D3.8 Scalability and replicability analysis (SRA) for all use cases

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Short Description

This deliverable presents the entire analysis conducted for all the use cases. The analysis is divided into a technical analysis and a non-technical analysis. The technical analysis is likewise divvied into the analysis of the solutions (system logic – Functions) and the communication architectures implemented in several demonstrations. The non-technical analysis covers a variety of topics with regard to the replication of the solutions in different countries around Europe.

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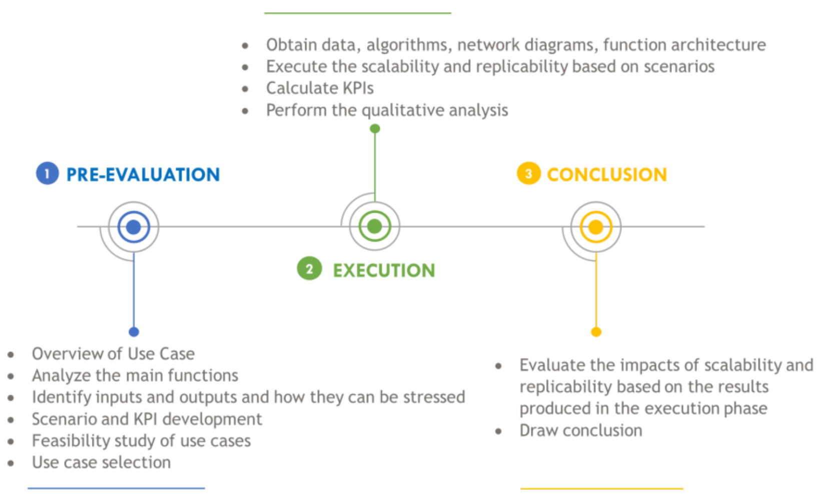
EXECUTIVE SUMMARY

InterFlex is a EU funded Horizon 2020 project aimed at addressing the various challenges faced by the Distribution System Operator (DSO) when modernising their systems and business models in order to be able to support the integration of distributed renewable energy sources (DRES) into the energy mix.

The scalability and replicability analysis (SRA) of the use cases aims at collectively learning from the smart grid solutions tested within the demonstrations and evaluating the potential impacts of their implementation at a larger scale within a similar or alternative energy environment. The SRA aims to identify potential barriers or constraints which may prevent large scale deployment. It also assesses the effects of the boundary conditions for the implementation of the use cases by the implementation of several **methodologies** exposed in **section 2**. These boundary conditions encompass the technical, economic, regulatory and stakeholder-related issues. The SRA considers the boundary conditions imposed on the **technical** analysis in **section 3** based on a qualitative and quantitate approach. The boundary conditions for the **regulatory** (non-technical) analysis is, on the other hand, covered in **section 4** only comprised of a qualitative analysis which includes an investigation into the regulations based on the perspectives of associated stakeholders.

The technical SRA is considered as the analysis of the system logic and its impact onto the network through the use of algorithms, network operation, devices or through the services which relay anew in algorithms. The technical SRA attempts to identify potential barriers and constrains or even drivers of the system with respect to the network or the services which are being offered within the demos. Furthermore, the rapid growth of the Smart Grid within the energy sector is due to the introduction of the communication systems (ICT). Hence, due to the importance of these ICT systems, the SRA also includes a study of its large scale implementation alongside the technical analysis. Thus, the technical analysis presented in this documentation is subdivide into the two main areas, the Functional (system logic) and the ICT area with its primary focus on the communication infrastructure used to support the system logic.

In order to meet the SRA requirements of entire InterFlex project which consists of 5 different demos and their Use Cases (UC), the developed methodology for performing the technical (Functional-system logic) SRA is based upon a modularity design concept (demo based and Smart Grid Architecture Model - SGAM representation) and its adaptability. This methodology is structured in three separate phases: a pre-evaluation phase, an execution phase and a conclusion of the analysis performed for each of the demos. The methodology is described in **section 2.1.1** and represented in the following figure,



The pre-evaluation is a key process which is based on a qualitative analysis of all the UCs in the Demos. In this phase the aim is to gather the maximum amount of information regarding the tools available or developed, timelines, data availability, KPIs, use cases interaction, system configuration, assumptions and limitations. With so, this process can select the best strategy for the different analyses aiming to capture the most interesting and beneficial innovations from the InterFlex project. The inclusion of the SGAM mapping provides a common modular framework which enables functions identification in an equal manner throughout the demos.

DE Demo
- ☑ Feed in Management
- ☑ Demand Response
- ☑ Ancillary Services

CZ Demo
- ☑ Increase DER hosting capacity of LV distribution networks by smart PV inverters
- ☑ Increase hosting capacity in MV network by volt-var control
- ☑ Smart EV charging
- ☑ Smart energy storage

NL Demo
- ☑ Local Infrastructure Management Systems (LIMS)
- ☑ Charge Point Management System (CPMS)
- ☑ LIMS and CPMS Flexibility Market

SW Demo
- ☑ Use of DSR to optimize DSO operation by exploiting the interaction with different energy carriers
- ☐ Optimal use of a large heat pump asset providing the district heating grid with heat and electricity flexibility for grid management purposes
- ☑ Technical management of a grid-connected local energy system that can run in an islanded mode with 100 % of renewable generation
- ☐ Micro Grid Customer Flexibility facilitated by a peer to peer market platform and enabled by Demand Side Response Programs
- ☐ Increased ability to observe and steer the operation of a micro-grid in response to distribution network constraints

FR Demo
- ☑ Islanding
- ☑ Multi service approach for grid-connected storage system
- ☐ Flexibility

☑ Considered for the SRA ☐ Not considered in the SRA

The execution of the SRA considers the results of the pre-evaluations and creates the specific environments for each demo. In them, the solutions are applied, and the developed scenarios are considered in order to produce meaningful results for a complete system analysis with respect to the operational method and its potential impact on the network. This step is based largely on simulations (quantitative analysis) where different combinations of key parameters previously defined are combined in multiple ways.

Finally, the last step, deals with the analysis of the results provided by the execution phase and identifies potential barriers during the scaling process which would lead to poor system scaling. The conclusions are individually based on the outcomes of each demo and thereafter serve as a foundation for the InterFlex general technical conclusions. A brief overview of the different conclusions obtained is provided in order to condense the extensive analysis conducted.

- For the case of the **German demo,** covered in **section 3.1.1**, the objective was to design and implement a Smart Grid Hub (SGH) and demonstrate its capabilities to increase the efficiency and utilization of existing grid structures. In this regard, the concepts are centred around the possibilities of increasing the hosting capacity, avoid equipment violations, and offer ancillary services based on the implementation of the SGH. The SRA has shown that the increase in Photovoltaic (PV) penetration located at the customer premise, causes over loading and voltage violations when 100% of customer PV penetration is implemented. When considering the penetration of load devices, it was shown that the increase in penetration causes an increase in feeder loading when control functions are not implemented. When the increase of penetration where households are equipped with all flexible devices is under consideration, it was shown that the maximum line loading exceeds the regulatory limits when more that 50% penetration of each device is connected within the network. It was also shown that when the device control functions are applied, there is indeed a reduction of the maximum line loading. However, this decrease was still insufficient to avoid network violations entirely. The replicability analysis, with respect to seasonality, showed that the impact of seasonal changes is largely visible during the winter period when there is increased network loading due to heating devices, even when demand response techniques are implemented. In order to ensure that no network violations occur within the network at any moment, it is important the DSO takes into consideration impact of seasonality when operating a network.

- In the **Dutch demo** case, covered in **section 3.1.3**, the analysis is set to identify the potential network constraints due to excessive flexibility operation within the system, the increase of penetration of EV and PV and how these may affect these offerings and constraints and the use of the proposed solution, as a means of congestion management solved by the use of a flexibility process negotiation between the aggregators and the DSO. Based on the analysis of the scenarios implemented, where each flexibility source is individually considered, it is clear that they can be used for network congestion management up to a certain limitation. Additionally, what is concluded is that these flexibility operation and the different forecasting systems can also cause a congestion in the network therefore, changing the network operation. Aggregators strategies can cause a great impact on the network operation and opens the door for them to dive in with their flexibilities. How good these aggregators are able to deal with the flexibilities is mainly based on the forecasting system. Nevertheless, it is clear that the idea of creating congestion points where different aggregators are involved would provide a clear direction for the implementation of these smart solutions in the Netherlands. Although all the analysis is based on day-ahead operation, it can be considered as a promising solution for the network operator to preview how the system is going to be potentially the next day operated.

- The SRA analysis performed for **Czech demo**, covered in **section 3.1.2**, quantifies how much and type of distribution capacity investments will be needed for selected time periods (up to year 2020, 2030 and 2040). They are calculated for the different baselines, where no solution is implemented and their Smart Grid (SG) solution, where the solution is implemented in CEZ Distribuce operation areas. Czech demo use cases (solutions) tested within InterFlex project could be replicated worldwide, due to their main characteristic, they are embedded autonomous functions. Comparing baseline scenarios with scenario where SG solutions are used, it is clear that the Czech demo solutions improved the Distributed Energy Resources (DER) hosting capacity and possibility to accommodate higher share of EV charging stations and this reduces the needs for distribution capacity investments.
- The case of Sweden is divided into two different demos, of which covers the solutions demonstrated in Malmö and the other which covers the solutions in Simris.
    - In the case of the **Malmo Swedish demo**, covered in **section 3.1.4** the investigations of the demand response service offered by buildings and building blocks as well as the investigation of the use of the thermal inertia of the heat network for grid management purposes are carried out based on combined dynamic building and district heating network simulations. Physical building models are used to simulate the theoretical Demand Side Response (DSR) potential of different buildings and building types Dynamic district

heating network simulations are performed to calculate the theoretical demand response capabilities. The evaluation of the potential for using building's thermal inertia as a source of flexibility is carried out based on the flexibility key performance indicator (KPI).

- In the case of the **Simris Swedish demo,** covered in **section 3.1.5**, the main interest is in analysing the islanded operation mode without fossil fuel-based backup generation. The use case topology and assets as well as the control algorithm have been discussed in detail previous deliverables. The scalability analysis regarded different scenarios where certain assets were scaled up and the impact on the Micro Gird's (MG's) performance during islanding was examined. It was shown that focusing on scaling up only one asset type leads to marginal improvements. Instead, careful balancing between the different asset types is required. Moreover, the results indicate that the control concept is easily transferable to other designs.
- One of the objectives of the **French demo,** covered in **section 3.1.6**, was to define which systems would be required in order provide islanding for 21 consecutive days, which allows for sufficient repair time, should the connection to the main island of Cannes be compromised. This is to be achieved by incorporating an optimised combination of PV generation, battery storage systems and the potential integration of Demand Side Management (DSM) where a general load reduction technique is applied. When taking all these parameters into consideration, it is necessary to find the correct balance between them, in order to obtain the most optimal solutions. The replicability analysis, with respect to seasonality, showed that the islanding duration is highly dependent on seasonality when there is insufficient installed battery capacity.

The extension of the technical analysis is done through the ICT analysis. The **ICT methodology** developed and exposed in **section 2.1.2** and **implemented** in InterFlex involves all the different demos and is later applied in **section 3.2** to the two main architectures found within the project. These are classified either as upper or lower bound. This classification is based on the connection between the DSO and the customer. In order to provide a complete overview of the qualitative analyses performed, it was needed to make several assumptions. The qualitative analysis concluded that it cannot be stated that one architecture is better than the other one, this completely depends on the set up of actors and the use cases which are implemented and how they need to be implemented. Nonetheless, this is a positive result as there is this provides a choice of architectures and not one unique one.

The non-technical SRA analyses the drivers and barriers that non-technical boundary conditions may impose onto DSOs and stakeholders' acceptance. This **regulatory analysis** done in **section 4** takes a country-based approach, so that all six InterFlex participating countries are included: Germany, the Czech Republic, France, Sweden, the Netherlands where the demonstrations (5) are located and, additionally, Austria. Through the analysis, the strong need to develop the regulation and new business models based on current regulatory conditions was exposed. These regulations need to make provisions for these flexibilities and create favourable conditions for their integration. In this relation, the implementation of the Clean Energy Package will be a turning point regarding the use of flexibility at the local level by DSOs in the EU. DSOs have been traditionally investing in grid reinforcement and extension as part of their network planning process; therefore, it is essential to draw a clear picture of the cost-effectiveness of incorporating flexibilities in order to consider them as an alternative to conventional grid reinforcement approaches.

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LIST OF ACRONYMS

BAU	Business as usual
BESS	Battery Energy Service System
BMS	Battery Management System
CEP	Clean Energy Package
CHP	Combined Heat and Power
CP	Charge Point
CPMS	Charge Point Management System
CZ	Czech Republic
DCC	Demand Connection Code
DE	Germany
DER	Distributed Energy Resource
DG	Distributed Generation
DSO	Distribution System Operator
DSR	Demand Side Response
EU	European union
EV	Electric Vehicle
FAP	Flexibility Aggregation Platform
FR	France
GIS	Geographical information System
GMS	Grid Management System
HP	Heat Pump
ICT	Information and Communication Technologies
ID	Identification
KPIs	Key Performance Indicators
LCE	Low Carbon Emission
LEC	Local Energy Community
LIMS	Local Infrastructure Management System
LV	Low Voltage
Mb/s	Mega bit per second
MG	Micro Grid
MV	Medium Voltage
NAP	National Action Plan
NSH	Night Storage Heater
p.u.	Per unit
P2P	Peer to Peer
PCC	Point of Common Coupling
PF	Power Factor
PoC	Point of Connection
PTU	Point Time Units
PV	Photovoltaics
Q	Reactive Power
RES	Renewable Energy Source
REX	Return of Experience
RFG	Requirements for Generators
SCADA	Supervisory control and data acquisition
SE	Sweden
SG	Smart Grids
SGAM	Smart Grid Architecture Model
SGH	Smart Grid Hub

SLP	Standard Load Profile
SRA	Scalability and Replicability Analysis
SSU	Smart Storage Unit
TRL	Technology Readiness Level
TSO	Transmission system operator
U	Voltage
UC	Use case
UoN	Use of Network
USEF	Universal Smart Energy Framework
NL	Netherlands
WP	Work Package

1.INTRODUCTION

The European Union (EU) Project InterFlex (Interactions between automated energy systems and flexibilities brought by energy market players) is a response to the Horizon 2020 Call for proposals, LCE-02-2016 ("Demonstration of smart grid, storage and system integration technologies with increasing share of renewable: distribution system").
This call addressed the challenges of the distribution system operators in modernizing their systems and business models in order to be able to support the integration of distributed renewable energy sources into the energy mix. Within this context, the LCE-02-2016 Call pro-moted the development of technologies with a high TRL (technology readiness level) into a higher one.

InterFlex explored pathways to adapt and modernize the electric distribution system in line with the objectives of the 2020 and 2030 climate-energy packages of the European Commission. Six demonstration projects were conducted in five EU Member States (Czech Republic, France, Germany, the Netherlands and Sweden) in order to provide deep insights into the market and development potential of the orientations that were given by the call for proposals, i.e., demand-response, smart grid, storage and energy system integration.
With Enedis as the global coordinator and CEZ Distribuce as the technical director, InterFlex relied on a set of innovativeˇ use cases. Six industrial-scale demonstrators were set up in the participating European countries.
Figure 1 shows a map identifying the demo sites around Europe.

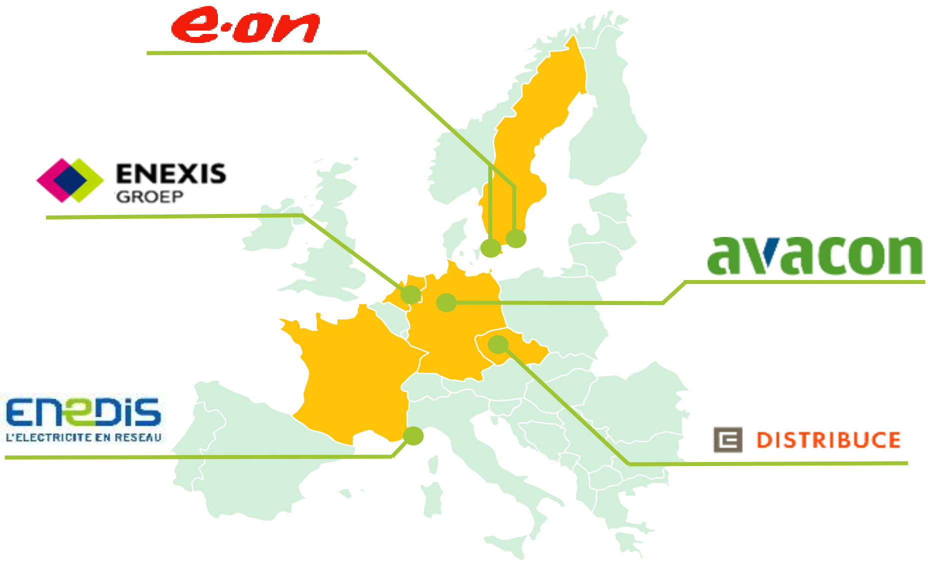

Figure 1 The map identifies the demo sites in the context of this project.

Through these demonstration showcases the InterFlex project assessed how the integration of the new solutions can lead to a local energy optimization. Technically speaking, the success of these demonstrations required that some of the new solutions, which were initially at TRLs 5-7, were further developed reaching TRLs 7-9 to be deployed in real-life conditions.

1.1. Scope of the document

The Scalability and Replicability Analysis (SRA) is built mainly on the approach developed and validated in the GRID4EU project. It is assumed that 12 use cases can be clustered out of the 18 demonstrated for the sake of completeness. The SRA process is made of two main stages: a technical analysis and a general analysis focused on the non-technical boundary conditions, which include regulations and the perspectives of the different stakeholders involved in the Cost Benefit Analysis (CBA) The CBA documentation can be found in D3.9.

The overall approach to perform the technical SRA builds on the concepts described in subsequent sections. The choice of the simulation model, Key Performance Indicators (KPI) and parameters to which sensitivities have to be performed needs to be adapted for each use case. This selection is mainly driven by the characteristics and goals pursued by the use case being analysed. For instance, power flow studies are required to evaluate voltage control strategies aimed at increasing network hosting capacity whereas time-domain simulation models are required to analyse use cases related to the islanded operation of part of the distribution network or impact of aggregation to solve congestion problems.

Replicability results may depend upon technical (seasonality and location) and non-technical aspects related to regulations or the involvement of relevant stakeholders. This sub task (non-technical) analyses the drivers and barriers that such boundary conditions may impose onto Distribution System Operators (DSOs): the regulatory drivers and barriers (DSO revenue regulation and smart grid solutions, DSO innovation incentives, DSO regulatory incentives: continuity of supply and energy losses, Distributed Energy Resources (DER) active participation and islanded operation, Smart metering and active demand, business models: aggregation, unbundling and self-consumption, Network charges for Distributed Generation, etc.) and stakeholders’ acceptance.

1.2. Structure of the document

The structure of the document is based on the consideration of two main focus areas, the technical analysis and the non-technical analysis. Section 2, therefore provides a detailed description of the methodology where each focus areas is considered individually. Section 3 addresses the technical scalability and replicability, while section 4 considers the non-technical scalability and replicability. Section 5 is dedicated to providing an overview of the conclusions obtained from each of the respective demos.

For the sake of completeness, additional supporting documentation for providing more details on the different approaches and simulations results are provided in the Annexes.

2. Developed methodologies

The methodology developed in order to fulfil the Task.3.2 is based upon reference models obtained from previous European projects. This is done due to the availability to adopt previously developed concepts conducted in projects such as Evolve DSO [1], Grid4EU [2], Reflex [3]. This does not mean that the same methodology is applied but rather is used as a foundation for which the InterFlex methodology can be adapted and extended to the requirements of the stakeholders involved within the process of the SRA. In addition, the methodology takes as a foundation in some respects for the information and system representation the Smart Grid Architecture Model (SGAM) approach. The inclusion of the SGAM provides the methodology which can be harmonised within a common European reference architecture from which future work can be implemented.

The methodology developed and implemented in the scalability and replicability analysis of the different use cases, considers four main areas. These consist of three technical areas, Functional, Information and Communications Technologies (ICT)[1] areas as well as an Economic and one non-technical area which focuses on the regulatory aspects. This distribution is outlined in Figure 2. It is considered that in order to properly assess the entire scalability and replicability of a smart grid solution, these four areas have to be analysed.

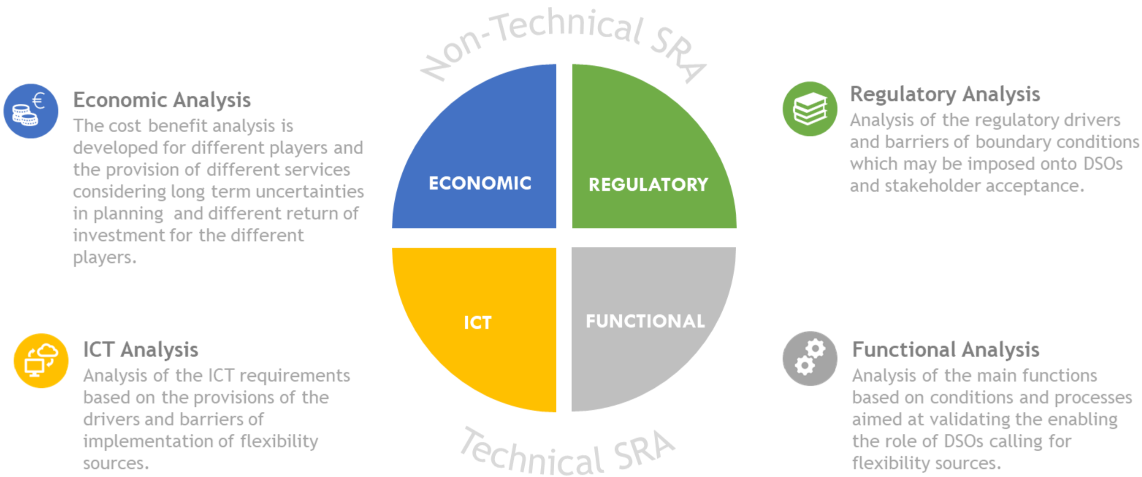

Figure 2: Technical and non-technical components of the SRA

In each of the four areas, the main idea prevails, which is the identification of potential barriers and constraints identified when a scaling of the system-set of solutions and replication is envisioned.

The scaling process results in an increase in the number of devices connected within the network. This increased penetration may have an operational impact on the network (functional), resulting in higher communication related traffic (ICT). It is, therefore, necessary to define these components within each of the smart grid solutions proposed in each demo.

The replicability analysis comprises of the set of solutions when applied in another time period (i.e. season) or in another location (nationally or internationally). The former is considered as part of the functional analysis, whereas the latter mainly forms part of the regulatory analysis.

[1] Although the ICT analysis is not part of the Grant Agreement, it has been included as part of the analysis since it is considered to be enabler for the transition to smarter grid functions as demonstrated in the InterFlex project.

However, each of the focus areas deals with a different aspect of a system which leads to a different internal approach of how to study and analyse the impact of the scalability and replicability process within it. Thus, the different approaches are collected within Table 1.

Table 1: SRA summary

SRA area	Type of study	InterFlex deliverable
Functional	Qualitative & Quantitative	D3.8
ICT	Qualitative	D3.8
Economic	Quantitative	D3.9
Regulatory	Qualitative	D3.8

2.1. Technical scalability and replicability

This section is divided into two subsections. The first subsection considers the methodology developed for the functional scalability (system logic and network impact) and the second subsection addresses the ICT scalability. An overview of the subsection and its structure within the analysis is shown in Figure 3. It should be noted that although the economic analysis is considered in deliverable D3.7 [4], required inputs from the technical analysis have been used for the economic analysis.

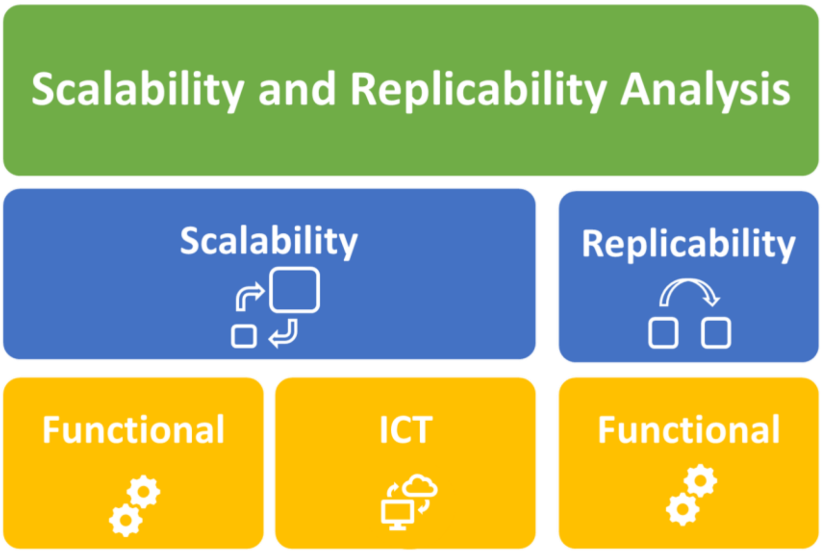

Figure 3: Focus areas of the SRA

Due to the complexity of the ICT replicability analysis based on the reasons addressed hereafter, it was removed from the scope of the additional analysis considered for the entire ICT analysis.

Since, the ICT layer acts as a support of the functional aspect of the demo and is thus considered as an 'enabler'. Therefore, replicating the ICT would require replicating alongside the functional part, which in some cases, alters the strategic purpose intended by the solutions developed within each use case of the Demos.

National replication from the same demonstrator can be considered as scaling the solution already implemented.

ICT replicability is mainly ensured through the implementation of standards and interoperability of devices providing an almost plug and play solution. In the case for the InterFlex project,

- ICT architecture is versatile, and most functions and services being demonstrated make use of well stablished business as usual operation as well as open standards on those new services, thereby, avoiding vendor lock and accessible to any interested party.
- Interoperability of services and devices is deeply analysed in a series of deliverables (D3.1, D3.3, D3.2, D3.7) where more information can be found.

2.1.1. Functional scalability and replicability methodology

The Functional SRA is initiated through the analysis which is used to identify potential barriers and constrains or drivers of the system with respect to the network or the services which are being offered within the demo. Services are considered when the network is relatively resilient, showing no constraints and the services integration and dimensioning represent the real challenge. Hence, this functional analysis is considered the analysis of the system logic and its impact on either the network through the algorithms, network operation, devices or through the services which are incorporated in algorithms.

The methodology developed to target the SRA, is based on the concept of modularity (which is demo based and incorporates SGAM representation) and adaptability, in order to provide a holistic analysis of all five demos which considers the unique approach upon which each demo is based. Thus, the process adapted for the methodology consists of three identifiable phases, *a pre-evaluation phase,* an *execution phase* and the *conclusion* of the analysis performed. The process which incorporates each of these phases are presented in Figure 4. These phases are further developed within the analysis of the individual requirement of the specific demos.

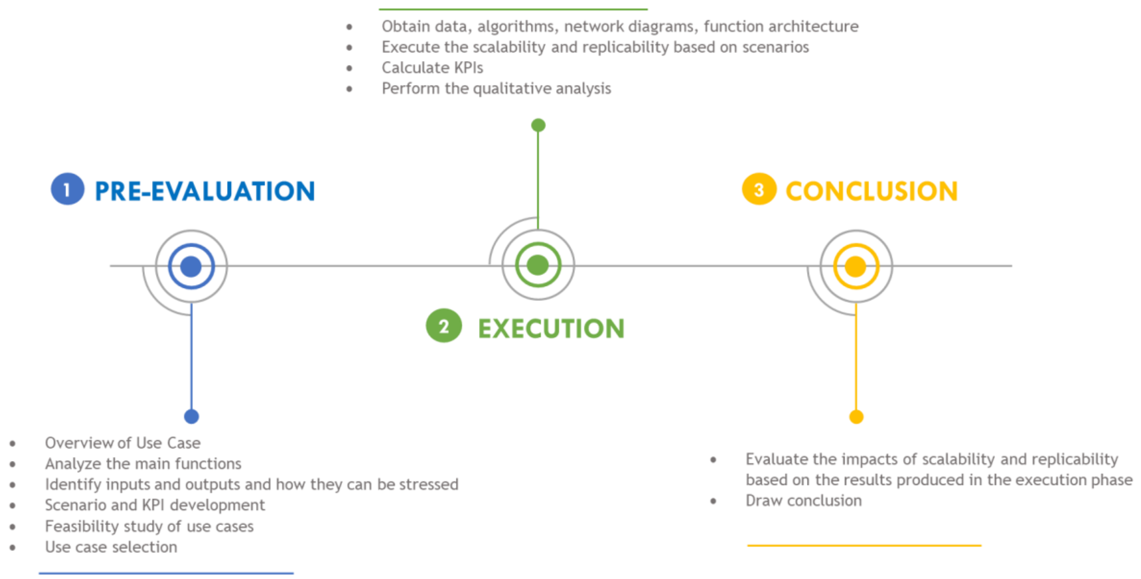

Figure 4: Functional methodology steps

Methodology steps

The first phase is based on a qualitative analysis of the set of all use cases (UC) from which the demo is composed. Information such as the tools available or developed, timelines, data availability, KPIs, use cases interaction, system configuration are gathered. Additionally, the SGAM of the demo is analysed as the functions are broken down and their inputs and outputs are assessed in order to identify the enabling functions and main functions. The qualitative analysis is an essential component of the adopted approach, since it is vital that the demo and its use cases are clearly understood and the potential points of interest to enrich the demo deployment and the members of the project are identified. This is done with the consideration of the implementation of the developed solution that is required to be scaled or replicated within their network or by another stakeholder in a future distribution network. Hence the collaboration with the demo leaders is crucial in order prioritize focus areas based on their specific requirements.

The result of this qualitative analysis provides the foundation for the UCs within a demo which have to be targeted. Assumptions with regard to those use cases are taken. Thereafter, scenarios are conceived in collaboration with the demo partners, based on the assumptions and existing limitations (i.e., access to the tools or data).

The execution phase follows thereafter which uses the outcomes of the pre-evaluation phase as a foundation upon which the technologies are actualised. The use of this specific environment, created for each of the demos, is to analyse the parameters when they are 'stressed'. Thus, the phase is based on large simulations (qualitative analysis) where different combinations of key parameters previously defined are combined in multiple ways. To be remarked, in some cases, the real system can be replicated as the environment is suitable for its application, while in other cases, due to the assumptions and data available a replication process is not conducted. Nevertheless, each approach is clearly defined and described more specifically within each of the Demo sections in section 3, and therefore is not discussed in this section.

Finally, the conclusion phase provides an evaluation of the outcomes of the execution phase. Here, a system analysis is performed in addition to identification of potential barriers during the scaling process which may lead to poor system scaling. Since each demo is targeted with individual environments, conclusions are offered specifically for each of the demos. These conclusions serve as foundation for the InterFlex general conclusion based on the functional, ICT (Information and Communications Technology) and regulatory analysis.

2.1.2. Information and communication technology (ICT) scalability methodology

With respect to the scalability of an ICT system, it is understood that it refers to the ability of an existing ICT system to be scaled-up without modifying its boundary conditions. The scaling process is done according to scaling-up scenarios which consider the functions and performance of devices involved, as well as scaling-up objectives. However, the scaling-up process may have an impact on the ICT system providing unexpected behaviour such as lags to get responses from requests or, in severe cases, a complete collapse of the ICT system. Both constitute performance failures where the impact of these failures could be considered as insignificant to dramatic respectively.

Existing working systems are usually based in complex architectures which involves not only many devices but also many interconnections and dependencies among devices. Therefore, it is highly challenging to quantify the global performance in order to identify a potential point of failure in the system. Hence, the system has to be decomposed into several branches and each of them analysed independently. Such analysis can show that a potential overload in a branch will arise once loads on the sub-branches increase in an unexpected range, leading to a performance failure.

The ICT methodology developed and implemented in InterFlex is applied to almost all the different demonstrators. The unique exception of a demo not included within the ICT scalability analysis is the Czech demonstrator and the peer to peer (p2P) platform in Sweden. In the case of the Czech demo, this is due to their own system configuration which is not ICT dependent, except for rare cases, which do not proportionate any potential bottleneck as they are considered as normal business operation. With respect to the p2p platform, it is targeted directly within the Swedish demonstrator and thus will not form part of this analysis. Nonetheless, since a p2p platform is based on the decentralization concept of the devices and the share of load among themselves, scalability is assured.

Methodology steps

In order to study the scalability of the system with regards to its ICT system architecture, the methodology developed is composed of the following condensed steps, represented within Figure 5. Contrary to the functional scalability process, which includes a 3-phase process, the ICT methodology introduces additional phases, due to the high complexity of the overall process.

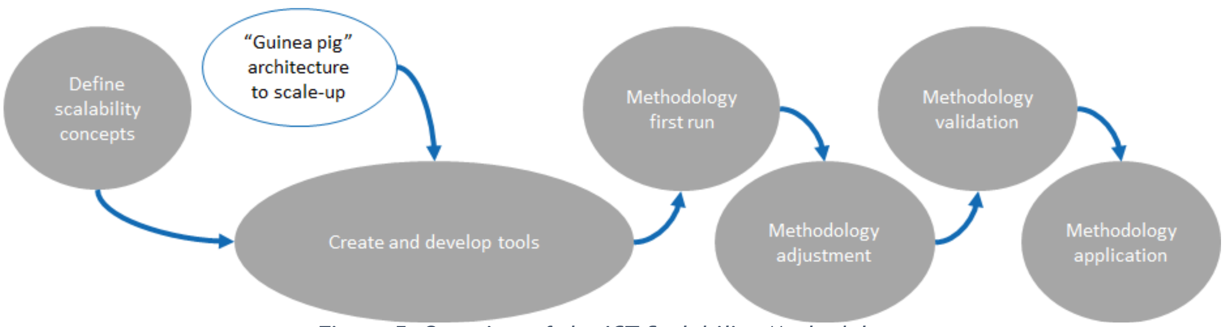

Figure 5: Overview of the ICT Scalability Methodology

Firstly, there is the necessity of defining which scalability concepts have to be considered, since it is necessary to reduce the overall system architecture complexity, identify which attributes are relevant and how they can be introduced into the qualitative analysis through their definition, classification and rating.

Once the attributes and their ratings are established, they are used as boundary conditions for the tools are created and developed. These tools are based on the foundation of the SGAM and their objective is to be the primary resource for the conduction of the qualitative analysis. Such tools help to assess the attributes selected, characterize the architecture, gather information regarding the system capacity and its own requirement and provide an estimation of results when scaling up the architecture through scenarios.

Nevertheless, these attributes and tools have to be tested in order to be improved if necessary and to identify the limitations of the analysis and acknowledge them through assumptions. To do so, the methodology is tested in a “guinea pig” environment.

After recollecting all the results from the “guinea pig” environment testing, the methodology can be adjusted, if necessary, through the return of experience (REX). This is extended through a validation process which confirms that the adjustments satisfy the analysis.

With a tested, refined and validated methodology, the next step is to implement it into the different architectures. For the architectures, a clustering approach is used based on the classification which can be done by analysing their interactions between actors. This results into two clusters, which correspond to an upper (inclusion of a third-party non-control by the DSO between the DSO and the Flexibility) and a lower bound (the DSO has control over the Flexibility through their own device/systems) architecture. A deeper explanation of this upper and lower bound can be found in [5]. This aggregation is based on the principal of selecting and taking one representative architecture within each bound for the analysis instead of individual cases. Thus, they are further developed with the internal steps of the refined and validated methodology in section 3.2.

However, the former description only provides a high-level overview of the developed and implemented methodology. Hence, to expand the internal processes and tasks within the methodology, Figure 6 is introduced, providing a summary of the internal methodology. Additionally, this summary includes the external stakeholders’ input and the different outputs throughout the process. As support information for Figure 6, Table 2 containing a brief description of the different process steps in the developed ICT methodology.

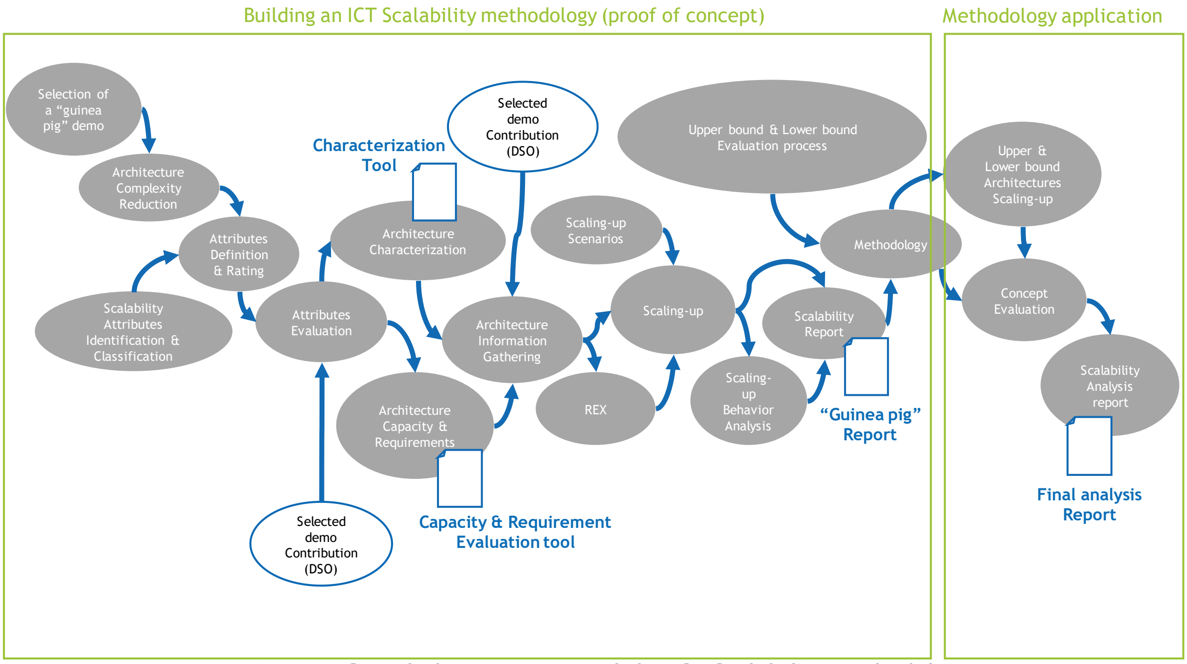

Figure 6: Detailed process steps of the ICT Scalability Methodology

Table 2: Description of methodology process steps

Step	Purpose
Architecture complexity reduction	Reduce the architecture complexity based on Client-Server relationships between architecture components
Scalability Attributes Identification and Classification	Identify ICT attributes relevant with the scalability analysis
Attribute Definition & Rating	Refine the attributes definitions to make them clear for the demo contribution & Refine attributes rating to get them relevant with the smart grid context
Attributes Evaluation	With the demo partner, getting an evaluation of his interest in particular attributes to be integrated / highlighted into the Scalability Analysis
Architecture characterization	Building an easy to use tool to gather information from the demo partner about ICT characteristics of his architecture
Architecture Capacity & Requirements	Building an easy to use tool to gather information from the demo partner about the Capacities of the individual components and links and the Requirements to run its demo on that “restricted” architecture
Architecture Information Gathering	Gathering information from the demo partner on his architecture for both Capacities and Requirements & Help the demo partner to use the provided tools
Scaling-up scenarios	Define scenarios for the scaling-up process Various realistic ranges, extreme ranges, etc.
REX	Evaluate the gathering of information on the following criteria: Attributes interest, Attributes information availability …
Scaling-up	Scale-up the architecture according to the selected attributes and selected scenarios
Compute results	Upper bound & Lower bound evaluation process
Scaling-up behaviour analysis	Identify abnormal behaviours of inappropriate attribute / scenario or computation & Adjust selection and computation
Scalability report	Write down the “Guinea pig” scalability report
Methodology	Ready for methodology application

2.2. Non-technical scalability and replicability

The global energy transition aims at decarbonizing the energy sector while introducing distributed sources of renewable and intermittent generation. In this context, flexibilities are identified as an important lever for the global system optimization and an essential component for smart grids, as a key driver of this transition.
The existing regulatory framework needs to be adapted or modified to enable and foster the use of flexibilities. In order to create favourable conditions for this paradigm shift, the respective roles and responsibilities of all stakeholders need to be clarified, including DSOs, flexibility owners, consumers, prosumers, local energy communities and aggregators. The non-technical SRA is performed in the frame of the InterFlex project to contribute to this clarification.

This analysis is focused on the following topics: regulation, standardization, user acceptance, business models for distributed generation (DG), and the targeted DSO service quality in the presence of flexibilities. The main objective of the non-technical SRA is to define key issues and possible solutions related to the before-mentioned topics. Moreover, the analysis considers all five countries having demonstrators in the frame of InterFlex, namely Germany, the Czech Republic, the Netherlands, Sweden, France, and additionally Austria, since two project partners are from Austria. This approach makes it possible to compare the regulatory framework and identify the best practices in the project participating countries.

2.2.1. Regulatory methodology

As previously mentioned, the activation of flexibilities significantly depends on the regulatory framework related to the involvement of different stakeholders and related business models. The present analysis takes a country-based approach, in which all six InterFlex participating countries are included: Germany, the Czech Republic, France, Sweden, the Netherlands where the demonstrations (5) are located and, additionally, Austria. InterFlex demonstrators differ from each other with respect to their focus areas. They cover a broad range of topics related to smart grid and local flexibilities.

The following two reference documents have significantly contributed to identify and structure the most important regulatory topics in the frame of the InterFlex project:

1. The SRA of Grid4EU H2020 project: Large-Scale Demonstration of Advanced Smart GRID Solutions with wide Replication and Scalability Potential for EUROPE [2]
2. The Clean Energy for All Europeans Package (further referred to as the Clean Energy Package - CEP) [6]

In 2016, the EU released the Clean Energy Package as the new energy rulebook designed to significantly transform the energy framework and to facilitate the transition from fossil fuel generation towards renewable energies. This initiative is considered an important commitment of the EU to the 2015 Paris Agreement. Issues related to flexibilities, local energy communities, data protection, and smart metering play an important role in the Clean Energy Package and are reflected in the InterFlex demonstrators. However, as the respective project demonstrators cover a very broad range of topics, a mapping of regulatory topics and use cases was conducted to identify the relevance of the specific regulatory aspects for the different demonstrators. This particular approach was taken from the Grid4EU project [2] and allowed to define focus areas within the non-technical SRA.

Subsequently, a detailed questionnaire was prepared and distributed among all InterFlex partners to collect their contribution. The questionnaire contained the following sections: participation of flexibilities in network services, business models for DG, network charges for DG, DSO costs and revenue regulation, resilience and reliability incentives based on flexibilities (including islanding), the DSO risk management associated to flexibilities, demand side management and smart metering. The questionnaire is attached to the present document in the Annex, section 7.3.1.

Based on the answers provided by the partners, the analysis was performed topic by topic and country by country. A comparative analysis of the current situation regarding the flexibility market is provided at the end of each section, highlighting the main trends and issues currently faced by flexibility markets according to the experience of the aforementioned six countries.

3. Technical scalability and replicability analysis

3.1. Functional scalability and replicability analysis

This section is structured according to the analysis of the different use cases within the projects respective Demos which are used as “cluster-approach”. This allows the analysis to provide direct focus and evaluate individual use cases in the demos. However, as previously stated, the analysis conducted per demo is based on the concept of modularity where not only one unique approach is used for all demos. Hence, depending on the outcome of the pre-evaluation (filtering process to understand, create SRA concepts and evaluate the use case for the best selection based on potential interest among the involved parties) the following use cases summarised in Table 3 are selected and, in some cases, are clustered for their analysis.

Table 3: UC summary selection for Functional SRA

Demo	UC considered	UC presented in this section
German	1, 2, 3	3
Czech	1, 2, 3, 4	1, 2, 3, 4
Netherlands	1, 2, 3	3
Sweden	1, 3	1, 3
France	1, 2	1

Hereafter, each demo individually explores the outcome of the pre-evaluation for this use case selection as shown in Table 3, to identify the limitations and assumptions made in order to analyse them. Once these concepts are explained and introduced, due to the large quantity of information gathered and the extent of the simulations and detailed analysis conducted over the scalability and replicability analysis in this functional area, not all the information is condensed in this section. The approach used to expose the information is based on presenting those use cases which the analysis can combine other use cases, as in Germany, Netherlands or France. In other cases, individual use cases are targeted as in the Czech or Swedish demo. Conclusions for each demo are offered as a summary of all the different analyses conducted for each demo. As a summary of the different internal section which can be found are,

- Use case selection & limitations
- Approach
- Scalability and replicability analysis (can be either aggregated in one internal section or separated into various sections, depending on the demo)
- Conclusion

The additional information to support in some case and in others to extend the analysis can be found in the annexes under section 7.2, with different subsections for each demo.

3.1.1. DE Demo

Pre-evaluation: Use Case selection & limitations

The objective of this Demo is to design and implement a Smart Grid Hub (SGH) and demonstrate its capabilities to increase the efficiency and utilization of existing grid structures. In this regard, the concepts are centred around the possibilities of increasing the hosting capacity, avoid equipment violations, and offer ancillary services based on the implementation of the SGH. The DE Demo encompasses the use of the SGH from three perspectives, Use Case 1: Feed in Management, Use Case 2: Demand Response, and Use Case 3: Ancillary Services, of which were analysed in detail in the pre-evaluation in the annexes under section 7.2.1. Based on the pre-evaluation of the Use Cases, it can be observed that Use Case 3 encompasses the concepts introduced in both Use Case 1 and Use Case 2, and thus, for the case of the Scalability and Replicability Analysis (SRA), more in depth review will be provided.

Approach

During the conduction of the pre-evaluation phase, it was identified that access to the SGH algorithms would not be possible due to security restrictions and continuous developments to improve the system by Avacon's technical team. Based on this limitation, it was necessary to develop a new approach for the conduction of the SRA by the relevant stakeholders. The new approach, therefore, considers that the SGH, and its functionality, as a 'black box' which encompasses pre-existing smart grid solutions and is considered as a 'smart system' as shown in Figure 7. The SRA, therefore, implements these smart grid solutions and primarily focuses on the overall network behaviour when the respective control functions are activated.

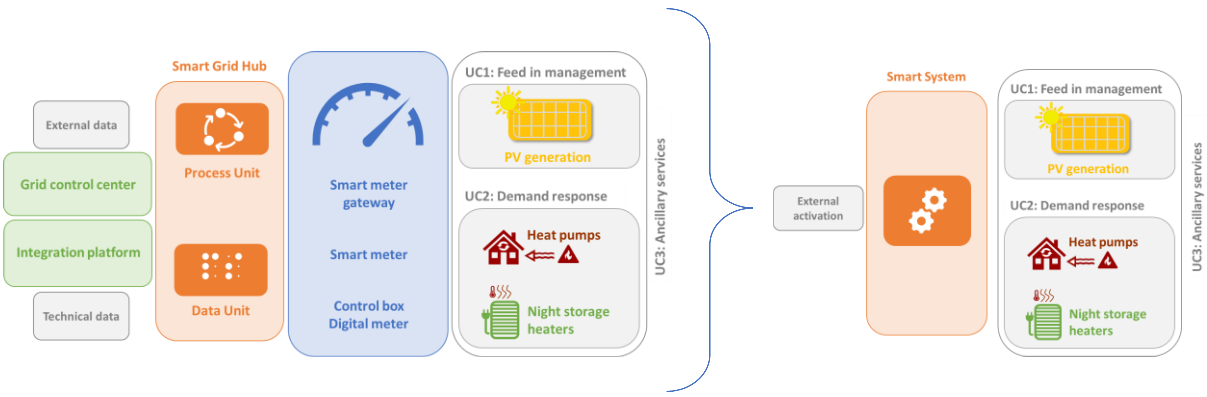

Figure 7 Original system configuration with SGH (left) and adapted configuration with the smart system (right)

Once the input profile data for each system component and network model is established, the SRA methodology consists of implementing a series of scenarios in which each of the network components are scaled accordingly. An overview of the process adopted for the DE demo is shown in Figure 8 and a more detailed discussion for each of the UCs will be considered in subsequent sections.

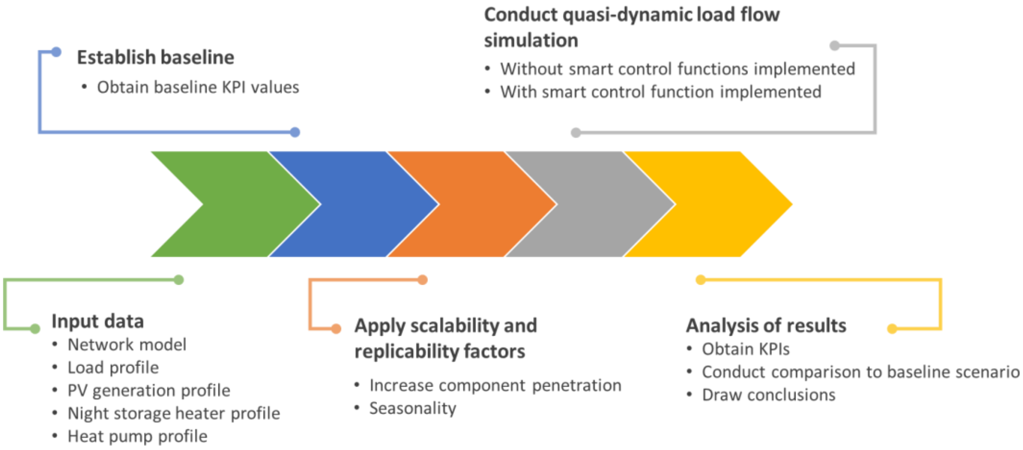

Figure 8 Overview of SRA methodology used to conduct the SRA of the DE demo

The analysis is initially based on a quasi-dynamic load flow study. It is used to establish a baseline scenario for later comparison with other scenarios through their internal KPIs. A scalability factor is then applied to each of the components to observe the impact of scalability without the use of the 'smart system'. Thereafter, the implementation of their respective 'smart' control functions is applied to achieve the main objectives of each of the UCs. Finally, the results from each scenario are analysed accordingly.

Due to the length of the analysis and the structure of the use cases which is based upon the foundation of UC1 and UC2, which when combined, forms UC3 which includes all devices considered for this demo. Therefore, only the analysis for UC3 will be presented in this section while the other use cases are individually analysed and can be further investigated within the annexes the annexes in section 7.2.1. However, Figure 9 provides a compact view of how the different scenarios are conducted within the scalability and replicability analysis of the three use cases.

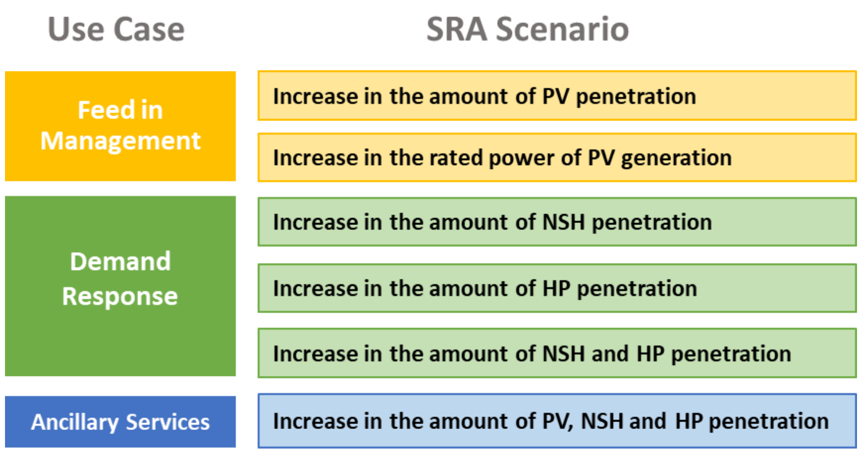

Figure 9 Summary of scenarios conducted in the SRA

Some assumptions and remarks which are considered in the analysis are:

- Only PV generation will be considered for power injection within the network for feed in management in UC1. This was considered, during the pre-evaluation phase conducted with Avacon, as the primary source of generation which will be prominent in future distribution networks.
- For the case of demand response in UC2, only night storage heaters and heat pumps are considered, since they are expected to a have an increased presence due to their increased roll out. However, it is acknowledged that other devices are also relevant to the modern LV grid, such as the combined heat and power units (CHPs) and electric vehicles (EVs). These devices do not form part of the scope of this analysis yet should be considered for future work.
- The characteristics curves for all devices, generators and loads, cannot be 100% accurate replicated, therefore it was necessary to assume a degree of through the use of synthetic profiles
- Due to the high level of detail which the SRA sets for analysis of the German use cases, only one representative network was chosen as it is a combination of radial and meshed grid layout. Additional information can be found at the annexes, in section 7.2.1.
- Scalability is achieved through the increase in the penetration of devices on the network with the objective to observe the impact on the network. Observations are made based on the impact in terms of feeder loading and voltage variations in order to assess whether any violations occur. The scalability is conducted on all three use cases and the same methodology for each is followed. Since it is noted that UC 3 represents a combination of UC 1 and UC 2, a more in-depth analysis is provided.
    - In each scenario, the number of households equipped with each of the devices is indicated in order obtain an understanding of the distribution of devices within the network. Thereafter, the analysis with respect to the maximum line loading and voltage variations are presented. It should be noted, that the analysis is done on line element level and that a summarised analysis per feeder is provided. In each case, the extreme values are taken, i.e. maximum line loading, maximum line voltage and minimum line voltage, which is then attributed to its respective feeder. This is therefore a representation of the worst-case conditions which are evident on the network.
- The analysis considers a common baseline scenario to which the developed scenarios for scalability and replicability can compare its KPIs. This baseline is specified in the following section for scalability and replicability sections respectively.

Scalability analysis

Use Case 3 takes into consideration of the potential of utilising distributed flexibilities on the flexible market in order to provide ancillary services to the DSO in terms of localised system balancing. For the purpose of the SRA, this use case can be considered as a combination of UC1 and UC2, where the combination of feed in management and demand response are considered simultaneously. Therefore, UC3 is presented here in more detail whilst the reader is referred to the Annex for a more detailed analysis of UC1 and UC2. It is noted, however, that in reality, UC3 was not successful due the overlap between generation and flexible demand being too small. This was expected at the time of the SRA scenario conception and therefore is still included as a theoretical analysis. Further details pertaining to this can be found in D5.8.

The baseline scenario is also included in order to provide a foundation against which the results can be compared. The baseline scenario is considered as the per demo scenario upon which the scalability and replicability scenarios can be applied per demo.

Scalability Baseline (constant for all UC)

In this scenario, the baseline characteristics are obtained. In this case, each household load is represented through the SLP, as discussion in section 7.2.1 in the Annex and it is considered that households are not fitted with any other device under consideration (PV, NSH or HP). The baseline scenario is conducted with 123 households which are distributed amongst the feeders. A representation of the number of households per feeder is shown in Figure 10.

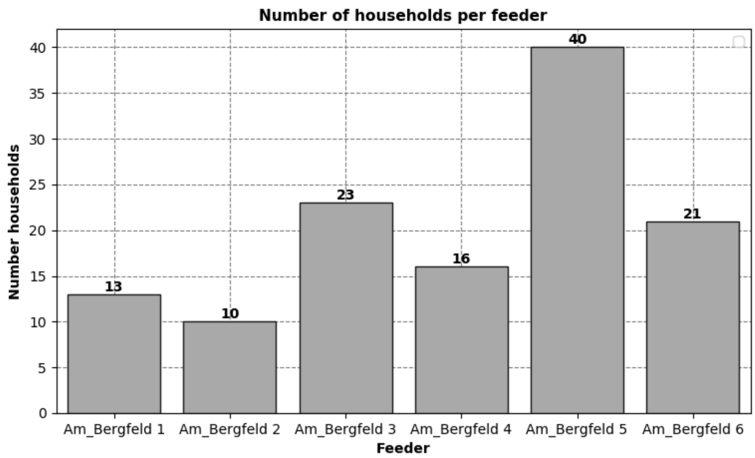

Figure 10 Number of households per feeder

Based on the number of households connected, each with a standard load profile, the maximum line loading can be established. Based on the quasi-dynamic simulation results, the maximum line loading per feeder over the entire duration of 2017 is shown in Figure 11.

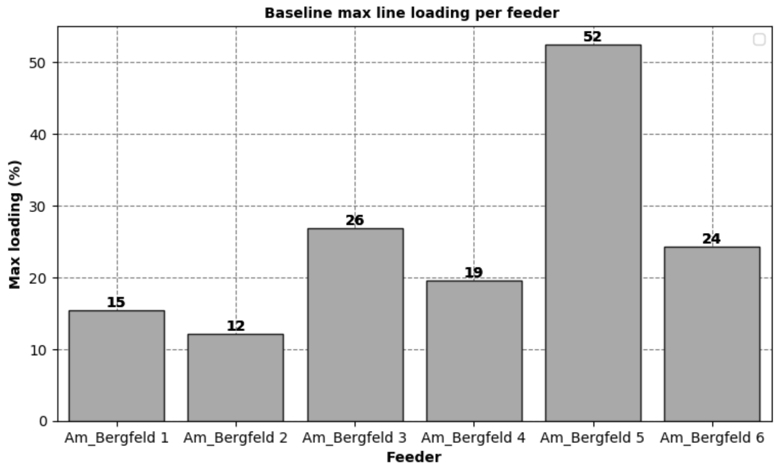

Figure 11 Baseline maximum line loading per feeder.

As can be seen, the maximum line loading ranges from 12% on Am Bergfelde 2 to 52% on Am Bergfelde 5. This is consistent with the network layout and is expected, since Am Bergfelde 5 contains the highest number of households, it is the longest feeder, and it forms part of the radial network. In general, the network can be considered as reasonably loaded and forms a realistic representation of a typical German network.

Furthermore, the maximum and minimum voltage variation for the baseline scenario was obtained and is shown in Figure 12.

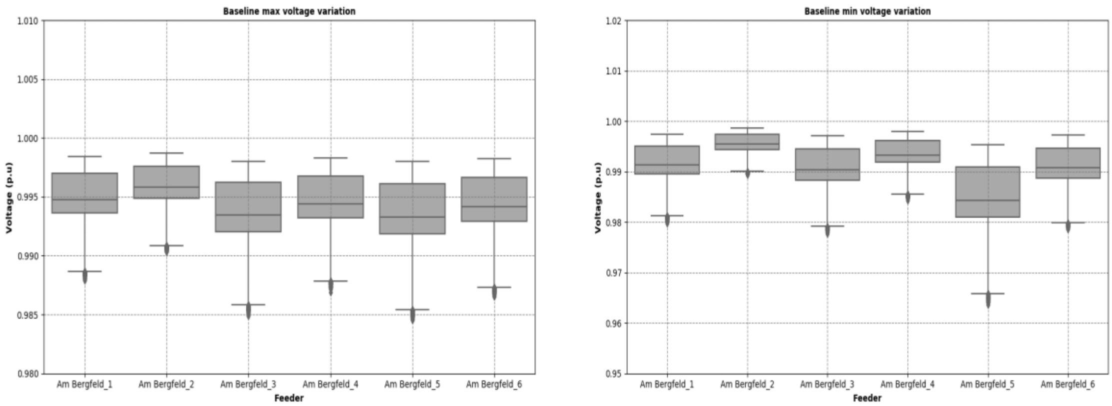

Figure 12 Maximum and minimum voltage variation per feeder

As can be seen, the baseline scenario does not exhibit any voltage violations under baseline conditions and that the maximum and minimum voltages are within the limitations set by the LV Grid Code [7].For the purpose of the SRA, and under voltage is considered as voltages less than 0.94 p.u. while over voltages are considered as voltages higher than 1.03 p.u.

UC3- Scalability analysis: Ancillary services

In this case, two separate conditions are investigated, firstly the case where there is a 50% distribution of customers with PV, NSH and HP. It should be noted that, the randomisation algorithm of selecting customers with devices is applied separately. This means that the allocation of devices is assigned independently and that some household may or may not be equipped with each specific device. Additionally, the case of 100% penetration of devices, is considered to be the worst-case scenario, since it may not be likely that every house is to be equipped with all three devices simultaneously (especially that of a HP and a NSH), however it is included for demonstrative purposes in order to observe the impacts on the network as it is considered as a scalability technique. Additionally, it is expected that future scenarios within the network, would need to make way for additional loads, especially when considering the increased use of electric vehicles.

The distribution of each of the devices, PV, NSH and HP for each feeder is shown in Figure 13, Figure 14 and Figure 15 respectively.

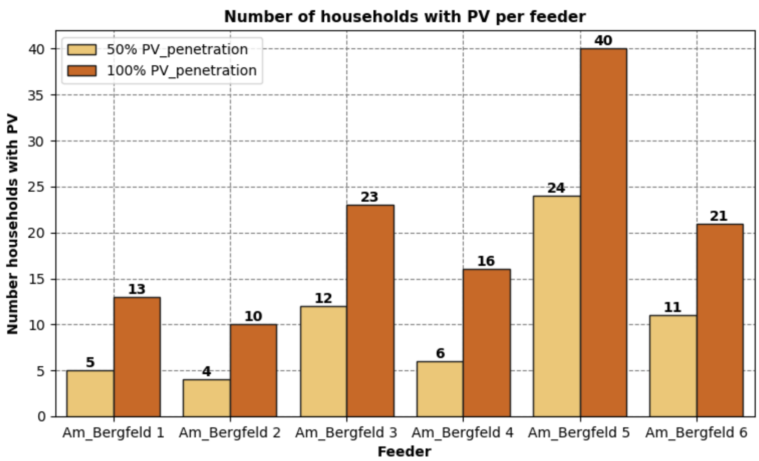

Figure 13 Number of households equipped with PV per feeder

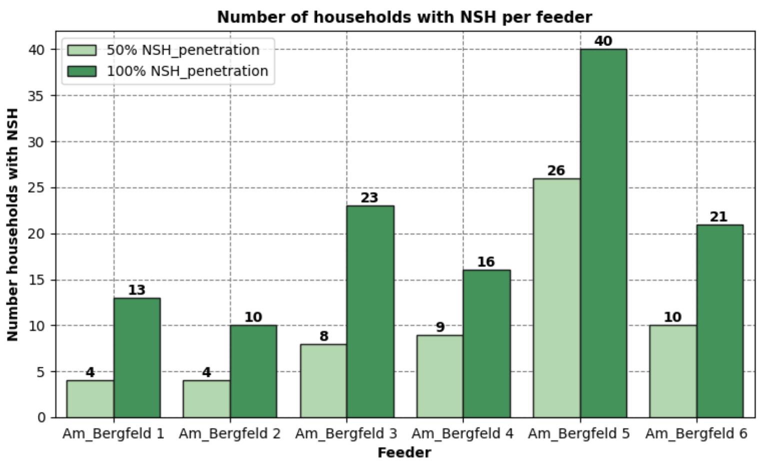

Figure 14 Number of households equipped with NSH per feeder

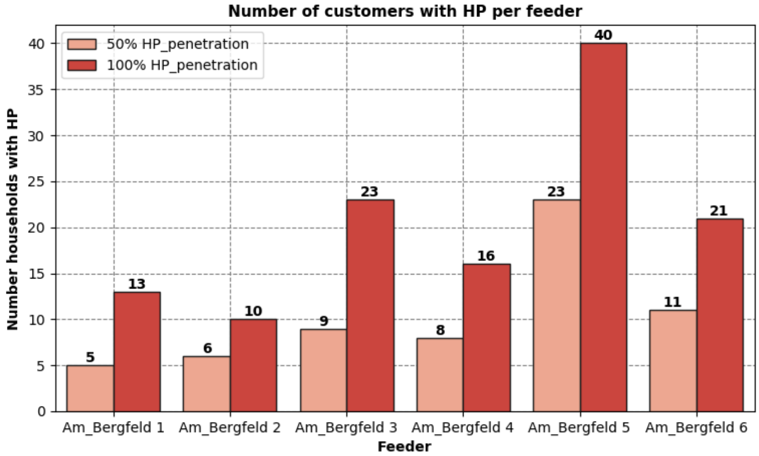

Figure 15 Number of households equipped with HP per feeder

As can be seen, the distribution of devices for each household with 50% penetration is not equal, meaning that a single household may or may not be equipped with all devices simultaneously. However, in order to observe the extreme case, the scenario is then performed when all customers are equipped with a PV, NSH and HP simultaneously. A summary of the device distribution, with their relative percentage, is shown in Table 4.

Table 4 Summary of device distribution per feeder for 50 % and 100% device penetration

	Distribution of 50% penetration for each device type						100% penetration of per device	
	PV		NSH		HP		PV, NSH and HP	
Feeder	Number of households	%	Number of households	%	Number of households	%	Number of households	%
Am Bergfelde 1	5	38	4	31	5	38	13	100
Am Bergfelde 2	4	40	4	40	6	60	10	100
Am Bergfelde 3	12	52	8	35	9	39	23	100
Am Bergfelde 4	6	38	9	56	8	50	16	100
Am Bergfelde 5	24	60	26	65	23	58	40	100
Am Bergfelde 6	11	52	10	48	11	52	21	100

The above device allocations form the basis of the remainder of the SRA, when all devices are present within the network. As was done in UC1 and UC2 (see section 7.2.1), the analysis in terms of maximum line loading and variations in voltage was conducted and is presented in the following sections.

Hosting capacity analysis

In order to obtain a holistic analysis in terms of the amount of active and reactive power within the network when there is an increased injection of PV, NSH and HP devices, an analysis was conducted in order to compare the results with the hosting capacity in terms of initial spare load capacity and DER capacity of the network (as presented in section 7.2.1). Table 5 shows how an increase in penetration of devices with and without control function compares with the maximum spare load hosting capacity.

Table 5 Maximum Active Power (load) Spare load capacity

	0% Penetration	50% Penetration		100% Penetration		Max. Spare load capacity (kW)
Feeder	**SLP only**	**No control**	**With control**	**No control**	**With control**	
Am Bergfelde 1	27.52	48.65	36.87	92.77	81.71	185
Am Bergfelde 2	21.82	46.02	35.79	72.21	62.75	188
Am Bergfelde 3	47.61	89.74	68.10	164.71	144.46	185
Am Bergfelde 4	34.88	76.28	61.53	113.78	100.45	185
Am Bergfelde 5	81.81	206.54	171.92	283.89	252.00	167
Am Bergfelde 6	43.25	95.23	76.14	149.85	131.54	186

As can be seen, Am Bergfelde 5 exceeds the spare load capacity when there is more than 50% penetration of devices, despite feed in management and demand response techniques being implemented. Despite this, there does prove that there is some degree of potential when implementing these functions, as the DSO would be able to improve the hosting capacity by reducing the load by 34.62 kW (50% penetration) and 31.89 kW (100% penetration).

In terms of the DER capacity analysis, the results are presented in Table 6, the amount of active power and reactive power with increasing levels of device penetration is shown.

Table 6 Distributed Energy Resource (DER) Capacity generated power with control

Feeder	50% Penetration		100% Penetration		Max. DER Capacity (kW)
	Active Power (kW)	Reactive Power (kVar)	Active Power (kW)	Reactive Power (kVar)	
Am Bergfelde 1	25.00	12.10	65.00	31.48	196
Am Bergfelde 2	20.00	9.68	50.00	24.21	195
Am Bergfelde 3	60.00	29.05	115.00	55.69	196
Am Bergfelde 4	30.00	14.52	80.00	38.74	195
Am Bergfelde 5	120.00	58.11	200.00	96.86	174
Am Bergfelde 6	55.00	26.63	105.00	50.85	195

As can be seen, Am Bergfelde 5, exceeds its maximum DER capacity by 26 kW when there is 100% penetration of PV devices.

Maximum line loading per feeder with increasing levels of PV, NSH and HP Penetration

Based on the aforementioned device distribution amongst households, an analysis on the maximum feeder thermal loading for increasing levels of device penetration, with and without control functions, over the entire year was conducted. The results of the analysis are shown in Figure 16.

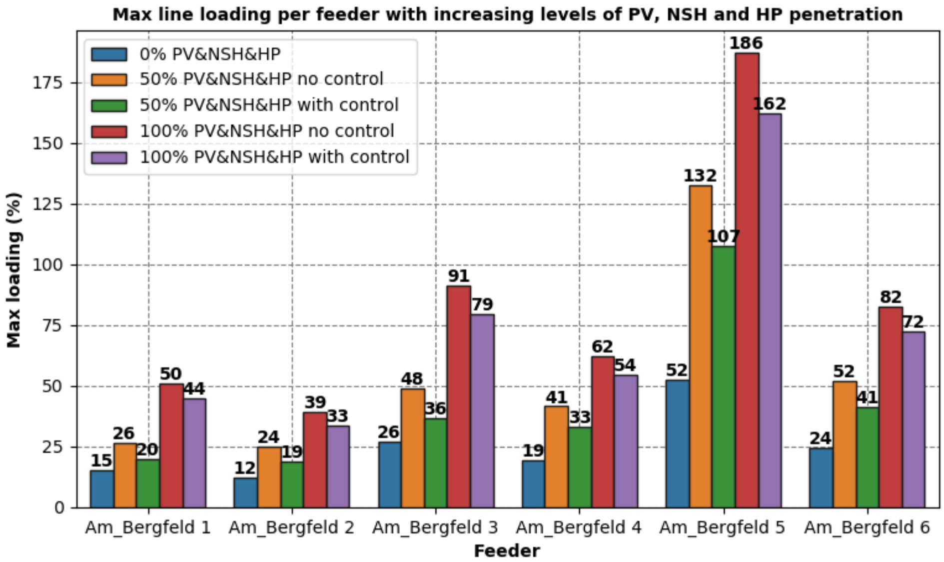

Figure 16 Maximum line loading per feeder with an increase in PV, NSH and HP penetration

As can be seen, all feeders exhibit an increase in thermal loading with an increase in penetration of all devices, when no control functions are active. Am Bergfelde 5 exhibits the largest degree of violations due to its radial nature, high number of customers, and long length (with respect to the other feeders on the network). When there is 50% penetration of all devices on the network, only Am Bergfelde 5 exceeds the thermal loading limit, and thus will be discussed in more detail. In this case, the thermal limit of the feeder is exceeded by 32% when there are no control functions implemented. In the case of 100% penetration of devices, the thermal loading limit is exceeded by 86%. Although networks are usually designed with a degree of capacity reserve in order to cater for an increased loading for a certain period of time, an increase of 80% is not considered feasible and thus alternative solutions to increase the hosting capacity should be employed. When considering the case, where the control functions are implemented, it is possible to see a reduction of the maximum line loading. For Am Bergfelde 5, the over loading can be reduced by 25 % (from 132% to 107%) when there is 50% penetration of all devices and by 24 % (from 186% to 162%) when there is 100% penetration of all devices though the activation of the control functions.

Furthermore, it was observed that the use of the reactive power control functions caused an increase of thermal loading due to the increase in reactive power generation. Additionally, the reduction of load, through the curtailment of the NSH during the day time (since curtailment between 22pm and 6am is not possible) has a significant affect in reducing the overall thermal loading of the feeder and that the overall reduction of thermal line loading can be attributed to the control functions of the NSH. The combination of the control functions used to provide feed in management and demand response was intended to provide a localised balancing such that the avoidance of network violations would be achieved. However, the results show that despite the combination of device implementation within the network, it is difficult to achieve an optimised balance between feed in management and demand response, even when their control functions are intended to complement one another.

Maximum transformer loading with increasing of PV, NSH and HP Penetration

The consideration of the maximum loading of the substation transformer is analysed in this section. The impact of the maximum loading of the transformer is important when considering the necessity of transformer upgrades and in order to assess whether there is enough leverage through flexibilities in the LV network to reduce congestion on the MV network. The amount of transformer loading with increasing levels of device penetration is shown in Figure 17.

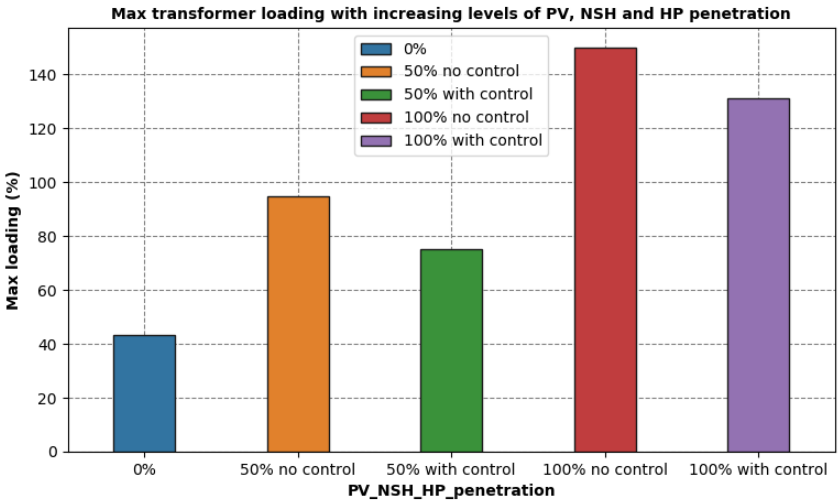

Figure 17 Maximum transformer loading

As can be seen, the maximum thermal loading of the transformer is exceeded when there is an increase in the penetration of devices of more than 100% penetration. In this case, insufficient ancillary services would be available for the operations of the network. However, since it is considered to be the worst-case scenario (since it is unlikely that all customers are to be equipped with all devices of which have a unity power factor) there still exists some potential when implementing feed in management in combination with demand response. This is evident when considering the reduction of transformer loading by 19% (50% penetration) and 17% (100% penetration).

Voltage variation with increasing PV, NSH and HP penetration

An analysis was performed to investigate the impact on voltage variation with increasing levels of penetration of devices into the network both when control functions are active and when they are not. As was shown in UC1, the effects of increasing the penetration of PV (without control) showed that an overvoltage occurs on Am Bergfelde 5 when there is 100% PV penetration within in the period of analysis. On the contrary, UC2 showed an overall voltage reduction of each feeder, due to the increase in customer load when 100% HP and NSH with no control is implemented. The maximum and minimum voltage variation is therefore presented in the following section.

Maximum voltage variation

The maximum voltage variation of UC3, therefore combines the effects seen in UC1 and UC2 and is shown Figure 18.

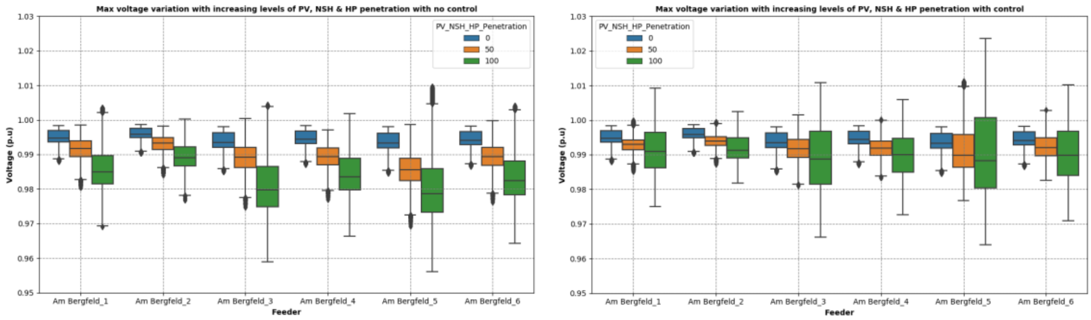

Figure 18 Maximum voltage variation with increasing PV, NSH & HP penetration with no control (left) and with control (right)

As can be seen, the variation of voltages shows an overall decreasing trend with respect to the mean voltages when there is an increase in device penetration. In the case where there is 50% penetration of devices, the voltages for each feeder are within the allowable range and in accordance with the LV grid code. When there is a further increase in device penetration of 100%, Am Bergfelde 3 and Am Bergfelde 5, exhibit an under voltage during the period of analysis. The lowest voltage observed are 0.962 and 0.965 for Am Bergfelde 3 and Am Bergfelde 5 respectively, of which exceeds the limitations the voltage bandwidth (although only slightly). In the scenario for when the control functions are implemented when there is an increase in device penetration is shown Figure 18 (right). As can be seen, no voltage violation exists when the control functions are implemented. This is the case for all levels of device penetration. For the case where the is 0% penetration the mean voltage for each feeder is approximately 0.995 p.u. with increasing levels of penetration, the mean voltage decreases to 0.994 p.u. and 0.99 p.u. This voltage variation does not prove to be significant and is within the allowable limits as set by the LV grid code.

Minimum voltage variation

The minimum voltage variation for the case of increasing combination of PV, NSH and HP devices is shown in Figure 19.

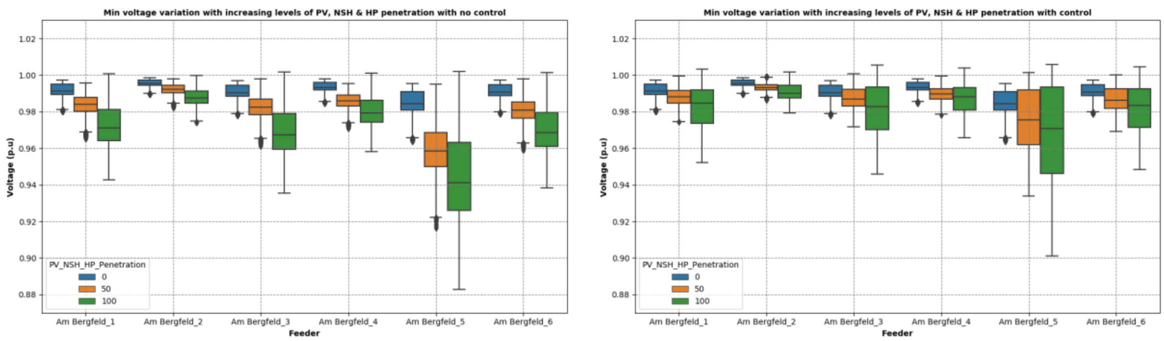

Figure 19 Maximum voltage variation with increasing PV, NSH & HP penetration with no control (left) and with control (right)

As can be seen, the minimum voltage variation of the network is evident on Am Bergfeld 5, which sees a minimum voltage of 0.887 p.u. when no control functions are implemented. The median value of Am Bergfelde 5 is centred around 0.959, while the overall percentiles of the plots extend beyond the 0.94 p.u. voltage constraint. When the control functions are implemented, voltage violations are still present on the Am Bergfelde 5, and thus indicates that even through the use of feed in management and demand response, voltage violations are not avoided.

Replicability analysis

Replicability Baseline (constant for all UC)

In order to achieve a basic understanding of the performance of the network, simulations are conducted with a baseline scenario where the network is considered 'as-is' or 'status-quo'. In this regard, the baseline KPIs are established, to which, KPIs from other scenarios can be compared.

Mean feeder loading analysis

In this scenario, the mean feeder loading per day in %, for Am Bergfelde 5, is determined in order obtain an overall set of results for the entire year of 2017. For the purpose of this study, the mean values per day are analysed in order to observe the effects of seasonality and not the case of the maximum values, which considers the results based on worst case conditions of the network, thus indicating the extreme values. Since the purpose is to analyse general the performance of the network, the mean values are used in order to avoid over estimations. Figure 20, show the mean feeder loading per day for the baseline scenario.

