AN FTI CONSULTING REPORT FOR SMARTEN

A roadmap for cost-reflective electricity network tariffs in the EU

smartEn SMART ENERGY EUROPE

MARCH 2025

FTI CONSULTING

smartEn

SMART ENERGY EUROPE

smartEn is the European association of the Flexible Demand Management Industry. We aim to create opportunities for every company, building, and car to support an increasingly renewable energy system.

For further information please visit: **www.smarten.eu**

ade · AFRY · ANEO · APEX LAB · APPLiA Home Appliance Europe · ARVAL BNP PARIBAS GROUP · aug·e · bamboo energy · Beebop
bne · CHAMELEON TECHNOLOGY · CheckWatt · cleanwatts · CyberGrid · dcbel · decade · DEFTPOWER
DELTAGREEN · DNV · EATON Powering Business Worldwide · EDF · ELECTRON · elisa · Elli · ENEIDA.IO
enel x · Energy Market of Things · Energy Pool · CATAPULT Energy Systems · energy web · EnergyHub · enjoyelec · Entelios
entra · Energy of things · epexspot · epq · ev.energy · Fermata Energy · FEVER · FLEXCITY by VEOLIA
FLEXIBLEPOWER ALLIANCE NETWORK · FLOWER · FRACTAL ENERGY · Fusebox .energy · Futurize · Google · Greenvolt · Gridio · gridX
HIVE POWER · HONDA The Power of Dreams · HSLU Lucerne University of Applied Sciences and Arts · HUAWEI · i-EM · ignes · INEA · Itron · KALUZA
Landis+Gyr · LCPDelta · lunar energy · MAGNUS energy · Microsoft · THE MOBILITY HOUSE · MONTA · NODES
NORD POOL · NUVVE · OAKTREE POWER · octopus energy · Ohme · openADR ALLIANCE · Orus Energy · Photon Energy · piclo
Plexigrid · Powernaut · R8 tech · REGALGRID · Schneider Electric · SIEMENS · sight-E analytics · SMART ENERGY LAB · SMPnet
sonnen · sympower · SYNERGI · TESLA · THERMOVAULT · tibber · tiko · Tilt · THE TRAXIS GROUP
utiligize · vaasaETT · VIESSMANN · VIOTAS · Voltalis · VOLVO · watt is · Wirepas

ABOUT SMARTEN

smartEn, representing the Flexible Demand Management Industry, is the European business association integrating the consumer-driven solutions of the clean energy transition. We aim to create opportunities for every company, building and car to support an increasingly renewable energy system.

For further information please visit:
www.smarten.eu

ABOUT FTI CONSULTING

FTI Consulting is an independent global business advisory firm dedicated to helping organisations manage change, mitigate risk and resolve disputes: financial, legal, operational, political & regulatory, reputational and transactional. FTI Consulting professionals, located in all major business centres throughout the world, work closely with clients to anticipate, illuminate and overcome complex business challenges and opportunities.

Connect with us on Twitter (@FTIConsulting), Facebook and LinkedIn. **www.fticonsulting.com**

A roadmap for cost-reflective electricity network tariffs in the EU– March 2025

MANAGEMENT AT FTI CONSULTING:
Jason Mann, Senior Managing Director

Martina Lindovska, Managing Director

Tim Schittekatte, Senior Director

Joe Couchman, Senior Consultant

PROJECT MANAGEMENT AT SMARTEN:
Andrés Pinto-Bello Gómez, Head of Research and Projects

smartEn and FTI Consulting would like to thank smartEn members for their invaluable contributions and feedback that made this report possible.

DESIGN:
Think Things Studio Barcelona

DISCLAIMER

This report has been prepared by FTI Consulting LLP ("**FTI Consulting**") for smartEn Smart Energy Europe ("smartEn") in connection with examining a harmonised approach for the development of cost-reflective distribution network tariffs in the EU under the terms of smartEn engagement letter with FTI Consulting dated 17 June 2024 (the "**Contract**").

This report has been prepared solely for the benefit of smartEn in connection with examining a harmonised approach for the development of cost-reflective distribution network tariffs in the EU and no other party is entitled to rely on it in whole or in part for any purpose whatsoever.

The distribution of this report in or from certain jurisdictions may be restricted or prohibited by law. This report may not be distributed or supplied to any third party without FTI Consulting's prior written consent which consent may be conditional upon any such third party entering into a hold harmless letter with FTI Consulting on terms agreed by FTI Consulting. Recipients are required by FTI Consulting to inform themselves of and comply with all such restrictions or prohibitions. FTI Consulting does not accept any liability to any person in relation to the distribution or possession of this report in or from any jurisdiction. This report is not to be referred to or quoted, in whole or in part, in any registration statement, prospectus, public filing, loan agreement, or other agreement or any other document, or used in any legal, arbitral or regulatory proceedings without the prior written approval of FTI Consulting. FTI Consulting and its members, and their employees, consultants, representatives, officers, directors, subsidiaries and advisors accept no responsibility, duty of care or liability whatsoever (whether in contract or tort or otherwise, including for, but not limited to, negligence) to any person (except to smartEN under the relevant terms of the Contract) in relation to the content of this report. Accordingly, FTI Consulting disclaims all responsibility for the consequences of any person acting or refraining to act in reliance on this report or for any decisions made or not made which are based upon such report.

This report contains information obtained or derived from a variety of sources. FTI Consulting does not accept any responsibility for verifying or establishing the reliability of those sources or verifying the information so provided.

The information set out in this document will not form the basis of any contract and should not be relied on in relation to any contract or commitment.

Nothing in this report constitutes investment, legal, accounting or tax advice, or a representation that any investment or strategy is suitable or appropriate to the recipient's individual circumstances, or otherwise constitutes a personal recommendation, and it is not intended to form a basis of any investment decision.

No representation or warranty of any kind (whether express or implied) is given by FTI Consulting to any person as to the accuracy or completeness of this report.

This report is based on information available to FTI Consulting at the time of writing of this report and does not take into account any new information which becomes known to us after the date of this report. We accept no responsibility for updating this report or informing any recipient of this report of any such new information.

This report and its contents are confidential and may not be copied or reproduced in whole or in part without the prior written consent of FTI Consulting.

UK COPYRIGHT NOTICE

Table of contents

Executive Summary

Executive Summary

1. Electricity demand has been growing rapidly and is expected to continue to grow significantly in the European Union ("EU"), driven, to a significant extent, by electrification of transport and heat at the distribution level. In turn, electricity networks will need to expand as decarbonisation and electrification progresses but the actual need for grid investment will be highly dependent on how grids are used. The need for network reinforcements (and associated costs, borne by consumers), is mainly driven by the peak demand on the network, which can be reduced by leveraging demand-side flexibility. Other things being equal, there is a preference for networks to be used efficiently, i.e. for consumption to be distributed over time. From a consumer perspective, the incentives to consume at a particular point in time can be influenced by two factors: the price of energy (in turn driven by the wholesale electricity price) and the price of network capacity being accessed to consume electricity. The latter is determined by the underlying network tariff design.

2. While the relevance of allowing electricity prices to better reflect supply and demand dynamics at wholesale-level is widely understood, network tariff design has been receiving less attention from policymakers. In this context, the European Commission plans to kick off a new mandate in Q1 2026, with a revised workplan building on the EU Action Plan for the Future of our Grids. Recognising the importance of leveraging demand-side flexibility to optimise grid usage, one pillar of this workplan is intended to be the design of network tariffs, and how these tariffs can provide appropriate signals to consumers to make the most efficient use of the available grid infrastructure.

3. This is an important development as network tariff design can change consumers' incentives by putting an explicit price on consumption (and injection) of electricity in specific periods, and thus incentivise grid usage to be spread across time, similar to how wholesale electricity prices can incentivise consumption to shift over time periods. A key policy question is how to design a cost-reflective network tariff that finds the right balance between building out grids and leveraging consumer flexibility. Cost-reflective network tariffs are required to support the EU's electrification effort in the most cost-efficient manner and avoid harmful cross-subsidies between different consumer groups (e.g. rapidly and more slowly electrifying consumers).

4. In this context, FTI Consulting has been engaged by smartEn, representing the Flexible Demand Management Industry, to examine the case for more cost-reflective network tariff designs and to develop a roadmap for cost-reflective electricity network tariffs in the EU. The objective of the roadmap is to provide practical guidance on network tariff design considering the state of play across EU Member States, which adds to the high-level guidance under the current EU regulatory framework.

5. We mostly focus on distribution network tariffs in this report, but the described guiding network tariff design principles apply equally to transmission networks. Differences in the exact implementation of a cost-reflective network tariff between the different voltage levels can be driven by a range of considerations, including for example practicability.

Status quo: network tariffs in the EU

6. There is a wide range of network tariff designs currently in place across the EU, ranging from relatively simple ones which do not provide any incentive to spread consumption, to more complex ones which can do so to a certain extent. For an important share of households in the EU, e.g. in Germany and Hungary, the network tariff design still consists mostly of flat volumetric network tariffs (in €/kWh).[1] Flat volumetric

1 · We recognise that some Member States have transitioned to more advanced network tariff designs for households (e.g. Spain and Slovenia) and that for higher voltage-levels in most EU Member States network tariff design has evolved.

network tariffs are not cost reflective as they are disconnected from the underlying drivers of the costs that these charges seek to recover. They also risk acting as a barrier to electrification since consumers cannot avoid significantly higher network charges when adopting electric appliances that are kWh-intensive (e.g. electric vehicles ("EVs") and heat pumps), independent of how these appliances are used. This barrier to electrification could be removed by transitioning to a more cost-reflective network tariff design.

The case for change

7. There is a case for change with respect to network tariff design in the EU. Intermittent renewables increasingly represent a dominant share of electricity generation and consumers with EVs or heat pumps are opting into dynamic energy price plans (reflecting wholesale electricity prices) to access low-priced electricity in hours of high renewable supply. When there are no cost-reflective network tariffs complementing dynamic energy pricing plans, there is a risk that increasingly flexible consumption unintendingly creates new local demand peaks in hours with low energy prices.[2] The resulting increase in network congestion can lead to an inefficient network outbuild and ultimately rising consumer costs. Network build-out may also run into supply chain constraints; or, if not delivered on time, can lead to involuntary demand curtailment.

Wide range of network tariffs: long list and short list

8. Network tariff designs are defined along three dimensions: the physical unit ("format"), the temporal granularity ("timing") and the spatial granularity ("location"). Based on these building blocks we formulated, in collaboration with smartEn and its members, a subset of nine combinations of network tariff options, across the three dimensions (and subsets of options). These network tariff designs represent a progressive set of designs, ranging from simple (status quo) arrangements through to more complex ones that currently are only discussed in academic circles.

9. Of these, we shortlisted four network tariff designs for an in-depth quantitative analysis. We selected tariffs that covered a broad envelope of sophistication, and that also enabled us to compare and contrast key features of network tariff design (such as the format and timing). These shortlisted network tariff designs are, ranked from the least cost-reflective to the most cost-reflective:

— **Tariff 0 (status quo):** flat volumetric network tariff (in €/kWh), which is our 'counterfactual' tariff.

— **Tariff B:** capacity-based subscription network tariffs based on individual peak usage (in €/kW), which provides incentives to smooth their energy consumption over the year.

— **Tariff C:** 3-part time-of-use ("ToU") seasonal capacity-based subscription network tariff (in €/kW), which augments Tariff B by adding temporal granularity, distinguishing across seasons and time of day.

— **Tariff E:** dynamic volumetric network tariffs (in €/kWh) and a uniform fixed charge (in € per connection) vary hour-by-hour based on expected network conditions, and thus provide highly granular (and complex) incentives for consumers to shift load across different periods of time.

Setup of the quantitative analysis

10. In the quantitative assessment of the shortlisted network tariffs, we focussed on a case study illustrating how cost-reflective network tariff design can reduce aggregate peak demand across consumers and hence limit the build-out of the distribution grid under increasing EV adoption. Using empirical data, we model a population of 200 households connected to a single feeder under scenarios featuring increasing EV adoption from 0% to 60%. We assume all modelled households opt into a dynamic energy tariff, complemented with four different network tariff designs as described above. We assume households with EVs seek to charge their EVs such that they minimise their total electricity bill (consisting of energy and network charges), whilst respecting their predetermined EV charging requirements.

2 · Cost-reflective network tariffs are not the only tool to unlock consumer flexibility for grid purposes. Local flexibility markets and smart connection agreements are other important tools that are complementary to cost-reflective network tariff designs.

Assessment criteria

11. The criteria used in our quantitative analysis to assess the performance of the shortlisted network tariffs reflect key regulatory principles of network tariff design:[3]

— Cost reflectiveness, which is proxied by the impact of the different network tariff designs on the total electricity costs (energy plus network)[4] of the population of households under varying degrees of EV adoption;

— Practicability, which includes:

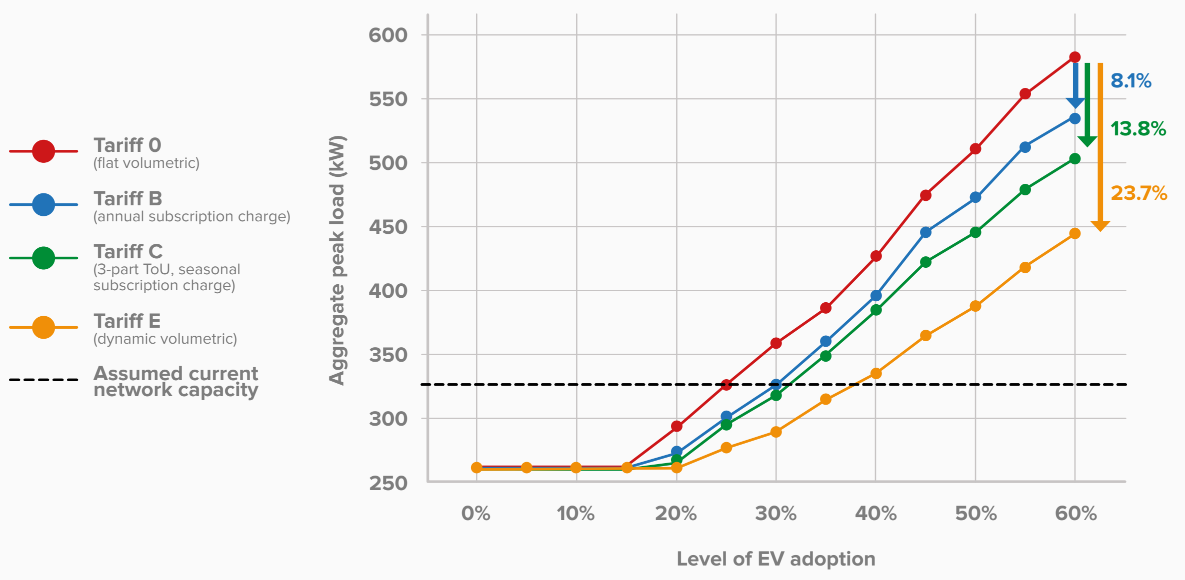
- **incentives for electrification** proxied by the impacts of the different network tariff designs on the cost of EV charging; and

- **distributional impacts** proxied by the impacts of the different network tariff designs on the electricity costs of non-EV consumers.

Key findings of the quantitative assessment

12. The growth of the aggregate peak load under the different network tariff designs for rising levels of electrification is shown in Figure 1.

FIGURE 1 — Aggregate peak load on the distribution network under each modelled tariff design (kW)



Source: FTI Consulting

13. Up to 15% EV adoption there is no change in the aggregate peak load under any network tariff design. This is because there are few EVs on the network and those EVs' charging requirements (typically fulfilled during the night when wholesale electricity prices are low) do not cause an increase in the aggregate peak load, independent of the network tariff design.

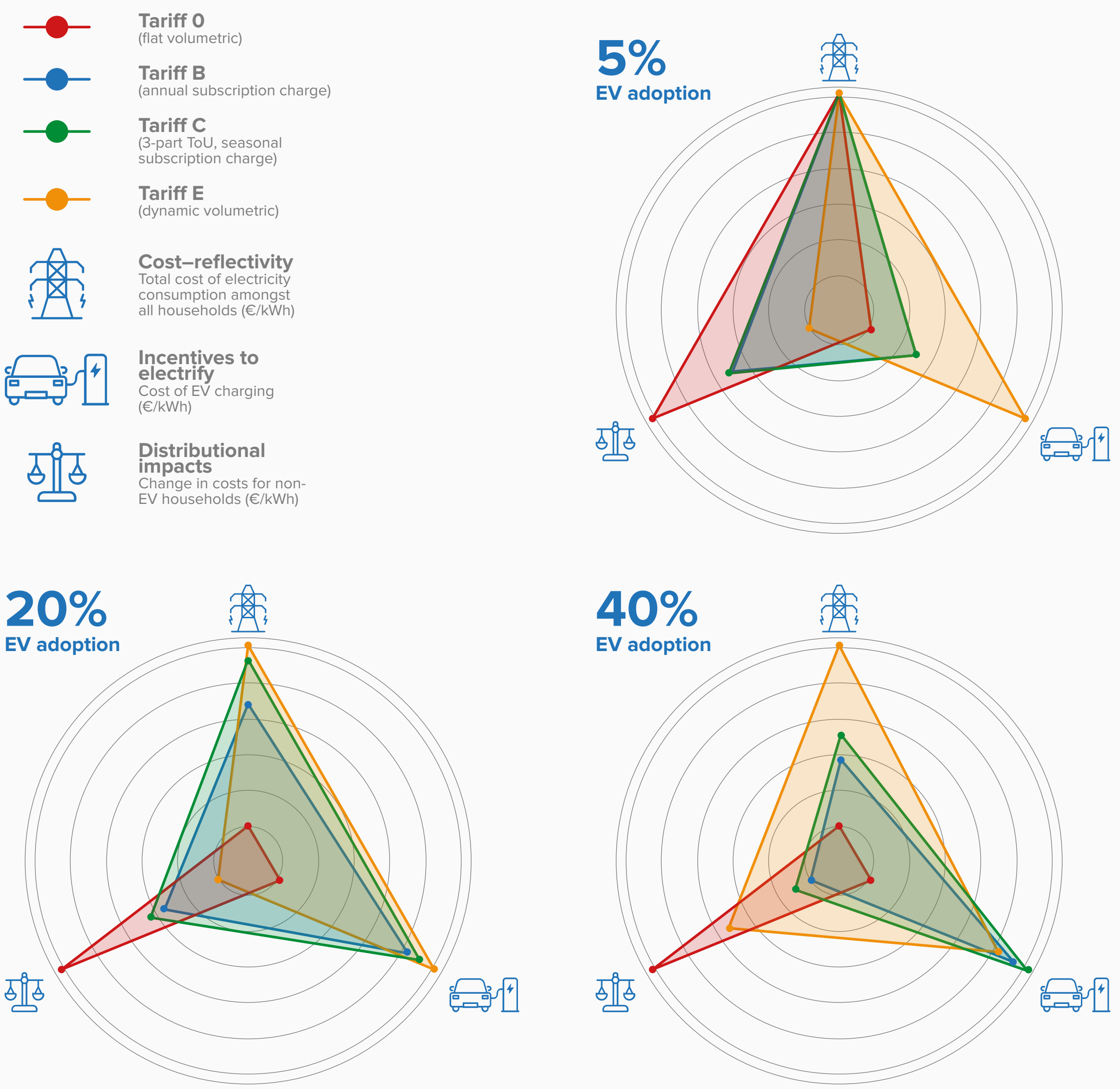
3 · The cost recovery principle is enforced by design, i.e. all network costs are recouped via network charges under all tariffs examined, and this criterion performs identically across the modelled tariffs.

4 · We focus on total electricity costs and not only network costs as there can exist a trade-off between a network tariff design: (i) mitigating the need for network outbuild; and (ii) steering consumers away from the lowest priced hours in the wholesale market (to avoid overstressing the network at those moments).

14. From 20% EV adoption, the aggregate peak load starts to increase under all modelled tariffs and continues to increase as EV penetration grows. This is in line with expectations and reflects the network requirements driven by the electrification of household demand. However, the rate at which the aggregate peak load grows varies significantly across the modelled network tariffs. The more cost-reflective a network tariff, the slower the rate of growth in the aggregate peak load (and thus network outbuild) with rising levels of electrification. At 60% of EV adoption, we find that Tariff B, C and E can reduce the aggregate peak load by 8.1%, 13.8% and 23.7% relative to Tariff 0, respectively. Assuming a long-run marginal network cost of €100/kW, this implies that relative to Tariff 0, Tariff B, C and E can reduce the annual average network costs per modelled household by €23.6, €40.2, and €69.1 respectively.

15. We have also systematically tested each of the four distribution network tariffs (Tariff 0, B, C and E) against the three assessment criteria (cost reflectiveness, incentives for electrification and distributional impacts), at different levels of electrification. We summarise the key findings in Figure 2 below, for a selection of EV adoption shares.

FIGURE 2 — Relative performance of modelled network tariffs at 5%, 20%, and 40% EV adoption. For any given performance metric, the further out to the edge of the circle a tariff sits, the better its performance.



Source: FTI Consulting

16. Figure 2 shows that when considering all assessment criteria:

— There is no single 'best' network tariff. Rather, there are trade-offs between the total electricity costs of meeting demand, distributional impacts and incentives for electrification.

— The trade-offs between tariffs change as the adoption of EV increases, so policymakers in different regions and/or at different times may face different choices.

17. The quantitative analysis shows that there is a clear case for more cost-reflective tariffs (B, C and E) in regions where electrification is ramping up. As shown in Figure 2:

— At **any level of electrification,** the least cost-reflective Tariff 0 acts as a barrier to electrification by increasing the costs of charging EVs.[5]

— Initially, at **20% of EV adoption,** Tariff B and C perform nearly as good with regards to cost-reflectiveness as Tariff E while mitigating to a larger extent distributional consequences.

— With **higher levels of electrification** (e.g. 40% of EV adoption), the most cost-reflective tariff (Tariff E) performs relatively well on all three assessment criteria, and the case for a highly cost-reflective network tariffs substantially strengthens. This is because, at high levels of electrification, the magnitude of network costs is more important than the split, i.e. the quantum of the network costs is so high that even if non-EV consumers bear a significant share of these costs, they benefit more from a reduction in the total quantum of network costs (e.g. Tariff E) than they would have benefitted if the total quantum remained high and they only reduced the share of costs they bear (e.g. Tariff B or C).

18. Overall, a complex set of varying trade-offs arises when transitioning to more cost-reflective network tariffs. This indicates that there may be merit in sequencing the introduction of progressively more cost-reflective network tariffs as electrification increases. Along such transition, policymakers need to consider the extent to which they wish to (1) accelerate electrification; (2) mitigate total electricity costs to consumers; and (3) manage distributional consequences of the tariff design choice, with different choices available at different levels of electrification.

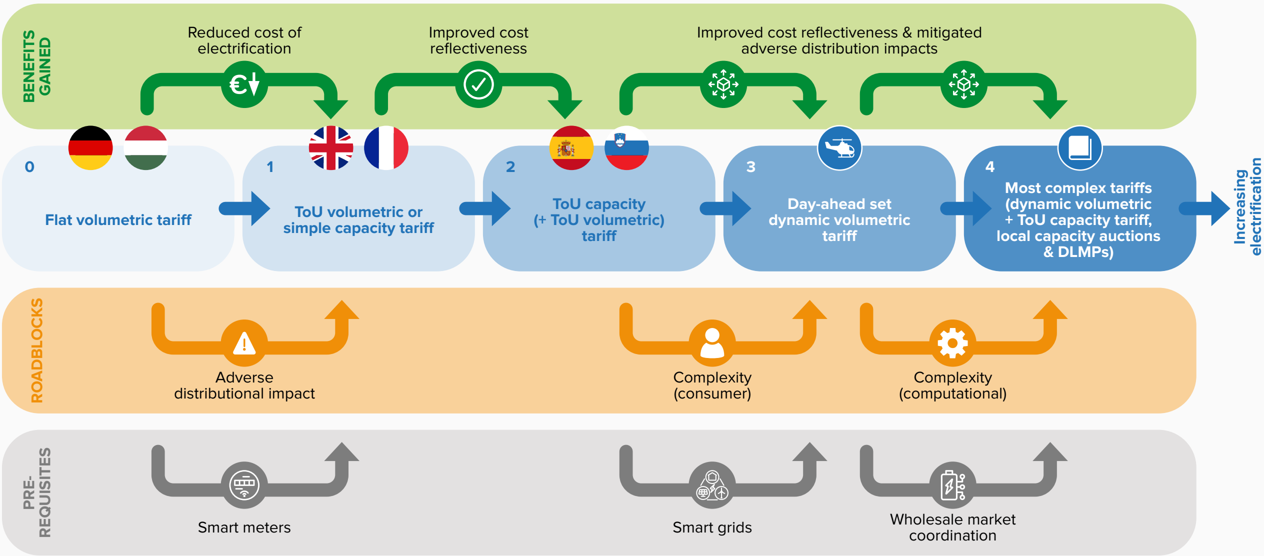
19. In our case study we focussed on EV charging. In reality, many households who adopt EVs may also adopt other flexible (and price-responsive) electric load with different consumption characteristics to EVs, such as heat pumps or electric water boilers, which could further add to the benefits case of more cost-reflective network tariff designs. When adopting battery energy storage systems and solar photovoltaic panels (or engaging in vehicle-to-grid) consumers would as well be able to inject electricity into the network. An additional advantage of Tariff E relative to Tariff B and C is symmetry, i.e. paying consumers injecting into the network during times of high local demand the same as other consumers pay to withdraw from the network at the same moment (and vice versa in case network peaks would be driven by consumer injections). While the potential of a symmetric network tariff design to reduce network costs (relative to a non-symmetric network tariff design) is evident, its quantification merits further examination.

Roadmap for Europe's electricity network tariff design

20. Informed by the qualitative and the quantitative assessment, we propose a roadmap that illustrates how network tariff design can evolve as electrification progresses, recognising that each Member State may be at a different step (e.g. Germany and Hungary at step 1, and Spain and Slovenia further ahead). We illustrate the roadmap, consisting of four steps, in Figure 3.

5 · EV charging is found to be up to 30% more expensive under Tariff 0 compared to the more cost-reflective network tariffs.

FIGURE 3 — Roadmap of EU electricity network tariff design



Source: FTI Consulting

Notes: (1) The pace at which EU Member States would choose to follow this trajectory towards a more cost-reflective network tariff design will depend on the local context; (2) We do not necessarily recommend following the roadmap step-by-step. There can be valid arguments to leapfrog several steps; (3) The country flags indicate examples of countries that currently have the described distribution network tariff in place for households.

21. The roadmap illustrates the key benefits of increasing the cost-reflectiveness of different tariffs, but also identified potential 'roadblocks', i.e. factors that would need to be considered by policymakers in deciding which network design tariff was best suited for their circumstances, and pre-requisites, i.e. technology or conditions that would need to be in place. In other words, the merits of different network tariff designs are highly context-dependent and there is no one-size-fits-all. The roadmap presented above sets out a potential way for different jurisdictions to consider implementing progressively more cost-reflective tariffs, driven by their local circumstances.

22. The pace at which EU Member States would choose to follow this trajectory towards a more cost-reflective network tariff design will depend on the local context, especially the extent to which networks have been overbuilt in the past and the expected speed of future electrification. We do not necessarily recommend following the roadmap step-by-step. There can be valid arguments to leapfrog several steps if the circumstances of a particular Member State indicate that they would benefit from "jumping" straight to a more cost-reflective design or if the governance processes to redesign network tariffs are deemed particularly burdensome.

23. As network tariff designs become more cost-reflective, complexity for the consumer appears to increase rapidly (e.g. from step 3 to 4). However, that is only true if all consumers were to be directly exposed to such network tariff design. There are two potential solutions to this perceived issue:

— First, end users could be exposed to the more advanced network tariff designs on an active opt-in basis.

— Second, suppliers/aggregators could internalise the network tariffs in their commercial offer, such that the complexity of the tariff design could be shifted away from the end consumer.

24. A combination of both approaches to reduce complexity could be to introduce an option for consumers to opt-in certain appliances in a "flexi-grid" tariff. By opting-in an appliance, the consumer would receive a discounted network charge in exchange for giving their consent to a third party to operate the relevant appliance whenever the maximum capacity in the local grid is reached. The coordination between the grid operator and the relevant third party would likely require local highly dynamic price signals, but the consumer would not be exposed to any of that complexity.

1

Introduction

A. Background

1.1 Europe, alongside many other parts of the world, has been rapidly decarbonising its energy use, with significant changes to the way electricity is produced and consumed. Intermittent renewables are increasingly representing a dominant share of electricity generation, while electricity demand is growing mostly through the electrification of transport, heating, and industrial processes. Electricity demand is also becoming increasingly flexible, with new technologies being deployed to enable consumers to respond to price signals, and increasingly controllable via apps and the internet allowing increased optimisation by third parties. This transition thus poses both opportunities and challenges to the electricity system.

1.2 One of the main aspects of the energy transition concerns the development of transmission and distribution networks, including both how much infrastructure is required and, directly related, what mechanisms need to be put in place to use the existing infrastructure efficiently. In 2026 the European Commission ("EC") plans to kick off a new mandate, with a revised workplan building on the European Union ("EU") Action Plan for the Future of our Grids. One pillar of this workplan is intended to be the design of network tariffs, and how these tariffs can provide the appropriate signals to consumers to make the most efficient use of the available grid infrastructure.

1.3 Network tariffs are a key (and sometimes underrated) component of the regulation and market design that supports the EU's energy transition. A network tariff design that reflects the real costs of using network infrastructure (and hence incentivises efficient usage of such infrastructure) contributes to the formation of an efficient price signal that some consumers can respond to ("demand side response"). Conversely, a network tariff design that is not cost reflective can lead to harmful cross-subsidies between consumers or limit the full potential for active consumer participation.

1.4 In this section we first provide a high-level overview of network tariffs. Second, we describe the drivers of network investment. Third, we set out the case of change in the way that network tariffs are currently designed. Finally, we describe the purpose and structure of this report.

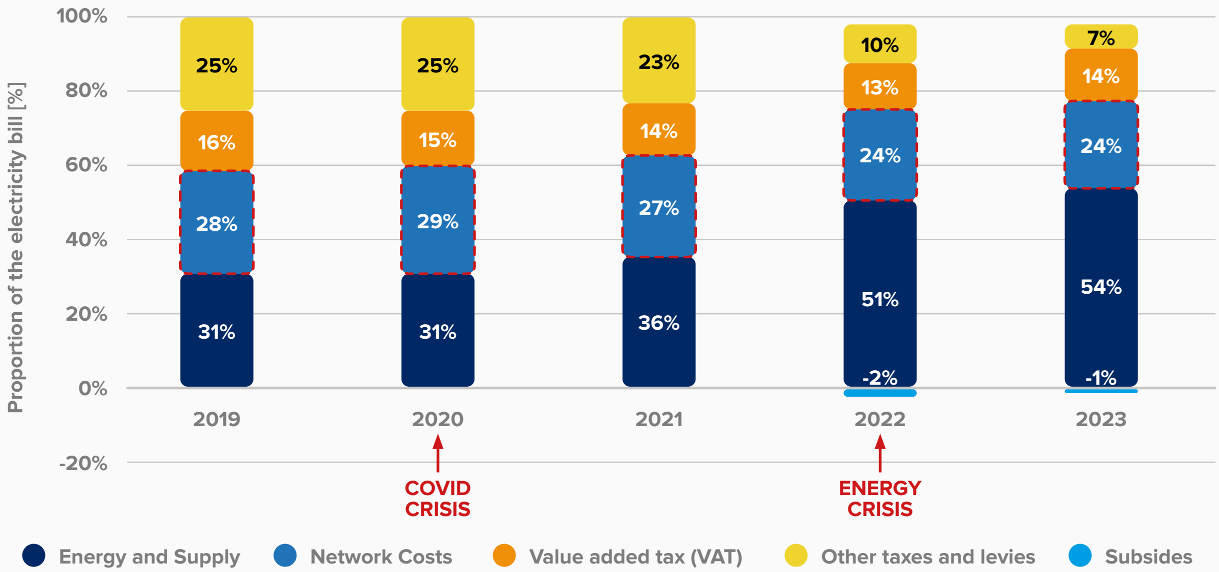
B. Overview of network tariffs

1.5 In the EU, transmission and distribution system operators ("TSOs" and "DSOs") are responsible for building and maintaining transmission and distribution networks, and these costs are recovered from network users (consumers or generators).[1] In practice, the central mechanism for recovering network costs from end users is via periodically billed electricity network access charges.

1.6 For residential consumers in EU Member States, network charges represent between 24-29% of the electricity bill in recent years as shown in Figure 1.1. Most network charges in residential consumers' bills are distribution network charges. The other components of the bill are energy supply costs and taxes and levies. The exact proportion of network charges relative to the other components in the bill mostly depends on annual fluctuations in energy supply costs (dark blue in Figure 1.1). Energy supply costs were low during the Covid crisis and high during the energy crisis reflecting the conditions in the electricity wholesale market. Network costs typically do not change abruptly from one year to another but, as discussed in more depth later in this section, are expected to gradually rise in the years to come.

1 · Typically, network costs have been mostly allocated to consumption, rather than generation.

FIGURE 1.1 — Breakdown of the average electricity costs for EU households 2019—2023 (%)



Source: ACER and CEER[2]

1.7 Until recently, network access tariffs for residential and small commercial consumers have been primarily structured as volumetric (in €/kWh) in most EU Member States.[3] Volumetric charges were seen as fair to the extent that high electricity consumption (and thus higher network charges) was thought to correlate well with the level of consumer affluence. Apart from some Member States (e.g. Spain and Italy), the volumetric charge was typically flat, i.e. the same €/kWh charge for every hour of the year, and there was little spatial differentiation. Such tariffs are predictable, simple, and compatible with the meter equipment capabilities (e.g. most meters were only capable of measuring the cumulative consumed volume of electricity).

C. Drivers of network investment

1.8 The need for network investment, and in turn the level of network charges borne by consumers in the longer run, can be driven by several factors:

— Growth in the aggregate peak electricity demand of all grid users connected to the network. This is because the most important network elements, i.e. lines, cables, and transformers, are all dimensioned based on peak loads.[4] When peak loads frequently exceed the nameplate capacities of these network elements, they need to be upgraded which is costly.

— In areas with high penetration of solar PV at low-voltage also injection peaks in the network and/or resulting voltage fluctuations can cause the need for network investment.

— Mostly at medium-voltage distribution and transmission an important driver for investement needs has been the connection of large RES production. RES installations are typically land-intensive and dependent on local weather conditions and therefore have been developed in more remote regions, further away from the consumption centres for which the grid was initially built.

2 · ACER and CEER, "2024 Market Monitoring Report. Energy Retail and Consumer Protection" (September 2024) [LINK].
3 · The share of volumetric charges represented about 73% in EU distribution network charges for households in 2015. Source: FTI Consulting-CL Energy, "Distribution charges: review of experiences on tariff structure and new challenges" (13 May 2016) [LINK]. From the 2019, 2021 and 2023 ACER reports on electricity transmission and distribution tariff methodologies [LINK] [LINK] [LINK], it can be inferred that the share of volumetric charges in EU network tariffs has been decreasing over the last years.
4 · For more detail, please see Chapter 4 of MIT, "Utility of the Future" (December 2016) [LINK].

1.9 There is a disconnect between the simple volumetric network charges (in €/kWh) and the underlying drivers of the costs that these charges seek to recover. This disconnect, particularly between total electricity offtake by consumers and their contribution to the peak electricity demand, started to become increasingly visible when consumers started adopting rooftop solar photovoltaic ("PV") generation. Most meters could only register the net consumption of a customer over a certain horizon (e.g. year), adopters of solar PV generation significantly reduced their net volume of electricity offtake from the distribution network. As a direct consequence, the contribution of solar PV adopters to the recovery of network costs significantly reduced.

