WP5: D5.1

Tech & Econ Evaluation of replicability and scalability of solutions to increase the DER

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Abstract

This document summarizes the technical and economic analysis of the scalability and replicability potential of smart grids solutions to increase the DER penetration in distribution networks. These solutions were selected in previous work packages of the IGREENGrid project (WP4) and identified as most promising solutions.

A technical analysis of the different smart solutions for DER integration preselected in WP4 was carried out. The general performance of the solutions was evaluated through extensive simulations performed on a set of relevant MV and LV networks from the eight participating DSOs. The performance of the solutions has been evaluated in terms of achievable hosting capacity increase, impact on network losses and impact on reactive power balance.

Besides the technical analysis, an economic assessment of the different solutions has been performed from six of the eight participating DSOs, analyzing on the one hand the costs related to the solutions and on the other hand identifying the benefits provided by them for the large scale integration of renewable generation in distribution networks.

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1 Introduction and scope of the document

Most of the publications on network integration of distributed renewable energy resources (DRES) consider one or a few specific networks with a specific DRES-scenario [1]. While these studies can provide very interesting results on specific integration solutions, they do not provide any generic results which can be applied to other networks and an analysis of the scalability and replicability (S&R) potential is usually missing.
Only a few studies were published in the last years address this gap at the level of specific regions [2], [3] and [4] or countries [5], [6] and [7]. However, these studies are limited to particular network integration solutions (e.g. reactive power control through PV inverters), specific areas or regions and specific countries.
The main objective of IGREENGrid WP5 is to perform an in-depth analysis of the different DRES integration solutions selected in previous work packages as “most promising solutions” in terms of scalability and replicability. These technical and economic analyses have been performed with the methods and tools developed in this work package (see deliverable D5.2) and their main outcomes are summarised in this report.

The purpose of the technical analysis was to evaluate the deployment potential of the selected smart grids solutions on the basis of different relevant network conditions. While the performance of the smart grids solutions is mainly measured in terms of achievable hosting capacity increase, other aspects such as their impact on network losses and on the reactive power balance are also in the scope of the study.
The purpose of the economic analysis is on the one hand to analyse the costs incurred by DSOs when deploying the DRES integration smart solutions into the field considering a period of twenty years and to compare them with the costs of conventional grid assets; and on the other hand to identify potential benefits that may be provided by the smart solutions.

Against these very ambitious objectives, the authors are aware that the conclusions are strongly depending on the assumptions made and on the network considered.

1.1 Notations, abbreviations and acronyms

Acronym	Meaning
ACC	Annual Cost Comparison
AMI	Automated Meter Infrastructure
BA	Benefits analysis
CA	Cost analysis
CapEx	Capital Expenditure
CBA	Cost Benefit Analysis
CDF	Cumulative Density Function
DER	Distributed Energy Resources
DG	Distributed Generation
DMS	Distribution Management System
DoE	Department of Energy (USA)
DPL	DIgSILENT Programming Language
DRES	Distributed Renewable Energy Resources
DSO	Distribution System Operator
EC	European Commission
EC JRC	European Commission Joint Research Centre
ENTSO-E	European Network of Transmission System Operators
EPRI	Electric Power Research Institute
EU	European Union
HC	Hosting Capacity
HV	High Voltage
ICT	Information and Communication Technology
JRC	Joint Research Centre (European Commission)
KPI	Key Performance Indicator
LHS	Latin Hypercube Sampling
LV	Low Voltage
MAE	Mean Absolute Error
MCS	Monte Carlo Simulation
MV	Medium Voltage
NPV	Net Present Value
OLTC	On Load Tap Changer
OpEx	Operational Expenditures
OPF	Optimal Power Flow
PF	Power Flow
PLF	Probabilistic Load Flow
PV	Photovoltaics

Acronym	Meaning
PVTC	Present Value of Total Costs
RES	Renewable Energy Resources
RMSE	Root Mean Square Error
RTU	Remote Terminal Unit
S&R	Scalability and Replicability
SCADA	Supervisory Control and Data Acquisition
SE	State Estimator
SRA	Scalability and Replicability Analysis
SUT	Solution Under Test
T&D	Transmission and Distribution
TYNPD	Ten-Year Network Development Plan
VOS	Value Of Service
VRDT	Voltage Regulated Distribution Transformer[1]
WP	Work Package

Table 1 (Acronyms)

1.2 How to read this report

The objective of this work was to analyze the deployment potential (scalability and replicability) of the set of smart grids solutions identified in previous work packages as most promising. This work should provide the reader useful insights into the general performance and costs of the considered smart grids solutions under different network conditions.

The final decision for a DSO to implement one or another solution relies on complex considerations which cannot all be easily quantified and monetarized in a harmonized way throughout Europe. The analyses presented in this report do therefore not replace the network planning work of DSOs but should provide them as well as other stakeholders (e.g. component manufacturers) with some general trends guiding their decisions to one or another solution.
Even if solutions are compared in terms of technical performance (e.g. achievable hosting capacity increase) or in terms of costs (present value of total costs, OpEx, CapEx), an overall ranking is not provided in this report. Indeed, while the solutions have been compared on a common basis (maximal reachable hosting capacity), the situations faced by DSOs are very diverse and complex. In some cases, a “less performant” but cheaper solution is the best option to enable to integrate a given DRES penetration while in other cases more complex and costly solutions are preferable.

Besides the comparison of the different solutions, this report provides some guidance on the factors impacting the performance (technical and economic) of the solutions and should support the decision-making process of stakeholders.

[1] In this report, the term distribution transformer stands for the “last transformer” located in the secondary substation, stepping down the voltage to the LV.

The authors are fully aware of the difficulty of exercise conducted in this project and of the limitations of the validity of the results. Having acknowledged this, the value of this work is expected to be high since:

- This is one of the first attempts to tackle this complex issue.
- The assumptions used have been justified as much as possible.
- The data basis used for the studies is large.

This report is structured as follows:

- In chapter 2, the methodologies used for the technical evaluation and for the economic assessment are explained.
- In chapter 3, a short description of the smart grids solutions under study is provided.
- In chapter 4, an overview of the considered MV and LV networks of the involved DSOs is provided.
- In chapters 5, 6, 7 and 8, the technical analysis is carried out:
    - In chapter 5, the modeling approach and assumptions are exposed.
    - In chapter 6, the technical evaluation of the scalability and replicability potential of MV solutions is summarized.
    - In chapter 7, the technical evaluation of the scalability and replicability potential of LV solutions is summarized.
    - In chapter 8, the main results of a comprehensive statistical analysis performed on two large LV network datasets are presented.
- In chapters 9, 10 and 11 the results of the economic analysis are presented:
    - In chapter 9, the JRC-functionalities and the assets of the solutions under study are identified.
    - In chapter 10, the main results of the Cost Analysis and the Benefits Analysis of the MV solutions are summarized.
    - In chapter 11, the main results of the Cost Analysis and the Benefits Analysis of the LV solutions are summarized.
- The main conclusions of both the technical and economic analyses are detailed in the chapter 12.
- Additional information is provided in the annexes.

2 Methodology for the scalability and replicability analysis

This chapter provides a general overview of the proposed approach to evaluate the scalability and replicability potential of the selected smart grids solutions (solutions aiming at enhancing the hosting capacity for high penetration levels of distributed renewable energy resources).
The ambition of this study was very high since a quantitative evaluation of the deployment potential of smart grids solutions to enhance the hosting capacity of existing distribution networks is expected. This is a major step from the usual case-study approach followed by most demonstration projects. Indeed, most of the past demonstration projects in the field of smart grids [1], even the largest, focused on the implementation and demonstration through lab or field tests. The work done in this study goes far beyond this and tries to generalise the results obtained by individual projects.
The approaches (for the technical and economic assessment) try to follow a sound methodology while taking into account the limitations on data availability, data confidentiality, etc. Unavoidably, the number of assumptions and limitations is high. The proposed approach was to identify the best possible assumptions and justifications to reach generic but realistic results.
The authors are fully aware of the difficulty of this exercise, of the limitations of the validity of the results. Having acknowledged this, the value of this work is expected to be high since this is one of the first attempts to tackle this complex issue.
The general approach followed in the technical assessment has been a top-down approach. This approach is based on the analysis of artificial scenarios defined by the hosting capacity. This approach has been selected since it allows a common comparison between solutions independent on questionable scenarios about DRES deployment in the next decades. For example, roadmaps from industry organisations or from international organisations ([2]–[6]) present a very large uncertainty due to unknown political and economic developments.

2.1 Methodology for the technical evaluation

Figure 1 and Figure 2 provide a general and detailed overview of the chosen methodology. This methodology is based on three steps with an increasing level of complexity. It is interesting to note that the results of each one of the three steps provide information about the actual deployment potential of smart grids solutions for the considered networks. The three steps are presented in Figure 2.

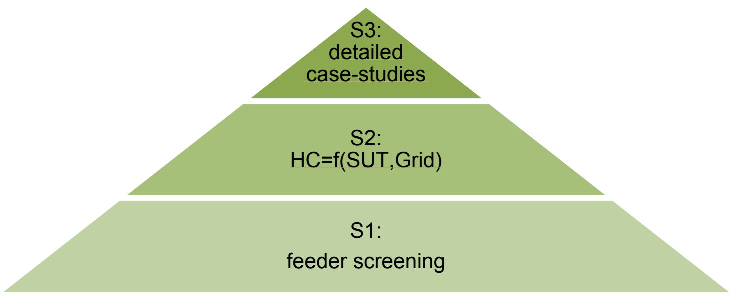


Figure 1 (General overview of the three steps for SRA)

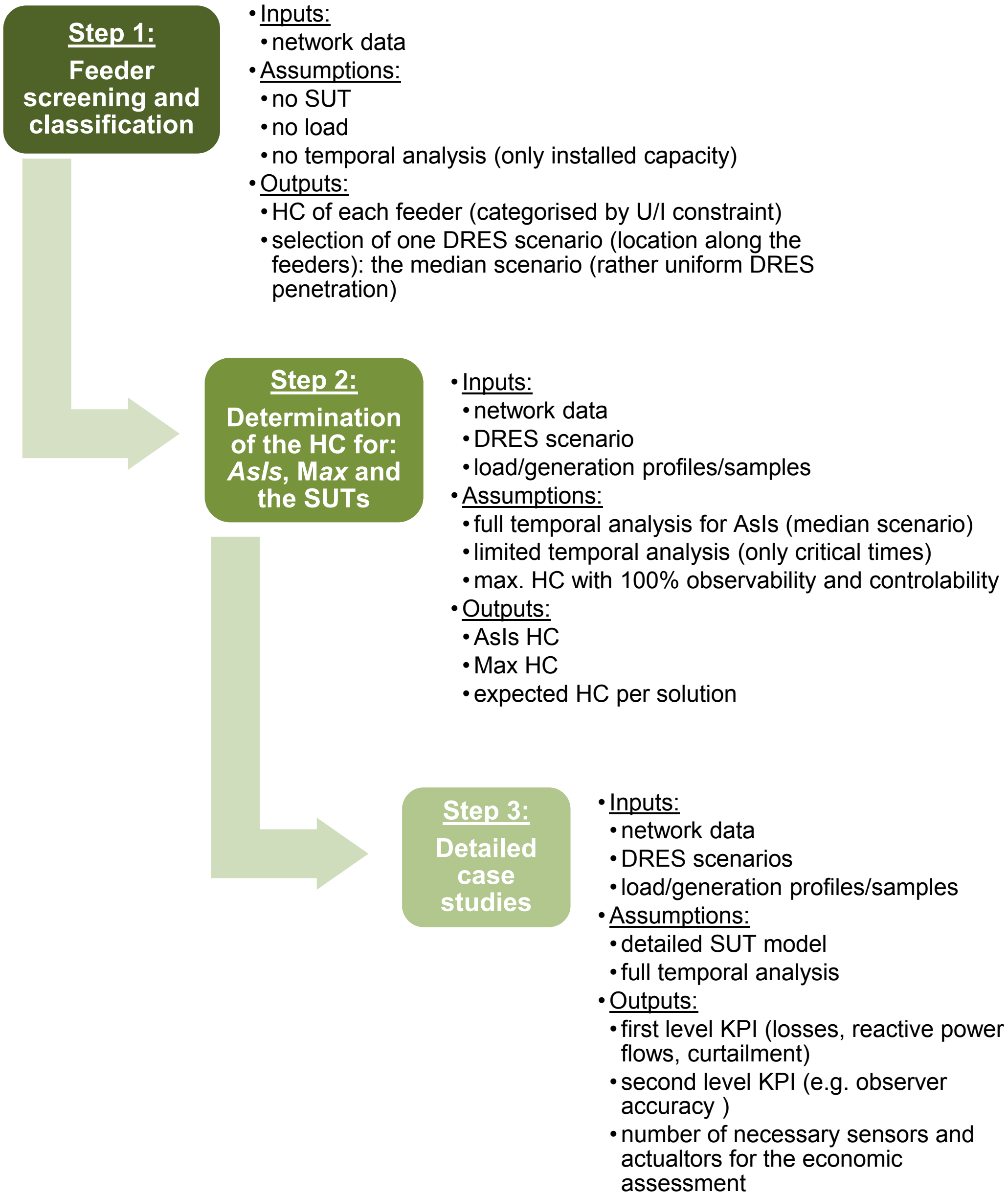


Figure 2 (Detailed overview of the three steps for SRA)

2.1.1 Step 1 – Feeder screening and classification

This first step aims at selecting one DRES scenario, i.e., to select a common reference distribution of generation units along the feeders. Indeed, the hosting capacity of a feeder heavily depends on the location of the generation along the feeder (high hosting capacity when the generation is connected at the beginning and low when it is connected at the end in the case of a voltage constraint). While the determination of the "horizontal" DRES distribution could be based on a priori considerations (e.g. generation profile along the feeder), the scenario is defined on the basis of its implication on the hosting capacity (main KPI). This definition allows a fully automated implementation (see Figure 6).
For the whole study, one single DRES distribution has been proposed: a "median hosting capacity"

scenario, corresponding to a rather uniformly located generation along the feeders and leading to the median hosting capacity.
In the reality, each feeder might experience specific conditions (many small highly distributed generators or large generators at the beginning or at the end of the feeder). In some countries, depending on the subsidies in place to support DRES, some may prevail. For example, the largest share of the installed PV power is located in LV networks in Germany[2] while most of the PV generation in Spain is connected at MV level. In any case, the purpose of the technical assessment of smart grids solutions is to perform a comparative study. Even if the selected scenario is only one of many possible scenarios in terms of DRES distribution along the feeder, it provides a common basis to compare solutions.
To determine such a scenario, Monte-Carlo simulations (see deliverable D5.2) are used to generate randomly different distributions of generation along each feeder (e.g. 0.33/0.33/0.17/0.17 for the feeder on the left and 0.17/0.17/0.33/0.33 for the feeder on the right of Figure 3).

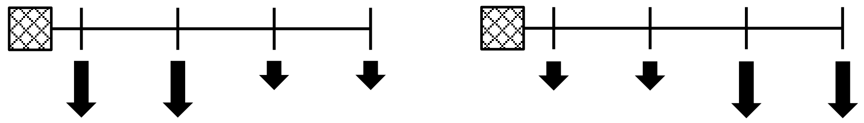


**Figure 3 (Two examples of "horizontal" DRES scenarios.
Left: generation dominantly at the beginning. Right: generation dominantly at the end)**

For each single distribution of generation along the feeder, the hosting capacity is evaluated by scaling up the power of each generator until one of the constraints (voltage/current[3][4]) is reached. This is done by a script (implementation details in chapter 6.1) which uses an own programmed Secant Method algorithm[5]. The script determines the scaling factor for the generators that leads to one of the two constraints.
Loads are not considered in this step since the objective is only to screen all the possible scenarios in terms of distribution of the generation power along the feeders. Out of this procedure, the hosting capacity and the limiting constraint are determined. The value calculated in this procedure is the lower limit of the hosting capacity because the loads are not considered and the coincidence factor is assumed to be 100 % for all generators. Figure 4 illustrates the calculation process leading to the hosting capacity for two types of feeders with a given random DRES distribution. In the Feeder A, identified as rural, the voltage constraint is reached before the loading (thermal) constraint when the PV power increases; in the Feeder B, the thermal limit is reached before the voltage limit as it is sub-urban. Thus Feeder A is classified as voltage constrained (blue point) and Feeder B is classified as loading constrained (red point).

[2] 70 % according to [7].
[3] Note that only voltage and current constraints are considered for the hosting capacity determination. Other limitations such as protections are not considered.
[4] Note that only the loading of cables and lines are considered here (not the transformers in primary substations).
[5] The secant method is a root-finding algorithm that uses a succession of roots of secant lines to better approximate a root of a function.

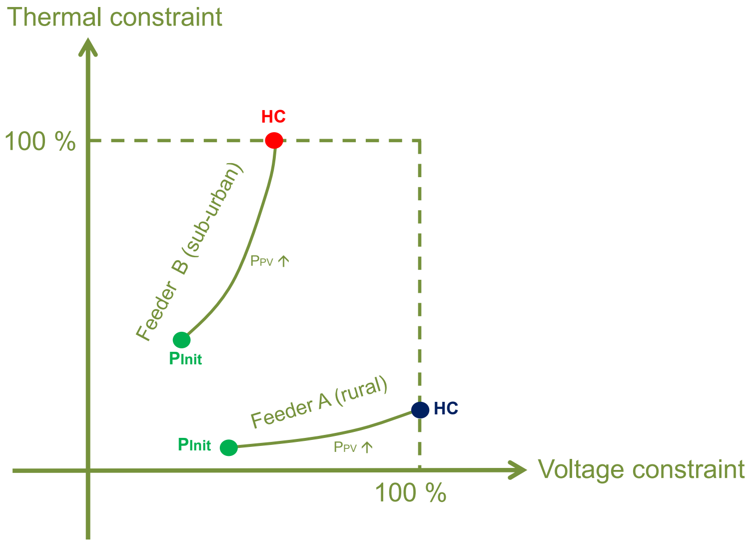


Figure 4 (Illustration of the hosting capacity calculation for two type of networks)

This procedure to calculate the hosting capacity is repeated for each DRES distribution generated in the Monte-Carlo simulations and the hosting capacity Cumulated Distribution Function (CDF) is created. In addition to the hosting capacity figures, the type of constraint (voltage or current) is stored and shown on the CDF. Finally, the median hosting capacity distribution can be extracted from it.
Figure 5 shows an example of the outcomes from Step 1:

- The hosting capacity Cumulated Distribution Function (CDF) coloured according to the constraint (blue: voltage / red: current).
- The 50th percentile-point on the CDF-curve corresponding to the DRES scenario (distribution along the feeder) selected for further study.

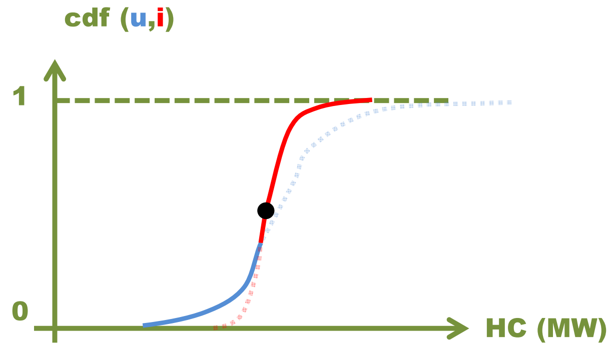


Figure 5 (Cumulative distribution function – CDF of the hosting capacity)

The implementation of the procedure used in Step 1 is explained in Figure 6. Note that this definition of the DRES distribution is based on a uniform probability of having generators connected along the feeders. Therefore, it does not consider the probability of having generators mostly at the end of the feeder, which might be observed in rural areas where PV generators tend to be installed on farms at remote nodes (e.g. in the south of Germany).

Generate DRES distributions	• generate N random numbers summing 1. (N = number of nodes of the feeder) • allocate these N random numbers to the N generators
Determine the hosting capacity for each DRES distribution	• scale-up the power of each generator to reach the voltage or current limit (hosting capacity) with a Secant Method algorithm • store this value as the hosting capacity of the corresponding DRES scenario • store the limiting constraint (u or i)
Select the median DRES distribution	• build the estimated cumulative distribution function (cdf) of the HC • select the horizontal PV distribution corresponding to the median on the cdf

Figure 6 (Implementation of Step 1)

2.1.2 Step 2 - Determination of the expected hosting capacities for the case-studies

The second step aims at determining a more realistic hosting capacity value for the following cases:

- Without any modification: **"AsIs" hosting capacity** (network as it is, without reinforcement and without smart grids solutions).
- With a perfect control assuming 100 % observability and 100 % controllability (active and reactive power at generators and tap changers at transformers): ***"Max" hosting capacity***.
- With the solutions under test (or families of solutions): ***expected hosting capacity***.

Contrary to Step 1, the time characteristics of load and generation are considered in this step. In the first phase, a probabilistic power flow is computed considering load and generation samples, with the DRES distributions previously determined (Step 1). The probabilistic power flow is based on Monte-Carlo simulations and it uses 268.800 samples (see D5.2).

If a violation caused by the load is observed inside a feeder, i.e. an under voltage or an overloading (due to inaccuracies in the provided feeder load profiles), the installed load power is reduced in order to respect the planning rules set by the DSO[6].

After this phase, another probabilistic power flow is computed with the (modified) load values. In order to limit the computation burden, critical times have been introduced: for each solution which does not involve the OLTC, the critical times correspond to the occurrence of the **highest voltage** among all the nodes and **highest loading** among all the lines of the **feeder**. For OLTC-based solutions, the critical time corresponds to the occurrence of the **maximum voltage spreading** inside the **network**.

Once these critical times are determined (two critical times per feeder or one critical time for the network), the hosting capacity is evaluated by considering these critical times. The procedure to calculate the hosting capacity for a given solution is the following: firstly, the system is parametrised accordingly to the study-case (e.g. DSO-limits, Solution Under Test (SUT)-

[6] For each network, the applicable voltage limits (from the DSO) have been considered for medium and low voltage networks. These values can be found in Table 4

parametrisation)[7]; secondly, a snapshot is made at the critical times determined previously. Finally, the hosting capacity (to reach one of the limits) is determined, as for Step 1, by scaling the installed power with a Secant Method algorithm. Note that for the solutions which do not involve any OLTC, two critical times are determined for each feeder, leading to two possible values of the hosting capacities in case the maximum voltage and maximum loading don't occur at the same time. In this case, the selected hosting capacity is the smallest.

Correct the installed load power	• run Monte-Carlo simulations (power flow) for all the samples (268.800) • correct the installed load power if any violation occured
Determine the critical times	• run Monte-Carlo simulations (power flow) for all the samples (268.800) with the corrected load values • determine the critical times for each case-study (time of maximal voltage and time of maximal loading or time of maximum voltage spreading)
Determine *"AsIs" HC*	• for each feeder, select the critical times-intervals and scale-up the power of the generators to determine the hosting capacity until a limit is reached (voltage or current) • store the voltage and loading values at the hosting capacity
Determine *"Max" HC*	• implement an optimal power flow (with 100% observability and controllability) • select the critical time-interval leading to the maximum voltage spreading and scale-up the power of generators to determine the hosting capacity until a limit is reached (voltage or current) • store the voltage and loading values at the hosting capacity
Determine *expected HC*	• implement the solutions under test • scale-up the power of generators to determine the hosting capacity until a limit is reached (voltage or current) • store the voltage and loading values at the hosting capacity

Figure 7 (Implementation of Step 2)

2.1.3 Step 3 – Detailed analysis of case-studies

This last step presents the highest complexity in terms of simulations, since the undertaken probabilistic load flow simulation in Step 2 (with 268.800 samples) is executed for each SUT with the expected hosting capacity. For the detailed case-studies, more accurate models of the solutions under test are used. A full temporal analysis using load and generation samples generated from time series is done for all the considered solutions in order to be able to evaluate several key factors such as annual network losses or curtailment. By using a detailed model of the solutions, their actual performance (e.g. accuracy) can, in addition, be assessed.

In addition to the pure technical evaluation of the results, some key results are forwarded to the

[7] Refer to chapter 5 for more details on the parametrisation (assumptions) of each solution

economic analysis. Moreover, the maximum voltage and loading of each feeder are analysed to validate the HC calculated in Step 2.
The individual subtasks of Step 3 are summarised in Figure 8.

SUT simulations	• run monte-carlo simulations with the solutions implemented in a higher level of detail for all the samples (268.800)
Result analysis	• results analysis • validation of the hosting capacity • evaluation of first level KPIs • evaluation of second level KPIs

Figure 8 (Implementation of Step 3)

2.2 Methodology for the economic evaluation

The methodology of evaluation of costs and benefits in the IGREENGrid project is based on the "Guidelines for conducting a cost-benefit analysis of Smart Grid Projects" [8] proposed by the EC Joint Research Centre (JRC), but many adaptations have been done in order to manage the number of DRES integration solutions and reference networks. In summary, the main differences are:

- The JRC methodology considers the smart grid project as a whole taking into account all possible functionalities, services and benefits expected from every single component of the solution. Instead, IGREENGrid focuses on the expected functions for the targeted objective and introduces a share factor on the cost attribution.
- The JRC methodology suggests a list of up to 22 benefits and formulae to be quantified following the "Guidebook for Cost/Benefit Analysis of Smart Grid Demonstration Projects" by the EPRI. A second list of 54 KPIs/Benefits hard to be monetized is also introduced. IGREENGrid identifies both types of expected benefits, either direct or either side for comparison and further reference but it is impossible to accurately evaluate them.
- This approach is in line with the *ENTSO*-E "Guideline for cost-benefit analysis of grid development projects" [9], that argues that most of the investment decisions are not purely economic. Therefore, the side by side comparison of costs and benefits is discarded.

The methodology of evaluation of costs and benefits in the IGREENGrid project, CA&BA, is shown on Figure 9

Methodology of evaluation of costs and benefits of solutions in IGREENGrid

"Most promising" solutions

1. Description and general context
2. Identification of assets & functionalities
3. Grouping

Costs Analysis (CA)

4. Identification and estimation of costs
5. Comparison of costs of different solutions
6. Sensitivity analysis of costs

Benefits Analysis (BA)

7. Identification of main benefits
8. Formulation of main benefits
9. Identification of other benefits

Assessment

10. Assessment of costs analysis and benefits analysis

Figure 9 (Methodology of evaluation of costs and benefits considered in IGREENGrid)

In the IGREENGrid CA&BA, the first accomplished task consists in the description of the solutions (*steps 1, 2 & 3 in* Figure 9), then, two different and parallel analyses are carried out: The Costs Analysis and the Benefits Analysis.

The purpose of the **Cost Analysis (CA)** (steps 4, 5 & 6 in Figure 9) in IGREENGrid is to analyse the negative cash flow (i.e. the costs) incurred by DSOs when deploying the DRES integration solutions into the field considering a period of twenty years[8]. This study period of 20 years may be critical to directly compare conventional grid assets (which technically have a lifetime of 50 years and more) with smart solutions (technical lifetime of about 10 – 20 years), as the costs of smart solutions may significantly increase in a 50 years period (see chapter 10.1.2).

In order to compare the conventional solutions based on grid deployment with the smart grid approaches, the network simulations produce a rough estimation of the number and length of circuits required to reach the same increase of the hosting capacity as the "best" smart solution being studied.

The purpose of the **Benefits Analysis (BA)** (steps 7, 8 & 9 in Figure 9) is to identify potential benefits that may be provided by the smart solutions. On the one hand, main benefits are identified (taken from the list of 22 potential benefits of JRC methodology) and formulae to potentially be monetized are proposed. On the other hand, other benefits are also identified (taken from the list of 54 KPIs/Benefits proposed by JRC methodology).

In the last step in Figure 9 (step 10), the aim is to draw down the main conclusions summarizing the main results of both the analysis of costs (CA) and the identification of benefits (BA).

It is important to underline that the IGREENGrid CA&BA is not aimed to support the selection of the best solution for every country and any network because the studied distribution networks may not be representative of the country they belong to and too many factors are intentionally left out for simplification purposes (e.g. residual value of network assets and deployed smart grid equipment).

[8] A period of 20 years has been chosen but the life expectancy of assets can be far beyond 20 years (up to 40-50 years).

3 Smart Grids solutions considered for the S&R analysis

Building on the analysis work done in the previous work packages of the project, the solutions identified as most promising solutions (deliverable D4.2) have been grouped into families of solutions for the purpose of the technical assessment of the scalability and replicability potential.
The detailed technical implementation of the solutions is not considered here because the focus of this work lies on the general performance of the solutions in terms of e.g. hosting capacity, impact on network losses, etc.

The list of smart grids solutions considered in Cost Analysis and Benefits Analysis (CA&BA) within the IGREENGrid project is[9]:

- **Medium Voltage, Voltage Monitoring:**
  - MV Voltage Monitoring (field measurements)
  - MV Voltage Monitoring (SE)
  - MV Voltage Monitoring (PLF)
- **Low Voltage, Voltage Monitoring:**
  - LV Voltage Monitoring (AMI)
- **Medium Voltage, Voltage Control:**
  - MV Distributed Voltage Control with OLTC
  - MV Distributed Voltage Control with OLTC, DG
  - MV Centralized (field measurements) Voltage Control with OLTC
  - MV Supervised (field measurements) Voltage Control with OLTC & DG
  - MV Supervised Voltage Control with OLTC & DG
  - MV Centralized (SE) Voltage Control with OLTC
  - MV Centralised (SE & OPF) Voltage Control with OLTC
  - MV Centralised (SE & OPF) Voltage Control with OLTC & DG
- **Low Voltage, Voltage Control:**
  - LV Distributed Voltage Control with OLTC
  - LV Distributed Voltage Control with DG
  - LV Distributed Voltage Control with OLTC, DG
  - LV Distributed (field measurements) Voltage Control with OLTC, DG

[9] The list of "most-promising" solutions includes also the functionality "Medium Voltage Congestion Management", but due to the uncertainty of the possibility to deploy this kind of solutions and the required regulatory changes in European countries, this functionality is out of the scope of the CA&BA.

Additionally, in order to simplify and facilitate the understanding of this report, some clarifications on the nomenclature or appellations used in the text are necessary:

- ***Solution or implementation***
    - These two words are used interchangeably throughout the document. The words "solution" and "implementation" are used to refer to the “most-promising” solutions identified in WP4.
- ***Solution group or functionality***
    - These two words are also used interchangeably throughout the document. The “most-promising” solutions identified in WP4 have been grouped by the problem they solve i.e. by the main functionality or objective they accomplish, so that the word “Functionality” means “main objective in which we base to form solution groups” in this report.
- “***Functionality***” refers to “***Objective***” while “***JRC functionality***” refers to “***Capability***”
    - As explained above, the word “Functionality” means main objective or solution group in this report.

When speaking about “JRC functionality” provided by a smart grids solution, we refer to a capability added to the network operation thanks to the implementation. “JRC functionalities” are taken from the list of 33 functionalities proposed by the EC Task Force from Smart Grids 2010a – see Table 46 in the Annex 5.

For each voltage level (LV and MV), the most promising solutions have been described according to their two basic functions: observer/monitoring and actuators as visible on Figure 10 and Figure 11 respectively. After this step, they have been grouped into families of solutions for the purpose of the simulations. The mapping between the individual solutions and the families of solutions is provided in Table 2 and Table 3. In this report, the default OLTC-control is considered to be the control to a constant voltage. When part of a solution, the OLTC-control is more advanced.

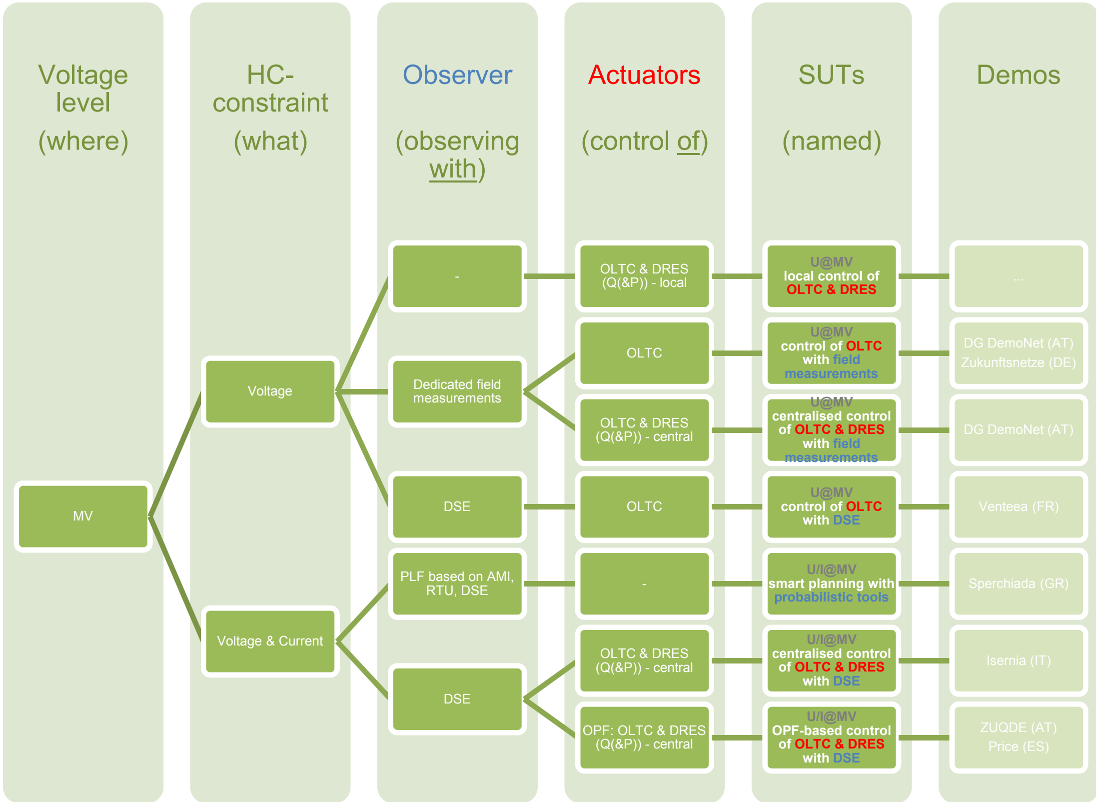


Figure 10 (Categorisation of MV solutions for the technical evaluation)[10]

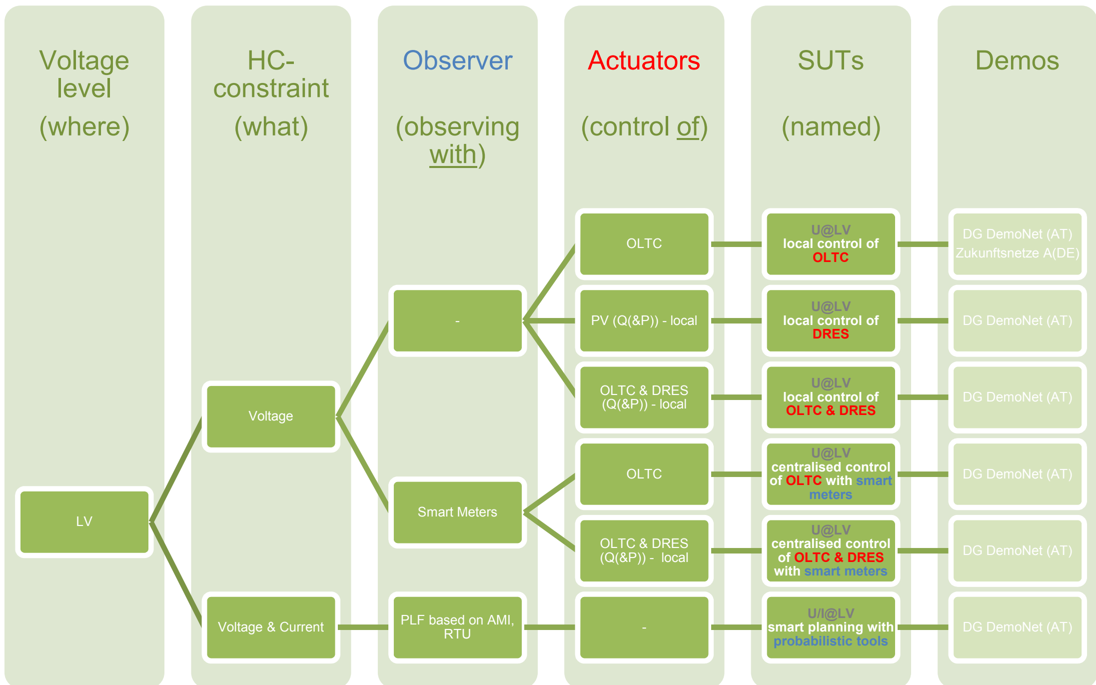


Figure 11 (Categorisation of LV solutions for the technical evaluation)

[10] In this report, observer and monitoring will be used as interchangeable terms and design the action to monitor / observe the magnitudes necessary for the controls (or planning).

Solution (see Figure 10)	"Short family name"
U@MV local control of OLTC & DRES	"VVC" - VoltVAr control
U@MV control of OLTC with field measurements	"WAC" – Wide Area Control
U@MV centralised control of OLTC & DRES with field measurements	"WAC&VVC"
U@MV control of OLTC with DSE	"WAC"
U/I@MV smart planning with probabilistic tools	"AsIs"[11]
U/I@MV centralised control of OLTC & DRES with DSE	"OPF"
U/I@MV OPF-based control of OLTC & DRES with DSE	"OPF"

Table 2 (Mapping MV solutions – family of MV solutions for the simulations)

Solution (see Figure 11)	"Short family name"
U@LV local control of OLTC	"VRDT" – Voltage regulated distribution transformer[12]
U@LV local control of DRES	"VVC" - VoltVAr control
U@LV local control of OLTC & DRES	"VRDT&VVC"[12]
U@LV centralised control of OLTC with smart meters	"WAC" – Wide Area Control
U@LV centralised control of OLTC & DRES with smart meters	"OPF"[13]
U/I@LV smart planning with probabilistic tools	"AsIs"11

Table 3 (Mapping LV solutions – family of LV solutions for the simulations)

In addition to the families of solutions listed previously, two additional purely local solutions have been investigated for both the MV and LV networks: the fix curtailment ("FixCurt") and the VoltWatt-Control ("VWC"). The fix curtailment consists of limiting the injected power to 70 % of the installed power, according to the regulation in force in Germany for installations below 30 kW [10]. The "VWC" consists of a P(U) control which only curtails the output power if the voltage reaches a defined threshold.

[11] The fact of using Monte-Carlo simulations to get a better estimate the hosting capacity as it has been done for the AsIs scenario is actually the solution "smart planning with probabilistic tools"
[12] This solution has been investigated theoretically (see chapter 8.1)
[13] This solution has been modelled with an OPF although is not implemented with an OPF to keep a similar approach as for the MV solution.

Finally, another smart grids solution for LV networks which was not directly investigated in the IGREENGrid demonstrations has been considered: phase balancing. The concept and results of these solutions are presented in chapter 7.4.
In this report, the short names will be used and the reader should keep in mind that these names stand for a rather generic solution.

4 Distribution networks used to investigate the S&R potential

4.1 MV networks

As explained in chapter 2, the networks provided from the DSOs have been used for the analysis. In total, 27 MV networks (149 feeders) have been analysed (with a number of networks per DSO between 1 and 7, depending mostly on the data availability and selection process). Figure 12 shows for each DSO the number of feeders and the feeder length per network. Note that 19 networks have a nominal voltage of 20 kV and 10 have a lower nominal voltage (10 kV, 13.2 kV or 15 kV)[14]. Therefore, a comparison of networks is only possible within certain limits.
Figure 12 shows that most of the networks are rather inhomogeneous (consisting of very short (<5 km) and long (>20 km) feeders). For this reason, hosting capacity studies must be performed at feeder level. This figure shows that there are purely urban networks (ENEL-Network3 and IB-Networks4-6) which usually have a high (>10) number of short feeders (<5 km). There are very few purely rural networks with mostly long (>20 km) feeders (GNF-Network2).
As explained previously, the rather large number of networks and feeders allows covering a great number of real situations but is still too small to perform a full statistical analysis and determine in a statistically sound way the quantitative S&R potential of smart grids solutions. However, it already gives valuable indications on the expected potential of the considered smart grids solutions.

[14] GNF networks 1 and 2 have a nominal voltage of 15 kV, network 3 has a nominal voltage of 20 kV, all the considered IB networks have a nominal voltage of 13.2 kV, the RWE network has a nominal voltage of 10 kV, the EAG and SAG networks at operated at 30 kV and the ENEL, HEDNO and ERDF networks have a nominal voltage of 20 kV.

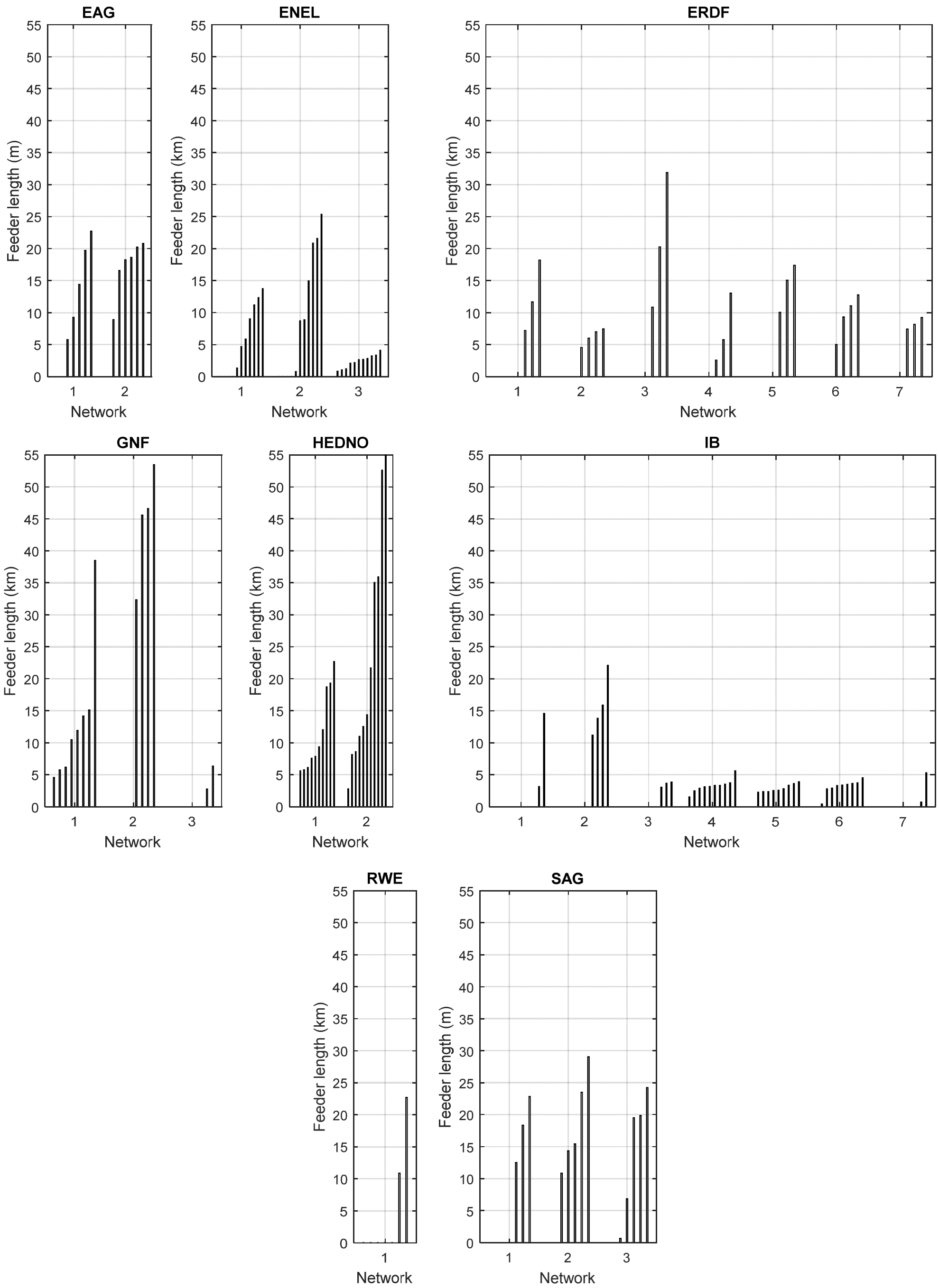


Figure 12 (Feeder length per network and DSO)[15][16][17]

[15] GNF networks 1 and 2 have a nominal voltage of 15 kV, network 3 has a nominal voltage of 20 kV, all the considered IB networks have a nominal voltage of 13.2 kV, the RWE network has a nominal voltage of 10 kV, the EAG and SAG networks at operated at 30 kV and the ENEL, HEDNO and ERDF networks have a nominal voltage of 20 kV.
[16] For ERDF, only three feeders have been modelled per network (most critical feeders).
[17] The feeders are sorted by ascending length to facilitate the visualisation.

4.2 LV networks

For the LV level, in total, 16 LV networks (55 feeders) have been analysed (with a number of networks per DSO between 1 and 9, depending mostly on the data availability and selection process). Figure 12 shows the number of feeders and the feeder length per network for each DSO (only three) for which data was available. This figure shows that most of the networks are rather inhomogeneous (having very short (<50 m) and long (>400 m) feeders), which confirms here also that hosting capacity studies must be done at feeder level. As explained previously, the rather large number of networks and feeders allows covering a great number of real situations but is still too small to perform a full statistical analysis and determine in a statistically sound way the quantitative S&R potential of smart grids solutions. However, it already gives valuable indications on the expected potential of the considered smart grids solutions.

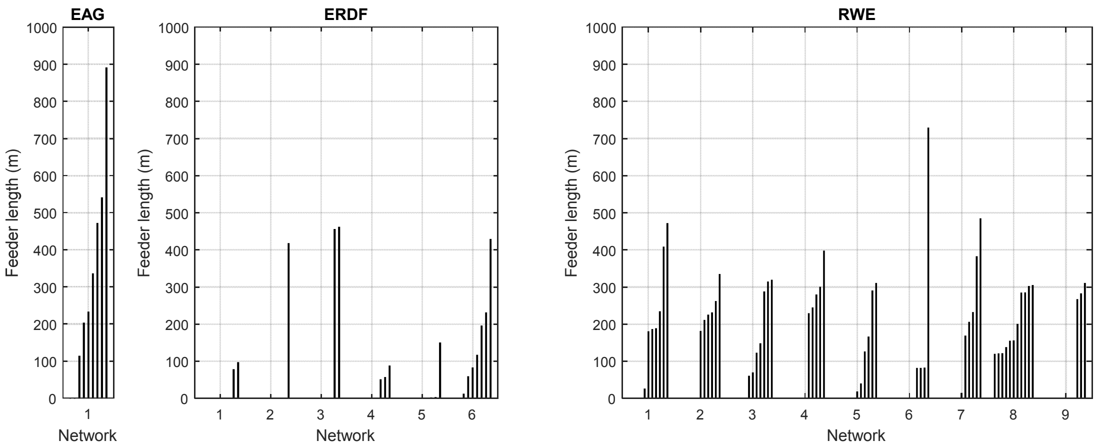


Figure 13 (Feeder length per network and DSO)[18]

[18] The feeders are sorted by ascending length to facilitate the visualisation

5 Modelling assumptions and simulation tools

Among all the different types of renewables, photovoltaic and wind power can be considered as the main renewable sources that will trigger the main needs for network reinforcement or smart grids deployment in the next years [11]. [11] considers other distributed energy resources such as biomass, CHP, hydropower as well as the demand evolution as secondary drivers. These are therefore not considered in this study. In [12], PV and wind power are also the main RES considered.

Due to the focus of the project (enhancing the hosting capacity of existing distribution networks with smart grids solutions), wind power has not been considered. In fact, the connection rules of most of the countries considered foresee the connection through a dedicated feeder to the primary substation for generators with an installed power above 4 to 6 MVA (one or two average wind turbines). However, it is expected that most of the results would not be significantly different if wind power had been considered (a comparison between PV and wind curtailment is provided in chapter 6.1.3.3.3). Mainly the profiles (actually the Monte Carlo samples) would be different and the generation would be less distributed. One exception is for the curtailment solutions since the number of full load hours is significantly different for wind power than for PV. A short discussion is included in chapter 6.1.3.3.3.

The general proposal has been a top-down approach. This approach is based on the analysis of artificial scenarios defined by the hosting capacity (e.g. generation = hosting capacity without smart grids solution or generation). This approach has been selected since it allows a common comparison between solutions independently from existing estimates. For example, roadmaps from industry organisations or from international organisations ([2]–[6]) present a very large uncertainty due to unknown political and economic developments would not bring a decisive added value in this type of study.

The type of questions to be answered can be formulated for example as:

"*Network "A" can host XX kW PV, how much more could it host by implementing smart grids solution "X" and at which costs…*"

Figure 14 shows the very basic approach followed in this work. This approach is mainly based on the use of so-called reference networks (Inputs in Figure 14), which are intended to be representative for the DRES integration for each DSO of its own supply area. In some cases, the representativeness of reference networks could not be clearly established but these networks were selected to cover a wide range of networks types relevant for the study of the selected smart grids solutions.

Each DSO of the consortium has provided a set of MV networks, which form the basis to perform the comparative study between solutions. For LV solutions, a more limited set of networks was available (see previous chapter).

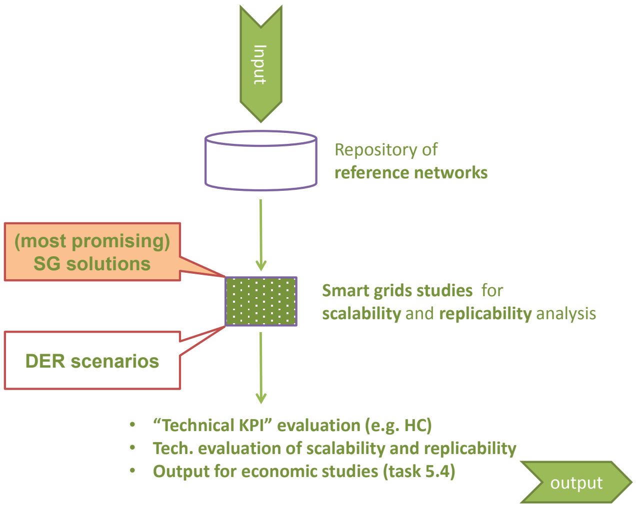


Figure 14 (General approach for the technical evaluation)

The core of the evaluation consists of the “smart grids studies”: after some preparatory work to define DRES scenarios and to model the smart grids solutions (SG solutions in Figure 14), simulations are run to evaluate the performance of the solutions according to the metrics defined in the previous stage of the project (e.g. Key Performance Indicators - KPIs).

5.1 System boundaries

The different voltage levels (MV/LV) of the considered distribution networks are investigated separately. For both, the upstream network will be modelled by using a slack with a constant voltage, since the use of a variable slack voltage (in reality the voltage at the primary side of HV/MV and of MV/LV transformers is of course varying) would in general not improve the quality of the results for the targeted simulations.

For MV networks, secondary substations (representing either a public LV network or a private customer connected to the MV network) are modelled by an equivalent load directly connected to the MV nodes.

The experience from several demonstration projects showed that it is very important to take into account the topology changes that happen for example in case of maintenance work (planned) or in case of outage (unplanned) [13]. For MV networks, alternative network configurations allow increasing the reliability of the supply. For this purpose, a reserve is needed to avoid constraints (voltage and loading) even in case of alternative network configurations. These topological changes can be either internal or external (supply of additional parts of a neighbour network or the supplied network is smaller than in the default network configuration).

For external topology changes, the neighbour networks must be also considered causing additional complexity in planning and operation.

Since the IGREENGrid approach requires comparing the most promising solutions (including network reinforcement) on a common basis, the issue of network topology changes is ignored at the simulation level. A discussion about the implications of network configuration changes is included in chapter 12.

5.2 Type of simulations

For the investigations performed in this work, the standard tools from the simulation software DIgSILENT PowerFactory [14] have been used:

- Load flow (LF) and probabilistic load flow (PLF)[19].
- Optimal power flow (OPF).
- State Estimator (SE).
- Quasi-Dynamic simulations.
- RMS (stability) – simulations (for the curtailment solution VoltWatt-control).

5.3 Input data

For the simulations, load and generation data have been used as a basis to generate Monte-Carlo samples for the probabilistic load flow computations. In order to correctly model the dependency between consumers and/or generators, the following approach has been used. A time frame analysis of extensive measurements allows considering the time-dependence and the correlation of most loads and PV generation with the daylight. Three time frames are considered:

- Time frame within the day depicted by using a 15 min interval (96 per days).
- Time frame within the week (by considering weekdays and weekends (two types of day)).
- Time frame within the year depicted by considering the four seasons.

In a Monte-Carlo simulation, the number of samples should be large enough in order to reach a sufficient accuracy. While most of the authors do not address this question of the minimum number samples, the value of 10.000 can be found in some publications (e.g. [15]).

In [16], a formula to determine the necessary number of samples to estimate a percentile ε with a given confidence level β is given (equation (1)). As seen in the formula, there is a larger sensitivity to the percentile than to the confidence level. While it is very inexpensive in terms of number of samples to estimate the expected value of a variable by Monte-Carlo simulations, the higher the percentile, the more costly the simulations.

$$N \geq \frac{2}{\epsilon} ln\left(\frac{1}{\beta}\right) + 2n_\theta + \frac{2n_\theta}{\epsilon} ln\left(\frac{2}{\epsilon}\right) \tag{1}$$

ε	Percentile to be estimated
β	Confidence level
n_θ	Size of the problem (1 here)

For the use in network computations, the high percentiles are relevant. In order to estimate the 99 % percentile with a 1 % confidence level, almost 2.000 samples are needed. Following the time frame previously mentioned (15 min intervals, weekend/weekdays, seasons), the necessary number of samples for a single simulation run would be about 2.5 Millions. This very high number of samples would require limiting the number of scenarios strongly in order to keep a realistic simulation time.

In order to limit the number of necessary samples, a method has been proposed in the literature

[19] By using Monte-Carlo simulations without non-temporal input data (samples instead of time series), some limitations have to be accepted For example, the number of switching operations for On Load tap Changers (OLTC) and switched capacitors cannot be evaluated.

[17]: the Latin Hypercube Sampling (LHS) instead of random sampling. This method converges faster than the traditional sampling method for both the mean and the percentiles, which allows using a reduced number of samples for the simulations. In order to obtain accurate results, the number of samples was set to 200 instead of 2.000.
As it is important to keep the ratio between the type of days in the samples, 500 samples are generated for the weekdays and 200 for the weekends, giving a total number of samples of 268.800 to represent a full year.

5.3.1 Load data

In order to model the load variability two types of load data have been used:

- Measured and/or synthetic load profiles (e.g. for RWE or EAG). A power factor of 0.95 has been assumed.
- Feeder measurements (e.g. IB,ERDF)

For networks for which feeder measurements have been used, the sum power has been allocated along the feeder according to the contracted or installed power per secondary substation.
On the basis of these profiles, some Monte-Carlo samples have been created. For LV networks, smart meter data provided by RWE have been used[20].

5.3.2 DRES data

For the DRES (limited to PV here), the same approach as for the loads has been followed (use of the same time frame with 15 min, weekend/weekday, seasons). Considering a maximum feeder length for MV networks of up to 50 km for some rural feeders, the renewable power generation (PV) can be assumed to be fully correlated. PV data measurements were obtained from the inverter manufacturer Fronius for PV systems in the six countries covered in the project. In total, data from 108 installations in six countries were provided (5 min average power, installed power, location). This data has been analysed and processed to filter out wrong values. Figure 15 shows the “equivalent full load hours” (capacity factor multiplied by 8760 hours) for each installation from the six countries as an illustration of the data analysis. This evaluation has been used to identify installations with an “average” yield to avoid outliers (e.g. installations with trackers).

[20] Smart Meter data from Nordrhein-Westfalen (Germany), 2013 (RWE Deutschland AG, E-Energy Projekt E-DeMa)

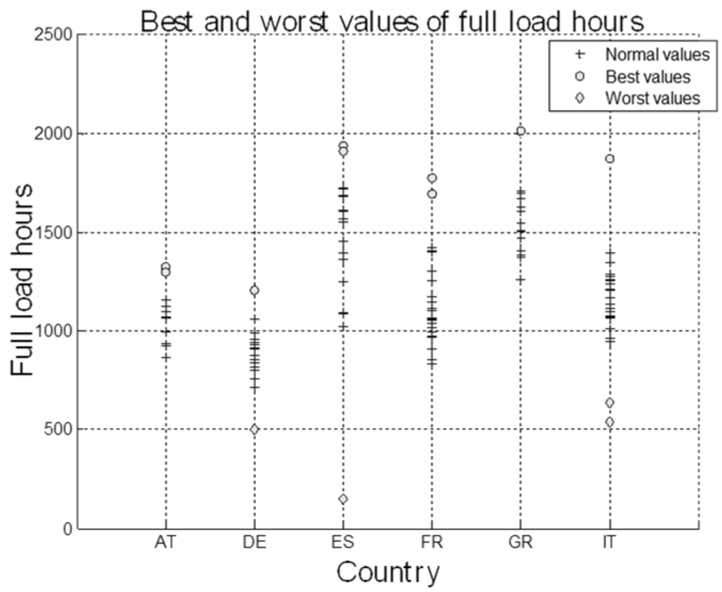


Figure 15 (Equivalent full load hours for the PV installations)

5.4 Planning rules

In order to be able to determine the hosting capacity of a network with or without the use of smart grids solutions, the planning and operation rules[21] must be analysed in details. Although network planning is not a straight-forward task since a large and complex framework of circumstances needs (e.g. cabling programs, reliability issues or general asset management issues…), planning is reduced in this study to the following two components:

- Compliance with voltage limits ("U-problem").
- Compliance with the loading limits ("I-problem").

5.4.1 Available voltage band

The total voltage band available is considered to be ±10 % (20 % in total) according to [18]. This total band is usually divided to a part for the MV network and another part for the LV network. An example is provided on Figure 16.

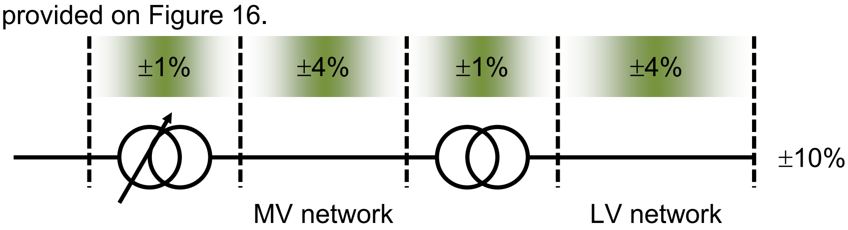


Figure 16 (Schematic representation of the voltage band – own illustration adapted from [19])

Moreover, the available voltage band is divided among users (loads and generators), as visible in Figure 17. In most countries, the voltage band has been unequally allocated between loads (voltage drop) and generation (voltage rise) for historical reasons (very small DRES penetration), which strongly limits the hosting capacity according to the current connection assessment rules.

[21] The rules proposed here are based on current rules that might however partly change in the next years.

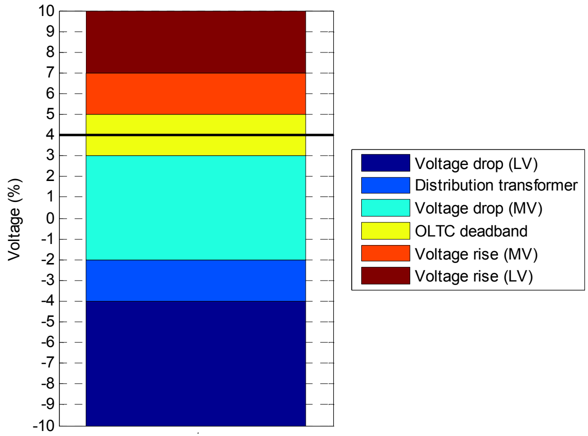


Figure 17 (Example of voltage band allocation) – illustration based on [20]

In order to take into account the differences between countries and DSOs, individual limits have been used for each DSO. These limits are shown in Table 4.

DSO	EAG	ENEL	ERDF	HEDNO	GNF	IB	RWE	SAG
ΔU_{MV} (%)	+2 -5	+2 -5	+2 -6	+2 -2	+4.6 -4.6	+4.6 -4.6	+2 -5	+2 -5
ΔU_{LV} (%)	+3 -6	+3 -7	+1 -5	+3 -3	+1.4 -1.4	+1.4 -1.4	+3 -6	+3 -6

Table 4 (Planning levels of voltage rise and voltage drop along MV and LV lines)

5.4.2 Maximal allowed loading

The N-1 criterion is usually applied differently depending on the types of constraint (load / generation) at MV level[22]. This criterion requires that assets are not fully loaded under normal conditions in order to leave some reserves to supply additional loads from a neighbour network in case of failure or maintenance. In [11], the maximum loading under normal conditions is set to 60 %. This criterion is however usually not applicable for generation [11] which means that the maximum loading in case of reverse power flow is set to 100 %.

5.4.3 Network topology changes

The experience from several demonstration projects showed that it is very important to take into account the topology changes happening, for example, in case of maintenance work (planned) or in case of outage (unplanned) [21]. For MV networks, alternative network configurations allow increasing the reliability of supply and require at the same time suitable reserves (voltage and loading). These topological changes can be either internal or external (addition of supply of a part of a neighbour network or a smaller supplied network than in the default topology). For external topology changes, the neighbour networks must be considered, increasing significantly the complexity. Since the S&R approach aims at comparing the most promising solutions on the basis of reference networks, the issue of network topology changes can be ignored at the level of the simulations but it is discussed in chapter 12.

[22] The N-1 criterion is not systematically be used for every single MV line. In particular, some very rural feeders can be purely radial without any alternative supply.

5.5 Modelling details

5.5.1 LV networks

For LV networks, load and generation unbalance will be considered since it directly affects the hosting capacity. Some of the solutions are addressing this issue. Generally, for customers with a three-phase connection, no information about the actual phase connectivity is available. Planning schemes have to be accordingly conservative to avoid any voltage violation.

While the network models fully support unbalanced power flow computations, the assumptions on the phase distribution of e.g. single-phase generators play an important role. For this, a similar approach as in Step 1 of the general concept for the SRA is proposed (see chapter 7.4). Via Monte-Carlo simulations, the spectrum of possible phase combinations is evaluated and three scenarios are selected for further studies (slightly, moderately and heavily unbalanced – the last one being the most interesting for the investigated solution).

LV networks are modelled as three-phase / four wires networks. The actual earthing system used in the LV networks provided by the DSOs (e.g. usually TT in France, Italy and Spain, and T-N-C-S in Germany and Austria) have not been considered since the effect on the load flow results are negligible [22].

5.5.2 OLTC modelling

The transformers currently installed in the distribution grids used for the simulations have been sized considering the peak load and are not suitable for the penetration rates simulated in this study. Given that the purpose of this study is to compare different solutions on a same basis, it has been necessary to avoid the limitation imposed by the rating of existing transformers in primary (or secondary) substations[23]. In this study, the rated power of transformers is supposed infinite (the loading limitation is only considered for the lines and cables). The parameters of the OLTC installed in the considered networks have not been considered explicitly[24]. In fact, the non-ideal behaviour of OLTCs (e.g. dead-band depending on the step size) is considered at the planning level by allocating part of the voltage band to the OLTC (2 %-4 % usually).

In order to calculate the hosting capacity of the OLTC-based solutions (e.g. “WAC”, “OPF”), a control strategy must be set-up as it is obviously not possible to treat each feeder independently like for the other solutions.

The control strategy implemented in Step 2 (see chapter 2.1.2) to determine the hosting capacity is the following: in the first step, the OLTC tap position control is deactivated and a load flow/OPF[25] calculation is done to identify the terminal with the minimum voltage $U_{min,Grid}$ (Figure 18 (a)) . After this, another load flow/OPF is performed and the OLTC is parametrized to bring $U_{min,Grid}$ to the lower voltage limit of the corresponding DSO ($U_{min,DSO}$), increasing the available voltage band for the feeders (Figure 18 (b)). To make sure that the tap position does not change while the feeders are scaled-up, the OLTC is deactivated and replaced by a slack at its lower side. The slack voltage is adjusted to the upper side voltage. In this way $U_{min,Grid}$ is equal to $U_{min,DSO}$, as illustrated in Figure

[23] In reality, the transformer capacity can of course actually be the most limiting factor.

[24] In reality, the OLTCs might experience some limitations and the set-point might not be reach when reaching the upper or lower tap position. This can occur for example in case of high voltage situation at the HV side, combined with a strong reverse power flow and a reactive power surplus. See [29] for more explanations.

[25] The load flow is executed for WAC and WAC&VVC and the OPF in case of Max and OPF SUTs.

18 (c). Afterwards, the hosting capacity of each feeder can be calculated by scaling them up separately. In the Figure 18 (d), only feeders F1 and F2 have been scaled because they are voltage constrained. The last step (not included in the figure) in which the OLTC is reactivated, is also performed to control if the voltage remains within the limits with the calculated amount of DRES.
This procedure is run for specific critical times which are explained in chapter 6.1.2.1.

