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DISTRIBUTION SYSTEM OPERATORS OBSERVATORY

From European Electricity Distribution Systems to Representative Distribution Networks

Giuseppe PRETTICO, Flavia GANGALE, Anna MENGOLINI, Alexandre LUCAS, Gianluca FULLI

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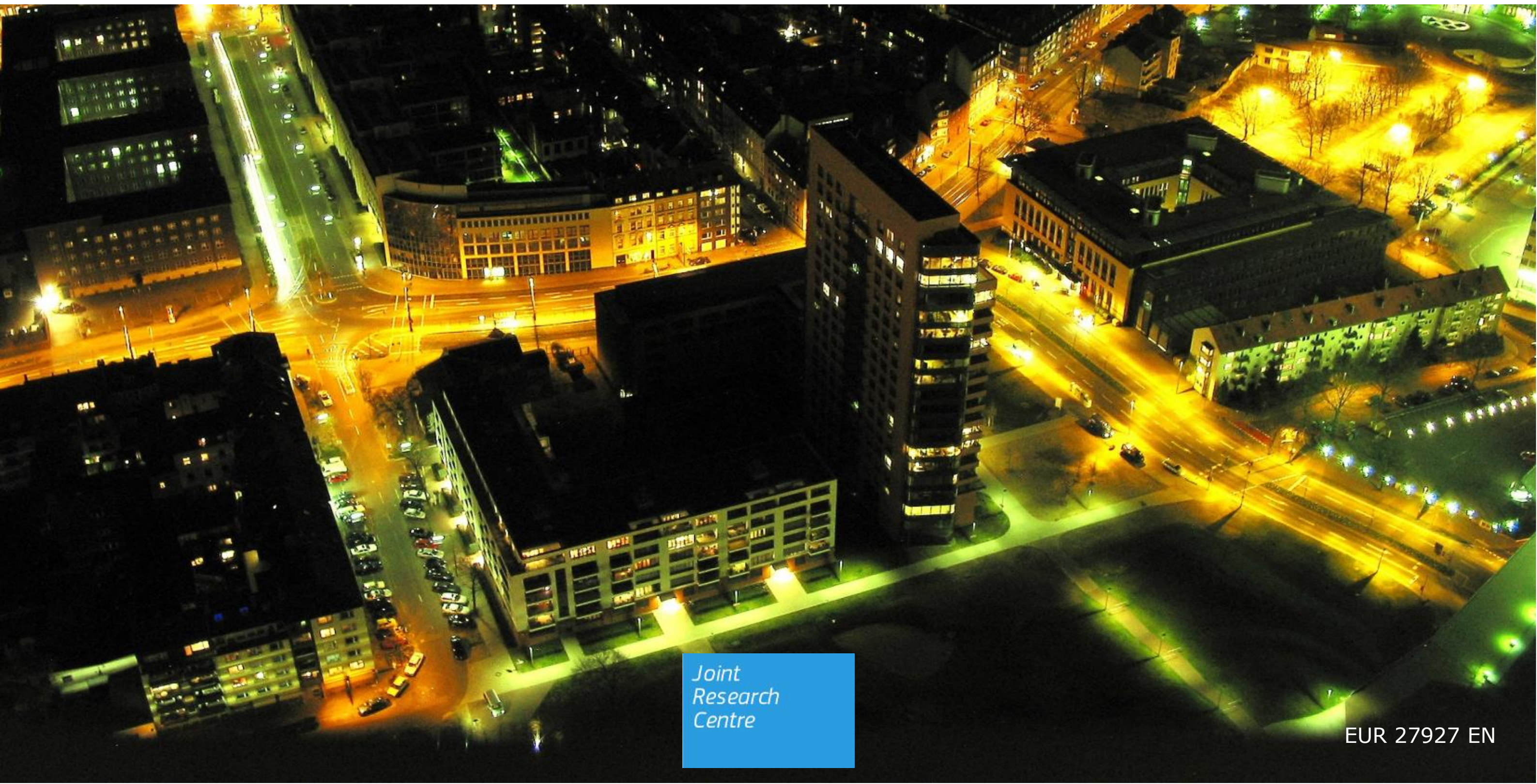

Joint Research Centre

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From European Electricity Distribution Systems to Representative Distribution Networks

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Executive Summary

The European electricity sector is undergoing radical changes in every segment of the power industry, from generation to supply. Ambitious policy goals set at European level to enhance the competitiveness, security and sustainability of the EU's energy system have called for major changes in the regulatory, technological, and market structure fields.

The distribution sector is particularly affected by these changes. The increasing penetration of local renewable generation and the emergence of demand response enabling solutions are placing new requirements on the distribution networks, posing challenges to the reliability and efficiency of system operation. At the same time, however, these new applications can also create opportunities to manage the distribution grids in a more flexible and efficient way, paving the way to new services to end-consumers.

Smart grid concepts and technologies have an important role to play to address these new challenges and opportunities. A variety of solutions are already being tested in Europe, with encouraging results. Identifying the best technical, economic and societal options requires a deep understanding of their impact on the physical distribution networks. Such knowledge is also necessary to evaluate the viability of replicating and scaling up pilot experiences already successfully implemented in Europe.

At present, there is little publicly available information on the European distribution system operators (DSOs) and the networks they operate. This lack of knowledge is partially attributable to constraints in sharing data that DSOs consider as assets of commercial value, but it is also due to the vast number and heterogeneity of the distribution systems in Europe. The situation varies radically from country to country, due to historical as well as geographical, legal, political and economic reasons. In some Member States there is only one DSO, while in others there are tens or hundreds of them operating their networks on a regional or even municipal basis. Differences concern also other aspects, e.g. the scope of the DSO activities, the level of unbundling, the operated voltage levels and other key technical information on the networks.

In the last years, the Joint Research Centre of the European Commission (JRC) has expanded its role as an independent observer of the energy system. A big effort has been put in collecting, processing and analysing data on the power sector (from smart grid project costs and benefits to consumer engagement strategies, from power system techno-economic features to integrated regional systems/markets). This activity is aimed at providing stakeholders with tools and analyses to better understand the rapidly changing scene, enabling early identification of developments and opportunities and supporting evidence-based policy making.

This report presents the latest JRC data brokering effort – the *DSO Observatory project* - focused on European distribution system operators and their distribution networks. The aim of the report is to contribute to a better understanding of the challenges that the transition to a new energy system is posing to European distribution system operators and to elaborate sound solutions to address them.

To the best of our knowledge, this is the most comprehensive data collection exercise on European distribution systems published so far. Based upon this inventory, detailed Reference Network Models (RNMs) were used to develop representative distribution networks for analysing the impact that Renewable Energy Sources (RES) penetration and network automation can have on their technical performance.

The starting point of the DSO Observatory project was the collection of technical and structural data from the DSOs. Given the vast number of DSOs in Europe, the data collection exercise was limited to the bigger ones, i.e. the 190 DSOs that have to comply with the unbundling requirements set out in the EU Electricity Directive (i.e. the DSOs serving more than 100,000 customers, also referred to in the report as "larger" DSOs). An online survey was launched in January 2015 with the aim of collecting several clusters of data, relating to types of ownership and unbundling, network structures and designs, amounts and types of connected distributed generation, and reliability of supply indicators.

79 out of the 190 larger DSOs responded to the survey. The representativeness of the obtained sample is quite high: the respondents manage more than 70% of the electricity supplied by all DSOs serving over 100,000 customers. Overall, the 79 DSOs distribute more than 2,000 TWh of electricity to over 200 million customers per year, covering a total area of more than 3 million square km.

The collected data were used to build 36 indicators, divided in three categories, i.e. network structure, network design and distributed generation. These indicators allow for comparison of the parameters and criteria used by DSOs when designing and sizing their network installations. They help to shed some light on the different characteristics of some of the major European distribution networks and to support research activities by reducing the amount of resources that are typically devoted to compiling input data and building case studies.

The project also aimed at providing a tool to enable more sophisticated technical and economic assessments of different policy and technological solutions. For this purpose, 10 of the 36 indicators were chosen to create representative distribution networks using RNMs, i.e. large-scale network distribution planning tools that allow designing realistic distribution networks useful for simulation activities. RNMs allow the design of networks that supply the expected demand while taking into consideration the need to minimize the total investment and associated operational costs and to meet the defined reliability of supply criteria. By providing a realistic distribution network, RNMs offer the possibility to reliably simulate the impact of different scenarios on the grid without the need to have access to the actual network data.

Two large-scale representative networks, one rural and one urban, were selected to carry out the simulation analyses. The networks were used to analyse the impact of increasing levels of RES penetration, in particular solar photovoltaic (PV) and wind, on the technical performance of the grid. The impact on network voltages and network overloads was then monetised by means of a penalty cost function.

The analysis shows that the number and size of PV units, as well as their concentration/distribution on the network, are all relevant parameters. By way of illustration, results highlight that limiting the size of the generation units would allow mitigating voltage and congestion problems, maximizing renewable penetration with no

need of additional network investments. A careful consideration of the local conditions of each distribution area as well as of the different connection patterns - including unit sizes, technologies and location within the network - is therefore of paramount importance to minimize adverse impacts on the network.