1.10 However, PV generation often does not coincide with the aggregate peak demand. For example, on a winter evening when peak demand occurs, solar PV would not be generating any electricity. Hence, in most EU member states solar PV adoption has had little impact on the need for network investment (or network investment even increased due to local issues with injection peaks).[5] With a network cost recovery requirement remaining largely unchanged and consumers with rooftop PV reducing their network charges, consumers that did not install rooftop PV saw their network charges increase.[6]

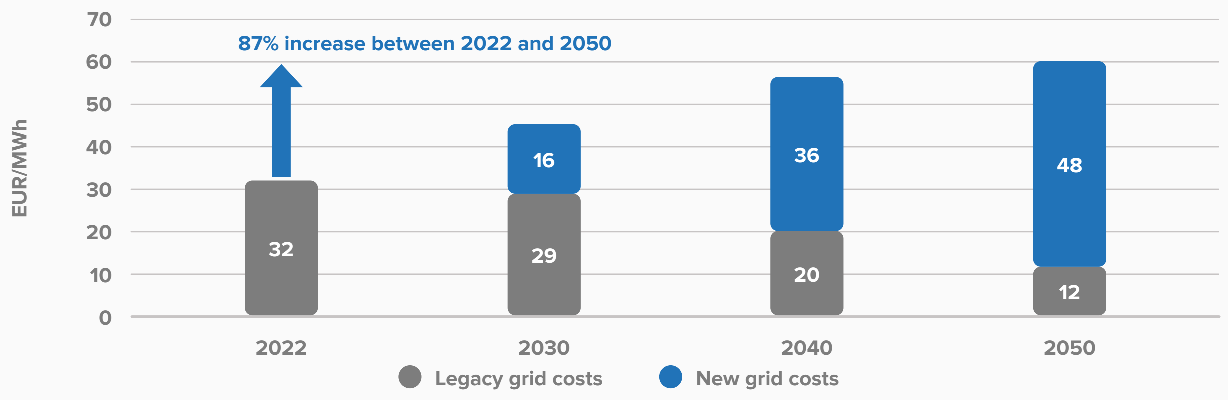
1.11 The case of solar PV adoption highlighted the fundamental challenge associated with network tariffs: to remain fit-for-purpose in the evolving technology, market and policy landscape, the way network costs are charged from end users may need to evolve.

D. Case for change: electrification, decarbonisation, and time-varying energy prices

1.12 To reach the EU's climate goals, the electrification of large sectors of the economy has started to, and will need to further, accelerate, while the integration of renewables continues to decarbonise the electricity network. Electrification implies a rapid growth in demand with a large share of the new electric demand having a flexible consumption profile, with prime examples being electric vehicles ("EVs"), heat pumps and battery energy storage systems ("BESS").[7]

1.13 One direct consequence of electrification is that investments in electric networks are expected to significantly rise in the next decades. Figure 1.2 illustrates expected annual investments in electricity networks (on a per MWh basis) to almost double between 2022 and 2050 in the EU.[8]

FIGURE 1.2 — EU expected electricity distribution network investment in a selection of years, 2022 – 2050



Source: ACER and CEER[9]

5 · The exception being countries with a summer peak load due to air-conditioning.

6 · Policymakers in the EU reacted by prescribing a phase-out of net-metering in the Clean Energy Package (CEP) for all Europeans. The requirement for Member States to abolish net-metering, which to date has not yet been enforced everywhere in the EU, has been a first step towards an improved network tariff design. EC (2019). Directive (EU) 2019/944 of the European Parliament and of the Council of 5 June 2019 on common rules for the internal market for electricity. Official Journal of the European Union [LINK].

7 · For example, as the price of BESS has decreased significantly, German battery storage capacity increased by 50% in 2024, with batteries installed in domestic homes reaching 15.4GWh. Source: Clean Energy Wire, "German battery storage capacity increases 50% in 2024" (31 January 2025) [LINK].

8 · Coupled with increasing electricity demand, the expected increase in total annual network investments would be expected to be greater than the per MWh increase.

9 · ACER, "Electricity infrastructure development to support a competitive and sustainable energy system" (16 December 2024) [LINK].

1.14 The major driver for this increase in electricity network investment is growing electricity demand, the majority of which is expected to be at distribution-level in the EU (as opposed to transmission-level) due to increasing decentralised generation and the electrification of residential and commercial transport and heating.[10] An important caveat to the numbers cited above is that the actual need in grid investment will be highly dependent on how grids are used; limited flexibility in consumption is the standard assumption in most studies.

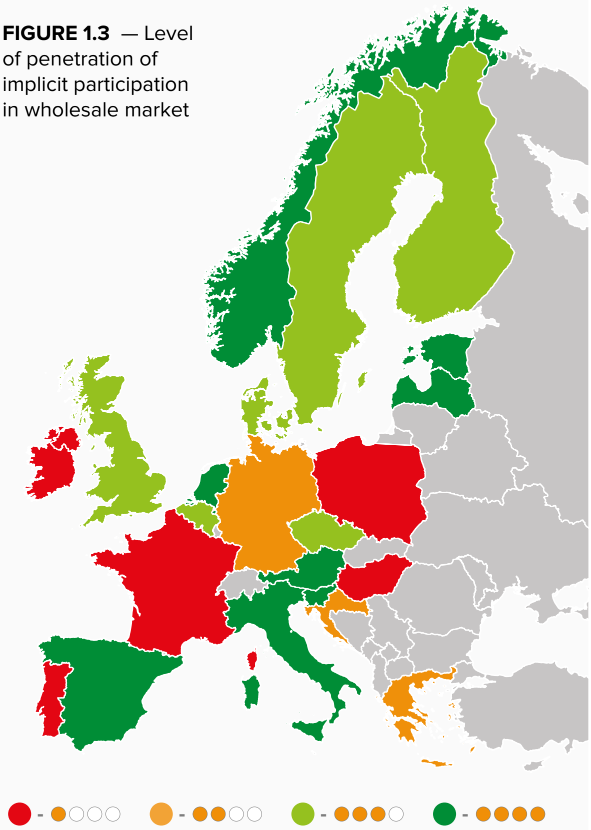
1.15 In parallel with growing electrification, the increased integration of renewables leads to electricity wholesale prices becoming more volatile within the day and across seasons as prices reflect generation from intermittent renewables. This creates opportunities for consumers with flexible demand to reduce their energy supply costs in the electricity bill (the dark blue segment of the bar charts in Figure 1.1).

1.16 One option involves opting into time-varying energy pricing plans and scheduling their consumption in hours with low priced electricity. Time-varying energy plans can range from simple time-of-use ("ToU") prices to dynamic prices (i.e. pass-through of hourly day-ahead wholesale prices).[11,12]

1.17 Another option is to pass control of their flexible demand to a trusted third party (such as a supplier or an aggregator) who can both minimise the cost of supply, and provide additional sources of revenue to consumers from ancillary/balancing services and from local flexibility markets potentially leading to even higher savings.

1.18 Figure 1.3 shows the current levels of adoption of implicit participation in the wholesale market (through dynamic pricing contracts, or through a fixed tariff where the supplier trades in energy markets). Some standout countries are Norway (where 93% of residential supply contracts are dynamic); Denmark (69%); Finland (30%); and Latvia, where 52% of commercial customers are on dynamic pricing contracts. Even though the take-up of dynamic pricing contracts has decelerated in recent years in some Member States due to high energy wholesale prices during the energy crisis, generally the uptake of time-varying energy pricing plans is projected to increase in the years to come.

FIGURE 1.3 — Level of penetration of implicit participation in wholesale market



Source: : smartEn.[13] Countries in light grey are not included in the EU27 + Norway + UK

1.19 Electrification and greater demand sensitivity to wholesale prices (either through consumers' increased adoption of dynamic price contracts, or through consumers adopting managed tariffs whereby suppliers and aggregators are responsive to, and minimise wholesale electricity costs) is, in principle, desirable in the context of the energy transition and decarbonisation objectives. Consumers with flexible appliances responding to wholesale price signals leads to consumption patterns aligning with volatile (renewable) supply. This represents a paradigm shift away from controllable (often fossil fuel

10 · IEA, "Net Zero by 2050 - A Roadmap for the Global Energy Sector" (Version of October 2021) [LINK].

11 · Under ToU energy pricing, energy prices are predetermined at the beginning of a billing cycle (e.g. semester) and vary according to predefined time period within the day (peak, shoulder or off-peak), season and day-type (weekday vs weekend or holiday).

12 · For example, a recent study using 2019 US data finds that residential off-peak ToU charging would reduce average EV charging cost by 24%. Source: Borlaug, B., Salisbury, S., Gerdes, M., and Muratori, M., "Levelized cost of charging electric vehicles in the United States. Joule 4, 1470–1485" (15 July 2020) [LINK].

13 · smartEn "smartEn Map 2024: Wholesale Electricity Markets" (January 2025) [LINK].

based) supply following inflexible demand and has the potential to lead to an overall more cost-efficient power system including reduced curtailment of renewables.

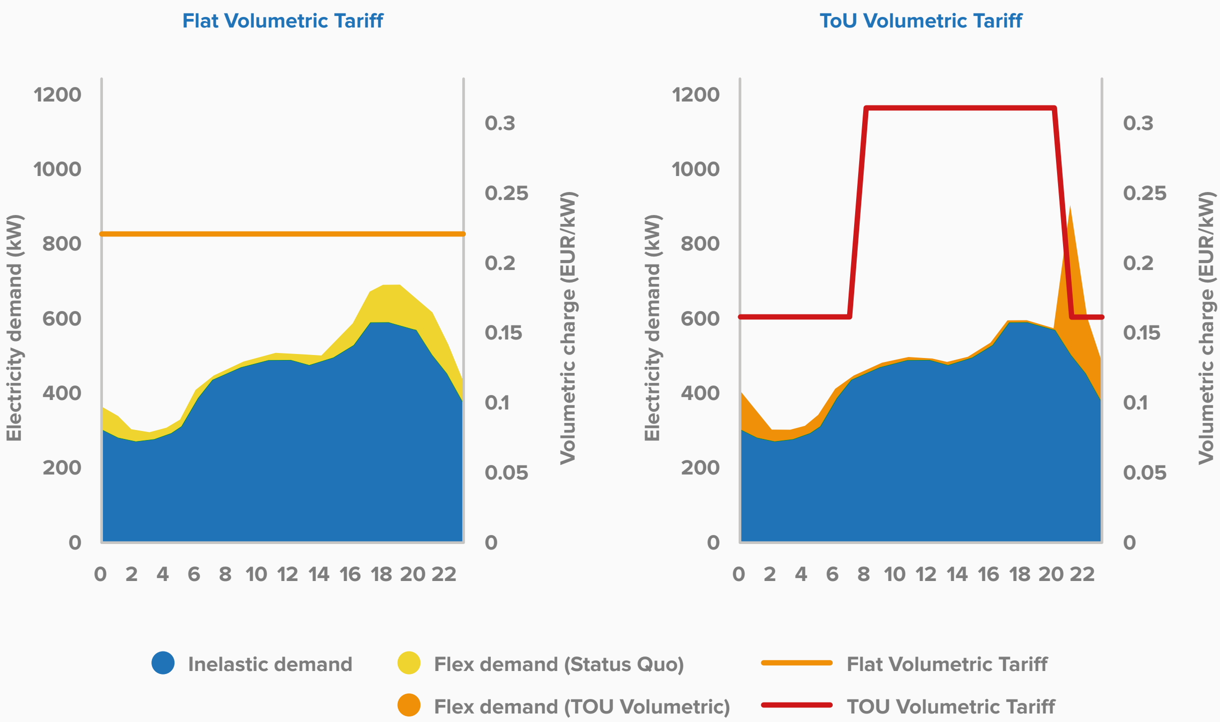
1.20 However, the wholesale electricity prices to which consumers respond, reflect supply and demand dynamics at the bidding zone-level (often equalling the territory of a country) and hence do not reflect grid conditions at the transmission[14] or at distribution-level.

1.21 In this context, flexible consumers responding to time-varying energy prices (directly or via third parties) can induce new local demand peaks that appear during periods with low wholesale prices, i.e. the "peak shifting" effect. For an illustration of this phenomenon, see Box 1.1 below.

BOX 1.1 — Peak shifting by flexible demand

Figure 1.4 below shows an example of the impact of a ToU volumetric tariff on flexible electricity demand for a particular illustrative group of consumers with inelastic and flexible demands. Under a flat volumetric tariff, consumers do not have any incentive to schedule their flexible load in a particular way, i.e. the consumption pattern of the flexible load is independent of power system conditions. Under a ToU volumetric tariff, consumers are incentivised to schedule their flexible demand when the ToU tariff is low. With a significant volume of flexible load this can quickly lead to a new local demand peak in the first hour when the tariff drops which exceeds the original peak demand.

FIGURE 1.4 — Ilustrative aggregate demand profile under flat and ToU volumetric tariff



Source: : FTI Consulting

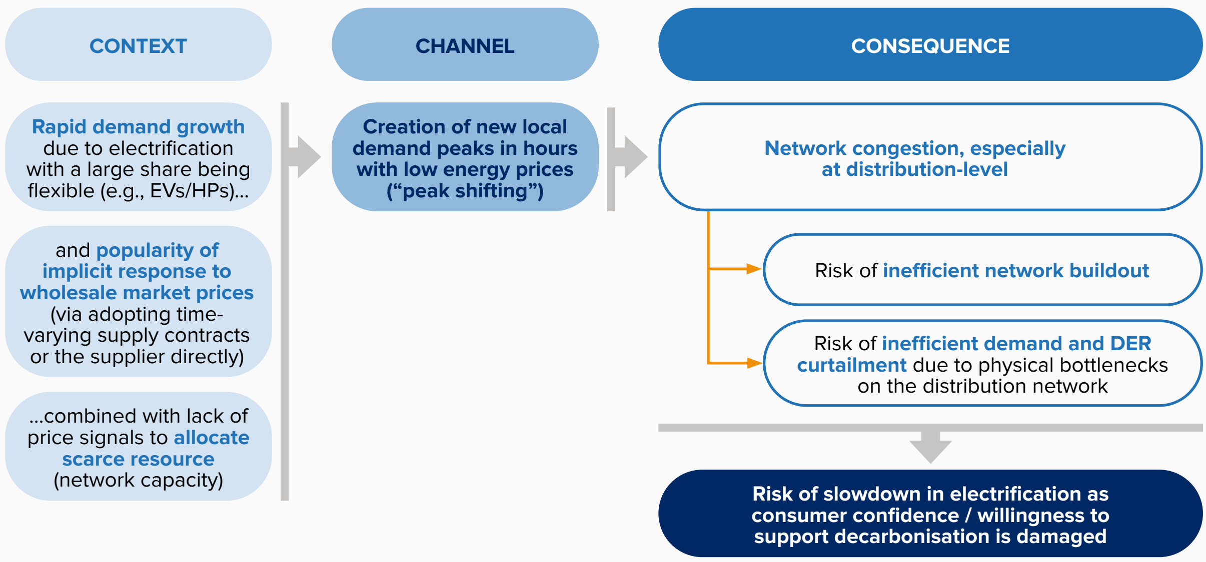
14 · In practice, wholesale prices can sometimes provide 'false' signals to consumers to increase consumption in regions where such increased consumption is not feasible due to transmission and/or distribution network constraints. This report does not examine the needs case for locational wholesale market signals, but for more detail on the merits of locational wholesale market signals to provide operational signals to demand, storage, generation and interconnectors, see FTI Consulting, "Assessment of locational wholesale electricity market design options in GB" (October 2023) [LINK].

1.22 One study using data from Massachusetts, US, finds that, after about 10-15% of EV adoption among customers connected to the same low-voltage network, peak shifting occurs.[15] Another study using data from Slovenia finds that peak-shifting can already occur after 5% of heat pump adoption in a local network area.[16] Even at relatively low overall levels of electrification peak shifting can already occur because the adoption of EVs and heat pumps is often concentrated in certain neighbourhoods (e.g. driven by relative affluence of the local population).

1.23 In summary, in a context of (i) rapid demand growth; (ii) a high uptake of time-varying energy pricing plans; and (iii) no price signals to allocate scarce local network capacity, there is a risk for the creation of new local demand peaks in hours with low energy prices leading to significant increases of network congestion, particularly at distribution-level. This increase of network congestion can lead to an inefficient network outbuild, as additional network capacity to meet the greater peaks would lead to significant redundancy in many other hours.

1.24 While the current pace of electrification has been slower than projected, there is a risk that the magnitude of the required grid expansion due a sudden acceleration of electrification might be too large to cope with due to supply chain constraints if poorly managed.[17] For example, workforce and supply of materials are limited and often there is significant public or environmental resistance against the buildout of new networks. In such a scenario, inefficient or even involuntary demand curtailment may occur if network build-out lags behind the increases in peak electricity demand.[18,19] In that regard, if the impacts of electrification and adoption of time-varying energy pricing plans are not well managed, consumer willingness to support the decarbonisation agenda could be damaged, as summarised in Figure 1.5.

FIGURE 1.5 — Potential negative consequences of rapid demand growth combined with time-varying energy supply charges and lack of price signals to allocated scarce local network capacity



Source: FTI Consulting

15 · Turk, G., Schittekatte, T., Martínez, P. D., Joskow, P. L., & Schmalensee, R., "Designing distribution network tariffs under increased residential end-user electrification: Can the US learn something from Europe? MIT CEEPR Working Paper" (January 2024) [LINK].

16 · Morell-Dameto, N., Chaves-Avila, J.P., Gomez San Roman, T., Duenas-Martinez, P. & Schittekatte, T., "Network tariff design with flexible customers: Ex-post pricing and a local network capacity market for customer response coordination.", Energy Policy, 184, 113907 (24 November 2023) [LINK].

17 · A practical example are bans for new connections in certain areas, which is already happening in some parts of the Netherlands. Source: Wood Mackenzie, "The Netherlands' gridlock: a cautionary tale for the US" (5 September 2023) [LINK].

18 · Generation curtailment can also be an issue in areas with significant installed distributed generation and low load, e.g. rural areas with high concentrations of solar PV.

19 · Conversely, an often less recognised risk of poorly managed electrification in contexts where there are limited blocking factors to build out grids is that rapid grid expansion occurs earlier than required. Where technologies such as solar PV and BESS become cheaper and more accessible, and are adopted at increasing rates, previous forecasts of required network capacity may have been an overestimate, leading to wasted investment in the distribution network.

1.25 Introducing cost-reflective network tariffs can help mitigate these challenges by reflecting local network conditions that complement time-varying energy pricing plans. Concretely, cost-reflective network tariffs should allow consumers to still leverage their flexibility to profit from electricity during hours with low energy prices at bulk-system level while excessive buildout of the network is avoided due to better local coordination.

1.26 However, network tariff design is a politically sensitive matter and requires careful stakeholder management including an evaluation of stakeholder impacts under different tariff designs.[20] These real-world constraints make directly mandating a "first best" network tariff design at EU-level unlikely to be feasible (at least in the short term). Therefore, in this report we assess different options that can be deployed to move from the status quo network tariff design in many Member States to gradually improved designs as electrification evolves (and the urgency to increase the cost-reflectiveness of the tariff increases) – we refer to this sequence of options as a 'roadmap'.

1.27 There are alternative and complementary approaches to cost-reflective network tariffs that can serve as mechanisms to unlock flexibility for grids (and specifically distribution grids), including for example smart connection agreements (also called non-firm connection agreements) and local flexibility markets. While these are not explored in detail in this report, we summarise their main characteristics below in Table 1.1. Moreover, throughout the report where relevant we will discuss the interaction between network tariff design and these complementarity mechanisms to unlock flexibility for grids.

TABLE 1.1 — Overview of key mechanisms to unlock flexibility for grids

	Uniform or opt-in	Price setting	Contracts/Settlement
Network access tariffs	Uniform	Administrative	Recurring charges in the bill
Smart connection agreements	Opt-in	Administrative	Long-term arrangements
Local flexibility markets	Opt-in	Market-based	Long-term auctions and/or short-term markets

Source: FTI Consulting

E. Purpose and structure of this report

1.28 The purpose of this report is to examine, both qualitatively and quantitatively, the merits of different designs of cost-reflective distribution network tariffs in the context of energy transition in the EU. Based on this assessment, our objective is to propose a roadmap towards a pan-European, harmonised approach to have a common reference for the range of possible designs of cost-reflective network tariffs that Member States could use as a guide to implement them (while recognising relevant national nuances).

1.29 Throughout this report we focus mostly on distribution network tariff design for small commercial and residential consumers connected to low voltage networks, but the principles and the network tariff design options described in this report are also relevant for transmission network tariffs, as well as for energy communities, medium and large users.

20· For example, in Flanders the Ministry sued the Flemish regulator for proposed changes to the network tariff design [LINK]. There are many accounts of resistance to changes to network tariffs in Europe and around the globe, examples of resistance in US States to tariff changes are provided here.

1.30 This report has the following sections:

— In Section 2 we set out key principles of network tariff design, describe the current EU regulatory framework, and provide a brief overview of the status of network tariff design in the EU.

— In Section 3 we map out a range of different network tariff design options, identify a shortlist of design options to examine in more detail and qualitatively assess the shortlisted options. We also briefly discuss three regulatory approaches to overcome the perceived complexity of more cost-reflective network tariff designs.

— In Section 4 we quantitatively illustrate how different network tariff designs impact consumer incentives, electricity bills and required network investments. We describe our methodology and key findings.

— In Section 5 we present a roadmap for EU network tariff design.

1.31 This report also has three appendices:

— In Appendix 1 we set out the relevant EU Regulation on cost-reflective network tariffs.

— In Appendix 2 we described the data used for the quantitative assessment in Section 4.

— In Appendix 3 we describe the heuristic used to calibrate a dynamic volumetric network tariff which is one of the network tariffs that is part of our quantitative analysis in Section 4.

2

Key network tariff design principles, regulatory framework, and status

A. Introduction

2.1 In this section, we provide background to network tariff design in theory and practice: we first describe the key principles of network tariff design according to economic theory and discuss the most relevant real-world barriers in implementation (Section B). We then discuss how these key principles are currently reflected in the relevant EU regulatory framework (Section C). In the final subsection we provide a brief overview of the status of network tariff design in the EU (Section D).

B. Key principles of network tariff design

2.2 The two key principles of network tariff design as described in economic theory are cost reflectivity and cost recovery. In this report, we define the terms as follows:

— **Cost reflectivity** means that a network tariff exposes end users to the network cost their usage causes. Under cost-reflective network tariffs the end user is exposed to the trade-off between incurring the anticipated network costs caused by their usage and the discomfort of changing their network withdrawal/ injection pattern (leading to “disutility”).

— **Cost recovery** means that network companies, who build, maintain, and operate the network, recover their “reasonably incurred” costs.

2.3 To be acceptable to policy makers and consumers, a network tariff design must also be **practicable,** which encompasses a wide range of considerations such as simplicity, no undue discrimination, and acceptable distributional impacts when transitioning from one network tariff design to another. A further consideration for practicability is the ‘future-proofness’ of a tariff. Grid usage can evolve rapidly rendering some tariff designs that were previously suitable to become outdated not much after their implementation. This would require frequent updates to the network tariff design while regulatory procedures to revise the network tariff design are typically slow. As such, alongside cost reflectivity and cost recovery, practicability is an additional network tariff design consideration that policy makers need to take into account.

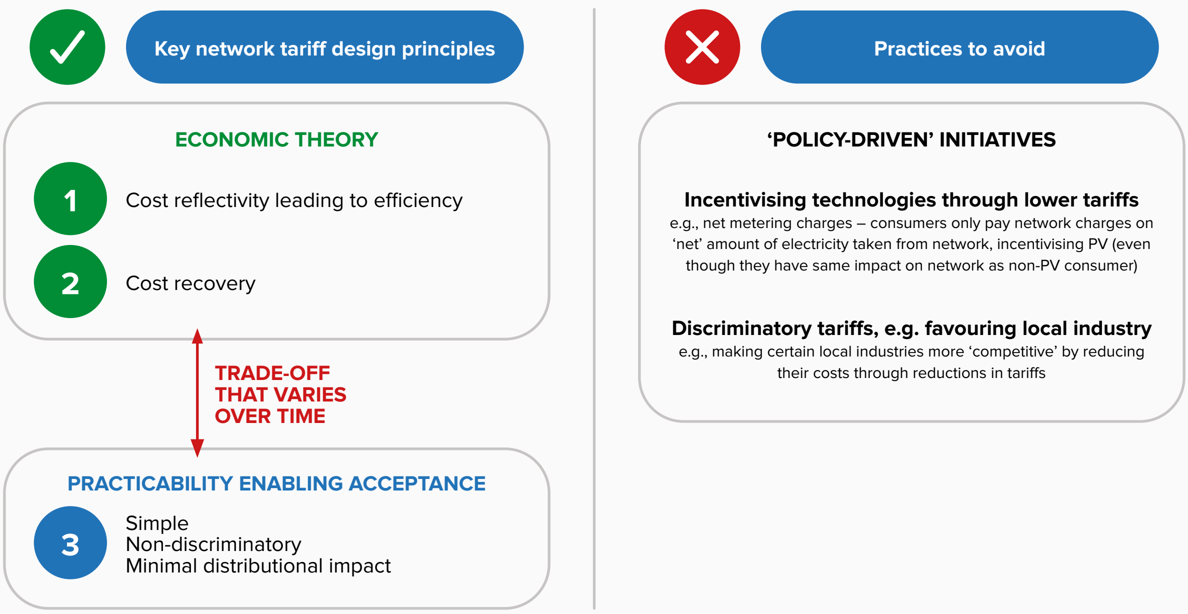
2.4 Conversely, there are practices that ideally should be avoided, such as deploying network tariff design that are intended to support other policy objectives. For example, policy makers may want to keep in place net-metering, i.e. network charges a calculated based on the volume of electricity withdrawn from the network minus injection over a certain timespan, to stimulate the adoption of rooftop PV. However, by doing so, policy makers keep in place a network design that is not cost-reflective, i.e. network costs are not driven by the net volume of electricity flowing through the network over a certain time span. Another example is where policy makers exempt certain industrial consumers from paying their share of network costs to foster industrial competitiveness. In doing so, policy makers would be introducing a discriminatory tariff design which would lead to industrial consumers disregarding their cost impacts when making consumption and siting decisions on networks, which then would be socialised over other consumers.

2.5 While the examples of accelerating the adoption of rooftop PV and of improving industrial competitiveness are important policy goals and providing implicit subsidies via the network tariff design might be appealing, good regulatory practice is for these policy goals to be supported via explicit subsidies. Purposely introducing cross-subsidies between network users will highly likely lead to inefficiencies, in turn making networks more expensive than they could be. The inefficiencies might have been small in the past but can become substantial as the ability of consumers to respond to electricity price signals (e.g. via automation) increases.

2.6 The opposite situation is as well possible, i.e. an incumbent network tariff design working against a policy objective. This is arguably the case for the policy objective to electrify transport and heating which is made is costlier to achieve under flat volumetric network charges. This network tariff design is still in place for an important share of households in the EU as discussed in ¶ 2.37. Flat volumetric network charges levy a tax on electrification that could be removed by transitioning to a more cost-reflective network tariff design. Hence, increasing the cost reflectiveness of the network tariff and the policy objective to electrify many end uses are aligned. We discuss this case in more detail in ¶ 2.13.

2.7 Figure 2.1 provides a schematic overview of the key principles of network tariff design and practices to avoid. In the remainder of this sub-section, we describe in more detail the key principles.

FIGURE 2.1 — Overview of key network tariff design principles and practices to avoid



Source: FTI Consulting
Note: The practices to avoid according to good regulatory practice, while the political reality might make avoiding these more complicated, are two specific examples. They are not intended to be exhaustive.

COST REFLECTIVITY LEADING TO EFFICIENCY

2.8 As set out above, cost-reflective tariffs seek to accurately represent the nature of the costs in developing and using the network. Specifically, such tariffs recognise that the short-run marginal cost ("SRMC") of using the network is small (e.g. losses) and existing network costs are sunk. Given projected rapid growth in electricity demand, of the potential drivers for network investment described in ¶ 1.8, we consider the reinforcement or expansion driven by expected increases in coincident network peak usage as the main network cost driver. Hence **a network tariff design is cost reflective if it is proportional to the contribution of grid users to the aggregate ("coincident") network peak.**[21] This definition is applicable for all users and voltage levels. As cost-reflective network tariffs reflect future anticipated long-run marginal costs ("LRMC") of the network, they are by definition forward looking in this context.

2.9 Cost-reflective network tariffs can impact consumer incentives both in operational and in investment timescales:

— In operational timescales, cost-reflective tariffs encourage efficient consumer decisions, such as charging electric vehicles or heating/cooling houses outside of peak hours.

— In investment timescales, cost-reflective tariffs can guide the siting and sizing of investment decisions of DERs and of EV charging infrastructure to areas of the network where there is ample capacity. In the

21 · In this report we focus on the main cost driver of the distribution network, which is the coincident peak demand leading to the need to reinforce or expand the network. However, we recognise that losses are included in the costs to be recovered via network access charges in many jurisdictions. Due to lower voltage, losses in distribution networks are typically in the order of 4-10 % of the total energy offtake and smaller in the transmission network (1-3%). Instantaneous losses increase and decrease in proportion to the square of the current, i.e. the more loaded lines are, the higher losses incurred. Considering this cost driver for losses, a volumetric network charge that is scaled to: (i) the expected aggregate local consumption, combined with (ii) the wholesale electricity price during the relevant settlement period, can be considered a cost-reflective charge for distribution losses. An in-depth discussion of how to optimally implement such charges is beyond the scope of this report.

same way, they can also influence retirement or closure decisions, which would also be beneficial to free up network capacity for more economically valuable uses.

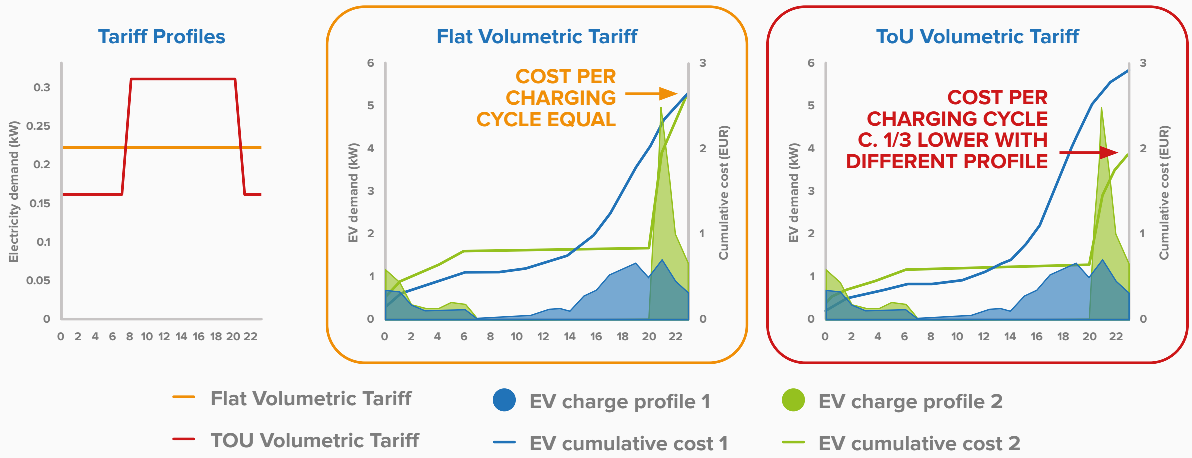
2.10 As such, cost-reflective network tariffs improve overall system efficiency, i.e. system costs are saved by finding the right balance between flexibility and grid investments. Part of the network savings end up with flexible users that have made those savings possible via reduced network charges. In the long run, all grid users benefit as excessive grid investments can be avoided which they would have otherwise had to pay for.

2.11 A key feature of a cost-reflective network tariff is that it should be symmetric, meaning that depending on the sign (+ or -) of the network charge, the network charge implies a cost or an income for withdrawals or injections. The underlying idea is that the injection of one kWh occurring at the same time and location offsets a withdrawal of one kWh and hence should be priced equally. If those two actions were priced differently, distortions would be introduced. For example, during a moment of local network stress, a consumer connected to the relevant part of the network owning a battery should be paid as much to inject one kWh as another consumer connected to the same network is charged to withdraw one kWh. By the battery injecting in the network at that moment, valuable network headroom is created. If injections would be paid less than withdrawals at that moment (and location), the battery would likely not offset local network stress, leading to a sooner than optimal need to upgrade the network.

2.12 A direct consequence of a cost-reflective tariff is that it is technology-agnostic, i.e. the network tariff design does not subsidise nor penalise the uptake of specific technologies (e.g. EVs, heat pumps, PV and stationary storage). If the uptake of a specific technology changes consumption during moments of local peak usage, the network charges for that consumer will also proportionally change. If a technology allows for flexibility in its usage, a cost-reflective network tariff will provide the opportunity to limit increases in network charges after the adoption or even reduce network charges.

2.13 For example, if a consumer buys an EV and volumetric flat network charges are in place, home charging would lead to a significant increase in network charges, independent of when the EV is charged. This is illustrated by the two different charging profiles in Figure 2.2 having the same cost per charging cycle (e.g. across a day) under the flat volumetric tariff. Instead, under more cost-reflective network charges, an EV owner can substantially decrease its network charges from home charging if the EV is charged in a way that there is no additional stress on the local network from charging. Under the more cost-reflective tariff as shown in the example, the second charging profile leads to a significantly lower network charges per charging cycle.

FIGURE 2.2 — Illustrative costs for an EV under a flat volumetric tariff and ToU volumetric tariff for two different charging profiles satisfying the same total charging requirement in kWh (i.e. the blue and green coloured surface of the EV charging profiles is equal in size).



Source: FTI Consulting

COST RECOVERY TO SUPPORT EFFICIENT INVESTMENT

2.14 As network companies are considered natural monopolies, their allowed income required to recover incurred costs in building, maintaining and operating the network is usually determined by the regulator. The main mechanism is the income from network charges set by the regulator.[22] The recovery of reasonable costs is important because network owners that face uncertainty about cost recovery would risk increasing the cost of capital for new investments, which would in turn be passed through to end users.

2.15 While cost-reflective network tariffs will lead to the recovery of a portion of costs associated with the development, construction, maintenance and operation of networks, the total collected income will typically be lower than the required amount to deliver full cost recovery.[23] This is because cost-reflective network tariffs reflect future costs with the aim to send efficient signals to grid users that find the right balance between leveraging their flexibility and network outbuild, which is an objective that is distinct and separate from the objective to recover historical costs. It is historical costs, as approved by the regulator, that are relevant for cost recovery.

2.16 Typically, a complementary residual network charge, in addition to a cost-reflective network charge, is needed to comply with cost recovery. In contrast to cost-reflective network tariffs, residual network charges are backward looking, i.e. they are in place to ensure the full recovery of historical costs incurred by the network owner. Ideally residual network charges are designed in a non-distortive way, i.e. they do not impact the incentives provided by cost-reflective network tariffs. The reason being that the costs they are intending to recover are sunk; no change in behaviour of any end user impacts the level of sunk costs that needs to be recovered.

2.17 How the residual charge is allocated among load, generation or storage is mostly a policy choice. An argument to allocate most residual costs to load is that generation or storage, which are typically more active in power markets, would try to pass-through those residual network charges in their wholesale market bids/offers to end users.[24] Such pass-through could lead to inefficiencies which are avoided when allocating the residual costs directly to (inelastic) load.