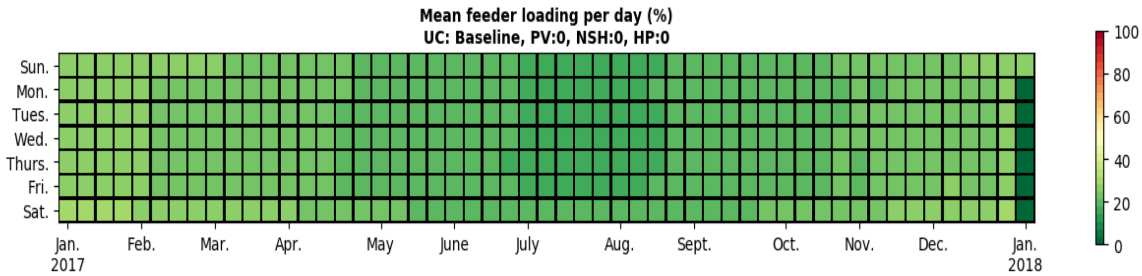

Figure 20 Mean feeder loading per day (%) for the Baseline

The mean feeder loading for the baseline scenario indicates a loading within the range of 20-30% throughout the year. This indicates that when households are only modelled with a standard load profile (SLP), no network violations with respect to feeder loading are present on Am Bergfelde 5. It can be noted that, the variation of loading over the entire year is not significant, however, a higher loading is present during the winter season. This is as expected since households are expected to consume more load due to increased usage of lighting and other appliances such a dryer etc. It should be noted that this scenario does not include the use of electrical heating, which will be analysed in subsequent sections. Therefore, it can be concluded that the variations of network loading on the Am Bergfelde 5 feeder, does not exhibit significant variations which can be attributed to seasonality.

Maximum and minimum voltage variation analysis

The maximum and minimum voltage variation for Am Bergfelde 5, in terms of the baseline scenario, is shown in Figure 21.

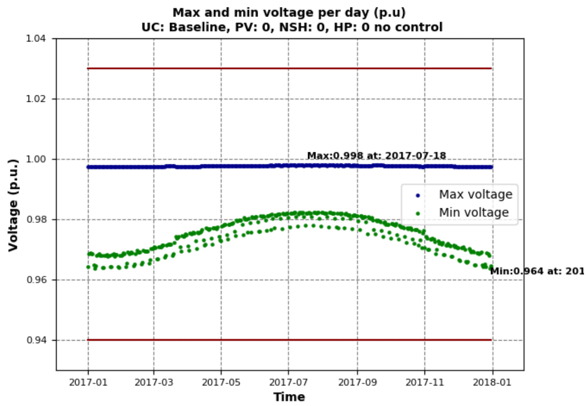

Figure 21 Maximum and minimum voltage variation for the baseline of Am Bergfelde 5 for 2017

As can be seen, the maximum voltage (blue curve) occurs on the 18-07-2017 when a maximum voltage of 0.998 p.u. is seen. Over the course of the year, the variation of the maximum voltage is not considered as significant and can be considered as constant, irrespective of the season. When considering the variation of the minimum voltage (green curve), it can be seen that the variation of the minimum voltage increases during the summer months. This can be attributed to the decrease in customer load consumption base on the standard load profiles. However, in both cases, the voltage variation is still within the limits according to the grid code, and no voltage violations are present for the entire duration of the year.

UC3-Replicability analysis: Ancillary services

In this section, the analysis of UC3, with respect to seasonality is conducted. In this scenario the combination of household devices i.e. PV, NSH and HPs are considered to be installed at the customer's premises. The impact of seasonal changes when 50% and 100% of households on Am Bergfelde 5 which are equipped with these devices, is investigated.

Mean feeder loading with increasing PV, NSH and HP penetration

In Figure 22, the mean feeder loading per day with 50% device penetration for Am Bergfelde 5 is shown. As can be seen in the top image, the feeder exhibits high loading levels of greater than 80% during the months of winter. This is attributed to the combination of high loading levels of the NSH and HPs with low PV penetration. During the warmer months, extending from April to October, the loading levels are within the ranges of 50%.

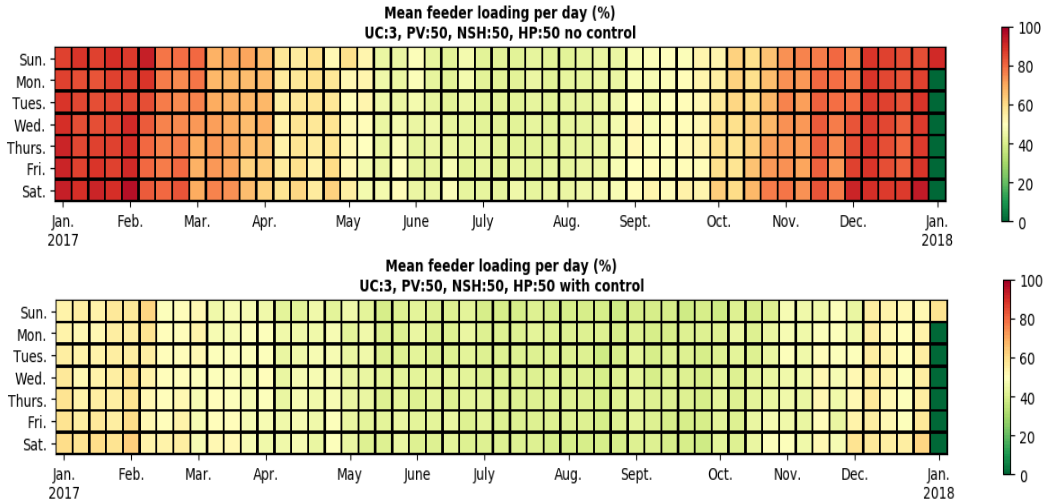

Figure 22 Mean feeder loading per day with 50% PV, PV, NSH and HP penetration without (top) and with control (bottom)

When the control functions are implemented, the loading levels of the feeder reduce to 50% feeder loading throughout the year. The effects of demand response are highly evident during the winter season and therefore reduces the impact of seasonality over the year.

The effect on the loading of the feeder is even more prominent when there is 100% penetration of devices, as can be seen in Figure 23. In the first image, the feeder exhibits a high degree of over loading violations through the winter season due to the high levels of loading and no demand response implemented.

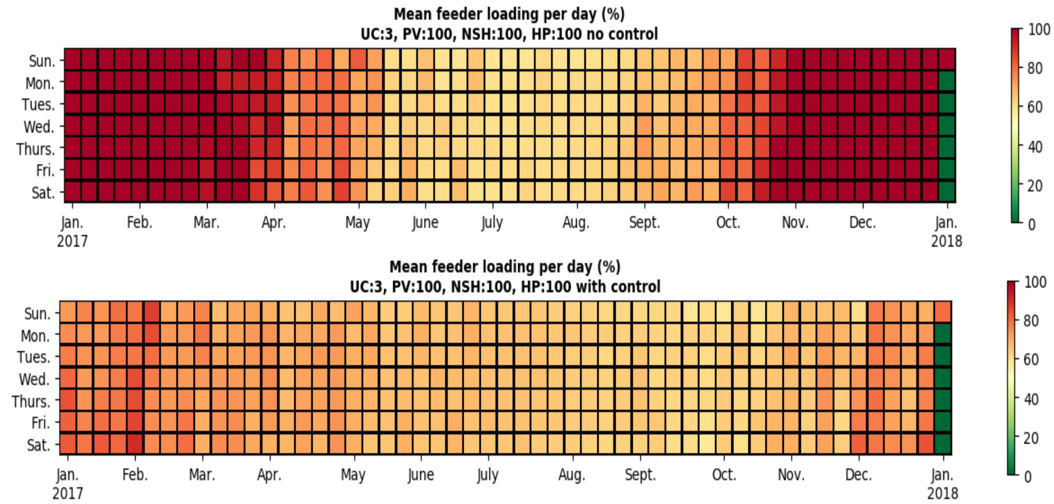

Figure 23 Mean feeder loading per day with 100% PV, PV, NSH and HP penetration without (top) and with control (bottom)

On the other hand, when the control functions are implemented, as shown in the lower plot, it can be seen that the amount of loading over the winter period is reduced to approximately 70%, which allows for significant relief on the loading on the feeder.

In both cases, with and without control functions, the summer season does not exhibit such high degrees of line loading and are within the 50% range. This is due to the reduction of heating loads during the summer seasons. It is also important to note, that as was shown in UC1, and increase in feeder loading exists during the summer months due to the increase reactive power injection when PV control functions are active. In this case, the impact of the load devices proves to have a higher degree of impact on the loading of the feeder. The effects of seasonality are, however, significant in both cases when 100% device penetration is implemented, and the DSO would thus need to take this into consideration in order to ensure that no violations occur.

Maximum and minimum voltage variation with increasing PV, NSH and HP penetration

In this section, the impact of seasonality on the maximum and minimum voltages are explored. Figure 24, shows the voltage variations for 50% penetration of the devices incorporated in UC 3. As can be seen, the minimum voltage falls below the limits specified in the LV grid code during the winter seasons. The increase in loading due to heating devices (HP and NSH) contribute to the extreme under voltages (0.92 p.u.), especially when the households are located at the end of the feeder.

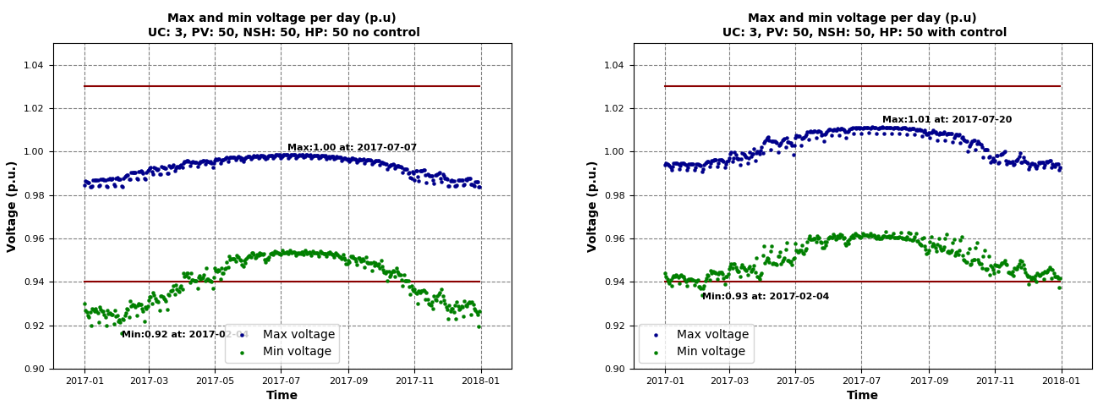

Figure 24 Maximum and minimum voltage variation for Am Bergfelde 5 with no control (left) and with control (right) for 2017 with 50% PV. NSH, HP penetration

The effects of the control functions are clearly demonstrated in the Figure 24 (right) where the degree of under voltages are reduced. However, the under voltages are still evident during February, when the minimum voltage is 0.93 p.u.

For the case of 100% penetration of devices, the results are shown in Figure 25 for the case where no control (left) and with control function implemented (right). As can be seen, extreme under voltages exist in both bases and are evident throughout the year. Despite the implementation of the existing control functions, under voltages are still present when during the winter periods when there is increased load.

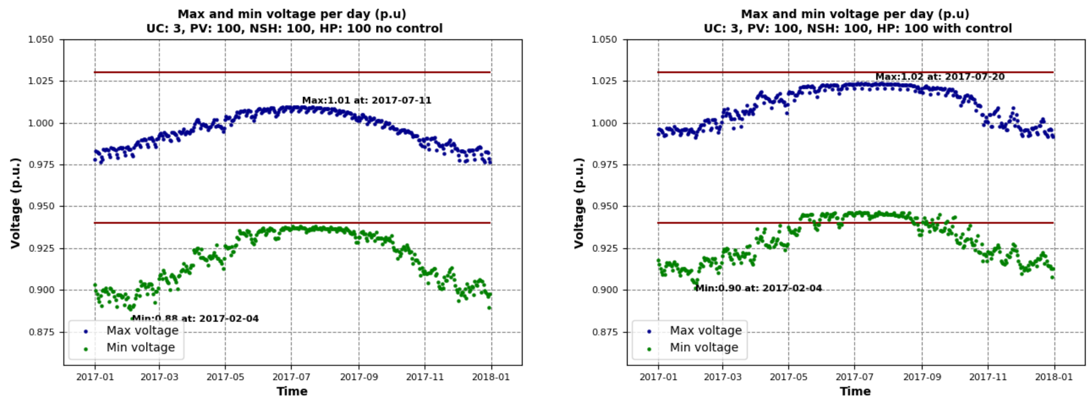

Figure 25 Maximum and minimum voltage variation for Am Bergfelde 5 with no control (left) and with control (right) for 2017 with 100% PV, NSH and HP penetration

Therefore, it is clear that the DSO needs to be conscience of the household devices present within the network. Additionally, adequate control functions need to be implemented as far as possible in order to avoid any potential violations.

Conclusions

For the case of the DE demo, it was shown that the increase in PV generation penetration located at the customer premise, causes over loading and voltage violations when the 100% PV penetration is implemented on Am Bergfeld 5. Line loading violations become present in the case where the reactive power control functions are activated while over voltage violations occur in the case when there is no PV control. In this regard, it can be observed that a trade-off between the two parameters is required in order to ensure that such violations do not occur. In the case where households were simulated with 10 kW_p PV generators (additional information in Annex 7.2.1), the network loading violations extended well beyond the limits set by the grid code.

When considering the penetration of load devices, it was shown that the increase in penetration NSH and HPs cause an increase of feeder loading when control functions are not implemented. For the case of NSH penetration, it was shown that when all 100% of households are equipped with NSH devices, results in an overloading of the network. Similarly, this was the case when all household are equipped with HPs. Furthermore, it was shown that in the case where there are control functions implemented on NSH, a significant reduction of loading is possible. On the contrary, it was found that the HP control functions used for the SRA proved to be insignificant and did not contribute to any significant reduction in network loading. The DSO would therefore need to ensure that sufficient demand response initiatives are implemented in order to ensure that violations do not occur, if network upgrade solutions are to be avoided. Customer engagement is, therefore, considered as essential part of ensuring that the network is able to operate in accordance with the grid code.

When there increase of penetration where households are equipped with all flexible devices under consideration. It was shown that the maximum line loading exceeds the regulatory limits on Am Bergfeld 5 when more that 50% penetration of each device is connected within the network. It was also shown that when the device control functions are applied, there is indeed a reduction of the maximum line loading. However, this decrease was still insufficient to avoid network violations entirely. Likewise, in the case of the variation of voltage, both in terms of maximum and minimum values, voltage violations occur when there is 100% penetration of all devices.

In all the case, the worst-case scenarios have been presented and therefore it is noted that there is further room for improvement in order to obtain a more realistic scenario. This includes the use of input data profiles obtain from measurement devices as opposed to over simplified profiles. In order to achieve an improved network capability, especially with respect to Am Bergfeld 5, it would also be necessary to improve the control functions in such a way that it would be able to optimise the activation of the flexibilities. This means that the activations of control function would not be simultaneously applied on a large scale across the entire network, but rather a more localised approach would likely result in reduced network violations.

The replicability analysis, with respect to seasonality showed that the impact of seasonal changes is largely visible during the winter period when there is increase network loading due to heating devices, even when demand response techniques are implemented. It was also identified that, although the PV control functions cause in an increase in feeder loading, the increase was, on average, not significant enough to result in loading violations. In order to ensure that no network violations occur within the network at any moment, it is important the DSO takes into consideration impact of seasonality when operating a network. The inclusion of flexible devices control strategies, therefore, also need to include incentives which cater for variations in seasons.

3.1.2. CZ Demo

Pre-evaluation: Use Case selection & limitations

Due to the highly involvement of CEZ Distribuce in the SRA, the pre-evaluation phase conducted for the Czech demo did not require such an extensive pre-evaluation phase. This results in an availability of data and accuracy of it which exceeds normal SRA operation. A deeper view of steps and simulations performed for the Czech demo can be found in the following deliverable, *“D6.3 Demonstration activities results”*.

Due to the requirements of the Czech Government addressed in the National Action Plan (NAP), the DSO provides emphasis to these criteria within their simulation in order to be compliant.

Analysis assumptions & limitations which are considered within this analysis are,

- All forecasts and scenarios listed in this document are shown for CEZ Distribuce areas (approx. 66% area of the Czech Republic), which is illustrated in Figure 26.
- Renewable and electric vehicles (EV) development scenarios are based on official government documents published from 2015 to 2017. Actual figures in future could differ from current expectations.
- Distributed energy resources (DER) are separated according to the voltage levels at which they are connected or planned to be connected.
- Time scale and steps are years 2020, 2030 and 2040. Between those, linear approximation is applied.
- All figures shown in tables and graphs are installed power in case of DER and new loads and maximum charging power in case of EVs
- All use cases are considered individually, there is no clustering.

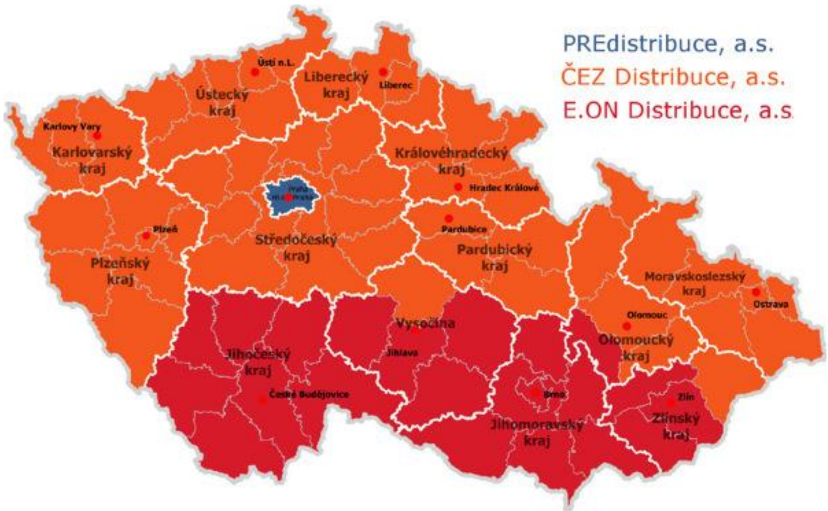

Figure 26: Area operated by CEZ Distribuce in the Czech Republic (orange regions)

Approach

Given the ideal conditions to produce a quantitative technical analysis for the Czech demo, the approach selected for the analysis is based on the results obtained from load flow calculations, taken from the connection study standard approach which can be found in [8]. In the study, the worst-case conditions are evaluated based on a momentary state estimation and therefore, time series characteristics do not need to be considered. These calculations are split into different sections based on the distribution area considered, LV or MV and filtered by resource type considered, generation and EV integration. To produce such an analysis, LV and MV networks have to be characterized, in order to create representative networks for the analysis.

LV representative feeders are based on technical and statistical data gathered from the available SAP grid database and geographic system GIS for districts operated by CEZ Distribuce. Due to the increased complexity of the of MW networks, the statistical approach to build representative models proved to be a tedious task. Therefore, it was necessary to develop 15 representative feeders which characterize the entire 4000 MW network.

Since the availability of data is for the entire year, this allows for the ability to evaluate the yearly data for consumption and generation (DER Connection) during the pre-evaluation phase. Three significant seasonal periods were identified for the LV networks, Winter season[2]; Summer season[3] and Mid-term season[4]. Due to rather little differences between summer and mid-term PV production (PV efficiency decrease with summer outdoor temperatures), the mid-term season was chosen, in particular, 3rd Sunday in May 2017 2PM. Contrary to the simulation of DER connection, the integration of EV results in an increase in network disturbances in times of peak consumption. In this scenario, few thousands of randomly selected secondary substation annual measurements were analysed. The analysis showed that on the 5th January 2016 at 6PM, the average highest peak in LV was identified as 36,5 % of secondary substation installed power.

Table 7, provides a compact view of the CZ SRA scope selected for the analysis, whilst Figure 27 provides a simplified process flow where the different phases of the SRA of the CZ are represented.

Table 7: CZ SRA scope summery

Section	Network type used	Time selected for Hosting capacity	Time selected for EV integration	SRA
Low Voltage	Statistical Representative LV grids based on feeder length and municipality size	3rd May 2017 at 2PM	5th January 2016 at 6PM	For every district[5] (areas)
Medium Voltage	15 Representative feeders	3rd May 2017 at 2PM	5th January 2016 at 6PM	For every district (areas)

[2] High consumption, high CHP generation, very low PV generation.
[3] Low consumption, no CHP production, maximum PV generation
[4] Average - rather low consumption, considerable CHP production, very high PV generation.
[5] CEZ has a total of 59 districts (areas) which are represented in Figure 26

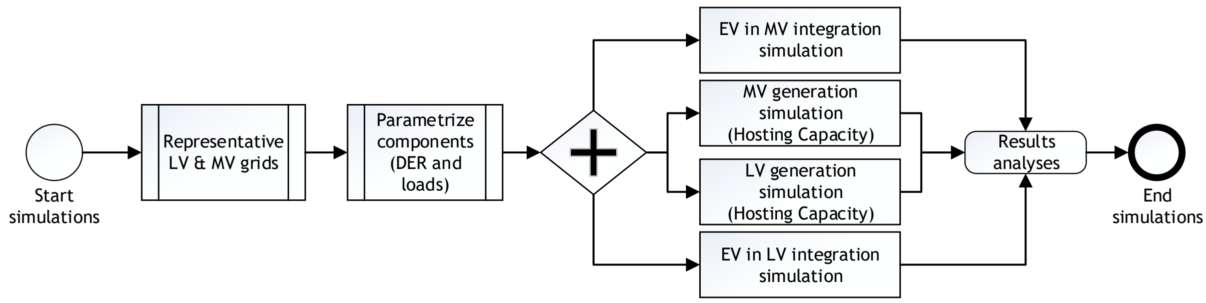

Figure 27: SRA CZ steps process flow

Scalability and Replicability analysis

For the Czech demo, the scalability and replicability process can be seen as one unique process which can be done simultaneously, as the system is not restricted to the districts defined by the demo, but also includes other districts for the whole Czech Republic creating a baseline set of scenarios for the replicability as all the districts are considered on top of the scaling ones based on the different penetrations dictated by the NAP which serve as a reference.

The entire process of how the load flow simulations are calculated and developed (entire parametrization of the system for MV and LV) for the different use cases cannot be covered due to over extension within this section. Hence, the main outputs are described hereafter and its steps to generate the models are completely covered in the corresponding annex section (Annex 7.2.2) for the additional Czech documentation generated.

For each use case the analysis performs a scalability and replicability analysis (location based) in order to capture the total gain of each individual use case for the different districts where the DSO operates. A detailed description of WP6 solutions are further described in deliverable D6.1.

Within this section of the SRA, the baseline and SG calculation for the scenarios which correspond to the 2020 deployment are implemented. The additional two scenarios, 2030 and 2040 are collected in the Annex 7.2.2 .
The results offered are performed through a collection of figures where, the following colour scheme is used,

- Red marks insufficient hosting capacity in the district.
- Green marks sufficient hosting capacity the district.

Table 8: Type of distribution capacity investments for baseline which are needed for DER or EV integration for calculated NAP scenario - additional investments which are not a part of standard grid renewal and development included in DSO plans

Baseline [6]	2020	2030	2040
Use case 1	0 km of LV feeders	0 km of LV feeders	over 20.000 km of LV feeders
Use case 2	1.261 km of MV feeders	537 km of MV feeders	1.507 km of MV feeders
Use case 3	0 of MV/LV transformers	0 of MV/LV transformers	8.943 of MV/LV transformers
Use case 4	0 km of LV feeders	0 km of LV feeders	16.049 km of LV feeders

Table 9: Type of distribution capacity investments is case of UC1, UC2, UC3 and UC4 large scale implementation which are needed for DER or EV integration for calculated NAP scenario - additional investments which are not a part of standard grid renewal and development included in DSO plans

SG[7]	2020	2030	2040
Use case 1	0 km of LV feeders	0 km of LV feeders	16.049 km of LV feeders
Use case 2	898 km of MV feeders	155 km of MV feeders	463 km of MV feeders
Use case 3	0 of MV/LV transformers	0 of MV/LV transformers	4.938 of MV/LV transformers
Use case 4	0 km of LV feeders	0 km of LV feeders	9.444 km of LV feeders

[6] Distribution capacity investments
[7] Distribution capacity investments

UC1

Figure 28 shows the 2020 scenario results of the different LV networks targeted for each area where CEZ is responsible for. As can be seen the hosting capacity is increased through the use of the grid automation functions embedded in the customer's inverters. Its penetration within the distribution network is expected to increase dramatically. Its decentralisation reduces the necessity of DSOs to have intense central control systems and reduces the amount of times the operator is required to leave the control desk in order to attend to a network problem, which may require high effort and be time consuming. With a decentralised approach, the operator is thus able to provide focus on the MW injection of the renewables large scale generation farm

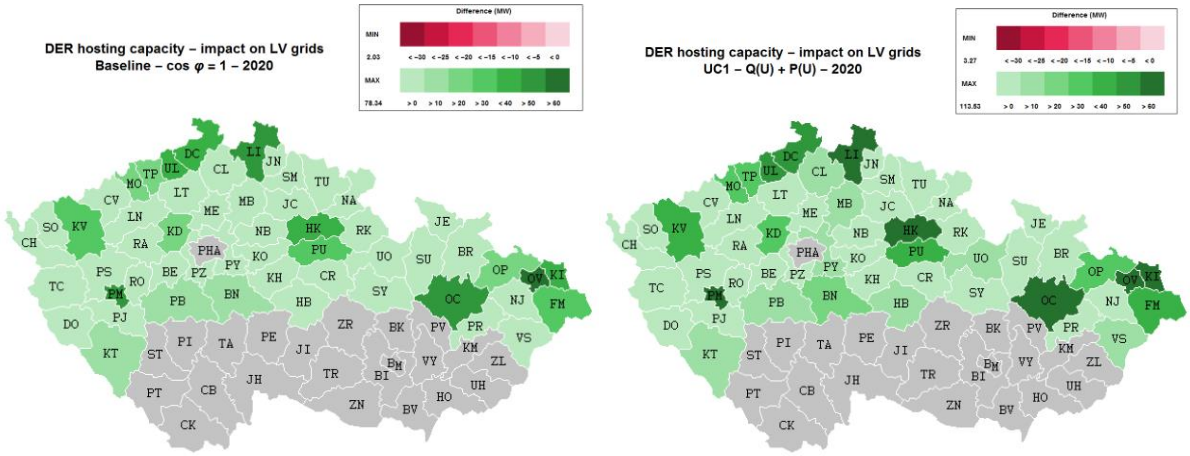

Figure 28: DER hosting capacity surplus/deficit on LV level in CEZ Distribuce districts (Use case 1 – baseline and SG with Q(U) and P(U) solution – year 2020)

UC2

The results obtained for use case 2 are promising as represented in Figure 29. The comparison between the scenarios where the smart functions are activated (volt-var control) for MV control for the different DERs (wind turbines for example) results in a clear increase in the hosting capacity of the network by a large extent. This affects those which already have a lower value, leading to favourable potential scenario if more units start being targeted by this function at MV level.

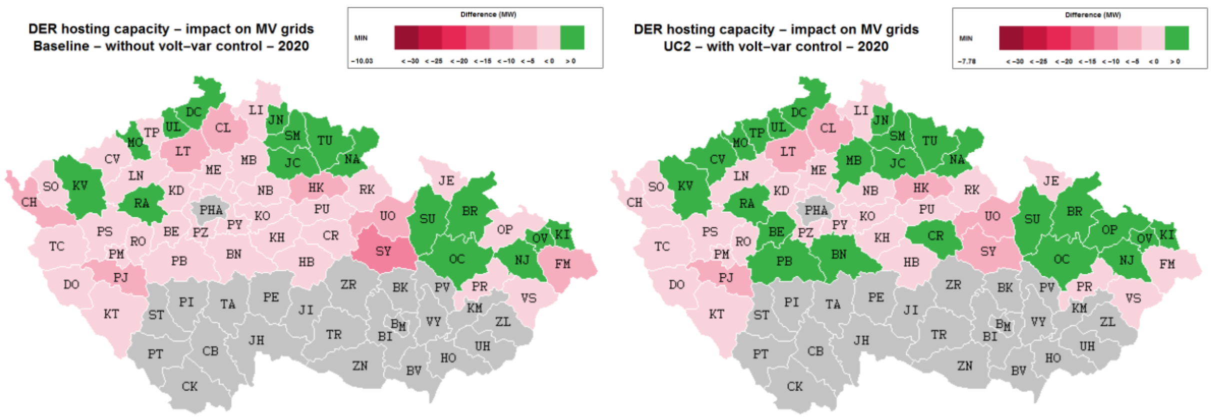

Figure 29: DER hosting capacity surplus/deficit on MV level in CEZ Distribuce districts (Use case 2 – baseline without volt-var control and SG with volt-var control - year 2020)

UC3

With respect to the integration of EVs and its impact into the network, with the ability of controlling the charging power output when required and adapt it to the network's necessity, the hosting capacity can be increased in most of the areas by a great extent. This is reflected in Figure 30, proving that its can be considered as a viable potential source of flexibility for network operation in the upcoming years.

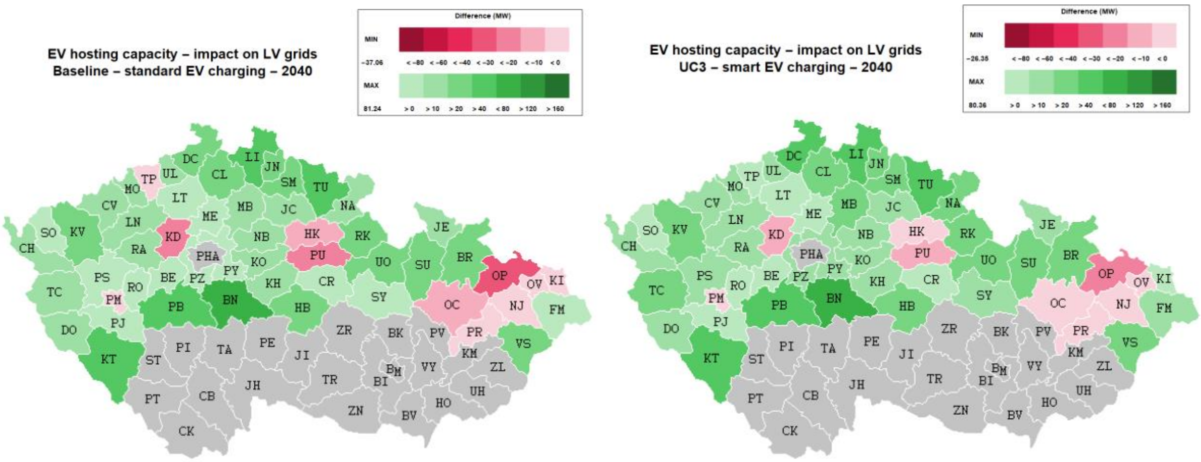

Figure 30: EV hosting capacity surplus/deficit on LV level in CEZ Distribuce districts (Use case 3 – baseline with standard EV charging and SG with smart EV charging - year 2040)

UC4

As for use case 4, where residential customers who have or would have a combination of assets such as PV and battery coupled together, their control through inverters and triggering of smart functions for power control is based on autonomous functions and provides similar results to those captured in Use Case 1. However, since in this use case, a battery storage system is added at the customer side, PV injection is expected to be reduced, hence producing better results than in use case 1, where only PV is considered as the main asset of the customer.

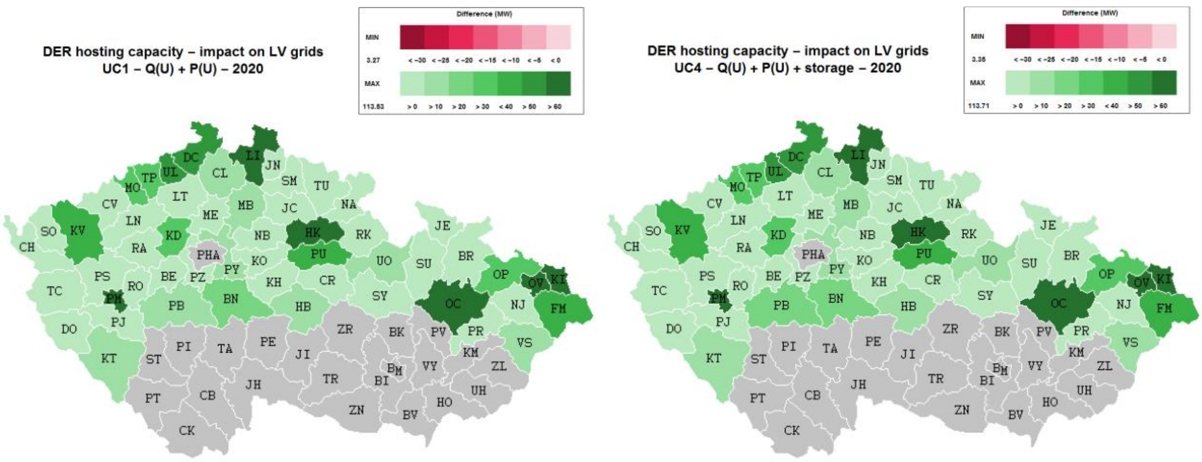

Figure 31: DER hosting capacity surplus/deficit on LV level in CEZ Distribuce districts (Use case 4 – baseline (UC1) and SG with feed-in power limitation from the system PV + battery – year 2020)

Conclusions

The SRA analysis performed for WP6 quantifies how much and type of distribution capacity investments will be needed for selected time periods (up to year 2020, 2030 and 2040), although in this section only the immediate scenarios are included (2020 scenarios). They are calculated for the different baselines as in 2020, 2030 and 2040, where no solution is implemented, and their SG solution compared to the same baselines.

This comparison between the baseline with and without the implementation of the SG solutions shows that the solutions described in WP6 contribute to improving the DER hosting capacity and possibility to accommodate a higher share of EV charging stations and thus reduces the need for distribution capacity investments. Also, the inclusions of Home Energy storage system (Batteries) which are integrated alongside PV, may foster the penetration of renewables at the MV since the renewables impact will be reduced at LV.

With respect to the implementation itself, WP6 use cases (solutions) tested within InterFlex project could be easily replicated worldwide, due to their main characteristic, they are embedded autonomous functions in field devices. This leads to the DSO being able to operate with a higher focus on the MV network where increased injections of power will take place as large scale renewable farms are integrated. Yet, this solution in case of under voltage still is able to properly steer the assets if needed to support the DSO operation at LV. A more detailed description of WP6 solutions can be found in deliverable D6.1. With respect to the economic analysis, the detailed CBA results are collected in the D6.3 Demonstration activities results as well as in D3.9.

3.1.3. NL Demo

Pre-evaluation: Use Case selection & limitations

The SRA conducted for the Dutch demo is based on the pre-evaluation phase where the three use cases of the demo are analysed in order to find the potential interests to be exploited and the limitations of the analysis. From this analysis, where the main functions are considered and individually studied, it is concluded that the best approach is to replicate the solution at a minor scale, where the focus shall be on the interaction of the different Flexibility Aggregation Platforms (FAPs) and the Grid Management System (GMS), both described with in detail in D7.1 & 7.2 and D7.3. A goal for this analysis is set to identify the potential network constraints due to excessive flexibility operation[8] within the system, the increase of penetration of EV and PV (and how these may affect these offerings and constraints) and the use of the proposed solution in the Dutch demo, as a means of congestion management solved by the use of a flexibility process negotiation between the aggregators and the DSO. The abstraction of the interaction tools developed and the systems actors within the demo are shown in Figure 32.

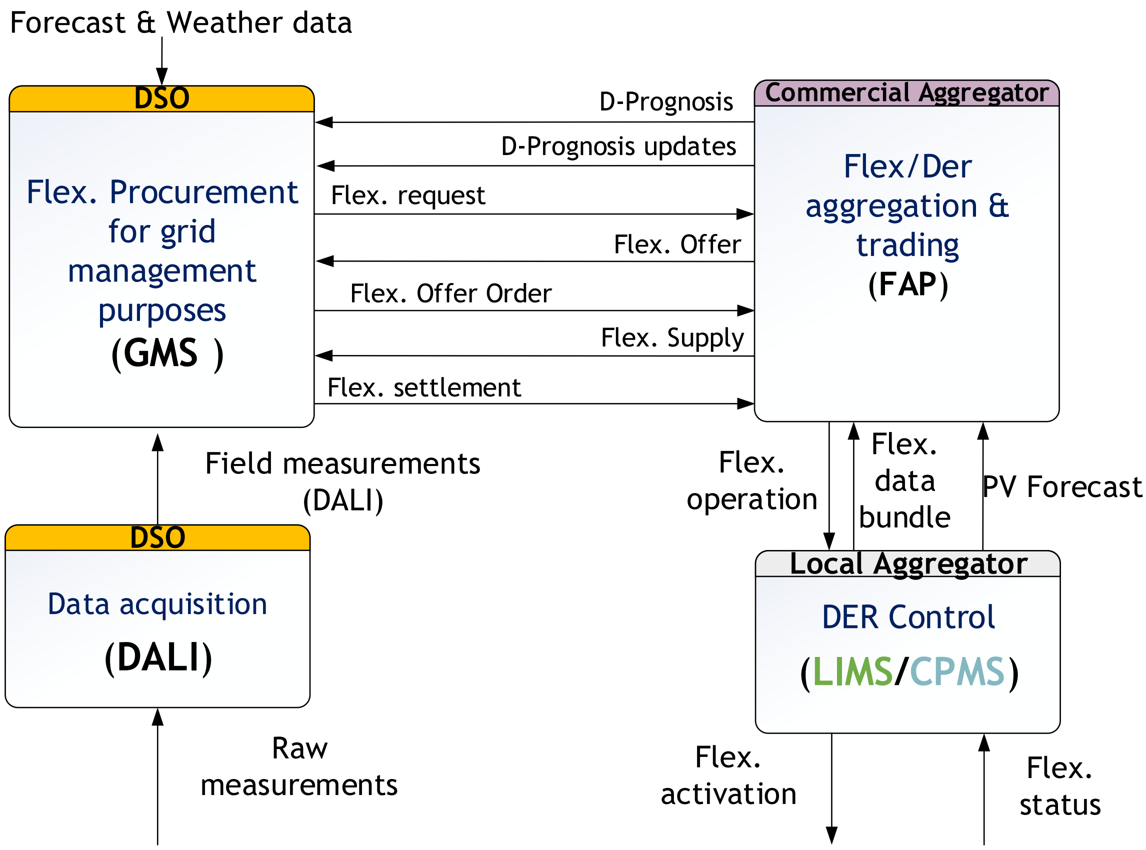

Figure 32: Actors' tools connection

The use cases in the Dutch demo, work as a cascade where UC1 and UC2 are based on the different aggregators, Local Infrastructure Management System (LIMS) and Charging Point Management System (CPMS). The first considers all flexibility types except for EVs whereas the second, CPMS, is only focused on EV aggregation. This leaves UC3 as a wrapper for the other use cases. In UC3, all the solutions are combined, and the actualised solution is implemented. Therefore, all use cases are considered in the analysis. Nonetheless, certain assumptions and simplifications have to be taken as the system complexity and data access

[8] D-prognosis files collect how the aggregator is operating their assets.

is reduced, due to aggregators strategies involved. These assumptions and simplifications, due to limitations, taken are as follows.
The analysis will be based on 1 week time series simulations where “virtual” aggregators are created and provide offers (D-prognosis files) to the DSO at the different congestion points in order to see the dependency of the flexibility sources such as EV, PV and a central battery storage known as smart storage unit or SSU.

In order to define the congestion points, Enexis provided a network diagram which is used as the main input for the analysis. This network diagram is divided into two different substations from which their simplification is represented in Figure 33, and collects all the flexibilities and the congestion points with the active power rating associated to each substation and location of the congestion point within the network. In total there are 4 congestion points, 2 located at each substation and two (simulated) at each feeder to which the flexibilities are connected. This distribution of congestion points and flexibilities is a replication of the demo configuration implemented by the Dutch demonstration Enexis within Strijp-S.

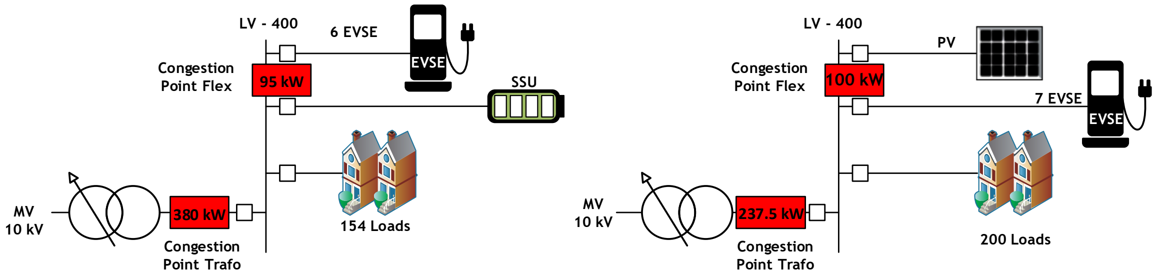

*Figure 33: **Left** figure shows Network simplification for substation 1 and **right** figure for substation 2*

The flexibilities considered are a central SSU, EVs and PVs which are managed by two different aggregators, one which has control of the SSU and PV and the other has control of the EV.

Due to the fact that there is no possible access to the aggregator logic (core commercial business), its logic has to be assumed, meanwhile for the DSO system, the GMS, access is granted, allowing for the possibility of its replication to a certain extent.

The information exchange is based on the Universal Smart Energy Framework (USEF) protocol. There has been a significant amount of time invested into working with the pre-developed USEF webservers provided by the USEF foundation in an attempt to use more tools from the demo. However, there was no success due to a lack of technical-development support for its framework implementation for the simulations, old dependencies (not updated) used and an overcomplex and verbose system which makes every minor change a complex task. Therefore, only the core basis of the communication exchange is considered as an input for this SRA development which dictated a 15 min time step as basis of information resolution, based on congestion points and per aggregator. Nonetheless, not everything from the USEF framework can be disregarded, since some exemplary data is used for the representation of the loads.

Due to over dimensioning of the current network and strength of it, the loads have to be scaled up to force potential congestions. It is assumed that the loads and devices are connected with the 0.95 PF which reflects high penetration of renewables into the network. This is a similar consideration as for other demos, like those in the Czech demo.

Several internal developed algorithms are used to emulate the forecasting’s systems for the flexibility aggregators, where only active power is considered since the purpose is stablished in congestion management (active power) and no forecasting system is used for the DSO GMS

in this case for the emulation. In reality, the system from the DSO not only used forecasting but many more modules. This is a system simplification for the emulation.
The KPIs considered in the Dutch demo also shape the simulation as they can be integrated in the simulation in addition to new ones, which are defined internally for each use case to collect its essence, as the battery duration, flexibility volume, etc.

Approach

As previously explained in the pre-evaluation, use case selection and limitations were identified, and the analysis is done based on a 1 week long time-step simulation using day-head estimations with 15 min time-steps looking at potential congestions produced by a scaling effect of the flexibilities (PV and EVs), where FAPs are emulated and the GMS is replicated exchanging virtual offers. For the SSU, capacity scale up is explored to a certain range, as the SSU strategy logic allows it. In both, the scalability and replicability analysis the two substations are considered. On the one hand, during the scalability process, individual units are scaled while the network is maintained the same. On the other hand, during the replicability process, the analysis is based on the seasonal aspects of the different flexibility sources and how it can impact the flexibilities offers, in addition to creating a new substation as a mix of the two other substations. Nonetheless, in either the scalability or replicability the four following main points are considered,

- GMS: is based on the current solution offered by Enexis, it is replicated up to minor extent, with general assumptions being made.
    - There is no load forecasting based on network data, instead the created load profiles are used as the forecasting input.
- FAP-EV: uses an internal forecasting algorithm based on Dutch data and self-developed strategies for charging based on real data trends.
- FAP- (PV +SSU):
    - PV: uses an internal forecasting algorithm for different PV strings sizes based on the current GIS location of the demo.
    - SSU: uses an internal developed strategy to follow market inputs as the main objective of aggregator operation.
- The FAPs-GMS interaction is emulated where real data is taken into consideration for the different PoC at the congestion points and transformer. Nevertheless, the second interaction of the negotiation process is out of scope as that is business logic.

The approach selected, is developed in steps following the logic behind the Use Case descriptions, where first, in UC1 the virtualization of the PV through forecasting algorithms in addition to the battery logic are created for D-prognosis. It is then followed by UC2, where EV forecasting algorithms development for a 2030 scenario where EV shall have a higher penetration (around 40%) [9] . Finally, synthetic loads are created and scaled based on a variety of data found in the USEF foundation example library which then are mixed into the network with the flexibilties and simulations are conducted to analyse the impact of all units together as UC3 intends. While applying this approach the scalability and replicabilty process takes place.

Scalability analysis

Due to the extension of the analysis, within this section only partly UC3, combination of UC1 and UC2 in addition to load scaling, is exposed. The analysis of UC1, UC2 and remaining of UC3 can be found in the corresponding section within the annexes, section 7.2.3.

UC3 scalability analysis is based on the combination of flexibilities for congestion management in low voltage networks. The actors considered within this use case is aligned with the previously explained approach, a multi-step aggregation process as reflected in Figure 34. Local aggregators provide the flexibility status to the commercial aggregators which then provide the D-prognosis (how they are going to operate their assets) for the next day, day-head context at each congestion point in each substation with a total of 4 congestion points 2 at each transformer and one at each flex connection.

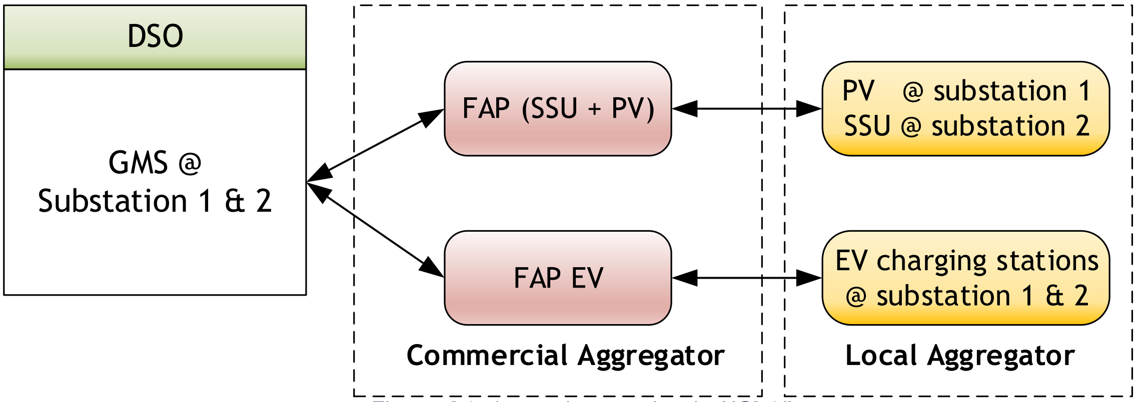

Figure 34: Actors interaction in UC3-NL

The scenarios developed for the simulation analysis consider a scaled version of the PV generation within the suburban area of the demo, an EV penetration based on the current status and a 40% scenario, a central battery storage unit with market inputs and synthetic household loads scaled up based on the criteria where customers are not equipped with controllable devices. This is to represent the electrification process which is currently taking place where the trend is to move towards electric devices (heat pumps, electric vehicles, electric stoves, etc.). These scenarios are aggregated in Table 10 and Table 11 based on each substation. However, during this section, only the baselines with low EV penetration and scenarios 1.3 with higher EV penetration (40%) are presented due to the high volume of data to present at each scenario. These particular scenarios are chosen as it is expected that PV and EV increase their penetration into the network in the upcoming years, and the flexibility solution might help DSO to operate [9], [10].

Table 10: Scalability scenarios for Substation 1

ID	Load	EV	PV
Baseline	200 unique profiles	Id-0[9]	2 strings of 134kWp
Scenario 1.1	200 unique profiles	Id-3	1 string of 303.8kWp
Scenario 1.3	200 unique profiles	Id-4	1 string of 303.8kWp
Scenario 1.3	200 unique profiles	Id-5	1 string of 303.8kWp
Scenario 1.4	200 unique profiles	Id-6	1 string of 303.8kwp

Table 11: Scalability scenarios for Substation 2

ID	Load	EV	SSU
Baseline	156 unique profiles	Id-0	315kWh 255 kVA inverter/PoC 173 kVA
Scenario 1.1	156 unique profiles	Id-3	315kWh 255 kVA inverter/PoC 173 kVA
Scenario 1.3	156 unique profiles	Id-4	315kWh 255 kVA inverter/PoC 173 kVA
Scenario 1.3	156 unique profiles	Id-5	315kWh 255 kVA inverter/PoC 173 kVA
Scenario 1.4	156 unique profiles	Id-6	315kWh 255 kVA inverter/PoC 173 kVA

The remarks of the set up exposed in both tables are the following,

- The battery, the model developed in UC2, is used, which operates with a charging efficiency and a discharging efficiency in order to make a more realistic simulation, based in the parametrization done at the laboratories at AIT's premises.
- The EVs are selected based on the current calculated penetration and the 2030 estimated penetration target for the Netherlands, with some scenarios covering an upgrade of the exiting EVSE currently deployed in the demo.
- The PV baseline is the "current" PV potential installation which works with 2 strings of 134 kW_p each, in total 268 kW_p. It has not currently been installed but it is anticipated that is will be in the near future. The scaled-up version is based on the maximum area which could be covered at the parking installation. This process calculation for the individual scaling of the PV system is detailed in the annexes.
- Loads are created based on standard load profile examples obtained from the USEF foundation [11]. Each load has a unique load-profiles when connected at each substation, in addition to an integrated scaling factor of 30%. This scaling factor reflects the electrification process as it brings the loads up to a 2 kW peak mean value.

The following section presents the results of the scalability process, however not all the different scenarios are collected in it as previously stated. The generated documentation would extend this document and the aim of a clear overview and main results for the demo would be lost. Hence the individual scaling of for UC1 and UC2 in addition to the additional scenarios run for UC3 are all collected in the annexes for the Dutch demo, under Annex 7.2.3.

[9] The information regarding the numbering system of the EV data and the sizing of the PV can be found in the annexes

Substation 1: Scenarios baseline and 1.3

The following subsection presents the comparison of the results for both selected scenarios (baseline and 1.3) in substation 1. Figure 35 represents the entire evolution of the simulation over the network status in both congestion points with their congestion points limits. This is supported by the break-down of the different PTUs (point time units) where the network requires the aggregator to change its operation ("reduce points") or for new operation ("available points") as specified in USEF. The total break-down of number of points where the aggregator needs to reduce or can inject/load more the network as it has "available" periods are collected in Table 12. Additional support figures such as Figure 35, networks congestion status and Figure 36 and Figure 37 are included as means to demonstrate the output calculation from the GMS at each PTU. Figure 36 and Figure 37 provide the information regarding the amount of flexibility which could be injected in order to reach the upper limit or lower limit of the congestion point.

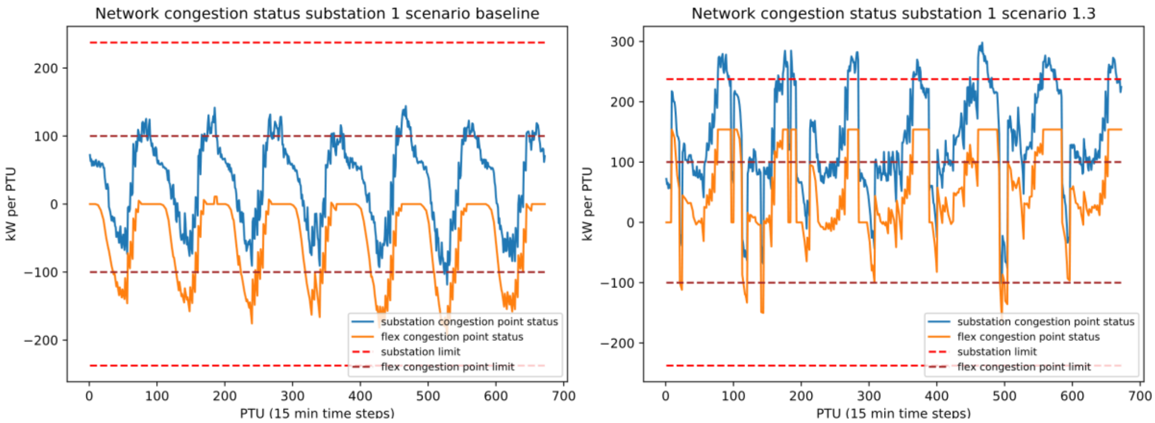

Figure 35: Network congestion over an entire week for substation 1 - baseline vs 1.3 scenario

Clearly, the higher penetration of renewables and the higher penetration of EV into the system, the total number of congestion points increases. This is natural as more units are included into the system, however the duration of this congestions is drastically reduced due to the potential correlation of the EV load forecasting and the PV forecasted in one direction (downwards for generation or upwards for loads) but increase for the other direction as there is a greater stress from the loads due to EV. The maximum flexibility that could be injected into the system also changes through the simulations as appreciated in Figure 36, for the baseline scenario, when compared to results from scenario 1.3 as shown in Figure 37.

Table 12:Total Available vs Reduce time points at each congestion point for substation 1

Periods	Trafo_CP_baseline	Flex_CP_baseline	Trafo_CP_1.3	Flex_CP_1.3
Available	672	484	561	435
Reduce	None	188	111	237

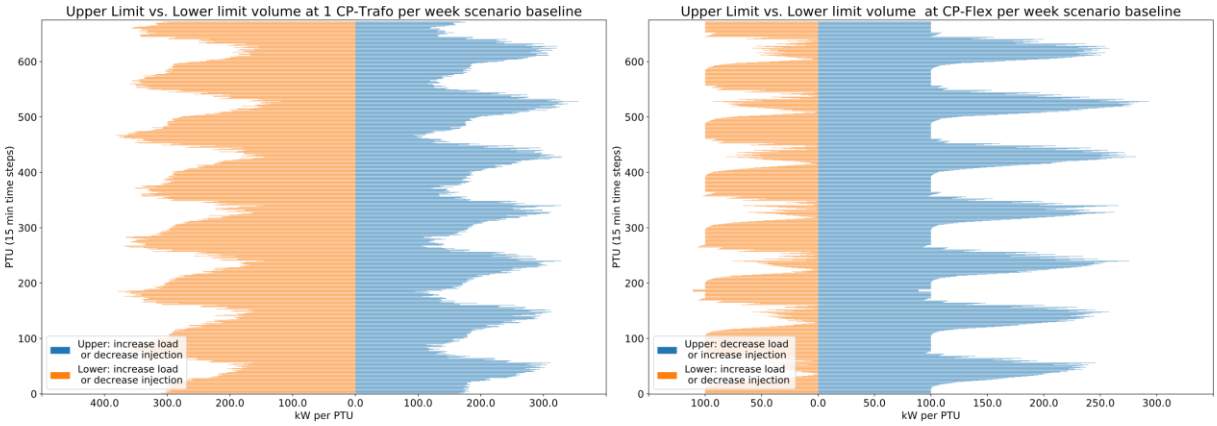

Figure 36: Total volume per PTU for a week at transformer (left); flexibility point of connection (right), baseline

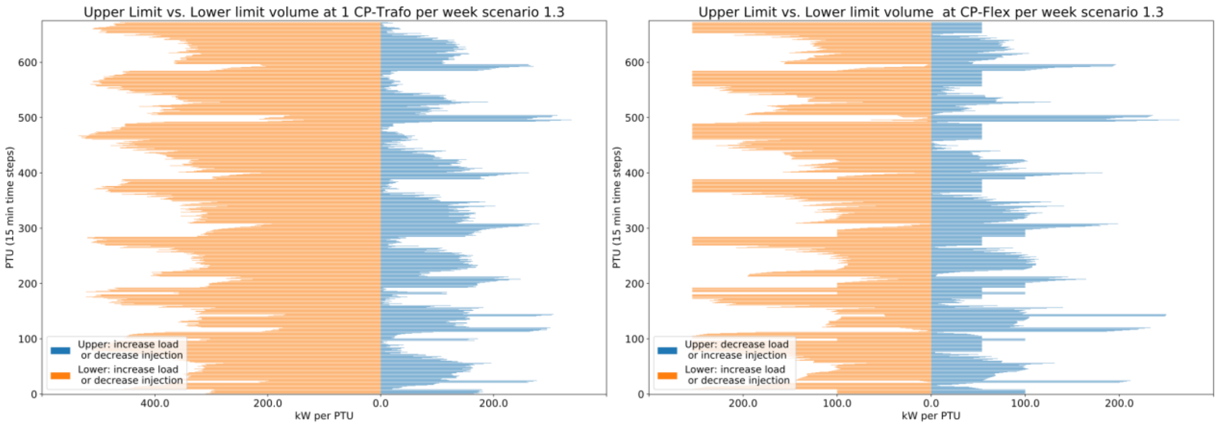

Figure 37: Total volume per PTU for a week at transformer (left); flexibility point of connection (right), scenario 1.3

Substation 2. Scenarios baseline and 1.3

The combination of the SSU and the EV at the different congestion points produces a shift of the total curve for the combination of both assets, which is clearly reflected in Figure 38. It represents the entire evolution of the simulation over the network status in both congestion points with their congestion points limits. This entire shift is due to the batterys' ability to inject into the network when discharging and load the network when charging. It is in the moment when the battery discharges that compensates the heavy EV load demand. In the other moments where the battery charges, it produces resonance as it catapults the values way over the limits as seen in Figure 38 for the "flex congestion point".

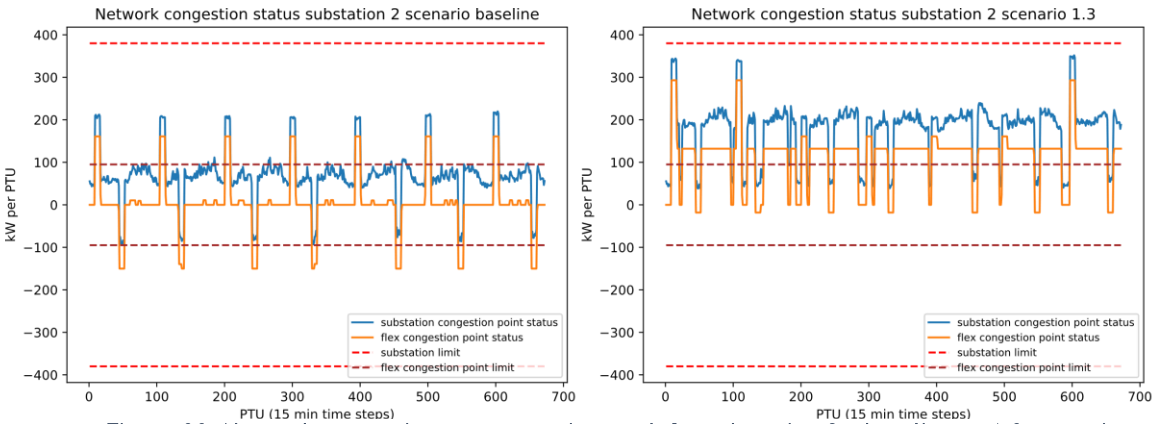

Figure 38: Network congestion over an entire week for substation 2 - baseline vs 1.3 scenario

This behaviour results in no congestion at the transformer due to a higher loading capacity (rated power) in this second transformer. But, there is a dramatically increase at the flexibility point of connection considered as the congestion point. This creates a need to provide congestion management almost during the entire time frame (1 week). In reality, this number, even though they are based on the real demo parameters, have been double checked and are far to produce any congestion in the real network, as it is oversized accordingly to the technical specification of the lines and limits in the demo.

Table 13: Total Available vs Reduce time points at each congestion point for substation 2

Periods	Trafo_CP_baseline	Flex_CP_baseline	Trafo_CP_1.3	Flex_CP_1.3
available	672	560	672	136
reduce	None	112	None	536

In Figure 39 and Figure 40 the impact of the SSU clearly produces spikes at the flexibility congestion point either due to the resonance factor when the battery charges and couples with the EV or when the battery discharges and creates an almost 0 balance at the congestion due to the correlation discharging-EV charging. If this correlation were to be exploited, the hosting capacity of the network can be successfully increased.

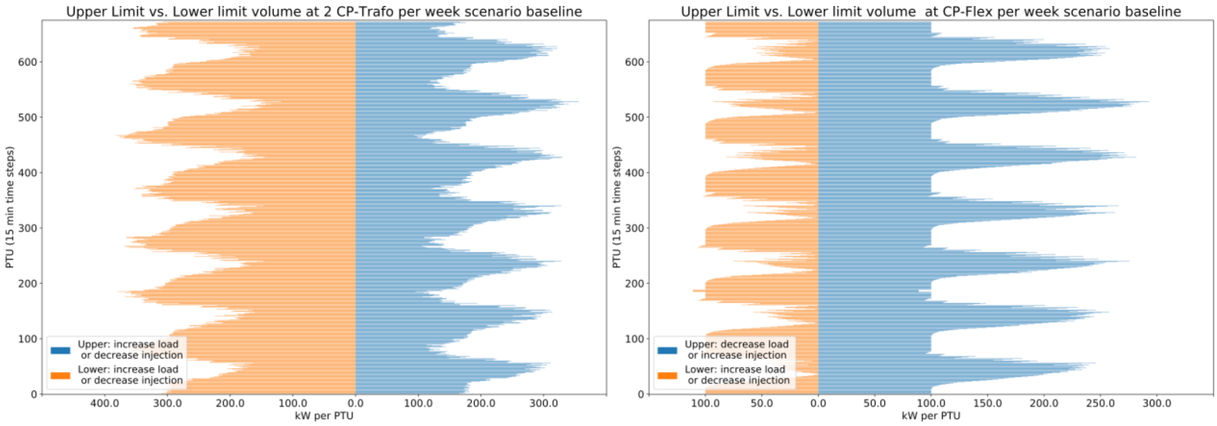

*Figure 39: Total volume per PTU for a week in the **baseline** scenario at transformed in the scenario (left); flexibility point of connection (right)*

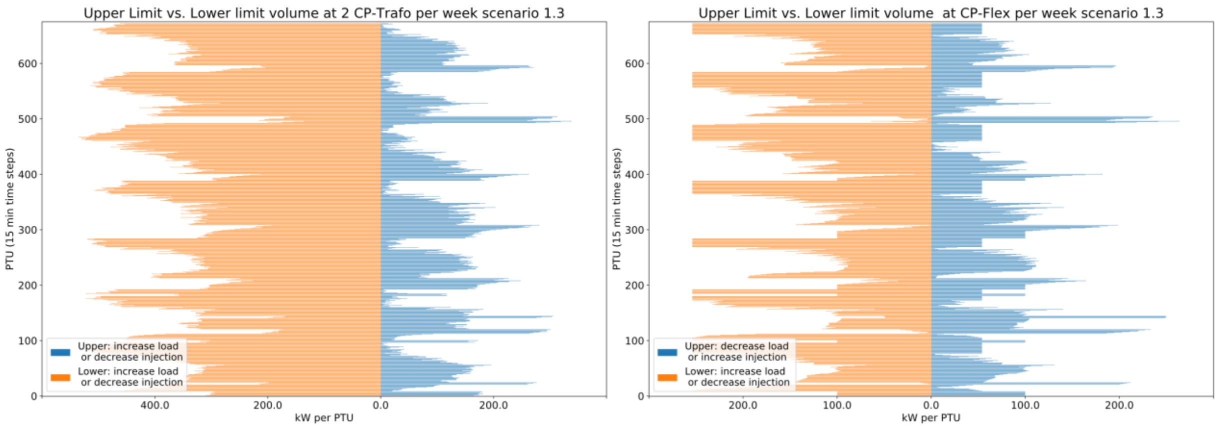

*Figure 40: Total volume per PTU for a week in the **1.3** scenario at transformer (left); flexibility point of connection (right)*

Replicability analysis

Anew due to the extension of the analysis as in this case the replicability takes place not only in time but also location. For the replicability in time, different seasons are considered since some of the flexibilities are seasonal dependent (PV). In the case of the EV, seasonality is considered as stable. Although in reality there is a difference between the energy demand, especially in the winter season, due to temperature impact into the batteries, the difference between them is not great enough, hence the scalability values are maintained. With respect to the batteries, in order to explore seasonality, prices for weeks starting on Mondays (due to EV forecast output requirement) are considered. A more extended subsection can be found at the annexes where these seasonalities are analysed. This annex can be found in section 7.2.3.

With respect to the current subsection, it only deals with the replicability of UC3 by means of replicability in terms of location. A new substation is created based on the combination of the two substations in order to evaluate the total combination of flexibilities with the same logic as developed in the previous ones. This results in a substation which is based on 200 loads and has as flexibility sources, PV with different injections, EV (with different combinations as in the scaling scenarios) and an SSU with the same parametrization as in substation 2.

The set of simulations on which this analysis is based, are recollected in Table 14, which includes at the same time the scaling process evaluation of it.

Table 14: Scenarios for Substation 3

ID	Load	EV	PV	SSU
Baseline	200 unique profiles	Id-0[10]	2 strings of 134kWp	315kWh 255 kVA inverter/ PoC 173 kVA
Scenario 1.1	200 unique profiles	Id-3	1 string of 303.8kWp	315kWh 255 kVA inverter/ PoC 173 kVA
Scenario 1.3	200 unique profiles	Id-4	1 string of 303.8kWp	315kWh 255 kVA inverter/ PoC 173 kVA
Scenario 1.3	200 unique profiles	Id-5	1 string of 303.8kWp	315kWh 255 kVA inverter/ PoC 173 kVA
Scenario 1.4	200 unique profiles	Id-6	1 string of 303.8kWp	315kWh 255 kVA inverter/ PoC 173 kVA

The same remarks taken for the set-up of the scalability analysis are valid for this replicability process as it is either a combination of sources (location replicability) or it uses the same combination and explores seasonality (time replicability).
Within the following section, only the baseline scenario and the labelled as “1.3” are exposed within it. The reasoning behind is similar to that as previously mentioned for the scalability scenario.

[10] The information regarding the numbering system of the EV data can be found in the annexes

Substation 3 (Location replicability)

The results obtained for this particular set of scenarios do not differ much from the root scenario which is substation 1. Since this substation is a combination of substation 1 and the addition of the SSU, the results offer almost no change into the analysis. Nevertheless, it is clear that the SSU can have a great impact into compensating the network balance or producing congestion as the total number of "reduce" periods collected in Table 15.

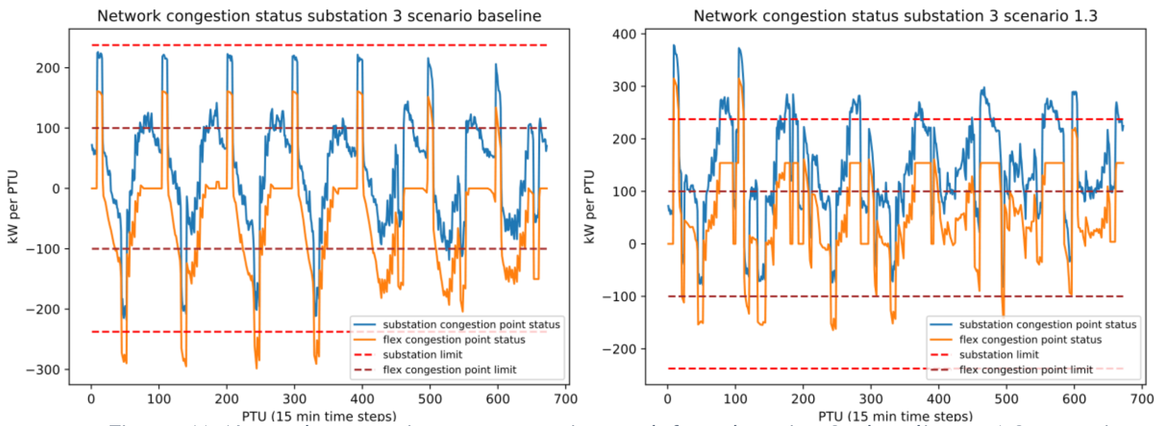

Figure 41: Network congestion over an entire week for substation 3 - baseline vs 1.3 scenario

Table 15: Total Available vs Reduce time points at each congestion point for substation 3

Periods	Trafo_CP_baseline	Flex_CP_baseline	Trafo_CP_1.3	Flex_CP_1.3
available	672	407	545	398
reduce	None	265	127	274

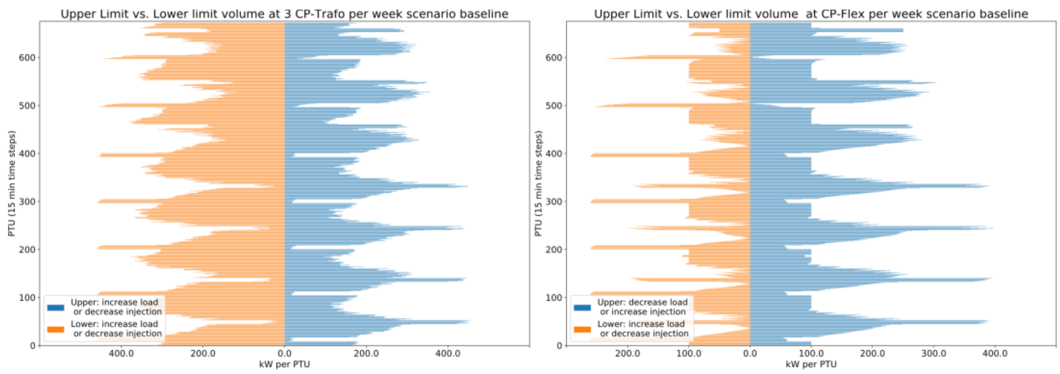

Figure 42: Total volume per PTU for a week at transformer (left); flexibility point of connection (right)

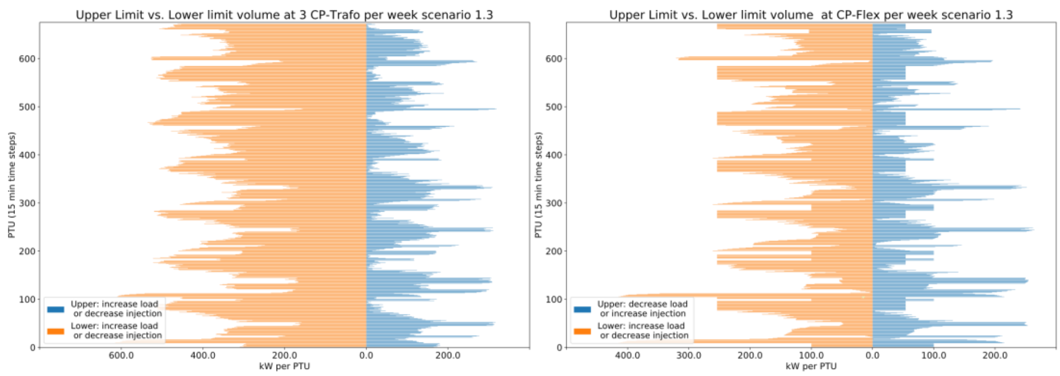

Figure 43: Total volume per PTU for a week at transformer (left); flexibility point of connection (right)

Conclusions

Over the different scenarios presented in the analysis for the scalability and replicability for the Dutch demo, the penetration of renewables through PV; penetration of EV based on the current status and the forecasted values for 2030 along with multicombinations of EV operation and battery inclusions are considered for creating potential scenarios to be seen in the future.

From the analysis of the different scenarios conducted, where each flexibility source is individually tackled, it is clear that they can be used for network congestion management up to a certain limitation. For example, PV operation is as observed in other studies and further emphasised in this one, is seasonal dependent. However, due to the decrease of the PV price, it is fast becoming an attractive means of investment, as the operation and maintenance labour and cost is lower than other sources. This increase can be perfectly couple with EV; however, their forecast is the key part for profile matching or with a SSU to operate with.

These flexibility operation and the different forecasting systems are the real potential bottleneck to the network as they can totally influence in the network operation.

Aggregators strategies can cause a great impact as if they pursue economic maximization of their assets can cause a huge impact as in the battery operation or EV operation when the aggregator masks its operation with the worst case of the day. Nonetheless, it also opens the door for other aggregators to dive in with their flexibilities. This might result into a game theory problem where in reality the aggregators would self-regulate themselves.

How good these aggregators are able to deal with the flexibilities is mainly based on the forecasting system. The better and more precise their forecasting system, the easier it is to operate the flexibility with the exclusion of the economic consideration which would highly influence the strategic development plan. An example of how to gain as much granularity as possible is provided through the flexibility calculation of the EVs, where the forecasting considers the likelihood for each day and hour decomposition being able to place offers which mask their operation and let them provide flexibility for those other points where they won't be operating. Although this is a possible strategy for EV operation, other strategies might emerge and impact differently the network.

Nevertheless, it is clear that the idea of creating congestion points, where different aggregators are involved, would provide a clear direction for the implementation of these smart solutions in the Netherlands. Although all the analysis is based on day-ahead operation, it can be a decent solution for the network operator to preview how the system is going to be potentially the next day operated. With the inclusion of the new feature which is behind developed by the Enexis research team for intraday operation, it definitively will support the network operation as it has a higher resolution with respect of forecasting errors than the day ahead operation.

3.1.4. SE Demo: Malmö

Pre-evaluation: Use Case selection & limitations

This use case focuses on the process used to operate and distribute Demand Side Response (DSR) using the building's envelope thermal inertia and how to use the thermal inertia of Malmö's heat network for grid management purposes.

Approach

The investigations of the demand response service offered by buildings and building blocks as well as the investigation of the use of the thermal inertia of the heat network for grid management purposes are carried out based on combined dynamic building and district heating network simulation. Therefore, a dynamic and holistic system model in the modelling language Modelica [12] is used. Physical building models are used to simulate the theoretical DSR potential of different buildings and building types. In this project, low-order building model provided within the AixLib library [13] are used to perform building simulations. Hereby, building elements are lumped into thermal resistances and capacitances to describe heat transfer and heat storage effects. Dynamic district heating network simulations are performed to calculate the theoretical demand response capabilities. For this purpose, a part of the Malmö district heating network is considered and simulated. The evaluation of the potential for using building's thermal inertia as a source of flexibility is carried out based on the flexibility KPI.

Scalability analysis

In order to evaluate the potential of the use of the thermal building envelope for demand response services, the proportion of buildings with BMS is increased within the scope of the scalability analysis in the considered part of the heating network. In the first scenario, the BMS is controlled according to the demand profile; in the second scenario, renewable electricity production is used as the control signal.

First Scenario

In the first scenario the BMS operation is defined based on the demand profile to smooth the load curve of the buildings, the indoor temperature is decreased during the peak load period (peak shaving) and increased during off-peak period (valley filling). For the definition of the periods, an average annual demand profile was calculated.

- 04:00 – 06:00: peak load -> decrease of set temperature by 0.5 K
- 14:00 – 16:00: off-peak -> increase of set temperature by 0.5 K

In order to investigate the flexibility potential of the BMS operation and the effect on network operation, three cases are considered in which the number of BMS based on the number of customers is increased i.e. 0%, 50% and 100% BMS
Figure 44 shows the heat load in the network for the three BMS scenarios exemplified for four days in September due to data availability.

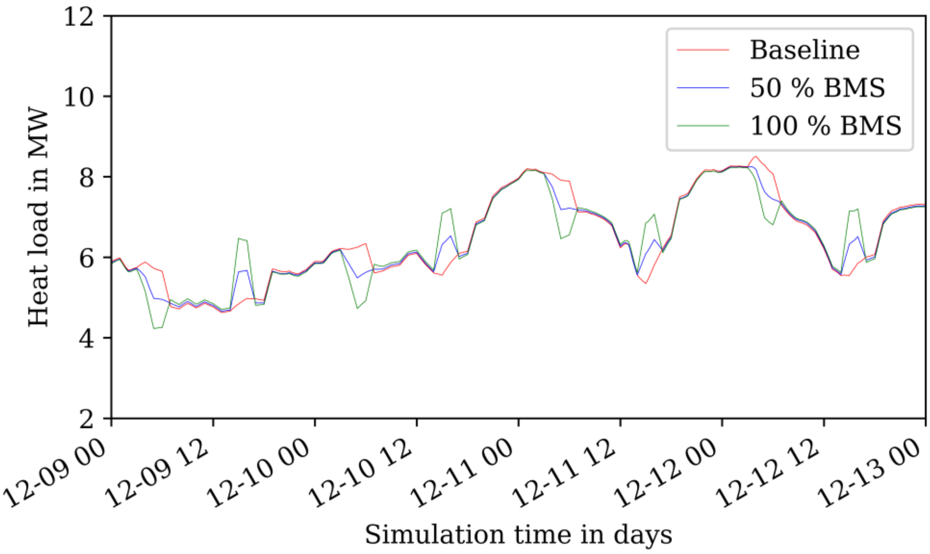

Figure 44: Influence of BMS operation on the heat load

Table 16 summarizes the flexibility KPIs for both scenarios. With a BMS rate of 50 %, it is possible to switch off or on approx. 10 % of the loads in the network by controlling the interior temperature of the buildings. By doubling the number of buildings equipped with BMS, the load in the network that can be switched on and off can also be approximately doubled. Overall, the simulation results for this scenario show that the use of BMS leads to significant flexibility in heat supply. By adjusting the set point to the interior temperature by 0.5 K, approx. 20 % of the heat supply can be switched on and off if all connected buildings are equipped with BMS. This flexibility can be transferred to the power grid through the use of electrical systems for heat supply in both upward and downward directions.

Table 16: Summary of simulation results for the use of BMS

Case	Max. load reduction (Flexibility)	Max. additional load (Flexibility)
50 % BMS	871 kW (10.3 %)	852 kW (10.0 %)
100 % BMS	1780 kW (20.9 %)	1740 kW (20.5 %)

Second Scenario

In the second scenario, the BMS operation is defined based on the renewable power generation (PV, wind) in Sweden. For this purpose, the BMS is activated by using the signal shown in Figure 45. This time series covers the entire power produced in Sweden from wind and PV and thus represents the renewable power generation mix in Sweden. In order to investigate the flexibility of the system and the associated possibility of integrating renewable energy into the heat supply, this signal is used to control the BMS and the network temperatures. A limit value for renewable electricity production in Sweden is used to control the set point for the indoor temperature of buildings. Thus, the load in the heating network is increased when there is a high supply of renewable electricity and reduced when there is low supply of renewable electricity. This control of the buildings supports the integration of renewable energies in the heat supply. As an example of the application of the control, a limit value of 2 GW of renewable electricity production is used. The limit value is used here as an example; the influence of different limit values on providing flexibility will be illustrated subsequently using the example of a heating network in Austria.

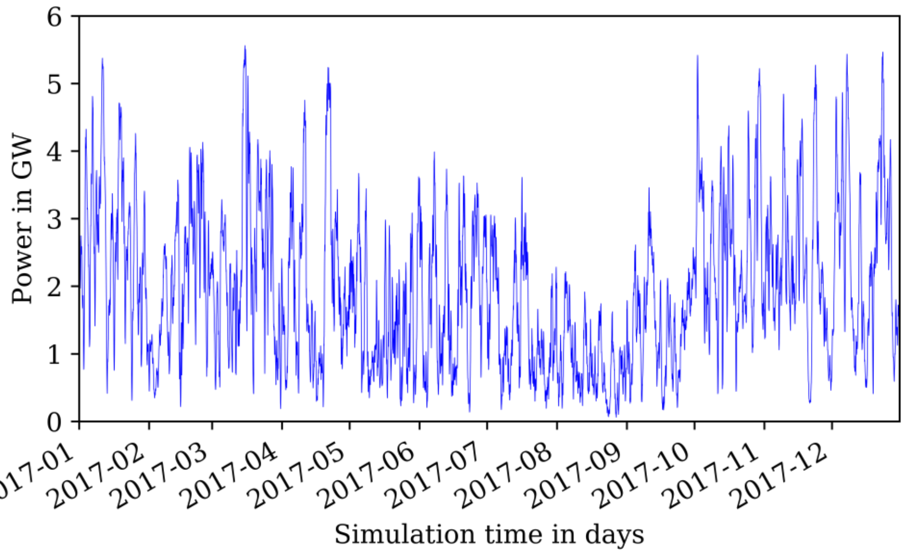

Figure 45: Renewable electricity production by wind and solar in Sweden 2017

Figure 46 shows the comparison of the heat loads in the network with BMS using the load profiles (peak shaving/valley filling) and the renewable power production. In both cases, the BMS rate is 100 %. It can be seen that the control of the BMS on the basis of the renewable power signal leads to significantly longer periods in which the room temperature is increased or decreased. In addition, the maximum additional power (7.8 MW) and the maximum power reduction (5.9 MW) increase significantly. This leads to significantly improved flexibility KPIs of 91.8 % and 69.4 % respectively. The reason for this is due to the increased thermal activation of the building mass. Due to the long periods in which the room temperature is increased by the BMS, heat is stored in the building mass, which is initially transferred to the room when the room set point temperature is reduced. This heat transfer of the building mass leads to a strong reduction of the required heating power.