Another way to mitigate the voltage spread introduced by the increasing penetration of PV connected to the distribution network has been studied considering the installation of storage units where the PV units are located. The analysis highlights that significant voltage spread reduction is only observed when big storage units are installed in combination with each PV unit. The high costs per kWh of batteries (estimated on the basis of the current storage solutions market) suggest that other solutions should be considered to mitigate voltage spread in the distribution network.

Finally, a reliability analysis is presented, showing how the System Average Interruption Frequency Index (SAIFI) and the System Average Interruption Duration Index (SAIDI) could be reduced by increasing the installation of tele-controlled switches in the distribution network.

The analyses presented in the report provide an illustrative example of the potential applications of the representative networks built within the DSO Observatory project. Other applications are however possible and this report can be seen as a first step of an exercise that will continue in the future. To foster more research on such a key subject, the JRC is planning to share the representative networks built as part of the DSO Observatory project with all interested parties carrying out research activities and techno-economic studies in this field[1]. The JRC will continue and expand its scientific and policy support activities in this sector to better understand and address the challenges DSOs face in the transition to the new energy system.

[1] To get the built representative networks modeled in Matlab/Matpower please visit the webpage: http://ses.jrc.ec.europa.eu/distribution-system-operators-observatory

1 Introduction

In the last years the European electricity sector has gone through radical changes in every segment of the power industry, from generation to supply. Ambitious policy goals set at European level to enhance the competitiveness, security and sustainability of the EU's energy system have called for major changes in the regulatory, technological, and market structure fields.

All actors of the power industry are affected by these changes. Until recently, much research and debate has occurred over the bulk power system (generation and transmission), while less attention has been paid to the planning, operation, and management of the distribution systems (L'Abbate, Fulli, Starr, & Peteves, 2008).

Lately however, the rapid changes occurring in the distribution segment have brought this sector at centre stage of the debate. The increasing penetration of local renewable generation and the emergence of demand response enabling solutions are acting as main transformative forces in the power sector, making the distribution grids the primary recipient of all the new interactions initiated by these numerous distributed units (Glachant, Rious, & Vasconcelos, 2015). These new technologies are expected to radically change local electricity industry and markets at the distribution level (Ruester, Perez-Arriaga, Schwenen, Batlle, & Glachant, 2013), creating opportunities but also posing challenges to the reliability and efficiency of system operation.

Several smart grid solutions are being tested in Europe to address these challenges and opportunities. Identifying the best solution requires a deep understanding of the impact of the different options on the distribution networks. Technical and economic assessments of alternative investments require a detailed knowledge of the networks and of the context in which they are operated. Such knowledge is also necessary to evaluate the viability of replicating and scaling up pilot experiences already successfully implemented in Europe.

Yet, not much is known about European distribution system operators (DSOs) and the networks they operate. This lack of knowledge is due to the confidential nature of much of this information as well as to the vast number and heterogeneity of electricity distribution systems in Europe. According to a recent study (Eurelectric, 2013), there are well over 2,000 distribution system operators in Europe, connecting 260 million customers, operating 10 million km of lines, and supplying 2,700 TWh of energy per year.

The situation varies radically from country to country, due to historical as well as geographical, legal, political and economic reasons. In some Member States there is only one DSO, while in others there are tens or hundreds of them operating their networks on a regional or even municipal basis. Differences concern also other aspects, e.g. the scope of the DSO activities, the level of unbundling, the operated voltage levels and other key technical information on the networks.

Very little information is available in the public domain and it generally does not allow for in-depth analyses. Against this background, the Joint Research Centre decided to launch an initiative – the DSO Observatory project - to fill in this knowledge gap by collecting a variety of data directly from the distribution system operators. Given the huge number

of DSOs in Europe however, the collection exercise was restricted to the main ones, i.e. those that have to comply with the unbundling requirements set in the EU Electricity Directive (i.e. the DSOs serving more than 100.000 customers).

The data gathering exercise was the starting point for the creation of representative distribution networks using Reference Network Models (RNM) that can reliably simulate the impact of different scenarios on European distribution networks without the need to have access to the actual technical data. For this purpose, on the basis of the collected information, several network structural indicators were derived and later used to validate the soundness of the representative distribution networks. These networks were then converted into Matlab/Matpower format and used to analyse the impact of increasing levels of RES penetration and network automation on the technical performance of the grid.

This ambitious project aims at shedding some light on the different characteristics of some of the major European distribution networks and at supporting research activities by reducing the amount of resources that are typically devoted to compiling input data and building case studies. This in turn will contribute to a better understanding of the challenges that the transition to a new energy system is posing to European distribution system operators and to elaborate sound solutions to address them.

2 State of play of Distribution System Operators in Europe

Electricity distribution is a crucial activity in the value chain from production to consumption of electricity, as it links the transmission grid with final customers. Traditionally, the European electricity sector was dominated by vertically integrated monopolies that were either state-owned or privately-owned. The primary components of electricity supply - generation, transmission, distribution, and supply – were therefore integrated within individual electric utilities.

During the 1990s, the European Union and the Member States decided to open the electricity markets to competition in a gradual way. The liberalization process intended to achieve competitive prices through the game of market forces and to establish a unified energy market that would also be conducive to ensuring secure energy supplies (Glachant, Rious and Vasconcelos 2015).

DIRECTIVE 2009/72/EC

Distribution means the transport of electricity on high-voltage, medium-voltage and low-voltage distribution systems with a view to its delivery to customers, but does not include supply.

Distribution system operator (DSO) means a natural or legal person responsible for operating, ensuring the maintenance of and, if necessary, developing the distribution system in a given area and, where applicable, its interconnections with other systems and for ensuring the long-term ability of the system to meet reasonable demands for the distribution of electricity.

One of the main cornerstones of the reform was the separation between the competitive parts of the industry (generation and supply) and the non-competitive parts (transmission and distribution networks). Electricity networks were considered non-competitive as, from an economic perspective, they are 'natural monopolies', implying that alternative and competing networks can only be built at very high costs.

Successive rounds of EU electricity market legislation, lastly Directive 2009/72/EC, introduced *unbundling* requirements, which oblige Member States to ensure the separation of vertically integrated energy companies. These reforms resulted in the separation of the various stages of energy supply, i.e. generation, distribution, transmission and supply. While transmission and distribution were exempted from competition and subject to regulatory control, generation and supply, as potentially competitive activities, were open to liberalization.

As stated in the preamble of Directive 2009/72/EC, the reasoning behind the new rules was that *'without effective separation of networks from activities of generation and supply (effective unbundling), there is an inherent risk of discrimination not only in the operation of the network but also in the incentives for vertically integrated undertakings to invest adequately in their networks'*.

For the distribution segment, the unbundling requirements do not create an obligation to separate the ownership of assets of the distribution system operator from the vertically integrated undertaking, but provide for separation at functional and legal level (article 26 of Directive 2009/72/EC).

Functional unbundling requires that the network operator is independent in terms of its organization and decision making rights from the other activities not related to that network. *Legal unbundling* requires that the distribution activities are done by a separate 'network' company (separate legal entity); the network company must not necessarily own the network assets but must have 'effective decision making rights' in line with the requirements of functional unbundling (DG Energy & Transport 16.1.2004).

In other words, functional unbundling is a prerequisite in order to ensure the independence of network operators in terms of organization and decision making processes, while legal unbundling involves the setting up of a separate network company (Ropenus, et al. 2009).

Member States were left free to exempt from these requirements those integrated electricity undertakings serving less than 100,000 connected customers, or serving small isolated systems. This last provision is quite relevant, as the majority of electricity distribution system operators in Europe are below the threshold set by the Electricity Directive (Table 2-1) and can therefore be exempted from the EU unbundling requirements.

Country	Total no. of DSOs (in 2011)	DSOs > 100,000 customers
Austria	138	13
Belgium	24	15
Bulgaria	4	3
Croatia	n/a	1*
Cyprus	1	1
Czech Republic	3	3
Denmark	72	6
Estonia	n/a	1
Finland	n/a	7
France	158	5
Germany	880	75
Greece	n/a	1
Hungary	6	6
Ireland	1	1
Italy	144	2
Latvia	11	1
Lithuania	1	1
Luxembourg	6	1
Malta	n/a	1*
Netherlands	11	8
Poland	184	5
Portugal	13	3
Romania	n.a.	8
Slovakia	3	3
Slovenia	n/a	1
Spain	n/a	5
Sweden	173	6
United Kingdom	7	7

Table 2-1 DSOs number per Country (Eurelectric 2013)

* *Data for Malta and Croatia were not reported in Eurelectric (2013)*

According to (European Commission 2012), the majority of Member States have actually made use of the exemption rule. In its last review on the status of the unbundling requirements for DSOs, (CEER 2015) estimated that only 189 of the 2,400 DSOs operating in Europe have been unbundled[2]. This picture is however quite fluid and constantly changing, due to the ever changing national circumstances.

