Pathway to a Competitive European Fuel Cell micro-CHP Market

REPORT

Economic value of mCHP's participating in power and grid service markets

Deliverable 4.3

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Executive summary

This report comprises Deliverable 4.3 of the PACE Project “Pathway to a Competitive European Fuel Cell micro-Cogeneration market”. It is a public deliverable representing the culmination of Tasks 4.2, 4.3 and 4.4 within PACE Work Package 4 (WP4).

The objective of PACE WP4 is to identify additional income streams from the participation of fuel-cell micro-CHP units (mCHP) in grid service markets, taking advantage of the electrical flexibility that is enabled by the mCHP. The work includes quantitative and qualitative economic value analysis (EVA) of mCHP participation in grid service markets. A broad analysis of potential factors influencing the revenue of the mCHPs from participation in grid service markets is also included in the work.

Under current conditions, the greatest opportunity for monetisation of mCHP flexibility comes from maximising self-consumption. Substantial savings in annual electricity costs can be achieved by converting gas to electricity, reducing the expenditure associated with purchasing electricity from the public grid. The effect is maximised for highly efficient CHP units such as those considered in PACE.

Device flexibility can be offered to grid service markets in return for payment, where ‘grid services’ are understood to be broader than classical frequency balancing. A range of grid services exists in Europe, representing a wide variety of commercial opportunities to mCHP owners. At the transmission level, frequency balancing services procured through the transmission system operator (TSO) are identified as being the most easily accessible to mCHP devices in the short-term. In this work, a detailed model-based optimisation framework for mCHP devices is developed, based on a dynamic programming modelling approach coupled with an advanced simulation of household space heating demand, electrical demand and hot water demand. The model is applied to frequency balancing markets in Germany, Belgium and the Czech Republic in order to determine the potential value that could be captured by the device owner. Various scenarios are considered in a quantitative sensitivity analysis, combining self-consumption and revenue from frequency balancing markets. The research also considers grid services for voltage control, congestion management capacity markets and other grid services, but barriers are identified for each. In particular this is due to mCHP dimensions, which limit the available flexibility that can be offered to such markets; as a result further quantitative modelling is not carried out for these services.

The analysis found that, out of the countries studied, the most attractive case for self-consumption was Germany, with cost savings from up to 1’429 Euros per year for a single-family house, and up to 2’239 Euros per year for a three-family house. Revenue from flexibility offered to frequency balancing markets was highest in the Czech Republic, where a single-family house could receive an additional income of up to 301 Euros per year in the best case.

The analysis therefore also considered value streams associated with the distribution system operator (DSO), including avoidance of grid extensions that could be enabled by taking advantage of mCHP flexibility, and the potential participation of mCHP in DSO grid service markets. A study of DSO practices, drivers and emerging DSO grid service markets was conducted, and the suitability of mCHP to participate in these markets was considered. A detailed literature review was also conducted on the potential of mCHP to reduce the need to reinforce electricity distribution networks. The review found that the value of demand-side flexibility (DSF) in avoiding grid investments can be estimated between 24 and 500 €/kW.

1 Introduction

1.1 Scope and objectives of the deliverable

The objective of PACE Work Package 4 (WP4) is to identify additional income streams from the participation of fuel-cell micro-CHP units (mCHPs) in grid service markets. This report is the public deliverable representing the culmination of Tasks 4.2, 4.3 and 4.4 within PACE WP4. The scope of the tasks and the deliverable are summarised in Figure 1 and explained below.

Task 4.2	Task 4.3	Task 4.4	Deliverable D4.3
• Establish methodology for quantifying EVA of mCHP in grid service markets • Appraisal of options for possible revenue streams from grid service markets • Sensitivity analysis • Analysis of thermal storage • Apply methodology to Germany • Conduct multi-criteria evaluation to Identify two further countries for further study (Belgium and Czech Republic)	• Evaluate EVA of mCHP through avoidance of grid extensions (literature review)	• Apply methodology for quantifying EVA of mCHP in grid service markets to Belgium and Czech Republic • Sensitivity analysis	• Commentary on options for possible revenue streams from grid service markets • Results of EVA analysis for grid service markets in Germany, Belgium and Czech Republic • Results of EVA analysis for avoidance of grid extensions attribtable to mCHP • Commentary on legal and commercial hurdles, future developments across Europe

Figure 1: Scope of Tasks 4.2 – 4.4 and of Deliverable 4.3

Tasks 4.2 and 4.4 were concerned with quantitative and qualitative economic value analysis (EVA) of mCHP participation in grid service markets. In Task 4.2, a methodology was established for quantifying EVA and was applied to a first case in Germany. Two further countries (Belgium and the Czech Republic) were selected for further study on the basis of a multi-criteria evaluation (MCE) conducted during Task 4.2. Task 4.4 then applied the EVA methodology to Belgian and Czech Republic grid service markets. At each stage, an appraisal was conducted of the options for possible revenue streams for mCHPs from grid service markets, leading to the selection of those that were most promising in each jurisdiction. The work also included a sensitivity analysis for dominating variables such as the annual total energy demand or the fuel cell technology used (PEM vs. SOFC), and assessed the necessity of additional thermal storage to provide these grid service products. Task 4.3 considered a different value stream, evaluating instead the economic value add provided by mCHP through the avoidance of grid extensions. Task 4.3 comprised a literature review and provided recommendations that complemented the Ene.field project [1].

In completing Tasks 4.2 – 4.4, the research also included an analysis of the relevant grid services markets, covering the legal situation, possible legal and commercial hurdles, future developments, grid fees, levies and taxes. An analysis of grid services markets across Europe considered the market attractiveness from the point of view of the PACE-members, the level of the power-market liberalization, the availability of power market and grid service data, attractiveness of the electrical power and grid service markets and the expected heat demand.

A broad range of candidates for grid services were considered in the completion of the tasks. Transmission System Operator (TSO)-procured grid services were assessed, considering which are most easily accessible to mCHP devices in the short-term. The methodology is fully extendable to other types of grid services. In total, the work has resulted in a detailed model-based optimisation framework for mCHP devices which allows for the quantification of revenue streams from participation in grid service markets. This model has been coupled with an advanced simulation of household space heating demand, electrical demand and hot water demand. For completeness, the work has also considered TSO grid services for voltage control, congestion management capacity markets and other grid services, although quantitative analysis was not conducted for these.

PACE consortium members requested that the work also considered possible revenue streams from Distribution System Operator (DSO)-procured grid services. While the European DSO is undergoing significant change as a result of the growth of distributed generation, and while DSO-procured services have the potential to act as an alternative solution to conventional planning and operation, grid services markets for distribution networks are not yet fully established, and DSO's continue to operate in a way that handles most of the distribution grid issues through reinforcement. It was therefore difficult to replicate the modelling of TSO frequency balancing services on DSO grid services. Instead, in line with the scope of Work Package 4, the consideration of this aspect was investigated in Task 4.3 through a consideration of the avoidance of grid investment costs.

1.2 Previous work and links to other work packages

This Section gives an account of previous projects which have analysed mCHP technology and the earning potential for the technology through European grid service markets.

The Ene.field project, Europe's largest demonstration project for mCHP and a predecessor to PACE, deployed more than 1000 residential mCHP installations across 10 European countries [2]. The project reported the status of the technology capability and potential at the time (2017). The Ene.field field trials went on to more specifically reveal technical aspects about the technology encountered by end users and installers thereby recounting their perceptions and barriers.

Earlier PACE deliverables built on the ene.field project, including by Element Energy (Deliverable 4.1) [3] and Challoch (Deliverable 5.3) [4]. PACE Deliverable 4.1 provided a literature study on the state-of-the art of virtual power plants and identified six virtual power plant (VPP) projects that include mCHP in their portfolio, demonstrating test capabilities such as wholesale and imbalance market participation and optimisation, maximisation of self-consumption, DSO congestion grid avoidance, peak shaving, and remote-control capabilities. Task 4.1 identified Germany, Belgium, France, UK and Ireland as countries that monetise demand side flexibility in all possible service value streams[1], based on a Smarten and Delta EE study [5]. PACE Task 5.3 addressed issues surrounding standardisation but also touched on grid services and barriers to market access for mCHP. The report described early signs of the emergence of a grid service market on the distribution level with flexibility procurement platforms for DSOs in the UK and Germany.

Outside ene.field and PACE, the QualyGridS project [6] assessed the economic potential for TSO and DSO grid services across Europe to reduce the production cost of hydrogen in 1MW PEM and alkaline water electrolysers. Germany and Norway were identified as the most attractive TSO grid service markets for the revenue earning potential of water electrolysers. The QualyGridS project came to the conclusion that no relevant established grid service markets existed on the distribution level in 2017/2018.

More broadly in relation to small scale distributed flexibility, in recent years a large number of research projects have targeted the full scale roll-out of demand response (DR) using integrated multi-agent-based ICT and blockchain-based platforms [7]–[9]. Such projects can be seen as future enablers for DR integration into the power grid, help to reduce the barriers for small production units such as mCHP to participate in VPPs, and lower the cost for small units to participate in such markets. Others are looking to foster coordination between TSOs and DSOs, VPPs and microgrids and DSO and aggregators for efficient and secure operations that lower the costs for small distribution units to participate in markets. The focus of the majority of the projects lies in hardware development and research into the communication possibilities and challenges of conducting large scale demand response interactions as well as the development of flexibility procurement platforms for DSOs and TSOs, rather than on the specific EVA related to grid services themselves. For example, blockchain based DR platforms are studied, among others, in [7]–[9].

One example is DRIvE [7], which aims to deliver a fully-integrated, interoperable and secure DR management platform for aggregators to empower a cost-effective market. Another project aiming to integrate micro grid and VPPs to a local power grid is eDREAM [8]. The vision of eDREAM is to enable distribution system operators (DSOs) and aggregators to cooperate in an efficient and secure way by a novel near real-time closed loop optimal blockchain based DR ecosystem. The ongoing H2020 project DELTA [9] aims to unleash the DR potential of small and medium-sized electricity prosumers in Europe. In Task 2.3 of the DELTA project six generic DR business models for small and medium-sized prosumers were described. The report states that in general, the more promising business models for DR are the ones where the DR service is embedded in a larger service package such as energy efficiency services (EES), facility management, supply of electricity or equipment provision [10]. The improvements of such a larger service package on the business case are not considered in the revenue calculations in this report since they are out of scope of PACE WP4.

[1] Ancillary services, interruptible loads, capacity mechanism, TSO/DSO network charges, day ahead and intraday markets, new DSO values.

The potential of consumers' flexibility as dynamic VPPs are also explored in Flexcoop [11] by using the flexibility of energy users and loads in residential buildings (i.e. HVAC, lighting, DHW, EVs). Flexcoop also provides an overview of value chains in different business models depending on how the flexibility is monetised. BM 3 "Participation into balancing and ancillary services" described the value chain and ecosystem for participating in grid service markets. A revenue calculation, however, as modelled based on time-series data in WP 4 of PACE, was not part of the project. The optimal management of prosumers is also studied in DR BoB [12], where a dynamic programming algorithm was used to coordinate dispatch among multiple HVAC units. The aim of the project is to demonstrate the economic and environmental benefits of DR in blocks of buildings by optimising the local energy production, consumption and storage in real time. Different scenarios for four demonstration sites in the UK, Italy, France and Romania were studied. Another project aiming for a scalable local energy market solution is Dominoes [13]. The project aim is to deliver new business models for DR and VPP operations and demonstrate how DSOs can dynamically and actively manage grids with a large share of microgrids, distributed generation and energy independent communities.

UNITED-GRID [14] aims to secure and optimise operation of the future intelligent distribution networks for future smart grid and micro grid solutions. Countries for which scenarios of future power grids have been observed within these projects are France, Netherlands and Sweden. The project will demonstrate the capabilities of intelligent distribution grids hosting more than 80% renewables and evaluate new DSO business models, pathways to guide the DSOs towards future intelligent distribution grids.

Two projects, focused more on hardware solutions improving the low voltage grid monitoring, are Net2DG [15] and RESOLVD [16]. Net2DG will develop a proof-of-concept solution to leverage measurement data from smart meters and smart inverters with off-the shelf hardware, in order to enable and develop novel LV grid observability applications. The RESOLVD project is developing innovative advanced power electronics devices with certain storage management capabilities improve low voltage grid monitoring with wide area monitoring capabilities and automatic fault detection and isolation. Projects such as these may pave the ground towards a more sophisticated distribution grid management and thus strengthen DSO grid service markets of the future.

1.3 Structure of this deliverable

Chapter 2 starts by providing an overview of opportunities for mCHPs related to the provision of various grid services. The opportunity for economic value capture in grid service markets is first described. Then, grid services at the transmission level are explained, including frequency and non-frequency services, and the potential for mCHP participation in TSO markets. The evolving role of the DSO is then investigated in detail, considering conventional DSO practices, emerging DSO grid service markets, state-of-the-art DSO pilot projects, and the potential role for mCHP.

Chapter 3 lays out the methodology that is applied to the research building blocks throughout the report. First, the country selection process is outlined. The self-consumption optimisation is then described, including both the scenario development and the methodology to identify the cost-optimal self-consumption policy. Third, the approach used for the qualitative and quantitative analysis implemented throughout this deliverable is explained. Finally, the literature review methodology is outlined, focusing on how cost savings from avoided grid extensions at DSO level are quantified.

In Chapter 4, the results of the self-consumption policy optimisation are presented. Chapter 5 then applies the self-consumption policy to selected frequency balancing markets in Germany, Belgium and the Czech Republic. A discussion follows that includes an analysis of hurdles for mCHP participation in TSO grid service markets and a discussion on the requirements for hot water storage.

Finally, Chapter 6 presents the results of the literature study relating to the value of mCHP in avoiding grid extensions. The value of demand-side flexibility (DSF) is discussed, and a number of case studies are presented. Finally, the results of the literature study is presented.

2 Background

Summary box of the Chapter

This chapter provides an overview of opportunities for EVA for mCHP, covering grid services and EVA from the avoidance of grid extensions. The opportunity for economic value capture in grid service markets is first described. Then, grid services at the transmission level are explained, including frequency and non-frequency services, and the potential for mCHP participation in TSO markets. The evolving role of the DSO is then considered in detail, considering conventional DSO practices, emerging DSO grid service markets, state-of-the-art DSO pilot projects, and the potential role for mCHP in providing services to the DSO.

Grid service market mechanisms introduced in this Chapter apply to the ENTSO-E area in general. Country-specific variations and deviations are analysed in Chapter 5.

2.1 The opportunity for economic value capture in power and grid service markets

Within a contemporary European electric power system, electricity is produced by bulk generators and transferred to end users via transmission and distribution networks. Grid operators are responsible for maintaining safe and reliable power transfer from the point of production to the end user. This joint responsibility is normally achieved by using a number of integrated planning, operation and management functions or 'services'. Services are either purchased through a market-based setup or procured based on obligations.

A transition to a decarbonised energy system in recent years has significantly increased the number of distributed energy resources (DERs). Such resources increase the complexity of the system operators' task of maintaining the power transfer within the acceptable limits. However, distributed resources can also be used to support the system operators in their role, and their inclusion in the list of service providers is the focus of intense effort by regulators and system operators and supported by policy in the Clean Energy Package.

While multiple routes to market may exist for DERs, and while regulatory and legal steps are underway to open markets up to small scale resources, some markets remain closed, while others are open but may be effectively closed due to market power of incumbent technologies or the lack of commercial viability of small-scale participation. This deliverable assesses the revenue potential for mCHP that can be achieved by participating in grid service markets. A necessary starting point is therefore an assessment of which grid service markets are accessible to mCHP.

The term 'grid services' does not have a formal definition. PACE Deliverable 4.1 described the principal routes to market for the flexibility provided by mCHP as part of a VPP, categorised according to energy services, capacity services, frequency balancing services and network services. A definition of grid services was also introduced by USEF [17] and in the QualyGridS Deliverable Report D1.1 [18], where grid services can be categorised according to the entity procuring the service, specifically TSO, DSO, Balance Responsible Party (BRP), or end user (Figure 2). Within Deliverable 4.3, it is this classification of grid services that has been used.

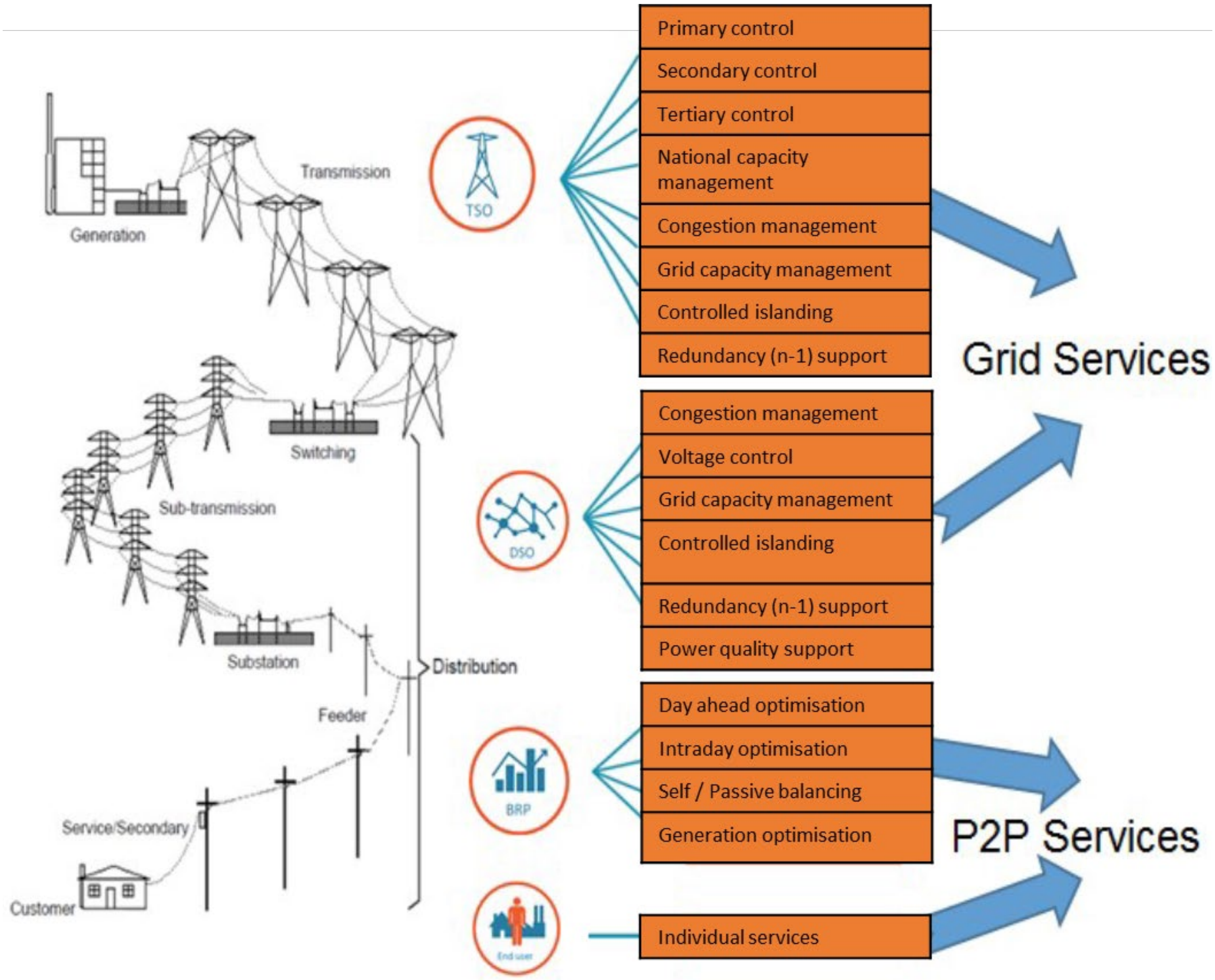

Figure 2: Categorisation of grid services retrieved from [19]

The remainder of this chapter considers the role that mCHPs can play in TSO and DSO grid service markets as the most attractive markets as evaluated in [18], and the status of the DSO in establishing such markets as an alternative to traditional reinforcement. Section 2.2 first provides an overview of the potential for mCHP to act as a grid service provider, and the principal considerations in relation to the technology in this regard. Section 2.3 provides a short summary of grid services at the transmission level, and the suitability of mCHP for participation within them. Section 2.4 considers DSO grid services in the context of the changing role of the DSO. A more detailed consideration of the evolving DSO is provided in Section 2.4.4 in order to establish the context for Chapter 6, where the potential value of mCHP in avoiding grid reinforcement costs in distribution networks is analysed.

2.2 Fuel Cell mCHP as a grid service provider

mCHP devices have the potential to act as a service provider to TSOs and DSOs. In this section, the basic configuration of the mCHP is described, and its potential to act as a grid service provider is explained.

A typical installation of mCHP in conjunction with an auxiliary gas burner is shown in . Electrical loads are supplied either by the power grid or by the mCHP. To meet thermal demand, comprising domestic hot water and space heating, heat is generated in the mCHP, supported as necessary by the auxiliary gas burner. A hot water storage tank is installed to buffer temporal discrepancies in heat production and electricity generation. The inherent thermal inertia of the building itself can also be seen as an additional storage element.

During periods of high electricity demand within the building, unused waste heat can be deposited in the hot water storage tank or delivered into the thermal inertia of the building using the space heating system for later use. There is a limit to the maximum permissible temperature in both the hot water storage tank and the building, therefore overheating must be prevented. To do so, the mCHP is switched off, which in turn results in less electricity generation, meaning the electricity demand must be covered by imports from the local grid.

During periods of high heat demand, where instantaneous demand exceeds the mCHP’s thermal output, the hot water storage tank (HWST) is depleted. Once the tank is empty, or if the excess demand relates to space heating, the auxiliary gas burner must be activated in order to meet demand. In this way, the comfort level of the inhabitants is guaranteed since the HWST temperature is always above a certain minimum temperature limit.