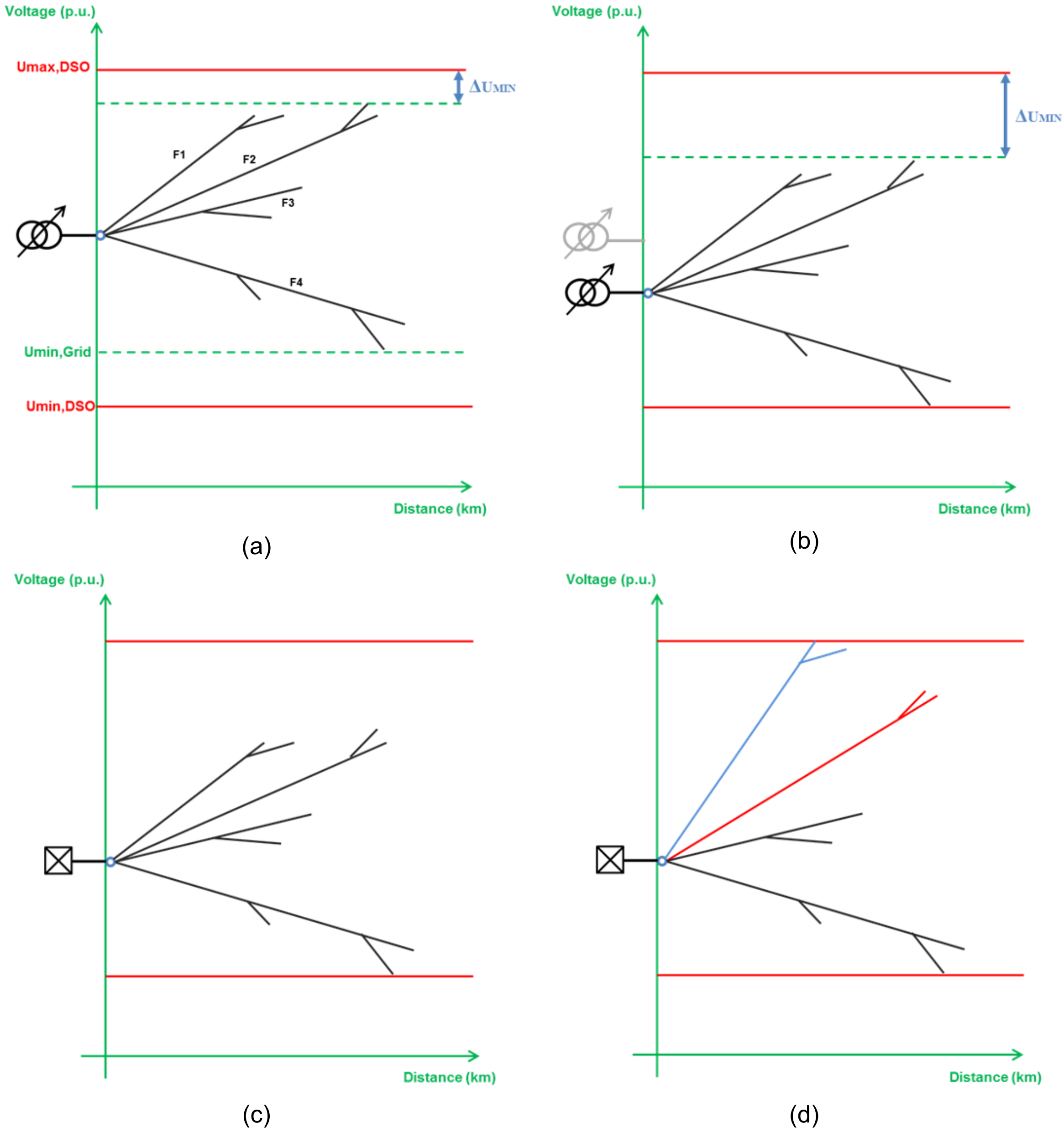


Figure 18 (OLTC control strategy in Step 2)

In the Step 3 (chapter 2.1.3) and for the solution "Max", the Monte-Carlo simulation with the full number of samples is run and the installed amount of DRES is the one calculated in Step 2. A standard OLTC model is used and is controlled via the OPF (is parametrized to keep the voltage within the limits).

5.5.3 Q(U) and P(U) parametrisation (“VVC” and “VWC”)

The Q(U) control for the solution “VVC” has been implemented using the standard function of the simulation tool PowerFactory [14]. The parameters of the Q(U)-characteristics have been chosen to fit the planning voltage limits of each DSO.
Using the results of a previous work [30], the following approach has been followed to parametrise the Q(U)-control. The dead-band has been set to 20 % and the “saturation” to 70 % of the voltage rise allowed by the DSO. Using, for example, a maximal allowed voltage rise of +5 % of the nominal voltage would result in the values shown in Table 5.
The P(U) control (solution “VWC”) is shown in the same figure (Figure 19) and starts at 70 % of the voltage rise allowed by the DSO: beyond this value, the injected power is reduced linearly. The P(U) control has been programmed in a dedicated function since it is not available in the used simulation tool.

Control	Point	Setting (p.u.)
Nominal voltage		1.00
Q(U)	Dead-band	[1.00-1.01]
	Linear part	[1.01 1.035]
	Saturation	[1.035-1.05]
P(U)	Dead-band	[1.00-1.035]
	Linear part	[1.035-1.05]
	Saturation	>1.05

Table 5 (Example of Q(U) and P(U) settings for a maximum voltage rise of +5 %)

Figure 19 provides an illustration of the chosen parametrization. The x-axis shows the percentage of the voltage rise allowed by the corresponding DSO planning rule.

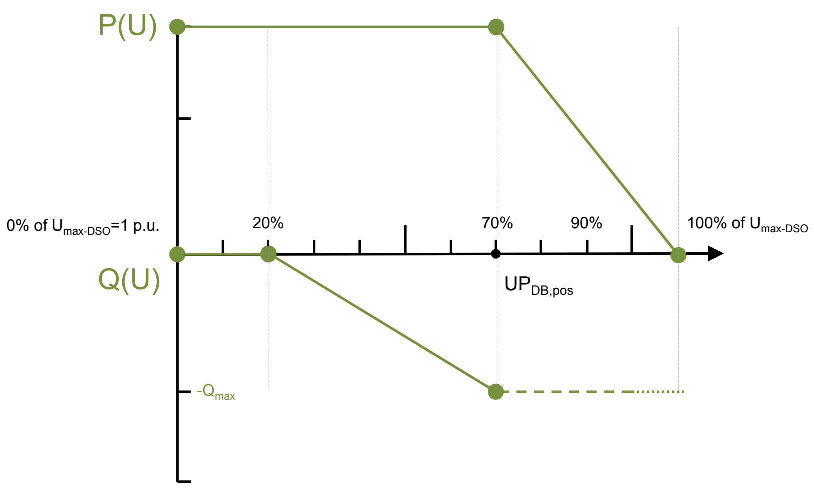


Figure 19 (Q(U) and P(U) parametrization)

5.5.4 OPF – optimal power flow

The standard OPF engine of the simulation tool PowerFactory has been used [14]. As objective function, the minimisation of the losses has been selected networks.

5.5.5 DSE – distribution state estimator

The performance of the distribution state estimator (DSE) implementation proposed in the IGREENGrid demonstrations has been investigated. The results are summarised in chapter 6.3.
For this purpose, the standard state estimator of the simulation software [14] has been used and parametrised as follows:

- Accuracy of active and reactive power sensors : 3 % of rating.
- Accuracy of voltage sensors (if used): 0.5 % of rating.
- Accuracy of pseudo-measurements: 50 % of rating.
- Number of active and reactive power sensors: one per feeder.
- Number of voltage sensors: several per feeder (located at secondary substations where communication for remote control is available).
- Load estimation algorithm: variable (see chapter 6.3).

5.6 Implementation into the simulation framework and supporting tools

The tools used for the technical assessment of the S&R potential of smart grids solutions have been selected on the basis of the following criteria:

- Flexibility.
- Performance.
- Compatibility between each other.
- Compatibility with programs used by partners.

The network simulations are all done with the simulation package DIgSILENT PowerFactory [31] and the data handling, processing and analysis is done with Matlab [32] and Python [33]. The following sub-chapters present the approach selected to manage the data and to implement the simulation and analyses presented in the previous chapters.

5.6.1 Data management

The work with a high number of network files, load and generation files and scenarios requires a well-structured and organized platform to ensure an efficient and reliable work within a project team. For this reason a Sub-Versioning System (SVN [34]) was used. Files that were included into the versioning system are network files, sample files, source code for results analysis and documentation. With this system, all versioned files have a documented history of changes allowing an accurate tracking of changes.

5.6.2 PowerFactory tools

The simulation package PowerFactory has been selected for the network simulations. The following sub-chapters provide a short description of the tools from this simulation package which have been used. The description is not complete; it aims at giving the reader an idea of the tools used for the simulations.
Several Built-in tools of PowerFactory are used in the studies, including DSL (DIgSILENT Simulation Language), DPL (DIgSILENT Programming Language) as well as standard functions such as Optimal Power Flow (OPF) and voltage control functions which are available (e.g. Q(U)).

For LV networks, detailed three-phase / four wires network models have been used, which enables an accurate modelling of unbalanced conditions.
Two programming environments, DPL and Python, have been used to carry out the automation of calculations for a high number of networks and/or scenarios. Considering the large number of networks and scenarios, an automation of the simulations is absolutely necessary.
The built-in PowerFactory programming environment DPL allows scripting every interaction with the program. However, it offers only a limited built-in standard library that can be extended by own libraries. On the contrary, the Python interface offers a high flexibility and an access to higher level functions such as optimisation.

5.6.3 Parallelisation of the simulations

The necessity to cover a high number of networks and simulation scenarios leads to the problem, that the computation power of a single computer is insufficient for the purpose of the studies.
In order to speed-up the simulations, efforts have been taken to setup a parallelization environment for the different tasks:

- Preparation: Import of network data on several powerful virtual machines.
- Execution: Split of simulation tasks assigned to virtual machines and/or (virtual) users.
- Analysis: Aggregation and processing of result files.

For the parallelisation, the cluster available at AIT is used. It consists of 24 operative nodes and one Central Management/Storage Node which are connected via 40 GBit/s Infiniband and 10 GBit/s Ethernet (24 nodes with 12 cores per node and 128 GB per node). With this parallelisation environment, a substantial gain of time has been achieved and has made the work possible.

5.6.4 Matlab tools

Matlab has been primary used to prepare the input data (Monte Carlo samples) and to analyse the results. In addition, it was used to process automatically simulation results from previous steps and to generate configurations needed for various simulations scenarios. More details can be found in deliverable D5.2.

6 Technical evaluation of the S&R potential of MV solutions

Most of the results of the simulations performed for the MV networks are summarised in this chapter. Some of the detailed results are provided in the annexes.
In the first sub-chapter (6.1), the methodology presented in chapter 2.1 is applied step by step to an example network (which is further used along the whole report) to ensure a good readability.
In the second sub-chapter (0), the results are shown for all the considered MV networks in an aggregated way in order to draw conclusions on the S&R potential of smart grids solutions from a technical point of view. Finally, the last sub-chapter (6.3) is devoted to the accuracy of observers which are an important part of some smart grids solutions (see chapter 3).

6.1 Illustration example

In order to illustrate the approach and explain the results in detail, an example network (one of the networks provided by the DSOs) has been chosen and used along the whole report (except for evaluation of the observer/monitoring accuracy – chapter 6.3). This network represents a rural area with a few zones with a higher load density.

6.1.1 Feeder screening and classification

As explained in chapter 2.1.1, the first step consists of selecting a common reference distribution of generation along the feeders (DRES distribution). In order to determine this scenario for each feeder, 1000 DRES distributions are randomly generated and for each of them the hosting capacity is calculated. Furthermore, the loading and voltages values are saved to categorize the feeder (whether it is voltage or loading constrained) for each value of the hosting capacity.
This procedure is applied to the example network which contains 8 feeders. The length and the number of DRES connected to each feeder are shown in Table 6.

	F01	F02	F03	F04	F05	F06	F07	F08
Length (km)	11.9	6.2	38.5	14.2	4.6	5.8	15.1	10.5
DER number	24	18	87	43	8	19	50	24

Table 6 (General properties of the illustration network)[26]

Figure 20 shows the Cumulative Distribution Function (CDF) of the hosting capacity of Feeder 01 of this example network. In this rural feeder (11.9 km long), the hosting capacity varies between 2.35 MW and 3.29 MW. The highest hosting capacity corresponds to a distribution in which the RES are located mostly at the beginning of the feeder. Similarly, the lowest HC corresponds to a distribution in which RES are located at the end of the feeder. The feeder is purely voltage constrained for all the considered DRES distributions.

[26] For each load, one generator has been assumed. The power of each generator is determined from the DRES scenario (Step 1 – Monte Carlo simulations)

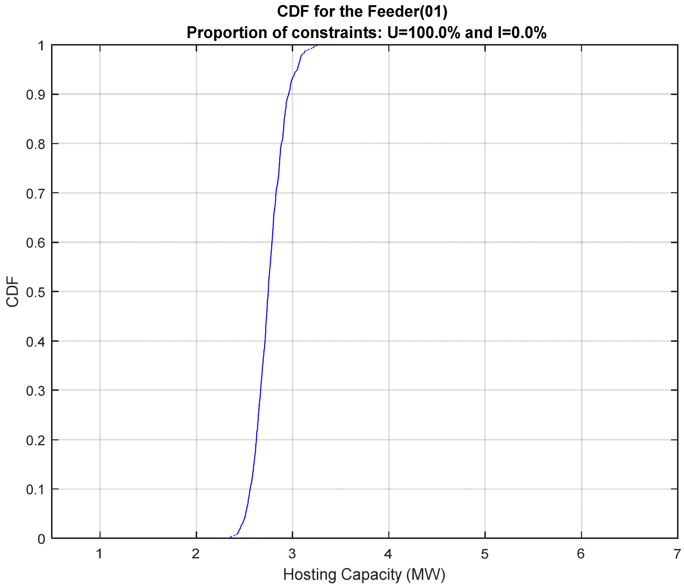


Figure 20 (CDF of the hosting capacity in Feeder 01)

Figure 21 shows the CDF of the hosting capacity for the entire network. For each feeder, the constraint is identified by its colour: blue if the feeder is voltage constrained, red if it is loading constrained. It can be easily noticed that a correlation exists between the feeder length and the nature of the constraint. Indeed, the rural feeders (F01, F03, F04, and F07) are purely voltage-constrained whereas the semi-urban feeders (F02, F05, F06 and F08) are mostly loading constrained (some specific distributions can lead to a change in the constraint but these are mostly outliers). However, the nature of the constraint doesn't only depend on feeder length as the comparison between F01 and F08 shows. In this case the difference is explained by the line ratings.

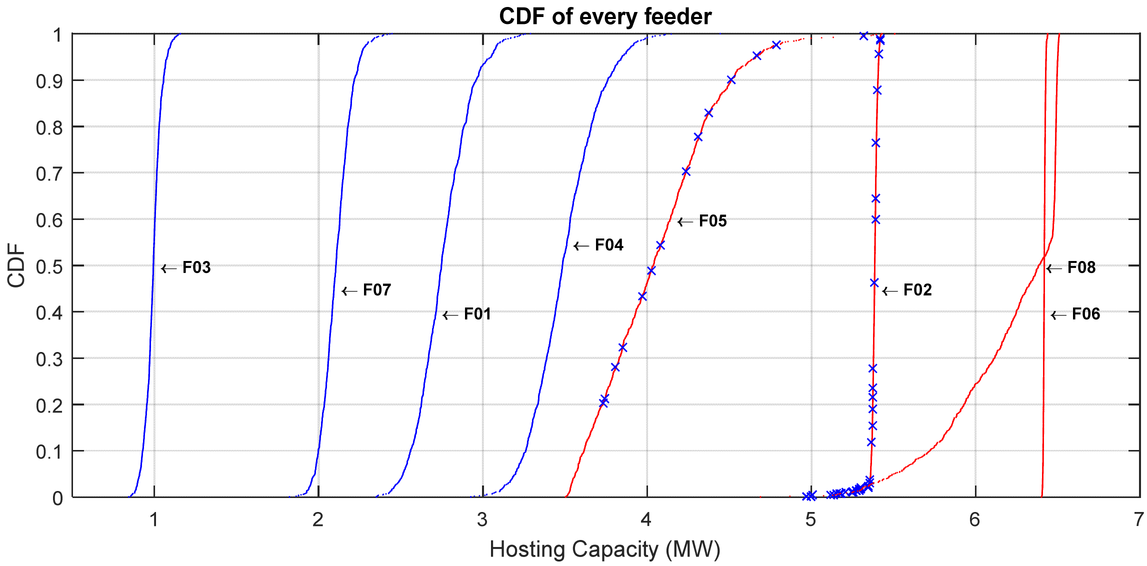


Figure 21 (CDF of the hosting capacity for the entire network)

Once the CDF have been created, it is possible to determine the "median hosting capacity scenario" which is considered for the next steps. The process is illustrated in Figure 22.

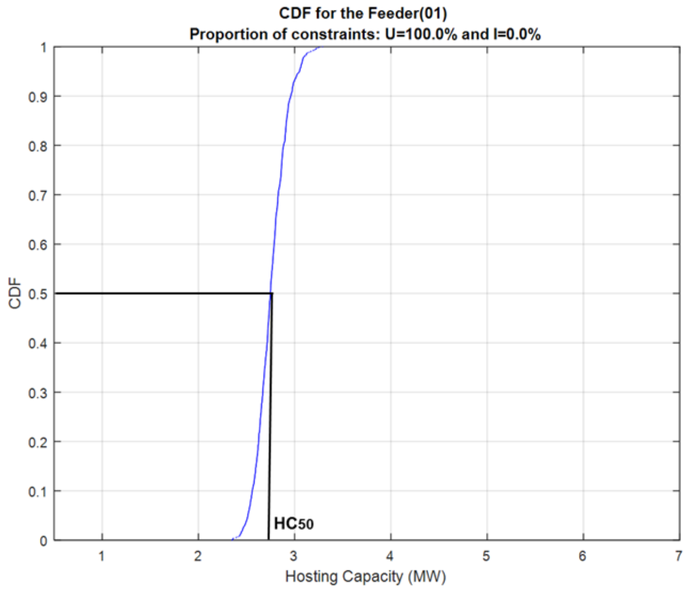


Figure 22 (Determination of the median DRES distribution)

Firstly, the median hosting capacity is extracted from the CDF and, secondly, the distribution linked to this hosting capacity is defined as the "median hosting capacity scenario".

6.1.2 Expected HC for all the DSOs and SUTs

The goal of Step 2 is to determine a realistic hosting capacity for the case-studies: unlike the previous step in which loads were not considered and a single power value was used for the generation, time characteristics for loads and generators are now considered. The distribution of generation used for the feeders is the one calculated previously (median scenario from Step 1).
In the first step, a probabilistic power flow is computed to identify eventual problems. Table 7 presents the results of the simulation: for each feeder, the maximum voltage, maximum loading (100 % percentile) as well as the minimum voltage (0 % percentile) are extracted.

	F01	F02	F03	F04	F05	F06	F07	F08
Umax (p.u.)	1.042	1.042	1.014	1.037	1.035	1.011	1.032	1.033
Umin (p.u.)	0.985	0.991	**0.714**	0.972	0.997	0.995	**0.940**	0.985
Lmax (%)	47.0	99.2	75.7	54.7	99.7	88.1	35.2	91.7

Table 7 (Results of the first probabilistic power flow)

An under-voltage violation occurs for F03 and F07 (in this specific network the lower voltage limit is 0.954 p.u.). The causes of such violations can be some inaccuracies in the provided load or feeder profiles (due to e.g. unreported changes in the topology). This problem is resolved by scaling down the loads of the feeders which are problematic, if necessary.
A Secant Method algorithm is used to scale down the loads in order to meet the criteria of the planning rules if necessary and another Probabilistic Load Flow (PLF) is computed with the calculated load scaling parameters. The critical time intervals are determined from the PLF analysis. The values of the maximum voltage and the maximum loading occurring at the critical times[27], as well as the minimum voltage for the entire computation period, are presented in the section "*Step 2.1 – Worst case scenarios*" of Table 8. It can be noticed that none of the feeders

[27] The critical time corresponding to the maximum voltage spreading is not shown in the table.

which were voltage-constrained in Step 1 now reaches the upper voltage limit (the maximum voltage observed is 1.042 p.u. whereas the limit set by the DSO is 1.046 p.u. for this network). The reason for this is that the loads, which were not considered in the previous step, are now compensating part of the generation[28]. The same observation can be made for the lines loadings, which are below the planning limit of 100% (except for the feeders F02 and F05 in which the installed load power is very low as reflected in the minimum voltage).
Once the critical times (maximum voltage, maximum loading and maximum voltage spreading) of each feeder are identified, it is possible to calculate the hosting capacity for each solution. The procedure used to determine the hosting capacity is explained in the next sub-chapters for the groups of solutions. The detailed analysis of each solution is presented in the following chapters.

6.1.2.1 Explanation of the determination of the hosting capacity for the different solutions

In this chapter, the details of the methodology to determine the hosting capacity of each solution are explained. It is separated in two sub-sections depending on the properties of the solutions (active use of an OLTC or not). The approach is explained based on the results of the exemplary network shown in Table 8.

6.1.2.1.1 "Solutions without OLTC-control"

For every solution that belongs to this category (i.e. "AsIs", "VVC" and "FixCurt"), the procedure to calculate the hosting capacity of each feeder consists of making a snapshot of the specific feeder at each critical time and then scaling up[29] the installed generation until a constraint is reached.
The case to be analysed is the reference case "AsIs". Table 8 presents the maximum voltage and maximum loading of the feeders for the hosting capacity calculated. F01, F03, F04 and F07 reach the upper voltage limit whereas F02, F05, F06 and F08 are loading-constrained. As a consequence, the "VVC" will not be implemented for these feeders and the table remains empty (with a "-"); for the feeders in which "VVC" is implemented, the HC increase compared to "AsIs"[30] is also given. The "FixCurt" SUT is the only one that can be implemented in loading constrained feeders.

6.1.2.1.2 "OLTC-based solutions"

For every solution using an OLTC (i.e. "Max", "WAC", "WAC&VVC" and "OPF"), the procedure is different as there is only one critical time interval for the entire network. The reason is that for an OLTC, the worst case scenario occurs when the voltage spreading inside the network is the highest[31], and the remaining voltage band available for the flexibility is the smallest. Once the critical time interval is identified, the voltage constrained feeders are scaled-up separately until they reach the voltage or the loading limit. Just like for the "VVC", it is not necessary to calculate the hosting capacity of the feeders which are loading constrained with the "AsIs" case-study because the OLTC would not have any effect on them; in the table these feeders remain empty (with a '-').

[28] The reader should remind that the generation has been considered as fully correlated („synchronous"), which consists in a worst-case assumption.
[29] As in the Step 1, the installed power of the generation units is scaled by keeping the DRES distribution.
[30] The hosting capacity of each SUT compared to the reference case "AsIs" is located in the rows with the "*ΔHC (%)"* legend.
[31] In case the maximum voltage spreading occurs at night, which can be the case if the load power is important, another time interval is selected.

A special attention is required by “homogeneous” and “heterogeneous” scenarios. The homogeneous scenario consists in assuming that all the feeders behave similarly (when the voltage increases in one feeder due to the generation connected to it, the voltage of the other feeders also increase and the OLTC can tap to avoid an over-voltage situation). In such a case, the voltage spreading is limited and the voltage band remaining available for the OLTC is significant, resulting in large hosting capacity values which are in reality not always expectable.

In order to evaluate the impact of a feeder with a reduced generation on the hosting capacity, a “heterogeneous scenario” has been created. Thus in the Table 8 two different scenarios are presented for each OLTC-based solutions: the “homogeneous scenario” corresponding to the standard scenario in which every feeder has a large generation capacity; the “heterogeneous scenario” for which the generation installed capacity of one (the feeder with the largest voltage drop) feeder (identified with “*”) was reduced to 10% of its initial capacity (compared to “AsIs”).

DSO / MV1

		F01	F02	F03	F04	F05	F06	F07	F08
Step 1 - Feeder screening									
	Length (km)	11.9	6.2	38.5	14.2	4.6	5.8	15.1	10.5
	DER number	24	18	87	43	8	19	50	24
	U constraints (%)	100.0	4.0	100.0	100.0	1.4	0.0	100.0	0.0
	I constraints (%)	0.0	96.0	0.0	0.0	98.6	100.0	0.0	100.0
	HC_{50} (MW)	2.7	5.4	1.0	3.5	4.0	6.4	2.1	6.4
Step 2.1 - Worst case scenarios									
	Umax (p.u.)	1.042	1.042	1.038	1.037	1.035	1.011	1.035	1.033
	Umin (p.u.)	0.985	0.991	0.954	0.972	0.997	0.995	0.954	0.985
	Lmax (%)	47.0	99.2	16.2	54.7	99.7	88.1	32.8	91.7
Step 2.2 - HC determination									
As Is	*HC (MW)*	3.0	5.4	1.2	4.2	4.1	7.2	2.6	7.0
	Umax (p.u.)	1.046	1.042	1.046	1.046	1.035	1.013	1.046	1.036
	Lmax (%)	51.5	100.0	19.3	67.1	100.0	100.0	41.9	100.0
Max	*HC (MW)*	5.4	-	3.5	6.4	-	-	5.8	-
	ΔHC (%)	81	-	200	54	-	-	121	-
	Umax (p.u.)	1.026	-	1.046	1.021	-	-	1.031	-
	Lmax (%)	100.0	-	69.6	100.0	-	-	99.9	-
VVC	*HC (MW)*	4.4	-	1.7	5.5	-	-	3.7	-
	ΔHC (%)	48	-	42	33	-	-	43	-
	Umax (p.u.)	1.046	-	1.046	1.044	-	-	1.046	-
	Lmax (%)	84.4	-	30.4	100.0	-	-	68.0	-
WAC Homogeneous	*HC (MW)*	5.1	-	2.0	6.4	-	-	4.8	-
	ΔHC (%)	71	-	75	54	-	-	82	-
	Umax (p.u.)	1.041	-	1.041	1.028	-	-	1.041	-
	Lmax (%)	91.3	-	34.5	100.0	-	-	75.6	-
WAC Heterogeneous	*HC (MW)*	3.2	-	1.5	5.2	-	-	*	-
	ΔHC (%)	8	-	25	24	-	-	*	-
	Umax (p.u.)	1.041	-	1.041	1.041	-	-	*	-
	Lmax (%)	51.7	-	20.7	69.4	-	-	*	-
WAC & VVC Homogeneous	*HC (MW)*	5.4	-	2.7	6.4	-	-	5.8	-
	ΔHC (%)	80	-	135	53	-	-	122	-
	Umax (p.u.)	1.026	-	1.041	1.020	-	-	1.033	-
	Lmax (%)	100.0	-	48.8	100.0	-	-	100.0	-
WAC & VVC Heterogeneous	*HC (MW)*	5.2	-	2.2	6.4	-	-	*	-
	ΔHC (%)	74	-	89	55	-	-	*	-
	Umax (p.u.)	1.041	-	1.041	1.032	-	-	*	-
	Lmax (%)	95.4	-	37.0	99.9	-	-	*	-
OPF Homogeneous	*HC (MW)*	5.3	-	3.1	6.4	-	-	5.7	-
	ΔHC (%)	78	-	169	53	-	-	118	-
	Umax (p.u.)	1.026	-	1.041	1.022	-	-	1.031	-
	Lmax (%)	100.0	-	62.0	100.1	-	-	100.0	-
OPF Heterogeneous	*HC (MW)*	5.2	-	2.4	6.3	-	-	*	-
	ΔHC (%)	75	-	102	52	-	-	*	-
	Umax (p.u.)	1.040	-	1.041	1.033	-	-	*	-
	Lmax (%)	100.0	-	43.4	100.0	-	-	*	-
FixCurt	*HC (MW)*	4.2	7.7	1.6	5.6	5.7	10.0	3.7	9.0
	ΔHC (%)	40	42	41	35	42	39	41	29
	Umax (p.u.)	1.046	1.042	1.046	1.046	1.035	1.013	1.046	1.036
	Lmax (%)	51.3	100.0	19.2	65.8	100.0	100.0	41.6	100.0

Table 8 (Expected hosting capacity for the exemplary network and all the considered solutions)

6.1.2.2 SUT="Max"

Figure 23 shows the hosting capacity increase for the ideal solution "Max" (assuming a full observability and controllability). This figure is a graphical representation of the hosting capacity increase provided in Table 8. The lower bars show the hosting capacity of the reference (first) solution, here "AsIs". The colour (blue or red) shows whether the feeder is voltage or current-constrained respectively. The upper bars show the hosting capacity increase which can be reached with the second solution, here "Max". For this solution which intends to control the voltage to increase the hosting capacity, the hosting capacity increase is only computed for feeders which are voltage-constrained in the reference scenario ("AsIs"). For this reason, lower bars which are red do not have any upper bar[32].

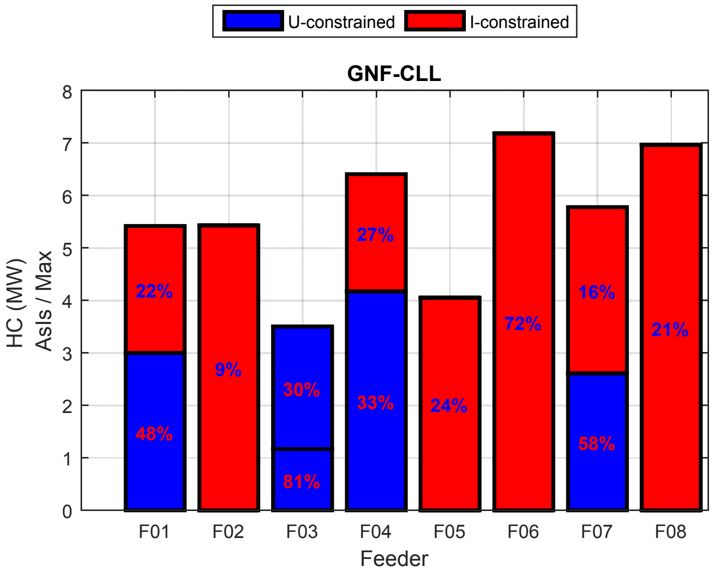


Figure 23 (Hosting capacity increase – "Max" vs. "AsIs")

The percentages shown in the bars represent the reserve to the non-limiting constraint (current for voltage-constrained feeders and voltage for current-constrained feeders, see Figure 24). The colour shown in the bars represents the reserve to the non-limiting constraint. For example, for feeder F03 which is voltage-constrained for "AsIs" (blue colour), the hosting capacity is about 1.2 MW and the reserve to the maximum loading limit is 81 % (percentage shown in the lower blue bar ("AsIs")). Implementing the solution "Max" enables to increase the hosting capacity by 2.3 MW but leads to an increase of the loading (due to the reactive power consumption and to the additionally connected generation→reduction of the reserve to maximal loading to 30 %: the percentage shown in the upper blue bar for "Max"). This type of information is very important to analyse the real deployment potential of specific smart grids solutions since solutions which do not have an (accurate) observer of the line loading cannot be implemented.

[32] The only solution which is computed for current-constrained feeders is "FixCurt" (curtailment to 70 % of the installed power).

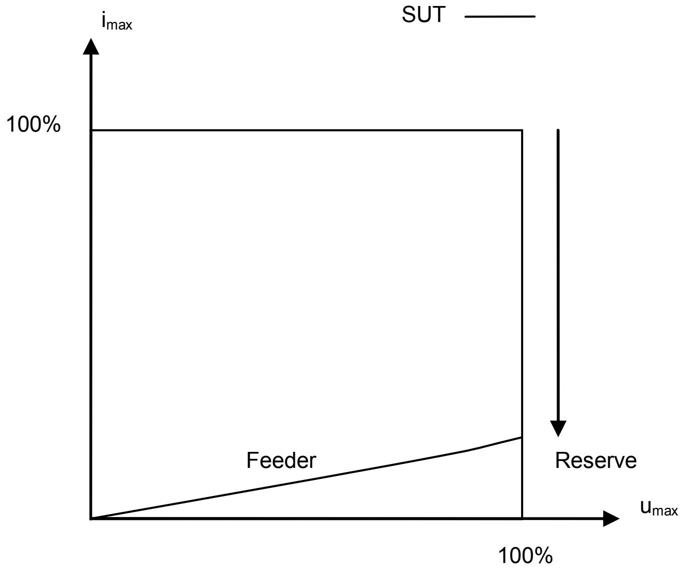


Figure 24 (Definition of the reserve to the non-limiting constraint;
Example of voltage constrained feeder)

Figure 23 shows:

- The hosting capacity can be increased between 54 % and 200 % (see also Table 8) with the solution "Max".
- However, taking into account that most of the solutions are devoted to voltage control and do not observe accurately the loading, these figures must be carefully considered.
- From the four feeders which are voltage-constrained for the reference ("AsIs"), only one remains voltage-constrained with the solution "Max".

6.1.2.3 SUT="VVC"

Figure 25 shows the same type of analysis for the solution "VVC" compared to the reference "AsIs".

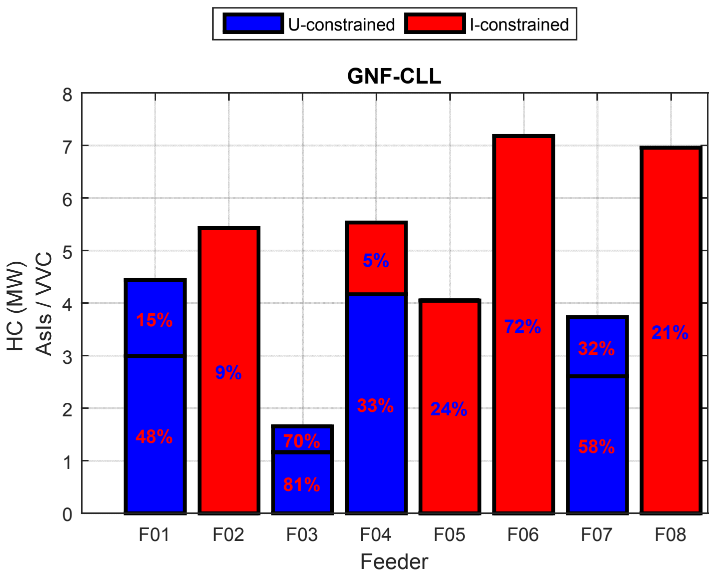


Figure 25 (Hosting capacity increase – "VVC" vs. "AsIs")

This figure shows:

- The hosting capacity can be increased by 33 % to 48 % (see also Table 8) with the solution “VVC”.
  This hosting capacity increase is in line with equations (2) and (3) [30]. Using this rough estimation with the median R/X ratio of about 1.5 for the feeder F01 and cosφ=0.9 leads to an increase of the hosting capacity by a factor 1/(1-0.48/1.5)=1.49 (+49 % increase) which is very close to the obtained value (+48 % in Table 8).

$$\Delta U \approx \frac{R \cdot P}{U_N^2} \cdot \left[1 - tan(\varphi) \cdot \frac{1}{R/X}\right] \tag{2}$$

$$\Delta HC \approx {}^{1}\Big/\left[1 - tan(\varphi) \cdot \frac{1}{R/X}\right] \tag{3}$$

ΔU	Relative voltage rise
ΔHC	Hosting capacity increase
φ	Displacement angle (according to cosφ=0.9)
R/X	R/X ratio at the node of connection
P	Nominal active power
U_N	Nominal voltage

- However, taking into account that the solution “VVC” does not provide any observation of the loading, the increase of hosting capacity can actually be fully used only for feeders which remain voltage-constrained (a small reserve to take into account inaccuracies in the network planning should be foreseen).
- From the four feeders which are voltage-constrained for the reference (“AsIs”), three remain voltage-constrained (with a sufficient reserve >10 %) with the solution “VVC”.
- This means that this solution has an actual deployment potential in three out of four voltage-constrained feeders (among the eight feeders).
- These three feeders are, as expected, the feeders with the initially lowest hosting capacity having a large reserve to the current-constraint or in other words being purely voltage-constrained (very rural area), which is an additional benefit. Indeed, although this solution is not deployable in current-constrained feeders (here F02, F05, F06 and F08), these feeders already have a high hosting capacity (between 4.2 MW and 7.2 MW) which is probably even higher than the actual potential in terms of available roof space or land space for PV (or Wind Power).

6.1.2.4 SUT="WAC"

Figure 26 shows the same type of analysis for the solution "WAC" considering a homogeneous scenario (all feeders having a strong DRES penetration, see chapter 5.5.2) compared to the reference "AsIs".

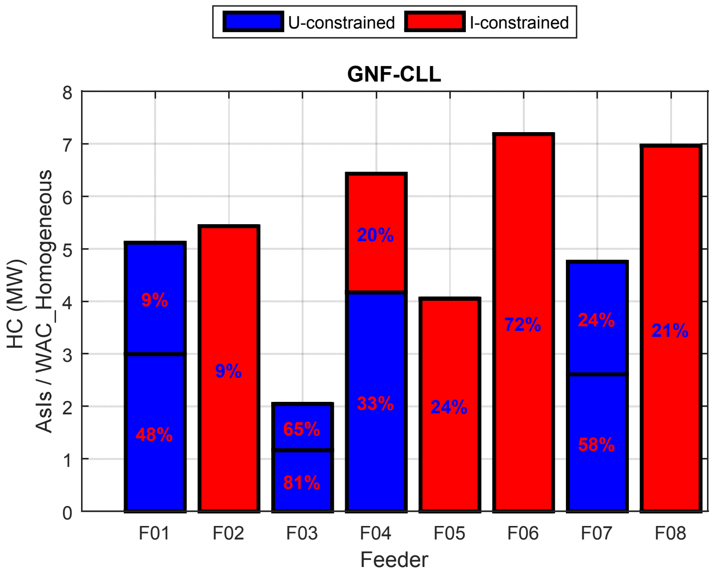


Figure 26 (Hosting capacity increase – "WAC_Homogeneous" vs. "AsIs")

This figure shows:

- The hosting capacity can be increased by 54 % to 82 % (see also Table 8) with the solution "WAC" for a homogeneous distribution of DRES among feeders. This hosting capacity increase is significantly higher (+71 % on average) compared to one which can be reached with the solution "VVC" (+41 % on average) for this network.
- However, taking into account that the solution "WAC" does not provide any observation of the loading, the increase of hosting capacity can actually be used only for feeders which remain voltage-constrained (a small reserve to take into account inaccuracies in the network planning should be foreseen).
- From the four feeders which are voltage-constrained for the reference ("AsIs"), three remain voltage-constrained (with a sufficient reserve >10 %) with the solution "WAC" (the same as for "VVC").
- This means that, as the previous solution ("VVC"), this solution has an actual deployment potential in three out of four voltage-constrained feeders (among the eight feeders).
- The homogeneous scenario (all feeders behave similarly) is favourable to the solution "WAC". In this case (i.e. strong voltage rise at the same time), the OLTC can lower the voltage at the primary substation and release part of the voltage band for the generation. While the average hosting capacity increase in the homogeneous scenario reaches +71 %, it reaches only +19 % for the inhomogeneous case. Indeed, in the inhomogeneous scenario, the DRES penetration has been limited to 10 % of the hosting capacity for the feeder with the highest voltage drop. Therefore, the OLTC potential to lower the voltage at the primary substation is limited. In that case the increase of hosting capacity in the other feeders is blocked.

6.1.2.5 SUT="WAC&VVC"

Figure 27 shows the same type of analysis for the solution "WAC&VVC" considering a homogeneous scenario (all feeders having a strong DRES penetration) compared to the reference "AsIs".

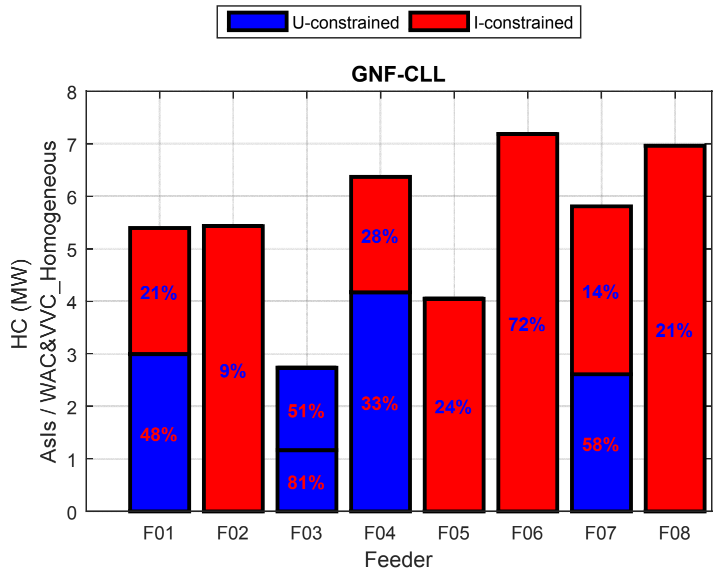


Figure 27 (Hosting capacity increase – "WAC&VVC_Homogeneous" vs. "AsIs")

This figure shows:

- The hosting capacity can be increased by 53 % to 122 % (see also Table 8) with the solution "WAC&VVC" for a homogeneous distribution of DRES among feeders. This hosting capacity increase is higher (+97 % on average) compared to one which can be reached with the solution "WAC" (+71 % on average) for this network.
- However, taking into account that the solution "WAC&VVC" does not provide any observation of the loading, the increase of hosting capacity can actually be applied only to feeders remaining voltage-constrained (a small reserve to take into account inaccuracies in the network planning should be foreseen).
- From the four feeders which are voltage-constrained for the reference ("AsIs"), only one remains voltage-constrained with the solution "WAC&VVC" (the same as for "Max").
- This means that this solution has a lower actual deployment potential (only one out of four voltage-constrained feeders (among the eight feeders)).
- The inhomogeneous scenario leads, as expected, to a smaller hosting capacity increase for the only feeder which remains voltage-constrained (+89 % instead of +135 %).

6.1.2.6 SUT="OPF"

Figure 28 shows the same type of analysis for the solution "OPF" considering a homogeneous scenario (all feeders having a strong DRES penetration) compared to the reference "AsIs".

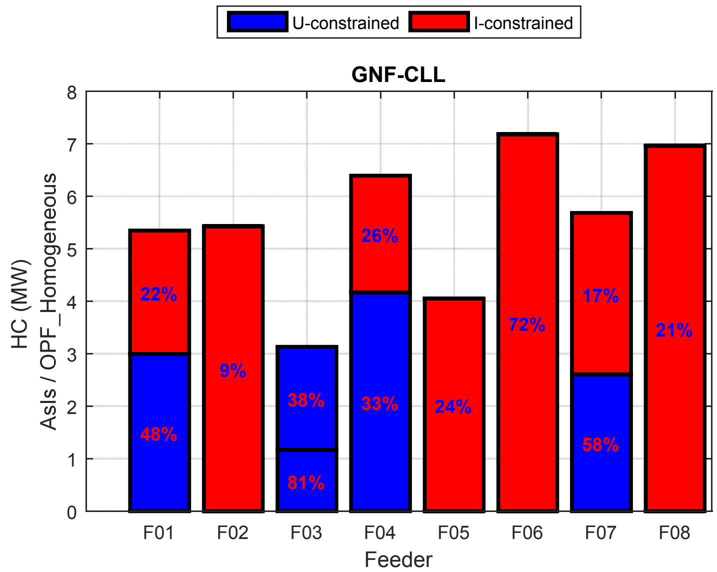


Figure 28 (Hosting capacity increase – "OPF_Homogeneous" vs. "AsIs")

This figure shows:

- The increase of the hosting capacity for the solution "OPF" is slightly lower than for the solution "Max" due to the fact that the observer/monitoring is not ideal (a voltage margin of 0.5 % accounting for the accuracy of the observers has been considered). This is particularly visible on the only feeder which remains voltage-constrained (F03). In this case the increase of hosting capacity amounts +169 % instead of +200 % for "Max".
- As for the previous solution and for "Max", only one out of the four feeders which are voltage-constrained for the reference ("AsIs") remains voltage-constrained.
- The inhomogeneous scenario leads, as expected, to a smaller hosting capacity increase for the only feeder which remains voltage-constrained (+102 % instead of +169 %).

6.1.2.7 SUT="FixCurt"

The hosting capacity for the solution "FixCurt" (all generators limited to 70 % of the nominal power) which can be implemented to voltage and current-constrained feeders is shown in Figure 29.

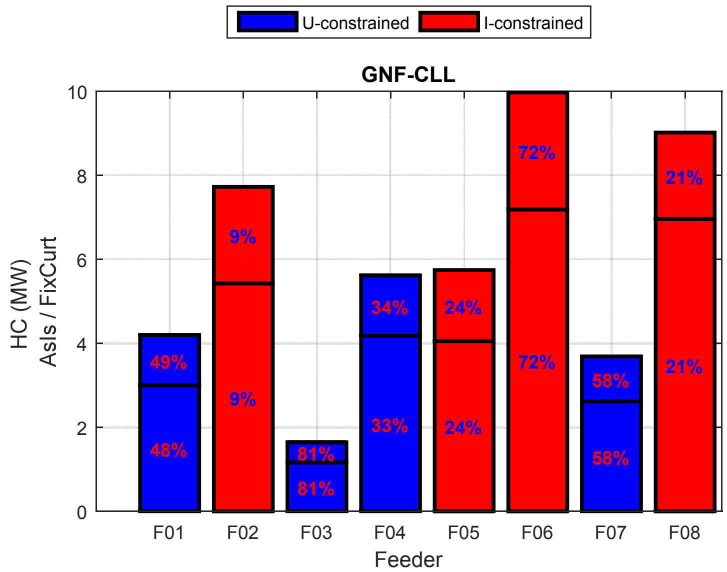


Figure 29 (Hosting capacity increase – "FixCurt" vs. "AsIs")

This figure shows:

- The hosting capacity increase is not exactly the same for every feeder[33]. The maximum theoretical increase is 43 % which is reached by most of the feeders except F04 and F08 (29 % and 35 %);
- Unlike the other solutions, it can be applied to all type of feeders and the reserve or loading or voltage is unchanged;
- The average increase of hosting capacity is of the same order of magnitude as "VVC" (+39%).

6.1.3 Detailed analysis of the simulation cases

6.1.3.1 Planning of the SUTs

In order to implement some of the solutions into the detailed simulations (or in practise), an analysis of the network must be performed to determine the location of (voltage) sensors. This is in particular necessary for the solutions "WAC" and "WAC&VVC" (location of dedicated field measurements).

[33] Considering a linear relation between the maximum power of the DRES and the hosting capacity, a curtailment at 70% would increase the hosting capacity by a factor 1/0.7=1.43, i.e. by 43%. In case the DRES are not a full power during the critical time, then the potential of increase is reduced (If the power is at 90%, then the maximum increase is equal to 0.9/0.7=1.29 i.e. 29%).

For this purpose, the concept of critical nodes introduced in [35] has been used. The critical nodes are determined by the following two-step process:

1) Identification of “extreme nodes”
   Get the list of nodes exhibiting the highest or lowest voltage levels in the network during at least one instant in the considered time frame (e.g. one year or here the whole Monte-Carlo samples).
2) Grouping of “extreme nodes” into “critical nodes”
   Since many of the extreme nodes are “neighbouring nodes” with very similar voltage variations (the voltage of one node is sometimes higher and sometimes lower than the voltage of the neighbour node, although the difference is very small at any time). This grouping is made by grouping nodes for which the maximal difference between the voltage profiles along the whole considered time frame is smaller than a threshold. A threshold of 0.5 % corresponding to the usual accuracy of voltage transducers has been chosen. This means that extreme nodes whose voltage profile (for the whole considered time frame) deviates by less than 0.5 % are grouped and only one sensor would be installed.

Taking the exemplary network, a set of 28 extreme nodes is identified, which can be grouped into 12 groups meaning that in total 12 sensors would be necessary to implement the observer/monitoring consisting of dedicated measurements for the considered network.
Figure 30 shows the result of the grouping of the extreme nodes into the critical nodes in the form of a tree. The leaves of the tree are the extreme nodes and the horizontal line between two nodes (leaves) or two group of nodes (leaves) represent the maximal voltage deviation between the corresponding voltage profiles. The horizontal red line shows the 0.5 %-threshold used to group the nodes. All the leaves having a common branch below this line are grouped equipped with one sensor only.

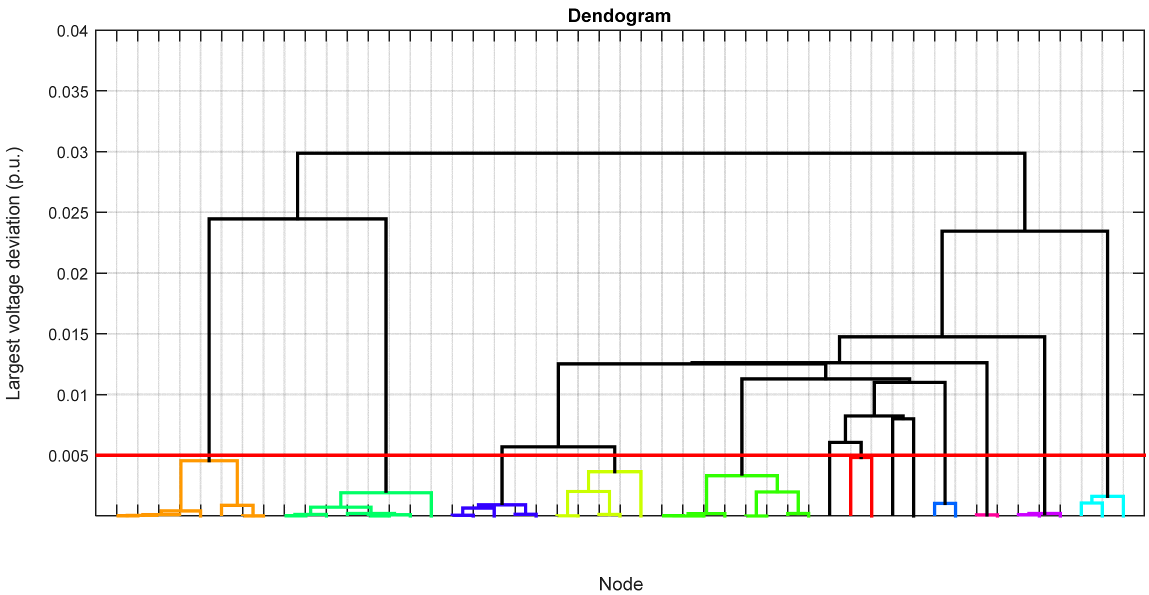


Figure 30 (Determination of the number of critical nodes – Dendrogram for the exemplary network)

The results of this analysis are summarised in Table 9. This table shows that most of the feeders should be equipped with one or two voltage measurements[34]. The reader should notice that not only voltage-constrained feeders but also current-constrained feeders can need voltage sensors. Indeed, current-constrained feeders might experience non-negligible voltage drops which must be taken into account by the OLTC control in the solution “WAC”.

DSO/MV1	F01	F02	F03	F04	F05	F06	F07	F08
Feeder properties								
Length (km)	11.9	6.2	38.5	14.2	4.6	5.8	15.1	10.5
DER number	24.0	18.0	87.0	43.0	8.0	19.0	50.0	24.0
U constraints (%)	100.0	4.0	100.0	100.0	1.4	0.0	100.0	0.0
I constraints (%)	0.0	96.0	0.0	0.0	98.6	100.0	0.0	100.0
HC_{50} *(MW)*	2.7	5.4	1.0	3.5	4.0	6.4	2.1	6.4
Number of critical nodes	2	2	1	2	2	0	1	2

Table 9 (Number of critical nodes per feeder – exemplary network)

6.1.3.2 Validation of the HC

In Step 3, the solutions are implemented and the amount of generation is equal to the expected hosting capacity calculated in Step 2. However, the simulation is not limited to the critical times but is done for the full set of samples. The analysis of the results (in particular the voltages and loadings), is shown in this chapter, as the validation of the results and of the methodology.

6.1.3.2.1 SUT=”AsIs”

Figure 31 shows the boxplots of the maximum and minimum feeder voltages, as well as the maximum feeder loading. The parameters of the variables that are illustrated on the boxplot are the minimum (lower black line), the 5th percentile (lower blue line), the median (red line), the 95th percentile (upper blue line) and the maximum (upper black line). For example, considering the maximum voltage of F01, the minimum, 5th percentile and the median are all equal to 1.0 p.u. (i.e. the voltage at the slack), the 95th percentile is equal to 1.03 p.u. and the maximum is 1.046 p.u. The figure shows that with the hosting capacity calculated in Step 2 for the critical times, the loading and voltage limits are never violated on the total set of Monte-Carlo samples. Thus, the amount of generation calculated in Step 2 is the real hosting capacity of the network for “AsIs”. Moreover, the 95th percentile of the maximum feeder voltage remains below 1.03 p.u. for all the feeders, meaning that the operation of the network is safe most of the time. The same remark can be made regarding the loading,of which the 95th percentile is lower than 70%.

[34] In order cover N-1 situations, further sensors can usually be necessary.

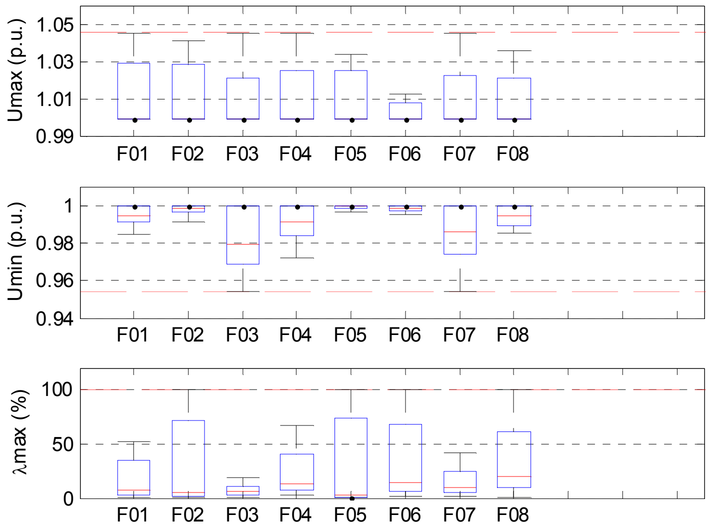


Figure 31 (Boxplot of the loading and voltages for “AsIs” – exemplary network)

6.1.3.2.2 SUT=”FixCurt”

The analysis of Figure 32 shows that none of the constraints is violated. This means that for the solution “FixCurt” also the estimated hosting capacity has been accuractely determined. Although the minimum and maximum values of the voltages and loading are equal for “AsIs” and for the solution “FixCurt”, the hosting capacity difference leads to a general increase of these values: considering the 95th percentile of the maximum feeder loading, its average value is increased from 48% to 64%, thereby impacting the losses. Similarly, the 95th percentile of the maximum feeder voltage is increased from 1.023 p.u. to 1.032 p.u.

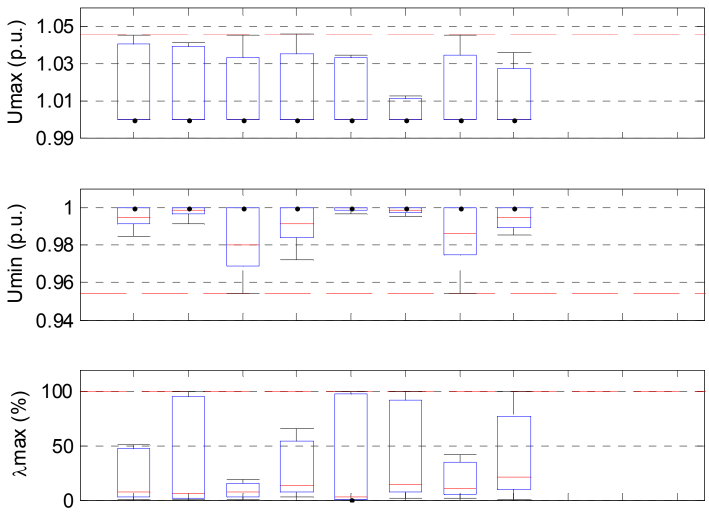


Figure 32 (Boxplot of the loading and voltages for “FixCurt” – exemplary network)

6.1.3.2.3 SUT="VVC"

For current-constrained feeders (F02, F05, F06 and F08 for "AsIs") the installed generation has not been increased since they cannot benefit from the solution "VVC". For this reason, the voltage increase is not visible on Figure 33. This figure shows again a very good agreement between the results of Step 2 (reduced set of samples) and Step 3 (all Monte-Carlo samples).
Even if the amount of generation installed in each feeder is very similar between "FixCurt" and "VVC", the maximum voltage is generally lower in the second case because of the droop control which is active for voltages above 1.009 p.u.[35]. Nevertheless, the loading is consequently increased because of the reactive power consumed by the generators: from 27 % for "AsIs" to 47 % for "VVC" on average for all the feeders (considering the 95 % percentile), relative to 38 % for "FixCurt".

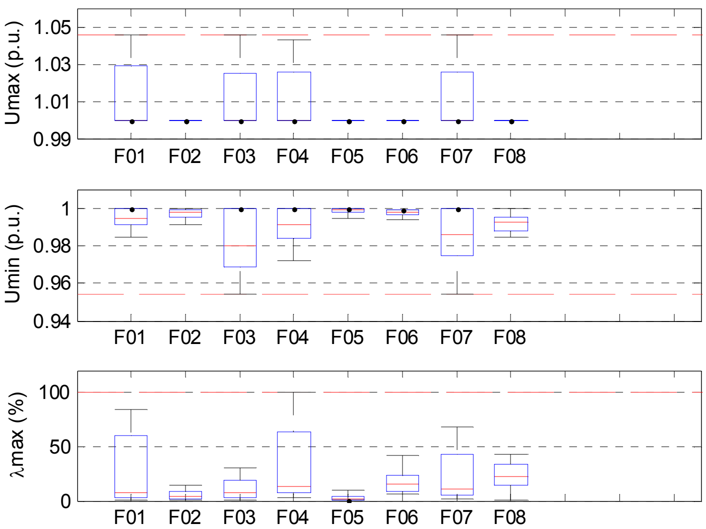


Figure 33 (Boxplot of the loading and voltages for "VVC" – exemplary network)

6.1.3.2.4 SUT="Max"

Unlike the previous case-study, a few loading violations are observed in several feeders. Regarding the feeders which were loading-constrained when being scaled in Step 2 (i.e. F01, F04 and F07 as shown in Table 8), these small violations are caused by the fact that the critical time (with the highest voltage spreading) is generally obtained for high loading condition (leading to strong voltage drops on some feeders) which is therefore not the worst-case from the loading point of view. However, the violations are not significant since the maximum loading observed is 104 %. It can be tolerated, especially as the relatively low 95th percentile indicates that the loading remains low most of the time. Concerning the feeders which are not scaled-up during Step 3 (i.e.F02, F05, F06 and F08 as they are loading constrained), the reason for the small violations is that the loading is already substantial without any scaling (over 99 % for feeders F02, F05, and F08 as shown in the section 'Step 2.1 in the Table 8). It is very likely that the overloading is caused by some reactive power produced or consumed by the generators due to the OPF. The maximum voltage in F03 is

[35] In this network, the maximum voltage set by the DSO is equal to 1.046 p.u. Considering that the generators starts consuming power starting from 20% of voltage rise with the implemented droop control, this leads to a value of 1.009 p.u. (=1+0.2*(1.046-1))

equal to 1.046 p.u., which is the limit reached in Step 2: from a voltage band perspective, the control strategy developed seems to be optimal.

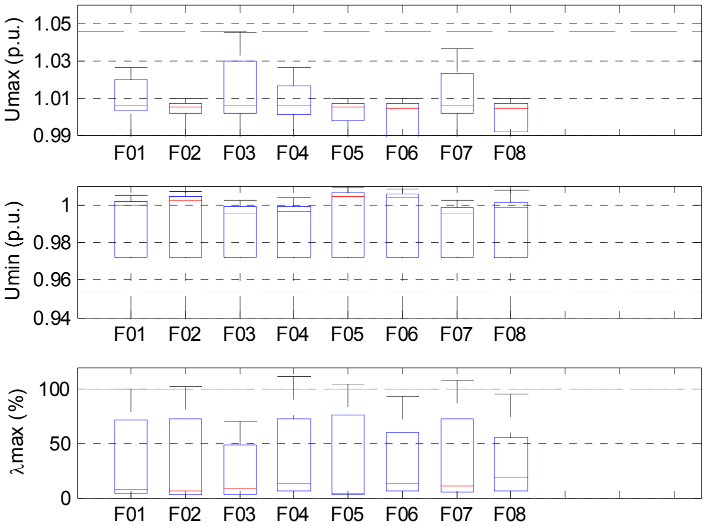


Figure 34 (Boxplot of the loading and voltages for "Max" – exemplary network)

6.1.3.3 "Side effects" of enhancing the hosting capacity with smart grids solutions

This chapter presents the results of the analysis of some "side effects" which are the impact of the solutions on the network losses, the impact on the reactive power exchange with the upstream network and the impact on the curtailed energy.

6.1.3.3.1 Impact on losses

The network losses as well as the power balance have been exported for all the simulations. The energy efficiency KPI introduced in D2.2 has been evaluated according to the following formula:

$$\eta = \frac{W_{load} + W^{-}_{Upstream}}{W_{DRES} + W^{+}_{Upstream}} \tag{4}$$

W_{load}	Energy consumed by the loads
W_{DRES}	Energy injected by the generators (DRES)
$W^{-}_{Upstream}$	Energy delivered by the upstream network
$W^{+}_{Upstream}$	Energy injected into upstream network

This KPI has been evaluated for the exemplary network, for each feeder separately; the results are shown in Figure 35. This figure shows that the average efficiency is about 99.0 % for "AsIs" and 98.1 % for the "VVC" solution (decrease of about 0.8 %).

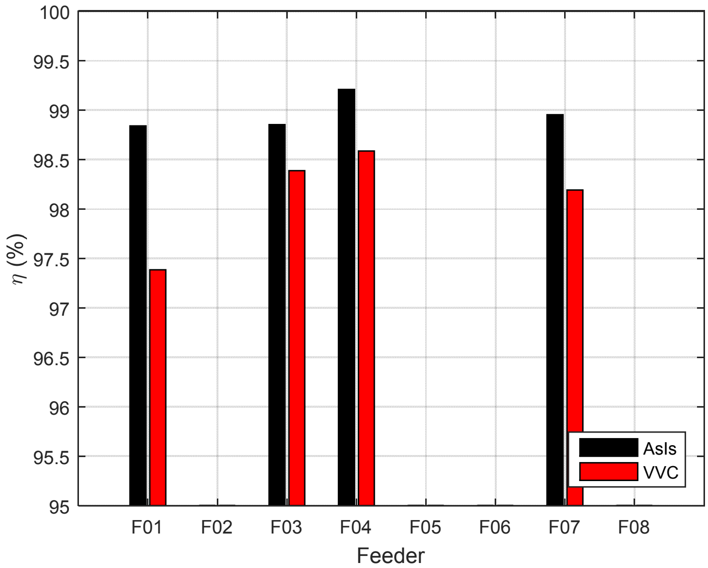


Figure 35 (Energy efficiency KPI: "AsIs" vs. "VVC" – exemplary network)

The same analysis has been done for all the considered feeders. The results are presented in chapter 6.2.3.3.

6.1.3.3.2 Impact on reactive power exchange with the upstream network

With the publication of the Network Code on Demand Connection [36], the relevance of the reactive power exchange at the border between transmission and distribution networks has increased. This code requires that "*For Transmission Connected Distribution Networks, the actual Reactive Power range specified by the Relevant Network Operator shall not be wider than 0.9 Power Factor of the larger of their Maximum Import Capability or Maximum Export Capability in import to 0.9 Power Factor of their Maximum Export Capability in export, except in situations where either technical or financial system benefits are demonstrated by the relevant TSO and the Distribution Network Operator through joint analysis*" and that "*Transmission Connected Distribution Networks shall have the capability at the Connection Point to not export Reactive Power (at nominal Voltage) at an Active Power flow of less than 25% of the Maximum Import Capability, except in situations where either technical or financial system benefits are demonstrated by the Relevant TSO and the Distribution Network Operator through joint analyse, while respecting the provisions of Article 9(3)*".

Although similar requirements were already in force (e.g. Belgium with 3.4 €/MVArh according to [37]), charging was not always systematically implemented in most countries.

Acknowledging the importance of this issue, the reactive power exchanged between the considered (MV) networks and the upstream networks (HV) have been investigated. The reader should remember that in some countries, the (upstream) HV networks (sub-transmission) are operated by the DSO (e.g. 110 kV network in Germany and Austria) and in other countries they are operated by the TSO (e.g. TSO operating all networks with nominal voltage above 45 kV in France). This means that the reactive power exchange computed for the considered MV networks is not always fully relevant since there is, on some cases, one additional voltage level between the considered networks and the transmission network.