PRACTICABILITY TO ENABLE ACCEPTANCE

2.18 To enable acceptance (by end users and by policy makers), a network tariff design must also be practicable, as described earlier. For example, the network tariffs need to be sufficiently simple, so that they can be explained to end users and monitored by policy makers. They should also not be (unduly) discriminating for example among classes of end users or among owners of different flexible assets.[25] To the extent that a particular network tariff design leads to specific distributional impacts among cohorts of stakeholders, these need to be in line with policy maker preferences.[26] Finally, network tariff design shall be 'future-proof' as grid usage patterns can evolve rapidly while regulatory procedures to revise the network tariff design are typically slow.

2.19 Limitations in network tariff design for practicability reasons are different for both components of the network tariff: (i) cost-reflective "forward-looking" network tariffs, and (ii) residual "backward-looking" network tariffs. We discuss the key issues in turn below.

22 · Allowing network companies to determine their own profit-maximising network tariffs could lead to excessively high network charges.

23 · A scenario where cost-reflective network tariffs lead to a higher income than required to guarantee cost recovery is in theory also possible, e.g. a combination of: (i) stretched networks leading to high cost-reflective network charges, and; (ii) limited historical investment for which the costs need to be recovered. In such scenario, the excess income can be kept on an escrow account to reduce residual network charges at a later point in time as discussed in Schittekatte, T., Mallapragada, D., Joskow, P.L. & Schmalensee, R., "Reforming retail electricity rates to facilitate economy-wide decarbonization", Joule, 7(5), pp.831-836 (11 April 2023) [**LINK**].

24 · This argument relates to "Ramsey pricing", i.e. allocate sunk costs inversely proportional to the elasticity of the grid user to minimise deadweight loss.

25 · However, "due" discrimination, based on economically objective factors, e.g. time of consumption, reflecting different costs associated with using the network, is an appropriate and desirable feature of a network tariff.

26 · As discussed more in Sections 3 and 4 of this report, we recognise that the efficiency of a tariff may, sometimes, conflict with the policy makers' objectives such as simplicity or distributional impacts.

Complexity of cost-reflective "forward-looking" network tariffs

2.20 Truly cost-reflective network tariffs are highly temporally and spatially granular. High temporal granularity, e.g. network charges with varying charges from one hour to another, create challenges with regards to simplicity and predictability. While high spatial granularity, e.g. tariffs that vary from one region to another, may create public acceptance concerns (though this may depend on the size of the region concerned).

2.21 Cost-reflective network charges also face technical obstacles in their implementation. For example, technology required to measure the real-time network flows and smart meters required to identify to what extent different consumers contribute to stress on the network are not yet fully deployed. Also, to calibrate the cost-reflective charges implies that future network costs need to be estimated by forward-looking network models that are often still in the stage of early development.[27] Therefore, in practice, cost-reflective network tariffs will proxy the anticipated network cost that grid usage causes. The more complex a network tariff, the closer the proxy will align with the actual network cost drivers.

Perceived unfairness of residual "backward-looking" network tariffs

2.22 Optimally implemented residual charges are ideally designed as fixed charges per connection. The reason being a fixed charge does not distort a consumer's incentive to use the network. The only way to avoid a fixed charge is to disconnect entirely which is currently not a realistic option for most consumers in the EU. The main issue with fixed charges, when being uniform per grid connection of a certain voltage level, is that they are generally regarded as unfair. Concretely, they are typically regressive as smaller users, e.g. a single person living in a studio apartment, would pay the same fixed charge as large users, e.g. a family occupying a big house.

2.23 This perceived unfairness can to a certain extent be mitigated by differentiating fixed charges based on certain proxies for affluence. For example, it may be possible to differentiate fixed charges by neighbourhood, size of the physical connection capacity (the "fuse"), historical consumption of a certain grid user (labelled "backward" cost causality), or income (as recently to some extent introduced in California).[28,29] Alternatively, there is the possibility to recover the residual costs via general taxation rather than via non-distortive charges in the electricity bill.[30]

2.24 Overall, the appropriate balance of cost reflectivity, cost recovery and practicability of network design tariffs is a function of the prevailing technology options, end user attitudes and policy choices, with different types of network tariffs likely to be most attractive in different contexts. This is explored further in the next section.

THE BALANCE BETWEEN COST REFLECTIVITY AND COST RECOVERY DEPENDS ON THE CONTEXT

2.25 The conceptual framework that differentiates between cost-reflective "forward-looking" network charges combined with a residual "backward-looking" network charge, is commonly used by policy makers (for example by Ofgem in its ongoing reform of access network tariffs).[31] The framework is not unique to electricity infrastructure. For example, advanced pricing schemes of transport infrastructure such as highways can be designed in a similar way: (i) congestion charges that rise during moments of high traffic intending to incentivise drivers to adapt their itinerary with the aim to (in the longer term) avoid the need to excessively expand highways, complemented with (ii) a fixed fee to be paid by all drivers wanting to make use of the

27 · Network cost models at the distribution-level are significantly more complex than at the transmission-level due to the sheer number of network elements at distribution-level versus transmission level. See e.g. Meeus, L., Govaerts, N., and Schittekatte, T., "Cost-reflective network tariffs: experiences with forward looking cost models to design electricity distribution charges", FSR Policy Paper 2020/04 (April 2020) [LINK].

28 · See e.g. Batlle, C., Mastropietro, P. and Rodilla, P., "Redesigning residual cost allocation in electricity tariffs: A proposal to balance efficiency, equity and cost recovery", *Renewable Energy,* 155, pp.257-266 (15 April 2020) [LINK].

29 · The income-based charges that were adopted in California only differentiate for two income classes. Initially much larger differences in fixed charges for a wider range of income bracket were proposed by the Californian Public Utilities Commission than. See e.g. Borenstein, S., "Reality Checking California's Income-Graduated Fixed Charge", Energy Institute Blog (13 May 2024) [LINK].

30 · See e.g. Pollitt, M.G., "Electricity network charging in the presence of distributed energy resources. Economics of Energy & Environmental Policy", 7(1), pp.89-104 (March 2018) [LINK].

31 · Ofgem, "Reform of electricity network access and forward-looking charges: a working paper" (6 November 2017) [LINK].

highway, independent of how much distance they drive, to recover the residual costs of the highway.[32] Alternatively, residual infrastructure costs can be recovered via general taxation.

2.26 In designing the most appropriate network tariff, the relative importance of the cost reflectivity and cost recovery principle depends on the context. Figure 2.3 provides an overview of the key elements related to the cost reflectivity and cost recovery principle and their balance.

FIGURE 2.3 — Overview of the key elements related to the cost reflectivity and cost recovery principle and their balance

COST REFLECTIVITY	COST RECOVERY
Approach: Forward-looking, reflecting future network costs to find the balance between investment and flexibility.	**Approach:** Backward-looking, aiming to recover past costs while being non-distortive.
Charging methodology: Ideal charge reflects the coincident peak usage and is as temporally and spatially granular as possible.	**Charging methodology:** Ideal charge is a fixed charges paid when connected to the grid.
Potential pitfalls in terms of practicability: ● Complex and potentially unpredictable for end users ● Technical barriers ● Implementation choices lead to: — Distributional impacts — Impacts on electrification incentives	**Potential pitfalls in terms of practicability:** Politically difficult due to likely distributional impacts requiring designing more complex non-uniform fixed charges.
Priority principle in: High load growth environment.	**Priority principle in:** Low load growth environment with significant past buildout

In the current context of rapidly increasing electrification, the emphasis should be laid on the design of the cost-reflective forward-looking network charge component.

Source: FTI Consulting

2.27 In the recent past, distribution networks in the EU were typically overbuilt while load growth was typically limited. In such context, there are only relatively modest forward-looking costs to be reflected via cost-reflective network tariffs. The emphasis in such context is on the design of residual charges to recover sunk costs.

32 · An example is the Swiss motorway vignette [LINK].

2.28 Today, with accelerating energy transition, the context is different. Electricity demand is expected to grow significantly, and networks are expected to expand rapidly (see also Figure 1.2). In such context, the emphasis should be placed on the design of the cost-reflective network charges to avoid excessive future network investment costs.

2.29 In this report we focus on the design of the cost-reflective component of the network tariff (rather than on the cost-recovery component), as this is expected to be the main issue in the coming years, given projected rapid growth in electricity demand and network build.

C. Current EU regulatory framework

2.30 This section examines the current EU regulatory framework related to network tariff design. In the first subsection, we set out how cost-reflective network tariffs are described in the relevant EU Regulation. In the second subsection, we briefly discuss the regulatory framework around the adoption of smart meters, which are generally considered to be required to adopt cost-reflective network tariffs.

DESCRIPTION OF COST-REFLECTIVE NETWORK TARIFFS IN EU REGULATION

2.31 Regulation (EU) 2019/943, which was part of the Clean Energy Package ("CEP") for all Europeans, includes principles that network tariffs in the EU should respect and emphasises that the key principle of network tariff design is cost reflectiveness. The recently adopted Regulation (EU) 2024/1747, amending Regulation (EU) 2019/943 as a response to the European energy crisis, also includes a reference to cost reflective network tariffs. However, the relevant articles in the EU Regulations only describe at a very high level how a cost-reflective network tariff should be designed in the EU and significant discretion is left to individual Member States in terms of implementation.[33] Appendix 1 summarises the most relevant paragraphs.

2.32 More concrete recommendations are provided by ACER's best practice report on transmission and distribution network tariff design.[34] The aim of the best practice reports is to provide monitoring of transmission and distribution network tariff designs across Member States. Regulation (EU) 2019/943 states that national regulatory authorities ("NRAs") shall duly take the best practice reports into consideration when fixing or approving distribution and transmission tariffs or their methodologies. This can be challenging as often network tariffs are approved based on (or constrained by) national legislation.

2.33 The most relevant ACER recommendations regarding the cost-reflectivity of network tariffs in the latest best practice report for transmission and distribution network tariff design concerns three areas: the introduction of time-of-use signals to reflect system costs, tariff structure and cost recovery, and injection charges.

— ACER strongly recommends the introduction of time-of-use signals to reflect network costs.

— ACER recommends differentiating network cost categories and identify for each category the cost driver (although no specific tariff structure is explicitly recommended, and it can in practice be difficult to match cost-drivers such as coincident peak usage with a simple tariff design). For example, losses are driven by the volume of electricity flowing through the network, network investments are driven by increases in coincident peak usage and administrative costs do not have a direct cost driver.

— With regards to injection charges, especially relevant for batteries, ACER recommends that if a network user both withdraws from and injects into the grid, both network uses should be considered when setting the tariffs, by properly considering the potential cost-offsetting effect and the overall cost impact to the network.

33 · The most relevant are Art. 18 of Regulation (EU) 2019/943 and recital 23 of Regulation (EU) 2024/1747. See Appendix 1 for more details.
34 · The latest report is ACER, "Report on Electricity Transmission and Distribution Tariff Methodologies in Europe" (January 2023) [LINK].

SMART METERS AS AN ENABLER FOR THE ADOPTION OF COST-REFLECTIVE NETWORK TARIFF DESIGN

2.34 As described earlier, there are many pre-requisites to implement cost-reflective network tariffs. Of all pre-requisites, the most important one is likely the deployment of smart meters, in order to measure real-time consumer usage at a granular level. Smart meter adoption has been promoted by EU Regulation, but implementation has been lagging in some Member States.[35]

2.35 In Directive (EU) 2019/944 it is stated in Article 19 (2) that *"Member States shall ensure the deployment in their territories of smart metering systems that assist the active participation of customers in the electricity market. Such deployment may be subject to a cost-benefit assessment [..]."* It is of utmost importance to consider in the cost-benefit assessment that the introduction of a cost-reflective network tariff is obstructed when not having smart meters in place. The exception being when using data from dedicated measurement devices, but that would mean that only a part of the consumer load at the connection point would be subject to cost-reflective tariffs.

D. Status of distribution network tariff design in the EU

2.36 ACER reports in its latest best practice report that 25 of the 27 EU Member States have some form of capacity-based distribution network charge in place (based on the maximum capacity in kW measured or kW contracted, with or without time-differentiation) and 20 had static ToU volumetric distribution tariffs in place in 2022.[36] As a complement to those relatively cost-reflective charges, 17 Member States have a (minor) fixed charge in place.

2.37 These capacity-based and/or ToU energy network charges often only apply to grid users connected to medium voltage or above. Because of the many nuances in each Member State, it is hard to verify what network tariffs households connected to the lowest voltage level are facing. From the ACER best practice report it can be estimated that currently at least in one third of the Member States households are facing some sort of capacity-based and/or ToU energy network charges. The remainder of households still faces more simplified distribution network charges which typically consist of flat volumetric and a fixed charge.

2.38 Based on the above, we consider that there is a case to further refine network tariffs in the EU to become more cost-reflective, which is imperative to avoid excessive network investments as electrification is expected to ramp up in the years to come. The current regulation and regulatory guidance regarding network tariffs are only provided at a high-level and more practical guidance on implementation can be beneficial to ensure network tariffs are in place that actively support the energy transition process. We elaborate upon how network tariffs can concretely be redesigned to become more cost-reflective in the next section.

35 · Directive (EU) 2019/944 defines a 'smart metering system' as an electronic system that is capable of measuring electricity fed into the grid or electricity consumed from the grid, providing more information than a conventional meter, and that is capable of transmitting and receiving data for information, monitoring and control purposes, using a form of electronic communication.

36 · ACER, "Report on Electricity Transmission and Distribution Tariff Methodologies in Europe" (January 2023) [**LINK**].

3

Formulation and qualitative assessment of different network tariff design options

A. Introduction

3.1 In this section we build on the theoretical network design principles described previously, to set out in detail how network tariffs can be defined in practice. First, we describe the key building blocks of network tariff design, i.e. the components that can be varied in designing variants of network tariffs (Section B). Second, we combine the building blocks to map out a range of different network tariff design, ranging from relatively simple ones (closely related to the status quo in the EU) to highly complex designs (Section C). By doing so, we set out a spectrum of options that policy makers have when developing network tariffs. Third, we qualitatively assess these different network tariff designs and identify a subset of tariffs for a more detailed quantitative assessment (Section D). Finally, we discuss regulatory approaches to overcome the perceived complexity of more cost-reflective network tariff designs (Section E).

B. Building blocks of network tariff design

3.2 Key characteristics of network tariffs can be defined using three dimensions:

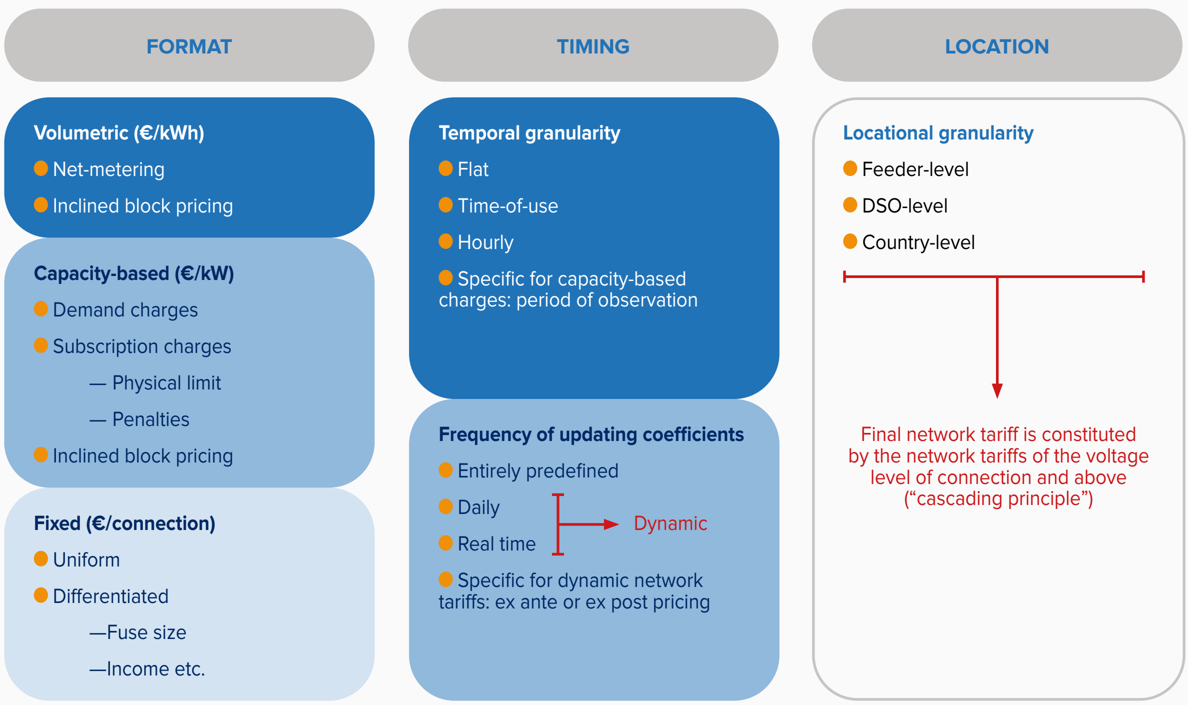
— **Format:** the physical unit (in €/kWh, €/kW, and/or €/connection);

— **Timing:** temporal granularity and frequency in updating the tariff coefficients; and

— **Location:** locational granularity.

3.3 In turn, potential sub-variants for each of the three dimensions are summarised in Figure 3.1 below (although these do not seek to be exhaustive). A network tariff design can therefore be defined using a combination of the three dimensions: for example, a network tariff can be volumetric (dimension 1), flat (dimension 2) and DSO-level (dimension 3). We discuss these sub-variants in detail below, and we set out options for combining these building blocks into different network tariff designs in the next subsection.

FIGURE 3.1 — Schematic overview of the building blocks of network tariff design



Source: FTI Consulting

FORMAT - THE PHYSICAL UNIT OF THE NETWORK TARIFF DESIGN

Volumetric network tariffs

3.4 **Flat volumetric charges (in €/kWh)** are the simplest approach to designing network tariffs. In this approach, network costs are charged in proportion to the accumulated volume of electricity withdrawn/injected during a certain billing period (e.g. quarterly, or annually). This approach has been commonly used in the past across Europe and other parts of the world. Typically, when injecting electricity into the network, the mechanical meters reversed leading to "net-metered" consumption being used to calculate the owed network charges per billing period. More recently, for consumers with smart meters, **volumetric network tariffs with a finer temporal granularity** can be implemented (and smart meters also enable volumetric network tariffs to differentiate between withdrawals and injections, for example to **track gross withdrawals** rather than net withdrawals).

3.5 Another volumetric network tariff design to recover network costs that has been popular around the world is **inclined block pricing.** Inclined block-pricing implies that the volumetric network coefficient increases as a function of the total consumption over a certain period. For example, the first 500 kWh consumed in a billing period (e.g. quarter) are priced at lower unit price (in €/kWh) than the kWh's consumed above the 500-kWh threshold. However, while on the surface inclined block pricing might appeal attractive from an affordability perspective, we do not examine this option further in this report. This is because, in essence, inclined block pricing is not cost reflective.[37] It also tends to discourage electrification. For example, it would discourage consumers from adopting a heat pump, which consumes a relative high volume of electricity, even though for a well-insulated house the heat pump could to a large extent be scheduled overnight when network stress is low. Under an inclined block volumetric tariff, independent of how the heat pump is used, it would be a very costly heating choice (e.g. relative to a gas boiler) as a large share of its electricity consumption would likely be priced at a high unit rate.

Capacity-based network tariffs

3.6 Under a capacity-based network tariff consumers are charged for network costs based on **their capacity usage (in kW).** Capacity-based tariffs can be implemented in many ways, and generally their design can be grouped in two broad types: ex-post measured and ex-ante contracted.

3.7 **Ex-posted measured capacity-based charges, or demand charges,** charge consumers based on the observed maximum capacity usage in a predefined period (e.g. all peak hours in a month). Typically, the maximum capacity usage is measured as the instantaneous capacity usage averaged over a short time interval (e.g. fifteen minutes or one hour).

3.8 **Ex-ante subscribed capacity charges, or subscription charges,** are a network tariff design where consumers decide ex-ante about how much network capacity they want to contract for. The contracted capacity will always be lower or equal than the physical capacity at the connection point. If a consumer experiences that its subscribed capacity is too low/high, they can opt to increase/decrease its subscribed capacity at regular time intervals (e.g. each quarter). There can be different charges (in €/kW) for different periods, e.g. capacity during peak hours in the winter versus capacity during off-peak hours in the summer.

3.9 A possible implementation of subscription charges is that the **contracted capacity becomes a physical limit for capacity usage** during all hours in a billing cycle. A more advanced implementation variant can be that the subscribed capacity implies guaranteeing a minimum capacity a consumer will always have access to. For example, if a consumer contracts 5 kW the consumer will likely only have access to 5 kW (and will get curtailed if more is withdrawn) during peak times, but in off-peak times the consumer can potentially have access to more capacity as there would be ample network capacity available.[38]

37 · Inclined block pricing for volumetric network tariffs is not cost reflective as the network costs caused by a specific user at a particular time and location is not a function of how many kWh that a specific user has consumed over a timespan up to that moment. Similarly, inclined block pricing for capacity-based tariffs is not cost reflective as each kW that contributes to the coincident peak creates a similar need for grid investment, whether it is the first kW of a user or the second kW of another user under the same feeder. Inclined block pricing design strongly discourages electrification as high volume/capacity appliances such as EVs and heat pumps are disproportionally financially penalised.

38 · This could be implemented via a "stoplight system" with the colour of the stoplight depending on the contracted capacity and local network conditions.

3.10 Subscription charges with a physical limit imply agreeing to a non-firm connection, i.e. a consumer may not always be able to withdraw/inject as much as its physical connection would allow. In this sense, subscription charges can be seen as a basic form of smart connection agreements (see Table 1.1). The difference is that with smart connection agreements typically discretion is given to a DSO when a connection can be curtailed of end users that have agreed to a smart connection (with limits on the cumulative curtailment over a certain period). Under subscription charges, the consumer decides ex-ante during what periods its connection capacity would be limited to a certain level.

3.11 An alternative implementation of subscription charges is that the **contracted capacity would not lead to a physical capacity limit, but consumers would incur penalties** if their capacity usage exceeded the contracted capacity. The penalties should be calibrated in a way that would provide incentives for consumers to contract more capacity when the contracted capacity threshold is frequently exceeded.

3.12 In an advanced implementation the penalties can be time-varying or even dynamic. For example, the penalty can be near zero when the capacity threshold is exceeded during moments when the network has idle capacity (e.g. in the night) and very high when the coincident peak is expected to occur. In this advanced implementation, subscribing to a certain capacity can be seen as forward contracting capacity to limit exposure to dynamic near real-time (penalty) price signals for grid usage.

3.13 For capacity-based tariffs there is also the possibility to have an **inclined block pricing** structure. For example, using/contracting the first few kW capacity might be priced at relatively modest prices (€/kW) while as more kW's are used/contracted the price per kW used/contracted can increase.

Fixed network tariffs

3.14 Fixed network charges imply the payment of a certain **fee per connection point per billing period,** independent of the volume consumed (kWh) or maximum capacity usage (kW). In that sense, a fixed charge should not impact consumption behaviour. In an extreme case, very high fixed charges could lead to consumers disconnecting from the network entirely, which is the only way to avoid paying fixed charges.

3.15 Fixed charges can be uniform, i.e. all grid users connected to the same voltage level pay the same flat fee per billing period or differentiated. Fixed charges can be differentiated in many ways. Examples include the size of the physical connection, i.e. the fuse size (which can only be changed by incurring substantial investment costs), location-specific characteristics (e.g. urban, rural) or income-specific characteristics (e.g. exemption from the fixed charge for low-income or vulnerable households).

TIMING – TEMPORAL GRANULARITY AND FREQUENCY IN UPDATING THE TARIFF COEFFICIENTS

3.16 Network charges can vary not only in terms of the format (described above), but also in temporal terms. For example, network charges can be higher at the times when the network is stressed and lower when there is idle network capacity. The extent to which network charges reflect actual (or expected) grid conditions depend on implementation choices with regards to (a) the temporal granularity of the network charge and (b) the frequency in updating the tariff coefficients. We discuss each of these two elements below in turn.

3.17 With regards to the **temporal granularity,** on one extreme, the network charge per kWh or per kW is flat over the entire billing period (e.g. a year). On the other extreme, the network charges can be highly granular, driven by the length of the measurements by the smart meter, e.g. the charges can be different for every five-minute period.

3.18 In between these two extremes, there is a wide range of options available to policy makers. One approach is where the temporal granularity equals one hour (or lower), in which case volumetric (€/kWh, varying by hour) and demand charges (€/kW, varying by hour) become indistinguishable.[39]

39 · Under the condition that capacity usage is measured as the instantaneous withdrawal or injection averaged over the same duration of the settlement period of the volumetric charge.

3.19 Another approach in between the two extremes are ToU network charges. ToU network charges typically vary per predefined season (e.g. winter, other seasons), day-type (weekday, weekend/holiday) and time-of-day (e.g. peak, off-peak, shoulder). The interaction between ToU network tariffs and the format (e.g. whether the ToU tariff is expressed in €/kW or €/kWh) is also critical, as the incentives for consumers to spread their consumption under time-varying volumetric and capacity-based network charges can be very different. We illustrate below in Box 3.1 how a ToU capacity-based network tariff provides better incentives for consumers to spread their consumption during peak times, as compared to a ToU volumetric tariff.

BOX 3.1 — Consumer incentives under time-varying volumetric and capacity-based network tariffs

The interaction between the format (volumetric and capacity-based network charges) and temporal granularity (e.g. ToU) is a key driver of how consumers would respond to network charges by changing their consumption profile. In the stylised example below, we illustrate how a ToU capacity-based network tariff provides better incentives for consumers to spread their consumption during peak times, as compared to a ToU volumetric tariff.

We assume a simple ToU network tariff with two levels of network charges: off-peak and on-peak (shown in Figure 3.2). This ToU tariff would look the same for a volumetric and capacity-based network charge (though it would be expressed in different physical units). For the volumetric charge, depending on whether the consumption occurs during the on or off-peak period, the €/kWh network costs differs. For the capacity-based charge, the maximum hourly capacity observed during the on and off-peak periods across the day is used to calculate the network charges, with a higher charge per kW for peak usage during the on-peak period.

FIGURE 3.2 — ToU volumetric tariff and capacity-based tariff

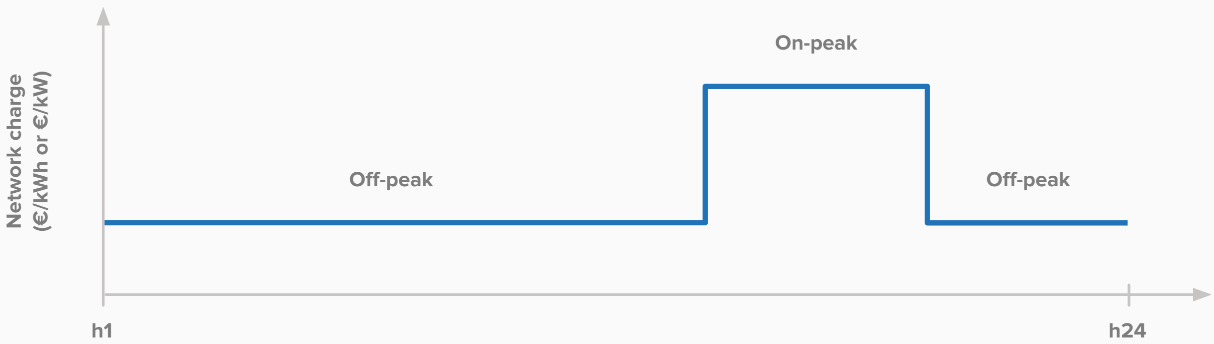
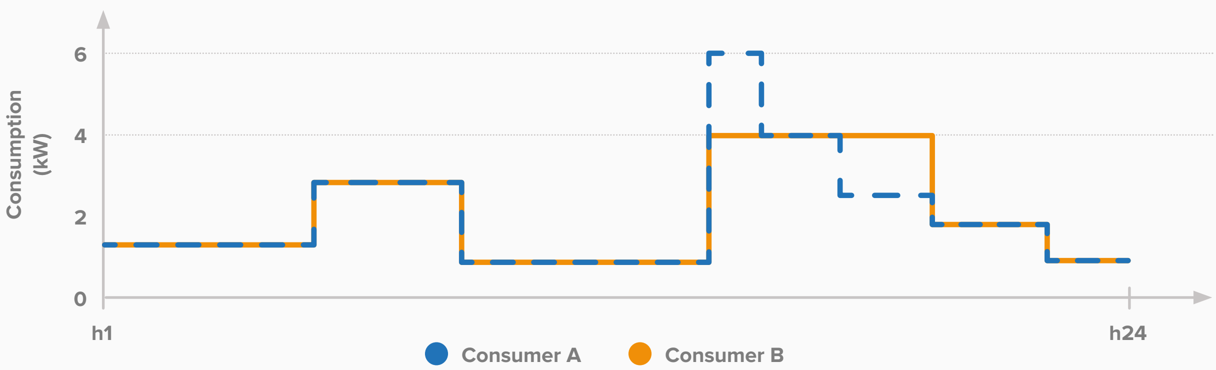


Figure 3.3 shows the (ex-ante) consumption profile of consumers A and B. Both consumers consume the same volume of electricity within the on-peak and off-peak period but the consumption profile during the on-peak period is different.

FIGURE 3.3 — Consumers A and B, with the same daily consumption but different consumption profile



Source: FTI Consulting

Under a ToU volumetric network tariff, both consumers pay exactly the same network charges. However, under the ToU capacity-based network tariff, consumer B pays 50% more network charges than consumer A. This is because Consumer B's peak consumption during the on-peak period is 6kW (while Consumer A's peak consumption during the on-peak period is 4kW).

Both tariffs incentivise consumers to shift their consumption from on-peak towards the off-peak hours (which is a desirable outcome). However, the ToU capacity-based tariff also (and additionally) incentivises consumers to spread their consumption within the on-peak and within the off-peak periods. This means that under a ToU capacity-based tariff more "spiky" consumer profiles (such as Consumer B) lead to higher network charges compared to consumer profiles with a flatter consumption (such as Consumer A), even though the total volume of electricity consumed across a certain period is the same. This would be in line with the cost reflectiveness principle as more "spiky" consumer profiles would typically also lead to higher network.[40]

3.20 Another element related to the temporal granularity that is important for demand charges is the length of period over which the maximum capacity usage is observed. For example, the maximum capacity usage can be observed each month, i.e. the highest capacity usage within a month is used to calculate the network charge, independent of the hour during which the consumer's peak capacity usage occurred within the month. Alternatively, the maximum capacity usage can be observed in different intervals per day, i.e. the highest capacity usage within a specific period (e.g. on/off-peak) across the day, is used to calculate the daily network charges. The shorter the period over which the maximum capacity usage is observed, the more cost-reflective the capacity-based charge.

3.21 The second element of the temporal granularity is the **frequency of change of the tariff coefficients per kWh or kW.** The tariff coefficients relate to the numerical values that are attached to the network charge (e.g. €X/kW or €Y/kW). Again, there is a spectrum of options: at one extreme, all tariff coefficients, independent of the temporal granularity of the network charge, can be entirely predefined before the start of the billing period (e.g. per quarter). On the other extreme, the tariff coefficient can be updated in real time (e.g. every 5 minutes) according to prevailing network conditions. The latter are **dynamic network tariffs.** Dynamic network tariffs have by definition a very fine temporal granularity. There is a range of options in between these two extremes. For example, network tariff coefficients can be published day-ahead for the entire day (e.g. at noon D-1, the network charges for all hours of the next day are published).

3.22 A last design choice that is relevant especially for highly dynamic network charges is whether the volumetric network charge is announced **ex-ante based on expected network usage,** e.g. day-ahead, or **ex-post, based on observed network usage.**[41]

LOCATION – LOCATIONAL GRANULARITY

3.23 Network tariffs can vary depending on the physical location of the point at which electricity is being withdrawn/injected onto the network. This can be either in terms of the level of voltage of the connection point, or in geographical terms (or a combination of both). The finest spatial granularity is the local distribution network feeder level, while the crudest spatial granularity is at country-level. An approach in between is having different network charges per DSO-area. In practice, many countries differentiate network charges based on the voltage level at which consumers connect (i.e. transmission network charges and distribution network charges).

3.24 The total network charges are not driven by the single specific voltage level at which the consumer connects. Rather, the final network charge seen by a consumer is typically the compounded network

40 · Unless the spikiness of all consumption profiles is entirely random. This would be unlikely, e.g. many consumers can be subject to the same volatile wholesale prices and consumption spikes can signal low wholesale prices. Similarly, consumers that are connected to the same network would be subject to the same weather patterns which can explain synchronous consumption spikes.

41 · With regards to the latter also an implementation is possible where network charges are paid based on the average demand of a consumer during a predefined number of ex-post observed coincident network peaks (e.g. triads that used to be in place in Great Britain).

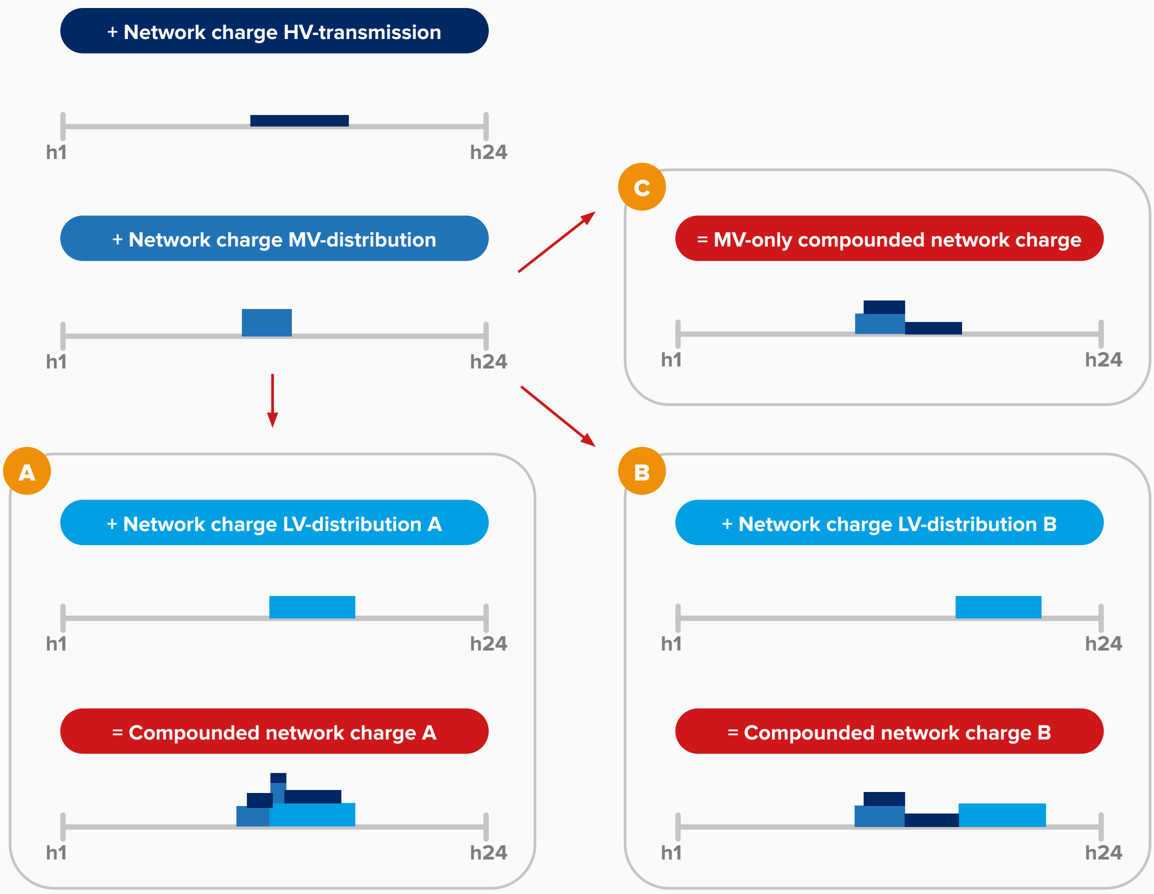
charge over the different voltage levels to which the consumer is (directly or indirectly) connected, often referred to as the **cascading principle.** Figure 3.4 provides a schematic example for the volumetric network charges seen by: (i) two consumers that are connected to different low voltage networks (the finest spatial granularity considered here) but the same medium voltage network (consumers A and B); as well as (ii) a third consumer that is connected at the medium voltage network level (consumer C).[42] In this illustrative example, we show that:

— Each consumer faces a combined set of network charges, related to the particular low-, medium- and high-voltage networks to which the consumer has access.