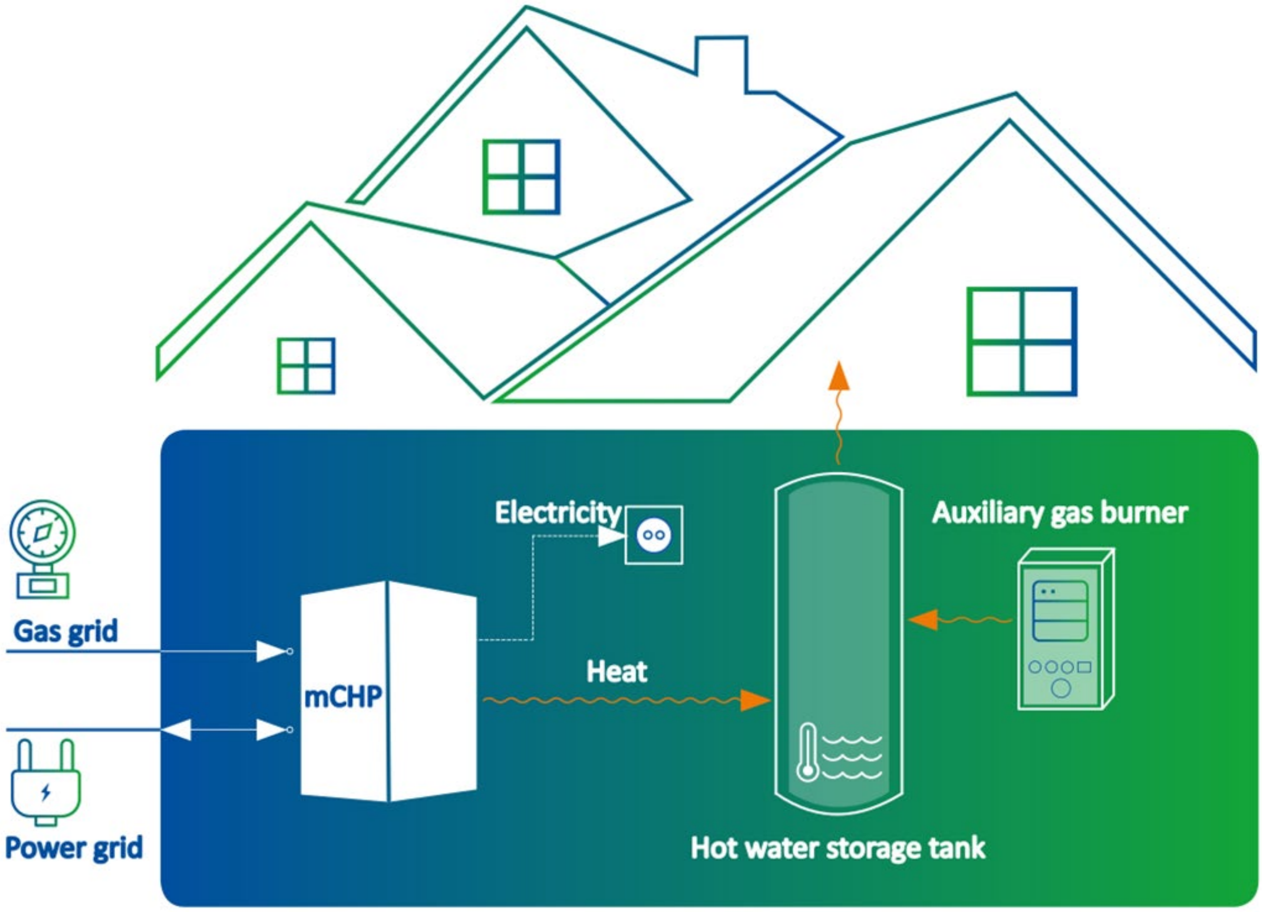

Figure 3: Typical installation of a mCHP in conjunction with an auxiliary gas burner. Figure adapted from [20]

The interplay between the modulation of the mCHP, the thermal demands of the building, the hot water storage tank, the auxiliary gas burner and the grid connection provides temporal flexibility for the energy needs of the house. This temporal flexibility can be monetised by taking advantage of fluctuations in electricity prices or by accessing markets that reward flexible operation.

Under current conditions, the greatest opportunity for monetisation of the mCHP output comes from maximising self-consumption. However, the temporal flexibility, as described above, can also be offered to grid service markets. For a grid service market to be accessible and attractive to a mCHP, there must be:

1. market regulations that permit aggregation of multiple DERs,
2. a market that is accessible to mCHP, either directly or via an aggregator,
3. market products that are suitable for technical and operational characteristics of mCHP allowing its participation either directly or via an aggregator,

4. remuneration that makes participation commercially viable, creating an incentive to participate,
5. available market data to allow a business case to be made for investment in technology for participating in the market, such as control equipment or metering.

The market must allow third party intermediaries to enter the market and provide services. A mCHP unit is too small to participate in grid service markets alone and thus needs to be pooled into a virtual power plant (VPP) in order to trade flexibility as a sizeable unit on the market. Therefore, a route to market via aggregation must be possible. This is important as the majority of consumers will not be willing or able to bid directly into a given market and would only be able to contribute flexibility if market access was delivered as a service.

Assuming aggregation is permitted in a given market, residential participation by mCHP must be permitted in the aggregator's portfolio, and technical / regulatory barriers must be sufficiently low to incentivise the aggregator to include mCHP units in their portfolio. The participation of aggregated loads, traded as single units, should be legal, encouraged and enabled. Householders should be able to contract with an aggregator of their choice without interference from their electricity supplier.

Market products must be suitable for the technical and operational characteristics of mCHP devices. Critical technical requirements are the minimum bid size, technical specifications as defined in the prequalification process, product resolution, requirements for symmetry, and notification time. The level of bid size will increase or decrease the complexity of the task of the aggregator in recruiting and managing the resource pool, with lower bid sizes simplifying the task for the aggregator, and so increasing the likelihood that he will consider including smaller resources. For smaller, aggregated devices such as mCHPs, it is preferable that prequalification takes place at the pooled, rather than the individual level, so reducing costs and complexity. Considering product resolution, it is preferable that the resolution, i.e. minimum bid duration, does not unduly interfere with comfort settings within the property served by the mCHP device. High bid duration, if transferred from the aggregator to the single reserve providing unit, increase the chance that comfort levels cannot be maintained, meaning that the device would have to use alternative forms of heat generation or electricity generation, potentially undermining the marginal benefit from participating in the grid services markets. Regarding symmetry, it is preferable that the products are not symmetrical, although this depends on the mCHP technology that is deployed. The operating regimes of some mCHP types prevent symmetrical operation. Finally, a notification time is required that is sufficiently long to allow the mCHP controller to respond to requests to provide the grid service, or to allow the device to move from standby to active mode of operation.

There must be a suitable level of remuneration of flexibility so that the service, when aggregated, can compete on equal terms with bulk generation or large-scale demand response. SEDC recommends that distributed services be compensated at the full market value of the service provided. For mCHP to compete effectively, supply-side price signals should be correct and not distorted by merit order effects caused by subsidies that are offered to other participants in the market in question. Markets should also include rules that allow the fair allocation of remuneration for services to retailers, aggregators, BRP's and prosumers.

With these basic considerations in mind, we now take a closer look at the specific grid services and discuss the suitability of mCHP for participation in the respective markets.

2.3 Grid services at the transmission level

2.3.1 Grid services for frequency control

Balancing refers to the situation after markets have closed in which a TSO acts to ensure that demand is equal to supply, in and near real time. In Europe, balancing is procured in the form of defined services from a balancing market, where efficient balancing markets ensure the security of supply at the least cost.

Balancing services (also called frequency balancing services[2]) consist of two main types: balancing energy (the real-time adjustment of balancing resources to maintain the system balance) and balancing capacity (the contracted option to dispatch balancing energy during the contract period). Selected bids in the balancing capacity market are transferred to the balancing energy market. Furthermore, there is differentiation between upward regulation, also called positive regulation, which means increasing energy inflow or reducing load, and downward regulation, also called negative regulation, which means decreasing energy inflow or increasing load.

Depending on technical requirements to be fulfilled, such as speed of activation, ENTSO-E distinguishes the products Frequency Containment Reserve (FCR), which means the operational reserves activated to contain system frequency after the occurrence of an imbalance, Frequency Regulation Reserve (FRR), which means the active power reserves activated to restore system frequency to the nominal frequency, and Replacement Reserve (RR) which means the reserves used to restore/support the required level of FRR to be prepared for additional system imbalances (NC OS).

2.3.2 Grid services for voltage control, congestion management, capacity markets, and other services

Various services exist in addition to those required for frequency balancing. Transmission constraints arise where the system is unable to transmit power to the location of demand due to voltage issues or congestion at one or more parts of the transmission network. Services relating to voltage control and services for congestion management are also therefore requested by the TSO. Another category is the capacity market which is designed to deal with shortfalls in generating capacity exacerbated by the intermittency of renewable generation.

[2] Any imbalance expresses by a drift of the 50 Hz grid frequency.

Voltage control is accomplished by managing reactive power on the transmission system. Reactive power can be produced and absorbed by both generation and transmission equipment. In Europe, the provision of reactive power is typically an obligation for large-scale generators implemented via the grid code or from other reactive power facilities (e.g. capacitors and Static Var Compensators) connected to the transmission network. In some countries like Denmark, reactive power reserve can be acquired through a market-based tendering process, but typically the service can only be provided by a small number of facilities, limiting competitiveness.

Congestion management refers to the avoidance of thermal overload of system components by reducing the amount of power transferred. Normally, grid congestion is caused by insufficient grid capacity, and so can be observed at all levels of the electricity system, from cross-border interconnections to transmission networks to distribution networks. Congestion management can be implemented through grid reinforcement by the grid operator, or by the system operator by optimally dispatching capacity offered by service providers.

Unlike frequency response, reactive power is a location-dependant service, further limiting the pool of potential providers. This means that, as well as limiting the pool of providers, the requirements relating to capacity, service time window, ramp rate and reactive capabilities vary from case to case. Today, most TSOs base their choices of the units participating in localised services via bilateral contracts which obscures pricing transparency.

2.3.3 Fuel cell mCHP participation in TSO grid services

Frequency balancing markets are the most established and mature, with many years of standardised procurement of services. Significant transition is underway in the procurement of these services as TSO's adapt to a decarbonised, decentralised system, meaning new markets are emerging for residential flexibility. Frequency balancing services are therefore considered highly relevant for mCHP. In reference to the criteria identified in Section 2.3:

1. Aggregation is permitted in a number of countries across Europe,
2. Residential participation is proven in some frequency markets via an aggregator, including for residential reserve providing units (such as mCHP),
3. Mature markets exist with clear, stable products, published prices and volumes, and clearly defined criteria for participation. TSO's are adapting market rules and products to encourage participation of smaller actors and emerging technology, and market products fit the characteristics of mCHP devices,
4. Frequency balancing markets typically have high liquidity, lowering the entry barrier for new market participants. Prices are such that markets support a wide range of participants,
5. Price and volume data is generally publicly available across Europe, meaning commercial modelling is possible, and allowing new entrants to assess the commercial benefits of entering the market.

It is important to note that the technical requirements and commercial opportunities differ in each frequency balancing market, meaning that the viability of mCHP participation varies for each country.

2.4 The evolving DSO and the potential earned value for mCHP

2.4.1 Overview

This section describes the current and emerging role of the DSO in light of their planning and practices in order to offer a perspective of where mCHP, as a flexibility-enabling distributed energy resource (DER), can be positioned in their agenda of strategic priorities, especially as the DSO becomes moves towards active grid management. The section goes on to describe the hindrances of revenue regulation for transition into the new role, DSO grid service markets, and the state-of-the-art in DSO grid service market pilot projects. The section concludes by highlighting the opportunity for mCHPs in local grid service markets, the economic value of which is later qualitatively assessed in Section 6 by considering the potential value that can be captured by the DSO in the avoidance of grid extensions.

Throughout this section distribution grid services are considered synonymous with local flexibility services. Services are delivered by the demand side flexibility (DSF) of distributed energy resources. DSF refers to the portion of demand in the system that can be reduced, increased or shifted within a specific duration [21]. Demand response (DR), a specific type of DSF service, is the focus here for delivering peak shaving in particular.

2.4.2 DSO Conventional practices and planning

According to Article 2(6) of the Directive 2009/72/EC, a DSO is '*a natural or legal person responsible for operating, ensuring the maintenance of and, if necessary, developing the distribution system in a given area and, where applicable, its interconnections with other systems and for ensuring the long-term ability of the system to meet reasonable demands for the distribution of electricity*.' Beyond regional distribution and supply, the DSO is also responsible for ensuring network security and a high level of supply reliability and quality.

In the traditional power system the role of the DSO consists of connecting and disconnecting DERs, planning maintenance and network management, supply outages management, and in some cases billing [22]. DSOs are required to optimise, reinforce and expand their networks in order to enable distribution of electricity and support the connection of new loads or generation [23].

To guarantee security and quality of supply, DSOs have historically made use of an approach known as ‘fit and forget’. ‘Fit and forget’ is synonymous with passive DSO management with minimal operator involvement and the use of few system services to ensure a reliable and stable system through network reinforcements. Network reinforcements are essentially copper and iron solutions used to tackle voltage and thermal constraints (congestion issues), that when exclusively relied upon can lead to cost inefficiencies as they tend to induce over-investment in an underutilised system when DER penetration is low [24], [25].

Cost-based regulation approaches have traditionally been used for the DSO (such as cost-plus models). This form of regulation guarantees a return for the DSO based on the size of the regulated asset base. Such models limit the incentive for the company to minimise its costs because it can increase its profits by expanding its asset or cost base. An alternative incentive-based system has replaced the cost-based regulation system in many countries response to the latter's drawbacks. Under the incentive-based system, rewards and penalties provide incentives for the DSO to find efficiencies. The application of incentive-based systems differs from country to country, meaning it is not possible to compare countries directly. However, no country is completely unique, as the 'toolbox' of regulatory instruments is limited, meaning that many countries are comparable in their approach. As a result, it is informative to consider conventional practices in the DSO in specific countries that are experiencing high levels of DER penetration, and possible to draw more general conclusions from these practices about the likely behaviour of DSO's across Europe.

In a 2019 annual Bundesagentur survey of 815 German DSOs, the most common measures undertaken to optimise and reinforce networks were analysed. These were, in descending order:

- Increasing cable cross-sections,
- Undergrounding of overhead lines (showed year-on-year decrease),
- Increasing transformer capacity,
- Installation of metering technology,
- Isolation point optimisation (showed year-on-year decrease),
- Changing network topology.

In the 2019 survey, DSOs were asked for the first time whether they make use of peak shaving as a network optimisation measure; 6% (49 DSOs) reported they did [23].

The survey also found that substantial expansion in renewable energy installations and the legal obligation to integrate installations and the energy they generate, regardless of the network capacity, challenges the DSO's conventional planning and operations approach. For DSOs to deliver a secure reliable network under such circumstances, they need to take additional measures to mitigate voltage violations and thermal overloading of power lines. To mitigate and remedy these issues DSO have at their disposal classic grid expansion[3], use of intelligent equipment[4], grid optimisation[5], and active grid operation and planning [23].

The experiences of 10 representative large-scale DSOs dealing with the technical challenges brought about by the grid integration of DERs (especially PV decentralized systems) were analysed [24]. Their findings, shown in Table 1 and

[3] Replacing local distribution transformers, segmenting local grid and laying parallel cables
[4] Voltage regulators and voltage-regulated distribution transformers
[5] Individual tap changing of distribution transformers, wide-area control, reactive power feed-in and changing grid topology

Table 2, highlight the practical solutions in a DSO's toolkit when faced with these challenges. All DSOs have had to implement measures to guarantee the integration of PV systems. Grid optimisation measures are usually the most economical initial step, after which DSOs expand the grid due to PV growth.

Grid expansion measures are primarily undertaken to ensure compliance with the permissible voltage and current limits, for example in southern Germany where overloading of operating equipment is seen as the main cause for grid expansion, whereas in the north maintaining the voltage range is the main cause. Grid expansion measures include replacing local distribution transformers, segmenting the local grid, increasing conductor cross-section as well as laying parallel cables. The integration of PV generation has resulted in supply outstripping demand causing reverse power flows and peaks. Transformer upgrades to accommodate PV growth have therefore become a widespread practice for all the surveyed DSOs. Transformers were found to be the initial congestion point of a low voltage grid, and for those with relatively lower PV generation a transformer replacement was necessary only in a few rare instances.

Grid expansion is not only carried out to integrate more renewable and embedded generation, but also for replacing end-of-life investments. In December 2016, only 19% of planned grid investments were attributable to renewable energy in Germany, although this can vary widely from DSO to DSO [26]. The planned growth in renewable energy integration accounted for EUR 1.94 bn (2016 inflation adjusted) planned investment volume in Germany's distribution network. [24], [26] find that a source of uncertainty that makes grid expansion planning challenging is predicting the future connection rate of DERs in the 10-year grid expansion planning in a way that allows the DSO to identify grid issues beforehand in order to mitigate and minimise the cost of distribution network reinforcement and operational actions, especially when distributed generation penetration is high or predicted to be high.

Table 1 and Table 2 show the capacity and voltage mitigation measures employed by the 10 German DSOs in the study, some of which are experiencing the effects of massive PV integration. These are ranked with respect to how frequently the measures are applied from the perspective of the DSOs in 2018. "Other" measures stem from literature. It was found that the DSOs responded similarly in that the sequence of mitigation measures chosen when responding to capacity and voltage issues were in alignment. In 2021, it is expected that the "other" measures encompassing DSF are gaining importance and will play a prominent role in the future for reasons set out in Section 2.4.4.

Table 1 Mitigation measures for capacity issues resulting from conducted interviews with German DSOs. Adapted from [24]

	Measures addressing capacity issues	**Application frequency (2018)**	**Brief Assessment**
(1)	Replacing local distribution transformers	High	Typical initial measure
(2)	Segmenting local grid	High	Secondary measure applied when potential of (1) is exhausted
(3)	Changing grid topology	Low	Potential initial measure, however, scope of application is limited
(4)	Other: active power curtailment of PV inverters, implementation of large-scale battery systems, control of demand-side appliances	Low	Implementation limited to pilot projects for research purposes

Typically, the replacement of the local distribution transformer is of high relevance. The capacity of the distribution transformer is usually upgraded, and if the maximum permissible capacity has been reached, segmenting of the local grid is the subsequent measure. This option might also be the most economical if an adjustable local grid transformer is installed and the planning procedures show that one or more of the involved power lines might face voltage problems in the near future due to the continued expansion of PV systems [24], [27]. A change in grid topology is also a potential initial measure that can be implemented even before replacing the local distribution transformer, although this can only be applied in low voltage grids that do not have a radial structure, which limits is suitability in some countries [28]. Consequently, power lines often cannot be rearranged in a way that has a meaningful impact by reconfiguring the grid switches. As such, DSOs could rely more on innovative alternative measures such as control of demand side devices or battery systems, but at the time these were not applied frequently, and were instead limited to pilot projects [24].

Table 2 Mitigation measures for voltage issues resulting from conducted interviews with German DSOs. Adapted from [24]

	Measures addressing voltage issues	Application frequency (2018)	Brief Assessment
(1)	Wide-area control	High	Wide-area control is the initial measure that raises hosting capacity of all low-voltage grids connected to the substation.
(2)	Reactive power feed-in	High	Since 2012 PV inverters in Germany supply reactive power by using the standard factory setting. No direct control by the DSOs.
(3)	Laying parallel cables	High	Typically implemented for voltage issues, as the effect of (1) and (2) is limited.
(4)	Individual tap changing of distribution transformers	Medium	Initial measure implemented by several DSOs
(5)	Voltage-regulated distribution transformers	Low	Only economical in specific cases.
(6)	Voltage regulator	Low	Only economical in specific cases
(7)	Segmenting local grid	Low	Potential option but mostly implemented in the context of capacity issues
(8)	Increasing conductor cross-section	Low	Mostly applied if cables are about to reach end of lifetime. DSOs prefer running parallel circuits to overlaying with increased cable cross-sectional area
(9)	Changing grid topology	Low	Potential initial measure, however, scope of application is very limited
(10)	Replacing local distribution transformers	None	Has a positive effect on the voltage drop, but typically not implemented for voltage issues
(11)	Other: active power curtailment of PV inverters, implementation of large-scale battery systems, control of demand-side appliances	Low	Implementation limited to pilot projects for research purposes

The implementation of wide-area control is typically the initial measure to increase the hosting capacity of the medium-voltage grid and low-voltage grids. Laying parallel cables is typically the next mitigation measure. Reactive power feed-in by PV inverters also plays a role, especially since it is required by law in Germany. However, DSOs do not actively control the reactive power setting during operation. For the remaining mitigation measures, their applicability and frequency of use seem to be low in comparison for various reasons. Nevertheless, in specific cases, voltage-regulated distribution transformers, local grid segmentation or changes in the grid topology are sometimes the most economic options and are thus implemented, albeit less often than the aforementioned measures. According to the interviewed DSOs, alternative options (11) were not yet economically and/or technically viable in 2018. On the other hand, some academic papers suggest that the regulatory framework sometimes hinders their implementation [29]. A note of caution is due here since these measures and the sequence of their application are valid for the German context only. DSOs in other countries faced with their own challenges might be expected to some differences in the list of priorities; however, it is reasonable to expect that “other” measures would also rank low in their application frequency given that regulatory similarities exist between Germany and many other countries in Europe [30].

2.4.3 DSO revenue regulation

DSOs’ current revenue streams in most member states consist of connection charges and usage of the system charges charged to consumers as illustrated in Figure 4. As of 2019 in Germany, DSOs can claim planned investment costs directly in the revenue cap and thus price them into network charges [23]. The DSOs’ expenses are made up of capital expenditures (CAPEX) and operational expenditures (OPEX). CAPEX goes towards any planned expenditure, typically system investments such as reinforcements of transformers, cables, etc., while the OPEX is used to support usage of the transmission system (paid to the TSO), ancillary services (AS) to keep a balance on the system (also paid to the TSO), the energy losses in the system and the day-to-day operations and maintenance of the system [31].