Figure 36 shows the distribution of the reactive power balance (consumer arrow system) for the reference (“AsIs”) for the exemplary network. The active and reactive power values are normalised to the maximum apparent power as mentioned in [36] and the cosφ=0.90 limits are represented by the red lines. On this figure, black areas represent operation conditions which are very frequent during the year. This figure shows that the network is mostly operated with a small active power demand (less than 30 % of the annual peak) and that the annual peak corresponds to the reverse power flow toward the upstream network due to the fact that the amount of generation is high (equal to the hosting capacity).

Figure 37 shows the same type of graphic obtained for the solution “VVC”. This figure shows a shift of the operation points corresponding to the reverse power flow toward reactive power consumption (P<0 and Q>0). A comparison between the reactive energy over the whole year shows that the solution “VVC” leads to a large increase of the consumed reactive energy corresponding to operation points below cosφ=0.90 (from 6805 MVArh to 14322 MVArh). Considering as an example the costs mentioned previously would lead to an annual bill of more than 40 k€ for this primary substation. This issue has been addressed in [38], where the authors mention even higher costs (more than 60 k€ for some primary substations) for networks with DRES. The reason for this is the reduction of the active power consumption with an unchanged level of reactive power flows – reactive power excess under light loading conditions in purely cable networks. With such high costs, the authors of [38] justify the installation of compensation equipment or the compensation of this reactive power by generators themselves.
As a conclusion of this analysis, the amount of reactive energy additionally consumed due to the local voltage control seems to be non-negligible and deserves some attention.

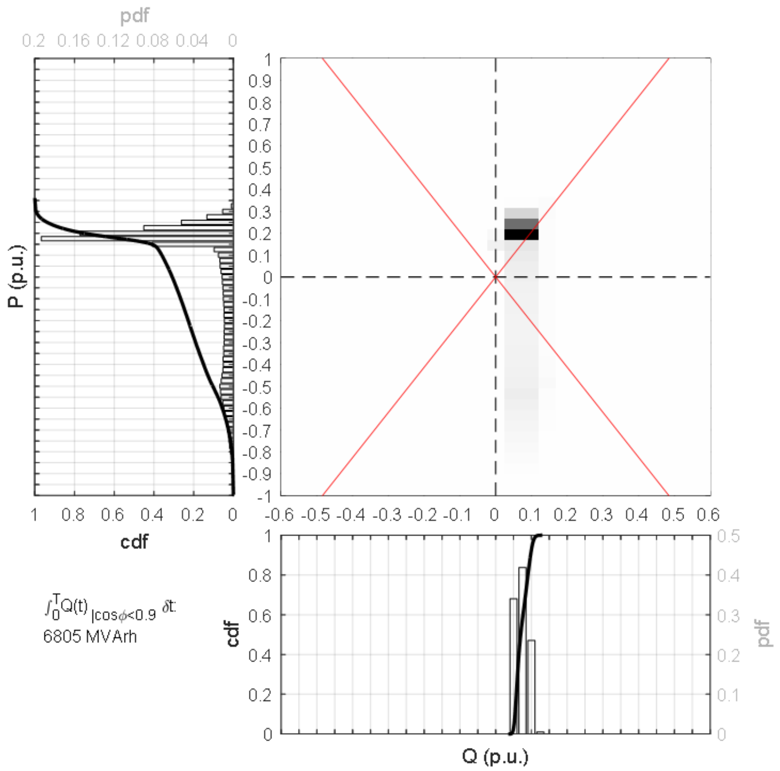


Figure 36 (Reactive power exchange with the upstream network – Q/P diagram “AsIs” – exemplary network)

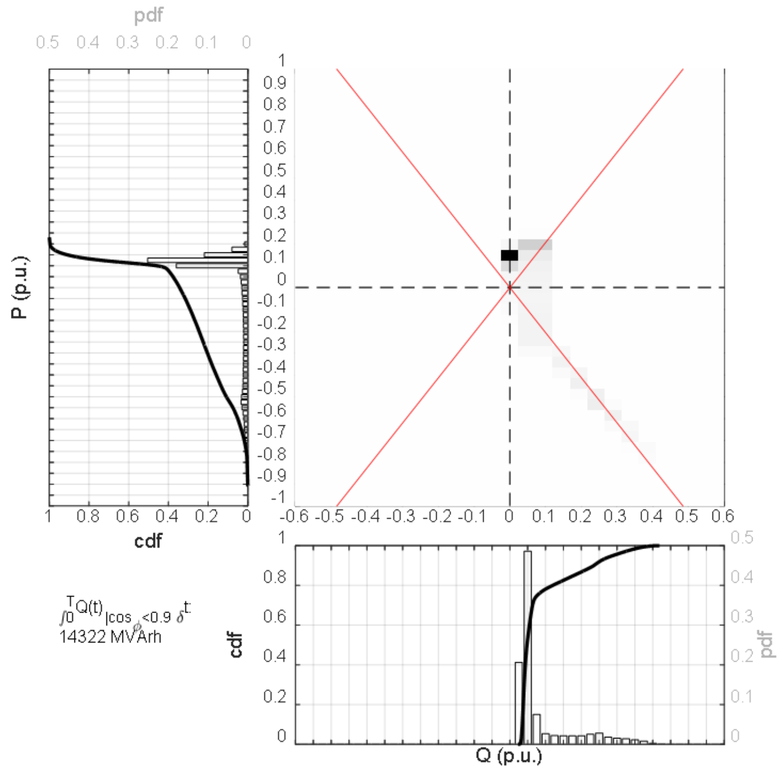


Figure 37 (Reactive power exchange with the upstream network – Q/P diagram "VVC" – exemplary network)

6.1.3.3.3 Impact on curtailment

The benefits of active power curtailment (here curtailment to 70 % according to [10]) have been quantified in chapter 6.1.2.7. In general, the maximal benefit can be easily estimated: reducing the maximum injected power to 70 % allows increasing the installed power by 1/0.7=1.43 (+43 %). A more detailed analysis is provided in chapter 6.1.2.7.

The amount of curtailed energy can be easily computed and depends on the location of the (PV) generator. Figure 38 shows the duration curve for the six IGREENGrid countries, based on the PV generation data used in this project (see chapter 5.3.2 – median installations have been used here). This figure shows that the major difference between southern European countries and central European countries is not so much in the high power values but on the middle part of the curve (power below 75 % of the maximal power). The annual yield of the chosen installations which is shown in Table 10 (first line) varies between about 1000 kWh/kWp (installation in Germany) and 1600 kWh/kWp (installation in Spain). Since it is not possible to define one typical PV installation per country (e.g. large difference between installations in the north and in the south of France), these installations should be considered as exemplary installations.

The 70 %-rule has been applied to the available power measurements from the selected PV installations in order to evaluate the curtailed energy per year. The results are shown in Table 10 (second line). Due to the shape of the duration curve (see previous analysis), the highest relative curtailment levels are not reached for installations in Southern Europe which have a larger yield but in central Europe (the curtailed energy varies between 2.9 % and 6.7 %). In reality, the curtailed energy is expected to be smaller since the 70 % limitation is applied to the installed power (kWp) and installations in central Europe usually seldom reach the nominal (kWp) power. This analysis therefore shows that with a small impact on the yield, the hosting capacity can be increased by up to 43 %.

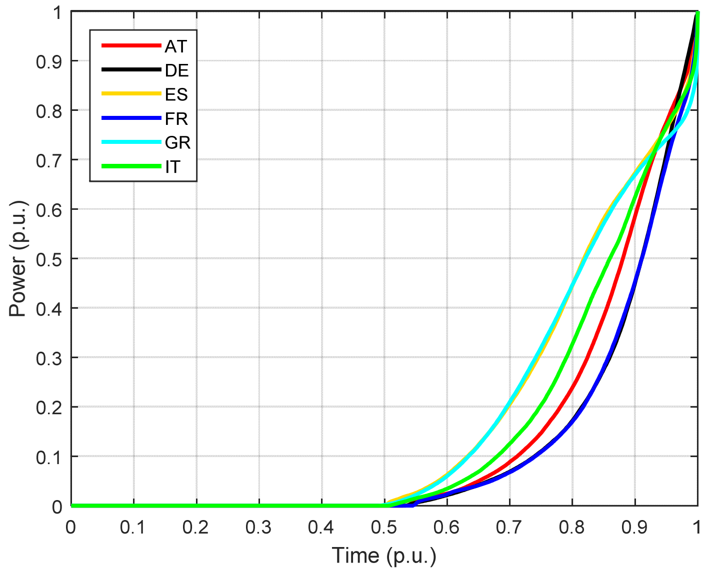


Figure 38 (Duration curve of the generated power of selected PV installations in the six IGREENGrid countries – 5 minutes average power, normalised to the maximum)

While an evaluation of the curtailed energy is rather simple for the solution fix curtailment (done previously), it is much more complex for the solution VoltWatt Curtailment ("VWC" or P(U) here). In theory, a P(U) control should lead to lower curtailment values (as e.g. reported in [39]). The remaining part of this chapter tackles this question and provides a discussion on the real benefit of this solution.

Since active power curtailment necessarily implies a loss of revenues for the generator owner, these generator owners or investors will request an estimation of the curtailed power or a logging of it. Measuring the curtailed power with a sufficient accuracy (e.g. 0.2 %) is not possible since the available power cannot be measured with a sufficient accuracy (even for large installations which usually have a detailed monitoring). Moreover, estimating the curtailed energy by comparing installations or using historic would lead to an error which is most probably even larger than the curtailed energy to be measured.

Having acknowledged the impossibility to measure the curtailed energy with a sufficient accuracy, the only remaining possibility is to evaluate the duration of the curtailment (how many hours per year the installation had to be curtailed). This simple evaluation is one of the practicable solutions mentioned in [40] and is rather simple to implement since inverters can log the amount of hours in which they had to move away from maximum power point [30]. If only the activation time of the curtailment is available, the yield reduction can only be assessed with a worst-case evaluation: assuming that all the power had to be reduced[36]. This conservative assumption, which is necessary due to the impossibility to accurately measure the available power, would lead to a significant reduction of the benefits of this solution. In order to analyse this effect, the total duration which would lead to the same curtailed energy as the 70 %-rule has been calculated for the six installations (Table 10), showing that the power could be reduced (to zero) for only between 50 and 81 hours in order to reach exactly the same curtailment as for the 70 %-rule.

[36] In practise, the actual output power could be considered, which would make the assumption less conservative.

The following paragraphs provides a comparison of the fix curtailment to a P(U) control when assuming the same amount of lost energy, considering the necessary worst case assumptions previously mentioned.

In Figure 39, the calculated curtailed energy (assuming a power reduction to zero) corresponding to the curtailed energy for the 70 %-rule (yellow area between the duration curve (red curve) and the 0.7 p.u. horizontal) can be visualised (both yellow areas are equal). The curtailed energy under the worst-case assumption leads to a reduction of the maximal injected power from 1 p.u. to 0.91 p.u.. This rather small reduction of the maximal injected power only represents an increase of the hosting capacity of 9 %. Table 10 (last line) shows that for all the installations, the hosting capacity increase obtained with the worst-case evaluation is rather limited (between 5 % and 18 %) compared to the increase reached by the fix curtailment (up to +43 % for the 70 %-rule).

This means that the conservative evaluation which is necessary due to the impossibility to accurately estimate the curtailed energy, reduces significantly the benefit of active power curtailment. Although the P(U) control leads to a smaller yield reduction, the necessity to use worst-case assumptions to evaluate the curtailed energy gives the 70 %-rule more benefits in terms of hosting capacity increase.

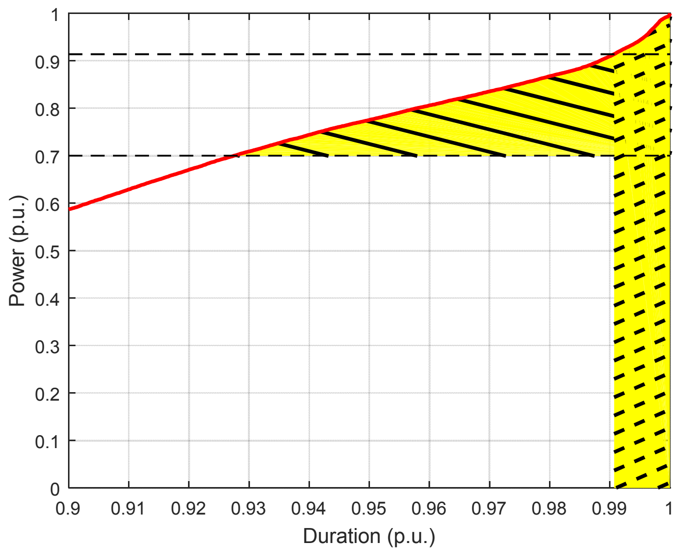


Figure 39 (Curtailed energy for the 70 %-curtailment rule and its conservative equivalent)

Country	**AT**	**DE**	**ES**	**FR**	**GR**	**IT**
Total yield (kWh/kWp)	1208	1022	1593	1001	1566	1347
Curtailed energy (P>0.70 p.u.) (%)	6.4	6.7	4.3	4.8	2.9	4.8
Duration of curtailment (h)	81	70	74	50	51	71
Reduced power (p.u.)	0.91	0.95	0.89	0.90	0.84	0.88
ΔHC (%)	9	5	12	11	18	14

Table 10 (Yield without and with curtailment per country)

Finally, Figure 40 shows, for comparison purpose, the duration curve of a wind and a PV installation (Austria): as expected, the duration curve for the wind generation is less sharp than for the PV. The considered wind power plant has about 2846 full load hours and the PV about 1208 (see also Table 10). For the considered wind power plant, the fix curtailment to 70 % leads to a reduction of the annual yield by more than 13 % which shows that fix curtailment is not applicable to wind power.

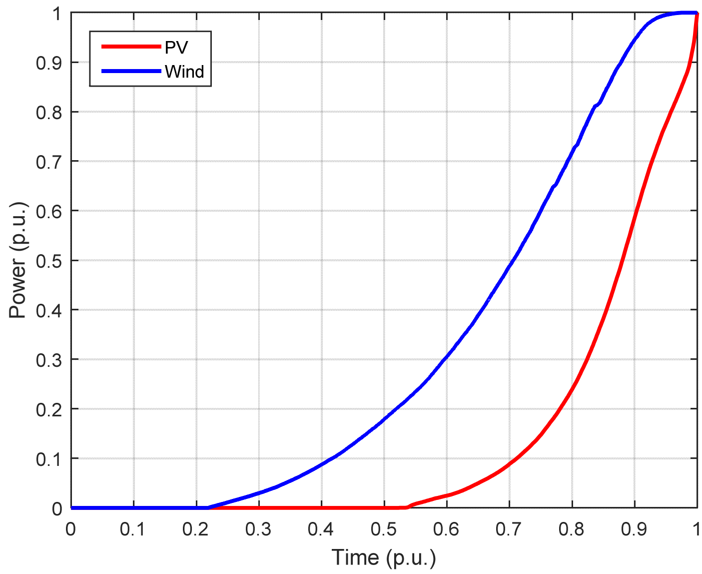


Figure 40 (Duration curve of the generated power for wind and PV (Austria), normalised to the maximum)

6.1.4 Network reinforcement approach

In order to be able to compare the smart grids solutions to the network reinforcement (economic assessment, chapter 9), a common approach to compute the network reinforcement is necessary.
The proposed concept, to compare the performance of solutions on different networks and feeders, shall be considered as an attempt to establish a common base only. Indeed, the exercise of determining the needed network reinforcement for a specific feeder under specific conditions (e.g. DRES penetration) is significantly more complex. Criteria such as the age of assets, reliability issues, cabling programs, etc. significantly impact the decision of when, where and how to reinforce.
Nevertheless, an approach has been implemented and is briefly explained in the following paragraphs.
The reinforcement is determined for each feeder achieving the same hosting capacity as the solution considered. The algorithm used for the computation for a single feeder is presented in Figure 41.

Algorithm: Network reinforcement for one feeder
Set 'trigger' to critical time
Scale-up the generation to reach the hosting capacity
If U-constrained
Repeat
Find the steepest line L
Reinforce L (new parallel line)
Include L in the list of reinforced lines
Run a load flow and get $U_{max,feeder}$
$\Delta U = U_{max,feeder} - U_{max,DSO}$
Until $\Delta U < \varepsilon$
ElseIf λ-constrained
Repeat
Find the most loaded line L
Reinforce L (new parallel line)
Include L in the list of reinforced lines
Run a load flow and get $\lambda_{max,feeder}$
$\Delta\lambda = \lambda_{max,feeder} - \lambda_{max}$
Until $\Delta\lambda < \varepsilon$
EndIf
Export the list of reinforced lines

Figure 41 (Network reinforcement algorithm)

In the first step, a snapshot of the feeder is made for the critical time interval and the generation is scaled-up with the hosting capacity of the solution being considered: for instance, in order to calculate the reinforcement of "FixCurt" for the F01 of the illustration example, the total amount of generation inside the feeder is equal to 4.2 MW (refer to Table 8 results). As a consequence, the feeder will be constrained because no solution is implemented. If the feeder is voltage constrained, the steepest lines are reinforced (with parallel lines, disregarding the type of line or cable[37]) until the maximum voltage of the feeder $U_{max,feeder}$ remains under the limit $U_{max,DSO}$. In case of overloading, all over-loaded lines are reinforced. Finally the list of reinforced lines as well as their length is exported to be further analysed. The evolution of a feeder voltage profile for one iteration of the algorithm is shown in Annex 1.
The results of the computation for each feeder of the exemplary network are presented in Table 11. This table shows that the total line length is above 20 km for one feeder. This outlier is a very long feeder (38.5 km). For this feeder, the computed reinforcement is not realistic: assuming an average cost of about 100 €/m would lead to a total reinforcement cost of more than 3 M€ for this feeder only. In such cases, if the hosting capacity is exhausted, other solutions would be implemented (e.g. building of a new primary substation).

Feeder	F01	F02	F03	F04	F05	F06	F07	F08
Total length (km)	7.7	1.9	34.1	5.1	1.3	0.6	11.9	0.7

Table 11 (Output of the network reinforcement for "Max"– exemplary network)

[37] In reality, cables or lines would be replaced by another with a larger cross-section or would be laid e.g. to split one feeder into several feeders.

6.2 Summary for all the networks

This sub-chapter presents the results obtained for all the DSOs/networks/feeders in an aggregated way. The first three subchapters (6.2.1, 6.2.2 and 6.2.3) correspond to the three steps (see chapters 2.1 and 6.1) and the last sub-chapter shows the results of the network reinforcement according to the concept proposed in chapter 6.1.4.

6.2.1 Feeder screening and classification

As the result of the first step of the proposed methodology, the hosting capacity is determined via a Monte-Carlo simulation varying the DRES scenarios for each feeder. In addition to the hosting capacity, the limiting constraint (voltage or current) is also analysed.

Figure 42 shows the median of the hosting capacity for each feeder of each network of each DSO (the bars are sorted for a better visualisation). The reader should keep in mind that the HV/MV transformers at the primary substation have not been taken into account as explained in chapter 6.1.1, which means that the sum of the hosting capacity for all the feeders of a network might exceed the rated power of the transformer (e.g. 85 MW for ENEL-Network3).

In Figure 42, the colour of the bars shows whether the feeders are voltage-constrained, current-constrained or both (for all DRES scenarios). This figure shows, as expected, that within a network, feeders which are current-constrained usually have a greater hosting capacity than voltage-constrained feeders. Comparisons among networks (from different DSOs) are not straightforward, since the nominal voltages are not identical (the hosting capacity is expected to vary approximately linearly with the nominal voltage for current-constrained feeders and square based on the nominal voltage for voltage-constrained feeders). At lower nominal voltage like for the IB and RWE networks, on average a smaller hosting capacity can be observed.

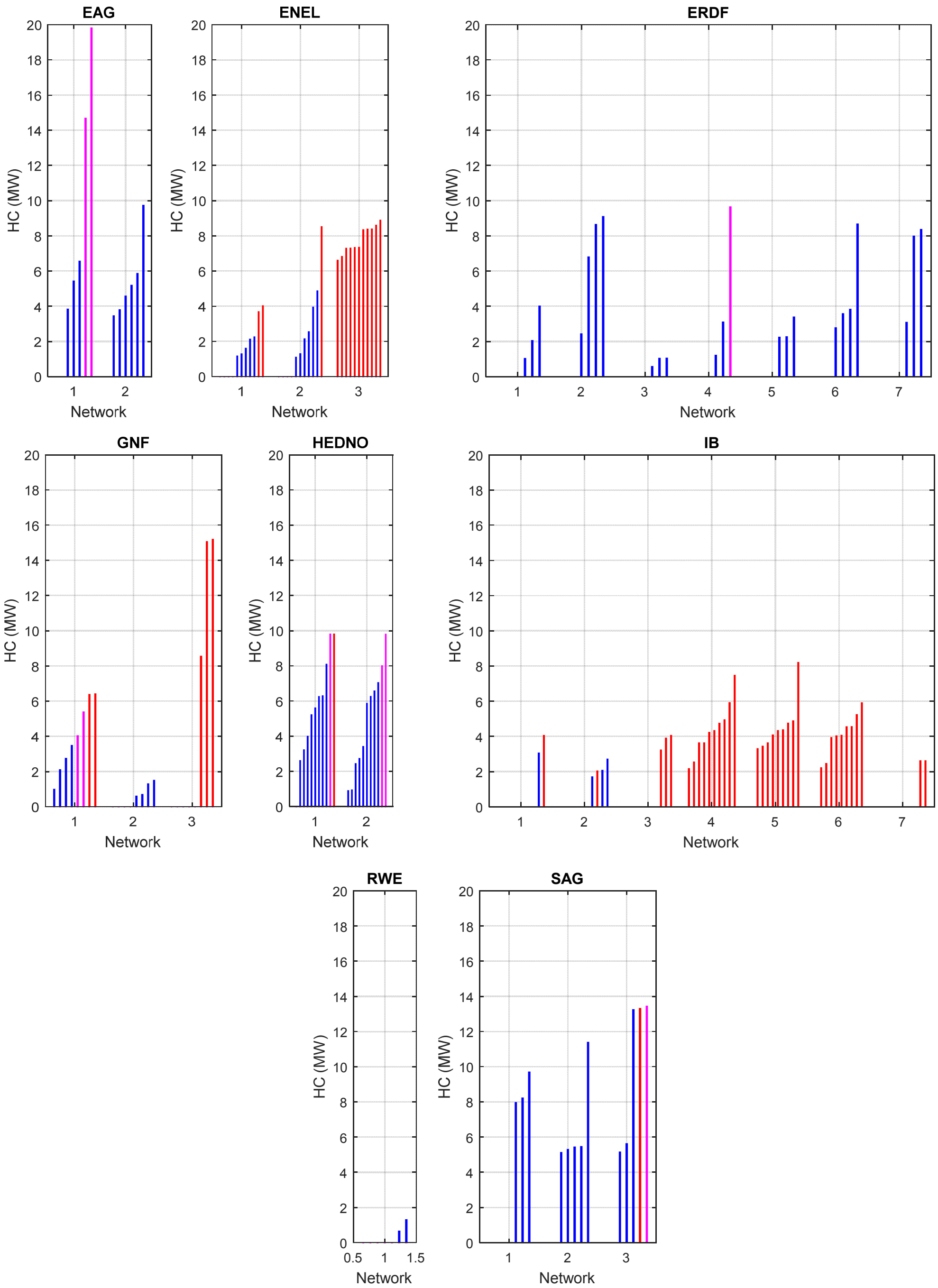


Figure 42 (Median (related to the DRES scenario) hosting capacity per network and DSO[38]
blue: feeders with 100 % of the DRES scenarios constrained by voltage
red: feeders with 100 % of the DRES scenarios constrained by current
magenta: feeders with mixed constraints voltage and current (depending on the DRES scenario))

[38] The feeders are sorted by ascending hosting capacity to facilitate the visualisation (a comparison with Figure 12 is not directly possible)

Although the comparison among feeders of different networks is not straightforward, Figure 43 shows the behaviour of feeders (being voltage- or current-constrained) as a function of their feeder length. The y-axis of this figure shows the reserve to the non-limiting constrained (reserve to the maximal allowed loading for voltage-constrained feeders (shown here negatively) and reserve to the maximal allowed voltage for current-constrained feeders (shown positively here)). The data used for this evaluation correspond to the AsIs scenario (network as it is without smart grids solution) in which the generation has been scaled up to reach one of the two constraints (installed generation = hosting capacity).

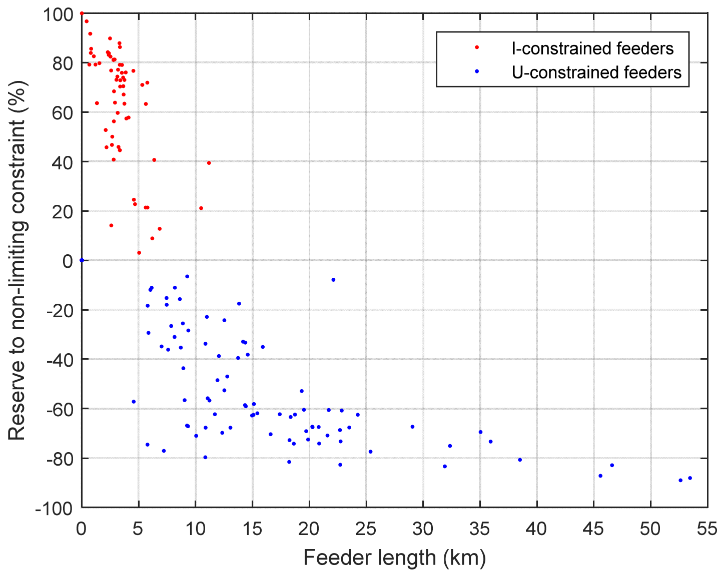


Figure 43 (Reserve to non-limiting constraint as a function of the feeder length – all feeders/networks/DSOs)[39]

While the general trend matches the expected characteristic, this figure demonstrates a rather large overlapping of current- and voltage-constrained feeders of length below 15 km (keeping in mind that the comparison between feeders on the basis of their length is biased due to the different nominal voltages).

From the 149 considered feeders, about half (58 %) are voltage-constrained (this figure is not automatically representative for the whole supplied area of all the considered DSOs).

[39] For red points, 100 % reserve means that almost the full voltage band is available. For blue points, -100 % reserve means that the loading of the highest loaded line/cable is very low.

Figure 44 shows the distribution of the feeders according to the reserve to the non-limiting constraint (using the same basis as in Figure 43).

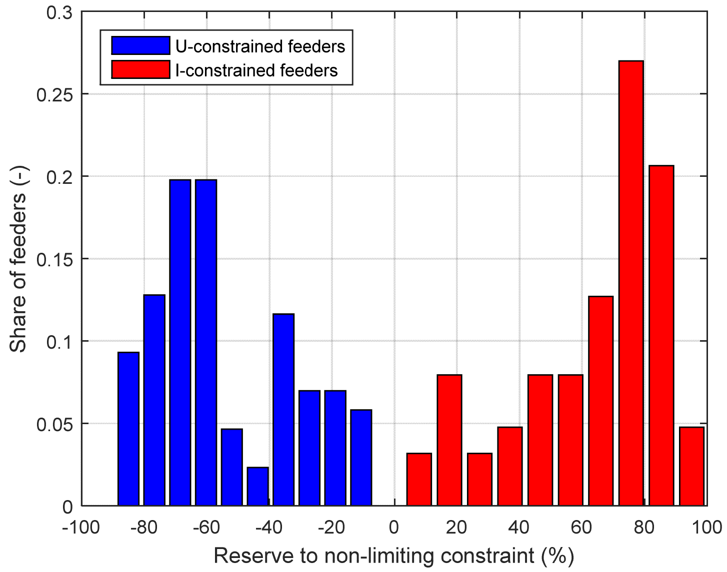


Figure 44 (Distribution of the reserve to non-limiting constraint – all feeders/networks/DSOs)[40]

The most important part is the share of the voltage-constrained feeders (blue) which are far from the loading constraint (with a high reserve to the loading constraint). The idea behind this analysis is that an increase of the hosting capacity for voltage constrained feeders with smart grids solutions supposes an increase of the current. As a result, these solutions have an actual benefit only for feeders for which the loading limit is not reached.

In the following, the increase of the current is estimated (trend) for the two main "families" of solutions[41]:

- Reactive power control
  The reactive power consumption used to reduce the voltage rise implies an increase of the current (by 11 % for cosφ=0.9[42]). The reduced voltage rise (achievable reduction of about 50 %[43] for an R/X ratio of 1 (rather favourable assumption for MV networks) and cosφ=0.9) allows increasing the installed power (i.e. hosting capacity) and therefore automatically leads to a further (roughly linear) increase of the current. This solution would therefore lead to an approximate increase of the current by a factor 2.22 (1.11/0.5).
- Voltage band release thanks to OLTC control
  The released part of the voltage band allows an increase (roughly linear) of the installed power (hosting capacity increase) and therefore supposes an increase of the current (roughly linearly). Assuming a doubling of the voltage band effectively available means approximately a doubling of the hosting capacity and therefore of the current (or loading).

Both types of "families" of solutions would hence lead to an approximately doubling of the current, which means that smart grids solutions aiming at increasing the hosting capacity of voltage-

[40] Note that the share shown is the share within a category (voltage or current constrained).

[41] The considerations shown here are rough approximations based on a linearization of the power flow and are only provided to explain the trends observed in the data.

[42] This calculation is only valid if all generators consume the full reactive power. For VVC, the factor would be smaller.

[43] $\Delta U \approx \frac{R \cdot P}{U_N^2} \cdot \left[1 - \tan(\varphi) \cdot \frac{1}{R/X}\right] = \frac{R \cdot P}{U_N^2} \cdot \left[1 - 0.48 \cdot \frac{1}{1}\right] = \frac{R \cdot P}{U_N^2} \cdot [0.52]$

constrained feeders only provide benefits in feeders which maximum loading is below 50 % (when combining these solutions (e.g. VVC and WAC), the reserve must be even larger). This very simple idea can be visualised in Figure 45 considering two voltage-constrained feeders. Feeder1 can fully benefit from smart grids solutions while Feeder2 cannot (or only partly) benefit from smart grids solutions.

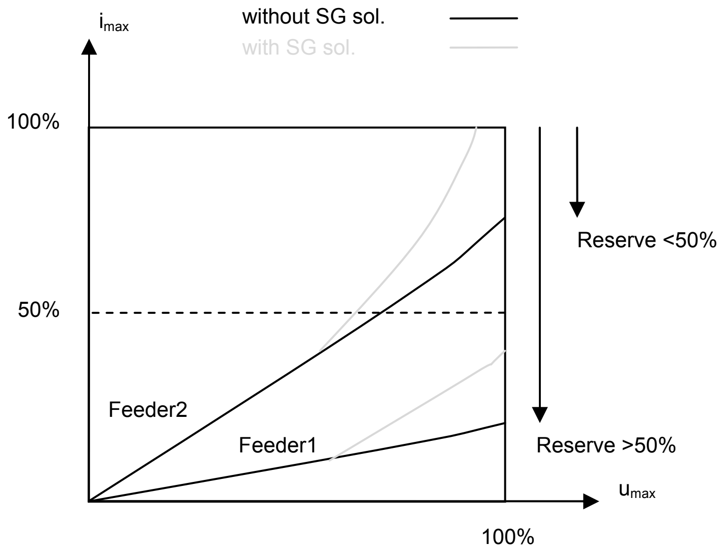


Figure 45 (Distinction between voltage-constrained feeders with and without actual potential of smart grids solutions)

From the considered feeders, about 71 % of the voltage-constrained feeders have a reserve to the current-constraint of more than 50 % and therefore exhibit a priori a potential in terms of hosting capacity extension. The actual hosting capacity extensions for each solution considered (see chapter 6.2.2) are evaluated accurately and presented in the next chapter.

Figure 46 shows a comparison between the hosting capacity determined from the feeder screening (obtained by using the installed power without considering any temporal information) and the detailed simulations with generation and load profiles for all the feeders. This figure shows a good correlation between the two series. There is however a systematic deviation: the hosting capacity obtained by considering the generation and load profiles is on average about 30 % higher than the hosting capacity obtained by using only the installed power. This systematic deviation is caused by the following factors:

- The maximal value from the (PV) generation profiles is smaller than the installed module power (by a factor of up to 15 % [7]) .
- Loads can, depending on their location and the shape of the profiles, compensate the voltage rise caused by the PV infeed.

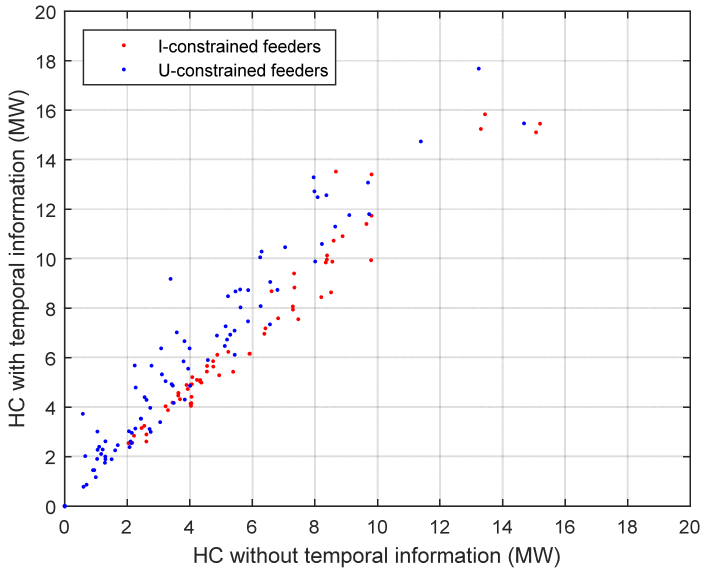


Figure 46 (Comparison between the hosting capacity determined from the feeder screening (without temporal information) and from the detailed simulations (with temporal information))

6.2.2 Expected HC for all the DSOs and SUTs

This chapter presents the overall analysis of the hosting capacity evaluation for each DSO/network/feeder and each solution according to the following two criteria:

- Basic deployment potential.
- Benefit in terms of hosting capacity increase.

The deployment potential of each solution is evaluated by analysing the voltage and current constraints reached. In this context, a distinction must be made between two groups of solutions:

- Distributed voltage control solutions without centralised observer/monitoring (loading no observed: "VVC", "WAC", "WAC&VVC", "FixCurt"
- Centralised voltage (and loading) control solution: "OPF"

"AsIs" and "Max" are not shown in the previous list since they are (not) real solutions. Distributed solutions of voltage control not able to observe the loading of lines or cables can be implemented and used to their full extent only if the feeder remains voltage-constrained. Otherwise the potential of voltage control is blocked by current constraints. On the contrary, the solution able to observe the loading of assets can be effectively implemented in feeders which are or turn to be current-constrained.

The benefit in terms of increasing the hosting capacity should be evaluated according to the previous criterion – basic deployment potential). The hosting capacity increase shown in the following paragraphs has been calculated on the subset of feeders remaining voltage-constrained for the considered solutions.

In the first part, the results are shown in an aggregated way for all the solutions and DSOs\Networks\Feeders. In the second part, the hosting capacity increase distributions are shown. Figure 47 shows the share of feeders remaining voltage-constrained. 100 % (e.g. "FixCurt") means that all the feeders which are voltage-constrained for AsIs remain voltage-constrained, which means that the deployment potential is unrestricted.

This figure shows that the solution “VVC” is deployable in about 60 % of the voltage-constrained feeders, which means that these feeders have enough reserve to the loading limit. While this share is slightly lower for the solution “WAC”(about 48 %), there is a significant difference for the solution “WAC&VVC” for which only about 20 % of the feeders can actually benefit from this solution. The solution “OPF” is not considered in this evaluation since it has the ability to observe the loading (through the centralized observer/monitoring implemented as a state estimator). It is considered in Figure 49.

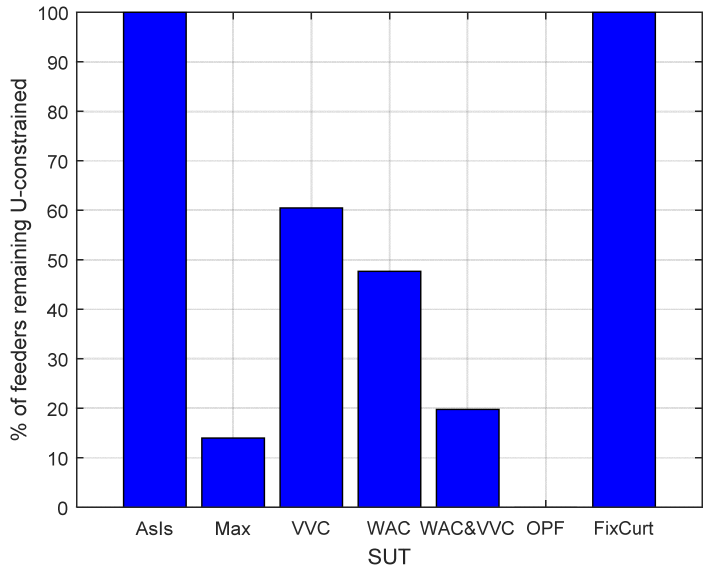


Figure 47 (Share of feeders remaining voltage-constrained for each SUT)

Figure 48 shows the hosting capacity increase of each solution not featuring loading-observation (except “OPF”) for the whole data set (all DSOs\Networks\Feeders). The red value corresponds to the average, the lower box line to the minimum and the upper box line to the maximum. The “Max” solution is shown as the reference.

According to Figure 48, the hosting capacity can be increased on average by about 74 % for the solution “VVC” in feeders which can actually benefit from it. The maximum hosting capacity increase of +172 % can be seen as an outlier (one overhead feeder with an R/X ratio even below 1).

The solution “WAC” leads to a similar average hosting capacity increase (slightly lower), but leads for some feeders to an increase of the hosting capacity by about 289 %. This solution uses the OLTC control to better use the available voltage band. The large dispersion is mainly due to the strongly spreading voltage limits among the DSOs.

The solution “WAC&VVC” leads to a higher average hosting capacity increase (about +148 %) but is only usable for a limited number of feeders (only 20 % of the voltage-constrained feeders –see Figure 47).

The solution “FixCurt” leads, as expected, to the smallest spreading with an average hosting capacity increase of about 31 %.

Figure 49 shows the same results for the solution “OPF”, with, as expected, a significantly higher increase of the hosting capacity (+235 % on average). The maximal increase reached is +464 %. The “Max” solution is shown as the reference.

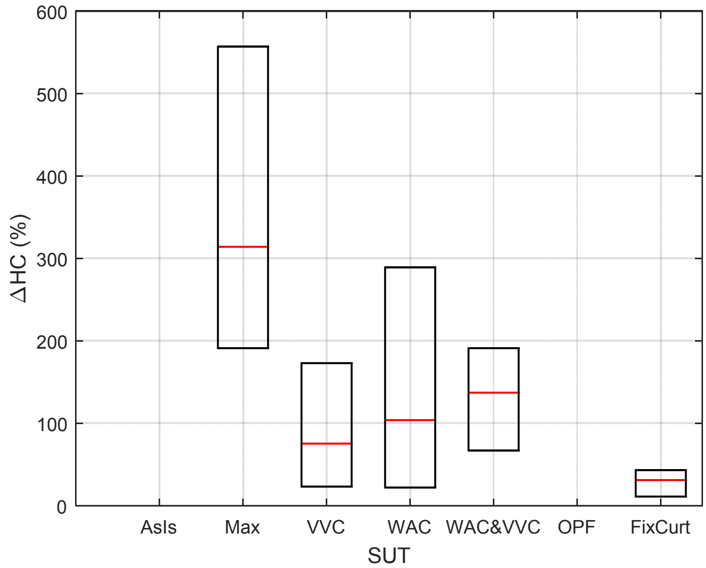


Figure 48 (Hosting capacity increase per SUT (except "OPF") for all feeders benefiting from them)[44]

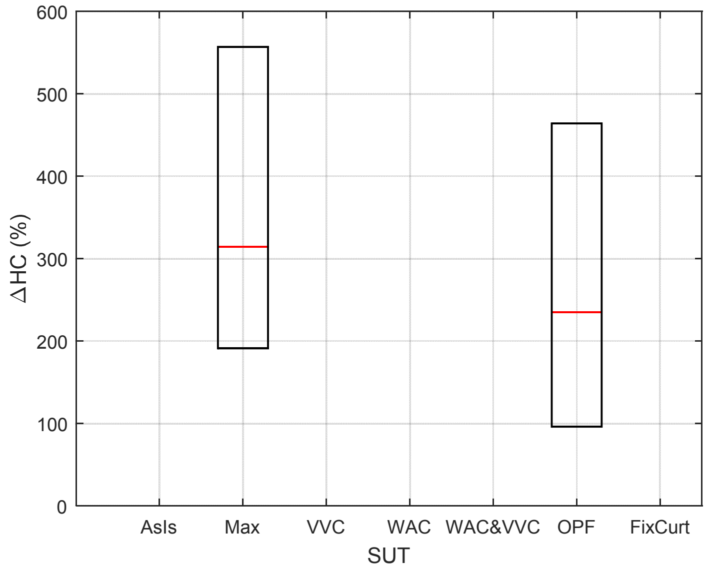


Figure 49 (Hosting capacity increase for "OPF" for all feeders)

The distribution of the hosting capacity increase for the solutions "VVC", "WAC-Homogeneous" and "WAC&VVC-Homogeneous" of feeders actually benefitting from these are shown on Figure 50, Figure 51 and Figure 52 respectively.

[44] The highest hosting capacity increase is greater for WAC than for WAC&VVC. This is due to the fact that only feeders remaining voltage-constrained are considered here.

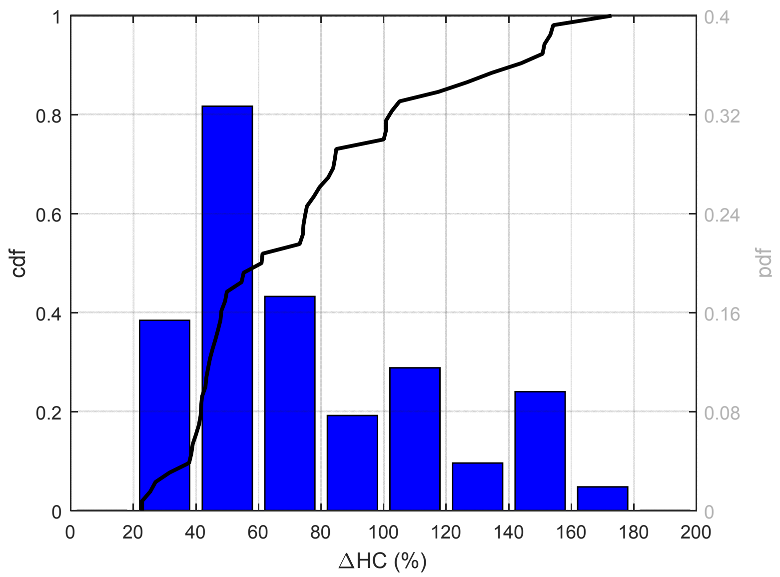


Figure 50 (Distribution of the hosting capacity increase with “VVC” for feeders remaining voltage-constrained)

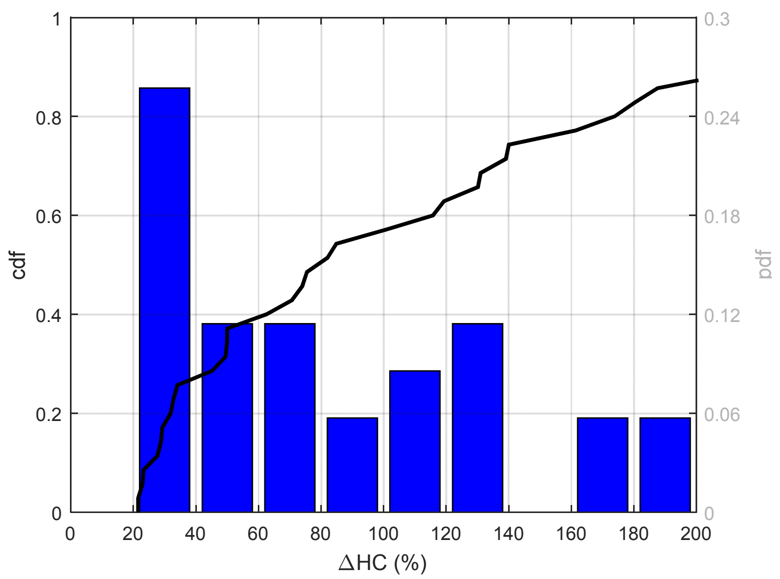


Figure 51 (Distribution of the hosting capacity increase with “WAC-Homogeneous” for feeders remaining voltage-constrained)[45]

[45] Note that the x-axis has been cut to 200 %, explaining why the cdf does not reach 1.

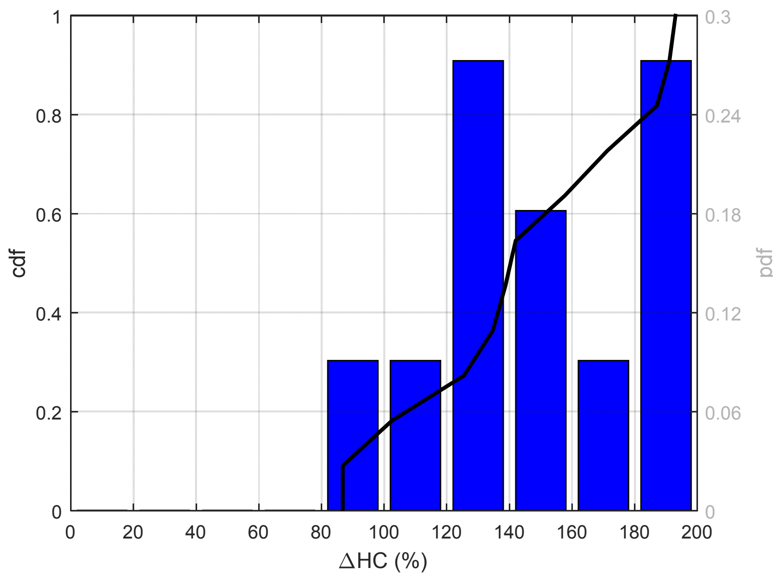


Figure 52 (Distribution of the hosting capacity increase with "WAC&VVC-Homogeneous" for feeders remaining voltage-constrained)

For the solution "OPF-Homogeneous", none of the feeders is voltage-constrained. The increase of hosting capacity is between +96 % and +464 % with an average of +235 %.
For the solution "FixCurt", the increase of hosting capacity is between +11 % and +43 % with an average of +31 % (see chapter 6.1.2.7).

6.2.3 Detailed analysis of the simulation cases

This chapter summarises the analyses presented in chapter 6.1.3 for the exemplary networks, extended to all the networks and feeders.

6.2.3.1 Planning and parametrisation of the SUTs

In order to implement some of the solutions into the detailed simulations (or in practise), an analysis of the network must be performed to determine the location of (voltage) sensors. This is in particular necessary for the solutions "WAC" and "WAC&VVC" (location of dedicated field measurements). For each feeder, the voltage profiles obtained from the Monte Carlo simulations performed with the full set of Monte-Carlo samples have been analysed according to the concept explained in chapter 6.1.3.1. For each feeder, the number and location of critical nodes have been obtained. The distribution of the number of critical nodes per feeders is shown on Figure 53. This figure shows that the great majority of feeders (almost 80 %) have only one critical node. Some special feeders have, however, up to five critical nodes. The reader should keep in mind that this particular result depends on the assumed DRES distribution. Indeed, some particular DRES distributions (e.g. several two large generators located at different end-nodes would result in a higher number of critical nodes).

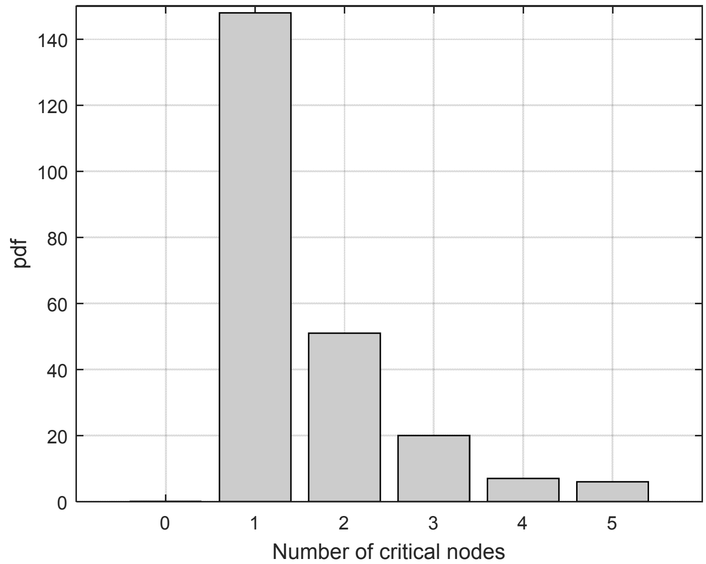


Figure 53 (Distribution of the number of critical nodes per feeder – all DSOs/feeders)

6.2.3.2 Validation of the HC

Following the approach in 6.1.3.2, the simulation results have been analysed to verify the accuracy if the followed approach. In particular, the maximum voltage and the maximum loading have been evaluated for all the Monte Carlo samples (268.000). Figure 54 and Figure 55 show the distribution (over all the feeders) of the maximum voltage for “AsIs” and for the solutions “VVC”, “FixCurt” and “VWC”. For these figures, the voltage values are normalised to the voltage band used by each DSO to allow a comparison. These figures show that the voltage limits have been (slightly) exceeded only for a few feeders. The reader should keep in mind that the values evaluated for the distributions are the maximum values which typically occur rarely. For some of the feeders, the maximum voltage is greater than the allowed voltage limits. This is mostly due to reduction of the samples to a few critical time intervals in Step 2 (see chapter 2.1.2). In some cases, a “shadow effect” might occur and the time of occurrence of the maximum voltage might change, meaning that when further increasing the installed power after having implemented a solution, the maximum voltage might occur at a different time which is not considered to estimate the hosting capacity. The simulations show, however, only a minor impact on the results and a good accuracy of the results from Step 2 (see chapter 2.1.2). Similar were drawn for the maximum loading.

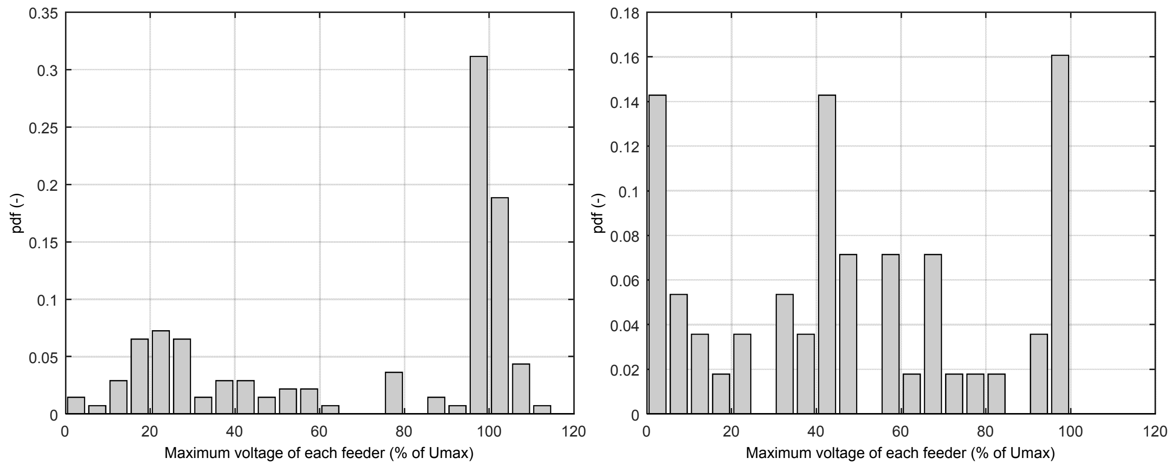


Figure 54 (Distribution of the maximum voltage (over the feeders))
Left: "AsIs" – all feeders / Right: "VVC" – feeders benefiting from it[46]

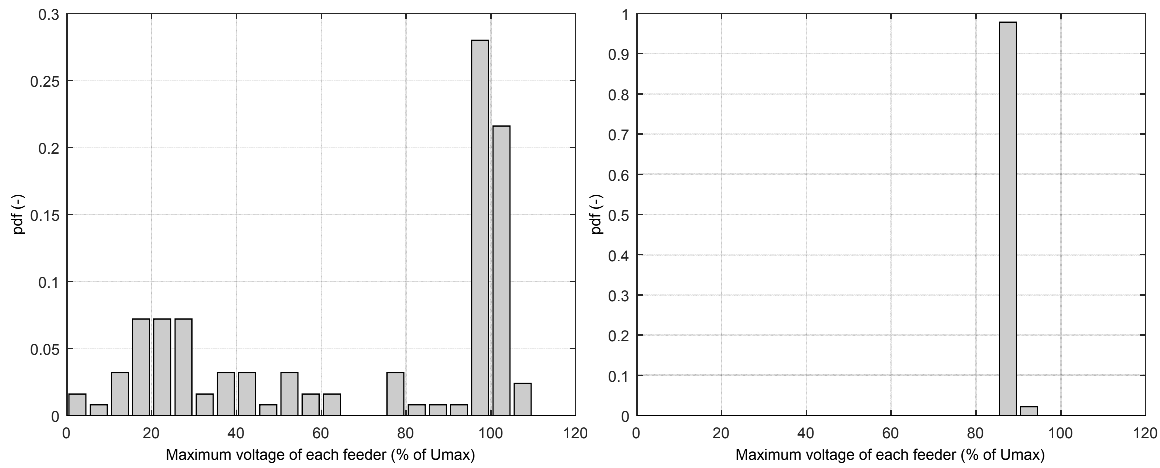


Figure 55 (Distribution of the maximum voltage (over the feeders))
Left: "FixCurt" – all feeders / Right: "VWC" – voltage-constrained feeders

6.2.3.3 "Side effects" of enhancing the hosting capacity with smart grids solutions

The analysis of the "side effects" (see chapter 6.1.3.3) has been limited to the energy efficiency. A general analysis and a discussion on the curtailment are included in chapter 6.1.3.3.3. The energy efficiency KPI shown in this chapter has been computed on the basis of equation (4) (chapter 6.1.3.3.1).

Figure 56 and Figure 57 show the distribution of the energy efficiency KPI for all the considered feeders. A comparison between both figures shows that the solution "VVC" leads as expected to a decrease of the efficiency (mainly due to the reactive power consumption needed to reduce the voltage and therefore increase the hosting capacity).

Figure 56 and Figure 57 show the distribution of the energy efficiency KPI for "AsIs" and "VVC" respectively, for the feeders benefiting from VVC (voltage-constrained feeders for which "VVC"

[46] The maximum values are shown as percentage value of the planning limit for the corresponding DSO.

allows to increase the hosting capacity). A comparison between these two figures shows that the efficiency generally decreases when "VVC" is implemented (and the installed generation increased up to the extended hosting capacity). The 95th percentile (over the feeders) decreases from 97.8 % ("AsIs") to 96.9 % ("VVC"). However, this simple analysis hides a more complex behaviour of feeders, as visible in Figure 58. On this figure, the difference between the energy efficiency for "VVC" and "AsIs" is shown. It confirms that the efficiency is generally lower for the results from "VVC" than for the results of "AsIs" but shows that there are exceptions (only 3 feeders). For these feeders "VVC" results in a small increase of the efficiency due to the following phenomenon: the additional generation causes additional losses due to the reactive power consumption (Q(U)) for only a very limited number of hours per year (given the small amount of full hours of PV generation) while it can reduce losses for a larger number of hours when the local generation leads to a reduction of the total demand which needs to be delivered by the upstream network. The reader should therefore keep in mind that the efficiency is also influenced by other factors. For the solution "VVC", the installed generation is larger than for "AsIs", which leads to:

- The consumption of reactive power by the Q(U) control to control the voltage (increase of losses).
- An increase of the reverse power flow (amount and duration) due to the fact that the ("VVC") solution allows increasing the hosting capacity (can result in an increase or decrease of losses).

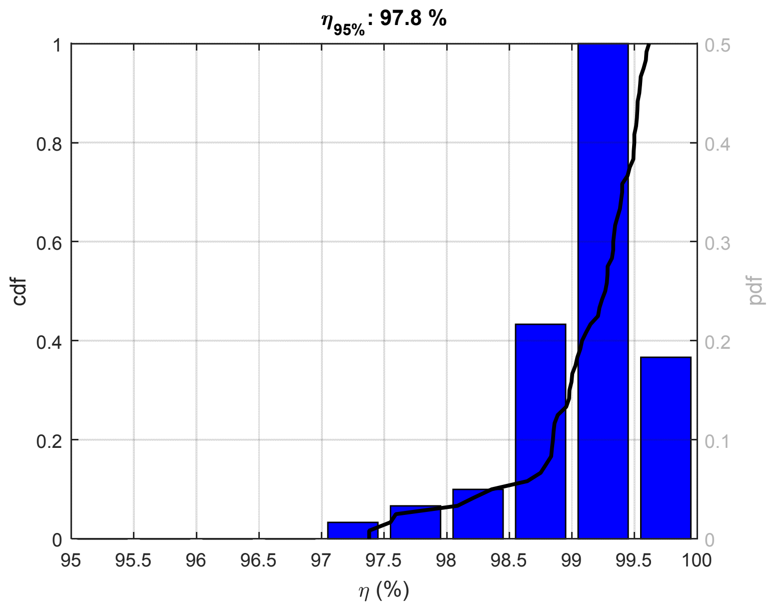


Figure 56 (Distribution of the efficiency KPI – "AsIs")

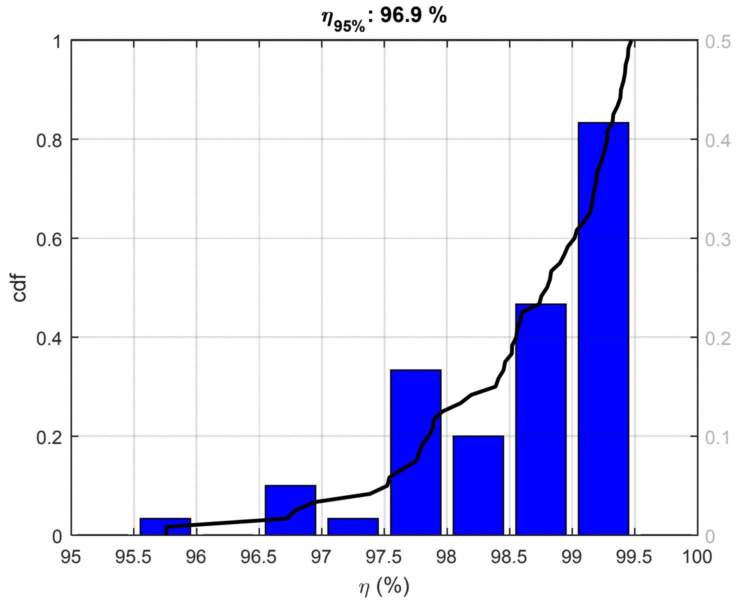


Figure 57 (Distribution of the efficiency KPI – Solution “VVC”)

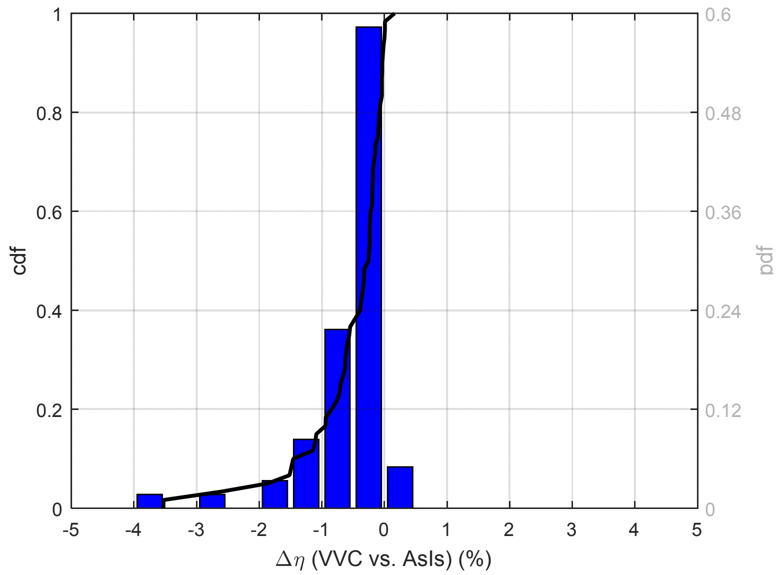


Figure 58 (Efficiency variation: “VVC” vs. “AsIs” for all feeders benefiting from “VVC”)

As a conclusion, the energy efficiency KPI is on average slightly smaller for “VVC” than for “AsIs”, with an average reduction of about than 0.5 %. This impact on the network losses can be quantified as moderate.

6.2.4 Network reinforcement

Figure 59 shows the distribution of the total line length computed as feeder reinforcement to achieve the same hosting capacity as the solution “Max”. The determination of the feeder reinforcement is restricted to the voltage-constrained feeders and is based on the methodology presented in chapter 6.1.4.

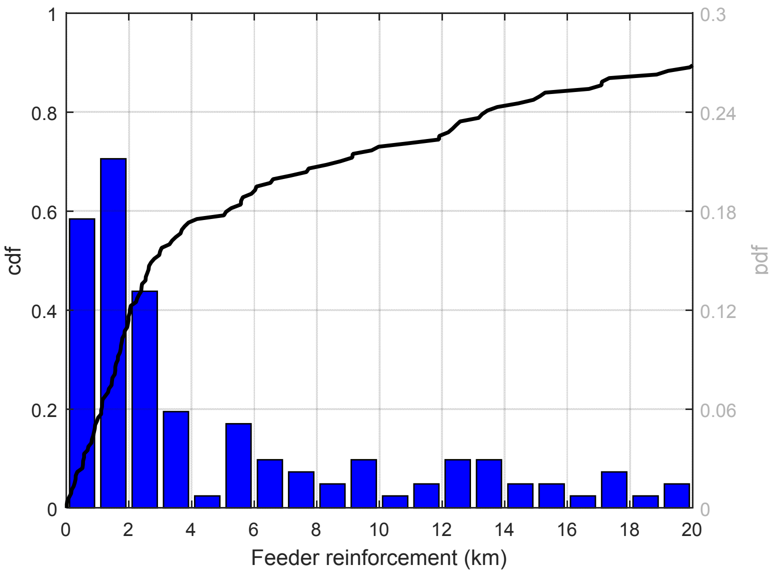


Figure 59 (Distribution of the total line length network – solution “Max”)

Figure 59 shows that for 10 % of the feeders the total line length exceeds 20 km. These outliers (beyond 20 km) correspond to very long feeders (12 feeders with a feeder length between 22 km and 56 km). For these feeders, the computed feeder reinforcement is not realistic: assuming an average cost of about 100 €/m would lead to a total reinforcement cost of more than 2 M€ for these feeders. In such cases, if the hosting capacity is exhausted, other solutions would be implemented (e.g. a new primary substation). Further analyses are provided in chapter 9. When filtering out these outliers, the total reinforced line length is on average 4.1 km per feeder with, however, large variations from feeder to feeder (between 0 and 20 km).

6.3 Accuracy of oberservers/monitoring

In order to investigate the accuracy of the observers, a state estimator has been implemented into the simulation environment and used for an exemplary feeder (voltage constrained feeder). The basic settings of the state estimator (see chapter 5.5.5) are summarised here:

- Accuracy of active and reactive power sensors: 3 % of rating.
- Accuracy of voltage sensors (if used): 0.5 % of rating.
- Accuracy of pseudo-measurements: 50 % of rating[47].

One of the most important parts of the distribution state estimator is the load estimation [42], i.e. the process to distribute the active and reactive power measured at the feeder level along the feeder. In this study, several options have been considered. They are summarised in Table 12. On this table, there are two families of parametrisation:

- Distribution of the load and generation power according to the contracted or installed power.
- Distribution of the load and generation power according to historic and synthetic load profiles and with PV nowcasting.

Test Case	Loads	(PV) Generators	Voltage sensors
1a	Based on contracted power	Based on installed power (zero during the night)	No
1b			Yes
2a	Based on historic profiles	Based on PV nowcasting	No
2b			Yes

Table 12 (Considered load allocation algorithms)

In order to identify the performance of different concepts (in particular the way pseudo-measurements are determined), the noise/uncertainty of the (real) measurements has not been considered.

PV nowcasting consists in using a reference installation in the area where active power measurements are received in real time and scaling the power to the other installations on the basis of the installed power and any other information which might be available (e.g. orientation). In general, DSOs do not have significantly more information than the rated power (module and inverter power). An alternative is to use an irradiance and temperature measurement and to compute the active power which is injected by each installation on the basis of the installed power. In any case, shadow effects, modules orientation and inclination and other factors with relevant impact on the total performance of the PV system are unknown.