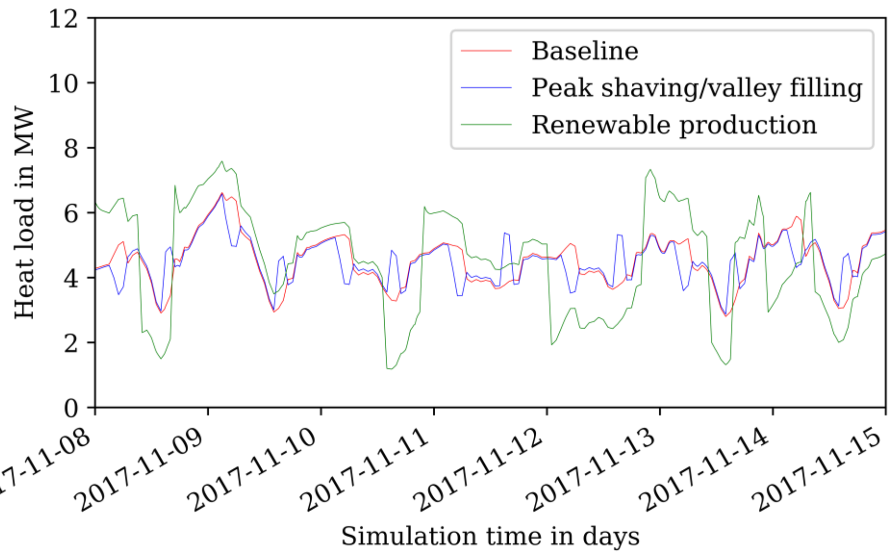

Figure 46: Comparison of the heat fed into the heating network for the base case and BMS using load profiles and BMS using the renewable electricity production

As an addition to the second scenario, in the following scenario the thermal capacity of the heating network is also used. For this purpose, the network temperature is increased to the maximum value of 110 °C if the renewable electricity production exceeds 2 GW. This means that in addition to increasing the heat load in the network by raising the interior temperatures of the buildings, the thermal storage capacity of the network is loaded in order to further increase flexibility. The impact of the additional use of the thermal capacity of the network is shown in Figure 47. Compared to the utilisation of the BMS for load control only, the use of the thermal capacity of the network results in significantly higher connectable and disconnectable loads. The thermal charging of the network makes it possible, for example, to completely switch off the heat supply to the network for limited periods of time.

Especially for the integration of renewable energy sources into the heat supply, the use of the thermal network capacity has increased advantages, 66 % of the annual heat supply takes place at times with a renewable electricity production of more than 2 GW. By applying electrical heating systems, a large amount of heat can be supplied using renewable energy sources. At the same time, however, the heat losses from the system increases due to the higher network temperatures, so that the annual heat supply also increases by 0.5 GWh. This corresponds to approx. 1.8 % of the annual heat supply in the baseline case.

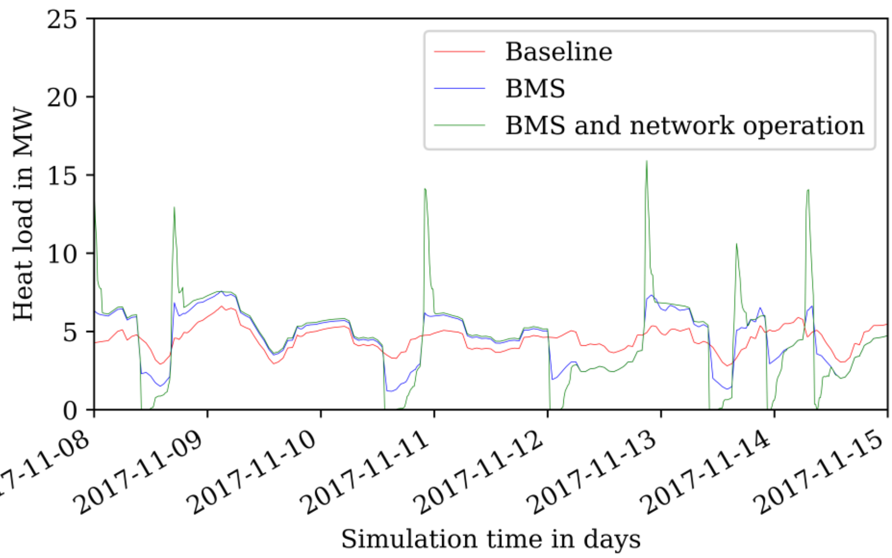

Figure 47: Comparison of the heat load using BMS and using BMS in combination with additional use of the thermal capacity of the network

Replicability analysis

Replicability (time): seasonal in Sweden

In the replicability analysis, the transferability to other seasons on the one hand and the transferability to another location on the other hand are considered. For the first part of the replicability analysis, the influence of the season on the impact of the BMS and the flexibility achieved by BMS is examined for the thermal network in Malmö. For this purpose, exemplary three different periods of the year are considered for the first scenario.

Figure 48, Figure 49 and Figure 50 show the heat load in the network for summer, winter and the transition period for the baseline as well as for the scenarios with 50 % and 100 % BMS. Table 17 summarizes the simulation results for the use of 50 and 100 % BMS respectively with respect to the three periods considered. Overall, it can be seen that the flexibility potential of BMS operation is strongly influenced by the season and the associated changes in the heat load in the network. Large differences are particularly significant considering the maximum additional load and maximum load reduction in the three seasons. In winter, maximum additional load and load reduction are in the same order of magnitude for both 50 % and 100 % BMS. In summer and especially during the transition period, the loads that can be switched off are significantly higher than those that can be switched on, as cooling systems have a great demand. In addition, the season has a major influence on the feasibility of the BMS operation. In winter, by controlling the interior temperature of the building, flexibility for both load reduction and additional load can be achieved comparatively reliably. When considering the transition period and the summer, it becomes apparent that the change in the set point temperatures does not always result in a change in demand for space heating. This concerns the periods in which the interior temperature has already reached or exceeded the increased set point value of 21.5 °C as a result of internal loads and solar radiation and the load in the network is mainly caused by the demand for domestic hot water.

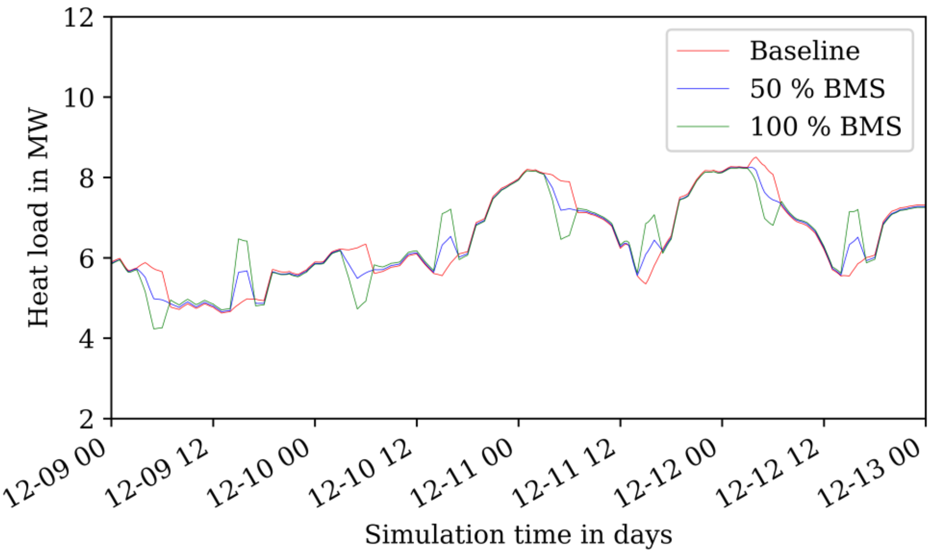

Figure 48: Flexibility provided by BMS in winter

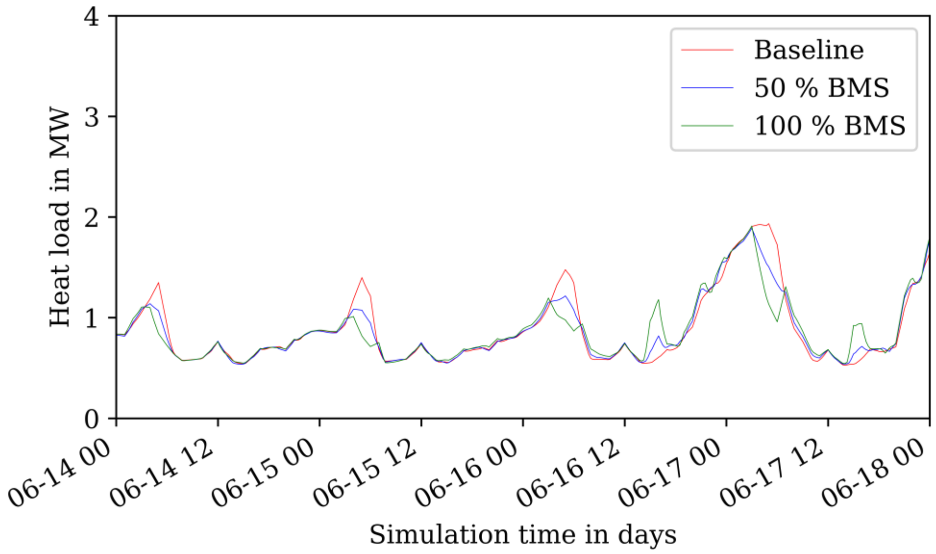

Figure 49: Flexibility provided by BMS in summer

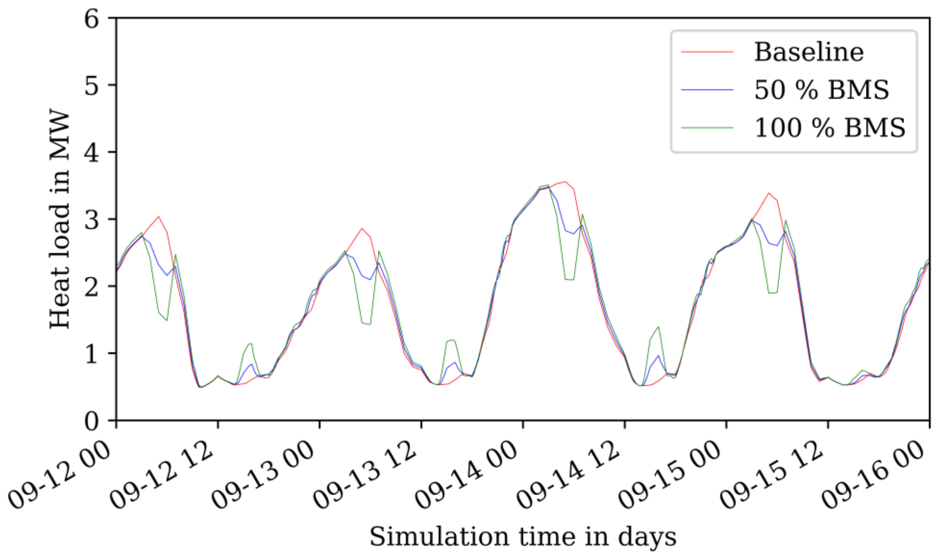

Figure 50: Flexibility provided by BMS in transition period

Table 17: Summary of simulation results for max. load reduction and max. additional load in different seasons

Season	Max. load reduction (50 % / 100 % BMS)	Max. additional load (50 % / 100 % BMS)
Winter	767.7 kW / 1598.2 kW	782.2 kW / 1521.4 kW
Transition	746.9 kW / 1491.4 kW	373.5 kW / 804.6 kW
Summer	428.2 kW / 799.4 kW	212.7 kW / 573.1 kW

Replicability (location): thermal network from Austria

In order to investigate the replicability of the use of thermal inertia of thermal networks to provide flexibility, a different location is also considered. A thermal network in Austria is therefore considered for this purpose. The network supplies a total of 50 single-family, multi-family and commercial buildings with heat and has a total pipe length of 4.3 km. The flow temperatures in normal operation are between 75 °C and 94 °C; the maximum permissible flow temperature is 105 °C. In order to investigate the thermal storage effects of the heating network and the resulting flexibility, this network is also modelled and dynamically simulated. The 50 buildings are divided into a total of 10 clusters, five clusters with single-family buildings, 3 clusters with multi-family buildings and 2 clusters with commercial buildings. The measured heat demands of the buildings are used as inputs, so that this analysis only considers the operation of the thermal network and not the operation of the building energy systems. In normal network operation, the control of the flow temperature is dependent on the outdoor temperature. In order to utilize the thermal storage capacity of the network, the flow temperature is raised to the maximum value of 105 °C. For this purpose, renewable electricity production is also used as a control signal; Figure 51 shows renewable electricity production from solar and wind power in Austria in 2017. The signal of renewable electricity production gives information on the availability of much renewable electricity and when it can be used for heating purposes.

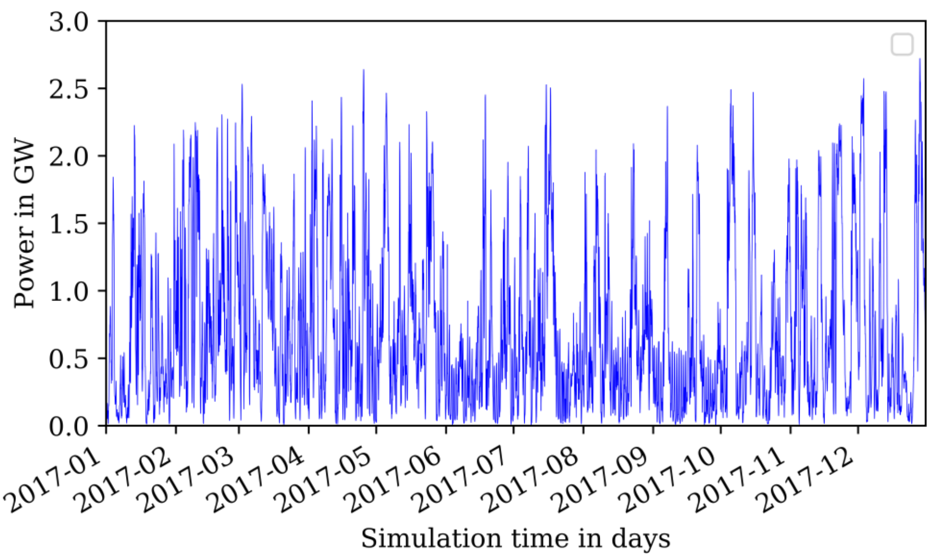

Figure 51: Renewable electricity production by wind and solar in Austria 2017

In order to investigate the storage effects of the heating network and the resulting flexibility, the following two limit values are considered for the control of the low temperature:

- Renewable electricity production higher than 1.0 GW
- Renewable electricity production higher than 1.5 GW

When this limit is exceeded, the network temperature is heated up to the maximum permissible temperature of 105 °C. Figure 52 shows the influence of the limit value of renewable electricity production on the control of the flow temperature for both cases for one week. In the baseline case, the flow temperature is between approx. 85 - 90 °C, in the other two cases the set point temperature is raised several times to 105 °C. It can be seen that the lower limit value of 1 GW results in the temperature set point being at the maximum temperature of 105 °C more often and for longer periods of time.

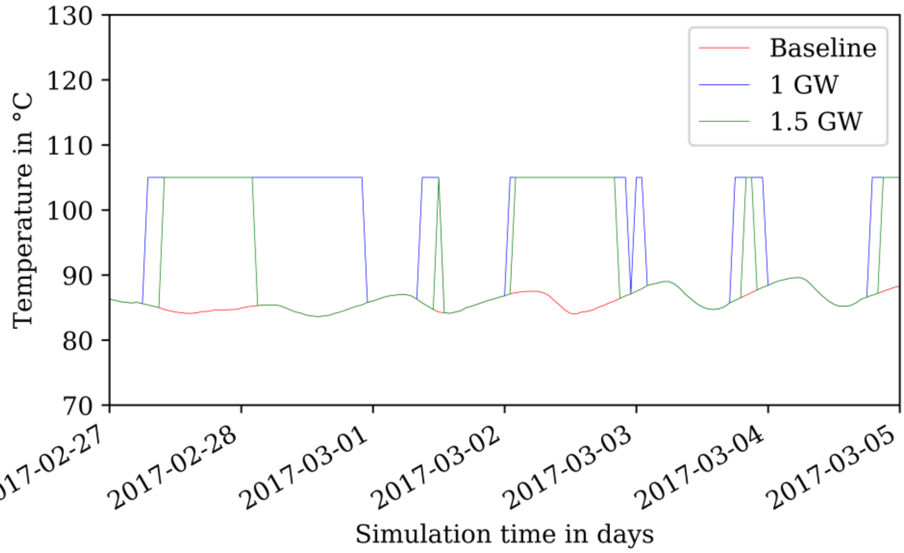

Figure 52: Control of the flow temperature for the baseline and for the limit values for renewable electricity production of 1 GW and 1.5 GW

Figure 53 and Figure 54 show the influence of temperature control on the heat supplied to the network. For this purpose, the heat supply is compared with the baseline in both cases. In addition, Table 18 summarises the simulation results for both limit values of the renewable electricity production. It can be seen that a lower limit value results in the thermal network being overheated more often and for extended periods of time. The higher limit value of 1.5 GW in particular means that the temperature of the heating network is raised comparatively rarely to the maximum value. In the week shown in Figure 54, there are therefore few differences in the heat supply. The annual analyses show for both cases similar values for the maximum additional load and for the maximum load reduction by controlling the network temperature. These are in the range of 700 - 770 kW and 800 kW respectively. Based on the maximum heat load in the baseline of approx. 2.2 MW, this results in a flexibility of approximately 31 – 37 %. Larger differences result from the consideration of the annual energy amounts. On the one hand, a lower limit value enables a higher share of heat supplied at times of high renewable electricity availability; on the other hand, it also increases the heat losses of the network. In the case of the limit value of 1.0 GW, approx. 17 % of the heat is fed into the network at times of high renewable electricity production, so that there are increased opportunities for the integration of renewable energies. The investigation thus shows, in addition to the previous investigation of the network in Malmö, that the use of the thermal storage capacities of thermal networks by controlling the network temperatures offers great potential for providing flexibility. The consideration of two thermal networks of different sizes demonstrates the replicability and scalability of this concept.

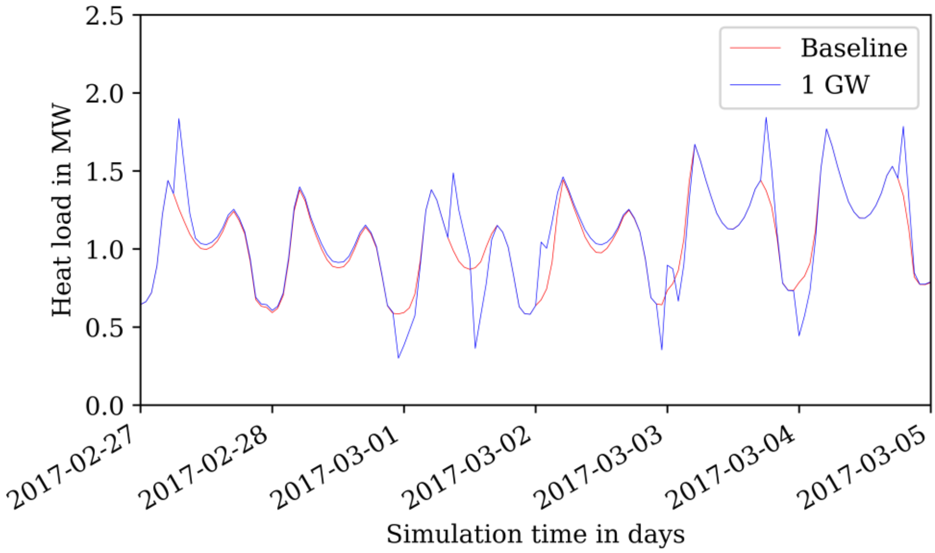

Figure 53: Comparison of heat supply of baseline and temperature control based on renewable electricity production (1 GW)

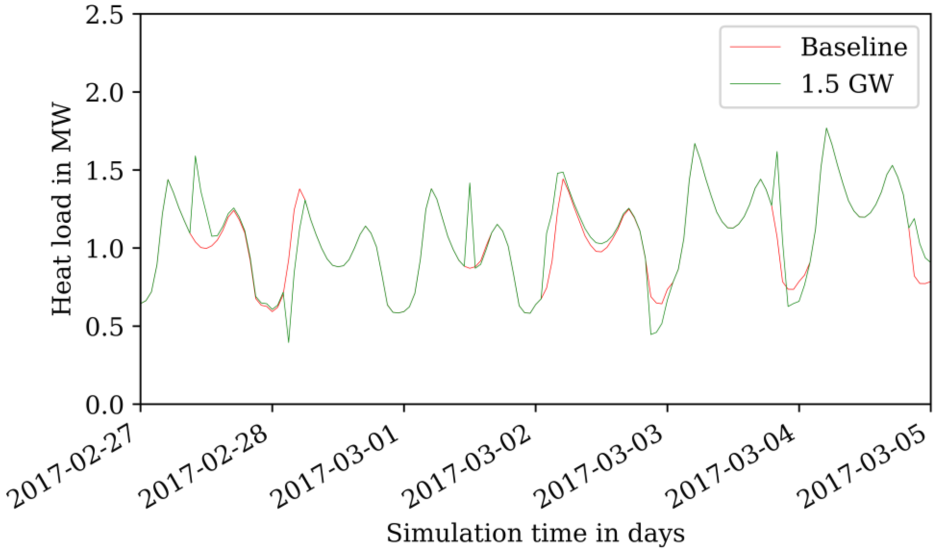

Figure 54: Comparison of heat supply of baseline and temperature control based on renewable electricity production (1.5 GW)

Table 18: Summary of simulation results for different network controls for a thermal network in Austria

Parameter	Limit value: 1 GW	Limit value: 1.5 GW
Max. load reduction	768.7 kW (34.9 %)	692.4 kW (31.4 %)
Max additional load	823.5 kW (37.4 %)	801.5 kW (36.4 %)
Share of renewable heat supply	17.3 %	9.6 %
Additional heat losses	56.4 MWh	40.7 MWh

Conclusions

In order to evaluate the potential of the use of the thermal building envelope for demand response services, the proportion of buildings with BMS is increased within the scope of the scalability analysis in the considered part of the heating network. In the first scenario, the BMS is controlled according to the demand profile; in the second scenario, renewable electricity production is used as the control signal. Overall, the simulation results for the first scenario show that the use of BMS leads to significant flexibility in heat supply. Compared to the utilisation of the BMS for load control only, the use of the thermal capacity of the network results in significantly higher connectable and disconnectable loads. By applying electrical heating systems, a large amount of heat can be supplied using renewable energies.

In the case of the replicability analysis performed considering seasonality the flexibility potential of BMS operation is strongly influenced by the season and the associated changes in the heat load in the network. Large differences are particularly significant considering the maximum additional load and maximum load reduction in the three seasons.

Regarding the replicability analysis done by a different location (considering the Austrian case), the investigation shows, in addition to the previous investigation of the network in Malmö, that the use of the thermal storage capacities of thermal networks by controlling the network temperatures offers great potential for providing flexibility. The consideration of two thermal networks of different sizes demonstrates the replicability and scalability of this concept.

3.1.5. SE Demo: Simris

Pre-evaluation: Use case selection

This section deals with use case 3 of the Swedish demonstration sites, i.e., the Simris Micro-Grid (MG). In particular, the rule-based control (RBC) is evaluated for different scenarios, which will subsequently be described. Hereby, the main interest is in analysing the islanded operation mode without fossil fuel-based backup generation. The use case topology and assets as well as the control algorithm have been discussed in detail previous deliverables such as D8.11 and, thus, will not be further described.

Approach

The microgrid, its assets and control mechanisms are modelled using MATLAB Simulink, to run quasi-continuous time-series simulations. A detailed description of the simulation environment can be found in the deliverable D8.13.

Within this study, the focus lies on three KPIs, i.e., *Islanding duration*; *RES utilization* and *Storage flexibility*.

The *Islanding duration* KPI is defined as the time that the MG can remain in islanding mode, i.e. without physical connection to the main grid, for the given scenario without applying load shedding.

The *RES utilization* KPI indicates the amount of RES that can be hosted in the system. In particular, it is defined as the ratio between non-curtailed renewable generation and total available renewable generation over a given timeframe, i.e.,

$$\text{RES utilization} = \frac{RES_{total} - RES_{curtailed}}{RES_{total}} \times 100\%$$

Thus, a small value indicates small utilization due to curtailment of the RES, whereas a value close to one indicates high utilization of renewables.

The *Storage flexibility* KPI compares the available flexibility provided by the Battery Energy Storage system (BESS) that could potentially be allocated in the MG against the actual used flexibility over the given time of analysis. Within this analysis, the focus lies on islanding operation. Preliminary simulations have shown that charging and discharging power are not the limiting factor in the context of islanding operation. Instead, it was found that the storage capacity is rather limiting in the islanding duration as sufficient capacity is required to store surplus energy in order to serve the demand at times of low renewable generation. Therefore, we define the storage flexibility KPI as the utilization of available storage capacity, i.e., the main battery, the redox flow battery and the distributed batteries. In particular, the difference between the maximum SOC and the minimum SOC of each storage device is considered. Thereafter the weighted average across all storage devices using their storage capacity as weights is obtained, i.e.,

$$\text{Battery flexiblity} = \sum_{\forall i \in S} \frac{C_i}{\sum_{\forall j \in S} C_j} (\max SOC_i(t) - \min SOC_i(t)) \times 100\%$$

where S is the set of storage devices and C_i is the storage capacity of $i \in S$. This is equivalent to taking the difference between the minimum stored energy and the maximum stored energy for each asset, averaging them and normalizing the result by the total maximum capacity. A value close to one indicates that the batteries are highly utilized, but also that only few flexibilities remains for allocation. Thus, a value of 100% might also not be desirable. In this sense, the KPI measures whether the combined storage assets are utilizing their full range of capacity.

The simulation is based on measured data from 01.11.2018 - 9:00 until 07.11.2018 - 09:00, i.e., 6 days, since within this period of time all required data for all assets was available and coherent.

In the following, several different scenarios are regarded. The scalability scenarios investigate how the upscaling of different assets of the MG affects the three KPIs. In particular, the power output of the PV park, the main battery, the distributed PV assets, the distributed battery storage systems and the demand response assets are scaled up. For the sake of comparability of the distributed assets with the centralized assets, the alteration of the wind generation is not included. Besides, scaling up PV plants is regarded as a more practical and cost-efficient way of increasing RES generation. The replicability scenarios investigate seasonality effects as well as the viability of the rule-based control in the context of a different MG topology.

Scalability analysis

Scalability analysis - Scenario #1

In this scenario, the goal is to investigate the impact of increasing renewable penetration in the MG, particularly PV. This is done by linearly increasing the power output PV park proportionally.

Figure 55 shows the three KPIs as a function of the proportional factor, where a proportional factor of one refers to the base case. The system is not capable to serve the baseload during night whereas during the day, an excessive amount of energy is generated. No matter how much PV assets are being added to the system, the islanding time does not significantly increase since the storage devices do not have sufficient capacity to serve the loads during times of low PV and wind generation. Subsequent scenarios will deal with increased storage capacity. Besides, one can also observe in Figure 55 that the utilization of renewables decreases substantially as more renewables are added to the MG. The battery cannot store the surplus energy, which vastly exceeds the present load. Moreover, the storage flexibility KPI shows that the capacity of the BESS devices is almost fully utilized. The remaining margin is due to curtailment taking place when the SOC of the main battery is around 95%, and due to the delay in the control of the other BESS devices, which is also why the KPI increases as the scaling factor increases.

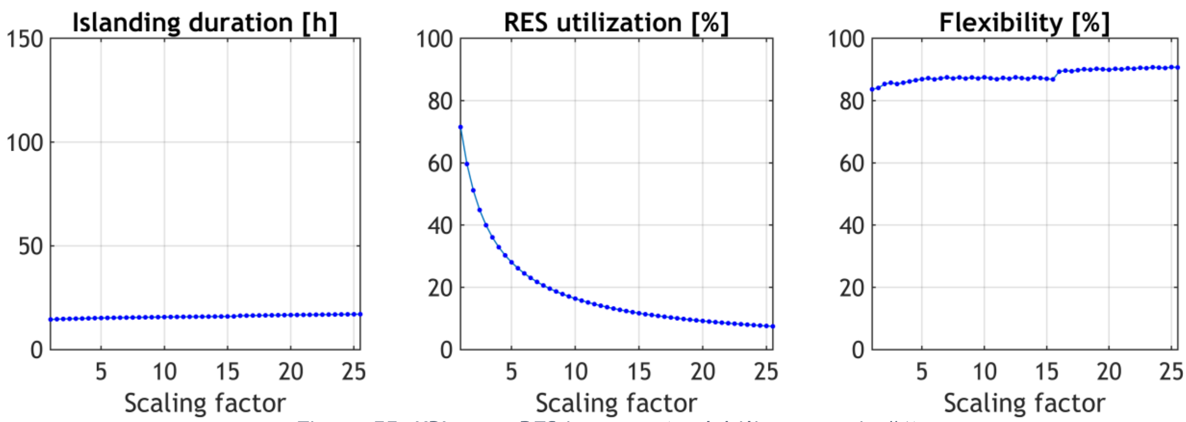

Figure 55: KPIs over RES increase (scalability scenario #1).

This leads to the conclusion that substantially increasing the amount of renewables does not yield performance improvements. The islanding duration increases slightly while the utilization of RES decreases significantly. The additional amount of RES is only used as an attempt to serve the baseload, which is not efficient.

Scalability analysis - Scenario #2

In this scenario, the effect of increasing the battery size of the central battery is investigated. In particular, the battery capacity is stepwise increased by its original capacity and the KPIs are evaluated. Figure 56 shows the KPIs as a function of the battery capacity factor, where one refers to the base case. Initially the battery size increase leads to a significant increase in the islanding duration. This is due to the fact that the battery can store enough energy to sustain through short periods of high load demands and minimal generation. Thereafter, an increased battery size only increases islanding time marginally using its slightly increased initial energy. However, the MG does not host enough generation units to charge the batteries to run sustainably and recharge the BESS. This becomes clear when studying the RES utilization, which indicates that the generated energy is fully utilized. The flexibility utilization in the third plot in Figure 56 shows that the storage capacity is only 50% utilized. This is due to insufficient charging energy, suggesting that more renewables may be hosted within the MG to prolong islanding duration.

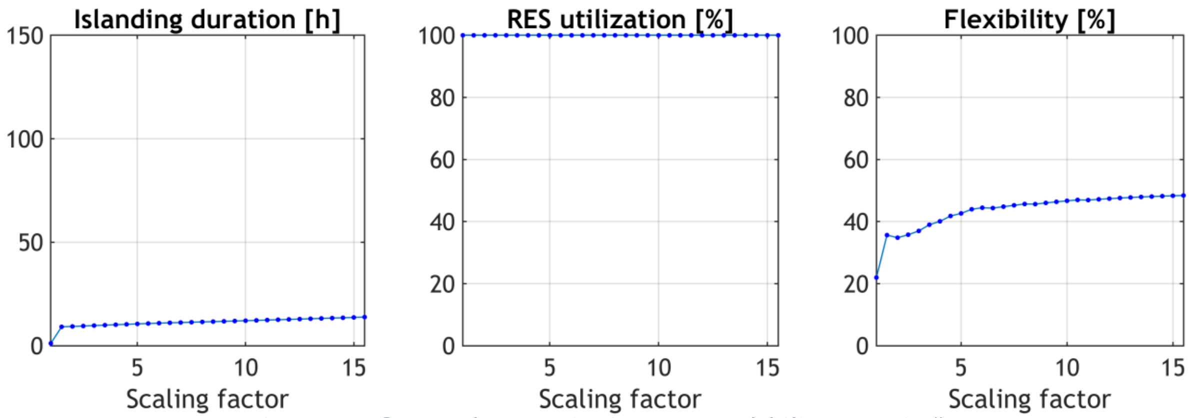

Figure 56: KPIs over battery size increase (scalability scenario #2).

Scalability analysis - Scenario #3

This scenario deals with both an increase in PV generation and an increase in the battery capacity. The output of the PV park and the battery size are proportionally increased in steps of 0.5, starting with the baseline as reference. Figure 57 depicts the KPI evaluation. Although the islanding duration increases significantly more than in scenario #2, it is still a linear relationship. The fact that the RES utilization decreases indicates that the amount of generation substantially exceeds the available storage capacity to outlast a period of low generation.

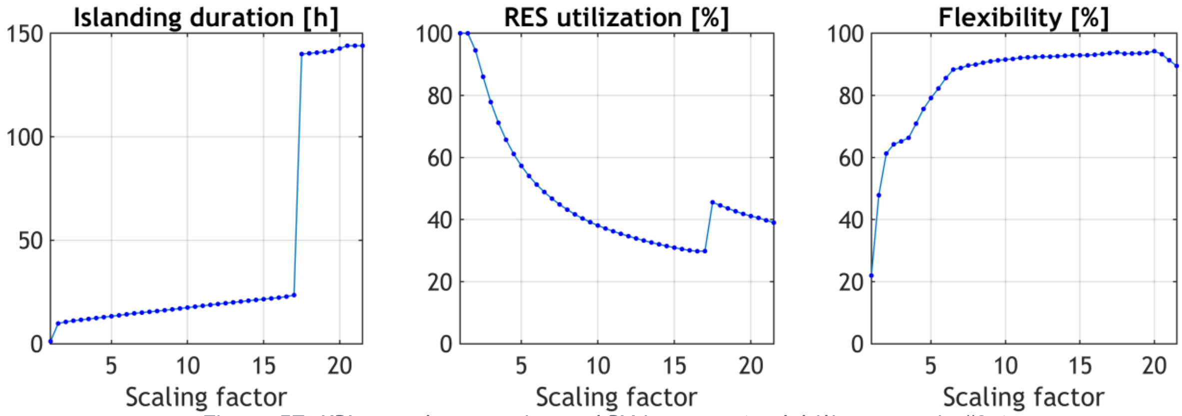

Figure 57: KPIs over battery size and PV increase (scalability scenario #3a).

Moreover, another simulation was carried out, where the battery size was increase in steps of 0.5 and the PV park output in steps of 0.25. The results can be seen in Figure 58. One can observe that the RES utilization curve is lifted and shifted to the right, indicating higher RES utilization (requiring less investments), while only slightly deteriorating the islanding duration. The sudden step at the end of the simulation horizon is due to the BESS being able to provide enough energy to run through an extended period of low generation. Furthermore, the results indicate that a central battery storage with 20 times more storage capacity and a PV park with 10 times more output can provide enough energy and flexibility to stay in islanding mode for an extensive period of time. Presumably, the amount of PV generation could be further reduced as the BESS was identified as the bottleneck. However, the goal of this analysis is to provide qualitative insights. This emphasizes the importance of proper dimensioning of the system’s assets as over-dimensioning RES mainly leads to curtailment and thus, financial loss.

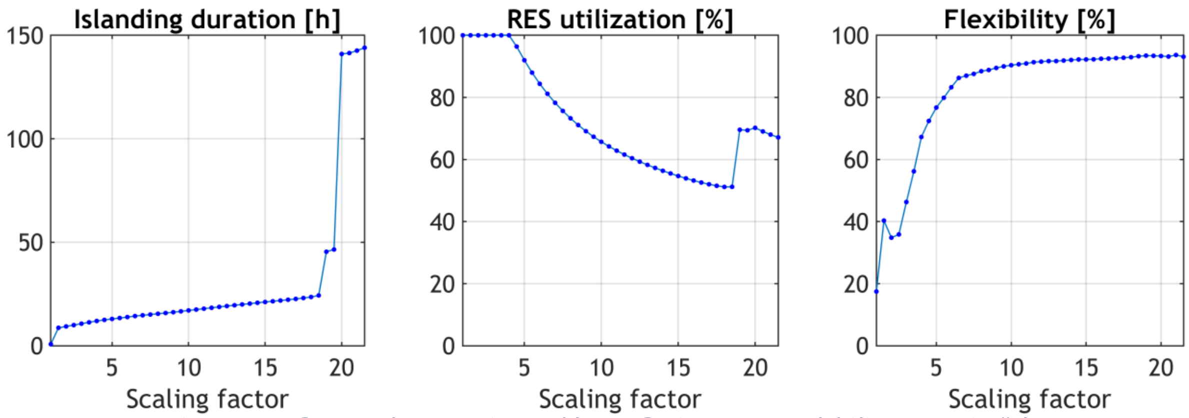

Figure 58: KPIs over battery size and lower PV increase (scalability scenario #3b).

Scalability analysis - Scenario #4

In this scenario, the impact of increasing distributed, customer BESS and PV installations instead of the central battery size and the PV park is investigated. However, the central BESS is still present and used to cover immediate power imbalances. The storage capacity of the distributed BESS is increased by a factor of 10 and the PV installations by 5. Figure 59 shows the evaluation of the KPIs. Initially, the increase in the number of distributed battery installations has a very similar effect to increasing the size of the central battery. At some point however, the performance clearly deteriorates in comparison to scenario #3. This is due to the structure of the RBC algorithm. The RBC uses the SOC of the central BESS as the control signal to the distributed assets. In case of comparably high distributed capacity, it leads to a situation where the distributed storage facilities alternatingly charge and discharge the central BESS instead of supporting its operation. This effect becomes increasingly destabilizing. Thus, the charging and discharging losses increase vastly. One can conclude that the current implementation of the RBC is not suited to host a comparably high distributed storage capacity. A simple mitigation of this issue is to increase the control frequency as the results in Figure 60 illustrate. In this regard, the results are very similar to the results from scenario #3b that are depicted in Figure 58.

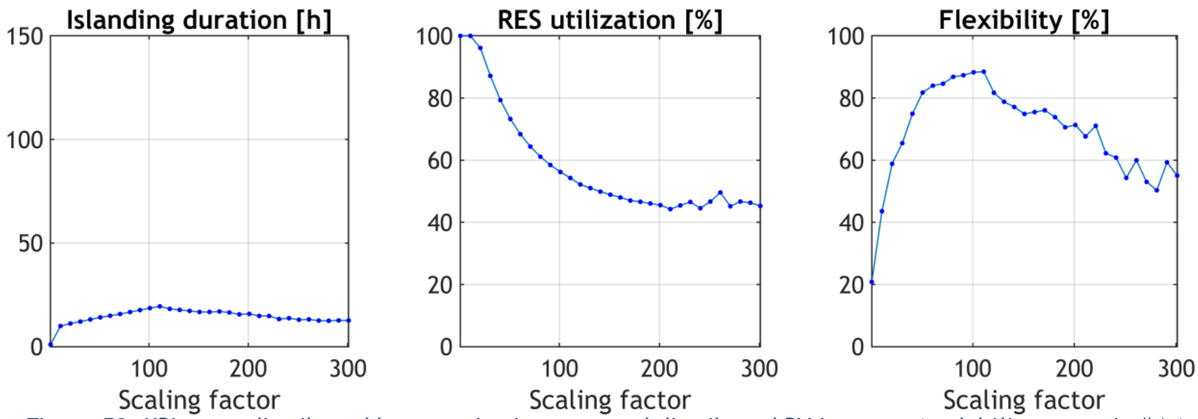

Figure 59: KPIs over distributed battery size increase and distributed PV increase (scalability scenario #4a).

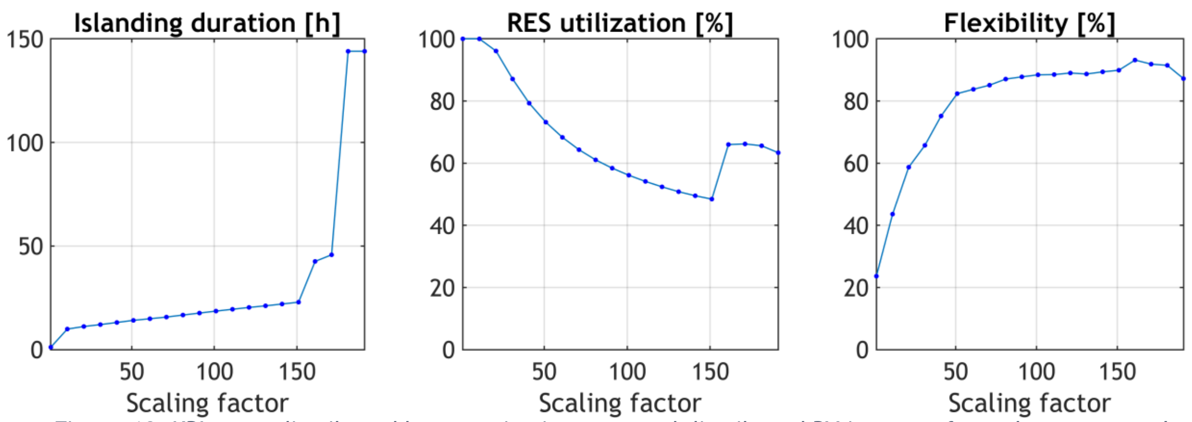

Figure 60: KPIs over distributed battery size increase and distributed PV increase for a shorter control frequency (scalability scenario #4b).

Scalability analysis - Scenario #5

This scenario investigates the effect of introducing more controllable loads on the customer premise. In particular, the number of controllable loads was increased by a factor of 30. For the sake of comparability, the main battery size as well as the PV park output was stepwise increased by a factor of one and 0.5, respectively. Figure 61 depicts the KPIs over the scaling factor. When comparing the results with the results from scenario #3b, which are illustrated in Figure 58, one can observe that the KPI curves have a similar shape. However, one can also see that the RES utilization increases. This is due to the fact that the controllable loads are able shift their demand to some extent to times of high RES generation, thus reducing the curtailed energy. Moreover, the islanding duration is slightly higher than for the case without additional demand response assets. One can conclude that demand response assets help with prolonging the islanding duration and increase RES utilization by shifting some demand to times of high RES utilization. However, demand response can only act as a supplementary measure as it does not reduce the total energy consumption and the provided flexibility is limited.

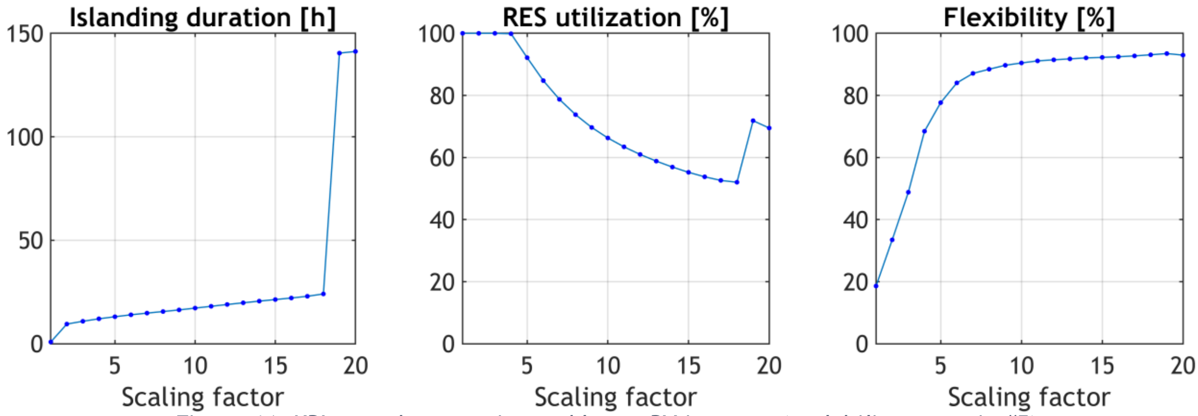

Figure 61: KPIs over battery size and lower PV increase (scalability scenario #5).

Replicability analysis

Replicability analysis (time): seasonal impact

In this scenario, the effect of a different season is investigated. The scalability scenarios are all based on data from November 2018, whereas this scenario uses data from August 2018, where a coherent dataset corresponding to one week was available, in order to investigate the qualitative effects of different seasonal data. For the sake of comparability, the KPIs are evaluated when the main battery and the PV park are scaled up. The battery size is increased by a factor of one and the PV park output by a factor of 0.5. The results can be found in Figure 62. It can be seen that the results are quite similar to the results from scenario #3b shown Figure 58. However, now prolonged islanding duration is achieved with a smaller scaling factor. This is mainly due to the increased PV generation and shorter night times. One can conclude that a typical summer day is less critical than a typical day in autumn.

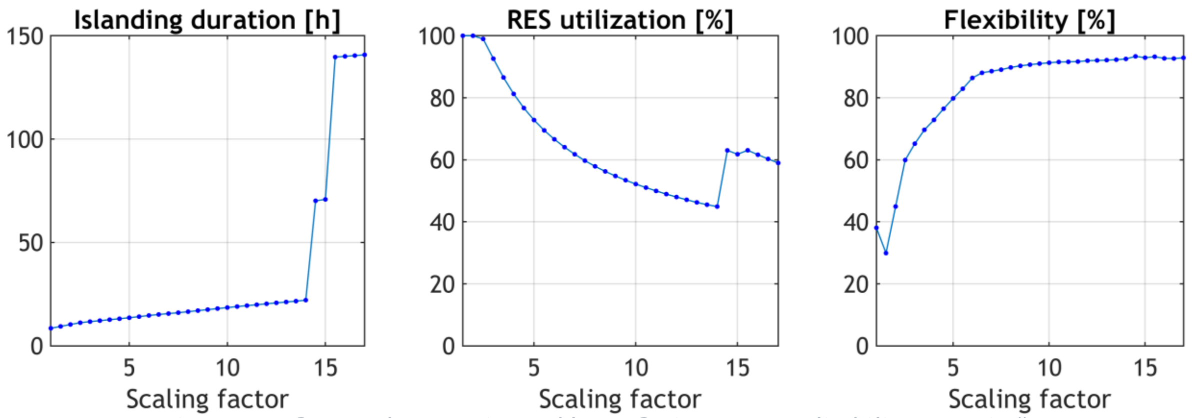

Figure 62: KPIs over battery size and lower PV increase (replicability scenario #1).

Replicability analysis (location): different network

In this scenario, the control concept and its impact are evaluated for a different network, which is closely based on the CIGRE LV benchmark network [14]. The battery size and the PV generation are increased step-wise. The results are shown in Figure 63. It can be seen that the control concept can be easily transferred to another system. Moreover, given sufficient battery size and RES penetration, the system can sustain islanding mode for an extensive amount of time. However, one can also see that the assets are not always fully utilized, i.e., the RES utilization decreases significantly. On the one hand, it can be explained by the fact that the system was not carefully tuned. On the other hand, it also indicates that increasing islanding duration and islanding reliability requires over-dimensioning of assets if flexibility mainly stems from battery and energy generation is largely based on PV.

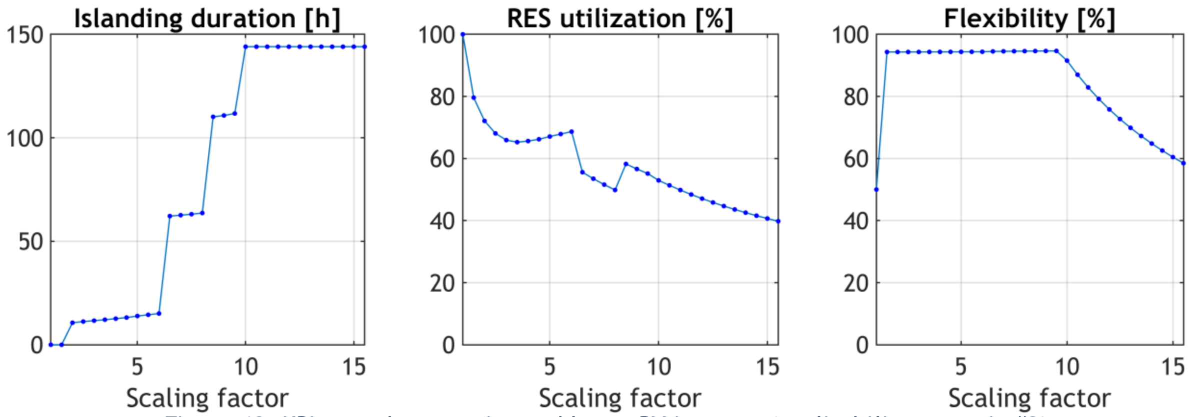

Figure 63: KPIs over battery size and lower PV increase (replicability scenario #2).

Conclusions

In this section, the scalability and replicability of use case 3 of the Swedish demonstration site was analysed. The scalability analysis regarded different scenarios where certain assets were scaled up and the impact on the MGs performance during islanding was examined. Within the replicability analysis, the concept was applied during a different season as well as to a different MG architecture. It was shown that focusing on scaling up only one asset type leads to marginal improvements. Instead, careful balancing between the different asset types is required. Moreover, the results indicate that the control concept is easily transferable to other MG designs. However, one should keep in mind that this analysis did not assess the quality of the control concept. The goal was rather to understand the impact of different components when applying a simple, robust control mechanism.

3.1.6. FR Demo

Pre-evaluation: Use Case selection & limitations

The selection of the UC for the French demo is based on the pre-evaluation study in which it was provided an insight to drive the SRA to focus on UC 1 and UC 2.

UC1 focuses on the islanding operation of the Lérins islands in order to ensure continuous supply in the case of a network interruption in which supply can no longer be maintained from the main island of Cannes. The environment created for UC1 forms the basis of the SRA, of which is the primary focus in this study. Since UC2 is a business orientated use case, it is introduced in combination with UC1 in order to investigate the flexibility potential of the battery storage system to provide multiple-services. This is done in addition to providing islanding operation and is analysed through SoC parameterisation. These simulations are based on time-series simulations where the network impact is considered through the power rating of the system. UC3 focuses on a local flexibility market to assess how the flexibility could help the DSO to solve electrical constraints on its grid. An in-depth review of UC 3 is provided in D9.1. The SRA scenarios (within which each individual system parameter is scaled) are further developed from the baseline scenario and are fully presented within the Annex in section 7.2.4.

Approach

One of the objectives of UC 1 is to define which systems would be able to island for 21 consecutive days, which allows for sufficient repair time, should the connection to the main island of Cannes be compromised. With respect to the SRA, the main objective is to find the theoretical minimum system requirements in order to achieve the 21 days of islanding by incorporating an optimised combination of PV generation, battery storage systems and the potential integration of Demand Side Management (DSM) where a general load reduction technique is applied. The baseline for the demo is based on the proposed specification obtained from Enedis, of which can be further reviewed in more details in the Annex, section 7.2.4. This baseline is used to provide a scenario upon which the suggested SRA scenarios can be compared in order to conduct the analysis. The baseline technical information for the implementation of UC1 can be found in D9.1 where a more detailed description is provided for the Grid Forming Unit (central and main battery) and the Grid Support Unit. A summary of the assumed system used for the baseline analysis is shown in Table 19.

Table 19 System component rating of the Islanding system

System component	Rating
Load profile	As per provided substation data
PV Generation	130 kW_p[11]
GFU	SoC_{max} = 620 kWh, P_{max} = 250 kW
GSU	SoC_{max} = 274 kWh, P_{max}[12] = 100 kW

[11] No PV generation was finally installed on the islands because of administrative difficulties to obtain the authorization in the timeline of the project. The simulations considered for this analysis are conducted with the values which were originally planned for.
[12] The final rating in the demo was downsized to 33kW due to the space limitation. Nevertheless, the simulations considered for this analysis are conducted with the values which were originally planned for.

In this analysis, the worst-case scenarios pertaining to three different network conditions are considered. Additionally, further analysis of the effects of demand side management with respect to load reduction and the impact SoC on the islanding duration will be explored. In the final scenario, a small scale (72 hour) system parameterisation is proposed, which aims to consider the case when the system islanding is to cater for the time duration required to deliver backup diesel generators to the island. For all cases, the approach for the SRA, follows a methodology in which the system parameters are 'stressed' accordingly. For the case of the UC 1, based on the system components, three main parameters were identified namely, power generation[13], storage capacity, and demand side management (load reduction). An overview of the SRA parameters and its associated observations can be seen in Figure 64.

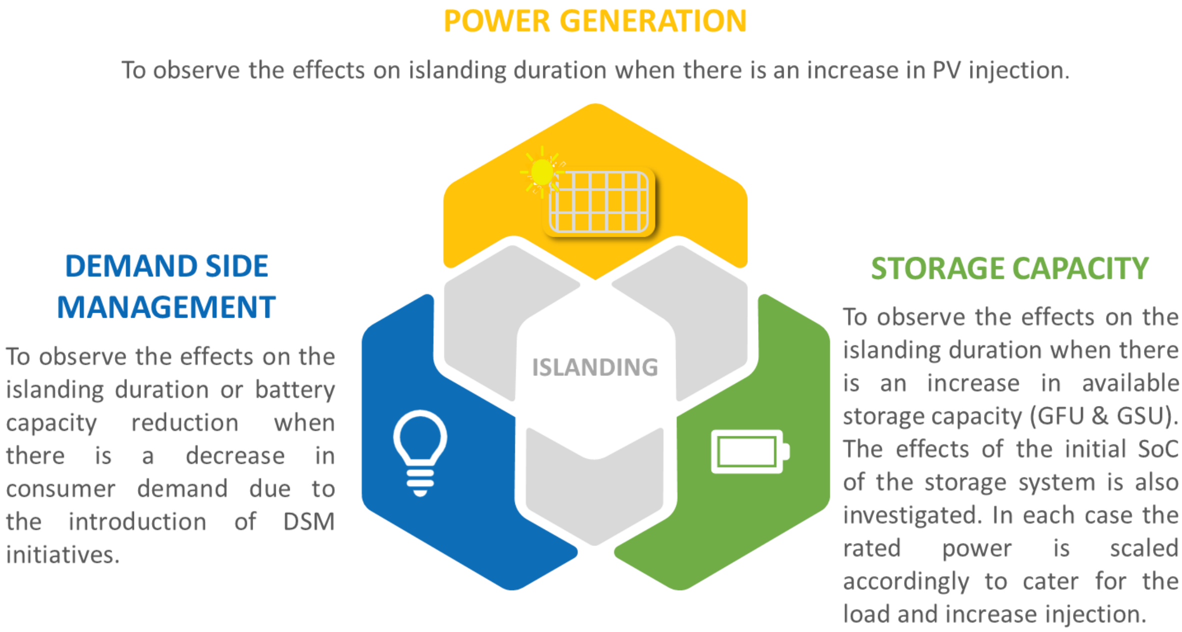

Figure 64 Overview of SRA parameter and its associated observations

To conduct these time-series simulations, data profiles and system components were developed. Their processing is Python based in order to create an automation process tool from which the various system response conditions could be calculated. An overview of the SRA methodology created for FR demo can be seen in Figure 65, which consists of the PV generation data taken from the online tool [15] and parsed to match the time series provided from Enedis for the load profile and the storage system data for its parametrization. A more detailed discussion regarding these profiles are available within section 7.2.4 of the Annex. This data, once processed, is passed into the analysis using the simulation environment developed by the AIT team, which consists of Python scripts and contains data analysis results as an output.

[13] Only PV is considered as the available generation source. The amount of wind available on the island was investigated using (ref: https://www.windy.com/)) and was concluded that the amount of wind is insufficient. Other sources of fossil fuel generation (such as diesel) is not included, since the mandate is to propose solutions which have the least CO_2 emissions and to reduces the overall impact on the environment, since the islands are considered to be protected areas.

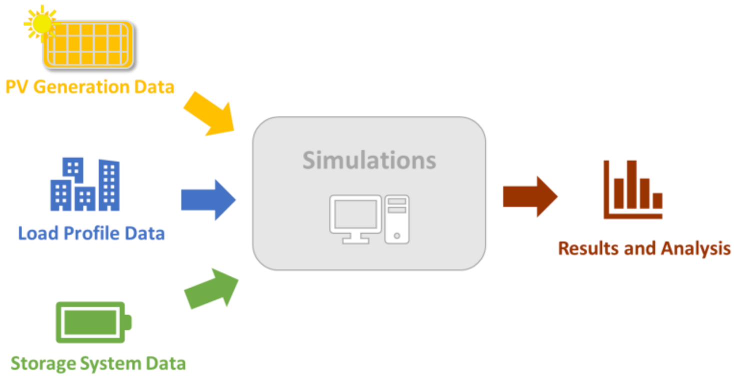

Figure 65 Overview of the SRA methodology for the FR Demo

In order to conduct the SRA, each of the input parameters were scaled independently in order it identify its impact on the overall system. Thereafter, the parameters were scaled simultaneously such that the scalability of the entire system can be holistically assessed.

Overview of simulated scenarios

Based on the pre-evaluation study, a summary of the scenarios conducted in the SRA is shown in Figure 66.

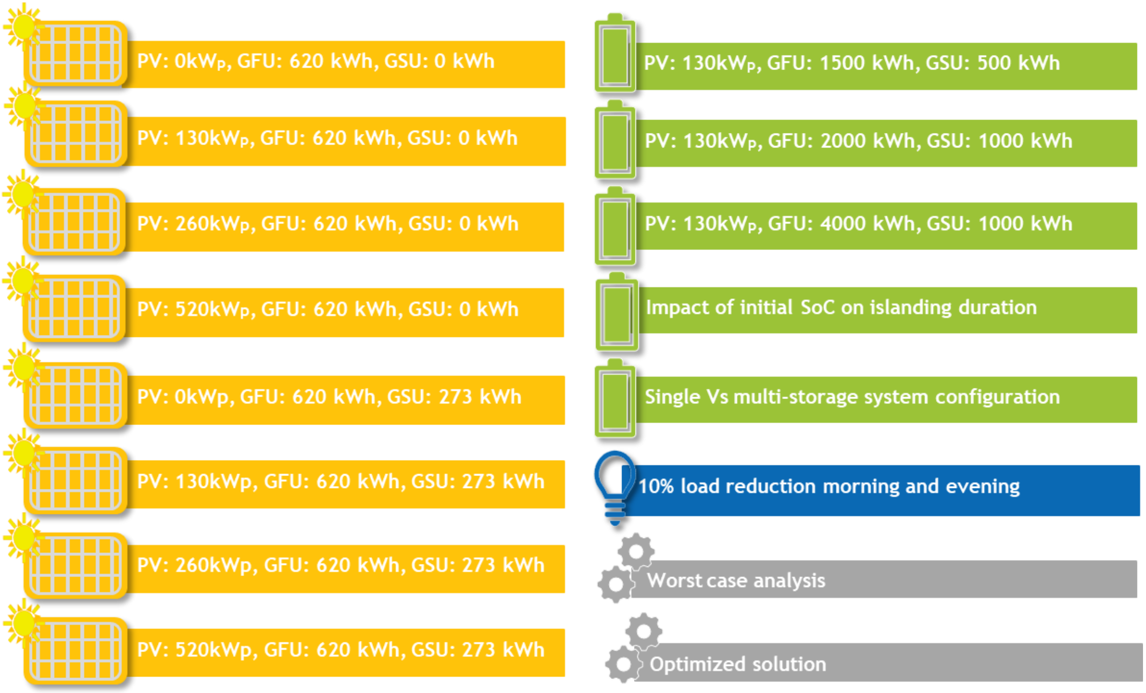

Figure 66 Summary of various scenarios simulated in the SRA

With respect to the above, the three worst case scenarios are identified as follows:

- Worst Case A: Maximum load with minimum PV generation.
- Worst Case B: Longest period of consecutive days with minimal PV generation.
- Worst Case C: Highest load consumption in combination with lowest PV generation.

Scalability analysis

In this section the different worst cases explored for the combination of scaling individual assets are presented. As previously mentioned, this section presents only one worst case scenario case (Case C) while the additional SRA scenarios can be found in the annexes. Additionally, the case for the small scale recommended solution is also included.

Worst case C parametrization: Highest load consumption in combination with lowest PV generation

In this scenario, the worst-case condition of the given system was identified to be the situation where there is the highest load consumption with the least amount of PV generation for the same period of time. For the provided input load and PV data, the worst-case condition was identified to be as follows:

- Islanding start date: 9 October 2018
- Total Consumption: 80.33 MWh
- Peak load: 0.26 MW
- PV full load hours: 79.2 h/week

The results of the simulation can be seen in Figure 67, which shows the installed total power obtained from the generation of PV and the total capacity of the batteries with respect the total islanding duration measured in hours.

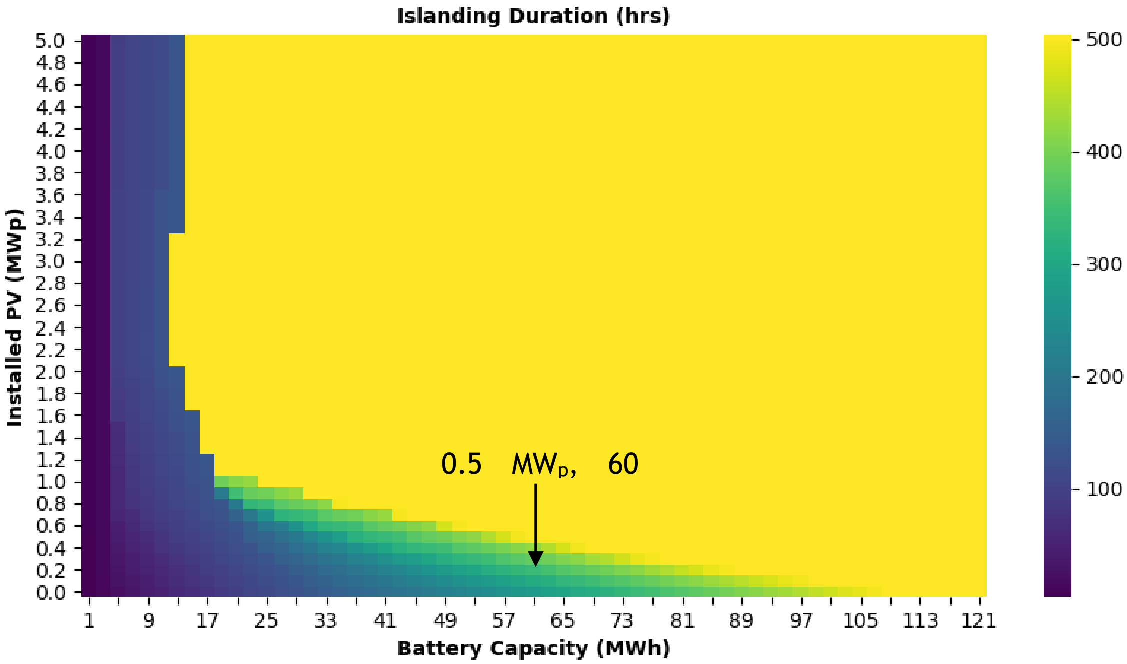

Figure 67 Minimum system requirements to achieve 21 days of Islanding duration

As can be seen, in order to achieve 21 days of Islanding duration with 500 kW_p, a minimum of 60 MWh battery storage would be required. In the case where there is no PV generation, a battery size of 110 MWh would be required. In the case where there is more than 2 MW of PV generation, the battery storage capacity can be reduced to 14 MWh. This is achievable if rooftop PV for each of the 56 customers is included (as shown previously)[14]. In the case where not every customer agreed to rooftop PV, the combination of a 520kW_p, 27 customers (~50%)

[14] Note that in this section, no administrative authorization is considered.

providing 1040 kW_p would allow for the battery capacity requirement to be reduced to 18 MWh. Alternatively, the introduction of alternative power generation sources should be investigated. It is however, interesting to note, that increasing the PV generation beyond 2 MW does not provide additional benefits in terms of meeting the 21-day islanding duration requirements when the storage system is sized to 17 MWh.

The Impact of Demand Side Management

When considering the worst-case scenario (as identified in Figure 67) with a battery size of 60 MWh and 500 kW_p PV, it can be observed that with a 10% load reduction through DSM measures, there are two possible consequences: as shown in Figure 68, either the islanding duration could be increased by 1.75 days, resulting in a total of 22.6 days, or the storage capacity could be reduced to 56 MWh while maintaining the islanding duration of 21 days (504 hrs).

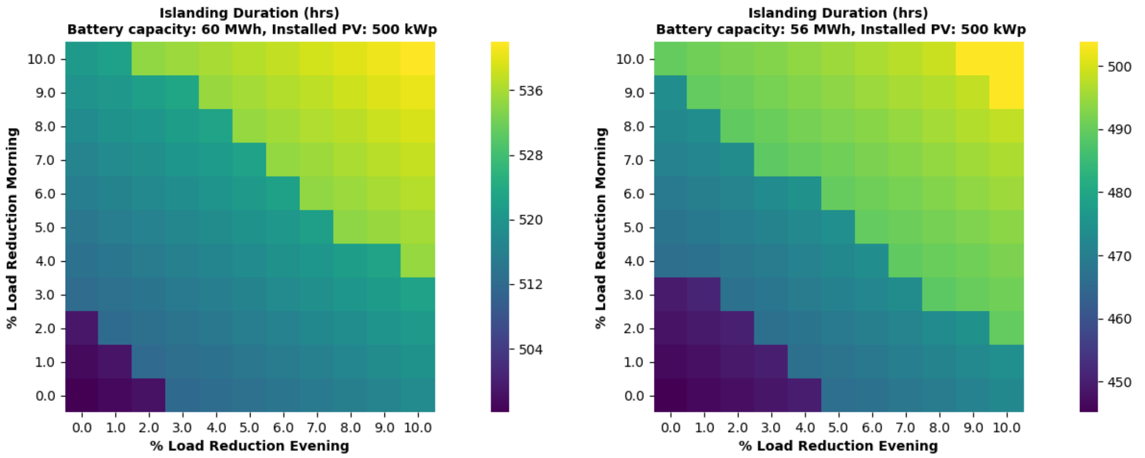

Figure 68 Increased islanding duration (left) and reduced battery size (right)

DSM measures leading to a 10% load reduction in the morning and evening profile allow therefore to reduce battery capacity by ~7%, while still ensuring an unaltered 21-day islanding duration. If the installed battery capacity was to be maintained at 60 MWh, the 7% surplus battery capacity could also be considered for additional flexibility offered on the flexibility market.
It shall be noted that a load reduction of 10% implies relatively light DSM measures, limited to postponements or reshaping of the load curve. If the curtailment of non-critical appliances was to be included in the DSM scheme, much higher load reductions could be achieved. Given the potential value of non-distributed energy (ranging from 9 to 20 k€/MWh) the reduction in battery size will most likely be a cost-effective choice. It can be concluded that in either case a load reduction through the implementation of DSM techniques has a direct consequence on the sizing specifications of the microgrid system in order to meet the required islanding duration.

Further details regarding the DSM implementation is described in section 7.2.4 (annex).

Impact of SoC on Islanding duration

Figure 69 shows the results of the variation of the initial SoC of the 60 MWh storage system with 500 kW_p PV injection in order to maintain 21 days of islanding duration.

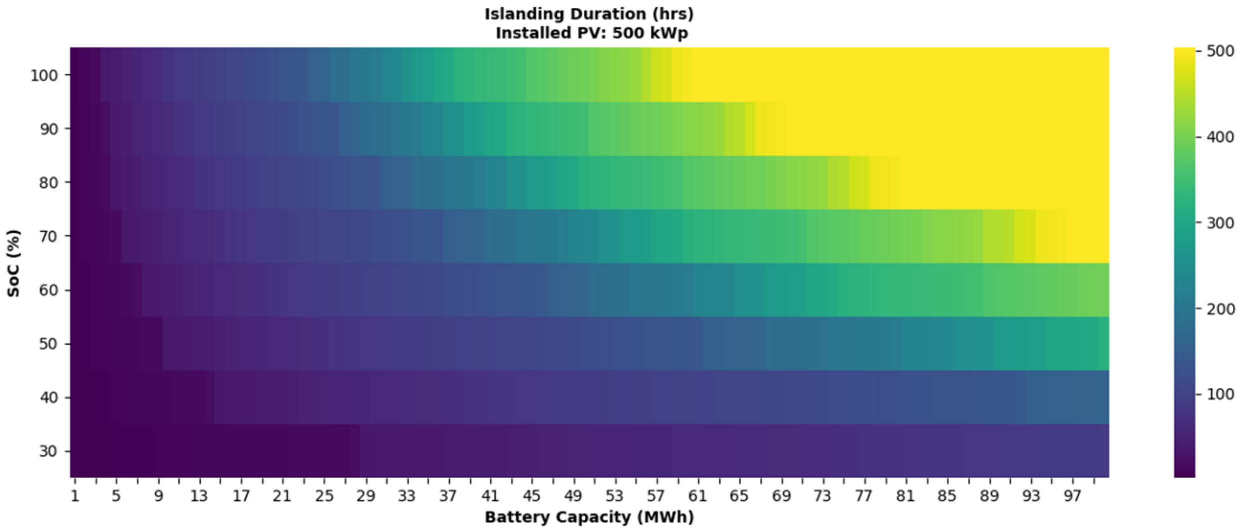

Figure 69 Effects of initial SoC of the 60 MWh storage system for 21 days islanding duration

Thus, the potential of SoC of the storage system can affect the islanding duration and that if the storage system owner has the intention to offer his asset on the flexibility market, it is vital that the SoC of the system is taken into consideration if he is to meet the minimum islanding duration requirements. This analysis proved that in order to participate in the flexibility market a larger battery storage system would be required. Various system configurations (single vs multi-storage) of the islanding system were investigated and showed that each of possible has its advantages and disadvantages, both of which should be considered in order to find a feasible solution.

Combination of all characteristics

Based on each of the aforementioned scenarios, this section aims to demonstrate the most feasible solution in order to achieve 21 days of islanding duration. This scenario combines the findings obtained from the scalability of each of the individual parameters (PV generation, storage capacity and demand response), into one overall solution. In this case, the PV generation of the entire system is considered to be most feasible when the addition of rooftop PV on all 56 customers is implemented, translating to a total PV generation of between 2.1-2.5 MWp. Additionally, the consideration of load reduction through the use of DSM initiatives is also included. Therefore, when combing the effects of installing rooftop PV in combination with load reducing DSM initiatives, the downsizing of the battery capacity can be achieved. In this case, the size of the storage system can be reduced to 12 as can be seen in Figure 70.

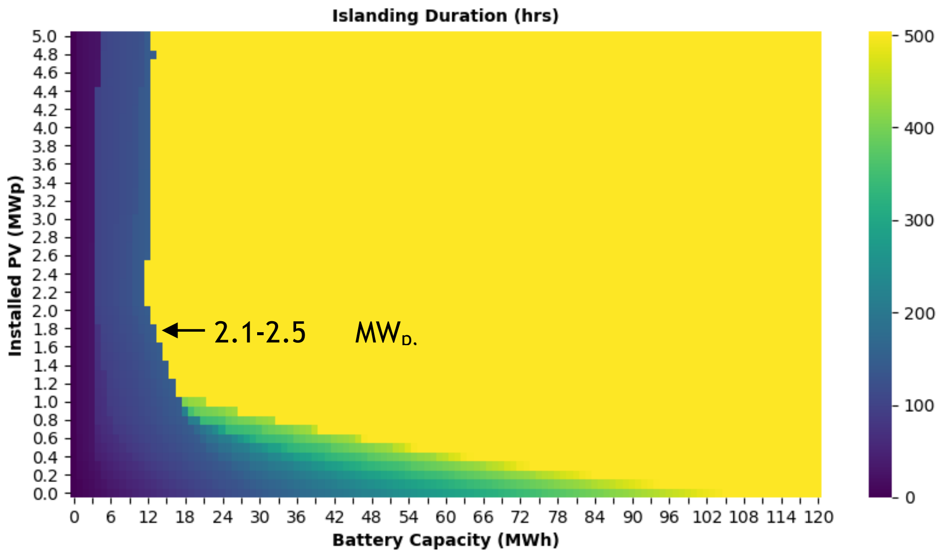

Figure 70 Heatmap showing battery capacity VS PV generation with load reduction initiatives for Case C

For each of the cases presented, the results obtained show that an islanding duration of 21 days is theoretically possible using the well-sized assets. However, the overall system (PV + storage systems) would likely be too cumbersome to be installed on the islands, even when the use of DSM initiatives is incorporated.

Small Scale Recommended Solution

In this scenario, the system parameters are sized in order to sustain 72 hrs of islanding duration. This is considered the maximum duration required in order to deliver diesel generators to the island when there is no supply from the main island and local islanding is required. In this case the solution was calculated based on the following:

- Islanding start date: 23 July 2019
- Total Consumption: 18.61 MWh
- Peak load: 0.377 MW
- PV full load hours:15.16 h/week

With the above analysis, the results can be seen in Figure 71, where a minimum battery of 16 MWh is required with 0.5 MWp PV injection in order to sustain 72 hours.

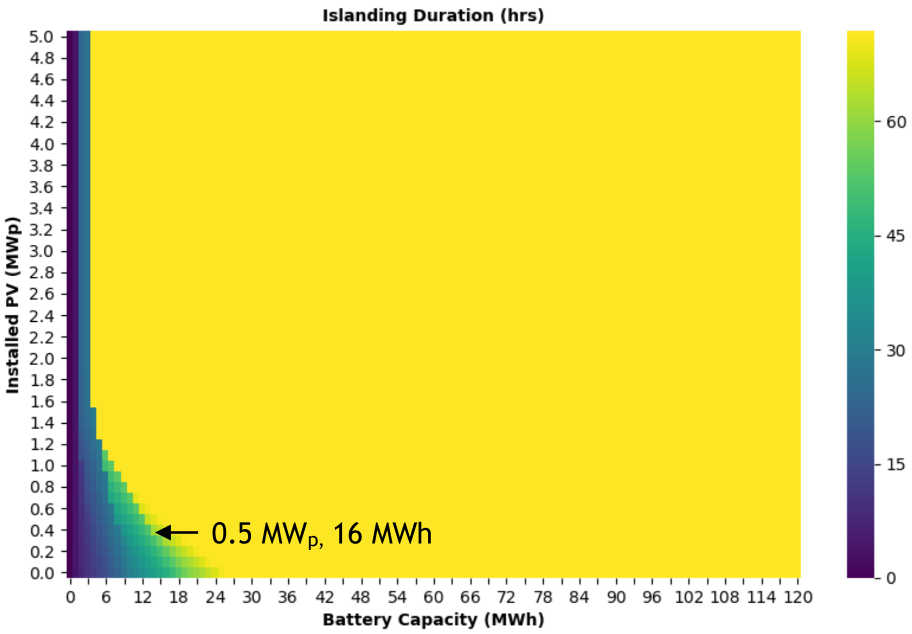

Figure 71 Minimum system requirements to achieve 72 hours of Islanding duration

Impact of DSM Load reduction

For the case of a 72 hour islanding duration analysis, when the demand side management in terms of 10% load reduction in the morning and evening is applied, the islanding duration can be extended to a total of 87.5 hours (3.6 days) as shown in Figure 72 (left).

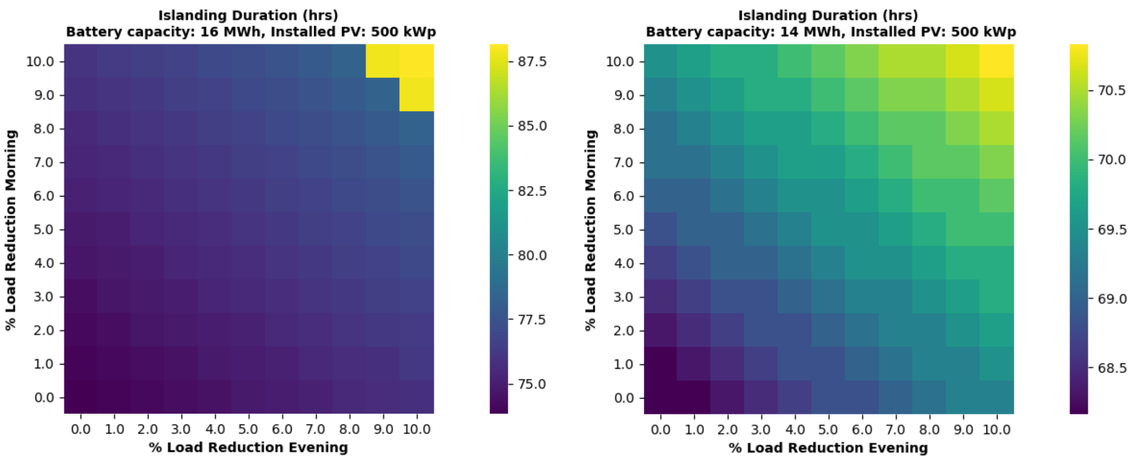

Figure 72: Increased islanding duration (left) and reduced battery size: 14 MWh (right)

On the other hand, it can be seen that the battery can be reduced to 14 MWh while still maintaining 72 hours of islanding duration, which can be seen in Figure 72(right).

Impact of SoC on Islanding duration

In terms of the requirements of the SoC when considering the size of the battery, it can be seen Figure 73, that an increase in battery capacity would be required if the SoC of the battery is reduced.

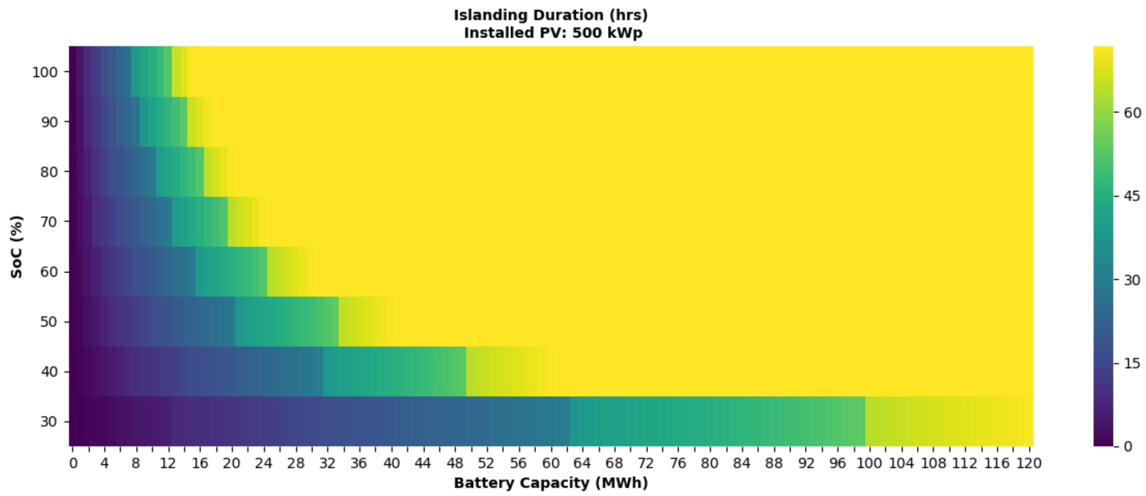

Figure 73 Effects of initial SoC of the 16 MWh storage system for 72 hrs islanding duration

Combination of all characteristics

Finally, in the case where the battery is sized with the incorporation of PV injection obtained from rooftop PV on the customer premise and demand side manage based on load reduction, the battery capacity can be reduced to 5 MWh as can be seen in Figure 74.