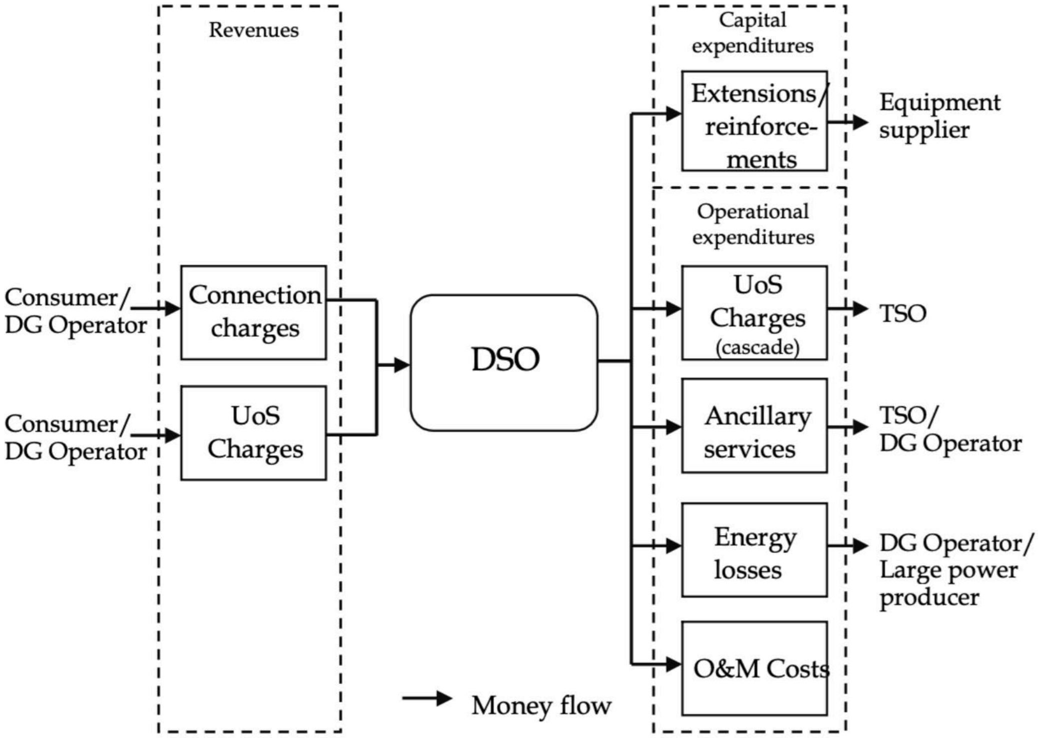

Figure 4 Overview of DSO cost and revenues. Sourced from [32]

[33] explains how economic regulation influences whether DSOs invest in physical network assets or solve grid issues by operational, analytical means. This is due to the economic incentives being tied to the type of expenditure. Network regulation usually remunerates CAPEX at a regulated cost of capital. The CAPEX remuneration depends on the asset base invested in, therefore fewer investments reduce the asset base and thus the CAPEX regulated remuneration whereas the OPEX remuneration, though handled in various ways[6], is not typically remunerated when increased. This creates a CAPEX-bias in the planning and operation of the distribution network.

[34] argues that an additional source of CAPEX-bias is OPEX-risk. Regulation does little to support the optimisation of the CAPEX-OPEX mix as increased OPEX today is typically not remunerated for decreased CAPEX today or CAPEX and/or OPEX in the future. This means that the postponement or avoidance of future investments exacerbates the CAPEX/OPEX imbalance, affecting the regulated revenue for DSOs under today's traditional model.

[6] Ex-ante based on efficiency requirements or applying benchmarking methodologies.

Nowadays DSO are also looking to investing in smart grid solutions, as described in the previous section. These would reduce the need for network investment-related CAPEX and increase the short-term OPEX, bringing into question the revision of regulatory price controls particularly under high levels of DER integration [34]. Smart grid components differ from conventional network components and equipment in that they have shorter useful lives, faster technological evolution, or different needs in terms of capital and operational expenditures. Thus, DSO revenue schemes must be adapted to take these differences into account [35].

Suggestions have been to fix the CAPEX-OPEX ratio or to link remuneration to the total costs incurred by the DSO, that is, both CAPEX and OPEX (TOTEX) [33]. The UK regulator addressed the CAPEX-bias by developing a form of TOTEX regulation that introduces a fixed OPEX portion that is to be considered and activated like CAPEX. That is to say, regardless of whether expenses are CAPEX or OPEX related, all are treated the same – as TOTEX [34]. By doing so the bias is eliminated and the DSO is incentivised to make the optimal choice between activating DER for example, and upgrading the grid without unfavourable repercussions. In light of challenges such as the low-carbon transition, aging infrastructure, growing demand for grid expansion and smarter networks, the UK regulator went on to introduce a regulatory framework called the RIIO model (Revenue = Incentive + Innovation + Output) that not only addresses the CAPEX-bias with a TOTEX approach, but also through rewards or penalties fosters desired output performance based on a set of predefined indicators and investment in innovation. This means that partial remuneration comes from desired output performance as opposed to solely remunerating input cost [34].

[36] has made calls for regulators to set up clear regulatory frameworks that allow DSOs to develop both short-term and long-term innovation needed for system transformation. This includes the development of dedicated innovation incentive schemes for smart grid projects, the role of the DSO as a neutral market facilitator, and incentives for OPEX in order to reflect the growing needs for OPEX related to flexibility in distribution networks. Regardless of the grid context, [36] underscores that future regulation will need to accommodate a high share of DERs, allow for the provision of new services and management of more complex flows. The pace of these innovative practices need to be met with regulatory innovation that give DSOs enough room to develop new system services and remuneration schemes that also encourage their use.

2.4.4 The emerging role of the DSO

In spite of the regulatory constraints described in the previous Sections, [22] views the emergence of distributed renewable generation, smart homes and smart grids as a means of shaping the responsibilities of a new DSO role in European legislation that is better equipped to deal with peak load management and network congestion management inter alia. In this new role, the DSO is going from passivity to pro-activity in response to new grid needs, responsibilities, market entrants and enabling technologies. The passive role which was characterised previously as the 'fit and forget' approach solves grid issues in the planning phase with the help of grid reinforcements or extensions. When DER penetration is low the network is oversized, however, when DER penetration rises it becomes less economical as significant extra investment is required to accept new connection requests.

A ‘reactive DSO’ is another type of DSO role that is characterised by an ‘only operation’ approach. Here congestion is solved as and when it occurs in the operations phase. This is seen often with curtailment or interruptible load programs, which are most widely practiced where no restrictions on distributed generation connections exist.

Finally, the advanced DSO role is the pro-active DSO which takes a more active approach in finding solutions in both planning and operations phases. Here, the DSO utilises the increased volume of DER connections and the flexibility services they offer (e.g. DR and congestion management) as a means of deferring or reducing grid investments ideally through a market-based procurement of flexibility from local distributed generation and loads to economically optimise network capacity.

Despite the high regulatory requirements needed to frame the new role of the DSO and incentives needed for expenditure in alternative grid operations or technology, the emergence of new business models, new market designs and actors collectively work to encourage the DSO to take on their new role. This can be seen in grid digitalisation that provides better grid visibility and granularity for active management and control of more localised parts of the network. Automation has enhanced DER technology readiness in responding to price signals. Growth in smart homes has opened up energy-as-a-service business models in bundled intelligent services that include peak load reduction, monitoring, control and automation of energy consumption [37].

2.4.5 Grid services procurement by the DSO

[38] points out that renewable energy sources, storage, demand response and cogeneration provide an alternative that is of increasing interest to the DSO and aggregators as aggregators may provide them for other purposes when the grid is in a normal operational state. The techno-economic potential in obtaining grid services from DERs, third parties and end users (for increasing the flexibility of distribution grid operation) is recognized by DSOs in Europe and is the subject of numerous research and pilot projects. To mobilise these new resources, active network management methods [8] and local flexibility markets [39] might be utilized in specific cases. DSOs, as a part of their neutral market facilitator role, will be the entity responsible for validation of traded flexibility related to assets connected to the distribution grid. This process will prove its usefulness in using local assets in TSO-frequency balancing as well as in TSO- and DSO congestion management.

Table 3 provides a non-exhaustive list of the state-of-the art in European DSO pilot projects that aim to advance flexibility-supporting technological solutions, platforms, planning tools and frameworks in an effort to demonstrate replicability, adaptability and scalability for DSOs. In this section, a more detailed consideration of demand response is provided, as it represents the DSO grid service that is most easy to realise in the near term.

Table 3 DSO flexibility pilot projects

Pilot Project	Location	Description	Source
Flexplan	Pan-European (6 locations)	Establishes a new grid planning methodology that maximises economic efficiency for TSOs and DSOs when introducing new storage and flexibility resources in electricity transmission and distribution grids as an alternative to building new grid elements. Looking to determine the role flexibility could play and how its usage can contribute to reduce planning investments yet maintaining current system security levels.	[40]
InteGridy	Pan-European (10 locations)	Integrates cutting-edge technologies, solutions and mechanisms in a framework of replicable tools to connect existing energy networks with diverse stakeholders, facilitating optimal and dynamic operation of the distribution grid, fostering the stability and coordination of distributed energy resources and enabling collaborative storage schemes within an increasing share of renewables. Pilots trialled demand response, energy storage, electric vehicle integration, and smartening the distribution grid.	[41]
DRIMPAC		Develops a comprehensive solution to transform buildings into active participants of the European energy market through the use of intelligent, interoperable and demand-response-enabled building management systems. Aims to bridge the gap of communication between grid/market and buildings by providing a unique and universal technological framework that facilitates the end-to-end communication of the necessary information for the discovery and delivery of demand flexibility.	[42]
DELTA	UK Cyprus	DELTA proposes a Demand-Response management platform that distributes parts of the Aggregator's intelligence into a novel architecture based on Virtual Power Plant principles. It will establish a more easily manageable and computationally efficient DR solution and will deliver scalability and adaptation into the Aggregator's DR toolkits.	[43]
GOFLEX	Germany, Cyprus and Switzerland	Aims at increasing the integration of renewables by applying smart grid technologies to make existing energy flexibilities usable for the grid. Pilots will: • test a microgrid a flexibility source • optimise the balance for the DSO to reduce corrective costs • optimising the balance for the distribution system operator to reduce corrective	[44]

Demand response (DR), one of the more conventional demand side flexibility services, is a voluntary change by end-consumers of their usual electricity use patterns in response to market signals (such as time-variable electricity prices or incentive payments) [45]. DR is considered to be a controllable load thus making it a type of distributed energy resource (DER), along with behind-the-meter batteries, distributed generation, smart charging electric vehicles and power-to-heat [22]. Within this work, mCHP is considered a type of DER device capable of providing demand side flexibility in the form of DR for providing peak shaving/peak load reduction – a primary DR service. A short overview of DR is therefore provided here. In Section 6, a review of the value of mCHP flexibility that can be estimated as result of peak shaving is presented.

When procuring demand-side response as a flexibility service, DSOs have the option to procure it either implicitly or explicitly. Implicit DR makes use of grid tariffs (distribution charges) as price signals to guide grid-friendly consumer behaviour during different states in grid conditions. Time-varying tariffs incentivise manual or automated load adjustment, enabling consumers to save on energy bills while benefiting the system. The time-varying price signals are determined based on either the power system balance or on short-term wholesale market price signals [46]. Table 4 describes three time-of-use (TOU) tariffs and their effect on the grid.

Table 4 Grid tariffs descriptions. Adapted from [47].

Tariff	Description	Resulting effect
Static time of use tariffs (sTOU)	Fixed timeframes Higher price applied during fixed daily time frame when peak demand occurs, price is the same for all DR service providers at all locations.	Effective to reduce peak demand when peak times are known to consistently occur in the same timeframe. DSO can potentially avoid/delay CAPEX by reducing congestion caused by peak demand.
Dynamic time of use tariffs (dTOU)	Changing timeframes Higher price can be applied during timeframes when demand-supply imbalance is forecasted. Higher price can be applied when there is transmission grid congestion based on regular congestion forecast. Price is same for all providers at all locations.	Solves TSO congestion, however, does not necessarily solve DSO congestion. This is because dTOU tariffs are based on wholesale market prices which rarely coincide with local network peaks, therefore, they are less effective than sTOU tariffs in reducing peak demand.
Locational dynamic pricing	Changing timeframes and location Dynamic pricing applied but the price can be different for different service providers at different locations. Higher price is applied where congestion exists.	DSOs can potentially avoid or delay CAPEX by reducing congestion caused by peak demand. DSO can potentially avoid OPEX by avoiding RES curtailment payments.

Under price-based mechanisms, there is no guarantee that a predetermined amount of DR will be activated. On the other hand, in volume- or incentive-based (explicit) DR a predetermined volume (MW) of DR is contracted and paid for as an incentive. It is in this case that it is considered “explicit”, in the sense that the activated level of flexibility needs to be explicitly defined in advance [47].

Relevance of the case can be seen from the UK example, where flexibility providers receive payments for contracted capacity and an energy payment when the flexibility is actually activated. UK DSO UK Power Network’s business plan forecasts savings of around £ 40 million [EUR 52 million] from DR schemes from 2015 until 2023, based on successful trials. This can be procured via:

- Direct control operation of DERs with bilateral flexible contracts,
- Issuing calls for tenders for the DR service they require,
- Establishing a local market for DR providers using local pricing.

According to [47], the most efficient and effective option depends on the number of DR providers that are connected to the network (market liquidity). Forming bilateral agreements are most efficient when there are only few providers and forming a local market can be efficient when there are sufficiently many market players. For the purpose of integrating DER it is imperative that network tariffs are designed in a way that provide incentives in accordance with the local conditions to support the desired grid effect. Given that local conditions differ and will change, it is the authors’ view that freedom in designing tariffs tailored to the solutions that best meet the local needs without restrictive regulation would be favourable.

[48] conclude that key developments point to a promising outlook for DSF as DSOs more frequently source flexibility locally and major utility companies further diversify their offerings into virtual power plants (VPPs) that include DR packaged with other forms of DSF and generation. The same authors argue that, as the presence of distributed generation, electric vehicles and other electrified loads in distribution grids increase, distribution network owners and operators will try to defer or avoid grid upgrades and reinforcement by using less traditional “non-wire” alternatives such as local DSF. The UK, the Netherlands, Germany and Norway have made advances in employing alternatives either through third-party platforms or direct procurement by DSOs.

2.4.6 Fuel cell mCHP in distribution grid services

The regulatory framework at European level is conducive to the use of mCHP for services on the distribution network. The Clean Energy Package provides DSOs with a framework to use flexibility and optimise network investment decisions. For example, the Energy Efficiency Directive (2012/27/EU) requires that, where it is technically and economically feasible, high efficiency co-generation operators, such as those under study in PACE, can offer frequency balancing services and other operational services at the level of the DSO (Article 15, par 5). It mandates that such services are part of a services bidding process that is transparent, non-discriminatory, and open to scrutiny.

As of yet prosumer markets are emerging (e.g. Piclo Flex market), but still are highly experimental, or based on constrained case studies, or reflect in unique situations with bilateral agreements. Thus, these markets are unreliable, and while the mCHP is capable of providing services to these markets in accordance with the constraints outlined in Section 2.2, the immaturity of these markets make it very difficult to apply meaningful revenue modelling or to draw any meaningful conclusions about the possible legal and commercial hurdles that could influence the revenue of mCHP participation in these markets. There is no substantive justification for mCHP to not be on an equal footing with other technologies, even less so when aggregated in local energy communities or as collective home energy management systems. Eurelectric calls on policy makers to ensure short-term procurement of flexibility is always open to all resources [49]. Where they suggest that DSO and DER interactions established for flexibility service procurement should be governed by a regulatory framework that allows for fair revenue setting for flexibility determined by the value it provides a particular local network configuration and ideally be defined by a common high-level methodology agreed nationally.

2.5 Summary

In this chapter we provided an overview of opportunities for EVA for mCHP, covering both transmission and distribution grid services, and introduced the possibility for EVA resulting from the avoidance of grid extensions. The opportunity for economic value capture in grid service markets was first described. Then, grid services at the transmission level were explained, including frequency and non-frequency services, and the potential for mCHP participation in TSO markets was discussed. The evolving role of the DSO was then considered in detail, considering conventional DSO practices, emerging DSO grid service markets, state-of-the-art DSO pilot projects, and the potential role for mCHP.

Maximising self-consumption provides the greatest financial benefit for the mCHP owner, a fact that will also be confirmed in Chapter 5 where income streams are simulated and quantified. Additionally, frequency balancing services on the transmission level are considered to be the most accessible revenue stream for mCHPs across the range of grid services that exist in Europe.

The avoidance of grid extension costs is the most transparent and obvious way to capture value and monetise DSO services. However, DSO markets are immature, and there remains significant uncertainty around the future strategic priorities of the DSO in relation to the procurement of services to support grid planning and operation. The greatest short-term opportunity at distribution level is through the procurement of demand response.

Unlike the more standardised transmission level grid services, the distribution grid services that will be requested in the future will be customised, designed to meet the specific requirements of a DSO’s network. Herein lies the opportunity for mCHP: mass coordination in line with DSO designed flexibility services that delay or remove the need for immediate or future grid reinforcements. The financial savings arising from this become the revenue stream for flexibility service providers. Self-consumption, frequency balancing services and local flexibility services jointly support mCHP value stacking, however close TSO-DSO coordination is a prerequisite for practical implementation to avoid technical conflicts in service provision and cannibalisation of each other’s markets.

3 Methodology

Summary box of the Chapter

This Chapter describes the qualitative and quantitative methods employed throughout this deliverable. Firstly, the country selection process for selecting countries for further analysis is explained. Using a multi-criteria assessment, each country is rated considering factors such as potential mCHP market size and spark spread. Secondly, the approach used to quantify the additional income streams from participating in TSO balancing markets is laid out. The available remaining flexibility is determined by optimising the mCHP operation towards a cost-optimal self-consumption policy. As an optimisation input, energy demand profiles of typical houses are forecasted, and domestic energy prices including subsidies are investigated for all selected countries. Then, the revenue streams from offering the remaining flexibility to the TSO balancing auctions are quantified based on historic market data. Finally, a literature review used to estimate the cost savings from avoided grid extensions at the DSO level is outlined.

3.1 Overview (building blocks of the research work)

Deliverable 4.3 brings together research work associated with PACE WP4 Tasks 4.2, 4.3 and 4.4. As illustrated in Figure 1, Tasks 4.2 and 4.4 are concerned with quantifying the economic value added for mCHP through the participation in grid service markets. Task 4.3 is concerned with an analysis of the economic value added from the avoidance of grid extensions, attributable to mCHP as a source of flexibility.

The principal research foundations for Task 4.2 started with a multi-criteria evaluation (MCE) process that selected the four most mCHP-friendly European markets (Section 3.2.1) and subsequently evaluated the most favourable grid service markets from the four countries selected (Section 3.2.2). Input from PACE consortium members steered the process to include a fifth additional country (Czech Republic). After which two countries (Belgium and Czech Republic) with their respective grid service markets (GSMs) were chosen along with Germany in a detailed analysis.

The additional revenue streams from providing grid services are quantified following a two-step methodology as shown in Figure 5: In a first step, the optimal self-consumption policy was identified based on country-specific market mechanisms. For all three countries, a total of four scenarios each were parametrised to cover both proton-exchange membrane fuel fell (PEMFC), and solid oxide fuel cell (SOFC) technology. Aligned with the respective scenarios, energy demand profiles for different buildings were forecasted for all countries. Building parameters such living area or insulation thickness were chosen to represent the future mass-market for mCHP devices based on inputs from previous work packages. An optimisation framework was developed based on the “dynamic programming” algorithm to identify the cost-optimal self-consumption policy.

The optimisation results (outcome of the first step in Figure 5) then served as input to the second step where the GSM income was quantified. A set of balancing products was selected in deliverable 4.2 [50] according to the methodology outlined in Section 3.2 below. The revenue streams for each product and scenario were quantified based on publicly available historic market data. Data availability, market clearing mechanisms and the regulatory framework differ substantially among the countries considered. Hence, the methodology applied to quantify the revenue streams was adapted to accurately reflect the respective country (see Section 3.4).

Identify optimal self-consumption policy

First step – Described in Chapter 0

- Predict energy consumption patterns for electricity, hot water, and space heating
- Optimise self-consumption policy using dynamic programming
- Quantify how much flexibility can be offered to the grid service markets

Quantify additional grid service market income

Second step – Described in Chapter 5

- Based on historic market data and knowledge or the available flexibility: Estimate the additional grid service market income by deviating from the ideal self-consumption policy upon activation

Figure 5: Workflow for the quantitative EVA as a two-step methodology

Given the nascence of GSMs in distribution systems, an estimation of the economic value added, attributable to mCHP as a flexibility source, was undertaken in a qualitative analysis. By a review of literature, the value capture realisable through the avoidance of grid extensions is estimated (Section 3.5).

3.2 Selection of target countries and GSM products for modelling

The methodology for selection of target countries and grid services is described first within this section. In a two-step process consisting of a multi-criteria evaluation (MCE) followed by a comparative analysis, the mCHP market attractiveness and grid service market (GSM) attractiveness of the EU-27 plus Norway and Switzerland were respectively assessed. Germany, as the most developed European mCHP market, was automatically selected for detailed analysis. The following section details the approach taken in selecting the two additional countries for detailed modelling of the optimal self-consumption policy and additional grid service market income.

3.2.1 Selection of target countries using multi-criteria assessment

The MCE is a structured approach to formalise a decision by comparing alternatives. With the assistance of PACE consortium members, the 29 countries under consideration were reduced to four according to process outlined in Figure 6. In the given context, the MCE was used to rank alternative countries based on a set of evaluation criteria defining their market attractiveness [51], providing a basis for the likely success of the mCHP market in those countries. The criteria were identified and chosen to evaluate market attractiveness based on literature. Economic Value Added (EVA) and Market Potential made up the top tier criteria that were further decomposed into a second tier of criteria consisting of spark spread, existing self-consumption policies, government subsidies, potential market size, heat demand, future policy changes and the mCHP installed base. For the second step, one-on-one interviews with PACE members allowed for the numerical rating of countries according to the defined criteria, followed by the weighting of the criteria using the Analytical Hierarchy Process (AHP)[7] to give an overall assessment of a country's mCHP market attractiveness once scores were aggregated. Belgium, Ireland, Italy, and the United Kingdom (UK) made the shortlist of countries with the potential for having the most attract mCHP markets. The criteria weighting and the selection of countries were both reviewed and accepted by the PACE team and advisory board. A summary of the results of the analysis is provided in Appendix B.