In order to try to determine the order of magnitude of the error which can be expected from the nowcasting, measured generation data for 73 PV installations located within a LV network [43] has been used. In total, data for about two years have been analysed. Figure 60 shows the histogram of the normalised power deviation between the median generator and all the other generators. The Mean Absolute Error (MAE) and the root Mean Square Error (RMSE) are shown on the figure (6.0 % and 4.6 % respectively). In addition, the 95 % and 99 % percentiles are given (18.0 % and 31.4 %).

[47] [41] mentions a range between 20 % and 50 % for the accuracy of pseudo-measurements. In this study, the upper limit has been chosen to account for the fact that the generation embedded at the LV level impacts the synthetic/historic MV load profiles.

Given that the dispersion of the PV production is expected to increase with the geographical distance (the analysed generators have different orientations and inclinations but they are located within a few hundred meters), a larger value than the obtained RMSE has been used for the standard deviation used to generate the PV generation measurements for the state estimator: 20 % (normal distribution with σ=0.20).

In addition to the load and generation allocation algorithms, voltage sensors can be used. Since the scope of this study was not to perform a detailed investigation on the performance of state estimators (including e.g. criteria for the optimal placement of voltage sensors), the concept proposed in one of the IGREENGrid demonstration has been followed. It consists in placing voltage sensors in secondary substations which already have a communication infrastructure (RTU, mainly for the remote control of switches). The location of these sensors for the considered feeder is shown Figure 61.

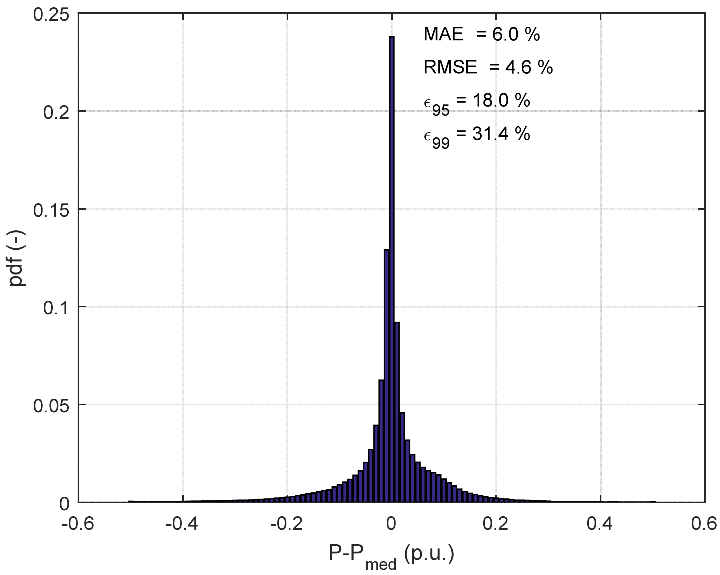


Figure 60 (Histogram of the deviation between the median generator and the rest of the generators)

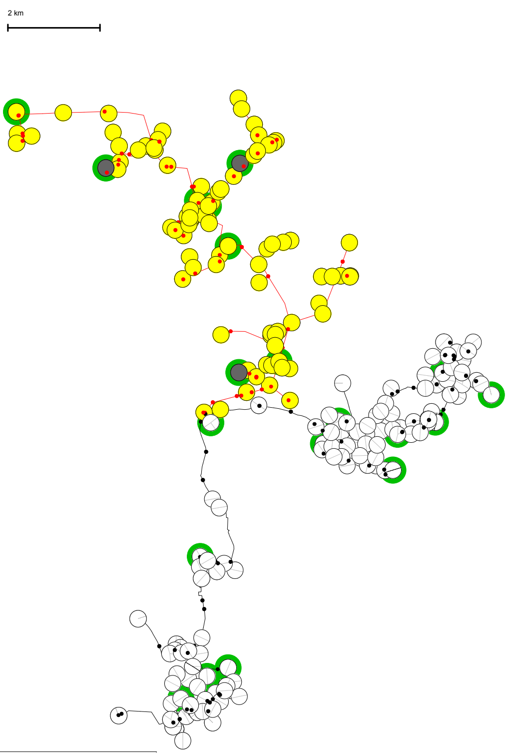


**Figure 61 (Overview of the considered feeder (yellow)
Green circles indicate the location of voltage sensors)**

Figure 62 shows the distribution of the voltage error (difference between the load flow and the result of the state estimator) for Test Case 1a (see Table 12). For this analysis, all nodes are considered and the RMSE (for the voltage) reached 0.5 %, with a 99th percentile error of about 1.3 %.

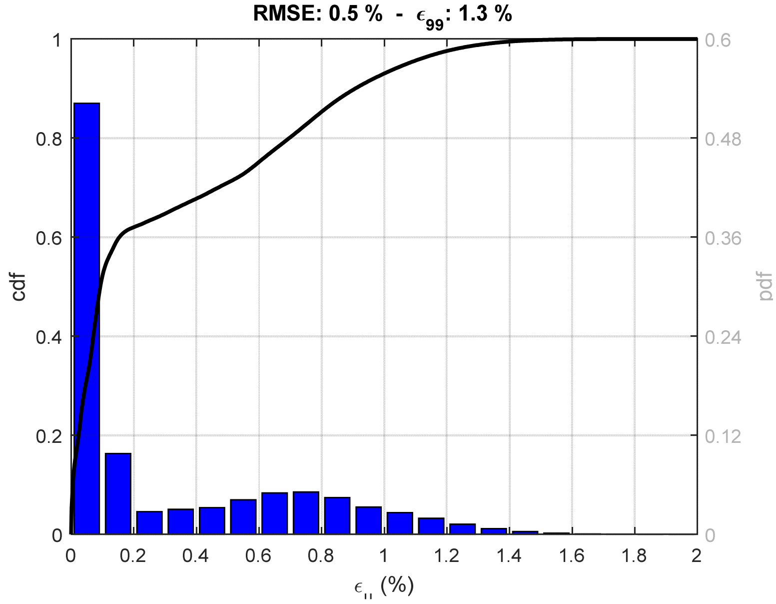


Figure 62 (Error for test Case 1a: load and generation distributed with the contracted / installed power)

Figure 63 shows the distribution of the error on the voltage (difference between the load flow and the result of the state estimator) for Test Case 2a (see Table 12). For this analysis, all nodes are considered and the RMSE (for the voltage) reached 0.1 %, with a 99th percentile error of about

0.6 %[48]. This large improvement of the estimation accuracy is mainly due to the fact that the synthetic profiles used as pseudo-measurements are very close to the actual ones. In practise, larger deviations could occur, especially in case of unpredicted changes in the customer behaviour (e.g. stop of a large consumer facility for unplanned maintenance).

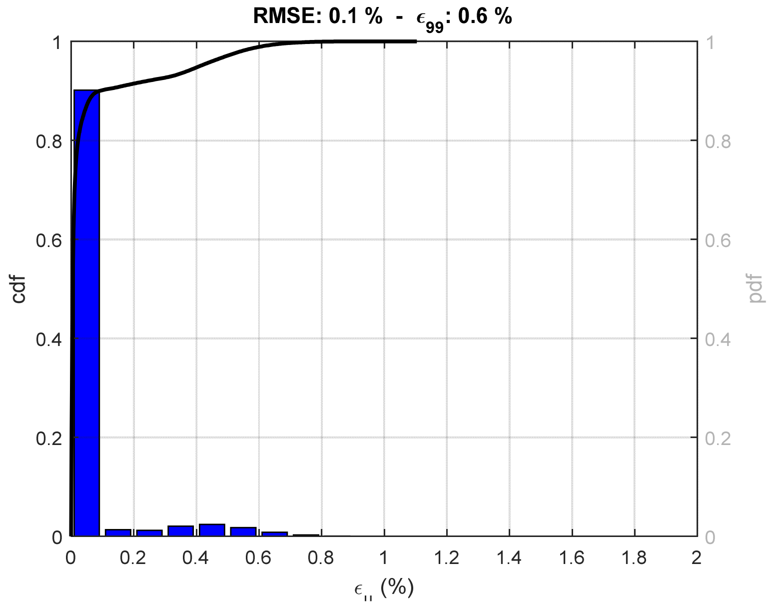


Figure 63 (Error for test Case 2a: load and generation distributed with historical data / PV nowcasting)

These results show that given the high impact of the generation on the feeders' behaviour (installed generation = hosting capacity). The state estimation accuracy can be increased significantly by using improved load / generation estimation. The added value of PV nowcasting, which is rather simple to implement is clearly demonstrated.
By using the mentioned criterion to install the voltage sensors (at secondary substations already equipped with communications), the state estimator accuracy could not significantly be improved as these nodes are not (systematically) presenting the largest voltage variations. An improvement would be to install voltage sensors at the critical nodes, determined according to the approach presented in chapter 6.1.3.1.
This analysis shows that the accuracy of the state estimator is strongly depending on the complexity of the algorithm used for the load estimation. These values are close to the values assumed when modelling the state estimator and the optimal power flow (see chapter 5).

[48] The reader should remind that the measurement noise has been ignored for this analysis. In practise, the deviations would probably reach about 1 %.

7 Technical evaluation of the S&R potential of LV solutions

The results obtained from the simulations of the LV networks are summarised in this chapter. Since the methodology is the same as for the MV networks, only the overall results are shown (no illustrative example).

7.1 Feeder screening and classification

As a result of the first step of the proposed methodology, the hosting capacity is determined as for the MV networks via a Monte-Carlo simulation varying the DRES scenarios for each feeder. In addition to the hosting capacity, the limiting constraint (voltage or current) is also analysed.
Figure 64 shows the median of the hosting capacity for each feeder of each network of each DSO (the bars are sorted for a better visualisation). The reader should keep in mind that, as for the MV networks, the MV/LV transformers at the primary substations have not been taken into account. This means that the sum of the hosting capacity for all the feeders of a network might exceed the rated power of the transformer (e.g. 1.5 MW for RWE-Network2).
In Figure 64, the colour of the bars shows whether the feeders are voltage-constrained, current-constrained or both (for all DRES scenarios). This figure shows that a network, feeders of which are current-constrained, usually has a greater hosting capacity than one with voltage-constrained feeders.

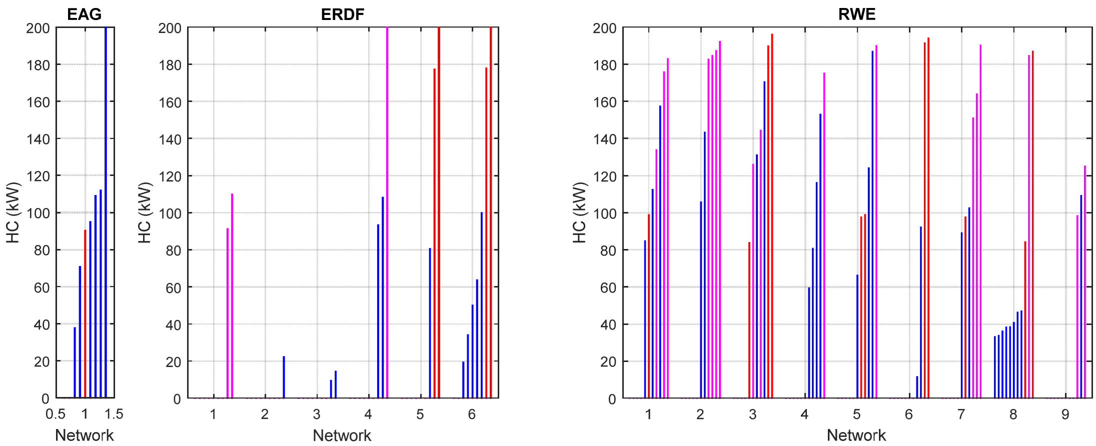


Figure 64 (Median (related to the DRES scenario) hosting capacity per network and DSO)[49]
blue: feeders with 100 % of the DRES scenarios constrained by voltage
red: feeders with 100 % of the DRES scenarios constrained by current
magenta: feeders with mixed constraints voltage and current (depending on the DRES scenario)

Although the comparison between feeders of different networks is as previously mentioned not straightforward, Figure 65 shows a correlation between the behaviour of feeders (being voltage- or current-constrained) as a function of their feeder length. The y-axis of this figure shows the reserve to the non-limiting constraint (reserve to the maximal allowed loading for voltage-constrained feeders

[49] The feeders are sorted by ascending hosting capacity to facilitate the visualisation (a comparison with Figure 12 is not directly possible)

(shown here negatively) and reserve to the maximal allowed voltage for current-constrained feeders (shown positively here)). The data used for this evaluation correspond to the AsIs scenario (network as it is without smart grids solution) with the generations scaled up to achieve one of the constraints.

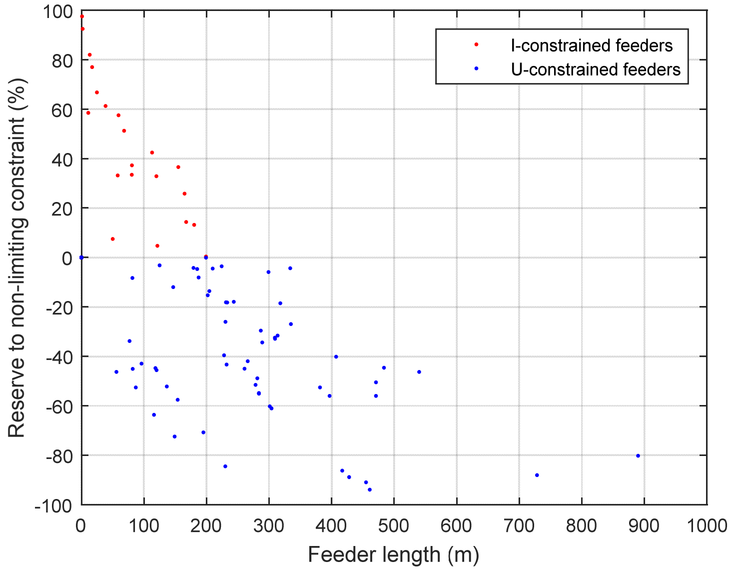


Figure 65 (Reserve to non-limiting constraint as a function of the feeder length – all feeders/networks/DSOs)

While the general trend meets the expectation, this figure shows a rather large overlapping between current- and voltage-constrained feeders for a feeder length below 200 m.

From the 55 considered feeders, about 75 % are voltage-constrained and 25 % are current-constrained (this figure is not automatically representative of the global situation for the whole supplied area of all the considered DSOs). Figure 66 shows the distribution of the feeders according to the reserve to the non-limiting constraint (using the same basis as in Figure 65).

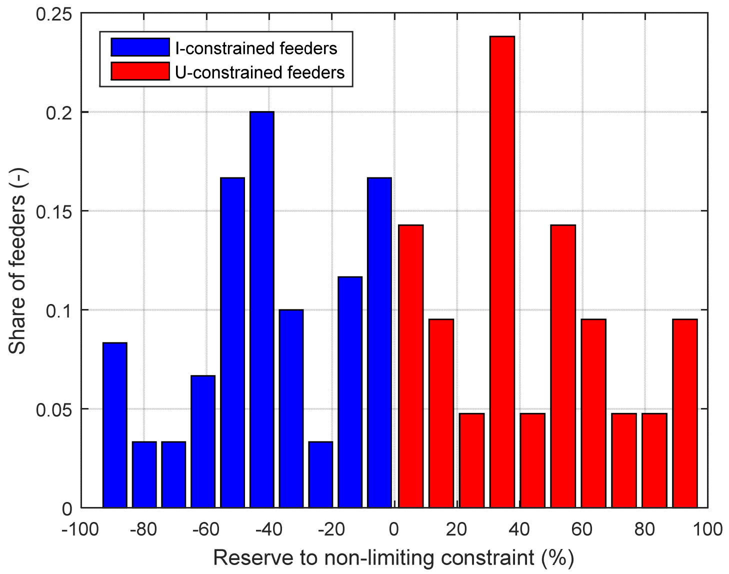


Figure 66 (Distribution of the reserve to non-limiting constraint – all feeders/networks/DSOs)[50]

[50] Note that the share shown is the share within a category (voltage or current constrained)

The distribution of the reserve to the current-constraint in voltage-constrained feeders (blue bars on Figure 66) do not show any particular pattern. The most important part is the share of the voltage-constrained feeders (blue) which are far from the loading constraint (with a high reserve to the loading constraint). The idea behind this analysis is that increasing the hosting capacity for voltage constrained feeders with smart grids solutions supposes an increase of the current. Feeders can benefit from this only when the loading limit is not reached.
In the following, the increase of the current is estimated (trend) for the two main "families" of solutions[51]:

- Reactive power control: approximate increase of the current by a factor of 2.22 (see chapter 6.2.1)
- Voltage band release thanks to OLTC control: approximate increase of the current by a factor of 2 (see chapter 6.2.1)

Both types of "families" of solutions would therefore approximately lead to a doubling of the current, which means that smart grids solutions aiming at increasing the hosting capacity of voltage-constrained feeders only have an actual benefit in feeders which have at least 50 % reserve to the current limit (when combining these solutions, the reserve must be even larger).
From the considered feeders, about 37 % of the voltage-constrained feeders have a reserve to the current-constraint of more than 50 % and therefore exhibit a priori a potential in terms of hosting capacity extension by voltage control solutions.
The actual hosting capacity extensions for each considered solution are evaluated accurately and provided in the next chapter.
Figure 67 shows a comparison between the hosting capacity determined from the feeder screening (obtained by using the installed power without considering any temporal information) and the detailed simulations with generation and load profiles for all the feeders. This figure shows a good correlation between the two series. The hosting capacity obtained by considering the generation and load profiles is on average only about 8 % higher than the hosting capacity obtained by using only the installed power. A comparison with the MV results (chapter 6.2.1) shows that the deviation between both evaluations, with and without temporal information, is significantly lower for the LV networks than for the MV networks. The main reason for this is the lower variability of loads at MV levels due to the aggregation. At MV level, load profiles are less stochastic and the ratio highest to lowest load is significantly lower than at LV level.

[51] The considerations shown here are rough approximations based on a linearization of the power flow and are only provided to explain the trends observed in the data.

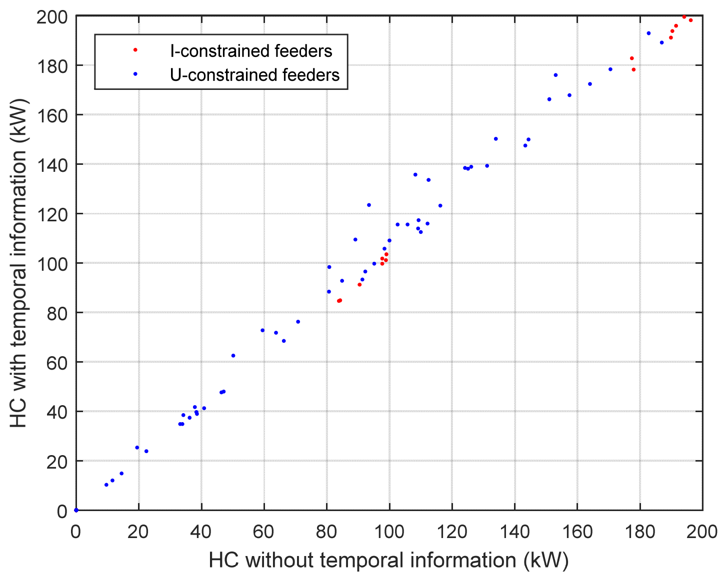


Figure 67 (Comparison between the hosting capacity determined from the feeder screening (without temporal information) and from the detailed simulations (with temporal information))

7.2 Determination of the expected hosting capacities

This chapter presents the overall analysis of the hosting capacity evaluation for each DSO/network/feeder and each solution according to the following two criteria:

- Basic deployment potential
- Benefit in terms of hosting capacity increase

The basic deployment potential is evaluated by analysing the constraint reached after implementation of each solution by increasing the installed generation (hosting capacity determination). In this context, two groups of solutions have to be distinguished:

- Distributed voltage control solutions without centralised observer allowing observing the loading: “VVC”, “WAC”, “WAC&VVC”, “FixCurt”
- Centralised voltage (and current) control solution: “OPF”

As explained in chapter 3, the solution OPF has been simulated but is not really relevant since it has not been identified as a promising solution (nor investigated in the IGREENGrid demonstrations). “AsIs” and “Max” are not shown in the previous list since they are not real solutions. Distributed solutions for voltage control which not observing the loading of lines or cables can actually be implemented and used to their full extent only if the feeder remains voltage-constrained. On the other hand, solutions observing the loading of assets can be effectively implemented in feeders which are or turn to be current-constrained (none of the solutions analysed).

The benefit in terms of hosting capacity increase should be evaluated according to the previous criterion – basic deployment potential. The increase of hosting capacity shown in the following paragraphs has been calculated on the subset of feeders remaining voltage-constrained for the considered solutions.

In the first part, the results are shown in an aggregated way for all the solutions and DSOs\Networks\Feeders. In the second part, the hosting capacity increase distributions are shown. Figure 68 shows the share of feeder which remain voltage-constrained for all the DSOs\Networks\Feeders. 100 % (e.g. “FixCurt”) means that all the feeders which are voltage-constrained for “AsIs” remain voltage-constrained, which means that the deployment potential for voltage control is unrestricted.
This figure shows that the solution “VVC” is deployable in more than 70 % of the voltage-constrained feeders (these feeders have enough reserve to the loading limit). There is a significant difference with the solutions “WAC” and “WAC&VVC” for which less than 30 % of the feeders can actually benefit from these solutions. The solution “OPF” is, as previously mentioned, not considered here.

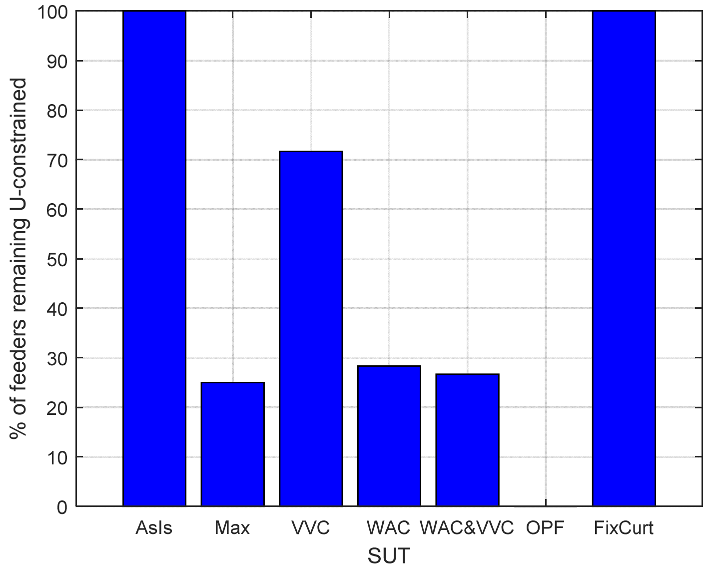


Figure 68 (% of feeders remaining voltage-constrained for each SUT)

Figure 69 shows the hosting capacity increase of each solution not featuring loading-observation for the whole data set (all DSO\Networks\Feeders). The red value represents to the average, the lower box line to the minimum and the upper box line to the maximum. The “Max” solution is only shown as a reference.

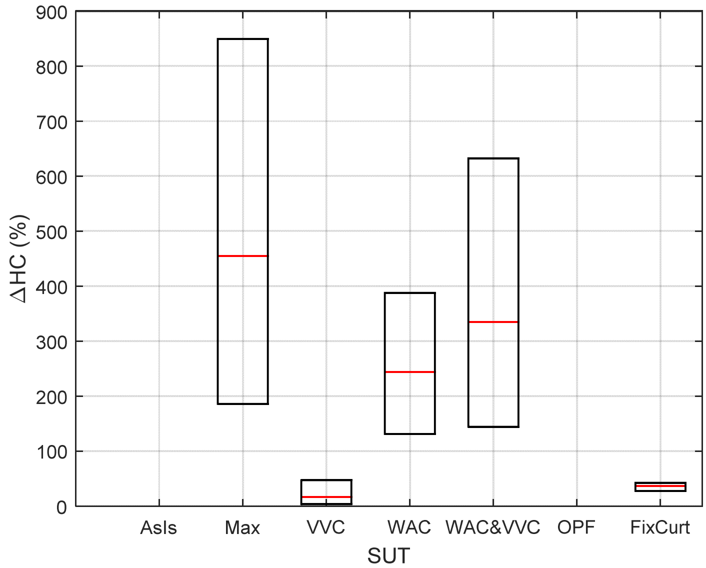


Figure 69 (Hosting capacity increase per SUT (except “OPF”) for all feeders benefiting from them)

According to this figure, the hosting capacity can be increased on average by about +16 % for the solution “VVC” in feeders which can actually benefit from it. This is about half of the average hosting capacity increase of this solution for the considered MV networks (see chapter 6.2.2), which is mainly due to the higher cable share of the considered LV networks which reflects the general trend observed in Europe (see Figure 70). The dispersion between feeders is however large and the increase reaches +47 % for some feeders.

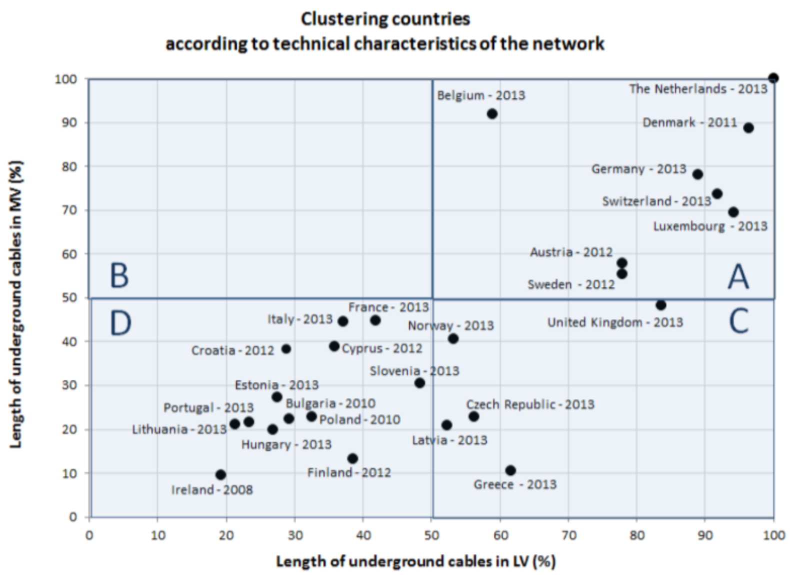


Figure 70 (Share cable / overhead line of European countries [44])

Compared to the results obtained from the MV analysis, the solutions “WAC” and the solution “WAC&VVC” lead to a significantly higher increase of hosting capacity (with however a larger varying range). The main reason for this is that the voltage rise allowed in most of the considered LV networks is rather low. Using an OLTC to control the voltage allows using part of the voltage band allocated to loads to host more generation, which results in these networks in a large hosting capacity increase. This high effectiveness of the OLTC is explained by the fact that the homogeneous scenario has been considered in this plot (the inhomogeneous scenario - see chapter 5.5.2 - would result in a lower hosting capacity increase). This type of control leads to a very high hosting capacity with a uniform PV penetration (on each feeder). For scenarios with inhomogeneous PV penetrations, other solutions (e.g. local reactive power control - VVC) might lead to a sufficient hosting capacity given the actual PV potential in the considered network.
The solution “FixCurt” leads as expected to the smallest spreading with an average hosting capacity increase of about 37 %.
Figure 71 shows the same results for the solution “OPF” (although actually not in the scope of the analysis), with as expected a significantly higher increase of the hosting capacity (+397 % on average).

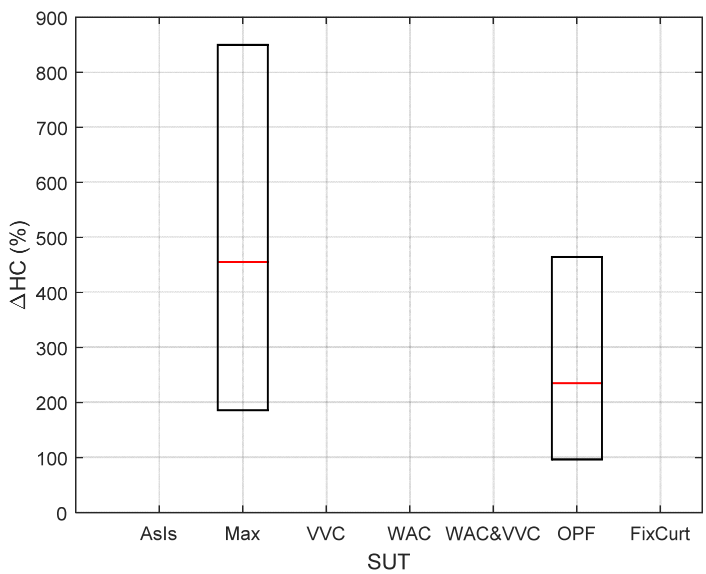


Figure 71 (Hosting capacity increase for “OPF” for all feeders)

The distribution of the hosting capacity increase for the solution “VVC” of feeders actually benefiting from these are shown on Figure 72. For “WAC-Homogeneous” and “WAC&VVC-Homogeneous”, the number of feeders actually benefiting from these solutions is low and the distributions are not shown.

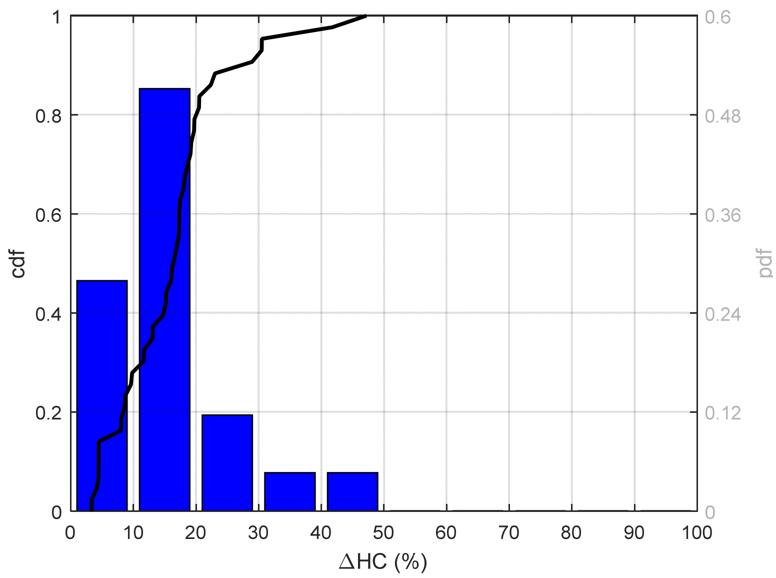


Figure 72 (Distribution of the hosting capacity increase with "VVC" for feeders remaining voltage-constrained)

7.3 Detailed analysis of the simulation cases

7.3.1 Planning and parametrisation of the SUTs

In order to apply some of the solutions into the detailed simulations (or to implement them in practise), an analysis of the network must be performed to determine the location of (voltage) sensors. This is in particular necessary for the solutions "WAC" and "WAC&VVC" (location of dedicated field measurements or smart meters with voltage sensing). For each feeder, the voltage profiles obtained from the Monte Carlo simulations performed with the full set of Monte-Carlo samples have been analysed according to the concept explained in chapter 6.1.3.1. For each feeder, the number and the location of critical nodes have been obtained. The distribution of the number of critical nodes per feeder is shown on Figure 73. This figure shows a significant number of feeders (about 40 %) having only one critical node[52]. Some special feeders have however up to five critical nodes. The reader should keep in mind that this particular result depends on the assumed DRES distribution. Indeed, some particular DRES distributions, e.g. several two large generators located at several different end-nodes would lead to a higher number of critical nodes. Compared to the results from the MV networks (chapter 6.2.3.1), the number of critical nodes is significantly higher for the LV networks, which reflects the much higher stochasticity of LV networks (mostly due to loads).

[52] In reality, depending on the level of unbalance, this number might be greater.

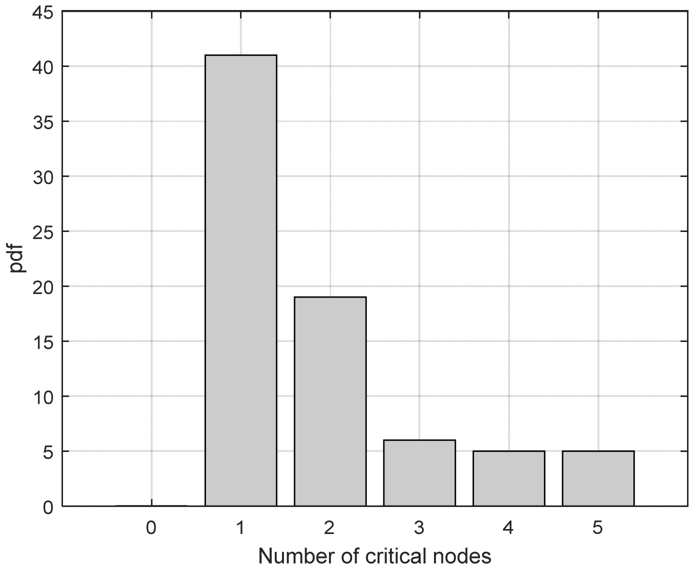


Figure 73 (Distribution of the number of critical nodes per feeder – all DSOs/feeders)

7.3.2 Validation of the HC

As for the MV analysis, the results of the Step 3 simulations (with all the 268.800 Monte Carlo samples) have been analysed to verify the accuracy of the methodology. The results are similar to those for the MV network studies, showing a good accuracy with only few voltage violations (small violation for only a few feeders and only a few samples).

7.3.3 Network reinforcement

Figure 74 shows the distribution of the total line length computed as feeder reinforcement to reach the same hosting capacity as the solution "Max". The determination of the feeder reinforcement is restricted to the voltage-constrained feeders and is based on the methodology presented in chapter 6.1.4.

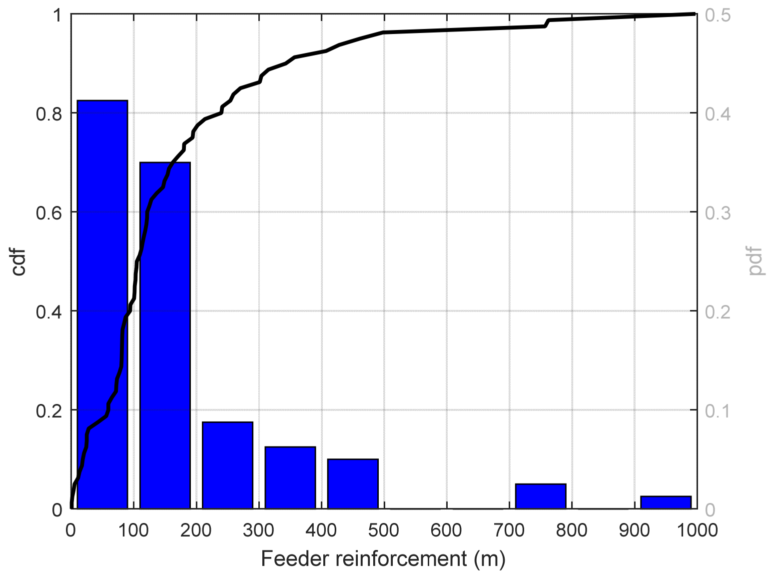


Figure 74 (Distribution of the total line length network – solution "Max")

Figure 74 shows that the total line length to be reinforced is above 500 m for less than 5 % of the feeders. These outliers (beyond 500 m) correspond to the long feeders (3 feeders with a feeder length between 455 m and 890 m). For these feeders, the computed feeder reinforcement is not realistic: assuming an average cost of about 100 €/m would lead to a total reinforcement cost of more than 50 k€ for these feeders. In such cases, if the hosting capacity is exhausted, other solutions would be implemented (e.g. building of a new secondary substation). Further analyses are provided in chapter 10. When filtering out these outliers, the total reinforced line length is on average 137 m per feeder with however large variations from feeder to feeder (between 0 and 500 m).

7.4 Phase balancing in LV networks

Unbalanced conditions in LV networks can occur due to unsymmetrical loads or generators, such as single-phase PV systems. Voltage unbalance can reduce the available voltage headroom and therefore the network hosting capacity. For instance, a single-phase PV generator causes an about 6 times higher voltage rise than a symmetrical 3-phase generator of the same power [45].
Having recognised the importance to balance the single-phase infeed over the three-phases, some DSO-planning rules recommend to connect single-phase generators to the phase number obtained from equation (5), where Φ is the phase of connection (L1,L2 or L3) and *mod* is the reminder after division [46].

$$\boldsymbol{\Phi} \approx \boldsymbol{mod}(\boldsymbol{HouseNumber}, \mathbf{3}) + \mathbf{1} \tag{5}$$

Figure 75 illustrates the dependence of the hosting capacity on the length of the feeder and the voltage limit, following the approach shown in chapter 8.1 (Figure 85). The underlying data for the figure is based on a load flow computation of a simplified LV feeder (95 mm^2 aluminium cable) with one PV system and one line segment. The y-axis represents the maximal generation that does not results in over-voltage or over-loading. The x-axis represents the feeder length (note that a LV feeder has been considered). The lines in the diagrams represent the locus of the hosting capacity depending on line length. In addition, various voltage limits have been considered (1.005 p.u. to 1.1 p.u.).
Figure 75 shows that the hosting capacity starts being limited by loading and turns to be limited by the voltage limit at the length called “critical length” in [47]. The higher the voltage limit, the longer the “critical” length is.
The comparison between the case with a single-phase connection (right part of Figure 75) and the case with a symmetrical connection (left part of Figure 75) shows that the hosting capacity is about 6 times lower in the area of voltage constraint and 3 times lower in the area of loading constraint. For example, at the length of 600 m and the voltage limit of 1.1 p.u., the hosting capacity is about 15 kW in the case of single-phase connection for this particular feeder. For a three-phase connection, the hosting capacity of the feeder equals 90 kW.

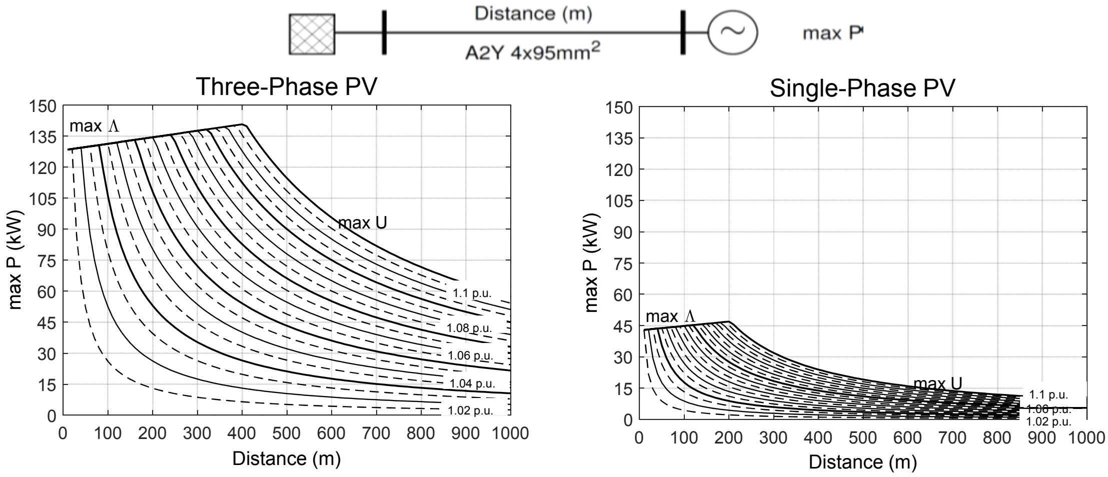


Figure 75 (Hosting capacity depending on the voltage limit and feeder length [48])

In addition to the increased voltage rise caused by unsymmetrical infeed, a neutral point displacement occurs and affects the other phases [45]. This can result in a severe voltage decrease in one phase and in an increase of the voltage unbalance factor which is a power quality indicator defined as the ratio between the positive and the negative sequence components [49]. In addition to these impacts on power quality, unsymmetrical infeed might lead to a strong increase of the current in the neutral conductor and therefore increase the losses [50].

Most of the previously mentioned effects of unsymmetrical infeed affect directly the hosting capacity. In fact, although some concepts have been proposed recently to actively reduce the voltage unbalance by unsymmetrical control of PV-inverters [49], [51]–[53], trying to solve the problem at its source appears quite natural. Phase balancing, which consists of trying to distribute the unsymmetrical infeed as well as possible over the three phases, can therefore be considered as a feasible solution to increase the hosting capacity [54]–[56].

The work summarised in this chapter focuses on phase balancing to increase the hosting capacity and an unbalance indicator is therefore defined as the difference between the highest and the lowest phase voltages in p.u. (phase spreading), considering the generation only[53]. Having three phase voltages with 103 %, 99 % and 95 % would result in an unbalance indicator (later *unbalance* only) of 8 %. The highest unbalance value among all buses is considered as the unbalance value of the feeder.

This work is based on the concept introduced in [54], which consists of determining a Pareto-efficient improvement of the distribution of the infeed over the three phases via Monte-Carlo simulations.

Figure 76 shows the flowchart used to determine the set of Pareto-efficient phase switching. The basic requirement in order to be able to improve the situation with regard to unbalance is to have a detailed knowledge of the situation (i.e. the distribution of the single-phase power over the three phases). This is nowadays possible with most smart meters [57], [58] and enables an optimisation of LV networks.

[53] In reality, the unbalance might change dynamically due to loads. A short discussion is included later.

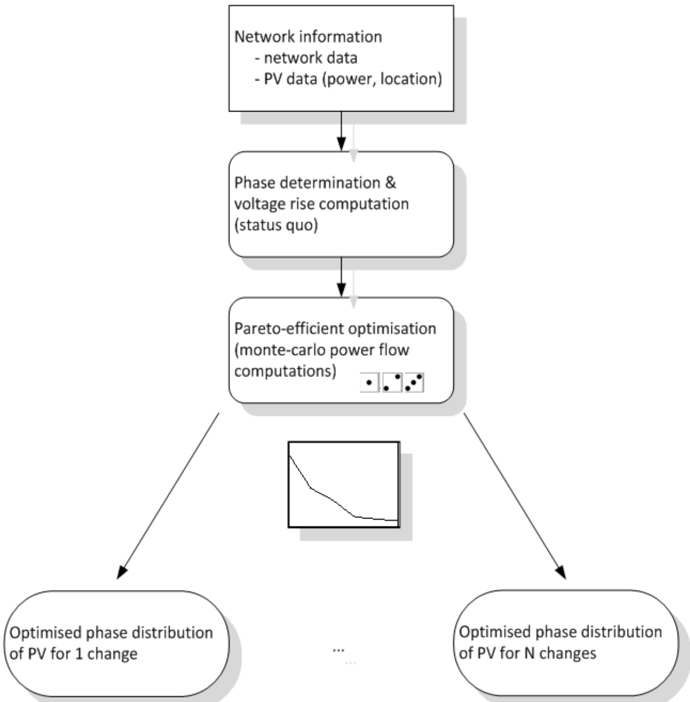


Figure 76 (Flowchart of the pareto-efficient balancing [54])

The basic idea of the Pareto-efficient optimisation is to determine the highest possible improvement with a given number of switches using Monte-Carlo simulations. Since changing the phase assignment of PV installations supposes some significant manpower efforts (e.g. coordination between DSO personal, customers and PV installer), the number of phase assignment changes should be limited.

Figure 77 shows as example the result of the optimisation process for an exemplary feeder. It shows the CDF curve of the voltage rise for a specific feeder with a given number of (single-phase) PV installations. The initial distribution is marked with a circle. By changing the phase assignment in one installation only, a reduction of the voltage rise by more than 1 % can be achieved. By changing the phase assignment in three installations, a reduction of the voltage rise of 2 % can be achieved.

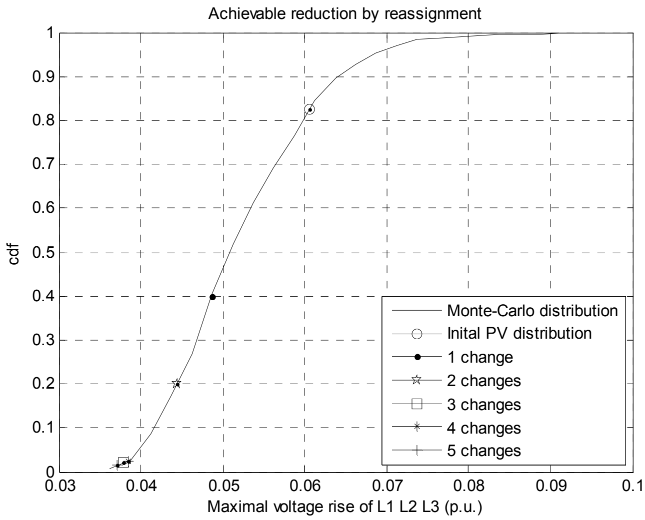


Figure 77 (Minimisation of the voltage rise with up to five switching [54])

In the rest of this chapter, this basic approach will be used, enhanced and applied to a set of networks analysed within the framework of the project IGREENGrid. In comparison to [54], time-domain simulations with profiles over one year have been performed in order to determine the effective improvement in terms of decrease of voltage rise and in terms of network losses.

7.4.1 Methodology for the determination of an improved phase distribution

In order to investigate and quantify the potential of balancing the unsymmetrical power, some reference scenarios are needed. Scenarios are defined on the basis of the hosting capacity and the unbalance that can occur in the considered feeders, following the basic idea that phase balancing will have a great potential in feeders exhibiting a low hosting capacity due to a high voltage unbalance. Using a Monte-Carlo simulation, a large number of scenarios has been defined and simulated and a reference scenario has been selected: it corresponds to the 20th percentile of the hosting capacity and the 80th percentile of the unbalance.

The generation of possible scenarios has been implemented using pseudorandom phase connections (A, B, C) and nominal power values from a uniform distribution. The procedure uses 10 000 scenarios, so that every step represents a unique configuration of PV systems in terms of power distribution along the feeder and over the three phases. For each of these scenarios, the hosting capacity and the voltage unbalance (defined as previously mentioned as the phase spreading) are calculated. A two-dimensional graphic can be created (Figure 78) that represents all scenarios in a plane of hosting capacity and voltage unbalance. This figure shows for example the three hosting capacity-scenarios of 80th, 50th and 20th. The points in the region around the hosting capacity scenarios (± 5 %) are selected to create sub-sets, and the 80th percentile of unbalance in every sub-set defines the scenarios for further studies.

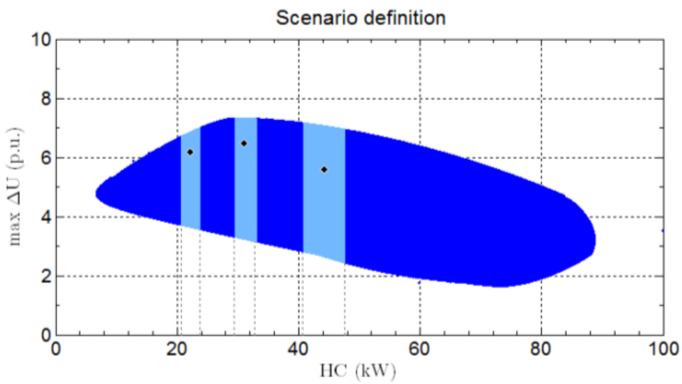


Figure 78 (Method to define scenarios based on unbalance and hosting capacity)

The phase-switching is implemented using a Monte-Carlo procedure (see flowchart in Figure 76). The method is applied for the number of nodes to be switched between one and five sequentially. First, random phase-switching is applied to one node for a large number of iterations (2 500). A load flow calculation is run to obtain the corresponding change in unbalance and the configuration of the network is restored to the initial state. Then the same procedure is repeated for phase-switching at two nodes, and so on. After a certain number of iterations (2 500), the best results for every number of switched nodes (1…5) is chosen as the solution. An example outcome of phase-switching process is shown on Figure 79.

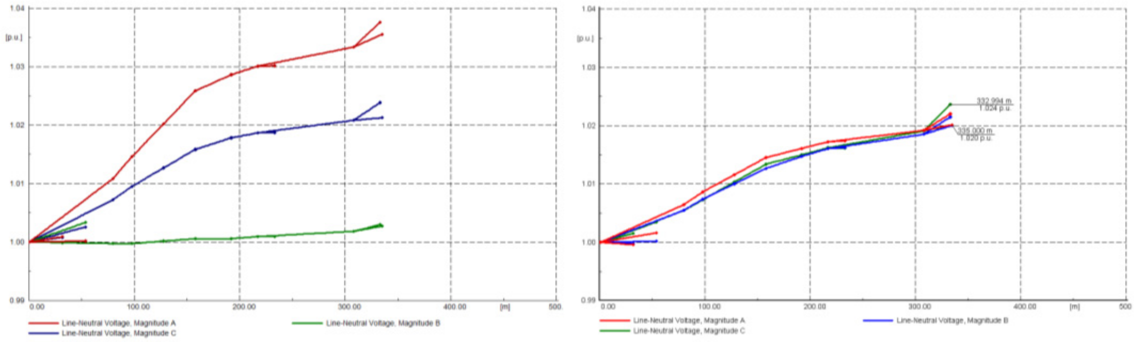


Figure 79 (Unbalance reduction before and after phase-switching)

In the following chapters, the main results of the scenarios definition and of the quantification of the benefits (in terms of voltage rise decrease and decrease of losses) are summarised. The quantification of actual benefits has been accomplished using statistical samples of PV profiles and smart meter measurements[54]. The work has been done for the LV networks provided by EAG, ERDF and RWE. The detailed results are shown in Annex 2.

7.4.2 Definition of scenarios for optimisation

The scenarios that have been defined for phase-switching correspond to the 20th percentile of hosting capacity. The loads have not been considered at this step, and the PV systems have the power factor of 1. The sets of scenarios are presented on Figure 80 for 2 exemplary feeders, that are predominantly current-constrained (left) and voltage-constrained (right). The red dots represent scenarios leading to the current-constraint and the blue dots scenarios leading to the voltage–constraint. In the feeders that are illustrated in the figure, both variants of limitations are observed.

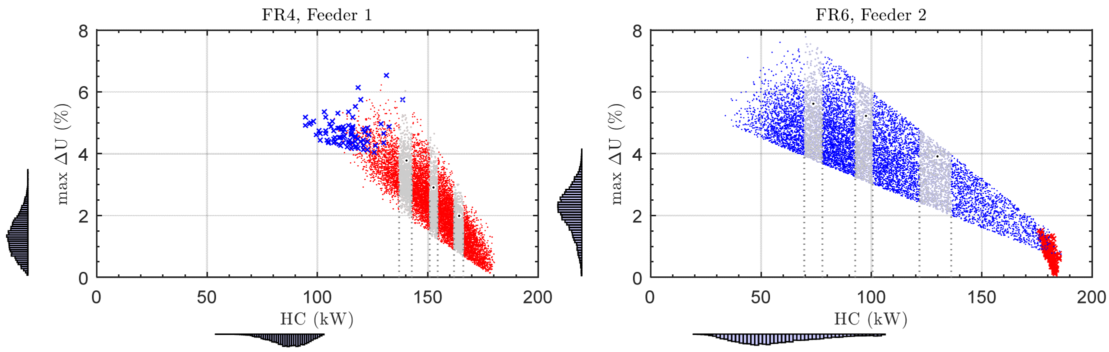


Figure 80 (Scenarios of 2 example feeders)

The y-axis of Figure 80 corresponds to the unbalance in p.u. (phase spreading), and the x-axis to the hosting capacity in kW. The grey areas are the sets that contain the required scenarios, and the black points represent the chosen scenarios. As explained previously, a scenario with a large expected benefit is considered (low hosting capacity (20 % percentile) and large unbalance (80 % percentile)). The figures for all considered feeders are included in the Annex 2.

[54] Smart Meter data from Nordrhein-Westfalen (Germany), 2013 (RWE Deutschland AG, E-Energy Projekt E-DeMa)

7.4.3 Quantification of the benefits of Phase-switching

The actual benefits of the proposed phase balancing are evaluated in terms of decrease of voltage spreading (which is available for the connection of further generators) and in terms of decrease of network losses. Although a quantification of the additional hosting capacity would be interesting, its determination would need a very large number of assumptions (location, size, phase of each additional generator). For this reason, it has not been determined.

Figure 81 shows the outcome of the phase balancing for the three considered scenarios (20 %, 50 % and 80 %) when considering up to five switching actions. These results are only based on purely “static” simulations considering only the installed capacity of each PV generator (loads and PV profiles are not included). This figure therefore shows the expected reduction of unbalance for the theoretical case of maximum PV generation and no consumption. The contribution of PV to the network unbalance is in this case isolated from the unbalance of loads. The expected benefits are used as the reference to evaluate the results of the time-domain simulations.

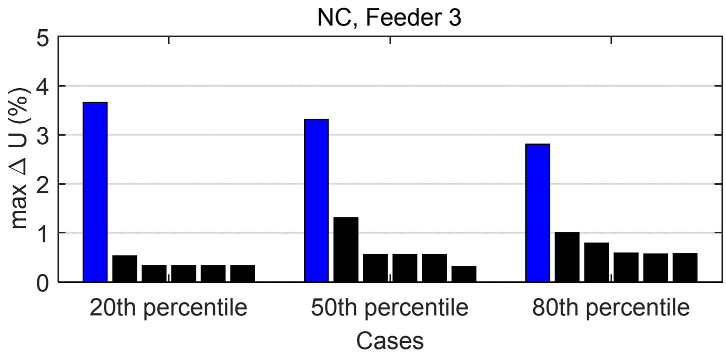


Figure 81 ("Pareto-optimal" phase balancing in NC_F3)

On Figure 81, the first bar is the unbalance before optimization and the blue colour indicates that the hosting capacity is limited by voltage constraint. The first switching has a substantial benefit and the next ones have a lower impact. In this case, following the Pareto principle, the phase would be switched only at one installation since additional efforts would only result in a very small further improvement.

The final analysis of the performance of the proposed method is done using a time-domain simulation. It is based on the load flow calculation of the selected scenarios with Monte-Carlo samples for PV generators and loads. The samples are based on actual measurements of PV and consumption during one year (following the same statistical distribution), allowing to draw conclusions about the real expected benefits. The procedure allows calculating the probability of occurrence of overvoltage and high unbalance level. Furthermore, it allows calculating the network losses within one year.

Figure 82 shows the CDF-curve of the maximal voltage spreading (left) and of the maximal voltage (right) before and after phase balancing (the results for the other networks/feeders are shown in Annex 2). This figure shows that the maximal unbalance is lower after the phase balancing (the 98^{th} percentile of the phase unbalance is decreased by slightly less than 2 % of the nominal voltage). However, the maximum value is almost not affected by the balancing (remaining around 5.5 %) due to the fact that it is probably mainly caused by unsymmetrical loads. For the maximal voltage, the situation is different and the maximum voltage can effectively be decreased by about 1.5 % of the nominal voltage.

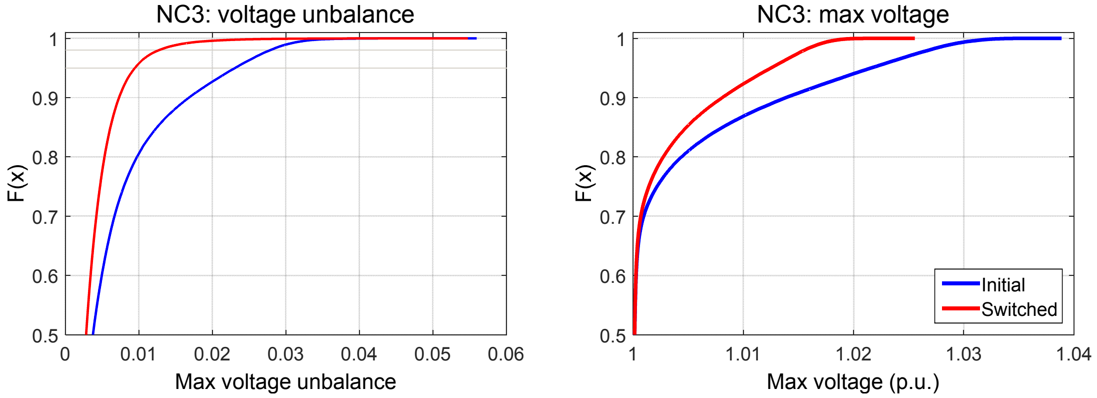


Figure 82 (ECDF of the initial and new ΔU and U_{max} in %)

The results seen on Figure 82 have been observed for most of the feeders considered: the benefits in terms of voltage spreading reduction at the 100^{th} percentile are lower than expected, due to the unsymmetrical loads. Figure 83 shows the same type of results for three different feeders, considering two different percentiles (100^{th} and 99^{th}).

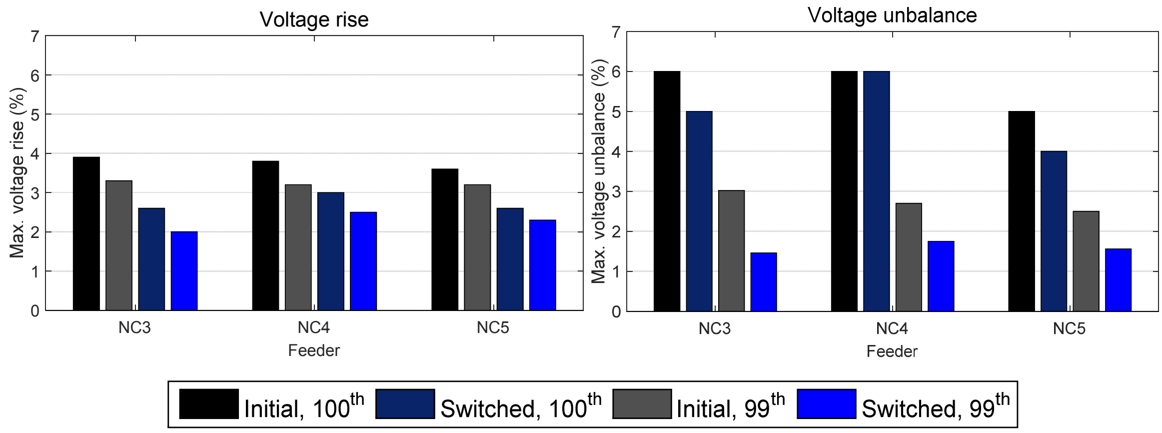


Figure 83 (Actual benefits of phase balancing)

For example, the 99^{th} percentile of the unbalance is reduced by 1.50 % for feeder NC3, by 1 % for NC4 and by 1% for NC5, which represents an improvement of 30 % to 50 %. In the case of NC4, the 100^{th} percentile is not even lowered at all (unbalance situation driven by loads only).

A similar analysis can be done for the maximal voltage rise (right part of the figure). The 99^{th} percentile of the voltage rise can be reduced by 0.75 to 1.2 % for these three feeders which also represents an improvement of 30 % to 50 %. This reduction of the voltage rise provides the potential to increase the hosting capacity (between 43 % and 100 % considering a linear relation).

Finally, the losses before and after the optimization have been evaluated and are shown for the chosen feeders in Table 13. The losses shown in this table are rather low due to the presence of a non-negligible amount of PV generation (reducing the total demand, mentioned as “load” here). The right approach would be to compute the energy efficiency KPI (see chapter 6.1.3.3.1) but since the produced PV energy is constant for the two considered cases (before and after phase balancing), a simple comparison is possible. The relative reduction of the network losses varies between 4.7 % and 11.8 % for the feeders considered here (more comprehensive results are provided later on).

Table 5: Losses in NC feeders

Feeder	Losses, kWh	Relative to load	Relative to load, switched	Relative reduction
NC3	455	0.53 %	0.46 %	11.8 %
NC4	562	0.69 %	0.65 %	4.7 %
NC5	909	0.8 %	0.75 %	6.5 %

Table 13 (Reduction of losses through balancing)

These results show as expected that phase-switching is beneficial for network losses.

7.4.4 Summary and discussion of the deployment potential of the solution "Phase balancing"

An implementation of the phase-balancing in LV networks requires information about the phase connections of customers, in order to clearly identify the initial situation. This requires the phase identification function implemented in smart meters. To be efficiently used, such meters should be area-wide installed in order to allow the DSO to identify the LV feeders with the most severe unbalance in order to decide which feeders should be improved and to prioritise the work. Some further work has been done in [22].

The proposed phase balancing concept allows improving the distribution of the singe-phase infeed over the three phases. The real potential of this solution strongly depends on the unbalance level of existing networks, which is in most cases unknown. In a limited number of feeders, the unbalance level might reach high values. Having a tool to identify such feeders and to determine the most "economic" (Pareto-principle) way to better balance the unsymmetrical infeed would allow DSO to improve the situation in these feeders with limited and targeted efforts.

For the considered feeders, the actual benefits are slightly lower than those theoretically expected due to the load unbalance which is not taken into account in the optimisation process. The voltage unbalance (considered in this study to be the spreading between phase voltages) could be reduced by 20 % to 30 %. The maximal voltage could be reduced to the same extent. In scenarios with higher penetration levels, the benefits are expected to be even higher.

8 Statistical analysis and classification of LV feeders

This chapter summarises the research done on a comprehensive set of LV networks obtained for two DSOs (all LV networks of the whole supply area from EAG and SAG, both in Austria). Due to time and resources constraint as well as the availability of simulations models of LV networks, it was not possible to extend this analysis to other DSOs. The methodology developed in this project can however be easily extended to further DSOs provided that the network data is available in a suitable format.

The relevance of these investigations can be justified by:

- On the one hand, the actual hosting capacity of low voltage (LV) networks is usually badly known. This is mainly due to their number, the number of loads connected to them and the general lack of detailed network models, making it difficult to estimate the hosting capacity of the potential of smart grids solutions to enhance it.
- On the other hand, a significant part of the installed photovoltaic capacity is connected to low voltage networks (e.g. about 70 % in Germany [7]), which justifies the need to have a better knowledge of low voltage networks.

Due to the very large number of LV networks, dedicated studies are not possible and statistical analyses are necessary. Considering the sustained growth of DER, the question of the actual replicability potential of smart grids solutions is raised and an answer is expected from different stakeholders (e.g. distribution system operators (DSOs), industry providers). In this context, the work presented in this chapter aims at filling this gap for LV networks.

Due to the fact that the diversity of feeders among networks is very high (one network might have several very long feeders and a few very short feeders), the statistical analyses are performed at feeder level, which has also been proposed for example in [59].

The concept of hosting capacity introduced in [60] is restricted to the two most relevant limitations in distribution networks: the maximal admissible voltage rise and the maximal admissible loading. An illustration of this is shown in Figure 84.

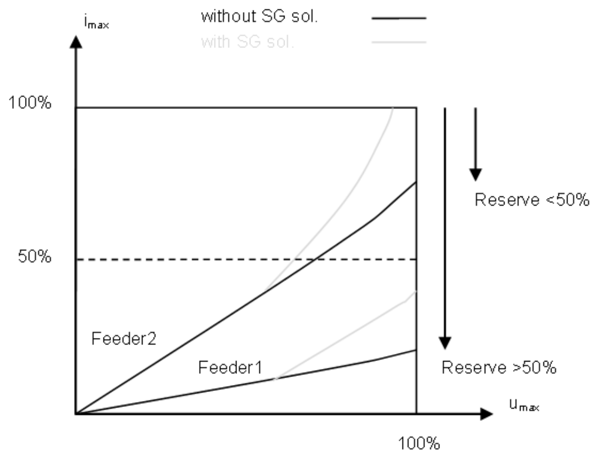


Figure 84 (Hosting capacity visualisation on the U-I plane)

8.1 Theoretical analysis

Following the project objective to evaluate the potential of smart grids solutions aiming at increasing the hosting capacity of existing distribution networks, the approach followed in this work is based on the characterisation of LV feeders in terms of hosting capacity constraint. As previously explained, the hosting capacity has been considered to be limited by two factors only: the voltage and the loading limits. On this basis, feeders can be classified as following:

- Voltage-constrained feeders tend to be limited by the voltage constraint first (usually "long" feeders)
- Current-constrained feeders tend to be limited by the current constraint first (usually "short" feeders)

Figure 85 illustrates this concept showing which of the constraints is actually limiting the hosting capacity. For short feeders (small x values on Figure 85), the hosting capacity is mainly limited by the thermal limit of cables or lines and for long feeders (large x values on Figure 85), the hosting capacity is mainly limited by the voltage limit. The frontier between both constraints has been defined as "critical length" in [47].

