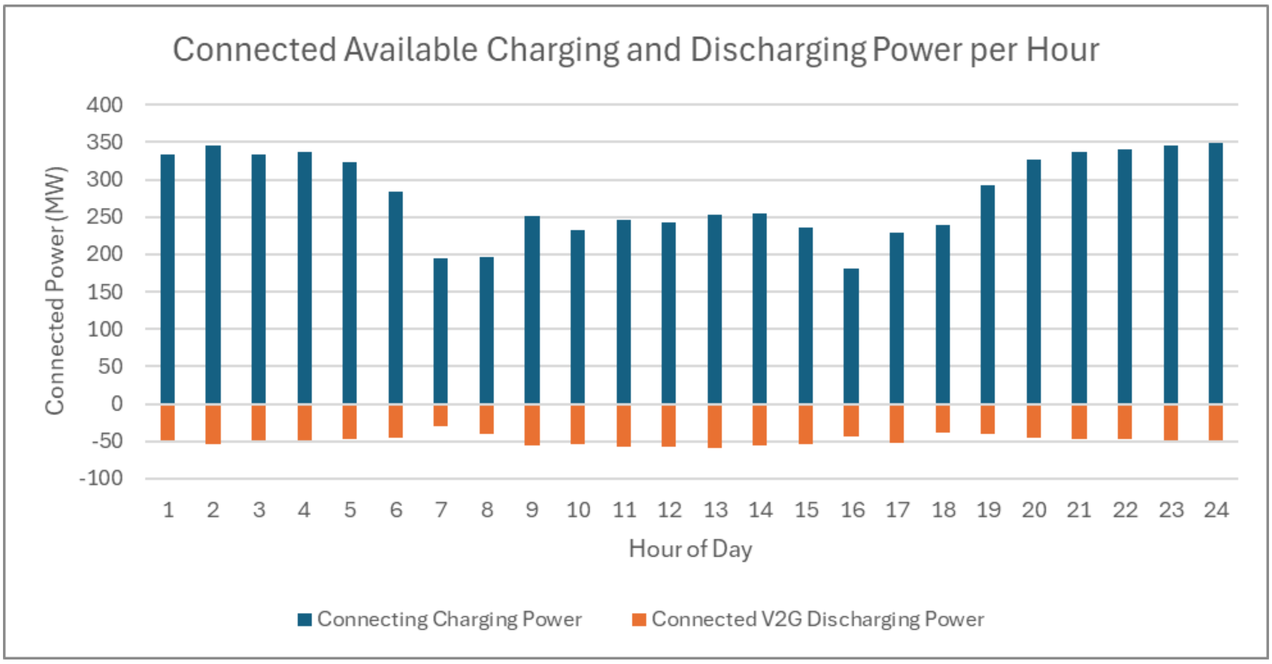

Winter High-Generation Day: Unmanaged Charging
Winter Low-Generation Day: Unmanaged Charging
Summer High-Generation Day: Unmanaged Charging
Summer Low-Generation Day: Unmanaged Charging
Power (MW)
TotalGenerationMW
GridDemandOffset
RemainingDemandMW
UnmanagedEVMWCh
Net Import