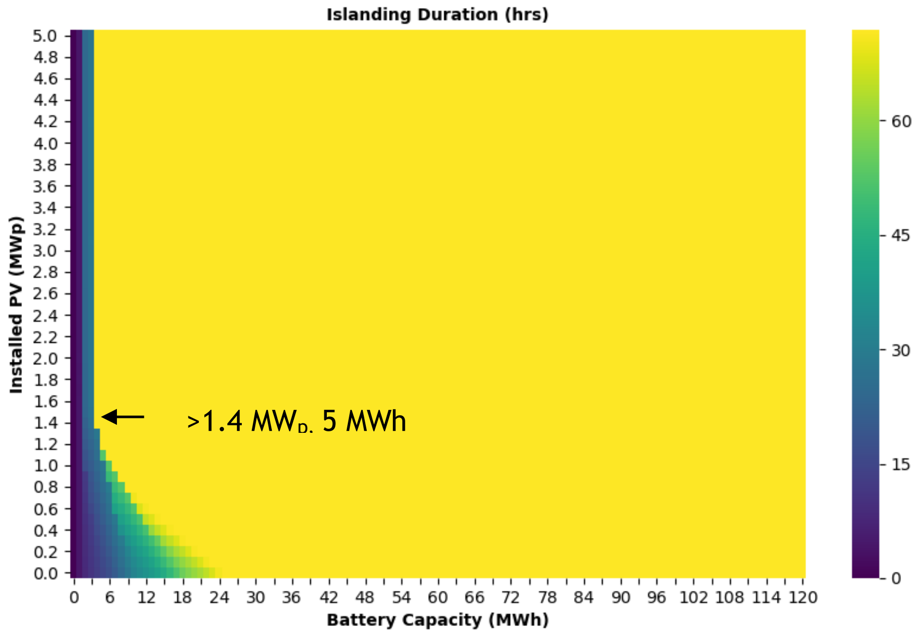

Figure 74 Heatmap showing battery capacity VS PV generation with load reduction initiatives for 72 hrs of islanding duration

This reduction in battery capacity can thus be considered as the most feasible solution to incorporate on the islands. In comparison with all cases conducted, this solution proposes the smallest battery system. This would be the most cost effective and have the least impact on the environment. However, since the longest duration of islanding is based on 72hrs, Enedis would have to send gensets onto the islands and can consider the option of islanding to be used during emergency situations. Therefore, the impact on customer interruptions would be minimised, since the option of islanding can be utilised to ensure continuity of supply and sending gensets may require a few days.

Replicability analysis (time)

In this section the different worst-case scenarios are explored for the duration under different condition throughout the year, as it uses the information and parametrization done in the scalability analysis. In each case the results are assessed by calculating the islanding duration for each 10 min time interval and then obtaining the average islanding duration (in hours) for each day.

Worst Case A

Based on the results obtained in Figure 157 Heatmap showing battery capacity VS PV generation with load reduction initiatives for Case A, which incorporates load reduction in combination with 2.5 MW_p PV generation and a battery size of 21 MWh, it was shown that 21 days of islanding duration is achievable when sizing the battery based on the combination of the highest load consumption with the least amount of PV irrespective of the timestamp.

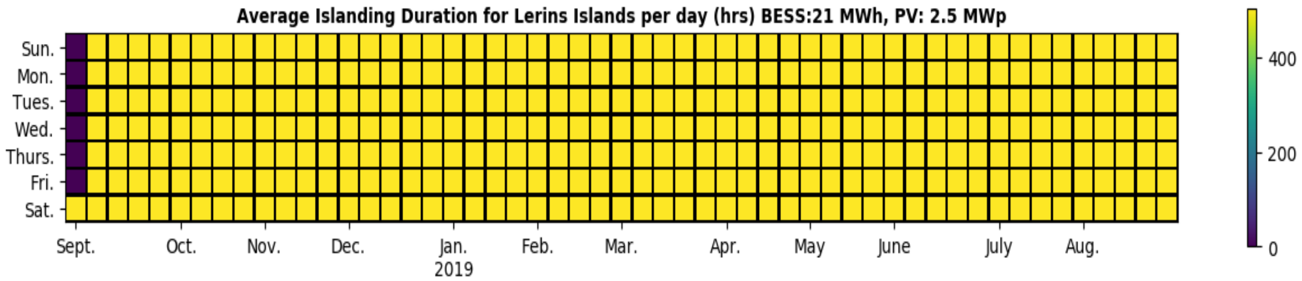

Figure 75 Average islanding duration for 25 MWh storage system and 2.5 MW_p PV for case A

Worst Case B

Based on the results obtained in Figure 161, which incorporates load reduction in combination with 2.5 MW_p PV generation and a battery size of 25 MWh, it was shown that 21 days of islanding duration is achievable when sizing the battery based on the consideration of the period of consecutive days when minimum PV is generated. The average islanding duration per day in hours is shown in Figure 76.

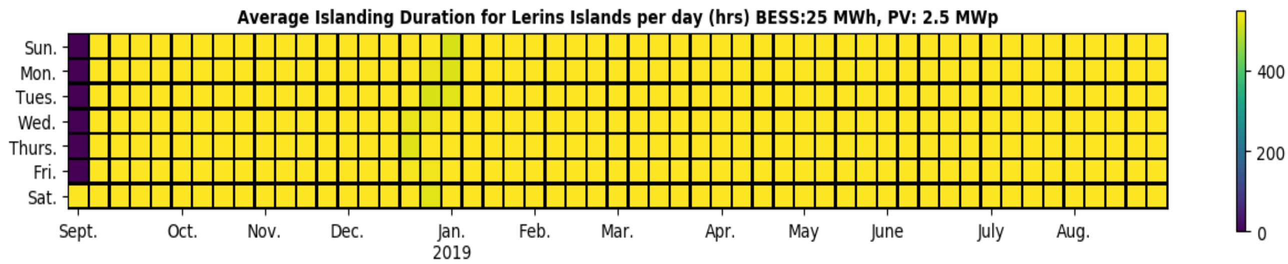

Figure 76 Average islanding duration for 25 MWh storage system and 2.5 MW_p PV for case B

As can be seen, sizing the battery according to the longest period of consecutives days where there is minimum PV generation, i.e., 25 MWh, the battery is capable of lasting a period of 21 days should islanding occur at any moment in time throughout the period of analysis.

Worst Case C

Based on the results obtained in Figure 70, which incorporates load reduction in combination with 2.5MW_p PV generation and a battery size of 12 MWh, it was shown that 21 days of islanding duration is achievable when sizing the battery based on the highest load consumption with the lowest PV generated with considerations of the timestamps being identical. The average islanding duration per day in hours is shown in Figure 77.

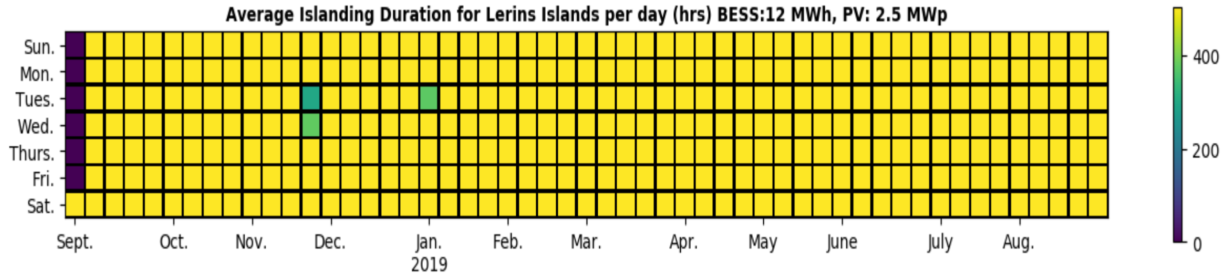

Figure 77 Average islanding duration for 12 MWh storage system and 2.5 MW_p PV for case C

As can be seen, despite the battery capacity being sized based on the worst week in starting in the 09 October 2018, the battery is unable to last 21 days in all cases where the islanding duration is to start at other moments in time based on the average duration per day. This is evident in the case of 2 days in November and 1 day in January, when there is insufficient sun to charge the battery to its maximum capacity.

In all of the above cases, it is clear that the dependence of seasonality is highly reduced due to the large size of the battery capacity, which for the most part of the year is able to cater for periods when there is reduce PV production.

Conclusion

In conclusion, the SRA for the FR Demo has shown that a theoretical 21 days of islanding duration is theoretically achievable through the optimal combination of PV generation, battery storage and DSM. When scaling the PV generation from 500 kW_p to 2.5 MW_p (through the inclusion of rooftop PV) and through the use of possible DSM techniques which results in a 10% reduction of load demand during peak hours, it was shown that the required battery capacity can be further reduced from 120 MWh to 21 MWh for case A, from 80 MWh to 25 MWh for case B and 60 MWh to 12 MWh for case C, when considering the worst-case scenarios. Nonetheless, it is noted that the overall system (PV + storage systems) would likely be too cumbersome to be installed on the islands, even with the use of a DSM system.

As can be seen in all cases, as the initial SoC of the storage system is decreased, the minimum requirement of the battery storage is increased if 21 days islanding duration is to be sustained. The analysis was performed on a theoretical basis and it is noted that there would be an optimal SoC(t) function to start the islanding operation which would be less than the SoC_{max} defined. This 'excess' could be made available for additional services. This is of particular importance, where the possibility of using the additional storage capacity within the flexibility market is considered. It was observed that with battery storage systems of 120 MWh, 80 MWh and 60 MWh combined with 500 kWp PV systems, the DSO would require the system to always be charged to 100% during worst days if it is to be able to sustain the full duration of 21 days, still under worst case conditions. Therefore, in order to participate in the flexibility market and to ensure that a 21-day islanding duration is fulfilled, a larger battery storage system would be required or the battery storage system will only be monetized on markets when day-ahead forecast show that 100% is not needed. Since the battery storage system is already of an enormous scale, alternative solutions should be investigated such as curtailing not critical electric appliances during the islanding in order to reduce the need for energy during worst case and then reduce the battery system storage sizing.

A proposed solution is provided in the final section. The study case for a smaller battery sizing to cater for 72 hr duration was also presented in order to cater for the duration it is required to deliver diesel generators to the island. The case study also showed that when the incorporation rooftop PV and demand side management techniques are implemented, the battery capacity can be reduced to 5 MWh.
In summary, the scalability analysis shows that it is important to consider various aspects of the entire islanding system, this includes PV generation, battery capacity, and the load of the system. When taking all these parameters into consideration, it is necessary to find the correct balance between them, in order to obtain the most optimal solutions.

Lastly, the replicability analysis, with respect to seasonality, showed that the islanding duration is highly dependent on seasonality when there is insufficient installed battery capacity. It was shown that during the summer months the impact of tourism has a significant impact on the islanding duration due to the increased load demand, even in the case where PV injection is increased. In the case where there is a sufficient storage system installed, the impact of seasonally is reduced. Thus, it is important that the effects of seasonality with respect to weather and tourism are careful considered when designing an islanding system.

3.2. ICT scalability analysis

This section focuses on the analysis of the two main architectures found within InterFlex. These architectures are classified either as upper or lower bound, based on the connection between the DSO and the customer. The representative architectures for each cluster are, on the one hand for the lower bound the German demonstration, as the steering occurs directly from the DSO taking advantage of the direct interface they have over customer's assets. On the other hand, for the upper bound, the Dutch demonstration is selected since it is the clearest example of how the flexibility steering is done through a third party, such as a multi stage aggregator since more than one level of aggregators are involved (local and commercial one).

The same refined and validated methodology is applied for both architectures. This methodology is a product of the different steps followed in order to create this ICT scalability methodology. These steps were previously introduced in section 2.1.2. However, it is provided hereupon a brief summary of the steps applied for the refined and validated methodology, which is as follows,

- **Attributes evaluation** form each of the clusters (upper and lower bound)
    - Each demo has to evaluate the final selected attributes based on importance and impact
- **Architecture characterization** by means of the architecture characterization tool.
    - The upper and lower representative architectures are evaluated to one set of attributes selected in order to provide a current status analysis of their different component and links (SGAM based).
- **Architecture capacity and requirement** by means of the capacity and requirement evaluation tool
    - The upper and lower representative architectures are analysed based on certain set of attributes selected in order to provide an average value of different components and links (SGAM based) with respect of that set of attributes.
- **Scenarios conceptions** to provide context of potential scaling in the architecture
    - A set of scenarios are mapped to the different subnetworks, if they were, to see the potential impact into different branches (links) which would be affected by this potential scenario.
- **Performance analysis** of the different outputs from each tool based on using the conceptual scenarios as the context for real time and deferred operation scaling
    - Real time operation: data streaming. When data is generated, it is pushed upstream/downstream.
    - Deferred operation: not data streaming. When data is created it is stored and later pushed upstream/downstream.
        - A set of calculations within the deferred operation takes place to observe the theoretical bandwidth and storage use in order reaffirm if it matches the available capacity and requirement of the system. Time performance is covered by deliverable 3.7.
- **Conclusions** for each architecture

3.2.1. ICT assumptions

Although the various steps and their respective purpose of the methodology were previously introduced in section 2.1.2, it is necessary to state the assumptions taken in order to provide a complete overview of the qualitative analyses performed. These assumptions are hereafter motivated.

It is assumed that the ICT system is a combination of several components (devices, systems or subsystems) which are interconnected through links and can be represented in an accessible and clear way through the SGAM. Therefore, the SGAM is one of the main inputs used for the study. However not all the interoperability layers have to be considered due to relevance from the point of view of the ICT. Indeed, only the Component; Information and Communications layer are taken into consideration while the Functional layer acts as a boundary condition for the functions implemented and, similarly, the Business layer helps defining emplaced regulation, especially for data.

It is assumed that the ICT system are usually sized according to the intended use of the system based on its "original" design as a demo, creating a system and equipment legacy which cannot be avoided.

Additionally, it is assumed that an ICT system has been designed for and restricted to economic and/or electrical power consumption considerations, consequently its performance could be compromised when scaling due to these restrictions. This design is understood that it can be either considered to work in real time operation or to work in deferred operation where the data is pushed and shared not continuously as in real time but rather in bursts.

Finally, it is assumed that the SGAM developed for each demonstrator is the main architecture and as a result it is considered as the primary input despite acknowledging its simplification with respect to all the components involved within the ICT system. In addition, the simplification extends to the attributes selected used in the different steps as Table 20 reflects and their respective definitions are summarized in Table 21. Nonetheless, this simplification is a noble approach as it is a trade-off between system overcomplexity and resources available for the analysis, since the ICT is not required by the SRA grant agreement analysis but is considered as a beneficial addition to the entire InterFlex analysis. The additional information of the concepts for scalability are introduced and explained in more detail in Annex 7.3.

Table 20: Attributes tool-classification use

Categories	Attributes	Used in
Reliability	Autonomy	Characterization
	Robustness	Characterization
	Redundancy	Characterization
Computational resources	Device Storage	Capacity & Requirement
	Response time	Capacity & Requirement
	Processing speed	Capacity & Requirement
Manageability	Data volume	Capacity & Requirement
	Data periodicity - How often	Capacity & Requirement
	Configuration effort/complexity	Characterization
	Automatization	Characterization

Table 21: Attributes score table map

Category	Reliability			Computational Resources			Manageability			
Attribute	Autonomy	Protocol Robustness	Redundancy	Device Storage	Response time	Processing speed	Data Volume	Data Periodicity	Configuration effort/complexity	Automatization
Definition	Component internal number of factors for continuous operation	Assessment of the protocol features to cope with non-perfect data	Assessment for component or link necessity for duplication	Storage in the component	Request response behaviour between two components	Assessment of the orders processed by a component	Average volume dealt with	Average for exchange of information on a link between two components	Assessment of the process for component/link integration	Assessment of the level of automation for the component operation
Rating										
1	No fail-safe mechanisms	Has noise immunity	Avoid	No storage	Stalls often	µControler	<1 Kb or analog value	less than once a day	Requires Human involvement but complex	Requires HM to operate it every time
2	Data buffer	Additionally has Error checking	Not necessary	Volatile, small but fast	Needs to make at least two trials	Embedded Linux	1Kb < X < 100 Kb	Once a day	Requires Human involvement but average	Requires HM to supervise most of the time
3	"Cold" safe mode	Additionally has Packet recovery	Passive redundancy Active only when malfunction	Volatile, large and fast	Admissible time response	PC	100Kb < X < 10 Mb	Several times a day	Requires Human involvement but easy	Partially autonomous, requires HM interaction in frequent cases
4	"Warm" safe mode between 1h and 24h	Additionally has Out-of-order data capability**	Passive redundancy Active for a limited period	Permanent, small	Low delay response	Server	10 Mb < X < 1 Gb	Every hour	Assisted configuration but with small Human changes	Partially autonomous, requires HM interaction in seldom cases
5	Warm safe mode more than 24h	Additionally has data encrypted	Fully redundant Always active	Permanent, large	No significant delay	Grid computing	> 1 Gb	Less than an hour	Auto-configuration	Fully autonomous, does not require any HM interaction

3.2.2. Upper bound analysis

The following subsections provide the outputs of the applied methodology to the NL demo. For mapping the numeric outputs of each subsection, Table 21 can be used as a mapping tool.
The upper bound analysis can be applied to the architectures of the French, Swedish and Dutch demos. From this architecture, the Dutch is selected for the analysis as it is considered as the most representative since it contains three use cases which are structured around the concept of flexibility aggregation and DSO-Aggregator connection. However, the other architectures also provide their contributions, through a questionnaire process, where their views are collected during the attributes identification & classification step in order to analyse if all share the same views since they belong to the same cluster, the upper bound. The results can be found in the annexes under section 7.3.2. With respect to the Dutch results, hereafter the different outputs for each of the previously explained steps are collected in the next subsections.

For the upper bound, the analysis focuses on the architecture deployed in UC3, which encompasses the other two use cases. This architecture is represented in Figure 78, which represents the SGAM component layer in addition to numeric layer for links identification.

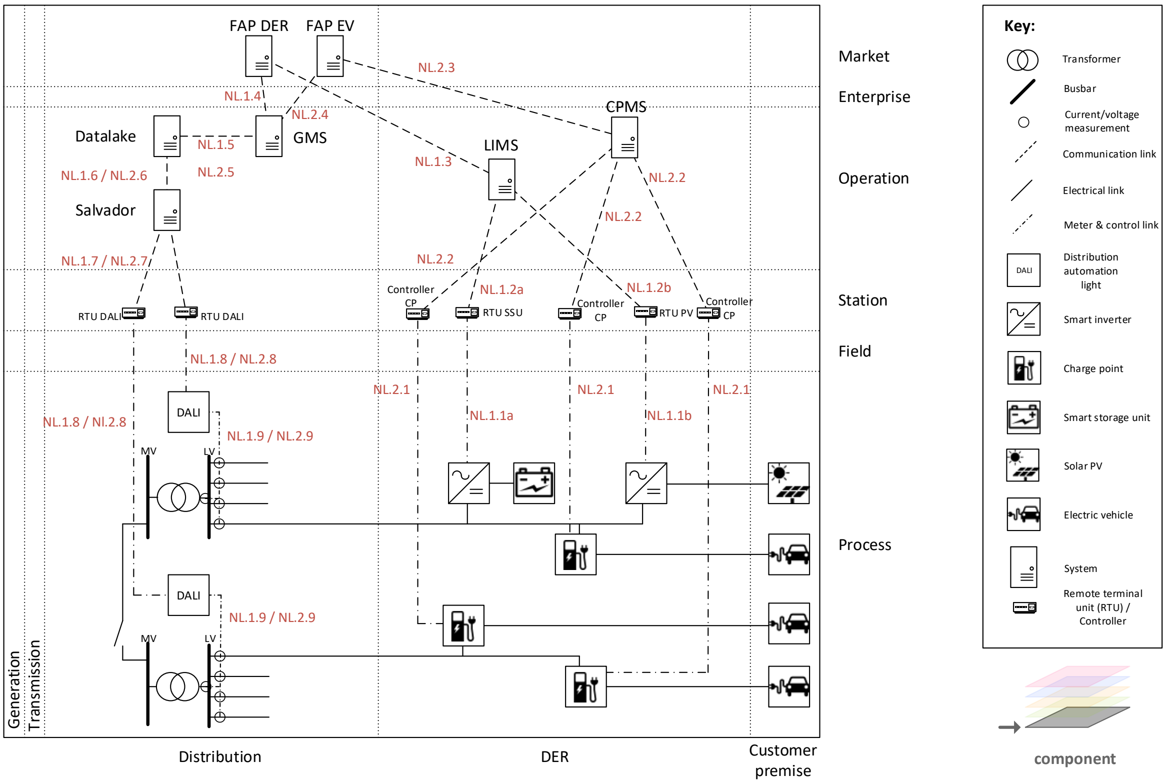

Figure 78: Upper Bound interface selection

Attributes evaluation output

Table 22 collects the upper bound results obtained over the assessment of the attributes in the upper bound architecture.

Table 22: Upper bound (NL-demo) attributes evaluation assessment results

Categories	Attributes	Expected Impact	Interest towards it	"Available information?
Reliability	Autonomy	Medium	Important	Limited
	Robustness	High	Very Important	Limited
	Redundancy	Medium	Very Important	Limited
Computational resources	Device Storage	Low	Not important	Yes
	Response time	High	Very Important	Limited
	Processing speed	High	Very Important	Limited
Manageability	Data volume	Medium	Important	Yes
	Data periodicity - How often	High	Very Important	Limited
	Configuration effort/complexity	Low	Important	Yes
	Automatization	Medium	Very Important	Limited

Architecture characterization outputs

Component

Table 23, collects the components characterization performed for the upper bound architecture.

Table 23: Component upper bound (NL) characterization

Component characterization		Component layer			
Component	Type	Autonomy	Redundancy	Configuration effort/complexity	Automatization
Dali	C-S[15]	2	2	3	4
RTU Dali	C-S	2	2	4	4
Salvador	C-S	3	3	5	3
Datalake	C-S	3	2	3	4
GMS	C-S	4	5	2	4
FAP DER	C-S	1	2	3	5
FAP EV	C-S	2	2	3	5
CPMS	C-S	3	3	4	4
LIMS	C-S	2	3	3	5
Controller CP	Server	2	1	4	5
RTU SSU	C-S	2	5	2	5
RTU PV	C-S	5	5	3	5
SSU inverter	C-S	2	5	2	5
PV inverter	Server	5	5	2	5
Charging Point (CP)	Server	2	1	1	5

[15] C-S: stands for client and server component type. For more detail, please consider the annexes.

Links

Links not applicable are due to, integrated circuits (NL.18/2.8 & NL2.1), serial communication (NL1.1b), which only targets the network protocol exchange. Table 24 shows the results obtained for the links characterization.

Table 24: Links upper bound (NL) characterization

Links	Network protocol layers			Application protocol layer		
ID	Robustness	Configuration effort/complexity	Automatization	Robustness	Configuration effort/complexity	Automatization
NL.1.1a	3	2	5	4	1	5
NL.1.1b	4	1	5	N.A.	N.A.	N.A.
NL.1.2a	5	3	5	4	2	5
NL.1.2b	5	3	5	4	2	5
NL.1.3	5	3	5	4	2	5
NL.1.4	3	2	5	4	3	4
NL.1.5	3	2	5	3	3	4
NL.1.6	4	2	4	4	3	4
NL.1.7	4	2	4	1	4	4
NL.1.8	N.A.	N.A.	N.A.	N.A.	N.A.	N.A.
NL.1.9	2	4	4	N.A.	N.A.	N.A.
NL.2.1	N.A.	N.A.	N.A.	N.A.	N.A.	N.A.
NL.2.2	4	3	5	2	2	4
NL.2.3	4	2	5	2	3	4
NL.2.4	3	2	5	4	3	4
NL.2.5	4	2	5	4	3	5
NL.2.6	4	2	4	4	3	4
NL.2.7	4	2	4	4	3	4
NL.2.8	N.A.	N.A.	N.A.	N.A.	N.A.	N.A.
NL.2.9	2	4	4	N.A.	N.A.	N.A.

Architecture capacity and requirement outputs

Components

The following tables represent the results obtained during the architecture capacity and requirement process. Their results are divided into two tables where Table 25 collects the data from the sender component (component "A"), while Table 26 collects the data for the receiver component (component "B).

Table 25: Components "A" - initiators (clients) assessment

Link	From	Maximum storage	Processing speed	Required storage	Data retention duration	Response time
NL.1.1a	RTU SSU	5	2	2	5	4
NL.1.1b	RTU PV	4	3	2	5	5
NL.1.2a	LIMS	5	4	5	5	5
NL.1.2b	LIMS	5	4	5	5	5
NL.1.3	FAP DER	5	4	4	5	5
NL.1.4	FAP DER	5	4	4	5	5
NL.1.5/2.5	GMS	4	4	4	5	4
NL.1.6/2.6	Datalake	5	5	3	5	5
NL.1.7/2.7	Salvador	5	5	3	5	5
NL.1.8/2.8	RTU Dali	4	2	3	5	5
NL.1.9/2.9	Dali	N.A.	N.A.	N.A.	N.A.	5
NL.2.1	Controller CP	4	1	1	1	5
NL.2.2	CPMS	5	4	3	5	4
NL.2.3	FAP EV	4	4	4	4	4
NL.2.4	FAP EV	4	4	4	4	4

Table 26: Component "B" - receiver (sever) assessment

Link	To	Processing speed	Response time to send the answer
NL.1.1a	SSU Inverter	3	4
NL.1.1b	PV Inverter	3	5
NL.1.2a	RTU SSU	2	5
NL.1.2b	RTU PV	1	5
NL.1.3	LIMS	4	5
NL.1.4	GMS	4	4
NL.1.5/2.5	Datalake	4	4
NL.1.6/2.6	Salvador	4	4
NL.1.7/2.7	RTU Dali	5	5
NL.1.8/2.8	Dali	4	2
NL.1.9/2.9	Lines	1	2
NL.2.1	CP	1	5
NL.2.2	Controller CP	1	4
NL.2.3	CPMS	4	4
NL.2.4	GMS	4	4

Links

The scores collected in Table 27, represent the results obtained in the characterization for the links' capacity and requirement tool.

Table 27: Links assessment

Link	Maximum bandwidth Kb/s	Maximum number of links	Network Data volume	Network Data periodicity	Application Data volume	Application Data periodicity
NL.1.1a	3	4	3	5	3	3
NL.1.1b	5	1	1	5	1	5
NL.1.2a	2	3	2	5	2	5
NL.1.2b	2	3	2	5	2	5
NL.1.3	3	5	3	5	3	5
NL.1.4	4	5	2	4	2	4
NL.1.5/2.5	4	2	3	1	3	1
NL.1.6/2.6	4	3	3	5	3	5
NL.1.7/2.7	4	5	2	5	2	5
NL.1.8/2.8	5	2	2	5	2	5
NL.1.9/2.9	5	2	2	5	2	5
NL.2.1	N.A.	N.A.	N.A.	N.A.	N.A.	N.A.
NL.2.2	2	5	1	5	1	5
NL.2.3	5	5	2	5	2	5
NL.2.4	4	2	2	4	2	4

Scenarios

In order to create scenarios to target the architecture and thus, the component and links from which it is composed, the architecture is first broken down into several subnetworks for subnetwork-branches identification. This helps track where there are subnetwork interconnections and follow the data paths. Then, the conception scenarios provide the context of how the system is most likely to scale (data sources, actors, etc.) and thus can be mapped to the subnetworks and branches, in order to see what (components & links) and where (subnetwork) are impacted.

The network breakdown is represented in Figure 79, where the three subnetworks which compose the entire network are highlighted. These networks are divided based on the main internal actors participating in such network, the DSO as system operator, the Aggregator as flexibility provider and the DERs as flexibility sources.

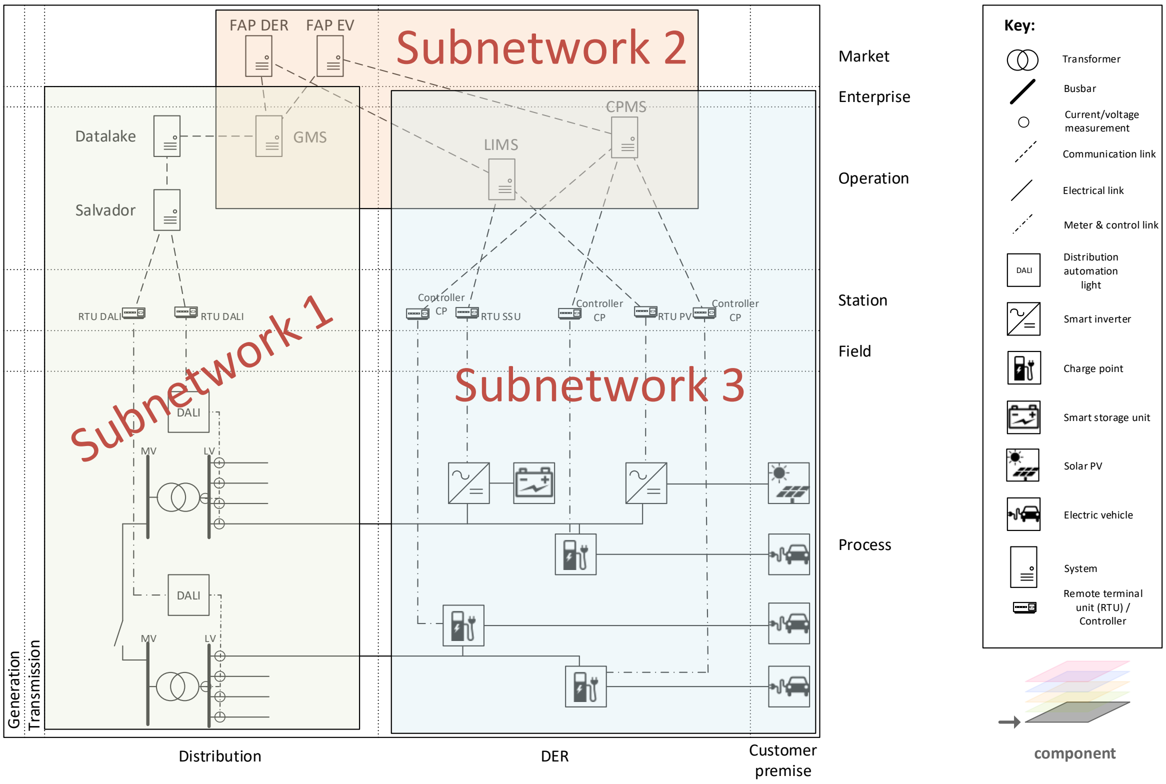

Figure 79: Upper Bound network decomposition

From the subnetwork-1 point of view, two possible scenarios might affect its network performance,

- __Scenario 1__: Increase of smart measuring points located either at the secondary substations at distribution level or at the congestion point created for the aggregators to connect to. This is supposed to provide a higher granularity which results in a deeper analysis, an improved overview and possible improved performance of the load forecasting system as there would be more data points. The subnetwork is based on the perspective of a single actor, the DSO.
- __Scenario 2__: Multiple aggregators at a commercial level are considered in this scenario. Each of which need to be linked with the DSO to send the D-prognosis and if selected activated their flexibilities when needed. These are activated through the technical aggregator. This is an increase of the main interface between the DSO and the commercial aggregators.

From the point of view of subnetwork 2-3, two scenarios can be considered that might have an impact into the network performance,

- **Scenario 3**: increase in the flexibilities (generation units – PV and load units-Public charging station) by scaling their current number.
- **Scenario 4**: introduce new type of flexibility into the system (wind turbine, household load, heat pump, etc.), which would be an additional source of flexibility for the system and a new connection for the local aggregator.

These scenarios can be mapped used Table 28 between the scenario, the interface-link which can be potentially affected and the subnetwork where it is located.

Table 28: Scenario - link interface mapping

Scenario	Interface-Link	Subnetwork
1-Measuring points	1.6/2.6, 1.7 / 2.7, 1.8. 2.8, 1.9/2.9	1
2-Number of aggregators	1.3/2.3, 1.4/2.4	1-2
3-Increase flexibilities	1.1a, 1.2a, 1.1b, 1.2b, 2.1, 2.2,	2-3
4-Introduce new flexibilities	1.1c[16]	2-3

Performance analysis

The analysis of this section considers the system performance under operation. This analysis observes two main operational timeframes. Firstly, the real time when the operation of the system has to be carried out instantaneously and secondly, the deferred operation, when the operation of the system can be carried out at a later time.

This is done as not all the different functionalities in the architecture have the same time resolution. Forecasting systems can rely on aggregated data to produce an output, while steering a flexibility or flexibility negotiation which has the necessity to be done instantaneously or with a small resolution time window (process should be fast).

In addition to this differentiation, it is also noted that this analysis covers an entire ICT architecture where all the systems are considered. However, these systems can be potentially aggregated into two major ICT clusters, the “ICT in the Operation/Market” SGAM zones and the “ICT in the Field” SGAM zone. This is represented in Figure 80.

[16] This link is not present in the SGAM. It is added following the numbering logic for the interfaces identification in the SGAM.

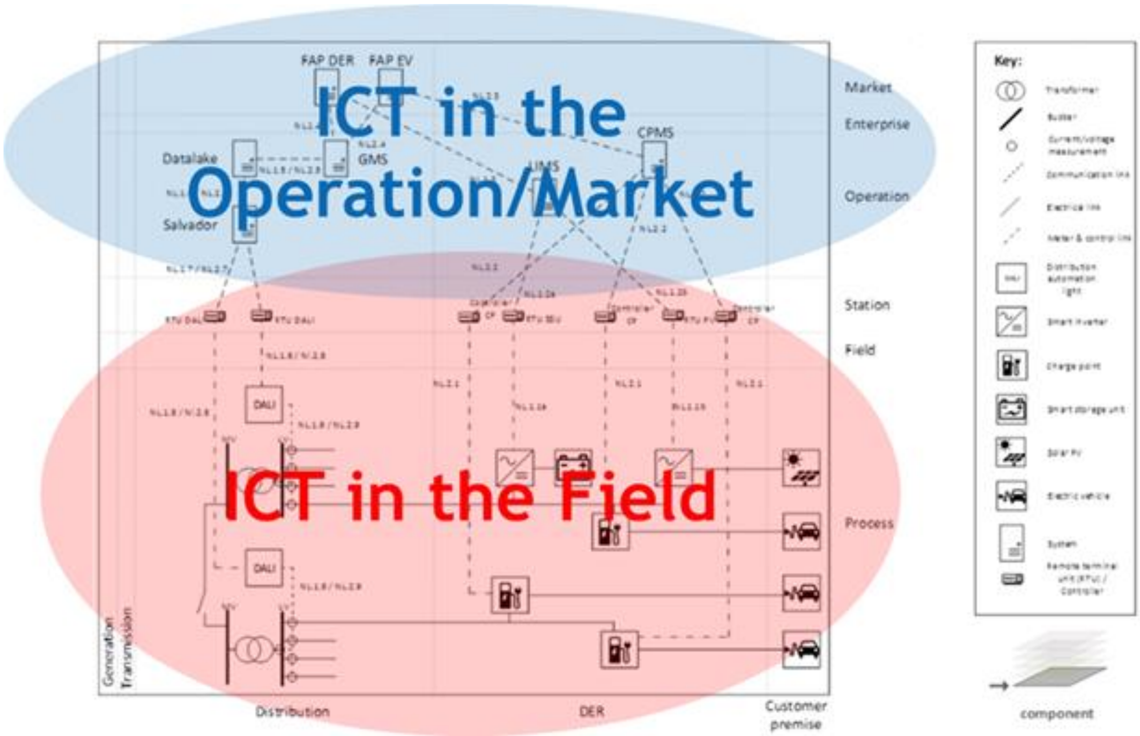

Figure 80: Time resolution and ICT operations

For each of the time resolutions (real time & deferred) the analysis studies the potential impacts upon the components and links. It considers those attributes which can be altered "by use" and are the ones considered at the Architecture capacity and requirement step.

Real time data

Real time data in the upper bound would mainly cover the higher frequency of exchange of data. For the upper bound architecture, the Dutch SGAM representation, would translate into intraday operation for flexibility activation. Even though this is not real time data to with per second resolution, the time window to operate is still inferior to the normal operation of day ahead (deferred operation).

Components

For those components, the main category affected regardless of the applied scenario to the architecture, is *computational resources* category. Here, the pre-requisite to keep performance regardless of their location in the SGAM (Operation/Market or Field) shall follow the following logic operation for *processing speed*,

$$Response\ time\ *\ Number\ of\ \ treatments\ <\ Processing\ speed$$

This due to the fact that the time resolution in this case brings in real data time operation. In such operation it is crucial that the entire system is able to cope with the increasing demand of processing data as the time resolution decreases. In other words, data which could be processed and decisions which could take up to 24h (day ahead), now have to be taken with a 15 min resolution or lower. Devices requested to push the data, will produce burst of data which the entire system has to process in less time. When analysing the results obtained, there are no potential constrains foreseen, although it cannot be fully guaranteed. This really depends on the applications which have to be verified according to the load of these applications in the components. It can only be guaranteed for the devices which follow a grid computing system structure as they can fully adapt to the workload change at any time. Nonetheless, it is necessary to remark that when checked, the priority shall be on the joint connection components which interconnect subnetworks, such as the RTUs. These usually run several applications at the same time and shall be correctly dimensioned.

Data storage at the component level, would not be so critical as the time to retain the data could potentially decrease since the data is always in continuous movement or moved within a higher frequency. However, bearing in mind that those components located at the Operation/Market zone will still require scalable storage systems as their functions usually required to retain data for longer periods.

Links

In case of the links, the category impacted is also the *computational resources*, as the streaming of data over the links will mainly require that the speed of transmission in addition to the bandwidth available are properly dimensioned for the services. Nonetheless, all the use cases targeted in the upper bound architecture, mainly depends on the number of clients to be served and connected. In this case, as well as in the other upper bound architectures, the links are mainly 1 to 1, which means that they are completely dedicated for them.

With respect of *bandwidth capacity* due to this reason of having 1 to 1 connection between the component, no concerns are foreseen in this regard.

With respect of the *speed* used to transmit the data, this can be impacted by the latency of the application and the network. This is reflected in the type of communication protocol chosen to interconnect the components. The more real time the application moves to, the higher the speed it would need in order to cover up for the possible latencies even though the data being transmitted is minimal.

Deferred operation

Deferred operation in the upper bound mainly targets how the system was conceived. Data would be aggregated, then services use this data for internal forecasting and later offers would be required by the DSO and complimented by the aggregators as their operation would be based on day-ahead operation and the time resolution is not that critical.

Components

For those components, similar to real time operation, *computational resources*, is the main category affected. The real challenge for the components is, that if any of the scenarios are to be applied, the ability to cope with the large volumes of data created.

Therefore, when analysing how the data can be used and treated, the same pre-requisite as in the real time operation that the *processing speed* has to be cross checked based on the response time needed. This is especially true for those components which act as junctions and main connections between the system such as the GMS, the FAP and the local aggregators.

With respect to the *storage*, this is a linear scaling process, since all of the connections are based on direct and unique connections. However, storage has to be dimensioned based on the data retention duration. In Table 29, a theoretical storage calculation considering the best and worst case is presented vs the available data. The exact numbers of the available storage for each comment which shall deal with storage is known by each owner. However, an approximation was done with the intention of showing potential numbers to consider.

Since the scaling is linear and data is increased with the addition of each new device into the system, components will have to check their limits based on the different scenarios
.

Table 29: Theoretical component storage calculation

Link	Component	Calculation Best (Mb)	Calculation Worst (Mb)	Available
NL.1.1a	RTU SSU	0.18	2.777777778	Permanent, large
NL.1.1b	RTU PV	0.00072	166.6666667	Permanent, small
NL.1.2a	LIMS	720	1.66667E+16	Permanent, large
NL.1.2b	LIMS	720	1.66667E+16	Permanent, large
NL.1.3	FAP DER	7.2	16666666667	Permanent, large
NL.1.4	FAP DER	3.6	555555555.6	Permanent, large
NL.1.5	GMS	0.05	11574074.07	Permanent, small
NL.1.6	Datalake	0.072	1666666.667	Permanent, large
NL.1.7	Salvador	0.072	1666666.667	Permanent, large
NL.1.8	RTU Dali	0.072	1666666.667	Permanent, small
NL.1.9	Dali	n.a		
NL.2.1	Controller CP	5.55556E-10	0.016666667	Permanent, small
NL.2.2	CPMS	0.072	1666666.667	Permanent, large
NL.2.3	FAP EV	2.4	16666666667	Permanent, small
NL.2.4	FAP EV	1.2	555555555.6	Permanent, small

Links

In case of the links, the category impacted is also the *computational resources*. The potential increase of data, regardless of the scenario applied will result in an increase of data transmitted through certain links (those which are affected in each conceptual scenario, as introduced in Table 28).

The potential impact to each of the links is collected in Table 30 which shows the best-case scenario and the worst-case scenario and the available bandwidth of the link. This calculation takes into consideration the following pre-requisite,

$$\left(\frac{Applicative_{volume}}{Applicative_{periodicity}}\right) + \left(\frac{Network_{protocol\,volume}}{Network_{protocol\,peridodicity}}\right) < Available_{bandwidth}$$

The best and worst-case scenarios are calculated through a translation of the scores obtained in the architecture capacity and requirement step. The lower limit of each score is considered as the best case and the upper limit of each score is considered as the worst case. This calculation, in addition, considers the use of the bandwidth for each link which connects a 1 to 1 component, with following results,

Table 30: Theoretical link bandwidth use calculation

Link	Calculation Best (Mbps)	Calculation Worst (Mbps)	Available bandwidth (Mbps)
NL.1.1a	0.0000694	0.169444444	0.1
NL.1.1b	0.0000000	3.33333E-05	1000
NL.1.2a	0.0000011	0.003333333	0.001
NL.1.2b	0.0000011	0.003333333	0.001
NL.1.3	0.0001111	0.333333333	0.1
NL.1.4	0.0000006	0.000111111	10
NL.1.5	0.0000008	0.000231481	10
NL.1.6	0.0001111	0.333333333	10
NL.1.7	0.0000011	0.003333333	10
NL.1.8	0.0000011	0.003333333	1000
NL.1.9	0.0000011	0.003333333	1000
NL.2.1	not relevant since it is integrated		
NL.2.2	0.0000000	3.33333E-05	0.001
NL.2.3	0.0000011	0.003333333	1000
NL.2.4	0.0000006	0.000111111	10

Upper bound conclusions

The following section provides a set of recommendations and pre-requisite rules to be considered when the architecture is scaled. These recommendations and pre-requisite are based on the analysis conducted in the previous sections covering the different steps of the methodology.

Each of the conclusions are broken-down according to the main categories *reliability*, *computational resources* and *manageability*.

For the upper bound, it is clear in this case that the system is well dimensioned, however the following set of recommendations and pre-requisites are to be considered when deploying the architecture at a later stage.

Reliability

The relevant attributes for *reliability* are the *autonomy*, *protocol robustness* and *redundancy*. Based on the obtained results during the characterization, capacity & requirement and the performance analysis, the following set of recommendations and pre-requisites are to be considered.

Considering the status of the components characterisation, the components which create the system architecture, do take care of the potential malfunctions of the system as most of them have fail-safe modes, which ensure continuous operation. This, in addition to the redundancy level added into certain components, creates a reliable system from the component side. If the system reliability needs to be maintained over the scaling process, the recommendation is to take the current characterization and at least those new components added to the system in order to keep the same logic as the ones implemented in the demo.

With respect of the links, their *protocol robustness*, most of the links do take care of the data to cope with imperfect data, which thus provides a smooth baseline to ensure safe operation in either real time or deferred operation as the end to end principal in the communication stack is considered and each part of the link (network and application) is treated in the correct manner. However, it is still recommended to the new protocols However, it is still recommended that if new protocols are implemented or if there is a migration to alternative protocols, then there is a need to focus on and analyse aspects such, as data integrity control, data repairing mechanism and retry mechanism. The main nodes where the links shall consider these aspects are in those which interconnect the different subnetworks as the data there is especially crucial as it has been already aggregated.

Computational resources

The relevant attributes for *computational resources* mainly focus on the components side by means of device *storage*, *response time* and *processing speed*. Based on the results obtained during the characterization, capacity & requirement and the performance analysis, these are the following set of recommendations and pre-requisites, are to be considered.

With regard of the components, the main points of view to be considered are the component processing for its operation and the data storage to be used within at each component.

For component processing, it is necessary to consider the response time, the number of treatments (specific to each application) and the processing speed of the processing speed of the component. This is dependent on the operation time (real or deferred) and the location of the component within the architecture network, more or less critical. In case of the upper bound those connections, which act as the main connection points between the architecture, have to be properly dimensioned as they are the ones treating high volumes of data. Since the upper bound architecture is divided in three subnetworks but managed by different actors these points of connection are based on components which are used (servers or which are already grid computing), creating no constraints when data process is increased regardless the potential scenario that can be applied. With respect to components at the field zone location in the SGAM, it is understandable not to be power houses (extremely powerful devices) as the cost of having these components at each connection would be unfeasible. Nonetheless, the recommendation is, when the system introduces new components, to consider the two time frames of operations of these components, as the functions will require so and to follow the pre-requisite for processing speed dimension of,

$$Response\ time\ *\ Number\ of\ \ treatments\ <\ Processing\ speed$$

For data storage, these changes, depending on the granularity of the functions within the system, can cause ICT field devices to not be properly dimensioned, as the system requires to have data buffers within it, based on the current system status. Although the calculations are only theoretical within the analysis, it is recommended to double check the technical specifications of the field devices as, once largely deployed, their upgradability might be complicated. In case of the upper bound, large volumes of data aggregated are not to be massively expected due to the modularity of the system since it is a combination of different actors working in synergy.

Manageability

The relevant attributes for *manageability* are divided in two main parts, data itself (**Data**, *volume* & *Data periodicity*) and the system integration of its components and links (complexity and automatization). Based on the results obtained during the characterization, capacity & requirement and the performance analysis, these are the following set of recommendations and pre-requisites to be considered.

Managing such a multi-actor system implies the maintenance of adequate communication and reliable communications (which they are) among the different actors. The concept of having a 1 to 1 link communication system between most of the components and even actors, provides a solution where the data, if increased, will have the entire bandwidth capacity to push the data. No matter the type of operation, it is recommended that when new components are introducted and to the links which connect them to properly choose the requirements based on the demo ones, as they show no constraint in this aspect.

The manner in which this data transmission is managed in addition to how the links are operated, can create potential bottlenecks within the system during its operation. However, since this is a multi-actor system, the complexity of system integration of the links and components used is reduced. Additionally, this is helped by having a high level of automation where the system can be autonomously operated with the technical supervision to ensure correct operation.

3.2.3. Lower bound analysis

Similar to the upper bound analysis since it is used as reference model. The lower bound analysis follows the same approach to that of the upper bound and considers the following architecture as the lower bound main representative, the German architecture. To be remarked that the Czech architecture (depending on the use case), even though it could be considered as lower bound, is not included as previously explained.

The lower bound main characteristics is that it creates a direct communication between the customer and the DSO providing the DSO flexibility and control over the best flexibilities needed for operation by the DSO. This operation is reflected in the three use cases from the German demo, which uses the same architecture principal, but different endpoints connected to the control box which is the device which enables DSO controllability. Hence the analysis focuses on the architecture deployed in UC3, encompasses the other use cases into one. This architecture is represented in Figure 81 by the SGAM Component layer, which adds on top a numeric layer for link identification.

For the upper bound, the analysis focuses on the architecture deployed in UC3, which encompasses the other two use cases. This architecture is represented in Figure 81, which represents the SGAM component layer in addition to numeric layer for links identification.

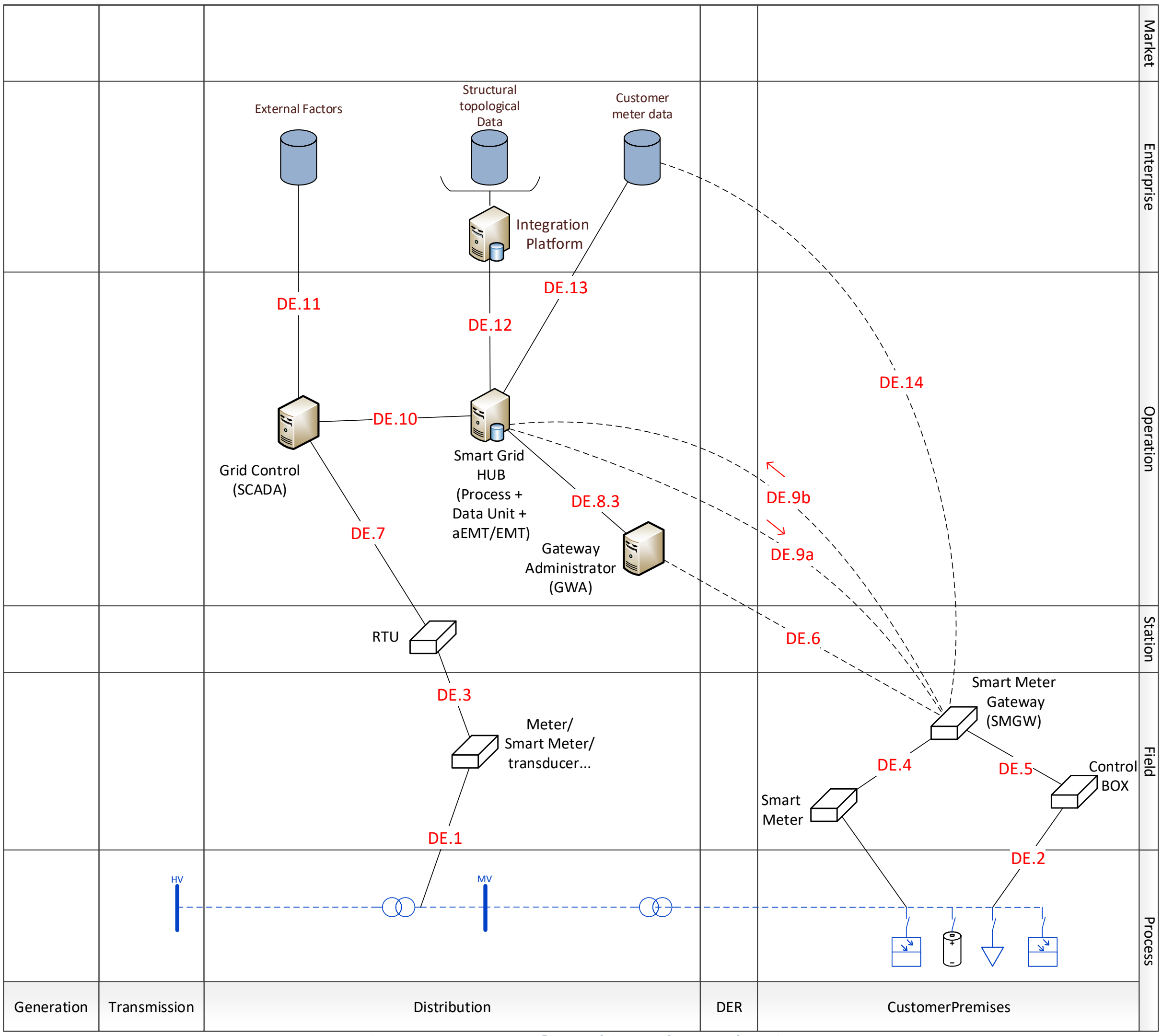

Figure 81: Upper Bound interface selection

Attributes evaluation output

Table 31 collects the lower bound results obtained over the assessment of the attributes in the upper bound architecture, as done with the upper bound.

Table 31: Lower bound (DE-demo) attributes evaluation assessment results

Categories	Attributes	Expected Impact	Interest towards it	"Available information?
Reliability	Autonomy	Medium	Not important	Limited
	Robustness	High	Important	Limited
	Redundancy	Medium	Important	Limited
Computational resources	Device Storage	High	Important	Yes
	Response time	High	Very Important	Yes
	Processing speed	High	Important	Limited
Manageability	Data volume	Medium	Important	No
	Data periodicity - How often	High	Very Important	Yes
	Configuration effort/complexity	Medium	Not important	Limited
	Automatization	High	Important	Yes

Architecture characterization outputs

Component

Table 32, collects the components characterization performed for the lower bound architecture
.

Table 32: Component lower bound (DE) characterization

Component characterization		Component layer			
Component	Type	Autonomy	Redundancy	Configuration effort/complexity	Automatization
Substation	C-S[17]	4	2	2	5
Control box	C-S	5	1	2	5
Meter/SM[18]/Transducer	Server	4	1	2	5
Smart Meter	Server	3	1	2	5
Smart Meter Gateway	C-S	3	1	2	5
Gateway administrator	C-S	5	5	5	5
RTU	C-S	4	1	1	5
Smart Grid Hub	C-S	5	5	5	2
Grid Control (SCADA)	C-S	5	5	5	3
External Factors	Server	2	1	1	5
Integration platform	Server	2	1	1	5
Customer meter data	Server	5	5	1	5

[17] C-S: stands for client and server component type. For more detail, please consider the annexes.
[18] SM: Smart Meter

Links

Table 33, presents the scores obtained in the characterization tool for the lower bound architecture.

Table 33: Links lower bound (DE) characterization

Links	Network protocol layers			Application protocol layer		
ID	Robustness	Configuration effort/complexity	Automatization	Robustness	Configuration effort/complexity	Automatization
DE.1	1	1	5	1	1	5
DE.2	1	1	5	1	1	5
DE.3	1	1	5	1	1	5
DE.4	5	3	5	5	3	5
DE.5	1	1	5	1	1	5
DE.6	5	3	5	5	3	5
DE.7	1	1	5	1	1	5
DE.8	5	3	3	5	3	3
DE.9a	5	3	3	5	3	3
DE.9b	5	3	3	5	3	3
DE.10	5	2	2	5	2	2
DE.11	1	4	3	1	4	3
DE.12	1	4	3	1	4	3
DE.13	5	4	3	5	4	3
DE.14	5	3	5	5	3	5

Architecture capacity and requirement outputs

Components

The following tables represent the results obtained during the architecture capacity and requirement process. Their results are divided into two tables where Table 34 collects the data from the sender component (component “A”), while Table 35 collects the data for the receiver component (component “B).

Table 34: Components "A" - initiators(clients) assessment

Link	From	Maximum storage	Processing speed	Required storage	Data retention duration	Response time
DE.1	Meter/SM/Transducer	2	1	2	4	3
DE.2	Control box	2	1	2	5	4
DE.3	RTU	2	1	2	1	4
DE.4	Smart Meter Gateway	3	2	3	5	3
DE.5	Smart Meter Gateway	3	2	3	5	3
DE.6	Gateway administrator	5	5	5	5	5
DE.7	Grid Control (SCADA)	5	5	5	5	5
DE.8	Smart Grid Hub	5	5	5	5	5
DE.9a	Smart Grid Hub	5	5	5	5	5
DE.9b	Smart Meter Gateway	3	2	3	5	3
DE.10	Grid Control (SCADA)	5	5	5	5	5
DE.11	Grid Control (SCADA)	5	5	5	5	5
DE.12	Integration platform	5	4	5	5	5
DE.13	Smart Grid Hub	5	5	5	5	5
DE.14	Smart Meter Gateway	3	2	3	5	3

Table 35: Component "B" - receiver (sever) assessment

Link	To	Processing speed	Response time to send the answer
DE.1	Substation	2	5
DE.2	load	1	5
DE.3	Meter/SM/Transducer	1	5
DE.4	Smart Meter	1	4
DE.5	Control box	1	4
DE.6	Smart Meter Gateway	2	3
DE.7	RTU	1	5
DE.8	Gateway administrator	5	5
DE.9a	Smart Meter Gateway	2	3
DE.9b	Smart Grid Hub	5	5
DE.10	Smart Grid Hub	5	5
DE.11	External Factors	4	4
DE.12	Smart Grid Hub	5	5
DE.13	Customer meter data	4	5
DE.14	Customer meter data	4	5

Links

The scores collected in Table 36, represent the results obtained in the characterization for the links' capacity and requirement tool.

Table 36: Links assessment lower bound

Link	Maximum bandwidth Kb/s	Maximum number of links	Network Data volume	Network Data periodicity	Application Data volume	Application Data periodicity
DE.1	1	1	1	5	1	5
DE.2	1	1	1	5	1	5
DE.3	1	1	1	5	1	5
DE.4	2	1	1	5	1	5
DE.5	1	1	1	5	1	5
DE.6	2	5	1	5	1	5
DE.7	1	5	1	5	1	5
DE.8	2	2	2	5	2	5
DE.9a	2	5	1	5	1	5
DE.9b	2	1	2	5	2	5
DE.10	2	1	2	5	2	5
DE.11	2	2	3	5	3	5
DE.12	2	1	4	2	4	2
DE.13	2	1	3	2	3	2
DE.14	2	1	2	2	2	2

Scenarios

Similar to the upper bound case, conceptual scenarios are created in order to provide some context for the potential scaling of the system and its possible impact into the different components and links which play a part in the lower bound architecture.

The similar concept of breaking down the network into subnetworks is done, in order to create possible smaller clusters to see which subnetworks and branches (links) will be affected under a system scaling of its components. For the lower bound, since there is no market connection to any aggregator, the increase of participants (actors) can only be done through the increase of flexibilities (components) as there cannot be an there can only be one DSO per network

The network breakdown is represented in Figure 82, where the three subnetworks which compose the entire network are highlighted. These networks are derived based on the main internal functions which can be found, where the data gathering, subnetwork 1, the decision taken, subnetwork 2 and the flexibility steering, subnetwork 3 takes place. It is interesting to observe that both the upper bound or the lower bound, even under different points of view, result in a similar network decomposition.

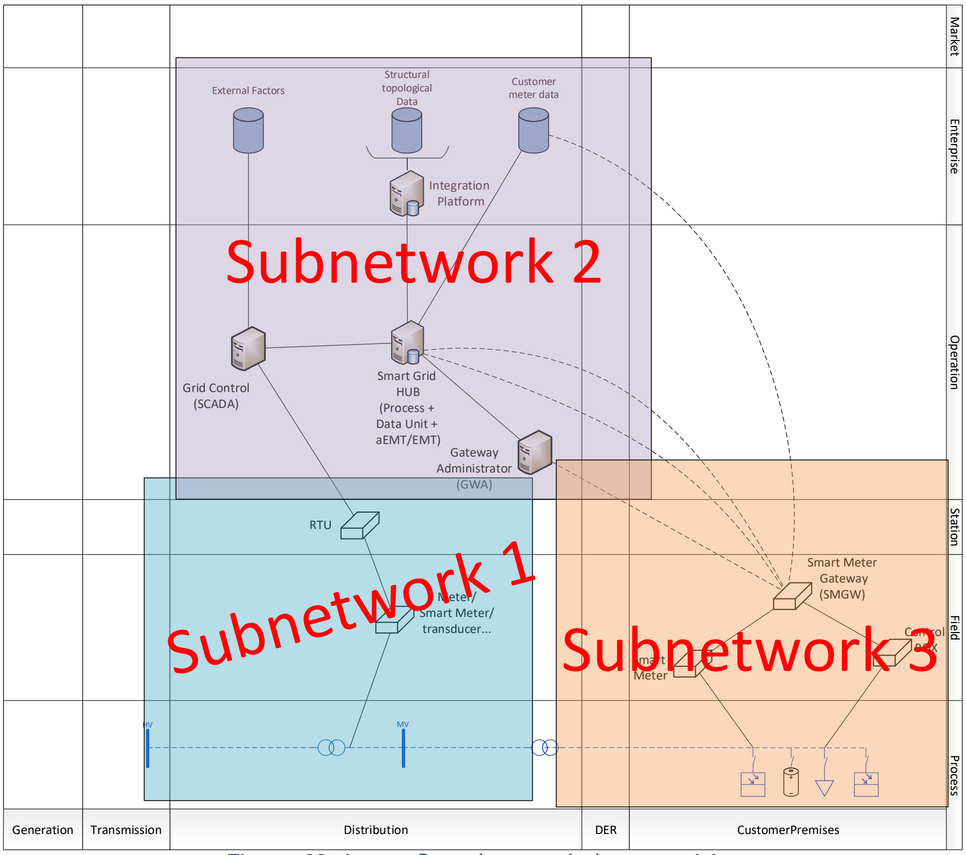

Figure 82: Lower Bound network decomposition

From the subnetwork-1-2 point of view, two possible scenarios are considered that might affect its network performance,

- <u>**Scenario 1**</u>: Increase of smart measuring points located either at the secondary substations at distribution level or at the feeder level in case a higher granularity is needed by the DSO. This would affect subnetwork 1-2.

- **Scenario 2**: increase of the internal data exchange for the Smart Grid Hub where the forecasting process and data units calculate where and how the flexibilities have to be activated/deactivated. More information regarding the functionalities of the Smart grid hub can be found in several deliverables, such as D5.3, D5.4, D5.6. this would affect subnetwork 3 only.

From the point of view of network 2-3, two scenarios can be considered that might have an impact on the network performance as in reality it affects both networks as they are interconnected

- **Scenario 3**: increase on the flexibilities as more customers which are able to be controlled are included, this would add new points to consider in the algorithms but also would increase the data stream into the DSO. This would affect subnetwork 2-3.
- **Scenario 4**: inclusion of new flexibility types as then the SGH would deal with a bigger data volume. This would affect subnetwork 2-3.

These scenarios can be mapped using Table 37 between the scenario, the interface-link which is can be potentially affected and the subnetwork where it is found.

Table 37: Scenario - link interface mapping

Scenario	Interface-Link	Subnetwork
1: Measuring Points	1, 3, 7	1 - 2
2: Internal tools	10, 12, 13	2
3: New customers	2, 4, 5, 6, 9a, 9b, 14	2-3
4: New flexibilities	2, 4, 5, 6, 9a, 9b, 14	2-3

Performance analysis

The analysis done under the lower bound is equal to the upper bound since, the architecture decomposition is similar; the entire architecture is covered and for the time resolution which the system can operated.

Under operation, the nominal operation is based on deferred operation as the time resolution is higher than real time since it targets day ahead operation. However, the system can move towards real time operation if needed.

For each of the time resolutions (real time & deferred) the analysis studies the potential impacts into the components and links taking into consideration those attributes which can be altered “by use” as the scenarios would be applied. Those attributes are the ones considered at the Architecture capacity and requirement step.

Although the entire architecture is targeted, the components can be clustered anew in two main clusters as represented in Figure 83, for which later set of recommendations can be made. These clusters are the “ICT in the Operation/Enterprise” covering the SGAM Enterprise and Operation zone and the “ICT in the Field” covering the Station and Field SGAM zones.

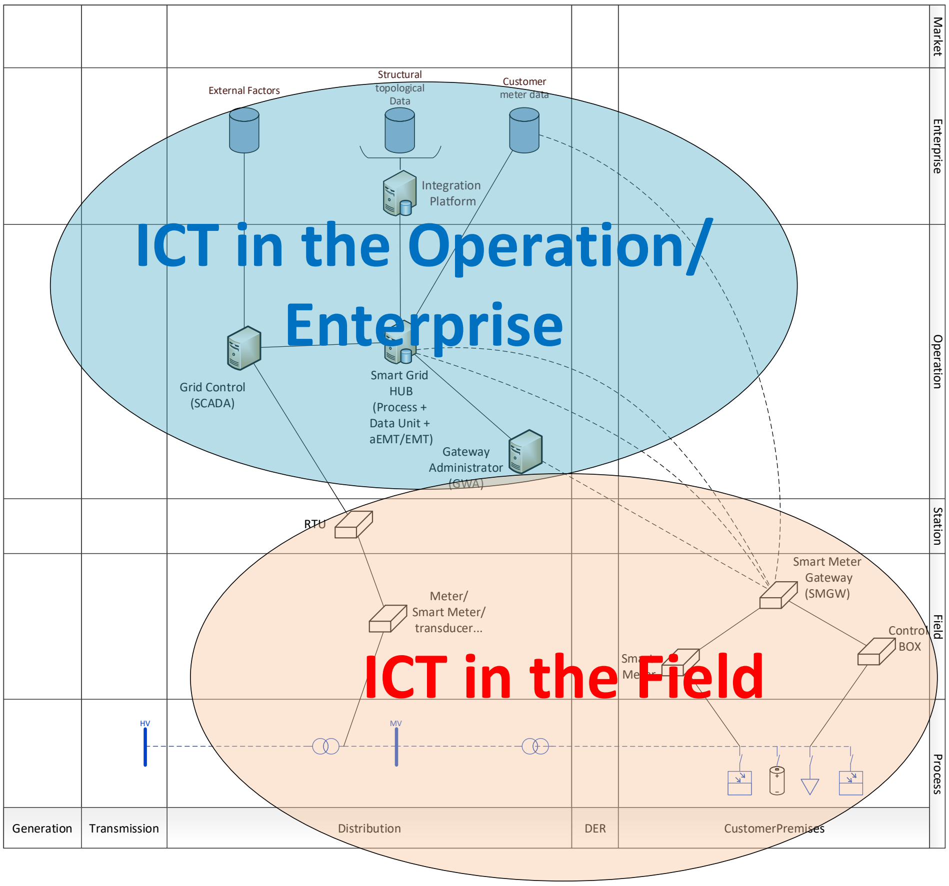

Figure 83: Time resolution and ICT operations

Real time data

Real time data, it is not conceived how the UC are stated. However, since the architecture is the same for any type of operation, this means that the architecture can potentially be used if there is a change of operation time and move towards real time operation as data streaming of the smart meters up to the DSO for data monitoring or the participation of intraday steering of assets.

Components

From the component point of view, when considering the performance, this is reflected in the *computational resources*, hence the same equation exposed for the upper bound. In this case it has to be considered regardless of the scenario, as for real time data it would require components to process data as fast as possible. Such equation to keep the performance demand satisfied is,

$$Response\ time\ *\ Number\ of\ \ treatments\ <\ Processing\ speed$$

Links

In case of the links, for real time operation the *computational resources* in this case the link capacity and speed of transmission based on the communication technology chosen does not really impose any potential constraints.

The chosen communication technologies already include technologies such as LTE/4G which guarantees a scalability process to real time data. Nonetheless, the main issue with new and more powerful technologies, is the coverage of them. An older technology like GSM can have a better coverage, however, it would not be able to support newer technologies as sufficiently where scalability processes and operations are shifted to real time.

In addition, all of the links are considered have a 1 to 1 relation between components, therefore, no medium is “shared” as with technologies like PLC, reducing the channel capacity, which in this case is individually dedicated.

Deferred operation

This mode of operation is the main one which architecture is conceived for. Since there is no data aggregation done by any third party, all the data generated, is directly shared with the DSO through the Smart Meter Gateway, key point of interconnection between the different subnetworks (2-3).

Components

The main challenge for the components once again for the deferred operation is based on the *storage* of the data generated and being retained over their “*data retention duration*”. The storages needed is calculated using the theoretical calculation approximation whose results are collected in Table 38.

Since the scaling is linear, the more data points added, the more data exchange in the internal functions. New flexibilities added or the new customer which have flexibilities, results in a data increase. Hence, the technical specification which of the components shall be checked when considering the large scale deployment of such a system, especially since the manager of this architecture only falls mainly into one actor, the DSO, which owns all the components represented in the architecture.

Table 38: Theoretical component storage calculation

Link	Component	Calculation Best (Mb)	Calculation Worst (Mb)	Available
DE.1	Meter/SM/Transducer	0.24	144	Volatile, small but fast
DE.2	Control box	0.72	288	Volatile, small but fast
DE.3	RTU	5.55556E-05	0.1	Volatile, small but fast
DE.4	Smart Meter Gateway	72	28800	Volatile, large and fast
DE.5	Smart Meter Gateway	72	28800	Volatile, large and fast
DE.6	Gateway administrator	720000	2880000000	Permanent, large
DE.7	Grid Control (SCADA)	720000	2880000000	Permanent, large
DE.8	Smart Grid Hub	720000	2880000000	Permanent, large
DE.9a	Smart Grid Hub	720000	2880000000	Permanent, large
DE.9b	Smart Meter Gateway	72	28800	Volatile, large and fast
DE.10	Grid Control (SCADA)	720000	2880000000	Permanent, large
DE.11	Grid Control (SCADA)	720000	2880000000	Permanent, large
DE.12	Integration platform	15000	4000000	Permanent, large
DE.13	Smart Grid Hub	15000	4000000	Permanent, large
DE.14	Smart Meter Gateway	1.5	40	Volatile, large and fast

Links

The impact of the increasing data based on the conceptual scenarios for the lower bound, also needs to check even though all the connections are dedicated the bandwidth for analysis completion, using the following calculation whose results are collected in Table 39.

$$\left(\frac{Applicative_{volume}}{Applicative_{periodicity}}\right) + \left(\frac{Network_{protocol\ volume}}{Network_{protocol\ peridodicity}}\right) < Available_{bandwidth}$$

Table 39: Theoretical link bandwidth use calculation

Link	Calculation Best (Mbps)	Calculation Worst (Mbps)	Available bandwidth (Mbps)
NL.1.1a	0.0000000011	0.0000333333	1
NL.1.1b	0.0000000011	0.0000333333	1
NL.1.2a	0.0000000011	0.0000333333	1
NL.1.2b	0.0000000011	0.0000333333	1000
NL.1.3	0.0000000011	0.0000333333	1
NL.1.4	0.0000000011	0.0000333333	1000
NL.1.5	0.0000000011	0.0000333333	1
NL.1.6	0.0000011111	0.0033333333	1000
NL.1.7	0.0000000011	0.0000333333	1000
NL.1.8	0.0000011111	0.0033333333	1000
NL.1.9	0.0000011111	0.0033333333	1000
NL.2.1	0.0001111111	0.3333333333	1000
NL.2.2	0.0002314815	0.0462962963	1000
NL.2.3	0.0000023148	0.0004629630	1000
NL.2.4	0.0000000231	0.0000046296	1000

Lower bound conclusions

The following section provides a set of recommendations and pre-requisite rules to be considered when the architecture is scaled based on the analysis conducted in the previous sections covering the different steps of the methodology.

Each of the conclusions are broken-down to the main categories as the analysis is conducted by category considered, *reliability*, *computational resources* and *manageability*.

For the lower bound, it is clear in this case that the system is well dimensioned, however the following set of recommendations and pre-requisites when deploying the architecture at a larger scale and later stage, shall be considered.

Reliability

The relevant attributes for *reliability* are the *autonomy*, *protocol robustness* and *redundancy*. Based on the obtained results during the characterization, capacity & requirement and the performance analysis, these are the following set of recommendations and pre-requisites, to be considered.

Most of the components are dimensioned with a sufficient *autonomy* which takes care of data backups in case there is a service problem. Therefore, the *redundancy* found with the setup is coherent. This implies that a system scaling, regardless of the scenario, its scaling has to follow the pre-requisite for real time and deferred operation to actively change the fail-safe capabilities of the new devices installed. They shall take as a baseline the technical details of the components which are already deployed within the demo.

With respect to the links, which their main attribute is the *protocol robustness*, clearly shows that the system already is ensuring a proper performance when the system is under stressful environments. The set of recommendations is to check for both, real time and deferred operation, since the data transmission has to be ensured regardless of the operation, as concepts such as, data integrity, data repairing mechanism, nominal and degraded functioning mode in a restricted time and retry mechanism. These aspects shall be considered at all links level, but especially for those based at the connection nodes, such as the Smart Meter Gateway or the gateway administrator, since here the data is crucial to ensure a proper transmission.

Computational resources

The relevant attributes for *computational resources* are *device storage*, *response time* and *processing speed*. Based on the results obtained during the characterization, capacity and requirement and the performance analysis, these are the following set of recommendations and pre-requisites, to be considered.

With regard of the components, two points of view have to be considered.

On the one hand for the component processing, with *response time*, number of treatments and *processing speed* attributes for both real time and deferred operation the recommendation in order to ensure a proper performance as the system is scaled. This can be done by new components and by stressing the current ones with more data to be processed. The recommendation is to, correctly dimension the capabilities (RAM, RAID management, etc.) of the Smart Meter Gateway Administrator by considering a potential increase in the data flow which has to be processed at the customer side, since once deployed, it would require a higher investment to upscale if needed.

With respect to the control box, as it is a following device (slave), the dimension of the current version is more than capable to cope with a system scaling as it mainly function is to follow control orders for the activations. The case of the Gateway Administrator and the SGH is where the DSO should follow the recommendation into grid computing investment where the services are located in auto-scalable devices which adapt to the load demand in each type. An increase of data either comes from more data points at the distribution level meter or flexibilities will require a higher capacity of calculation. This also can be optimized by the algorithms at the SGH and at the Gateway to open new channels. This is as it stands and has been dimensioned for a deferred operation which is not critical, as the time window is not close to provoke any constraints, however, this shall be taken into consideration.

For all the cases the pre-requisite for correctly dimension to be considered shall be based on the following equation,

$$Response\ time\ *\ Number\ of\ \ treatments\ <\ Processing\ speed$$

On the other hand, the main issue of the system scaling will face is *data storage*. Again, the recommendations for both operations (real time and deferred operation), since the system requires a certain data retention is to properly dimension the storage systems as new data will be fed into the system. This dimension is especially necessary in those cases where the components are going to be deployed at the field level. Once they shall be at a large scale deployed, the investment of upgrading them can be costly for the system operator[19]. Therefore, the pre-requisite for when the system upscaling in terms of components which will generate data, is to consider the following,

$$Required\ storage\ *\ \ Retention\ duration/\ Application\_periodicity\ \ <\ Available\ storage$$

[19] Economics of the system are treated at D3.9

Manageability

The relevant attributes for *manageability* are divided in two main parts, data itself (*Data, volume* & *Data periodicity*) and the system integration of its components and links (complexity and automatization). Based on the obtained results during the characterization, capacity & requirement and the performance analysis, these are the following set of recommendations and pre-requisites, to be considered.

With respect of the data itself, the increase of it is based on the scale up of data sources, this in reality is not a challenge to how the data is transmitted. Transmission capacity is well dimensioned and additionally the links are based on a 1 to 1 relationship, providing the entire bandwidth capacity to the link. However, it is necessary to be considered when adding new data sources, the following pre-requisite especially in deferred operation as the data will be transmitted and handle in burst,

$$\left(\frac{Applicative_{volume}}{Applicative_{periodicity}}\right) + \left(\frac{Network_{protocol\,volume}}{Network_{protocol\,peridodicity}}\right) < Available_{bandwidth}$$

How this data will be transmitted, is based on the communication technologies, which as seen during the architecture characterization, which the recommendation is to follow the proper dimensioning and future proof technologies as 4G/LTE as when the system data scale is considered, the architecture already is able to manage such an increase. When this is not possible due to location constraints other technologies shall be considered, such as PLC but with the consideration, the bandwidth will be shared among the users. Nonetheless, the positive feature of such technologies is as the system scales, the coverage increases. Each new customer will act as an amplifier (daisy chain) hence the converge can increase ad signal damping reduced.

With respect of the system integration of the components and links, the system as mainly handled by the DSO is based in certain business as usual processes, which lower the configuration and complexity of handling the system in addition to their high degree of *automation*. The set of recommendations is that *automation* and especially scheduling for operation shall help the system to be at a manageable stable situation. When increasing the different components based either at measuring points or flexibilities, it is necessary that the systems still needs to move towards the plug and play solution based on a low complexity and high automatization systems. This would result, in the DSO being able to incorporate more potential customers, with a less effort but also maintain the performance as the system can operate on its own.

3.2.4. ICT conclusions

Although the analysis has been derived in clusters, the methodology applied to it has been consistent in providing a good opportunity for comparison between the cluster architectures.

It is interesting to observe that despite the conducted analysis performed by grouping the architectures into two clusters, the outcomes of the analysis are quite similar. Both clusters have the same end goal, which is flexibility activation. The subnetwork analysis breakdown is an example of how similar these architectures are. Three main subnetworks are found within the architectures as the connection of the devices are identical with the caveat of the path followed. The upper bound triggers the activations from a market and operational perspective including different actors in the process, whereas the lower bound activates the flexibilities from an operation perspective all under the same actor, namely the DSO.

This activation behaviour proves that the system management is in one case shared among the different actors included in the architecture, upper bound, while in the lower bound the responsibility completely resides in the network operator. Hence, moving towards a plug and play system where new devices are integrated with a low level of complexity and effort based on automatization tools, will ensure a proper the scaling-up of the system. This observation is corroborated by the results obtained for the qualitative analysis.

The results obtained over the qualitative analysis where the performance is also checked, concludes, in a qualitative way, that the system conception in these demos, is able to provide the desired output, scalable architectures. However, as mentioned during the analysis, it is advised to consider the different internal recommendations and pre-requisites provided for each of the aspects covered, such as bandwidth, storage, processing, etc.

The main challenge for both of the systems, potentially can be found with the data storage as in the large scale scenario. Indeed, the requirements of the actors can have an impact on the amount of data which has to be stored at certain points, especially the connection points between subnetworks. This challenge might become a concern mainly to those components which are at the Field level (SGAM zone), as once they are largely deployed and the functions on top of the components start to request more data, could require a component-upgrade if they were not correctly dimensioned over the process of this demonstrations. With the data gathered in this analysis and especially with the different lessons learned over the period of the project, if these architectures are deployed, the system configuration can be almost perfectly adequate to the future use cases although it is correctly dimension for the current one.

Finally, it cannot be stated that one architecture is better than the other one, as this completely depends on the set up of actors and the use cases which are implemented and how the need to be implemented. Nonetheless, this is a positive result as there is a choice of architectures and not a unique one, where both architectures are scalable and have similar scaling behaviour as exposed during the analysis.

4. Non-technical scalability and replicability analysis

4.1. Regulatory scalability and replicability analysis

The aim of the non-technical scalability and replicability analysis is to conduct a comparative study of the current situation related to the use of flexibilities on a local scale, in the EU InterFlex participating countries: Germany, the Czech Republic, the Netherlands, Sweden, France and Austria. The main topics of interest are the following: regulation, standardization, user acceptance, business models for distributed generation (DG), and the DSO quality of service in the presence of flexibilities. Each sub-section of section 4 is dedicated to one of these topics and defines the key issues, regulatory barriers and provides some recommendations.

4.1.1. Participation of flexibilities in network services: storage, DG and active demand

Firstly, in the frame of the SRA it is important to identify the current state of development of flexibilities and their use on the local distribution level. Therefore, this section is dedicated to the participation of flexibilities in network services, types of contracts existing between DSOs and flexibility providers, and the influence of the Clean Energy Package (CEP) and similar EU energy directives on national standards for the use of flexibilities in InterFlex participating countries.

In Germany the DSO has the right to carry out curtailment directly only under certain critical conditions (a similar situation is observed in France, whereas the need for curtailment is not as challenging as in Germany). Renewable energy producers in Germany have a legal obligation to offer controllability to the DSO and to participate in curtailment schemes; there are no incentives, but all producers under the feed-in tariff scheme (EEG) are reimbursed by the DSO for all production losses. For flexible loads, there is a contractual option to offer interruptible loads to the DSO in exchange for reduced grid charges. However, the details of this mechanism will only be described and are expected to be clarified in statutory law by 2020/2021. There is another national initiative to develop the curtailment mechanism further towards a market-based approach. Finally, regarding the influence of the CEP and similar EU energy directives on German national standards for the use of flexibilities, the CEP does not yet significantly affect flex mechanisms, and it is too early to provide any conclusions on the future regulation.