— Two consumers connecting at the same voltage level (in this case LV), but in different distribution areas, can face a different compounded network charge, reflecting their geographical differences – as is the case with consumers A and B.

— Consumer C, which connects at the medium-voltage level, also faces different network charges, but this is because it does not use the low-voltage network – meaning it does typically not have to pay the additional charges for the low-voltage network levied on consumers A and B.[43]

FIGURE 3.4 — Example of volumetric network charges for three consumers connected to: (i) different low-voltage distribution networks; and (ii) the medium-voltage distribution network



Source: FTI Consulting

42 · Compounding capacity-based network tariffs is possible but harder to visualise.
43 · In areas with high generation at low voltage levels leading to electricity flows from low to medium voltage levels the cascading principle can be questioned. This discussion goes beyond the scope of this report.

C. Formulation of potentially cost-reflective network tariff designs

3.25 As discussed in the previous section, there is a wide range of options available to policy makers in specifying cost-reflective network tariff designs. In collaboration with smartEn members, we developed a subset of nine combinations of network tariff options, across the three dimensions (and subsets of options). These combinations are summarised in Figure 3.5 below. They represent a progressive set of designs, ranging from simple (status quo) arrangements through to the most complex ones, including, at the most complex end of the spectrum, an option that has not yet been implemented in practice anywhere in the world, known as distribution locational marginal pricing ("DLMP"). The list of options is not intended to be exhaustive, and many other permutations are possible.

FIGURE 3.5 — Range of potentially cost-reflective distribution network tariff designs

INCREASING COMPLEXITY

NETWORK TARIFF DESIGN	DESCRIPTION
0 Flat regional volumetric network charge (€/kWh)	**Status quo:** Single unit rate (€/kWh) for all consumers within a DSO area, for a given year (no time-of-day differentiation)
A Regional ToU volumetric network charge (€/kWh)	Same unit rate (€/kWh) for all consumers within a DSO area, per given block of hours (e.g. lower night-time network tariffs). Fixed for a year.
B Regional capacity-based charge (€/kW)	Consumers pay to subscribe for a max. capacity or are charged for maximum instantaneous kW consumed (e.g., averaged over 30min) within an observation period (e.g., month).
C Regional ToU capacity-based charge (€/kW)	Consumers pay to subscribe for a max. capacity they want to use within a given block of hours or are charged for maximum instantaneous kW consumed (e.g., averaged over 30 min) within a given block of hours.
D A + C (€/kWh & €/kW)	Combination of the above.
E Dynamic local volumetric network charges (based on forecasted load) (€/kWh/h)	Network charges change from hour to hour, reflecting expected local network conditions (e.g. at DA stage, determined by an algorithm forecasting demand). Higher prices when network is congested. Charged per unit of energy consumed.
F C + E (€/kW & €/kWh/h)	Combination of the above.
G Local capacity auction (€/kW/h)	Network capacity prices are determined in a local auction taking place day-ahead. Suppliers, knowing the next day's WS prices, bid to reserve hourly blocks of local network capacity. Scarce capacity is allocated to those bidding the highest price.
H Distribution locational marginal pricing (€/kWh)	Network constraints and end users withdrawal/injection schedules are internalised in the wholesale energy market clearing. WS prices can differ across distribution nodes.

All can be combined with fixed charge

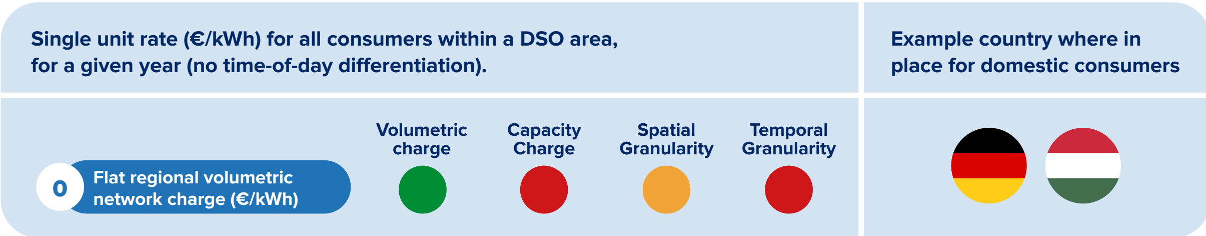
Source: FTI Consulting

Notes: (1) The list of options is not intended to be exhaustive and many other permutations are possible; (2) The cost-reflective network tariff components in the table above can be combined with a fixed charge to allow for the recovery of reasonably incurred network costs; (3) We consider the flat volumetric network charge (Tariff 0) as our 'status quo' tariff. Our assessment considers the merits of alternate tariff designs relative to Tariff 0.

3.26 In the next sub-section, we describe the different network tariff designs in more depth and briefly assess them qualitatively. We also explain how we have shortlisted four designs in agreement with smartEn from the available options for the quantitative assessment in Section 4.

D. Qualitative assessment of potentially cost-reflective network tariff designs

OPTION 0: FLAT REGIONAL VOLUMETRIC NETWORK CHARGES (€/KWH)



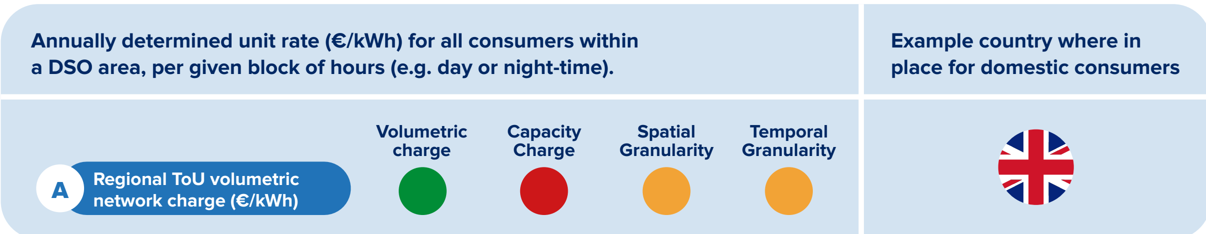
3.27 This network tariff design is currently in place for an important share of residential and small commercial consumers in the EU. It does not provide any incentive to shift consumption over the course of a day or across days. In the case where flat volumetric network charges are combined with time-varying wholesale prices, the risk for peak-shifting occurs (see Box 1.1 in Section 1.D).

3.28 The often-cited advantage of flat volumetric charges is that they are easily implementable and comprehensible for consumers. However, the fundamental drawback of flat volumetric network tariffs is that the main network cost driver is not the volume consumed over a certain time span. As discussed earlier in the report, network costs are driven by increases in the coincident peak usage. Due to their lack of cost reflectivity, flat volumetric network charges often lead to significant cross-subsidies between consumers with and without specific assets (notably rooftop solar PV) making them unsustainable (as already explained in the introduction of this report). Further, flat volumetric network tariffs risk slowing down electrification as significant higher network charges cannot be avoided when adopting electric appliances that are kWh-intensive (e.g. EVs and heat pumps), independent of how these appliances are used.

3.29 An example of a country where this network tariff design is currently in place for the majority of households is Germany[44] and Hungary[45].

3.30 **Given the prevalence of this tariff, and its nature as the simplest tariff available, we have shortlisted this network tariff design to serve as a counterfactual for the other network tariff designs in the quantitative analysis.**

OPTION A: REGIONAL TOU VOLUMETRIC NETWORK CHARGE (€/KWH)



3.31 This network tariff design leads to an incentive to use more electricity at times of lower combined energy prices and network charges. Under this network tariff design the risk for peak-shifting remains. The difference compared to Option 0 is that the newly created peaks might occur at different moments. Only dynamic volumetric network charges that vary more strongly over time and location (such as under Option E) can target hours with very low/high network usage with precision, leading to improvements in cost reflectivity.

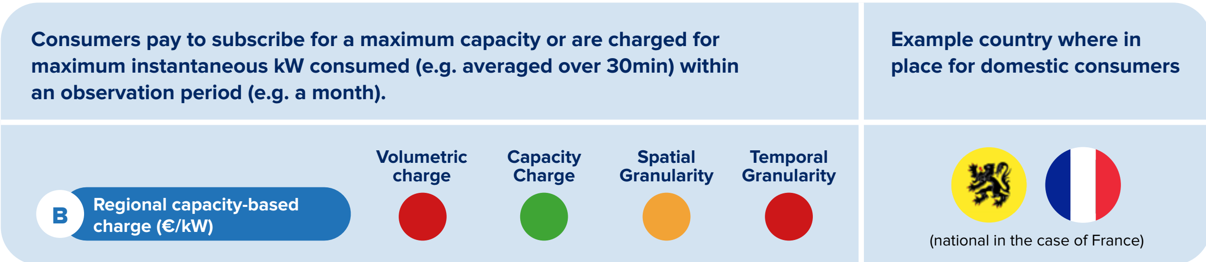
44 · Bundesnetzagentur, "Network Charges" (2024) [LINK].
45 · ACER, "Report on Electricity Transmission and Distribution Tariff Methodologies in Europe", January 2023; Table 35 [LINK].

3.32 The major advantage of this network tariff design relative to the status quo is that this network tariff design can lead to significant reductions in the network charges for kWh-intense appliances (if scheduled flexibly). It thus removes an important roadblock for increased electrification.

3.33 An example of a country where this network tariff design is currently in place for households is Great Britain.[46]

3.34 **We have not shortlisted this network tariff design for the quantitative analysis as, other than enabling electrification, the incentive properties are not very different from those under the status quo, and hence we do not expect the quantitative analysis to provide significantly new insights on its efficiency or distributional impact.**

OPTION B: REGIONAL CAPACITY-BASED NETWORK CHARGE (€/KW)



3.35 This network tariff design incentivises consumers to spread their consumption over the course of a day, whether implemented as an ex-post measured demand charge or an ex-ante subscription charge. As described earlier, this is because consumers are charged based on the highest kW usage over a certain period (e.g. a month). This can mitigate, to a certain extent, the peak shifting risk as consumers are incentivised to spread out their consumption during hours with low energy prices.

3.36 One particular issue with this network tariff design is that the individual peak consumption of a consumer might not be correlated with the timing of the coincident network peak and, hence, the cost reflectivity of this tariff design can be limited. Because the individual peak consumption is used to calculate network charges, high-capacity usage during hours when the network is idle is discouraged. This is potentially inefficient as during those moments high individual capacity usage has no network cost implications. A limit on capacity-usage during hours that the local network is not constrained would not allow the consumer to fully profit from lower prices in wholesale markets.[47] Therefore, this network tariff design can to a certain extent slow down the rate of electrification, especially the uptake of kW-intense appliances.

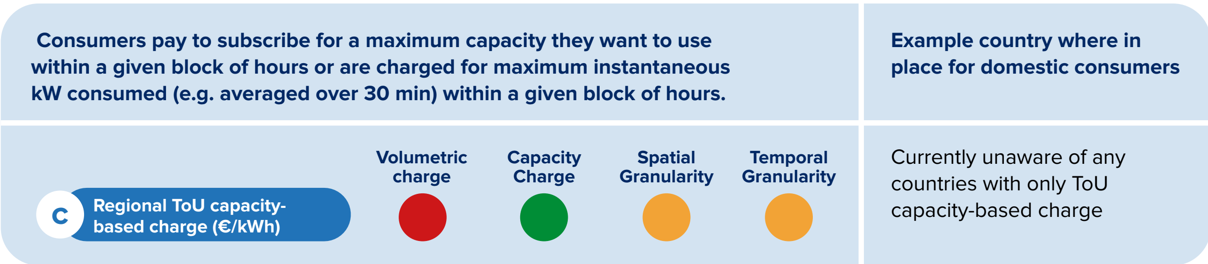
3.37 Another limitation of this network tariff design is that it is not straightforward (if possible at all) to make the network tariff symmetric (see ¶ 2.11), i.e., rewarding consumers for injecting into the network as much as consumers that are withdrawing from the network at the same moment (and potentially location).

3.38 An example of an ex-post measured capacity-based tariff for households is the recently adopted distribution network tariff in Flanders, the Dutch-speaking region in Belgium.[48] An example of an ex-ante subscribed capacity tariff is the French distribution network tariff for residential and small commercial users, which has been in place for several years.[49] In the case of France, distribution tariffs are not spatially granular (i.e. they are flat across the country) and are partly capacity-based (kW) and partly energy-based (kWh).[50]

46 · UKPowerNetwork, "2024 DUoS dashboard" [LINK].
47 · Another unintended consequence can be the revenue potential from participating in balancing markets (enabled via an aggregator) would be reduced.
48 · VREG, "Beslissing" (November 2022) [LINK].
49 · CRE, "Deliberation of the French Energy Regulatory Commission of 21 January 2021 on the tariffs for the use of public distribution electricity grids (TURPE 6 HTA-BT)" [LINK].
50 · The capacity-based part (kW) is in ToU for customers larger than 36 kVA and the energy-based (kWh) is frequently ToU for all categories of customers. The energy-related parts can to an extent be considered cost-reflective as they include a formula for kWh-related probability of contributing to peak situations and the purchase of transmission/distribution losses by the TSO/DSO.

3.39 **We have shortlisted this network tariff design for the quantitative analysis as it isolates the impact of a capacity-based charge relative to the status quo, and thus provides insights into the merits of this particular tariff design format.**

OPTION C: REGIONAL TOU CAPACITY-BASED NETWORK CHARGE (€/KW)



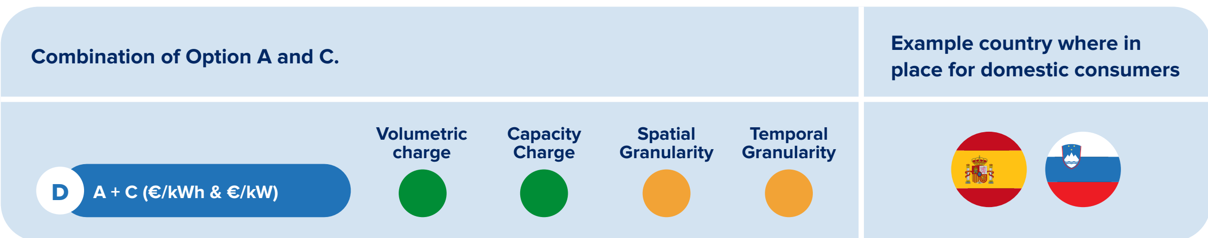
3.40 Similarly to Option B, this network tariff design incentivises consumers to spread their consumption over a period of time. However, compared to Option B, this variant can provide different magnitudes of this incentive for predefined periods because of the ToU element. For example, the capacity-based charge can be high during peak hours in the winter and very low during the night, independent of the season. As such, this network tariff design is more cost reflective than Option B and alleviates the potential risk of inefficiently limiting high individual capacity usage at times when the network is not constrained.

3.41 This option helps mitigate the risk of slowing down the rate of electrification that we identified earlier in Option B. However, it cannot be considered entirely cost reflective because the network charge does not reflect real-time network conditions. For example, there might be hours during which this network tariff incentivises consumer to spread consumption while there is no risk for network congestion. The same issue with the potential of the network tariff to be symmetric as discussed in ¶ 3.37.

3.42 We are currently unaware of countries with only ToU capacity-based charge. Some countries however use a combination of regional ToU-capacity charges and ToU volumetric network tariffs (see Option D below).

3.43 **We have shortlisted this network tariff design for the quantitative analysis as it has the potential to overcome important limitations of Option B, and thus provides insights into the merits of this particular temporal design feature.**

OPTION D: REGIONAL TOU VOLUMETRIC COMBINED WITH TOU CAPACITY-BASED NETWORK CHARGE (€/KWH & €/KW)



3.44 This network tariff design improves cost reflectivity relative to Option C by providing more granular volumetric signals on how to better spread demand within time blocks of a ToU capacity charge. Depending on the relative size of the volumetric vs capacity-based network coefficients, different distributional impacts and impacts on the incentives for electrification can be expected when compared to Option C. The ToU energy part of the network tariff can also be designed symmetrically (even though typically the ToU capacity component is expected to be the larger cost component of the two).

3.45 Examples of countries that have adopted regional ToU capacity charges combined with ToU volumetric charges for residential and small commercial users are Spain[51] and Slovenia.[52]

3.46 **We have not shortlisted this network tariff design for the quantitative analysis as we do not anticipate its assessment to be substantially different from the assessment of Option C, and hence we do not expect the quantitative analysis to provide significantly new insights on its efficiency or distribution impact properties.**

OPTION E: DYNAMIC LOCAL VOLUMETRIC NETWORK CHARGES (BASED ON FORECASTED LOAD) (€/KWH/H)

Network charges change from hour to hour, reflecting expected local network conditions (e.g. at day-ahead stage, determined by an algorithm forecasting demand). Higher charges are introduced when the network is anticipated to potentially be congested.	Volumetric charge	Capacity Charge	Spatial Granularity	Temporal Granularity	Example country where in place for domestic consumers
E Dynamic local volumetric network charges (based on forecasted load) (€/kWh/h)	● (merge)	● (merge)	●	●	Pilot projects (e.g. Swiss utility Group E, see Box 3.2)

3.47 Volumetric network tariffs with finer temporal granularity can be cost reflective when well calibrated. Concretely, introducing dynamic network charges can lead to an overall smoothening of the aggregate load and hence reduce the need to reinforce the network by having higher network charges during the hours when the coincident peak usage is forecasted to occur and lower network charges when the local network is forecasted to be idle. In addition, dynamic volumetric network tariffs can be designed as symmetric allowing network injections to as well reduce network investments.

3.48 DSOs typically already have monitoring in place at some level of their network (e.g. primary substation or the grid supply point between the transmission and distribution system). However, depending on the DSO, dynamic network charges could require more sophistication in terms of monitoring than what currently is in place, as frequent (e.g. daily) load forecasting at local level is a necessary input to calibrate the network charges. This implies that the implementation of Tariff E (in contract to Tariff 0 to D) can, but not necessarily, require investments in specific hardware and software.

3.49 A potential issue with highly dynamic volumetric network tariffs with a fine temporal granularity is that they can lead to peak shifting, i.e. hours with low volumetric network charges and low energy supply charges can attract significant volumes of flexible demand. Consequently, suddenly new aggregate peaks are created in the hours during which the network was forecasted to be idle (and the forecast turned out to be wrong). As dynamic network charges have a fine temporal and spatial granularity, this issue is expected to appear only at higher degrees of electrification relative to Option 0 and Option A.

3.50 One approach to address the peak-shifting problem is to determine the dynamic network charges ex-post based on the realised aggregate local load profile (rather than setting them ex-ante). However, the issue with ex-post pricing is that it creates uncertainty for consumers and can lead to inefficiencies due to wrong anticipations of consumers when the network peak is expected to occur. A second approach is to internalise the consumer responses into the calibration of the dynamic network charges, such that peak shifting is forecasted and to a certain degree is addressed, ex-ante, in the calibration of the dynamic charges. We discuss our approach used in the quantitative assessment to calibrate the dynamic volumetric charge further in Appendix 3.

51 · CNMC, "Boletin oficial del estado Núm. 306" (22 December 2022) [LINK].
52 · PIRS, "Akt o metodologiji za obračunavanje omrežnine za elektrooperaterje" [LINK].

3.51 Another potential issue with Tariff E (and the other Tariffs that are described below) relative to Tariffs 0 to D is its perceived complexity. However, that is only true if all consumers were to be directly exposed to such network tariff design. An alternative to directly exposing consumers to dynamic network tariffs is to let this complexity be internalised by third parties managing flexible appliances on behalf of consumers (discussed more in depth in Section 3.E). An example is a "flexi-grid tariff" under which by opting-in an appliance, the consumer would receive a discounted network charge in exchange for giving their consent to a third party to operate the relevant appliance whenever the maximum capacity in the local grid is reached. The coordination between the grid operator and the relevant third party would likely require local highly dynamic price signals, but the consumer would not be exposed to any of that complexity.

3.52 An example of a pilot project where dynamic local volumetric network charges are implemented is provided in Box 3.2.

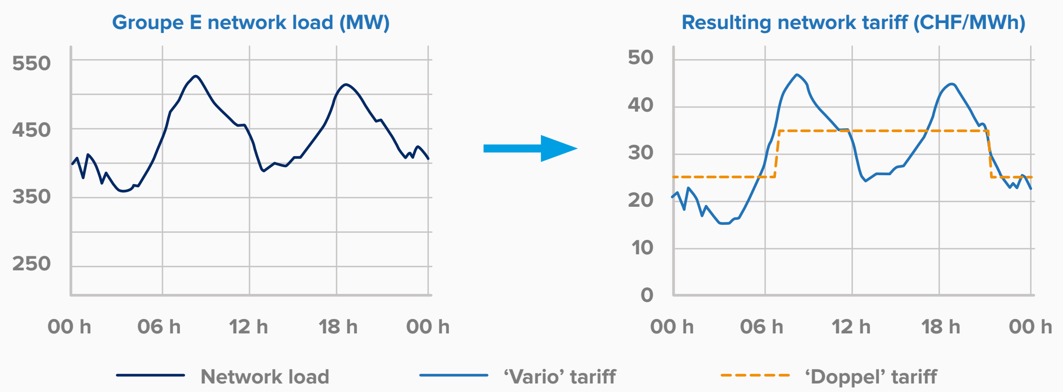
3.53 **We have shortlisted this network tariff design for the quantitative analysis as it has the potential to overcome important limitations of Option C, and thus provides insights into the merits of these particular format and temporal design features.**

BOX 3.2 — Real-world example of dynamic local volumetric network charges

Swiss utility Groupe E supplies electricity to customers in several regions of Switzerland.[53] Since January 2024,[54] they have offered customers with an annual consumption of less than 100 MWh[55] the 'Vario' tariff – which adjusts electricity prices every 15 minutes depending on the expected load on the electricity network.[56]

The forecast network load determines the shape of the bundled tariff (energy + network + taxes and levies) for the day, and the magnitude of the bundled tariff is determined by scaling it to be equal to the 'Doppeltarif', an underlying bundled ToU tariff.[57] This results in prices above the Doppeltarif when network load is expected to be higher, and prices below the Doppeltarif when network load is expected to be lower. Figure 3.6 below shows an example network load profile (left) and the resultant bundled 'Vario' and 'Doppel' bundled tariffs (right).

FIGURE 3.6 — Example 'Vario' tariff based on forecast network load



53 · Group E acts as a regulated vertically integrated monopoly in charge of retail, distribution operation and generation. The transmission grid is operated by Swissgrid.
54 · SmartGridready, "In der Schweiz haben wir Tarifstrukturen aus dem letzten Jahrhundert" (2024) [LINK].
55 · 100 MWh threshold implies that the tariff is targeted to households and small to medium commercial users. For reference, the annual electricity consumption of an average household in the EU consumes ranges between less than 2 MWh (Romania) and slightly more than 10 MWh (Sweden) [LINK].
56 · Groupe E, "Der dynamische Tarif als Option" [LINK].
57 · Groupe E, "Vario – der dynamische Tarif als Option – Technische Informationen" [LINK].

Groupe E sets, and publishes, the calculated tariff for the following day by 18:00h. The tariffs are available online and also through an interface used by consumer energy management systems, allowing consumers to automatically adjust their load for the day ahead – for instance, by producing hot water during the cheapest hours of the day, by charging their EV during the cheapest overnight hours, or even by discharging and charging home batteries during the most profitable hours, such as by charging their batteries in hours with a solar renewable surplus.

OPTION F: REGIONAL TOU CAPACITY-BASED NETWORK CHARGE COMBINED WITH DYNAMIC LOCAL VOLUMETRIC NETWORK CHARGES (BASED ON FORECASTED LOAD) (€/KW & €/KWH/H)

Combination of Option C and E.					**Example country where in place for domestic consumers**
	Volumetric charge	**Capacity Charge**	**Spatial Granularity**	**Temporal Granularity**	R&D/ academic concepts
F C + E (€/kW & €/kW/h)					

3.54 Under this network tariff design, the peak-shifting issue under Option E can potentially be reduced due to the introduction of a capacity-based network component. This network tariff design is also expected to be more cost reflective than Option D as the volumetric component is dynamic and more temporally and spatially granular.

3.55 We are currently unaware of any pilot projects that combine dynamic volumetric charges with ToU capacity-based charges. It is currently in the early R&D phase or only exists as academic concepts.

3.56 **We have not shortlisted this network tariff design for the quantitative analysis as we do not anticipate its assessment to be substantially different from the assessment of Option E, and hence we do not expect the quantitative analysis to provide significantly new insights on its efficiency or distribution impact properties.**

OPTION G: LOCAL CAPACITY AUCTION (€/KW/H)

Network capacity prices are determined in an auction taking place day-ahead. Suppliers, knowing the next day's energy prices, bid to reserve hourly blocks of local network capacity. Scarce capacity is allocated to those bidding the highest price.					**Example country where in place for domestic consumers**
	Volumetric charge	**Capacity Charge**	**Spatial Granularity**	**Temporal Granularity**	R&D/ academic concepts
G Local capacity auction (€/kW/h)					

3.57 Under a local capacity auction consumers provide price-quantity bids (measured in €/kW/h and kW/h, respectively) to "book" local network capacity (e.g. day-ahead). The network capacity that is placed under auction is limited by the physical capacity of the local network. To implement the auction, a piece-wise linear pricing "network capacity supply curve" would be introduced with the network capacity price being zero when there is a lot more available network capacity than demand. This would imply a linearly increasing price from a certain point when the demand for capacity is considered relatively high (e.g. 75% of available capacity), ending at the estimated value of lost load ("VOLL") when the physical available capacity equals the capacity demand.[58]

58· Morell-Dameto, N., Chaves-Avila, J.P., Gomez San Roman, T., Duenas-Martinez, P. & Schittekatte, T. (2024). Network tariff design with flexible customers: Ex-post pricing and a local network capacity market for customer response coordination. *Energy Policy,* 184, 113907 [LINK].

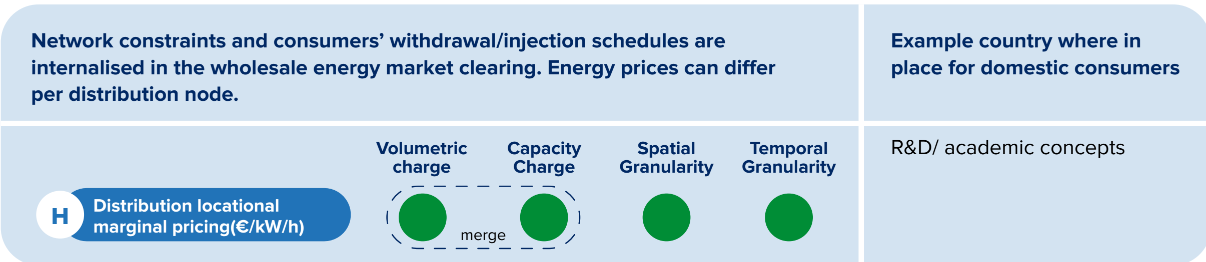
3.58 In real time, deviations from the booked capacity would be charged the clearing price of the auction or curtailed if all capacity is booked. Hence, the local capacity auction can be seen as a hedging complement to dynamic volumetric network charges which avoids the peak-shifting issue without introducing the uncertainty created by ex-post pricing.

3.59 However, this mechanism is complex to set up, administer and participate in. Suppliers and aggregators would likely have to play an important role in shielding end consumers from this complexity as discussed in ¶ 3.51. Despite its complexity, this mechanism still retains a degree of inefficiency as the energy and network prices are disconnected. Specifically, when bidding in the capacity auction, energy supply prices would need to be forecasted by consumers, as those prices will not be known yet. Errors in forecasts of the energy prices would lead to sub-optimal bids in the capacity auction and eventually somewhat inefficient consumption patterns.

3.60 We are currently unaware of any pilot projects for local capacity auctions. They are currently in the early R&D phase or only exist as academic concepts.

3.61 **We have not shortlisted this network tariff design for the quantitative analysis as it is complex to model. However, we revisit this network tariff design in the roadmap section as it is an example of how network tariff design could evolve in a highly electrified future.**

OPTION H: DISTRIBUTION LOCATIONAL MARGINAL PRICING (€/KWH)



3.62 This option is a highly innovative variant of network (and wholesale energy) charging that has not been tested in practice anywhere in the world. It builds on the concept of Locational Marginal Pricing ("LMP"), also often referred to as "nodal pricing" in the context of transmission.[60] A pre-requisite for this option is that the power market is designed with (transmission-level) locational marginal pricing. Under DLMPs, the willingness to withdraw/inject at a certain distribution node during a certain market time unit (e.g. 30 min) is considered in the wholesale market clearing. The wholesale energy market clearing thus internalises all network elements, including transmission and distribution (requiring therefore a central dispatch managed by a system operator based on offer and demand curves of all players, thus replacing the current system of self-activated dispatch based on trade mainly via power exchange platforms).[61] By doing so, the downsides of Option E/F and Option G are avoided. With regards to the former tariffs, the willingness of consumers to use network capacity under this design is endogenous rather than exogeneous, thus entirely avoiding the peak-shifting issue. Regarding the latter, energy supply prices do not need to be forecasted anymore as network constraints (both transmission and distribution) are internalised in the wholesale market clearing.

3.63 While this solution can be seen as the theoretical first best in term of cost reflectiveness, it is very hard to implement in practice. Several academics, e.g. Caramanis et al. and Papavasiliou, have modelled DLMPs but so far there is, as far as we are aware, no example of a practical implementation of this concept.[62] Particular technical barriers are the computational complexity due to the number of bids and offers and

59 · This is a similar problem as with explicit auctioning of transmission rights, which is a well-known issue.

60 · Constraints in the transmission network as well as losses result in diverging costs of electricity supply between nodes. Nodal electricity prices, which are determined at the transmission substation level, reflect these costs.

61 · Ideally a price adder is introduced if at certain locations the network capacity is close to being fully utilised to signal forward-looking network costs.

62 · Caramanis, M., Ntakou, E., Hogan, W.W., Chakrabortty, A. & Schoene, J., "Co-Optimization of Power and Reserves in Dynamic T&D Power Markets With Non-dispatchable Renewable Generation and Distributed Energy Resources", *Proceedings of the IEEE,* 104(4) (April 2016) [LINK]; Papavasiliou, A, "Analysis of distribution locational marginal prices", *IEEE Transactions on Smart Grid*, 9(5), pp.4872-4882 (February 2017) [LINK].

the number of network elements to consider. Also, correctly modelling the physics at the distribution level is more complex than at the transmission level as reactive power, losses and transformer degradation play a more important role. Further, DLMPs could potentially lead to different wholesale prices from one feeder to another, which would likely raise public acceptance issues, as well as requiring significant reforms and organisational efforts from policymakers, institutions and market participants, given that power market platforms would need to be replaced by a system operator centrally scheduling an important share of assets.[63]

3.64 We are not aware of any pilot projects for DLMPs. They are currently in the early R&D phase or only exist as academic concepts.

3.65 We have not shortlisted this network tariff design as it is complex to model and unlikely to be a credible option for distribution network charges given the resistance, in most European countries, to transmission-level LMP. However, similar as for Option G, we revisit this network tariff design in the roadmap section as it is an example of how network tariff design could evolve in a highly electrified future.

SUMMARY OF KEY FINDINGS OF THE QUALITATIVE ASSESSMENT

3.66 In Figure 3.7 below we summarise the key findings per distribution network tariff designs introduced in Figure 3.5, including:

— Summary of the key features of the design;

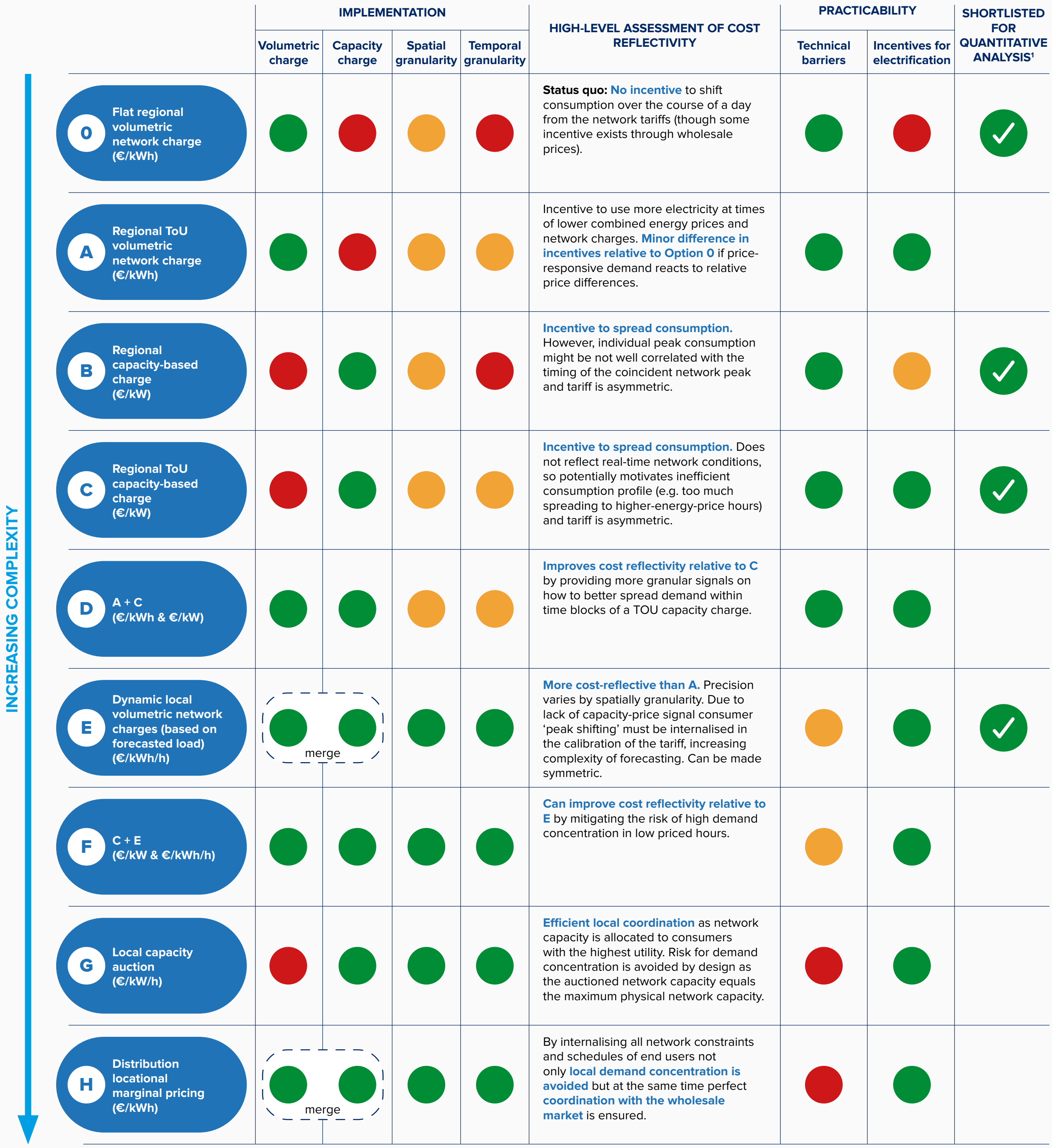
— High-level assessment of the cost-reflectivity of the network tariff design; and

— High-level qualitative assessment of the practicability of the network tariff design in terms of technical barriers and how the network tariff design impacts incentives for electrification.