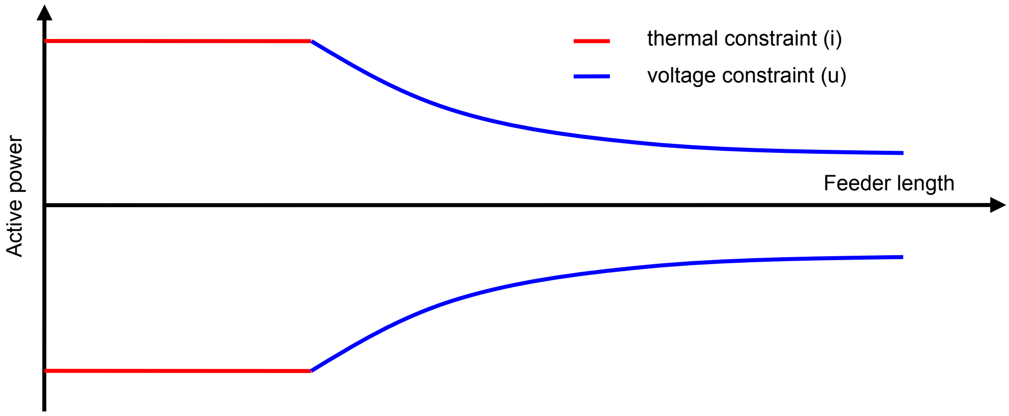


Figure 85 (Schematic visualisation of the feeder classification current constrained feeders vs. voltage-constrained feeders)

In [47], the critical length (frontier between voltage-constrained feeders and current-constrained feeders) has been determined for synthetic continuous feeders (with a uniform DRES penetration) of different types (cable with a cross-section between 50 mm^2 and 240 mm^2 and overhead lines with a cross-section between 50 mm^2 and 120 mm^2, both aluminium). The focus of the investigations in [47] was to determine the minimal length of feeders actually enabling full benefits[55] from a voltage band extension (made possible by the use of a voltage regulated distribution transformer[56]). This investigation consists in determining the length of feeders which are still voltage-constrained even with an extension of the voltage band (extension from +3 % according to current planning rules [54] and [55] to +8.5 % in this paper).

Figure 86 shows the critical length obtained from the calculations. For example, standard cable feeders (150 mm^2) with uniform generation can only benefit from a voltage band extension if their length exceeds about 700 m (or about 990 m with reactive power control).

[55] Feeders shorter than the critical length cannot benefit from the full benefit of the voltage band extension due to the over-loading risk but can partly benefit from it (keeping some margin to the over-loading).

[56] In this report, the term distribution transformer stands for the "last transformer" located in the secondary substation, stepping down the voltage to the LV.

For 70 mm² overhead lines, only feeders exceeding about 501 m (or about 630 m with reactive power control) would actually benefit from the voltage band extension and the reactive power control.

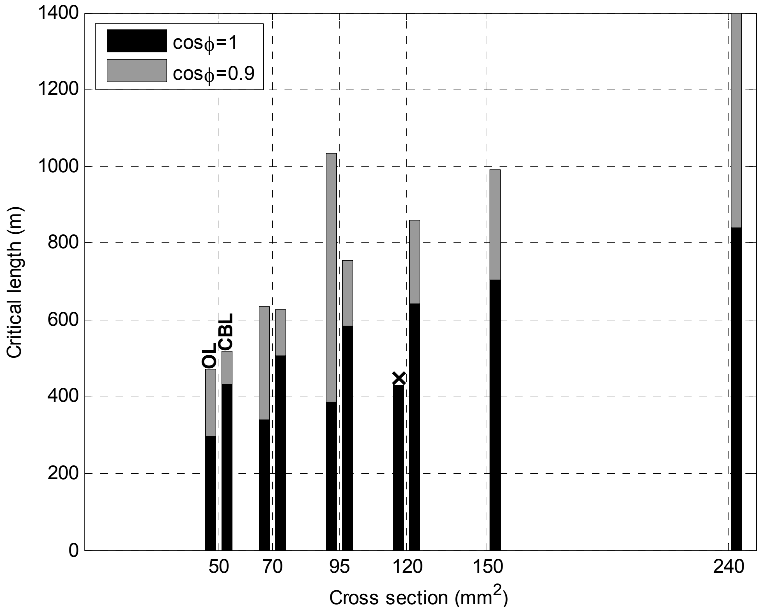


Figure 86 (Critical length with two different power factors for a uniform generation (OL: Overhead Line | CBL: CaBLe))

The rest of the investigations are not based on this simple feeder characterisation, but using as basis a comprehensive set of real feeder data, as explained in chapter 8.3.

8.2 Methodology

In the past years, a few studies aiming at clustering distribution networks have been published [59], [63]–[69]. Most of these studies use some clustering algorithms (e.g. “k-means clustering [32]”) to group feeders or networks with similar properties together. The clustering is usually used on a set of parameters determined systematically for a large set of feeders or networks. These parameters vary significantly from one to another study, depending among others on the data availability. For example, the impedance-based indicators which are used in this study are not considered at all in [59] (because they are not available). One of the severe limitations of such approaches is that there is no guarantee that the clustering result is relevant for the investigated problem (in this report, the quantification of the hosting capacity).

Acknowledging this shorting of most existing studies, the approach followed here is different. It is based on the classification of feeders into two categories (voltage-constrained feeders and current-constrained feeders). The analyses done on the classification of LV feeders is summarised in chapter 8.7.

8.3 Input data and parameters used

In the framework of the project IGREENGrid, the LV networks of the two Austrian DSOs participating to the project (EAG and SAG) have been analysed extensively in order to evaluate the deployment potential of smart grids solutions. The data have been exported from the GIS-database and been imported into the simulation software DIgSILENT PowerFactory [14].
As explained in the introduction, the analysis of the LV networks has been done at feeder level. The first step was to define automatically feeders for each LV network and to run a series of automated scripts to verify the coherence of the data imported from the GIS-export. Among others, the validation included verifications on the following properties:

- Radiality
- Minimal short-circuit impedance
- Maximal geographical distance between nodes

After this initial validation, a set of about 11.000 validated LV networks and 37.000 LV feeders was available.
In order to characterise LV feeders and to quantify the potential deployment of smart grids solutions, suitable indicators have been introduced.

- Descriptive statistics-indicators.
- Hosting capacity related indicators.

The descriptive statistics-indicators include for example the short-circuit impedance at the weakest node, the R/X ratio, the feeder length, the equivalent sum impedance [65], the number of lines and network connections, the average number of neighbours and distance to neighbours, the mesh-factor…
The hosting capacity related indicators are based on a calculation of the hosting capacity for specific scenarios (assumptions). One of the basic assumptions is the distribution of the generation along the feeder (DRES scenario). In this work, 3 scenarios were defined for this purpose. They are briefly defined below, using the example of the indicator hosting capacity:

- "Uniform": generation placed uniformly along the feeder (at all connection boxes) and then scaled-up to reach the hosting capacity (loading limit or voltage limit is reached).
- "Weighted": generation distributed according to the summed annual consumption at the connection boxes) and then scaled-up to reach the hosting capacity. This scenario is relevant when assuming that most of the further DRES deployment will be close to the loads and driven by self-consumption.
- "Eof" ("end of feeder"): generation connected at the "end node" which is defined as the node with the highest voltage for the uniform scenario.

Beside the DRES scenarios, smart grids solutions have been considered in a simple way:

- Reactive power-based voltage control (cosφ(P) and Q(U)).
- Voltage band extension through the use of voltage regulated distribution transformer VRDT (transformer with On-Load-Tap-Changer (OLTC)).

The control-cosφ(P) has been parametrised according to [62] and was operated at full power during the active power scaling (cosφ=0.90). The Q(U)-control has been parametrised according to recommendations from previous projects [30], [70]. In order to investigate the benefits of a voltage regulated distribution transformer, the voltage limits have been extended as proposed in [47] (sensitivity analysis of the impact of the allowed voltage rise on the hosting capacity –see chapter

8.1). Current connection rules [61], [62] foresee a maximum voltage rise of 3 % for the generation embedded in the LV network. In the sensitivity analysis on the impact of the voltage band on the hosting capacity, the maximum voltage rise has been increased up to +8 %. This value of 8 % has been chosen considering that a VRDT allows decoupling the LV from the MV network in terms of voltage level. With an equal allocation of the voltage band to loads (voltage drop) and generation (voltage rise) and a controller dead-band of ±2 %, the maximal voltage rise can be extended to +8 %.

For each of these scenarios, the indicators (e.g. hosting capacity) have been evaluated. Note that loads have are not considered in this work and that the generation is considered to be symmetrical (the issue of unbalance mitigation is addressed in chapter 7.4).

Figure 87 summarises the types of “hosting capacity scenarios” considered to classify the LV feeders.

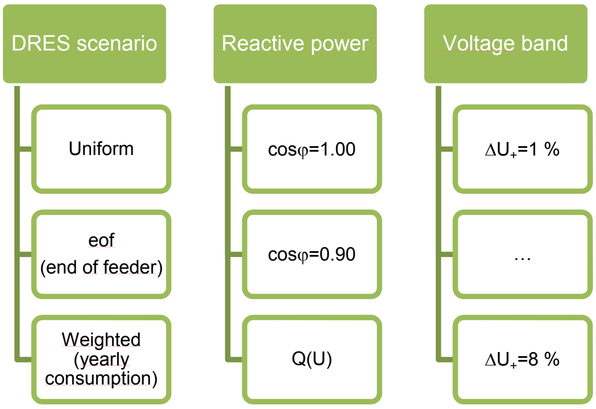


Figure 87 (Overview of hosting capacity scenarios)

Chapters 8.4 to 0 summarise the results based on the dataset from EAG. For some particular analyses, a comparison with the dataset from SAG is provided.

8.4 Basic feeder statistics

This chapter provides some general statistics of the indicators computed. For most of the figures, the statistics also show the share of voltage and current-constrained feeders. The idea behind this is to try to identify parameters which can be suitable to classify feeders.

Figure 88 shows the distribution of the feeder length. For each length class, the share of voltage-constrained feeders is show in blue, the share of voltage and current-constrained feeders in magenta and the share of current-constrained feeders in red (for the DRES scenario “uniform”).

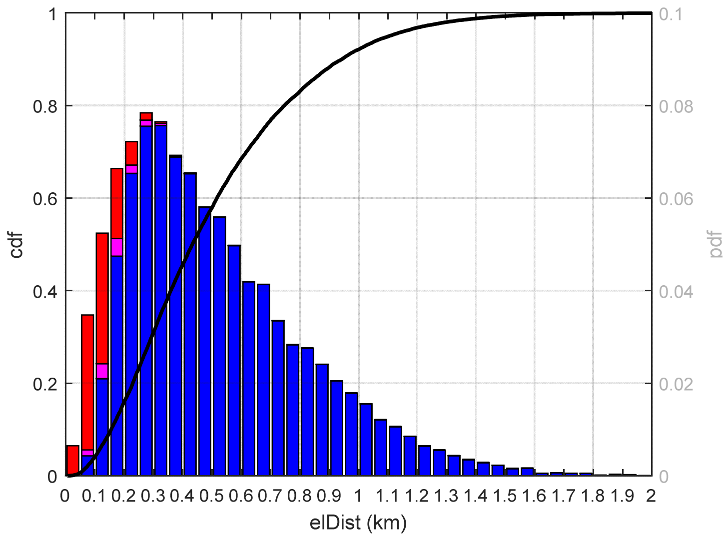


Figure 88 (Feeder length distribution
Maximal electrical length per feeder)

This figure shows that 90 % of the feeders are shorter than 977 m and that current-constrained feeders are typically (99th percentile) shorter than 396 m. Figure 89 shows a similar representation for the equivalent sum impedance.

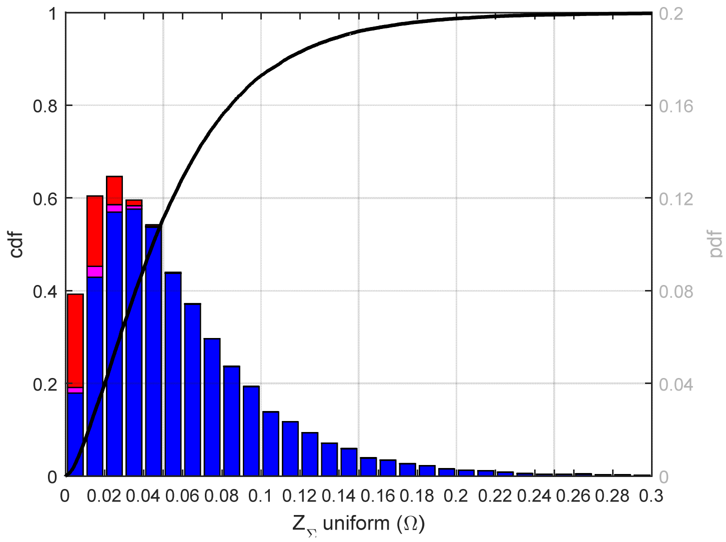


Figure 89 (Equivalent sum impedance
DRES scenario: uniform)

Figure 90 shows the distribution of the short-circuit impedance at the weakest node (the reader should have in mind that the impedance of the distribution transformer is not included). The impedance at the weakest node is for the majority of the feeders (90th percentile) below 0.36 Ω and for almost all the feeders (99th percentile) below 0.58 Ω. The reader should note that these statistics are related to the weakest node of each feeder and should be carefully interpreted (e.g. compared to the reference impedance of 0.28 Ω [71]).

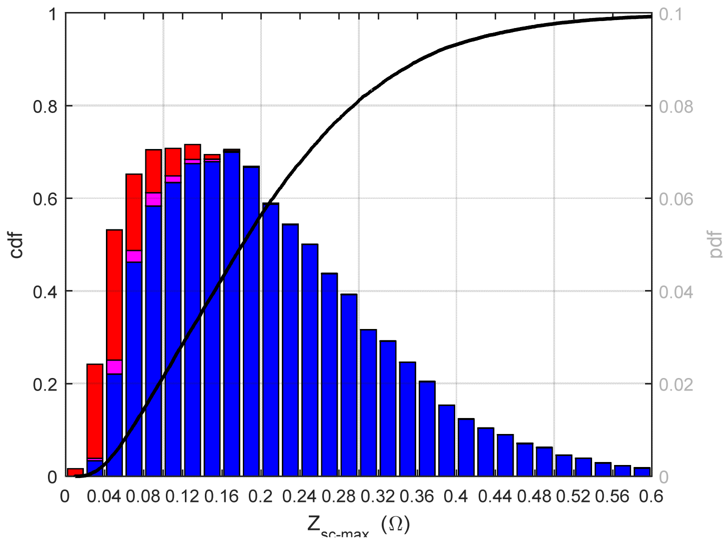


Figure 90 (Short-circuit impedance at end node DRES scenario: uniform)

Figure 91 and Figure 92 show the distribution of the average distance to neighbours as well as the average number of connections per feeder.

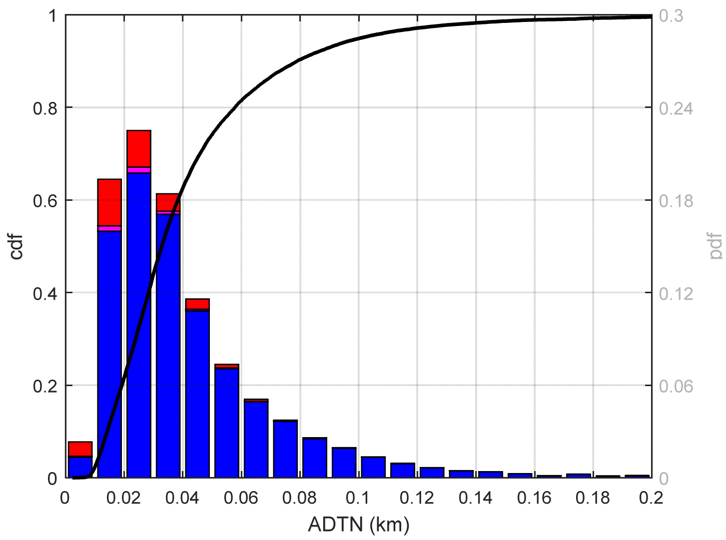


Figure 91 (Average distance to neighbour)

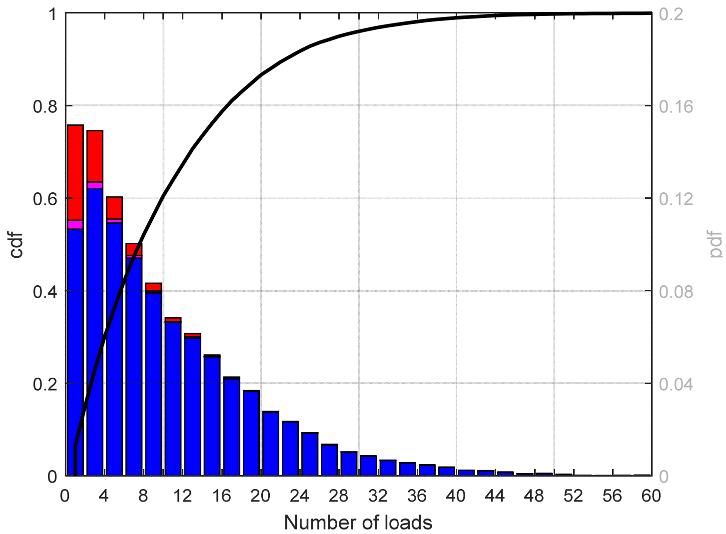


Figure 92 (Number of network connections per feeder)

Figure 93 shows the average line length per network connection.

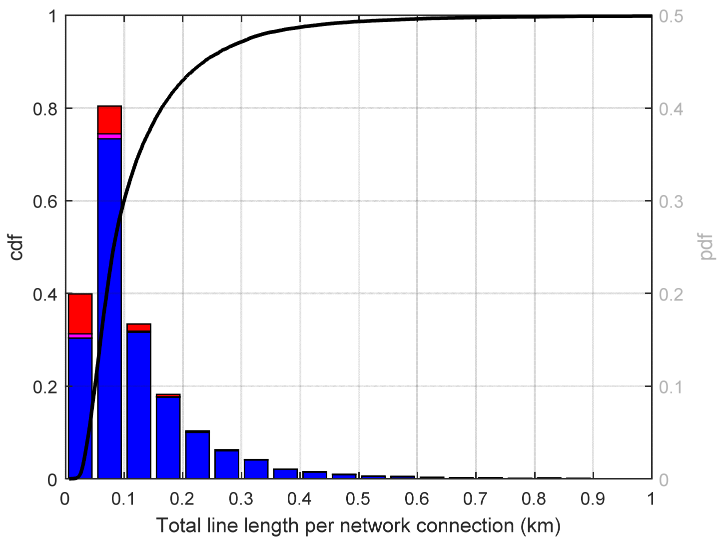


Figure 93 (Average line length per network connection)

Finally, Figure 94 shows the distribution of the R/X ratio at the end node for the DRES scenario "uniform" (the reader should have in mind that the impedance of the distribution transformer is not included). This figure shows as expected that the R/X ratio is almost always above 1 and that only about 21 % of the feeders have an R/X ratio below 2.4 which allows a compensation of the voltage rise by 20 % with cosφ=0.90. The large peak for an R/X ratio of 2.6 corresponds to the most common cable type Al150 mm^2.

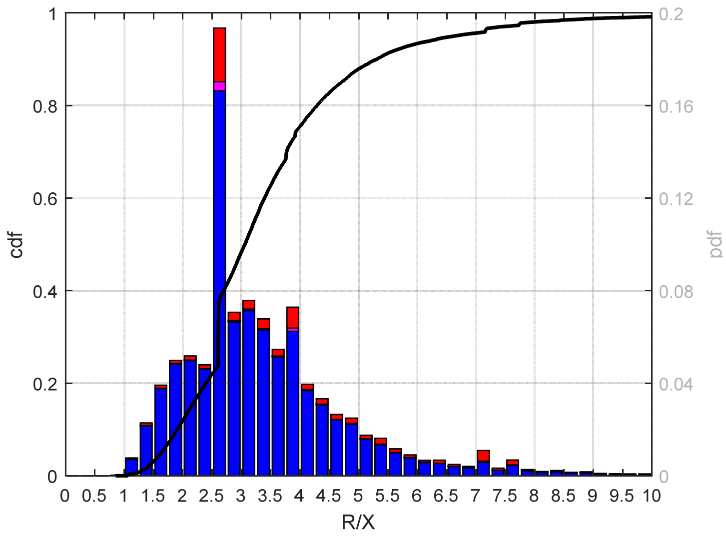


Figure 94 (R/X ratio at end node
DRES scenario: uniform)

The same analysis for SAG resulted in comparable values with however some differences (which will be explained later). As expected, the observation of simple characteristics of the feeders does not allow easily classifying feeders into voltage-constrained feeders and current-constrained feeders.

8.5 Hosting capacity statistics

Figure 95 shows the distribution of the hosting capacity computed for the uniform DRES scenario.
The hosting capacity is limited to about 148 kW for the majority of the feeders (90^{th} percentile), or to 230 kW for almost all the feeders (99^{th} percentile). 99 % of the current-constrained feeders have a hosting capacity greater than 68 kW while 99 % of the voltage-constrained feeders have a hosting capacity lower than 186 kW.
This distribution exhibits two peaks (for the current-constrained feeders) corresponding to the most two common cable types $Al95mm^2$ and $Al150mm^2$ (128 kW and 187 kW respectively).

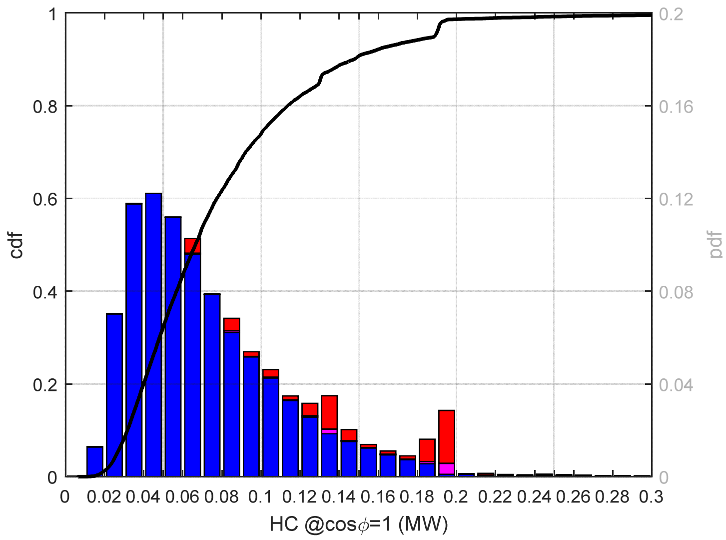


Figure 95 (Hosting capacity - EAG DRES scenario: uniform)

Further analyses show no major difference between the DRES scenario “uniform” and “weighted” but there are some significant differences between “eof” (end of feeder) and “uniform”, especially for feeders with low hosting capacity.

Figure 96 shows the results of the same evaluation with some differences – note the difference in the x-axis scaling. The peak corresponding to current-constrained feeders with Al150 mm^2 cables is even larger due to the higher share of urban networks for SAG.

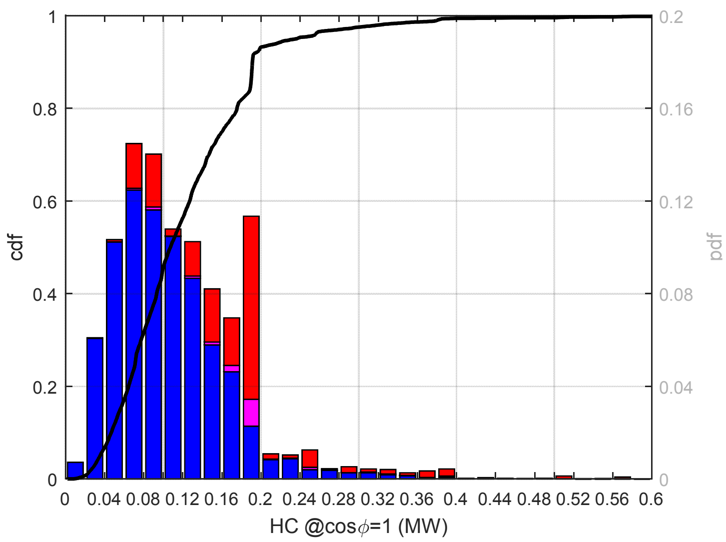


Figure 96 (Hosting capacity - SAG DRES scenario: uniform)

8.6 Statistics dedicated to the S&R analysis

This chapter investigates the scalability and replicability potential of two basic smart grids solutions:

- Extension of the voltage band by using distribution transformers with On-Load-Tap-Changers (OLTC) (sub-chapter 8.6.2)
- Reactive power control to reduce the voltage rise (sub-chapter 8.6.3)

The first sub-chapter (8.6.1) provides an analysis of the current situation ("AsIs") using the current planning rules (i.e. allowed voltage rise of 3 % and maximal loading of 100 %) and without smart grids solution.

Sub-chapter 8.6.4 investigates the impact of the loading-reserve on the results, acknowledging that implementing smart grids solutions to enhance the hosting capacity implies a direct and sometimes indirect increase of the loading. Considering that the maximum loading of overhead lines and cables cannot be easily monitored or even evaluated during the planning process, some reserves should be kept in order to be sure that overloading is avoided even considering the uncertainties of the planning process.

Finally, sub-chapter 8.6.5 investigates the homogeneity of feeders which is particularly relevant for smart grids solutions based on a distribution transformer with OLTC.

8.6.1 AsIs (current planning rules, no smart grids solution)

Figure 97 shows the share of voltage (blue) and current (red) -constrained feeders on the "U/I plane" (magenta is used for feeders which are voltage and current-constrained). Each point on the main part of the figure (upper right) represents a feeder which is coloured according to the constraint. This figure shows that about 90 % of the feeders are voltage-constrained, confirming that meeting the voltage limits is dominantly limiting the hosting capacity for the great majority of the feeders. Additionally, this figure shows that most of the voltage-constrained feeders (blue) are "far from the corner" (voltage and current constraint) which means that the maximal loading of most of the voltage-constrained feeders is rather far from the 100 % loading limit. For 50 % of the voltage-constrained feeders, the maximal loading is below 37 % which means that there is a large reserve in respect to over-loading. This means that there is a priori a large deployment potential of smart grids solutions aiming at controlling the voltage (without observing the loading) without taking the risk or running into overloading.

The result of the same analysis is shown ion Figure 98 for SAG. A comparison between Figure 97 and Figure 98 shows that the share of current-constrained feeder is more than twice larger for SAG which is due to the characteristics of the supplied area (significantly larger share of urban area).

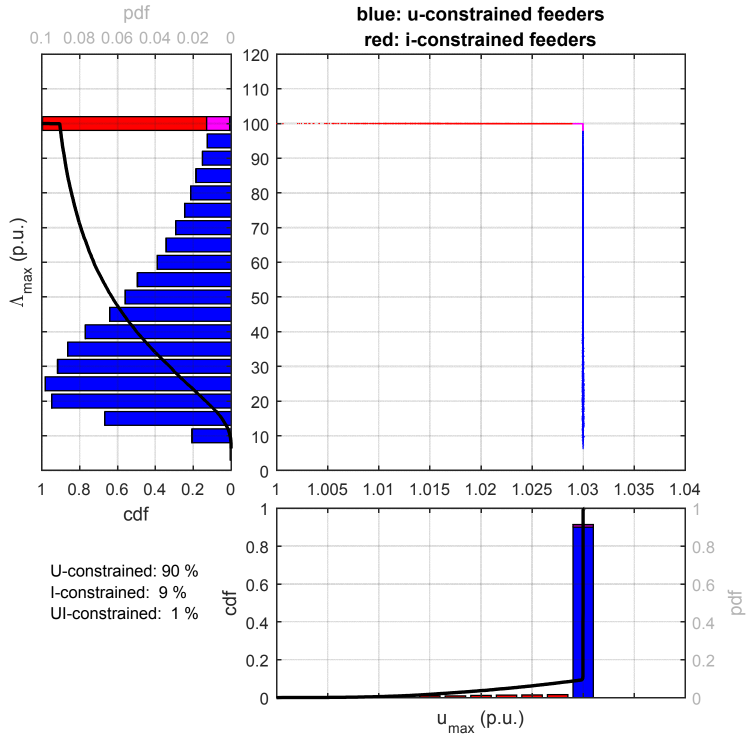


Figure 97 (Share of voltage- and current-constrained feeders – EAG Umax=1.03 p.u. – Imax=100 % DRES scenario: uniform)

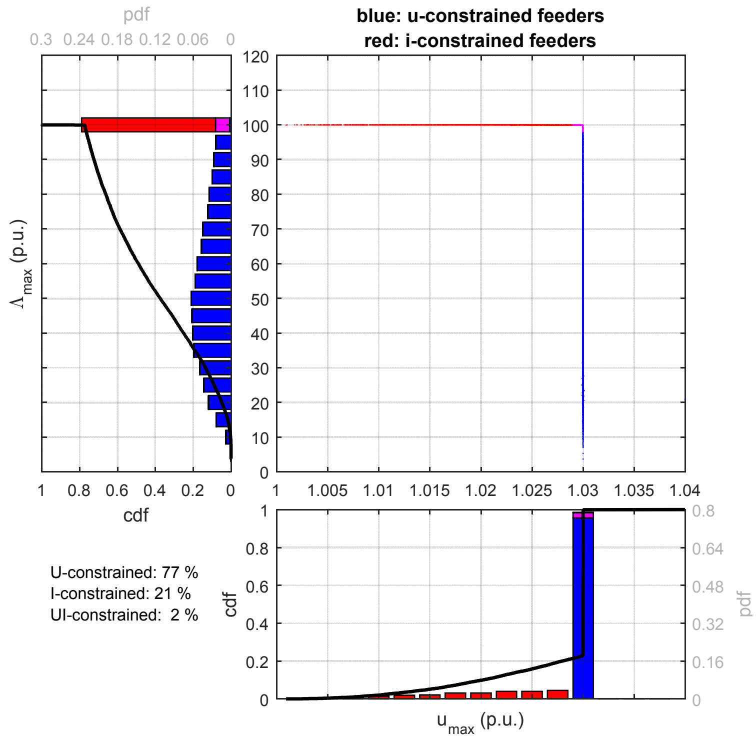


Figure 98 (Share of voltage- and current-constrained feeders – SAG Umax=1.03 p.u. – Imax=100 % DRES scenario: uniform)

Further analyses show that there is almost no difference between the DRES scenario “uniform” and “weighted” and only a small one between “eof” (end of feeder) and “uniform”. For a uniform distribution of the generation along the feeder, the share of voltage and current-constrained feeders is 90 %/10 % while it is 92 %/8 %, assuming that all the generation is connected at the end of the feeder.

Figure 99 shows the feeder hosting capacity per network connection. This figure shows that 50 % of the feeders have a hosting capacity below 8 kW per network connection[57] (practically all (>99.7 %) voltage-constrained).

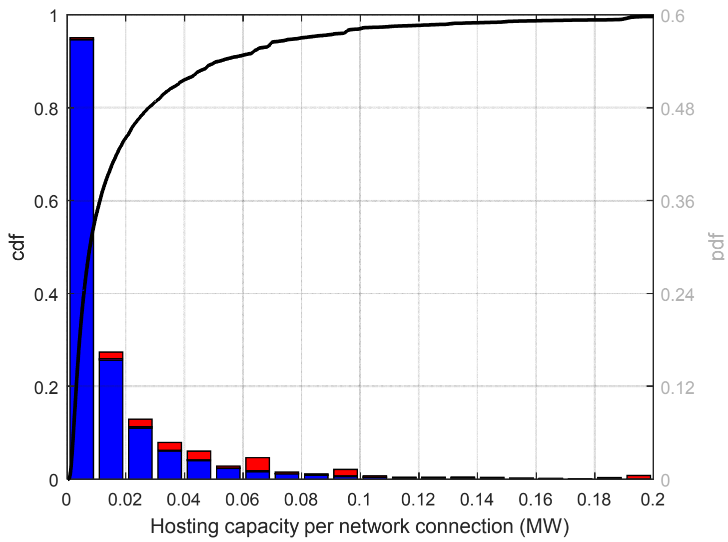


Figure 99 (Hosting capacity per network connection
Umax=1.03 p.u. – Imax=100 %
DRES scenario: uniform)

8.6.2 Impact of an extended voltage band (≡OLTC)

Figure 100 shows the result of a sensitivity analysis performed to investigate the impact of the allowed voltage rise on the share of voltage and current-constrained feeders for the DRES scenario “uniform”. For this, the maximal voltage has been changed from 1.01 p.u. to 1.08 p.u. (meaning in fact that the allowed voltage rise has been varied between +1 % and +8 %). As expected, the share of voltage-constrained feeders decreases if the allowed voltage rise increases. When doubling the voltage rise allowed according to current planning rules [72][73] (+3 %), the share of voltage and current-constrained feeders changes from 90 % / 10 % to 60 % / 40 %. The extension of the allowed voltage rise to +8 % would correspond to a scenario in which all the secondary substations have a distribution transformer with on-load-tap-changer, reserving a voltage hysteresis of ±2 %. With this extreme assumption, about 43 % of the feeders are still voltage-constrained. In other words, this means that the maximum increase of the hosting capacity offered by a distribution transformer with on-load-tap-changer can be actually used “only” in about 43 % (this is a large share due to the fact that most of the area supplied by this DSO is rural) of the feeders.

[57] A network connection can be a whole building or a connection box used for a single-house.

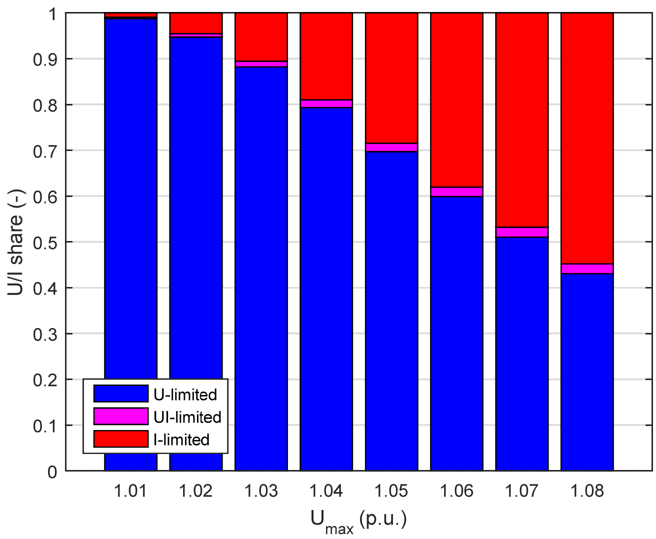


Figure 100 (Share of voltage- and current-constrained feeders
Umax=[1.01 - 1.09] p.u. – Imax=100 %
DRES scenario: uniform)

For comparison purpose, Figure 101 shows the result of the same evaluation for the three considered DRES scenarios (“uniform”, “end of feeder” and “weighted”). As previously, the scenarios “weighted” and “uniform” lead to very similar results. The scenario “end of feeder” leads to a higher share of voltage-constrained feeder (almost 10 percentage points).

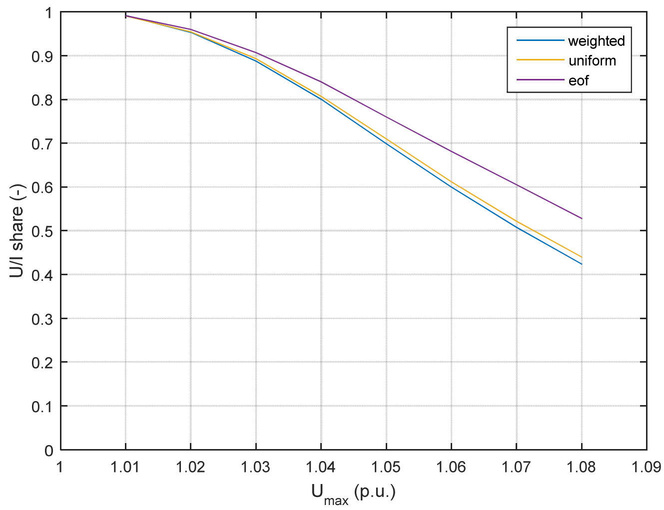


Figure 101 (Share of voltage- and current-constrained feeders
Umax=[1.01 - 1.09] p.u. – Imax=100 %
DRES scenario: uniform, end of feeder, weighted)

Figure 102 shows the distribution of the hosting capacity for the reference voltage band (+3 % voltage rise – data on the x-axis) and for the extended voltage band (+8 % voltage rise – data on the y-axis). This figure shows a clear shift towards a higher loading.

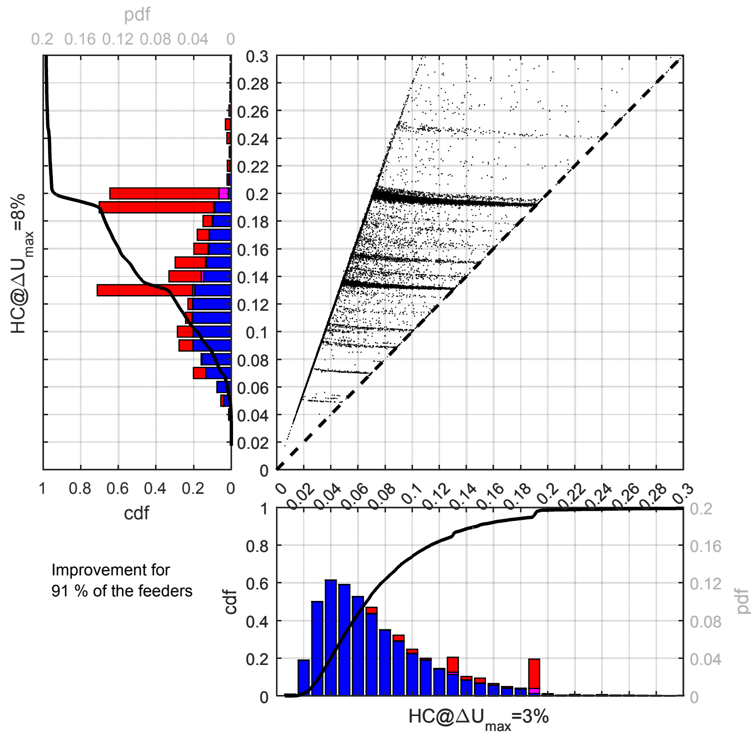


Figure 102 (HC increase
Umax=1.03 and 1.08] p.u. – Imax=100 %
DRES scenario: uniform)

The average feeder hosting capacity increases for feeders which remain voltage-constrained from about 44 kW to 123 kW (+179 %) when increasing the allowed voltage rise from +3 % to +8 %. The AsIs average hosting capacity of voltage-constrained feeders is significantly higher (71 kW compared to 44 kW) due to the fact that feeders remaining voltage-constrained are necessary far from the loading constraint (long rural feeders) which means that they generally have a low hosting capacity.

In other words, the expectancy value of the hosting capacity increase for an extended voltage band for feeders which can actually benefit from it is very high: +179 %.

The horizontal lines correspond to the rating of typical cables (e.g. 270 A ~ 190 kW for 150 mm^2 cables or 70 mm^2 overhead lines).

8.6.3 Impact of reactive power control (≡cosφ(P) or Q(U))

Figure 103 shows the expected hosting capacity increase with reactive power control (cosφ(P) according to [62]). The colouring of the curve corresponds to the constraint of the reference case (without reactive power control).

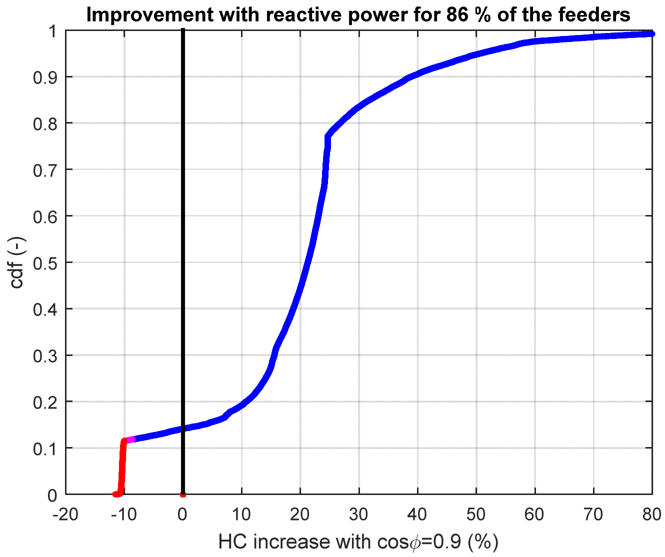


Figure 103 (HC increase with cosφ=0.9 Umax=1.03 p.u. – Imax=100 % DRES scenario: uniform)

According to this figure, the expected hosting capacity increase:

- Exceeds +30 % for about 17 % of the feeders.
- Is between +20 % and 30 % for about 28 % of the feeders.
- Is below +20 % for about 31 % of the feeders.
- Is negative (decrease) for about 14 % of the feeders.

Figure 103 should however be carefully interpreted since it does not take into account the constraint corresponding to the operation with reactive power control. The actual benefit of reactive power control should, as for the extension of the voltage band, only be evaluated for feeders remaining voltage-constrained (done in the following).

The inflexion point corresponds to 150 mm^2 cables having a R/X ratio of 2.6 which leads to a hosting capacity increase of about 23 % at cosφ=0.90.

Figure 104 shows the distribution of the hosting capacity without reactive power control (x-axis) and with reactive power control (y-axis). The reactive power control implemented is a cosφ(P) control according to [62] and the colouring is done individually for both cases.

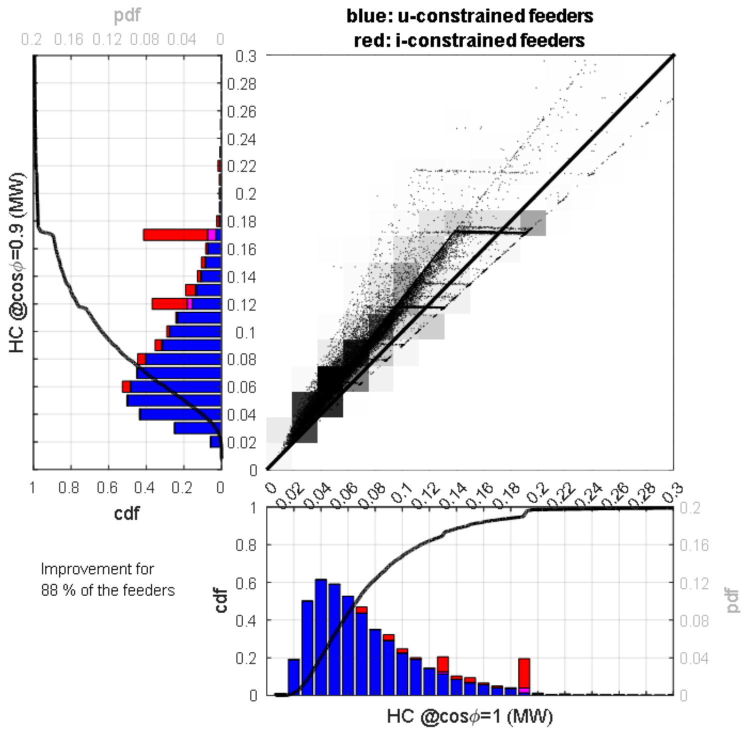


Figure 104 (HC increase cosφ=0.9 vs. HC@cosφ=1 DRES scenario: uniform)

Figure 104 shows as expected an increase of current-constrained feeders (similar effect as for the extended voltage band (see Figure 102) with however a significantly smaller shift.

The full potential offered by reactive power control (cosφ=0.90) can be actually used in 81 % of the feeders (which remain voltage-constrained with reactive power control) and leads to an average increase of the hosting capacity by about +25 % (increase of the average feeder hosting capacity from 63 kW to 79 kW).

In other words, the expectancy value of the hosting capacity increase for reactive power control for feeders which can actually benefit from it, is moderate compared to the voltage band extension but non negligible: +25 %.

Figure 105 shows a comparison between the effectiveness of the Q(U) and the cosφ(P) control (which is used as reference since it is automatically higher).

The Q(U) control generally leads to a lower reactive power consumption since reactive power is only consumed when the voltage is actually high. However, the effectiveness of the Q(U)-control is necessarily lower than the effectiveness of the cosφ(P) control since not all the generators are fully contributing (only those at the end of the feeder).

For most (95 %) of the voltage-constrained feeders, the effectiveness of the Q(U) is not significantly lower (<4 %) than the effectiveness of the cosφ(P). This means that the difference between both controls in terms of effectiveness is very small and confirms previous work on this.

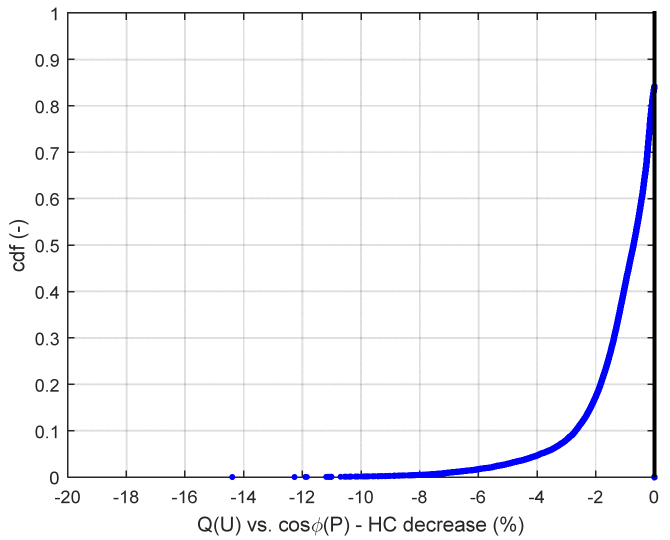


**Figure 105 (Q(U) vs. cosφ(P) – HC decrease
Umax=1.03 p.u. – Imax=100 %
DRES scenario: uniform
(U-constrained feeders only))**

Figure 106 shows the share between voltage and current-constrained feeders (considering in addition an extension of the voltage band) for the following two cases (DRES scenario "uniform"):

- Without reactive power control.
- With cosφ(P) according to [62].

This figure shows that the share of voltage and current-constrained feeders drop from 43 % / 57 % without reactive power control, to 27 % / 73 % with reactive power control (both for an allowed voltage rise of +8 %). This means that the full potential of the reactive power control can in addition to the voltage band extension (by using a distribution transformer with OLTC) "only" be used in about 27 % of the feeders without taking the risk of overloading some line sections.

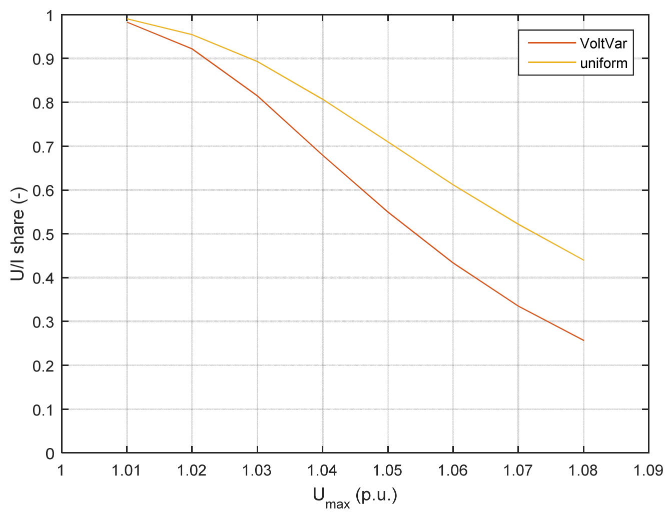


**Figure 106 (Share of voltage- and current-constrained feeders
Umax=[1.01 - 1.09] p.u. – Imax=100 %
DRES scenario: uniform
Control: w/o, Q(U))**

8.6.4 Impact of the loading reserve

Figure 107 shows the impact of keeping a loading reserve (allowing a maximal loading smaller than 100 %) on the share of voltage/current-constraints for the reference case (“AsIs” – upper part), the voltage band extension from +3 % to +8 % (middle part) and the reactive power control (cosφ(P) – lower part). For each of these cases, a reserve of 10 %, 20 %, 30 %, 40 % and 50 % has been considered, and the reserve seems to imply a linear loss of deployment potential in the considered range. Looking at all the three cases at the same time, keeping a 20 %-reserve (maximal loading = 80 %) implies losing a potential by about 20 % (the number of still voltage-constrained feeders is decreased by about 20 %).

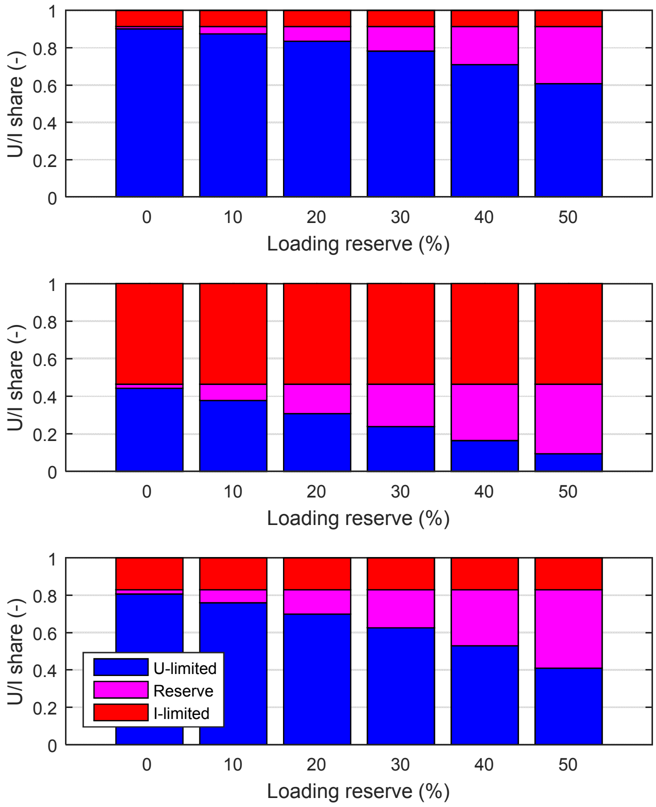


Figure 107 (Share of voltage- and current-constrained feeders Loading reserve = [0,10,20,30,40,50] %, DRES scenario: uniform Upper: Umax=1.03 p.u. @cosφ=1.0 (current voltage band) Middle: Umax=1.08 p.u. @cosφ=1.0 (extended voltage band) Lower: Umax=1.03 p.u. @cosφ=0.9 (current voltage band with reactive power))

8.6.5 Homogeneity of networks

In all the previous analyses and as mentioned in chapter 8.2, the analyses have been made at feeder level. In this sub-chapter, the homogeneity of networks is investigated. The analysis of the homogeneity of networks tries to answer the question of the potential of distribution transformers with OLTC against line voltage regulators which can be connected in feeders which actually need voltage control and need to be decoupled from the rest of the networks. The results shown in this sub-chapter only provide a very partial answer to this question since the feeder behavior is dictated to the greatest extent by the penetration of DRES in the voltage-constrained feeders (namely if all voltage-constrained feeders have a large DRES penetration).

Figure 108 shows the distribution of networks with different shares of voltage-constrained feeders and current-constrained feeders. This figure shows that most of the networks have at least one voltage-constrained feeder. Moreover, a significant part of the networks (about 75 %) only have voltage-constrained feeders. In such feeders, the use of a distribution transformer with OLTC leads to the full expected benefits only if all the feeders actually have a high DRES penetration. A more precise quantification is not possible at the level of details chosen in this study and can only be achieved on an individual analysis considering the local situation (actual load and generation situation).

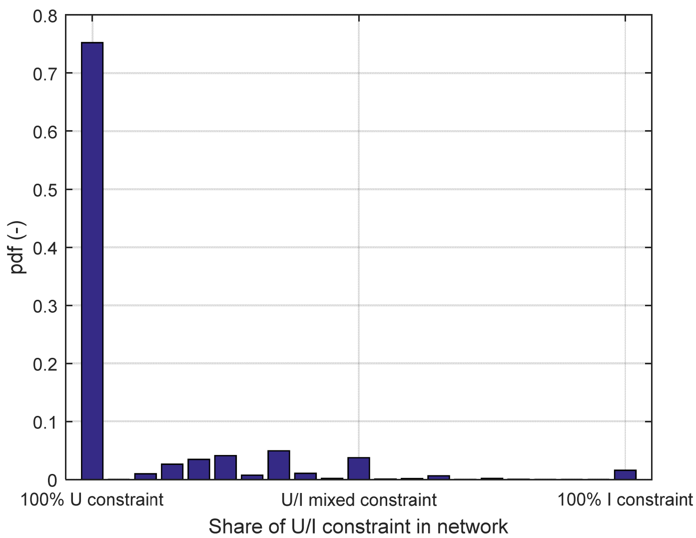


Figure 108 (Distribution of the number of networks according to the share of U/I feeders U/I=100/0, 90/10, 80/20, …, 10/90, 0/100 %)

In [74], the authors also report about the potential of distribution transformers with OLTC against voltage regulators. For this purpose, they use generic networks and define a feeder homogeneity indicator which is based on the load or generation moment factor. The authors conclude that line voltage regulators at feeder level outperform voltage regulated distribution transformers for networks with a high feeder inhomogeneity factor (>0.7). The authors mention that this approach should be applied to real LV networks.

8.7 Feeder classification

In this chapter, the results of classifying LV feeders into two categories, voltage and current-constrained, are presented. The basis is a set of simple indicators that might be available directly from GIS.

In the first sub-chapter, the results of a few dedicated investigations are shown. The purpose of these investigations was to find a set of parameters which would allow distinguishing between voltage and current-constrained feeders. Among others, a correlation analysis has been made in order to ensure that redundant parameters having a high correlation are avoided. The first sub-chapter shows a few analyses from this work.

In the second sub-chapter the results of the classification attempts are summarised.

8.7.1 Initial search for indicators suitable for the feeder classification

Figure 109, Figure 110 and Figure 111 show the distribution of different groups of two parameters to try to find a suitable indicator for the feeder classification. These groups of parameters have been selected on the basis of the most relevant literature, mainly [65].

In [65], the joint examination of the equivalent sum impedance (with a slightly different definition than here – multiplying the equivalent sum impedance as defined in the study by the number of network connections) with the number of loads has been identified as a suitable indicator for clustering networks (countryside, village and suburb). Figure 109 shows the distribution of the feeders according to these two parameters (the colouring shows whether the feeders are voltage (blue) or current (red) constrained). Despite the fact that the red points (current-constrained feeders) are concentrated in a specific area, having a close look at the figure (zoom) shows that many blue points are also present in the “red area”, meaning that this evaluation (alone) does not seem to provide a very high discrimination level.

Figure 110 shows a similar analysis for the parameters equivalent sum impedance (computed according to the definition chosen in this study – note the difference with Figure 109) and the average distance to neighbour which was also identified in [65] to be especially interesting. As for the previous analysis, these indicators (alone) do not lead to a high discrimination level. Finally, Figure 111 shows a similar analysis for the indicators equivalent sum impedance and feeder length, leading to the same conclusion.

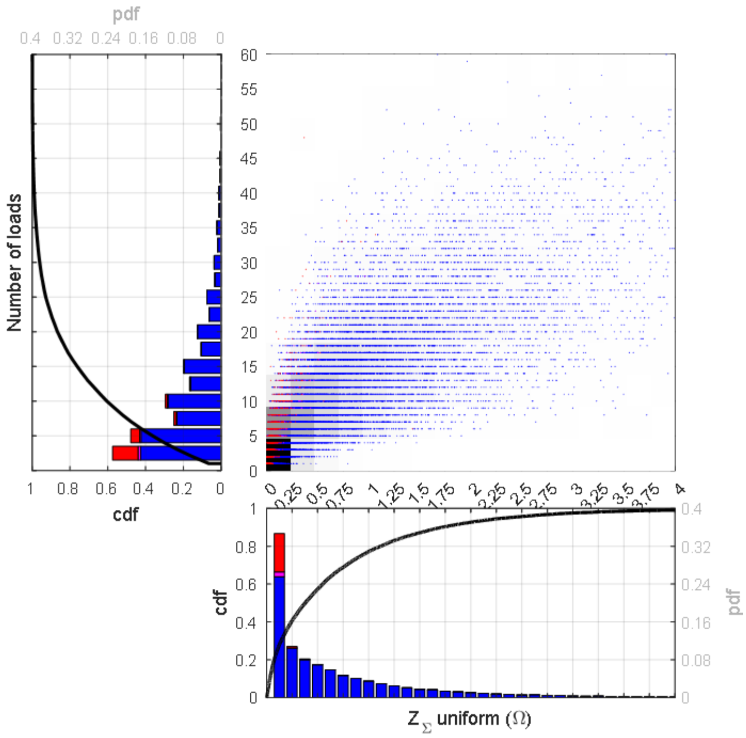


Figure 109 (Number of house connections vs. Equivalent sum impedance Umax=1.03 p.u. – Imax=100 %, DRES scenario: uniform)

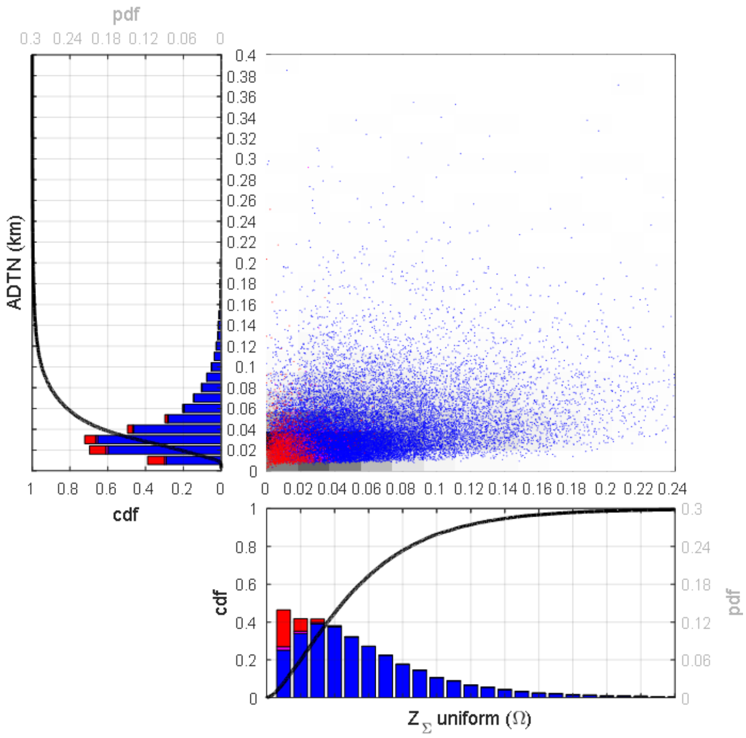


Figure 110 (Average distance to neighbour vs. Equivalent sum impedance Umax=1.03 p.u. – Imax=100 %, DRES scenario: uniform)

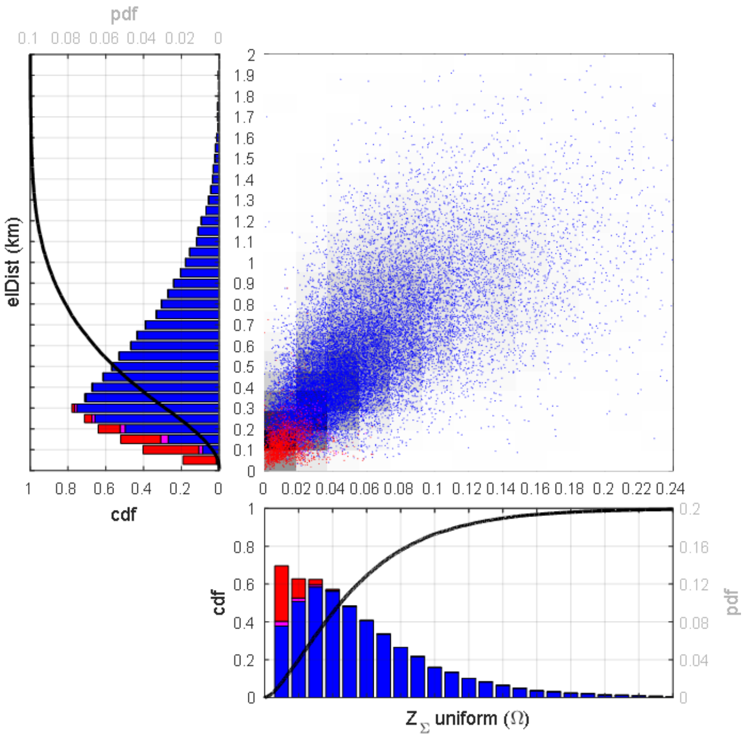


Figure 111 (Electrical length vs. Equivalent sum impedance Umax=1.03 p.u. – Imax=100 %, DRES scenario: uniform)

Figure 112 shows the distribution of the feeders according to the reserve to the "non-limiting constraint" and the equivalent sum impedance. The reserve to the non-limiting constraint is defined by equations (6) and (7).

$$\boldsymbol{R_U} = \Lambda_{max} - \Lambda_{MAX} \tag{6}$$

$$\boldsymbol{R_I} = -(\boldsymbol{U_{max}} - \boldsymbol{U_{MAX}}) \tag{7}$$

$\boldsymbol{R_U}$ Reserve to non-limiting constraint for voltage-constrained feeders

$\boldsymbol{R_I}$ Reserve to non-limiting constraint for current-constrained feeders

Λ_{max} Maximal feeder loading

Λ_{MAX}/X Considered loading limit (here 100 %)

$\boldsymbol{U_{max}}$ Maximal feeder voltage

$\boldsymbol{U_{MAX}}$ Considered voltage limit (here 1.03 p.u.)

This figure shows as previous ones that most feeders are voltage constrained and have a large reserve to the maximal loading limit. In addition, it shows an inverse proportional envelope (feeders with a large equivalent sum impedance have a larger reserve to the maximal loading limit). This figure further shows that with this parameter only it is not possible to distinguish between voltage and current-constrained feeders (i.e. below 0.04 Ω).

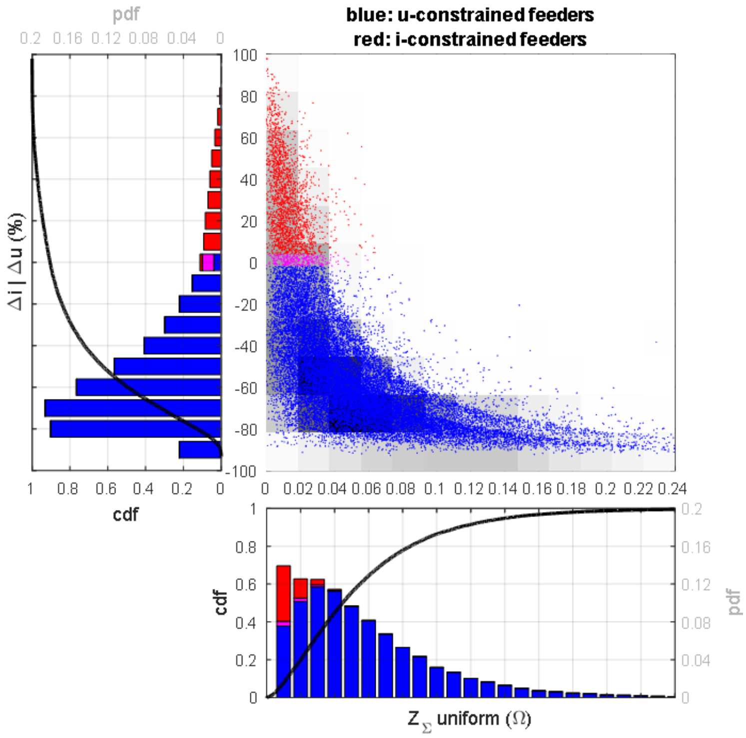


Figure 112 (U/I reserve vs. Equivalent sum impedance
Umax=1.03 p.u. – Imax=100 %
DRES scenario: uniform)

8.7.2 Classification of feeder with decision tree learning

As previously explained, the feeder classification has been implemented trough supervised machine learning techniques.

“*Machine learning explores the study and construction of algorithms that can learn from and make predictions on data. Such algorithms operate by building a model from example inputs in order to make data-driven predictions or decisions, rather than following strictly static program instructions*” [75]. Among the different techniques (e.g. discriminant analysis, decision tree learning, support vector machine), decision tree has been selected on the basis of several criteria (having tried several types of classifier). A side advantage of decision tree learning is that the results (trees) are easy to interpret.

“*Decision tree learning uses a decision tree as a predictive model which maps observations about an item to conclusions about the item's target value*.” [76]

With the selected classifier the tree has been trained and then evaluated on the basis of the resubstitution (compare the true class with the predicted class = result of the classifier) as well as on the basis of a cross-validation (evaluate the performance on another data-set as the training data-set).

The indicators used for the classification have also been varied, showing that good results can be obtained with the following four parameters (with only a small added value of including more indicators):

- Equivalent sum impedance.
- Feeder length.
- Short-circuit impedance at the end node.
- Average line length per network connection.

Although the best results were obtained for this parameter set, other parameter sets also lead to a very similar performance.

Figure 113 shows an example of a tree obtained when using only two indicators for easier interpretation. According to this tree, feeders with an equivalent sum impedance greater than 19 mΩ or with a sum impedance smaller than 19 mΩ and an average distance to neighbour greater than 25 m are voltage-constrained.