In the Czech Republic, the DSO has access to the flexibility unit's generation and consumption profiles for grid operation purposes. Curtailment of generation is used only in case of emergency (without any remuneration). As in many other countries (e.g., France) control of consumption (demand response) is used on a daily basis with LV grid customers under the historical double-tariff scheme (essentially thermal residential loads such as electric heating, water boilers or heat pumps are switched off during on-peak hours). Customers under this double tariff scheme have significant discounts on energy tariffs because they are providing flexibility (comparable demand respond schemes have been set up in various countries to address historical balance issues, to maximize the use of cheap production means and optimize temporary variations in the power availability-consumption balance). Flexibility owners are not obliged by the regulation to provide their services, it is optional.
In the case of the Netherlands, flexibility services provided to DSOs are today limited to experimental set-ups and pilot projects. There is a lack of favourable regulation, and consumers are not allowed to provide such services. The positive trend is that different pilot

projects on the use of flexibilities already consider the CEP requirements and studies are carried out by DSOs to suggest regulatory improvements in the future including CEP aspects. Regarding the Swedish flexibility market, there are some local flexibility services, and the DSOs own metering devices at the connection point and have access to the metering data (with different time resolution). Consequently, while respecting applicable data privacy rules the DSO is able to create generation/consumption profiles for grid operation purposes, which might result in more accurate models and be customized for different areas. Today, the DSO uses bilateral contracts for production and consumption steering, but in the near future, aggregators will be included to mediate between the flexibility services. Flexibility owners have no obligation to provide their services, and contracts are stipulated based on civil law agreements. Finally, in Sweden there is a visible impact of European directives on the local regulations. Thus, on November 20, 2019, The Swedish Energy Inspectorate was expected to present the result from the ongoing inquiry as to how the CEP will be implemented within the Swedish law. For example, it is expected to be clarified whether it will be mandatory in future for grid planning to take into consideration the available flexibility services as an alternative to today's traditional grid investments. The EU Network Codes (for example the Network Demand Connection Code (DCC) and Requirements for Generators (RfG)) stipulate different criteria for connection to the grid. Consequently, in the future Sweden expects significant modification of conventional regulatory framework, and the change of the status quo of flexibilities. In Sweden the need for grid capacity has increased dramatically due to the political goal of 100% renewable production by 2040, and also due to new electricity intensive industries (e.g. data centres), electrical vehicles and urbanization. Currently in Sweden there are existing capacity constraints in the transmission grid due to generation in the north and loads in the south, which will take many years to be solved with conventional grid investments.

In France, the Law #2015-992 of August 2015 relative to energy transition defined in its Article 199 an experimental framework allowing local authorities in partnership with producers and consumers to propose to the DSO a local service offer for flexibility provision. Currently Article 199 is under revision, and its updated version is expected to establish a new regulatory framework for flexibilities, also taking into account Article 32 of the CEP requiring DSOs to consider flexibility as a service. The French regulator (CRE) approved the first "commercial" agreement for a flexibility service in November 2018. However, this experimental framework is not considered as the target model. In order to prepare procurement of flexibility services from the market, Enedis conducted, from December 2018 to February 2019, a broad consultation of network stakeholders: a local DSO, the TSO, markets actors, local authorities, business associations, producers, universities, etc. This consultation allowed for the definition of the following framework for flexibility procurement:

1. A Request for information (RFI) is published based on the DSO's analysis and identification of opportunities for the use of market-based flexibility services,
2. A call for tender is published, including specifications based on the feedback from the RFI.

The first RFI has been published by Enedis in the end 2019, with a focus on 6 different areas in France, in the aim to contract flexibility services for 2020. This consultation is designed to launch a new revenue stream (potentially enabling more investment in RES) and shall allow grid investment deferrals, where economically efficient.
In parallel, as of today, Enedis is offering to interested power producers requesting access and connection to the distribution grid a specific contract including flexibility provision (possibility for the DSO to curtail upon demand). In exchange, the power producers benefit from reduced grid connection fees due to reduced or deferred grid reinforcement.

Finally, in Austria flexibility services do not exist on a standardized commercial basis, there is an active voltage control focus within various research projects, although there might be bilateral agreements between a DSO and an individual grid customer (consumer, generator or prosumer). For some components, such as batteries, there is Q(U) regulation focused on overvoltage. Beyond that, ripple control systems for load management are at least widely put in place, according to Fronius, even though their use might not be as widespread. As an example of a bilateral agreement, on LV level, metering points with interruptible loads pay approximately half of the kWh-based component of the normal grid tariff. Units such as wind turbines are able to obtain a closer and less expensive connection point in case they allow a regulation in critical voltage situations. Regarding the visibility of flexibility profiles by the DSO, in general, the DSO is not allowed to interfere with generation/consumption profiles, except for special cases such as emergencies or grid topology changes due to maintenance, as this would conflict with the rule that the DSO is not allowed to be involved into the commercial activities. Nevertheless, DSOs are informed which flexibilities participate in the balancing markets during a prequalification process, and DSOs have access to metering points with interruptible loads (e.g. boilers) for which the terms and conditions are defined in the grid access contract. However, those systems are the remains from the previous integrated energy market model, which existed before the liberalization of the electricity market. Therefore, the practical relevance of these systems for addressing today's flexibility needs is doubtful, as the ripple control systems tend to use fixed (non-variable) timeslot patterns, which might not necessarily correspond to the real grid load. It is important to note that today in Austria (as in most other EU countries), flexibility is increasingly acquired, bundled and activated for the use cases/business cases outside the DSO-domain (e.g. for the kWh business, i.e. commercial activities), or for the use cases/business cases of the TSO domain, which is in charge of the balancing power regime. In the future, following the CEP guidelines, it is expected to develop the LECs in Austria.

To summarize this section, variable and localized energy production as well as E mobility, mainly connected to distribution grid will increase peak power flows on the distribution network. In order to avoid grid constraints that might be created by these peaks, the DSO has been traditionally investing into grid reinforcement and extension, but this approach is becoming very costly, and depending on the dynamics of the energy transition, the DSO may not be able to catch up with the changing environment. Flexibilities have a value for the DSO if they provide a benefit vs. historical levers. Therefore, there is a strong need for development of tools (such as flexibility platforms) and new business models, which take into account the potential of flexibility and encourage flexibility market participants to reach out for profitable approaches to system optimisation. In this regard, one of the most important requirements for the future is to establish clear and non-ambiguous policies and regulations to provide a stable ground for industrial developments and ensure safe and reliable flexibility activations. Based on experience, TNO estimates that technology and innovations are often seen to follow the regulation. In this relation, the implementation of the Clean Energy Package will be a turning point regarding the use of flexibility at the local level by distribution network operators in the EU. In addition, there should be continuous coordination between DSOs and TSOs to ensure coherent actions and developments on local markets. Finally, flexibility activation is also an opportunity for clients, including residential customers, to become an active part of the energy system and market. As such, customers could be considered as a new form of an asset.

4.1.2. Business models for DG

As it was mentioned earlier, flexibilities (including storage assets and DG), Local or Citizen Energy Communities (LECs, CECs) and microgrids can drive the energy transition from centralized to distributed and thereby local generation. Such a transition creates new energy market players, which need to be integrated into the regulatory framework and business models. For example, CECs are considered as entities gathering producers, consumers and prosumers connected on the LV grid and exchanging energy amongst themselves. This section is dedicated to possible business models, which create favourable conditions for flexibility services, including the management of storage assets.

Partners were asked to suggest the best player (in their opinion) to operate storage facilities on the grid. This is a much-discussed topic and the current regulation leaves room to interpretation and suggestion of different solutions. Indeed, Article 36 (54 as far as TSOs are concerned) of the E-Directive allows Member States to decide whether DSOs can own, develop, manage or operate energy storage facilities, under certain conditions that remain to be specified, so this is an open question in the majority of Member States today.

In the opinion of Avacon, all energy market participants (aggregators, domestic and industrial consumers, DSOs, LECs, power producers) should be authorized to operate storage facilities without specifying any particular type of operators. Regarding the topic of electricity resale for/from storage, currently in Germany, storage is considered as a consumer when charging and as a generator when discharging, and in both cases, unbundling is strictly being upheld.

In the case of the Czech Republic, domestic or industrial customers, power producers, and the DSO should – according to CEZ Distribuce and CEZ Solarni – be authorized to maintain the operation of storage units. However, the definition of energy storage in national law is still missing as well as related decrees and rules.
In the opinion of all Dutch InterFlex partners, aggregators, industrial customers, and LEC should be authorized to operate storage facilities. Enexis and TNO state explicitly that they are in favour of considering domestic customers as possible storage operators. The Dutch market promotes more decentralized models, where different parties can operate storage units.

In the opinion of the Swedish DSO E.ON, aggregators, industrial consumers, LECs, and power producers should be able to operate storage facilities. The situation in Sweden is similar to the one in France: the DSO is allowed to use battery storage only in case of power interruption and to compensate for grid losses.

In France, the DSO Enedis considers that storage assets should be primarily operated by market players, including aggregators, domestic consumers, power producers, industrial consumer and LECs. Enedis is aligned with the CEP considering that regulated bodies (TSO, DSO) should not be restrained from owning or operating storage assets under well-defined specific situations where the benefit of the storage is directly bound to the stakeholder's regulated activity, and where storage services do not provide any economic advantage. Currently the DSO is limited to use cases which other players cannot handle.
In the opinion of Engie, there is no reason for a network operator to be more efficient than a market player operating a storage. Indeed, a network operator owned asset could only be monetized as a service for the network when a market player owned asset has access to a wider set of value pockets (bill optimization, services for producers and consumers, energy and capacity markets, ancillary services and other services for network operators. Therefore, if an investment in a storage is not profitable for a market player, there is no obvious reason why it should be profitable for a DSO. Therefore, if a network operator invests where a market player couldn't in terms of profitability, it suggests that either it won't be profitable for the network operator and then it will be a cost for the electric system leading to higher network tariffs, or market players weren't aware of the whole set of sub-services providing value to the network operator. In the latter case, ways shall be found to share the knowledge of the full value. Finally, if in absence of offers from market players, DSOs were

to own, develop, manage or operate storage facilities, Engie requests as a preliminary condition to set up an open, transparent and non-discriminatory tendering procedure. In order to ensure a coherent implementation of the directive, as well as to avoid any distortion of the internal electricity market, the tendering procedure should be harmonized on the European level.

In Austria, the opinion of the project partners varies: AIT suggested that the DSO should be allowed to operate storage facilities, whereas Fronius believes that only market players should be authorized to operate storage facilities. Local Austrian regulation generally does not restrict the use of the grid infrastructure to sell electricity to/from storage. Nevertheless, there are requirements of labelling the primary source of electricity fed into the grid. In case of a third party battery storage directly connected to the grid (for example in residential self-consumption applications), the grid tariff is applied twice: firstly, when the battery is charged, because charging is seen as a consumption subject to the grid tariff, and secondly, when the energy is discharged and sold to a customer over the grid, the customer pays the grid tariff for his consumption.

Another important topic covered in this section is the business models for LECs allowing them to sell their flexibilities. In Germany, LEC members can sell their flexibilities on the wholesale market and provide other ancillary services. Whereas in the Netherlands LEC are allowed to sell their flexibilities through contracts with aggregators, and there are some energy providers allowing consumers to sell electricity, but there is no differentiation among the respective sources, for example, between DG or battery units. In France, LEC is not yet defined in the legislation, but it is expected to be defined in the upcoming French energy transition law.

In Austrian and Czech energy market regulations, LECs are not identified. However, in Austria it is assumed that the presence of LECs will not change the basic principles of the electricity market model, because it is allowed by any party to use the grid infrastructure to sell electricity from all sources, including storage, without consideration of the economic viability of the related business models.

Special attention shall be payed to the current situation in Sweden with respect to LECs. Only Balance Responsible Parties (BRPs) are allowed to participate in the Swedish balancing market today. A new role as Balance Service Provider (BSP) is expected to be introduced at the earliest by the end of 2019 - beginning 2020. The BSP will subsequently be responsible for submitting bids to the Swedish TSO. At the same time, there are ongoing pilot projects in different areas in Sweden to establish local markets for flexibility and other ancillary services, and the DSO use bilateral contracts to buy flexibility services.

It can be concluded that in all InterFlex participating countries, the roles of the DSO and TSO are strictly regulated: grid operators work on the ground of regulated business models, while the actions of other players are driven by the market and competition rules. DSOs are not allowed to trade energy and participate in competitive markets according to the European unbundling reflected in Directive 2009/72/EC.

Regarding the storage facilities, regulation currently doesn't differentiate energy flows: electricity consumed when charging batteries, and electricity fed into the grid while discharging are considered to be equivalent. Storage units are simply seen as electric load while charging, and as a power generators while discharging. Furthermore, if double grid fees apply for charging and discharging this can be considered an obstacle that needs to be solved for flexibility provided by battery storage. There is also an issue regarding the storage asset valorisation, as storage asset owners seek opportunities to provide various services in order to make their investments attractive. This relates to one of the main topics treated in the frame of multi-service storage use cases in InterFlex – in Nice Smart Valley or Simris in Sweden – where complementary services are combined for economic reasons: in addition to local services, ancillary services are provided to the TSO to reinforce system security and create additional value.

4.1.3. Network charges for DG

This section is dedicated to existing and possible future network charges and tariff schemes applied to DG. Connection charges and the use of network (UoN) charges applied to DG are the focus of interest, as well as UoN charges applied to storage assets.

In comparison to Germany, where according to the renewable energy law (EEG) no connection charges apply to DG, the Netherlands have capacity-based connection charges. In the near future, the existing Dutch regulatory framework is expected to be modified to adapt the grid fees to the effectively used capacity. Similarly, in France, a production capacity-based approach is implemented, based on the analysis of the transmission and distribution network hosting capacity on a regional level. The method defines a fee per added kW production in order to divide grid investment costs fairly among producers over 100 kW (soon 250 kW). Producers over 5 MW pay 100% of the grid connection cost, including a fee per added kW production. However, for those who are under 5 MW, there is a reduction rate: installations under 500 kW receive 40% reduction, whereas installations between 500 kW and 5 MW receive smaller reductions (reduction decreases linearly as the capacity of installation increases). Enedis is currently conducting experiments with Smart Connection Agreements (SCA) allowing the curtailment of DG in exchange for lower connection cost and a shortened connection procedure.
In the Czech Republic, there is a specific type of connection charges for DG: per Amp on LV grid (only if existing circuit breaker must be increased), and per kW in MV/HV grid.

In Sweden, DG connected to the LV grid are considered micro-producers which have no connection charges.

In the Austrian grid, to connect DG units to the existing grid, the DSO defines a technically suitable connection point, which can host the electrical power of the DG. In the best scenario, this is an already existing connection point of the customer. Elsewise, the plant operator can lay his own cable to the defined (distant) connection point, or he can make a co-payment to the DSO for reinforcing the existing grid down to a closer or the closest connection point.

In all participant countries, except for Sweden and Austria, DG units do not pay UoN charges, in Sweden they are kWh based, and in Austria generators below 5 MW generally don't have UoN charges. Although, in Austria, there is a monthly rental fee for measuring devices, and reduced network charges for the electricity consumption of pumped hydro power plants. In France, the situation is similar, meaning that DG units pay only management and meter rental fees, and reactive energy charges (kVArh), if the producer does not apply the regulation requested by the DSO.

Regarding the UoN charges applied to storage assets, in Germany there is no such type of charges, but during battery charging there are fees on consumption (with some exemptions under certain conditions), and no fees are applied while discharging. In the Netherlands, Sweden and the Czech Republic currently storage assets are not taxed for the UoN. In the case of France, there are no specific UoN charges for storage, batteries are considered as a consumer when charging and as a DG when discharging. In Austria, according to AIT, the elimination of double grid tariffs for grid/community storages is currently under discussion.

In general, today in aforementioned countries there are different schemes of billing DG units. In some countries DGs are charged for connection, and there are specific UoN charges, and in others DGs have free access to the grid. A similar situation concerns storage units, however, in most cases they are considered as simple consumers while charging, and can freely inject electricity to the grid, unless they cause perturbations in the network.

4.1.4. DSO costs and revenue regulation

This section discusses the influence of flexibilities on the DSO cost and revenue regulation. The aim of this section is to identify the role of flexibilities when calculating DSO revenues, and the issues related to DSO investments in flexibility services. In other words, to understand to what extent flexibilities are explicitly taken into account by DSOs in order to postpone or reduce network investments, considering that they constitute a full alternative the conventional investments in the planning process or as the last solution when all other approaches fail. In order to make flexibilities a viable alternative, it is essential to include the remuneration of flexibility services and related investments into the cost base determining the distribution tariffs.

First, in order to integrate the cost of flexibilities into DSO cost and revenue regulation, it is important to identify which model the regulators use to estimate the cost of the DSO (OPEX and CAPEX). In Germany, the Netherlands, the Czech Republic, and Austria the benchmarking approach is used, meaning that the DSO is benchmarked against its own past performance to stimulate financial efficiency. Under the current local regulations in all of the before mentioned countries, the potential use of flexibilities is not considered when calculating DSO revenues. In Sweden, the majority of purchased flexibility services are considered as OPEX and thereby inflicted with efficiency demands. In France, discussions on the regulator's approach to integrate flexibility and estimate the corresponding cost are ongoing. An experimental framework for real-scale test has been set up and analysed. In the current state, flexibilities are considered primarily as an instrument to postpone network investments, whereas in some cases they might also be used to enhance the network operation and reliability. In the case of the Netherlands, flexibilities are considered today only as the last solution before failure and for DSOs it is not an instrument to postpone or reduce network investments, and in general, they are still only in experimental phase.

Project partners were asked to give their opinion on the ways to ameliorate the regulatory scheme, so that it could encourage the DSOs to consider flexibilities as a full alternative to reduce and/or postpone network investments.

The German DSO Avacon suggested, firstly, to establish clear guidelines on the ways of contracting flexibilities, in order to tackle unbundling related issues. Secondly, to develop a commercial mechanism to contract flexibility, meaning to create a market platform, introduce pricing, coordination of competition for flexibilities, and allocation between regulated and non-regulated use cases. Thirdly, the regulator should be committed to accepting the cost for flexibility as part of OPEX, and consequently consider the implementation of a Total Expenditure (TOTEX).

The French partners follow the same logic, meaning that the regulatory scheme should follow two basic principles: allow market innovations and reduce future costs. Following this reasoning, the implementation of TOTEX regulation should be considered. Taking into consideration the total cost allows all stakeholders to compare effectively the cost of grid reinforcement with the cost of using flexibility. This model has proven to be cost-efficient in given applications in the United Kingdom [16]. In such economic evaluations, the regulation needs to take into account and evaluate new risks bound to the use of flexibilities, define roles and responsibilities as well as clear and comprehensive criteria for all players to participate in flex market. Finally, it needs to be clearly defined who is eligible to be declared as a flexibility unit.

The Dutch project partners drew the attention to the fact that the regulator needs strong and reliable arguments to allow flexibility as an alternative for conventional cable or transformer reinforcement. In order to simplify the integration of flexibilities, the regulator should consider dynamic network transport tariffs and energy tariffs, and taxation not fixed per kWh but coupled to these tariffs. That will enable viable business cases for smart grid, smart charging, aggregators, self-consumption, LECs, and other energy market players.

The Swedish DSO E.ON points out that the regulator must change the revenue cap model to give the DSOs incentives to use more flexibility services. Regarding financial compensation for congestion management: when the subscription to overlaying grid (TSO) cannot be raised, the costs are regarded as “pass through” in the next regulatory period 2020-2023. The regulation constitutes a risk, because it is today unclear what the regulator will regard as reasonable remuneration. Today the national legislation is unclear on the possibility for the DSO to activate flexibility for a more efficient use of the grid. Current revenue regulation incentivizes building and reinforcement of the grid before using “local services”, in other words local flexibilities.

According to the Austrian project partners, the regulator will push DSOs towards lowest costs. If conventional grid reinforcement is cheaper than flexibility, there would be no financial interest in changing the regulatory scheme. Nevertheless, investments to electro-technical necessity of grid reinforcement should be assessed more critically, particularly of those addressing peak constraints for a few hours per year.

In summary, the majority of InterFlex partners reached the conclusion that in order to incentivize the activation of flexibilities on the grid, regulators should review the current DSO cost estimation scheme, and consider TOTEX based regulation. Today in many cases and areas the flexibility value is very low and consequently the flexibility providers are difficult to recruit at local level, while conventional grid reinforcement appears to be easier (due to established business procedures) and less risky for the DSO than acquisition of an adequate flexibility for solving grid constraints. This is particularly true in countries where grid constraints are exceptional today and opportunities to use flexibilities remain rare. In the early starting phase it may be necessary to financially incentivize the DSO to promote the use of flexibilities to manage smart grids with DG units. Regulations will thereby have to consider new risks, which DSOs will be facing when calling for flexibility services (this topic is discussed in more details in section 4.1.5).

4.1.5. Flexibilities’ role in DSO reliability incentives (including islanding) and DSO’s risks associated with flexibilities

The presence of flexibilities on the grid might create new risks for the DSO, who is responsible for the power quality and continuous supply of electricity. In other words, with the emerging presence of flexibilities, it is important for European DSOs to maintain the high quality of supply which is a reference today in the EU Member States.

In general, all DSOs participating in the InterFlex project are obliged to meet specific quality and supply targets under the existing regulatory schemes. These targets are generally based on economic evaluation of energy not supplied (ENS), system average interruption duration index (SAIDI), system average interruption frequency index (SAIFI), as well as, on the maximum duration of a single power interruption and a maximum number of interruptions

per year. These requirements might complicate the integration of flexibilities. For example, in Sweden, according to the legislation (Energy Act), no power interruption is allowed to last more than 24 hours. Moreover, there is an additional rule for power outages above 2 MW (“funktionskrav”- performance requirements) with even stricter demands regarding the restoration time for power interruptions. However, to facilitate the provision of flexibility services there has been a proposal to remove this additional rule. The Swedish Energy Act has priority over civil law, and thereby limits the possible agreements with flexibility providers.
The main risk and uncertainty for the DSO, associated to flexibility, is its reliability and availability when needed. As it was stated earlier, DSOs are responsible for the quality and continuity of supply, and therefore, they must be sure that the tools at their disposal – let them be assets or (flexibility) services - provide the required performances and guarantees. This is one of the reasons why traditional grid investments, whenever financially accessible, are often chosen as the preferred option compared to flexibility services. The continuity of supply is considered as overall satisfactory within the EU Member States, and currently there is no need for its improvement, except for resilience against additional stress and unforeseen external damages/attacks. There is very limited willingness to pay for such improvements, which are not of a high priority, according to Fronius. On the contrary, increasing constraints call for the efficient integration of flexibilities to contribute to maintain the currently high standard of supply.

Flexibilities can also be used to ensure the continuity of supply and to improve the grid resilience when remote-controlled islanding capabilities are developed in specific portions of the network. Conventionally, for maintenance and resiliency reasons, DSOs have been managing embedded and islanded micrograds for the last decades through the use of temporarily operated diesel generators (e.g. when there is an outage or during maintenance works on the grid). In recent years, the massive development of RES connected to the distribution grid, opens up the possibility for local islanding during a given period of time, in case of an incident and based only on RES and storage, either on a portion of the grid or at individual consumer level, and thereby reduce the need for fossil fuel generators. In case RES are set to generate power continuously during islanding (which is prohibited by some regulations), the legal framework has to define specific rules for energy storage. According to Engie, in this specific case, during grid outage, DSOs should be allowed to operate the assets (generators and storages) to manage the islanding mode. However, the usual asset operators should receive a proportional retribution (defined in advance) for these actions. Hence, regulation should allow the DSO to pay the asset owner. Moreover, according to Engie, the regulatory framework should allow the DSO to consider the existing generation and curtailment capacities at local level to guarantee the quality of supply through islanding instead of reinforcing the grid. It can be mentioned that in some countries under specific conditions it is allowed to operate microgrids without connection to the main grid. For instance, in Sweden in some agricultural sites, industrial parks, (maritime) ports, airports, or in Austria for some alpine areas, particularly with hydro power plants. To summarize, in general in the InterFlex participating countries, there are different pilot and research projects on microgrid islanding with the use of flexibilities.

In conclusion, today in the InterFlex participating countries, there are no significant issues related to the quality, continuity or reliability of supply. However, flexibility services can potentially improve network resilience in the case of an outage through microgrid islanding, thereby ensuring the local continuity of supply. Also, flex can be used for grid operation plan, as well as to recover electricity supply after an outage for a large number of customers (not only in the specific case of islanding). Besides the question of non-remunerated services provided by market players (services required by grid codes, active/reactive power control) should be answered to ensure the robustness and development of smart grids.

4.1.6. Demand side management and advanced metering infrastructure (AMI)

This section is referring to demand side management, including grid tariff differentiation, questions related to advanced metering infrastructures (AMI), as well as customer data privacy or ownership. These topics are of high importance when creating a flexible energy market. The AMI is the key equipment, which allows monitoring of energy consumption and, depending on its functionality, the AMI can be a load control element. In addition, customer engagement is an issue of very high priority, because demand response is based on the customer's willingness to participate in such mechanisms.

The InterFlex project participating countries have different schemes to differentiate tariffs for various time periods. For example, in the Netherlands and the Czech Republic there is a grid tariff differentiation varying between peak/base periods. In Germany there is a reduced grid charge on flexible load. In Sweden there is an ongoing inquiry considering regulated network tariffs (which are today set by the DSO), in order to increase the efficiency on the grid; focus areas are capacity tariffs and time-differentiated tariffs. In France, grid tariffs are differentiated for residential and non-residential customers, and for RES based on their capacity. In general, there is a wide variety of options, including peak/base grid tariffs differentiation, three types of dynamic tariffs with various price differentiation periods depending on the time of a day and season of a year, including periods with critical peak pricing.

The type of infrastructures used to activate demand response can be manyfold: smart meters at consumer's location, internet boxes or radio systems, all associated to control interfaces and devices, or alternatively behaviour-based activation. Their respective technical potential and economic interest may be different depending on the type and use of the flexibility.

The installation of AMIs can be on a voluntary basis or mandatory. For mandatory AMI installation, there are specific smart metering rollout programs. In the Netherlands, Sweden, France and Austria such large-scale regulated rollout programs are already in progress. In Sweden, for instance, under the ongoing smart meter rollout program (to be completed by January 1st, 2025) all consumers connected to the low voltage grid (<1000V) are invited to install smart metering devices. In Austria, it is foreseen that 95% of consumers shall be equipped by the end of 2022. In the case of France, it is required to install Smart Meters through the article L. 341-4 of Energy code, which is based on the European Directive 2009/72/EC, and which foresees 35 M smart meters to be installed by 2021 (mainly covered by Enedis' Linky meter deployment). In parallel to the ongoing smart meter rollout in France (more than 20 M smart meters in place today), peak load shaving has been successfully tested as a source of flexibility for the TSO or the capacity market, considering that the customer involvement is very important in this process. In Germany, the national smart meter framework is defined, but the mandatory rollout program has not started yet. In contrary, in the Czech Republic, there is a promotion by DSOs of demand response among consumers, but AMI implementation is voluntary, because of negative CBA for deployment in the country. For LV consumers, demand response is well known standard product on the Czech market, which is well defined by the regulator mainly for national balancing purposes. Any customer fulfilling conditions for demand response could participate regardless on the customer's location. Demand response is activated based on CEZ Distribuce's command through simple narrow band one-way PLC communication devices, customer's installation is ready to switch-on/off loads based on the received commands (electric heating, water boilers or heat pumps).

Regarding the main functionalities of smart meters, in Germany AMIs allow today only for data acquisition, all other active use cases, such as load control, load limitation, generator curtailment are currently being debated. In the Netherlands by regulation the DSO is only allowed to use the smart meters to conduct outage checks and for remote metering for the production companies regarding their billing processes. The DSO would like to have more permissions for reading out the meters, according to Elaad. Smart meter reading could be very useful to conduct smart charging based on real time flexibility in the grid, since only limited information on this flexibility is now available to the DSO. In addition, some third parties offer to the end customer High-level Entity Management Systems (HEMS) or other monitoring tools. Today in France smart meter functionalities cover load shedding and peak shaving by the supplier and remote metering, outage detection as well as power quality management by the DSO. The local load management functionalities require the customer to plug a control interface device into the smart meter, to communicate with specific appliances and their steering protocols. Technically the French smart meter has up to 10 relay contacts that are designed to be activated, for instance, for steering of EV charging or any other DSM action. Similar functions are included in the Swedish smart meter devices, with a focus on remote control of the power supply, meaning that the DSOs can turn on/off the power through the meter. In Austria AMIs are used for remote metering and visualisation.

In conclusion, large scale AMI rollout programs are taking place in the majority of the observed countries, meaning that in the near future consumers will have a visibility over their own electricity consumption, this does not only include large industrial consumers, but also domestic ones. AMIs are instruments which establish the interaction between the DSO, the energy supplier and the customer, which open up a possibility for customers to participate in the flexibility market, and which integrate load control functions. AMIs allow the DSO to exploit metering data for constraint or failure management and enable market players to build new offers. However, in order to encourage consumers to become active players of the energy market, it is important to incentivize them mainly through financial means.

4.1.7. Conclusion

This conclusion reflects the main topics evaluated in this ‘non-technical’ or technology-independent section of the SRA report. Flexibility services are beginning to emerge in the energy market in growing numbers. Their local use can improve the grid resilience and relieve grid congestions via demand response or curtailment schemes. It remains to be evaluated to what extent these flexibilities may introduce new risks for the DSOs, market players and customers.

Currently there is a strong need to adapt the regulation and develop new business models, which take flexibilities into account and create favourable conditions for their integration. In this relation, the implementation of the Clean Energy Package will be a turning point regarding the use of flexibility at the local level by DSOs in the EU. DSOs have been traditionally investing in grid reinforcement and extension as part of their network planning process; therefore, it is essential to draw a clear picture of the cost-effectiveness of incorporating flexibilities in order to consider them as an alternative or complementary approach to conventional grid reinforcement: DSOs are seeking to optimize grid planning and management by using all available means, including flexibilities.

This highlights another important conclusion: in order to incentivize the activation of flexibilities on the grid, regulators should review the current DSO cost estimation scheme by considering the TOTEX based approach, which has shown positive results in the UK [16].

Storage facilities have combined properties of a generator and a consumer. Consequently, the grid tariff is applied twice, in some countries, separately for drawing energy from the grid during battery charging, and for feeding energy into the grid during discharging. This dual fee which accounts for the bi-directional use of the network can constitute an obstacle for battery-storage based flexibility and needs to be addressed.

Finally, Advanced Metering Infrastructures (AMIs) are considered enabling tools for flexibility development. They establish a bridge and create interaction between the DSO, the energy supplier and the customer. AMIs induce the possibility for the customer to participate in the flexibility market and for market players to build new offers. Moreover, some AMIs feature load control functions and allow the DSO to exploit metering data for constraint or failure management. However, in order to encourage consumers to become active energy market players, it is important to incentivize them, in particular by financial means.

5. Conclusion

This deliverable presents the results of the scalability and replicability analysis of the smart grid solutions demonstrated by the InterFlex Project. The SRA methodology is based on the concept of modularity and adaptability in order to have a homogenous method which is capable of analysing the various solutions implemented in five different demonstrators.

The SRA identifies the most favourable conditions and potential barriers against a large-scale deployment of the solutions. It also assesses the effect of the boundary conditions for the implementation of the use cases. These boundary conditions encompass the technical, ICT, regulatory and stakeholder-related. Each of these areas has been analysed and additional supporting documentation is also provided for completeness.

Three different stages were used in the technical analysis in order to focus on those innovation streams functions which are characteristic of the InterFlex project.

With respect to the technical SRA, the functional analysis was performed based on a three-step process: a pre-evaluation phase based on a qualitative analysis of the use cases in each demo with the scope of gathering the required information and providing the data for the development of the scenarios used in the second stage: the execution phase. The execution phase, thereafter, considers the input from the pre-evaluation and makes uses of simulations for applying different scenarios to the demo's use cases to obtain the results to be analysed in the conclusion phase. From all these phases, the main conclusions can be extracted, where each individual UC and Demo is concluded individually. However, it was observed in more than one demo, that if there is a higher penetration of renewables and EVs, the operation of the network can be adequately sustained, and the functions developed within InterFlex will improve the overall performance and sustainability of the network. This can be seen as a driver for fostering the penetration of renewables as the DSOs will be equipped with sufficient solutions to handle network problems which are expected to arise in the future. Nonetheless, it is always advised that deeper analysis should be considered for specific deployments, where the network could potentially be constraint, although networks as for today are strong.

Regarding the ICT analysis, it has provided a clear characterization of the lower and upper architectures considered through the components and links which compose it. This help the different partners properly visually what is the current state of their ICT infrastructure and where potential bottlenecks can be found. Examples of these potential bottlenecks are the devices which connect subnetworks as they are the main key information exchangers or problems with data storage due to long data retention. Nonetheless, none of the deployed demo architectures in reality present scaling barriers, but as suggested through the analysis, it is recommended to follow the demo requirements and extend the concepts in order to ensure a future large scale roll out successfully.

Finally, the non-technical analysis, was able to cover interesting topics and open many discussions among the different partners involved. This helped envision the current problems at a local level but also at an international level. Such visions are necessary as although DSOs are operating nationally (most of the time), aggregators and service providers tend to operate internationally. With the discussions provided, future and reshaped business models can be created for all the partners. This intention of new business models will provoke the need for regulation to further develop the integration of flexibilities and create favourable conditions for its future large scale deployment, since it involves all the energy actors and requires the different solutions as InterFlex has showed.

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7. Appendices - Annexes

7.1. Smart Grid Architecture Model (SGAM)

The different interoperability layers for each of the SGAMs which are created in InterFlex can be found in D3.4.

7.2. Functional additional support documentation

7.2.1. Additional German Demo support documentation

This section of the annex provides additional information to compliment the information exposed in section 3.1.1 for the German demo. In this section, the parametrization used for the scalability analysis simulations is exposed.

Network model: Am Bergfelde Network

For the purpose of the SRA, the secondary substation Am Bergfelde, and its connected network, were selected since it was is representative of a typical network in Germany and includes a combination of a radial and meshed grid layout. The network is located in the Rettmer/Lüneburg area in Germany and is operated and owned by the local DSO, Avacon. The network can be divided into 6 feeders to which a total of 123 residential customers are connected. A schematic diagram with feeders labelled 1 to 6 of the Am Bergfelde network is shown in Figure 84.

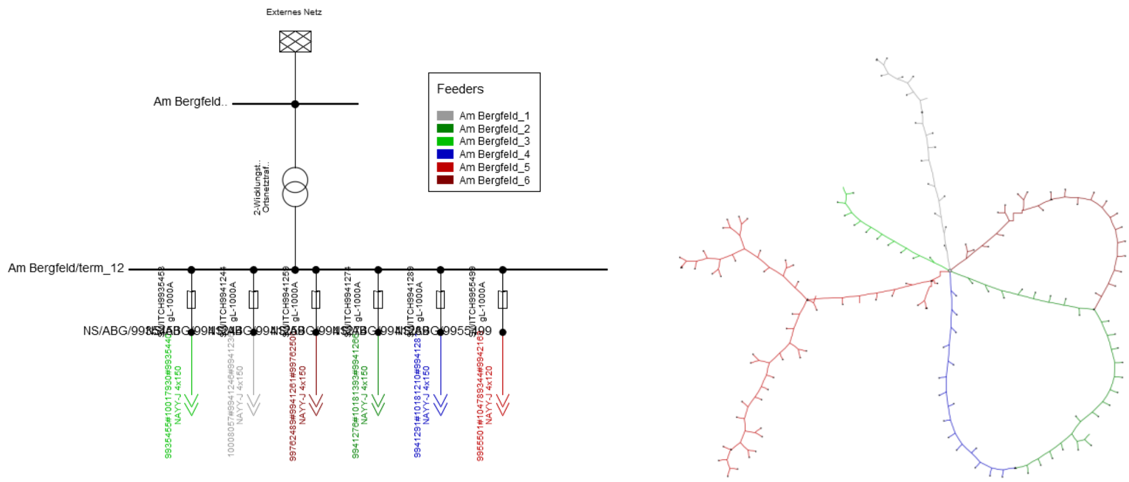

Figure 84 Schematic and network layout diagram of the Am Bergfelde network from DigSilent Power Factory

As can be seen, the Am Bergfelde network consists of a combination of meshed and radial feeders. Based on the network diagram the following feeder statistics can be extracted and are shown in Table 40.

Table 40 Table showing the number of customers and total line length per feeder

Feeder	Number of customers	Length (km)
Am Bergfelde1	13	0.63
Am Bergfelde 2	10	0.12
Am Bergfelde 3	23	0.50
Am Bergfelde 4	16	0.48
Am Bergfelde 5	40	1.30
Am Bergfelde 6	21	0.62
Total	123	3.67

Input data description (profiles and control functions)

The analysis for each of the simulations is based on various input profiles which are at 15 min time intervals conducted for the entire year of 2017. The input data profiles for each household and respective devices (PV, NSH and HP) are discussed as follows:

Household Load Profile

For the purpose of this study, the customer load profiles are based on representative standardised household profiles obtained from an online source [17]. The standard load profile (SLP) is based on a 1 MWh per annum consumption which was then scaled to 3 MWh accordingly. This is assumed to be a representative consumption based on households located in Germany and is in line with Avcaon's expectation. One disadvantage of applying a SLP simultaneously to every household, is that it resembles all households identically, with a unity coincidence factor, which in not the case of an active LV network. Therefore, in order to create some degree of variation, a randomness factor (+/- 15%) was applied to the profile so that each profile is independently represented. For the purpose of the SRA, it is accepted that a unity power factor would be representative of the 'worst-case' scenario when all customer loads exhibit their maximum consumption simultaneously and thus the coincidence factor remains at 1. An example of the SLP for one day for 3 different households is shown in Figure 85.

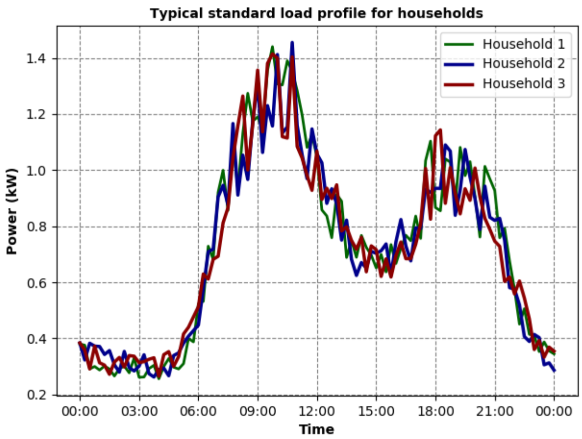

Figure 85 Representative standard load profiles for households

PV Generation Profile

The PV generation profile data was obtained from *pvlib* incorporated within the Python environment [18], since Python was used as the automation tool to run the scenarios in Power Factory. The PV generation profile was created with the *pvlib* code which takes into account the latitude, longitude and altitude of the location for which the PV penetration is required through the use of solar positioning. The generated profile obtained from *pvlib* was then normalised and scaled to 5 $kW_{p,}$ based on a summary of the installed capacity for Interflex customers in D5.6. An example of the maximum PV generation profile for each season is shown in Figure 86.

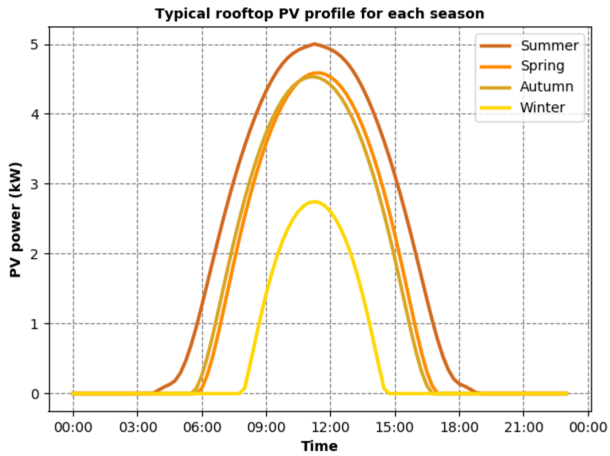

Figure 86 Typical rooftop PV profile with rated power of 5 kW_P for each season

As seen the variation of PV generation between seasons is clearly evident, with the max PV generation of 5 kW_P in the summer and 2.7 kW_P in the winter.

The controllabitly of the amount of PV generation (i.e curtailment) is achieved through the implementation of an on or off state for each of the small scale PV generators. For the case of this SRA, this on-off state is asummed as synonomous with the case where 50% of households are without PV generation i.e thier PV generators have been turned to the off state. The curtailment of devices, through the use of active power reduction implies a reduction in earnings for the PV system owner and thus can be considered as an additional expense to the DSO, if they are to provide monetary compensation.

In order to implement reactive power control, a cosφ(P) control function according to the German LV Grid Code [7] is developed and the characteristics are set within the DigSilent Power Factory [19] environment when conducting the SRA scenarios. A representation of the reative power control function is shown in Figure 87.

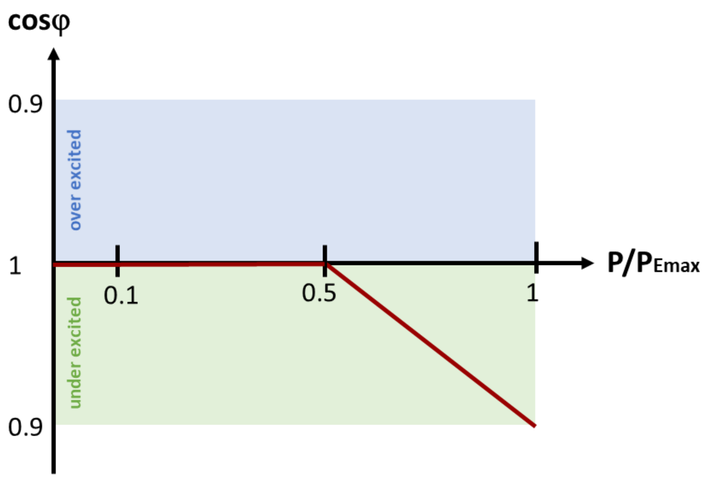

Figure 87 cosφ(P) function adapted from the LV grid code in Germany

Since reactive power control can be used to maintain voltage levels within acceptable range, through the use of inverters, this control function is becoming more prominent in LV networks. This is in contrast to traditional power system operation which makes use of an On-Load-Tap-Changer (OLTC) located at the substation.

Night Storage Heater Profile

The electric night storage heater (NSH) is considered as flexible device located at the customer premise and serves as a possible device to use in demand side management. For the case of the SRA, it is assumed that the power rating for the NSH is 3 kW based on an average size value for room size be 18m^2 and 24m^2 [20].This NSH is modelled as a switchable load and for the purpose of the SRA, curtailment of these devices is achieved through the implementation of a step function where the device is switched off during the day (between 6am and 10pm). Outside of this timeframe, it is considered that customers are in full use of these heaters for central heating purposes and making use of the night time tariffs to charge up their units. The demand profile for the NSH with and without its control function implemented is shown in Figure 88.

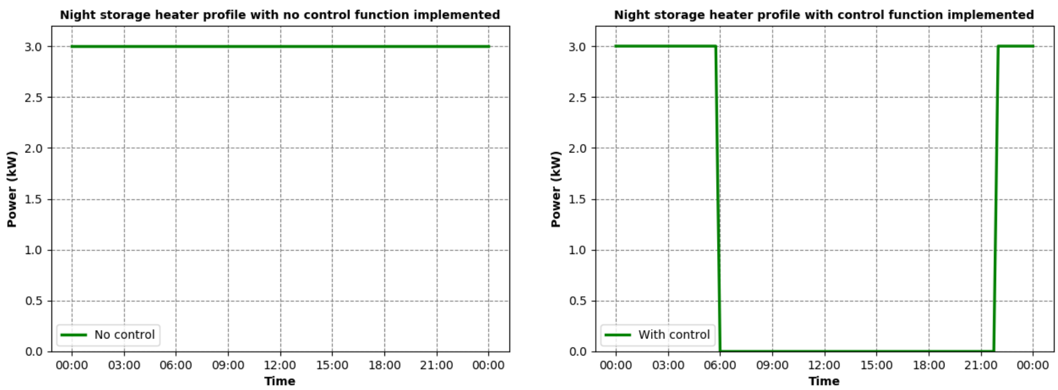

Figure 88 NSH profile with no control (left) and with control function implemented (right)

For the purpose of the SRA, it is assumed that identical NSH are allocated to each household and that there are controllable simultaneously. This is done to represent the impact of the NSH devices and its control functions on a worst-case scenario basis.

Heat Pump Profile

The heat pump (HP) profile is obtained using a standardised load profile, as described in [21]. HP devices are considered to be flexible throughout the day and thus are considered to be the most flexible device when offered to the DSO. For the purpose of the SRA, the control functions for the operation of the HP are set to be activated at the times of the day when maximum peaks are seen and is based on a load reduction of 30% for a maximum duration of 30 min at a time, followed by a minimum of 1 hour of uninterruptible load. It should be noted that this 30% load reduction is merely a representation of the load reduction as it is not permissible to reduce the load beyond the minimum power heating threshold required for customer heating. Additionally, the load curtailment control may not be performed more than 3 times per day. A representation of the HP load profile and its control functions are shown in Figure 89.

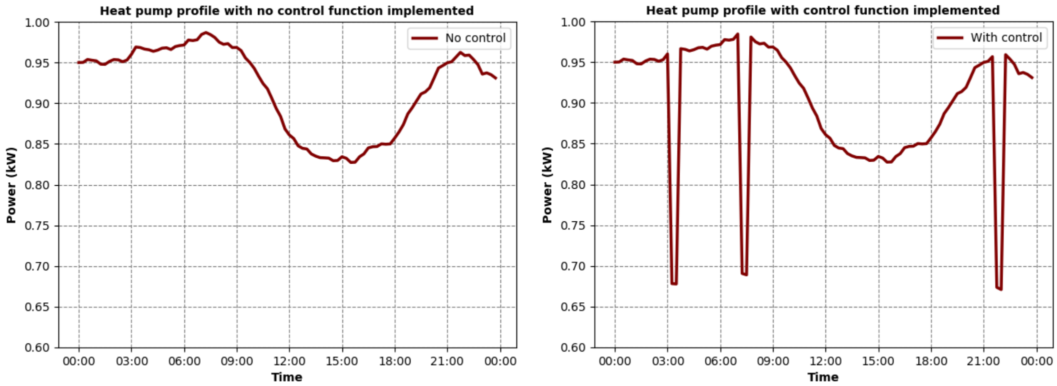

Figure 89 Heat pump profile without control (left) and with control function implemented (right)

It should be noted, that for the purpose of the SRA, customers are allocated with an identical HP which operates with an identical HP demand profile. Despite this not being the case in reality, this is done in order to observe the maximum achievable impact of the flexible device. It is also assumed that the triggering signal for the curtailment of these devices is 'broadcasted' globally such that all devices are controlled simultaneously. This is to observe the impact of the load curtailment on a large scale on the overall network.

Allocations of devices through randomisation

In order to conduct the scalability scenarios through the increase in penetration of devices, a monte-carlo approach is conducted in order to allocate devices to random households. The randomisation to allocate respective devices to households is applied over the entire network (as opposed to per feeder) in order to remove any bias in the allocation of customers with any device (PV, NSH or HP). Thus, all customers are considered to be equally likely to have any device. Once the households are selected, the control functions are applied to the same set of selected households so that a direct comparison of results can be made.

UC1-Scalability: Feed in Management

Increase in PV Penetration

The technical aspects associated with incorporating PV generation into LV networks, is that it is known to reduce the hosting capacity and increase the voltage, particularly at locations downstream of the feeder. Therefore, this UC will investigate the impact on the network when there is an increase in PV penetration. In this analysis, the amount of PV penetration is increased by increasing the number of households which have PV units connected to the network. Initially, the network is simulated with no PV, thereafter, the network is simulated with 50% PV penetration, of which random households across the entire Am Bergfelde are selected via a monte-carlo approach, as discussed previously. Lastly, the network is simulated with a 100% penetration of PV generation, which considers the scenario where every households on the network is equipped with 5 kW_p of PV. In each case, the scenarios are performed with and without the reactive power control functions implemented such that the effects on the network loading and voltage variations can be observed.

PV distribution per feeder

Based on the random monte-carlo simulation, the selection of households with PV is statistically represented. Considering the allocations of households which are equipped with 5 kW_p PV for UC1, the distribution of selected households per feeder is can be seen in Figure 90.

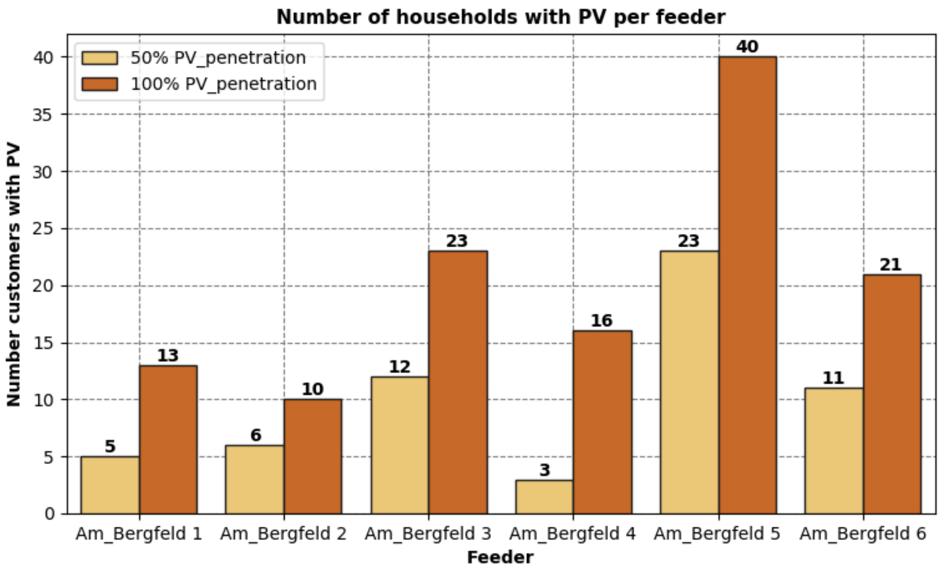

Figure 90 Number of households equipped with 5 kW_p PV

As can be seen, the distribution of customers based on the randomisation process allocates PV with unequal distributions per feeder. In this case, Am Bergfelde 2 has 60% of its connected customers equipped with PV, while Am Bergfelde 4 only has 19% of customers with PV.

Maximum line loading per feeder with increasing PV Penetration

In this section the maximum line loading per feeder with increasing PV penetration is discussed and is shown in Figure 91. For the baseline condition (i.e. 0% PV penetration), the maximum line loading per feeder ranges from 12% on Am Bergfelde 2 to 52% on Am Bergfelde 5. Due to the network configuration, it is expected that Am Bergfelde 5 has a higher percentage of loading due to the higher number of customers connected as well as due to the customers located 1.3 km away from the substation, putting more strain on the network.

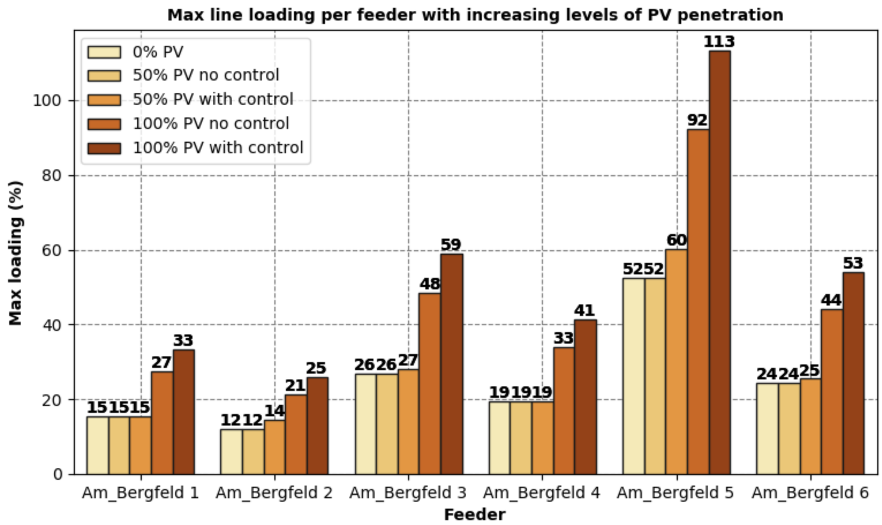

Figure 91 Maximum line loading per feeder with an increase in PV penetration

As the penetration of PV generation increases, it is expected to see an increase in the line loading as more power is injected into the network. For the case with 50% PV penetration, it can be seen that there is an increase in the maximum line loading for each feeder, except for Am Bergfelde 1 and Am Bergfelde 4. These feeders do not demonstrate significant changes in maximum loading over the entire year due the number of PV generators allocated to the feeder (i.e. Am Bergfelde 4 only has 19%) and due to the location of where the active PV generators are located since these feeders form a meshed grid. Typically, lines located at the beginning of a feeder take more strain, since they are required to supply the entire feeder. In all other cases, the increase in PV penetration, shows an increase in maximum line loading per feeder. In particular, Am Bergfelde 5 shows an increase in loading from 52% to 92% when the PV penetration is increased from 50% to 100%.

When the control function is activated, the maximum line loading is observed to increase. This is due to the increased reactive power injection into the network in order to provide control of the variation of voltage (this will be discussed in subsequent section). On Am Bergfelde 5, in the case of 100% PV penetration, the maximum line loading increases from 92% to 113% when the control function is implemented. This suggests, that if all household on Am Bergfelde 5 equip themselves with a 5kW PV system and its inverter is required to comply with the cosφ(p) control, then the feeder will become over loaded and no longer comply with the limits set in the LV Grid Code.

Based on the above, it can be concluded the worst case of feeder loading is observed when there is 100% PV penetration with control functions active. In this case, it was then investigated to identify the duration of the year the overloading is exhibited. Therefore, the duration of the maximum line loading for each feeder over the entire year is shown in Figure 92.

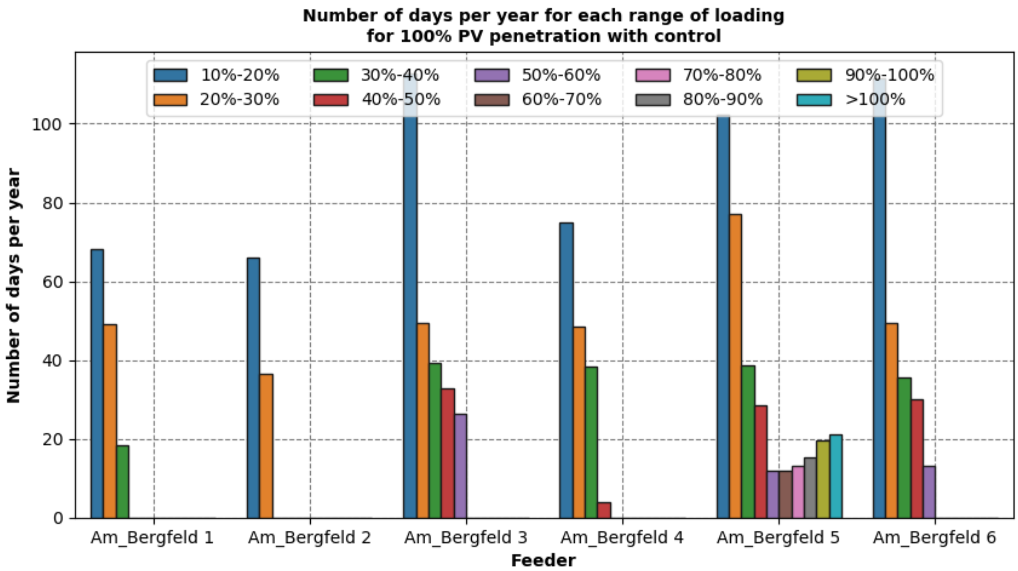

Figure 92 Total number of days per year per loading range for Am Bergfelde network

As can be seen, the network loading falls into the range of 10%-20% loading for most of the time during the year. In general, the network can be considered to be a resilient network and thus does not experience loading violations for most of the year. Additionally, since this analysis is based on PV penetration, the loading is dependent on the amount of PV generation the network experiences during the year (this will be further discussed in Replicability section). Am Bergfelde 5 experiences the widest range of loading throughout the year and, as was shown in Figure 91, exceeds the loading limits of 100%. In terms of duration, this occurs for a total of 21 days (5.75%) per year. Although, this is considered a violation, network design usually caters for such overloading, especially when its only for a short duration.

Reactive power control: Cosφ(P)

The control function implemented for the PV generators is based on the cosφ(p) as per the LV Grid Code in Germany [7]. Based on the above, an analysis was performed in order to investigate the total amount of active and reactive power within the entire network with increasing levels of PV penetration. For the case of 50% PV generation, the total network active and reactive power with no control and with control functions implemented, is shown in Figure 93.

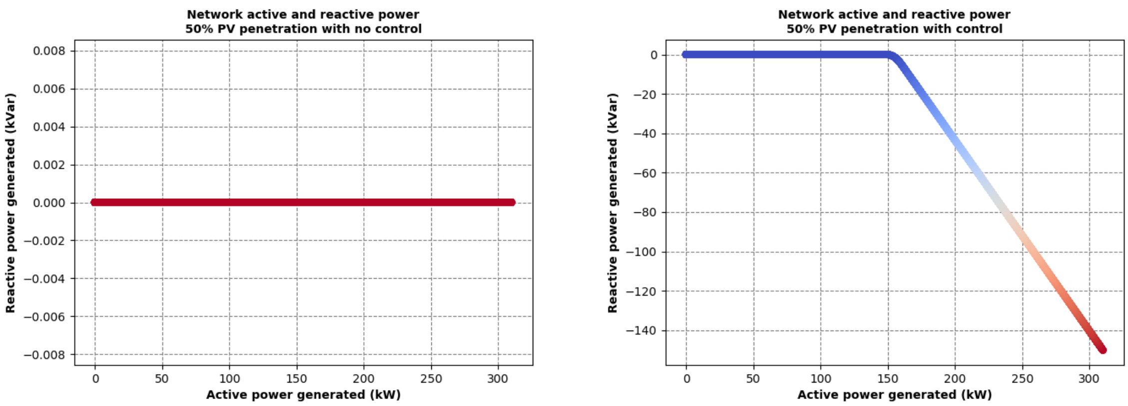

Figure 93 Network power with no control(left) and with control (right):50% PV penetration

As can be seen a total of 307 kW of active power is generated when 50% of customers in the network are equipped with PV generators. Additionally, Figure 93 (left) shows that when there are no controllers activated, no reactive power is injected into the network. On the other hand, Figure 93 (right), shows that, due to the voltage control, a total of 150 kVar is injected when there is 307 kW of active power. Similarly, the case for 100% PV penetration is shown in Figure 94.

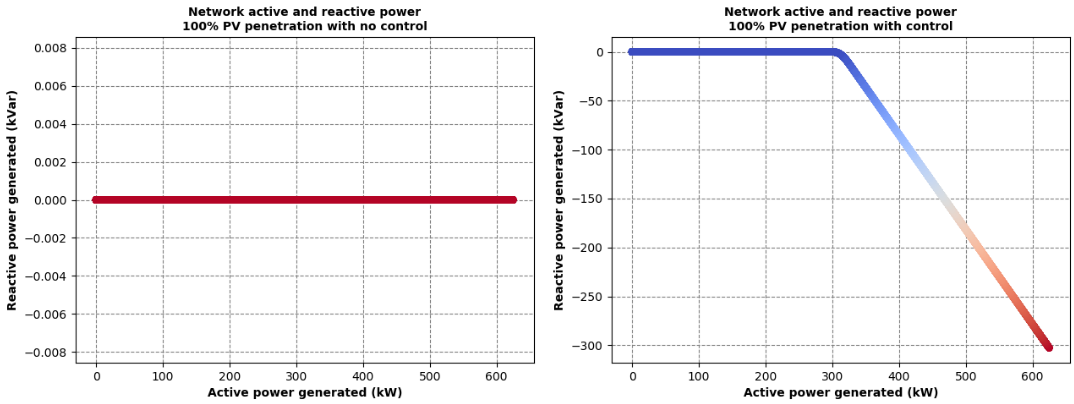

Figure 94 Network power with no (left) and with control (right): 100% PV penetration

When 100% PV penetration is achieved, the total amount of active power injected into the network is 615 kW. By implementing the control function of the PV, a further 305 kVar is generated. In both cases it is evident that the network behaves according the requirements depicted in the Grid code.

Voltage variation with increasing PV penetration

For this analysis, the voltage variation within the network is also observed in order to identify whether there is a voltage violation at any point thought-out year while the network is in operation when the amount of PV penetration is increased. In this case, both the maximum and minimum voltage variation in analysed.

Maximum voltage

The maximum voltage variation results from the quasi-dynamic simulation for the entire year of 2017 is shown in Figure 95.

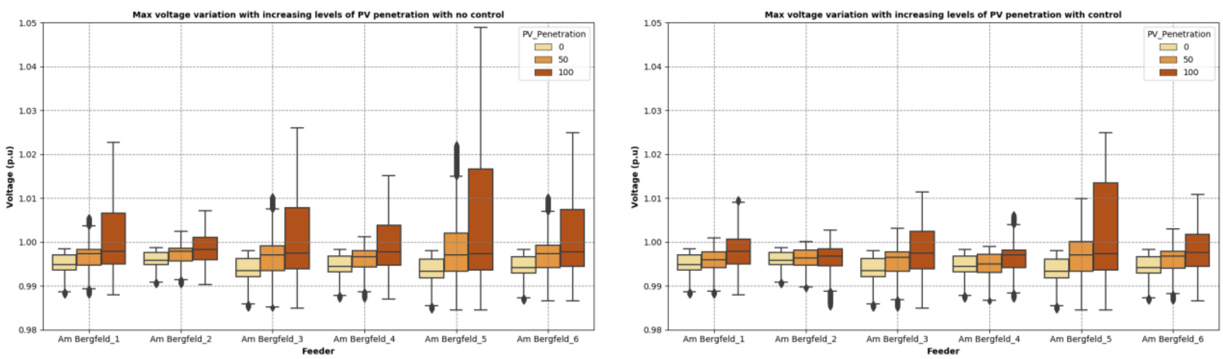

Figure 95 Maximum voltage variation with increasing levels of PV penetration with no control (left) and with control (right)

When considering the voltage limits set within the grid code which restricts the LV voltage band to 1.03 p.u. and 0.96 p.u[20], it can be seen that a voltage violation only occurs on Am Bergfelde 5 when there is 100% PV penetration with a maximum voltage of 1.049 p.u. Although, the network does not experience many voltage violations for most part of the year, it nonetheless indicates that voltage variations should not be ignored when implementing increased levels of PV penetration on a network, since these extreme cases do exist and could possibly be magnified when load consumption from customers is increased. When the control functions are active, it can be seen that on all feeders the voltage level is well within the voltage limitations and do not exhibit any violations.

Minimum voltage variation

The results of the quasi-dynamic simulation, with respect to the minimum voltage per feeder, is shown Figure 96.

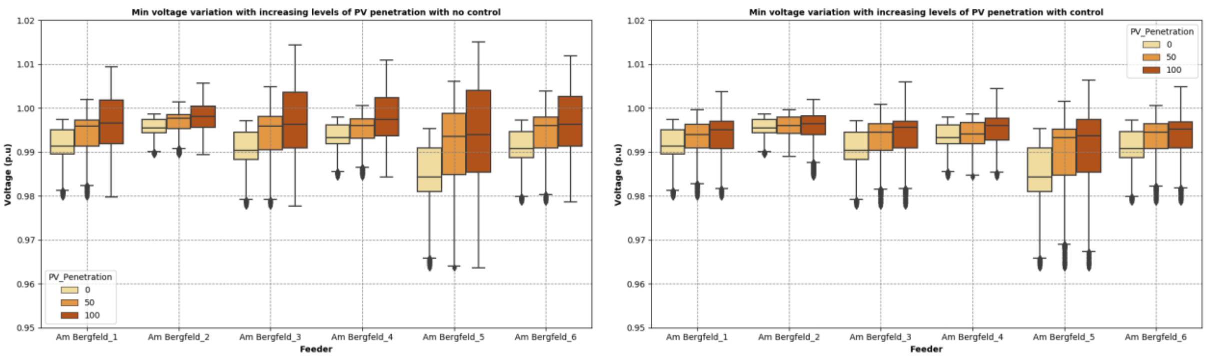

Figure 96 Minimum voltage variation with increasing levels of PV penetration with no control (left) and with control (right)

In the case where there is no control function implemented, the network does not exhibit any voltage violations with respect to the minimum voltage, when the PV penetration is increased. Similarly, when the control functions are activated, the minimum voltage is within the specifications according to the LV Grid code.

In both cases, the cosφ(p) inverter function allows for voltage control such that the network voltages are brought within the voltage limits set within the grid code. In particular, Am Bergfelde 5 no longer experiences an over voltage violation at any time within the year when the control functions are implemented.

Increase in rated power PV generation

For demonstration purposes, the scenario where all customers are equipped with a PV generator and the rated power of the device is scaled to 10 kW_p is shown Figure 97. As can be seen, when the rated power of the PV Generator is increased, so the amount of network loading is increased. In this scenario thermal loading violations are experienced on Am Bergfelde 3 and Am Bergfelde 5 in the case when there is no PV control active. Furthermore, thermal loading violations are further increased when the control functions are active as shown where four out of the six feeders (Am Bergfelde 3-6) of the network indicates over loading.

[20] The cumulative relative voltage rise caused by DER must not exceed 10%

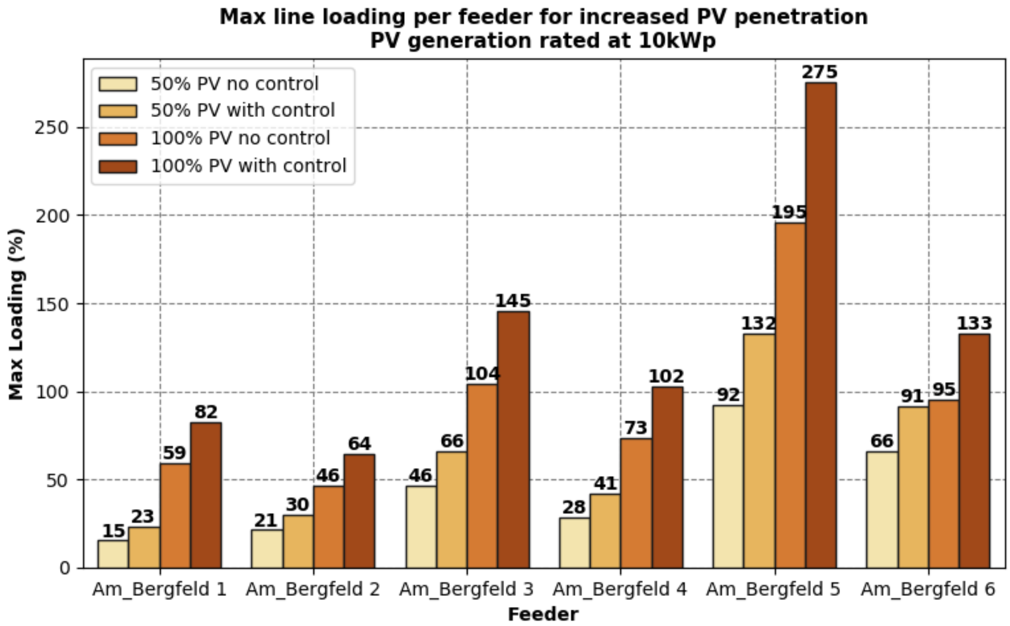

Figure 97 Maximum line loading per feeder with an increase in 10 kW_p PV penetration

For the case of maximum voltage variation analysis, over voltages are expected with high penetration of PV and thus are clearly are evident across the entire network when no control functions are implemented, as shown in Figure 98.

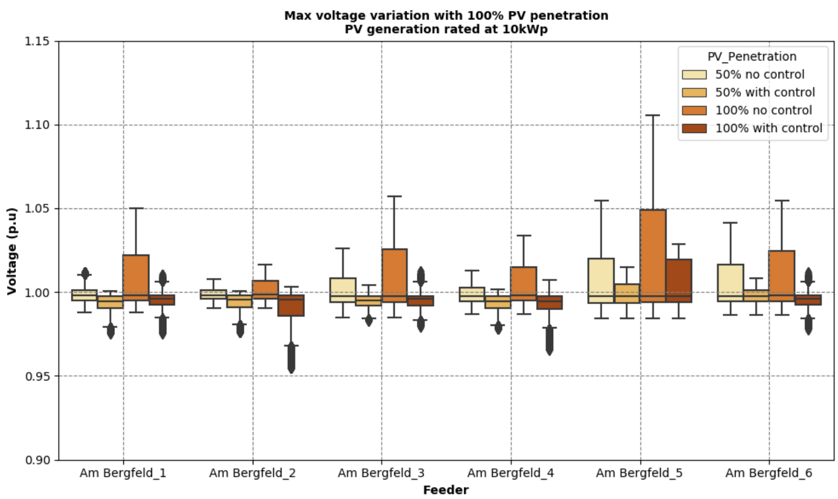

Figure 98 Maximum voltage variation with 10kW_p PV penetration with and without control

In the case when no PV control functions are implemented, a maximum voltage of 1.105 p.u is visible on Am Bergfelde 5. When control functions are implement, it is visible that there is a reduction of the degree of voltage violations, however they are not completely removed, since on Am Bergfelde 5, the voltage still exceeds 1.03 p.u.

UC1-Replicability: Feed in Management

The replicability study for UC1, takes into consideration the increase in PV penetration into the network when feed in management is present.

Mean feeder loading analysis

The mean loading of Am Bergfelde 5 per day when there 50% PV penetration, both with and without feed in management, is shown in Figure 99.

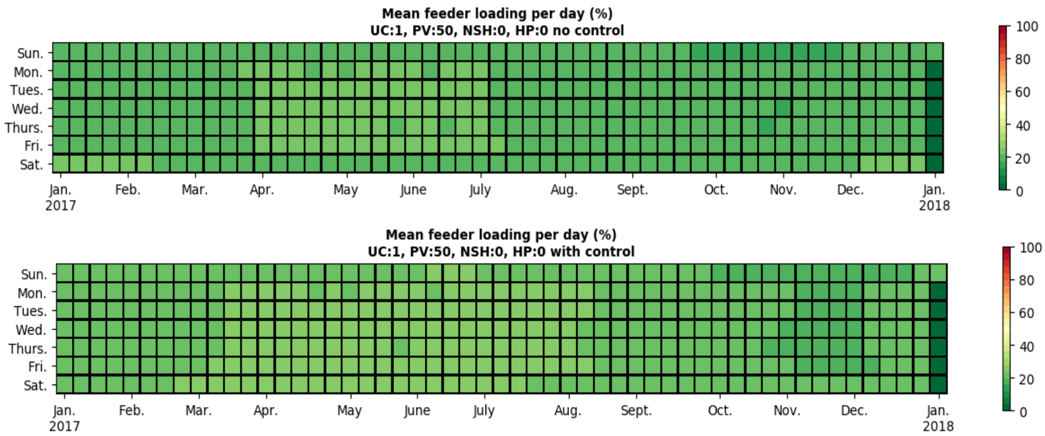

Figure 99 50% PV penetration without (top) and with control (bottom)

As can be seen, the mean feeder loading per day still remains in the 20%-30% loading range when there is an increase in PV penetration on the feeder. A slight level of increase in feeder loading can be seen during the summer months, when there is an increased level of PV generation. Additionally, where the control functions are implemented (bottom), an increase in loading is seen, and is attributed to the increase in reactive power, as was explained in the scalability section of UC1. The impact of the mean feeder loading becomes more prominent when there is a further increase in PV penetration and can be seen in Figure 100 for the case of 100% penetration.

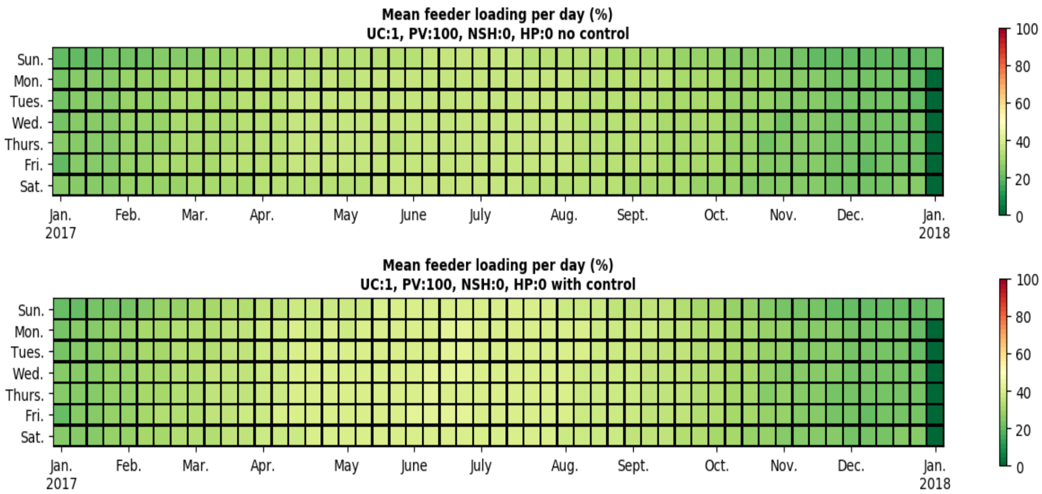

Figure 100 100% PV penetration without (top) and with control (bottom)

Based on the results shown, an increase in feeder loading becomes more prominent during the summer months, as expected. The mean feeder loading per day is seen to increase up to 52% for Am Bergfelde 5 during the summer months and when there is an increase in reactive power injection. These results show that there is no feeder loading violation when considering the mean value of the feeder loading per day.

Maximum and minimum voltage variation with increasing PV Penetration

The maximum and minimum voltage variation over the course of the year for increasing levels of PV penetration is shown in Figure 101.

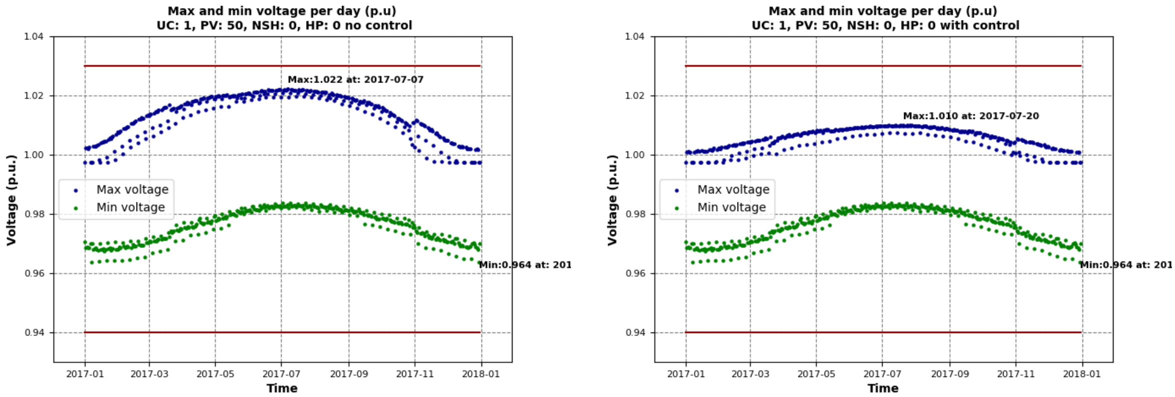

Figure 101 Maximum and minimum voltage variation for Am Bergfelde 5 with no control (left) and with control (right) for 2017 with 50% PV penetration

When there is 50% PV penetration, the maximum and minimum voltage variation remains within the limits set by the LV grid code. However, it can be seen that during months with increased PV generation i.e. summer, an increase in both the maximum and minimum voltage occurs in comparison to the winter months. When there is reactive power control implemented (Figure 101 right), the variation of the voltage levels is reduced as voltage control becomes more prominent. The results for 100% PV penetration is shown in Figure 102.

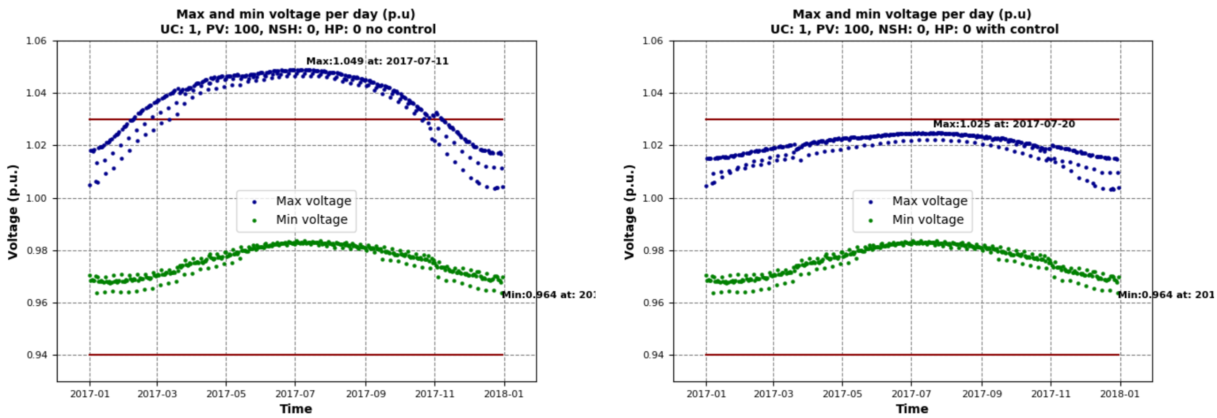

Figure 102 Maximum and minimum voltage variation for Am Bergfelde 5 with no control (left) and with control (right) for 2017 with 100% PV penetration

Voltage violations are clearly evident in the case where there are no voltage control functions implemented. Maximum voltage violations are seen as early as February and are evident every day through the summer period and are only seen to subside in November. The maximum voltage is 1.049 which occurs on 11-07-2017. When the control functions are implemented, the maximum voltage violations are avoided for the entire period under study (even during summer). Although an increase in voltage exists during the summer period, the maximum value of 1.025 still remains within the limit set by the grid code and thus the feeder can be operated accordingly.

UC2-Scalability: Demand Response

This use case incorporates the analysis of incorporating the demand response of customers connected within the network based on their overall household consumption and flexible devices. In this use case, only night storage heaters (NSH) and heat pumps (HP) are considered. The load profiles and their respective control functions was presented previously. Initially, the penetration of each device type will be investigated individually and thereafter in combination with each other. It should be noted that a similar approach is followed, when increasing the penetration of devices, as was conducted in UC 1 with respect to PV penetration.

Increase in NSH Penetration

NSH distribution per feeder

As in the case of PV penetration, a monte-carlo approach was implemented in order to allocate a NSH device to a respective household. The results of the allocations are shown in Figure 103.

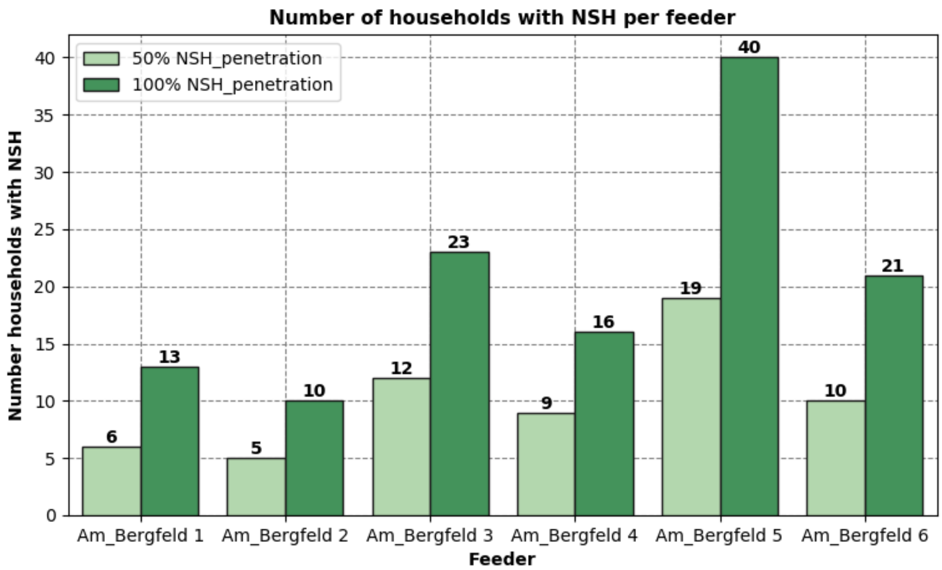

Figure 103 Number of households equipped with NSH per feeder

In case of 50% penetration, the distribution of households equipped with a NSH ranges from 46% on Am Bergfelde 1 to 56% on Am Bergfelde 4. Thus, the variation of the distribution of NSH per feeder does not vary to a large degree and can be considered fairly even. In this regard, the impact of NSH penetration across the entire network is evenly represented.