3.67 Overall, we have agreed with smartEn to shortlist Tariff Option 0, B, C and E for a more detailed quantitative assessment. These shortlisted network tariff designs do not necessarily represent recommended network tariff designs. Rather, in agreement with smartEn, we have selected these options because we expect these options to capture the most important dynamics in terms of impacts on consumers' incentives and the impact of those individual incentives on the aggregate coincident peak.

63 · Self-scheduling would still be an option under such market design (i.e. acting as a price-taker of the DLMP) but most market parties would have an incentive to centrally schedule.

FIGURE 3.7 — Summary of the nine listed distribution network tariffs, high-level assessment of the considered designs, and shortlisted options



Source: FTI Consulting
Note: (1) Network tariff designs that are shortlisted for the quantitative analysis do not necessarily represent recommended network tariff designs. Rather, in agreement with smartEn, we have selected these options because we expect these options to capture the most important dynamics and insights in terms of impacts on consumers' incentives and the impact of those individual incentives on the aggregate coincident peak.

E. Overcoming the perceived complexity of more cost-reflective network tariffs

3.68 As discussed in the first subsection on key principles of network tariff design, there can sometimes be a tension between the cost reflectivity of the network tariff design and practicability. This same trade-off surfaces in the qualitative assessment of the considered network tariff designs shown in Figure 3.7 above. Concretely, due to the relatively high degree of unpredictability and complexity that is inherent to highly cost-reflective network tariffs, they might not be perceived acceptable for all types of consumers.

3.69 We discuss below three high-level potential approaches to mitigate this tension:

— Approach A: allow the complexity to be internalised by electricity suppliers

— Aproach B: allow end users to be exposed to the more advanced network tariff designs on an active opt-in basis; and,

— Approach C: allow end users to opt-in to schemes under which third parties can reschedule (part of) their load (i.e. a combination of Approach A and B).

APPROACH A: ALLOW THE COMPLEXITY TO BE INTERNALISED BY SUPPLIERS

3.70 Currently there is no regulation at the EU level that prescribes whether network tariffs are required to be passed through by the supplier to consumers in exactly the format as they are approved by the regulator. However, there can be requirements in place at the national level. An alternative to the pass-through of the network tariff as approved by the regulator is to allow suppliers to offer contracts to consumers that internalise network charges in their commercial offer. This is, for example, a possibility in Spain where network charges are composed of a ToU volumetric charge and ToU capacity-based charges (Option D), but suppliers can offer retail contracts where consumers choose to only pay flat volumetric tariff that implicitly embeds the network charges.

3.71 A compelling argument to allow suppliers to internalise the network tariffs in their commercial offer is that the complexity of the tariff design can be shifted from the consumer to the supplier. This would be similar to the current arrangements for the energy supply component of the bill, i.e. consumers can be directly exposed to the wholesale price (via a dynamic pricing contract) but can also choose for a stable price contract offered by suppliers who bear the risk of wholesale price exposure on behalf of the consumer.

3.72 In case consumers opt into a contract that removes the complexity of the network tariff, the supplier still has an incentive to engage with the consumer to align the consumer's consumption profile in a way that network charges are minimised (and thus in this case network tariffs are cost reflective leading to the avoidance of excessive network costs). This is because the supplier's profit margin is a function of the difference between what the consumer pays the supplier for network costs and the actual network charges the supplier must forward to the respective network owners.

3.73 The incentive for suppliers to engage with consumers to optimise their load profile might be larger than for the energy component as for the network tariff no hedges would be readily available. The only hedge for high network charges would be a natural hedge, i.e. the consumer's flexibility to adapt its load profile.

APPROACH B: ALLOW END USERS TO BE ONLY EXPOSED ON AN ACTIVE OPT-IN BASIS

3.74 If imposing a highly cost-reflective network tariff design on all consumers is deemed unacceptable, an alternative is to provide consumers with the option to actively opt into more cost-reflective tariffs.[65] Consumers with flexible devices would likely benefit from opting into a more cost-reflective tariff design as they can schedule their consumption during periods of limited (local) network stress when network charges would be low. This can benefit all consumers: those with flexible devices (e.g. EVs) would see

64 · CNMC, "Boletin oficial del estado Núm. 306." (22 December '2022) [LINK].
65 · Ideally the existing less cost-reflective network tariff would be gradually phased-out, i.e. a sort of grandfathering arrangement.

lower network charges, and network stress would be lower. Even consumers who do not have flexible devices, or cannot operate their flexible devices in a tariff-responsive manner, benefit from reduced overall network charges.

3.75 Opting into the more cost-reflective network tariff design can also be done at device level rather than per connection-point. This opt-in approach is much less discriminatory and susceptible to gaming than imposing a technology-specific network tariff on all consumers adopting a certain technology (e.g. network charges mandated exclusive for EVs) but not on others.

APPROACH C: ALLOW END USERS TO OPT-IN TO SCHEMES UNDER WHICH THIRD PARTIES CAN RESCHEDULE (PART OF) THEIR LOAD

3.76 A combination of Approach A and B could be to allow consumers to opt-in certain appliances in a “flexi-grid” tariff. By opting-in an appliance, the consumer would receive a discounted network charge in exchange for giving their consent to a third party to operate the relevant appliance whenever the maximum capacity in the local grid is reached. The coordination between the grid operator and the relevant third party would likely require dynamic price signals, but the consumer would not be exposed to any of that complexity.[66]

3.77 At this stage, we consider that the attractiveness of these three options is likely to vary across jurisdictions and different contexts. We re-visit these three options and, more generally, the approach to dealing with network tariff complexity, in the roadmap (Section 5).

66 · An example of such automated load control in in place in France where a time-differentiated signal is in place to activate domestic hot water tanks during off-peak hours. This control scheme is administered by the grid operator. Whether a third party (supplier or aggregator) or a grid operator is best placed to administer an automated load control scheme aimed at avoiding network congestion is a discussion that would need to be examined further.

4

Quantitative assessment of selected network tariff design options

A. Introduction

4.1 In the previous sections of this report, we presented a qualitative assessment of a range of distribution network tariff designs. We shortlisted four network tariff designs, which vary in cost-reflectiveness and complexity, for an in-depth quantitative assessment. These four network tariff designs, ranging from the least cost-reflective (and least complex) to the most cost-reflective (and most complex) are:

— **Tariff 0 (flat volumetric):** Levied as a flat €/kWh charge in each hour across the year. Tariff 0 is our 'status quo', or 'counterfactual', tariff.

— **Tariff B (capacity-based charge)**: We model the capacity-based charge as a €/kW charge levied on an individual's subscribed capacity requirement across the year.

— **Tariff C (3-part ToU, seasonal capacity-based charge):** Tariff C adds temporal granularity to Tariff B by levying separate capacity charges based on the consumer's kW-subscription level in six distinct periods (three time-of-use periods per day across two seasons).

— **Tariff E (dynamic local volumetric and fixed charge):** Under Tariff E, volumetric network tariffs vary hour-by-hour reflecting expected network conditions (e.g. as forecasted by a day-ahead load forecasting algorithm). The volumetric network tariffs are supplemented with fixed network charges to ensure full cost recovery for network owners.

4.2 In this section, we quantitatively assess how cost-reflective network tariffs can impact individual household consumption behaviour, as well as the evolution of network costs in a context of increasing electrification (see Section 1.C). Using empirical data on household EV charging, our assessment aims at, as realistically as possible, presenting how cost-reflective network tariff design can aid in finding the right balance between network investments and leveraging flexibility under a scenario of increasing electrification. We choose to focus on households with EVs[67] as a case study in this quantitative analysis because:

— many consumers have already adopted EVs, and EV adoption is projected to grow in the future;

— EV charging is transparent to isolate, and model given the data available to us; and

— EVs represent a particularly flexible source of load, which means that they can respond to both the wholesale electricity price signal and the network tariff signal, enabling us to examine the interactions between the two.

4.3 Specifically, for each of the four shortlisted network tariff designs, we assess how the household EV charging schedules change in response to the tariff signals. To compare the four designs, we consider the following key assessment metrics:

— the **cost-reflectiveness** of the network tariffs design, quantified by the impact on the average cost of electricity consumption (energy plus network costs);

— the **practicability** of the network tariff design, quantified by the **distributional impacts** on households without an EV; and the impact on the **cost of EV charging** for households with an EV.

4.4 We also quantitatively illustrate the interactions between the network tariff design and other flexibility mechanisms (see Table 1.1), such as flexibility markets. Finally, we discuss the overall performance of the network tariffs against the assessment criteria.

67 · The insights from this analysis can be, to an extent, applied to other types of consumers (e.g. non-household) and other types of electricity consumption. We describe how this analysis can be applied more widely in Section 5 (Roadmap).

4.5 In the remainder of this section we:

— describe the modelling framework and key assessment metrics;

— present the modelling results; and

— summarise the key findings from the modelling, and describe limitations and next steps.

4.6 In Appendix 2 we describe the input data and how we calibrated the model.

B. Description of the modelling framework and key assessment metrics

4.7 In this sub-section we describe the modelling methodology and key metrics against which we assess the four shortlisted network tariff designs. In particular, we describe:

— the high-level modelling framework;
— the calibration of the network tariff designs shortlisted for modelling;
— the network revenue requirement and cost recovery mechanism; and
— the key assessment metrics.

HIGH-LEVEL MODELLING FRAMEWORK

4.8 To perform the assessment of different network tariffs, we model a small population of households connected to a single feeder under scenarios featuring increasing EV adoption. We model increasing electrification by testing increased levels of adoption of EVs among households. Specifically, we model a population of 200 households connected to a single feeder[68], at varying levels of EV adoption ranging from 0% to 60%.[69]

4.9 We assume that the observed household load (excluding EV consumption) is entirely inelastic. As we increase EV adoption in the model, we progressively assign EVs to individual households. Specifically, households are assigned an EV with a unique, empirical set of EV charging requirements (explained in detail in ¶ A2.13).

4.10 We assume the modelled households opt into a dynamic energy tariff (reflecting wholesale electricity prices) complemented with four different network tariff designs as described above. We make this assumption because, in practice, consumers with EVs typically adopt managed time-varying energy tariffs to minimise their EV charging costs. Alternatively, households can also opt into plans that allow third parties to optimise the charging of the EV for them.[70] For simplicity, in what follows we refer to "EV consumers" which includes consumers and third parties controlling the EVs on behalf of consumers.

4.11 EV consumers then optimise the charging schedule in response to the aggregate price signals they are exposed to: the sum of the wholesale price – passed through via the dynamic energy tariff – and the modelled distribution network tariff. The objective of each EV consumer is to minimise the total cost of their EV charging across the year, subject to their unique set of EV charging requirements.[71,72] To isolate the impact of EV adoption on household energy consumption, we also assume that households without an EV are also on a dynamic energy tariff.

68 · We recognise that in practice the number of households behind a single feeder can vary significantly across countries and also between rural and urban consumers. The total number of households modelled in this way does not affect the qualitative results of this study. However, to tailor specific tariff designs for different EU countries and for different categories of consumers, additional quantitative modelling would be required.

69 · EV adoption rates in Europe were around 1.7% in 2023 but have been growing significantly (from 0.02% in 2013 to 1.7% in 2023). Source: Eurostat, Passenger cars in the EU [LINK]. We have been unable to find projections for EV penetration in Europe in the future but recognise that EV adoption is growing and varies significantly across member states.

70 · Energy retailers can take direct control of a consumer's at-home EV charger and target charging at the cheapest hours, subject to conditions defined by the consumer. For example, on the Intelligent Octopus Go tariff, Octopus Energy pairs directly with the consumer's car and/or car charger and uses machine learning to minimise the cost of EV charging subject to a minimum state of charge and charging times defined by the consumer.

71 · We solve a linear program to minimise the electricity bill subject to empirical EV charging requirements (see Appendix 2).

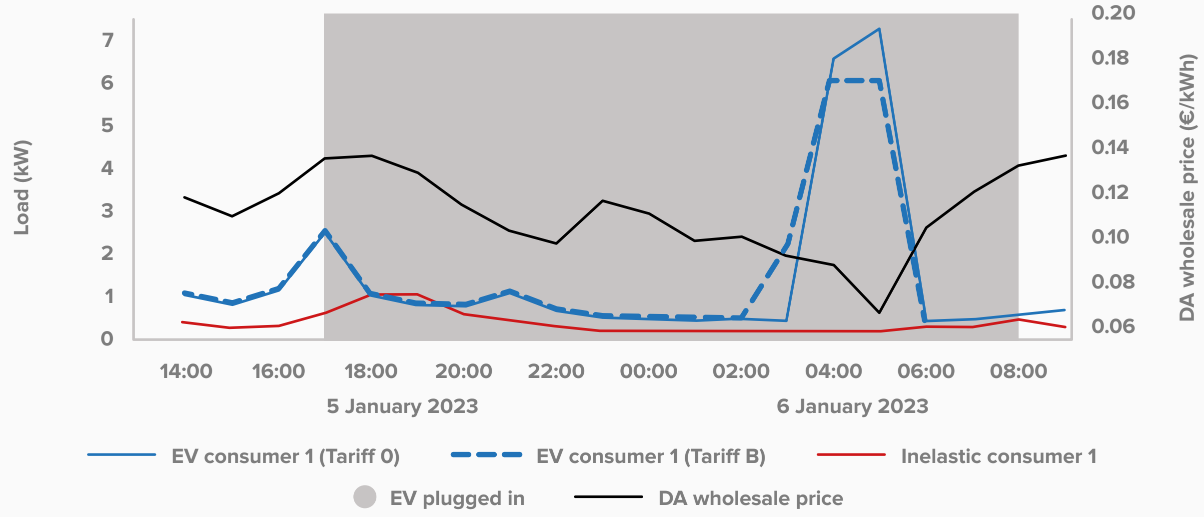
72 · We note that EV charging requirements and characteristics are based on data from UK households as described in more depth in Appendix 2. In the UK the average size of at-home EV chargers is c.7kW. This can vary across countries, for example France (which already uses a capacity-based network charge) where EV chargers are generally smaller than 7kW.

4.12 We vary the network tariff that the modelled household population is subject to and assess how the EV consumers alter their EV charging schedules in response to the network tariff designs. Though the total EV charge requirement in kWh over a charging cycle remains the same under each network tariff design. For example, when Household 1 must achieve a 40% increase in SoC over a certain plugged-in period, it will schedule the EV charging in a way that its electricity costs are minimised while respecting the 40% increase in SoC. We provide an example in Box 4.1. In this analysis are mostly focussed on how changes in individual EV charging schedules under the different network tariff designs impact the aggregate load profile of the population because increases in the aggregate consumption peak drive network investment needs.

BOX 4.1 — Illustration of how EV consumers respond to price signals in the model

Figure 4.1 below shows three hourly load profiles: (1) the load profile of an inelastic consumer, (2) the load profile of an EV consumer under Tariff 0 (flat volumetric); and (3) the load profile of the same EV consumer but under Tariff B (capacity charge). A snapshot starting from the afternoon of 5 January until the morning of 6 January is shown.

FIGURE 4.1 — Example hourly load profile under Tariff 0 and Tariff B



Source: : FTI Consulting

The load of the inelastic consumer (red line) is highest early in the evening and late morning, consistent with the typical domestic consumer load profiles (as demonstrated in Appendix 2).

The load profiles of the EV consumer under both network tariffs (blue and dashed blue line) are identical other than from 1am until 5am on 6 of January. The EV consumer under Tariff 0 charges their EV at their maximum import capacity of 7.1kW at 5am which is the hour with the lowest wholesale price (black line). Under Tariff B the consumer smooths their consumption to limit its capacity usage. Because the total EV consumption is assumed the same per charging cycle under both network tariff designs, they opt to begin charging their car slightly earlier than they otherwise would have under Tariff 0 (from 2am rather than from 3am). Their maximum load, including the inelastic load and the EV charging load, is 6.1kW. By smoothing out its load, the EV consumer pays reduced capacity charges compared to when the EV charging schedule would have been the same as under Tariff 0. As explained in ¶ 4.12, the EV must respect its EV charging requirements regardless of the network tariff design. The total energy consumption under Tariffs 0 and B is therefore identical.

Individual consumers smoothening out their load under Tariff B can also lead a lower aggregate peak load and thus lowering network investment costs. However, as explained in ¶ 4.21, the incentive to smoothen out load provided by Tariff B comes with a trade-off of having to incur slightly higher energy costs, i.e. more electricity is consumed during hours with slightly higher wholesale prices. In the next subsection, where we discuss the modelling results, we analyse this trade-off in more depth.

CALIBRATION OF THE TARIFF DESIGNS SHORTLISTED FOR MODELLING

4.13 As explained in Section 3.D, we have selected four network tariff designs for modelling:

— **Tariff 0 (flat volumetric):** Levied as a flat €/kWh charge in each hour across the year. Tariff 0 is our 'status quo' tariff[73] and provides no incentive for households with EVs to reduce their peak load. At 0% EV adoption, we set Tariff 0 equal to €0.045/kWh. As explained in the following subsection, network tariffs are recalibrated at each level of modelled EV adoption to ensure full recovery of network costs.

— **Tariff B (capacity-based charge):** We model the capacity-based charge as a €/kW charge levied based on an individual household's subscribed capacity requirement across the year. Under Tariff B consumers decide ex-ante their kW-subscription level. The chosen subscription level places a hard cap on the maximum instantaneous power a consumer can withdraw from the grid.[74] In reality, consumers would likely choose their subscription level with reference to their previous year's load profile, with some buffer to allow for uncertainty and load growth. To simulate this, we first run the model without the subscription element, i.e. assuming consumers can perfectly forecast their load across the year and fully optimise their consumption in a way that the sum of the kW-charge and the dynamic energy tariff is minimised. We then apply a 1kW buffer to their maximum load[75] observed in this model run to account for the uncertainty a consumer would face when forecasting their load. Consumers are then free to consume up to, but not in excess of, their chosen subscription level across the year. By charging consumers as a function of their estimated (individual) peak load, Tariff B reflects to some extent underlying drivers of required network investment and provides incentives for consumers to smooth their EV schedule across the hours an EV is plugged in, so as to avoid exceeding their maximum kW-subscription level.

— **Tariff C (3-part ToU, seasonal capacity-based charge):** Tariff C adds temporal granularity to Tariff B by levying separate capacity charges based on the consumer's kW-subscription level in six distinct periods (three time-of-use periods per day across two seasons). We repeat the process described for Tariff B to set each consumer's subscription level, except now each consumer has a different subscription level for each of the six distinct periods. The subscription costs (€/kW charge) are calibrated to be higher in periods when the aggregate load is expected to be higher. For example, the €/kW will typically be higher for winter evenings than for summer nights. The objective of the added temporal granularity is two-fold: first, it seeks to better incentivise consumers to shift flexible consumption away from periods during which a high aggregate load is anticipated on the distribution network. Second, it aims to avoid placing excessive charges on consumers who have high individual consumption peaks when the aggregate local peak is expected to be low[76], e.g. overnight hours when the wholesale electricity price is low in a scenario where few EVs are adopted.

— **Tariff E (dynamic local volumetric and fixed charge):** Under Tariff E, we set volumetric network tariffs that vary hour-by-hour reflecting expected network conditions (e.g. as forecasted by a day-ahead load forecasting algorithm). If load on the distribution network is forecasted to reach or exceed the maximum network capacity, the hourly tariff is set at a relatively high level. Conversely, if forecasted load is low, the hourly tariff is set at a relatively low level. This allows DSOs to directly target hours where aggregate load on the network is expected to be high and incentivise consumers to shift load away from these hours. Any under or over recovery from the dynamic volumetric charge of the network revenue requirement – explained in more detail in ¶ 4.19 and Appendix 3– is corrected for via fixed network charges or refunds (€ per connection).[77]

73 · Whilst distribution network tariff design varies across jurisdictions, domestic consumers in some large European Countries (for example Germany) are subject to flat volumetric network tariffs as discussed in Section .D (see: Bundesnetzagentur, "Network charges" [LINK]).

74 · For simplicity, we do not model consumption a sub-hourly scale, i.e. we assume the instantaneous power withdrawn by a consumer to be constant across an hour.

75 · 1kW represents a 20% buffer on the average peak hourly load (5.1kW) for non-EV consumers in our modelling sample.

76 · High individual consumption in such periods does not contribute to an increase in the aggregate local peak, and therefore it would be inefficient to discourage it. Tariff C helps to avoid such potential inefficiency (unlike Tariff B which potentially incentivises inefficient load-reduction by some consumers in some periods).

77 · See Appendix 3 for a detailed description of the modelling methodology behind Tariff E.

CALIBRATION OF THE NETWORK TARIFFS TO SATISFY THE NETWORK REVENUE REQUIREMENT

4.14 In addition to cost reflectivity, as explained in ¶ 2.14 - 2.17, another important principle of tariff design is cost recovery. We therefore consider how the network costs increase as EV adoption progresses and ensure that, under each network tariff design, network costs are fully recovered via the network charges collected from all consumers. Throughout the remainder of this section, we refer to the costs that must be recovered via the network tariff as the "revenue requirement".

4.15 We calculate the "initial revenue requirement" as the total revenue collected under Tariff 0 at 0% EV adoption (equal to the total household consumption (in kWh) multiplied by €0.045/kWh). Each network tariff is then calibrated such that the revenue collected at 0% EV adoption is equal to the "initial revenue requirement". The network tariff charge at 0% EV adoption is shown in Table 4.1 below.

TABLE 4.1 — Distribution network tariffs at 0% EV adoption

Network tariff	Network charge under 0% of EVs
Tariff 0 (flat volumetric)	€0.045/kWh[78]
Tariff B (annual subscription charge)	€41.41/kW
Tariff C (3-part ToU, seasonal subscription charge)[79,80]	€4.97/kW (off peak non-winter) €9.06/kW (mid peak non-winter) €12.68/kW (on peak non-winter) €4.91/kW (off peak winter) €8.52/kW (mid peak winter) €12.07/kW (on peak winter)
Tariff E (dynamic local volumetric and fixed charge)	€209.97 fixed charge per house, no volumetric dynamic charge as no flexible load under 0% of EVs[81]

Source: FTI Consulting

4.16 As EV adoption amongst our modelled households increases, electricity consumption and the aggregate peak load on the network also increase. As explained in ¶ 4.12, increases in the aggregate peak load drive the need for further investment into the network.

78 · In England, domestic consumers are subject to a ToU volumetric tariff (Tariff A from Figure 3-5) with three differentiated time periods. Since our household load data is drawn from South Eastern English consumers, we calibrate Tariff 0 as the weighted average volumetric charge paid by the consumers in our sample using the 2023/24 'South Eastern England Electricity Network Domestic DUoS charges' (see: UKPowerNetwork, 2024 DUoS dashboard [LINK]).

79 · Tariff C is calibrated such that 50% of revenue is recovered from winter months and 50% from non-winter months. Within a given season revenue is recovered in a 3:2:1 ratio from on, mid and off-peak periods.

80 · Time periods and seasons are calibrated according to our modelling sample. Time periods are defined as follows: on-peak is 8-10am and 4-8pm; mid-peak is 10am-4pm; off-peak is 8pm-8am. There is no differentiation between weekdays and weekends. Winter is defined as December through March, with April through November defined as non-winter. A DSO looking to implement a similar tariff design should configure the time periods and seasons according to their unique network conditions.

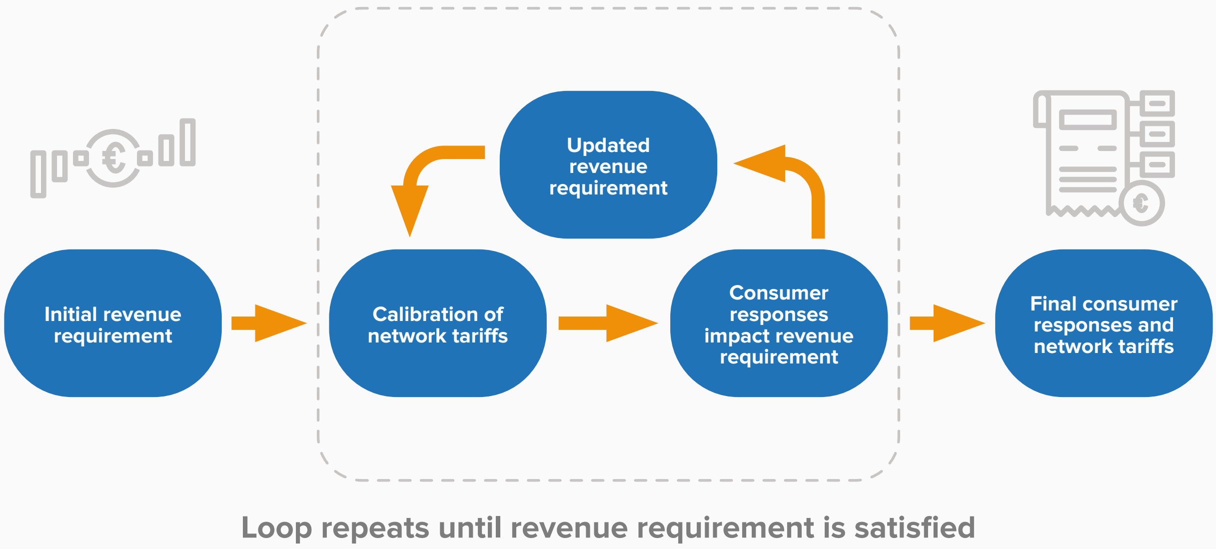
81 · At no EV adoption, Tariff E is comprised entirely of a fixed network charge. The share of network revenues captured by the dynamic volumetric tariff increases gradually as the adoption of EV grows (at the expense of the share of the fixed charge).

4.17 We assume that network costs scale linearly with the increase in the aggregate peak load, proportional with the LRMC of the network.[82] The revenue that must be recovered at each simulated level of EV adoption can therefore be calculated as the initial revenue requirement plus the additional costs on the network due to the increase in aggregate peak load. At any given level of EV adoption, i, the revenue requirement is characterised by the following equation:

$$\textit{Revenue requirement}_i = \textit{LRMC} * (\textit{Peak load}_i - \textit{Peak load}_0) + \textit{Initial revenue requirement}$$

4.18 At each level of EV adoption, we re-calibrate Tariffs 0, B and C and repeat the process of re-calibrating the network tariff such that the final tariffs are sufficient to recover the full revenue requirement. This process is illustrated in Figure 4.2 below.

FIGURE 4.2 — Calibration of network tariffs to satisfy cost recovery requirement



Source: FTI Consulting

4.19 Unlike Tariffs 0, B, and C which follow the iterative process described above, under Tariff E, the application of the dynamic volumetric tariff may result in either under (or over) recovery of revenue. This is corrected for by complementing the dynamic volumetric charge with a fixed charge (or refund) levied equally across all households. In Appendix 3, we provide more detail on how the dynamic volumetric network is calibrated.

KEY METRICS FOR ASSESSING THE PERFORMANCE OF NETWORK TARIFF DESIGNS

4.20 We have defined key metrics to assess the performance of each network tariff design based on the key network tariff design principles described in Section 2.B. By design the cost recovery principle is fulfilled in our modelling, since we calibrate the tariffs in a way that always ensures all costs are recovered from consumers. Hence, we focus on the cost reflectivity and practicability of the network tariff in this quantitative assessment.

82 · We recognise there is a wide range of estimates for the LRMC of distribution networks, varying by jurisdiction and over time. For example: Cutter et al., *"Distribution Grid Cost Impacts Driven by Transportation Electrification"*, Energy+Environmental Economics, page 10 (June 2021) [LINK]; estimates a co-incident peak load driven costs within the range of $14 - $175/kW/yr (2020 values). The California Public Utilities Commission, *"2022 Distributed Energy Resources Avoided Cost Calculator Documentation"* (June 2022) [LINK], page 54; estimates the 2023 distribution marginal capacity costs at around $48 /kW/yr (nominal terms). For the purpose of this estimate we assume a LRMC of €100/kW which sits within the range of the estimates presented above.

4.21 In this section, we quantify the **cost reflectivity** of the network tariffs through the **total cost of electricity consumption,** which can be broken down into:

— **Network costs driven by the aggregate peak load.** As explained in ¶ 1.8, the aggregate peak load on the distribution network drives the need for reinforcement. Therefore, a network tariff that reduces the aggregate peak load on the network can save consumers money through reduced need for distribution network investment.

— **Cost of energy.** Whilst more cost-reflective network tariff designs serve to reduce total network costs, they may increase consumers' energy costs, leading to a trade-off between energy and network costs.[83] For example, under Tariff 0, an EV will likely be scheduled to charge at maximum capacity during the cheapest wholesale energy hours. By contrast, under Tariff B (a capacity charge), an EV may be scheduled in a way that the charging schedule is smoothened. Consequently, the EV might be scheduled to charge in some more expensive wholesale energy hours to reduce the consumer's individual peak load (which eventually can result in lower overall network costs). However, this means that the EV charging schedule may no longer target the lowest wholesale priced hours. The potential increase in energy costs under Tariff B can therefore offset some of the savings in network costs.

4.22 We also quantify the practicability of the network tariffs by assessing:

— **Change in costs for non-EV consumers.** Whilst the load of non-EV consumers is assumed to be entirely inelastic, the network tariff design impacts the total network costs paid by non-EV consumers. Large increases in the electricity bill of non-EV consumers due to changes to the network tariff design and/or higher network charges reflecting increased network costs caused by EV loads can be deemed unfair. We therefore examine the impact of each tariff (at different levels of EV penetration) on the total costs for non-EV consumers.

— **Cost of EV charging.** Different network tariff designs can impact the cost of EV charging and therefore the incentives for consumers to adopt EVs. As explained in ¶ 1.12, electrification is an important element of the EU's decarbonisation strategy and therefore the extent to which network tariff designs impact the incentives to adopt EVs is an important consideration.[84]

4.23 We also briefly discuss how cost-reflective network tariffs can be used **as a complement to other tools at a DSO's disposal,** such as flexibility markets.

4.24 Finally, we provide an **overall assessment of each tariff against the key assessment metrics.** We assess potential trade-offs between the cost reflectivity quantified by the total cost of electricity consumption, and practicability through the change in costs for non-EV consumers and the cost of EV charging.

C. Modelling results

4.25 In this section we present our modelling results for the four modelled network tariff designs and assess them against the key metrics introduced in ¶ 4.21: total cost of electricity consumption (including energy and network costs); the change in costs for non-EV consumers (as a proxy for distributional impacts); and the change in costs of EV charging (as a proxy for incentives to adopt EVs).

4.26 We then discuss the interactions that network tariffs may have with flexibility markets and how a DSO may use flexibility markets in conjunction with cost-reflective network tariffs.

83 · As discussed in ¶ 3.48, when network tariffs are well calibrated, this does not necessarily mean that network price signals are "conflicting" energy price signals. This interplay between network and energy prices should rather be interpreted as network price signals "correcting" energy prices (which do not contain any local network information).

84 · As discussed in ¶ 2.6, while policy objectives should ideally not impact designing a network tariff, the status quo network tariff is levying a tax on electrification that could be removed when transitioning to a more cost-reflective network tariff design. Hence, a change in the incentives to electrify due to a change in the network tariff design is considered an important practicability consideration. Impacts on incentives for electrification due to network tariff design can in theory be rectified via adjustments to subsidy regimes for electrification (if deemed important by policymakers). However, changes in subsidy regimes might be difficult to accomplish in practice.

4.27 In agreement with smartEn we show results for up to 60% of EV adoption across the modelled household population. While there is significant uncertainty regarding the speed of transport electrification, we consider that the range from 0-60% of EV adoption seems most relevant in short to medium term and its assessment provides the most interesting insights for policymakers.[85]

COST REFLECTIVITY: TOTAL COST OF ELECTRICITY CONSUMPTION

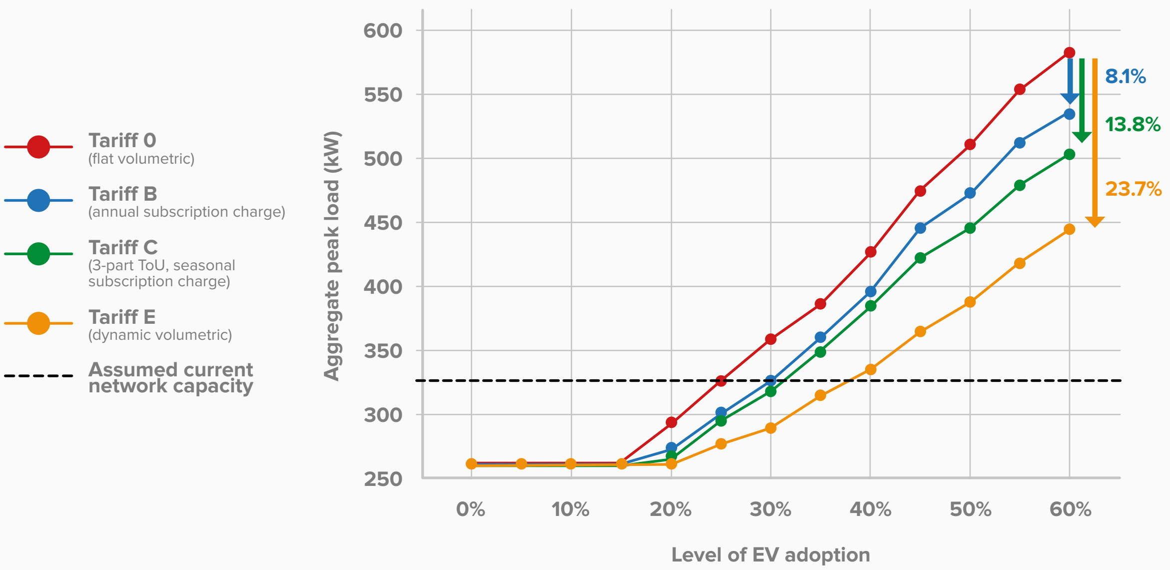
4.28 In this study we focus mostly on how improved network tariff design can mitigate the need for incremental network investments. However, it is important that the reduction in network investment costs does not come at the expense of significant increases in energy procurement costs. For example, discouraging consumers to simultaneously consume in the hours with the lowest wholesale costs might lower network costs. However, at the same time, this will likely lead to higher energy costs as more consumption will occur in hours with higher wholesale electricity prices.[86] To capture this trade-off, we focus on the total cost of electricity consumption for the modelled consumer population, which consists of network and energy costs.

4.29 In the following subsections, we start by focussing on the network costs driven by the aggregate load peak under the different network tariff designs. We then look at how network tariff designs impact energy costs. Finally, we describe total energy costs under the different network tariff designs.