Figure 6: Multi-criteria evaluation approach applied in PACE

Additionally, four marginal countries that missed making the shortlist were also identified during the shortlisting process: Czech Republic (CZ), France, the Netherlands and Spain. At the request of the consortium members, for reasons of gaining market insights beyond Central and Western Europe, CZ was included in the subsequent comparative study alongside the four shortlisted countries, increasing the shortlist to five. As the only marginal country representing Eastern Europe, CZ was also selected for further investigation, because:

- Czech reliance on coal would mean a transition to gas causes immediate significant reduction in primary fuel carbon intensity, making natural gas-based mCHP an attractive technology;
- There has been a limited focus in other projects on Eastern European markets in previous works;
- It would be useful to understand the attractiveness of the technology in a different market context.

3.2.2 Final country selection and choice of GSM products for detailed modelling

By means of a comparative study to assess grid service market attractiveness, the five countries were further narrowed down to two. The criteria used to down-select the countries were the existence of suitable grid service market products for mCHP; the ease of grid service market accessibility; grid service market remuneration; information quality; and availability of data. The primary focus for the down-selection was an appraisal of the frequency balancing markets, as these were found to be the most mature. The result, when

[7] AHP is a method used for pairwise comparison of elements or criteria, which are structured in defined hierarchy resulting in weights for the criteria and checking the consistency of the evaluation [110]. Details of the evaluation process can be found in D4.2.

combined with the broad market attractiveness conducted prior, was a recommendation of three countries (including Germany) and seven balancing products selected for the detailed modelling (laid out in Section 3.4).:

- Germany aFRR +/-
- Belgium mFRR +/-
- Czech Republic aFRR and mFRR +/-

Belgium is a country with political power segregated to three levels: the federal government, and the three regions (the Flemish Region, the Walloon Region, and the Brussels-Capital Region). COGEN Vlaanderen summarised the situation in [52] as: “Energy and CHP related matters are regional responsibilities”. Correspondingly, subsidy schemes deviate between the three regions. In this report, we focus on the Flemish region where most of the Belgian mCHP units are installed to date. Most of the installed base (over 400 mCHP units) is in Flanders, while only 11 units are in Brussels [53], [54]. This choice of the region does not affect the modelling of the TSO grid service income in Chapter 5 since Elia is the only TSO active in Belgium and spans all three regions. The choice of the Flemish region is however reflected in Chapter 0, where the cost-optimal self-consumption policy is derived based on typical energy prices, subsidies and energy demand profiles. Full justification for country selection is provided in D4.2

3.2.3 Justification of GSM products

A general rule of thumb regarding the profitability of frequency balancing products: the faster the activation time, the higher the value of the service, despite the variation between countries [3]. As a result, FCR is typically remunerated the highest and mFRR the lowest[8]. Unfortunately, the stringent FCR prequalification requirements, especially with respect to activation speed, disqualifies mCHP participation in Germany, Belgium and Czech Republic.

For Germany, mCHPs can in principle provide mFRR, however, their lower remuneration makes the business case less attractive for the service provider. Given that mCHPs have the capability of fulfilling the technical pre-qualifications requirements of aFRR whilst receiving a relatively more attractive remuneration than mFRR, though less than FCR, positive aFRR and negative aFRR are selected as the most suitable balancing products to be modelled for Germany. Further justification for modelling aFRR positive and negative (aFRR+/-) is that:

- some PACE manufacturers already comply with aFRR prequalification requirements,
- other PACE manufacturers see the five minutes reaction time as a realistically achievable goal provided the investment is economically sensible.

[8] A counter example of this being in Switzerland, where FCR is remunerated less than aFRR as FCR is traded internationally.

As explained in T4.2, mFRR is most suitable in the case of Belgium because similar to Germany, mCHPs cannot fulfil the reaction time for FCR; and unlike Germany, aFRR was not open to aggregation at the time of writing. For the Czech Republic, both aFRR and mFRR +/- are suitable for modelling as mCHPs could fulfil the required activation speed of 10 minutes and 5-15 minutes respectively.

Grid services for the Czech Republic are defined in Appendix A.

3.3 Self-consumption policy optimisation

3.3.1 Scenario development for mCHP modelling

The two mCHP technologies represented in the PACE project (PEM and SOFC) were considered in separate scenarios and sensitivities were developed to support EVA modelling. Parameters for each scenario were chosen to represent the PACE manufacturer as accurately as possible, while still allowing to reasonably compare or interpolate between the different cases.

Inputs from preceding work packages served as a starting point for choosing the modelling assumptions and parameters used in this deliverable. In order to challenge the assumptions, the parameters were discussed and revised with all consortium partners on several occasions. In Task 4.2 [50], ten scenarios in total were modelled for Germany. In Deliverable 4.3, the modelling is repeated for the two additional countries. The final selection of parameters as reviewed by all manufacturers is summarised below. For further details see Deliverable 4.2 [50].

The final four scenarios applied to all three countries each are summarised as follows:

Scenario "PEM SFH"

Based on typical values from OEM datasheets, modelling assumed a PEMFC with η_{el} = 38%, and η_{th} = 52%. The maximum output power was chosen as 1.5 kW_{el}, and 2.05 kW_{th}. Modulation is not possible. Either the mCHP is running at full power, or it is shut down completely.

This scenario focusses on the single-family house (SFH) case according to the energy demand profiles from Table 5. When the PEMFC is running for a whole day, it generates 2.05 $kW_{th} \cdot 24$ h/day = 49.2 kWh_{th}/day. To ensure sufficient stack cooling, all heat generated by the mCHP must be utilised for space heating (SH), domestic hot water (DHW), or be stored in the hot water storage tank (HWST). In summer periods without SH demand, DHW consumption represents the only option to get rid of the heat. According to Section 4.1, DHW consumption is limited to 19 kWh_{th}/day. Consequentially, the mCHP can only be activated for a few hours a day. An optimisation framework is needed to pick the most profitable operating hours. During winter times, stack cooling is facilitated as additional waste heat can be utilised to cover SH demand. In winter months, the overheating problem is almost fully mitigated and the mCHP can be run the whole day long.

The assumed power rating of 1.5 kW_{el} for PEM is about 50% higher than typical values for commercially available units from PACE manufacturers to date. This is motivated by a variety of reasons. First, smaller units are less appealing to offer flexibility since less spare capacity is available to assist the grid as shall be seen in Chapter 5. Second, smaller units do not exhibit the overheating problem described above and are thus less limited in their operating policy. Therefore, the self-consumption strategy of such smaller PEM units is comparable to the SOFC scenario below where a heat output of only 750 W_{th} is assumed. Third, it would be unfair to assume different electrical output power for the scenario PEM compared to SOFC below. The revenue streams associated would not allow to draw a fair comparison between the scenarios. Fourth, mass market uptake of mCHP devices in Europe is expected to result in lower prices for fuel cells due to scale effects. Consequentially, bigger stacks may be offered at competitive prices.

Scenario “PEM 3FH”

This scenario should approximate the energy demand of a small enterprise with an electricity consumption of 12 MWh_{el} per year. Compared to the scenario “PEM SFH”, the energy demand profiles are each multiplied by a factor of three. This is motivated by the fact that a 1.5 kW_{el} fuel cell unit produces up to 12.9 MWh_{el} per year when running at full capacity.

Scenario “SOFC SFH”

Here, an electrical efficiency of η_{el} = 60%, and η_{th} = 30% is assumed, based on [55]. The power output can be modulated between 0.5 … 1.5 kW_{el}. Due to a high electrical efficiency, only 750 W_{th} are generated at maximum output power. Hence, the SOFC unit generates only 18 kWh_{th} per day when running constantly at full power. Even in summer without any SH demand, all heat generated by the mCHP is fully utilised for DHW consumption. The mCHP could thus be run the whole year long without overheating problems. The SOFC could of course still be switched off for economic reasons if it is financially more attractive to satisfy the heat demand by the auxiliary gas burner (AGB) as discussed in Section 4.3.

Scenario “SOFC 3FH”

Aligned with the scenario “PEM 3FH”, this scenario represents a small enterprise with an electricity consumption of 12 MWh_{el} per year. However, here an SOFC unit is assumed with a rated output of 1.5 kW_{el} according to Table 5.

The storage tank arrangement from Figure 7 is applied to all scenarios. Technical details such as heat exchangers needed to separate drinking water from heating water are omitted in the drawing. The HWST volume is set to 350 litres, based on the required sustain times for providing mFRR. Details on HWST dimensioning are discussed in Section 5.6.3.

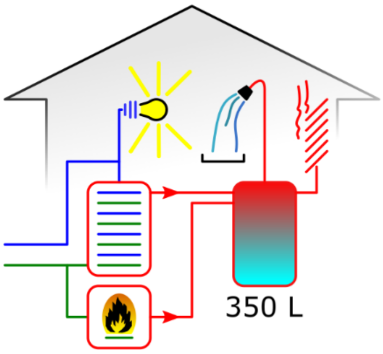

Figure 7: Heating system arrangement with HWST volume of 350 litres. The mCHP is backed up by the auxiliary gas burner

Compared to deliverable 4.2 [50], the following scenarios are excluded from this deliverable:

- **Biogas**[9]: Biogas is more costly than natural gas. Running the mCHP is thus more expensive and the spark spread is reduced. Similarly, running the auxiliary gas burner (AGB) with biogas results in a higher financial cost for heat. Consequentially, the optimal self-consumption policy is mostly unaffected by the gas price, even though the total operating costs do increase. Since the available flexibility follows directly from the self-consumption policy, the added value from GSM participation is comparable to the non-biogas case.
- **Small storage**: In deliverable 4.2 about Germany, a smaller HWST size of only 220 litres is found to be sufficient for aFRR market participation. However, for Belgium and the Czech Republic the mFRR products shall be considered here as well. For mFRR, the sustain times upon activation are generally longer by design, and therefore require an increased volume to avoid overheating. Further details on tank dimensioning will be discussed in Chapter 5.

3.3.2 Self-consumption policy optimisation

In this section, the mathematical methodology to work out the cost-optimal self-consumption policy is introduced. As explained in Section 3.3.1, providing sufficient cooling to the fuel cell unit can be challenging during hot weather periods with low heat demand. Throughout summer months, for some scenarios the mCHP must be switched off temporarily in order to avoid overheating. An intelligent control logic of the heating system ideally activates the mCHP when it is financially most attractive.

[9] Raw biogas mostly contains methane and CO_2, but also some amounts of carbon monoxide, sulfides, moisture and siloxanes that could damage the fuel cell stacks. In this chapter, biogas refers to processed gas in natural gas quality with all components other than methane filtered out.

One possibility to implement this is developed in the following based on a mathematical methodology referred to as "dynamic programming". The various input parameters for the optimisation framework, including energy demand profiles, energy prices, and the modelling of the heating system are summarised in Table 5.

Table 5: Input parameters to the optimisation framework

Parameter	Germany	Belgium (Flanders)	Czech Republic
Energy demand profiles for electricity and heat consumption	Hourly data for a full year - See Table 6		
Electricity price for electricity purchased from the grid	30.1 ct./kWh$_{el}$ [56]	28.5 ct/kWh$_{el}$ [57]	18.5 ct/kWh$_{el}$ [58]
Gas price (volumetric price, without fixed costs)	4.1 ct./kWh [59]	2.9 ct./kWh [60]	5.0 ct./kWh [61]
OPEX support, subsidies, and feed-in tariff (FIT) **Further details in Chapter 5**	– FIT according to "KWK Index" [62] – KWKG subsidy on produced electricity [63]	– Electricity purchase via DSO; depending on grid operator [64]	– "Green bonus" subsidy on first 3'000 operating hours per year [65], [66]
mCHP setup	– For SOFC: η_{el} = 60%, and η_{th} = 30% For PEM: η_{el} = 38%, and η_{th} = 52% – 1.5 kW$_{el}$ installed capacity for PEM and SOFC – Heating system integration according to Figure 7		

The optimisation algorithm iterates each time step in hourly resolution for the whole year. For each time step, the decision is taken regarding whether the fuel cell should be ramped up or down based on the variable costs induced, given the forecasted energy demand profiles. Figure 8 illustrates one example of the inputs and outputs to the optimisation framework. For this visualisation, the example of a PEM unit in Germany is selected according to the parameters in Table 5. The resulting operating hours of the mCHP are plotted in the middle sub-plot. Some space heating demand during the night-time hours is observed for the first three days (left half of the plot). During these three days, more operating hours of the mCHP are facilitated compared to the last days of the time interval displayed, where production is limited to few hours, concentrated to those with highest electricity consumption. The temperature trajectory of the HWST is drawn on the bottom subplot. Boundary conditions are set such that the volume-weighted HWST temperature stays between 40°C and 70°C. Temperature layering within the HWST volume then ensures a supply temperature of more than 50°C is always guaranteed for comfort. The AGB is activated if comfort levels would otherwise be violated.

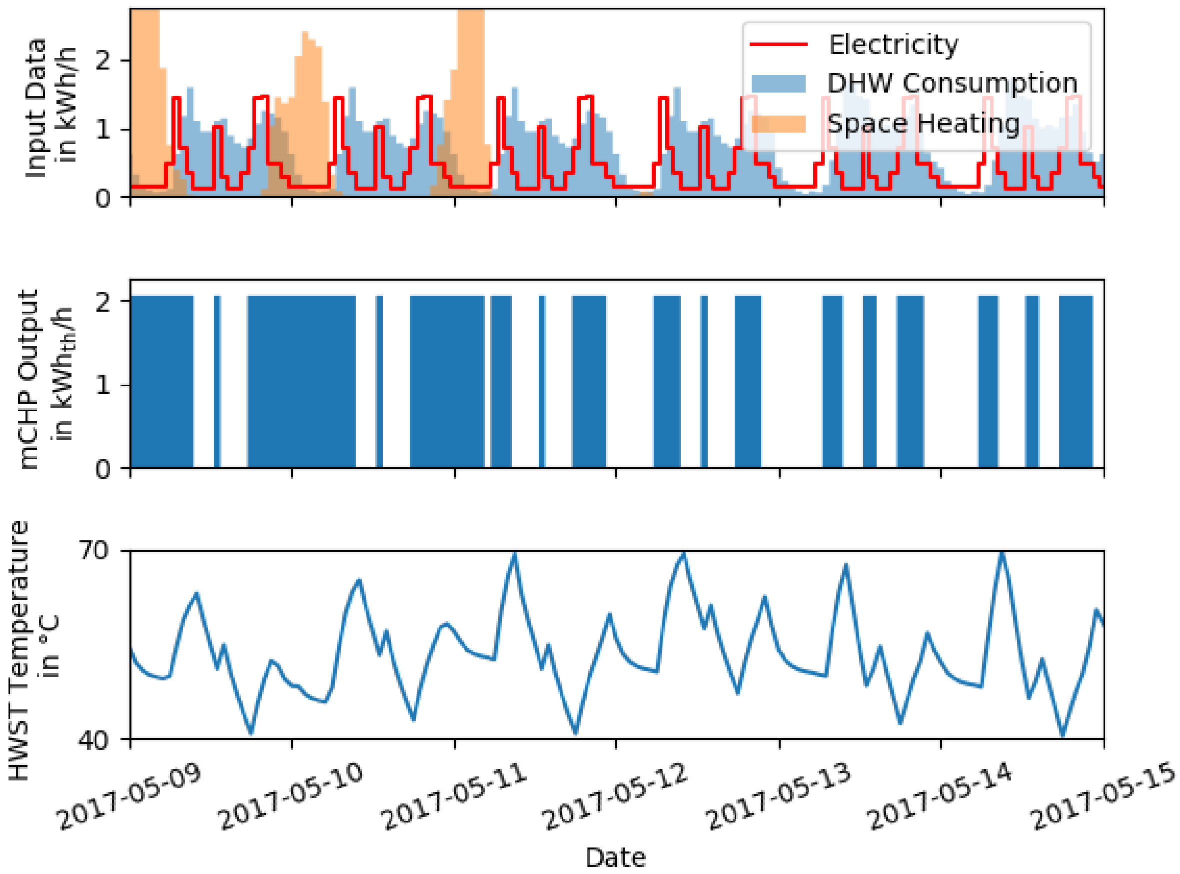

Figure 8: Optimised self-consumption policy for one week in May 2017. Parameters for the PEM device in Germany are given in Table 1

3.4 Estimating the additional income from balancing products

Section 3.2 notes that three countries were chosen for grid services revenue modelling: Germany, Belgium and the Czech Republic. For each of the three countries, a set of balancing products was selected according to the methodology in Section 3.2.2. For these products, the additional income streams are quantified in Chapter 5. As shown in Figure 5 first the self-consumption policy is optimised according to the methodology in Section 3.3. As a result, each time step is assigned to an mCHP operating state of either “running”, or “idle” respectively. In a second step, the additional income from offering aFRR and mFRR is quantified. Positive balancing (ability to increase electricity output upon activation by the TSO) is then offered to the market for all time periods where the mCHP is idle and thus able to increase power production. Vice versa, negative balancing is offered whenever power output could be reduced. The aggregator supplements the offered mCHPs capacity in his portfolio by other plants to comply with minimum bid sizes and bidding intervals.

3.4.1 Approach for Belgium / Germany

Two interrelated income streams are associated to balancing products: “availability” (also referred to as “reservation income”); and “utilisation” (also known as “activation income”).

Availability income compensates for being ready to adjust power output in case of activation. An auction is organised by the TSO where aggregators place bids for capacity in €/MW/h. The cheapest units are contracted until the predetermined quantity of balancing capacity is reached. In Germany, Belgium, and the Czech Republic, the payment scheme is paid-as-bid for availability. As the name suggests, cheap bids increase the chance of being accepted. However, the profit margin is reduced as the TSO pays no more than the specified bid price. The bidding strategy in this deliverable follows the methodology from QualyGridS [18], where it is assumed that an experienced aggregator should manage to obtain at least the volume-weighted average price. Raw data of anonymised availability bids published by the German TSOs [67] and Elia [68] are used to derive the needed price signal.

After market clearing for availability, the TSO organises a secondary auction that focusses on utilisation. There, the reimbursement for energy actually delivered upon activation is determined. For Germany and Belgium, utilisation payments follow the pay-as-bid scheme as well. The activation logic is sketched in Figure 9. The bid price for utilisation p^* specified by the aggregator (in €/MWh) determines the activation probability as the cheapest units are activated first and for longer. The more balancing capacity is activated, the higher the price.

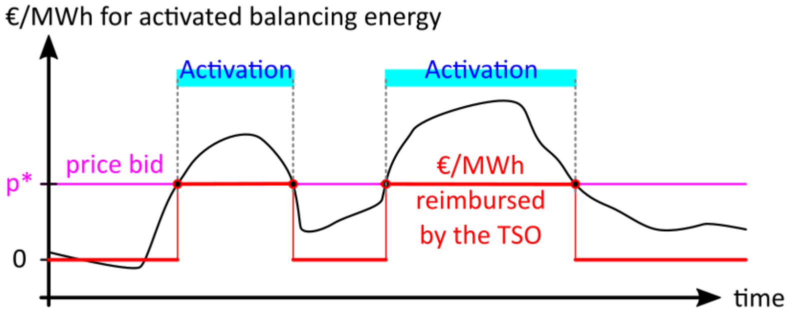

Figure 9: Balancing energy activation based on merit order principle

Aggregators try to place their utilisation bids such that overall profit is maximised. Offering at very high prices yields good profit margins once activated, but activation is very rare and overall profit from utilisation over time is lower. The optimal bid placement for utilisation also follows the methodology outlined in QualyGridS [18], where at least one year of historic data is used to calculate the optimal bid that maximises overall profit for each balancing product.

3.4.2 Approach for the Czech Republic

In the Czech Republic, availability is remunerated pay-as-bid (see [69, Para. 2.3.6]), just like Germany and Belgium. Consequentially, the process to quantify the availability income is very similarly to Section 3.4.1. However, there is one minor difference worth highlighting: According to the local experience of Czech aggregator Nano Energies a.s [70], most of the time accepted bid prices are close to each other, except for very few unpredictable expensive days per year. Based on experience, it is more profitable to place bids slightly below the predicted average, at the advantage to being selected very close to 100% of the time. It can be assumed that price seasonality is accurately predictable thanks to historic data analysis (moving average, outlier removal etc.).

The main public source to estimate balancing reserves income is the ENTSO-E transparency platform [71]. For the Czech market, there are different datasets available such as:

- Price of reserved balancing reserves for different reserve types (FCR/aFRR/mFRR) and contract types (yearly/daily)
- Volumes of contracting balancing reserves for different reserve types and contract types
- Accepted offers of balancing reserves for different reserve types
- Activated balancing reserves for different reserve types
- Prices of activated balancing energy for different reserve types
- Procured capacity (where it is possible to see different price bids)

Given that in PACE analysis considers a cluster of mCHP in the domestic sector, aggregators cannot guarantee the availability nor the exact volume one year in advance. Thus, among the current two available contract types (yearly and daily), aggregators would focus on the daily auctions. Up to the year 2019, the TSO only bought some individual hours at the daily market to complete its yearly contracts when it was necessary. Starting in 2020 however, the TSO bought a constant rate of 20 % to 25 % of balancing capacity on the daily market, enabling the development of a statistical model based on one full year of data.

According to Nano [70], the activation income is generally minor compared to the availability income. It can be estimated using average activation rates. In contrast to the merit-order principle for Germany and Belgium, aFRR activation is paid pro-rata. All RPUs are activated at the same time and at the same price. Regarding mFRR, bidders are activated based on their merit order, same as for Germany and Belgium.

3.5 Quantifying the economic value added from the avoidance of grid extensions

Prior to the systematic literature review, a consultation process involving PACE manufacturers was used to inform the scope of the review that would create the greatest value for the project partners. The process entailed video conferences with the manufacturers where semi-structured interviews were carried out. The responses were consolidated, and further discussions were conducted with COGEN Europe. The conclusions drawn focused the review on answering the question: what is the economic value mCHP flexibility adds to the distribution grid for DSOs? Additional areas of interest included understanding the strategic priorities for DSOs, their sources of revenue, and how these align with the benefits provided by mCHP units. Moreover, understanding the effects of mCHP units in reducing peak demand on the low voltage network when forming an integral part of a wider context e.g. home energy managements systems (HEMS) and local energy communities. Finally, partners wanted work to present the current state of pilot projects of DSO grid service markets.