[2] Different sources (e.g. (Eurelectric 2013), (European Commission 2012), (CEER 2013)) report different figures for the number of DSOs in Europe. Such differences are mainly due to the different timing of the

Finally, the extent of the unbundling also changes from country to country, with the more extensive form of separation, i.e. ownership unbundling, being adopted only in a minority of cases.

As for the role of DSOs, it also varies from country to country, due to their heterogeneity and to differences in national regulation. The traditional role of DSOs is to operate, maintain and develop the distribution network to ensure that electricity is delivered to end-users in a secure, reliable and efficient manner. DSOs also play a role in the efficient functioning of the European electricity markets, as they act as "entry gates" to retail markets in most EU countries (CEER 2013), potentially influencing the level of competition in this segment. They should therefore guarantee non-discriminatory access to the grid and provide system users with the information they need for efficient access to, including use of, the system.

Lately however, the changes triggered by the increasing penetration of local renewable generation and by the emergence of demand response enabling solutions are calling for a reconsideration of the role of DSOs. DSOs will be increasingly required to perform more (pro-) active grid development, management and operation as these changes place new requirements on the networks in terms of operational security, while they offer at the same time more options for the DSOs to manage their grids in a more flexible and efficient way (van den Oosterkamp, et al. 2014).

Research and debate is still open with respect to the new tasks, responsibilities and opportunities that are shaping up in the evolving power system (CEER 2015) (Eurelectric 2010) (Ruester, et al. 2013) (van den Oosterkamp, et al. 2014). These new tasks could in principle be performed by DSOs or they could be open to new and competing actors, in a market environment.

As highlighted above, European DSOs differ in size and activity profile, as well as in the technical characteristics of the networks and the challenges they need to face. Finding a common European approach to DSO regulation is therefore a challenging task (CEER 2015).

2.1 DSOs' Observatory Project

In the last years, the JRC has played an increasing role in collecting, processing and analyzing data on the power sector. This activity is aimed at providing different stakeholders with instruments to better understand the rapid changing scene, enabling early identification of developments and opportunities and supporting evidence-based policy making.

The first field which was investigated was that of smart grid research and development (R&D) and demonstration activities. In 2011, the first Smart Grid Projects Outlook, containing data and insights on smart grid projects in Europe, was released (Giordano,

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surveys and the fluidity of the sector. In the rest of this report, unless otherwise stated, we will refer to (Eurelectric 2013).

Gangale, et al. 2011). The report was updated twice, in 2013 (Giordano, Meletiou, et al. 2013) and in 2014 (Covrig, et al. 2014). In 2015, the data brokering activity was extended to the European laboratories landscape (Poncela, et al. 2015). The idea was to get an overview of all the smart grid technologies operational at laboratory level and to identify research activities, gaps and future trends.

In this context, the DSOs Observatory project can be seen as a further extension of the JRC data collection and analysis efforts to cover one of the main actors of the evolution towards a new electricity system, i.e. the distribution system operators.

The DSO Observatory project was launched at the end of 2014. The project had three main objectives: 1) getting an overall picture of the state of the research on several topics related to distribution system networks; 2) collecting and making accessible some technical indicators regarding the main DSOs in Europe, and 3) building representative distribution networks that could be used to perform different kinds of analysis and assessments without the need to have access to the real DSOs data.

During the study, the JRC collaborated with the IIT of Comillas Pontifical University, which supported the project with its established expertise and knowledge in the analysis and development of models for the simulation and optimization of future electricity networks.

One of the main challenges of the project was collecting enough data to substantiate the analysis. An online survey was launched in January 2015 (

Annex C: On-line survey) with the aim of collecting several clusters of data, relating to types of ownership and unbundling, network structures and designs, amounts and types of connected distributed generation (DG), and reliability of supply indicators. The survey was available on the EUSurvey web platform, where DSOs could directly fill in their data. In order to reach out to the DSOs and speed up the data gathering activity, the JRC teamed up with EURELECTRIC, an electricity industry sector association. Thanks to its collaboration, a link to the online questionnaire was sent to all the European DSOs that are subject to the EU unbundling requirements, i.e. those serving more than 100,000 connected customers.

The questionnaire was divided in two parts. The first part was mandatory and it was aimed at collecting general company information and some basic parameters on their networks design, e.g. the number of customers and circuit length per voltage level or the total installed capacity of generation connected. The response rate was quite high, as 79 out of the 190 larger DSOs replied.

The second part of the survey asked for additional information relating to the network structure, reliability indexes and connected distributed generation. Filling in this part of the questionnaire was only optional, but several DSOs decided to share their data: 20 DSOs provided information on their network design structure, 22 on the generation connected to their distribution network and 18 on the reliability indexes for long unplanned interruptions. In addition, 40 DSOs gave their availability for providing more customized information with the purpose of building representative networks of their company/country.

On the basis of the information collected through the survey, several network structural indicators were constructed, linking DSOs' inputs (e.g. the number of connected consumers, supplied area) and outputs (e.g. circuit length per voltage level, number and capacity of HV/MV and MV/LV substations). Chapter 3 presents and details the main indicators, highlighting the differences between DSOs and trying to account for the main reasons behind these differences.

Building on the structural indicators, 13 representative networks were constructed: 3 large-scale and 10 feeder-type networks. These grids are representative of European networks, but do not specifically represent any particular DSO or country. Chapter 4 introduces the concept of reference network models and guides the reader through the process for their construction.

Finally, Chapter 5 presents different simulation analyses that have been carried out to illustrate the potential application of these representative networks. One example of such simulations is the study of the impact of growing DG penetration on voltages and thermal limits. This type of analysis aims at identifying solutions to maximize renewable penetration with no need of additional network investment and can therefore be very useful for technical and regulatory purposes.

Overall, the DSO Observatory project successfully addressed all its main objectives. This study represents a first contribution to better understand and address the challenges DSOs will have to face in the transition to the new energy system. The JRC will continue its scientific and policy support activities in the field; this report can therefore be seen as a first step of an exercise that will continue in the future.

3 A clearer view of the European distribution networks

This chapter presents the results of the survey and explains how the collected data were used to build the indicators. From the list of 36 indicators derived by relating DSOs input and output data, 10 indicators were selected as the most relevant to build the representative distribution networks. Each indicator of this smaller subset is presented and explained in the following paragraphs, highlighting the differences between DSOs and trying to account for the main reasons behind these differences. To protect the confidentiality of the collected data, DSOs were anonymized. In each graph, they are not referred to by their name or by the country where they operate but they are numbered according to their position on the X-axis, which varies for each indicator. At a later stage, and subject to the conclusion of ad-hoc agreements with the DSOs, data by country will be published online on a dedicated JRC webpage[3].

3.1 Survey participation

79 out of the 190 larger DSOs responded to our survey. Even if the response rate was lower than 50%, the representativeness of the sample is quite high. Together, the 79 DSOs distribute more than 2,000 TWh of electricity to over 200 million customers per year, covering a total area of more than 3 million square km. They distribute over 70% of the electricity distributed by all DSO serving over 100,000 customers (Eurelectric 2013).

To provide a general perspective of the DSOs sample, two aggregated values are shown. Figure 3-1 shows the distribution of connected customers served by the DSOs in the sample. More than half of them serve between 400,000 and 4 millions of customers. Figure 3-2 shows the yearly distributed energy. In this case, more than 60% of the DSOs distribute between 3 and 60 TWh (of energy) per year to their customers.