Network costs driven by the aggregate peak load

4.30 As explained in ¶ 1.8, the main driver of the network investment is the aggregate peak load. Figure 4.3 below shows the aggregate peak load of the population at each discrete level of EV adoption from 0% to 60%. To illustrate how aggregate peak load may evolve with reference to the current network capacity, we assume that the network has a 25% buffer on the aggregate peak load observed at 0% EV adoption.[87]

FIGURE 4.3 — Aggregate peak load on the distribution network under each modelled tariff design (kW)



Source: FTI Consulting

85 · For example, Transport for London ("TfL") predicts that EVs could account between 34% and 49% of London's entire vehicle fleet by 2030 (TfL, "London's 2030 electric vehicle strategy" (December 2021) [LINK]). This figure could differ significantly by neighbourhood however, with some neighbourhoods achieving EV penetration greater than 49%. There is also uncertainty regarding the share of population that would own a private vehicle going forward.

86 · We do not model the feedback loop between changes in the EV charging schedules and wholesale electricity prices. In case this loop would be considered, it is likely that the same downward trend would still be visible, however the slope would depend on the incremental EV load relative to the incremental investment in generation capacity. We discuss this modelling limitation in more detail in Section 4D.

87 · As we assume that some headroom needs to be maintained in the network for security reasons, incremental network costs are incurred from the moment the pre-existing peak is exceeded.

4.31 Up to 15% EV adoption there is no change in the aggregate peak load under any network tariff design. This is because there are few EVs on the network and those EVs can fulfil their EV charging requirements without causing an increase in the aggregate peak load, independent of the network tariff design. This is the case even under Tariff 0, where EV consumers are not actively trying to keep their individual peak load low, and they charge their EV at the maximum of their import capacity in hours with the lowest wholesale prices. However, those hours with low wholesale prices are typically overnight and do not coincide with the aggregate peak periods that pre-existed without EV adoption, i.e. winter evenings during which wholesale prices are typically relatively high. As penetration of EVs is limited, the newly created overnight peaks do not exceed pre-existing demand peak without EV adoption.

4.32 From 20% EV adoption, the aggregate peak load starts to increase under all modelled tariffs and continues to increase as EV penetration increases. This is in line with expectations and reflects the network requirements driven by the electrification of household demand. However, the rate at which the aggregate peak load increases varies significantly across the four network tariffs modelled.

— Under Tariff 0, the EV population becomes large enough to create overnight peaks that are higher than aggregate peak periods that pre-existed without EV adoption. Eventually, under Tariff 0, the current network capacity is exceeded at c.25% EV adoption.

— Tariffs B and C incentivise consumers to reduce their peak load by levying the network charge as a function of individual peak load. Because of this incentive, consumers reduce their individual peak load (relative to Tariff 0). However, even though individual consumers reduce their peak load, eventually the network capacity is exceeded at levels of EV adoption of c.30% and 31%, respectively. Tariff C performs slightly better than Tariff B at all levels of EV adoption as the added temporal granularity improves the incentive for EV consumers not to charge during periods of high strain on the network (e.g. during the evenings in winter).

— Tariff E performs better in terms of limiting the peak increases than all other tariffs at all levels of EV adoption. The existing network capacity is not exceeded until c.38% of EV adoption. By sending dynamic, hour-by-hour, price signals based on forecasted aggregate load on the network, Tariff E can directly target the hours in which EVs are forecasted to increase the aggregate peak load. At 60% of EV adoption, we find that relative to Tariff 0, Tariff B, C and E can reduce the aggregate peak load by 8.1%, 13.8%, and 23.7%, respectively.[88]

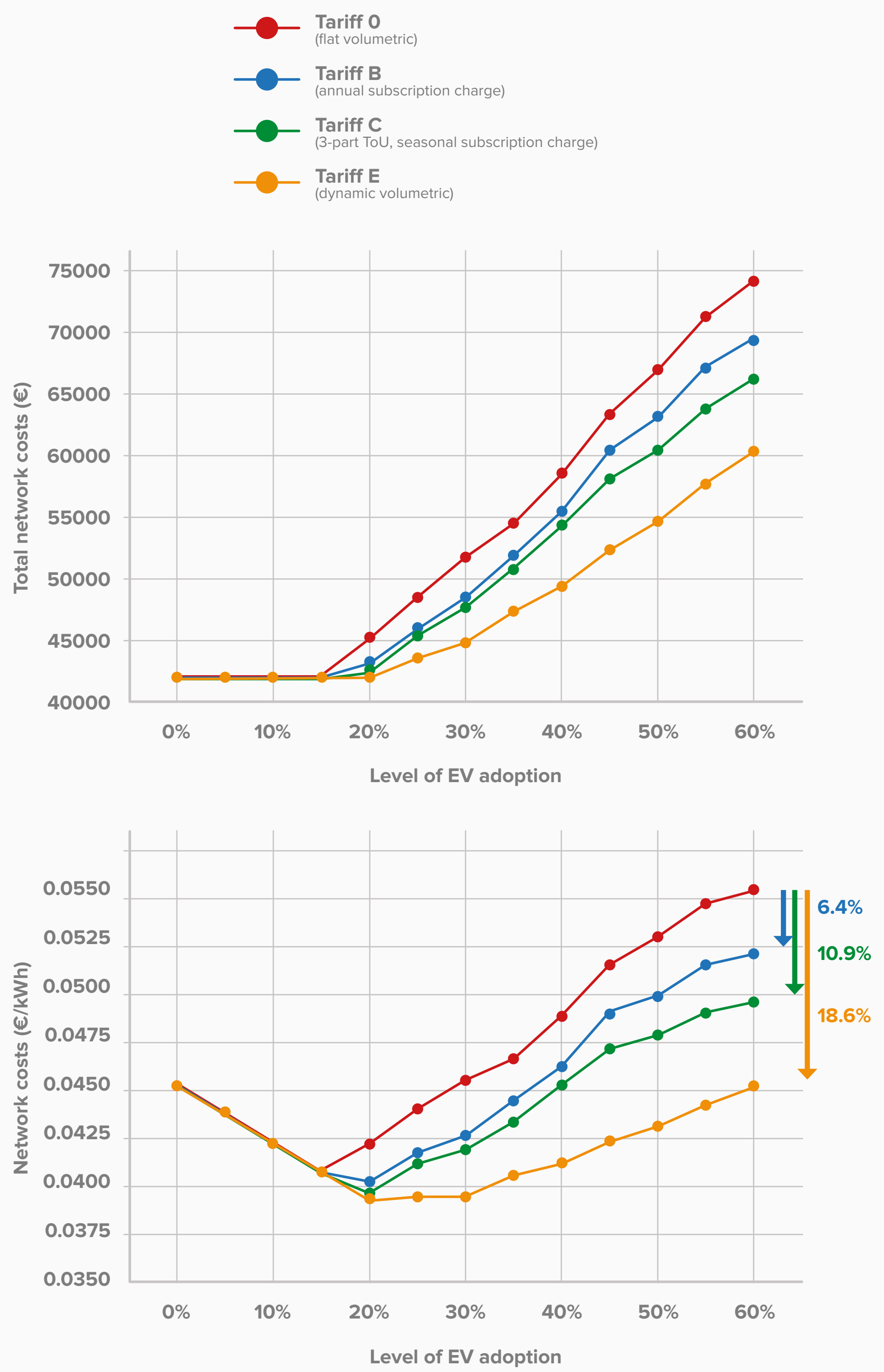
4.33 Figure 4.4 below shows how the reduction in peak load due to more cost-reflective network tariff designs drives savings in the total network costs (€) paid by consumers (left panel) and the total network costs divided by the total electricity consumed by all consumers (€/kWh) (right panel). We focus on describing the results shown in right panel as the total network cost (shown in the left panel) scale linearly with the aggregate network peak shown in Figure 4.3.

4.34 Initially, before the adoption of EVs exceeds 15%, there is a downward trend in network costs divided by the total consumption. This is because, with an unchanged aggregate peak load, network costs stay constant while the total consumption increases as more EVs are adopted. However, under Tariff 0, this trend reverses at EV adoption of 20% or more, as the increase in network costs outpaces the increase in consumption by EVs. Under Tariffs B and C, the trend is also reversed but to a lesser extent as under Tariff 0. This is due to a more cost-reflective network tariff design that manages to mitigate network costs increases as EV adoption grows. Under Tariff E, which is the most cost-reflective variant, the trend is reversed to an even lesser extent. The network is better utilised, and more electricity consumption (as EV adoption increases) can be served with lower network outbuild compared to the other network tariff designs. We explore the evolution of the network tariffs as EV adoption increases in Box 4.2 below.

88 · Under the status quo (Tariff 0) we model a 132% increase in the aggregate peak load from 0% EV adoption to 60% EV adoption. To verify this result, we created a sample of 200 randomly selected non-EV consumers from the standard variable tariff empirical data described in Appendix 2. We then substituted 60% of these households with EV consumer from the flexible EV consumer data described in Appendix 2. The increase in the observed aggregate peak load between these two samples was 127%, a very similar magnitude to our modelled increase of 132%.

4.35 At 60% of EV adoption, we find that relative to Tariff 0, Tariff B, C and E can reduce the network costs per kWh of consumption by 6.4%, 10.9%, and 18.6%, respectively. When dividing the network cost savings by the total number of modelled households (200), we find that relative to Tariff 0, Tariff B, C and E can reduce the annual average network costs per household by €23.6, €40.2, and €69.1 respectively.

FIGURE 4.4 — Total network costs (€) and network costs (€/kWh) under each modelled tariff design



Source: FTI Consulting

BOX 4.2 — Evolution of network tariffs over increasing EV adoption

As explained in ¶ 4.18, for Tariffs 0, B, and C we iteratively recalibrate the tariffs to ensure full recovery of the revenue requirement. For Tariff E, we supplement the application of the dynamic volumetric tariff with a fixed charge. Table 4.2 below shows the evolution of the tariffs as EV adoption increases.

TABLE 4.2 — Distribution network tariffs at 0%, 20% and 40% EV adoption

Tariff	No EV adoption	20% EV adoption	40% EV adoption
Tariff 0	€0.045/kWh	€0.042/kWh	€0.048/kWh
Tariff B	€41.41/kW	€39.3/kW	€47.53/kW
Tariff C	€4.9/kW €9.06/kW €12.68/kW €4.91/kW €8.52/kW €12.07/kW	€4.22/kW €8.48/kW €12.03/kW €4.21/kW €8.10/kW €11.66/kW	€5.09/kW (off peak non-winter) €11.36/kW (mid peak non-winter) €16.54/kW (on peak non-winter) €5.20/kW (off peak winter) €11.08/kW (mid peak winter) €16.31kW (on peak winter)
Tariff E	€0/kWh €209.97	€0.012/kWh €135.99	€0.021/kWh (mean volumetric charge) €110.95 (fixed charge)

Source: : FTI Consulting

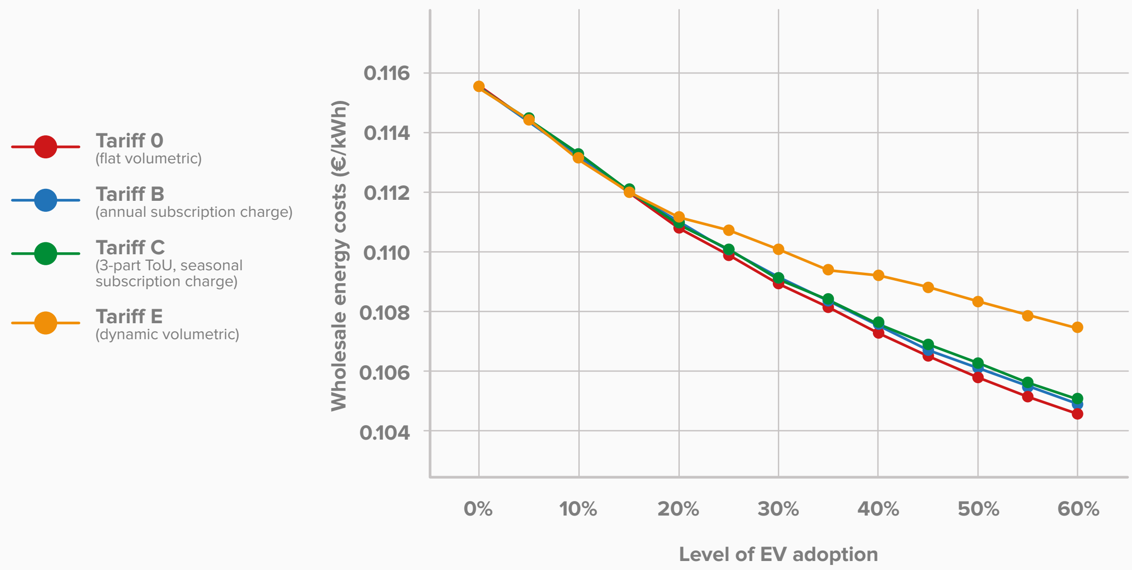
Consistent with ¶ 4.34, we see the levels of Tariffs 0, B, and C decline under 20% of EV adoption relative to under no EV adoption. This is because, network costs do not increase up to 15% EV adoption, but total consumption (and for some individuals peak load) does increase. The increase in network costs between 20% and 40% of EV adoption outpaces the increase in consumption. Consequently, at 40% of EV adoption, the network tariff levels are higher for Tariffs 0, B, and C than under no EV adoption.

Under Tariff E, as EV adoption increases, there are more hours in which forecast aggregate load is expected to be high relative to maximum network capacity. Therefore, there are more hours in which the volumetric charge is high. The result is that, as the average volumetric charge increases, the reliance on the fixed charge to recover network costs reduces.

Cost of energy procurement

4.36 The reduction in total network costs paid by consumers due to more cost-reflective network tariffs can come at the expense of increased energy costs. Figure 4.5 below shows the average wholesale energy costs paid by consumers under each network tariff design.

FIGURE 4.5 — Wholesale energy costs paid by consumers under each network tariff design (€/kWh)



Source: FTI Consulting

4.37 For all network tariffs, as EV adoption increases, there is a downward trend in the average wholesale price per kWh consumed. This can be explained by elastic EV load representing an increased share of total electricity consumption as EV adoption increases. In other words, EV electricity charging is flexible, and EV charging is typically scheduled for when wholesale prices are low. By contrast, the share of the inelastic non-EV consumption reduces as EV adoption increases. This inelastic consumption occurs both when wholesale prices are low but also when wholesale prices are high (as, by definition, inelastic demand cannot avoid consumption during high-price hours).

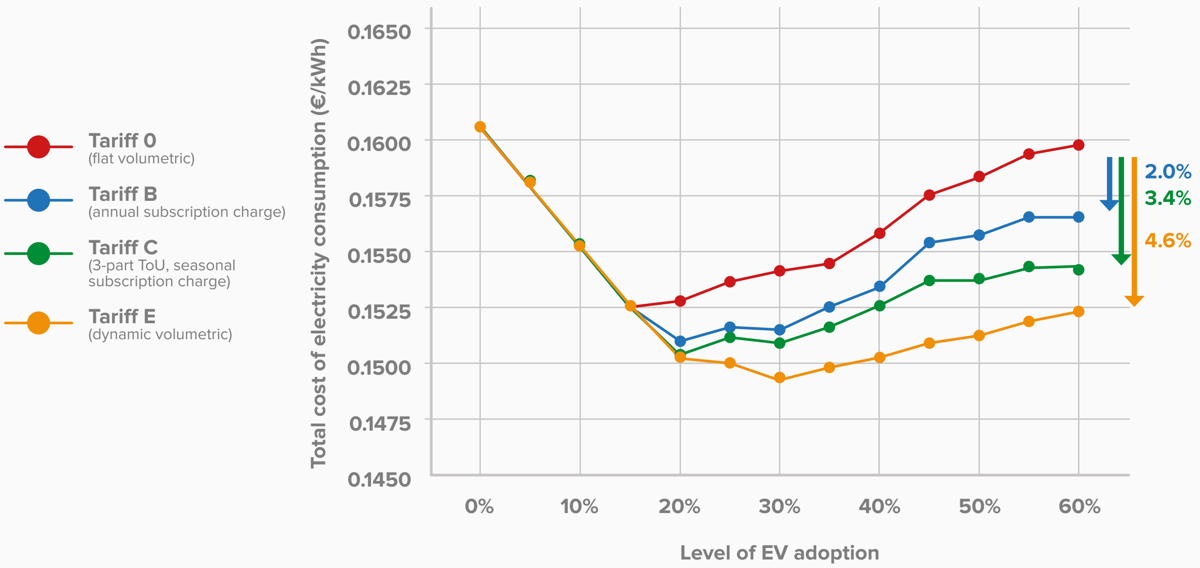
4.38 However, the average energy costs paid by consumers, at a given level of EV adoption, is higher under Tariffs B, C and E relative to Tariff 0 from around 20% of EV adoption. The increase in average energy costs relative to Tariff 0 grows as the tariffs become more cost reflective. This is particularly apparent with Tariff E (the dynamic volumetric tariff) which provides the strongest incentives to avoid (potentially excessive) network outbuild by smoothing consumption over time. Consequently, under Tariff E, EVs are to a lesser extent being scheduled when the lowest wholesale energy prices occur relative to the other modelled network tariffs. This illustrates the essence of the trade-off between reducing network costs and reducing energy costs when charging EVs based on wholesale price signals.[89]

Total cost of electricity consumption

4.39 Figure 4.6 shows the total cost of electricity consumption (network plus energy costs) per kWh consumed for each of the modelled tariff designs. The key finding is that savings in network costs achieved by Tariffs B, C and E outweigh the increase in energy costs relative to Tariff 0. Tariff E leads to lowest average costs of electricity consumption (i.e. energy and network costs combined) at all levels of EV penetration, followed by Tariffs C and B.

89· As discussed under modelling limitations in Section 4D, in this report we do not model the feedback loop between changes in the EV charging schedules and wholesale electricity prices.

FIGURE 4.6 — Total cost of electricity consumption under each modelled network tariff design (€/kWh)



Source: FTI Consulting

4.40 We find that, at 60% EV adoption, the total cost of electricity per kWh consumed is reduced by 2.0%, 3.4% and 4.6% respectively under Tariffs B, C, and E, relative to Tariff 0. This leads to average annual savings per household of €21.3, €36.8, and €49.7. In Box 4.3 we explore the impact of higher-than-average wholesale energy prices in 2023 on these results.

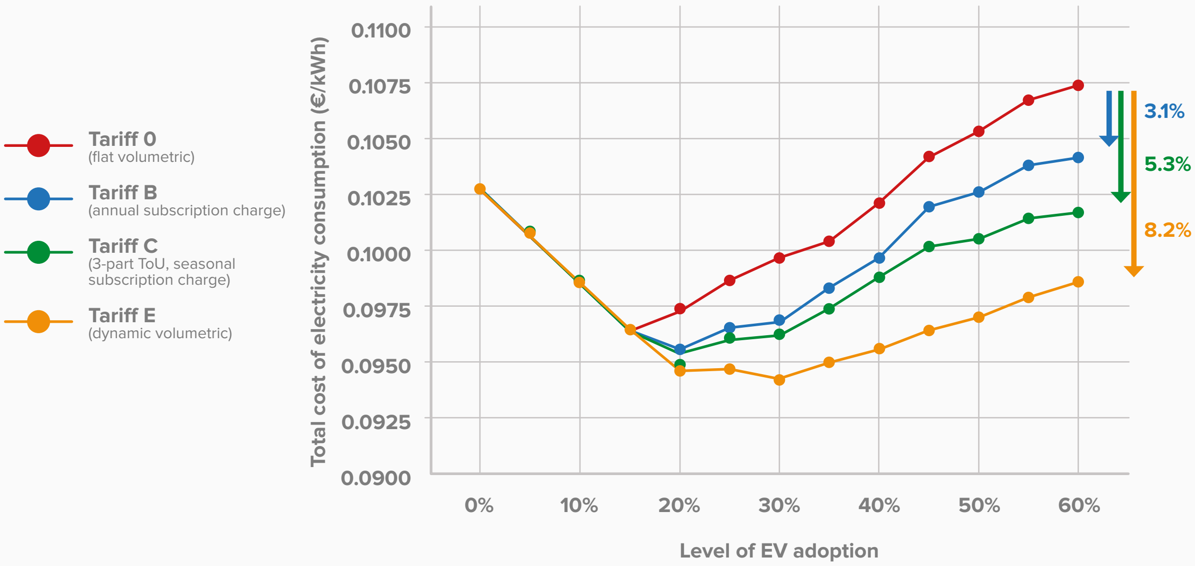
BOX 4.3 — Impact of energy crisis on total cost of electricity consumption

Across Europe, electricity prices increased dramatically in late 2021 and early 2022 after the Covid-19 pandemic and Russia's invasion of Ukraine (referred to as the "European energy crisis"). Whilst electricity prices began to fall during 2023, they were still, on average, significantly higher than pre-crisis levels. The level of the wholesale energy price impacts the extent to which increases in wholesale energy costs offset the savings in network costs achieved by cost-reflective tariff designs.

To illustrate this impact, we have tested how sensitive our modelling results would be if we assumed that wholesale electricity prices were 50% lower in each hour compared to the observed wholesale electricity prices in 2023 (i.e. the average wholesale electricity price would be €54/MWh rather than the observed €108/MWh).

Figure 4.7 below shows the total cost of electricity consumption under the different network tariff designs when reducing the 2023 wholesale price by 50% in each hour. With the lower energy prices, increases in energy costs under Tariffs B, C and E relative to Tariff 0 are less pronounced and therefore offset the savings in network costs to a lesser extent. The result is greater overall savings for consumers relative to Tariff 0. Compared to the savings described in ¶ 4.40 (under the observed 2023 wholesale prices) both the proportional and absolute savings under Tariffs B, C and E have increased. Relative to Tariff 0, the per kWh cost of electricity consumption is reduced by 3.1%, 5.3% and 8.2% respectively under Tariffs B, C, and E. This leads to annual average savings per household of €22.5, €38.5, and €59.4 from increasingly more cost-reflective network tariff designs.

FIGURE 4.7 — Total cost of electricity consumption after reducing the wholesale price by 50% (€/kWh)



Source: FTI Consulting

PRACTICABILITY: DISTRIBUTIONAL IMPACTS ON NON-EV CONSUMERS AND INCENTIVES FOR ELECTRIFICATION

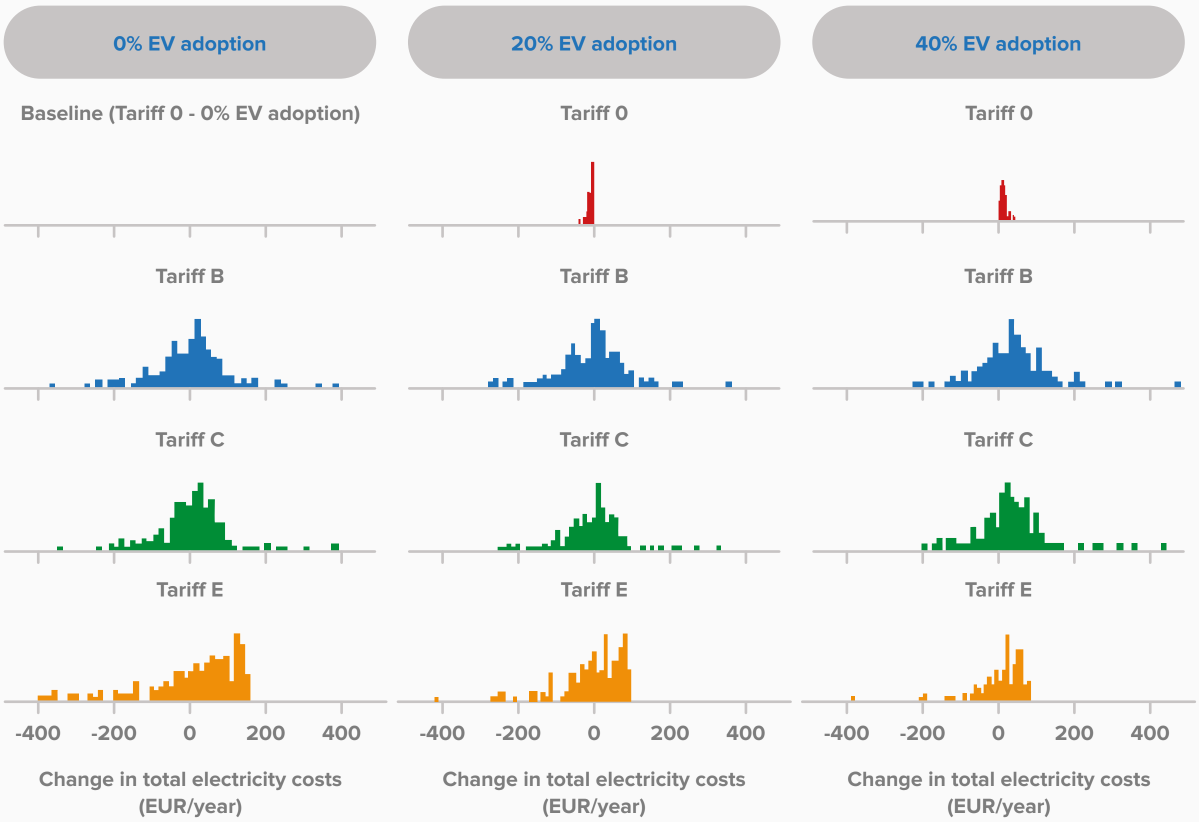
4.41 In this section we quantify how the different network tariff designs impact important practicability considerations: distributional impact of the network tariff designs (proxied by the impact on non-EV consumers) and their impact on incentives for electrification (proxied by the average cost of EV charging).

Change in costs for households without an EV

4.42 The consumers without EVs are assumed not to change their consumption based on the electricity prices and network tariffs they face. Wholesale electricity prices are assumed to be constant across tariff designs and the level of EV adoption (discussed in more detail under modelling limitations in Section D). This implies that non-EV consumers do not see changes in their energy costs as the EV penetration increases. However, different network tariff designs do impact the network costs paid by non-EV consumers. The reason is that the network tariff designs will impact the total distribution network costs and, consequently, the quantum of the network charges paid by the non-EV consumers.

4.43 Figure 4.8 below shows the distribution of changes in the total electricity costs on a household-by-household basis for non-EV consumers at 0%, 20% and 40% EV adoption relative to 0% EV adoption under Tariff 0. A positive change in electricity costs indicates that a non-EV consumer now pays more electricity costs (due to increased network costs) than they did under the status quo (0% EV adoption, Tariff 0).

FIGURE 4.8 — Distribution of change in annual electricity costs relative to no EVs under Tariff 0 (EUR/year)



Source: FTI Consulting

4.44 For Tariff 0, initially (e.g. at 20% of EV adoption shown in Figure 4.8), all non-EV consumers are better off when other consumers adopt EVs. The reason is that at 20% of EV adoption the increase in the aggregate network peak is relatively limited (see Figure 4.3) and thus the network revenue requirement is only slightly higher than under 0% of EVs. However, the same network costs are spread over more consumption as more EVs are adopted. Consequently, the network charge per kWh reduces (see Box 4.2) and non-EV consumers see a reduction in their total electricity costs.

4.45 This dynamic is shown in more detail in Figure 4.9 below displaying the simple average of the percentage change in the total cost of electricity consumption across all non-EV consumer. Indeed, up to 15% of EV adoption (when there is no aggregate peak increase – see Figure 4.3), there is a downward trend in the electricity cost for all non-EV consumers. This trend starts reversing from 15% of EV adoption onwards as the network costs start increasing with more EV adoption. From around 30% of EV adoption (or slightly before) the increase in network costs and the increase in consumption to spread the network costs over balances out. This means that the flat volumetric network charge becomes greater than it was under 0% of EV adoption from 30% of EV adoption onwards and all non-EV consumers become gradually worse off as EV adoption rises. This can be observed from the increase in electricity costs for all consumers under 40% of EV adoption in Figure 4.8. Despite this upward trend, the average change in electricity costs for non-EV consumers remains lowest under Tariff 0 relative to the other tariffs. The reason for this is that EVs consume a significant volume of kWh and EV consumers therefore pay a high share of all network costs. The downside, as discussed in the next subsection, is that EV charging is the most expensive under Tariff 0.

In other words, EV consumers cross-subsidise the network charges of non-EV consumers under Tariff 0.

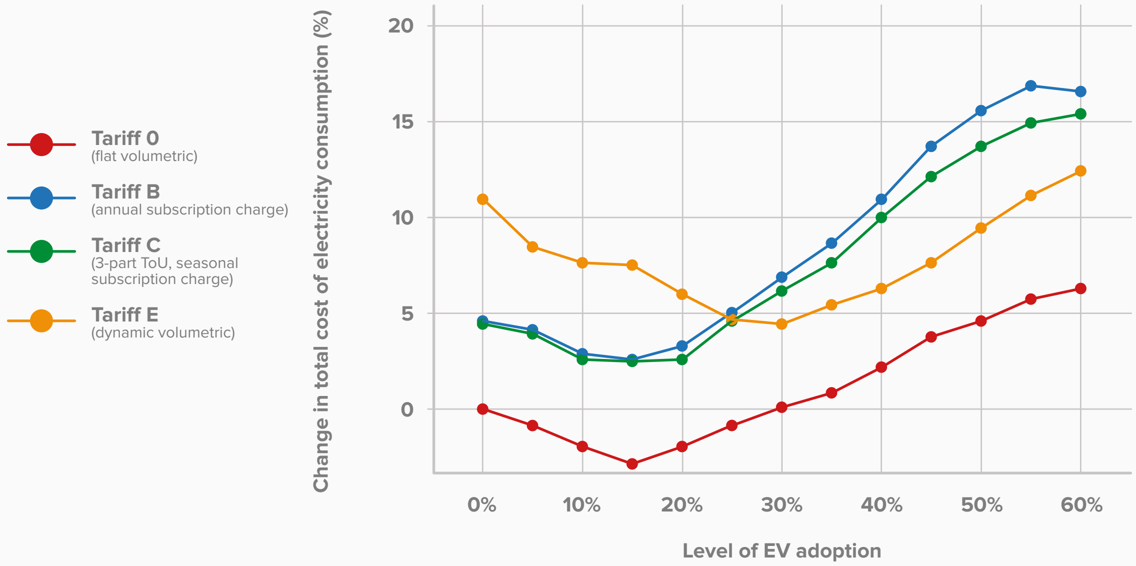
4.46 For Tariffs B and C, it can be seen from Figure 4.8 that at 0% EV adoption some non-EV consumers are better off whilst others are worse off (relative to Tariff 0 and 0% EV adoption). Whilst there is no change at the population-level in terms of the total electricity costs (that is, total network and energy costs are identical under all tariffs at 0% EV adoption) some households can experience relative increases in their individual bills. Figure 4.9 below illustrates these distributional impacts in more detail. Low-consumption high-peak households pay, under Tariff 0, relatively low network charges despite their relatively high peak loads. These households are therefore effectively cross-subsidised by lower-peak but higher-annual consumption households who pay relatively high network charges under Tariff 0. Under Tariffs B and C, the high-peak, low-consumption households are instead charged based on their relatively high peak loads and are therefore no longer subsidised by their counterparts, as discussed in detail in Box 4.4 below. As a result they see a relatively large increase in their electricity costs.

4.47 Overall, Figure 4.8 shows that independent of the level of EV adoption, under Tariff B and C the distribution of electricity cost impacts across all non-EV consumers appears to be broadly normal shaped with some outliers in either direction. As EV adoption grows, the mean of the distribution shifts more to the right, i.e. on average non-EV consumers see an increase in their electricity costs. This trend can also be seen by the increase in the average change in total electricity costs in Figure 4.9 below. Figure 4.9 below shows that as EV adoption increases, despite lower total network costs under Tariffs B and C relative to Tariff 0 (see Figure 4.4), non-EV consumers are worse off on average (i.e. their annual total electricity costs increase more relative to 0% EV adoption and Tariff 0 under Tariffs B and C relative to the other tariffs). This is because Tariffs B and C fail to charge EV consumers for the entirety of the incremental network costs they cause. Hence, non-EV consumers see their network charges increase as EV adoption increases. At 40% EV adoption, around 70% of non-EV consumers are worse off under Tariff B and C relative to Tariff 0 at 0% EV adoption. Note that at 40% of EV adoption all non-EV consumers are worse off under Tariff 0 than they were at 0% of EV adoption under the same tariff.

4.48 Under Tariff E, some non-EV consumers are considerably better off at low levels of EV adoption, whilst quite a relative high proportion are worse off (Figure 4.8). This is due to the relatively large, fixed charges levied equally across all households (as explained in Appendix 3). Very high-consumption households benefit from Tariff E at low levels of EV adoption as these households paid a higher-than-average share of network costs under Tariff 0. However, for a large share of non-EV consumers these fixed charges are greater than the total network costs they would have paid under Tariff 0. As shown in Figure 4.9 below, the latter dominates and the average increase in electricity costs across all non-EV households at low levels of EV adoption under Tariff E (relative to Tariff 0 and no EV adoption) is the largest across all tariffs.

4.49 At 40% of EV adoption, a slightly lower proportion of non-EV consumers (65%) are worse off under Tariff E than under Tariffs B and C (see Figure 4.8). Also, under Tariff E there are fewer consumers experiencing very large (e.g. in excess of €200/year) increases in their electricity bills. Because Tariff E manages to limit the increase in the aggregate peak better than Tariff B and C (see Figure 4.3) and allocates a large share of the incremental network costs to EV consumers, on average non-EV consumers are better off under Tariff E than under Tariff B and C from around 25% of EV adoption and upwards (shown in Figure 4.9 below).

FIGURE 4.9 — Average change in annual total electricity costs across all non-EV consumers relative to 0% EV adoption under Tariff 0 (%)

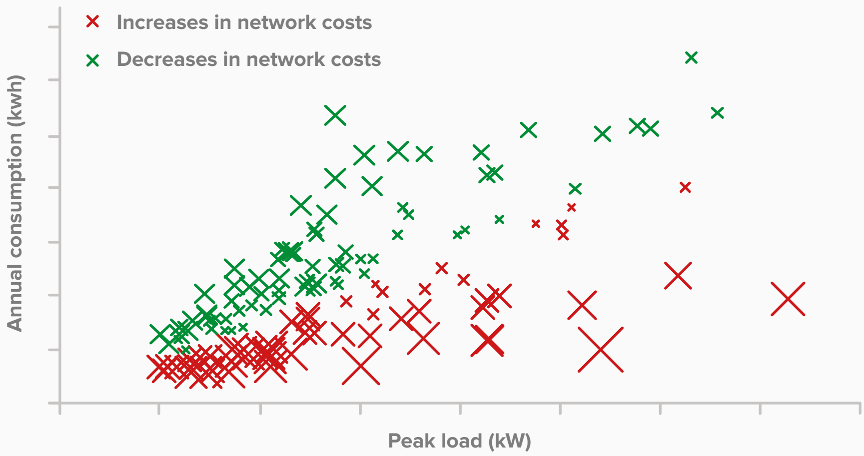


Source: FTI Consulting

BOX 4.4 — Drivers of changes in network costs for non-EV consumers under a capacity tariff (Tariff B)

Figure 4.10 below shows a scatter plot of annual consumption (kWh) against peak load (kW) plotted separately for households where network costs increased or decreased under Tariff B at 0% EV adoption, relative Tariff 0 and 0% of EV adoption. The scatter points are sized according to the absolute size of the change in network costs in € (e.g. a large red scatter point indicates a large increase in electricity costs). The values on the axis have been removed to preserve the anonymity of the data.