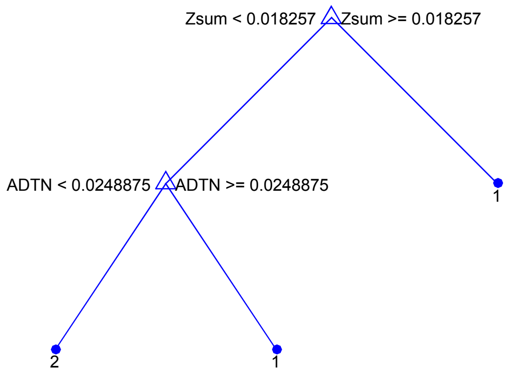


**Figure 113 (Example of classification tree
Class 1: voltage-constrained feeders / Class 2: current-constrained feeders
Zsum: equivalent sum impedance, ADTN: average distance to neighbour)**

Figure 114 shows the evolution of the misclassification as a function of the number of splits (2 in the previous example). It shows that the misclassification (measured with both metrics) error is low (good classification) and does not significantly decrease beyond 10 splits, which has been retained for the rest of the study.

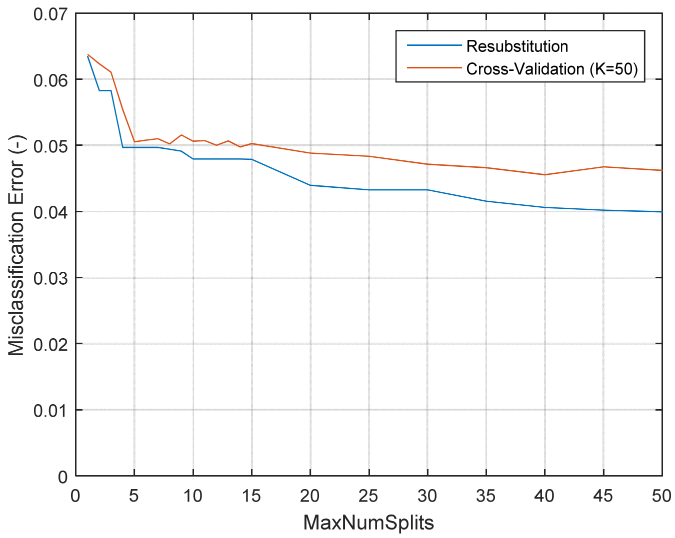


Figure 114 (Impact of the maximum number of splits on the misclassification error)

Beyond this overall figure to evaluate the performance of classifiers, the confusion matrix shows some interesting details. This confusion matrix shows a distribution of the feeders in two groups considering the true classes and the predicted classes. For a two-class problem, this matrix is a 2x2 matrix on which the diagonal elements shall be as high as possible (correct classification). The off-diagonal elements are misclassified elements. Figure 115 shows the confusion matrix obtained from the first attempt (with 10 splits). It shows that voltage-constrained feeders (true class) are generally correctly classified (98.5 % agreement) while current-constrained feeders (true class) are rather poorly classified (only 63.8 % of correct agreement). This result confirms the previous observations, namely that it is difficult to discriminate between voltage and current-constrained feeders in the area where both co-exist.

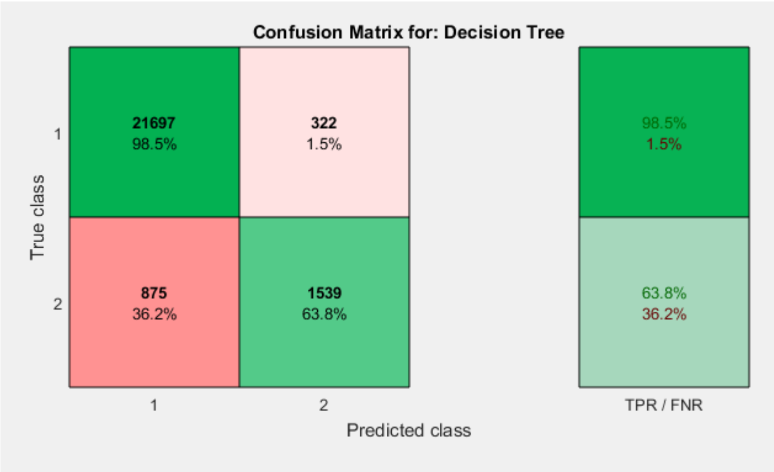


Figure 115 (Confusion matrix)

When classifying voltage and current-constrained feeders, the objective is mainly to be able to identify voltage-constrained feeders for which a smart grids solution enhancing the hosting capacity can be implemented. In this regard, and keeping in mind that it is generally more difficult to observe or estimate the line loading within the planning process, it seems mandatory to avoid misclassifying current-constrained feeders. To do so, the misclassification costs can be adjusted. Figure 116 shows as example the result of varying the misclassification costs. This figure shows that it is naturally not possible to reach a low misclassification rate for both classes. In other words, minimising the risk of misclassifying current-constrained feeders leads to an increased misclassification of voltage-constrained feeders and therefore to a reduction of the potential to implement smart grids solutions.
When using a very high cost for misclassified current-constrained feeders, these can be avoided but about 34 % of voltage-constrained feeders are misclassified (against less than 1.5 % with the original (uniform) cost factors see Figure 115) – see Table 14. This result is in agreement with the observation on Figure 116. This result might be interpreted as a very poor classification, but in fact the 34 % misclassification of voltage-constrained feeders is not as critical as it might appear. Indeed, all these feeders are voltage-constrained (and have been identified as current-constrained), but most of them (90 %) are in fact close to the maximum loading limit, which means that they would turn to be current-constrained when implementing a smart grids solution (e.g. voltage band extension).

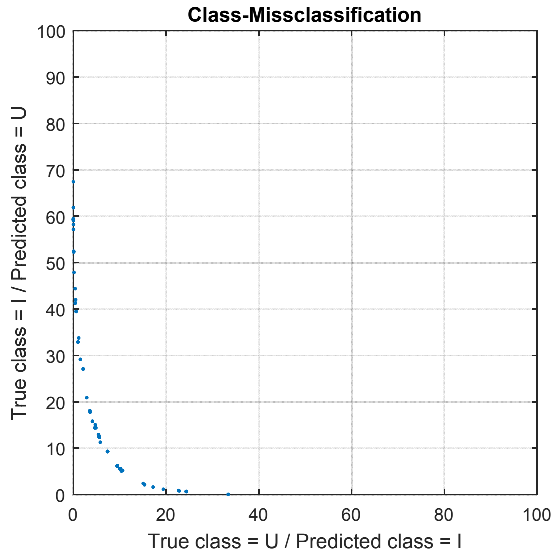


Figure 116 (Impact of the misclassification costs on the result)

Predicted Class / True Class	U	I
U	66	34
I	0.1	99.9

Table 14 (Misclassification rates)

As a conclusion of the feeder classification, the results can be summarised as follows:

- In order to avoid any misclassification leading to the risk of overloading, about 34 % of the voltage-constrained feeders are misclassified.
- This high misclassification rate does in reality only lead to a small loss of potential in identifying voltage-constrained feeders to implement smart grids functions enhancing the hosting capacity without observing the loading (only about 3 % of the feeders).

While the first results look very promising, other more advanced classification methods such as neural networks will be implemented to try to improve the classification performance.

8.8 Main conclusions and outlook of the statistical analysis of LV networks

Conclusions (based on the analysis of all the LV networks from two DSOs: EAG and SAG)

- A methodology has been developed and used to assess the potential of smart grids solutions in terms of hosting capacity increase on large sets of LV feeders. This method is based on the determination of the hosting capacity for different DRES distributions and of the limiting constraint (voltage or current).
- The two smart grids solutions considered in this study (voltage band extension through the use of voltage regulated distribution transformer and reactive power-based voltage control) are purely distributed solutions which only control the voltage without any “centralised”

observer. For this reason, they should be only implemented in feeders which remain voltage-constrained even after implementation of the smart grids solutions.

- The technical deployment potential has been evaluated according to the following criteria:
  - Identification of the feeders which can actually benefit from these solutions ("clearly" voltage constrained feeders)
  - Quantification of the benefits in terms of hosting capacity increase.
- The very first analysis of the feeder behaviour shows a large dominance of voltage-constrained feeders against current-constrained feeders (ratio 90 %/10 % or 77 %/23 % both DSOs). The general deployment potential of smart grids solutions aiming at controlling the voltage to increase the hosting capacity can be expected to be high.
- While the DRES scenario (distribution of the generation along the feeder) has a strong impact on the hosting capacity (for voltage-constrained feeders), it proved to have a rather limited impact on the feeder behaviour (e.g. share of voltage and current-constrained feeders).
- The potential of the considered solutions (voltage regulated distribution transformer (i.e. more than doubling of the available voltage band) and reactive power-based voltage control) is substantial for the two considered areas given their structure (high share of rural areas):
  - Deployment into more than 20 to 40 % of the feeders (for both DSOs) for the solution VRDT, with a hosting capacity increase of about +180 % on average[58].
  - Deployment into more than 60 % to 80 % of the feeders (for both DSOs) for the solution reactive power control, with a hosting capacity increase of about +25 % on average.
- Most of the feeders with a low hosting capacity (potentially experiencing a limitation) would actually benefit from the considered smart grids solutions (they mostly remain voltage-constrained)
- Instead of clustering LV feeders into clusters with similar properties (e.g. equivalent impedance, R/X ratio, etc. the proposed approach consists in classifying the feeders on the basis of the limiting constraint (voltage or current). In order to avoid problematic misclassifications (leading to the risk of unobserved feeder overloading), the actual deployment potential of smart grids solutions is reduced to, however, a limited extend.
- Promising results have been obtained from the classification and will be further investigated.

Outlook

This study is based on a very large number of scenarios and simulations to evaluate the hosting capacity and the deployment potential of smart grids solutions. It does not consider the DRES potential in each feeder. Even when having data allowing to estimate the DRES potential (e.g. available roof area), numerous assumptions are still needed to convert this potential in DRES penetration. Despite the complexity of this work, it can be highly automated and an additional added value is expected.

[58] For a smaller voltage band extension (i.e. a smaller hosting capacity increase), the share of feeders remaining voltage-constrained and therefore benefiting from it increases.

9 Economic evaluation of the S&R potential of the selected solutions

In this chapter the first part of the CA&BA methodology (see chapter 2.2) is carried out for the "most-promising" solutions within IGREENGrid project.

9.1 Overview of the "most-promising" solutions

The descriptions of the most promising solutions have already been exposed in chapter 3.

9.2 Identification of assets and JRC-functionalities

9.2.1 Assets identification

For each investigated solution the necessary assets have been identified and listed in Annex 3.

9.2.2 JRC-functionalities identification

9.2.2.1 JRC-functionalities of MV Voltage Monitoring

Having in mind the descriptions of the solutions and the main objective, the JRC-functionalities related to "MV Voltage Monitoring" are identified and shown in Table 15:

No.	JRC-functionality	Direct / Side and comments
7	Enhance monitoring and observability of grids down to low voltage level	Direct
8	Improve monitoring of network assets	Direct
10	Frequent information exchange on actual active/reactive generation/consumption	Direct
1	Facilitate connections at all voltages/locations for any kind of devices	Side
4	Update network performance data on continuity of supply and voltage quality	Side
9	Identification of technical and non-technical losses by power flow analysis	Side (by PLF)
19	Additional information on grid quality and consumption by metering for planning	Side

Table 15 (JRC-functionalities of "MV Voltage Monitoring")

9.2.2.2 JRC-functionalities of LV Voltage Monitoring

The JRC-functionalities of “LV Voltage Monitoring” are identified in Table 16:

No.	JRC-functionality	Direct / Side and comments
7	Enhance monitoring and observability of grids down to low voltage levels	Direct
8	Improve monitoring of network assets	Direct
10	Frequent information exchange on actual active/reactive generation/consumption	Direct
1	Facilitate connections at all voltages/locations for any kind of devices	Side
4	Update network performance data on continuity of supply and voltage quality	Side
9	Identification of technical and non-technical losses by power flow analysis	Side
19	Additional information on grid quality and consumption by metering for planning	Side

Table 16 (JRC-functionalities of “LV Voltage Monitoring”)

9.2.2.3 JRC-functionalities of MV Voltage Control

The associated JRC-functionalities achieved with “MV Voltage Control” aimed solutions are the following:

No.	JRC-functionality	Direct / Side and comments
3	Use of network control systems for network purposes	Direct
6	Enhance monitoring and control of power flows and voltages	Direct
7	Enhance monitoring and observability of grids down to low voltage levels	Direct
10	Frequent information exchange on actual active/reactive generation/consumption	Direct
12	Operation schemes for voltage/current control	Direct
1	Facilitate connections at all voltages/locations for any kind of devices	Side
4	Update network performance data on continuity of supply and voltage quality	Side

No.	JRC-functionality	Direct / Side and comments
9	Identification of technical and non-technical losses by power flow analysis	Side
11	Allow grid users and aggregators to participate in ancillary services market	Side
13	Intermittent sources of generation to contribute to system security	Side
17	Better models of Distributed Generation, storage, flexible loads, ancillary services	Side
19	Additional information on grid quality and consumption by metering for planning	Side
20	Participation of all connected generators in the electricity market	Side
21	Participation of virtual power plants and aggregators in the electricity market	Side
22	Facilitate consumer participation in the electricity market	Side

Table 17 (JRC-functionalities of “MV Voltage Control”)

9.2.2.4 JRC-functionalities of LV Voltage Control

The JRC-functionalities for “LV Voltage Control” solutions are listed in Table 18:

No.	JRC-functionality	Direct / Side and comments
3	Use of network control systems for network purposes	Direct
6	Enhance monitoring and control of power flows and voltages	Direct
12	Operation schemes for voltage/current control	Direct
4	Update network performance data on continuity of supply and voltage quality	Side
7	Enhance monitoring and observability of grids down to low voltage levels	Side
9	Identification of technical and non-technical losses by power flow analysis	Side
10	Frequent information exchange on actual active/reactive generation/consumption	Side
13	Intermittent sources of generation to contribute to system security	Side

No.	JRC-functionality	Direct / Side and comments
17	Better models of Distributed Generation, storage, flexible loads, ancillary services	Side
19	Additional information on grid quality and consumption by metering for planning	Side
22	Facilitate consumer participation in the electricity market	Side

Table 18 (JRC-functionalities of "LV Voltage Control")

9.3 Grouping of the solutions according to their functionalities

See chapter 3.

10 Economic evaluation of MV solutions

In this chapter the core of the CA&BA methodology (see chapter "*2.2 Methodology for the economic evaluation*") is carried out for the MV solutions selected as the most-promising ones within IGREENGrid project. The following subchapters cover the Cost Analysis (CA) and the Benefits Analysis (BA).

This analysis has been carried out only for the DSOs which have provided data of costs. They are the following: EAG, ERDF, GNF, HEDNO, Iberdrola and SAG.

10.1 Cost Analysis (CA) of MV solutions

The networks analysed in the "Economic evaluation of MV solutions" are characterized in technical simulations and thus this Cost Analysis (CA) is performed and limited to those cases that are technically necessary.

The costs incurred by DSOs when implementing the solutions resulting from the simulations can be classified into two categories: Capital Expenditure (CapEx[59]) and Operational Expenditure (OpEx[60]).

The comparison of the costs incurred in different smart grids solutions included within the same functionality (i.e. voltage control) is performed. The aim is to compare the solutions with a common objective or functionality (intended to solve the same problem) in terms of the costs that are incurred by DSOs. The cost analysis consists on the application of the following two methods considering a time horizon of 20 years:

- **Annual Costs Comparison (ACC)**: it consists of compiling the annual costs of the solutions over the study period (20 years) in order to make annual comparisons and identify individual years in which costs are higher and lower.
- **Present Value of Total Costs (PVTC)**: it consists of estimating the sum of present value of total annual costs (CapEx + OpEx) of the smart grids solution for the entire study period. The PVTC can be understood as the total costs 'brought back' to the first year (commonly called "year zero") by applying a discount rate (thereby accounting for the time value of money). The PVTC is calculated as shown by equation (8).

[59] *CapEx*: it refers to the capital amount which has been dedicated to the acquisition / development / deployment of the assets under test. It represents the investment related to the realization of the R&I solutions and it includes the installation and replacement costs of the related assets.
[60] *OpEx*: it considers the capital amount dedicated to the operation and management of the solution under test. It includes the scheduled maintenance operation, the primary energy supply (fuel for active assets), control resources, etc.

$$PVTC=\sum_{t=0}^{n}\frac{R_t}{(1+i)^t} \tag{8}$$

t	Time
i	Discount rate
R_t	Cost incurred in time t
n	Total number of periods considered

Regarding these two methods, the deployment schedule needs to be established for the solutions under analysis. The assumption is that the initial investment is incurred in the first year and the renewal of the assets is regarded as being at the end of the lifetime. All the negative cash flows over the 20 years study period are accounted for (including deployment and renewal) but the residual value of this equipment is not considered.

A sensitivity analysis of the costs is also carried out. The purpose of performing this analysis is to assess the impact of changes in variables on the solutions deployment performance.

It is necessary to identify those key variables that most influence the project's costs. In IGREENGrid project two key variables have been identified for MV solutions so that the sensitivity analysis will be carried out by varying:

- Discount rate (i):

  This sensitivity analysis is intended to reflect the impact that the economic situation of the markets may have on the costs associated with the implementation of the solutions.
  The average discount rate is taken and a big range of discount rate (i) is considered in order to ensure that the final and real costs of the implementations will very probably be within the total costs ranges obtained in the CA.
- Number of DG units to be retrofitted:

  Different scenarios have been defined in order to take into consideration the effect of the DG retrofitting in total costs. The assumption is that retrofitting DG makes sense when the DG unit is "big enough", i.e., when the capacity of the DG unit is important enough to perturb the network´s operation and to create some problems: 1 MW is assumed to be the minimum DG unit size that can be subjected to retrofitting.

In this chapter, a Cost Analysis (CA) is made in detail for one MV network (chapter 10.1.1) and then a summary (aggregated figures) of all the networks analysed is exposed (chapter 10.1.2).

10.1.1 Illustrative example of a MV network

The network under analysis supplies a rural area with a few more dense zones (see chapter 6.1).

10.1.1.1 Input data for the CA

As said before, this Cost Analysis (CA) is performed and limited to cases that are technically needed, in other words, only networks with voltage problems suitable to be solved with solutions aimed to MV voltage control are economically analysed.

10.1.1.1.1 Technical data of the MV network under analysis

Some necessary data for the Costs Analysis (CA) come from the technical analysis, such as the number of critical nodes in which a measurement device is recommended or the length of the network reinforcement required to reach a given hosting capacity.

For MV networks, technical data required for the Cost Analysis are listed in the following table:

Data needed for CA	Source of the data
Number of DG to be installed	It is calculated as the sum of the “DER Number per feeder”, resulting from the “Step 1 - Feeder screening” of the technical analysis.
Initial HC in the network	It represents the initial HC in the network without any solutions deployed. It is calculated as the sum of the “HC_{50} (MW)”, resulting from the “Step 1 - Feeder screening” of the technical analysis.
Number of measurement devices to be installed	It is calculated as the sum of the “Number of critical nodes”, resulting from the “Feeder properties” of the technical analysis.
Number of additional measurement points for State Estimator	It is known that the State Estimation algorithm requires a minimum number of measurements in order to accurately estimate the complete state of the network. For this study the assumption is that 3 more measurement points (with respect to the calculated ones) will be installed per feeder when the solution includes the SE, in order to ensure the correct gathering of data for the algorithm.
Maximum HC reached (MW) when implementing each solution	It is calculated as the sum of the “HC (MW) per feeder” of each solution simulated, resulting from the “Step 2.2 - HC determination” of the technical analysis.
Length needed for the network reinforcement	This data comes from the technical analysis and it is calculated as the sum of the length of reinforcements required in each feeder within the network, to reach as much hosting capacity as the “best” smart solution being studied. Due to the complexity of this technical calculation, a simplified approach is taken that does not reflect different planning approaches of DSOs.

Table 19 (Technical data required for the Cost Analysis of MV solutions)

10.1.1.1.2 Cost data of the assets within the MV solutions

Costs data have been provided by ERDF, GNF, HEDNO, Iberdrola, EAG and SAG, so that the economic analysis has been limited to the reference networks operated by these DSOs that may require one of the most-promising solutions.
Costs given by the DSOs are values for the year 2015 and a 1.5%[61] yearly rate of expected increase of these costs is assumed.
Due to confidentiality issues, these costs data provided by DSOs are intentionally removed.

10.1.1.2 Comparison of MV Voltage Monitoring solutions

The solutions within the functionality "MV Voltage Monitoring" are these three implementations:

1. MV Voltage Monitoring (field measurements).
2. MV Voltage Monitoring (SE).
3. MV Voltage Monitoring (PLF).

The third implementation, "MV Voltage Monitoring (PLF)", has not been analysed since no cost data of the asset related to the "Probabilistic Load Flow (PLF)" is available.
In Table 20, the assets and costs elements included in the two implementations under study of the functionality "MV Voltage Monitoring" are listed:

Implementation	Cost element (assets and others)
MV Voltage Monitoring (field measurements)	Measurement device (for MV line)
	Communication costs of Measurement device
	Costs in SCADA per measurement device
MV Voltage Monitoring (SE)	Measurement device (for MV line)
	Communication costs of Measurement device
	DMS – State Estimator
	Costs in SCADA per measurement device

Table 20 (Cost elements of the implementations under study of the functionality "MV Voltage Monitoring")

10.1.1.2.1 Annual costs comparison

The first method applied for the cost analysis of the MV Voltage Monitoring solutions is the annual costs comparison.

Total costs associated to the implementation and operation of the assets included in each solution are calculated for every year within the study, as the sum of CapEx and OpEx.

In Figure 117, the comparison of DSO incurred costs on the MV Voltage Monitoring solutions is shown for each considered year:

[61] Calculated as the mean value of the Consumer Price Index or CPI (2016-2018) expected for France, Spain, Italy, Greece, Germany and Austria.(source: http://www.expansion.com/economia/datosmacro.html, 2015/12/09).

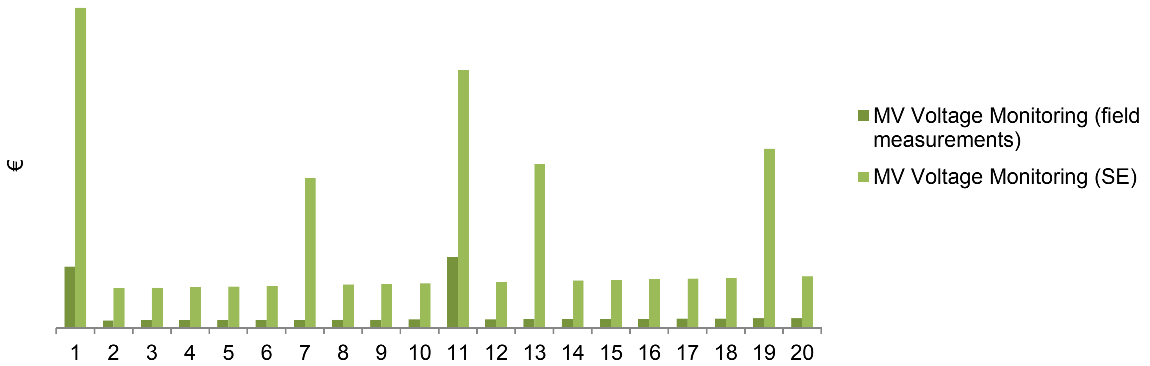


Figure 117 (Annual costs of the MV Voltage Monitoring solutions[62])

As the Figure 117 shows, at some years costs are higher than others and the main reasons are:

- In the years 7, 13 and 19, the investment needed for a new State Estimator is incurred by the DSO, as the lifetime of the SE in this case is assumed to be 6 years according to the data provided by this specific DSO.
- In the year 11, t a reinvestment of all the assets is needed since all the other assets except the SE have a lifetime of 10 years.

10.1.1.2.2 Present value of total costs (PVTC) and sensitivity analysis

Once annual costs are known, the present value of these annual costs (PVTC) is calculated, i.e. the total costs incurred during the study period of 20 years are calculated. As said earlier, PVTC can be understood as the total costs 'brought back' to the first year, commonly called "year zero", by applying a discount rate (i), thereby accounting for the time value of money.

In order to assess the impact of the discount rate on the PVTC (sensitivity analysis), a range of discount rate between 0.5% and 12% is considered, with the aim of ensuring that the final and real costs of the implementations will very probably be within the total costs ranges exposed in the Figure 118 below.

In Figure 118, the PVTC of MV Voltage Monitoring solutions, for different values of the discount rate (i), are shown:

[62] As previously mentioned, the costs are confidential and only comparative graphics are shown.

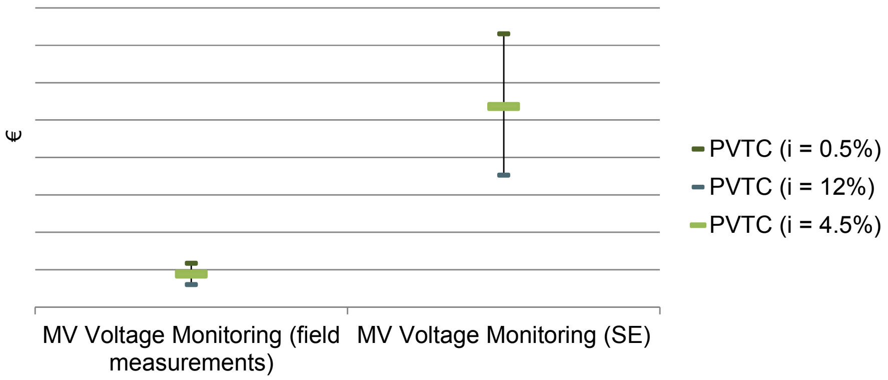


Figure 118 (PVTC of MV Voltage Monitoring solutions, considering a range of discount rates)

The main cause of the huge difference between the costs of these two implementations is the cost of the State Estimator (SE).

Including a SE seems interesting when this kind of implementations will be replicated in several locations and only if the data from the SE will be used with other objectives (in addition to hosting capacity benefits), as it is explained in more detail in the conclusions (see chapter 10.3.1).

10.1.1.3 Comparison of MV Voltage Control solutions

The solutions within the functionality "MV Voltage Control" are the next eight implementations:

- MV Distributed Voltage Control with OLTC.
- MV Distributed Voltage Control with OLTC, DG.
- MV Centralized (field measurements) Voltage Control with OLTC.
- MV Supervised (field measurements) Voltage Control with OLTC & DG.
- MV Supervised Voltage Control with OLTC & DG.
- MV Centralized (SE) Voltage Control with OLTC.
- MV Centralised (SE & OPF) Voltage Control with OLTC.
- MV Centralised (SE & OPF) Voltage Control with OLTC & DG.

In Table 21 the assets and costs elements included in these eight implementations under study of the functionality "MV Voltage Control" are listed:

Implementation	Cost element (assets and others)
MV Distributed Voltage Control with OLTC	Local control OLTC (in HV/MV)
MV Distributed Voltage Control with OLTC, DG	New Local control - DG P&Q control
	Retrofit of Local control - DG P&Q control
	Local control OLTC (in HV/MV)
MV Centralized (field measurements) Voltage	Measurement device (for MV line)
	Communication costs of Measurement device

Implementation	Cost element (assets and others)
Control with OLTC	Local control OLTC (in HV/MV)
	Costs in SCADA per measurement device
MV Supervised (field measurements) Voltage Control with OLTC & DG	New Local control - DG P&Q control
	Retrofit of Local control - DG P&Q control
	Measurement device (for MV line)
	Communication costs of Measurement device
	Local control OLTC (in HV/MV)
	Costs in SCADA per measurement device
	Costs in SCADA per measurement point in MV DG
MV Supervised Voltage Control with OLTC & DG	New Local control - DG P&Q control
	Retrofit of Local control - DG P&Q control
	Local control OLTC (in HV/MV)
	Costs in SCADA per measurement device
	Costs in SCADA per measurement point in MV DG
MV Centralized (SE) Voltage Control with OLTC	Measurement device (for MV line)
	Communication costs of Measurement device
	Local control OLTC (in HV/MV)
	DMS – State Estimator
	Costs in SCADA per measurement device
MV Centralized (SE & OPF) Voltage Control with OLTC	Measurement device (for MV line)
	Communication costs of Measurement device
	Local control OLTC (in HV/MV)
	DMS – State Estimator
	DMS – OPF
	Costs in SCADA per measurement device
MV Centralised (SE & OPF) Voltage Control with OLTC & DG	New Local control - DG P&Q control
	Retrofit of Local control - DG P&Q control
	Measurement device (for MV line)
	Communication costs of Measurement device
	Local control OLTC (in HV/MV)
	DMS – State Estimator

Implementation	Cost element (assets and others)
	DMS – OPF
	Costs in SCADA per measurement device
	Costs in SCADA per measurement point in MV DG

Table 21 (Cost elements of the implementations under study of the functionality "MV Voltage Control")

Additionally to analysing the costs of these eight MV Voltage Control solutions, the costs incurred by the DSOs when deploying smart solutions for the DRES integration are compared with the costs of the conventional solutions based on grid deployment required to reach the same increase of the hosting capacity as the "best" smart solution being studied.

10.1.1.3.1 Annual costs comparison

The first method applied for the cost analysis of the MV Voltage Control solutions is the annual costs comparison. The total costs associated to the implementation and operation of each solution, are calculated as the sum of CapEx and OpEx.

In Figure 119, the comparison of year by year costs of the MV Voltage Control solutions is shown:

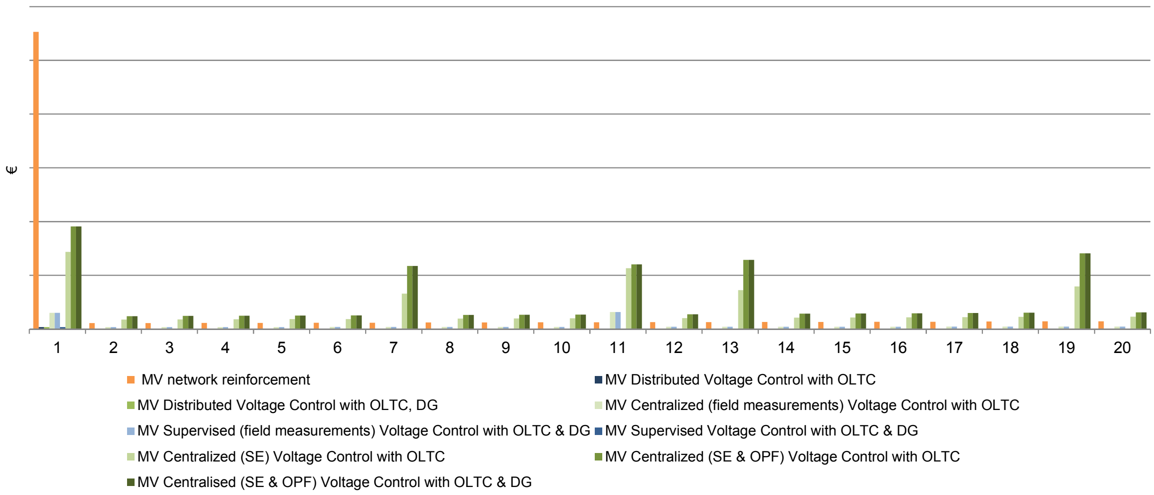


Figure 119 (Annual costs of the MV Voltage Control solutions)

As Figure 119 shows and as it occurs in the annual costs of MV Voltage Monitoring solutions, at some years costs are higher than others and due to similar reasons:

- In the years 7, 13 and 19, the investment needed for a new State Estimator is incurred by the DSO, as the lifetime of SE is assumed to be 6 years according to the data provided by this DSO.
- In the year 11, a reinvestment in measurement devices is required, as their lifetime expectation is 10 years.
- In the year 11, some additional costs are incurred due to the costs of communications and SCADA adaptation.

Additionally, the figure shows that the initial investment needed (i.e. costs incurred in the first year) of the solution "Network reinforcement" is much higher than costs of smart solutions, while, during the operation of the solutions (study period of 20 years), the costs are higher for smart solutions.

10.1.1.3.2 Present Value of Total Costs (PVTC) and sensitivity analysis

Once annual costs are known, their present value (PVTC) is calculated for the study period of 20 years.

In order to evaluate the sensitivity of total costs with respect to the discount rate, a range between 0.5% and 12% (the average discount rate considered is 4.5%) is used in this study and in Figure 120, the PVTC of MV Voltage Control solutions, for different values of the discount rate (i), are shown:

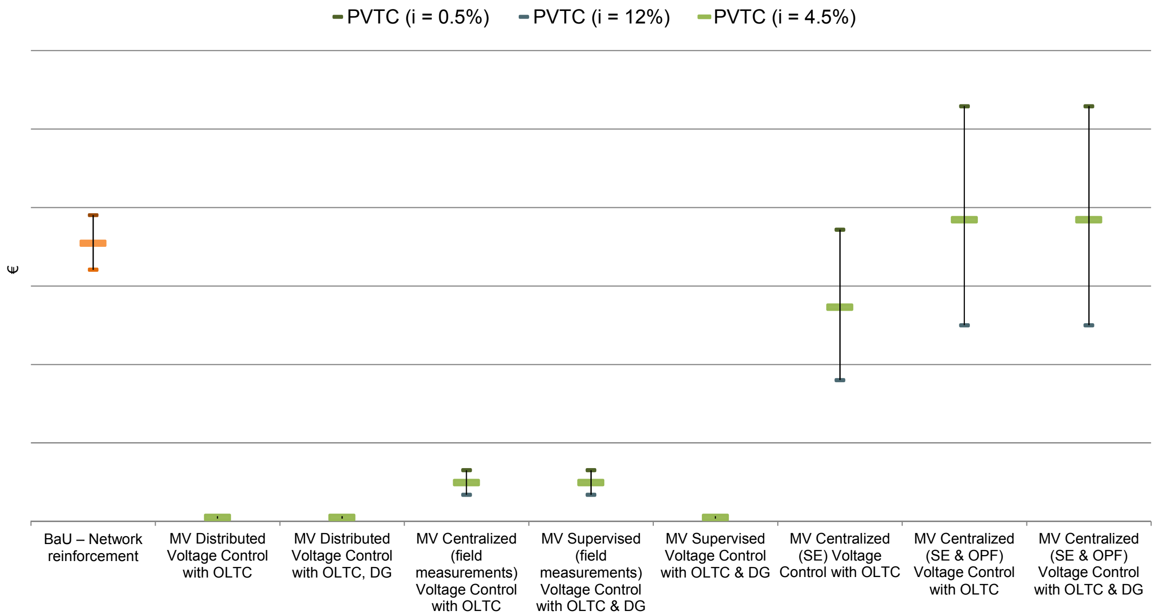


Figure 120 (PVTC of MV Voltage Control solutions, considering a range of discount rates)

Figure 120 clearly demonstrates that the costs highly increase if major changes are necessary in the distribution management system included in the smart solution: it is the case of SE- and OPF-based solutions.

In addition, taking into account that different hosting capacity improvements can be reached with each solution, the cost of increasing 1 MW of HC can be calculated for each solution:

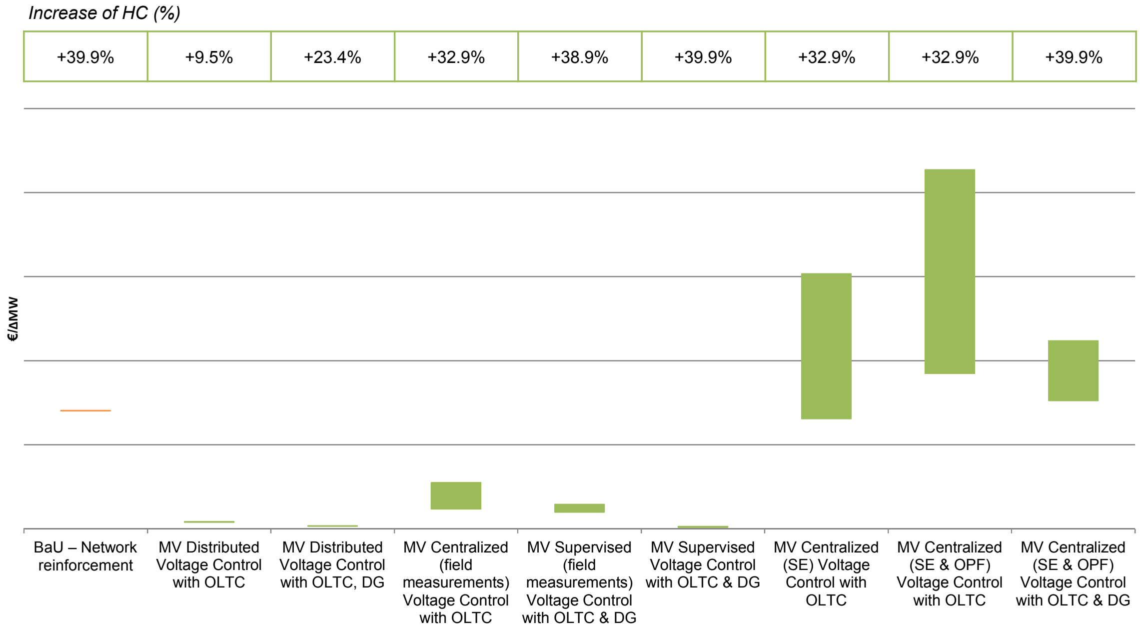


Figure 121 (Cost of increasing 1MW of HC for each MV solution)

In order to fully understand the results reported in Figure 121, the following points should be considered:

- The network reinforcement has no limit on the HC that can be obtained. Just with the purpose of this study and to compare the cost of increasing 1 MW of HC with conventional reinforcement versus smart solutions, a theoretical network reinforcement length is introduced. This network reinforcement has been determined in order to lead the same hosting capacity as the largest hosting capacity reached by a smart grid one.
- It should also be noted that, for some solutions, large spreads of HC can be experienced depending on the location of DRES units. In these cases, the cost per MW can be significantly impacted. In the technical analysis, two DG distribution scenarios are used (scenarios depending on the location of DRES units): homogeneous or heterogeneous (see chapter 6.1.2.1.2); some analyzed networks reflect a negligible difference between scenarios but some other networks show large differences.

Although the cost associated with 1 MW of HC increased is an interesting as such, it is also important to keep in mind that depending on the local situation, the actual need of hosting capacity extension may vary and motivate the choice of one solution or another.

In addition to this, it is also important to note that this does not represent a complete merit-order of the solutions, indeed some aspects are not taken into account. For instance, as the lifetime of the equipment and their residual value at the end of the study period are not considered, this figure can show similar cost for 1 MW increase of HC for two solutions when one of them would actually last twice longer, thus making it much more interesting from an economic point of view (see chapter 10.1.2).

Similarly to the sensitivity analysis related to the discount rate shown in Figure 120 above, and taking into account the information provided by the DSOs about the retrofitting of DG units to include P&Q control, a sensitivity analysis varying the cost of the DG retrofitting is carried out.

According to the experience of some DSOs, the cost of retrofitting of DG units to include P&Q control is not considered in their countries from the regulatory point of view, so in any case, this cost is assumed to be undertaken by DG owners. However, this regulatory situation could change and DSOs could be called to cover the costs of retrofitting the already operating DG units.

Thus, a sensitivity analysis is carried out to evaluate the impact that the cost of retrofitting DG units may have in total costs of the solutions.

The list of the four of the MV Voltage Control solutions that include P&Q control in DG units is:

- MV Distributed Voltage Control with OLTC, DG.
- MV Supervised (field measurements) Voltage Control with OLTC & DG.
- MV Supervised Voltage Control with OLTC & DG.
- MV Centralised (SE & OPF) Voltage Control with OLTC & DG.

Retrofitting DG units makes sense when the DG unit is “large enough”, i.e., when the capacity of the DG unit is important enough to significantly perturb the network operation and to create some problems. So, the following assumptions are made:

- The minimum capacity of a DG to be retrofitted is 1MW

  “Large DG” (susceptible to be retrofitted) = DG of 1MW

- The number of “large” DG units is not known, but it is assumed that if a critical node exists it may have sense to include P&Q control in this points

  Number of DG units susceptible to be retrofit = Number of critical nodes

These questions around the percentage of the retrofitting cost assumed by the DSO highlight the fact that this CA is a CA of the costs incurred by the DSO, not by the society as it would be in a classic JRC CBA. This leads us to question the regulatory framework which would not be needed in a CBA (all the costs would be taken into account) and also means that the figures give a ‘merit-order’ of the solutions from the DSO point of view.

The Table 22 lists the scenarios established for this sensitivity analysis:

Scenario		Explanation
1	No retrofit	The cost of retrofitting is covered by generators (no cost for the DSO).
2	Half of the “*susceptible to be retrofitted*” DG units are retrofit	Half of the costs of retrofitting are covered by generators and the other half by DSOs.
3	All of the “*susceptible to be retrofitted*” DG units are retrofit	The cost of retrofitting is entirely covered by DSOs.

Table 22 (Scenarios for the sensitivity analysis regarding the number of DG units to be retrofitted)

The Figure 122 shows the costs of each MW of hosting capacity increased with the four solutions that include P&Q control in DG units, according to the three scenarios explained in the Table 22. These costs are also compared with the network reinforcement solution (BaU):

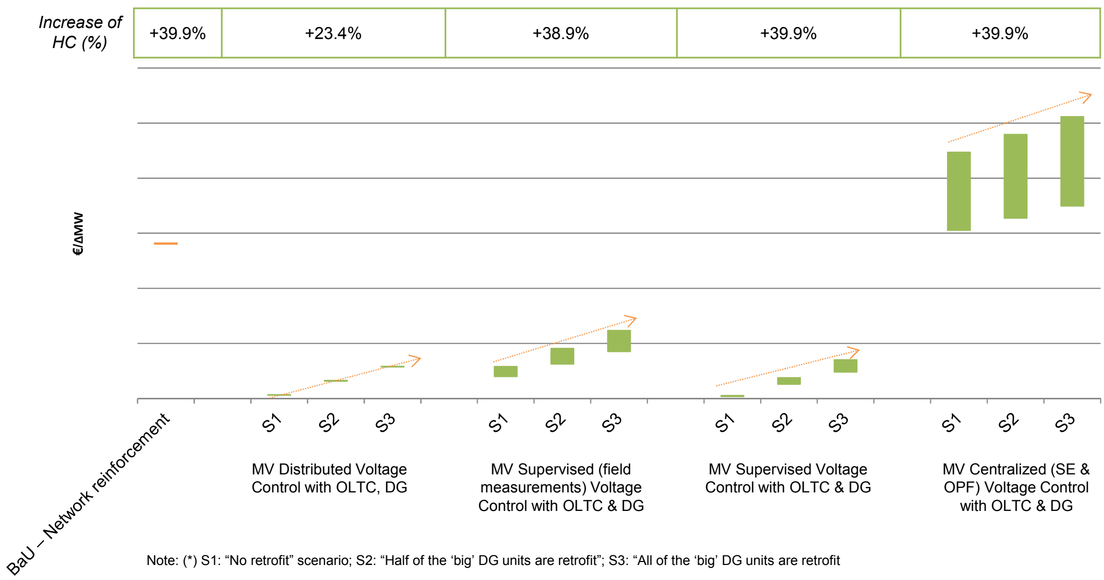


Figure 122 (Costs of each MW of HC increased (€/∆MW) depending on the scenarios)

From Figure 122, the following can be concluded:

- In this network, smart solutions based mostly on local actuators (that do not include major changes in the DMS) seem economically more efficient than the network reinforcement solution (in terms of €/∆MW). But this fact may change depending on the cable / line length needed to be reinforced in the network to reach the hosting capacity objective.

  In line with this, even if initial costs of the network reinforcement were higher than initial investment of smart solutions, operational and maintenance costs of conventional solutions are lower than those from smart assets operation.
- Smart solutions that include major changes in the DMS (i.e. SE or OPF) are in this case far more expensive than both smart solutions that do not include DMS and network reinforcement, because of the individual cost of some components, such as the SE:
  - In line with the previous point, the correct attribution of the share of the costs of some components (i.e. State Estimation) becomes the key for the economic viability of some approaches when deployed to several networks.
  - DMS components (network management supporting tools, such as SE and OPF) might bring further benefits and enable other functions not considered in the Cost Analysis. These benefits could be interesting to fulfil other objectives, thanks to the knowledge of the real status of the network (network planning), or solve other problems in the network (real time operation of the network).
  - When addressing the specific requirements of one case, applying solutions based mostly on local actuators with lower communication needs seems to be the most cost effective alternative (lowest costs per MW additionally installed) if the needed hosting capacity extension is not too high. If the problem to be solved with the distributed smart grids solution occurs in multiple locations in the distribution network, then centralized approaches may prevail, due to these other functions that network management systems (i.e. State Estimation) could contribute to the system.

10.1.2 Summary for the MV networks analysed

As MV Voltage Monitoring solutions are part of the MV Voltage Control solutions, in this chapter aggregated figures are focused on the results of the Cost Analysis (CA) of MV Voltage Control solutions.

Comparing the costs of different solutions for different DSOs is a challenging task. Indeed, the planning approaches are different among DSOs. Moreover, the practices on the economics are even more different (e.g. amortization time). The reader should remember that each DSO case is different and there is a wide range in the variation of some cost elements.

In Figure 123, the number of times of variation ranges[63] of some cost elements (costs data have been provided by the following DSOs: GNF, Iberdrola, ERDF, HEDNO, EAG and SAG) of the solutions within the functionality "MV Voltage Control" is shown:

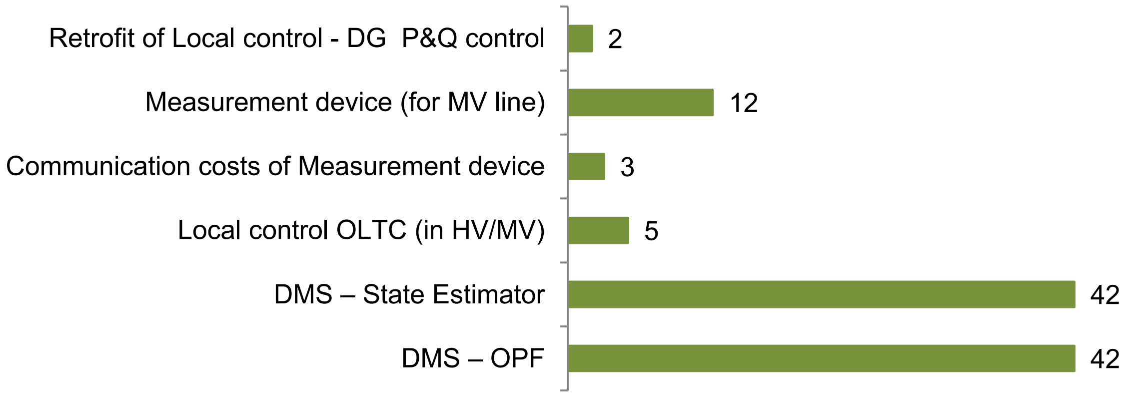


Figure 123 (Variation range (number of times) of some cost elements of the solutions within the functionality "MV Voltage Control")

These variation ranges are mostly caused by the different conditions of DSOs. For example, the cost ranges of the SE and the OPF may represent the difference between a commercial product integrated into the distribution management system and a customized development lacking of full integration. This fact affects the final cost figures, as the costs and also the amortization periods vary.

Costs of assets included in the smart solutions under analysis are decisive for the final cost figure but also the networks analysis.

Different types of networks (rural, urban and rural-urban) have been analysed. In total, 18 MV networks in four different countries are studied for the economic evaluation: 4 MV networks in Spain (2 from the distribution area of Iberdrola and the other two from GNF), 2 MV networks in Greece (HEDNO), 7 MV networks in France (ERDF) and 5 MV networks in Austria (3 from the distribution area of SAG and the other 2 from EAG, in Upper Austria).

[63] Spread between costs provided by DSOs.

The different characteristics of the countries (regulation, topography, etc.) and different planning approaches of DSOs also affect the final results, as each DSO case is different.

Specifically, large differences are detected on the needed network reinforcement to reach a given hosting capacity. This calculation is a very complex task and a simplified common approach has been used, meaning that the results must be carefully interpreted.

In Figure 124, the theoretical costs of network reinforcement coming from the technical simulations results are shown. Since in some cases the costs are very high, a cap corresponding to the average cost of a primary substation or a primary substation dedicated to generation is shown in the figure (orange and red lines).

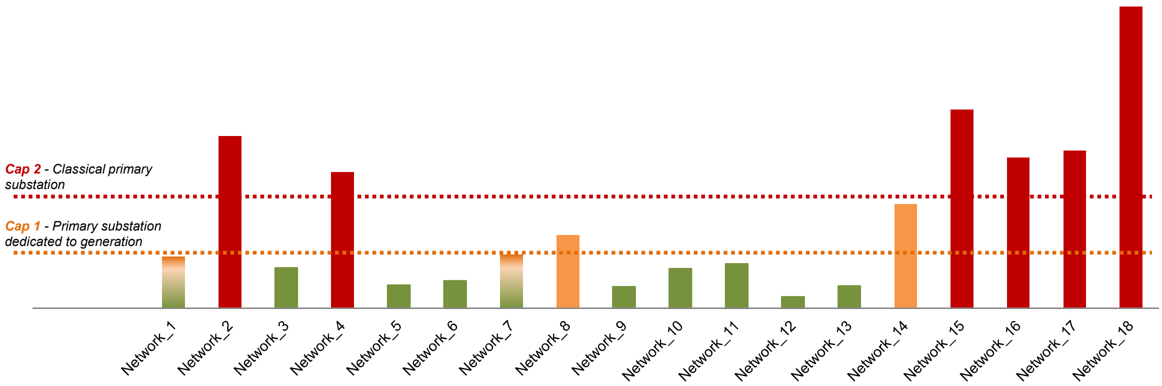


Figure 124 (Theoretical costs of network reinforcement coming from the simulations for the MV networks analysed[64])

As clear conclusion according to the Figure 124, it seems that a new Primary Substation would be built in case network reinforcement costs exceed the typical costs of a substation (for 33% to 44% of the considered MV networks).

Additionally, the methodology used in this cost analysis is implemented considering 20 years away, but, the estimated lifetime of some assets (typical network assets such as cables, and also some smart assets for some DSOs) exceeds this time horizon of 20 years. The inclusion of the life expectancy of some network assets (est. 40-50 years) on the analysis of the negative cash flows may be required to properly compare costs, as an asset that is more expensive but has a much longer life expectancy could turn out to be more profitable.

Figure 125 shows the differences of Present Value of Total Costs (PVTC) of the MV solutions under study when implementing in a network in both cases of a time horizon of 20 years and of 40 years:

[64] The caps are data provided by EAG, SAG and AIT, as reference values.

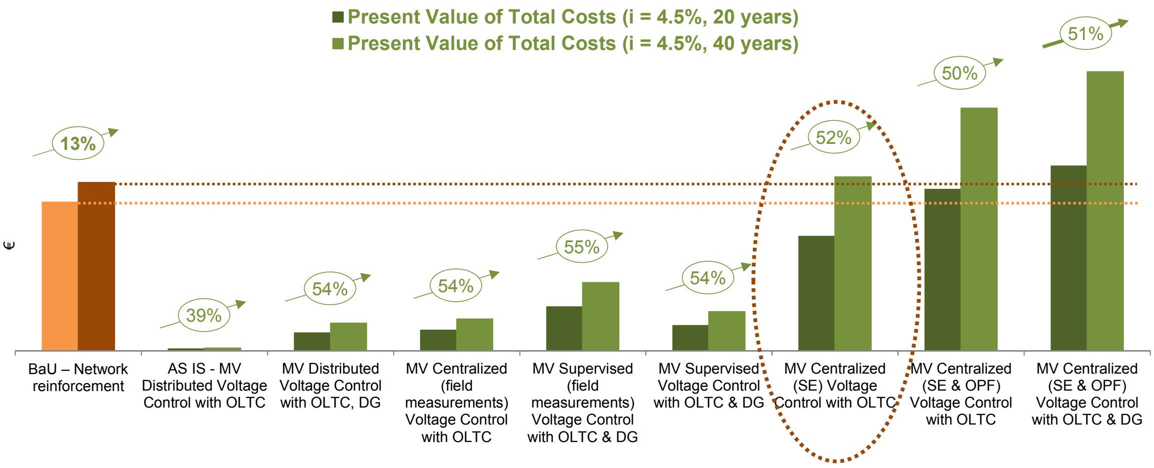


Figure 125 (Differences of PVTC of the MV solutions under study when implementing in a network in both cases of a time horizon of 20 years and of 40 years)

Looking at the solution "MV Centralized (SE) Voltage Control with OLTC" (circled in brown), it can be seen that in some cases the business as usual costs (network reinforcement) may be either much more expensive, either much cheaper than some smart grids solutions just varying this assumption of the methodology. Considering a long life time of network assets has, as expected, a negative impact on the overall costs of smart grids solutions against network reinforcement.

Taking into account these issues about the costs, the MV networks and the methodology, Figure 126 shows the maximum and the minimum values for the cost for each MW of hosting capacity increased among the obtained CA results of all the MV networks analysed:

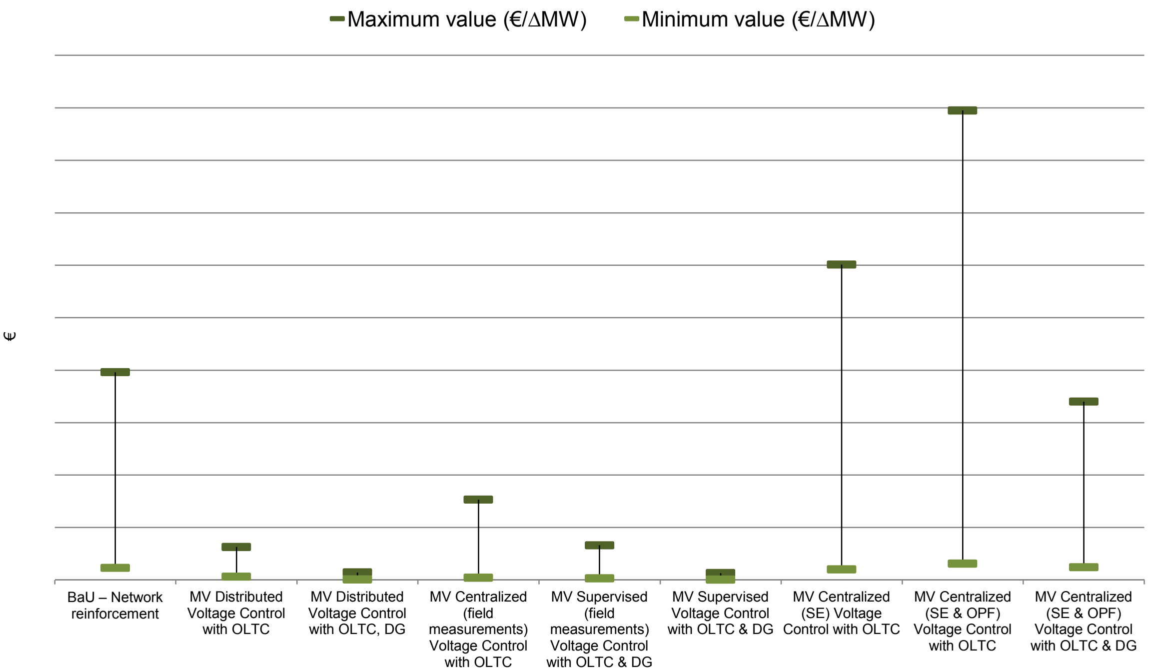


Figure 126 (Maximum and minimum values for the cost of each MW of hosting capacity increased among the CA results of all the MV networks analysed)

Following with Figure 126, Figure 127 shows the number of times of ranges of costs of each MW of hosting capacity increased with each MV solution analysed and the ranges of increase of HC (%) reached in the considered networks (HC target for BaU was in each network set to match the highest HC enabled by smart solutions):

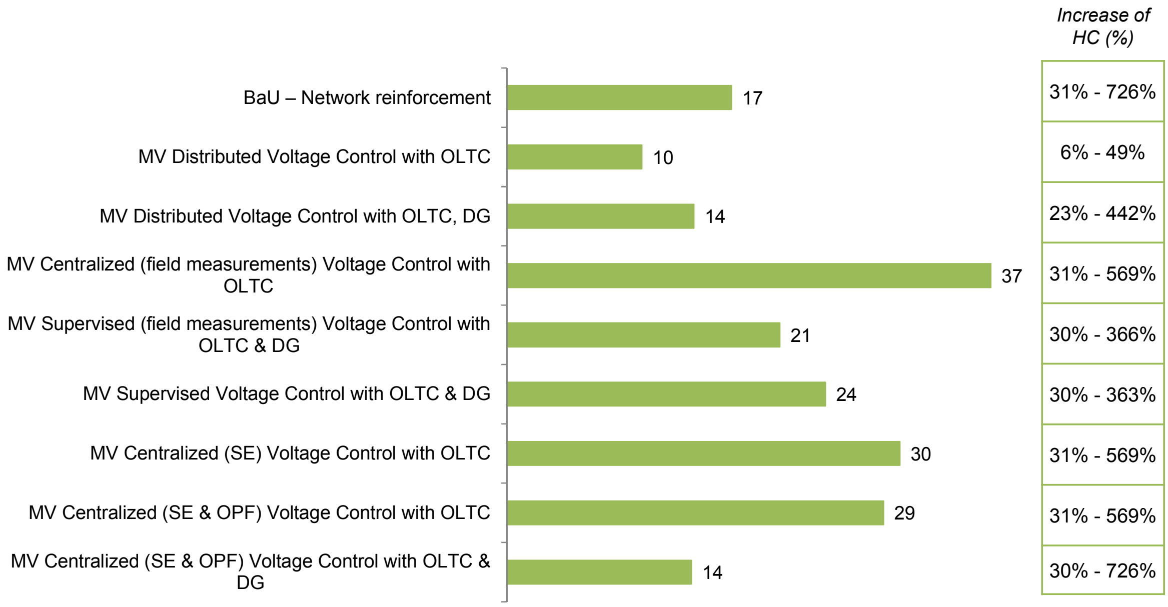
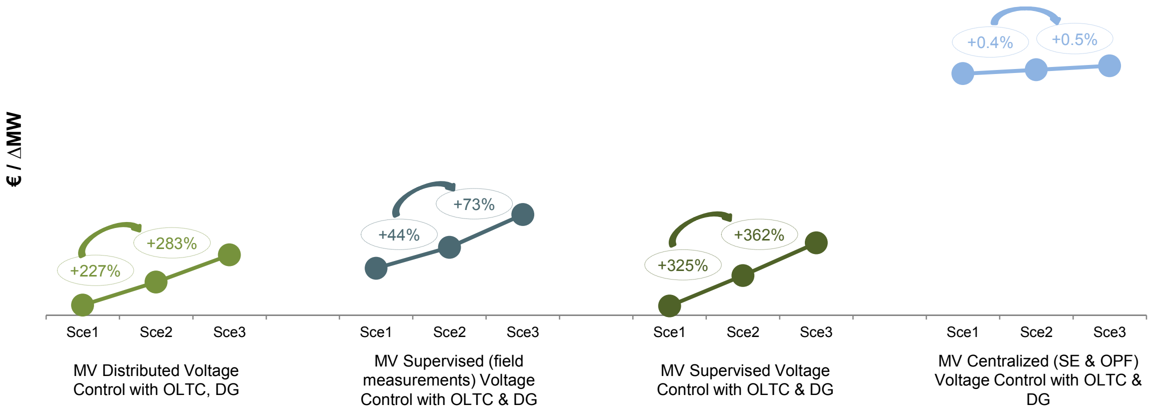


Figure 127 (Variation range (number of times) of costs of each MW of hosting capacity increased & Ranges of increase of HC (%) reached in the networks)

Figure 127 confirms that there is a high dispersion of costs of each MW of hosting capacity increased and that a wide range of HC can be reached depending on the network characteristics.

Now focusing on the implementation that include the P&Q control in DG units, if the expenditure of retrofitting DG units has to be covered by DSO, the Figure 128 shows that the total costs of the DSO significantly increase for "low-cost" solutions, i.e. total costs of DSO become in percentage terms much higher when the cost of the solution is lower and insignificant when the cost of the solution is higher:



Note: (*) Sce1: "No retrofit" scenario; Sce2: "Half of the 'big' DG units are retrofit"; Sce3: "All of the 'big' DG units are retrofit

Figure 128 (Differences on the costs of each MW of hosting capacity increased depending on who incurs the cost of retrofitting: the DSO or the generator)

10.2 Benefits Analysis (BA) of MV solutions

In this chapter the third part of the CA&BA methodology of IGREENGrid project is carried out for the MV solutions.

10.2.1 Identification of main benefits of the MV solutions

In this step the potential main benefits of the solutions are identified. These benefits are taken from the list of 22 potential benefits of smart grids projects (see Annex 6).

10.2.1.1 Main benefits of MV Voltage Monitoring

No.	Benefit	Direct / Side and comments
1	Deferred Distribution Capacity Investments	Direct
9	Reduced Electricity Losses	Side
20	Reduced T&D Equipment Maintenance Cost	Side

Table 23 (Main benefits of “MV Voltage Monitoring”)

The MV Voltage Monitoring would result in deferred distribution capacity investments because it allows to better estimate the real remaining hosting capacity of the network. In general terms, the planning of distribution network applies quite conservative limits aimed to handle risks and ensure that the quality of supply is always guaranteed leaving wide security margins that could be used if more information is available (monitoring). The margins are also due to other factors such as: the limited number of product ranges (when reinforcing e.g. a substation), or the costs of cable laying in urban areas urging the DSO to (over)reinforce the network in order to meet future needs and avoid frequent construction work in the streets.

The reduction of electricity losses and maintenance cost would come for the improved observability of the network, i.e. more accurate information about the real state of the network, device loading, applied voltages, etc. Reinforcing the network would also reduce the losses. Indeed, the comparison of the losses in the “network reinforcement” scenario and in the “MV Voltage monitoring” scenario could actually show that MV monitoring could end up increasing the losses as hosting capacity may increase if some reserves are actually available. In any case, these would be side benefits quite difficult to estimate and measure.

10.2.1.2 Main benefits of MV Voltage Control

No.	Benefit	Direct / Side and comments
1	Deferred Distribution Capacity Investments	Direct
5	Reduced Ancillary Service Cost	Side
6	Reduced CO2 Emissions	Side
7	Reduced Congestion Cost	Side
8	Reduced Electricity Cost	Side
9	Reduced Electricity Losses	Side
10	Reduced Electricity Theft	Side
20	Reduced T&D Equipment Maintenance Cost	Side
21	Reduced T&D Operations Cost	Side

Table 24 (Main benefits of “MV Voltage Control”)

The main objective of “MV Voltage Control” is to ensure that increased levels of DRES do not lead to voltage constraints that otherwise would have required network development to be solved. In this sense, additional wires and electrical infrastructure are delayed or even substituted by communications and intelligence in order to ensure security and quality supply.
Some side effects could also be expected but it is unclear what the real impact could be, for instance, in terms of losses: Increased levels of generation close to consumption nodes could reduce transmission network losses but also increase distribution network losses.

10.2.2 Formulation of main benefits

In theory, a CBA results in a single monetary value: the figure is typically obtained as the subtraction of total costs incurred in the project from the monetised value of the benefits provided by the solution. Although this seems simple and easy, it poses some problems and limitations, such as the confidentiality of data about investments and projects, the complexity and applicability of formulas, as well as the uncertainty of some variables.

EC JRC CBA [8] proposed some formulas to monetise benefits, and on the basis of this proposal (see Annex 7), the formulas to potentially calculate the monetised value of the main benefits identified before are exposed in Annex 4 for reference purposes.

10.2.3 Identification of other benefits of the MV solutions

The identification of main benefits is complemented by the identification of additional benefits brought by the project towards the achievement of the smart grids and of the policy goals behind it. These benefits are selected from the list of KPIs / Benefits defined by EC Task Force for smart grids 2010C (see Annex 8).

10.2.3.1 Other benefits of MV Voltage Monitoring

No.	Other benefit	Direct / Side and comments
2	Environmental impact of electricity grid infrastructure	Direct
4	Hosting capacity for distributed energy resources in distribution grids	Side
7	An optimized use of capital and assets	Side
15	Share of electrical energy produced by renewable sources	Side
22	Percentage utilization of electricity grid elements	Side
25	Actual availability of network capacity with respect to its standard value	Side

Table 25 (Other benefits of “MV Voltage Monitoring”)

Voltage Monitoring contributes to a higher DRES penetration but also permits to obtain better levels of security and quality of supply as Voltage Monitoring is the first step for voltage control, which can ensure a higher voltage quality. Moreover, increasing the hosting capacity of the existent distribution grids helps to optimise the use of the capital and assets as with a same infrastructure the system can be able to manage a higher number of DER generators due to the better knowledge of the state of the network provided by the Voltage Monitoring.