Maximum line loading per feeder with increasing NSH Penetration

In this scenario, the maximum line loading per feeder when there is an increase in NSH penetration is investigated. Figure 104 shows how the increase of NSH penetration with no control consequently increases the maximum line loading per feeder. This is as expected since increasing the penetration of NSH devices essentially increases the consumption of each household, thereby increasing the total load demand.

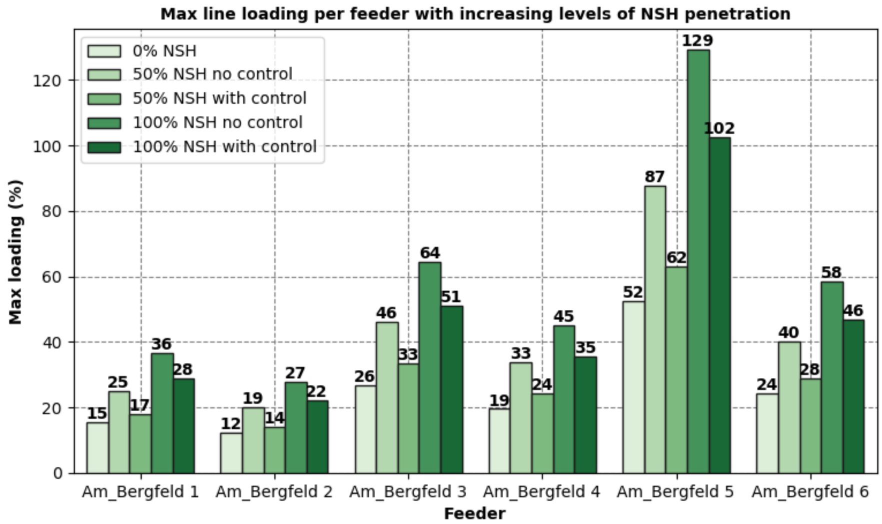

Figure 104 Maximum line loading per feeder with an increase in PV penetration

When the control functions are implements, the total amount of load is reduced in comparison to that when no control is implemented. Additionally, it can be seen that only in the case of Am Bergfelde 5, that feeder over loading is evident when 100 % NSH penetration is implemented both with no control (129%) and with control (102%). Therefore, it can be concluded that, if every household within the Am Bergfelde 5 network were to have a 3 kW_p NSH installed, the network experiences an over loading, despite the implementation of the demand side management techniques through the implementation of control functions.

Based on the above, where there is 100% NSH penetration with no control which resulted in the maximum increase in thermal loading, Figure 105, shows the total duration over the entire year for which these violations occur.

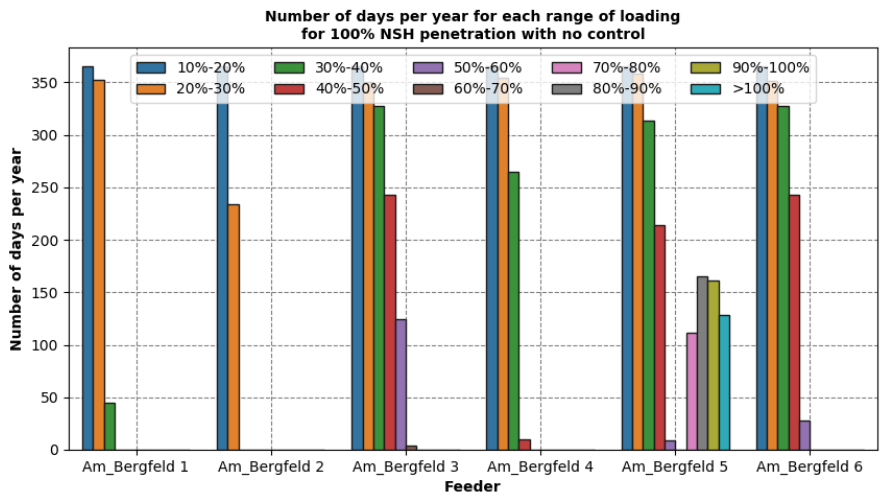

Figure 105 Total number of days per year per loading range for Am Bergfelde network

As can be seen, the Am Bergfelde 5 feeder, exhibits a maximim line loading violation for 125 days of the years and thus it shows that the control strategies of demand response is vital when ensuring that the network is operated effectively.

Voltage variation with increasing NSH penetration

Maximum voltage variation

The amount of maximum voltage variation per feeder with increaseing levels of NSH penetration is shown in Figure 106. For the case where no control fucntions are implemented, none of the feeders experience any voltage violations, as all the maximum voltages over the entire year are within the voltage bandwiths in accordance with the LV Grid Code.

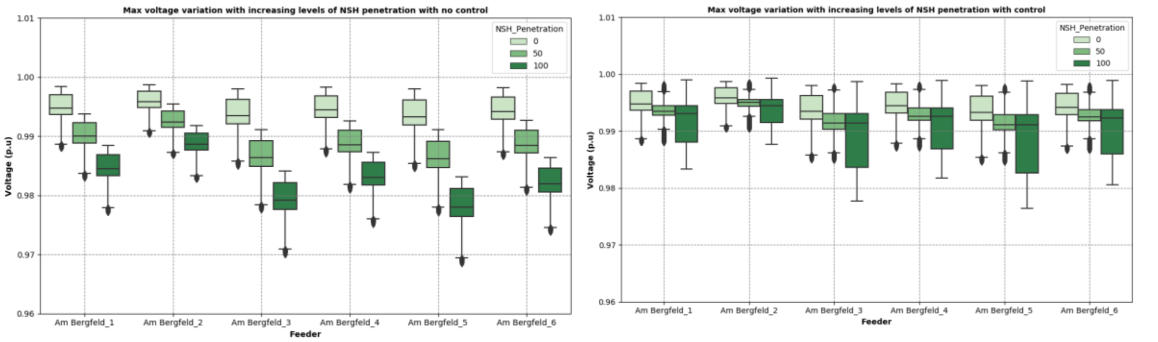

Figure 106 Maximum voltage variation with increasing NSH penetration with no control (left) and with control (right)

However, it should be noted that by increasing the penetration of NSH, and therefore load, the maximum voltage levels decrease. This is as expected, since increasing the load cause a reduction of the voltage, especially at the end of a feeder (i.e. the point farthest away from the substation). This is particularly noticeable on Am Bergfelde 5, which is the longest feeder within the Am Bergfelde network. In the case where the demand response control functions are implemented, the variation in voltage level do not vary to a large degree, as shown in Figure 106 (right). In this case, the maximum voltage level does not extend more than 1 p.u or below 0.986 p.u and, thus, is well within the voltage band with stipulated in the grid code.

Minimum voltage variation

In this scenario, the impact on the minimum voltage variation with increasing levels of NSH penetration is analysed. Figure 107, shows the results of the minimum voltage variation without and with control functions implemented.

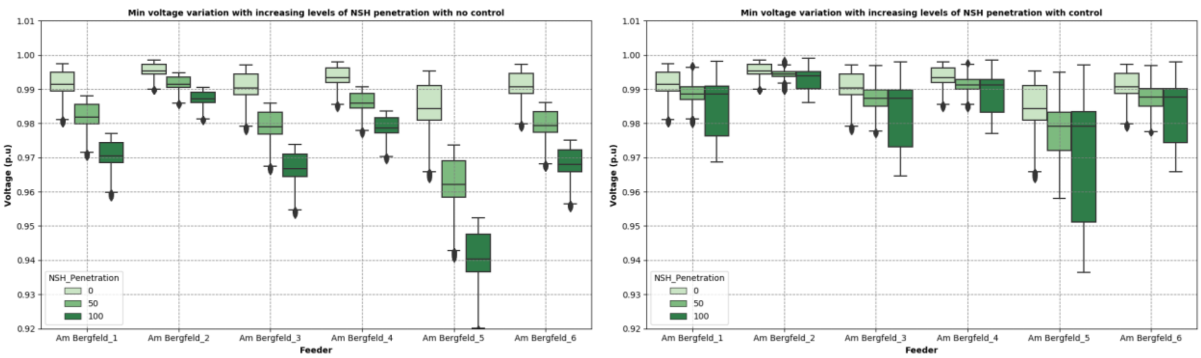

Figure 107 Minimum voltage variation with increasing NSH penetration with no control (left) and with control (right)

As can be seen, the minimum voltage variation for Am Bergfelde 5 exhibits a voltage violation in the case where 100% NSH penetration is implemented. Despite, the control functions being implement, which results in a reduction of customer load, voltage violations are still presents.

Increase in HP Penetration

In this section, the increase of HP penetration on the Am Berfgelde network is investigated. This is done independently of penetration of any other device (i.e. PV or NSH) such that the effects of HPs on the network can be investigated.

HP distribution per feeder

As with the PV and NSH penetration, the random function was implemented, and thus random households were allocated a HP device. The outcome of this randomisation is shown in Figure 108.

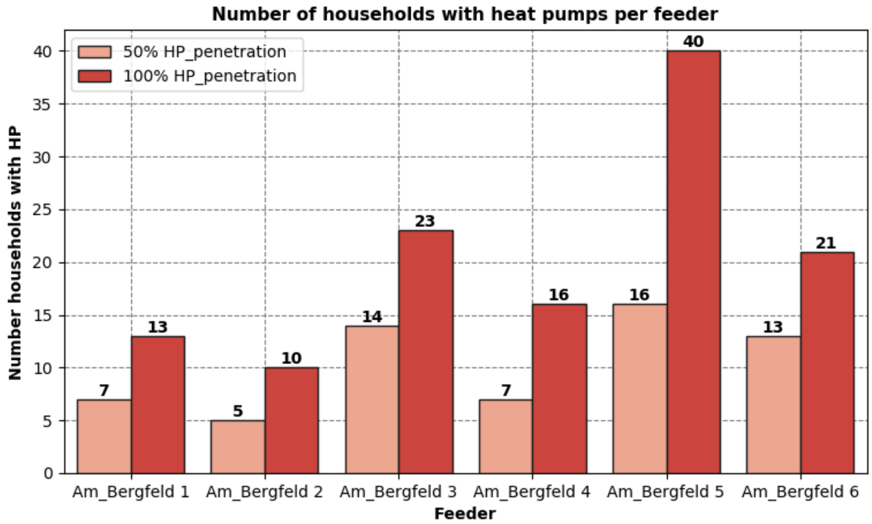

Figure 108 Number of households equipped with HP per feeder

As shown in the case of 50% penetration, the allocations of HP devices for each household per feeder ranges from 40% on Am Bergfelde 5 to 62% on Am Bergfelde 6.

Maximum line loading per feeder with increasing levels of HP Penetration

Once the aforementioned household allocations of households with HP was conducted, a study on the effects of increasing the HP penetration on line loading was performed. The results of the study for each scenario is shown in Figure 109.

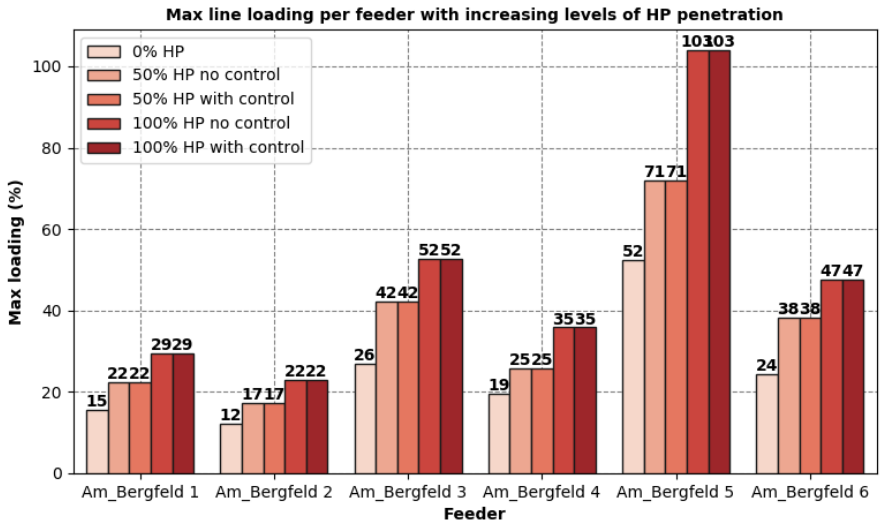

Figure 109 Maximum line loading per feeder with an increase in HP penetration

As can be seen, the maximum line loading per feeder increases with increasing levels of HP penetration. For the case of Am Bergfelde 5, a feeder over load violation is evident in both cases (103%) when the control functions are and are not implemented. It is interesting to note, that even a 40% HP household allocation causes a loading violation on Am Berfelde 5. Although this is considered to be the 'worst case' since the HP are implemented with the same profile and a coincidence factor of 1, it suggests in the case of Am Bergfelde 5, that less than 40% of household are able to be equipped with a HP in order for the network to avoid loading violations, of which may lead to dissatisfaction of customers.

On all feeders, it is evident that the control functions implemented do not have a significant impact with respect to the maximum line loading per feeder. This is due to the fact that the amount of load due to the HP is not as significant as that of other load devices, i.e. NSH. Additionally, the restriction of load reduction by 30% for 30 min at a time for a maximum of 3 times per day does not prove to have high value in terms of load reduction with respect to the entire feeder, even when there is a coincidence factor of 1 and that all HP load are reduced simultaneously.

The duration of maximum line loading violations for each which occurs within the year of analysis is shown in Figure 110.

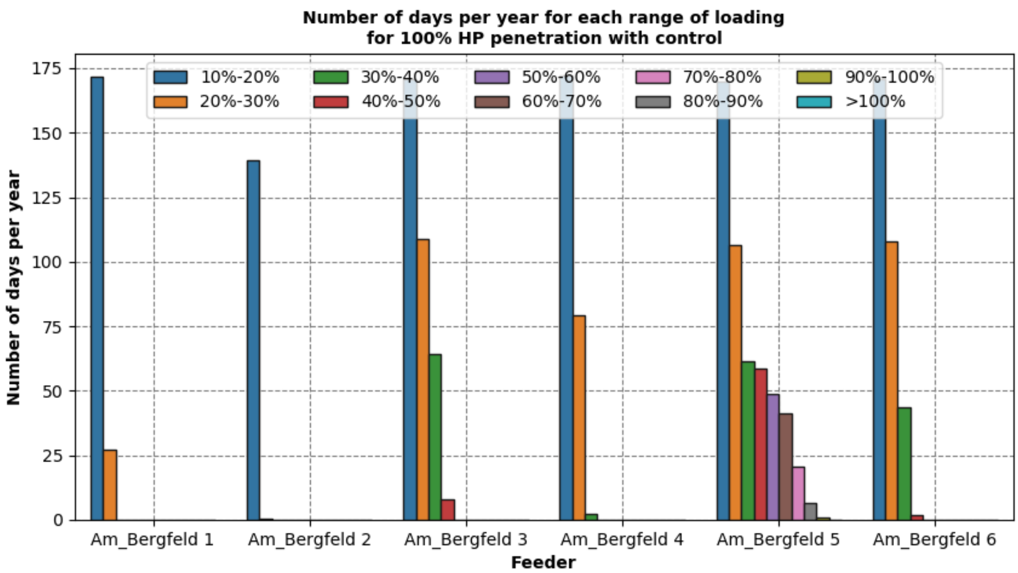

Figure 110 Total number of days per year per loading range for Am Bergfelde network

The results indicate that the occurance of maximum line loading on Am Bergfelde 5 for which the line is loaded more than 80% is less than 10 days of the year. As previously discussed, the impact of HP penetration with and without control functions implemented, does not pose a significant threat to the operation of the network.

Voltage variation with increasing HP penetration

The impact on voltage variation when there is an increase in HP penetration is discussed in the followings section.

Maximum voltage variation

The effects of increasing HP penetration on the feeder voltage with and without the control function on the HP, is shown in Figure 111.

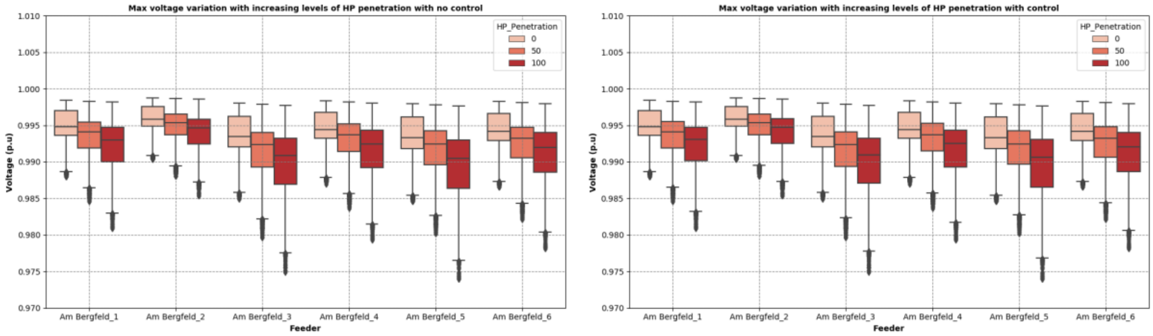

Figure 111 Maximum voltage variation with increasing HP penetration with no control (left) and with control (right)

As can be seen, the overall voltage of the network decreases when there is an increase in HP penetration. For the case of Am Bergfelde 5, which sees the lowest reduction of voltage which ranges from a maximum of 0.99 p.u to a minimum of 0.976 p.u. This is well within the voltage band with specified in the LV grid code. The voltage variation for the case where there is demand response active through the use of control functions is shown in Figure 111 (right). As with the levels of line loading, the maximum voltage variation does not differ in the case where there are control functions implemented and no voltage violations are present.

Minimum voltage variation

With respect to the minimum voltage variation with increasing levels of HP penetration, the results for the case of with and without control is shown in Figure 112.

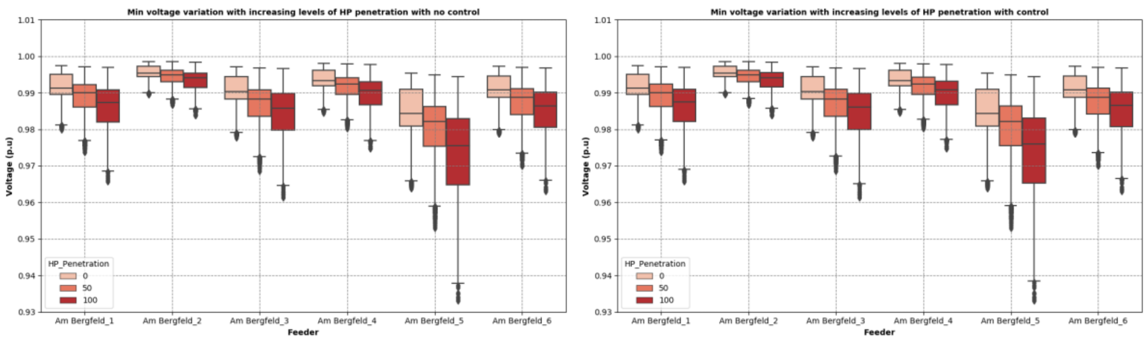

Figure 112 Minimum voltage variation with increasing HP penetration with no control (left) and with control (right)

In the case of no control, a voltage violation is present in the case of Am Bergfelde 5, which is seen to occur with the year under consideration. This is also visible in the case where control functions are implemented. Despite these violations, they are only occurred as a minimum point within the year, whilst for the majority of the year, the minimum voltage is within 1 p.u and 0.96 p.u respectively.

In all cases, with the control functions are implemented, the variation of voltage levels does not change significantly in comparison to when there is no control. In both cases, however, the voltage level does not produce any violations when there is an increase in HP penetration. As mentioned previously, the impact of demand response, therefore, does not have a significant impact with respect to increasing the penetration of HP in the network when line loading and voltage violations are considered.

Increase in NSH and HP Penetration

In this scenario, the simultaneous increase in penetration of NSH and HP is considered. This is to investigate the impact of demand response when the network contains both devices as an additional load. In reality, it is not expected that households would be equipped with both devices simultaneously, however the extreme case is presented here for indicative purposes. The allocation of household for each device was done separately, thus, caters for the probability where some households may or may not contain both devices. The number of each device allocated to each household per feeder is shown in Figure 113.

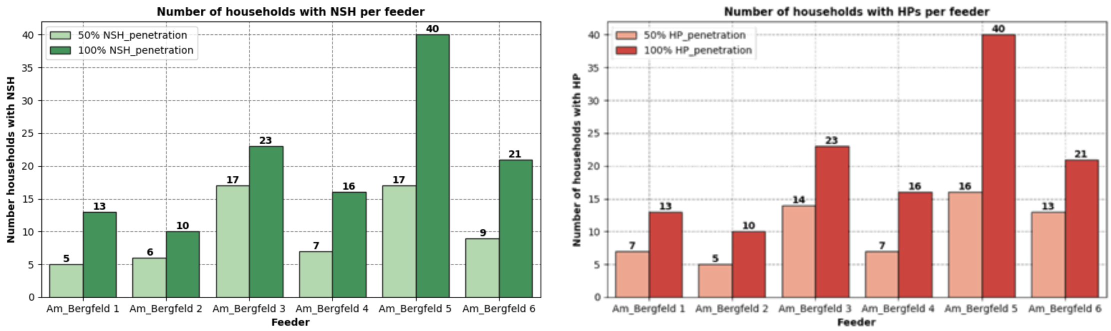

Figure 113 Total number of households equipped with a NSH (left) and/or a HP (right)

As can be seen, the amount of NSH and HP allocations per feeder is not identical, since the allocation algorithm was applied separately. As such, the randomised allocation of each device did not cater for the fact that a heating device may already be allocated to the households, and therefore it is possible that some households may be equipped with both. In this case, the DSO would need to be aware that some households are able to participate in demand response initiatives based on more than one device type.

Maximum line loading per feeder with increasing levels of NSH and HP Penetration

The maximum line loading per feeder, with increasing levels of both NSH and HPs is shown in Figure 114.

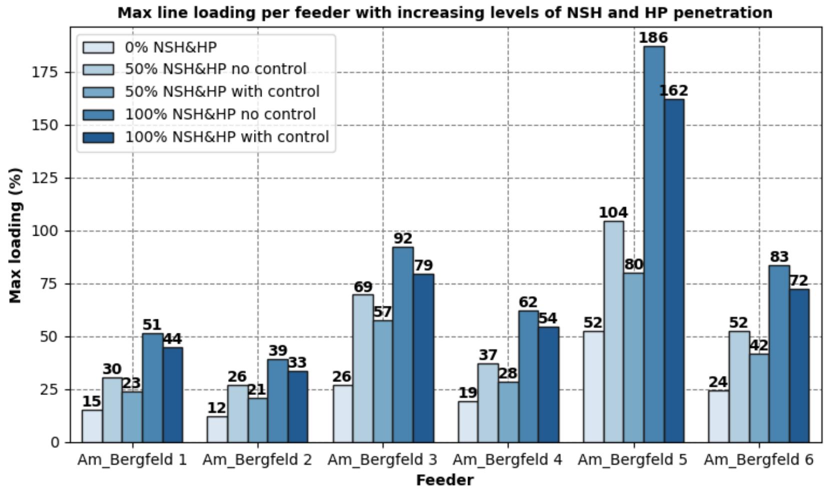

Figure 114 Maximum line loading per feeder with an increase in NSH and HP penetration

As indicated in the results, it is clear that there is indeed, an increase in maximum line loading when there is an increase in the penetration of NSH and HPs (i.e. load devices). This is as expected since the demand load profile for customers would increase. More specifically, Am Bergfelde 5, shows a loading violation of 104%, in the case when there is 50% penetration of both devices and there are no control functions implemented. By introducing, the demand response by activation of the control functions, the maximum line loading of Am Bergfelde can be reduced to 80% (i.e by 24%). Furthermore, in the case of 100% penetration, where all households are equipped with a NSH and a HP, a maximum line loading on Am Bergfelde 5 of 186% is visible. When demand response is implemented on both device types, the maximum line loading can then be reduced to 162%. Despite this reduction however, Am Bergfelde 5 still becomes overloaded for numerous times of the year and thus cannot facilitate the increase in load. The total duration in days for each loading range for all feeders when there is 100% penetration, with no demand response, is shown in Figure 115.

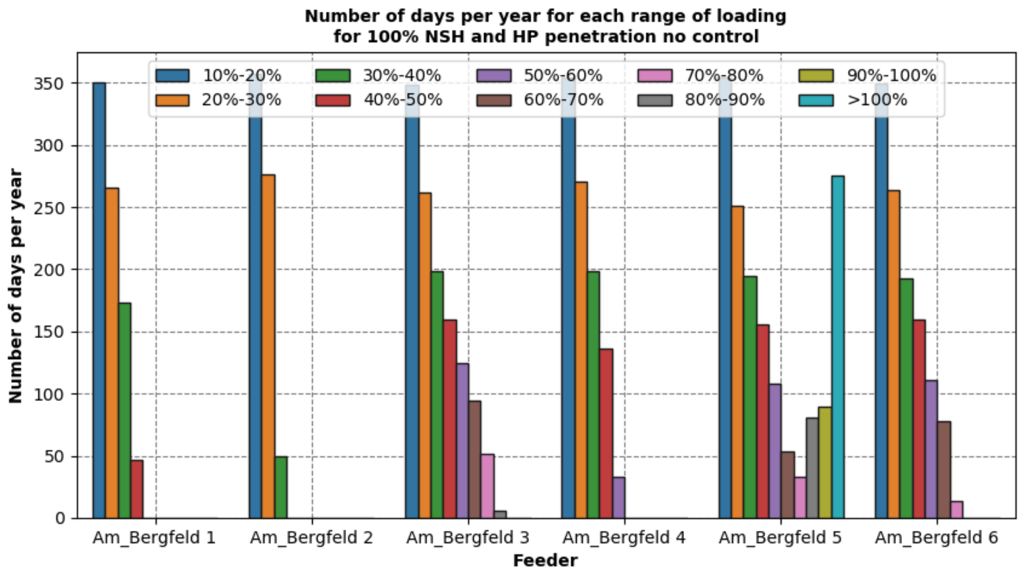

Figure 115 Maximum line loading per feeder with an increase in NSH and HP penetration

Since Am Bergfelde 5 is the only feeder which exhibits over loading, it can be seen that it exceeds the loading limit of 100% for 260 days of the year. This high loading in terms of both magnitude and duration shows that the feeder cannot be operational if all households on the feeder are equipped with both devices, even if they are both connected with the inclusion of demand response techniques. Based on previous analysis, it was shown that NSH have a larger impact on feeder loading than that of HP devices due to their higher value of rated power and due to the extended duration when NSH can be turned off by the DSO. Therefore, it is reasonable to assume that the overloading can be attributed to the increase in penetration of NSH as opposed to that of the HP. However, it should be emphasised that the increased combination of the number of NSH, together with HP, has a negative impact on Am Bergfelde 5 with respect to loading violations.

Voltage variation with increasing NSH and HP penetration

In this section, the variation of voltage with increasing penetration of load devices (NSH & HP) is investigated.

Maximum voltage variation

In Figure 116, the maximum voltage variation with and without demand response is shown.

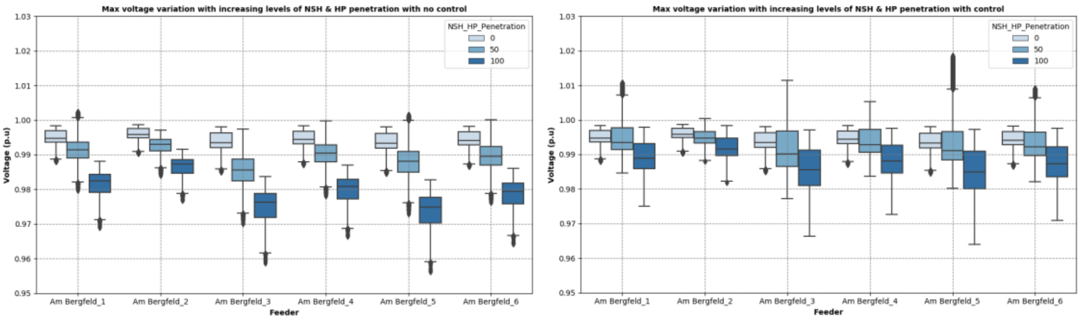

Figure 116 Maximum voltage variation with increasing NSH and HP penetration with no control (left) and with control (right)

The increase in load device penetration causes a reduction in the voltage over the entire network. The largest reduction is, again, seen on Am Bergfelde 5 where the voltage extends past 0.96 p.u. when 100% load (NSH and HP) penetration with no control is implemented. However, based on the additional statistics, the median is 0.986 p.u and thus falls comfortably within the voltage band with in terms of regulations. The voltage variation for when the control functions for each of the load devices are implemented is shown in Figure 116 (right). As expected, when the control functions are activated so the total of each household load demand is reduced and therefore the impact on voltage is also reduced. In this scenario it is therefore evident that no voltage violations occur at any time within the year under study.

Minimum voltage variation

The minimum voltage variation, with increasing in NSH and HP penetration is shown in Figure 117.

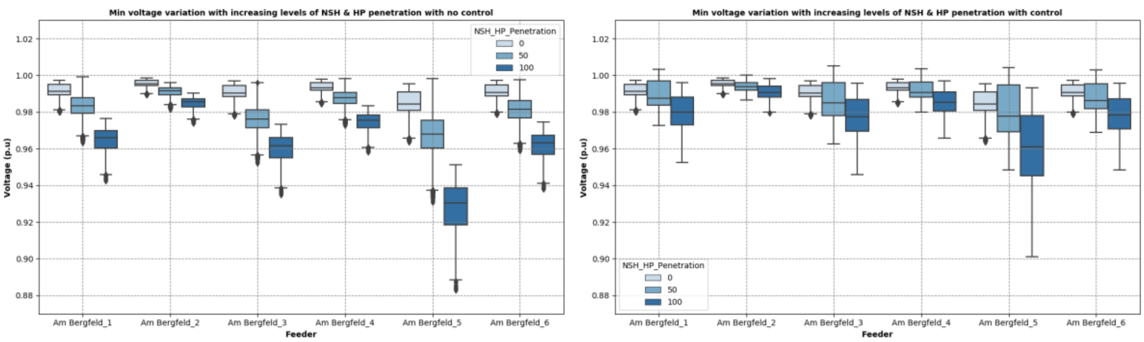

Figure 117 Minimum voltage variation with increasing NSH and HP penetration with no control (left) and with control (right)

As seen, the minimum voltage variation indicates that there are voltage violations on Am Bergfelde 1, Am Bergelde 3, Am Bergfelde 5 and Am Bergfelde 6 when there is an increase of NSH and HP devices up to 100%. This voltage violation extends as low as 0.889 p.u in the worst case on Am Bergfelde 5. When the demand response functions are implemented, the minimum voltage only causes a violation in the extreme case of Am Bergfelde 1 and am

Bergfelde 3, while on Am Bergfelde 5 the lowest voltage is near to 0.9 p.u. when 100% penetration is conducted. Additionally, it can be seen that voltage violations also exist in the case when there is 50% penetration but, in general, is to a lesser degree. This suggests that the DSO, will have to consider the amount of increased load devices of households, in particular on Am Bergfelde, if is to operate the network without any voltage violations.

UC2- Replicability: Demand response

In this section, the effects of demand response in terms of seasonality is investigated.

Mean feeder loading with increasing NSH penetration

The mean feeder loading on Am Bergfelde 5, when there is 50% NSH penetration, is shown in Figure 118.

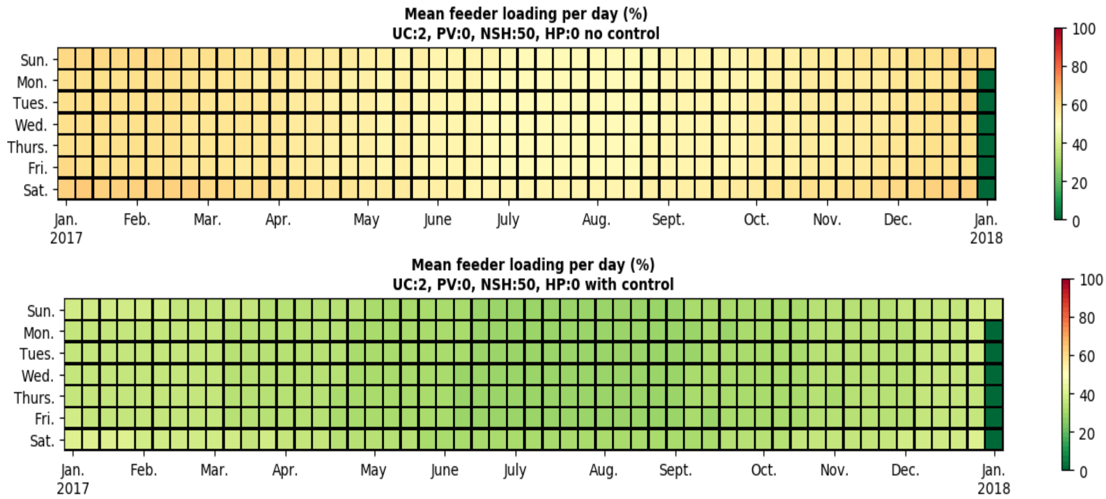

Figure 118 Mean feeder loading per day with 50% NSH penetration without (top) and with control (bottom)

As can be seen, the amount of feeder loading does not vary over the course of the year, especially in the case when there is no control function implemented and thus is not seasonal dependant. This is due to the simplified model used for the NSH within this study, where its load function does not vary during the various seasons of the year. During the quasi dynamic simulation performed in DigSilent Power Factory, the element is modelled identically for each load flow performed as it sweeps across the year. Thus, in summer, the model represents that it is still operational during the summer months. In reality, this is unlikely to occur, since NSH would most probably not be in use. In this case, it would be expected that the overall loading of the feeder would be reduced during the summer months. For the purpose of this study, the worst-case scenario is assumed, and the load is therefore, considered throughout the year, since the effects of demand response is the main focus of the study. In this regard, it can be seen in Figure 118, that when demand response functions are implemented the overall mean feeder loading per day is reduced to between 30-40%, in contrast to 50% mean loading when demand response is not implemented.

Similarly, the effects of seasonality are not clearly observed in Figure 119, when there is a 100% penetration of NSH, as previously explained. However, it can be seen that the mean feeder loading per day, is violated for every day of the year, when there is no demand response technique implemented within the feeder.

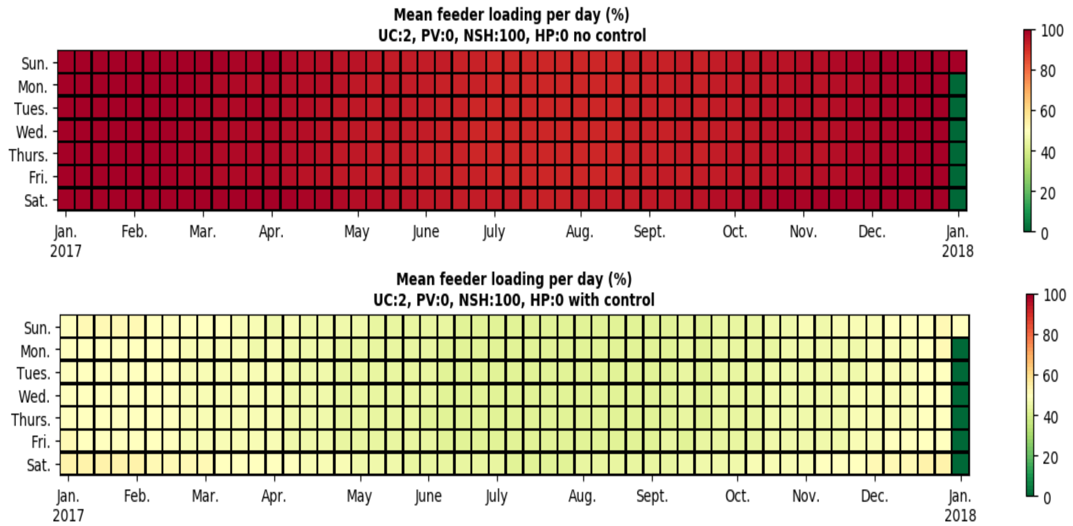

Figure 119 Mean feeder loading per day with 100% NSH penetration without (top) and with control (bottom)

When the control functions are implemented, the effects are to reduce the mean feeder loading to 50%. The DSO should take this into consideration in order facilitate the increase in load on the Am Bergfelde network and should consider that this is only possible when sufficient demand response techniques are implemented such that feeder loading violations are prevented.

Maximum and minimum voltage variation with increasing NSH penetration

In this section, the maximum and minimum voltage variation in terms of seasonality is explored. Firstly, the case when there is 50% NSH penetration, is shown in Figure 120.

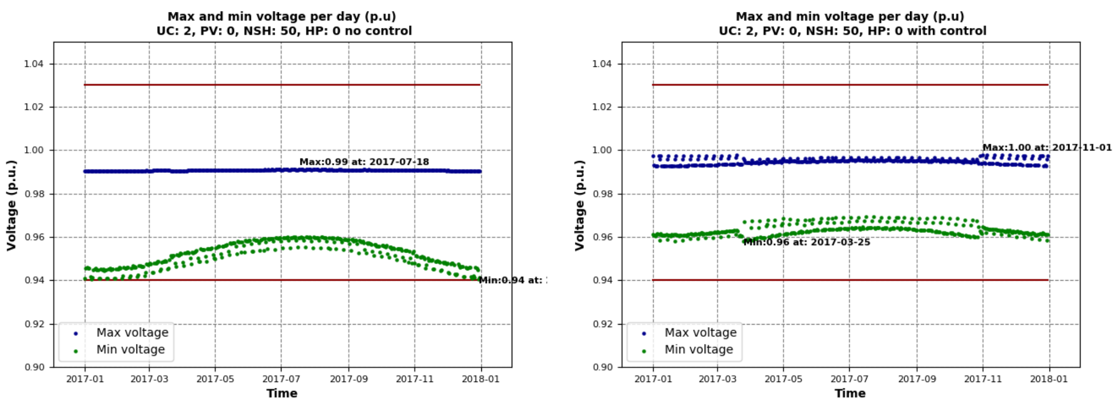

Figure 120 Maximum and minimum voltage variation for Am Bergfelde 5 with no control (left) and with control (right) for 2017 with 50% NSH penetration

In the first plot, the maximum voltage variation is minimal with an average centred around 0.99 p.u. The minimum voltage variation however, reaches the minimum threshold of 0.94 p.u. during the winter season. During summer, the minimum voltage increases up to 0.96 p.u from 0.92 p.u. when the summer season it at its peak. This increase seen during the summer season is attributed to the decrease in feeder load based on the standard load profile, as was discussed previously. During times when the NSH is able to be controlled (right) the maximum voltage is 1 p.u, while the minimum voltage variation increases to an average of 0.96 p.u. during the summer season.

The case for when there is 100% NSH penetration is shown in Figure 121 where an under-voltage violation exists for the entire duration of the year.

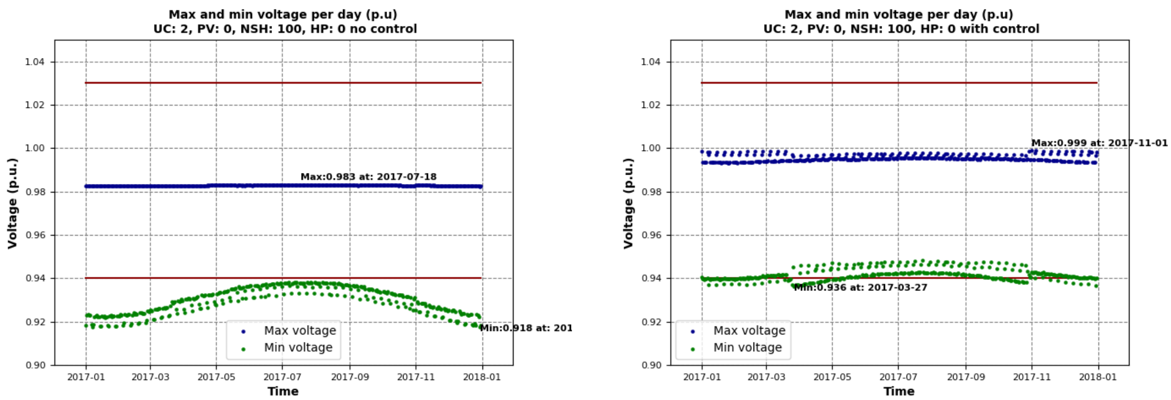

Figure 121 Maximum and minimum voltage variation for Am Bergfelde 5 with no control (left) and with control (right) for 2017 with 100% NSH penetration

Similarly, the case where demand response initiatives are implemented shown in Figure 121 (right) also exhibits under voltage violations during the year. Again, these under voltages can be attributed to the increase in load from households when they are equipped with NSH. It can be reiterated that the changes seen during the summer periods are worst case conditions since it is expected that households would not make use of NSH during the summer months.

Mean feeder loading with increasing HP penetration

In this section, the seasonal effects when there is an increase in HP penetration on the Am Bergfelde 5 network. The mean feeder loading for 50% HP penetration with and without demand response is can be seen in Figure 122.

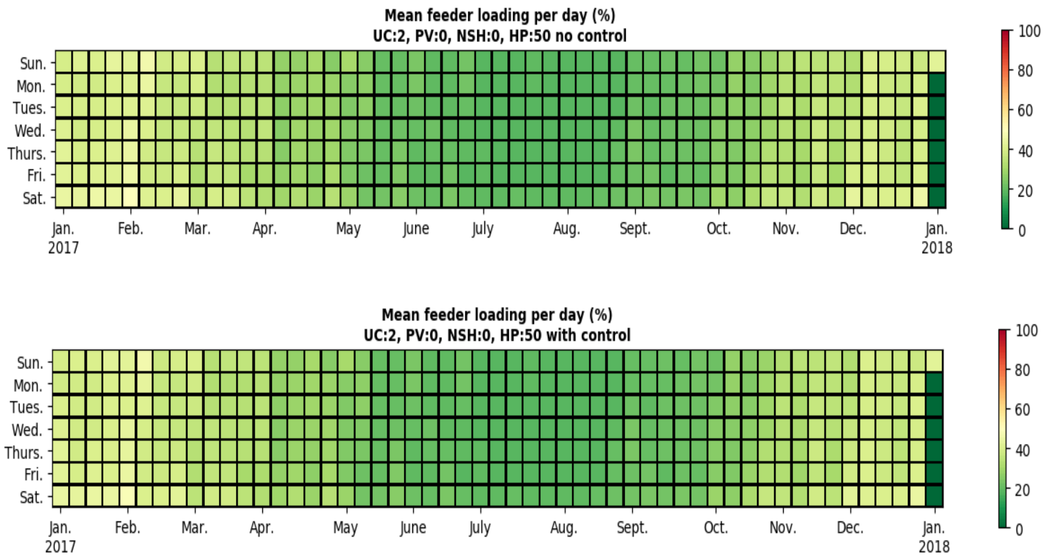

Figure 122 Mean feeder loading per day with 50% HP penetration without (top) and with control (bottom)

As was shown,in the scalability section, the impact of demand response on HP is negligible, as can be seen where both results (for when there are and are no control functions implemented) were identical. However, it is clear that the impact of HPs during the winter season is prominent where Am Bergfelde 5 reaches up to 50% loading from around 15% during the summer months. The model of the HPs used within these simulations take into consideration of the ambient temperatures for each of the days and thus is more accurately reflective as a load in comparison to that of the NSH. The effects of seasonality are even more prominent in the case of 100% penetration as is shown in Figure 123.

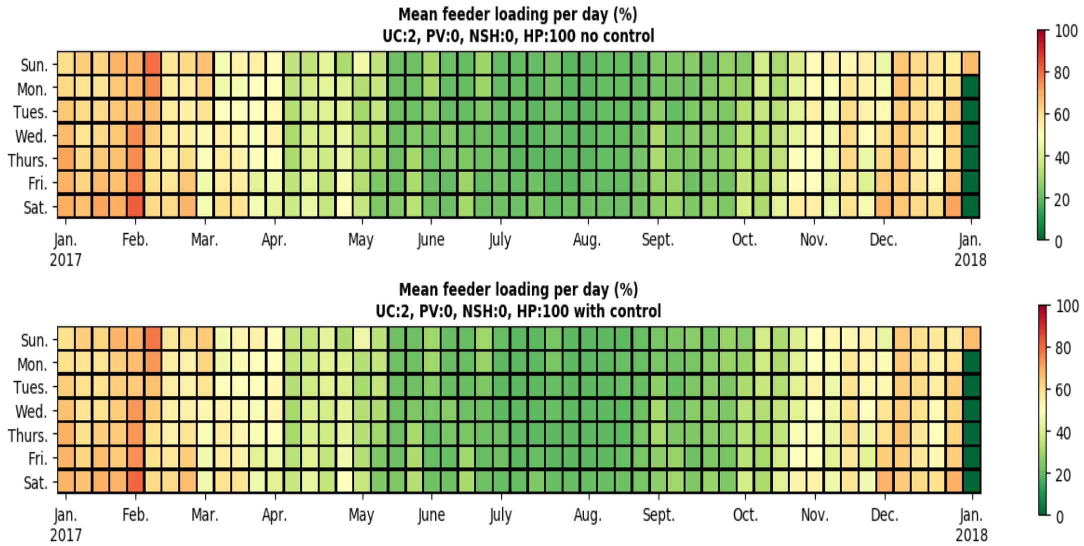

Figure 123 Mean feeder loading per day with 100% HP penetration without (top) and with control (bottom)

As can be seen, the increase in HP penetration causes an increase in network loading during the winter period and the effects of seasonality should be considered by DSOs, if they are to ensure that thermal loading violations are avoided.

Maximum and minimum voltage variation with increasing HP penetration

The maximum and minimum voltage variation with increasing HP penetration is further discussed in this section. As shown in Figure 124, when 50% HP penetration is connected to the feeder, no voltage violations are evident at any point throughout the year of analysis.

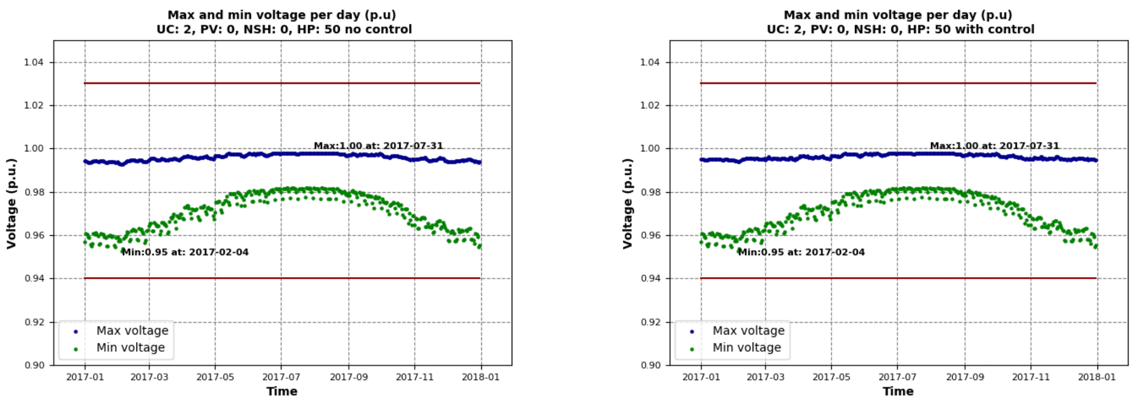

Figure 124 Maximum and minimum voltage variation for Am Bergfelde 5 with no control (left) and with control (right) for 2017 with 50% HP penetration

Furthermore, the results for the case when there is 100% HP penetration is shown in Figure 125.

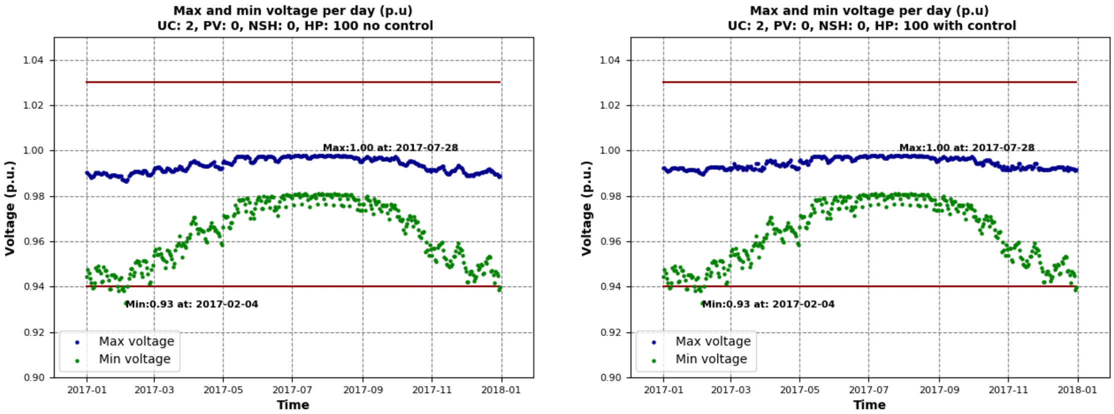

Figure 125 Maximum and minimum voltage variation for Am Bergfelde 5 with no control (left) and with control (right) for 2017 with 100% HP penetration

Voltage violations are visible during the winter period when the minimum voltage extends below the 0.94 p.u limit. The minimum voltage is 0.93 and occurs on 04-02-2017.

7.2.2. Additional Czech Demo support documentation

This section of the annex contains the additional support information for the SRA conducted in the Czech demo. This section covers how the simulations have been performed and the parametrization done for the network modelling for both, Medium Voltage (MV) and Low Voltage (LV).

Low Voltage (LV)

In order to analyse the LV grid for the SRA, certain aspects have to be characterized and parametrized for the simulations (EV integration and Hosting capacity calculation). Hence this sub section describes this proceeding.

LV – Network characterization

For the network topology characterization, various parameter definitions are required, this includes MV supply nodes, distribution transformers and investing plan for the different scenarios run for the years 2020, 2030 and 2040. The tool used for the load flow calculations is a software modelling tool developed by the Czech developer EGC named, DNCalc, shown as an example in Figure 127.In order to optimise the simulation times to run efficiently as possible, the tool incorporates an autonomous data input process which was developed in Python.

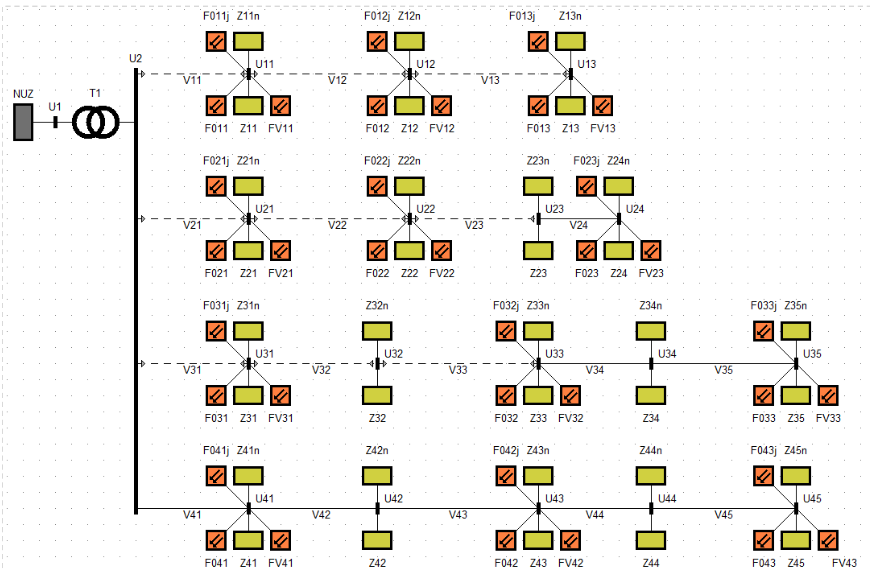

Figure 126: Example of LV calculation model in SW DNCalc

LV – MV supply nodes

For the consideration of the MV supply nodes, only the 22 kV supply nodes where considered as they are considered to be the most common, even though 35 kV transformers are present. The following characteristics where taken into consideration for their characterization as Table 41 reflects,

Table 41: MV supply nodes parametrization

U_n [kV]	U_0 [kV]	I_k [kA]	S_k [MVA]	R/X
22	23,1	1	38,1	0,6

LV – Distribution transformers

The following parameters collected in Table 42, represent the different installed transformers in LV rural and urban network types. For each type of municipality, depending on its population one of the following transformers is chosen.

Table 42: Distribution transformers parametrization

S_n [kVA]	U_1 [kV]	U_2 [kV]	P_k [KW]	U_k [%]
160	22	0,4	2,35	4
250	22	0,4	3,25	4
400	22	0,4	4,6	4

There is a distinction to be mentioned between those scenarios for DER connection and EV integration. For the first, transformers tap-changers were set to the neutral tap (±2 x 2,5 %) position. Consequently, this creates a higher voltage on the secondary side of the transformers which emulates an under loaded grid. For the second (EV and new load integration), tap+1 (+2,5 %) was chosen creating a lower voltage in a highly loaded grid model.

LV – Investment plan

The Investment plan, which represents the natural renewal and development of LV distribution grids from 2017 to 2040 also includes the expected variations for the years 2020, 2030 and 2040. This information is represented in Figure 127, which shows the development of new secondary substations in new areas or where a high penetration is needed due to the increase of cable line length instead of overhead lines.

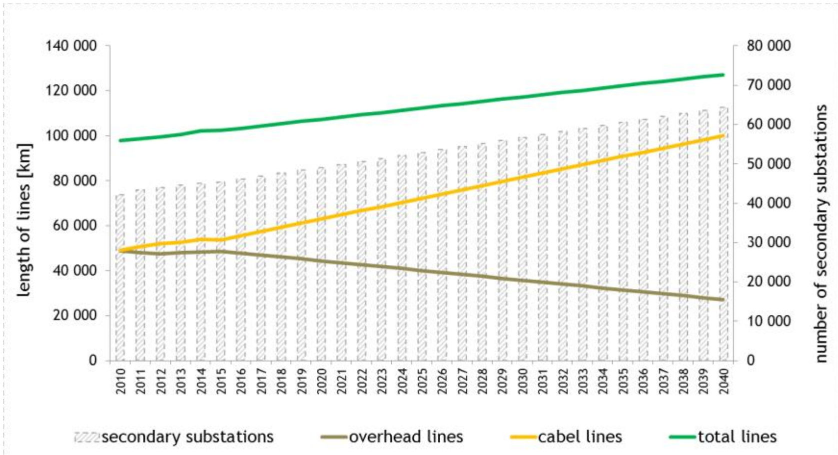

Figure 127: Development of cable lines and new secondary substations

LV – DER predicted power distribution parametrization

Due to the vast area covered by CEZ Distribuce in the Czech Republic, the 54 districts differ from one to another in terms of, households, solar irradiation, gas connection availability, population purchase power and exiting power plants. This is partially represented in Figure 128. Indeed, this has an impact at the time to select the amount of DER installed power for each area.

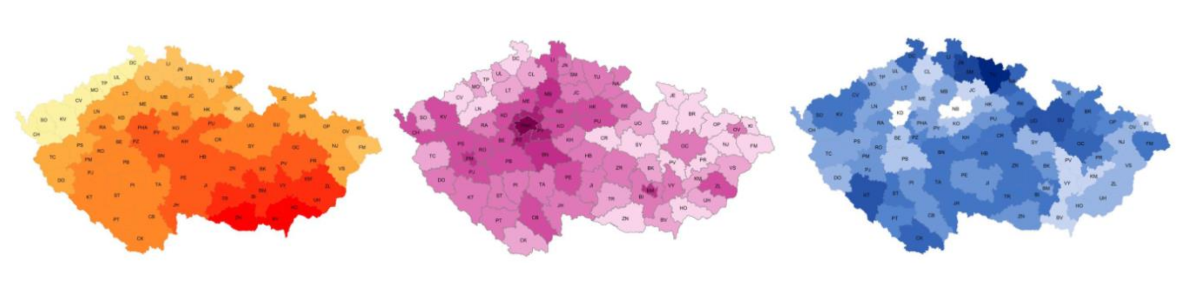

Figure 128: Czech Republic districts maps of solar irradiation, population purchasing power and current small hydro power plants in LV grids

In the representative LV models used, a total of 5 DER types are considered,

- 3-phase PV generator without voltage regulation (only in 2020)
- 3-phase PV generator with voltage regulation
- single-phase PV generator (phase A) without voltage regulation (only in 2020)
- single-phase PV generator (phase A) with voltage regulation
- single-phase PV generator without voltage regulation but connected to the same phase (phase B) as household load, and with solution preventing feed-in the grid. In the legislation it is called “simplified connection”.

Taking into consideration the differences previously explained, it was decided after numerous discussions among highly experienced specialists to:

- Reduce the complexity from 54 districts to 18 MV/LV representative grids according to their installed power at the MV/LV transformer station.
- Distribution of installed DER power to outlets by total feeder impedance.
- Distribution of installed DER power along feeder in ratio – 10 % at the beginning of the feeder, 60 % in the middle, 30 % at the end.
- Asymmetrical division of DER power was used – 75 % single-phase and 25 % three-phase.
- Simultaneous factor of DER and loads (based on simultaneity in simulated time season)
    - PV, small hydro, wind = 1
    - Micro CHP, biogas, biomass = 0,8

LV – Load parametrization

To correctly parametrize the load, a detailed analysis consisting of 10.000 distribution transformers was conducted. From the analysis, it can be estimated that the load is 10 % of S_n of the MV/LV transformer. This reflects the minimal load and maximum PV production when voltage rise issues arise. A current asymmetry of 50 % was selected for load modelling in LV networks. Based on the NAP SG expert analysis, Figure 129, represents the expected development for loads in the Czech Republic.

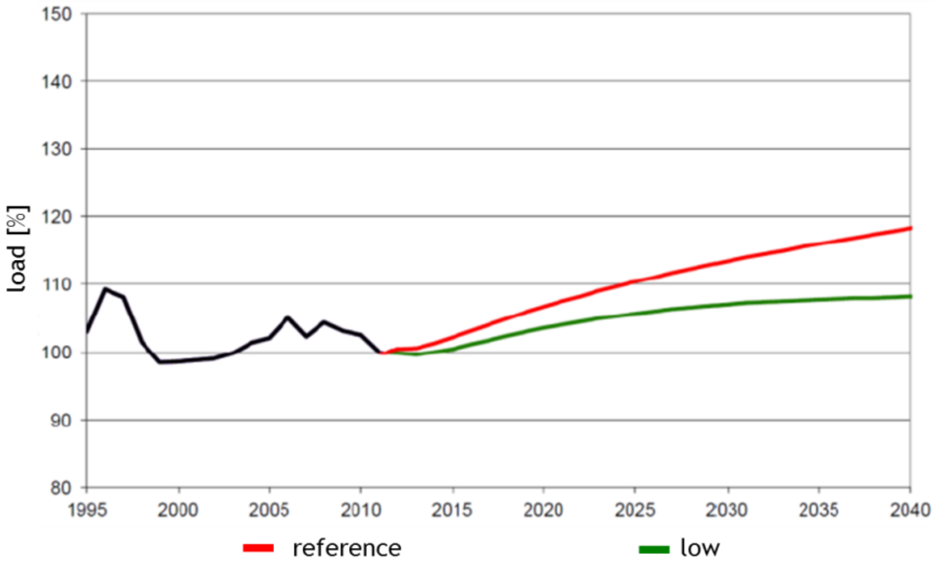

Figure 129: Consumption development in the Czech Republic

All load elements are parametrized in accordance with rules defined from the technical experts as follows,

- For all regions and models load was determined as a ratio to installed power of the transformer
- In order to respect the asymmetry rate, it was agreed that 50 % of the consumption is expected to be connected in three phases and 50 % in single phase (phase B in load flow).
- MV/LV transformer load is, in 2020, 10,41 % S_n; in 2030, 11,19 % S_n; in 2040, 11,85 % S_n.
- DER hosting capacity calculation only.
- The total load of each modelled network was first divided into individual outlets inversely proportional to the impedance at the end of the feeder.
- The load distribution along the feeder was similarly inversely proportional to the impedance of the nodes present at the feeder.
- For UC1 power factor 0,9 (under-excited mode) is used as it corresponds to the increased DER hosting capacity which is possible thanks to combination of Q(U) + P(U)
- For UC4 reduced power of PV system is modelled in representative grids since active power injection from PV system is limited to 50% (in sum over all phases). This is possible by the inclusion of home battery storage systems.

LV – EV integration calculation

There is already a set of scenarios which consider the integration of new loads in the entire Czech Republic for each DSO and district (including EVs). The following criteria defines the connected load''s power,

- Number of houses represents the theoretical potential EV purchase. Based on the Statistical Office data, the number of family and apartment houses was defined for each district.
- The higher purchasing power of the district the higher probability to purchase a new EV.

Types of new load elements in representative LV models

- EV with single-phase internal charger (connected to phase A)
- EV with 3-phase internal charger
- 3-phase heat pump (electric heating mode)
- 3-phase electric heating

Preconditions for new load distribution

- Division from districts (54) to MV/LV substation (18 representative grids) is according to installed power of MV/LV transformers in the station.
- Distribution of new load to feeders by total feeder impedance.
- Distribution of new load along feeder in ratio – 10 % at the beginning of the feeder, 60 % in the middle, 30 % at the end.
- Ratio between single-phase and 3-phase EVs developing in decades (single-phase share gradually decreasing).
- Simultaneous factor loads developing in time. It depends on control which scenario from the CBA.

Remark for Generation units

The chosen winter season and afternoon time of the day implies zero PV production, but still considerable generation from gas powered CHP units which are predicted to be used widely in Czech households as a substitute for old coal and other solid fuel boilers. The algorithm of division of CHP units into representative LV grids is the same as in case of SRA for generators simulation.

Connection limits and parameters on LV

- Voltage in every node in the modelled grid after simulated connection new load is not less than **90 %** $\boldsymbol{U_n}$ (207 V in each phase).
- Voltage **unbalance** in every node is not to exceed **2 %**.
- Lines, conductors and cables should not exceed **80 %** of their nominal **current** ampacity.
- MV/LV transformers should not exceed **80 %** of their nominal **current load**.

If at least one node or line exceeds the limit during the integration of new loads (EVs) this means the HC is at its maximum and thus it deems necessary to avoid further violations. These modifications are taken into consideration in the correspondent CBA for the CZ demo.

LV – Hosting capacity calculation

For the hosting capacity calculation required from the NAP, it is based on the provided methodology collected in the mandatory Distribution Grid Code [8]. Each new connection for a DER has to fulfil certain number of conditions and pass a connection quality assessment according to EN 50160. Only technical parameters which have a direct influence on the grid connection are considered. Hence the connection limits and parameters taken from [8] are,

- Voltage in every node in the modelled grid after simulated connection with maximum current injection should not exceed limit of 110 % U_n (253V in each phase).
- Voltage unbalance in every node should not exceed 2 %.
- Difference between voltage before and after connection should not exceed 3 % in every node of the tested grid.
- Lines, conductors and cables should not exceed 70 % of their nominal current ampacity.
- MV/LV transformers should not exceed 70 % of their nominal current load.

As a remark all DERs are tested simultaneously. If at least one point of common coupling (PCC) exceed the limits, then the hosting capacity (HC) is reached, and it has to be modified. These modifications are taken into consideration in the correspondent CBA for the CZ demo.

Medium Voltage (MV)

In order to analyse the Medium Voltage grid for the SRA, certain aspects have to be characterized and parametrized for the simulations (EV integration and Hosting capacity calculation). Hence this sub section describes this proceeding.

MV – Network characterization

Contrary to LV representatives' models, due to the high complexity of the MV grid, it is not possible to use the same approach based on statistics to build the model. Some of the reasons which prevent a statistical approach are, the many different branches from a primary feeder, topology changes and DER inclusion in the network. Therefore, a different approach is used for the MV network characterization which is to ask grid dispatchers and operators to identify the most relevant real grids that fulfil conditions defined by the research team. Anew, to study the different scenarios for 2020, 2030 and 2040, the same tool as for LV is used, DNCalc. Figure 130, shows a snapshot from one MV model.

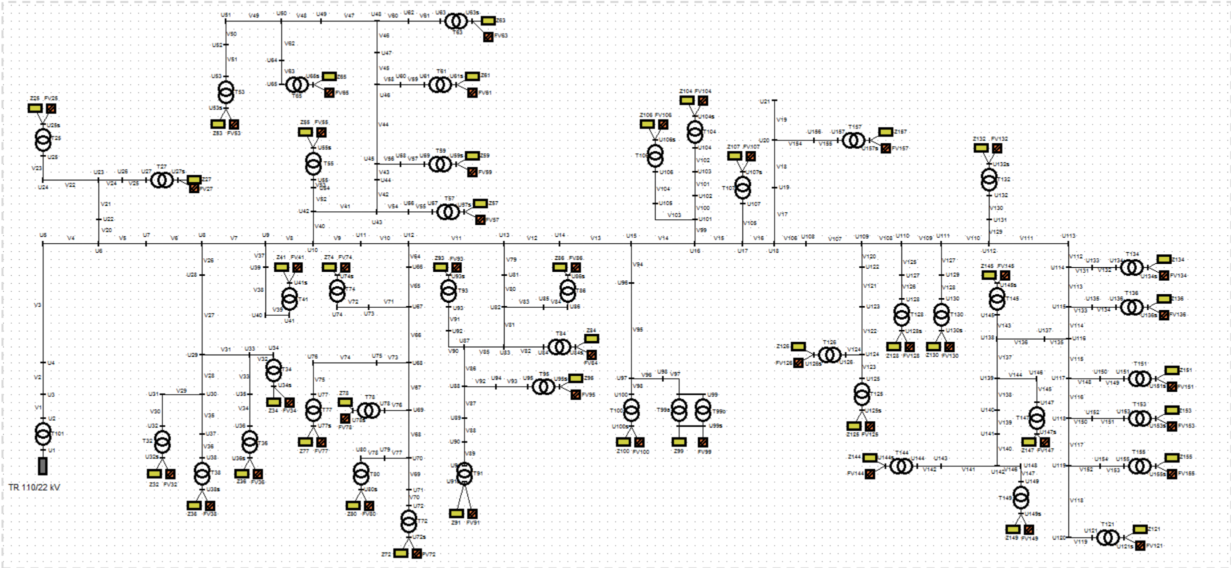

Figure 130: Example of MV calculation model in SW DNCalc

The following conditions have to be defined for the analysis,

- Create a maximum of 20 representative feeders from the available data source of 4000 different feeders, where it is considered,
    - Length and material
    - Type of the feeder (overhead, cable, mixed)
    - Number and attributes of existing installed DER
- Feeders' real topology is extracted from DMS/SCADA with its real load, generation from DER and real connection in HV/MV substation.
- Every real MV feeder was for the SRA replaced by one of the representative MV feeders.
- Every representative MV feeder was connected to real HV substation (230 in the year 2018).
- Existing DERs are connected into representative feeders in the model.
- New DERs according to different development scenarios were divided in similar principle as in low voltage, with district granularity (which could be simply joined to HV substations).
- Both existing and new DERs on MV level are connected to the same model nodes which were defined in the representative feeders by the research team.
- There are both 22 kV and 35 kV feeders (35 kV feeders are typically longer and used in mountain areas).

From the first point, it resulted in having a total of 15 representative feeders, collected in Table 43.

Table 43: MV representative feeders' parameters

Feeder no.	Feeder type	Feeder description	Existing DER	Primary line length [km]	Average cross-section $[mm^2]$	Average load [MW]
1	overhead	rural	no	8	70	1,01
2	overhead	rural	yes	4,1	100	1,24
3	overhead	rural	no	12	90	1,11
4	overhead	rural	yes	24,5	80	2,80
5	overhead	rural	yes	26	80	1,01
6	mixed	city	no	7,9	240	2,40
7	mixed	rural	yes	11,3	90	3,00
8	overhead	industrial	yes	20,1	95	2,38
9	overhead	business	yes	17	120	2,44
10	cable	industrial	no	5	240	1,08
11	cable	industrial	yes	8	240	4,95
12	cable	city	no	5	240	0,36
13	cable	city	no	5	240	0,41
14	overhead	rural	yes	30,8	70	1,50
15	cable	city	yes	8,9	240	1,00

As a side remark, one of the biggest challenges was to interface the existing and planned HV/MV primary substations to representative feeders and districts. This was addressed by partially automating the assignment by the strategic development department of CEZ Distribuce.

Remarks for MV grids developed

Development of MV grids for SRA must take into consideration the following remarks,

- The analysis must consider the almost 50 new HV/MV primary substations planned to be built over 2020, 2030 and 2040.
- Overhead lines reinforcement in the years 2020, 2030, 2040 is reflected through tweaked representative feeders, which are linked to real HV/MV substations.
- DSO investment programme for yearly MV cable development is considered. Hence the share of cable typed representative feeders was increased when linking them to real HV/MV substations. Currently approximately 21 % share of MV feeders are cable types. For 2020 – 22,3 %; 2030 – 26,5 % and for 2040 – 31,0 %

MV – DER predicted power distribution parametrization

Complexity of the MV not only affects the network topology and its calculation for representative feeders but also the number of elements within the MW network. The following division is done,

- DERs on LV – total numbers are distributed into districts, then HV/MV substations, representative feeders and into secondary substations by their installed power. In the model the LV DERs are represented as one 3-phase element per one secondary substation with a power factor equal to 0,99 (inductive mode) with respect to Q(U) and P(U) functions already in operation.
- Existing DERs on MV – models respect their actual installed power per MV feeder (from grid database). Power factor (PF) respects the scenarios described in CBA chapter. In baseline scenario PF equals to 1, in SG scenarios in 2020 is 0,99, in 2030 is 0,97 and in 2040 is 0,95 (all inductive modes) – this represents increased share of DER with

volt-var control system according to WP6 Use case 2 (reactive power could reduce voltage fluctuation/rise caused by DER generation). Fixed PF is used for hosting capacity calculations as it is within the margin of operational range which can be used when volt-var control systems are activated.

- New DERs on MV – distribution of new installed power based on NAP scenarios is similar to existing ones, with exception of new DER installation of 5 MW to 10 MW. Half of them are supposed to be connected directly into HV/MV primary substation.
- Both existing and new DERs on MV level are connected to the same model nodes which were defined in the representative feeders by the research team.
- New storage on MV – in connection simulation storage is considered as new generator with the same attributes as new DER (storage is expected to be operated based on owner needs and this will probably not correspond with DSO needs).

MV – Load parametrization

Load parameters for all secondary substations are the same as for LV grid models, only in this case the whole secondary substation is modelled as one load element. Load elements are 3-phase with PF equal to 0,95 (inductive) – this is compliant with standard methodology for load flow analysis within CEZ Distribuce.

Topology and number of elements in MV grids is more complex, so predicted new loads are divided accordingly:

- Loads on LV – total numbers are distributed into districts, then according to HV/MV primary substations, representative feeders and into secondary substations based on their installed power. In the model, LV loads are represented as one 3-phase element per one secondary substation with PF equal to 0,95 in 2020, 0,96 in 2030 and 0,97 in 2040 (inductive mode).
- New storage on MV – in power flow simulations, storage systems are considered as new load. Storage is expected to be operated based on owner needs and this will probably not correspond with DSO needs.

MV – EV integration calculation

Due to high complexity on MV grids new loads are divided into,

- Loads on LV – total numbers are distributed into districts, then HV/MV primary substations, representative feeders and into secondary substations by their installed power. In model LV loads are one 3-phase element per one secondary substation with PF equal to 0,95 in 2020, 0,96 in 2030 and 0,97 in 2040 (inductive mode).
- New storage on MV – in connection simulation storage is considered as new load. (storage is expected to be operated based on owner needs and this will probably not correspond with DSO needs).

Remark for Generation units

Additionally, due to the zero PV production and the division of the CHP units, small hydro power plants are expected to produce power in this scenario. The PF of DER connected directly to MV feeders' changes in time (this represents gradual increased share of DER with volt-var control system connected to MV grid). The volt-var control system is considered for all DERs: PF in 2020 is 0,99, in 2030 is 0,97 and in 2040 is 0,95 (all capacitive modes). The volt-var regulation helps to improve (increase) voltage when the grid is heavily loaded.

Connection limits and parameters on MV are:

- Voltage at every node in the modelled grid after simulated connection with maximum current loading should not fall under limit of **97 %** $\boldsymbol{U_n}$ (21,34 kV or 33,95 kV).
- Overhead lines should not exceed **70 %** of their maximum **current** ampacity.
- Underground cables should not exceed **50 %** of their maximum **current** ampacity.
- HV/MV transformers should not exceed **70 %** of their nominal **current load** (if at least three transformers in substation are in operation).
- HV/MV transformers should not exceed **50 %** of their nominal **current load** (if max two transformers in substation are in operation).

Equal to the EV integration connection limits and parameters, for MV operates with the same principal. If at least one node or line exceeds the limit during the integration of new loads (EVs) this means the HC is reached leading to necessary modification of the network in order to avoid the violation. These modifications are taken into consideration in the correspondent CBA for the CZ demo.

MV – Hosting capacity calculation

Following the same principal as done for the LV hosting capacity calculation, MV hosting calculation is based on the Distribution Grid Code [8]. Anew the connection quality study for DER connection according to EN 50160 has to be passed. Hence connection limits and parameters taken from [8] for MV are,

- Voltage in every node in the modelled grid after simulated connection with maximum current injection should not exceed limit of **110 %** $\boldsymbol{U_n}$ (24,2 kV or 38,5 kV).
- Difference between voltage before and after connection should not exceed **2%** in every node of the tested grid
- Overhead lines should not exceed **70 %** of their maximum **current** ampacity.
- Underground cables should not exceed **50 %** of their maximum **current** ampacity.
- HV/MV transformers should not exceed **70 %** of their nominal **current load** (if at least three transformers in primary substation are in operation).
- HV/MV transformers should not exceed **50 %** of their nominal **current load** (if max two transformers in primary substation are in operation).

As a remark all DERs are tested simultaneously. If at least one PCC exceed the limits, then HC is reached, and it has to be modified. These modifications are taken into consideration in the correspondent CBA for the CZ demo.

7.2.3. Additional Dutch Demo support documentation

This section of the annex provides extra information for the analysis perform in the SRA for the Dutch demo. In this section, UC1 and UC2 scalability and replicability processes are exposed.

UC1: Local infrastructure management system

This section deals with the scalability and replicability analysis for the flexibilities considered within this use case, a PV system and an SSU, which are operated by the LIMS and aggregated at the FAP.

PV system estimation

The PV system is based on the concept of covering the total surface area of the public parking area rooftop where the charging stations are located. Therefore, data is extracted from the GIS located in Strijp-S as shown in the following Figure 131 with the following GPS coordinates: 51.44802, 5.45881.

Figure 131: PV deployment area

Using this GIS information, it is calculated that the surface area required to accommodate the deployment of 2 arrays of 134 kW_p installed PV is approximately 1914.28 m^2, whereas the scaled version will cover the entire effective area with a total of 303.8 kW_p installed power. With this information the following standard parameters of 14% of system losses and PV crystalline silicon based are considered for the PV energy annual production using the available Joint Research Centre (JRC). Based on this, the forecasting of PV generation is performed using the available information from the area between 2007 and 2016. The forecasting method is used for both the 134 kW_p and the 303.8 kW_p installations in order to get 15 min based time steps to comply with the USEF specifications. These forecasts are represented in Figure 132, Figure 133, Figure 134 & Figure 135which shows an entire year forecast which will be used for the SRA when providing the D-prognosis for each day.

The delta shape is due to the time resolution of the data, 15 min values as USEF requires. This is clearly seen in Figure 133 and Figure 135 which are one randomly selected day from the data set considered.