FIGURE 4.10 — Annual consumption (kWh) against peak load (kW) by increases and decreases in network costs under Tariff B relative to Tariff 0



Source: FTI Consulting

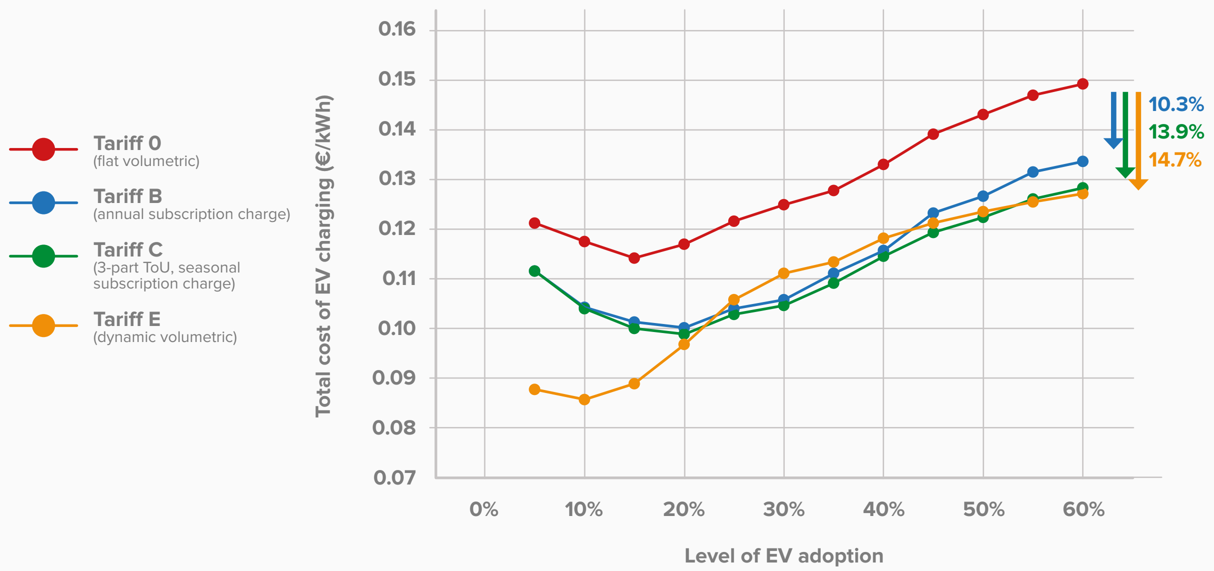
Non-EV consumers with low annual consumption and high annual peaks (those toward the bottom right of the plot) face the greatest absolute changes in network costs from the introduction of Tariff B, as indicated by the size of the crosses. These households use limited electricity throughout the year but display a relatively high power demand when electricity is being consumed.[90] Under Tariff 0, these households contribute relatively little to the recovery of the network revenue requirement, while the network investment to serve the peak demand needs to be incurred, independent of whether the annual consumption is low.

From a purely economic perspective, a capacity-based tariff reflects more accurately the contribution of those households to the required network investment compared to a flat volumetric tariff (Tariff 0). However, the relatively large absolute and relative increases in the annual network charges of some non-EV consumers under more cost-reflective network tariff designs may raise public acceptability and/or fairness concerns. We come back to this concern when describing the roadmap in Section 5.

Cost of EV charging

4.50 Varying network tariff designs may also impact the incentives to increase household electrification – e.g. adopt EVs in this case study. We assess this interaction by examining the average cost of EV charging under each network tariff design at increasing levels of EV adoption. Figure 4.11 below shows the total (network plus energy) cost per kWh of EV charging for EV owners.[91]

FIGURE 4.11 — Average cost of EV charging under each modelled tariff design (€/kWh)



Source: FTI Consulting

90 · These houses could for example be holiday homes.
91 · The cost of charging the EV is calculated as the incremental network and energy costs of a household incurred by adopting an EV divided by EV charging load of that same household.

4.51 Under Tariff 0, the decrease in electricity costs for non-EV consumers (as described in the previous subsection) comes at the expense of a high cost for EV charging, as EV consumers bear a greater share of the network costs. Of all network tariff designs, EV charging costs are highest under Tariff 0, independent of the level of EV adoption.

4.52 Tariffs B and C offer EV consumers a mechanism through which they can reduce their total network costs, i.e. by smoothening their load avoiding high peak load (with the consequence that total network costs reduce as well). Therefore, relative to under Tariff 0, EV charging becomes significantly cheaper under Tariffs B and C. Since the incentive to reduce peak load is more granular under Tariff C, it allows for further peak reduction and slightly cheaper EV charging relative to Tariff B at nearly all levels of EV adoption. As the EV adoption grows, under both Tariff B and C the capacity-based charge(s) (in kW) increase with a growing grid revenue requirement and the cost of EV charging gradually increases as well. However, the reduction in EV charging costs relative to Tariff 0 remains broadly constant.

4.53 Under Tariff E, a large share of network costs is recovered via fixed network charges at low levels of EV adoption (as explained in Appendix 3). Therefore, the incremental electricity cost from charging an EV only represent increases in energy costs; network charges remain approximately the same for all households - with or without an EV. However, as EV adoption increases, so does the number of hours in which the dynamic volumetric portion of Tariff E is high. Some EV consumers therefore charge during the higher priced hours (reflecting the wholesale price plus the dynamic network charge). Despite the lower overall network revenue requirements relative to all other tariffs (due to the lower aggregate peak load – see Figure 4.3), the cost of EV charging under Tariff E becomes gradually more similar to the cost of EV charging under Tariffs B and C as the level of EV adoption grows. At 60% of EV adoption the cost of EV charging under Tariffs B, C and E is 10.3%, 13.9% and 14.7% lower than under Tariff 0, respectively.

INTERACTION OF NETWORK TARIFF DESIGN WITH FLEXIBILITY MARKETS

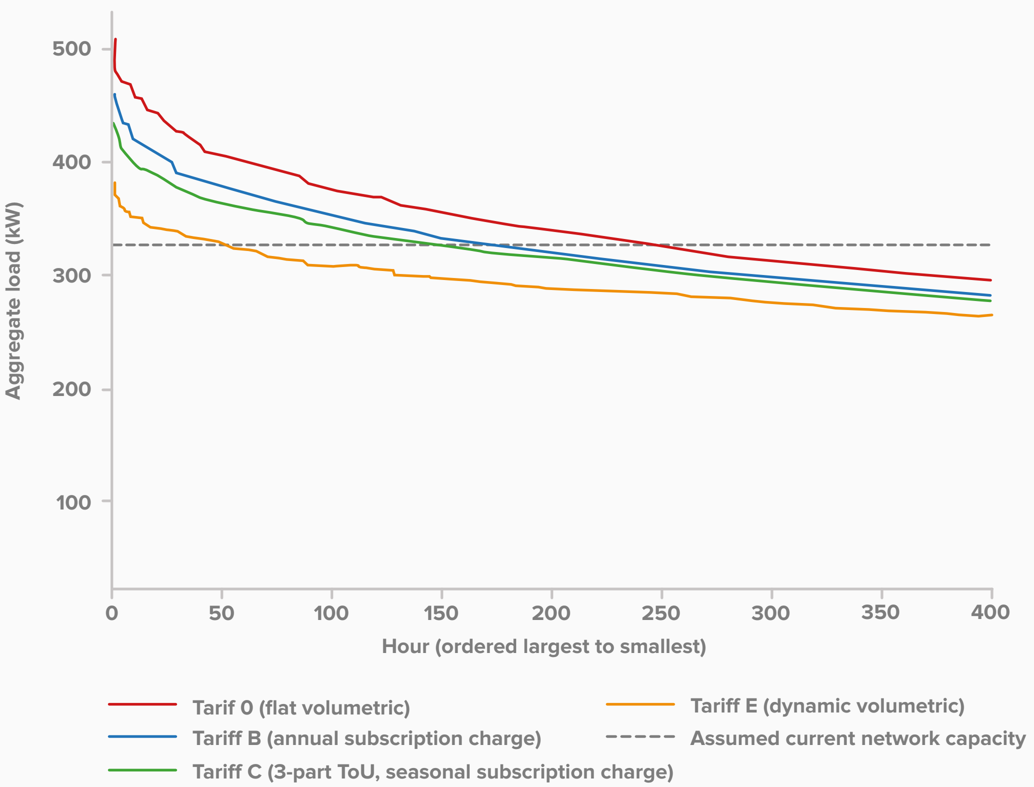
4.54 Our assessment in the previous section has focused on the performance of the network tariff designs in isolation. In reality, a DSO has other tools at its disposal that can be used in conjunction with cost-reflective tariff design. Here we focus on the interaction between network tariff designs and flexibility markets which were introduced in ¶ 1.27.

4.55 As demonstrated in Figure 4.3, a more cost-reflective network tariff design can reduce the aggregate peak load observed on a distribution network, and therefore lower the total required investment to reinforce or expand the network as electrification increases. However, rather than reinforcing the network when the peak load grows, a DSO might also opt to use market-based flexibility tools as an alternative. The latter can be a cost-efficient strategy when the number of hours during which the load is expected to exceed the network capacity is relatively limited. Because local flexibility markets can be more targeted than cost-reflective network tariffs they might be more effective in reducing load in “problematic” hours.[92] Conversely, if the load is expected to frequently exceed the network capacity, it is likely more cost-efficient to reinforce the network rather than incur flexibility market costs.

4.56 To explore how our modelled network tariff designs may work as complements to flexibility markets, we assess the extent to which each modelled tariff design can serve to reduce the total consumption in excess of an assumed maximum network capacity. Figure 4.12 below shows the aggregate load duration curves for the 400 hours with highest consumption at 50% EV adoption under each of the modelled network tariff designs. To illustrate the existing network capacity, we assume a 25% buffer on peak load at 0% EV adoption, as described in ¶ 4.30. The area between a curve and the assumed network capacity represents the total electricity consumption in excess of current network capacity.

92 · In addition, flexibility markets can also be used to procure other services, such as voltage issues, emergency back-up support or supporting network stability when several network elements are under maintenance.

FIGURE 4.12 — Aggregate load duration curves at 50% EV adoption (kW)



Source: FTI Consulting

4.57 As shown above, prior to the use of any local flexibility markets, a more cost-reflective tariff design can reduce total consumption in excess of the network capacity significantly, as represented by the downward shift of the aggregate load curves under Tariffs B, C and E relative to Tariff 0. The total consumption in excess of network capacity for each network tariff design is shown in Table 4.3 below.

TABLE 4.3 — Total consumption in excess of network capacity at 50% EV adoption (kWh)

Network tariff design	Total consumption in excess of network capacity (kWh)
Tariff 0	12,208
Tariff B	6,909
Tariff C	4,727
Tariff E	868

Source: FTI Consulting

4.58 Under Tariff 0, the DSO would have to engage in flexibility markets to target at least 12,208 kWh of electricity consumption to reduce the load in all hours of the year to be within that of the existing network capacity. The volume of required market-based flexibility can be reduced by 43% and 61% under Tariffs B and C respectively. Under Tariff E, the volume is reduced by 93%.

4.59 Considering the high volume of required market-based flexibility under Tariff 0, a DSO may conclude that it is more cost-effective to reinforce the network instead of engaging in flexibility markets. However, under Tariff B, C and especially E, a DSO is more likely to conclude that engaging in flexibility markets is a feasible and cost-effective solution. Cost-reflective network tariff design can therefore work as a complement to flexibility markets, i.e. a combination of cost-reflective network tariffs and a local flexibility markets has the potential to lead to the most cost-optimal solution.

D. Result summary, model limitations and next steps

4.60 In this last subsection of the quantitative analysis, we first provide an overall assessment of the different modelled network tariff designs against the key assessment criteria. We also discuss the model limitations and potential next steps.

OVERALL ASSESSMENT OF THE PERFORMANCE OF EACH TARIFF AGAINST THE KEY PERFORMANCE METRICS

4.61 Figure 4.13 below shows the performance of each network tariff against three key assessment metrics (total electricity costs; costs of EV charging and distributional impacts on non-EV owners), at 5%, 20%, and 40% EV adoption. For any given performance metric, the further out to the edge of the circle a tariff sits, the better its relative performance. All other tariffs are plotted relative to the best performing tariff.[93]

4.62 The results in Figure 4.13 illustrate our **two key findings:**

— There is no single 'best' network tariff. Rather, there are trade-offs between the total costs of meeting electricity demand, distributional impacts and incentives for electrification.

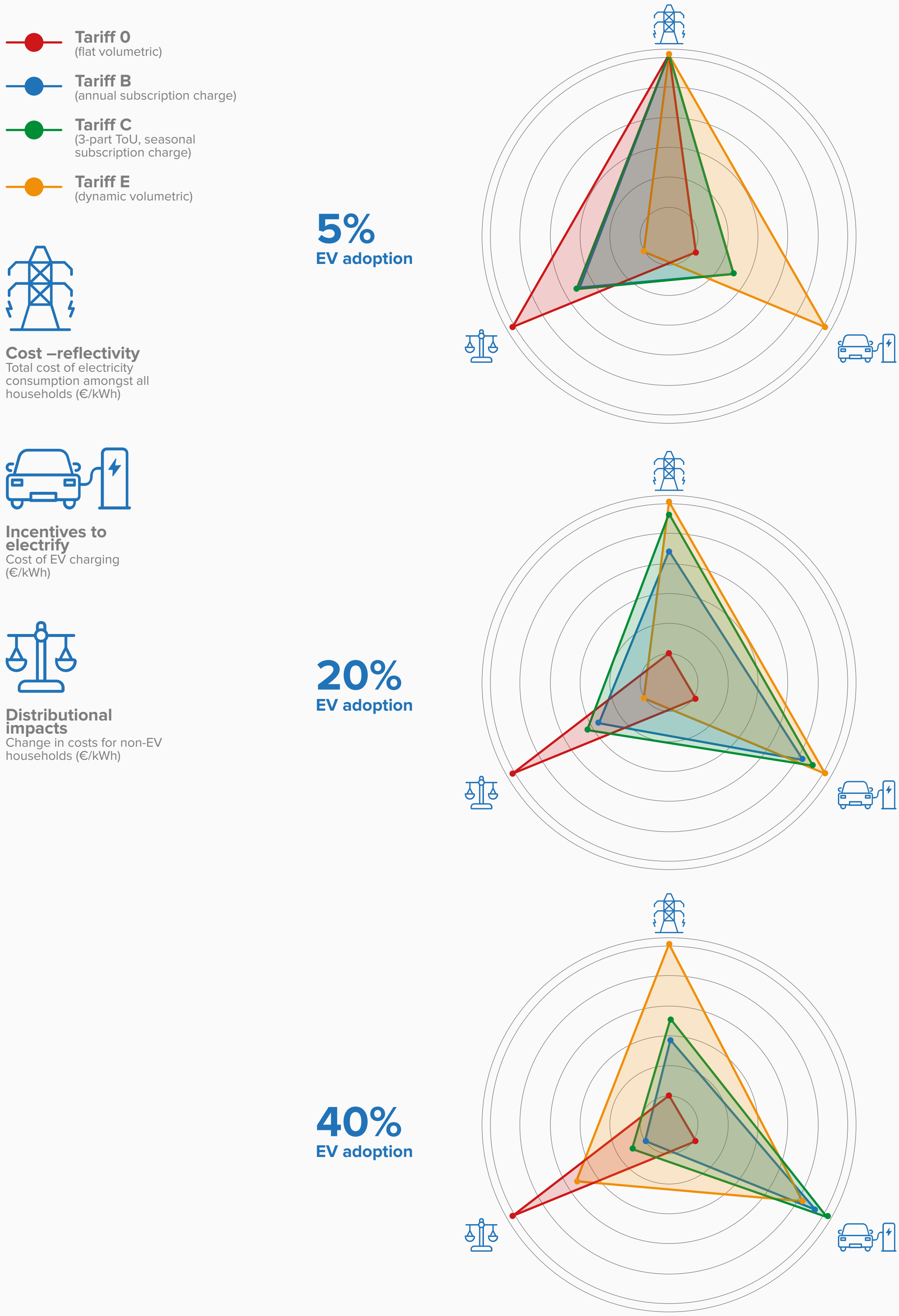
— The trade-offs between tariffs change as the adoption of EV increases, so policymakers in different regions and/or at different times may face different choices.

4.63 Specifically, we find that the simplest tariff (Tariff 0) discourages further electrification at all levels of EV penetration (compared to other tariffs) and also leads to unnecessarily high electricity costs; however, it performs consistently the best on the distributional impacts, by limiting adverse impacts on non-EV owners (essentially by EV owners cross-subsidising non-EV owners). More cost-reflective tariffs (B, C and E) lead to a complex set of trade-offs for policymakers, as they need to consider the extent to which they wish to (1) accelerate electrification; (2) mitigate total electricity costs to consumers; and (3) manage distributional consequences of the tariff design choice, with different choices available at different levels of electrification.

4.64 With higher levels of electrification, the most cost-reflective tariff (Tariff E) performs relatively well on all three assessment criteria, and the case for a highly cost-reflective network tariffs substantially strengthens. However, its attributes are not necessarily attractive at lower levels of electrification, indicating that there may be merit in sequencing the introduction of progressively more cost-reflective network tariffs as electrification increases.

93 · For example, if Tariff E is the best performing tariff in terms of total cost of electricity consumption it will be plotted at the edge of the circle. If Tariff C is 30% more expensive, it sits 30% closer to the centre of the circle.

FIGURE 4.13 — Relative performance of modelled tariffs at 5%, 20%, and 40% EV adoption. For any given performance metric, the further out to the edge of the circle a tariff sits, the better its performance.



Source: FTI Consulting

Low levels of electrification (<5%)

4.65 When the **adoption of EVs is limited** (e.g. at 5% of adoption in Figure 4.13), the urgency to make the network tariff design more cost-reflective to mitigate increases in network investment and overall consumer costs is still relatively limited and all tariffs deliver **similar outcomes in terms of total cost of electricity consumption.**

4.66 However, if policy makers wish to remove obstacles for further electrification (i.e. increased EV adoption), they could achieve this by introducing a more cost-reflective network tariff design (B, C or E).[94] Concretely, at 5% of EV adoption the cost of EV charging is found to be c.8% cheaper under Tariffs B and C, and 27% cheaper under Tariff E, relative to Tariff 0 (see Figure 4.11). Other things being equal, a decrease in EV charging costs would help accelerate the uptake of EVs.

4.67 If distributional impacts are the primary concern of policymakers, they would likely prefer Tariff 0 at this low level of EV adoption. This is because, on average non-EV consumers are better off under Tariff 0 relative to the other modelled tariffs, with some non-EV consumers seeing large increases in their bills due to the implementation of more cost-reflective network tariffs. As discussed in ¶ 4.51, this is at the expense of increased costs for EV owners.[95]

Modest levels of electrification (5-20%)

4.68 As the **adoption of EVs increases** (e.g. from 5% up to 20% of adoption as shown in Figure 4.13), more cost-reflective tariff designs also (in addition to encouraging further electrification) perform better than Tariff 0 in terms of cost efficiency. Indeed, as shown in Figure 4.6, at that point, the total cost of electricity starts to gradually diverge when comparing Tariff 0 with the more cost-reflective tariffs (Tariff B and C) with average savings on total electricity bills of 1.1% and 1.5% respectively. Additionally, the cost of EV charging is significantly reduced under Tariffs B and C relative to Tariff 0, with the annual cost of charging the average EV 14% and 16% cheaper at 20% EV adoption respectively.

4.69 Tariff E would provide directionally similar incentives to Tariffs B and C but with more extreme implications for all three metrics (i.e. even stronger incentives for electrification and higher cost efficiency, but worse outcomes for non-EV consumers). We expect that policy makers would likely wish to take into account the complexity and the potentially challenging distributional impacts of Tariff E. As such, Tariffs B or C could be seen as a reasonable 'compromise' or a 'stepping stone' as EV adoption starts taking off. The relative benefits of **Tariffs B and C** depend on the exact calibration of the two tariffs.[96,97]

4.70 Whilst EV penetration in many EU Member States is currently still relatively modest on a country-level scale, EV adoption is expected to grow significantly and can be concentrated in wealthier regions or neighbourhoods. As the regulatory process of revising network tariffs can be cumbersome (i.e. it typically takes several years to design and implement a new network tariff), it could be advisable in EU Member States where EV adoption is expected to accelerate to forward-plan and consider tariff designs that perform best at medium to high levels of electrification, even if they only see low to medium levels today. We discuss the concept of 'leapfrogging' tariff design in Section 5.

94 · However, there can be other reasons than increasing electrification to revise the network tariff design, e.g. cross-subsidies between consumer with photovoltaics (PV) and consumers without PV under Tariff 0.

95 · An alternative network tariff design enabling EV charging costs while potentially limiting distributional impacts would be Tariff A (ToU volumetric network tariffs) which we qualitatively assess in Section 3 but have not modelled in this section. The exact distributional impacts of Tariff A would need to be empirically assessed in more detail.

96 · Here we did not investigate how to further revise the ToU periods of Tariff C as EV adoption increases which would likely lead to a large difference in terms of cost-reflectiveness between Tariff B and C.

97 · Tariff D (ToU volumetric combined with ToU capacity-based network tariffs), which is not modelled here but qualitative assessed in Section 3, could be considered as alternative to Tariffs B and C as it provides more granular volumetric signals in how better to spread demand within time blocks of a ToU capacity charge. We would, however, need to empirically test this.

Medium levels of electrification (20-40%)

4.71 At **higher levels of EV adoption** (e.g. from 20% up to 40% of adoption as shown in Figure 4.13), the case for highly cost-reflective network tariffs such as Tariff E gradually increases. Not only does a more cost-reflective network tariff reduce total electricity costs (savings of 3.6% under Tariff E relative to Tariff 0 at 40% of EV adoption – see Figure 4.6), but our modelling shows that the negative distributional impacts for non-EV consumers (present at lower EV penetration levels) are reduced and become much more modest, with an average increase in total annual electricity costs of 6% (relative to 0% EV adoption under Tariff 0). Under less cost-reflective network tariffs (e.g. Tariff B and C), increases in the aggregate network peak are hard to mitigate and the incremental costs for the required network investments are increasingly – as the level of EV adoption grows – shifted onto non-EV consumers, with increases in the average annual electricity costs of 10-11% (relative to 0% EV adoption under Tariff 0), leading to challenging distributional impacts. Further, the cost of EV charging is 11% cheaper under Tariff E relative to Tariff 0 at 40% EV adoption.

4.72 We recognise that Tariff E retains some (albeit much more modest) adverse distributional impacts even under 40% EV penetration.[98] If this was a significant concern for policy maker (despite the strong attractiveness of Tariff E on other metrics), this could potentially be addressed by introducing non-uniform fixed charges to recover the residual costs with lower fixed charges levied from smaller households (as discussed in ¶ 2.23. Alternatively, policy levers (e.g. direct subsidies to vulnerable households), external to the tariff design, can be used.

High levels of electrification (40%+)

4.73 At high levels of electrification (e.g. beyond 40% of EV adoption) we see the energy costs gradually increase under Tariff E relative to the other tariffs (see Figure 4.5). It becomes increasingly difficult for the DSO (setting the dynamic network tariffs) to forecast the reaction of the aggregate flexible load. Mistakes in the forecasting of the aggregate load would lead to ill-calibrated dynamic network tariffs which eventually would reduce the cost-reflectiveness of this network tariff design. As well, the interaction between flexible load and wholesale price formation becomes more important, i.e. large volumes of flexible load shifting to hours with low wholesale prices will increasingly impact the wholesale prices.

4.74 At that stage of electrification, it would likely be necessary to examine more advanced network tariff designs in order to identify ones that could further optimise the trade-off between leveraging flexibility and network costs increases. Examples of such tariffs include dynamic volumetric network tariffs complemented with capacity-based charges (Option F) or local capacity auctions (Option G) which are both qualitatively assessed in Section 3 but have not been modelled. Alternatively, closer to real-time load forecasts, rather than day-ahead load forecasts, can inform help to further improve the cost-reflectiveness of dynamic network charges. Ultimately, DLMP can be considered if the implementation challenges discussed in ¶ 3.63 could be overcome.

LIMITATIONS AND NEXT STEPS

4.75 The quantitative assessment performed in this report relies on several key assumptions. In this section, we discuss the three main limitations of the quantitative part of this study: the technology modelled, the dataset, and the assumption around wholesale energy prices.

4.76 First, in this study we chose to focus on EV adoption as an example of increasing electrification and the impacts on distribution networks. As explained in ¶ 4.2, we chose EVs because:

— EV charging represents a material and growing form of flexible load;
— It is relatively easy to isolate from other household load given the data available to us; and
— It represents a particularly flexible source of load, and therefore contributes significantly to aggregate peaks on the network.

98 · We recognise that users of other flexible electric technologies not modelled as part of this study, such as storage heaters, could benefit in the same way as EV consumers from cost-reflective network tariff design. We discuss the limitations and next steps in the next sub-section.

4.77 In reality, many households who adopt EVs may also adopt other flexible (and price-responsive) electric load with different consumption characteristics to EVs, such as heat pumps or electric water boilers, which could further add to the benefits case of more cost-reflective network tariff designs. In practice, therefore, the impact of any given form of cost-reflective network tariff would need to consider consumers with a wider range of other electricity production, storage and consumption assets. A potential extension to this study would therefore be to consider increasing EV adoption alongside the adoption of other technologies, like the ones described above, to better approximate the real-world impact of network tariff design.

4.78 When adopting stationary batteries and solar panels (or engaging in vehicle-to-grid), consumers would also inject electricity into the network which is not considered here. An additional advantage of Tariff E relative to Tariff B and C is that it can be designed symmetrically, i.e. paying consumers injecting into the network during times of high local demand the same as other consumers pay to withdraw from the network at the same moment (and vice versa in case network peaks would be driven by consumer injections). While the potential of a symmetric network tariff design to reduce network costs (relative to a non-symmetric network tariff design) is evident, its quantification merits further examination.

4.79 Second, as explained in Appendix 2, our model has been calibrated using data on English households from two Octopus Energy tariffs (this has been a function of the data made available to us by smartEn members). In England, peak inelastic usage of electricity occurs during winter evenings while the highest EV charging requirements also occur in winter. This combination makes England a challenging case study as coincident peaks in the winter can be increased by both EV charging demand and other electric demand. Based on the weather profiles, similar results can be expected for other North-West European countries though this would need to be tested. By contrast, a case study considering another geography with different consumption patterns (e.g. Southern Europe), potentially with peak electricity demand occurring in the summer (driven by air conditioning demand) could lead to different quantitative results.

4.80 Third, we have not modelled the feedback loop between changes in EV charging schedules and wholesale price formation. Instead, we have considered wholesale energy prices to be fully exogeneous with respect to the EV charging behaviour. This assumption is reasonable and appropriate when EV charging load only represents a small fraction of the total load active in electricity wholesale markets.[99] With higher levels of EV penetration, the volume of price-responsive EV charging (responding to both wholesale and network cost element) would likely lead to a more endogenous price formation: as EV charging shifts over periods of time, periods with an increased demand would see increased wholesale prices (and vice versa for period with reduced demand).

4.81 Modelling the feedback loop between changes in EV charging schedules and wholesale prices would, in turn, likely have an impact on the relative comparison among the different tariff designs. For example, if this feedback loop was modelled, the very low wholesale prices during which, especially under Tariff 0, high volumes of charging would occur, would likely increase due to the higher demand. In that regard, the modelled increase in average energy wholesale costs under the more cost-reflective network tariffs relative to Tariff 0 (see Figure 4.6) is expected to be less pronounced in practice. This would, potentially, make the more cost-reflective network tariff designs more attractive compared to Tariff 0 than we found in this report.

4.82 As discussed in Box 4.3, the magnitude and volatility of the energy wholesale prices chosen to calibrate the model will also impact the quantitative results and using a different base period (whether past or modelled future) would also lead to different quantified results. However, we expect that the qualitative findings on the relative merits of cost reflective tariffs would remain broadly similar.

99 · Particularly under a national wholesale market design as is in place in most EU countries and Great Britain (i.e. with no locationally differentiate wholesale prices within a country), concentrated EV adoption in some neighbourhoods (whilst adoption at the country level remains low) is unlikely to impact the national wholesale price.

5

A roadmap of EU network tariff design

A. Introduction

5.1 In this section we describe a **roadmap** of how network tariff design can evolve from flat volumetric network tariffs to gradually more cost-reflective network tariff designs as electrification progresses. With regards to distribution network tariffs for households, some EU Member States are currently still at the initial step of this road map (e.g. Germany and Hungary) while other Member States are already a few steps ahead (e.g. Spain and Slovenia).

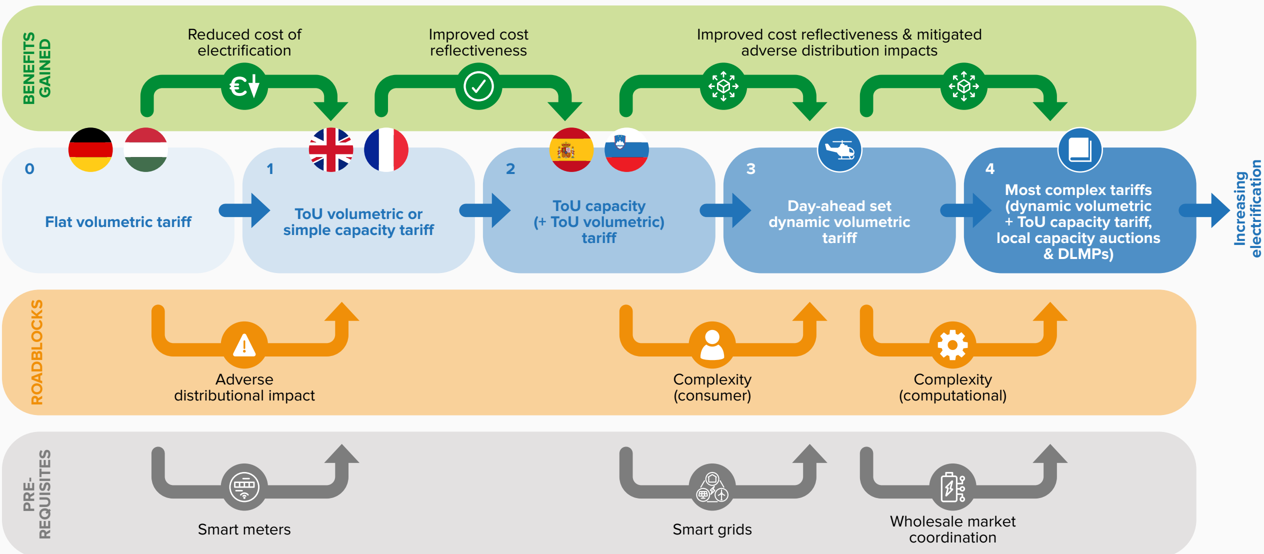
5.2 The pace at which EU Member States would choose to follow this trajectory towards a more cost-reflective network tariff design will depend on the local context, especially the extent to which networks have been overbuilt in the past and the expected speed of future electrification.

5.3 We do not necessarily recommend following the roadmap step-by-step. There can be valid arguments to leapfrog several steps if the circumstances of a particular Member State indicate that they would benefit from "jumping" straight to a more cost-reflective design or if the governance processes to redesign network tariffs are deemed particularly cumbersome. With regards to the latter, as a process to redesign the distribution network tariff design can take several years, any assessment of candidate network tariffs should be done in a forward-looking context. Considering the anticipated speed of electrification, the context at the start of the network redesign process can be radically different from the context when the revised network tariff design is eventually introduced.

5.4 In this report we focused on distribution network tariffs but the key principles for network tariff design apply equally to transmission networks. As described in Section 2 of this report, truly cost-reflective network tariffs are highly temporally and spatially granular which can create challenges with regards to simplicity and predictability. In that regard, subjecting high-voltage grid users to more complex network tariffs has typically been more acceptable than exposing low-voltage grid users to the same network tariff design. Hence, everything else equal, a transmission network tariff design can potentially be a few steps ahead of a distribution network tariff design.

5.5 We illustrate the roadmap of EU network tariff design in Figure 5.1 below. In what follows we discuss the different steps of the roadmap and end with summarising remarks.

FIGURE 5.1 — Roadmap of EU network tariff design



Source: FTI Consulting

Notes: (1) The pace at which EU Member States would choose to follow this trajectory towards a more cost-reflective network tariff design will depend on the local context; (2) We do not necessarily recommend following the roadmap step-by-step. There can be valid arguments to leapfrog several steps; (3) The country flags indicate examples of countries that currently have the described distribution network tariff in place for households.

B. Step 0 – Flat volumetric network tariffs

5.6 **The roadmap starts with flat volumetric network charges (in €/kWh)** which are currently still in place for an important share of household consumers in the EU (e.g. Germany and Hungary). Flat volumetric network tariffs are not cost reflective as they are disconnected from the underlying drivers of the costs that these charges seek to recover. The need for network investment, and in turn the level of network charges borne by consumers in the longer run, is mostly driven by growth in the aggregate peak electricity demand of all grid users connected to the network, as opposed to the total volume of electricity demand over a period of time.

C. Step 1 – ToU volumetric and individual capacity-based network tariffs

5.7 At relatively low levels of electrification, the main driver to move towards a more cost-reflective network tariff design is removing the tax on electrification that comes with flat volumetric network charges. **A first step forward** from flat volumetric network tariffs can be to make the network tariffs time-varying, i.e. **ToU volumetric network tariffs** (as currently in place in Great Britain), or to introduce **capacity-based network tariffs based on individual peak usage (in €/kW)** (as currently in place in Flanders, Belgium or France). These network tariff designs, while remaining relatively simple, are more cost-reflective and can lead to important reductions in the personal cost of EV charging. However, there are several challenges to implementing these tariffs:

— First, a key pre-requisite to effectively implement these network tariff designs is the installation of a smart meter. This may not be available in all EU Member States, or their penetration may not be sufficient.

— Second, a potential roadblock when transitioning to these network tariff designs can be concerns around their distributional impacts. This is because significant cost shifts between consumers can take place, particularly under capacity-based network tariffs: low-consumption households with a relatively high peak usage will see an increase in their network charges while high-volume households will typically see a reduction in their network charges (see Box 4.4 in Section 4). Such cost shifts might lead to public acceptability issues and political backlash that would need to be carefully considered (and potentially manged) by the regulator and/or relevant policymakers.

D. Step 2 – ToU capacity-based network tariffs (+ ToU volumetric network tariffs)

5.8 ToU volumetric network tariffs and capacity-based network tariffs based on individual peak usage remain only crude proxies for the network cost driver, i.e. the aggregate peak consumption. As electrification further progresses, it may be appropriate to transition to more advanced cost-reflective network tariff designs. A second step forward involves a transition towards **ToU capacity-based network tariffs** or **ToU capacity-based network tariffs combined with ToU volumetric network tariffs,** as currently in place in Spain and Slovenia.

5.9 The exact implementation of these network tariff designs can be tailored to the local context as there are many degrees of freedom in their design (see Section 3.B). However, the persistent issue with the capacity-based tariffs being non-symmetric remains. An important choice in that regard is between capacity charges based on observed peak usage versus capacity charges based on the levels of ex-ante precontracted peak usage in certain time windows.

5.10 We do not see any significant challenges in moving from the first step to the second step, as there are no additional pre-requisites for practical implementation. Moreover, the incremental distributional impacts are expected to be relatively limited (see the quantitative analysis in Section 4). Considering how long a network tariff redesign process can take, for EU Member States that are currently still at the initial step of the roadmap and where electrification has started to accelerate, it could be appropriate to consider an option to "leapfrog" directly from flat volumetric tariffs to the network tariff designs proposed in this step (or the next).

E. Step 3 – Day-ahead determined dynamic volumetric network tariffs

5.11 As electrification further evolves, the network tariff designs described in step two would no longer suffice to mitigate increases in aggregate peak loads. Our quantitative analysis has shown that at that point due to (1) the rising network revenue requirement; and (2) network tariffs not precisely allocating the incremental network costs to the consumers causing them, the network cost burden for non-electrifying households gradually rises. At this point, not only cost-reflectiveness but also distributional impacts (which initially were a blocking factor to move from the initial step to the first step) become an important driver to move to the next step in the roadmap.