[3] More information will be published on http://ses.jrc.ec.europa.eu

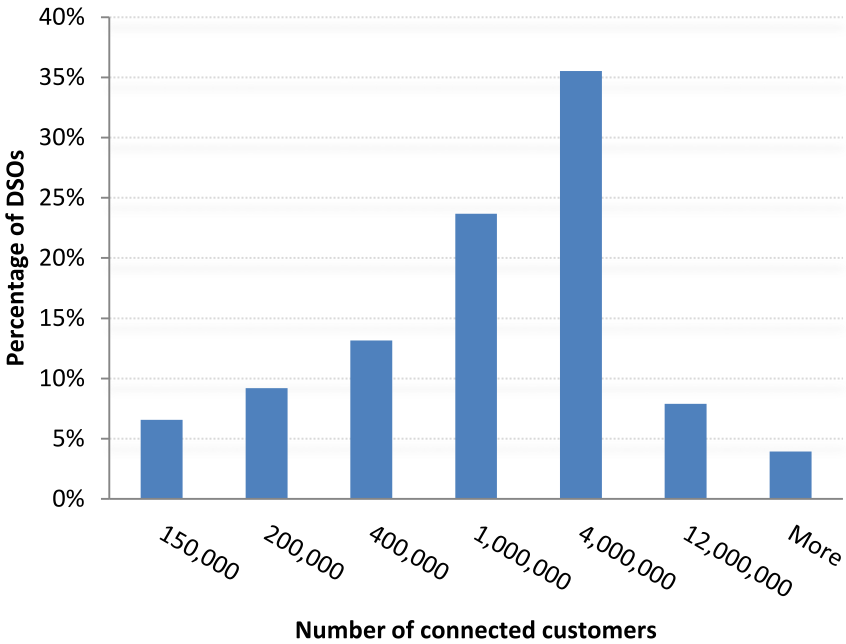

Figure 3-1 Distribution of connected customers

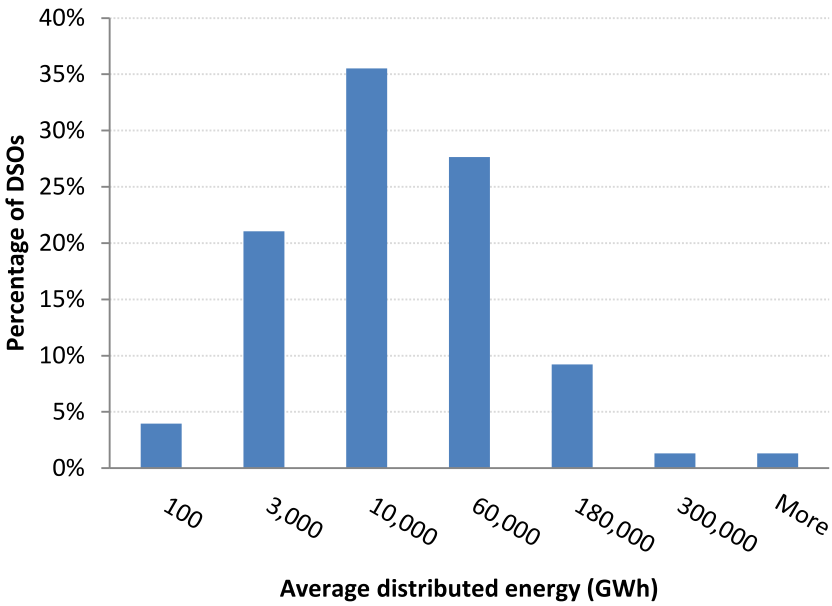

Figure 3-2 Distribution of yearly distributed energy

Table 3-1 shows for each country the number of respondents with respect to the total number of DSOs serving more than 100,000 customers (first column) and the percentage of connected customers over the total number of customers connected by the larger DSOs (second column).

Together, the 79 DSOs cover 74.8% of the total number of customers connected to the larger DSOs. In most countries this figure is over 70%, while in a few countries (e.g. Italy, Check Republic), it reaches 100%. Yet, there are a few cases with very small or even zero coverage (e.g. Austria, Malta). All together however, the 79 DSOs can be considered as a good representation of the investigated DSOs population.

Country	No. of DSOs	Customers covered
Austria	2/13	6.5%
Belgium	2/15	77.0%
Bulgaria	1/3	34.3%
Croatia	1/1	100.0%
Cyprus	1/1	100.0%
Czech Republic	3/3	100.0%
Denmark	3/6	41.2%
Estonia	1/1	100.0%
Finland	2/7	23.0%
France	1/5	96.0%
Germany	28/75	49.3%
Greece	1/1	100.0%
Hungary	3/6	45.9%
Ireland	1/1	100.0%
Italy	3/3	100.0%
Latvia	1/1	100.0%
Lithuania	1/1	100.0%
Luxembourg	1/1	100.0%
Malta	0/1	0.0%
Netherlands	2/8	39.0%
Poland	5/5	100.0%
Portugal	1/3	99.0%
Romania	2/8	78.5%
Slovakia	2/3	71.2%
Slovenia	1/1	100.0%
Spain	3/5	95.3%
Sweden	3/6	37.3%
United Kingdom	4/7	44.3%
Total general	79/190	74.8%

Table 3-1 Participation per country

Figure 3-3 visualises the same information through a colour-coded map. The different shades of red show how the percentage of covered customers varies across the EU 28, with the darker shades representing a higher coverage.

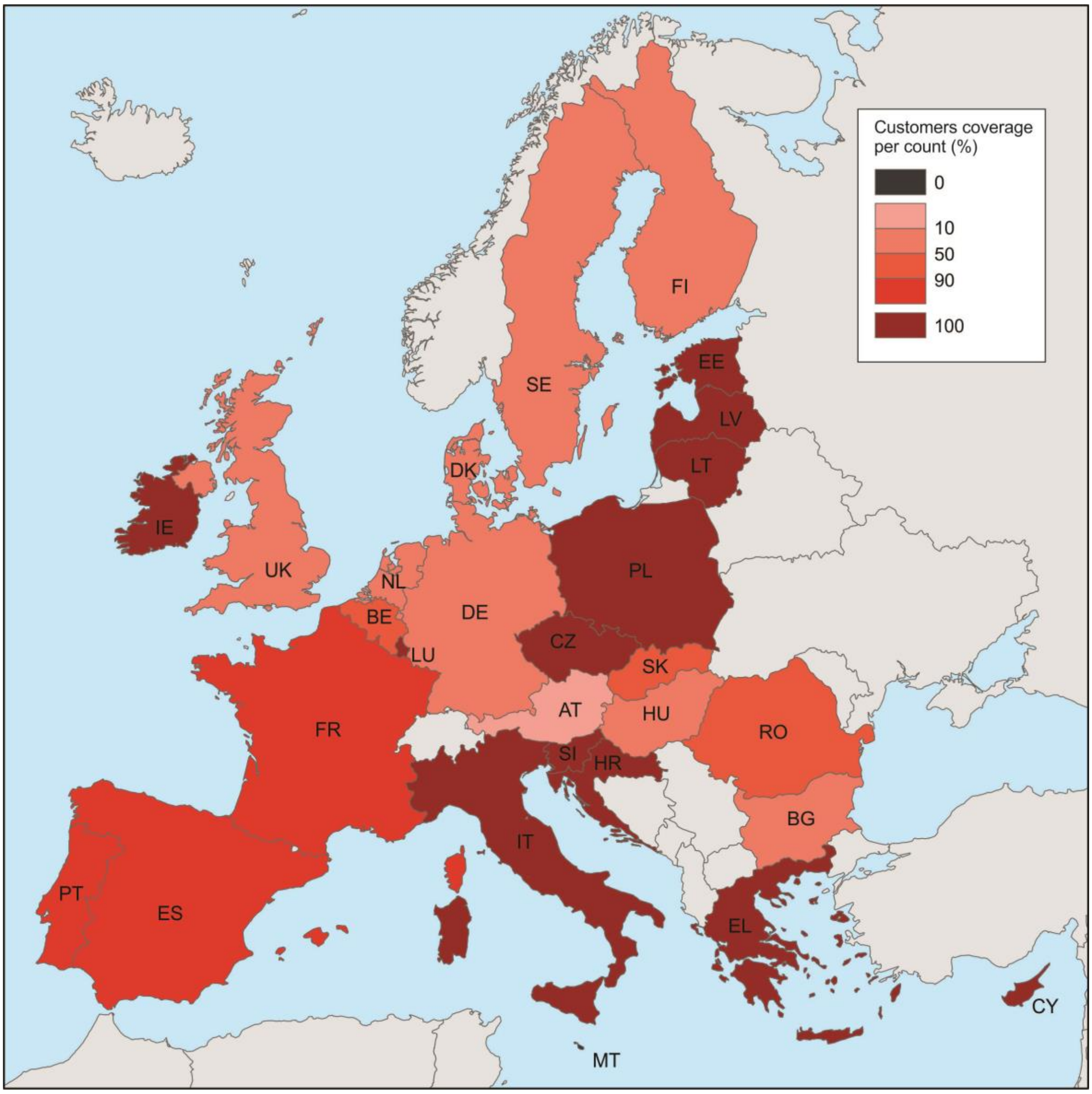

Figure 3-3 Customers coverage per country

3.2 DSOs indicators

This section presents 10 of the 36 indicators (Table 3-2, Table 3-3 and Table 3-4) that we have built from the collected data provided by the 79 DSOs in the database. The indicators have been devised in such a way to allow for a comparative analysis of the DSOs and can be divided in three main categories:

- Network structure
- Network design
- Distributed generation

Network structure and reliability indicators
1. Metrics associated to LV network
LV consumers per area
LV circuit length per LV consumer
LV circuit length per area of distribution
LV underground ratio
2. Metrics associated to MV/LV substations
Number of LV consumers per MV/LV substation
Area per MV/LV substation
Capacity of MV/LV substations per consumer
Area covered per capacity of MV/LV substation
3. Metrics associated to MV network
Number of MV consumers per area
MV circuit length per MV supply point
MV circuit length per area of distribution
MV underground ratio
4. Metrics associated to HV/MV substations
Number of MV supply points per HV/MV substation
Area per HV/MV substation
Capacity of HV/MV substation per MV supply point
Ratio of capacity of MV/LV substations per capacity of HV/MV substation
Area per capacity of HV/MV substations
5. Metrics associated to HV network
HV circuit length per HV supply point
HV circuit length per area
HV underground ratio
6. Other relevant metrics
Number of electric vehicle public charging points per consumer
SAIDI for long unplanned interruptions
SAIFI for long unplanned interruptions

Table 3-2 Network structure and reliability indicators

The **network structure** (Table 3-2) data covers DSO inputs referring to the main parameters (such as the number of connected consumers, distributed generation, area of supply and distributed annual energy) and DSO outputs corresponding to the assets planned by the DSO to cope with the given inputs. The outputs are divided by voltage level (LV, MV and HV) and consist of circuit length, number and capacity of substations, etc.