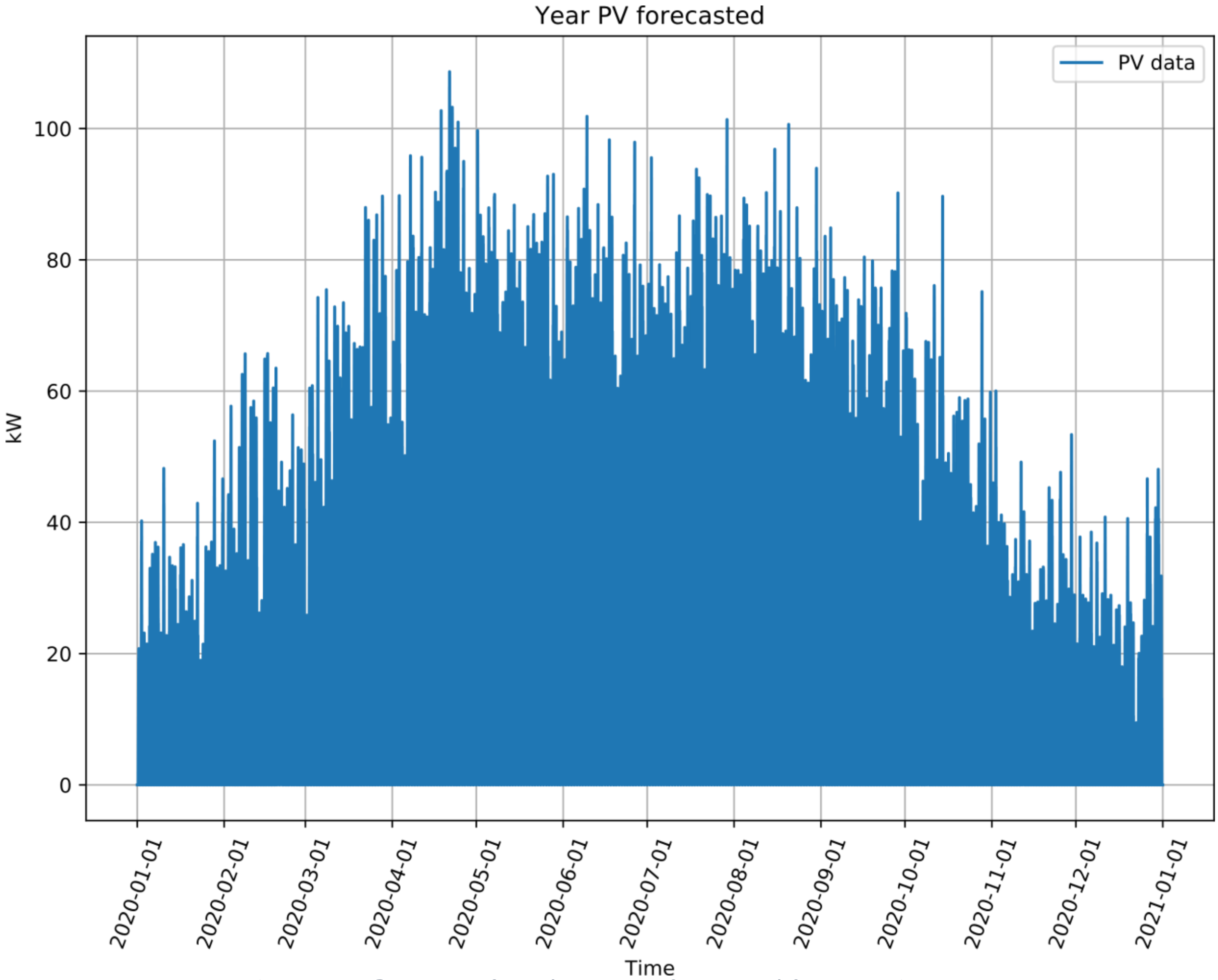

Figure 132: PV curve of 134 kWp array forecasted for an entire year

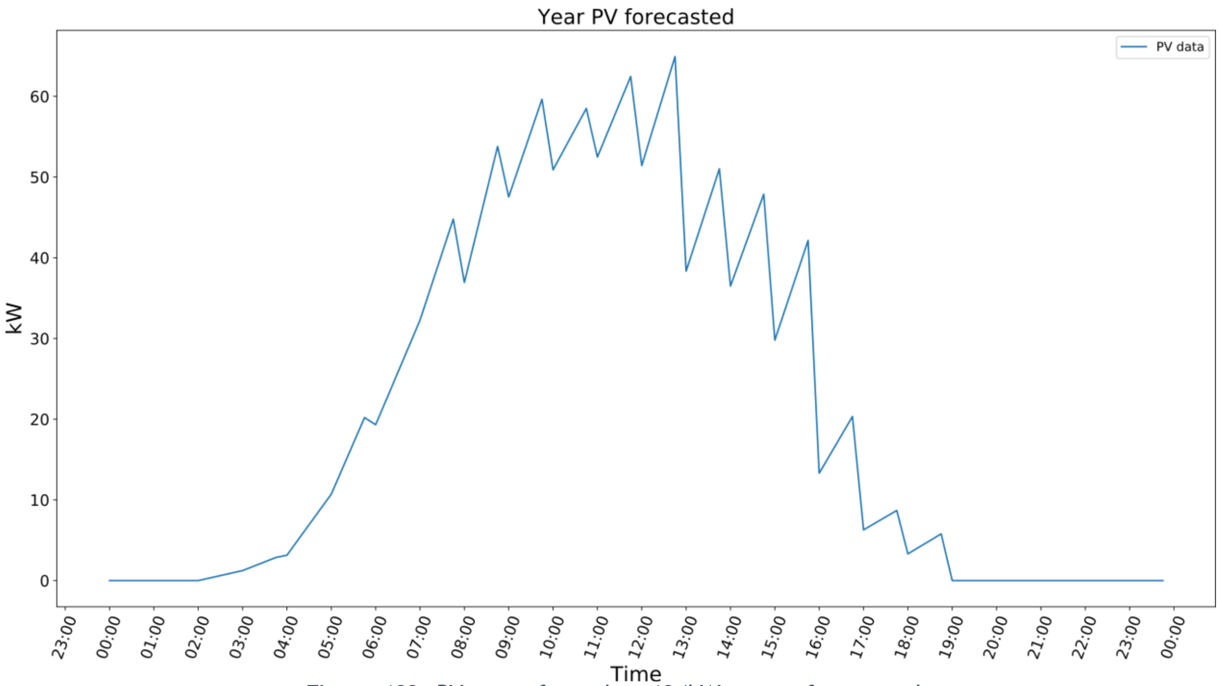

Figure 133: PV curve for a day, 134kWp array forecasted

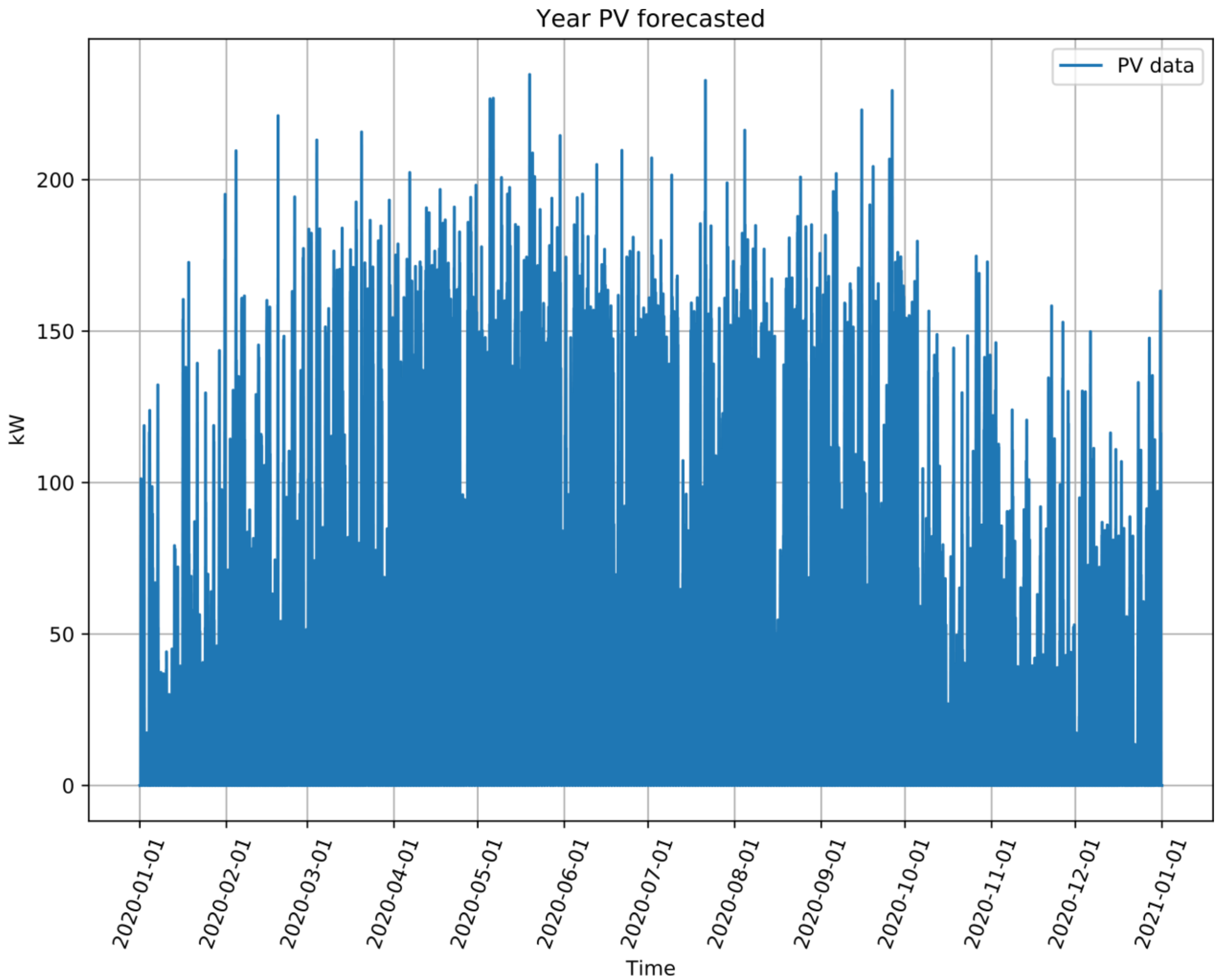

Figure 134: PV curve of 303.8 kWp array forecasted for an entire year

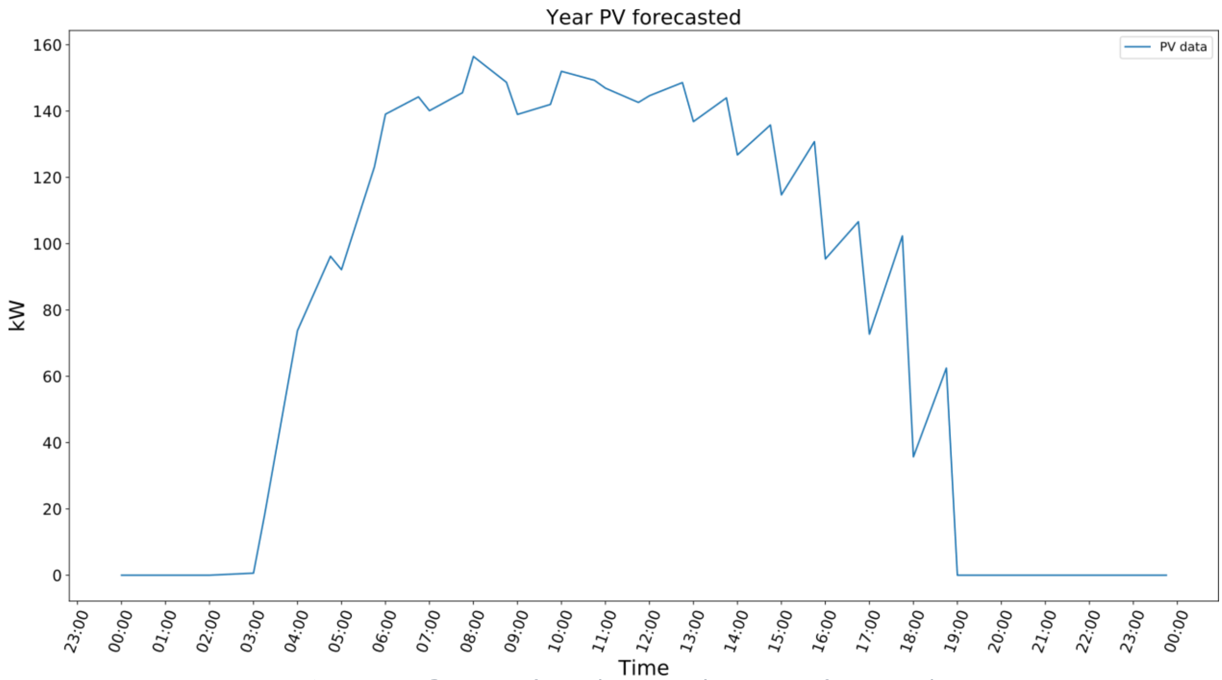

Figure 135: PV curve for a day, 303.8kWp array forecasted

Once the entire time steps are calculated, the selection of days for the scalability and replicability is needed. Since there is an interest of simulating one entire week, the following days are selected for scalability and replicability,

- Scalability: week with the highest PV production – "worst case scenario[21]" results on the 4th of June until the 10th of June
- Replicability: one representative week for each season based on 2020 forecasted data which the initial condition is to map the start of the week into a Monday as it needs to be used with other flex (battery and EV)
    - **Winter season**: from the 13th January until the 19th of January
    - **Spring season**: from the 18th of May until the 24th of May
    - **Summer season**: from 20th of July until the 26th of July
    - **Autumn season**: from 05th October until 11th October

Battery system estimation

The battery model is based on a self-developed battery model from AIT's lab which takes into consideration the efficiencies from charging and discharging, which impacts the PoC rated power. These efficiencies also impact the performance of the battery as it is not operating at nominal power due to a lower rating power at the PoC (condition assumed).
The battery forecasting system uses data from the USEF foundation database example for the baseline price EPX price input and additionally the EPX's prices for the different weeks which the replicability is considered, the same as for the PVs.

- Replicability: one representative week for each season based on 2018 data which the initial condition is to map the start of the week into a Monday as it needs to be used with other flex (PV and EV)
    - **Winter season**: from the 08th January until the 14th of January
    - **Spring season**: from the 07th of May until the 13th of May
    - **Summer season**: from 16th of July until the 22nd of July
    - **Autumn season**: from 24th September until 30th September
    - **Autumn season special**: from 15th October to 21st October.

The logic developed for the aggregation process assumes that the battery completes at least 1 cycle per day of operation, where it tries to maximize the capacity based on the price of the input power. During the process of developing the battery model, a scaling process was considered and measured which resulted in a major utilization of PTUs (time steps – 96, 15 min time steps per day) for charging and discharging when the capacity was increased in a linear way. These effects can be seen in Figure 136. Due to the logic of the algorithm developed, the time step which the battery starts charging is changed as it is more favourable for the charging battery operation. This change is due to the price optimization based algorithm implemented.

[21] As this is considered the week with the maximum PV injection.

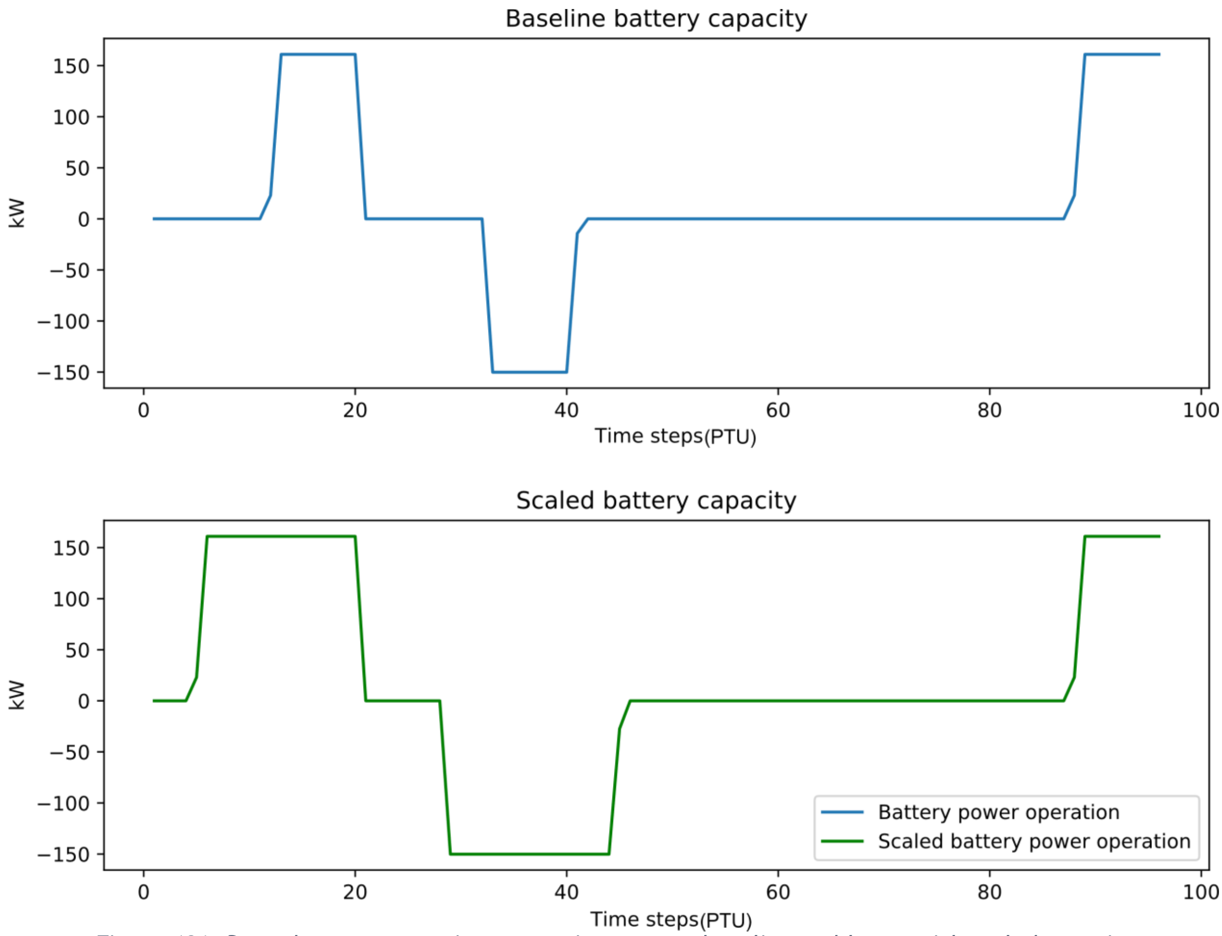

Figure 136: Demo battery operation comparison, upper baseline and lower with scaled capacity

UC2: Charging Point Management System

This section deals with the scalability and replicability analysis for the flexibility considered within this use case, electric vehicles, which are operated by the CPMS and aggregated at the FAP.

Electric Vehicles estimation

In order to calculate the D-prognosis for the EV, a forecasting algorithm is developed using the available data from the project partner Elaad. It collects a 1000 session distribution over the entire year in 2016 containing different parameters as *time to start*, *time to end*, *power average*, *power*, etc. From the demo side, the data used is the one available through the platform which Elaad provided the SRA team access to.

With this data, an extensive analysis for calculation of the current penetration is performed in the Netherlands based on data from [ref-from references.txt] and TNO's report [] and others. The current penetration is around 0.8% while in the future scenario for 2030 the penetration is to be expected around 40%.

Using the current and future penetration for EVs, the forecast provides the potential energy demand per day, the weekday occurrence and the charging duration in addition to the max power mean values collected in Table 44. This energy demand could be provided from 1 to n chargers. However, since the chargers are mostly operating between 9 kW and 11 kW (min and average value), the value of 9 kW is selected as the lower threshold. This implies that no charging station is able to reduce its power demand below 9kW.

Table 44: EV statistical data for weekdays

Weekday	Charge Time [h]	Total Energy [kWh]	Max Power [kw]	Weekday-Occurrence [%]
Monday	3.25	30.22	10.7	11.4
Tuesday	2.86	26.7	10.73	11.9
Wednesday	2.79	25.98	10.66	13.4
Thursday	2.69	25.17	10.83	12
Friday	2.97	27.94	10.75	14.7
Saturday	2.54	23.93	10.7	19.7
Sunday	2.68	25.76	10.84	16.9

EV seasonality is explored in addition to the values per day in order to observe the possible fluctuations per month as represented in Figure 137. Similar to the day data, this suffers no major fluctuations, therefore for the scalability and replicability analysis, the data considered for the simulations is that which is the one calculated based on each hour distribution for each day of the week, using mean values of the months.

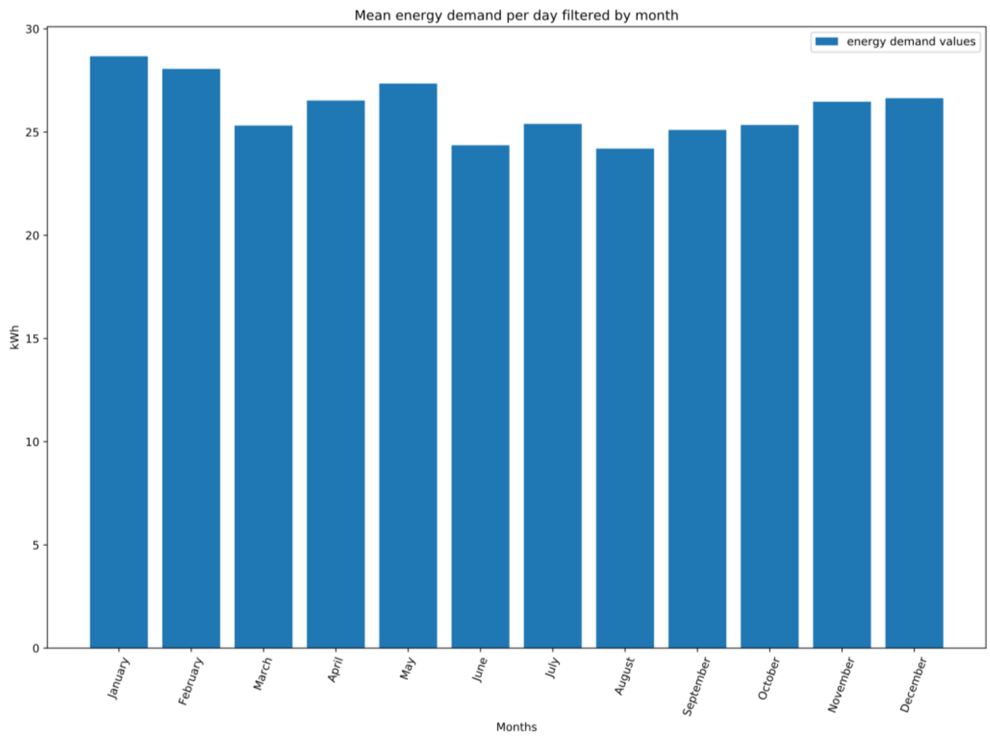

Figure 137: EV average monthly energy demand

Scenarios developed are separated for each substation with the same idea, as collected in Table 45. The idea behind such distribution is to provide a potential forecast of maximum theoretical load over different scenarios with different charging points and different EV penetration levels. The trading offer is entirely dependent on the forecasting algorithm the aggregator utilises. In this case, the algorithm is based on the random selection of all the points where the charging station has no possible occurrence to demand load at the start of each day with the internal day-hour-distribution. This system allows the aggregator to foresee where the flexibility could be allocated in case there is a need of load reduction from the DSO. These scenarios are those flagged as "*selected*". The rest of the scenarios, those flagged as "*All where non 0*", explore the idea of adding the maximum theoretical load that could be expected, i.e., the worst case scenario. An example of power distribution for both cases ("Selected" and "All where non 0") is provided in

Table 46.
Each substation is considered with the difference of substation 1 having 7 chargers and substation 2 having 6 chargers. The charger models consider the demo parameters. Hence, those scenarios where the system is upgraded to 22 kW, 50 kW and extreme 150 kW are an extension of the demo chargers to explore the potential upgrades these chargers could face.

Table 45: EV-SRA scenarios permutations

ID	Chargers involved	PTUs-time steps	PTU-Power
0	1 - (penetration 0,85%)	Selected	Selected values
1	1 - (penetration 0,85%)	All where non 0	Selected values
2	1 - (penetration 0,85%)	Selected	Upgraded to 22
3	1 - (penetration 0,85%)	All where non 0	Upgraded to 22
4	7 - cause of 40% penetration	All where non 0	Selected values *7|6
5	7 - cause of 40% penetration	All where non 0	Upgraded to 22 *7|6
6	7 - cause of 40% penetration	All where non 0	Upgraded to 50 *7|6
7	7 - cause of 40% penetration	All where non 0	Upgraded to 150 *7|6

Table 46: Power- Hour distribution for Mondays as example of "selected" and "all where non 0"

Hours	Hour distribution (%)	Selected Power-values [kW]	All where non 0 [kW]
0	0	0	0
1	0	0	0
2	1.052631579	0	11.1
3	1.052631579	0	13.8
4	1.052631579	0	10.6
5	0	0	0
6	1.052631579	0	10
7	6.315789474	0	10.23333333
8	6.315789474	0	10.8
9	6.315789474	0	10.8
10	6.315789474	0	10.81666667
11	3.157894737	0	10.26666667
12	8.421052632	0	11.2875
13	4.210526316	0	11.475
14	7.368421053	0	10.67142857
15	5.263157895	10.42	10.42
16	9.473684211	10.5	10.5
17	7.368421053	0	11.12857143
18	8.421052632	9.3	10.3
19	4.210526316	0	10.525
20	4.210526316	0	10.35
21	4.210526316	0	10.575
22	3.157894737	0	11.7
23	1.052631579	0	10.4

UC3: Aggregation

The following subsection provides all the info graphics from the different set of scenarios for the scalability and replicability analysis off the combination of PV, SSU and EV in substation 1, 2 and 3.

Regarding substation 3, this is created as a replication (location) substation based on the combination of the assets found in substation 1 and 2 and substation's 1 technical parameters for the congestion points. Thus, substation 3, shares the same limits stablished as substation 1.

All the substations undergo the same scenarios with their parametrized assets. The following information can be found for the scalability and replicability analyses.

On the one hand, with respect of Scalability analysis, the substations are monitored based on the network status of the congestion points created. These are located at the substation transformer and the flexibility connection point. This monitoring over the period of 1 week simulation, provides how many times there is a need for congestion management as the limits are violated. This information is recollected in tables for each of the congestion points. Additionally, information regarding the total volume of flexibility which can be injected/leaded at each congestion point is provided by tornado graphs. These have to be read in absolute values for each of the limits, as downwards from the point of view of the load would mean, load increase whereas for the generation units would mean increase generation.

On the other hand, with regard of the Replicability analysis, it follows the same structure as in the scalability analysis but with slightly differences. The main difference resides in the data being used for the simulation. In substation 1 & 3 data from January, May, July and October is used. In substation 2, data from January, May, July and September is used. This difference between October and September is imposed by the SSU, since the prices used for the algorithm is based on the German and Austrian Market of 2018 and in September of such year, the market was unbundled.

Scalability substation 1

Status

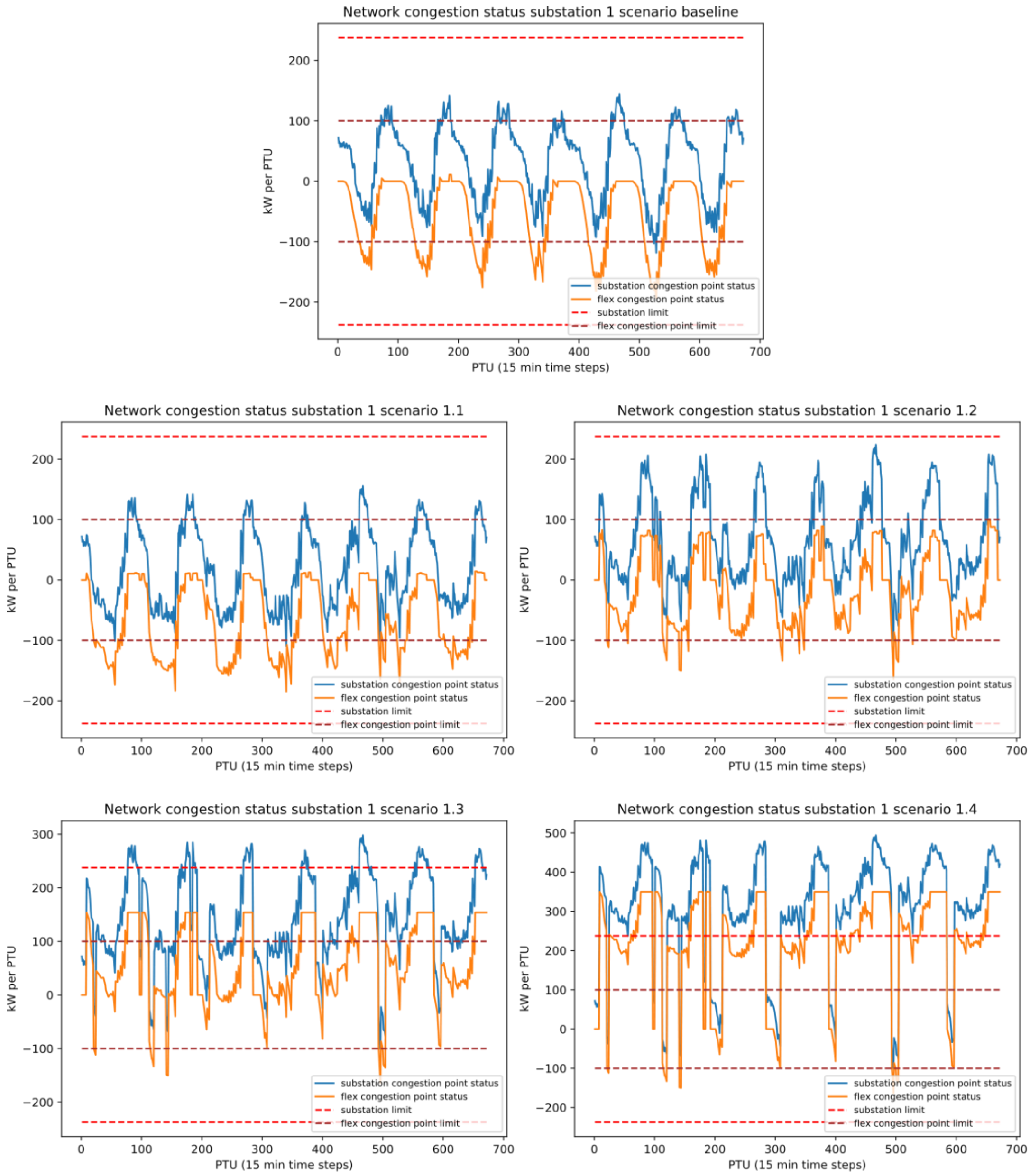

Figure 138: Network congestion status for substation 1 during scalability scenarios

Table 47: Transformer congestion point decomposition of points for scalability scenarios substation 1

Periods	Trafo_CP_baseline	Trafo_CP_1.1	Trafo_CP_1.2	Trafo_CP_1.3	Trafo_CP_1.4
available	672	672	672	561	114
reduce	None	None	None	111	558

Table 48: Flex congestion point decomposition of points for scalability scenarios substation 1

Periods	Flex_CP_baseline	Flex_CP_1.1	Flex_CP_1.2	Flex_CP_1.3	Flex_CP_1.4
available	484	411	634	435	90
reduce	188	261	38	237	582

Volume

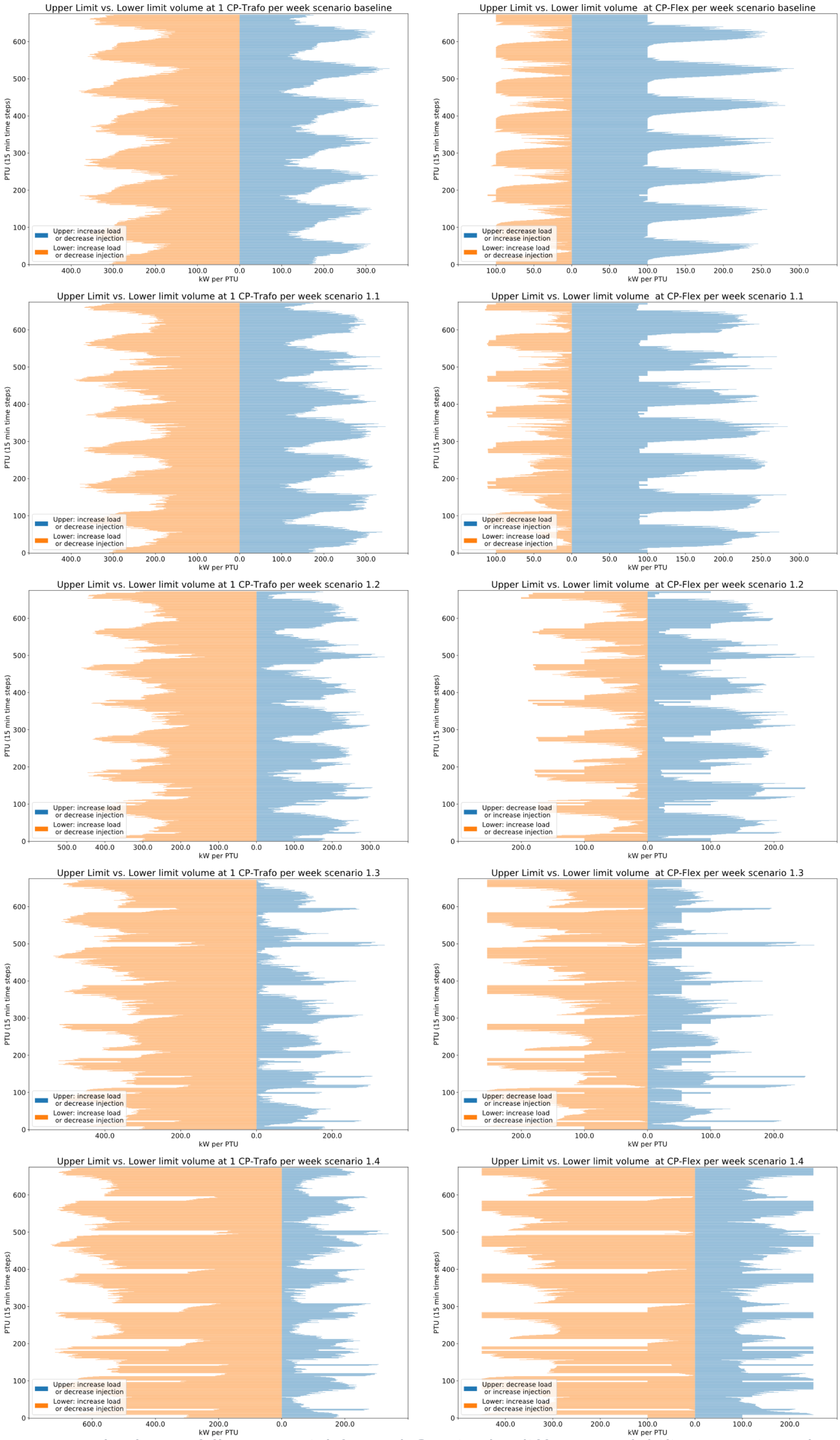

Figure 139: Total volume of flex potential for each PTU in the different scalability scenarios substation 1

Scalability substation 2

Status

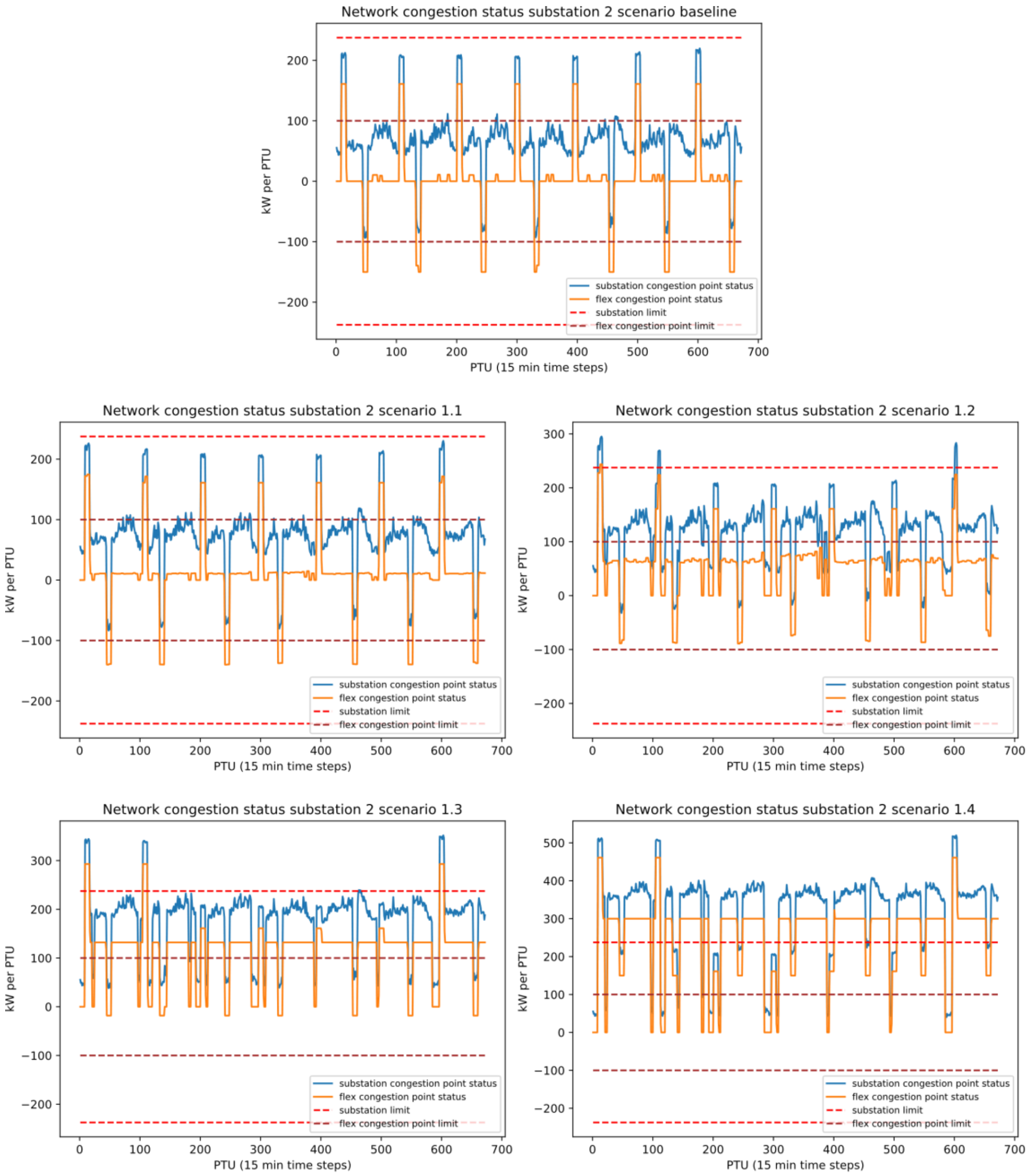

Figure 140: Network congestion status for substation 2 during scalability scenarios

Table 49: Transformer congestion point decomposition of points for scalability scenarios substation 2

Periods	Trafo_CP_baseline	Trafo_CP_1.1	Trafo_CP_1.2	Trafo_CP_1.3	Trafo_CP_1.4
available	672	672	672	672	554
reduce	None	None	None	None	118

Table 50: Flex congestion point decomposition of points for scalability scenarios substation 2

Periods	Flex_CP_baseline	Flex_CP_1.1	Flex_CP_1.2	Flex_CP_1.3	Flex_CP_1.4
available	560	560	616	136	80
reduce	112	112	56	536	592

Volume

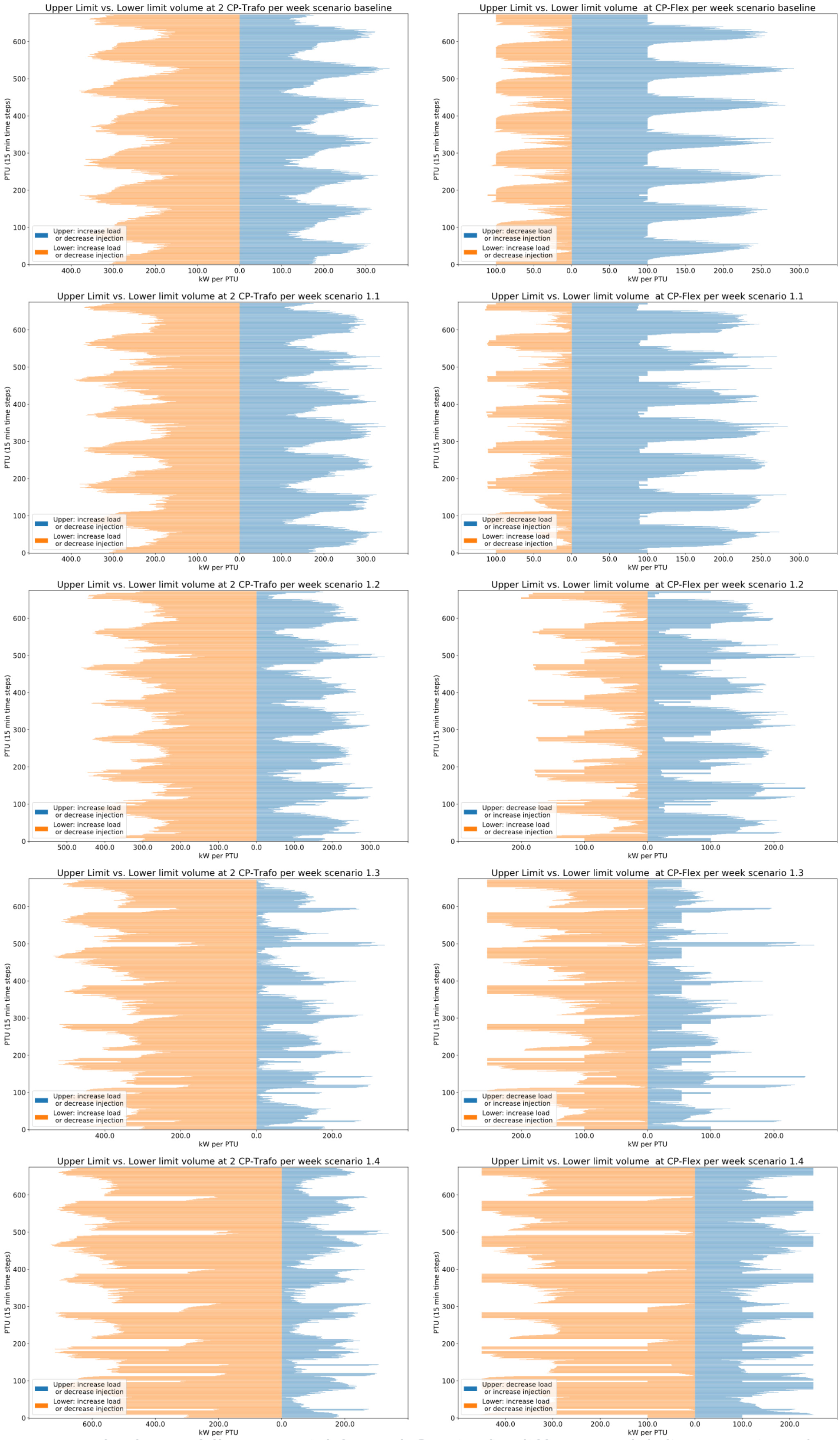

Figure 141: Total volume of flex potential for each PTU in the different scalability scenarios substation 2

Scalability substation 3

Status

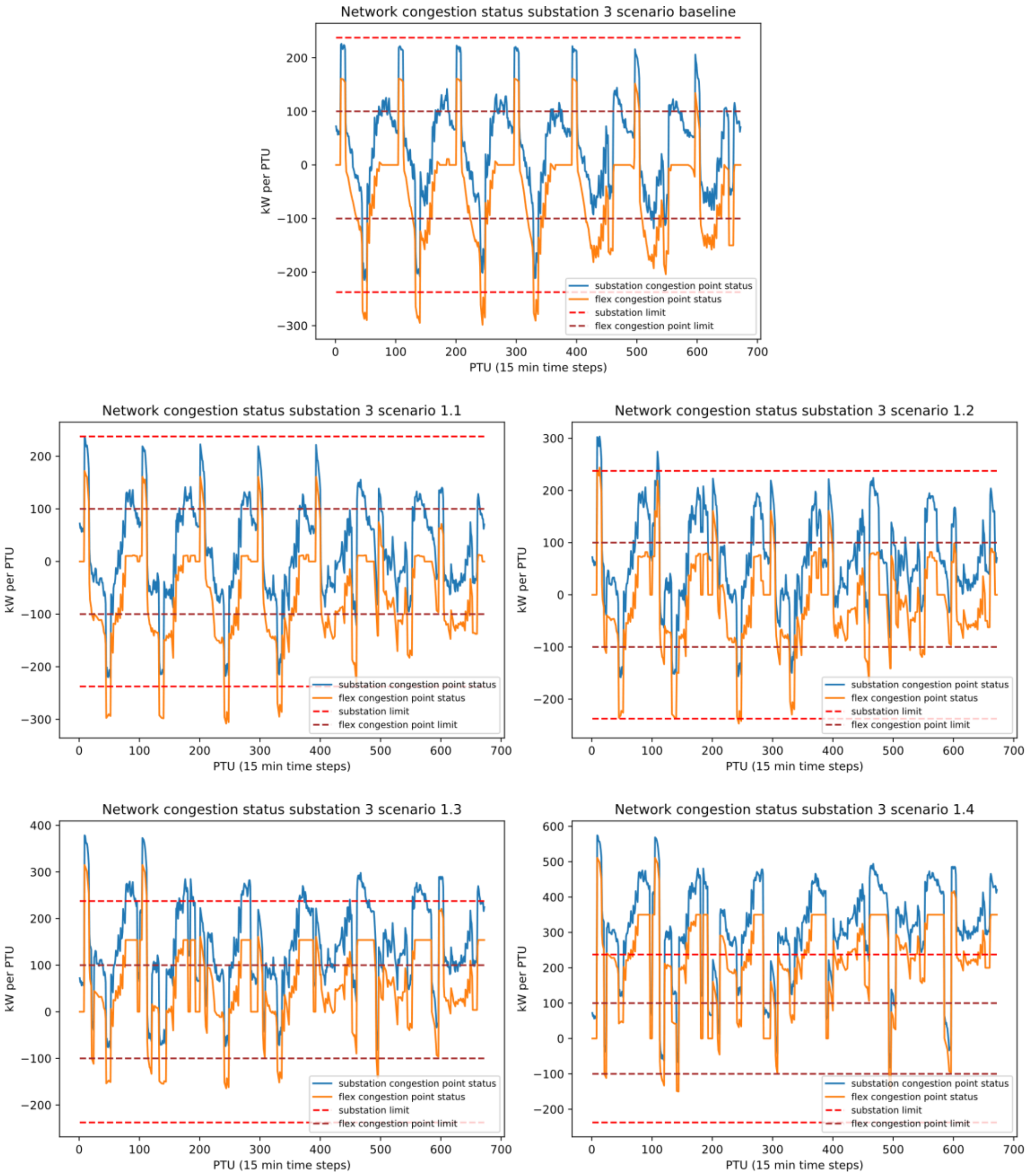

Figure 142: Network congestion status for substation 3 during scalability scenarios

Table 51: Transformer congestion point decomposition of points for scalability scenarios substation 3

Periods	Trafo_CP_baseline	Trafo_CP_1.1	Trafo_CP_1.2	Trafo_CP_1.3	Trafo_CP_1.4
available	672	672	661	545	148
reduce	None	None	11	127	524

Table 52: Flex congestion point decomposition of points for scalability scenarios substation 3

Periods	Flex_CP_baseline	Flex_CP_1.1	Flex_CP_1.2	Flex_CP_1.3	Flex_CP_1.4
available	407	359	558	398	108
reduce	265	313	114	274	564

Volume

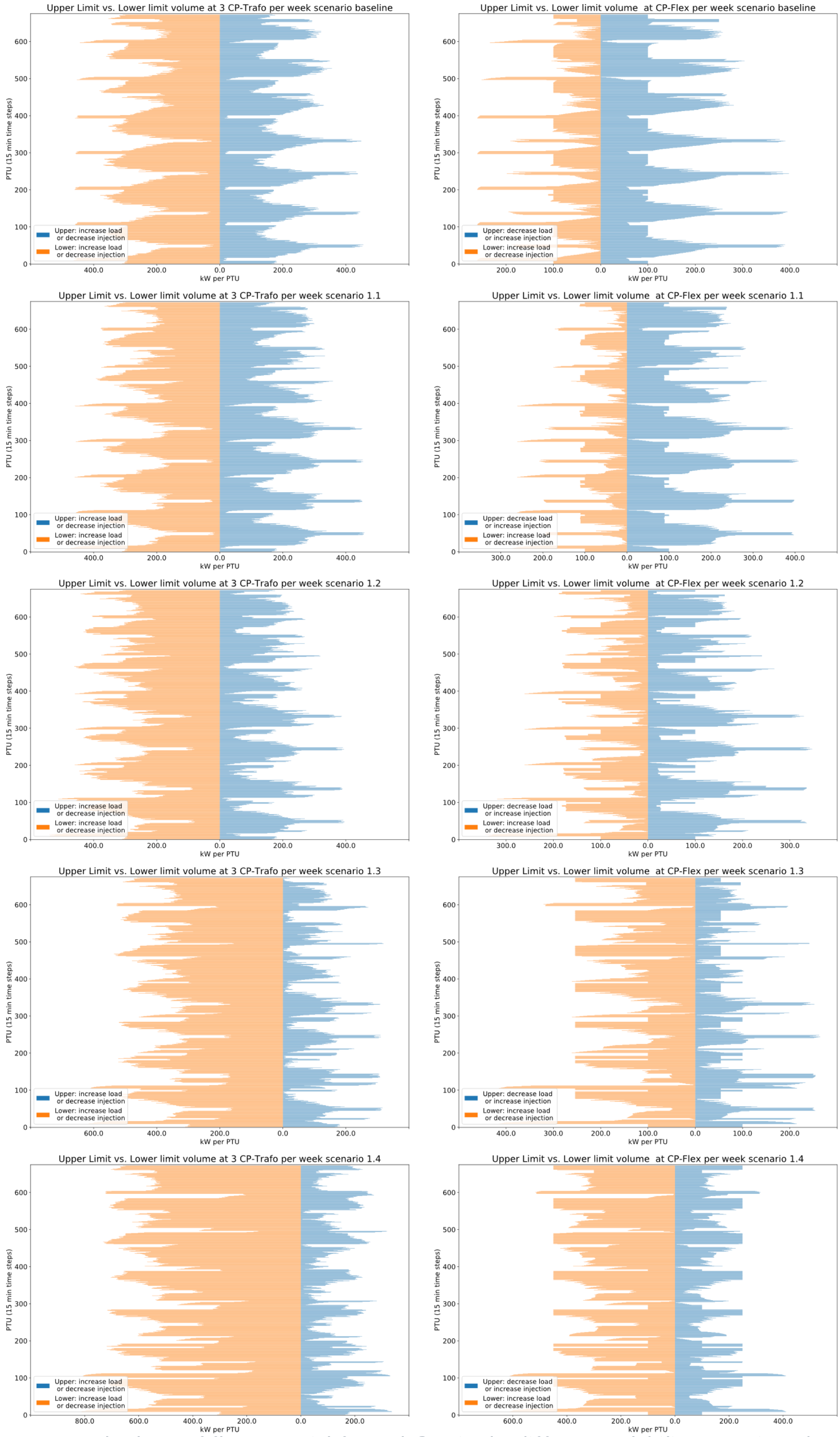

Figure 143: Total volume of flex potential for each PTU in the different scalability scenarios substation 3

Replicability substation 1 (time)

As the PV changes over the course of the year, its impact is clearly seen when compared the months of January and July. This provokes that the system will require more congestion management during larger periods of time.

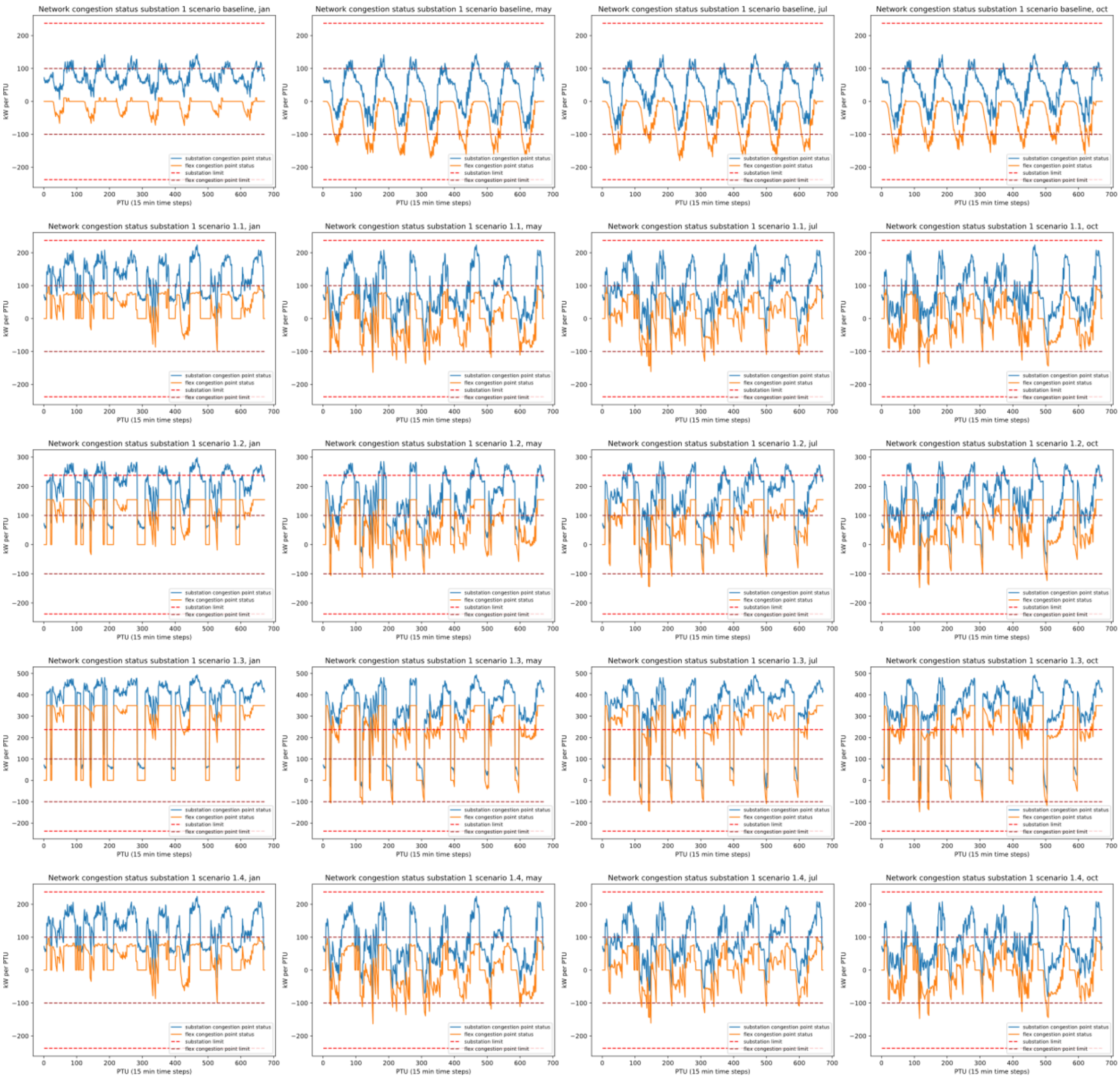

Figure 144: Network status for the different scenarios for each season substation 1

Replicability substation 2 (time)

The impact of the battery seasonality into the system is merely dependent of the prices since the logic is based on the optimization of time charging-best price point. This is correlated with the total injection and the dispatch needed by the market. Hence, the more renewable and more destabilization the more periods the battery is going to be used, and the more potential constraints this operation can cause at the LV if it is used in such way.

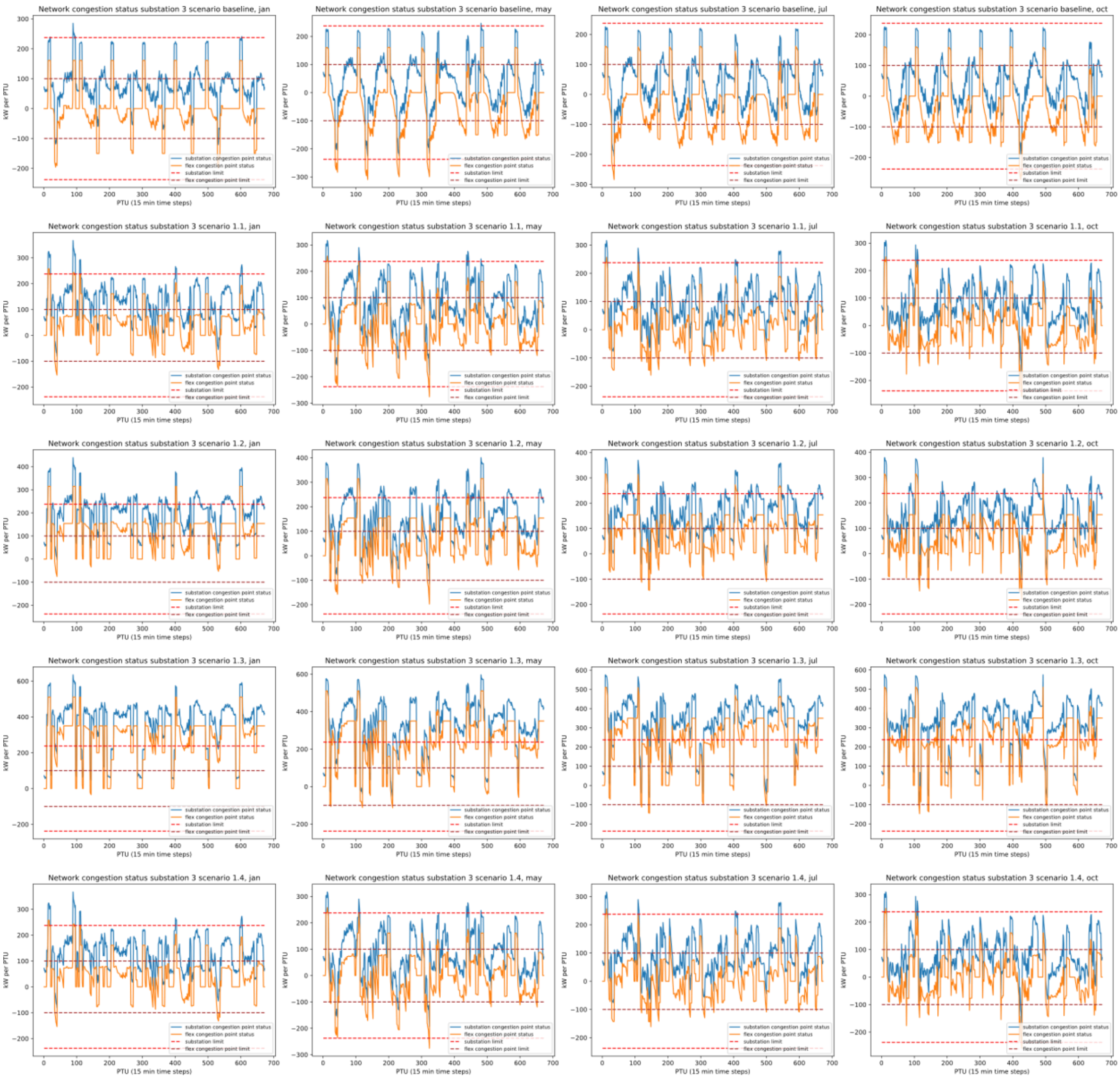

Figure 145: Network status for the different scenarios for each season substation 2

Replicability substation 3 (time)

The combination of all the assets create the best solution as the assets can be compensated among each other. The impact of the EV is especially interesting as it truly can help the reduction of injection into the network at substation level from the generation units and the potential support of the battery. Clearly, the strategy used for the battery would create a huge impact as it increases the demand and combines with the load demand form the EV, can produce a potential critical bottleneck in the network.

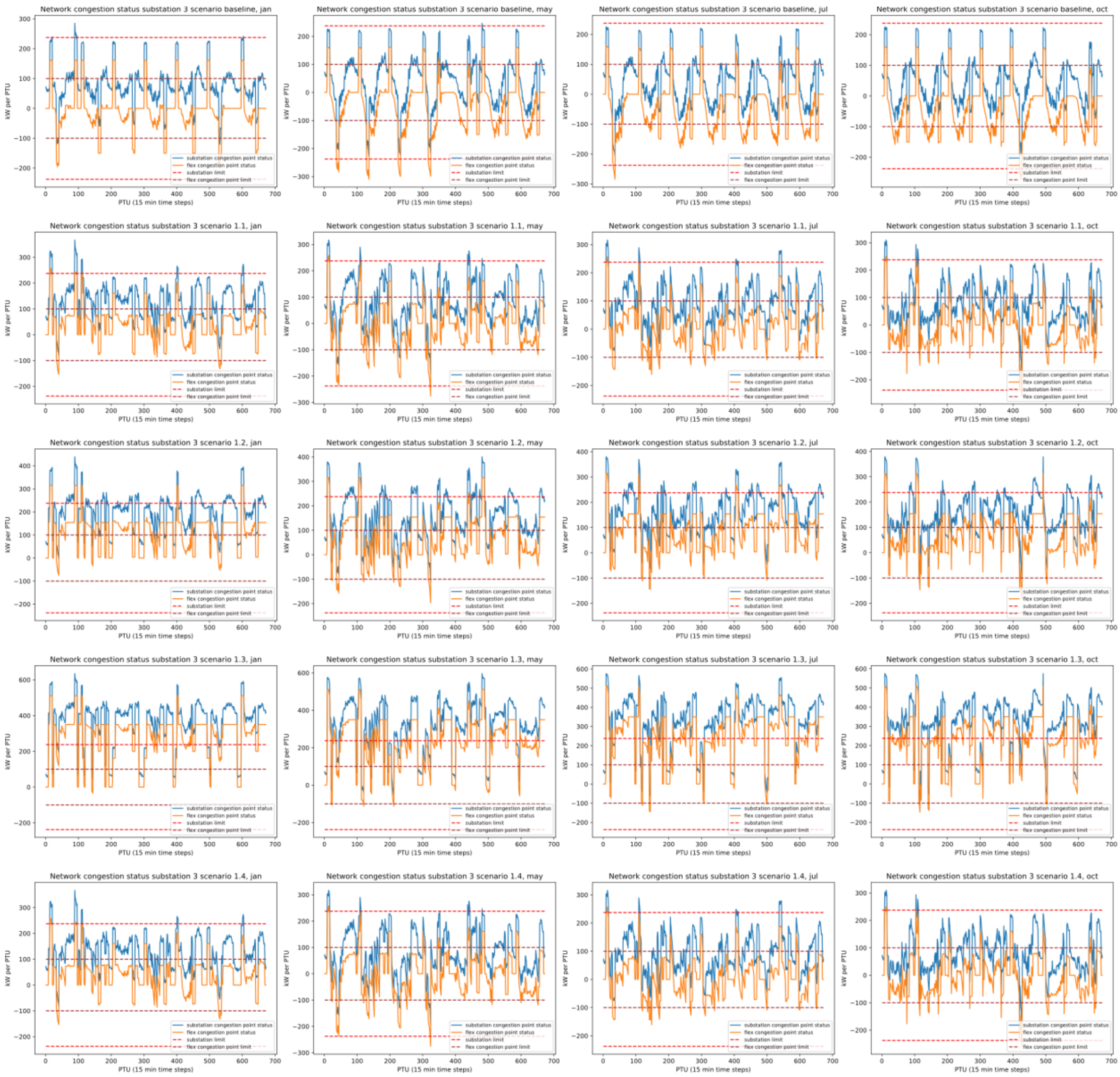

Figure 146: Network status for the different scenarios for each season substation 3

7.2.4. Additional French Demo support documentation

In this section of the annex, the additional information for the French Demo is collected. The different baselines as the internal steps of the process for the analyses such as the PV generation and battery sizing are exposed.

Scalability-Baseline

Baseline simulations for the data have to be created in order to obtain an overview of the system such that later simulations are able to be compared and analysed through the use of selected KPIs. In this UC, the identified KPIs are *Islanding duration*, *PV injected*, *Battery Capacity* and *Base Load Consumption*. In this section, the various baselines necessary for the simulation framework are provided.

Baseline profiles for load and PV generation

The island consists of an abbey and 55 customers. The analysis was conducted based on the 5 secondary substations load profile data obtained from Enedis from a measuring point located at the islanding breaker. This profile also contains a degree of randomness in order to mask the individual customers' profile. For the SRA analysis, the total consumption for the two Lérins islands for the period 01-09-2019 to 31-08-2019 was provided by Enedis. It is noted that the load consumption peaks during the summer months are due to the tourist season. The maximum and average consumption for the period is 427 kW and 204 kW respectively, which could be considered high for only 56 customers. However, this could be hypothetically attributed to the illumination of the fort, particularly at night. It should be noted that the reactive power has not been considered in this analysis since the total reactive power of the two islands is considered to be low (less than 40 kVar).

Due to current environment regulations implicated on the island, the intended 130 kW_p installation of PV generation was not achieved due to regulatory restrictions and thus no PV generation data could be obtained. It was, thus, necessary to estimate the total PV generation based on the rated value of 130 kW_p, as per the design concept discussed in D9.1. The estimated PV profile was obtained using an online tool [18] which creates a PV generation profile based on the GIS location. The GIS location is mapped directly to the island referencing data stored from previous years. The results of the online PV generation tool can be seen in Figure 147 for the period of analysis.

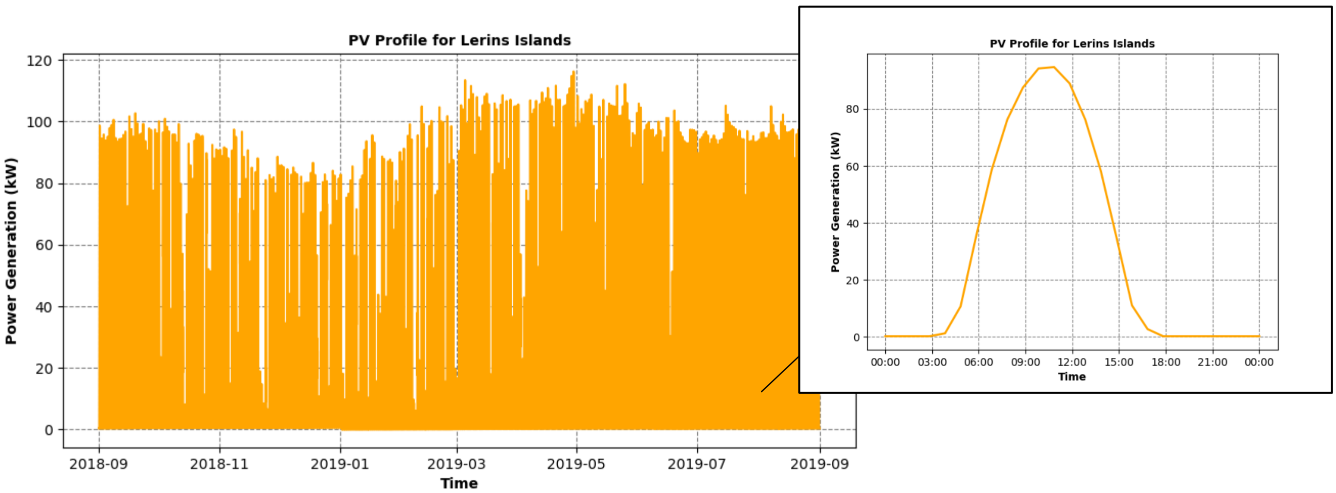

Figure 147 PV generation profile for Lérins Islands

It should be noted that this profile does not consider the possibility of the trees impeding the amount of PV generation, which are present on the island, and thus represents the maximum theoretical PV generation profile based on a maximum power of 130 kW_p and standard parameters for the losses (14%) as per the PV model.

Baseline parameters for the battery storage systems (GSU and GFU)

The battery storage system for the baseline scenario is based on the system parameters as previously intended for UC1. In this case the GFU, which is considered as the primary storage system, is rated with a capacity of 620 kW with a maximum power rating of 250 kW. The purpose of the GSU is to provide additional support to the GFU, as well as the possibly to be placed on the flexibility market. The GSU is rated with a capacity of 273kWh and a maximum power rating of 100kW. In both cases, it is assumed that the maximum SoC is 100% and the minimum SoC is 20%, as per common practice. The primary analysis is based on a theoretical islanding duration and thus the limitations of the battery efficiency and the number charge-discharge cycles are not considered when investigating the initial scalability of the systems. The battery model in the optimised solution, however, does take the characteristics of the battery into account.

Baseline islanding duration calculation

Based on the above baseline input data, the total duration of Islanding can be calculated and is shown in Figure 148. Since the system islanding start time can occur at any moment in time, i.e., in the case of a fault, DSO request or other, the islanding duration is calculated for each moment of time at 10min intervals over the entire period of analysis.

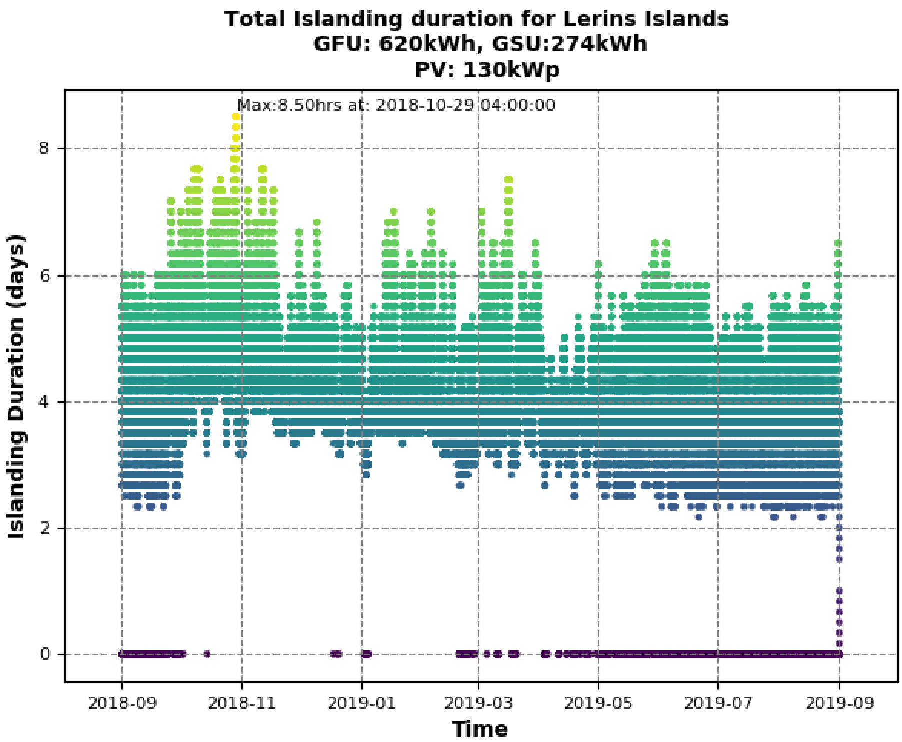

Figure 148 Maximum baseline islanding time for Lérins Island

Based on the results presented in Figure 148, it can be seen that islanding duration **cannot** be started successfully at **any moment in** time as some of the starting points will results in an islanding duration equal to 0 hours. This is due to the net consumption of the network exceeding the maximum power of the storage systems and thus there is insufficient battery power available to supply the load demand of the network. The maximum islanding duration is 8.5 hours when islanding operation starts at 29-10-2018 at 04:00. This time corresponds to 0 PV generation and 90 kW of load consumption. The average Islanding duration over the period of analysis is 3.66 hours. Therefore, this indicates that, based on the current system parameters, the system is unable to provide a reasonable duration of islanding time for

Lérins islands in order to allow for back up generations system to be delivered from the main Island since the minimum lag time for backup generator delivery is 72 hrs. This would cause customers on the island to be without supply for a significant amount of time, contributing to household discomfort and financial losses of local businesses. It is therefore imperative to conduct an investigation into the scalability of the system and thus provides sufficient motivation for the necessity to conduct a scalability analysis.

Baseline Impact of Demand Side Management

The impact of Demand Side Management based on load reduction was also considered as part of the study in order to analyse its effects on the islanding duration. The load reduction was implemented during the morning (00:00 to 06:00) and evening (18:00 to 00:00), where a 10% reduction was simulated. This time period was chosen since the impact on load reduction would be at its greatest, as the influence of PV generation is limited, and no other RES are present. Based on the baseline parameters, the islanding duration can be increased by 0.33 hours from 8.5 hrs to 8.83 hrs when load reduction is incorporated as shown in Figure 149.

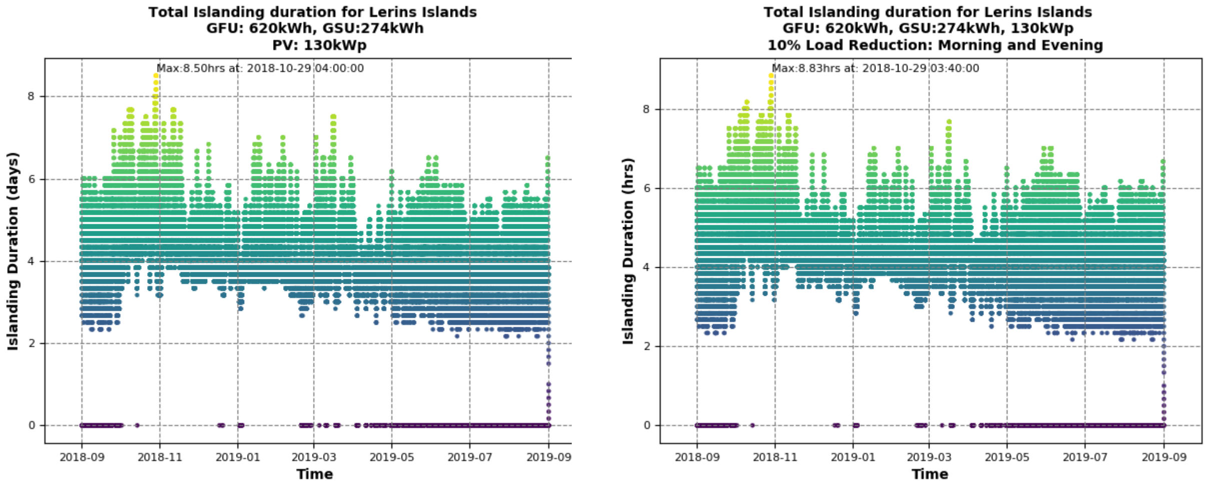

Figure 149 Baseline islanding duration (left) with a 10% load reduction during morning and evening (right)

Scalability of individual of assets

This section explores the scalability of the respective assets under consideration for this Demo, namely, PV generation and storage capacity. In this respect, the scalability of each assets is increased while ensuring that the other network parameters remain constant, such that the impact on the islanding duration of each asset is independently investigated.

Scalability: PV Generation

The Lérins islands has a surface area of 2.47 km^2, of which is mostly covered by forests, as can be seen in Figure 150. Due to the environmental protection of the area, the installation of the maximum amount of PV generation is limited to 520 kW$_p$ (0.12% surface area of the island) and is therefore considered as the upper boundary for this study. Furthermore, a study was conducted to analyse the possibility of including rooftop PV on the 56 customers. Table 54 shows the parameters [22] and [23] used for the analysis and the results respectively. It can be seen that in the case where all 56 customers were to install rooftop PV, an additional 2 MW$_p$ of generation would be achieved. In the case where only 50 % of the customers agreed to the installation, an additional 1 MW$_p$ would be possible as an optimistic target value.

Table 53 Parameters used to consider the maximum PV generation on the island

Parameter	Value
Total surface area of Islands	2.47 km²
Power output 1 panel	300 W
Surface area 1 panel	1.7 m²

Figure 150 Overview of the Lérins Islands source [24]

Table 54 shows a summary of the possible scaling of the PV generation system that could be installed on rooftops of customers.

Table 54 Summary of possible scaling of PV generation systems

PV Installation (kW_p)	Total Area Required (m²)	Number of panels	% Area of Island	Number of rooftops required
130	737	433	0.03	4
260	1,473	867	0.06	7
390	2,210	1,300	0.09	11
520	2,947	1,733	0.12	15
1,040	5,893	3,467	0.24	29
2,080	11,787	6,933	0.48	59
5,200	29,467	17,333	1.19	147

The objective of this scenario is to evaluate the effects on the duration of islanding time when the amount of PV generation is increased to analyse the impact of the increasing the generation independently within the system. In this scenario, the load consumption remains as per the baseline consumption profile for the entire period of analysis. Additionally, the battery storage systems are rated according to the baseline values and kept constant throughout these set of simulations. As previously mentioned, in the case where the net power of the network exceeds that of the installed battery power, the system would be unable to go into islanding, and thus the islanding duration is 0 hrs.

Initially, the increase in PV generation was analysed in the case where there was no GSU connected within the system and thus the system storage relies only on the GFU. This was done in order to represent the case where the GFU is not always available to provide the required flexibility by the aggregator. Based on the SGAM diagram (see Annex X), it can be seen that UC1 can be considered with and without the option of using the storage system as a flexibility. Since the GSU is operated by the DSO, it is considered as the central component for islanding operation. The results of increasing the PV generation from 0 kWp to 520 kWp are shown in Figure 151, which follows the increments based on Table 54. These results show the islanding operation evaluated at every 10 min time step over the different iterations done when scaling the PV injection. This PV increase results in an increase of the islanding duration from 4.3 hrs when there is no PV generation to 16.5 hours when there is 520kWp PV generation.

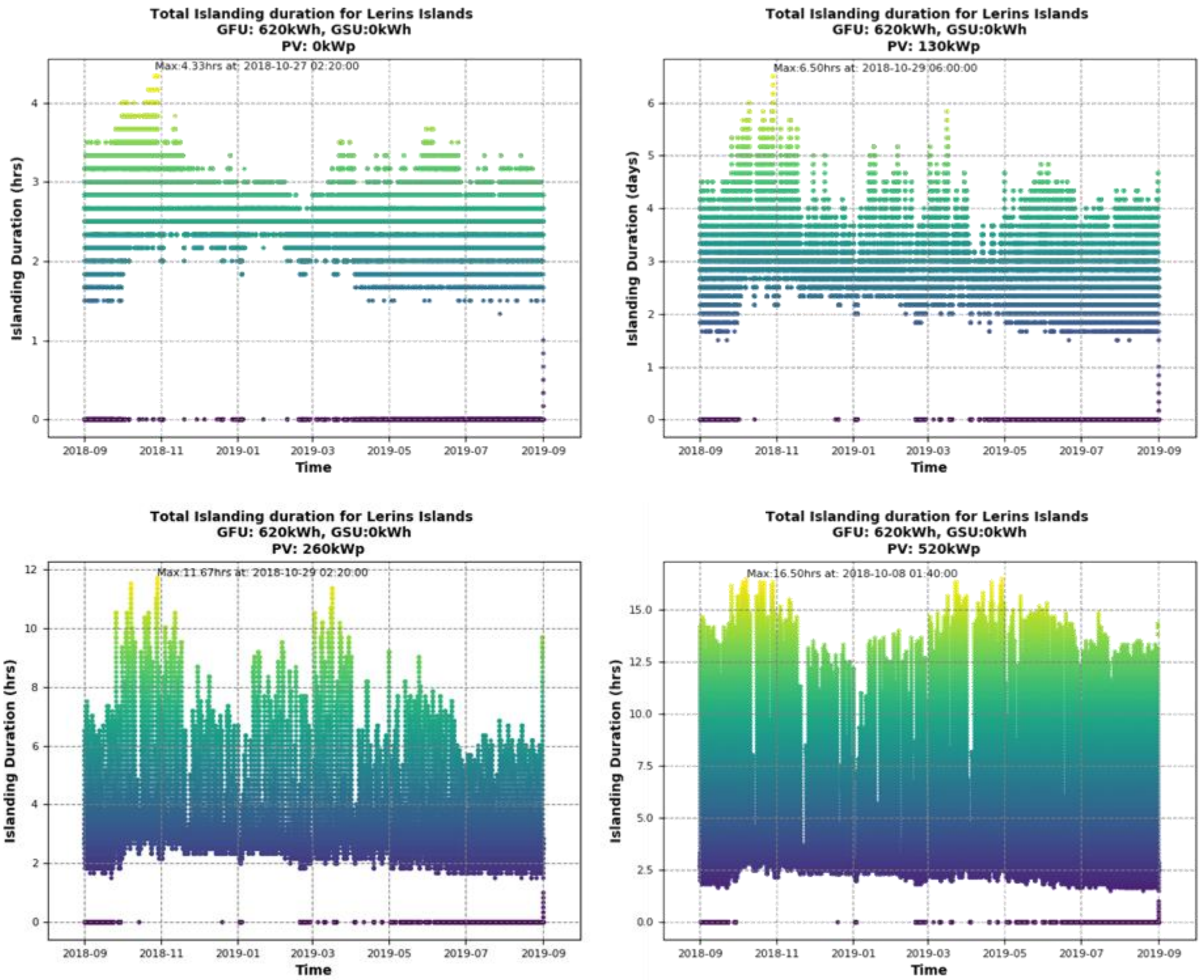

Figure 151 Total islanding duration for Lérins Island with increasing PV generation (0 kW_P to 520 kW_P, GFU: 62 0kWh, GSU: 0 kWh)

The following set of calculations include the combination of the GFU and the GSU, where the GSU compliments the GFU. It is expected that there would be an increase in the islanding duration due to the increase in storage capacity. The results of increasing the PV generation when the GFU and GSU are in use, are shown in Figure 152. It should be noted that for this analysis, it is assumed that the GSU is available for utilisation and its functionality is triggered simultaneously to that of the GFU.