5.12 In this context, a third step forward constitutes a transition towards **dynamic volumetric network tariffs** (as currently being tested out in several pilots across Europe, see e.g. Box 3.2). A potential implementation of a dynamic volumetric network tariff design is network charges that change from hour to hour reflecting expected local network conditions forecasted day-ahead stage. Higher charges are introduced when network is anticipated to potentially be congested and, vice versa network charges are very low in hours that the network is expected to be idle. These dynamic volumetric network charges can also be symmetric, i.e., consumers injecting electricity in the network when the network is stressed receive the same charge consumers pay when withdrawing electricity during the same timestep. The introduction of dynamic volumetric network tariffs would face several challenges:

— First, while DSOs typically already have monitoring in place at some level of their network (e.g. primary substation or the grid supply point between the transmission and distribution system), dynamic network charges could require more sophistication in terms of monitoring than what currently is in place. The sophistication of local DSOs and/or the required investement in hardware and software would therefore be an important factor in assessing the feasibility of these tariffs.

— Second, the significant increase in complexity under dynamic network charges could potentially raise social acceptability issues (e.g. whether consumers are able to engage with these tariffs in an effective manner). However, such concerns can be mitigated by transferring the complexity from the consumer to a retailer and/or making these network tariffs initially available as an option consumers can opt-in (as discussed in Section 3.E in this report).

F. Step 4 – Most complex network tariffs (advanced dynamic volumetric tariffs, capacity auctions & DLMP)

5.13 At very high levels of electrification, it becomes increasingly difficult to forecast the reaction of the aggregate flexible load to the signals provided by network tariffs. Difficulties with load forecasting could lead to pricing issues that overly (and inefficiently) steer consumers away from the lowest wholesale energy prices (due to the desire to avoid consuming during periods of a local peak load). As explained in ¶ 4.73, at that stage of electrification, it would likely be necessary to examine more advanced network tariff designs.

5.14 A **fourth step** forward involves a transition towards **dynamic volumetric network tariffs combined with capacity-based charges or local capacity auctions.** Alternatively, closer to **real-time load forecasts** can help to further improve the cost-reflectiveness of dynamic network charges. Ultimately, those network tariff designs are expected to gradually converge to the theoretical first-best approach of DLMP. Under DLPM network constraints and consumers' withdrawal/injection schedules are internalised in the wholesale energy market clearing. This implies that energy prices can differ per distribution node. In that regard, an additional pre-requisite is the coordination between the wholesale electricity market and distribution network pricing which be computationally complex (see ¶ 3.63). The network tariff designs described in this step 4 are currently in the early R&D phase or only exist as academic concepts.

G. Summarising remarks

5.15 The merits of different network tariff designs are **highly context-dependent** and there is no one-size-fits-all. The roadmap presented above sets out a potential way for different jurisdictions to consider implementing progressively more cost-reflective tariffs, driven by their local circumstances. There are specific challenges in moving across the different steps, as described above, and these need to be considered by policymakers.

5.16 This roadmap is **not necessarily intended to be a step-by-step guidance** on the tariff design, and in all cases a tailored assessment of the local consumption patterns and behaviours would be necessary to (1) identify how any given network tariff is likely to perform; and to (2) calibrate the specific design of any given tariff to achieve desired cost efficiency, distributional and incentive properties.

5.17 Other mechanisms to unlock consumer flexibility for grid purposes such as **local flexibility markets** and **smart connection agreements** are complements to network tariff designs. As described and quantified in Section 4, where cost-reflective network tariff reduces the total number of hours in excess of network capacity, other mechanisms can be more targeted.

5.18 With more advanced network tariff designs the boundaries between these different mechanisms to unlock local flexibility eventually blur. For example, ex-ante subscribed network tariffs can be seen a simple implementation of smart connection agreements. Both limit the capacity usage of a consumer under the physically installed connection capacity. Similarly, highly temporal and granular dynamic network tariffs or local capacity auctions can be derived from or integrated into flexibility markets.

Appendix

1

Relevant EU Regulation on cost-reflective network tariffs

smartEn SMART ENERGY EUROPE | FTI CONSULTING

A1.1 The most relevant paragraph with regard to cost-reflective distribution network tariff design is Article 18 of Regulation (EU) 2019/943 stating that:

— *Charges applied by network operators for access to networks, including charges for connection to the networks, charges for use of networks, and, where applicable, charges for related network reinforcements, shall be **cost-reflective,** transparent, take into account the need for network security and flexibility and **reflect actual costs incurred insofar as they correspond to those of an efficient and structurally comparable network operator** and are applied in a non-discriminatory manner. Those charges shall not include unrelated costs supporting unrelated policy objectives. [..] the method used to determine the network charges shall neutrally support overall system efficiency over the long run through price signals to customers and producers and in particular be applied in a way which does not discriminate positively or negatively between production connected at the distribution level and production connected at the transmission level. The network charges shall not discriminate either positively or negatively against energy storage or aggregation and shall not create disincentives for self-generation, self-consumption or for participation in demand response. Without prejudice to paragraph 3 of this Article, those charges shall not be distance-related.*

— ***Tariff methodologies shall reflect the fixed costs of transmission system operators and distribution system operators** and shall provide appropriate incentives to transmission system operators and distribution system operators over both the short and long run, in order to increase efficiencies, including energy efficiency, to foster market integration and security of supply, to support efficient investments, to support related research activities, and to facilitate innovation in interest of consumers in areas such as digitalisation, flexibility services and interconnection.*

— *Where appropriate, the level of the tariffs applied to producers or final customers, or both shall provide **locational signals** at Union level, and take into **account the amount of network losses and congestion caused, and investment costs for infrastructure.***

— *[..]*

— *Distribution tariffs shall be **cost-reflective** taking into account the use of the distribution network by system users including active customers. Distribution tariffs **may contain network connection capacity elements and may be differentiated based on system users' consumption or generation profiles.** Where Member States have implemented the deployment of smart metering systems, regulatory authorities shall **consider time-differentiated network tariffs** when fixing or approving transmission tariffs and distribution tariffs or their methodologies in accordance with Article 59 of (EU) 2019/944 and, where appropriate, time-differentiated network tariffs may be introduced to **reflect the use of the network,** in a transparent, cost efficient and foreseeable way for the final customer.*

A1.2 The recently adopted Regulation (EU) 2024/1747 includes the following sentences in recital 23 related to network tariff design:

— *"To that end, **network tariffs should be designed to take into account the operational and capital expenditures of system operators** or an efficient combination of both so that they can operate the electricity system cost-efficiently. The requirement for cost-reflectiveness should not restrict the opportunity to redistribute costs efficiently where locational- or time-variant network charges are applied. This would further contribute to integrating energy from renewable sources at the least cost for the electricity system and enable final customers to value their flexibility solutions."*

Appendix

2

Input data and calibration of the model

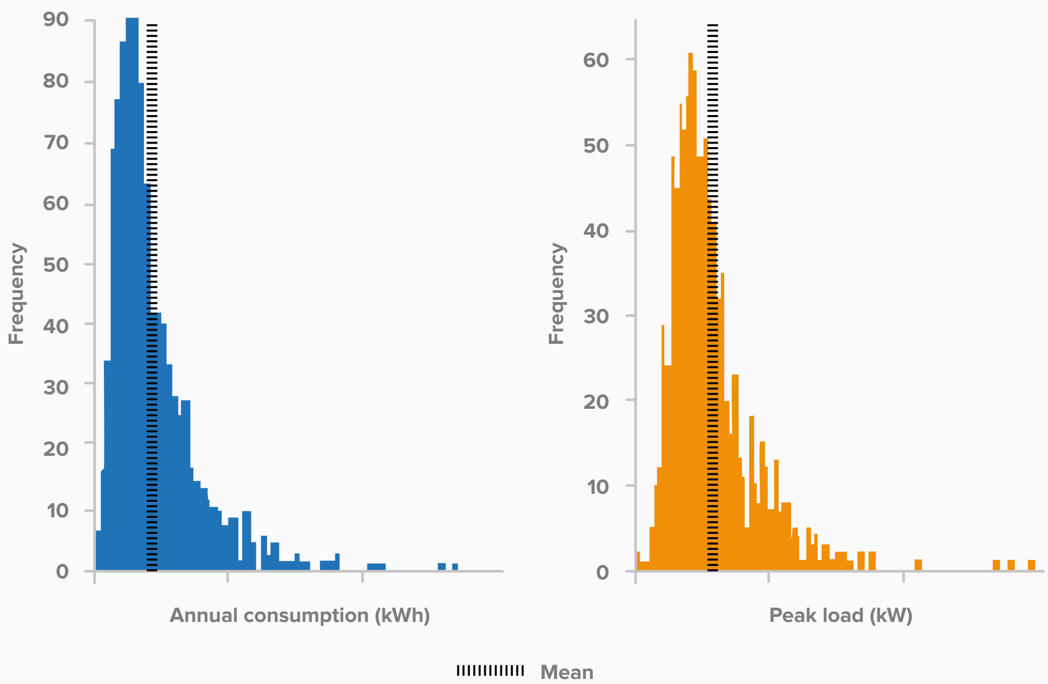
A2.1 We calibrate our model using anonymised data provided by Octopus Energy ("Octopus") for the year 2023.[100] These data consist of: (1) half-hourly consumption data of households without EVs, and; (2) half-hourly consumption data of anonymised households with EVs associated with specific EV charging related data. In this sub-section we first describe the data provided by Octopus and then explain how we use this data to calibrate the model.

INPUT DATA

A2.2 Octopus provided half-hourly meter readings for a sample of 1,000 rural English consumers on their standard variable tariff ("SVT").[101] Consumers on the SVT are subject to a flat energy and network price and therefore are unable to reduce their energy bill by shifting their consumption over different periods.[102] Based on their consumption profile, we assume these consumers do not own EVs.[103]

A2.3 Figure A2-1 below shows histograms of the total annual consumption and annual peak hourly load of the 1,000 non-EV consumers in the rural sample.[104] As expected, we see the annual consumption and peak load of most consumers concentrated around the mean, with the frequency of consumers decreasing as the distance from the mean increases. There are some outliers with a very high annual load and/or peak load.[105]

FIGURE A2.1 — Histograms of total annual consumption (kWh) and peak load (kW) for sample of 1,000 rural non-EV consumers



Source: FTI Consulting

100 · We have agreed with smartEn members that this data is appropriate for this study. No other data was made available to us to perform this analysis, though we recognise that information from other countries, types of customers or years could lead to different results.

101 · Consumers are sampled from the same or neighbouring postcodes in England.

102 · The price consumers pay may change periodically with notice.

103 · Octopus also provided a sample 1000 urban consumers on the same tariff. We opted to use the rural dataset because we have identified potential penetration of EVs and/or other flexible technologies amongst the sample of urban consumers.

104 · Values on the x-axis have been removed to preserve the anonymity of the data.

105 · When mapping the annual consumption on the peak load we see that some consumers in the sample display the characteristics consistent with a holiday home. These consumers spend a small proportion of the year in the property but consume a large amount of electricity when present which leads to a low annual consumption but an average or higher-than-average peak load.

A2.4 Octopus also provided a sample of 500 rural consumers with an EV on the Intelligent Octopus Go ("IOG") tariff. We understand that Octopus takes direct control of the at-home EV charger of the consumers on IOG. Subject to conditions set by the consumer, Octopus optimises the EV charging schedule in response to the day-ahead wholesale price plus the remaining components of the consumer's tariff (network tariff, levies and VAT).[106]

A2.5 For the full calendar year 2023, for each EV consumer, Octopus has provided:

— Half-hourly meter readings;

— The plug-in and plug-out times for each EV charging cycle during 2023;[107]

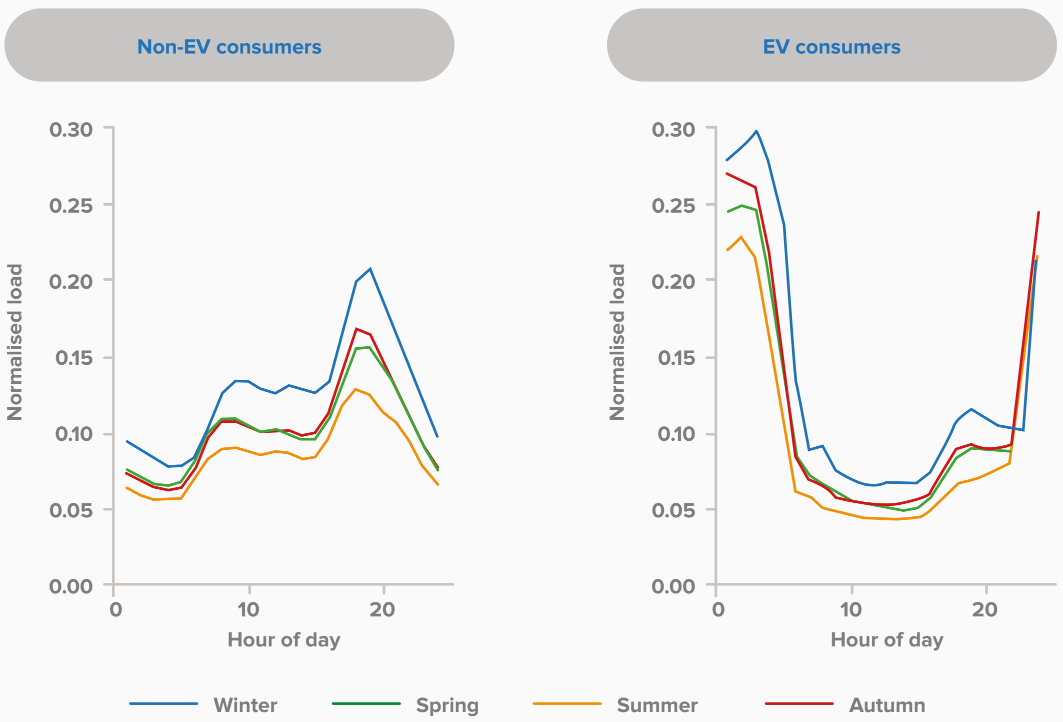
— The state of charge of the EV battery ("SoC") at the plug-in/out and plug-out time per charging cycle;

— The EV battery capacity; and

— The maximum import power of the consumers at-home EV charger.

A2.6 Comparing the EV and non-EV consumers, we see stark differences in their hourly load profiles. Figure A2-2 below shows the average normalised load profile for the samples of non-EV and EV consumers, separately by season. The average normalised load profiles are calculated by dividing the hourly load of each consumer by their individual annual peak load, and then taking a simple average across all consumers for each hour in the day.

FIGURE A2.2 — Average normalised load by hour day, non-EV and EV consumers



Source: FTI Consulting

106 · Levies and VAT are assumed to be constant and therefore do not impact EV charging schedules. There is some temporal granularity in GB network charges with red, amber and green pricing periods (where volumetric network costs are higher in periods of high demand such as weekday evenings). However, periods of high network costs generally coincide with high wholesale energy costs and vice versa, and therefore the wholesale energy impact dominates EV consumers responses.

107 · For the purpose of this analysis, we filter out charging cycles that have taken place away from home (e.g. EV charging at motorway service stations).

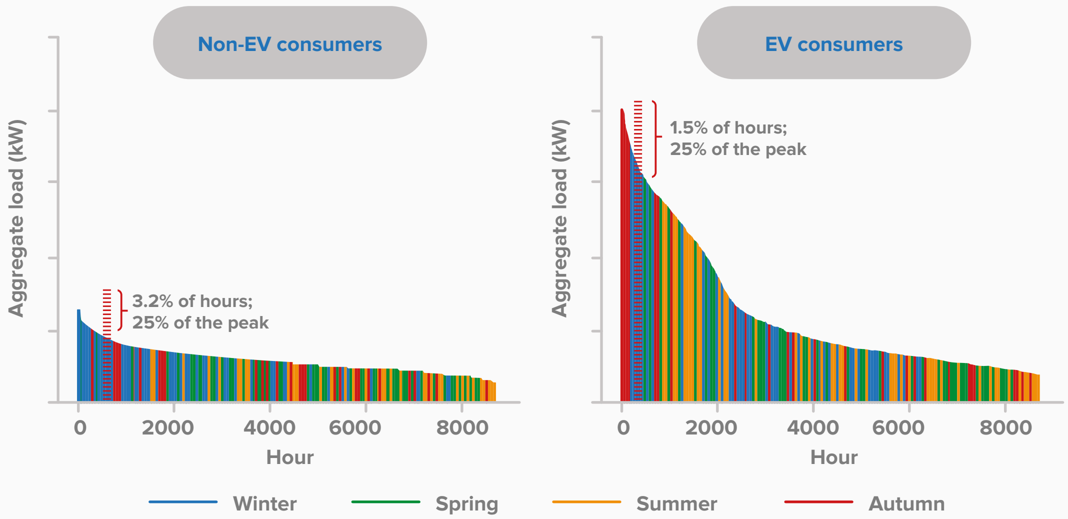
A2.7 For the non-EV consumers, the shape of the hourly load profile appears consistent with expectations. Consumers begin to ramp up consumption around 7am and evening peaks occur between 4 and 7pm. This pattern holds across seasons but, as expected, peak consumption is highest in the winter evenings when English consumers are likely to consume more energy to heat and lighten up their homes.

A2.8 For the EV consumers this shape of the hourly load profile looks very different from the non-EV consumers. Specifically, we see large peaks in the hourly load in the early hours of the morning. During those morning hours EV consumers are simultaneously targeting the (typically) low wholesale electricity price hours to charge their EVs. **The observed consumption pattern illustrates the risk that distribution networks are facing** when: (1) electrification increases over time, and; (2) the dynamic wholesale electricity price, based on which the EV charging scheduling is optimised, is not complemented with a more cost-reflective distribution network tariff design. We explore this further in Box A2-1 below.

BOX A2.1 — regate load duration curves of non-EV and EV consumers

Figure A2.3 below shows the aggregate load duration curve for 300 non-EV consumers and 300 EV consumers. The aggregate load duration curves plot the aggregate load in each hour of the year in descending order. The y-axis scales on both charts are identical, allowing for direct comparability.

FIGURE A2.3 — Aggregate load duration curves for 300 non-EV and 300 EV consumers (kW)



Consistent with A2.2, both EV and non-EV consumers display the largest aggregate load hours in the winter. The EV consumers, however, display a significantly peakier load-duration curve, most likely due to simultaneous targeting of the cheapest wholesale hours during EV charging.[108] For the EV consumers, only 1.5% of the hours are responsible for 25% of the peak load (compared to 3.2% for the non-EV consumers). This suggests that if cost-reflective network tariff design can target just a few of the largest load hours, it could achieve a significant reduction in the peak load.

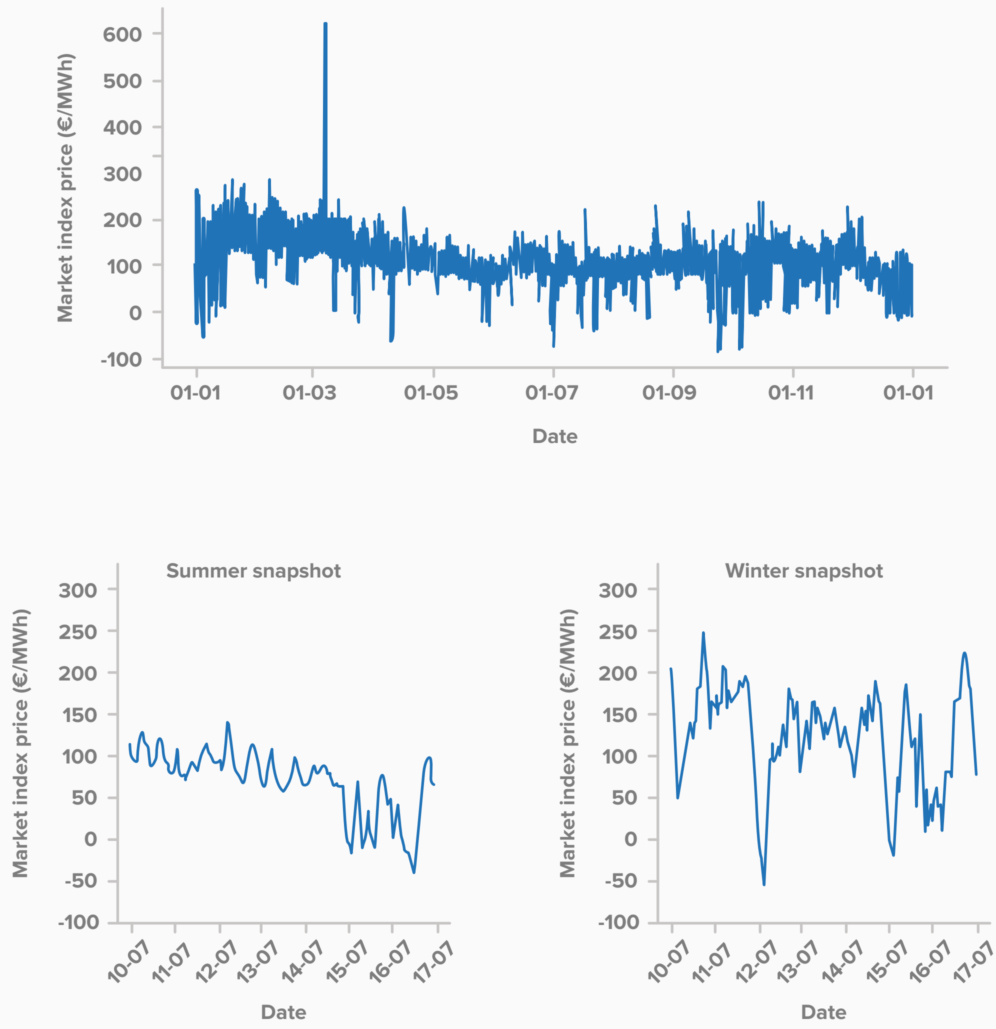
Overall, the aggregate peak load is almost four times greater for the EV consumers compared to the non-EV consumers. Total consumption, however, is just over two times greater. This suggests that the increase in peak load is not merely driven by greater overall consumption of EV consumers but is indeed likely mostly driven by the simultaneous targeting of cheap wholesale electricity hours. We analyse this further for our modelled sample in the result section of this quantitative analysis.

Source: FTI Consulting

108 · As EV adoption is more likely for households with standalone houses and more-than-average financial means, we can also assume that the consumption excluding from EV charging of the households with an EV is likely higher than the total consumption of households without an EV. However, from the data we were not able to separate the EV and non-EV consumption for the households with an EV.

A2.9 Consumers in our model are exposed to the day-ahead wholesale electricity price which we proxy with Market Index Price ("MIP") published by Elexon. The MIP reflects the price of wholesale electricity in GB in the short-term markets.[109] Figure A2-4 below shows the hourly MIP across the year, and weekly snapshots for the summer and the winter.[110]

FIGURE A2.4 — Hourly MIP, 2023 (€/kWh)



Source: : FTI Consulting analysis of Elexon, Market Index Prices (**link**)

A2.10 The average electricity price across the year is €108/MWh but can vary significantly hour-by-hour. As shown in the winter and summer snapshots, the level and volatility of the day-ahead wholesale price can also vary significantly dependent on the time of year.[111]

109 · Elexon, "Market Index Prices" **[LINK]**.
110 · We convert half-hourly MIP to hourly by taking an average of the two settlement periods within each hour and convert from GBP to EUR at an exchange rate of 1:1.15.
111 · We do not model the impact of increasing EV adoption on the wholesale electricity prices. We discuss this further in the subsection titled 'Limitations and next steps'.

CALIBRATION OF THE MODEL

A2.11 We create our modelling population by randomly selecting 200 households from the sample of non-EV consumers. The consumption of these 200 households is assumed to be inelastic. That is, the load cannot be shifted or reduced in response to wholesale or network price signals.

A2.12 As EV adoption increases amongst our population, households are randomly assigned EVs using the EV charging data from the IOG sample. Total household load is therefore comprised of the inelastic load described above and the additional flexible load due to EV charging.

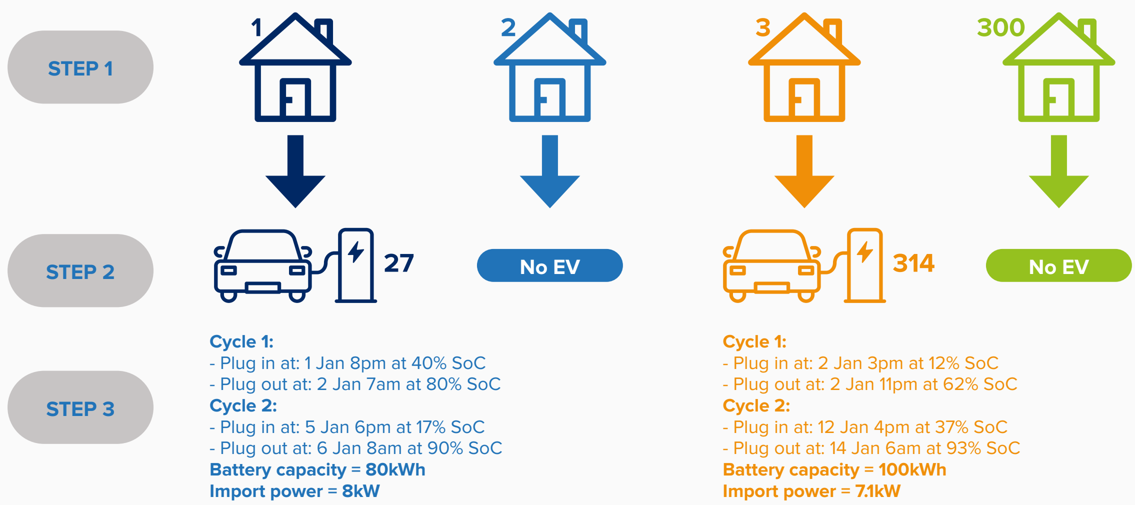
A2.13 The modelling sample is created according to the following steps:

— **Step 1:** We randomly sample 200 non-EV consumers from our sample of 1,000 non-EV consumers. The hourly load profile associated with an individual household is assumed to be inelastic and remains constant throughout the modelling. We refer to these households as "inelastic consumers".

— **Step 2:** At each discrete level of EV adoption (increments of 5% are modelled), we randomly assign the households in our modelling sample an EV from the sample of 500 EV consumers. For example, at 5% EV adoption, 10 households, randomly selected from our modelling sample of 200 households, are each assigned an EV from the sample of EV consumers.[112] Once as consumer is assigned an EV, we refer to it as an "EV consumer".

— **Step 3:** Each EV consumer must comply with the EV charging requirements of their assigned EV throughout 2023. This means that, for each charging cycle, the total increase in the EV battery SoC over the period the EV is plugged-in ("plugged-in period") needs to be the same as in the observed data. For example, if we assign EV #27 to Household #1, and if EV #27 plugged in at 8pm on 1 January 2023 and increased its SoC by 40% before unplugging at 7am on 2 January 2023 (the "plugged-in period"), then Household 1 must achieve a 40% increase in SoC over the plugged-in period. We visualise the EV sampling process in Figure A2.5. These strict EV charging conditions ensure that total load across households (inelastic load plus load due to EV charging) is consistent across the modelled tariffs. That is, each household consumes the same amount of electricity across the year regardless of the network tariff design, they do not reduce or increase consumption in response to changing tariff designs.

FIGURE A2.5 — Process to allocation EVs to households and to form modelling sampling



Source: FTI Consulting

112 · Once a household is assigned an EV, it retains that EV as the proportion of EVs in the entire sample increases. As well, no other household may be assigned the same EV. For example, if Household 1 is assigned EV 27 at 5% EV adoption, it retains EV 27 at each incremental level of EV adoption and no other household may be assigned EV 27.

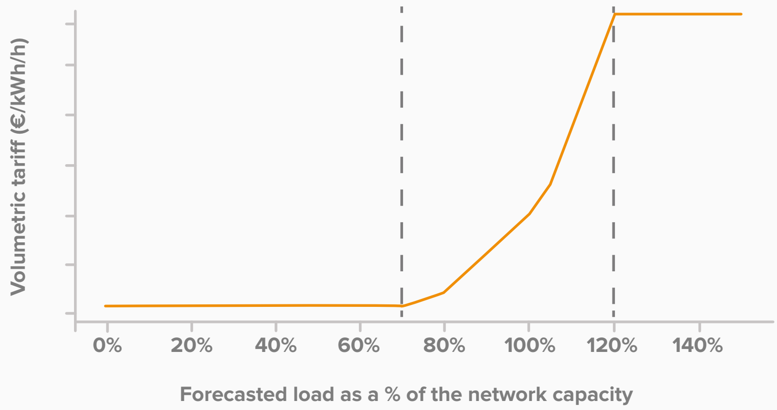
Appendix

3

Calibration of dynamic volumetric network tariff

A3.1 The level of the dynamic volumetric charge is determined based on the day-ahead forecasted load as a percentage of the assumed maximum network capacity, shown in Figure A3-1 below.

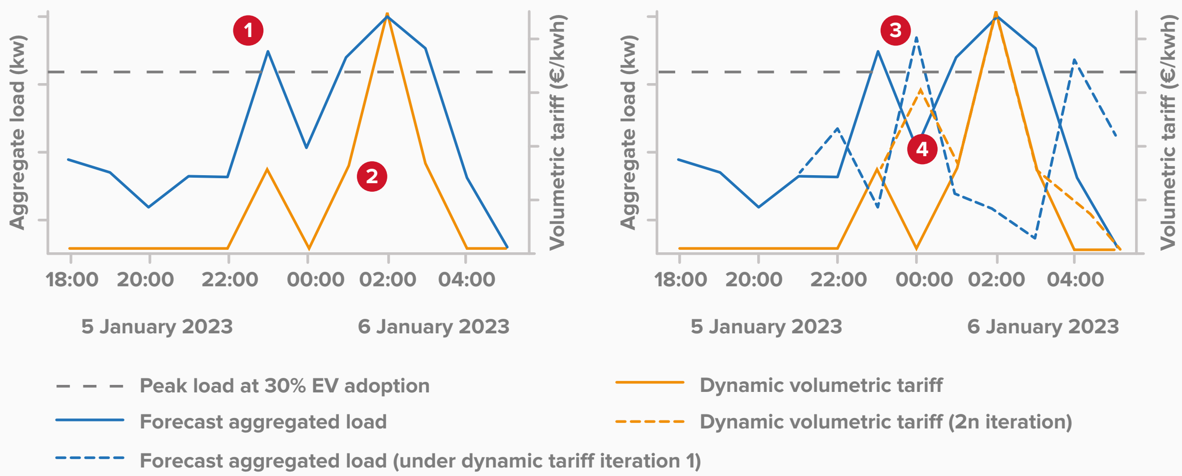
FIGURE A3.1 — Calibration of the dynamic volumetric network tariff as a function of the forecasted load



A3.2 When the forecasted load is below 70% of maximum network capacity, there is little strain on the network and thus the dynamic volumetric tariff is low. As forecasted load further increases and eventually exceeds the maximum network capacity, the dynamic volumetric charge increases.[113] In hours when the aggregate load is forecasted to be significantly in excess of maximum network capacity (e.g. at 120%) the dynamic volumetric tariff is set very high to incentivise flexible load not to consume in these high strain hours.

A3.3 When calibrating the dynamic network tariff in our model, we proxy the maximum network capacity as the peak load observed at the prior level of EV adoption (for example, at 35% EV adoption, the maximum network capacity is assumed to be the peak load observed at 30% EV adoption). The forecasted aggregate load is, initially, proxied using the observed aggregate load under Tariff 0 at the given level of EV adoption. We then follow an iterative process to calibrate the dynamic network tariff.[114] We describe this iterative process based on the example in Figure A3.2 below.

FIGURE A3.2 — Calibration of dynamic volumetric network tariff at 35% EV adoption



113 · Load can instantaneously exceed the maximum rated capacity of a feeder for a short duration but frequently doing so reduces the feeder's lifetime.

114 · Note that we here apply a relatively simple heuristic to compute the dynamic volumetric network tariff to illustrate its potential functioning. More elaborated approaches can be developed in follow-up work.

A3.4 In the example shown in Figure A3-2 above:

1) We begin with the initial forecasted load (assumed to be the observed aggregate load under Tariff 0 at 35% EV adoption (blue line in the left figure)). We assume that the maximum network capacity is the peak load observed at 30% EV adoption (the dashed black line).

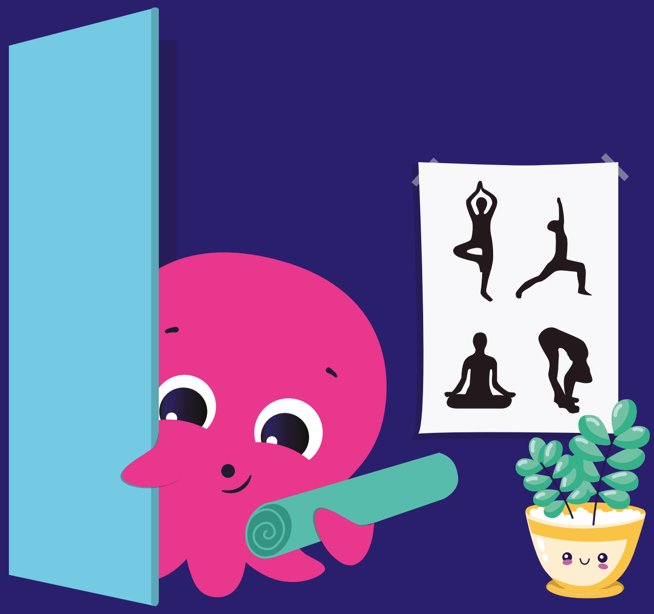
2) The dynamic volumetric tariff, shown as the solid yellow line in the left figure, is computed based on the initially forecasted load relative to the assumed maximum network capacity (see Figure A3.1). When the forecasted aggregate load on the network is low relative to maximum network capacity (e.g. between 6pm and 9pm on 5 January), the dynamic volumetric tariff is low. When forecasted aggregate load is high (e.g. at 2am on 6 January when EVs are projected to charge) the dynamic volumetric tariff increases.

3) In the second iteration, we simulate how consumers would respond to the dynamic volumetric tariff computed in the 1st iteration (full yellow line in the right figure). Responding to that dynamic network tariff, consumers have shifted their consumption away from the high charge at 2am and created new (albeit slightly lower) aggregate peaks at around 12am and 4am (the dotted blue line in the right figure).

4) We then compute a 2nd iteration of the dynamic volumetric tariff (shown by the yellow dashed line) based on the consumer responses described in point (3). We take the maximum value of the dynamic tariff in the 1st iteration (solid yellow line) and the 2nd iteration of the tariff (dashed yellow line). The latter term, i.e. dynamic volumetric tariff of the previous iteration, is considered in the updated dynamic volumetric tariff to prevent consumers from shifting back to the hours during which peaks were foreseen in load forecasts done in previous iterations.

A3.5 We repeat this process of iterating until a further iteration does not reduce the aggregate peak load any further. Any under- or over- recovery of the revenue requirement from the application of the dynamic volumetric charges is corrected for via fixed charges, or refunds, levied equally across all households. Under 0% EV adoption, there is no flexible EV load, and hence the entire revenue requirement is recovered via a fixed charge.

More flexibility is good for everyone



With the right tech, electric vehicles, heat pumps, batteries and electric heating become an opportunity, not a hurdle.

Let's unleash demand flexibility through-out our energy systems, and allow it to truly compete against fossil-powered generation.

octopus energy

smartEn
SMART ENERGY EUROPE

FTI CONSULTING