To this end, the search criteria focused on papers evaluating the avoided grid costs arising from micro-CHP flexibility. However, a clear gap in literature at the time of writing meant that this question could not be adequately addressed. Mateo et al. [72] and Cao et al. [73] are the two reference points for this work that both studied the distribution grid impacts of mCHP micro-generation specifically. Others focus on techno-economic analysis to determine the financial savings mCHP units can offer the prosumer as opposed to the grid [74]. Therefore, a broader definition of mCHP flexibility was adopted to include the value of demand side flexibility (DSF) delivered to the distribution grid through other means of distributed flexibility i.e. distributed energy resources (DERs). Broadening the search criteria in this manner allowed for the question of avoided grid costs to be more adequately addressed, albeit at the expense of generalisation.

Over 100 relevant papers were identified through ‘pearl growing’[10], citation chasing and a search using academic databases IEEE explorer, Scopus, Web of Science, Science Direct and Google Scholar. Filtering and applying the inclusion criteria narrowed those down to 18, allowing for a full text review and data extraction to

[10] Citation mining

be performed. This supported the analysis in Section 6 where data is compared and contrast in order to provide an estimation of the economic value of mCHP in terms of grid reinforcement avoidance.

It should be noted that the original scope of the task, as defined in the work package description, described the analysis of typical German electricity demand profiles coupled with mCHP infeed to determine the resulting maximal percentage grid peak capacity reduction. However, this was found not be of relevance to this work as the mandate was to qualitatively determine the EVA of grid extensions, and so the approach described above was adopted.

4 Results of self-consumption policy optimisation for mCHP installations in Germany, Belgium and Czech Republic

Summary box of the Chapter

Self-consumption currently represents the most important income stream and the main financial motivation for house owners to install an mCHP unit [3]*. In order to understand the potential EVA that can be obtained by mCHP through participation in grid services markets, it is necessary to develop a model for self-consumption. The rationale for, and outcome of, the modelling process are described in this chapter.*

To derive the cost-optimal self-consumption policy, energy demand profiles for each scenario were required. A model house was defined and built in simulation according to country-specific insulation standards and weather conditions. The energy demand profiles for domestic hot water, space heating and electricity consumption were then simulated for a full year using historic weather data.

The mCHP and storage tank operation policy was optimised based on the energy demand profiles and on the local energy prices within each country. The four scenarios described in Section 3.3.1 were repeated for all three countries.

The outcome of this chapter reflects how much flexibility is available in each scenario and serves as input for Chapter 5, where the additional income streams from offering that flexibility to the TSO are quantified.

4.1 Introduction

In all three countries considered, electricity purchased from the grid is more expensive per kilowatt-hour than natural gas. Substantial savings in annual electricity costs can be achieved by converting the chemical energy contained in gas into electricity for self-consumption. The effect is maximised for highly efficient CHP units such as those considered in PACE: PACE manufacturers offer solutions to integrate the mCHP's heat production into the existing heating system, enabling very high efficiencies of 90% and beyond.

The self-consumption policy is influenced by both the electrical and thermal demand profiles of the building. The interaction of the different profiles necessitates the deployment of a multi-energy model, which is developed in the following Sections. Section 4.1 focusses on energy consumption forecasting for typical houses in all three countries. The resulting time series data for space heating (SH), domestic hot water (DHW), and electricity consumption serve as a time series input to determine the cost-optimal self-consumption policy. An optimisation framework is developed, implementing some model-based optimisation algorithm called “dynamic programming”. The effectiveness of the proposed self-consumption strategy is compared to purchasing all electricity from the grid. Results are presented in Section 4.3 and discussed in Section 4.4

4.2 Energy consumption of a typical house

The optimisation framework relies on energy demand forecasts in hourly resolution. Time series data for electricity and heat demand for a typical house in all three countries are needed. The challenge is to find adequate data of sufficient quality that additionally is consistent between all countries. As no suitable data source could be found, it was decided to generate the required data as part of the task.

In this Section, a house is modelled according to a state-of-the-art simulation procedure, and using the static parameters delivered by previous work packages, including:

- Living area of the building to be modelled
- Type of construction (construction year, mechanical ventilation etc.)
- Location (meteorological conditions)
- Number of inhabitants.

The scope of WP4 focusses on the "typical domestic house". It represents the future mass market for mCHP installations in order to align with PACE targets to foster mass market uptake. After several feedback rounds with PACE manufacturers organised by HSLU, a house exhibiting an energy reference area (ERA) of 140 m^2 and five inhabitants was taken forward. As recommended by the preceding work package, thermo-physical properties of the house were taken from the EU buildings database [75] for all three countries. The hourly heat profiles were calculated using IDA ICE from EQUA Simulation AB. Results are visualised in Figure 10.

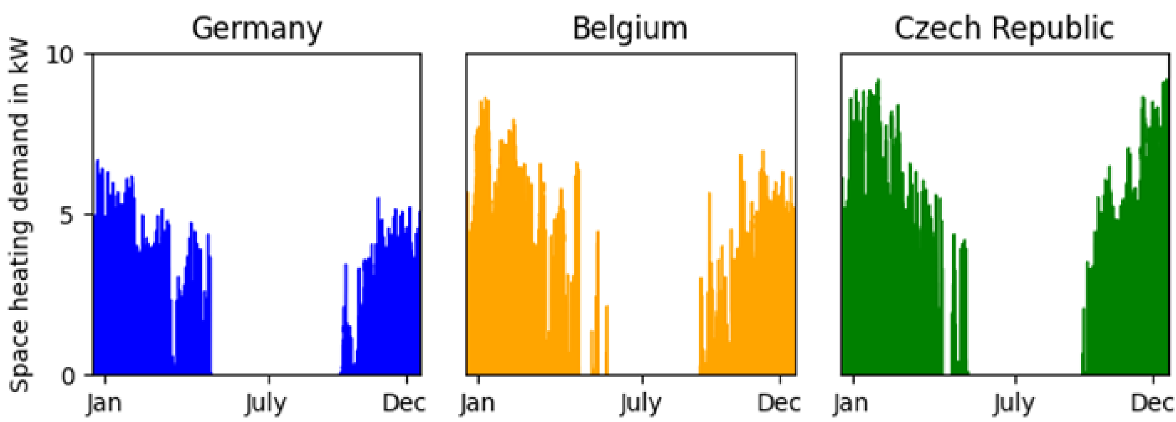

Figure 10: Space heating demand for a typical single-family house

According to the mCHP manufacturers, a DHW consumption of 19 kW_{th}/day represents a typical four to five person household. Heat demand within each day is distributed according to standard profiles from SIA norm 385/2:2015. Based on BDEW [76] an electricity demand of 4'000 kWh_{el} per year and household was taken forward. The hourly distribution within each day was adapted from standard profiles given in SIA norm 385/1:2011.

Table 6 summarises the key takeaways from this Chapter. Since electricity and DHW consumption are taken from standard profiles, no difference is observed when comparing the three countries. However, space heating demand varies due to geographic climate conditions and different country-specific insulation standards. The space heating demand in Prague sums up to 14.2 MWh/y, which is slightly higher than the 12.7 MWh/y in Antwerp or 9.3 MWh/y for Germany.

Table 6: Key input and output parameters of energy demand modelling

	Metrics	Germany	Belgium	Czech Republic
Input parameters	Living area	140 m^2		
	Number of inhabitants	4 to 5 persons		
	Location for meteo data	Berlin	Antwerp	Prague
Output parameters	Yearly total space heating demand	9.3 MWh/y	12.7 MWh/y	14.2 MWh/y
	Yearly total electricity demand	4 MWh/y distributed according to SIA 385/1:2011		
	Daily DHW consumption	19 kWh/d distributed according to SIA 385/2:2015		

4.3 Results of the self-consumption optimisation

For all three countries, the same four scenarios from Section 3.3.1 were optimised in hourly resolution. The resulting cost-optimal operating policy is visualised in Figure 11. There, the number of mCHP full-load operating hours is aggregated on a monthly basis. The y-axis "monthly mCHP utilisation" is normalised to 100 percent as some months exhibit less than 31 days. The following key points are observed:

- **Germany**: For almost all scenarios it is financially most attractive to run the fuel cell around the clock for the entire year. Only for PEM SFH, the output power is reduced in summer as discussed in Section 4.4.
- **Belgium**: The monthly utilisation figures has a similar shape to Germany. However, the monthly utilisation for both SOFC scenarios drops during the summer months as discussed in Section 4.4
- **Czech Republic**: The monthly operating hours for SOFC are constant throughout the year and thus unaffected by the seasonal heat demand. This is also discussed in Section 4.4.

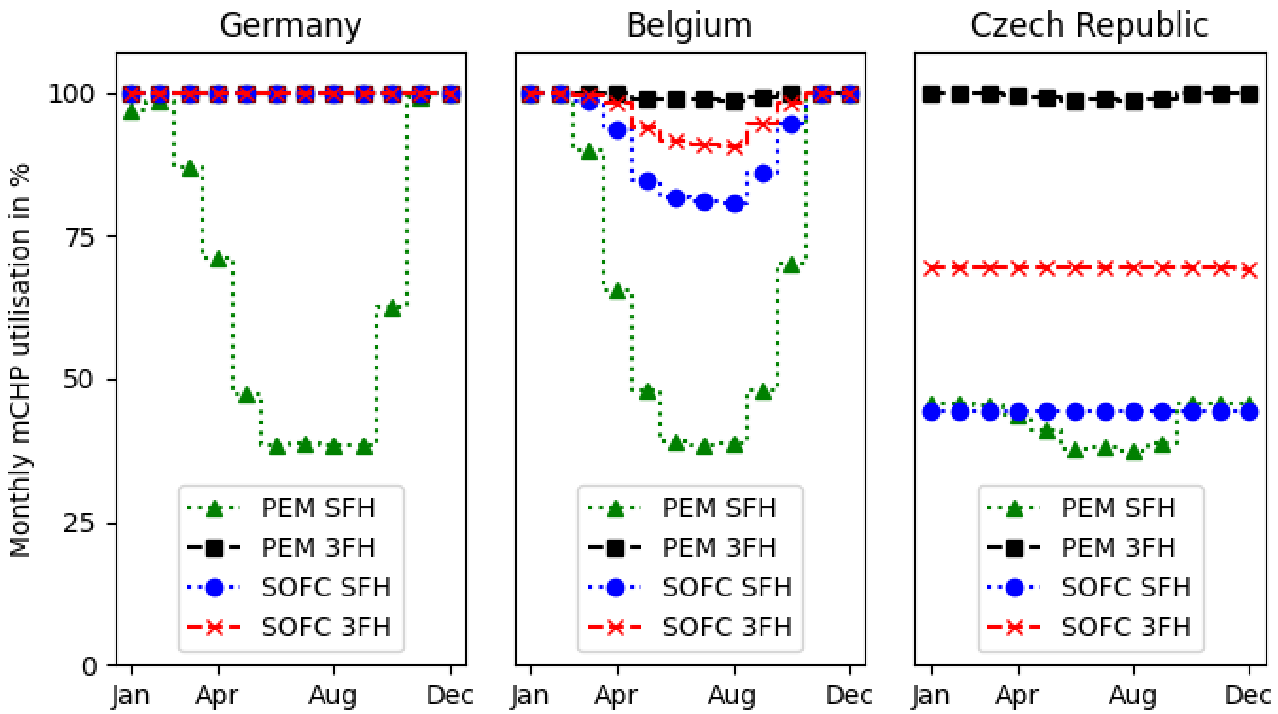

Figure 11: Results of the self-consumption policy optimisation. Model parameters are described in Table 5.

In Figure 12, the financial implications of self-consumption are compared. For each scenario, the blue bar "Energy costs without mCHP" represents the total yearly costs of purchasing all electricity and gas from the grid, assuming the heat demand is supplied entirely by a gas condensing boiler and the electricity entirely from the grid. The orange bar shows the yearly costs for electricity and gas consumption in case a mCHP is present and optimised for self-consumption.

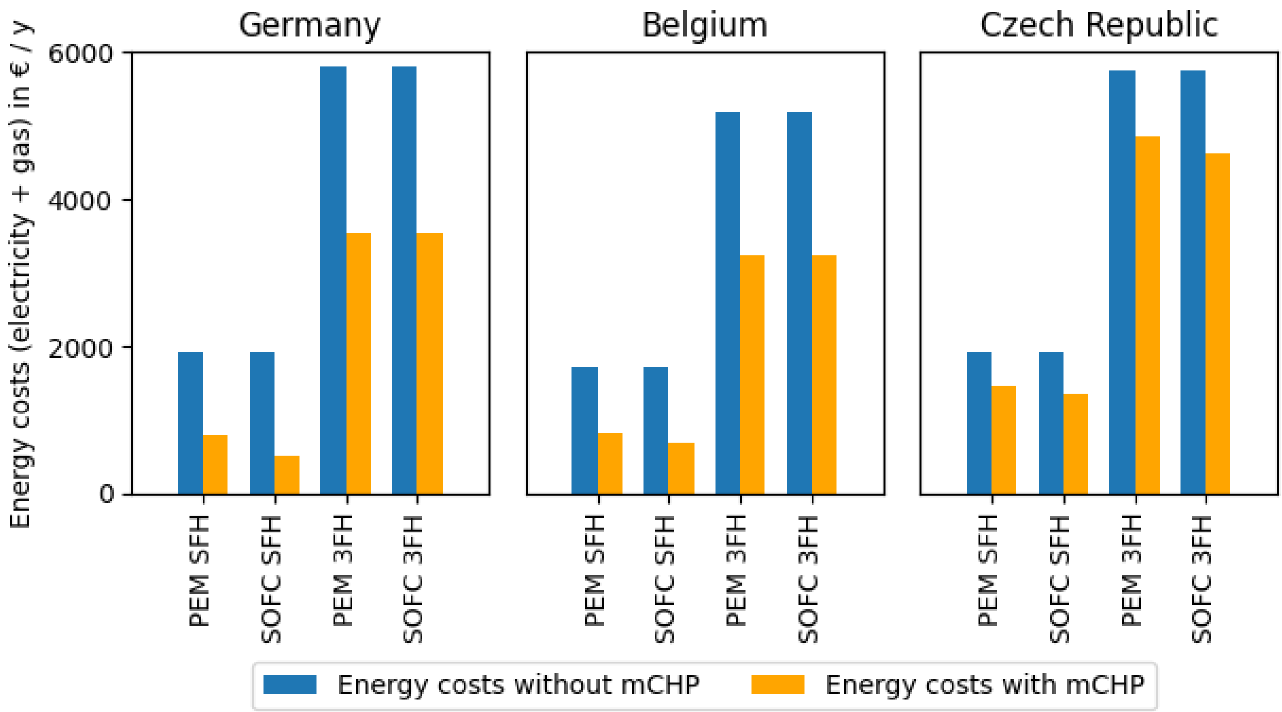

Figure 12: Comparison of total volumetric energy costs including electricity and gas costs. Model parameters are described in Table 5.

4.4 Impact of taxes and levies on the self-consumption optimisation

This section clarifies the impact of taxes and levies imposed on the gas or electricity prices. Recall from Section 3.3 that for the self-consumption policy optimisation the variable components of the electricity prices must be considered. Fixed costs, such as the annual fee per grid connection point, are considered sunk costs and do not influence the mCHP operating hours.

In Figure 13, the three main components of the domestic electricity price are compared across the three countries. The 'energy cost' component is open for competition on the free market, while the other two components are heavily regulated. The component 'grid usage fees' includes the distribution costs at DSO and TSO level. Under 'taxes & levies', several components are combined, dependent on the country.

As illustrated in the figure, the first two components for energy and distribution costs are very similar across all three countries. In contrast, the taxes and levies are directly dependent on political decisions and thus differentiate substantially. For Germany and Belgium, the tax component consists of mainly value added taxes (VAT), and government support programs for renewable energy production, among a variety of other levies and taxes. For the Czech Republic, more than 80% of the taxes are related to the support for renewables. When comparing absolute numbers, it is observed that this part breaks down to only about 2.3 €ct./kWh for the Czech Republic [58]. In Germany however, the “EEG surcharge” related to renewables is set to 6.4 €ct./kWh [56] and thereby almost a factor of three higher.

As explained in Section 3.3, the profitability of the mCHP relies on electricity prices being substantially higher than the price of natural gas. In the near future, it could be that the Czech Republic decides to ramp up its infrastructure investments in renewable energy production following the example set by German or Belgium, and the taxes could rise accordingly. If this indeed is the case, a situation where electricity prices in the Czech Republic will move towards Belgium or German levels seems realistic. At face value, this would create a stronger business case for mCHP in the Czech Republic.

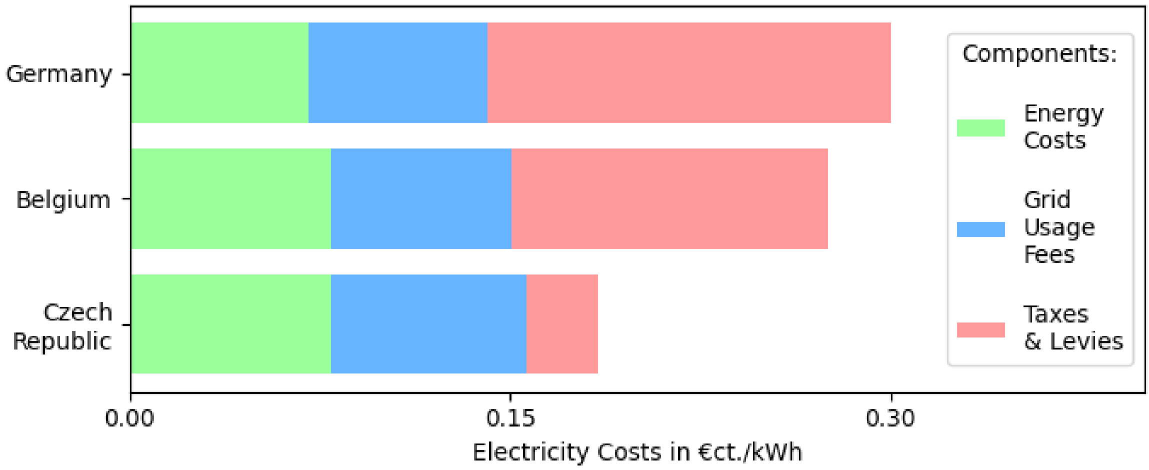

Figure 13: Components of the domestic electricity prices.
Own illustration based on [56], [58], [77]

Conversely, an increase in gas price has potential to reduce the difference between electricity and gas prices; so, not only is the electricity price of major importance, but also the taxes imposed on the gas price are equally relevant. As discussed in the policy review paper [78], many countries worldwide are considering CO2 taxes on natural gas as a tool towards achieving their emission reduction targets. Consequentially, gas prices would increase, which negatively affects the strength of the fundamental business case of the mCHP technology.

In Deliverable 4.2 [50, Ch. 3.3.5], the impact of the gas price is analysed within the sensitivity analysis by changing from standard natural gas to more expensive biogas. It is possible to draw conclusions from the analysis of biogas to a more general case where taxes on gas are higher. Increasing the gas price from 4.1 €ct./kWh to 7.1 €ct./kWh for biogas resulted in increased annual energy costs for gas and electricity from

818 €/y (standard gas) to 1643 €/y (for biogas). This is partially explained by the heat generated by the AGB running on biogas being financially more valuable. On top of that, the biogas consumed by the mCHP is also more expensive compared to the standard gas scenarios.

Previous work [50, Fig. 9] on Germany showed that the higher price for biogas also affects the cost-optimal self-consumption policy towards slightly fewer operating hours a year. However, the effect is only marginal, limited to the PEM scenario, and only during hours with medium to low self-consumption. No influence on SOFC is observed as long as the gas price stays below a certain critical threshold price where the additional gas consumption from running the mCHP is more expensive than purchasing all electricity from the grid.

The analysis in [50, Ch. 3.4] shows that balancing services can in principle be provided by mCHPs when running on biogas. However, higher prices for biogas do lower the income streams from balancing markets. For PEM, the yearly income from offering aFRR is roughly reduced to 50%. The main cause is that ramping up electricity production upon aFRR+ activation for supporting the grid leads to much higher gas costs. For SOFC, the impact is marginally negative since only aFRR- is offered.

In summary, it can be concluded that increased taxes on gas consumption, or lower taxes on the domestic electricity price do have a substantial negative impact on the business case of all mCHP applications. In order to support the market uptake of the mCHP technology as a tool to provide flexibility, policy makers need to consider the overall tax impacts associated with the spark spread. Introducing CO2 taxes on the gas price negatively affects the business case for mCHP unless at the same time suitable counter-measures (such as increased feed-in tariffs for excess mCHP electricity) are initiated.

4.5 Discussion of results

Figure 11 displays monthly operating hours. For Germany it can be observed that PEM SFH is the only scenario where the mCHP does not run for the entire year. During the summer months, the production drops down to about 40%. The explanation can be interpreted from Figure 8. Given the SFH's low heat demand in summer, the PEMFC must partly reduce output power in order to prevent overheating. In contrast, overheating is not an issue for the SOFC scenarios as those units generate only 750 W of thermal output, which can be dissipated to the DHW consumption alone. Regarding the three German scenarios that are not restricted by thermal limits, the cost-optimal self-consumption policy is to get as many operating hours as possible. For the SFH case, this policy results a substantial share of the produced electricity being exported to the grid. Operating hours where most of the mCHP production is fed back to the grid are much less profitable than hours with high degrees of self-consumption. However, favourable government subsidies listed in Table 5 cover the additional gas costs from mCHP operation and provide just enough financial motivation to keep the mCHP running in all hours.

In Belgium, the monthly operating hours show a very similar shape than the German case. Gas prices are cheapest compared to the other two countries (see Table 5), and electricity is almost as costly as in Germany.

However, the value of excess electricity depends on the local grid operator. The Flemish government supports mCHP technology in the form of “CHP certificates” and “green power certificates” [79]. The number of certificates is calculated as a function of installed capacity, not on realised operating hours. In conclusion, the financial viability of exporting excess electricity is even more marginal than in Germany, considering the additional gas consumption from mCHP operation. The marginal case can be seen for example by comparing the scenarios PEM_3FH to SOFC_3FH. The operating hours during summer are visibly lower for SOFC_3FH. Looking at these two scenarios in Figure 12, the operating costs (orange bars) are almost equivalent. This means that those deviating operating hours do not yield a solid profit, but instead are just at a break-even point.