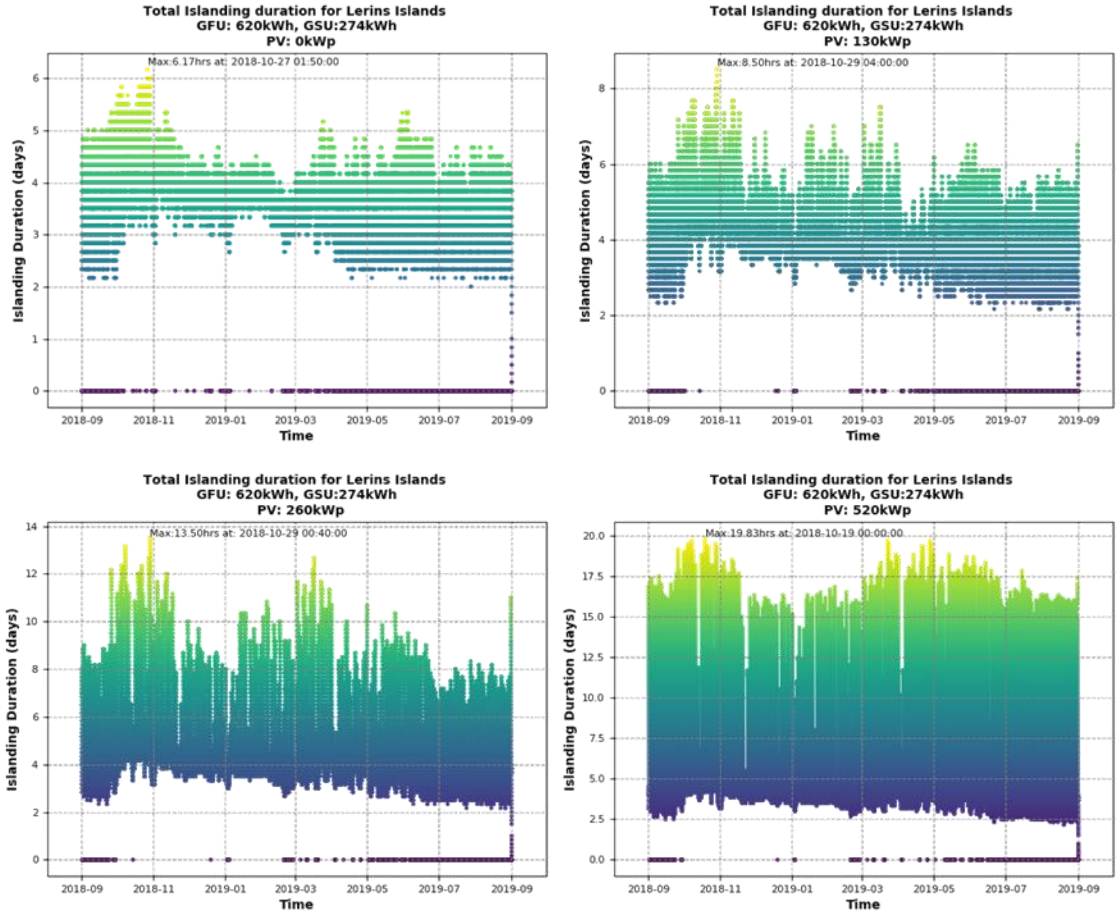

Figure 152 Total islanding duration for Lérins Island with increasing PV generation (0 kW_p to 520 kW_p, GFU: 620 kWh, GSU: 274 kWh)

Therefore, the increase of PV generation into the system with the addition of the GSU allows for the islanding duration to be extended from 6.17 hrs to 19.83 hrs.

A summary of the results of increasing the PV generation with and without the GSU is shown in Table 55.

Table 55 Summary of results of scalability of PV Generation with and without GSU support.

GFU	GSU	PV injection	Maximum islanding duration	Islanding start date and time for max islanding duration
620 kWh	0 kWh	0 kW_p	4.33 hrs	27.10.2018 at 02:20
620 kWh	0 kWh	130 kW_p	6.50 hrs	29.10.2018 at 06:00
620 kWh	0 kWh	260 kW_p	11.67 hrs	29.10.2018 at 02:00
620 kWh	0 kWh	520 kW_p	16.5.00 hrs	29.04.2019 at 01:20
620 kWh	273kWh	0 kW_p	6.17 hrs	27.10.2018 at 01.50
620 kWh	273 kWh	130 kW_p	8.50 hrs	29.10.2018 at 04:00
620 kWh	273 kWh	260 kW_p	13.50 hrs	29.10.2018 at 00:40
620 kWh	273 kWh	520 kW_p	19.50 hrs	19.10.2018 at 00:00

It is evident that with the current system, with the restriction of PV generation limited to 520 kW_p will not be able to sustain an islanding duration of 21 days. Therefore, it is necessary to consider alternative solutions in order to provide an optimised system. These will be investigated in the subsequent sections.

Scalability: Storage Capacity

The objective of this scenario is to evaluate the effect on the duration of islanding time when the amount of Storage Capacity is increased. In this scenario, the load consumption remains as per the baseline consumption profile for the entire period of analysis. Additionally, the PV generation systems are rated according to the baseline values which are kept constant throughout these set of simulations. The results of increasing the storage capacity are shown in Figure 153, where the islanding operation is analysed with increments of 10 min. The increase is done by steps where both batteries are increased at the same time with ranges from 100% to 366% as the batteries should be able to independently sustain the demand of the load.

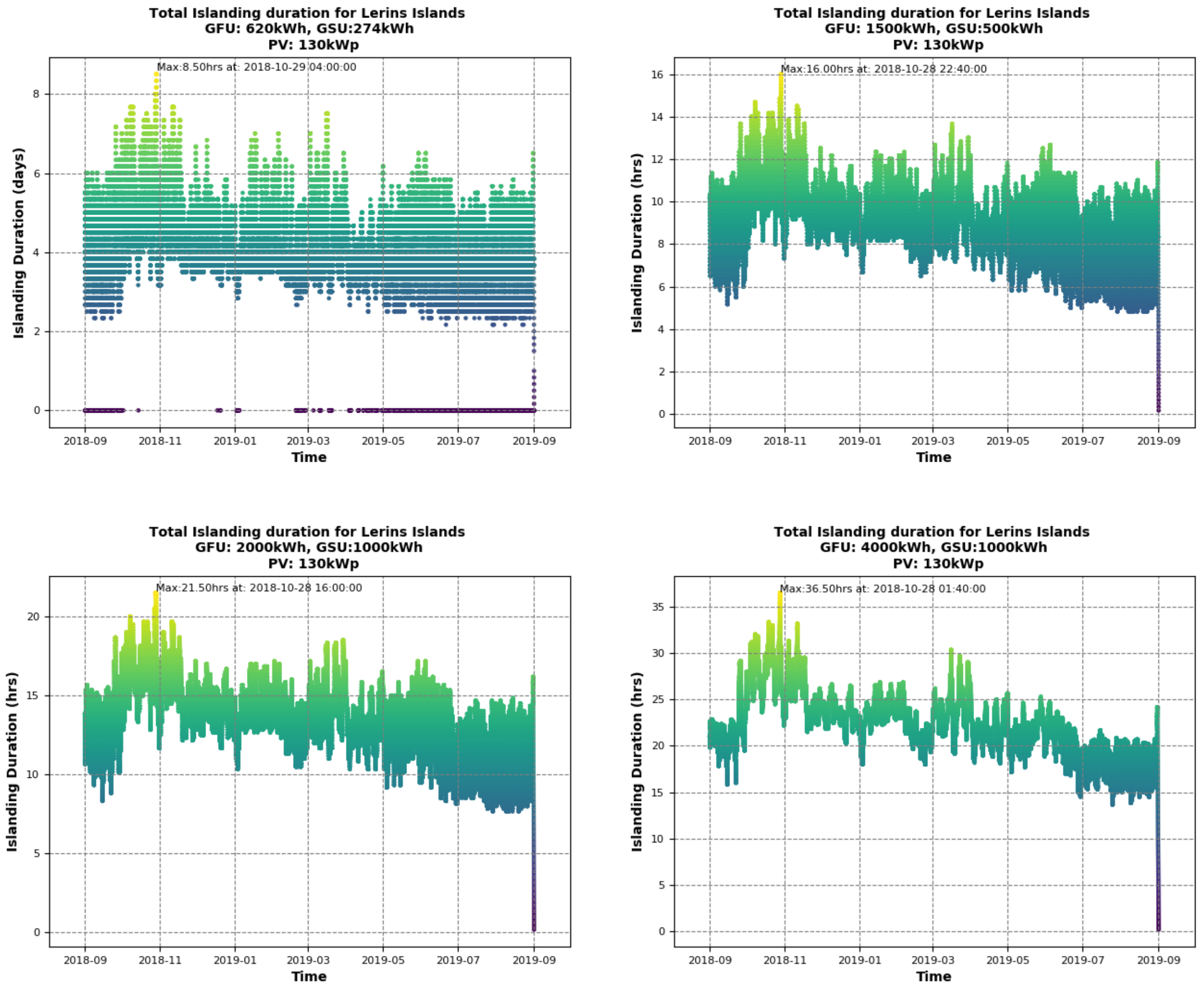

Figure 153 Total islanding duration for Lérins Island with increasing Battery Capacity of the GFU and GSU

As can be seen, increasing the storage capacity of both the GFU and the GSU has the potential to increase the islanding duration from 8.5 hrs to 36.5 hours (~329%), when the PV generation remains at $130kW_{P.}$ A summary of these results is shown in Table 56.

Table 56 Summary of the longest islanding duration results identified when the storage capacity is scaled

GFU	GSU	PV injection	Max islanding duration	Islanding start date and time
620 kWh	273 kWh	130 kW_p	8.5 hrs	29.10.2018 at 04:00
1500 kWh	500 kWh	130 kW_p	16.00 hrs	28.10.2018 at 22:40
2000 kWh	1000 kWh	130 kW_p	21.50 hrs	28.10.2018 at 16:00
4000 kWh	1000 kWh	130 kW_p	36.50 hrs	28.10.2018 at 01:40

Despite the increase in storage capacity up to a total of 5 MW, it should be noted that this is insufficient to sustain 21 days of islanding duration, since there is a lack of support of generation units, which would assist the batteries by providing a period of time to relieve the strain on the battery. Alternatively, the absence of generation does not provide sufficient provision for the possibility of battery charging, should the injection exceed the demand at that period of time.

Scalability-Worst Case A

Worst case A parametrization: Maximum load with minimum PV generation

In this case, the worst-case scenario is based on the combination of highest load consumption with the lowest PV generation, where the days are not correlated one to another. In this case the highest load consumption for 21 consecutive day was found to be the 21 days period starting on the 22-07-2019, which is in the summertime tourist season. The lowest 21 consecutive days of PV production was identified to start on the 12-01-2019 which falls within the winter season. For the provided input load and PV data, the worst-case condition was identified to be as follows:

- Min PV start date: 12 January 2019
- Max load start date: 22 July 2019
- Total Consumption: 126.71 MWh
- Peak load: 0.41 MW
- PV full load hours: 34.19 h/week

With this combination, the extreme worst-case scenario is obtained and is included for demonstration purposes, as it is expected that during the high load season (summer), there will be higher probability of PV generation than that of January. Based on the above system configuration, the outcome of the PV and battery sizing process is shown in Figure 154.

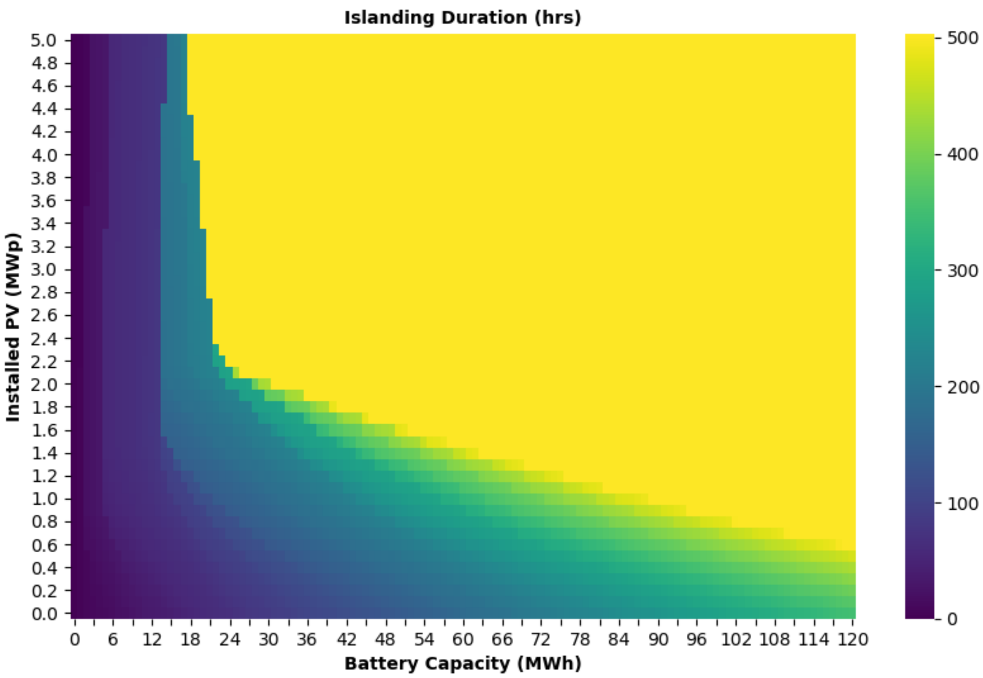

Figure 154 Minimum system requirements based on highest load consumption and minimum PV generation

As can be seen, with the limitation of PV generation restricted to 500 kW_p a battery capacity of greater that 120 MWh would be required in order to sustain the islanding duration of 21 days. This amount of storage capacity is considered to be too vast in the context of the island and thus, also does not serve as a feasible solution. Since the effects of increasing PV generation has a higher impact on islanding duration, in combination with the high costs of battery storage, an increase in power generation into the system should be considered. However, it should be mentioned that the battery capacity can be reduced to 22 MWh if a total of 2.5 MW_p of PV generation is achieved. This is achievable if rooftop PV for each of the 56 customers is included (as shown previously). In the case where not every customer would agree to rooftop PV, the combination of a 520 kW_p, 27 customers (~50%) providing 1.40 MW_p would allow for the battery capacity requirement to be reduced to 21 MWh.

The Impact of Demand Side Management

Based on the system parameters specified, the impact of DSM was investigated. The results of this analysis are shown in Figure 155.

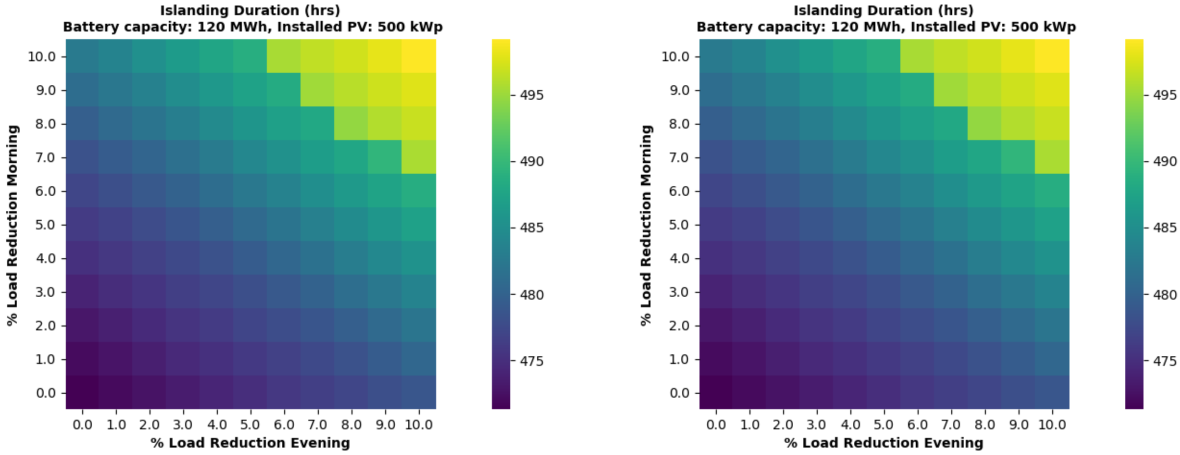

Figure 155 Increased islanding duration (left) and reduced battery size (right)

In both figures and it can be seen that the PV and battery system are close to, but not entirely, providing sufficient capacity in order to sustain 21 days of islanding. As was previously mentioned, a battery of greater that 120 MWh would be required, and it was concluded that this system would not be feasible for implementation on the island due to the environmental restrictions.

Impact of Initial SoC on Islanding Duration

In this scenario, the variation of the initial SoC of the stage system and its impact on the islanding duration was analysed for each of the worst-case scenarios. The results of these simulations are outlined below:

The effects of SoC of the battery is shown in Figure 156 when the system is sized with a 120 MWh battery and 500 kW_p installed PV injection. In this case, it can be seen that the battery is required to be charged to 100% SoC when islanding if it is to sustain 21 days of islanding duration.

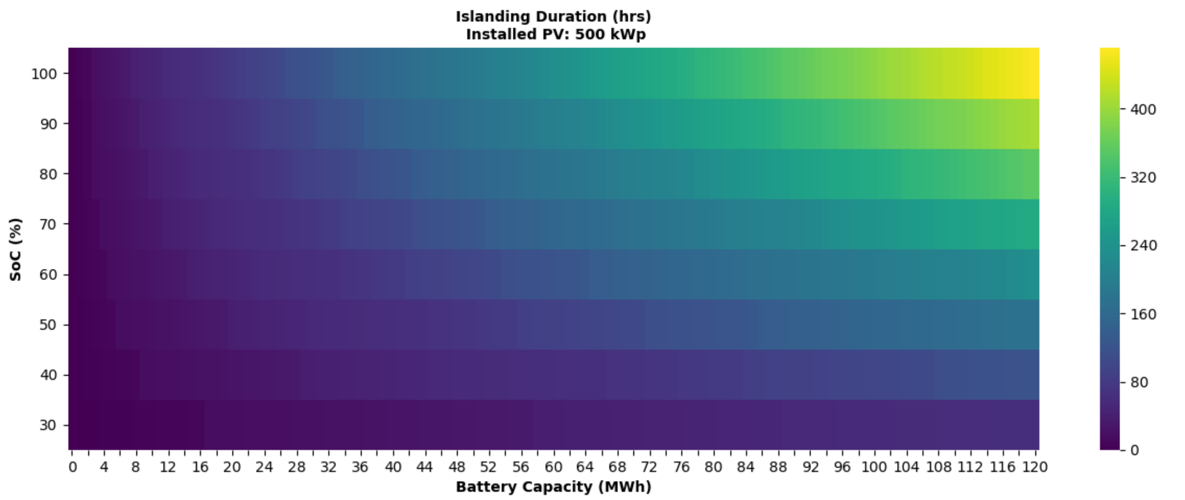

Figure 156 Effects of initial SoC of the 120MWh storage system for 21 days islanding duration

Combination of all characteristics

When considering the combination of all the characteristics discussed in the previous sections, the impact of increasing the amount PV injection (through the inclusion of rooftop PV), and by incorporating DSM initiatives in order to achieve 10% load reduction, the size of the battery system can be reduced from 120MWh to 21 MWh as shown in Figure 157.

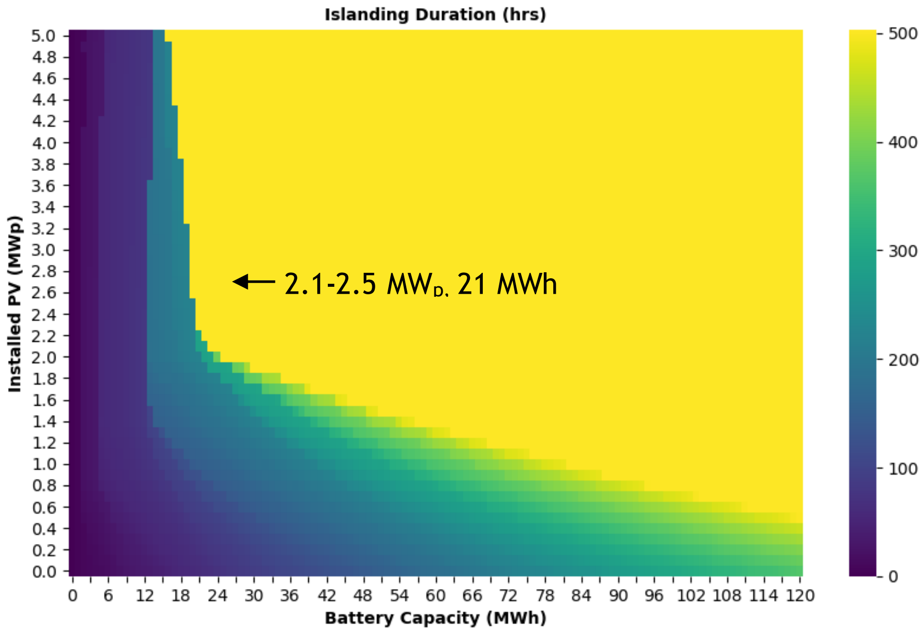

Figure 157 Heatmap showing battery capacity VS PV generation with load reduction initiatives for Case A

Scalability-Worst Case B

Worst case B parametrization: Longest period of consecutive days with minimal PV generation

In this scenario, the condition where there is the longest duration of minimum PV generation is considered. In this case, it was observed that the week starting 5-11-2018, contains 4 consecutive days where the total amount of PV generation was minimal due to poor weather conditions. In such cases, which is likely to occur during the winter period, the islanding duration is expected to rely heavily on the SoC of battery at the moment where islanding operation is to occur after a period of bad weather, since the battery is unable to charge due to limited PV generation, unless there is a connection to the main grid, therefore a reserve capacity is thought of for similar PV generation situations. For the provided input load and PV data, the worst-case condition was identified to be as follows:

- Islanding start date: 5 November 2018
- Total Consumption: 89.39 MWh
- Peak load: 0.252 MW
- PV full load hours: 65.26 h/week

Based on the aforementioned scenario, the PV and battery system were sized accordingly in order to sustain the 21 days islanding period and the results are shown in Figure 158.

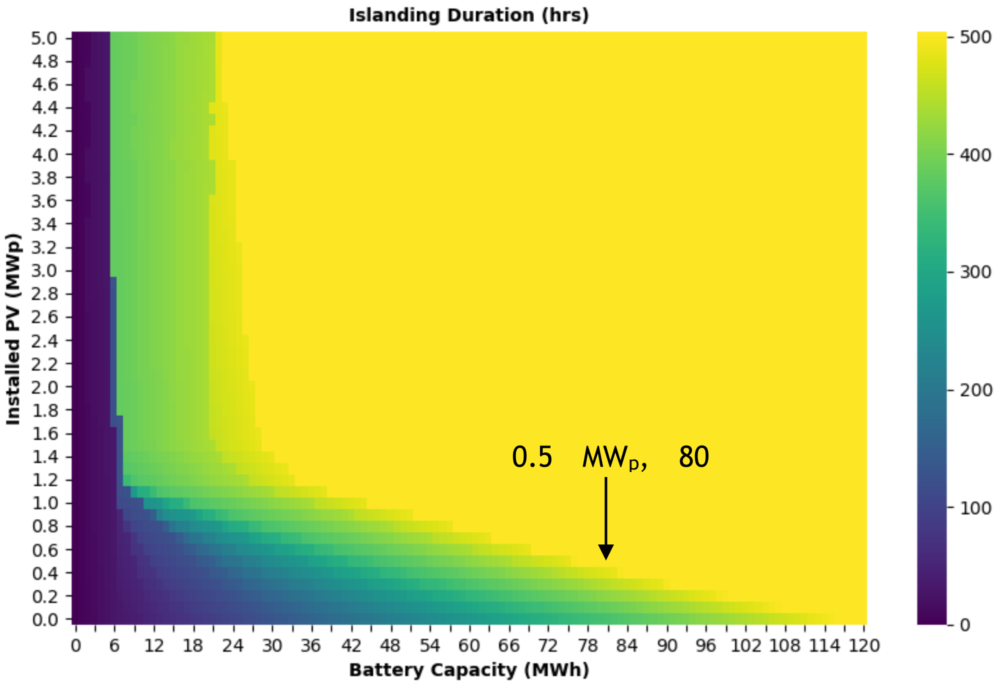

Figure 158 Minimum system requirements based on longest period of consecutive days of minimal PV generation

As can be seen, in this scenario, a battery size of 80 MWh would be required with 500 kW_p PV generation if the system is to sustain 21 days of islanding.

The Impact of Demand Side Management

With respect worst case B scenario, which incorporates an 80 MWh battery and when combined with 500kW_p PV generation, it can be observed in Figure 159 (left), that a reduction of load results in an increase in islanding duration of up to 572 hours, which translates to 23.83 days of islanding duration. On the other hand, the battery size can be reduced to 72 MWh while still maintaining the 21 days of islanding duration, as shown in Figure 159 (right).

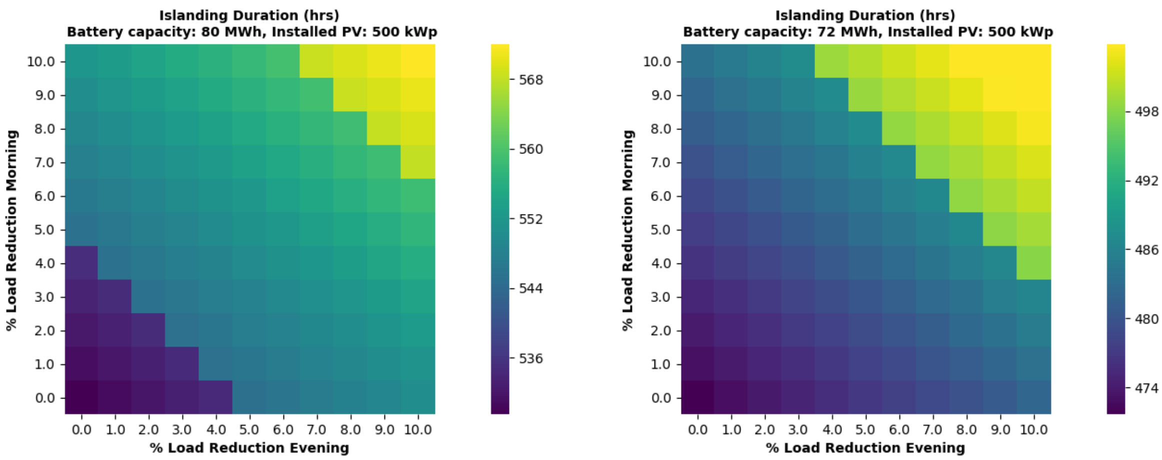

Figure 159 Increased islanding duration: 572 hrs (left) and reduced battery size: 72 MWh (right)

Impact of SoC on Islanding duration

Figure 160 shows the results for the variation of SoC of the 80 MWh battery storage system with 500 kW_p PV injection in order to maintain 21 days of islanding duration.

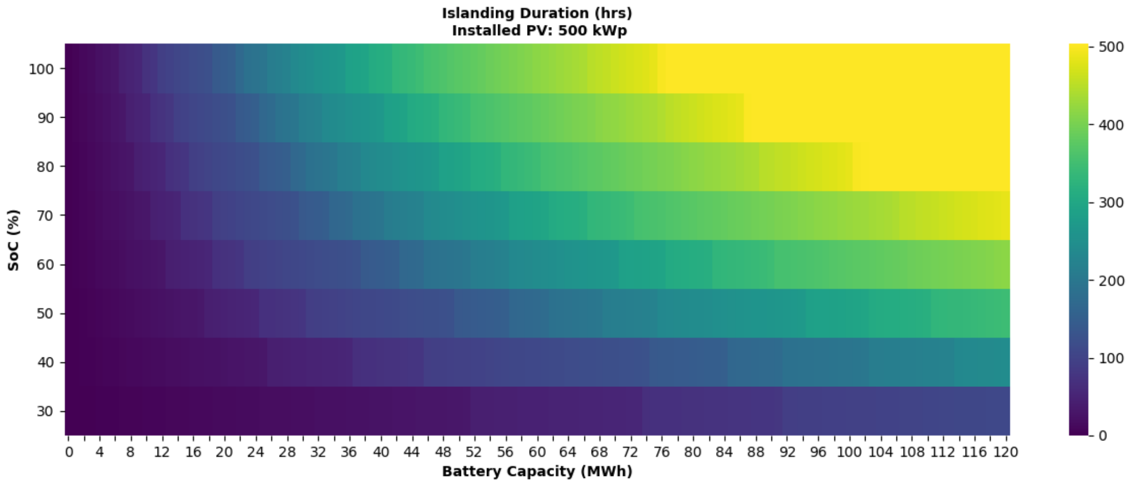

Figure 160 Effects of initial SoC of the 80MWh storage system for 21 days islanding duration

As can be seen, if the battery system is to sustain the requirement of 21 days of islanding, it would be necessary to increase the capacity of the battery capacity if the SoC of the system is less than 100%.

Combination of all characteristics

In this case, it can be seen in Figure 161, that when a load reduction of 10% for both morning and evening peaks, in combination with 2.5 MW_p obtained through the inclusion of rooftop PV, the battery capacity can be reduced from 80 MWh to 25 MWh.

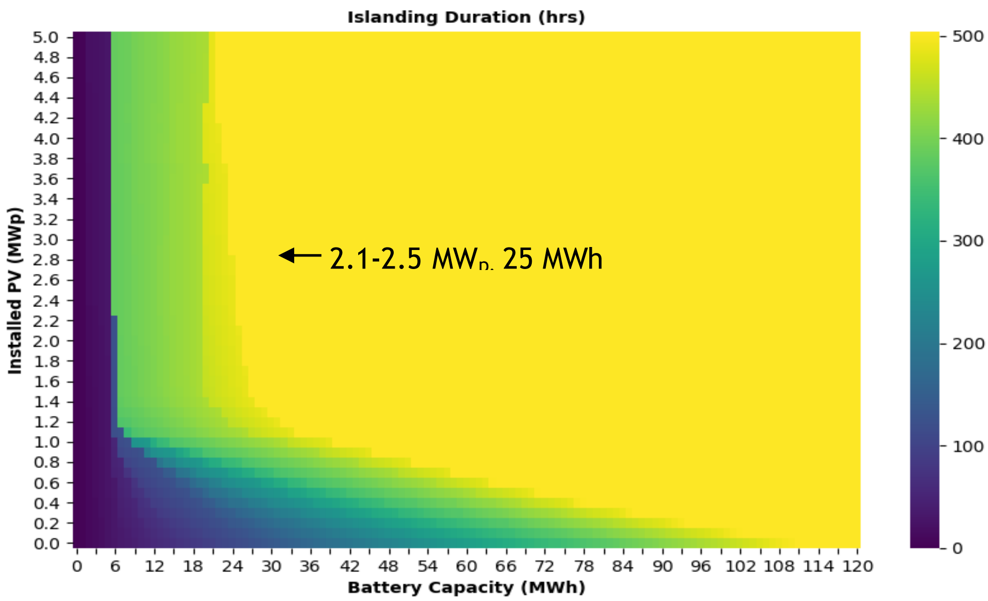

Figure 161 Heatmap showing battery capacity VS PV generation with load reduction initiatives for Case B

Replicability-Baselines

The replicability analysis of the FR demo in terms of seasonality allows for the analysis of the islanding duration variation based on different seasons throughout the year. For the purpose of the analysis only the 2-battery storage system configuration with a GSU and GFU is considered.

Initially, the results for the baseline scenario obtained and the average islanding duration for each day for the entire period is shown in Figure 162.

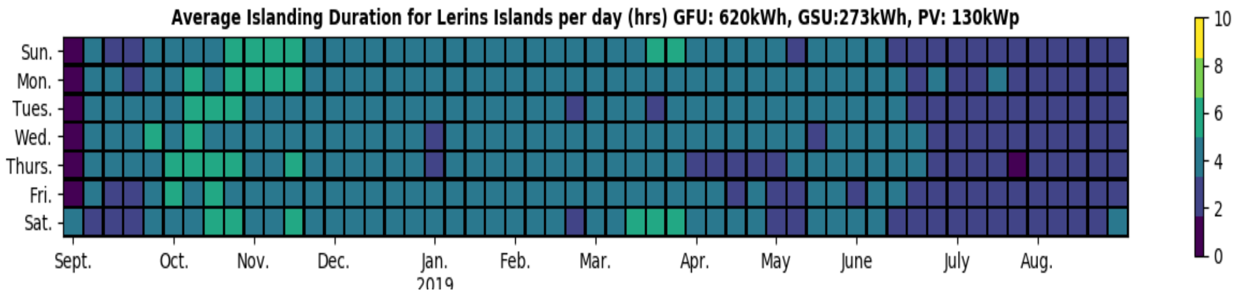

Figure 162 Average daily islanding duration for the baseline scenario for all seasons

As can be seen, the longest period of average islanding duration is seen during the month of October 2018, where an average of 6 hrs per day islanding duration is possible. This is due to the lower consumption demand due to the end of the tourist period (off peak season). In contrast, despite the increase of availability of PV generation (130kW$_P$) during the summer months, this did not contribute to an increase in islanding duration as only an average of 2 hrs islanding duration is achieved. This can be attributed to the increase in the consumption profile due to an influx of tourists during the peak season. Thus, in the case of the seasonality analysis of the baseline scenario, the load profile of the consumers is seen to have the most impact on the average islanding duration. As was shown in the scalability analysis, the impact of DSM techniques in order to reduce the load consumption would result in an increased islanding duration, and therefore should be taken into consideration, especially during the summer months when the load consumption is high.

Replicability of individual assets

In this section the replicability of the implementation of the scaling of the individual assets is presented. In each case, one parameter is scaled accordingly and an analysis of the islanding duration over the entire period (for all seasons) of analysis is observed.

Replicability: Scaled PV generation

In this scenario, the effects of seasonality on the islanding duration in the case where the amount of PV generation is scaled up to 520 kW_p is observed. As shown in Figure 163, an average islanding duration of 10 hrs per day is achievable during the months of October 2017. In this month it is observed that the load consumption was at its lowest with respect to the year of analysis.

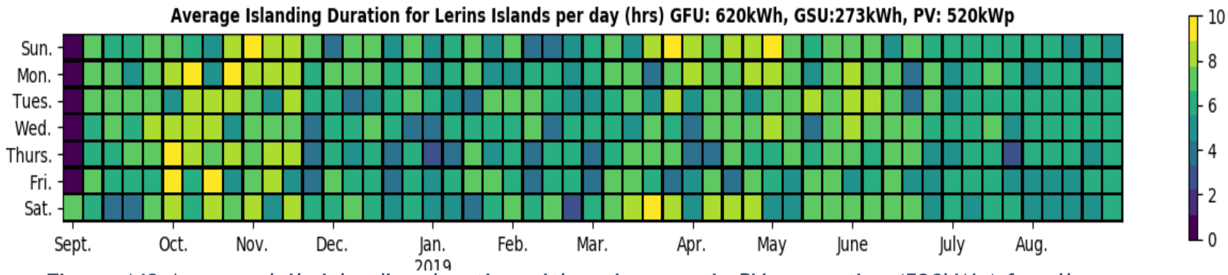

Figure 163 Average daily islanding duration with an increase in PV generation (520kWp) for all seasons

It can thus be concluded that by increasing the amount of PV injection, the average islanding duration per day over the entire year is increased and thus the islanding duration is dependent on seasonality. However, when considering the summer months (Jul-Aug), it would be expected that an increase in PV generation would have resulted in a longer islanding duration since PV injection is expected to be at its highest. In this case, the increase in load demand, due to the impact of increased tourism on the islands have proved, as shown previously, to have a higher impact on the islanding duration. During these months, an average islanding duration of more than 6 hrs is achievable with the increased load demand. However, in order to maximise the potential of increased islanding duration, additional PV panels should be installed in the most optimal manner at both utility and customer level. Also, if the system allows, maximum power point tracking systems should be considered.

Replicability Scale Storage Capacity

In this scenario, the effects of seasonality on the islanding duration are analysed in the case where the storage capacity is scaled up for the GFU to 1.5 MWh and the GSU to 0.5 MW. In this case the PV generation is as per the baseline of 130 kW_p. As can be seen Figure 164, the effects of increasing the battery storage capacity results in an increased average islanding duration (up to 10 hours per day) throughout the year of analysis.

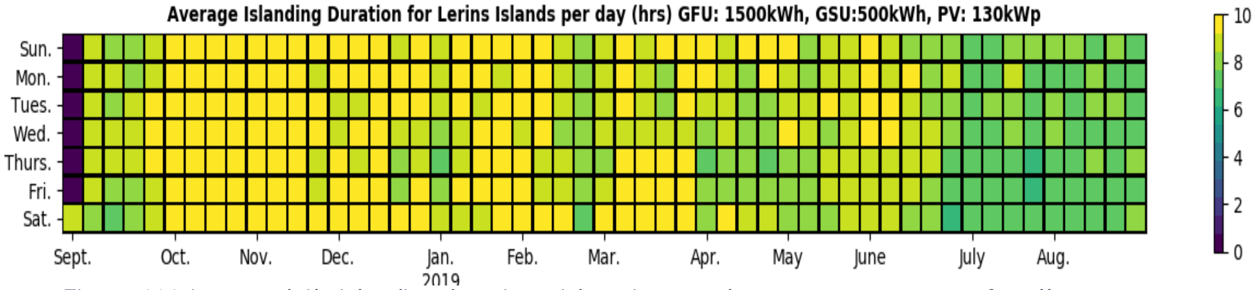

Figure 164 Average daily islanding duration with an increase battery storage system for all seasons

During the summer months, when there is increased load consumption due to the peak tourist period, the average islanding duration is approximately 7 hours per day. It can also be observed that the overall system becomes less dependent on the effects of seasonality when there is an increase in storage capacity. This is as expected since, unlike PV generation, battery capacity is not weather dependant. Therefore, in order to ensure that seasonality does not negatively impact the islanding duration, it is important to ensure that the scaled parameter is not affected by external weather conditions

Add on: Storage System Configuration Analysis

In this scenario the implementation of distributed storage systems (in contrast to a central storage system) was considered. The analysis was based on a 1, 2 and 5 battery system where the percentage of size of the system was scaled according to the ratio of loading seen at each of the transformer locations on the island. A summary of the system configuration is shown in Table 57.

Table 57 Summary of different storage system configurations on Lérins islands

System configuration	1 Battery System	2 Battery System		5 Battery System				
Location	Saint Honorat & Saint Marguerite	Saint Honorat	Saint Marguerite	Saint Honorat	Guerite	Incineration	Prison	Grand Jardin
% Load	100	17	83	17	10	41	19	13
Installed PV [MWp]	0.50	0.09	0.42	0.09	0.05	0.21	0.10	0.07
Battery capacity [MWh]	60	10.20	49.8	10.20	6.00	24.60	11.40	7.80

Furthermore, a summary of the advantage and disadvantages of a single vs multiple storage system is shown in Table 58. During the implementation of the islanding system each of these characteristics should be considered and optimised to obtain the most feasible solution.

Table 58 Summary of advantages and disadvantages of a single vs multiple storage system

System configuration	Single Storage System (x1)	Multiple Storage System (x2-x5)
Advantages	+ Reduced maintenance requirements + Easier communication infrastructure + Easier control	+ Increased opportunity to provide flexibility to markets + Increased overall system reliability + Possible multi-party investment + Different maximization approaches + Improved node control
Disadvantages	- Limited availability of large battery capacity requirements - One single point of failure - Possible loading issues in PoC - Operation is limited	- Higher capital costs - Higher O&M costs - Increase in control systems complexity - Communication essential for proper operation

As can be seen, each of the system configurations are associated with their respective advantages and disadvantages. When considering the existing possibilities of installing an islanding solution, it is there important that these factors are taken into consideration in order to find the most feasible solution.

7.3. Information and Communication Technology additional support documentation

Within the additional documentation which support the ICT scalability analysis in this section, the ICT concepts which the analysis uses as a foundation are described, in addition to the several qualitative tools developed for the analysis.

7.3.1. ICT scalability concepts

The objective of the qualitative analysis is to anticipate where the potential performance failures or potential barriers/limitations are located. Therefore, in order to conduct the study, the following concepts act as a foundation for the attributes which will be relevant for the ICT scalability analysis process:

- a complexity reduction concept for the ICT architecture to analyse each individual sub-system of the architecture that could be impacted by failures and/or limitations,
- an identification concept which helps locate the exact components which are unable to provide a software fail-safe functioning in case of failure,
- an identification concept which helps locate the exact components which are unable to provide a safe communication with other components,
- an identification concept which helps locate the exact components which are unequipped with hardware “spare wheel” in case of hardware failures,
- an identification concept which helps pinpoint capacity-under-sized components or links that will constitute bottlenecks in the scaled-up system and
- an identification concept which helps locate the components dependent on the human that could require increased human to machine interactions in the scaled-up system.

These concepts are deeper described within the following subsections.

Complexity reduction concept

An ICT architecture consists of components and their respective links between these components thus, creating an entire interconnected system that is partially represented by the SGAM component interoperability layer. Each component presented in the system has the ability to act as an information provider or an information consumer based on requests and responses. This ability can be expressed with the popular expression, "Client" and "Server", presented in Figure 165. When the component acts as a client, it requests and when it acts as a server it provides a response. Each component can be made of one or several clients and / or one or several servers, hence defining the attribute of the component's ability to communicate on links in the ICT system.

Figure 165: Typical ICT Client-Server architecture

Based on this ability, a complex ICT system can be broken down into different elemental ICT sub-systems which are composed by client-server architectures. These architectures represent the relation between two devices (components). Figure 166, shows how a complex system represented by its Component layer from the SGAM framework can be further reduced by the client-server architecture approach.

Each pair of components (devices) can be seen under this client – server architecture as a Client or Server depending on the functional[22] flow of information. Therefore, device "A" when communicating with "B" acts as a client when requests information from "B" and as a server when provides responses to "B" based on "B" requests. This approach provides enough reduction of complexity and flexibility for the qualitative analysis.

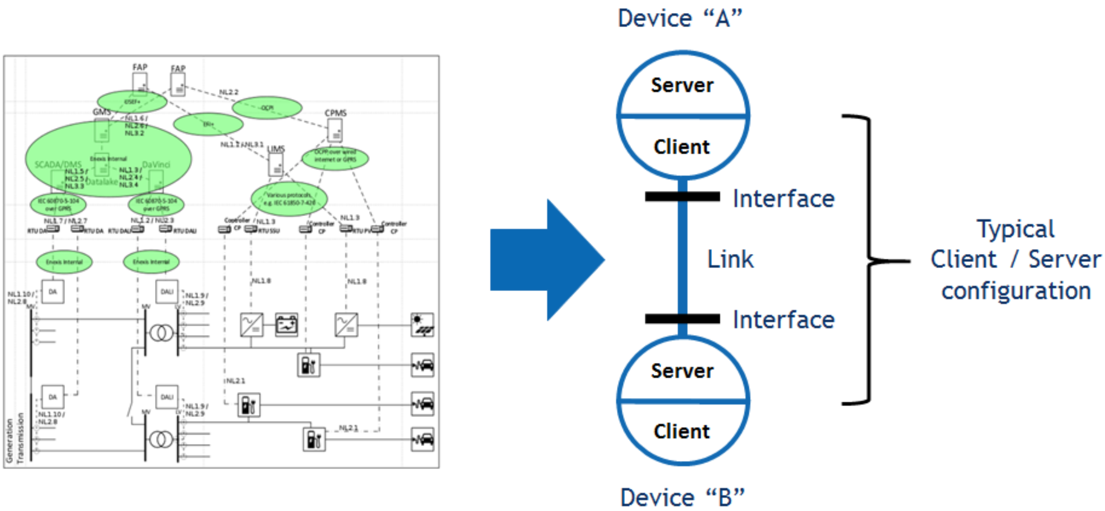

Figure 166: Reducing complexity of an ICT system

[22] It is understood as functional flow, as the functional part of a device defines if the device will require a client or a server and obviously the direction of the "main" data flow

Fail-safe functioning concept

When dealing with high data sensible systems, such as power grid networks, it is important to consider what happens with the data when there is a malfunction or a system collapse. Hence, the concept of fail-safe functioning provides the assessment of the ability for a component to recover from a malfunction and how long the data, during the time the component unavailable, will be stored until the component restored for operation. It there provides visibility of its ability for continuous operation.

Ensure safe communication concept

Another important aspect from the ICT system, when dealing with large data, is how the systems copes with imperfect data. This can be caused due to, *partial or total destruction of frames by external noises; loss of frames integrity due to transmission errors; packet loss; answering timeout and/or corrupted data*.

Spare wheel concept

Not only data treatment and safety are necessary under ICT systems, but also the consideration of the critically of a system to operate. Supervisory Control and Data Acquisition (SCADA) systems, for example, are critical systems which always need to be running as they are monitoring the status of the grid and without them the system would be operated blindfolded. In order to consider this important aspect, the concept of “spare wheel” provides the assessment for both, link and component redundancy.

Bottlenecks on a component concept

In a smart system, performance is important, therefore when scaling up, potential bottlenecks could be caused due to under performance of the components themselves. Thus, it is important to consider both requirements and capacity of a component. The requirement is what is expected from a component and the capacity is what this component is able to provide. Figure 167 illustrates how components are analysed to find potential bottlenecks, whereas Table 59 provides a brief explanation.

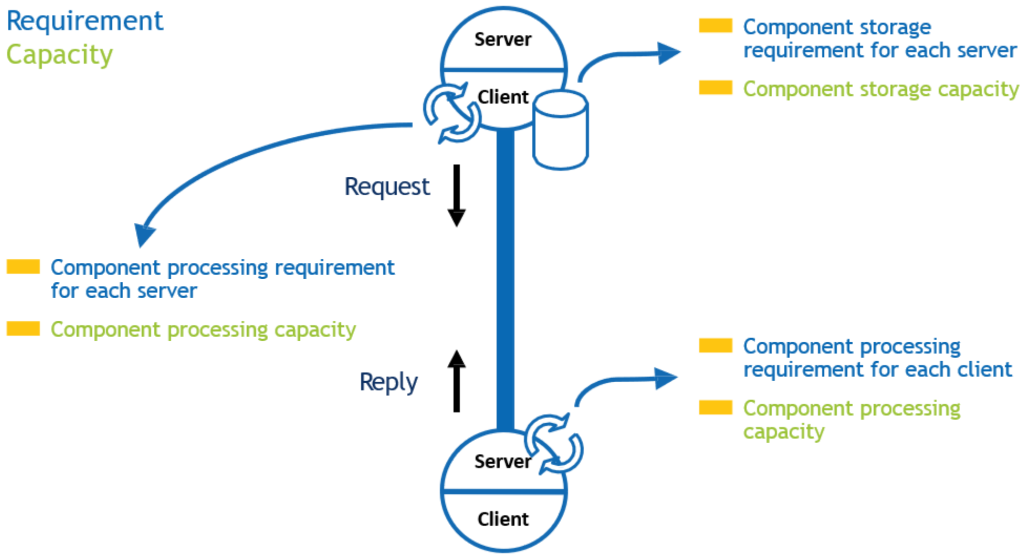

Figure 167: Bottleneck identification on a single component

Table 59: Component bottleneck concepts

Requirement & capacity attributes involved in the component bottleneck concepts	
Processing requirement for a client	Maximum amount of processing power requested to compute replies from servers
Processing capacity of a client	CPU processing power, RAM or other resources available to compute replies from servers.
Processing requirement for a server	Maximum amount of processing power requested to prepare replies to client requests.
Processing capacity of a server	CPU processing power, RAM or other resources available to prepare replies to client requests.
Storage requirement for a client	Amount of data to be stored for each server connected with.
Storage capacity for a client	Storage size available on the device and reserved for this client

Bottlenecks on a link concept

Similarly, to the components, links are also to be considered as important sources of potential bottlenecks when there is a scaling up due to their inherited capacity and legacy requirements. Figure 168 illustrates how links are analysed to find these whereas Table 60 provides a brief explanation of them.

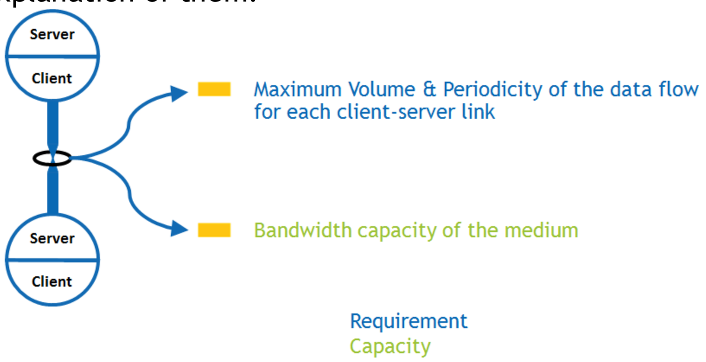

Figure 168: Bottleneck identification on a link

Table 60: links bottlenecks concepts

Requirement & Capacity attributes involved in the Link bottleneck concept	
Maximum Volume & Periodicity of the data flow requirement	The data flow has to be differentiated as Network protocol data flow and Application protocol data flow
Bandwidth capacity of the medium	Maximum capacity the medium can transport data flow

Dependence on the human concept

Due to the introduction of smart grid solution within electrical networks, autotomised systems are becoming more prominent and the reliance of human interaction is becoming reduced. However, component installation and configuration are still required. Therefore, this concept provides the assessment of the effort required for a component to be installed and configured. It also assesses the requirement of the component with respect to human to machine interactions when in operation, which is representative of its level of automatization.

ICT scalability attributes

Based on the conceptions formerly described, attributes are selected to match the conceptions definitions. Additionally, they are classified in order to help with the further analysis performed in section 3.2. They are formally presented in Table 61 and further explained in Table 62 to Table 65, including the scores which will be used at a later stage.

Table 61: Attributes conceptualization origin and their classification with the main categories

Concept	Attribute	Classification
Fail-safe functioning	Autonomy	Reliability
Ensure safe communication	Protocol robustness	
Spare wheel	Redundancy	
Bottleneck on a component	Component storage	Computational resources
	Response time	
	Processing speed	
	Data retention duration	
Bottleneck on a link	Data volume	Manageability
	Data periodicity	
	Maximum Bandwidth (kb/s)	
	Max number of links[23]	
Dependence on the human	Configuration effort / complexity	
	Automatization	

All the attributes previously exposed will not participate in all the stages of the ICT qualitative analysis. The following classification is done to filter which attributes will be used at each of the stages/phases of the analysis.

- Architecture Characterization:
  - Autonomy, protocol robustness, redundancy, configuration effort/complexity and automatization
- Architecture Capacity & Requirement:
  - Component storage, processing speed, data retention duration, data volume. Data periodicity, maximum bandwidth and max number of links

Additionally, in the hereafter presented tables, each of the attribute is presented individually in a table, where it definition and the internal scores for the analysis are provided.

[23] Maximum number of links of the same kind a client or server COULD handle at the same time if we SCALE-UP the demonstrator.

Table 62: Information for scaling attribute, autonomy

Information	Details
Attribute	Autonomy
Definition	Component internal number of factors for continuous operation[24]
Concept related to	Fail-safe functioning
Classification	Reliability
Score	Definition
1	No fail-safe mechanisms
2	Data buffer
3	"Cold" safe mode
4	"Warm" safe mode between 1h and 24h
5	Warm safe mode more than 24h

Table 63: Information for scaling attribute, protocol robustness

Information	Details
Attribute	Protocol robustness
Definition	Assessment of the protocol features to cope with non-perfect data
Concept related to	Ensure safe communication
Classification	Reliability
Score	Definition
1	Has noise immunity
2	Additionally, has Error checking
3	Additionally, has packet recovery
4	Additionally, has Out-of-order data capability[25]
5	Additionally, has data encrypted

Table 64: Information for scaling attribute, redundancy

Information	Details
Attribute	Redundancy
Definition	Assessment for component or link necessity for duplication in order to ensure a proper timing and reliable access when information is needed or used.
Concept related to	Spare wheel
Classification	Reliability
Score	Definition
1	Avoid
2	Not necessary
3	Passive redundancy, active only when malfunction
4	Passive redundancy, active for a limited period
5	Fully redundant, always active

[24] Internal mechanism to restart the component and how long data (during the component is not available) will be stored to be treated once the component is ready for duty again
[25] Ability of the component to answer to a request even if the answering timeout is over

Table 65: Information for scaling attribute, component storage

Information	Details
Attribute	Component storage
Definition	Storage in the component
Concept related to	Bottleneck on a component
Classification	Computational resources
Score	Definition
1	No storage
2	Volatile, small but fast
3	Volatile, large and fast
4	Permanent, small
5	Permanent, large

Table 66: Information for scaling attribute, response time

Information	Details
Attribute	Response time
Definition	Request response behaviour between two components[26]
Concept related to	Bottleneck on a component
Classification	Computational resources
Score	Definition
1	Stalls often
2	Requires at least two trials
3	Admissible time response
4	Low delay response
5	No significant delay

Table 67: Information for scaling attribute, processing speed

Information	Details
Attribute	Processing speed
Definition	Assessment of the orders processed by a component[27]
Concept related to	Bottleneck on a component
Classification	Computational resources
Score	Definition
1	µController (no OS)
2	Embedded with OS
3	PC
4	Server
5	Grid computing

[26] Required computational resources for one client-server link. It can be either (depending on client-server side considered):

- the response time required by a server to send a reply to a client request,
- or the response time required by a client to treat a server reply.

[27] Available computational resources to process either (depending on client-server side considered):

- all replies for each individual client connected to a server,
- or all replies received by a client.

Table 68: Information for scaling attribute, data duration retention

Information	Details
Attribute	Data duration retention
Definition	How long the data stays saved in a device
Concept related to	Bottleneck on a component
Classification	Computational resources
Score	Definition
1	Very low: <60s
2	Low: 60s < X < 1h
3	Medium:1h < X < 6h
4	High: 6h < X < 24h
5	Very High: > 24h

Table 69: Information for scaling attribute, data volume

Information	Details
Attribute	Data volume
Definition	Average volume dealt with
Concept related to	Bottleneck on a link
Classification	Manageability
Score	Definition
1	X <1 Kb or analog value
2	1Kb < X < 100 Kb
3	100Kb < X < 10 Mb
4	10 Mb < X < 1 Gb
5	X > 1 Gb

Table 70: Information for scaling attribute, data periodicity

Information	Details
Attribute	Data periodicity
Definition	Average for exchange of information on a link between two components
Concept related to	Bottleneck on a link
Classification	Manageability
Score	Definition
1	Less than once a day
2	Once a day
3	Several times a day
4	Every hour
5	Less than an hour

Table 71: Information for scaling attribute, configuration effort/complexity

Information	**Details**
Attribute	Configuration effort / complexity
Definition	Assessment of the process for component/link integration
Concept related to	Dependence on the human
Classification	Manageability
Score	Definition
1	Requires Human involvement but complex
2	Requires Human involvement but average
3	Requires Human involvement but easy
4	Assisted configuration but with small Human changes
5	Auto-configuration

Table 72: Information for scaling attribute, automatization

Information	**Details**
Attribute	Automatization
Definition	Assessment of the level of automation for the component operation
Concept related to	Dependence on the human
Classification	Manageability
Score	Definition
1	Requires HM[28] to operate it every time
2	Requires HM to supervise most of the time
3	Partially autonomous, requires HM interaction in frequent cases
4	Partially autonomous, requires HM interaction in seldom cases
5	Fully autonomous, does not require any HM interaction

[28] Human to Machine interaction effort

7.3.2. Qualitative tools developed

As means of implementation of the qualitative analysis for the ICT scalability, tools have been developed to conduct the analysis. This set of tools, which can be considered as a bundle has been developed with the intention to be fast shared, modified and easily accessible to any party involved. Hence, the development has been done through Excel sheets, highly customizable.

The bundle of tools consists of the following tools:

- Attribute assessment tool,
- Architecture Characterization tool,
- Capacity and Requirement tool and
- Scaling-up tool.

Attribute Assessment Tool

This tool reflects the first step of the qualitative analysis where all the distribution system operators are involved and were asked to fulfil the attributes classification selected for the ICT qualitative analysis. The objective of this assessment is to identify what information will be gathered for an ICT qualitative scalability analysis for the DSO. This classification is based on three parameters as exposed in Table 73.

The first, is the expected impact according to each demo leader when considering the scaling up the of system. The second, the interest towards that attribute to be further analysed. Finally, the third, the available information/documentation for that attribute to be studied with respect of the components or links or data which is relevant for. This available information will be crucial for the Architecture Characterization tool. The classification is done by means of a high to low, high importance to least importance and, yes/no/or limited information for each of the topics collected in Table 73 using Table 74. Additional comments are appreciated as it is understandable that not all the information might be available for each component and link.

Table 73: The “Attributes Classification” sheet

Categories	Attributes	Expected Impact	Interest towards it	Available information?	Additional comments
Reliability	Autonomy				
	Robustness				
	Redundancy				
Computational resources	Device Storage				
	Response time				
	Processing speed				
Manageability	Data volume				
	Data periodicity - How often				
	Configuration effort/complexity				
	Automatization				

Table 74: Rating scale legend for the attribute assessment tool

Impact	High	Medium	Low
Possible impact into the scaling of the System	Will have a great impact and is a constraint	Medium impact and could be a constraint	Low impact will hardly become a constraint
Interest	**Very important**	**Important**	**Not important**
Measures if the attribute shall be taken into consideration or not	Must be included into the analysis	Nice to have, but not fully necessary	Attribute is not interesting at all
Available information	**Yes**	**No**	**Yes, limited**
Can the information requested in the definition of the attributes be gathered?	All the necessary information requested can be gathered and shared	No information is available for the attribute	Some of the information might be missing
Additional comments			
Any further comment which needs to be considered or addressed			

Nonetheless, in order to fulfil the attributes classification, definitions of the attributes and their internal rating system are added to the tool for the user. This provides a clear view, as shown in Figure 169, which helps the user rate the attributes. However, not all the attributes are well suited for all components, links and data at the same time and are differentiated according to their physical difference. This specification is depicted in Table 75 which is added to the tool for maximum tool comprehension.

Table 75: Attributes Filter sheet

Categories	Attributes	Component layer		Communication layer[29]		Information layer [30]
		Client	Server	Network	Application	Data
Reliability	Autonomy	yes	yes	no	no	no
	Protocol Robustness	no	no	yes	yes	no
	Redundancy	yes	yes	yes	yes	no
Computational Resources	Device Storage	yes	"no"	no	no	no
	Response time	yes	yes	no	no	no
	Processing speed	yes	yes	no	no	no
Manageability	Data volume - How much*	no	no	no	no	yes
	Data periodicity - How often*	no	no	no	no	yes
	Configuration effort/complex	yes	yes	yes	yes	no
	Automatization	yes	yes	yes	yes	no

[29] Network (OSI Layer 1-6) or Application (OSI layer 7)
[30] Above Application layer 7.

Category	Reliability			Computational Resources			Manageability			
Attribute	Autonomy	Protocol Robustness	Redundancy	Device Storage	Response time	Processing speed	Data Volume	Data Periodicity	Configuration effort/complexity	Automatization
Definition	Component internal number of factors for continuous operation	Assessment of the protocol features to cope with non-perfect data	Assessment for component or link necessity for duplication	Storage in the component	Request response behaviour between two components	Assessment of the orders processed by a component	Average volume dealt with	Average for exchange of information on a link between two components	Assessment of the process for component/link integration	Assessment of the level of automation for the component operation
Rating										
1	No fail-safe mechanisms	Has noise immunity	Avoid	No storage	Stalls often	µControler	<1 Kb or analog value	less than once a day	Requires Human involvement but complex	Requires HM to operate it every time
2	Data buffer	Additionally has Error checking	Not necessary	Volatile, small but fast	Needs to make at least two trials	Embedded Linux	1Kb < X < 100 Kb	Once a day	Requires Human involvement but average	Requires HM to supervise most of the time
3	"Cold" safe mode	Additionally has Packet recovery	Passive redundancy Active only when malfunction	Volatile, large and fast	Admissible time response	PC	100Kb < X < 10 Mb	Several times a day	Requires Human involvement but easy	Partially autonomous, requires HM interaction in frequent cases
4	"Warm" safe mode between 1h and 24h	Additionally has Out-of-order data capability**	Passive redundancy Active for a limited period	Permanent, small	Low delay response	Server	10 Mb < X < 1 Gb	Every hour	Assisted configuration but with small Human changes	Partially autonomous, requires HM interaction in seldom cases
5	Warm safe mode more than 24h	Additionally has data encrypted	Fully redundant Always active	Permanent, large	No significant delay	Grid computing	> 1 Gb	Less than an hour	Auto-configuration	Fully autonomous, does not require any HM interaction

Figure 169: The "Attributes Definition & Rating" sheet

Assessment results

The following tables represent the results obtained from the different demonstrators with respect their architectures. Most of the results are similar, making the result interesting despite their use of different architectures for their goal fulfilment.

Table 76: Results of German demonstrator Avacon

Categories	Attributes	Expected Impact	Interest towards it	"Available information?
Reliability	Autonomy	Medium	Not important	Limited
	Robustness	High	Important	Limited
	Redundancy	Medium	Important	Limited
Computational resources	Device Storage	High	Important	Yes
	Response time	High	Very Important	Yes
	Processing speed	High	Important	Limited
Manageability	Data volume	Medium	Important	No
	Data periodicity - How often	High	Very Important	Yes
	Configuration effort/complexity	Medium	Not important	Limited
	Automatization	High	Important	Yes

Table 77: Results of Dutch demonstrator Enexis

Categories	Attributes	Expected Impact	Interest towards it	"Available information?
Reliability	Autonomy	Medium	Important	Limited
	Robustness	High	Very Important	Limited
	Redundancy	Medium	Very Important	Limited
Computational resources	Device Storage	Low	Not important	Yes
	Response time	High	Very Important	Limited
	Processing speed	High	Very Important	Limited
Manageability	Data volume	Medium	Important	Yes
	Data periodicity - How often	High	Very Important	Limited
	Configuration effort/complexity	Low	Important	Yes
	Automatization	Medium	Very Important	Limited

Table 78: Results of Swedish demonstrator Eon

Categories	Attributes	Expected Impact	Interest towards it	"Available information?
Reliability	Autonomy	Medium	Not important	Yes
	Robustness	High	Important	Limited
	Redundancy	Medium	Important	Limited
Computational resources	Device Storage	Medium	Important	Yes
	Response time	High	Very Important	Yes
	Processing speed	High	Important	Limited
Manageability	Data volume	Medium	Important	Limited
	Data periodicity - How often	High	Very Important	Yes
	Configuration effort/complexity	Medium	Not important	Limited
	Automatization	High	Important	Yes

Table 79: Results of French demonstrator Enedis

Categories	Attributes	Expected Impact	Interest towards it	"Available information?
Reliability	Autonomy	Medium	Very Important	Yes
	Robustness	High	Very Important	Limited
	Redundancy	Medium	Important	Limited
Computational resources	Device Storage	Medium	Important	Limited
	Response time	High	Important	Limited
	Processing speed	Medium	Important	Limited
Manageability	Data volume	High	Important	Yes
	Data periodicity - How often	Medium	Not important	Yes
	Configuration effort/complexity	Medium	Important	Limited
	Automatization	High	Very Important	Yes

Architecture Characterization Tool

The architecture characterization tool with the Capacity and Requirement tool, are the core tools used for data gathering. The architecture characterization tool is only applied to the upper and lower bound representative architectures selected. Selected as representative architectures are the German demo (DE) for the lower bound and the Dutch demo (NL) for the upper bound.

The characterization of the architecture is done through the characterization of each component and link. Each component and link are characterized by means of the attributes and their correspondent rating, previously introduced. The links present in the analysis are those which from the SGAM architecture. They are mapped since the SGAM does not provide an identification tag for them. In this case, an alphanumerical system is selected. It represents the architecture being analysed (NL or DE), the use case (i.e., 1., 2., 3.,) and the link number given to it. Both characterizations component and links are illustrated in Figure 170 and Figure 171 respectively are taken from the Dutch architecture (upper bound) as a reference as it was additionally selected as the “guinea pig” architecture.

Component characterization		**Component layer**			
Component	Type	Autonomy	Redundancy	Configuration effort / complexity	Automatization
Dali	Client	2	2	3	4
RTU Dali	Client	2	2	2	4
Salvador	Client and server	3	3	1	3
Datalake	Server	3	2	3	4
GMS	Client and server	4	5	4	4
FAP DER	Client and server	1	2	3	5
FAP EV	Client and server	2	2	3	5
CPMS	Client and server	3	3	2	4
LIMS	Executable	2	3	3	5
Controller CP	Client and server	2	1	2	5
RTU SSU	EMS	2	5	4	5
RTU PV	PLC	5	5	3	5
SSU inverter	Client Server	2	5	4	5
PV inverter	Inverter	5	5	4	5
Charging Point (CP)	Client and server	2	1	5	5

Figure 170: Architecture Characterization - Components

Links characterization								Network protocol layers			Application protocol layer		
Component "A" (From)	Component "B" (To)	Link	Type of link	Medium	Communication protocol	Application protocol	Data	Robustness	Configuration effort / complexity	Automatization	Robustness	Configuration effort / complexity	Automatization
RTU SSU	SSU Inverter	NL.1.1a	Wireless	Integrated (one system)	N.a.	N.a.	Metering Data	3	4	5	4	5	5
RTU PV	PV Inverter	NL.1.1b	Wire	Not know	Serial / RS485	N.a.	Actual produced energy , cumulative energy, voltage	4	5	5	n.a	n.a	n.a
LIMS	RTU SSU	NL.1.2a	Wireless	Internet/Tosibox	VPN	Modbus	Measurement data, Commands to control	5	3	5	4	4	5
LIMS	RTU PV	NL.1.2b	Wireless	Internet/openVPN	VPN	Modbus	Measurement data, Commands to control	5	3	5	4	4	5
FAP DER	LIMS	NL.1.3	Wire	Internet/websocket	https	EFI+	allocation of flex, metering data, availability etc.	5	3	5	4	4	5
FAP DER	GMS	NL.1.4	Wire	Internet	https	USEF	Flex negotiation messages (requests, orders, offers etc)	3	4	5	4	3	4
GMS	Datalake	NL.1.5	Wire	Internet	TCP	JDBC	Application / flex data	3	4	5	3	3	4
Salvador	Datalake	NL.1.6	Wire	Internet	Ethernet	AMQP	Metering data	4	4	4	4	3	4
RTU Dali	Salvador	NL.1.7	Wireless	Internet	LTE	IEC-60870-104 over IPSec tunnel	Metering data	4	4	4	1	2	4
Dali	RTU Dali	NL.1.8	Wire	Integrated	N.a.	N.a.	Metering data	n.a	n.a	n.a	n.a	n.a	n.a
Lines	Dali	NL.1.9	Wire	Rogowski coil + low voltage feeder measurement	ModBus	N.a.	Metering data	2	2	4	n.a	n.a	n.a
Controller CP	CP	NL.2.1	Wire	Integrated	N.a.	N.a.	N.a.	n.a	n.a	n.a	n.a	n.a	n.a
CPMS	Controller CP	NL.2.2	Wireless	Internet	http / websockets over GPRS	OCPP	Authorization data, metering data and charging profiles	4	3	5	2	4	4
FAP EV	CPMS	NL.2.3	Wire	Internet/websocket	http	OCPI	Start / stop notifications + charging profiles	4	4	5	2	3	4
FAP EV	GMS	NL.2.4	Wire	Internet	https	USEF	Flex negotiation messages (requests, orders, offers etc)	3	4	5	4	3	4
Datalake	GMS	NL.2.5	Wire	Internet	DB stream (streaming analytics job)	DB stream (streaming analytics job)	Application / flex data	4	4	5	4	3	5
Salvador	Datalake	NL.2.6	Wire	Internet	Ethernet	AMQP	Metering data	4	4	4	4	3	4
Salvador	RTU Dali	NL.2.7	Wireless	Internet	LTE	IEC-60870-104 over IPSec tunnel	Metering data	4	4	4	4	3	4
RTU Dali	Dali	NL.2.8	Wire	Integrated	N.a.	N.a.	Metering data	n.a	n.a	n.a	n.a	n.a	n.a
Dali	Lines	NL.2.9	Wire	Rogowski coil + low voltage feeder measurement	ModBus	N.a.	Metering data	2	2	4	n.a	n.a	n.a

Figure 171: Architecture Characterization -Links[31]

[31] Grey is for not applicable scoring.

Capacity & Requirement Gathering Tool

Capacity & Requirement Gathering tool is the other core part for data gathering but with more focus directed toward the technical analysis. Equal to the architecture characterization tool, it is only applied to the representatives architectures chosen for the upper and lower bound, Dutch and German respectively.

Anew, the SGAM Component interoperability layer is necessary as a visual aid to tag the different links and components which are going to be characterized. Links and components of the selected representative architecture for the upper and lower bound are listed and evaluated with respect of their capacity and requirements to perform over nominal operation. These attributes, listed within the capacity & requirement gathering tool, are taken mainly from the computational resources category (technical oriented), as those are relevant for system performance operation. Table 80 and Table 81 represent the tables used for Components and Links with a given example.

Table 80: Architecture Capacity & Requirement characterization example - Component

Component A						Component B		
From	Max storage	Processing speed	Required storage	Data retention duration	Response time to treat the answer	To	Processing speed	Response time to treat the answer
RTU SSU	5	2	2	5	4	SSU inverter	3	4

Table 81: Architecture Capacity & Requirement characterization example- Links

Link Between component "A" & component "B"					
Max bandwidth (kbps)	Max number of links	Data volume Network	Data periodicity Network	Data volume Application	Data periodicity Application
3	4	3	1	3	3

Scaling up tool

Once the system has been entirely characterised through the architecture characterization and the capacity & requirement tools, the scaling up of the system conception begins.

In order to scale up a system, some framework in order to facilitate this process has to be defined. This is represented through the creation of potential scaling up scenarios. In order to define a scenario, scaling up devices, a scaling frame and some scaling up rules have to be created.

In order to identify the scaling up of devices, it is also necessary to consider the SGAM business layer in addition to the Component layer since it identifies which components are relevant for the use case in the business context. Usually the components that are required to be scaled are located at the field zone on the SGAM component layer as they are data sources.

The scaling up frame also feeds from the SGAM business layer. This defines the time of operation of the UC. This has a significant impact into the analysis of the scalability of a system, as a real time system operation has different requirements than a deferred system operation. Therefore, the time considered for operation in the business layer, the scaling up focuses on different attributes. For real time systems, a “fast” response time is needed, thus attributes which consider the link bandwidth and computational resources are considered. Meanwhile, for deferral systems, fast communication is not needed, however data processing in bursts and storage of which adequate bandwidth for large data are considered.

Regarding the scaling up rules, these are created to quantify, in a qualitative way, the potential outlook of the system when the identified components and the scaling up frame (operation frame) are considered. They can be considered as “if – then” cases for the UC.
In order to provide a visual aid for the former explanation the following example tables are provided as in Table 82 and Table 83.

Table 82: Calculation example (Best case) 1

Links	Network Volume (bits)	Network Period (s)	Application Volume (bits)	Application Period (s)	Calculation (Mbps)	Avaiable bandwidth (Mbps)
NL.1.1a	100000	1800	100000	7200	0.0000694	0.1
NL.1.1b	1	1800	1	1800	0.0000000	1000
NL.1.2a	1000	1800	1000	1800	0.0000011	0.001
NL.1.2b	1000	1800	1000	1800	0.0000011	0.001
NL.1.3	100000	1800	100000	1800	0.0001111	0.1
NL.1.4	1000	3600	1000	3600	0.0000006	10
NL.1.5	100000	259200	100000	259200	0.0000008	10
NL.1.6	100000	1800	100000	1800	0.0001111	10
NL.1.7	1000	1800	1000	1800	0.0000011	10
NL.1.8	1000	1800	1000	1800	0.0000011	1000
NL.1.9	1000	1800	1000	1800	0.0000011	1000
NL.2.1	not relevant since it is integrated					
NL.2.2	1	1800	1	1800	0.0000000	0.001
NL.2.3	1000	1800	1000	1800	0.0000011	1000
NL.2.4	1000	3600	1000	3600	0.0000006	10

Table 83: Calculation example (Best Case) 2

Link	Components	Required storage (bit)	Data retention duration (s)	App. Period (s)	Calculation (Mb)	Available
NL.1.1a	RTU SSU	10000	129600	7200	0.18	Permanent, large
NL.1.1b	RTU PV	10000	129600	1800	0.00072	Permanent, small
NL.1.2a	LIMS	10000000000	129600	1800	720	Permanent, large
NL.1.2b	LIMS	10000000000	129600	1800	720	Permanent, large
NL.1.3	FAP DER	100000000	129600	1800	7.2	Permanent, large
NL.1.4	FAP DER	100000000	129600	3600	3.6	Permanent, large
NL.1.5	GMS	100000000	129600	259200	0.05	Permanent, small
NL.1.6	Datalake	1000000	129600	1800	0.072	Permanent, large
NL.1.7	Salvador	1000000	129600	1800	0.072	Permanent, large
NL.1.8	RTU Dali	1000000	129600	1800	0.072	Permanent, small
NL.1.9	Dali	n.a	n.a	n.a	n.a	
NL.2.1	Controller CP	100	10	1800	5.55556E-10	Permanent, small
NL.2.2	CPMS	1000000	129600	1800	0.072	Permanent, large
NL.2.3	FAP EV	100000000	43200	1800	2.4	Permanent, small
NL.2.4	FAP EV	100000000	43200	3600	1.2	Permanent, small

7.4. Regulatory additional support documentation

7.4.1. Non-technical SRA questionnaire

1. Participation of flexibilities in network services: storage, DG and active demand

The participation of flexibilities in network services will be subject to the regulation in force. Regulation may or may not allow coordination agreements between flexibility providers and DSOs. The objective of this block of questions is to characterize the current regulatory framework governing the participation of flexibilities in your country and future plans to modify it.

1.1 Are there any flexibility services (i.e., congestion management, curtailment, etc) provided to the DSO in your country?

1.2 Does the DSO have the access to the flexibility units' generation/consumption profiles for grid operation purposes?

1.3 What is the current contract type between DSO and flexibility providers? Are there any modifications expected in this respect in the near future?

1.4 Are flexibility providers obliged to provide their services (yes/no), and are they incentivized by your local regulation?

1.5 How does the Clean Energy Package and similar EU energy directives influence your national standards for the use of flexibilities?

1.6 Are there any plans to modify in the near future the current situation regarding flexibility units as a provider of network services? If yes, where does the initiative come from?

2. Business models for DG

Distributed Generation (DG) units produce energy that will be used to cover a certain demand from different consumers in the electric power system. This energy may be sold according to the local regulation. Energy storage in the form of batteries connected to the grid or EVs with V2G (Vehicle to Grid) capability can also buy and sell energy at different time periods. The questions below are designed to define current regulation on this topic in your country.

2.1 Who would you suggest operating storage facilities on the grid? Check all that apply:

- Aggregators
- Domestic consumers
- DSO
- Industrial consumers
- Local Energy Community

- Power Producer
- Other:
- Add comments or restrictions:

2.2 Is electricity resale for/from storage regulated?

2.3 How can members of local energy communities sell their flexibilities and under what conditions (in the wholesale market, through contracts with suppliers or aggregators, through P2P market, etc)?

2.4 According to your local regulation, what is the relationship between regulated and non-regulated players? Can you quote any agreement that those players would not be allowed to sign?

3. Network charges for DG

Network charges are designed by the regulator on the one hand to ensure fair and non-discriminatory network access for Distributed Generation (DG) agents, and on the other hand, allow DSOs full recovery of the costs for the accommodation of DG. Furthermore, there is a trade-off between providing incentives for the optimal siting of new generation capacity and facilitating entry for small-sized DG operators. For this purpose, connection charges and use-of-network (UoN) charges may be designed by the regulator for all agents connected to the distribution network, including DG. The following block of questions focuses on these two charges.

3.1 What kind of connection charges are applied to DG connections in your country?

3.2 Are there any plans to modify in the near future the current situation regarding connection charges applied to DG?

3.3 Does DG have to pay UoN charges in your country, if applicable what is the global structure of current/future DG UoN charges (i.e., split between kWh/kW)?

3.4 Are there specific UoN charges applied to storage assets?

4. DSO costs and revenue regulation

On the one hand, high levels of flexibilities penetration impact the CAPEX & OPEX for the DSO, mainly in network investment and grid operation. On the other hand, flexibilities may represent a potential replacement for network investment, and should be therefore considered by DSOs throughout the network planning process. The regulatory framework may implement different options to compensate DSOs for the incremental costs, and it may affect the consideration of flexibilities for network planning by DSOs.

4.1 Based on what model the regulators estimate the cost of the DSO (OPEX and CAPEX)?
* Check all that apply:

- Pass through
- Benchmarking

- Econometric modelling
- Engineering modelling
- Other:

4.2 Under the current local regulation, is the potential use of flexibilities taken into account when calculating DSO revenues? If applicable, briefly explain the mechanism.

4.3 Are flexibilities explicitly considered by DSOs in order to postpone or reduce network investments? If yes, are flexibilities a full alternative in the planning process or are they considered as the last solution when all other approaches fail?

4.4 If you consider the point of view of the regulator, what kind of regulatory scheme would be the most appropriate to deal with this problem? (if needed you can differentiate the schemes for different DG sources)

5. DSO reliability incentives

Flexibilities may have an effect on quality/continuity of service and offers potential for quality improvement, for example, due to the possibilities of operation in islanding mode in case of network outages. However, there is a strong need for an adequate risk management, and availability of offers ensuring the liquidity on the local energy market.

5.1 Under the current DSO regulatory scheme in your country, do DSOs have quality targets and are required to meet specific continuity of supply targets?

5.2 Are DSOs subject to incentives or penalties if the achieved performance is better or worse than required, in other words is there an economic evaluation of ENS?

5.3 How is continuity of supply measured/estimated (SAIDI, SAIFI, ENS, value of lost load, etc) and based on what considerations?

6. DER's role in reliability incentives

6.1 From your point of view, what hurdles have to be overcome to make flexibilities a new control element that can help to improve the continuity of supply?

- Reliability of flexibilities (how to ensure the presence of flexibility when needed).
- Estimation of flexibility capacity and how to ensure that it will be respected further.
- Capacity to capitalize the Lessons Learnt (REX) from the flexibilities and identify variables and parameters for flexibility models.

7. Microgrid islanding operation

The present questionnaire considers islanded microgrids from the operational point of view of the DSO. Regulation may or may not allow islanded operation and coordination agreements between flexibility providers and DSOs. Therefore, the following set of questions deals with the current and future regulatory framework related to islanded operation.

7.1 Do DSOs manage microgrids and flexibilities connected to them? Is there any other party managing flex?

7.2 What are the regulatory requirements that have to be met in order to allow islanding operation?

7.3 Are there any rules for the connection/disconnection of the microgrid to the network in real-time operation? Are there plans in the near future to modify the current situation?

8. Demand side management and smart metering

Demand side management is essential for smart grids, since it encourages the end user to be more energy efficient. Demand response is one of important tools of demand side management, and in order to enable demand response, advanced metering infrastructure must be deployed. Regulation may incentivize consumers to become more active as well. This set of questions is targeted to the current possibilities for cooperation between the DSO and consumers in the field of demand side management, as well as regulations on smart metering.

8.1 Is there any regulatory obligation for regulated/non-regulated players to include economic signals to differentiate tariffs for various time periods? If yes, please indicate which:

- Price differentiation for peak/base periods
- Super-valley tariff (In addition to peak and off-peak access tariffs, there is a cheaper time period from 1 am to 7am)
- Dynamic pricing (time-of-use pricing, critical peak pricing, real-time pricing)
- Other:

8.2 Does the DSO in your country actively promote demand response and customers active control of their load pattern (ex. Graphical User Interface to monitor consumption)?

9. Active demand

9.1 For what kind of consumers demand response is mainly promoted? Check all that apply:

- Industrial
- Commercial
- Domestic
- Other:

9.2 What type of infrastructure is used to activate demand response? Check all that apply:

- Smart meters at consumer's location
- Dedicated control devices
- Behaviour based activation (example: mobile text message)
- Other:

10. Smart metering

10.1 Is the implementation of smart metering regulated (it is mandatory/left to DSO/left to market initiative), and are there any specific smart metering rollout programs?

10.2 What are the main functionalities considered for smart meters (remote steering/device control, load limitation, etc)?

10.3 What type of AMI (Advanced Metering Infrastructure) is being deployed:

- Smart Meter - Meter database management system (MDMS)
- Smart Meter - Concentrator - MDMS
- Smart Meter - Concentrator - Gateway - MDMS
- Other:

10.4 Who owns AMI? Check all that apply:

- DSO
- Supplier
- Subcontractor
- Other:

10.5 Who is in charge of AMI installation, operation and maintenance? Check all that apply:

- DSO
- Supplier
- Subcontractor
- Other:

10.6 Who pays for AMI installation, operation and maintenance? Check all that apply:

- DSO
- Supplier
- Subcontractor
- Customer
- Other:

10.7 Regarding the local regulation on confidentiality and data protection, who is the owner of consumer data and who is allowed to access the information?