10.2.3.2 Other benefits of MV Voltage Control

No.	Other benefit	Direct / Side and comments
2	Environmental impact of electricity grid infrastructure	Direct
4	Hosting capacity for distributed energy resources in distribution grids	Direct
7	An optimized use of capital and assets	Direct
19	Voltage quality performance of electricity grids (e.g. voltage dips)	Direct
1	Quantified reduction of carbon emissions	Side
15	Share of electrical energy produced by renewable sources	Side
20	Level of losses in transmission and in distribution networks	Side (by OPF)
22	Percentage utilization of electricity grid elements	Side
25	Actual availability of network capacity with respect to its standard value	Side

Table 26 (Other benefits of “MV Voltage Control”)

The increase of sustainability is a direct benefit of the “MV Voltage Control” due to the reduction of environmental impact of electricity grid infrastructure. In other words, the improvement of hosting capacity for DER in distribution grids is based on communications and intelligence so it defers the need to install additional infrastructure. At the same time, tighter control of the MV network voltage improves the voltage quality performance.

Some of the side effects are due to the expected higher penetration of renewable energy sources into the network and into the generation mix. The remaining side effects are basically linked to exploiting network assets closer to the technical limits by advanced monitoring and control.

10.3 Overall economic assessment of MV solutions

IGREENGrid CA&BA is not aimed to support the selection of the best solution for every country and any network: in fact the studied distribution networks may be not fully representative of the country they belong to and too many factors are intentionally left out for simplification purposes.

In this chapter a summary of the main results reached from the CA and the BA of the MV solutions under analysis within IGREENGrid project are explained.

10.3.1 Results of Costs Analysis of MV solutions

Network reinforcement versus Smart MV solutions implemented at the analysed networks

The different characteristics of the countries (regulation, topography, etc.) and different planning approaches of DSOs affect the final results, as each DSO case is different.

Specifically, high differences are detected on the needed network reinforcement to reach a given hosting capacity but these numbers must be carefully interpreted.

First of all, the costs of network reinforcement to achieve a given HC have been evaluated using a simplified criterion that does not necessarily reflect the real costs that would be associated with this reinforcement.

Regarding the theoretical costs of network reinforcement coming from the simulations, it seems as a clear conclusion that a new primary substation would be built in many cases when network reinforcement costs exceed the typical costs of a substation. Even so, the feasibility of the construction of a new substation or the network reinforcement cannot be assumed for granted as it would require studies, detailed planning, permissions, space, time, etc.

In many networks analysed, the initial costs of the network reinforcement are higher than initial investment of smart solutions, but it has to be taken into account that operational and maintenance costs of conventional solutions are usually lower.

Additionally, the estimated lifetime of typical network assets (such as cables) exceeds the time horizon of 20 years considered in the Cost Analysis. The inclusion of this this aspect on the analysis of the negative cash flows may be required to properly compare costs, since an asset that is more expensive but has a much longer life expectancy could end up to be more profitable. This longer life expectancy tends to be more favourable to network reinforcement. This can bring more complex solutions (centralized solutions with extension of the SCADA-DMS) to be more expensive than network reinforcement.

The life expectancy parameter would also affect the comparison of the various smart grids solutions.

Smart MV solutions: Distributed versus Centralized solutions

If only the hosting capacity enhancement on one network is considered, centralized solutions tend to be preferred than distributed ones. However, according to the economic analysis, they result to have higher costs per MW of hosting capacity increased, because of the individual cost of some components, such as the State Estimation. Further added values and additional functions provided by the centralized solutions (e.g. State Estimation) could balance some of these additional costs but they cannot be easily integrated in this analysis.

Figure 129 shows an example in which the centralized solutions are much more expensive than distributed ones:

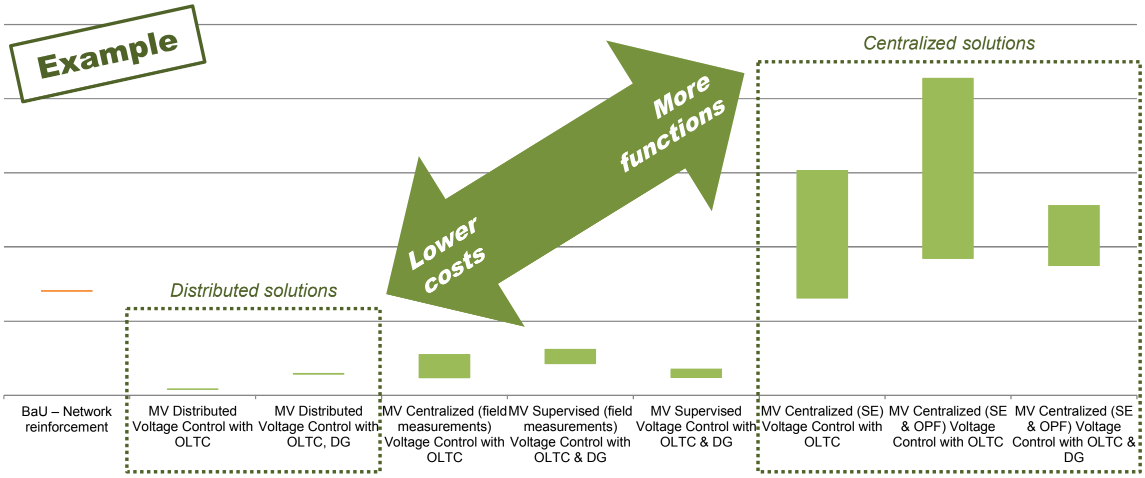
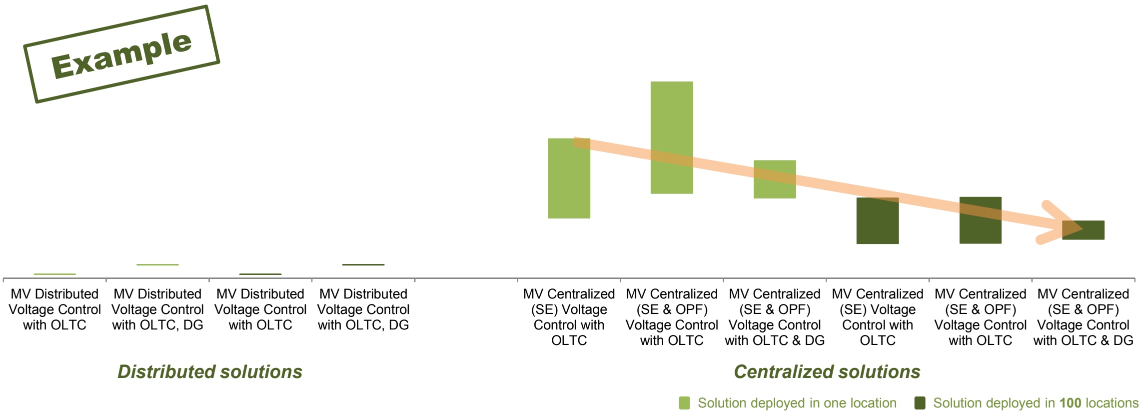


Figure 129 (Cost of each MW of HC increased (€/∆MW))

When addressing the specific requirements of one case, applying distributed solutions (mostly based on local actuators) with lower communication needs seems to be the most cost effective alternative (lowest costs per MW additionally installed). If the problem to be solved with the distributed smart grids solution occurs in multiple locations within the distribution network, then centralized approaches may prevail, due to the other functions that network management systems (i.e. State Estimation) could contribute to the system.

Figure 130 shows an example of the costs of each MW of HC increased when a solution is deployed just in 1 location and when the same solution is deployed in several locations:



Assets installed in these solutions are locally controlled, so that each time these solutions are deployed, the same costs are incurred.

→ ***Good approach for a localized problem in the network***

DMS assets (SE, OPF) need to be installed one time in each control center. So, if the problem extends in all over the network, the average cost of each deployment of these solutions installed in many locations is much lower than the costs of deploying these solutions just in one location.

→ ***Good approach to solve a problem occurring in an extended part of the network, which provides additional advantages (good scalability)***

Figure 130 (Cost of each MW of HC increased (€/∆MW): deployment in 1 location vs. several locations)

The correct attribution of the share of the costs of some components (i.e. State Estimation) becomes the key for the feasibility of some approaches when deployed on several networks. These components –network management supporting tools- enable other functions not considered in the cost analysis. These other functions could be interesting to comply with other objectives, thanks to the knowledge of the real status of the network (network planning), or solve other problems in the network (real time operation of the network).

Figure 131 shows an example about the percentage that the costs of DMS assets represent on the total costs of the smart solutions:

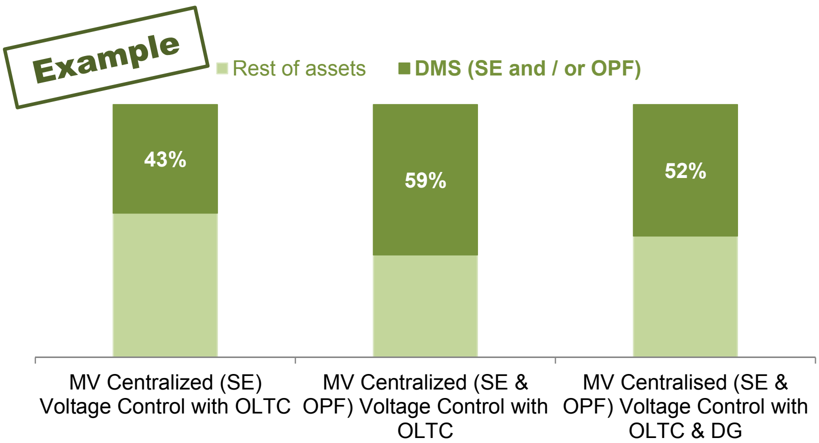


Figure 131 (% of costs of DMS assets compared to PVTC)

10.3.2 Results of Benefits Analysis of MV solutions

As explained before, it is difficult to quantify the expected benefits resulting from the implementation of one smart grids solution when it is deployed on a given network. Therefore the Benefit Analysis is limited to their identification and it draws the additional advantages that are not quantifiable benefits for the analysed MV functionalities.

The main benefit with a direct impact provided by the functionalities “MV Voltage Monitoring” and “MV Voltage Control” is the deferment of the distribution capacity investments or reinforcement.

Additionally, many benefits with side impacts can also be achieved in the distribution networks thanks to the MV solutions analysed, such as the reduction of electricity losses or the improvement of T&D equipment maintenance, among others.

11 Economic evaluation of LV solutions

In this chapter the core of the CA&BA methodology (see chapter 2.2) is carried out for the LV solutions selected as the most-promising ones within IGREENGrid project.

11.1 Cost Analysis (CA) of LV solutions

The networks analysed in the "Economic evaluation of LV solutions" are characterized in technical simulations. The Cost Analysis is limited to the LV networks requiring some solution to be safely operated.
The Costs Analysis of LV networks follows the same steps as those done for the CA of MV networks: firstly the costs incurred by DSOs (and only the DSOs), when implementing the solutions, are identified and calculated and secondly these costs are compared with the implementation of network reinforcement[65] needed to reach the same hosting capacity (see chapter 10.1).
The main difference between the Cost Analysis of LV networks and MV networks is the sensitivity analyses. In the CA of MV networks two sensitivity analyses are carried out, varying two key variables: the discount rate and the number of DG units to be retrofitted. In the CA of LV networks just one sensitivity analysis is performed, varying the discount rate. The retrofitting of already installed PV inverter, to include P&Q control, is not considered nowadays and in the near future.
In this chapter, the Cost Analysis (CA) of one LV network is omitted, due to confidentiality issues, but the summary analyses (aggregated figures) of all the LV networks are exposed.

11.1.1 Input data for the CA of LV networks

11.1.1.1 Technical data of the LV network under analysis

Some necessary data for the Costs Analysis come from the technical analysis (such as the theoretical network reinforcement). The technical analyses have been performed on the study / test LV networks of ERDF, EAG, and RWE. The technical data required for the Cost Analysis are shown in Table 27:

Data needed for CA	Source of the data
Nominal power of the Transformer	Data provided by DSOs.
Number of measurement devices to be installed	It is calculated as the sum of the "Number of critical nodes", resulting from the "Feeder properties" of the technical analysis.
Maximum HC reached (kW) when implementing each solution	It is calculated as the sum of the "HC (MW)" reached by each network when implementing each solution (Step 2.2)
Length needed for the network reinforcement	It is calculated in the simulations as the sum of the length of reinforcements required in each feeder to reach as much hosting capacity as the "best" smart solution being studied.

Table 27 (Technical data required for the Cost Analysis of LV solutions)

[65] The same method as for the MV networks has been used (see chapter 6.1.4).

11.1.1.2 Cost data of the assets within the LV solutions

Among the three DSOs that have provided LV test networks, only EAG and ERDF have also provided cost data of assets included in LV solutions. The CA was made only for these two DSO. The subset of the test networks that may require one of the solutions is economically analysed.
Costs given by these DSOs are referred to the year 2015 and the yearly rate of expected increase of these costs is assumed to be 1.5%[61].
Due to confidentiality issues, cost data are intentionally removed.

11.1.1.3 LV solutions under analysis

The only solution implementing the "LV Voltage Monitoring" functionality is "LV Voltage Monitoring (AMI)[66]". Since this solution assumes that AMI is already deployed and it is difficult to estimate the only additional asset required (a software module in charge of off-line processing of measured data to estimate low voltage profiles), this solution has not been economically analysed.

The solutions for the "LV Voltage Control" functionality which have been selected for the analysis are:

- LV Distributed Voltage Control with OLTC.
- LV Distributed Voltage Control with DG.
- LV Distributed Voltage Control with OLTC, DG.
- LV Distributed (field measurements) Voltage Control with OLTC, DG.

The first implementation in the list, "LV Distributed Voltage Control with OLTC", has not been analysed technically, so the CA is not performed due to the lack of information.

The Cost Analysis of the second implementation, "LV Distributed Voltage Control with DG", is zero in this study, because the only cost consists in retrofitting of already installed units to include P&Q control, but this cost is not charged to the DSOs. The new units will have this functionality included, to satisfy the associated new connection code.

In Table 28 the assets required for each solution of the functionality "LV Voltage Control" are listed:

[66] The reader should have in mind that not all the smart meters deployed in the different countries have the functionalities required to implement the considered solutions.

Implementation	Cost element (assets and others)
LV Distributed Voltage Control with OLTC	MV/LV Transformer with OLTC (50 kVA, 100 kVA, 250 kVA, 400 kVA or 630 kVA)
	Local control OLTC (in MV/LV)
	Residual value of the old MV/LV Transformer
	MV/LV Transformer substitution
LV Distributed Voltage Control with DG	New PV inverter with P&Q control
	Retrofit of PV inverter with P&Q control
LV Distributed Voltage Control with OLTC, DG	New PV inverter with P&Q control
	Retrofit of PV inverter with P&Q control
	MV/LV Transformer with OLTC (50 kVA, 100 kVA, 250 kVA, 400 kVA or 630 kVA)
	Local control OLTC (in MV/LV)
	Residual value of the old MV/LV Transformer
	MV/LV Transformer substitution
LV Distributed (field measurements) Voltage Control with OLTC, DG	New PV inverter with P&Q control
	Retrofit of PV inverter with P&Q control
	Measurement device (for LV line)
	MV/LV Transformer with OLTC (50 kVA, 100 kVA, 250 kVA, 400 kVA or 630 kVA)
	Local control OLTC (in MV/LV)
	Residual value of the old MV/LV Transformer
	MV/LV Transformer substitution

Table 28 (Cost elements of the implementations under study of the functionality "LV Voltage Control")

11.1.2 Summary for the LV networks analysed

The ranges of cost of the elements of the solutions for the functionality "LV Voltage Control" are not as large as in the case of MV solutions, as Figure 132 shows. Indeed, depending on the transformer rating, the cost data provided by the DSOs spread between 1 and 1.3 (variation of 30 %).

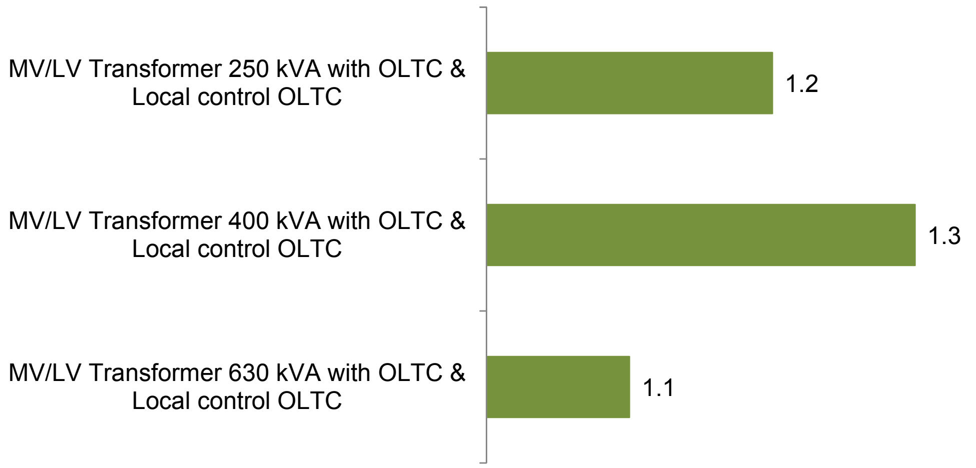


Figure 132 (Number of times of variation ranges of some cost elements of the solutions within the functionality "LV Voltage Control")

Within the approximations of the CA, these variations are rather limited.
The estimated lifetime of the most expensive assets (e.g. OLTC) included in the solutions of "LV Voltage Control" is close to 40 or 50 years, so the amortization period and the residual value of assets at the end of the study period (20 years) are not limiting factors to the economical comparison between smart and typical solutions.
Different types of LV networks have been analysed in different countries. In total, 7 LV networks in two different countries are economically studied: 6 LV networks in France (ERDF) and one LV synthetic network in Upper Austria (EAG).
The different characteristics of the countries (regulation, topography, etc.) and different planning approaches of DSOs may also affect the final results, as each DSO case is different.
The major factor limiting DRES penetration in the LV networks that were studied in this work is the voltage rise caused by DRES power injection. The technical analysis shows that the penetration of PV leads to higher voltage levels, but generally, the allowed voltage rise for LV distribution networks is very low. The current planning rules applied by each DSO, in this case the maximum acceptable voltage increase, are quite different (from 1% to 3% allowed voltage rise), then similar networks will allow several times higher DRES penetration just because of the network planning practices of DSOs.
In line with this fact, for some LV networks there is a very significant increase of HC thanks to the smart grids solutions using both the OLTC (using part of the voltage band allocated to loads) and the P&Q control in generation units, and so the length needed for the network reinforcement solution tend to be very long.
Due to the complexity of the calculation for the network reinforcement needed to reach a given hosting capacity, the same simplified common approach as in MV networks has been used and the results must be carefully interpreted.

In Figure 133 the theoretical costs of LV network reinforcement coming from the simulations is shown:

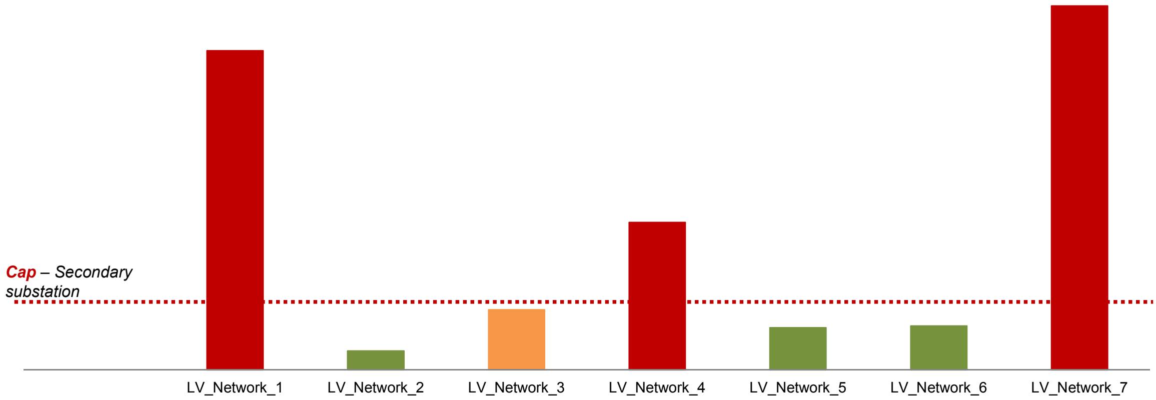


Figure 133 (Theoretical costs of network reinforcement coming from the simulations for the LV networks analysed)

According to Figure 133, a new secondary substation would be built for about the half of the considered networks (not fully representative due to the low number of LV networks) when network reinforcement costs exceed the typical costs of a substation (i.e. networks 1, 4 and 7), which is the case here since the method that is used consists in maximizing the HC and therefore brings all the feeders at the limit of constraints. The reader should remind that the scenario considered in this study correspond to a very high DRES penetration (i.e. the hosting capacity), assuming a high penetration in all the feeders, which explains the large network reinforcement costs.

Looking at the Figure 133, the studied LV networks can be classified into two groups according to length of reinforcement required:

- Network for which the theoretical costs of reinforcement are below the costs of a secondary substation (network 2, 3, 5 and 6).
- Network for which the theoretical costs of reinforcement are above the costs of a secondary substation (network 1, 4 and 7).

For both groups, the maximum and the minimum values for the cost of unitary hosting capacity increase (€/∆kW) applying smart solutions and typical network reinforcement are computed and shown on Figure 134 and Figure 135.

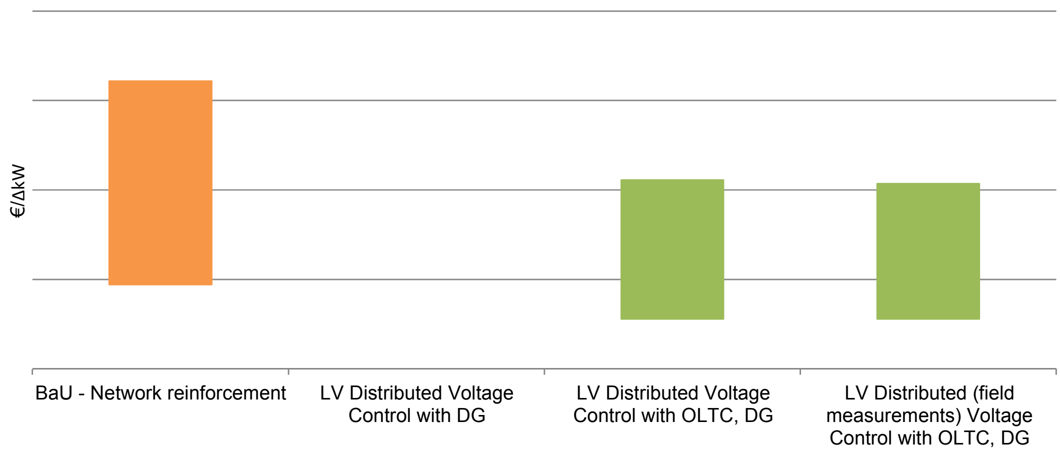


Figure 134 (Maximum and minimum values for the cost of each kW of hosting capacity (HC) increased (€/∆kW) compared with the network reinforcement solution for LV networks 2, 3, 5 and 6)

As Figure 134 shows, for the four networks (reinforcement costs below the costs of a new secondary substation), the studied smart solutions and the network reinforcement are similar from the economical point of view.

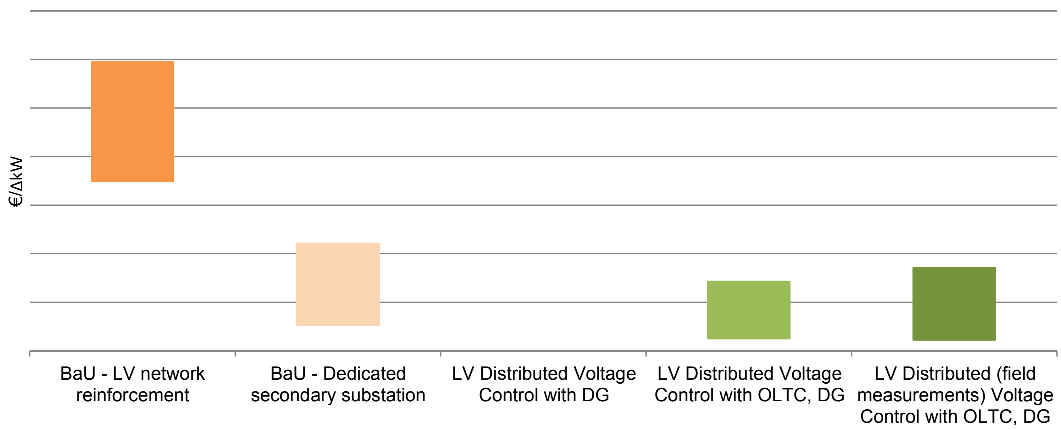


Figure 135 (Maximum and minimum values for the cost of each kW of hosting capacity (HC) increased (€/∆kW) compared with two typical solutions (network reinforcement and new secondary substation) for LV networks 1, 4 and 7)

According to Figure 135, it seems clear in this simulated situation that reinforcing the LV network makes no sense from the economic perspective for the networks in which the reinforcement costs are beyond the average costs of a secondary substation. However the simulated situation is not completely realistic since HC is maximized and all the feeders therefore may require reinforcements which are usually very expensive. In some more realistic situations with reasonable penetration of DRES, the costs of the reference situation would be much smaller compared to OLTC for example.

Figure 134 and Figure 135 provide interesting information about the costs associated to 1 kW of HC increase, but it is also necessary to consider that different hosting capacity levels can be reached with every smart solution.

According to the results of the technical simulations, the HC increase obtained by the OLTC is larger than that HC obtained with locally controlled generators reactive power modulation and with the curtailing of active power. The HC increase obtained in average when deploying both the OLTC and the local control P&Q in PV inverters on the studied networks is about 164%, but only the 14% of this percentage comes from the locally controlled generators.

To sum up, some ideas can be deduced from the study above (keeping in mind that it depends on the needed increase of HC in each specific network):

- The average European secondary substation is equipped with conventional off-load tap changing transformers and the cost of a comparable on-load tap changing transformer is currently in ratio of roughly 2 to 3 without taking account the costs of required sensors on the network and the additional costs for the installation and maintenance of the OLTC compared to conventional transformers. As important HC increase can be reached in LV networks when including OLTC, this solution appears very promising.
- The additional hosting capacity introduced by advanced controls on the DRES power interface should not be neglected because it also brings an important benefit with little additional costs also for the generators.

11.2 Benefits Analysis (BA) of LV solutions

In this chapter the identification of benefits is carried out for the LV solutions.

11.2.1 Identification of main benefits of the LV solutions

In this step the potential main benefits of the target functionalities have been identified.
These main benefits are identified from the list of 22 potential benefits of smart grids projects (see Annex 6).

11.2.1.1 Main benefits of LV Voltage Monitoring

No.	Benefit	Direct / Side and comments
1	Deferred Distribution Capacity Investments	Direct
9	Reduced Electricity Losses	Side
20	Reduced T&D Equipment Maintenance Cost	Side

Table 29 (Main benefits of “LV Voltage Monitoring”)

“LV Voltage Monitoring” provides interesting information that will improve the design and the operation of the LV networks, identifying potential voltage constraints appearing at LV network.

“LV Voltage Monitoring” would enable the integration of larger amounts of DER without increasing the distribution investments: since the information about the real state of network is more accurate, a higher hosting capacity is achieved, limiting the need for investments on new assets.

As in the case of “MV Voltage Monitoring” some side benefits could be obtained but, again, they are difficult to evaluate. For instance, increasing the penetration of local generation should reduce the power flows in transmission and distribution networks, but depending on the specific production and consumption profiles, opposite effects could be attained.

11.2.1.2 Main benefits of LV Voltage Control

No.	Benefit	Direct / Side and comments
1	Deferred Distribution Capacity Investments	Direct
2	Deferred Generation Capacity Investments	Side
5	Reduced Ancillary Service Cost	Side
6	Reduced CO2 Emissions	Side
7	Reduced Congestion Cost	Side
8	Reduced Electricity Cost	Side
9	Reduced Electricity Losses	Side
10	Reduced Electricity Theft	Side
20	Reduced T&D Equipment Maintenance Cost	Side
21	Reduced T&D Operations Cost	Side

Table 30 (Main benefits of “LV Voltage Control”)

The direct impact of the LV Voltage Control solutions is enabling a higher integration of DRES without network reinforcements and thus delaying investments on distribution network assets.
As in the MV Voltage Monitoring, there are several potential side benefits but the quantification is complex.

11.2.2 Formulation of main benefits

The formulas to potentially calculate the monetised value of the benefits, are detailed in Annex 4 (check also chapter 10.2.2).

11.2.3 Identification of other benefits of the LV solutions

The identification of main benefits is complemented by the identification of other additional benefits brought by the project towards the achievement of the smart grids and of the policy goals behind it. These benefits are selected from the list of KPIs / Benefits defined by EC Task Force for smart grids 2010C (see Annex 8).

11.2.3.1 Other benefits of LV Voltage Monitoring

The qualitative benefits identified for “LV Voltage Monitoring” are the same as those found and explained for the “MV Voltage Monitoring” (chapter 10.2.3.1):

No.	Other benefit	Direct / Side and comments
2	Environmental impact of electricity grid infrastructure	Direct
4	Hosting capacity for distributed energy resources in distribution grids	Side
7	An optimized use of capital and assets	Side
15	Share of electrical energy produced by renewable sources	Side
22	Percentage utilization of electricity grid elements	Side
25	Actual availability of network capacity with respect to its standard value	Side

Table 31 (Other benefits of "LV Voltage Monitoring")

11.2.3.2 Other benefits of LV Voltage Control

Other benefits identified "LV Voltage Control" are similar to those signalled and explained for the solutions for "MV Voltage Control" (see chapter 10.2.3.2):

No.	Other benefit	Direct / Side and comments
4	Hosting capacity for distributed energy resources in distribution grids	Direct
7	An optimized use of capital and assets	Direct
19	Voltage quality performance of electricity grids (e.g. voltage dips)	Direct
1	Quantified reduction of carbon emissions	Side
2	Environmental impact of electricity grid infrastructure	Side
15	Share of electrical energy produced by renewable sources	Side
20	Level of losses in transmission and in distribution networks	Side
22	Percentage utilization of electricity grid elements	Side
25	Actual availability of network capacity with respect to its standard value	Side

Table 32 (Other benefits of "LV Voltage Control")

11.3 Overall economic assessment of LV solutions

11.3.1 Results of Costs Analysis of LV solutions

The major factor limiting DRES penetration in the studied LV networks is the voltage rise produced by DRES power injection.

In the technical simulations, "highly distributed" DRES penetration scenarios are used, i.e., PV based DRES are simulated across most of the nodes of the LV distribution network. In particular, the technical analysis shows that the penetration of DRES leads to higher voltage levels, but for some DSOs, the allowed voltage rise for LV distribution networks is very low, which strongly limits the hosting capacity.

The planning rules applied by each DSO do have a significant effect on the hosting capacity under “AsIs” scenario. The maximum acceptable voltage raise can cover a wide range, from 1% to more than 3%, depending on the DSO. In other words, similar networks will allow several times higher DRES penetration just because of the normal planning practices of the DSOs (when considering the LV level only). The OLTC artificially benefits from these margins since it completely changes the way to deal with MV voltage variations and these LV margins are not taken into account anymore and the reference is changed, so this should be taken into account in the way the results are understood and interpreted.

The effect of these limits can also be observed on the total reinforcement length and costs of the business as usual cost: targeting the same hosting capacity with very restrictive voltage limits needs so major reinforcements that, in some cases, total reinforced cable / line lengths are close to effectively duplicating the network. Obviously, in these cases, when comparing total costs of smart solutions and total costs of network reinforcement, it would be cheaper to build a dedicated secondary substation and that would be the preferred solution to reach the same DRES penetration.

The transformers equipped with OLTC are a very effective solution to decouple voltage levels (MV/LV) and free part of the voltage band allocated to the upper voltage level and to loads for generation embedded in LV networks. The use of OLTC equipped transformers in secondary substations provides therefore an important increase of the hosting capacity in LV networks.

In line with this, the lengths needed for network reinforcement solution tend to be very long for some of the LV networks studied, as a very significant increase of HC is reached thanks to the smart grids solutions using both the OLTC and the P&Q control in generation units. However the simulated situation is not completely realistic since HC is maximized and all the feeders therefore may require reinforcements which are usually very expensive. In some more realistic situations with reasonable penetration of DRES, the costs of the reference situation would be much smaller compared to OLTC for example.

In the tested networks, according to the results of the technical simulations, the HC increase obtained by the OLTC is larger than the HC obtained with locally controlled DRES inverters adapting reactive power injection / consumption to the sensed voltage and curtailing active power if needed.

Then, the deployment of one smart grids solution such as the MV/LV transformer with OLTC leads to a significant increase of the hosting capacity in an easy but costly way as the average European secondary substation is equipped with conventional off-load tap changing transformers and the cost of a comparable on-load tap changing transformer is in a ratio of roughly 2 to 3 without taking account the costs of required sensors on the network and the additional costs for the installation and maintenance of the OLTC compared to conventional transformers.

It is also important to note that in some countries these assets are not considered as distribution assets, so DSOs do not receive neither incentives nor payments for them; making necessary a regulatory change in the DSO retribution scheme.

The additional hosting capacity introduced by advanced controls on the DRES power interface should not be neglected because it also brings an important benefit with little additional costs: DRES would adapt themselves to the local voltage measure in a distributed and unattended manner contributing to the network operation.

11.3.2 Results of Benefits Analysis of LV solutions

As explained before, it is almost impossible to quantify the expected benefits resulting from the implementation of one smart grids solution when deployed to one given network. Therefore the benefit analysis is limited to their identification.

The Benefits Analysis (BA) draws additional advantages and not quantifiable benefits for the analysed LV functionalities.

The main benefit with a direct impact provided by the functionalities “LV Voltage Monitoring” and “LV Voltage Control” is the deferral of the distribution capacity investments.

Additionally, as for the MV solutions analysis, many benefits with side effects can also be achieved thanks to the LV solutions analysed (impact on electricity losses and T&D equipment maintenance, among others).

12 Overall evaluation and recommendations

12.1 Discussion of the results on the deployment potential of SG-solutions

12.1.1 Results of the technical evaluation

Methodology

The followed three steps methodology (feeder screening, hosting capacity determination with a limited number of samples and detailed analysis) has been validated and proved to provide sound results. In the first step, the “AsIs” hosting capacity has been estimated and the feeders have been classified (voltage / loading-constrained) for different DRES distributions via Monte Carlo simulations. In the second step, the critical times have been identified from a Monte Carlo simulation and the hosting capacity increase achievable by each solution has been determined. In the last step, detailed simulations have been performed for the full set of Monte Carlo samples, allowing to evaluate further KPIs such as the energy efficiency KPI, the voltage quality KPI, and to investigate further issues such as the reactive power exchange with the upstream network. This last step also allows validating the hosting capacity determined in the previous step.

This approach has the advantage that it allows comparing solutions on a common set of feeders. The determined hosting capacities are for some networks large and probably beyond the actual DRES potential in the areas. This is one limitation of this approach but the purpose was to compare solutions on a common basis of real (representative) networks and not to do a planning exercise for specific networks.

Network landscape

As previously explained given the high number of networks and feeders considered in the simulations, the results can be seen as providing a correct picture of various relevant cases (helicopter view) but do not allow performing a scaling at country or European level in order to draw even more generic conclusions.

As shown in chapter 8, it is not possible to find clearly separated groups of feeders. The reader should keep in mind that the variety of networks is very large and that the local network properties condition the actual hosting capacity and the performance of smart grids solutions. For example, the sum of the considered hosting capacities per feeder may exceed the rating of the installed transformer (which was disregarded due to the analysis on feeder level).

In addition to the network properties, the corresponding network planning rules also play an important role. An example of this is the fact that allowed voltage rise for each participating DSO varies between +2 % and +4.6 % at MV level and 1.4 % and 3 % at LV level (expected factor or more than 2 for the hosting capacity of voltage-constrained feeders).

A direct comparison between networks from different DSO is therefore not meaningful (different voltage levels, different planning rules etc.).

The main advantage of the approach presented in the previous section is, that the feeder hosting capacity is a rather (over time) static result, which means that any changes or reinforcements in the upstream network do not influence the calculated hosting capacity values significantly or at all. Contrariwise, the bottom up approach calculating the hosting capacity on feeder level is highly useable to identify the “bottlenecks” that are limiting the full integration potential on feeder level. However, to fulfil these tasks, the full network data set of different DSO is needed.

Potential for voltage control in MV networks

The focus of the considered smart grids solutions (based on the demonstration projects) is voltage control to increase the network hosting capacity: all the solutions except the MV solution “OPF” (with state estimation) do not monitor the loading of lines and cables.

For this reason, it is especially important to identify feeders in which the hosting capacity is limited by the voltage rise when trying to assess the deployment potential of these smart grids solutions. This feeder characterisation (voltage / current-constrained feeders) has been done at the first step of the methodology (feeder screening) and repeated when implementing the solutions. Indeed, as the simulations have shown, a substantial share of the feeders turn from being voltage-constrained to being current-constrained, especially for the solutions leading to the highest hosting capacity gain. This effect which “limits” the actual deployment potential of smart grids solutions (especially those with a high effectiveness) has been quantified for each solution. For example, about 60 % of the voltage-constrained feeders can actually benefit from the solution “VVC” due to the fact that this solution leads to an increase of the loading (due to the reactive power flows and to the increased installed generation).

On the other hand, this group of limited feeders which can fully benefits from the smart grids aiming at voltage control solutions mostly consists of feeders with a very limited hosting capacity, meaning that this hosting capacity could actually be reached in the reality. The average hosting capacity gain varies between +31 % and +137 % for solutions without centralised monitoring (e.g. DSE) and +235 % for the solution “OPF”.

Potential of voltage control in LV networks / statistical analysis of large sets of LV networks

Following a similar approach to the MV networks, the feeders in which the hosting capacity is limited by the voltage rise have been identified in the first step.

In accordance to the expectations, the average effectiveness of the solution “VVC” is significantly lower for the LV feeders (+16 %) than for the MV feeders (+75 %) to the higher share of cables in LV networks. The solution “WAC” leads to a larger average gain of hosting capacity due to the fact that for most DSOs, the voltage band can be used to a greater extent (+250 %).

The statistical analysis of the complete sets of LV networks for two DSOs lead to interesting results in terms of methodology (the proposed methodology allowed to assess the potential of specific smart grids solutions) and in terms of results. The deployment potential for voltage control solutions (two distributed solutions: voltage regulated distribution transformers and reactive power control) is high for the considered areas, and the voltage regulated distribution transformers allow to reach on average a higher hosting capacity increase (about +180 %) than the reactive power control (+25 %). However, the share of feeders actually benefiting from the full potential that these solutions offer is smaller for the voltage regulated distribution transformers (21 %-43 %) than for the reactive power control solution (61 %-81 %).

A method for classifying LV feeders has been proposed and tested on the available data sets, showing very promising results. Using parameters which are usually available from GIS, voltage-constrained feeders with a potential for deploying voltage control solutions can be identified with high accuracy (only about 3 % of misclassified feeders reduce the potential to implement smart grids solutions).

The study performed on the phase balancing showed that when the information about the phase connections of customers is available (through the AMI), the potential for improvement can be easily computed.
In a limited number of feeders, the unbalance level might reach high values and having a tool to identify such feeders and to determine the most "economic" (Pareto-principle) way to better balance the unsymmetrical infeed would allow DSO to improve the situation in these feeders with limited and targeted efforts. For the considered feeders, the actual benefits have been slightly lower than those theoretically expected due to the load unbalance. The voltage unbalance (considered in this study to be the spreading between phase voltages) could be reduced by 20 % to 30 % and the maximal voltage could be reduced to the same extent. In addition to the benefits in decreasing the voltage unbalance, balancing the PV power allows reducing network losses. The simulations showed a limited benefit in terms of losses reduction (between -5 % and -10 % (relative decrease)) but for scenarios with larger penetration levels, the benefits (on network losses and voltage unbalance) are expected to be significantly higher.

Achievable hosting capacity increase through the deployment of the considered solutions
From the technical point of view, when evaluating only the achievable increase of hosting capacity, the more complex solution ("OPF" – centralized solution) leads to the highest effectiveness: the hosting capacity can be increased on average by about +240 %. The next solution with the second highest effectiveness is "WAC&VVC", which leads to an average hosting capacity increase of about +160 %. This solution is however only usable on a limited number of feeders (only 27 % of the voltage-constrained feeders). The two distributed solutions "VVC" and "WAC" lead to a similar average hosting capacity increase (between +80 % and +90 %).

Side effects of the smart grids solutions
All the considered smart grids solutions which allow increasing the hosting capacity have side effects (mainly an increase of network losses and of the reactive power exchanged with the upstream network and a possible active power curtailment).

Losses

These side effects have been quantified through the simulations. The energy efficiency KPI has been used to investigate the impact of the smart grids solutions on the network losses. For example, the implementation of the solution "VVC" leads to a decrease of the energy efficiency KPI of almost 1 % (one percentage point) for the least efficient feeder and about 0.5 % on average for all the feeders (combined effect of an increased generation and increased reactive power flows due to the solution)[67].

Reactive power exchange with the upstream network

As further side effect, the reactive power exchange with the upstream network has been quantified for several feeders, showing for example that the solution "VVC" could lead to more than double the amount of reactive energy exchanged with the upstream network at a power factor below 0.90. With the entry into force of the network code on demand connection [36], this issue will gain in importance (combined effect of an increased generation and increased reactive power flows due to the solution).

Curtailment

Finally, the reduction of the annual yield caused by active power curtailment has been evaluated

[67] Comparison between the smart grids solution with increased hosting capacity and AsIs scenario.

and a discussion has been included. When considering a fix curtailment to 70 % of the maximal output power ("FixCurt"), the relative curtailment varies between 2.0 % and 6.7 % (the highest curtailment is not reached for installations in Southern Europe which have a larger yield but in central Europe due to the shape of the power duration curve). In reality, the curtailed energy is expected to be smaller since the 70 % limitation is applied to the installed power (kWp) and typical installations in central Europe usually seldom reach the rated power (kWp). Additionally, if the limitation is foreseen for the point of common coupling, a high self-consumption rate would prevent curtailment at all. A more complex solution consisting in reducing the power only when the voltage reaches high values (e.g. P(U)) leads in theory to smaller curtailment values. Considering that the yield reduction should be evaluated (e.g. cap for a non-firm contract) and that this yield reduction cannot be determined accurately, worst case considerations are necessary. Although the P(U) control leads to a smaller yield reduction, the necessity to use worst-case assumptions to evaluate the curtailed energy gives the 70 %-rule more benefits in terms of hosting capacity increase.

Network reinforcement

A concept has been proposed to estimate the needed reinforcement in order to reach a given hosting capacity. This concept has the advantage to be easily applicable to any network and to serve as a common basis to compare solutions tested on different feeders. This approach however delivers results which should be carefully interpreted since the real-life practice is much more complex (for example, the network has to face continuous changes and network planning cannot only be done at once). Moreover, many other factors such as quality of supply, reliability or general asset management practices have an impact on how networks are reinforced. For some cases, the network reinforcement computation led to unrealistic figures (e.g. 20 km reinforcement for a single feeder at MV level and 500 m at LV level). If really a large amount of generation is built in a specific area, new primary substations dedicated to the generation (e.g. for large PV or wind parks) would be built instead of reinforcing the existing infrastructure.

Uncertainties in network planning

Most of the challenges of network planning are related to the stochastic nature of generation from renewables and of loads.

While at the MV level loads have an impact on the hosting capacity (a high valley load will reduce the reverse power flow), the stochasticity of LV loads is so high that is it not reasonable to consider any minimum load.

In practice, the effect of loads (in consuming part of the generated power locally and therefore reducing the reverse power flows) should be carefully considered even for MV networks. Indeed, loads are also subject to large changes (e.g. dismantling of a large industrial consumer) which can result in dramatic reduction of the demand in some feeders. If this compensation effect has been fully used to allow the connection of additional generators, some measures might be needed later (when large loads disappear), which can make the distribution of the reinforcement costs very complicated.

As the German experience on retrofitting PV inverters (change of frequency disconnection threshold or activation of P(f) control) [77] showed that retrofitting generators can be a very length and costly process. For this reason, the deployment of solutions should be done after a careful analysis (e.g. "*are the settings suitable for the current situation and for the future?"*)

12.1.2 Results of the economic evaluation

CA&BA Methodology

The methodology of evaluation of costs and benefits in the IGREENGrid project, CA&BA, is based on the "Guidelines for conducting a cost-benefit analysis of Smart Grid Projects" proposed by the EC Joint Research Centre (JRC), but many adaptations have been done in order to manage the number of DRES integration solutions and reference networks.

The IGREENGrid CA&BA is not aimed to support the selection of the best solution for every country and any network because the studied distribution networks may not be representative of the country they belong to and too many factors are intentionally left out for simplification purposes. Each concrete network needs to be studied in detail to identify the most suitable approach to solve the issues raised from the increased share of renewables into that distribution network.

Smart solutions vs network reinforcement solutions

Although the initial costs of the network reinforcement may be higher than initial investment costs of smart solutions, it has to be taken into account that operational and maintenance costs of conventional solutions are usually lower than smart assets operation.

Additionally, the estimated lifetime of typical network assets (such as cables) exceeds the time horizon of 20 years considered in the Cost Analysis. As the life expectancy of typical network assets is estimated around 40-50 years, taking into account this longer lifetime on the costs analysis may be required to properly compare costs, as a solution that includes a more expensive asset with a much longer life expectancy could end up more profitable. This longer life expectancy tends to be more favourable to network reinforcement. This can bring more complex solutions (centralized solutions with extension of the SCADA-DMS) to be more expensive than network reinforcement.

Smart solutions: Distributed solutions vs. Centralized solutions

When addressing the specific requirements of one case, applying distributed solutions (mostly based on local actuators) with lower communication needs seems to be the most cost effective alternative (lowest costs per MW additionally installed – as long as the gained hosting capacity is enough for the considered solution). If the problem to be solved with the distributed smart grids solution occurs in multiple locations within the distribution network, then centralized approaches may prevail.

In general terms, centralized solutions tend to be significantly more expensive than distributed solutions because of the individual cost of some components. In any case, some assets used at these centralized solutions (i.e. state estimation) enable other functionalities for DSO operation. The correct attribution of the share of the costs of these components becomes the key for a fair comparison of costs among solutions.

MV/LV transformer with OLTC and Local control in PV inverters

The average hosting capacity increase obtained when deploying both the MV/LV transformer with OLTC and the local control P&Q in PV inverters is over 160%, while deploying only locally controlled DRES inverters provides an increase of the hosting capacity below 20% on average for the considered networks. Therefore the HC increase obtained with the OLTC is larger than that HC obtained with locally controlled DRES inverters adapting reactive power injection to the sensed voltage and curtailing active power if needed. However, a part of the increase in HC observed for the OLTC could probably be obtained also by using conventional transformers with a larger range of taps or comes from the changes that were done to DSO planning rules regarding the LV margin when analysing the OLTC.

In Europe, the average secondary substation is equipped with conventional off-load tap changing transformers and the cost of a comparable on-load tap changing transformer is in ratio of about 2 to 3 without taking account the costs of required sensors on the network and the additional costs for the installation and maintenance of the OLTC compared to conventional transformers.. Due to the technical and economic performance of OLTC-based solutions, regulatory changes (in the DSO retribution scheme) should be envisaged (e.g. for countries in which these assets are not considered as distribution assets and which additional costs are not recognised).

Nevertheless, the additional hosting capacity introduced by advanced controls on the DRES power interface should not be neglected because it also brings an important benefit with little additional costs. The choice between OLTC and advanced controls on the DRES control interface is also highly dependent on the expected penetration of DRES at a specific time horizon since it will not necessarily maximize the HC of the network and therefore will impact the costs of the reference solution and thus the benefits of the smart ones.

Solutions analysed in IGREENGrid: tools to solve voltage problems

This study provides interesting results and tries to quantify the deployment potential on the base of a large set of networks. The results of the analysis are based on large number of network / feeders but cannot fully reflect the actual situation of each and every DSO. A simple extrapolation of the results is not reasonable.

In summary, the cost analysis done in IGREENGrid confirms that the set of most promising solutions identified earlier in the project should be considered as a group of available tools. Other smart grids solutions applied at the demonstration projects were discarded for further analysis in IGREENGRID due to the limited resources, but they may also be included among the possible alternatives: the AVR deployed to the German demonstrator, the STATCOM at the Spanish demo or the battery based storage system studied at the Italian and French demos.

Each concrete network should be studied with detail in order to identify the most suitable approach to solve the issues raised from the increased share of renewables into that distribution network.

12.2 Factors impacting the deployment potential of smart grids functions

The deployment potential of the considered most promising smart grids solutions has been presented from the technical and economic point of view in chapters 6, 7, 8 and 9, and summarised in chapter 12.1. Besides these conclusions, interesting discussions have emerged out of the meetings with the demonstration experts. Some of these discussions are briefly presented in the following chapter.

12.2.1 Impact of technical factors

Topology changes

Topology changes (not considered in this study) needed e.g. in case of maintenance or in case of failure of some network components, require some reserves compared to the normal operation. While the current approach is not to have full redundancy (n-1) for generators, meaning that in case of necessary change of topology, some generators might be disconnected or curtailed. When driving the network close to the limits (hosting capacity), such measures can be expected to occur more often, and the complexity of the network planning is increasing.

Growing complexity of network planning

The real deployment potential of some smart grids solutions depends on the generation structure. For example, implementing a state estimation followed by an OPF might only be feasible for networks with a few large MV generators. For networks in which the (PV) generation mostly comes from the LV level but causes some problems at the MV level, this solution might not be attractive due to prohibitive communication costs (if a connection is required to every single generator). This is especially true to centralised solutions requiring communications.

A way to better use the network infrastructure is to improve the network planning. By doing so, available reserves can be identified and used for additional connection capacities. However, in order to limit the risk which automatically increases when approaching the limits, suitable tools are necessary. Suitable tools such as probabilistic load flow fed by historic load and generation profiles are necessary and the data basis must be regularly updated to ensure that the network computations are always as accurate as possible. At the end, some of the reserves must be maintained to account for external uncertainties (e.g. dismantling of a large industrial complex resulting in a decreased load and possibly a lower hosting capacity for generators).

Despite the tools and data needed to improve the network planning, a large variety of more complex factors must be taken into account. The following example can be mentioned: reactive power control is more effective for overhead lines than for cables. For LV networks, the effect of the distribution transformer reactance is also non-negligible and can allow a significant reduction of the voltage rise. However, these two aspects (presence of overhead lines and presence of small transformers with a large short-circuit voltage) might be, with a high probability subject to change. Indeed, overhead lines tend to be replaced by cables in order to increase the continuity of supply. Moreover, small transformers (with possibly a large short-circuit voltage and therefore a large reactance) tend to be replaced by larger transformers with a smaller short-circuit voltage and therefore with a smaller reactance. In such cases, the initial compensation of the voltage rise might be partly decreased by the network renewal and the hosting capacity might even decrease.

A further impact of implementing smart grids solutions to increase the network hosting capacity is the fact that network levels cannot be considered “independent” anymore (e.g. voltage band allocation according to [61]). As an example, the wide use of VoltVar control in LV networks has implications at the LV level but also at the MV level (e.g. increased power flows and losses). A further example includes the fact that On Load Tap Changers might come to their limit due to the situation of high voltage at the HV side and strong reverse power flow with a possible reactive power surplus [29].

12.2.2 Impact of economic parameters

Time horizon considered in the CA&BA Methodology

The methodology used in the Cost Analysis (CA) is implemented over the next 20 years. Even so, the estimated lifetime of some assets (typical network assets such as cables, and also some smart assets for some DSOs) exceeds this time horizon of 20 years. The inclusion of the life expectancy of some network assets (est. 40-50 years) on the analysis of the negative cash flows of DSOs may be required to make a proper comparison of the costs of different solutions, insomuch as a solution that is more expensive as a whole but has a much longer lifetime could turn out to be more profitable.

If the Present Value of Total Costs (PVTC) of a solution calculated with a time horizon of 20 years is compared with the PVTC of the same solution calculated with a time horizon of 40 years, this comparison shows that in some cases the business as usual costs (network reinforcement) may be either much more expensive, or much cheaper than some smart grids solutions just varying an assumption of the methodology. A longer study period tends to be more favourable to network reinforcement due to the longer life expectancy of network assets on average. This can bring more complex solutions (centralized solutions with extension of the SCADA-DMS) to be more expensive than network reinforcement.

Uncertainty of costs of assets

The uncertainty on the costs of new hardware or software components is very high and in particular, the development of these costs (e.g. learning rate) in the future is hard to predict (replicability in the future). In general, conservative (expensive) assumptions have been used for the economic assessment, considering todays’ prototype prices.

Performing the comparison of different solutions for different networks and DSOs is a very challenging task: the planning approaches are different among DSOs, the practices on the economics are even more different (e.g. amortization time) and at the end, each DSO case is different and there is a wide range in the variation of some cost elements.

The high variation ranges of some cost elements of the MV solutions are mostly caused by the different conditions of DSOs. For example, the ranges of the SE and the OPF may represent the difference between a commercial product integrated into the distribution management system and a customized development lacking of full integration. This fact affects the final cost figures, as the costs and also the amortization periods vary.

About the costs of ICT, they play an important role in centralised solutions. At the same time, the uncertainty about their costs and the expected developments is high. In some cases, DSOs rely on external providers and the costs are solely accounted as OpEx while in other cases there is a CapEx (DSO investment) and OpEx component. Therefore, some smart grids solutions result in a shift from CapEx to OpEx, which is, under current regulatory frameworks in most countries,

disadvantageous in terms of DSO remuneration.
Hence, costs of assets included in the smart solutions under analysis are critical for the final cost figure, so the final results have to be interpreted carefully due to all the issues exposed here.

Network reinforcement

Different types of networks (rural, urban and rural-urban) have been analysed in different countries. The different characteristics of the countries (regulation, topography, etc.) and different planning approaches of DSOs also affect the final results, as each DSO case is different.
Specifically, high differences are detected about the needed network reinforcement to reach a given hosting capacity. This calculation is a very complex task and a simplified common approach has been proposed. Due to this, the results must be carefully interpreted.
Spread spectrum of the values of the theoretical costs of network reinforcement is calculated from the data coming from the technical simulations. The clear conclusion drawn from this fact is that for a non-negligible share of networks, the costs of the network reinforcement are in the range of the typical solutions for a new primary (or secondary in LV networks) substation (if feasible, in some cases the cost of substation is not typical at all due to a lack of space for instance). The reader should keep in mind that the considered DRES penetration are very high (hosting capacity for the most performant solution), which explains why major reinforcement are necessary for some networks. In some cases, the considered penetration may not be realistic (e.g. DRES potential limited by the available roof area).

Discount rate

As shown in sensitivity analysis (chapters 10.1 and 11.1), the assumed discount rate has a rather large impact on the total cost figures (up to 30%).
The sensitivity analysis is intended to reflect the impact that the economic situation of the markets may have on the costs associated with the implementation of the solutions.

Impact of the asset age structure

As previously explained, the life expectancy of primary assets has a strong impact on the cost comparison between smart grids solutions and network reinforcement.
Moreover, as discussed in [72], the age of the assets which might need to be changed in order to reach the same hosting capacity as with a given smart grids solution has an impact on the economic evaluation.
Indeed, when trying to increase the hosting capacity in “old” networks, the total costs of network reinforcement are generally lower than the costs for implementing a smart grids solution leading to the same hosting capacity. The main reason for this is the low remaining value of existing assets, which will need to be changed soon anyway since they are close to the end of their technical life expectancy.
Applying e.g. voltage control solutions in areas with aged components will in general not be economically viable since the hosting capacity can be increased (if needed even before reaching the life expectance) with (premature) network renewal and reinforcement.

Impact of the solutions life expectancy

Although the residual value of the solutions deployed at the end of the study period is not taken into account in the CA&BA, it represents an important parameter. The life expectancy of the equipment can affect the merit order of the potential solutions just as much as their cost or their maximum hosting capacity.

12.2.3 Impact of structural factors

When considering the deployment potential of smart grids solutions, the size of the DSO might play an important role. While large DSOs have already powerful tools in term of GIS database, SCADA, distribution management including state estimation), small DSOs might be in a totally different position (about 140 in Austria and 890 in Germany). Solutions with centralized control are the solutions which are the most affected by the DSO size since they generally require higher costs and higher personal efforts. Furthermore, infrastructure needed for a specific smart grids solution may already be in use for other reasons (quality of supply etc.). Additionally, depending on the size of the DSO, this infrastructure may be an in-house development or a market available product.

12.2.4 Organisational and regulatory issues impacting the deployment of SG-solutions

"Organisational scalability" of SG-solutions

Organizational scalability is meant here as the organizational challenges and the additional burden for the DSO to deploy a smart grids solution on a large scale.

For example, the deployment of the solution VoltVar control (Q(U)) (for PV inverters), which has been identified, as distributed solution, as an “easy to deploy” solution, implies for the DSO to be relying on a solution implemented at the customer’s premises. A full rollout of such functions relying on pieces of equipment owned and operated by third parties (customers) represents a risk for DSOs.

Moreover, the large scale deployment of smart grids solutions (taking the example of the VoltVar control) requires:

- A more *complex network planning* to determine the suitable parameters of the controller.
- A *commissioning* to ensure that the controller settings are properly parameterized. Even if the function is type-tested, experiences shows that due to the lack of harmonization, manufacturers have a non-coherent parameterization approach (e.g. definition of capacitive / inductive reactive power, reference power and voltage for the normalization, voltage settings in V or in %...)
- A *verification* to ensure that the settings are not altered or that in case of exchange of the inverter (e.g. failure after 10 years), the new inverter will be parameterized according to the initial requirements. This verification function could in theory be undertaken (automatically) by smart meters, if a specific function is implemented.
- An *administration system* to keep track of the settings specified for all the generators.
- A more *complex trouble-shooting work* by the DSO. In case of complain (e.g. disconnection of existing PV installations), it might be difficult to clearly identify the cause of the problem (e.g. altered settings from a new generator).

All these considerations represent an additional burden which results in an increase of OPEX compared to the business as usual solution (network reinforcement). Under the current regulatory framework in most countries, this additional OPEX is clearly disadvantageous in terms of DSO revenues.

Recognition of the costs of pilot projects under current DSO-remuneration schemes

In order to foster the deployment of smart grids concept and to bring smart grids solutions from the laboratory into the field, some demonstration projects are necessary. In some cases, an almost full-scale implementation in a specific area (e.g. supply area of a primary substation) is necessary to investigate deployment issues in realistic conditions. Depending on the assets used and engineering needed, the costs can be large. Even if some costs might be covered by funded demonstration projects, a significant part of the project costs remains. Most current regulatory schemes do not foresee any recognition of these costs, which can be a clear barrier, especially for smaller DSOs.

Costs recognition for new assets under current DSO-remuneration schemes

In some countries (e.g. Spain), the remuneration scheme for the distribution activity is based on a unitary costs model (each type of asset has standard recognized CAPEX & OPEX). New assets like voltage regulated distribution transformers are not included in the standard list of assets yet, meaning in principle that any costs related to the deployment of such assets are not recognized. The regulation which does not foresee any freedom for new assets (e.g. Statcom) is a clear barrier for DSOs to deploy new technologies. In fact, similar issues could be raised for software licenses (e.g. SCADA-DMS, AMI, …)

Change in the regulatory framework at the TSO-DSO interface

With the publication of the Network Code on Demand Connection [36], the relevance of the reactive power exchange at the border between transmission and distribution networks has increased. Although similar requirements were already in force (e.g. Belgium with 3.4 €/MVArh according to [37]), charging was not always systematically implemented in most countries. Very rough estimations showed that substantial costs might occur depending on the load / generation behaviour in specific networks. The stochasticity of DRES might put an additional challenge to DSOs when trying to have a neutral behaviour (low reactive power exchange with the transmission network).

On the other side, DRES might offer additional degrees of freedom. An example of this is the provision of reactive power independently from the active power for modern PV and wind generators (example for PV in [73]).

Controllability and smart grids features of generators

In the technical evaluation of the smart grids solutions, the existing regulatory limitations have not been taken into account. For example, in Spain, DSOs cannot require from generators to provide reactive power according to their needs. Not changing this rule would lead in this country to renounce to the potential of voltage control through reactive power although this feature is required in several countries for almost 10 years. A clear recommendation toward regulatory bodies is therefore to adapt the rules as soon as possible to enable DSOs to make use of state of the art functions. The effectiveness of the new functions depends severely on the share of generators equipped with these functions. For this reason, the adaptation of the regulatory framework shall happen as soon as possible.

Demonstration projects moreover showed that it can be very challenging to adapt existing generators to include them into new control schemes. Besides the systematic reluctance ("do not change a running system"), older generators (even synchronous) may offer a very limited controllability due to the plant design made some decades ago. Besides these difficulties, retrofitting is always a very costly measure which is only justified when the system stability is jeopardised.

Regulatory framework for smart metering

The possibility to use the AMI infrastructure for smart grids solutions strongly depends on the regulatory framework and in particular on the target rollout (see Figure 136).

Moreover, the potential of smart meters for DRES integration depends of course on the functionalities implemented into the meters (e.g. collection of voltage values on demand, automatic gathering of voltage statistics, phase recognition…). For countries having rolled out smart meters early, the additional functions might be limited and the possibility to implement new functions might even be restricted. The availability of the AMI plays a crucial role for the deployment potential of coordinated and supervised smart grids solutions aiming at enhancing the network hosting capacity.

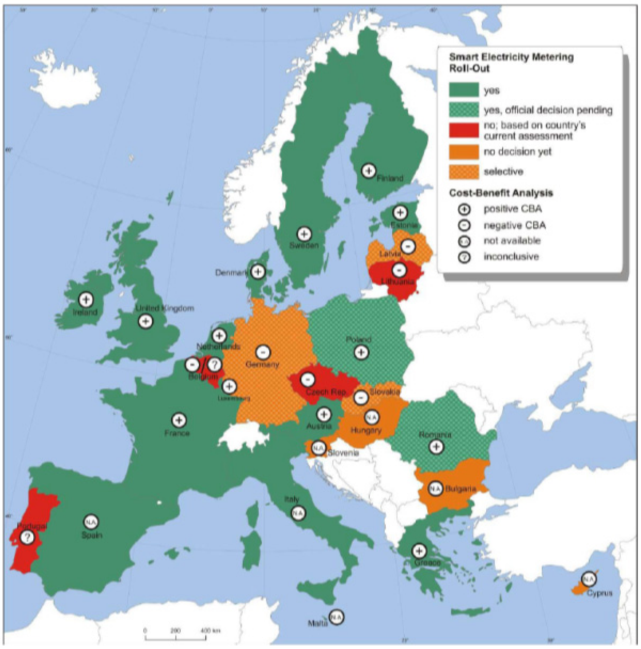


Figure 136 (Overview of CBA outcomes and intentions for smart metering large-scale roll-out (more than 80% of consumers) in Member States, by 2020 (status – July 2013) [74])

12.3 Experience from the use of KPIs to compare smart grids solutions

Among the three IGREENGrid KPIs proposed in D2.2 (hosting capacity, voltage quality and energy efficiency), the hosting capacity KPI (which definition and computation have been adapted to the methodology followed in the technical evaluation of the smart grids solutions) and the energy efficiency KPI proved to have a real added value when comparing solutions.

On the basis of the probabilistic approach followed in this work, the hosting capacity for the median DRES distribution has been used to compare solutions. This median DRES distribution has been obtained from the probabilistic evaluation of the impact of the distribution of the DRES along the feeder on the hosting capacity. When using different DRES distributions, the hosting capacity KPI could be affected for the different solutions, but this effect is expected to be small.

The energy efficiency KPI as defined in D2.2 also proved to provide interesting information. Due to the fact that the installed generation is varying when comparing solutions, normalizing the network losses to the load (or to the generation) leads to a biased value. On the contrary the energy efficiency KPI considers the network as a system and takes into account all the incoming and outgoing power flows (e.g. exchange with the upstream network, consumption by loads, injection by generators, etc.)

The KPI "Reduction of technical network losses" proposed in the project IDE4L [75] which consists in evaluating the relative decrease of network losses reached by the considered optimisation strategies is not suitable for the type of analyses done in IGREENGrid where the installed generation has been varied.

The voltage quality KPI introduced in D2.2 has also been evaluated. This KPI should be analyzed carefully since the better use of the infrastructure (operating the network close to the limits or implementing smart grids solutions allowing increasing the hosting capacity but at the same time impacting the voltage profiles along the year) is mostly related to a worsening of the voltage quality KPI. While increasing the hosting capacity or decreasing network losses can generally be the main objective of some measures, as long as the voltage remains within the limits, the voltage quality requirements are fulfilled and there is no direct added value of having very flat voltage profiles (voltage close to the nominal voltage).

The evaluation of the solutions and the discussions with the DSOs experts however showed that further aspects impact the performance and deployment potential of smart grids solutions. An example of this is the potential impact on the use wearing of on load tap changer or the reactive power exchange with the upstream network. In many cases, most of these aspects have an impact on the economic performance of the solution.