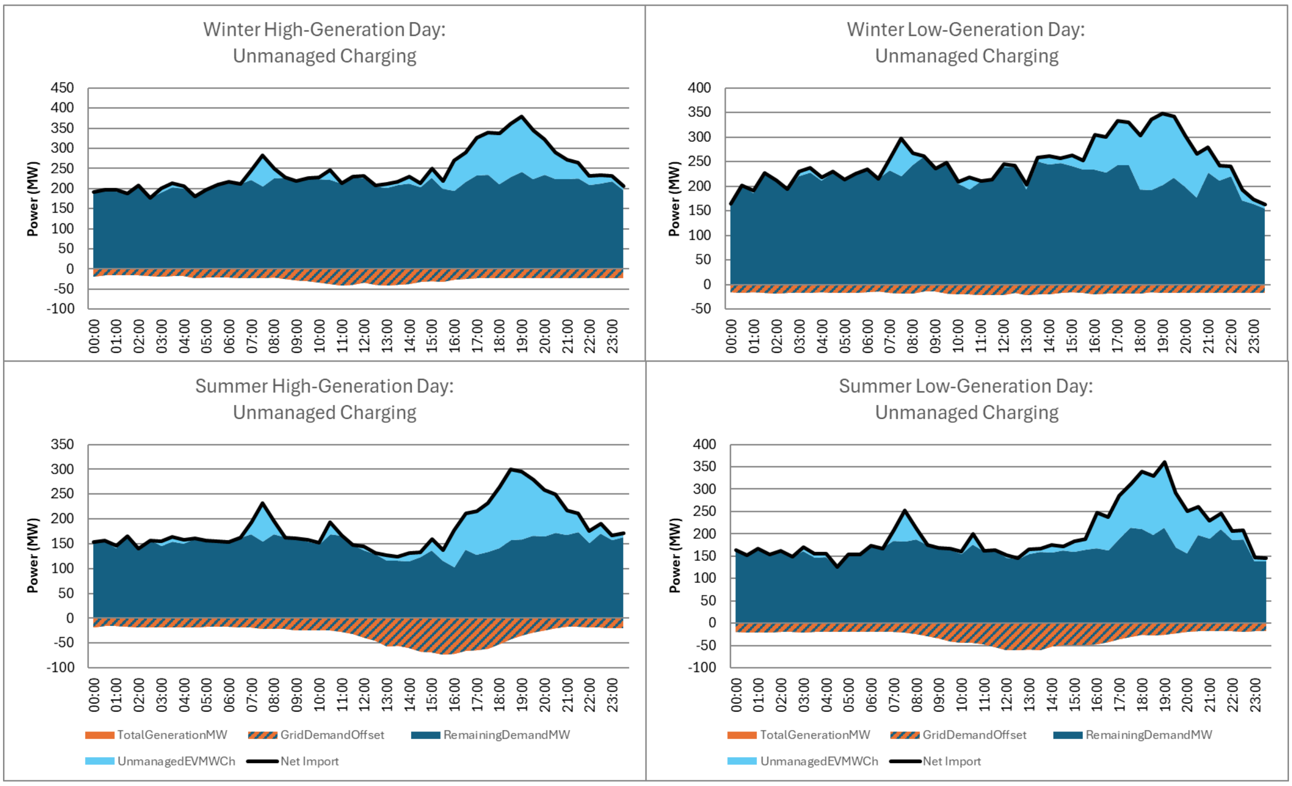
Southeast


Connected Available Charging and Discharging Power per Hour
Connected Power (MW)
350
300
250
200
150
100
50
0
-50
-100
1 2 3 4 5 6 7 8 9 10 11 12 13 14 15 16 17 18 19 20 21 22 23 24
Hour of Day
Connecting Charging Power
Connected V2G Discharging Power


Winter High-Generation Day: Unmanaged Charging
Winter Low-Generation Day: Unmanaged Charging
Summer High-Generation Day: Unmanaged Charging
Summer Low-Generation Day: Unmanaged Charging
Power (MW)
00:00 01:00 02:00 03:00 04:00 05:00 06:00 07:00 08:00 09:00 10:00 11:00 12:00 13:00 14:00 15:00 16:00 17:00 18:00 19:00 20:00 21:00 22:00 23:00
TotalGenerationMW
GridDemandOffset
RemainingDemandMW
UnmanagedEVMWCh
Net Import

Southwest


Connected Available Charging and Discharging Power per Hour
Connected Power (MW)
Hour of Day
Connecting Charging Power
Connected V2G Discharging Power


Winter High-Generation Day: Unmanaged Charging
Winter Low-Generation Day: Unmanaged Charging
Summer High-Generation Day: Unmanaged Charging
Summer Low-Generation Day: Unmanaged Charging
Power (MW)
TotalGenerationMW
GridDemandOffset
RemainingDemandMW
UnmanagedEVMWCh
Net Import

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