Given the structure of the data one can relate inputs and outputs through ratios in the following way: Input/Input (I-I), Input/Output (I-O), Output/Input (O-I) and Output/Output (O-O). The number of consumers and the full covered area are for instance the most relevant inputs to build the network structure indicators. Mainly invariant ratios O-I or I-O are calculated, e.g. LV circuit length per LV consumer or area covered per HV/MV substation. This type of indicators relate the inputs, which are the structure of the demand or the DG that the DSO must connect, with the outputs, which consist of the installations that the DSO uses to cover that given demand and to connect that given DG.

Additionally, network structure indicators of O-O or I-I type are calculated. The O-O indicators (such as capacity of MV/LV substations per capacity of HV/MV substation), analyze design criteria used by DSOs when sizing their network installations. The I-I indicators (such as consumers per area) analyze the structure of the demand and DG that the DSOs have to connect to their networks. Note that the DSOs have no control on the I-I indicators, while their planning decisions can affect the rest of indicators.

The **network design** indicators (Table 3-3) comprehend metrics associated to substations and feeders, and other relevant metrics. This information aims to identify which are the typical parameters that are used by DSOs for sizing and designing distribution installations.

Network design indicators
1. Metrics associated to substations
Typical transformation capacity of HV/MV substations
Typical transformation capacity of the MV/LV Substations in urban areas
Typical transformation capacity of the MV/LV Substations in rural areas
Average number of MV/LV substations per feeder in urban areas
Average number of MV/LV substations per feeder in rural areas
2. Metrics associated to feeders
Average length per MV feeder in urban areas
Average length per MV feeder in rural areas
3. Other relevant metrics
Voltage levels
Automation equipment and degree of automation

Table 3-3 Network design indicators

The analyses include for instance the typical transformation capacities of the HV/MV and MV/LV substations, how many MV/LV substations are connected to a MV feeder, and the average length of MV feeders. This information is generally presented broken down in urban and rural areas, as the network design depends on the type of area (e.g. MV feeders use to be longer in rural areas than in urban areas).

Distributed generation indicators
Total Installed Capacity/consumer
Percentage of generation connected to LV per technology
Percentage of generation connected to MV per technology
Percentage of generation connected to HV per technology

Table 3-4 Distributed generation indicators

The **distributed generation** indicators (Table 3-4) for the analysis of DG refer to the installed capacity per consumer, and the percentage of DG connected to each voltage level. Typically, the total installed capacity is available in the literature but it is not usually broken down per voltage level.

3.2.1 Main DSOs indicators explained

In the following a subset of the indicators (listed in Table 3-5) used to build the large-scale representative distribution networks is shown. In these graphs the DSOs are sorted by the indicator value, moving from the lowest to the highest value. This solution has been adopted mainly to protect the confidentiality of the data and the anonymity of the participants in the survey, as requested by certain DSOs. This means for instance that the DSO in position #1 in Figure 3-4 is the DSO with the lowest number of LV consumers per MV consumer, and it is not necessarily the same DSO in position #1 in Figure 3-5, which is instead the DSO with the lowest LV circuit length per LV consumer.

ID	DSOs indicators
1	Number of LV consumers per MV consumers
2	LV circuit length per LV consumer
3	LV underground ratio
4	Number of LV consumer per MV/LV substation
5	MV/LV substation capacity per LV consumer
6	MV circuit length per MV supply point
7	MV underground ratio
8	Number of MV supply points per HV/MV substation
9	Typical transformation capacity of MV/LV secondary substations in urban areas
10	Typical transformation capacity of MV/LV secondary substations in rural areas

Table 3-5 Subset of the total DSOs indicators used to build the large-scale representative distribution networks

The number of **LV consumers per MV consumer** is a measure of the percentage of LV residential & commercial and MV industrial consumers. The median for this indicator corresponds to 354 LV consumers per each MV consumer. From the figure 3-5 a noticeable gap is easily identified with a minimum of 10 and a maximum of 2008 LV consumers per MV consumers. This large gap is due to the fact that certain DSOs serve very large populated areas (urban areas) while others are serving more rural areas.

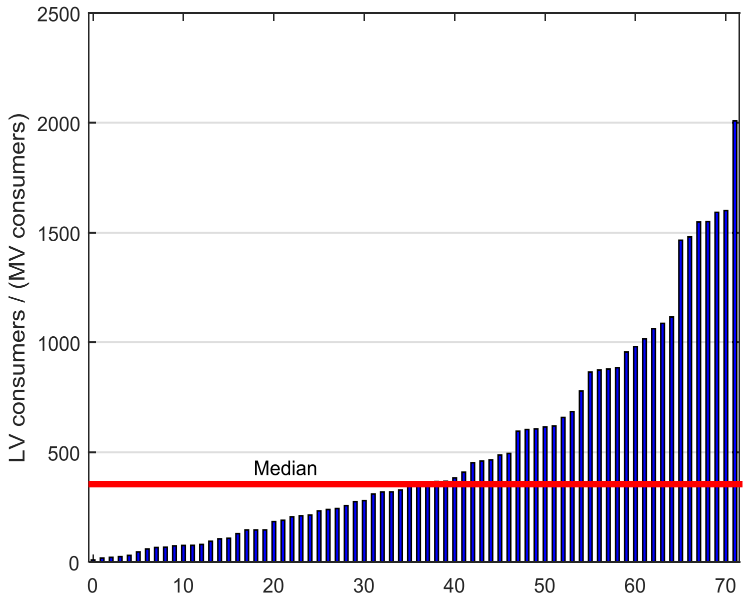

Figure 3-4 LV consumers per MV consumer

The **LV circuit length** depends mainly on the location of LV consumers and the distances among them. The median LV circuit length per LV consumer is around 0.023 km/LV consumer, with a maximum of 0.078 km/LV consumer and a minimum of 0.008 km/LV consumer. The LV circuit length per LV consumer is higher in more rural countries than in more urban countries because typically in cities, electric density is higher and the LV feeders have to be shorter. However, this also depends on the voltage levels of the distribution networks.

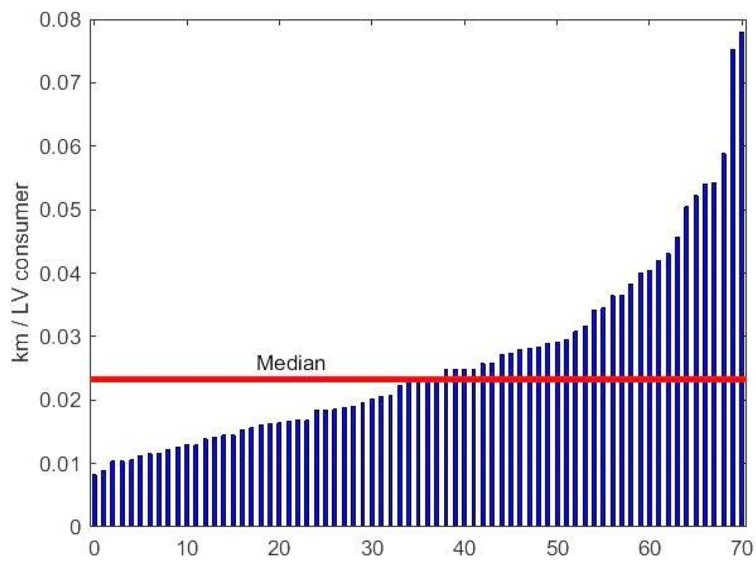

Figure 3-5 LV circuit length per LV consumer

The **LV underground ratio** is defined as the length of LV underground circuits divided by the total length of LV circuits (overhead and underground). The median LV underground ratio is 78%, with a maximum of 100% and a minimum of 11.5%. It is argued that a high underground ratio is desirable to reduce the number of interruptions

as the failure rate of this type of conductors is lower. However, in practice the decision of undergrounding cables is generally taken for aesthetic criteria (e.g. people do not want to have overhead electrical lines near their houses), rather than based on technical criteria. Typically the underground ratio is higher inside settlements than outside settlements. Urban areas with many consumers usually have more underground cables.