Besides these technical KPIs which had been defined previously in the project, an economic KPI has been defined. It consists in quantifying the costs for implementing and operating a solution divided by the increase of hosting capacity reached by this solution. This KPI allows comparing the costs of solutions which have a different effectiveness in terms of hosting capacity increase. It has also been used in [72].

12.4 Role of standardisation

Although grids codes or connection guidelines have been amended for about 8 years to allow the use of new features of DRES (e.g. [73], [82] in Germany and Austria respectively), most of the solutions are still at the stage of pilot project and have not been deployed on a large scale. An analysis of the experiences from the demonstration projects shows that there is still an acute need for standardization in the following fields:

- Standardization of the generator requirements between countries
  - e.g. unified reactive power capability (opposed to the current requirements of $\tan\varphi$=0.4, $\cos\varphi$=0.90 or $\cos\varphi$=0.95)
  - e.g. unified type of control (opposed to the coexistence of many different types of control)
  - e.g. unified parametrization (harmonized definition of reference arrow systems, parameter names, units, resolution, static and dynamic behaviour characteristics…)
- Standardization of the communication. In the pilot projects, a very large variety of communication solutions have been used (e.g. IEC 61850, IEC 60870-5-104, Modbus, proprietary PLC protocols at LV and MV level, …)

As the so-called “50.2 Hz problem” shows (this issue is not related to the hosting capacity of distribution networks but shows the importance of taking the right decisions at the right moment), taking late actions creates additional cost for the whole system (see [77] for more information on the retrofitting costs for the “50.2).

13 References

13.1 Project Documents

List of reference document produced in the project or part of the grant agreement
[DOW] – Description of Work
[GA] – Grant Agreement
[CA] – Consortium Agreement
D2.2. Report listing selected KPIs and precise recommendations to EEGI Team: Set of recommendations to improve Benefits and KPIs defined by EEGI in “Roadmap 2010-18 and Detailed Implementation Plan 2010-12”.
D4.1 Report listing selected KPIs and precise recommendations to EEGI Team: Set of recommendations to improve Benefits and KPIs defined by EEGI in “Roadmap 2010-18 and Detailed Implementation Plan 2010-12”
D4.2 List of reference targets (country-specific & EU-wide) for grid integration of DER: Identification of effective solutions for DRES integration in distribution grids that could be scaled and replicated
D5.2 IGREENGrid simulation and evaluation framework

13.2 External documents

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Annex 1: Illustration of the feeder reinforcement

Figure 137 (network diagram) and Figure 138 (voltage diagram) illustrate the concept proposed to determine the necessary reinforcement in a common way for all feeders.
For voltage constrained-feeders, an iterative approach is followed. One iteration is shown on Figure 137 and Figure 138. For each iteration, the steepest line (from the voltage diagram = the line with the largest p.u. voltage increase per km) is identified and reinforced. The procedure is repeated until the voltage falls below the upper voltage limit. By doing so, the minimum necessary reinforcement can be approached.

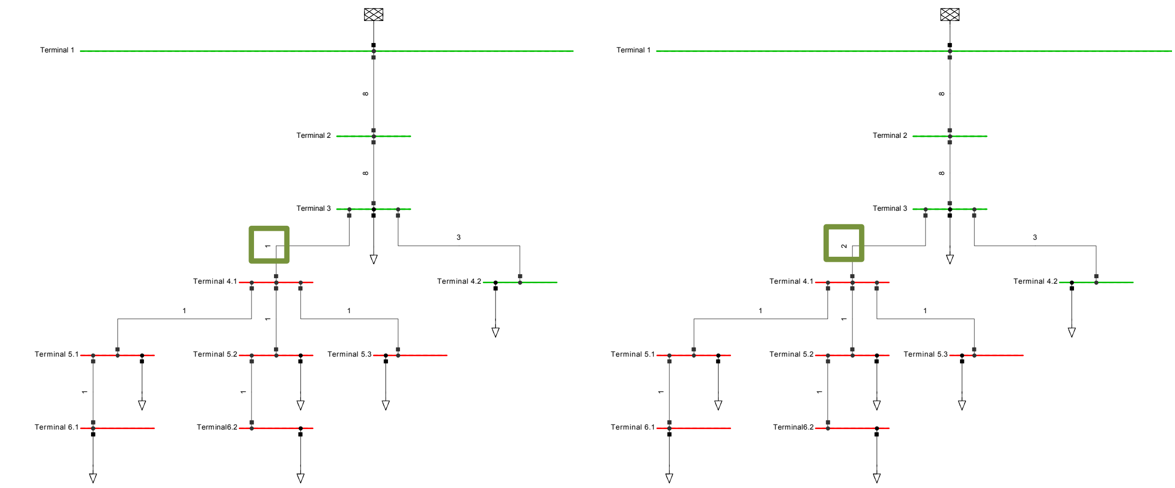


**Figure 137 (Illustration of the reinforcement concept – network diagram
Left: before / right: after)**

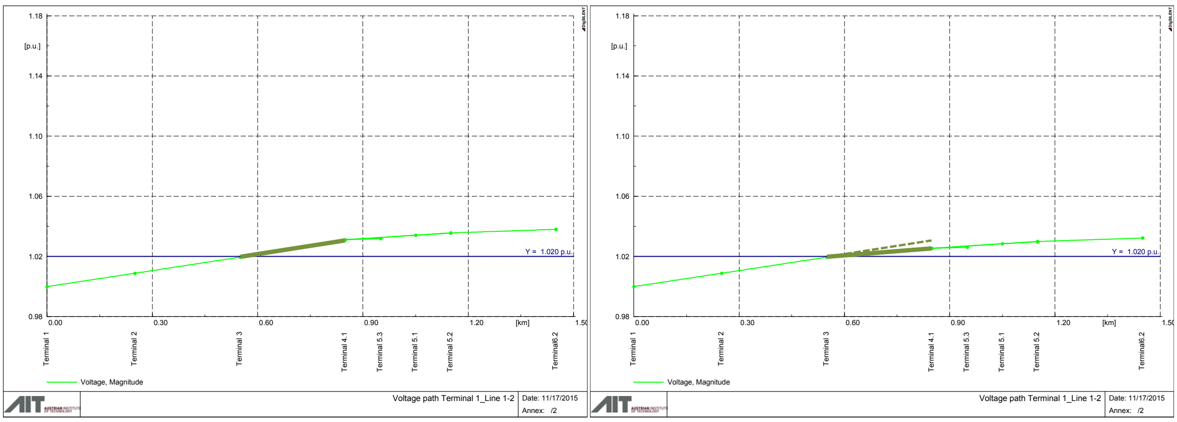


**Figure 138 (Illustration of the reinforcement concept – voltage diagram
Left: before / right: after)**

Annex 2: Detailed results on the phase balancing in LV networks

The annex includes the following figures:

- Summary tables of feeders

The tables summarise concisely the chosen feeders using such characteristics as length, min and max cable rated current, percentage of realistic points etc. The purpose of including this information is to give an overview and to enable the reader to better understand the results.
The table of the expected benefit summarises the results of phase-switching for every feeder it has been applied on. The table indicates the effectiveness of phase-switching in the theoretical scenario: PV generation and no consumption.

- Defined realistic scenarios

The data for scenario definitions for the unbalance study has been filtered, so that unrealistic configurations with too high (e.g. over 5 kW) generation per phase are not included. For some feeders, it was not possible to define the realistic scenarios because the hosting capacity was reached only when the power injection was above that threshold. Such feeders have been considered not to have a significant potential for the phase balancing.

- Outcome of the quasi-dynamic simulation

The ECDF figures of results of the quantification of the actual benefits are used to analyse the benefits statistically. It is important to know the effects of the phase balancing for more than the extreme time points. Comparison of the voltage levels and unbalance at different percentiles allows conclusions over the probability of reaching the voltage limits, and therefore over the relevance of the phase-switching in realistic conditions.

The DSOs names are mentioned as NA for ERDF, NB for RWE and NC for EAG.

Summary of feeders

Table 33 (Data of NA feeders, part 2)

Network	NA1		NA2	NA3		NA4				NA5
Feeder	F1	F2	**F1**	**F1**	**F2**	F0	**F1**	F2	F3	F1
Feeder length	124 m	117 m	421 m	461 m	547 m	150 m	56 m	53 m	88 m	1 m
max rated I	228 A	228 A	329 A	233 A	228 A	426 A	256 A	329 A	426 A	426 A
min rated I	228 A	228 A	105 A	228 A	228 A	426 A	256 A	329 A	123 A	426 A
1Φ PVs	2	1	6	2	1	0	57	15	10	25
3Φ PVs	3	3	4	2	2	0	5	3	6	7
Permutations	9	3	729	9	3	1	$2 \cdot 10^{27}$	$1 \cdot 10^{7}$	$6 \cdot 10^{4}$	$8 \cdot 10^{11}$
mean P_{50}, kW	20,96	26,63	3,14	3,44	6,86	—	2,46	3,85	5,73	10,90
HC_{50}, kW	107	106	31	14	20	—	153	189	191	219
IQHC kW	34	36	21	11	15	—	24	34	52	58
IQHC	0,31	0,34	0,69	0,84	0,72	—	0,16	0,81	0,27	0,26
$\max \Delta U$	0,1 %	3,4 %	7,3 %	7,0 %	5,5 %	—	6,5 %	4,2 %	7,5 %	0,1 %
Realistic points	0,2 %	5,3 %	44,2 %	69,4 %	19,5 %	—	61,8 %	0,2 %	0,1 %	0 %
U	0 %	0 %	100 %	100 %	100 %	—	0 %	0 %	35,3 %	0 %
I	100 %	100 %	0 %	0 %	0 %	—	100 %	100 %	64,7 %	100 %

Table 34 (Data of NA feeders, part 2)

Network	NA5		NA6							
Feeder	F2	F3	F0	F1	**F2**	F3	F4	**F5**	**F6**	**F7**
Feeder length	116 m	164 m	17 m	112 m	216 m	13 m	117 m	151 m	302 m	494 m
max rated I	256 A	426 A	426 A	256 A	426 A	256 A	329 A	329 A	329 A	329 A
min rated I	256 A	256 A	426 A	256 A	256 A	256 A	256 A	256 A	144 A	228 A
1Φ PVs	2	4	0	7	37	1	41	26	11	25
3Φ PVs	5	1	0	3	2	1	5	3	4	3
Permutations	9	81	—	2187	$5 \cdot 10^{17}$	3	$4 \cdot 10^{19}$	$3 \cdot 10^{12}$	$2 \cdot 10^{5}$	$8 \cdot 10^{11}$
mean P_{50}, kW	18,57	15,77	—	3,81	2,49	44,76	4,07	4,17	3,71	1,35
HC_{50}, kW	133	77	—	142	96	89	188	120	55	38
IQHC, kW	33	58	—	33	55	40	35	66	32	20
IQHC	0,25	0,75	—	0,23	0,57	0,44	0,18	0,55	0,58	0,54
$\max \Delta U$	0,3 %	8,6 %	—	7,7 %	7,8 %	1,7 %	4,9 %	7,6 %	7,5 %	7,2 %
Realistic points	0,7 %	0 %	—	3,0 %	53,6 %	1,5 %	0,1 %	8,1 %	19,8 %	98,8 %
U	0 %	99,9 %	—	23 %	98,6 %	0 %	0 %	80,1 %	100 %	100 %
I	100 %	0,1 %	—	77 %	1,4 %	100 %	100 %	19,9 %	0 %	0 %

Table 35 (Data of NB feeders)

Network	NB1		NB3	NB5			NB7	NB8	
Feeder	F4	F5	F3	F1	F2	F4	F7	F2	F5
Feeder length	408 m	471 m	334 m	294 m	397 m	299 m	728 m	505 m	381 m
max rated I	270 A	270 A	352 A	270 A	270 A	281 A	270 A	270 A	270 A
min rated I	98 A	98 A	98 A	119 A	141 A	119 A	75 A	141 A	119 A
1Φ PVs	0	0	0	0	0	0	0	0	0
3Φ PVs	37	43	32	17	16	29	2	16	34
Permutations	$6 \cdot 10^{28}$	$3 \cdot 10^{33}$	$8 \cdot 10^{24}$	$2 \cdot 10^{13}$	$3 \cdot 10^{12}$	$4 \cdot 10^{22}$	36	$3 \cdot 10^{12}$	$3 \cdot 10^{26}$
mean P_{50}, kW	2,73	1,83	4,77	2,94	4,11	5,09	3,34	5,08	2,34
HC_{50}, kW	101	79	153	50	68	151	7	84	81
IQHC, kW	23	16	39	14	20	36	6	29	17
IQHC	23	20,67	25,45	27,83	28,86	23,72	84,50	34,35	21,21
max ΔU	3,9 %	3,6 %	4,8 %	4,4 %	4,8 %	4,3 %	5,2 %	4,8 %	3,8 %
Realistic points	97,3 %	100 %	20,7 %	95,4 %	57,3 %	8,5 %	90,9 %	27,2 %	99,6 %
U	100 %	100 %	82,1 %	100 %	100 %	89,8 %	100 %	100 %	100 %
I	0 %	0 %	17,9 %	0 %	0 %	10,2 %	0 %	0 %	0 %

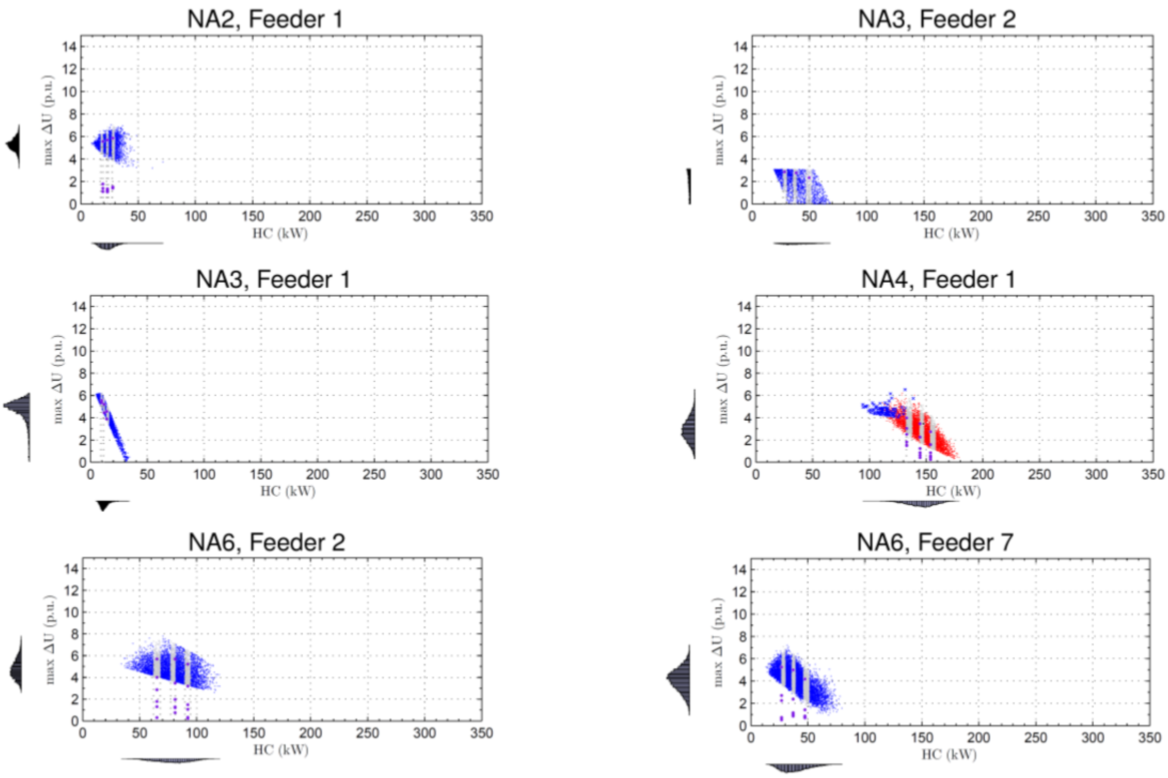
Table 36 (Data of NC feeders)

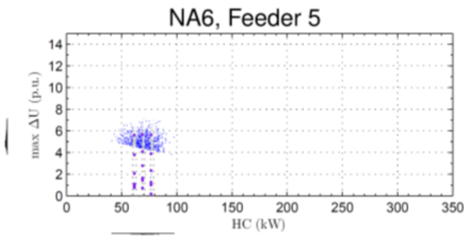
Network	NC1							
Feeder	**F1**	F2	**F3**	**F4**	**F5**	**F6**	F7	F9
Feeder length	471 m	202 m	335 m	540 m	232 m	772 m	113 m	508 m
max rated I	270 A	363 A	270 A	270 A	270 A	270 A	270 A	270 A
min rated I	98 A	363 A	98 A	98 A	98 A	98 A	128 A	98 A
1Φ PVs	0	0	0	0	0	0	0	0
3Φ PVs	25	4	19	36	25	40	3	2
Permutations	$3 \cdot 10^{19}$	1296	$6 \cdot 10^{14}$	$1 \cdot 10^{28}$	$3 \cdot 10^{19}$	$1 \cdot 10^{31}$	216	36
mean P_{50}, kW	3,15	36,08	4,72	1,69	3,78	1,13	22,49	13,58
HC_{50}, kW	79	142	90	61	95	45	68	27
IQHC, kW	19	64	30	14	23	10	18	15
IQHC	24,37	45,10	33,31	22,24	24,50	21,80	25,70	54,90
max ΔU	4,6 %	6,5 %	5,2 %	4,3 %	4,5 %	4,0 %	5,4 %	6,8 %
Realistic points	91,1 %	0 %	35,6 %	100,0 %	67,8 %	100 %	0 %	0 %
U	100 %	100 %	99,9 %	100 %	100 %	100 %	0 %	100 %
I	0 %	0 %	0,1 %	0 %	0 %	0 %	100 %	0 %

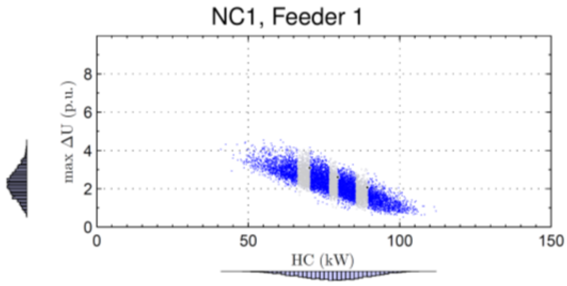
Table 37 (Expected benefit of phase balancing, based on 20 % scenario and 5 switches)

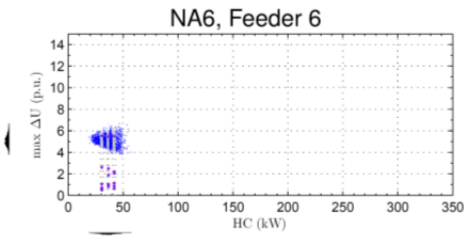
Feeder	Initial unbalance, %	Reduced unbalance, %	Relative reduction, %	Feeder	Initial unbalance, %	Reduced unbalance, %	Relative reduction, %
NC1_F1	3,09	0,88	71,55	NB7_F7	2,55	0,24	90,55
NC1_F3	3,66	0,33	90,93	NB8_F2	1,97	0,39	80,20
NC1_F4	2,89	0,66	77,16	NB8_F5	5,46	5,20	4,76
NC1_F5	2,99	0,47	84,38	NA2_F1	5,56	1,11	80,04
NC1_F6	2,66	0,38	85,90	NA3_F1	5,55	5,36	3,42
NB1_F4	2,69	0,29	89,29	NA3_F2	2,87	2,87	0
NB1_F5	2,52	0,59	76,59	NA4_F1	3,01	0,67	77,67
NB3_F3	3,54	1,21	65,82	NA6_F2	5,69	0,30	94,71
NB5_F2	3,23	0,45	86,13	NA6_F5	5,60	0,77	86,32
NB5_F4	3,33	0,19	94,41	NA6_F6	5,51	0,50	90,93
NB5_F5	3,29	1,20	63,53	NA6_F7	5,25	0,72	86,21

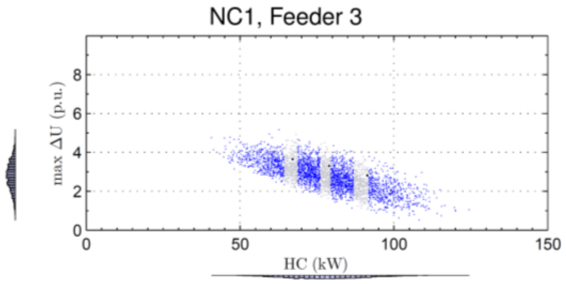
Definition of scenarios

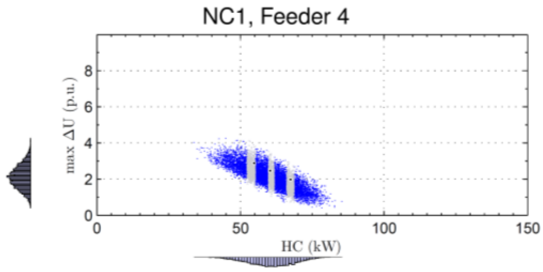


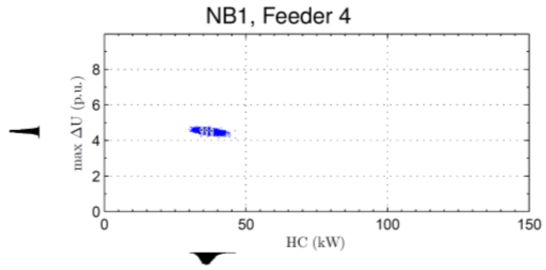

NA6, Feeder 5
max ΔU (p.u.)
HC (kW)

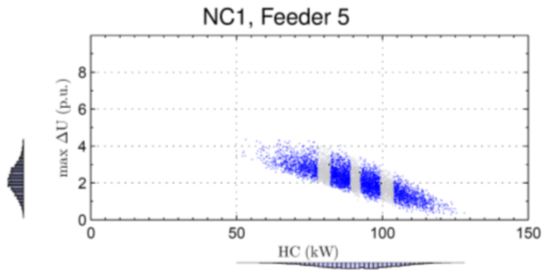

NC1, Feeder 1
max ΔU (p.u.)
HC (kW)

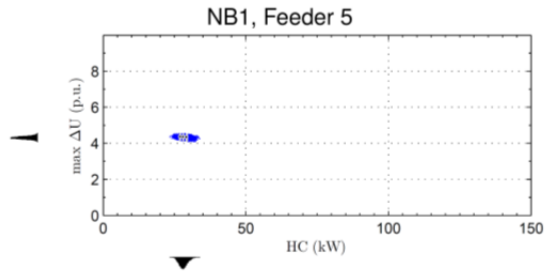

NA6, Feeder 6
max ΔU (p.u.)
HC (kW)

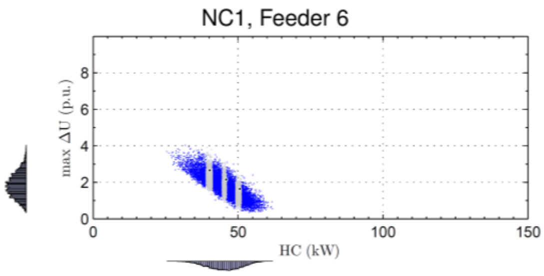

NC1, Feeder 3
max ΔU (p.u.)
HC (kW)

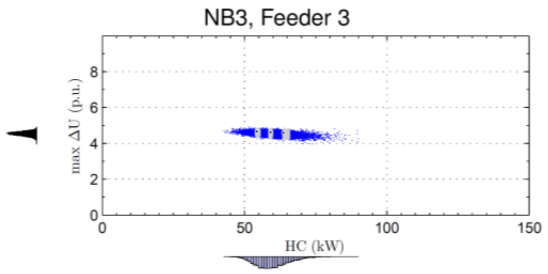

NC1, Feeder 4
max ΔU (p.u.)
HC (kW)

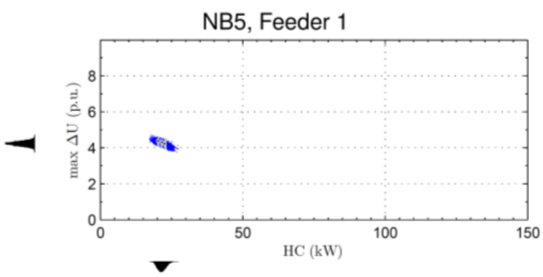

NB1, Feeder 4
max ΔU (p.u.)
HC (kW)

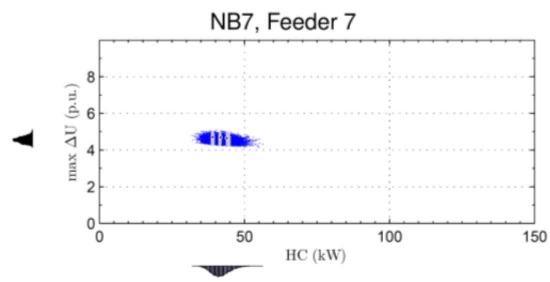

NC1, Feeder 5
max ΔU (p.u.)
HC (kW)

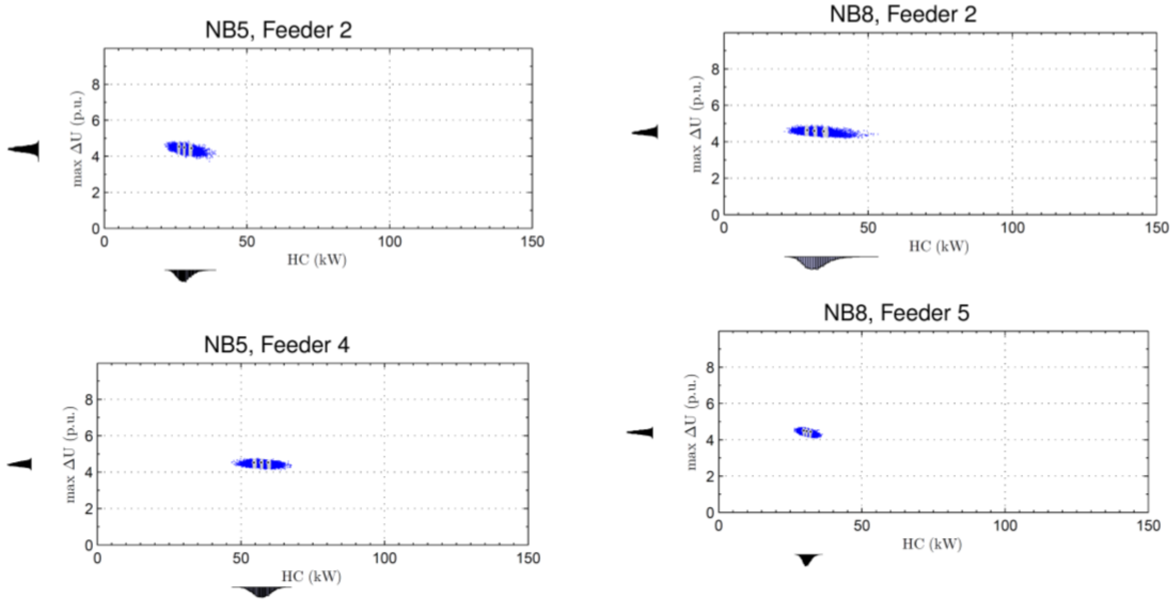

NB1, Feeder 5
max ΔU (p.u.)
HC (kW)


NC1, Feeder 6
max ΔU (p.u.)
HC (kW)

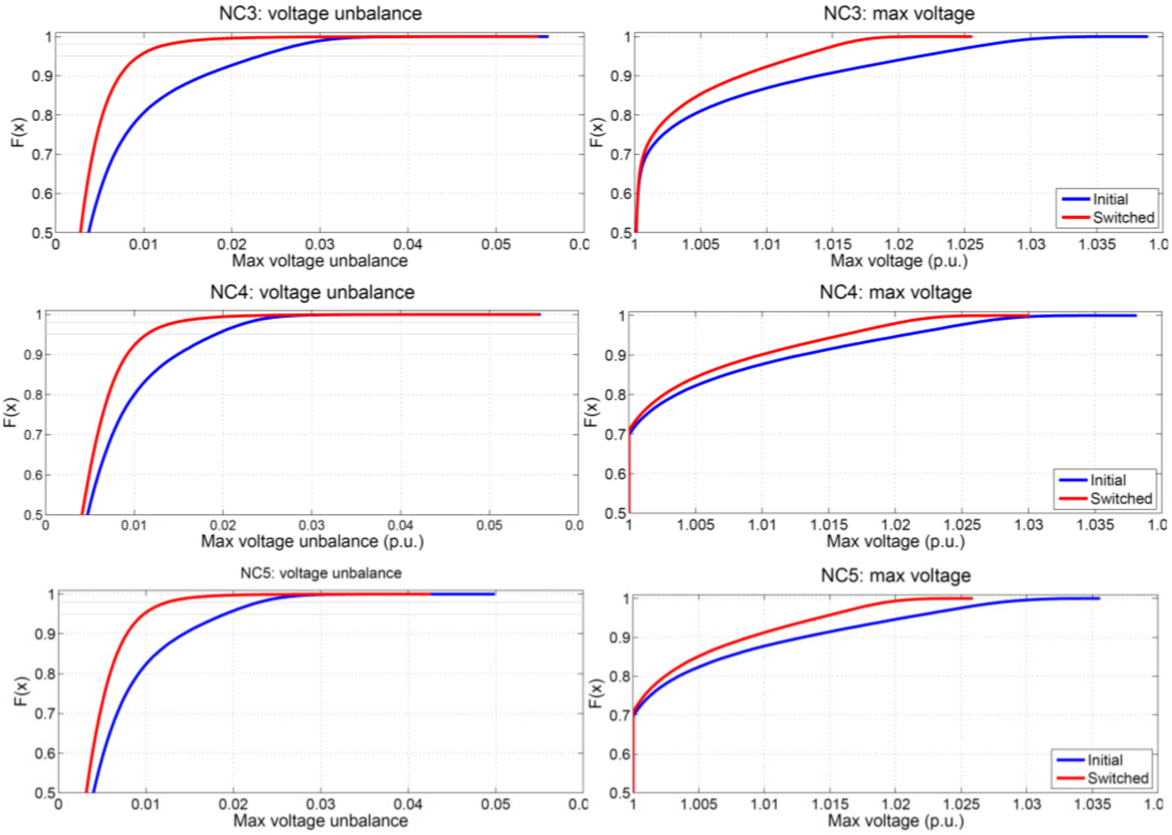

NB3, Feeder 3
max ΔU (p.u.)
HC (kW)


NB5, Feeder 1
max ΔU (p.u.)
HC (kW)


NB7, Feeder 7
max ΔU (p.u.)
HC (kW)


NB5, Feeder 2
max ΔU (p.u.)
HC (kW)
NB8, Feeder 2
max ΔU (p.u.)
HC (kW)
NB5, Feeder 4
max ΔU (p.u.)
HC (kW)
NB8, Feeder 5
max ΔU (p.u.)
HC (kW)

Results of time-domain simulations



Annex 3: Identification of cost elements of solutions

MV Voltage Monitoring	
Implementation	Cost element (assets and others)
MV Voltage Monitoring (field measurements)	Measurement device (for MV line)
	Communication costs of Measurement device
	Costs in SCADA per measurement device
	Costs in SCADA per measurement point in MV DG
MV Voltage Monitoring (SE)	Measurement device (for MV line)
	Communication costs of Measurement device
	DMS – State Estimator
	Costs in SCADA per measurement device
	Costs in SCADA per measurement point in MV DG
MV Voltage Monitoring (PLF)	Other asset for the distribution management
	Other cost element in DMS

Table 38 (Cost elements of each implementation of the functionality “MV Voltage Monitoring”)

LV Voltage Monitoring	
Implementation	Cost element (assets and others)
LV Voltage Monitoring (AMI)	Other asset for the distribution management
	Other cost element in DMS

Table 39 (Cost elements of each implementation of the functionality “LV Voltage Monitoring”)

MV Voltage Control	
Implementation	Cost element (assets and others)
MV Distributed Voltage Control with OLTC	Local control OLTC (in HV/MV)
MV Distributed Voltage Control with OLTC, DG	New Local control - DG P&Q control
	Retrofit of Local control - DG P&Q control
	Local control OLTC (in HV/MV)
MV Centralized (field	Measurement device (for MV line)

MV Voltage Control	
Implementation	Cost element (assets and others)
measurements) Voltage Control with OLTC	Communication costs of Measurement device
	Local control OLTC (in HV/MV)
	Costs in SCADA per measurement device
MV Supervised (field measurements) Voltage Control with OLTC & DG	New Local control - DG P&Q control
	Retrofit of Local control - DG P&Q control
	Measurement device (for MV line)
	Communication costs of Measurement device
	Local control OLTC (in HV/MV)
	Costs in SCADA per measurement device
	Costs in SCADA per measurement point in MV DG
MV Supervised Voltage Control with OLTC & DG	New Local control - DG P&Q control
	Retrofit of Local control - DG P&Q control
	Local control OLTC (in HV/MV)
	Costs in SCADA per measurement device
	Costs in SCADA per measurement point in MV DG
MV Centralized (SE) Voltage Control with OLTC	Measurement device (for MV line)
	Communication costs of Measurement device
	Local control OLTC (in HV/MV)
	DMS – State Estimator
	Costs in SCADA per measurement device
MV Centralized (SE & OPF) Voltage Control with OLTC	Measurement device (for MV line)
	Communication costs of Measurement device
	Local control OLTC (in HV/MV)
	DMS – State Estimator
	DMS – OPF
	Costs in SCADA per measurement device
MV Centralised (SE & OPF) Voltage Control with OLTC & DG	New Local control - DG P&Q control
	Retrofit of Local control - DG P&Q control
	Measurement device (for MV line)
	Communication costs of Measurement device

MV Voltage Control	
Implementation	Cost element (assets and others)
	Local control OLTC (in HV/MV)
	DMS – State Estimator
	DMS – OPF
	Costs in SCADA per measurement device
	Costs in SCADA per measurement point in MV DG

Table 40 (Cost elements of each implementation of the functionality “MV Voltage Control”)

LV Voltage Control	
Implementation	Cost element (assets and others)
LV Distributed Voltage Control with OLTC	MV/LV Transformer 250 KVA with OLTC
	MV/LV Transformer 400 KVA with OLTC
	MV/LV Transformer 630 KVA with OLTC
	Local control OLTC (in MV/LV)
	Residual value of the old MV/LV Transformer (replaced with 250KVA)
	Residual value of the old MV/LV Transformer (replaced with 400KVA)
	Residual value of the old MV/LV Transformer (replaced with 630KVA)
	MV/LV Transformer substitution
LV Distributed Voltage Control with DG	New PV inverter with P&Q control
	Retrofit of PV inverter with P&Q control
LV Distributed Voltage Control with OLTC, DG	New PV inverter with P&Q control
	Retrofit of PV inverter with P&Q control
	MV/LV Transformer 250 KVA with OLTC
	MV/LV Transformer 400 KVA with OLTC
	MV/LV Transformer 630 KVA with OLTC
	Local control OLTC (in MV/LV)
	Residual value of the old MV/LV Transformer (replaced with 250KVA)
	Residual value of the old MV/LV Transformer (replaced with 400KVA)
	Residual value of the old MV/LV Transformer (replaced with 630KVA)
	MV/LV Transformer substitution
LV Distributed (field measurements) Voltage	New PV inverter with P&Q control
	Retrofit of PV inverter with P&Q control

LV Voltage Control	
Implementation	Cost element (assets and others)
Control with OLTC, DG	Measurement device (for LV line)
	MV/LV Transformer 250 KVA with OLTC
	MV/LV Transformer 400 KVA with OLTC
	MV/LV Transformer 630 KVA with OLTC
	Local control OLTC (in MV/LV)
	Residual value of the old MV/LV Transformer (replaced with 250KVA)
	Residual value of the old MV/LV Transformer (replaced with 400KVA)
	Residual value of the old MV/LV Transformer (replaced with 630KVA)
	MV/LV Transformer substitution

Table 41 (Cost elements of each implementation of the functionality “LV Voltage Control”)

Annex 4: Formulation of main benefits

Once benefits are identified, formulas to potentially calculate the monetised value of these main benefits will be proposed, as visualising how to monetise or valuate benefits may help to better understand their causes.
These formulas will be selected from JRC CBA (see Annex 7: List of formulas to the calculation of main benefits (Annex II of [8])).

Formulas for main benefits of MV Voltage Monitoring

In the following table a proposal of formulas to potentially calculate the monetized value of main benefits identified in this document for "MV Voltage Monitoring" is shown:

No.	Benefit	Proposed Formulas
1	**Deferred Distribution Capacity Investments**	The economic benefit of the deferment of distribution capacity investments has different causes: • asset remuneration • asset amortisation • consumption reduction • peak load shift So that, to calculate the monetized value of this benefit it is necessary to take into account the economic benefit (or saving) due to each one of these causes. B1.1. Value of deferred distribution capacity investments due to asset remuneration: *Value B1.1. (€) = Annual DSO investment to support growing capacity (€/year) * Time deferred (# of years) * Remuneration rate of investment (%/100)* B1.2. Value of deferred distribution capacity investments due to asset amortisation: *Value B1.2. (€) = Annual distribution investment to support growing capacity (€/year) * Time deferred (# of years) * # of years capacity asset amortisation* B1.3. Value of deferred distribution capacity

No.	Benefit	Proposed Formulas
		investments due to consumption reduction: *Value B1.3. (€) = Peak demand reduction due to energy savings [MW]* [68] ** Incremental cost per MW of peak demand [€M/ΔMW]* B1.4. Value of deferred distribution capacity investments due to consumption reduction: *Value (€) = Peak demand reduction due to peak load shift [MW] * % networks where the peak corresponds with general peak * Incremental cost per MW of peak demand [€M/ΔMW]* So that, the global value of this benefit is: ***Value B1*** *(€) = Value B1.1. + Value B1.2. + Value B1.3. + Value B1.4.*
9	Reduced Electricity Losses	The value of benefit of reduction of electricity technical losses is: ***Value B9*** *(€)= Reduced losses via energy efficiency (€) + Reduced losses via voltage control (€) + Reduced losses at transmission level (€)*
20	Reduced T&D Equipment Maintenance Cost	The value of benefit of reduction of maintenance costs of assets is: ***Value B20*** *(€) = [Direct costs relating to maintenance of assets (€)]$_{Baseline}$ – [Direct costs relating to maintenance of assets (€)]$_{SGproject}$*

Table 42 (Formulas to potentially calculate main benefits of "MV Voltage Monitoring")

Formulas for main benefits of LV Voltage Monitoring

In the following table a proposal of formulas to potentially calculate the monetized value of main benefits identified in this document for "LV Voltage Monitoring" is shown:

No.	Benefit	Proposed Formulas
1	**Deferred Distribution Capacity Investments**	Same as the "***Value B1*** *(€)*", proposed for the main benefits of "MV Voltage Monitoring"
9	Reduced Electricity Losses	Same as the "***Value B9*** *(€)*",proposed for the main benefits of "MV Voltage Monitoring"
20	Reduced T&D Equipment Maintenance Cost	Same as the "***Value B20*** *(€)*",proposed for the main benefits of "MV Voltage Monitoring"

Table 43 (Formulas to potentially calculate main benefits of "LV Voltage Monitoring")

[68] Peak demand reduction due to energy savings [MW] = % demand reduction * Peak demand * % contribution of domestic and commercial load (or whatever load type is influenced by the project in question)

Formulas for main benefits of MV Voltage Control

In the following table a proposal of formulas to potentially calculate the monetized value of main benefits identified in this document for "MV Voltage Control" is shown:

No.	Benefit	Proposed Formulas
1	**Deferred Distribution Capacity Investments**	Same as the "***Value B1*** *(€)"*,proposed for the main benefits of "MV Voltage Monitoring"
5	Reduced Ancillary Service Cost	*No formula proposed in JRC CBA*
9	Reduced Electricity Losses	Same as the "***Value B9*** *(€)"*,proposed for the main benefits of "MV Voltage Monitoring"
17	Reduced Sags and Swells	*No formula proposed in JRC CBA*

Table 44 (Formulas to potentially calculate main benefits of "MV Voltage Control")

Formulas for main benefits of LV Voltage Control

In the following table a proposal of formulas to potentially calculate the monetized value of main benefits identified in this document for "LV Voltage Control" is shown:

No.	Benefit	Proposed Formulas
1	**Deferred Distribution Capacity Investments**	Same as the "***Value B1*** *(€)"*,proposed for the main benefits of "MV Voltage Monitoring"
2	Deferred Generation Capacity Investments	Investments in generation capacity are needed for: • peak load plants • spinning reserves So that, the economic benefit of the deferment of generation capacity investments has two causes: B2.1. Value of deferred generation investments for peak load plants: *Value B2.1. (€) = Annual investment to support peak load generation (€/year) * Time deferred (# of years)* B2.2. Value of deferred generation investments for spinning reserves: *Value B2.2 (€) = Annual investment to support spinning reserve generation (€/year) * Time deferred (# of years)* So that, the global value of this benefit is: ***Value B2*** *(€) = Value B2.1. + Value B2.2.*
5	Reduced Ancillary Service Cost	*No formula proposed in JRC CBA*

Table 45 (Formulas to potentially calculate main benefits of "LV Voltage Control")

Annex 5: List of JRC functionalities grouped in six services (Annex III of [8])

No.	Service / Functionality
A	**Enabling the network to integrate users with new requirements** Outcome: Guarantee the integration of distributed energy resources (both large- and small scale stochastic renewable generation, heat pumps, electric vehicles and storage) connected to the distribution network. Provider: DSOs Primary beneficiaries: Generators, consumers (including mobile consumers), storage owners.
1.	Facilitate connections at all voltages/locations for any kind of devices
2.	Facilitate the use of the grid for the users at all voltages/locations
3.	Use of network control systems for network purposes
4.	Update network performance data on continuity of supply and voltage quality
B	**Enhancing efficiency in day-to-day grid operation** Outcome: Optimize the operation of distribution assets and improve the efficiency of the network through enhanced automation, monitoring, protection and real-time operation. Faster fault identification/resolution will help improve continuity of supply levels. Better understanding and management of technical and non-technical losses, and optimized asset maintenance activities based on detailed operational information. Provider: DSOs, metering operators Primary beneficiaries: Consumers, generators, suppliers, DSOs.
5.	Automated fault identification/grid reconfiguration, reducing outage times
6.	Enhance monitoring and control of power flows and voltages
7.	Enhance monitoring and observability of grids down to low voltage levels
8.	Improve monitoring of network assets
9.	Identification of technical and non-technical losses by power flow analysis
10.	Frequent information exchange on actual active/reactive generation/consumption
C	**Ensuring network security, system control and quality of supply** Outcome: Foster system security through an intelligent and more effective control of distributed energy resources, ancillary backup reserves and other ancillary services. Maximise the capability of the network to manage intermittent generation, without adversely affecting quality of supply parameters. Provider: DSOs, aggregators, suppliers. Primary beneficiaries: Generators, consumers, aggregators, DSOs, transmission system, operators.

No.	Service / Functionality
11.	Allow grid users and aggregators to participate in ancillary services market
12.	Operation schemes for voltage/current control
13.	Intermittent sources of generation to contribute to system security
14.	System security assessment and management of remedies
15.	Monitoring of safety, particularly in public areas
16.	Solutions for demand response for system security in the required time
D	**Better planning of future network investment** Outcome: Collection and use of data to enable more accurate modelling of networks, especially at LV level, also taking into account new grid users, in order to optimise infrastructure requirements and so reduce their environmental impact. Introduction of new methodologies for more 'active' distribution, exploiting active and reactive control capabilities of distributed energy resources. Provider: DSOs, metering operators. Primary beneficiaries: Consumers, generators, storage owners.
17.	Better models of Distributed Generation, storage, flexible loads, ancillary services
18.	Improve asset management and replacement strategies
19.	Additional information on grid quality and consumption by metering for planning
E	**Improving market functioning and customer service** Outcome: Increase the performance and reliability of current market processes through improved data and data flows between market participants, and so enhance customer experience. Provider: Suppliers (with applications and services providers), power exchange platform providers, DSOs, metering operators. Primary beneficiaries: Consumers, suppliers, application and service providers.
20.	Participation of all connected generators in the electricity market
21.	Participation of virtual power plants and aggregators in the electricity market
22.	Facilitate consumer participation in the electricity market
23.	Open platform (grid infrastructure) for EV (electric vehicles) recharge purposes
24.	Improvement to industry systems (for settlement, system balance, scheduling)
25.	Support the adoption of intelligent home/ facilities automation and smart devices
26.	Provide grid users with individual advance notice of planned interruptions
27.	Improve customer level reporting in the case of interruptions
F	**Enabling and encouraging stronger and more direct involvement of consumers in their energy usage and management** Outcome: Foster greater consumption awareness, taking advantage of smart metering systems and improved customer information in order to allow consumers to modify their behaviour according to price and load signals and related information.

No.	Service / Functionality
	Promote the active participation of all players in the electricity market through demand response programmes and a more effective management of variable and non-programmable generation. Obtain the consequent system benefits: peak reduction, reduced network investments, ability to integrate more intermittent generation. Provider: Suppliers (with metering operators and DSOs), Energy Service Companies. Primary beneficiaries: Consumers, generators. The only primary beneficiary who is present in all services is the consumer. Indeed, consumers will benefit: either because these services will contribute to the 20/20/20 targets or directly through improvement of quality of supply and other services. The hypothesis made here is that company efficiency and the benefit of the competitive market will be passed on to consumers – at least partly in the form of tariff or price optimisation, and is dependent on effective regulation and markets.
28.	Sufficient frequency of meter readings
29.	Remote management of meters
30.	Consumption/injection data and price signals by different means
31.	Improve energy usage information
32.	Improve information on energy sources
33.	Availability of individual continuity of supply and voltage quality indicators

Table 46 (List of JRC functionalities grouped in 6 services)

Annex 6: List of main benefits that smart grids solutions could provide (Annex I of [8])

No.	Main Benefit	Description
1.	Deferred Distribution Capacity Investments	As with the transmission system, reducing the load and stress on distribution elements increases asset utilization and reduces the potential need for upgrades. Closer monitoring and load management on distribution feeders could potentially extend the time before upgrades or capacity additions are required.
2.	Deferred Generation Capacity Investments	Utilities and grid operators ensure that generation capacity can serve the maximum amount of load that planning and operations forecasts indicate. The trouble is, this capacity is only required for very short periods each year, when demand peaks. Reducing peak demand and flattening the load curve should reduce the generation capacity required to service load, and lead to cheaper electricity for customers.
3.	Deferred Transmission Capacity Investments	Reducing the load and stress on transmission elements increases asset utilization and reduces the potential need for upgrades. Closer monitoring, rerouting power flow, and reducing fault current could enable utilities to defer upgrades on lines and transformers.
4.	Optimized Generator Operation	Better forecasting and monitoring of load and grid performance would enable grid operators to dispatch a more efficient mix of generation that could be optimized to reduce cost. The coordinated operation of energy storage, distributed generation, or plug-in electric vehicle assets could also result in completely avoiding central generation dispatch.
5.	Reduced Ancillary Service Cost	Ancillary services are necessary to ensure the reliable and efficient operation of the grid, such as spinning reserve and frequency regulation. The level of ancillary services required at any point in time is determined by the grid operator and/or energy market rules. Ancillary services could be reduced if: generators could more closely follow load; peak load on the system was reduced; power factor, voltage, and VAR control were improved; or information available to grid operators were improved.
6.	Reduced CO_2 Emissions	Functions that provide this benefit can do so by reducing vehicle miles, decreasing the amount of central generation needed to their serve load (through reduced electricity consumption, reducing electricity losses, or more optimal generation dispatch), and or reducing peak generation. These impacts translate into a reduction in CO_2 emissions produced by fossil-based electricity

No.	Main Benefit	Description
		generators and vehicles.
7.	Reduced Congestion Cost	Transmission congestion is a phenomenon that occurs in electric power markets. It happens when scheduled market transactions (generation and load) result in power flow over a transmission element that exceeds the available capacity for that element. Since grid operators must ensure that physical overloads do not occur, they will dispatch generation so as to prevent them, thus interfering with market transactions and creating added transactions to monetize capacity access. The functions that provide this benefit provide lower cost energy, decrease loading on system elements, shift load to off-peak, or allow the grid operator to manage the flow of electricity around constrained interfaces (i.e. dynamic line capability or power flow control).
8.	Reduced Electricity Cost	Functions that provide this benefit could help alter customer usage patterns (demand response with price signals or direct load control), or help reduce the cost of electricity during peak times through either production (DG) or storage.
9.	Reduced Electricity Losses	Functions that provide this benefit could help manage peak feeder loads, reduce electricity throughput, locate electricity production closer to the load, and ensure that voltages remain within service tolerances, while minimizing the amount of reactive power provided. These actions make the system more efficient for a given load served, or by actually reducing the overall load on the system.
10.	Reduced Electricity Theft	Smart meters can typically detect tampering. Moreover, a meter data management system can analyse customer usage to identify patterns that could indicate diversion. These new capabilities can lead to a reduction in electricity theft through earlier identification and prevention of theft.
11.	Reduced Equipment Failures	Reducing mechanical stresses on equipment increases service life and reduces the probability of premature failure. This can be accomplished though enhanced monitoring and detection, reduction of fault currents, enhanced fault protection, or loading limits based on real-Time equipment or environmental factors.
12.	Reduced Major Outages	A major outage is defined using the beta method, per IEEE Std 1366-2003 (IEEE Power Engineering Society 2004). The monetary benefit of reducing major outages is based on the value of service (VOS) of each customer class. The VOS parameter represents the total cost of a power outage per MWh. This cost includes the value of unserved energy, lost productivity, collateral damage, the value of penalties and performance based rates. Functions that lead to this benefit can mitigate major outages by

No.	Main Benefit	Description
		allowing the system to be reconfigured on the fly to help restore service to as many customers as possible, enable a quicker response in the restoration effort, or mitigate the impact of an outage through islanding or alternative power supply.
13.	Reduced Meter Reading Cost	Advanced Metering Infrastructure (AMI) equipment eliminates the need to send someone to each location to read the meter manually leading to reduced meter operations costs. AMI technology can also reduce costs associated with other meter operations such as connection / disconnects, outage investigations, and maintenance.
14.	Reduced Momentary Outages	By locating faults more accurately or adding electricity storage, momentary outages could be reduced or eliminated. Moreover, fewer customers on the same or adjacent distribution feeders would experience the momentary interruptions associated with reclosing. Momentary outages last <5 min in duration. The benefit to consumers is based on the value of service.
15.	Reduced Oil Usage (not monetized)	The functions that provide this benefit eliminate the need to send a line worker or crew to the switch or capacitor locations in order to operate them, eliminate the need for truck rolls to perform diagnosis of equipment condition, and reduce truck rolls for meter reading and measurement purposes. This reduces the fuel consumed by a service vehicle or line truck. The use of PEVs can also lead to this benefit since the electrical energy used by PEVs displaces the equivalent amount of oil. This benefit is quantified in terms of gallons of oil and is not monetized.
16.	Reduced Restoration Cost	The functions that provide this benefit lead to fewer outages and/or help restore power quicker or with less manual labour hours, which results in lower restoration costs. These costs can include line crew labour/material/equipment, support services such as logistics, call centres, media relations, and other professional staff time and material associated with service restoration.
17.	Reduced Sags and Swells	Locating high impedance faults more quickly and precisely and adding electricity storage will reduce the frequency and severity of the voltage fluctuations that they can cause. Installing advanced reclosers that only allow a limited amount of current to flow through them upon reclosing can also reduce voltage fluctuations. Moreover, fewer customers on the same or adjacent distribution feeders would experience the voltage fluctuation caused by the fault. The benefit to consumers is based on the value of service.
18.	Reduced SOx, NOx, and PM-2.5 Emissions	Functions that provide this benefit can lead to avoided vehicle miles, decrease the amount of central generation needed to their

No.	Main Benefit	Description
		serve load (through reduced electricity consumption, reduced electricity losses, more optimal generation dispatch), and or reduce peak generation. These impacts translate into a reduction in pollutant emissions produced by fossil-based electricity generators and vehicles.
19.	Reduced Sustained Outages	A sustained outage is one lasting > 5 minutes, excluding major outages and wide-scale outages. The monetary benefit of reducing sustained outages is based on the value of service of each customer class. The VOS parameter represents the total cost of a power outage per MWh. This cost includes the value of unserved energy, lost productivity, collateral damage, administrative costs, the value of penalties and performance based rates. Functions that lead to this benefit can reduce the likelihood that there will be an outage, allow the system to be reconfigured on the fly to help restore service to as many customers as possible, enable a quicker response in the restoration effort, or mitigate the impact of an outage through islanding or alternative power supply.
20.	Reduced T&D Equipment Maintenance Cost	The cost of sending technicians into the field to check equipment condition is high. Moreover, to ensure that they maintain equipment sufficiently, and identify failure precursors, some utilities may conduct equipment testing and maintenance more often than is necessary. Online diagnosis and reporting of equipment condition would reduce or eliminate the need to send people out to check equipment resulting in a cost savings.
21.	Reduced T&D Operations Cost	Automated or remote controlled operation of capacitor banks and feeder and line switches eliminates the need to send a line worker or crew to the switch location in order to operate it. This reduces the cost associated with the field service worker(s) and service vehicle.
22.	Reduced Wide-scale Blackouts	The functions that lead to this benefit will give grid operators a better picture of the bulk power system, and allow them to better coordinate resources and operations between regions. This will reduce the probability of wide-scale regional blackouts.

Table 47 (List of main (quantitative) benefits that smart grids solutions could provide)

Annex 7: List of formulas to the calculation of main benefits (Annex II of [8])

a	**Reduction in meter reading and operation costs**	
	Reduced meter operation costs	*Value (€) = [Estimated cost reductions with remote meter operations (€)]$_{SGproject}$ – [Estimated cost reductions with remote meter operations (€/year) * Communications failure rate (%/100)]$_{SGproject}$*
	Reduced meter reading cost	*Value (€) = [Cost with local meter readings (€)]$_{Baseline}$ – [Estimated cost of obtaining local 'disperse' meter readings (€)]$_{SGproject}$* Where: *[Cost with local meter readings (€)]$_{Baseline}$ = [# of clients in LV * Historical meter reading cost/client/year (€)]* *[Estimated cost of obtaining local 'disperse' meter readings (€)]$_{SGproject}$= [# of clients in LV (# clients) * % of clients not included in the roll-out (%) * Average disperse reading cost per client (€/# clients)] + [# of clients in LV (# clients) * % of clients included in the rollout (%) * Communications failure rate (%) * Average disperse reading cost per client (€/#clients)]*
	Reduced billing costs	*Value (€) = [# of clients in LV * Historical billing cost/client/year (€)]$_{Baseline}$ – [# of clients in LV * Billing cost/client (€)]$_{SGproject}$*
	Reduced call centre/customer care costs	*Value (€) = [# of clients in LV * Historical customer care cost/client/year (€)]$_{Baseline}$ – [# of clients in LV * Customer care cost/client/year(€)]$_{SGproject}$*
b	**Reduced operational and maintenance cost**	
	Reduced maintenance costs of assets	*Value (€) = [Direct costs relating to maintenance of assets (€)]$_{Baseline}$ – [Direct costs relating to maintenance of assets (€)]$_{SGproject}$*
	Reduced cost of equipment breakdowns	*Value (€) = [Cost of equipment breakdowns (€)]$_{Baseline}$ – [Cost of equipment breakdowns(€)]$_{SGproject}$*
c	**Deferred distribution capacity investments**	
	Deferred distribution capacity investments due to asset remuneration	*Value (€) = Annual DSO investment to support growing capacity (€/year) * Time deferred (# of years) * Remuneration rate of investment (%/100)*
	Deferred distribution capacity investments due to asset amortisation	*Value (€) = Annual distribution investment to support growing capacity (€/year) * Time deferred (# of years) * # of years capacity asset amortisation*

	Deferred distribution capacity investments due to consumption reduction	*Value (€) = Peak demand reduction due to energy savings [MW] * Incremental cost per MW of peak demand [€M/ΔMW]* Where: *Peak demand reduction due to energy savings [MW] = % demand reduction * Peak demand * % contribution of domestic and commercial load (or whatever load type is influenced by the project in question)*
	Deferred distribution capacity investments due to peak load shift:	*Value (€) = Peak demand reduction due to peak load shift [MW] * % networks where the peak corresponds with general peak * Incremental cost per MW of peak demand [€M/ΔMW]*
d	**Deferred transmission capacity investments**	
	Similar monetisation formulae as at the distribution can be used.	
e	**Deferred generation capacity investments**	
	Deferred generation investments for peak load plants	*Value (€) = Annual investment to support peak load generation (€/year) * Time deferred (# of years)*
	Deferred generation investments for spinning reserves	*Value (€) = Annual investment to support spinning reserve generation (€/year) * Time deferred (# of years)*
f	**Reduced electricity technical losses**	
	Reduced electricity technical losses	*Value (€) = Reduced losses via energy efficiency (€) + Reduced losses via voltage control (€) + Reduced losses at transmission level (€)*
g	**Electricity cost savings**	
	Consumption reduction	*Value (€) = Energy rate (€/MWh) * Total energy consumption (MWh) * Estimated % consumption reduction with Smart Grid scenario (%/100)*
	Peak load transfer	*Value (€) = Wholesale margin difference between peak and non-peak generation (€/ MWh) * % peak load transfer (%/100) * Total energy consumption (MWh)*
h	**Reduction of commercial losses**	
	Reduced electricity theft	*Value (€) = % clients with energy theft (%/100) * Estimated average price value of energy load not recorded/client (€) * Total number of clients LV (# of clients)*
	Recovered revenue relating to ‘contracted power’ fraud	*Value (€) = % clients with ‘contracted power’ fraud (%/100) * Estimated price value of contracted power not paid/client (€) * Total number of clients LV (# of clients)*
	Recovered revenue relating to incremental ‘contracted power’	*Value (€) = % clients requesting incremental contracted power after smart metering system installation (%/100) * Average estimated value of recovered revenue due to incremental ‘contracted power’ (€) * Total number of clients LV (# of clients)*

i	Reduced outage times	
	Value of service	*Value (€) = Total energy consumed (MWh)/ Minutes per year (#/year) * Average non-supplied minutes/year (#/year) * Value of Lost Load (€/kWh) * % decrease in outage time (%)*
	Recovered revenue due to reduced outages	*Value (€) = Annual supplier revenue (€)/ Minutes per year (#/year) * Average non-supplied minutes/year (#/year) * % decrease in outage time (%)*
	Reduced cost of client compensations	*Value (€) = Average annual client compensations (€) * % reduction in client compensations*
j	**Reduced CO2 emissions and reduced fossil fuel usage**	
	Benefit of reduced CO_2 emissions due to reduced line losses:	*Value (€) = [Line losses (MWh) * CO_2 content (tons/MWh) * Value of CO_2 (€/ton)]* $_{Baseline}$ *– [Line losses (MWh) * CO_2 content (tons/MWh) * Value of CO_2 (€/ton)]* $_{SGproject}$
	Reduced CO_2 emissions due to wider diffusion of low carbon generation sources	*Value (€) = [CO_2 Emissions (tons) * Value of CO_2 (€/ton)]* $_{Baseline}$ *– [CO_2 Emissions (tons) * Value of CO_2 (€/ton)]* $_{SGproject}$
	Benefit of reduced CO_2 emissions	*Value (€) = Avoided # litres of fossil fuel (#) * Cost per litre of fossil fuel avoided (€)*
	Benefit of reduced oil usage	*Value (€) = Avoided # litres of fossil fuel (#) * Cost of one litre of fossil fuel (€)*
k	**Reduction of air pollution (particulate matters, NOx, SO2)**	
	Reduced air pollutant emissions thanks to wider diffusion of low carbon generation sources (enabled by the Smart Grid project)	For each pollutant: *Value (€) = [Air pollutant emissions (unit) * Cost of air pollutant (€/unit)]* $_{Baseline}$ *– [Air pollutant emissions (unit) * Cost of air pollutant (€/unit)]* $_{SGproject}$
	Reduced air pollutant emissions thanks to reduced line losses	For each pollutant: *Value (€) = [Line losses (MWh) * Air pollutant content (unit/MWh) * Cost of air pollutant (€/ unit)]* $_{Baseline}$ *– Line losses (MWh) * Air pollutant content (unit/MWh) * Cost of air pollutant (€/unit)]* $_{SGproject}$
	Reduced air pollutant emissions due to lower fleet mileage of field personnel	For each pollutant: *Value (€) = [Fleet mileage (km) * Air pollutant emissions (unit/km) * Cost of air pollutant (€/unit)] Baseline – [Fleet mileage (km) * Air pollutant emissions (unit/km) * Cost of air pollutant (€/unit)]SGproject*

Table 48 (List of formulas to the calculation of main benefits)

Annex 8: List of other potential benefits that smart grids solutions could provide (Annex IV of [8])

Other benefits	
Increased sustainability	
1	Quantified reduction of carbon emissions
2	Environmental impact of electricity grid infrastructure
3	Quantified reduction of accidents and risk associated with generation technologies
Adequate capacity of transmission and distribution grids for collecting and bringing electricity to the consumers	
4	Hosting capacity for distributed energy resources in distribution grids
5	Allowable maximum injection of power without congestion risks in transmission networks
6	Energy not withdrawn from renewable sources due to congestion and/or security risks in transmission networks
7	An optimized use of capital and assets
Adequate grid connection and access for all kinds of grid users	
8	First connection charges for generators, consumers and those that do both
9	Grid tariffs for generators, consumers and those that do both
10	Methods adopted to calculate charges and tariffs
11	Time to connect a new user
12	Optimization of new equipment design resulting in best/cost benefit
13	Faster speed of successful innovation against clear standards
Satisfactory levels of security and quality of supply	
14	Ratio of reliably available generation capacity to peak demand
15	Share of electrical energy produced by renewable sources
16	Measured satisfaction of grid users with the grid services they receive
17	Power system stability
18	Duration and frequency of interruption per customer
19	Voltage quality performance of electricity grids (e.g. voltage dips)
Enhanced efficiency and better service in electricity supply and grid operation	
20	Level of losses in transmission and in distribution networks

Other benefits	
21	Ratio between minimum and maximum electricity demand within a defined time period
22	Percentage utilization of electricity grid elements
23	Demand-side participation in electricity markets and in energy efficiency measures
24	Availability of network components (related to planned and unplanned maintenance) and its impact on network performances
25	Actual availability of network capacity with respect to its standard value
Effective support of transnational electricity markets by load flow control to alleviate loop flows and increased interconnection capacities	
26	Ratio between interconnection capacity of one country/region and its electricity demand
27	Exploitation of interconnection capacities, particularly related to maximization of capacities according to the regulation of electricity cross-border exchanges and congestion management guidelines
28	Congestion rents across interconnections
Coordinated grid development through common European, regional and local grid planning to optimize transmission grid infrastructure	
29	Impact of congestion on outcomes and prices of national/regional markets
30	Societal benefit-cost ratio of a proposed infrastructure investment
31	Overall welfare increase, i.e. always running the cheapest generators to supply the actual demand
32	Time for licensing/authorization of a new electricity transmission infrastructure
33	Time for construction of a new electricity transmission infrastructure
Enhanced consumer awareness and participation in the market by new players	
34	Demand side participation in electricity markets and in energy efficiency measures
35	Percentage of consumers on ToU/CPP/RT dynamic pricing
36	Measured modifications of electricity consumption patterns after new pricing schemes
37	Percentage of users available to behave as interruptible load
38	Percentage of load demand participating in market-like schemes for demand flexibility
39	Percentage participation of users connected to lower voltage levels to ancillary services
Enable consumers to make informed decisions related to their energy to meet the EU Energy Efficient targets	
40	Base-to-peak load ratio
41	Relationship between power demand and market price for electricity
42	Consumers can comprehend their actual energy consumption and receive, understand and act on free information they need

Other benefits	
43	Consumers are able to access their historic energy consumption information for free in a format that enables them to make like-for-like comparisons with deals available on the market
44	Ability to participate in relevant energy market to purchase and/or sell electricity
45	Coherent link is established between the energy prices and consumer behaviour
Create a market mechanism for new energy services such as energy efficiency or energy consulting for customers	
46	Simple and/or automated charges to consumers' energy consumption in reply to demand/response signals are enabled
47	Data ownership is clearly defined and data processes in place to allow for service providers to be active with customer consent
48	Physical grid-related data are available in an accessible form
49	Transparency of physical correction authorization, requirements and charges
50	Effective consumer complaint handling and redress
Consumer bills are either reduced or upward pressure on them is mitigated	
51	Transparent, robust processes to assess whether the benefits of implementation exceed the costs in each area where roll-out is considered, and a commitment to act on the findings by all the involved parties
52	Regulatory mechanisms that ensure that these benefits are appropriately reflected in consumer bills and do not simply result in windfall profits for the industry
53	New smart tariffs that deliver tangible benefits to consumers or society in a progressive way
54	Market design is compatible with the way consumers use the grid

Table 49 (List of other potential benefits that smart grids solutions could provide)