Czech Republic (Figure 11) shows markedly different results to the two other countries. As summarised in Table 5, electricity is the cheapest out of the three countries, while gas is the most expensive out of the three countries. Looking at governmental OPEX support, we see that the “green bonus” program subsidises the first 3’000 hours of operation per year [66], [70]. The green bonus applies to each kWh produced by the mCHP, irrespective of whether it is exported to the grid, or self-consumed. Hence, this subsidy scheme does not provide financial motivation for additional operating time beyond 3’000 hours. Additionally, there is no feed-in tariff for mCHP implemented yet [70]. Consequentially, exporting excess electricity to the grid is financially not attractive. The cost-optimal self-consumption policy is to switch off the mCHP in times of low self-consumption. Comparing the scenarios PEM_3FH to SOFC_3FH, it can be observed that the SOFC is often reduced to its production minimum of 500 W_{el} during hours of low self-consumption while the PEMFC is kept running at full power. The alternative would be to switch off the PEMFC completely (production minimum of 0 W_{el} according to Table 5). However, the baseload consumption in the 3FH house scenario is high enough to keep the PEMFC at 1.5 kW_{el} rather than importing electric power from the grid. For all four scenarios in the Czech Republic, the mCHP could technically deliver more energy and is only restricted by economic viability. In general, the financial value of excess electricity must be higher than the gas prices in order to motivate mCHP operators to keep their units running.

As shown in Figure 12, the biggest energy cost savings per installed mCHP unit are realised in Germany, followed by Belgium. The Czech Republic is least favourable due to the low spark-spread, the missing feed-in tariff, and how the green bonus subsidy scheme is implemented. For all countries considered, the energy costs savings are maximised for larger consumers that benefit from increased self-consumption. Germany is the only country where excess electricity is reimbursed at a point that is high enough to incentivise the mCHPs to produce as much electric energy as technically possible.

5 Evaluation of grid services revenue for mCHP in Germany, Belgium and Czech Republic

Summary box of the Chapter

This chapter describes the modelling and estimation of the potential revenue streams for mCHP devices when participating in grid services markets. The additional revenue from providing grid services in Germany, Belgium, and Czech Republic is quantified. The self-consumption policy optimisation from Chapter 0 outlined the available flexibility for each of the scenarios. In this chapter, short-term deviations from the self-consumption policy are offered on the balancing markets and a value for EVA is obtained. The bidding strategy is derived based on detailed historical grid service market data. Furthermore, sizing recommendations regarding the thermal storage for frequency balancing are analysed and discussed.

5.1 Introduction

This chapter focuses on the additional income streams from providing balancing services with a cluster of mCHP devices organised as virtual power plant. The aim is to compare and contrast the market situation in Germany, Belgium, and the Czech Republic. Within each country, a set of balancing products was selected based on a qualitative analysis in deliverable 4.2 [50] as summarised in Section 3.2. In short, the following products were selected to be analysed in this Chapter:

- In Germany, the aFRR markets,
- In Belgium, mFRR markets,
- In the Czech Republic, both aFRR and mFRR markets.

For all these products, both positive and negative balancing services were investigated. The term “positive” activation refers to the ability to ramp up electricity production upon activation by the TSO. Offering positive balancing is only possible during times when the mCHPs have not already reached the production maximum and production can be increased if needed. The time periods where positive or negative balancing can be offered is thus directly dependent on the self-consumption policy from Chapter 0.

In the remainder of this Chapter, the methodology used to quantify all revenue streams from balancing products (see Section 3.4) is applied to Germany (in Section 5.2), Belgium (Section 5.3), and the Czech Republic (Section 5.4). Results are presented in Section 5.5 for all scenarios. Section 5.6 discusses the results and contrasts between the different countries. Furthermore, a judgement about HWST size dimensioning is included.

5.2 Evaluation of Germany aFRR+ and aFRR-

The German frequency balancing market underwent several redesigns in 2018 and 2019, meaning no coherent market data is available for the last two years. Data from 2017 is therefore used in revenue calculations, which discards the market data inconsistencies related to the failed introduction of the “Mischpreisverfahren” [80]. Back in 2017, only two blocks per week are accepted. “Niedertarif” (NT) on weekdays between 20:00 and 08:00 and during weekends, and “Hochtarif” (HT) during weekdays between 08:00 and 20:00. Since 2018, the aggregator places his aFRR+ and aFRR- bids for intervals of four hours. Splitting the full week into four-hour blocks simplified the job of the aggregator substantially as explained in [3].

In 2017, both availability and utilisation are auctioned in a weekly auction for all four products called POS_HT, POS_NT, NEG_HT, and NEG_NT. The auction results for utilisation are shown in Figure 14. The x-axis represents the activated aFRR balancing power in MW, the y-axis the price for delivered energy. For each calendar week, one line displays the merit order of activation.

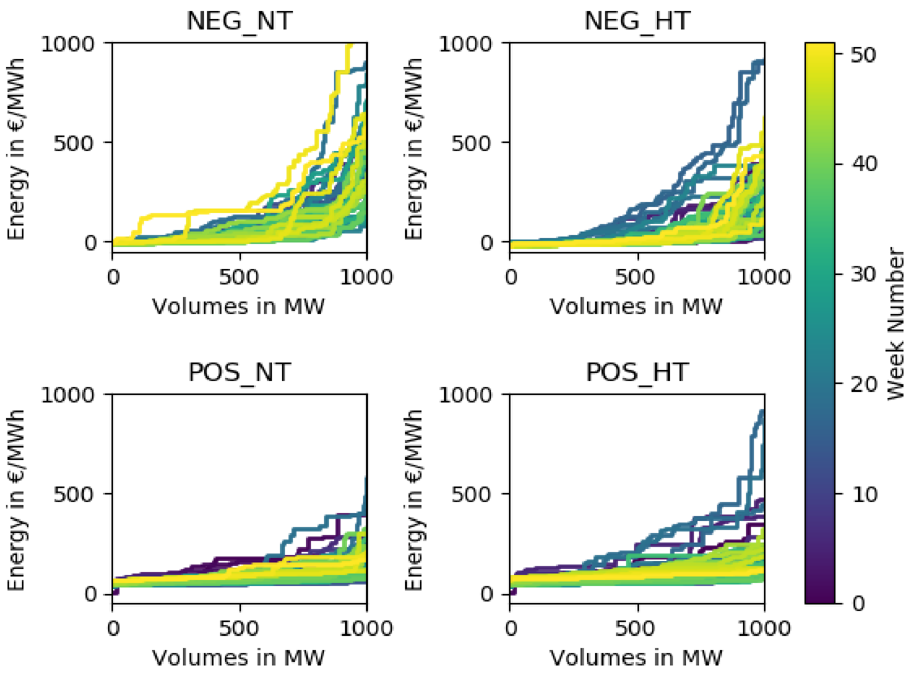

Figure 14: German merit order lists for utilisation in 2017

Based on this merit order list, the activation probabilities can be quantified as a function of the utilisation price bid. Cheap bids increase the activation probabilities and result in higher turnover. Offering below opportunity costs eats away from availability income upon activation. On the other hand, bidding at prices that are too high yields good profit margins once activated, but activation is very rare and overall profit from utilisation averaged over time is low. In this context, aggregators try to place their bids such that overall profit is maximised.

Following the methodology from Section 3.4, it remains to determine the ideal bid placement for utilisation. As an example, Figure 15 shows the additional income from offering aFRR+ / aFRR- as a function of the energy price bid for the case of the PEM SFH scenario. The curve for POS_NT represents the total income for availability plus utilisation. The availability income is calculated as described in Section 3.4 and thus independent on the utilisation price bid. Bidding for utilisation at 1’200 €/MWh or higher corresponds to zero activation probability and consequentially no utilisation income. For very low utilisation energy bids, the income becomes negative as the additional gas costs are more expensive than the reimbursement paid by the TSO.

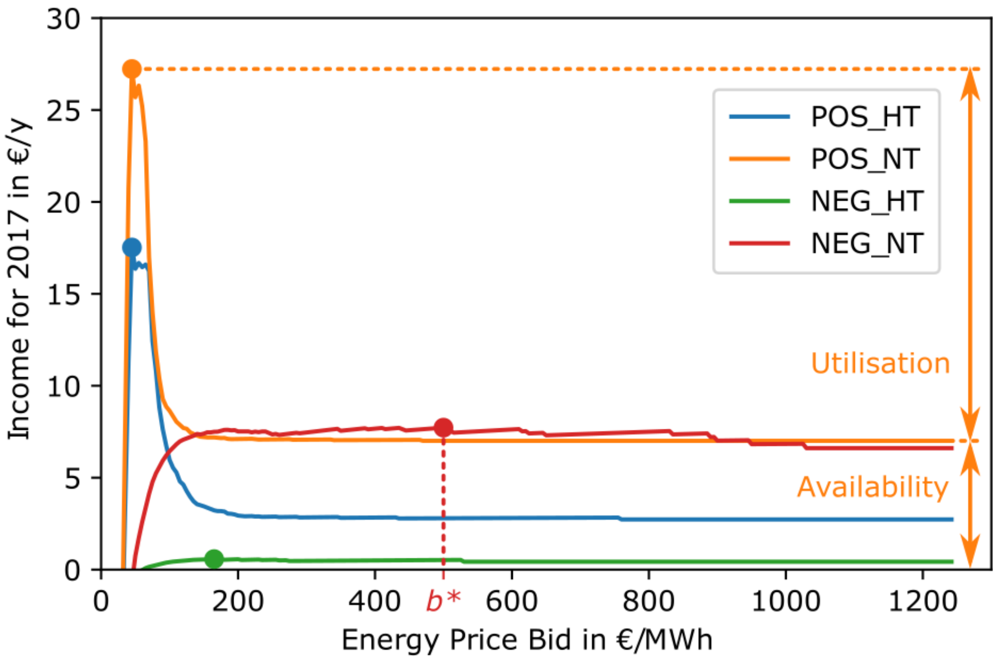

Figure 15: aFRR income as function of the energy price bid for PEM SFH in Germany. Parameters are listed in Table 5

For this scenario, the ideal energy price bid for NEG_NT is indicated by the label *b** on the x-axis for illustration. Negative utilisation is associated with high opportunity costs from reduced self-consumption and consequentially higher electricity import from the grid at high costs. The main income stream for negative utilisation predominately comes from availability. The utilisation price needed to compensate for opportunity costs is so high that the activation probability stays very low.

This calculation procedure was repeated for the three other German scenarios. Results are presented in Chapter 5.5

5.3 Evaluation of Belgium mFRR

As outlined in Section 3.4.1, the approach for Belgium was very similar to Germany with regards to market mechanisms and data availability via Elia [68]. However, a few key differences are worth highlighting:

- Historic GSM data for the time interval March 2020 to March 2021 serves as basis for the quantitative modelling. This date range was selected aiming to utilise the most recent data possible. Furthermore, a change in the terms and conditions for mFRR balancing service providers entered into effect on February 3rd, 2020 [81], which also improved data availability.
- In contrast to Germany, negative mFRR availability is not remunerated. As stated in [82, Ch. 3.4.2]: “Elia will not procure any negative balancing capacity other than aFRR since the required negative reserve capacity for FRR is expected to be covered with reserve sharing and non-contracted balancing energy bids with an acceptable probability”. The volume-weighted price for positive availability is shown in Figure 16 based on the anonymised bid ladder published by Elia [68].
- Availability and utilisation auctions are organised in four hour bid intervals instead of weekly auctions.

Other than those adaptions, the methodology for Germany is repeated for Belgium. Results are presented in Section 5.5.

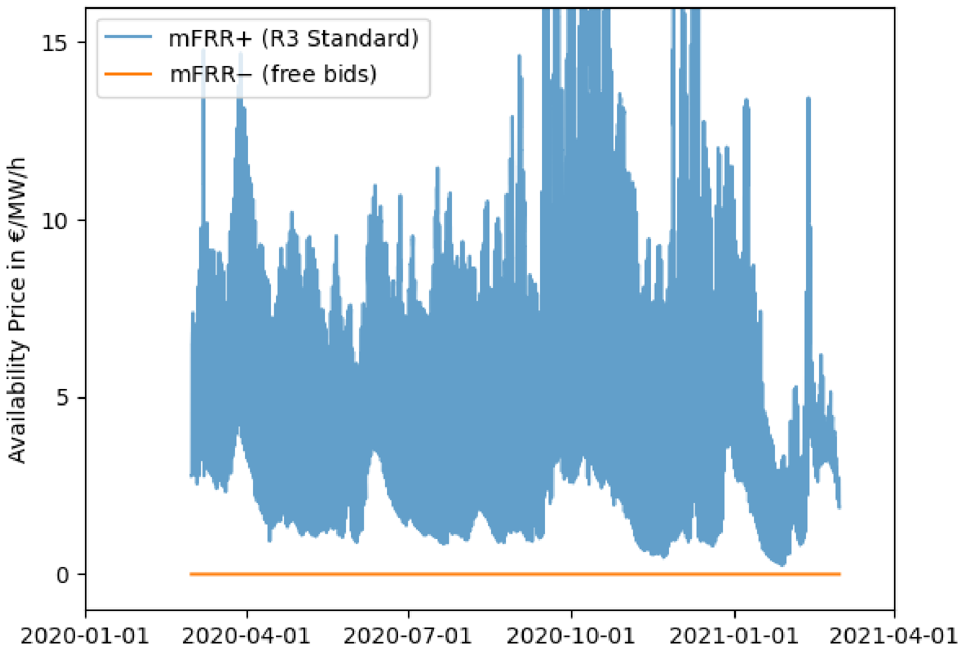

Figure 16: mFRR availability prices in Belgium. Own calculation based on data from Elia [68]

5.4 Evaluation of Czech Republic mFRR and aFRR

Based on the methodology from Section 3.4.2, a statistical model for the monthly average availability prices is developed by Nano [70] using public data from ENTSO-E [71]. Intermediate results are shown in Table 7. Grid service definitions are provided in Appendix A.

Table 7: Monthly average availability price bids based on [70], [71]

Month	aFRR-	aFRR+	mFRR-	mFRR+
Jan	17,44	11,83	18,84	15,68
Feb	17,03	14,48	18,49	17,45
Mar	19,82	18,23	19,42	18,54
Apr	21,88	19,43	22,02	17,96
Mai	31,97	22,54	36,17	17,99
Jun	33,17	23,41	35,95	19,15
Jul	23,33	23,26	24,12	20,28
Aug	20,94	21,38	21,93	20,13
Sep	18,99	21,36	19,04	20,02
Oct	17,98	20,72	17,62	19,65
Nov	13,89	16,97	14,29	18,62
Dec	11,94	13,95	12,07	17,99

Following the same methodology as for Germany or Belgium, the availability income is calculated directly from the availability prices and the cost-optimal self-consumption policy.

The income for aFRR utilisation is estimated based on a 5% average activation probability [70], [71]. The activation scheme is pro-rata and the utilisation prices are fixed to 0 €/MWh for negative utilisation, and 91 €/MWh for positive utilization.

For mFRR, activated energy is compensated using the merit order principle, i.e., bidders can choose their activation price, but a higher price means a lower activation rate. The income streams from activation are quantified using current average activation prices and rates (-25 €/MWh for down activation, 253 €/MWh for up activation).

5.5 Overview of results across all three countries

The results of this chapter are summarised in Figure 17. The income from providing balancing products is given in percentage of cost savings incurred from following the optimal self-consumption policy. Opportunity costs for additional gas and electricity consumption during positive and negative utilisation are fully reflected in the analysis. Excluded from the consideration are costs related to potentially increased stack ageing effects, and the additional effort for the metering infrastructure as this is assumed to be pre-existing infrastructure. The resulting split of income from balancing services between the aggregator and mCHP owner is beyond the scope of this deliverable.

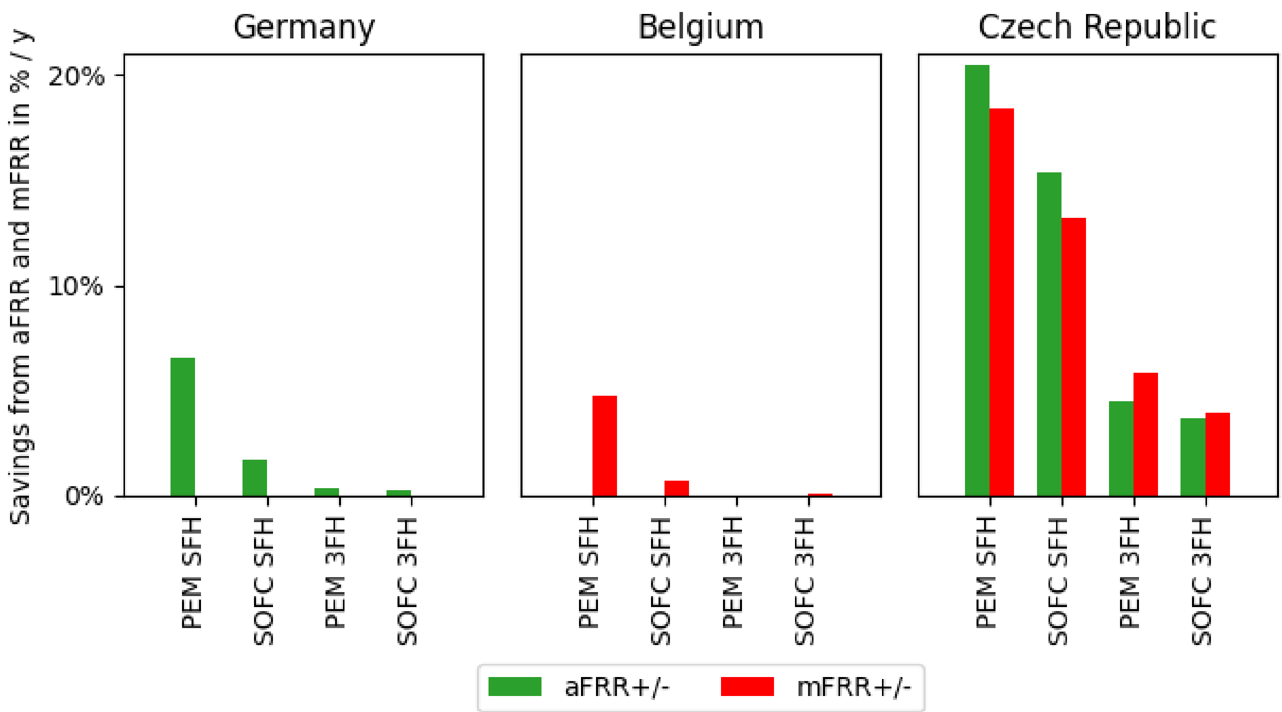

Figure 17: Additional income streams from providing aFRR+/- and mFRR+/- in relation to cost savings from self-consumption. Absolute numbers are given in Table 8

Absolute numeric values corresponding to Figure 17 are given in Table 8. Consider the PEM SFH scenario in Germany as numerical example: the income for aFRR+/- availability and utilisation sums up to 51.64 € per year and unit. The cost savings from operating the mCHP according to the cost-optimal self-consumption policy are at 1’139 €/y since the total costs for gas and electricity purchase decrease from 1931 €/y to 792 €/y. The supplementary income from aFRR+/- thus calculates to an additional 51.64 / 792 · 100% = **6.52 %** relative savings in Figure 17.

Table 8: Numeric values for Figure 17

Country	Scenario	Cost savings from self-consumption in €/y	Additional income from aFRR+/- in €/y	Additional income from mFRR+/- in €/y
Germany	PEM SFH	1’139	51.64	-
	SOFC SFH	1’429	8.41	-
	PEM 3FH	2’239	13.64	-
	SOFC 3FH	2’239	8.09	-
Belgium	PEM SFH	904	-	39.64
	SOFC SFH	1’034	-	4.84
	PEM 3FH	1’951	-	0.25
	SOFC 3FH	1’951	-	1.78
Czech Republic	PEM SFH	447	301	271
	SOFC SFH	564	208	178
	PEM 3FH	905	218	281
	SOFC 3FH	1’127	172	182

5.6 Discussion of the results

5.6.1 Contrasting the balancing income across the three countries

Looking at Table 8, the German and Belgium cases are observed to be very similar. For both countries, the revenue for PEM SFH is much higher compared to the three other scenarios. An explanation is found in Section 4.4, where the PEM SHF scenario is seen to run for the least number of operating hours for self-consumption. Especially in summer, the mCHP must regularly be deactivated to avoid overheating. In all those hours, positive availability is offered to the TSO. In contrast the 3FH scenarios are characterised by much more monthly operating hours, even reaching 100% utilisation throughout the whole year for Germany. Consequentially only negative balancing is offered to the TSO, which is financially less attractive for various reasons. First, the availability prices are typically lower. Second, being activated for negative balancing means that the mCHP is obliged to reduce output power. Hence, the missing electricity must be purchased from the grid instead. Recall from Table 5 that domestic electricity prices in Germany and Belgium both lay at roughly 300 €/MWh, much more costly than consuming electricity from the mCHP. Consequentially, negative utilisation is associated to high opportunity costs, which necessitate expensive bid placements. The activation probability thereof is very low, and so is the utilisation income (see also Figure 15).

Comparing PEM 3FH to SOFC 3FH for Germany shows that SOFC gains less aFRR- income even though both scenarios reach 100% monthly operating hours (see Figure 11). This this is due to the scenario specifications from Table 5. The SOFC may only offer 1 kW of balancing power, since the electricity output must stay between 500 W_{el} and 1.5 kW_{el}. For the PEMFC arrangements, the production minimum is set to zero and the full 1.5 kW are offered as balancing capacity. The income for PEM 3FH is thus higher than SOFC 3FH, as 50% more flexibility is available.

The additional yearly income from offering aFRR in Germany of 51.64 €/y for PEM_SFH is aligned with the predictions in deliverable 4.1 [3]. Retrofitting existing mCHPs with TSO metering and communication equipment is therefore not a viable business case since amortisation of initial costs would take years. A reasonable case might still be achieved if all balancing hardware requirements are included in the off-the-shelf control electronics. Further, prequalification tests should be completed by the installer or from remote to avoid costly car journeys or replaced by type tests.