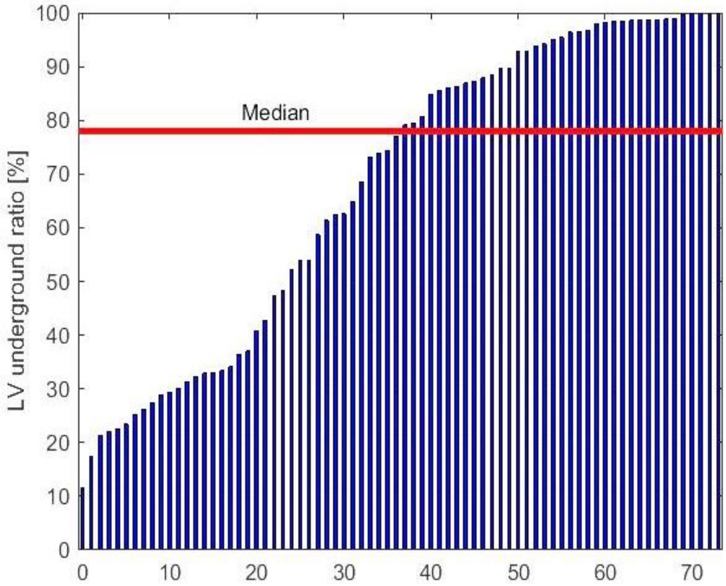

Figure 3-6 LV underground ratio

The median **number of LV consumers per MV/LV substation** is around 90, with a maximum of 278. This ratio is interesting because it gives an idea of the size of the low voltage network below each MV/LV substation. Of course, the length of the network will depend also on the dispersion of the consumers, being different in rural and urban areas. In urban areas, in which the capacity constraint is the most relevant one, the main parameters which affect this ratio are the peak power of the LV consumers and the capacity of the MV/LV substations. However in rural areas, voltage constraints can be also very relevant, and in that case this ratio also depends on the LV circuit lengths.

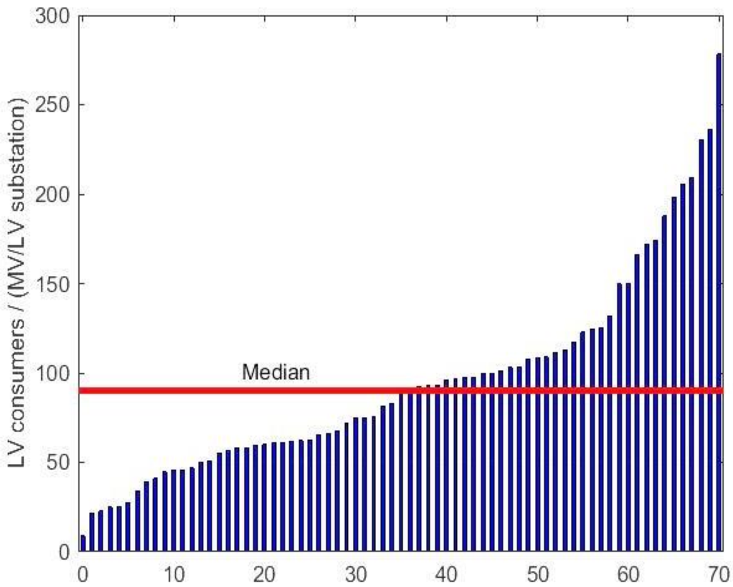

Figure 3-7 Number of LV consumers per MV/LV substation

The **capacity of MV/LV substation** per LV consumer is an indication on how much power is installed in the MV/LV substation for each LV consumer. This basically depends on the average typical peak power of the consumers, and on simultaneity factors. The higher the peak power of consumers, the higher the capacity of MV/LV substation required. In distribution areas in which the MV/LV substations are oversized, this value can also be higher.

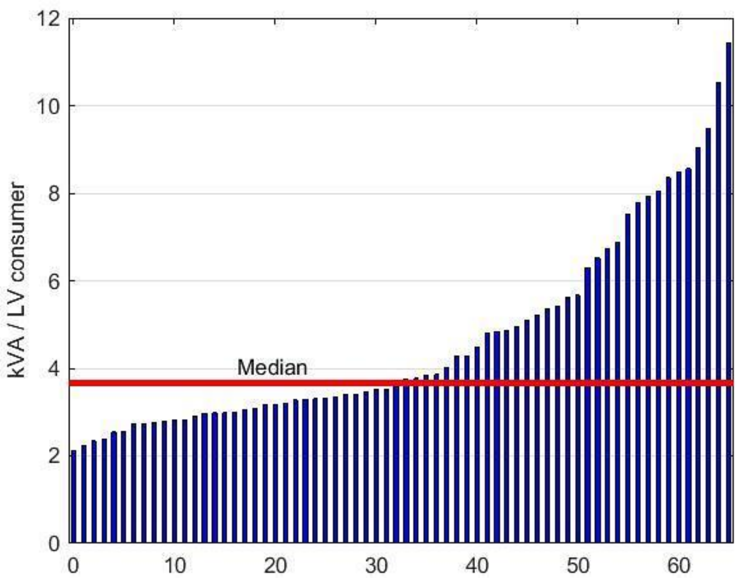

Figure 3-8 Transformers capacity per LV consumer

The median capacity of MV/LV substations per LV consumer is around 3.66 kVA, with a maximum of 11.4 kVA and a minimum of 2.1 kVA. This ratio depends, among others, on

the type of the household. For instance, a bungalow and a big apartment hosting more than four people have different load profile.

The MV supply points are MV/LV Substations and MV consumers. These are the key items of interest for the MV network when MV DG[4] is not connected or available. For evaluating the MV network length, the ratio **MV circuit length per MV supply point** was selected. As the number of MV supply points is much lower than the number of LV consumers, this parameter is much higher than the LV circuit length per LV consumer. The median MV circuit length per MV supply point is in fact around 0.73 km/(MV Supply Point), with a maximum of 1.86 km/(MV Supply Point) and a minimum of 0.11 km/(MV Supply Point). Despite the fact that there is so much variability in the number of MV consumers per area, the MV circuit length per MV supply point does not differ so much among different regions, meaning that the DSO can have some control on this variable, but the range is not so wide.

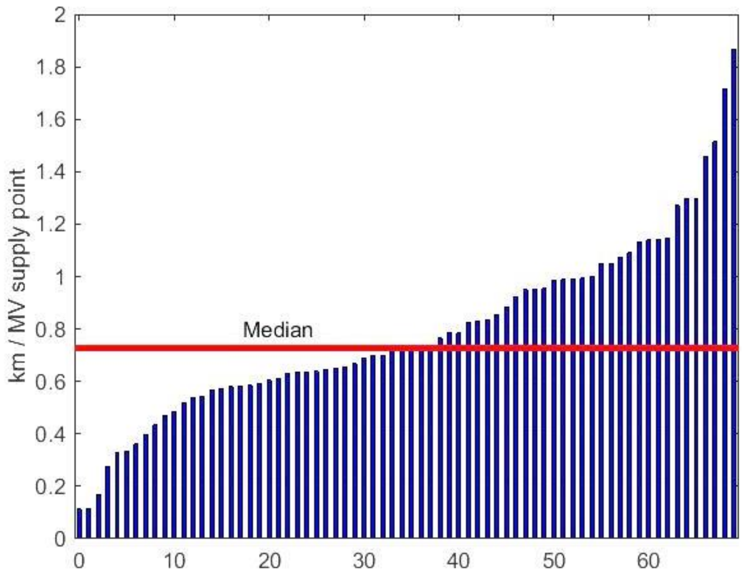

Figure 3-9 MV circuit length per MV supply point

The **MV underground ratio** is defined as the length of MV underground circuits divided by the total length of MV circuits (overhead and underground). In general the underground ratio is lower in rural areas than in urban areas. The underground ratio can have a side effect on reliability, as underground cables usually have lower failure rates (improving reliability) but requiring higher repair times. However, underground cables usually require more investments, due especially to the high cost of making the ditches rather than those related to the cost of cables themselves. Nevertheless sometimes the decision of installing underground or overhead cables could depend on aesthetic issues.

[4] MV DG was not considered due to the fact that the number of DG installations connected to each voltage level was not available.

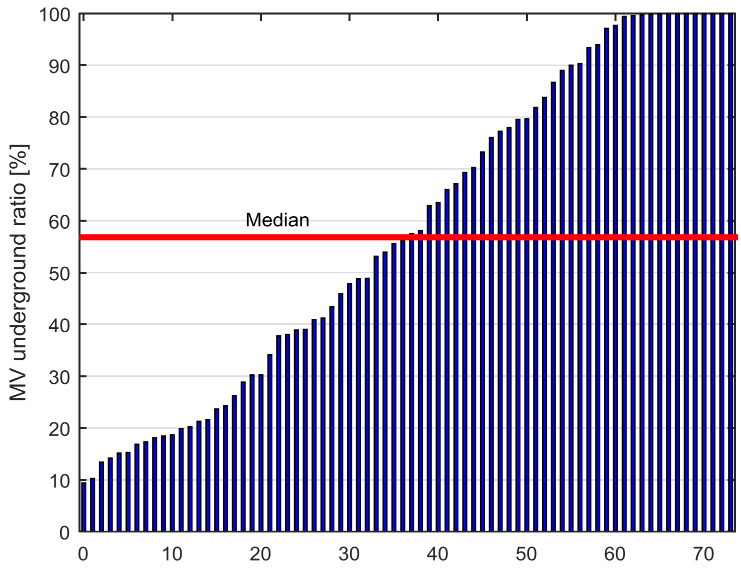

Figure 3-10 MV underground ratio

The median MV underground ratio is around 56.8%, with a maximum of 100% and a minimum of 9.4%. The median LV underground ratio was 78%, higher than in MV, possibly due to lengthy overhead MV feeders connecting several settlements. The large distance between the maximum and the minimum values could suggest that the DSOs have the freedom to choose this ratio; however specific national or regional regulations can impose a mandatory solution, meaning that the DSO cannot optimize this parameter in its planning.

The HV/MV substations have to supply electricity to MV supply points (MV consumers and MV/LV substations), apart from connecting MV distributed generation if any. The MV consumers and MV/LV substations are distributed along feeders, and therefore the **number of MV supply points per HV/MV substation** is the product of the number of feeders of the substations and the average number of MV supply points per feeder. Both of them are ratios which depend on the structure of the distribution networks, having the DSOs some control on them. The median number of MV supply points per HV/MV substation is 178, with a maximum of 1210.

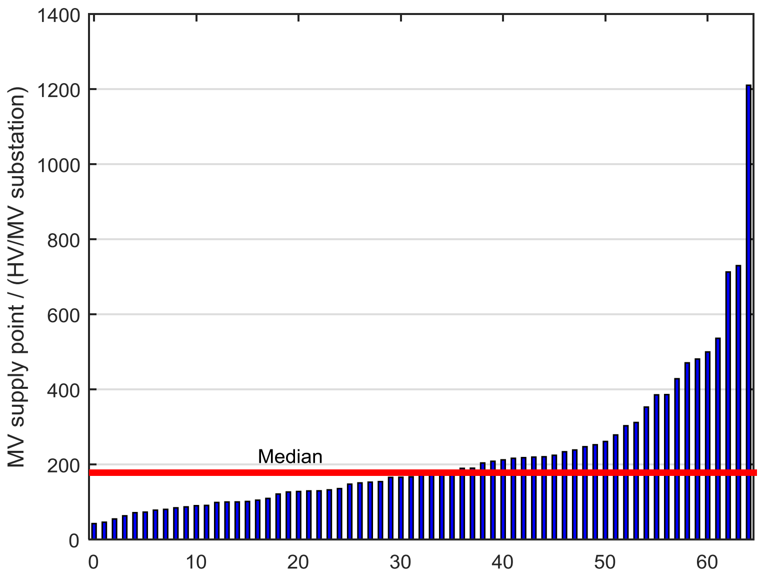

Figure 3-11 Number of MV supply point per HV/MV substation

The **transformation capacity of MV/LV substations in urban areas** (Figure 3-12) is typically higher than in rural areas, due to the increased electricity density. The most typical value of MV/LV substation capacity in urban areas is 630 kVA. The median transformation capacity of MV/LV substations in urban areas is 630 kVA, with a maximum of 1000 kVA and a minimum of 400 kVA.

The **transformation capacity of MV/LV substations in rural areas** (Figure 3-13) is generally lower than in urban areas, due to the reduced electricity density and increased distances. The most typical value of MV/LV substation capacity in rural areas is 400 kVA, followed by 250 kVA and 100 kVA. The maximum transformation capacity is 630 kVA and the minimum is 50 kVA.

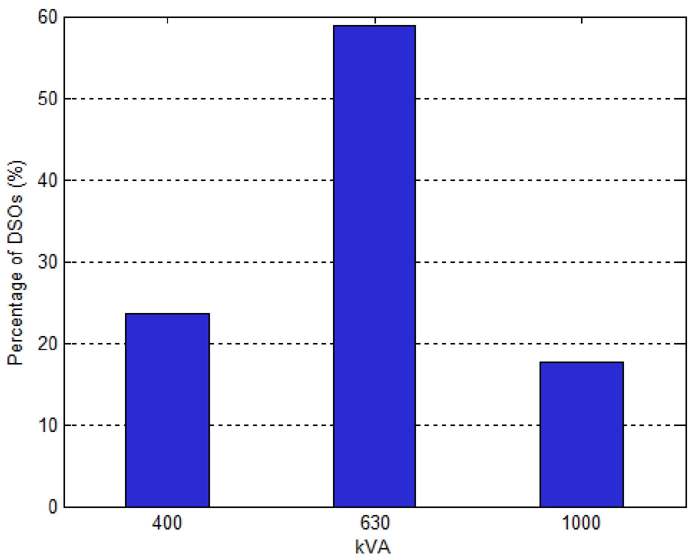

Figure 3-12 Typical transformation capacity of the MV/LV secondary substations in urban areas (kVA)

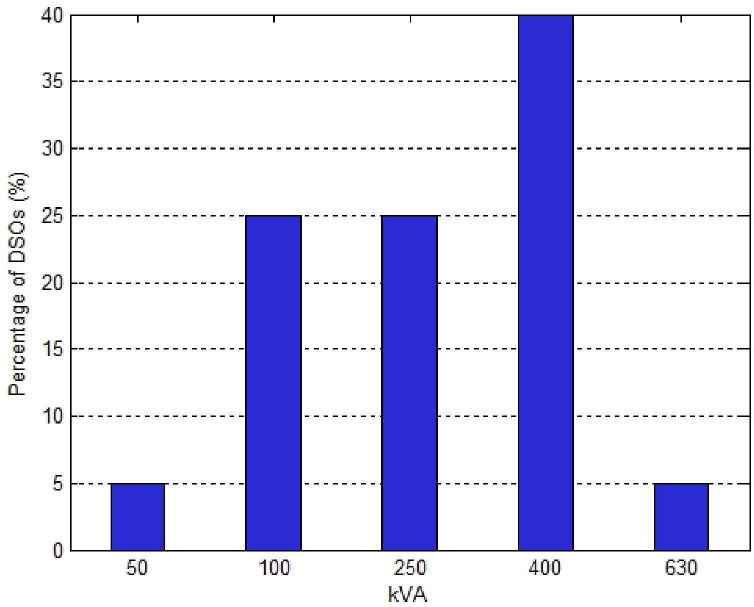

Figure 3-13 Typical transformation capacity of the MV/LV Secondary Substations in rural areas

The remaining indicators listed in Table 3-3, Table 3-4 and Table 3-5 are presented in the Annex B: Other indicators.

4 From Distribution Systems to Representative Distribution Networks

In this chapter a direct connection is established between the indicators presented in the previous chapter and the building process of representative distribution networks using the Reference Network Model. After introducing the concept of reference networks and their usage in literature, the methodology used in (Mateo, et al. 2011) is explained. Then the 13 typologies of networks (3 large-scale and 10 feeder-type topologies) that have been built through the collected data provided by the DSOs are described in detail.

4.1 The Reference Network Model concept

After the restructuring of the electric power sector, which started in many countries during the 1990s, electricity transmission and distribution being regulated activities started to be remunerated through new regulatory approaches. One of the key means used by energy regulators to apply these new regulatory tools was the concept of Reference Network Models (RNM) to build a reference utility (Rudnick 2000) (Román 1999). RNM are very useful tools also when several scenarios for the growth of real networks needs to be taken into account. Network expansion, reinforcements and maintenance costs necessary to accommodate potential increases in loads and penetration of distributed energy sources can be assessed (Jenkins 2014). Additionally, when performing costs-benefits analysis[5] (CBA) of smart grids projects, RNMs can also be used when future scenarios need to be considered.

There are two common techniques to build representative networks. One approach starts with the DSOs real networks and by applying clustering techniques, it tries to identify the most typical configurations of the considered networks. When real networks are not available, an alternative option is to build synthetic networks, using a large-scale distribution network planning tool. As real networks were not available in this study, the second approach has been used. Note that this approach coincides with that of a DSO whose aim is to distribute electricity in a given area of interest fulfilling present technical and physical constraints.

A RNM is a large-scale network distribution planning tool. Extensive data are required and several algorithms are run to obtain the design of a distribution network representation which can be very close to the real one. The RNM designs the distribution grid in a considered area of service from the transmission substations to the final consumers considering three hierarchical levels: high voltage, medium voltage, and low voltage. Both rural and urban zones included in the considered area of service are simultaneously optimized by designing the grid to supply all the customers (from thousands to millions) and including the connected distributed generators. Geographical constraints regarding streets topologies in urban areas and environmental factors (coastline, natural reserves, mountains, etc.) can be taken into account in the design.

[5] A CBA methodology for Smart Grid Projects is reported in (V. Giordano 2012).

The continuous interaction between the electrical network design algorithms and the Geographical Information System (GIS) ensures the feasibility and optimality of the layout and location of the planned installations (Gómez 2013).