The income for the Czech scenarios is observed to be substantially higher than for Germany or Belgium. PEM SFH, the additional income from providing aFRR calculates to 301 €/y (see Table 8). Compared to the cost savings from self-consumption of 447 €/y, the balancing income represents a respectable income stream.

The balancing income in the Czech Republic is mostly made up of the availability premiums. The pro-rata activation scheme for utilisation is not a key contributing factor to the income difference. Instead, market prices for availability in €/MW/h are substantially higher, which can be observed from comparing Table 7 (for the Czech Republic) to the values in Figure 16 (for Belgium).

5.6.2 Hurdles for mCHP to participate in TSO grid service markets

TSOs generally have high requirements on the confidentiality, availability and integrity of their infrastructures, also in terms of cyber security. Communication requirements for offering grid services are high. For historic reasons, TSOs became familiar with reserve providing units (RPUs) in the megawatt-scale where issues affecting one single unit (such as loss of communication), could in the worst case destabilise the grid. For residential RPUs connected over an aggregator, this mind-set is a major hurdle. Losing one mCHP delivering a few kilowatts does not pose a threat to grid stability. Nonetheless, most TSOs apply the same technical requirements independent of the RPU power output, resulting in fixed costs and administrative efforts that are disproportionally more expensive, or even unfair to smaller units.

As discussed in Section 5.6.1, it remains a challenge in all three countries to offer negative balancing energy. There is an interest conflict between negative utilisation and the cost-optimal self-consumption policy. Upon activation, the mCHP power output needs to be decreased, requiring more electricity to be purchased from the grid. As highlighted in [50, Para. 3.5]: “Grid tariffs on domestic electricity prices distort the competition in favour of commercial power plants that are exempted from all surcharges”. Some TSOs are aware of the current regulatory limitations and initiated pilot projects to study suitable frameworks for small-scale flexibility providers. One notable mention is the Dflex project in the Czech Republic [83].

In Germany and Belgium, aggregation is already an established practice, and has been for many years. In contrast, the Czech Republic only enabled aggregation recently through policy changes. Until the end of 2020, the Czech TSO ČEPS allowed aggregation up to four RPUs, but only if they are connected to the same distribution point. Starting from January 2021, the updated ČEPS code of transmission systems [69] facilitates residential RPUs to participate in the ancillary service market via aggregation. There is no lower limit on the RPU power output, which allows aggregators to build a virtual power plant from mCHP units. How the balancing market prices may adapt to those new policy changes is still uncertain at the publishing date of this deliverable due to the lack of experience and historic grid service market (GSM) data available. It typically takes months or years after such changes until the balancing market reacts and convergence to a new equilibrium is reached. In general, market openings bring in new capacity to the balancing markets and thus higher competition. However, not all market openings immediately resulted in decreasing prices. For example, the aFRR market opening in Belgium even led to increasing prices in the short term [84]. It took several market adjustments until prices came down again. Regardless of the country, the value of flexibility in the long term is rather expected to increase due to conventional power plants being decommissioned and replaced by much more volatile renewable energy producers.

5.6.3 Requirements on hot water storage tank volume dimensioning

Deliverable 4.2 [50] investigated the German aFRR market specifications. Conclusions are drawn that the provision of aFRR does not necessitate the instalment of a HWST that is bigger than 220 litres. Sustain time for aFRR+/aFRR- is restricted to 15 minutes under normal circumstances since mFRR by design is quickly activated to relieve aFRR for the next incident [85]. However, there is no guaranteed upper limit on the worst case sustain time. In rare critical situations, such as several repeated incidents within an hour, aFRR could theoretically be activated for hours at a time. On the other hand, sustain times of several hours are avoided in practice thanks to recent policy changes. Aggregators in Germany are allowed to purchase energy from the intraday continuous market to relieve their RPUs. Before July 2015 it took 45 minutes until such a schedule change was permitted by the TSO [86]. Starting in 2015, lead times in intraday continuous trading were stepwise reduced to between five to 20 minutes [86]. A small 220 litres HWST volume exhibits a thermal capacity of roughly 4 °K/kWh. Sustaining positive activation up to 30 min does not pose a problem since the HWST temperature raises only up to 4 °C for a 2 kW_{th} FC system. Obviously, the larger the storage volume, the slower it overheats. Most mCHP systems installed today, are sold in combination with a storage tank of at least 200 L to optimise self-consumption. Installing a bigger HWST exclusively for providing aFRR+ in Germany is not required.

For Belgium and the Czech Republic, the analysis in this deliverable also includes mFRR products. By design, typical sustain times for mFRR are longer than for aFRR (see Section 2.3) and a bigger HWST volume of 350 litres rather than 220 litres is found to be more appropriate. It is worth highlighting that the provision of negative balancing energy is not depending on a big HWST volume. Instead, the mCHP arrangement according to Figure 7 can easily provide negative balancing energy continuously for multiple hours. In case of negative activation, the mCHP electricity output is temporarily lowered, so is the thermal output. The missing heat is then counteracted by the AGB. Positive balancing energy is more critical as the temperature rises, provided that heat demand is simultaneously very low. In this case, the unpredicted thermal output slowly heats up the HWST and the upper temperature limit constrains the sustain times. However, all scenarios considered in this deliverable are dominated by negative utilisation (see Figure 11) and 350 litres therefore is found to be reasonable for all scenarios included in this deliverable.

6 Quantifying the value of mCHP in avoiding grid reinforcement costs in distribution networks

Summary box of the Chapter

This chapter summarises the results of a literature study on the potential for mCHPs to reduce the capacity requirements of local distribution grids, and hence provide economic value from the avoidance of grid extensions. The review was completed to provide an estimate of the potential economic value of distributed energy resources such as mCHPs to the DSO. It considered studies that demonstrate the ability of demand-side flexibility to defer or avoid grid costs incurred by DSOs. Findings suggest that the value of demand-side flexibility in avoiding grid investments can be estimated between 24 and 500 €/kW. Dedicated studies on mCHP show it as having a benefit within this range.

6.1 Introduction

The purpose of this Chapter is to determine the economic value added from the avoidance of grid extensions that could be attributed to mCHP. This is achieved by first describing the macroeconomic impacts of flexibility, and then detailing those impacts on a micro-level. A review of the most popular approaches undertaken to derive the economic valuations is conducted, and foundational differences between approaches are presented, in order to provide insights into the variation in the valuations identified. The results are presented in Section 6.4, where the quantitative values of distributed energy flexibility help to draw parallels with the economic value that mCHP flexibility adds to the distribution grid.

Increasing volumes of variable renewable energy sources (RES), and electrification of loads such as electric vehicles (EV) are contributing to transformative changes in electricity distribution networks that will drive the need for flexibility in grids across Europe. Detailed consideration of the options available to the DSO in dealing with capacity issues, and their preferences, are provided in Section 2.4, with grid expansion being the typical initial measure. The incurred grid investment costs triggers an increase in network tariffs which are eventually passed on to the end-consumer. However, it is possible to defer such investments (in the short-term or long-term) through the use of distributed energy resource flexibility by the DSO as it allows them to release untapped network capacity, and ultimately has the potential to reduce overall grid investments [29], [87], [88].

There is overwhelming commentary in literature attesting to the effectiveness of the use of DER for flexibility in deferring or avoiding grid investments through peak load reduction or the unlocking of additional capacity, in particular through demand side flexibility (DSF) [1], [89], [73], [90], [91]. On a systems level the use of distributed energy resources (DER) for flexibility has been shown to reduce peak load, wholesale electricity costs, consumer energy bills, RES integration costs, distribution and generation losses, emissions costs and curtailment costs [89], [92], [93].

Examples in literature provide an indication of the potential benefits to the DSO. [94] Demonstrates that DSF and/or integration can offer up to 37% of monetary savings in distribution grid expansion. [95] found that the annual EU grid reinforcement cost can be substantially reduced from EUR 10.8 billion to EUR 7.5 billion (-31%) in a low DR scenario and to EUR 4.8 billion (-51%) in a high DR scenario compared to a situation where the demand side is not flexible. A field trial conducted with PowerMatcher Suite in the Netherlands showed that peak demand can be reduced by 30% to 35% by managing heat systems (mCHP and heat pumps) [96]. Conversely, estimates have suggested that unless new flexibility services are acquired, an additional year-on-year cost of approximately EUR 11 billion will be incurred by EU DSOs towards 2030. In the UK , for example, distribution network operator UK Power Networks reportedly saved EUR 64.5 million in upgrade work for eight years as a result of DR trials [97]. Moreover, in 2019 UK Power Networks budgeted GBP 12 million to secure 200 MW of DSF to defer load related reinforcement over four years [98]. Since then, UK network operators have revised engineering standards (e.g. P2/7) to secure network security from DERs and use smarter pricing signals, through TOU tariffs and network charges, in an effort to defer or avoid investment in costly network assets [99].

The specific economic benefit that can be expected from DSF varies widely in studies as it is highly case-specific [92], [100], [101]. This Chapter aims answer the question in a general sense. Section 6.2 describes the most widely used methods to estimate the value of DSF. Section 6.3 presents case-specific insights of how DSF value can be estimated with three case studies. Section 6.4 estimates and validates the range in which DSF value can be expected to be based on the literature reviewed. Lastly, Section 6.5 concludes by discussing the results and highlighting the specific contexts in which DSF value can be expected to be greater or provide greater impact.

6.2 Approaches for quantifying the value of demand-side flexibility in distribution networks

The economic value added (EVA) is a metric that measures capital performance or profit generation of an investment against alternatives in order to identify the most economically valuable option [102]. A similar approach, the cost benefit analysis (CBA), guides decision-making by considering one or multiple decisions. A CBA differs from the EVA in that it subtracts the estimated costs from the quantified benefits, which can be direct, indirect and intangible (hard to quantify). Some CBA calculations also include the opportunity cost of not pursuing an alternative [103]. CBAs are therefore better suited than EVAs to the determining the intangible value of mCHP flexibility as they can take into account the opportunity cost of not investing in grid reinforcements. In addition, DSF does not generate surplus revenue for DSOs, but rather yields cost savings; which will not be identified as a return a profit in an EVA. This means that the CBA is the predominant method used in literature to estimate the value of DSF as opposed to EVAs to determine the extent to which DSF defers or avoids network reinforcements.

Generally, the costs considered in the CBAs for DSF implementation and investment include:

- Soliciting customer involvement (implicit DR) or developing a local flexibility market (explicit DR),
- The cost of activating the flexibility,
- Changes to billing and settlement,
- The cost of integrating DER devices,
- Smart grid integration and ICT investment costs: smart meters, monitoring, control and communication equipment,
- The initial cost of reinforcing the grid for hosting elevated levels of integrated DER prior to DSF provision.

Such costs may have a high level of uncertainty. For example, in one sensitivity analysis, assumed activation costs widely ranged between 1 and 150 EUR/MWh [104].

The net benefit attributed to DSF generally is the additional network capacity it releases in the short-term that allows improved management of local congestion issues and long-term deferral of grid investments [94]. Studies ([101],[104],[105],[106],[73]) have compared the net benefits (or costs) between alternatives under certain assumptions, commercial and technical constraints, and in some cases the intangible social benefits were also monetised and added to the overall benefits, increasing the overall economic value. However, studies (e.g. [87]) that considered social benefits as part of the net benefit of the CBA were not included in the analysis presented in this work as social benefits are beyond the scope of this study.

Figure 18 illustrates a generic approach to estimating grid investment savings as a result of flexibility where the cost of hosting peak loads is expressed as a function of residual peak demand. As the peak residual demand increases, so too does the cost of hosting peak loads, whether the hosting is done through grid reinforcements (c_{exp}) or flexibility (c_{flex}). However, the difference in cost rate between $c_{exp\ and}$ c_{flex} gives rise to a margin that depicts the incurred savings for the DSO when physical expansions are substituted by the use of demand flexibility. This margin of savings is the net benefit of DSF in cases where c_{flex} is less than c_{exp}.

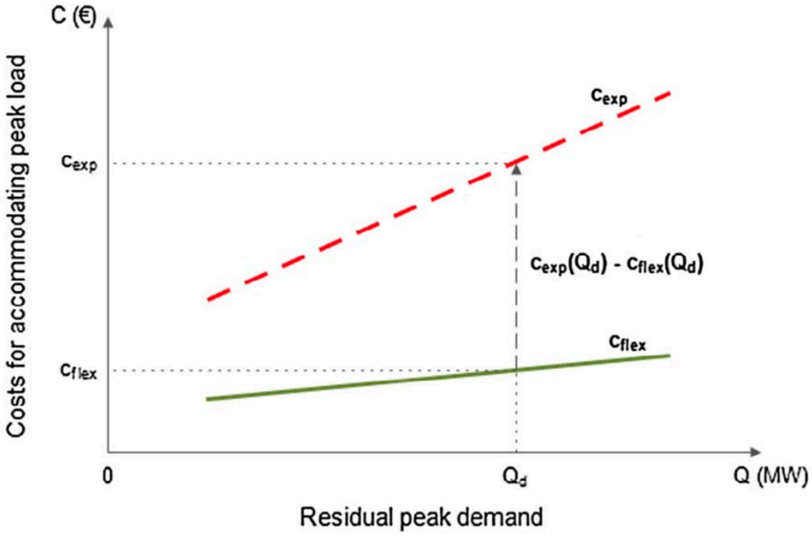

Figure 18: Savings occurred by deferring investment in the physical network by the use of flexibility. Sourced from [29].

The calculation approaches used in the CBA also differed between studies. Some CBAs are explicitly not full CBAs as certain costs were not considered [89]. In different studies different forms of DSF are acquired (e.g. time-of-use tariffs, direct load control, flexibility market); in others the forms were compared as alternatives [47]. Assumed reinforcement costs varied widely (e.g. 104 EUR/km, 77’000 EUR/km for as a value for reinforcement costs) as some studies focused on cable costs and excluded the dominant costs of excavation and roadway/ footpath reinstatement. Others included these extra costs, or focused on transformer replacements [88],[104],[107]. [108] determined the grid investment costs as a function of technology type (heat pumps, PV and EV) and urban setting, using 46–192 EUR/kWp, 41–1’247 EUR/kW and 31–127CHF/kW for PV, HP and EV, respectively, with the higher limit corresponding to rural areas. Substation replacements were valued between 133’000 EUR -213’200 EUR [87],[88]. Differences also stemmed from whether prosumer self-consumption was optimized prior to modelling the DER grid impacts [73], [108]. Estimated DSR costs, because admittedly highly speculative, were set to values such as £22/kWp [87] and $150 -$250 [104]. These variations are causes for the differences in the estimated value of DSF seen in literature.

The parameters often varied were:

- Flexibility (varied from 0-100%) or distributed generation penetration level (varied from 0-400%),
- Peak shaving capacities (varied from 0-100%),
- Settings (rural, urban and semi-urban),
- Technologies (HP, PV, EV, HEMS, Battery, small hydro, mCHP and domestic appliances),
- Demand growth forecasts or scenarios,
- System boundaries (substation – pan European electricity system).

In contrast to these, in [107] the varied parameters were peak shaving capacity and maximum initial line loading[11] (MILL) – an indicator for reinforcement decision making. Peak shaving was found to not be competitive for networks characterized by a MILL between 80 and 100%.

The most common DER technologies found in the studies were referred to as demand side response or (residential) demand side flexibility in general without referring to a specific technology provider. Those that did distinguish the technology consisted of hybrid technologies such as 'residential demand side flexibility' and PV or Electric vehicles in combination with flexible heat and electricity, making it difficult to draw conclusions about technology types.

6.3 Case Studies

Three case studies are provided as examples of how DSF grid impacts and value have been derived in specific grid contexts enabled specifically by DR, natural gas fuelled distributed generation and mCHPs. Conclusions are drawn in Section 6.4.

6.3.1 Case Study 1: The value of peak load reduction when replacing a substation

In a Southern Stockholm distribution network, the economic value of load reduction was estimated by quantifying the avoided cost of replacing an 880kVA power rated substation [88]. During peak loading, the substation was overloaded by 30% reaching a peak value of 1143 kVA. A DR program was required to shave the peak to 90% of the power rating in order to avoid replacing it with a larger 1600kVA substation. A relationship was established between the number of years a reduction in peak load could defer the investment and the net present value of the deferral (reproduced in Figure 19). The blue line indicates the level of reduced load, and the corresponding net present value (NPV) of the delayed investment is shown by the pink curve. For example, if 34% of the annual peak load is reduced, 20 years of investment can be delayed, giving rise to an NPV of delayed investment of EUR 1 million[12]. This translates to 335 EUR/kW[13] reduced peak load. In this context the maximum value of peak load reduction reaches 518 EUR/kW when 9% of the peak load is reduced, delaying investment up to 5 years.

[11] The maximal loading (in %) observed on all line sections of a given network at year 0, before load growth and reinforcements. Alternatively, the worst Initial line loading value of a given network
[12] Exchange rate 1 EUR:10.14 and inflation adjusted.
[13] Assuming a power factor of 1

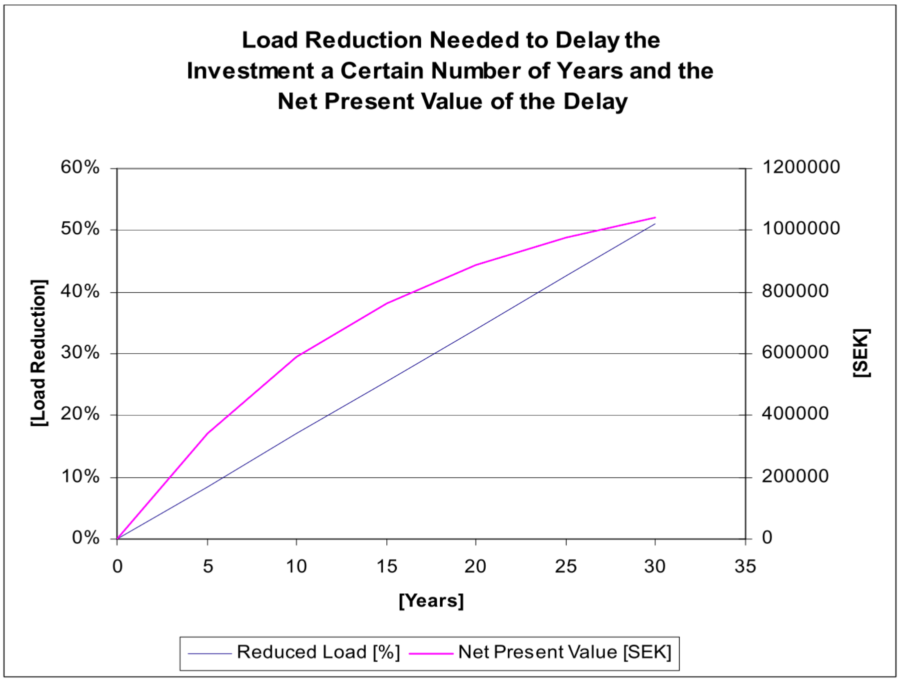

Figure 19: Relationship between load reduction, delayed investment and net present value of delayed investment. Sourced from [88].

6.3.2 Case study 2: The economic impact of natural gas-fuelled distributed generation on European electricity distribution networks

In order to quantify the impacts of natural-gas fuelled distributed generation[14] (NGDG) on European electricity distribution networks, [72] modelled NGDG systems in households such that they achieved the maximum prosumer benefits. The resulting distribution grid impacts were assessed. The findings were such that in countries where there is no expected growth in demand, a linear trend exists between percentage grid reinforcements and percentage NGDG penetration. This means that any NGDG penetration causes additional grid reinforcement costs to host the newly integrated NGDG as there is no growth in demand for it to compensate and provide a benefit to the grid. Such was the case for Germany where energy efficiency targets dampened expected growth in demand. As a result, any NGDG penetration resulted in a per NGDG household cost of about 150 EUR. This can be contrasted with France (1% growth) and Italy (1.3% growth) where both exhibit a U-shape trend in percentage reinforcements against percentage NGDG penetration levels. In these countries there is demand growth expected that has the potential to be compensated for with NGDG and yield cost savings, albeit only until a certain level of penetration. For France and Italy the required grid reinforcements decreased until NGDG penetration reached 30% and 40%, yielding savings of 150 EUR/

[14] This includes internal combustion engines fuel-cells, gas turbines and microturbines.

household and 900 EUR/household respectively. Higher levels would call for additional grid reinforcements to increase the hosting capacity of the grid.

6.3.3 Case Study 3: Comparing the costs and benefits of PV, mCHP and small hydro in the UK and Finnish LV network

The costs and benefits of distributed generation in the UK and Finnish distribution grids were investigated by determining the incremental value (EUR/kW) of PV (UK), mCHP (UK) and small hydro (Finland) grid impacts on rural and urban distribution networks in high- and low-density scenarios [73]. The costs were determined by calculating the cost of network reinforcements needed to mitigate technical problems arising from their integration such as voltage rises in rural networks and increase in fault levels[15] in the urban networks. The benefits of distributed generation were determined by computing the reduction in distribution losses in addition to the ability for distributed generation to release network capacity which could be used to accommodate future loads. The incremental network investment costs could not be fully covered by the potential capacity replacement benefits of distributed generation; however, it was shown that they could but provide relief.

The study compared mCHP with small hydro and PV. mCHP and small hydro were found to be capable of supporting network capacity as their maximum outputs coincide with peak loads, therefore, both can defer or remove the need for new network capacity and improve the utilisation of the existing network. The converse is true for PV, since maximum output generation of PV is in summer and maximum load is in winter, meaning the grid benefits of PV are weaker than that of mCHP. Despite similar capacities to relieve the grid, mCHP is more flexible than hydro with respect to grid location and can thus impact both rural and urban grids, whereas hydro is limited to the rural network.

For a 2.5% - 10% proportion of customers with mCHPs, the study found that the incremental benefit of mCHP reaches 60 EUR/kW to 211 EUR/kW[16] respectively. The incremental benefit from small hydro power generation is approximately 15.36€/kW for low density levels and 30.60€/kW for high density levels in Finland. Since the maximum power flow does not change with PV, the incremental value on network capacity replacement is zero.

It is worth noting that the specific values of the incremental benefit to the grid do not refer only to peak load reduction (i.e. releasing network capacity) but also account for the reduction in energy losses as mentioned before. Hence, we can expect that the mCHP benefit owing to load reduction alone to be less than 60-211 EUR/kW.

[15] Short circuit capacity
[16] Exchange rate 1 GBP: 1.5 EUR (inflation adjusted)

6.4 Results of the literature study

This section is a culmination of the findings of the economic grid modelled impacts of various flexibility providing technologies reviewed in literature. It provides a general estimation and validation of the value of DSF. It then goes on to present the favourable conditions for DSF value.

6.4.1 The specific value of DSF in the distribution grid

Figure 20 summarises the results of the studies whose findings were presented in a way that allows for unitary comparison. Other studies were reviewed, but their quantitative findings did not allow for their inclusion here. The comparison shows that for different DER technologies considered, the economic value that DSF can be expected to offer is 24 – 518 EUR/kW.

Only a small number of studies considered mCHP explicitly in their calculations. A single study found that the value attributable to mCHP lies within the general range for DSF, at between 60 and 211 EUR/kW [73]. The broader range is adopted for this report as the number of supporting sources are higher and meaningful justification for the narrower range could not be obtained from the single paper identified.

As a basic means of verification, Belgian and Swiss grid tariffs are used to compute the annual earnings (through savings) a household could expect by providing 1kW peak load reduction (as an average approximate assumption based on Section 4.3) with an annual demand of 4’500kWh. From literature, the range of earnings the household could expect is 24-500 EUR in a year. The Belgian grid tariff of 50 EUR/kW (confirmed during an interview (S. Marcu, personal communication, 14 December, 2020)) charged for the most expensive quarter hour of the year would result in an annual savings of 50 EUR for a household. Similarly, a Swiss study which valued flexible grid tariffs at 1.4 c/kWh would yield an annual savings of 60 EUR per household [109]. These values fall within the range of findings reflected in literature and thus support them.

Pudjianto et al. [1] appears to be an anomaly, valuing DSF of mCHP considerably higher at 1’660 EUR/kW in the PACE predecessor project Ene.field. This is largely because the distribution grid benefits considered extended beyond those relating to network capacity to include the following:

- The benefit of displacing the capacity of alternative heat sources,
- The benefit attributable to the displacement of central generators,
- The benefits attributable to a reduction in operating costs as net energy consumption is reduced by deploying mCHP devices with high energy efficiency[17],
- Benefits attributable to reduced carbon emissions.

[17] When overall mCHP efficiency is 90% given that combined cycle gas turbine efficiency is 60%

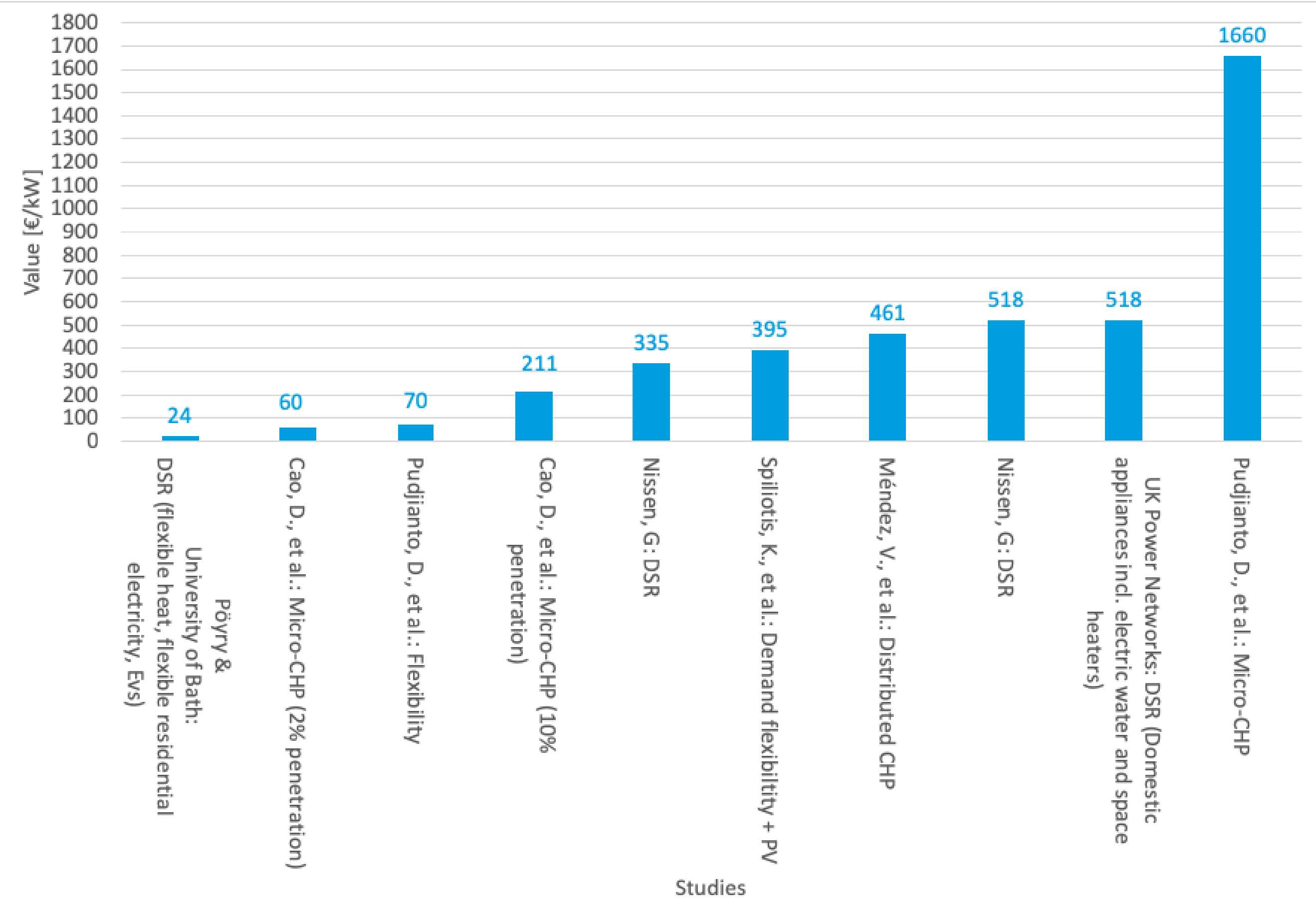

Figure 20 The economic value of demand side flexibility to the distribution grid

6.5 Discussion of the results

The extent to which DER flexibility is effective in delaying grid investments is multifactorial and contextual which gave rise to the wide range in DER flexibility valuation seen in Section 6.4. This section highlights the conditions under which DSF is considered of greatest benefit and thus value to the grid or the conditions under which it provides greater impact.

There are clear complexities underpinning the economic valuations of DSF making it difficult to unequivocally draw conclusions. Despite this, there are some general conditions under which DSF is favourable. They have been summarised in Table 9.

Table 9 Favourable demand side flexibility conditions

In congestion prone areas where prices are higher as a direct result of congestion
The business case for DSF is strengthened over grid reinforcement in areas experiencing low congestion hours as the high capital outlay is not justifiable for a few hours in a year
DERs that are in close proximity to a substation can mitigate the imminent replacement of a substation reaching 90% of its firm capacity.
DERs in close proximity to variable renewable energy sources have a greater impact by limiting grid usage to a very local level during peak periods
In a network where the MILL (the worst line is loaded) is less than 80%, there is a linear relationship between distributed generation penetration and cost savings resulting from peak shaving.
In networks where there is a lack of variety in distributed generation types (i.e. a single type of distributed generation), the similar generation profiles amplify their grid impacts. In such cases DSF is useful in counteracting this negative grid impact and increasing grid efficiency
With implicit DR there is a level of uncertainty regarding the effectiveness of the price signals to drive secure the level of flexibility needed by the DSOs from end-consumers. Explicit DR is of greater value to the DSO because load reduction is more effective in following the DSO's schedule
If implicit DR, closer to real time grid tariffs closely reflect the changing grid costs which provide greater savings as these are more effective in signalling a response from the end-consumer and
A pre-existing smart grid makes the business case for DR stronger. If no ICT infrastructure exists, the ICT infrastructure will need to be borne by the DR program. If this is the case it thus is recommendable to focus on DR at MV level to get most of the benefits as the ICT costs are lower here
Modest demand growth allows DSF to counteract the growth providing a benefit to the grid. With no growth in demand DSF adds no value but rather increases grid investment costs. In high growth situations it is difficult for DSF to provide sufficient grid relief releasing network capacity

7 Conclusions and outlook

The objective of PACE WP4 was to identify additional income streams from the participation of fuel-cell micro-CHP units (mCHP) in grid service markets, taking advantage of the electrical flexibility that is enabled by the mCHP. The work included quantitative and qualitative earned value analysis (EVA) of mCHP participation in grid service markets. A broad analysis of potential factors influencing the revenue of the mCHP that could be secured through participation in grid service markets was also included in the work.

Research found that under current conditions, the greatest opportunity for monetisation of mCHP flexibility comes from maximising self-consumption. Substantial savings in annual electricity costs can be achieved by converting gas to electricity, reducing the expenditure associated with purchasing electricity from the public grid. The effect is maximised for highly efficient CHP units such as those considered in PACE. The analysis found that, out of the countries studied, the most attractive case for self-consumption was Germany, with cost savings from self-consumption of up to 1’429 Euros per year for a single-family house, and up to 2’239 Euros per year for a three-family house. The savings were heavily dependent on the local governmental support, as well as spark spread. For example, for all four scenarios in the Czech Republic, the mCHP could technically deliver more energy and is only restricted by economic viability. Germany is the only country where excess electricity is reimbursed at a point that is high enough to incentivise the mCHPs to produce as much electric energy as technically possible.

Device flexibility can be offered to grid service markets in return for payment. A range of grid services exists in Europe, representing a wide variety of commercial opportunities to mCHP owners. At the transmission level, TSO-procured frequency balancing services are identified as being the most easily accessible to mCHP devices in the short term. Using a detailed model-based optimisation framework for mCHP devices, applied to frequency balancing markets in Germany, Belgium and the Czech Republic, it was found that revenue from flexibility offered to frequency balancing markets, could reach up to 301 Euros per year in the best case, with the highest income being available in the Czech Republic. Hurdles to participation exist, however. TSOs generally have high requirements on the confidentiality, availability and integrity of their infrastructures, also in terms of cyber security. Historical procurement practices may hinder the participation of smaller units, and aggregation – a pre-requisite for mCHP participation in this market - is not universally possible. The research also considered TSO grid services for voltage control, congestion management capacity markets and other grid services, but substantial barriers were identified for each, so further quantitative modelling was not carried out for these services.

The analysis also considered value streams associated with the DSO, including avoidance of grid extensions that could be enabled by taking advantage of mCHP flexibility, and the potential participation of mCHP in DSO grid service markets.

Distribution System Operator (DSO), community and prosumer markets for grid services are emerging, but still are highly experimental or based on constrained case studies or reflect unique situations with bilateral agreements. Thus, these markets are immature and not representative. Although the mCHP is capable of providing services to these markets in accordance with the constraints outlined in this report, the immaturity of these markets make it very difficult to apply meaningful revenue modelling. The grid-service modelling framework was therefore not applied to DSO markets in this study, but it is directly transferrable, and could be applied in future work once a suitable base for market data is established.

Findings suggest that the value of demand-side flexibility in avoiding grid investments can be estimated between 24 and 500 €/kW. Dedicated studies on mCHP show it as having a benefit within this range.

8 Glossary

aFRR	automatic Frequency Restoration Reserve
aFRR+	When positive aFRR reserves are activated through the transmission system operator, all reserve providing units that offer aFRR+ must increase their power production (or decrease power consumption for loads)
aFRR-	Negative aFRR is the opposite of aFRR+
AGB	Auxiliary Gas Burner
AHP	Analytical Hierarchical Process
BAFA	Federal Office of Economics and Export Control Germany
BAT	Best Available Technology
BRP	Balance Responsible Party
BSP	Balancing Service Provider
CEER	Council of European Energy Regulators
CAPEX	Capital Expenditure
CHP	Combined Heat and Power
CR	Consistency Ratio
DER	Distributed Energy Resources
DHW	Domestic Hot Water
DoW	Description of Work
DR	Demand Response
DSF	Demand side flexibility
DSO	Distribution System Operator
dTOU	Dynamic time-of-use
EC	European Commission
ENTSO-E	European Network of Transmission System Operators for Electricity
EPEX	European Power Exchange
ERA	Energy Reference Area
Etc.	Et cetera

EV	Electric vehicle
EVA	Economic Value Added
FC	Fuel Cell
FCR	Frequency Containment Reserve
GCI	Geometric Consistency Index
GSM	Grid Service Markets (see Figure 2)
HEMS	Home energy management system
HP	Heat pump
HWST	Hot water storage tank
HSLU	Lucerne University of Applied Sciences and Arts
ICT	Information and Communication Technology
KfW	Kreditanstalt für Wiederaufbau
KWKG	Kraft-Wärme-Kopplungs Gesetz- German Law for Cogeneration
MARI	Manually Activated Reserves Initiative
MCE	Multi Criteria Evaluation
mCHP	micro Combined Heat and Power
mFRR	manual Frequency Restoration Reserve
MSC	Micro Generation Certification Scheme
P2P	Peer To Peer
PEM	Polymer Electrolyte Membrane
PEMFC	Polymer Electrolyte Membrane Fuel Cell
PICASSO	Platform for the International Coordination of Automated Frequency Restoration and Stable System Operation
PV	Photovoltaics
RPU	Reserve providing units
RR	Replacement Reserves
SEG	Smart Export Guarantee
SH	Space Heating
SIA	Swiss Society of Engineers and Architects

SOFC	Solid Oxide Fuel Cell
sTOU	Static time-of-use
TERRE	Trans-European Replacement Reserves Exchange
TOU	Time-of-use
TSO	Transmission System Operator
UVAM	Virtually Aggregated Mixed Units
VPP	Virtual Power Plant
WP	Work Package

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Appendix A Grid service definitions - Czech Republic

Czech Republic

Grid service	Description	Procurement
Frequency Containment process (FCP)	**A local automatic process provided by primary control circuits and consists of a precisely defined change in the power output of a certain unit in response to a frequency deviation from its set value. An adequate primary control reserve must be available at the respective unit at all times in order to provide this service. The value of this reserve depends on the generating unit's technological parameters and Transmission System Operator requirements.**	**Procured through the day-ahead market with grid services or through long-term auctions**
Automatic frequency restoration process (AFRP)	**Automatic Frequency Restoration Process (aFRP) of a unit concerns a change in the power output of a regulated unit as requested by the load frequency controller. The quality of this service is determined by the amount of power offered and its enabling rate.**	
Manual frequency restoration process (MFRP5)	**The mFRR5 can be provided e.g. in the form of an increase in unit power output, discontinuation of pumping (at pump storage hydro power plants), or disconnection of the relevant load from the Czech power system. (aFRR) is provided by changing the set value of the unit controller.**	
Manual frequency restoration process (MFRP15+)	**The mFRR15+ can be provided e.g. in the form of an increase in unit power output, discontinuation of pumping (at pump storage hydro power plants), or disconnection of the relevant load from the Czech power system.**	
Manual frequency restoration process (MFRP15-)	**The manual frequency restoration process (MFRP) is a process of changing the power value of a regulated unit, as required by ČEPS Control Centre.**	

Grid service	Weighted average price [€/ MW/h]
Frequency Containment process (FCP)	**18.95**
Automatic frequency restoration process (AFRP)	**11.10 up** **8.73 down**
Manual frequency restoration process (MFRP5) / **Manual frequency restoration process (MFRP15+) /** **Manual frequency restoration process (MFRP15+)**	**14.10 up** **5.07 down**

Appendix B Country comparison of the final three countries

	Belgium	Czech Republic	United Kingdom
General mCHP market conditions	• Viable spark spread • Relatively significant installed base • High awareness of the primary energy savings efficiency CHP offers • Strong support for fossil µCHP in the past decade	• Mature market with domestic CHP manufacturers • Long tradition of cogeneration • Highest carbon intense electricity mix in the EU apart from Poland and Estonia • A broad awareness of the technology's advantages Increasing CHP electricity generation • Insignificant installed base	• Biggest future market potential • Relatively high installed base • Weakening currency • Brexit
Grid service markets	• Advanced balancing market • Good access to market for distributed resources • Favourable changes to certain products in recent years • New market design for secondary reserve (aFRR) will be implemented 2020	• No consumer presence on grid service markets • grid service market on the verge of meaningful change supported by pilot projects	• Falling grid service market prices • Good access to balancing market via independent aggregators • Nineteen commercial aggregation companies listed • Positive changes to products due to Electricity Balancing Guidelines (EB GL) • Transparency is lacking in several aspects (e.g. procurement through bilateral agreements)

Heat demand, gas grid connection rate and electricity prices	• Gas covered residential heat demand – 47% • Gas grid connection rate 55% • Household electricity price – 28.4 €/MWh • Network tariff – 28-34 % • Taxes and charges – 40-49%	• Gas covered residential heat demand – 27% • Gas grid connection rate – 64% • Household electricity prices – 15.8 €/MWh • Network tariff – 27% • Taxes – 18%	• Gas covered residential heat demand – 75% • Gas grid connection rate – 85% • Household electricity price – 19.60 €/MWh • Network tariff – 25% • Taxes and charges – 23%
Policy and agenda	• From 2030 government is looking to end gas grid connections to new builds and deep renovations	• Coal phase out discussions underway • Focus on encouraging the use of natural gas as a low-emission source of energy for small and medium-sized heating systems, in households and on decentralised heat sources (micro cogeneration)	• By 2025 government is looking to end gas grid connections to new builds
Governmental subsidies	• Certificates • Net metering	• Tax incentives • Guarantees of Origin Certificates to natural gas CHP under discussion	• New Smart Export Guarantee (SEG) export tariffs
Market alternatives	• Heat pumps • Solar (thermal and PV)	• Heat pumps • Biomass boilers • Solar thermal	• Heat pumps
Underlying economic factors	• **Spark Spread –** 22.6 c€/kWh • **Purchasing power –**	***Spark Spread**: 10 c€/kWh **Purchasing power –**	**Spark Spread:** 14.7 c€/kWh **Purchasing power:**

	€40’300 –> high • **Business case viability:** electricity: gas price ratio ≈5 –> viable	€19’500 –> low **Business case viability** – electricity: gas price ratio ≈3 –> possible	€36’400–> high **Business case viability:** electricity: gas price ratio ≈4 –> viable
Forecasts	• domestic CHP growth for the next 5 years	• 60% of heat supply systems are to be covered by cogeneration by 2040	
Summary of strengths and weaknesses	**Strengths:** • Governmental support • Spark spread • Access to verifiable time series data • Good access to well-functioning grid service market **Weaknesses:** • Uncertain future support for natural gas µCHP	**Strengths:** • willingness to move away from their heavy reliance on coal for meeting CO2 emission targets • the presence of a strong domestic CHP market and supply chain. • Net metering • Pilot projects supporting future movements towards aggregated flexibility and legislation **Weaknesses:** • Low electricity prices • Immature technology in the Czech context • Strong competition from market alternatives • No active form of governmental support	**Strengths:** • Governmental support • Good access to well-functioning grid service market **Weaknesses:** • Tumbling grid service market prices • Weaker currency • Uncertain gas grid future with new build connections

*2018

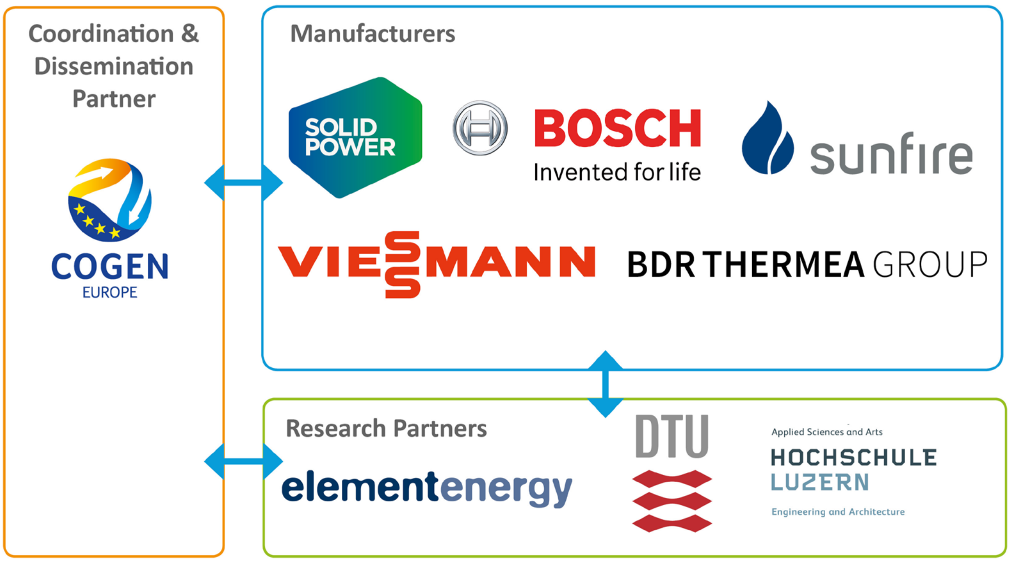
About PACE

PACE is a major EU project unlocking the large-scale European deployment of the state of the art smart energy solution for private homes, Fuel Cell micro-Cogeneration. PACE will see over 2,500 householders across Europe reaping the benefits of this home energy system. The project will enable manufacturers to move towards product industrialisation and will foster market development at the national level by working together with building professionals and the wider energy community. The project uses modern fuel cell technology to produce efficient heat and electricity at home, empowering consumers in their energy choices.

PACE project, which stands for "Pathway to a Competitive European Fuel Cell micro-Cogeneration market", is co-funded by the Fuel Cells and Hydrogen Joint Undertaking (FCH JU) and brings together European manufacturers, research institutes and other key energy stakeholders making the products available across 11 European countries.

For more information, visit *www.pace-energy.eu*
or contact Mr Janos Vajda via *info@pace-energy.eu*

The PACE partners are



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