From a computational point of view, the network planning is a difficult optimization problem whose complexity increases with the increasing number of consumers to be modeled (Mori 2003). To overcome these issues, RNMs address the problem through the use of heuristics, and considering several distribution areas, so that each of them can be planned separately, in order to diminish computing times by paralleling processes.

Two types of RNMs can be developed:

- A **green-field** model which designs the whole distribution grid, including substations and power lines, from scratch;
- An **expansion** model which designs the reinforcement and new additions to the existing network needed to face future situations, for instance growth of demand or new distributed generation.

In both models, the design problem consists in minimizing the total investment in new installations plus associated operational costs, mainly energy losses, in order to supply the expected demand while meeting reliability and quality of supply criteria (e.g. SAIDI, SAIFI, voltage quality, etc.). In this study only models of the first type (green-field) have been built. In the following three sections a technical explanation of the obtained outputs and the steps to follow to obtain them from the required inputs is given. The reader not interested in this level of detail can move directly to section 4.1.4 where the general methodology to connect the indicators to the representative networks is explained.

4.1.1 RNM Outputs

The result obtained by the RNMs is composed of two main layers. One provides a summary of the most relevant information of the designed network and the corresponding costs adequately broken down per type of network component. Additionally, the reliability indices obtained for the given network are provided.

The second one provides a collection of graphical files created by the RNMs. Each of these files corresponds to a type of network component including not only geographical information (GIS), but also electrical information such as impedances, thermal capacity and peak power flow.

4.1.2 RNM Inputs

To obtain the output previously explained, an extensive amount of data is required for building the RNM. As expected, the finer the available data the more accurate the built representative network can be.

The required input data can be grouped in four main categories: network users, transmission substations, network components and other relevant parameters (Gómez 2013).

"**Network users**" refers mainly to the identification and description of loads, Distributed Generation (DG), Electric Vehicles and storage units connected to the distribution network. The exact location of every single user (X and Y coordinates), the voltage level

at the point of connection, the contracted power or the installed capacity and power factor are key data for the RNM. For large distribution areas, the number of consumers, particularly small LV consumers, can be very large. The networks studied can range from several thousand users up to a few million connections. Gathering such very detailed information is one of the main difficulties of the RNMs.

"**Network components**" indicates a library of standard components that includes technical data on HV power lines, MV and LV feeders, HV/MV substations, MV/LV transformers, protection equipment (breakers, fault detectors and switches), maintenance crews, capacitor banks and voltage regulators. For each network component in the library, investment and maintenance costs, rated capacity, electrical properties such as impedances, and useful life of the component are specified. To compute the expected reliability indices it is also necessary to provide the models with failure rates and a standard annual duration of preventive maintenance actions that are carried out on each type of component (HV line, MV/LV transformer, etc.), for overhead and underground elements and in each kind of area (urban or non-urban).

"**Others relevant parameters**" refers to the remaining parameters which the RNM needs in order to perform a reliable computation. The most relevant ones are summarized as follows:

Simultaneity factors. Simultaneity factors are needed for planning purposes, in order to take into account that the maximum power flow in the different network components does not occur at the same moment. As the grid voltage level rises, more downstream customers and installations are aggregated. However, the peak of an upstream network element is lower than the sum of the peaks of its downstream fed network components, because they do not all occur at the same time. Therefore a simultaneity factor has to be considered when peak power flows are aggregated. Without simultaneity factors, LV grids and MV/LV transformers would be much bigger in terms of capacity than what it would be actually required. Similarly, MV/LV transformers and distribution substations have two different simultaneity factors, one upstream of the transformer and another downstream. The upstream simultaneity factor takes into account that not all transformers are at their peak at the same moment. The downstream simultaneity factor models the fact that not all the lines connected to the transformers will be loaded at their maximum simultaneously.

Economic parameters. Economic parameters are needed to calculate the present value of network costs and evaluate investment options. These comprise the cost of energy losses, the weighted average cost of capital (WACC), and the costs to install conductors in different types of areas.

Load modelling and GIS related parameters. Density and minimum number of consumers to classify them into different areas and identify settlements, degree of undergrounding required within settlements per voltage level, and street maps parameters.

Technical and quality constraints. The RNMs must observe the maximum and minimum bus voltages, the thermal constraints and the limits imposed on reliability of supply indices. The RNMs use the SAIDI (System Average Interruption Duration Index) which is a measure of the duration of the interruptions and the SAIFI (System Average Interruption Frequency Index) which measures the frequency of the interruptions. Bus voltage limits are set per voltage level and should comply with the limits imposed in the EN 50160. MV network must comply with zonal and individual reliability indices, which

are separately fixed for urban, semi-urban, concentrated rural, scattered rural and industrial areas.

4.1.3 RNM planning steps

One of the first steps for building a RNM is to decide the number, size and location of MV/LV power transformers once the inputs on LV final customers and distributed generation are given. An initial estimation of the number of MV/LV transformers is made on the basis of the power density of each identified city or town. An algorithm is used to locate the proposed MV/LV transformers.

After locating MV/LV transformers, the LV network can be planned connecting the LV final customers and the distributed generation. The process is carried out as follows. First, the Delaunay algorithm is run with all input data. Second, each final customer and distributed generator is associated to a MV/LV transformer, applying an electric momentum criterion, to obtain several clusters with a unique MV/LV transformer. Third, a minimum spanning tree is run in each cluster, where MV/LV transformers are the root nodes of the tree. Fourth, a branch-exchange optimization algorithm is executed to estimate a quasi-optimum LV network, subject to voltage and current constraints, minimizing investment, and operation and maintenance costs. This optimization sometimes implies relocating the LV/MV transformers and thus, returning to the first step. Finally, the conductor size optimization is performed to select the optimum for each LV overhead or underground line section. To this end, an additional term that takes losses into account is incorporated into the objective function.

The third stage consists in deciding the number, size and location of HV/MV substations. The logic for algorithms at this stage is similar to the one described for LV/MV transformers planning.

The fourth step of the algorithm is to map out the MV network, which will link MV/LV transformers to HV/MV substations. The process resembles LV network planning, despite including new features that allow taking the quality of service level into account.

4.1.4 RNM Methodology

In the following, the methodology used to build European large-scale representative networks is presented. The typical topologies of EU distribution networks have been modeled. The voltage levels considered are low voltage (LV) and medium voltage (MV).

The constructed representative networks can be categorized into two major groups:

- Large-scale networks (cases #1-3) model the network downstream of a HV/MV substation, including LV & MV consumers, LV & MV feeders and MV/LV substations. The main difference between these large-scale networks is the density of the demand. An urban network has been built modelling the distribution network inside a highly populated city. A rural network has also been built modeling farms and small settlements connected by a MV network. Finally a semi-urban network represents an intermediate situation in the outskirts of a city.

- Feeder type networks (cases #4-13). These networks include feeders downstream a single HV/MV or MV/LV substation and can be divided in:

  a. MV feeders (cases #4-11), with specific network configurations for MV reliability analysis, aimed at assessing the duration and frequency of the interruptions depending on the network configuration and the MV protection equipment. Networks with a low and high degree of automation have been produced in this case to be able to evaluate how the degree of automation impacts on the continuity of supply. Networks with a low degree of automation use fault detectors, switches and breakers which are manually operated; while networks with a high degree of automation use tele-controlled versions of some of these devices. In networks with a high degree of automation, typically tele-controlled devices are regularly spaced along the feeders to maximize reliability improvement.

  b. LV feeders (cases #12-13), aimed at making analysis of a single LV network, for example for installing photovoltaic generation in a low voltage residential network. Each of them represents the network downstream a MV/LV substation. Network #12 models an urban LV network while network #13 models a semi-urban LV network.

Table 4-1 summarizes the 13 representative networks built.

Representative network ID #	Type of area	Voltage levels	Degree of automation
1	Urban	LV & MV	Low
2	Semi-urban	LV & MV	Low
3	Rural	LV & MV	Low
4	Urban - Two substations interconnected	MV	Low
5	Urban - Two substations interconnected	MV	High
6	Urban - One substation and one switching station	MV	Low
7	Urban - One substation and one switching station	MV	High
8	Semi-urban - Substation ring	MV	Low
9	Semi-urban - Substation ring	MV	High
10	Rural	MV	Low
11	Rural	MV	High
12	Urban	LV	Low
13	Semi-urban	LV	Low

Table 4-1 Representative networks

The selected topologies and particular networks represent typical cases of EU distribution networks but other alternatives and variants could also be considered for specific analysis depending on their objective and scope.

Each synthetic network has been obtained using a Greenfield Reference Network Model (RNM). As already mentioned, the RNM requires as input the location and peak demand of every single customer. The geographical coordinates of the consumers for each type of network (urban, semi-urban, and rural) were determined by processing a street map image, downloaded from OpenStreetMap[6]. Next, this information was complemented with the peak demand of each consumer and a RNM catalogue (containing among others standard network installations). As a result, the synthetic network was built. Finally, an iterative procedure was carried out by readjusting the inputs of the model until the parameters of the obtained synthetic networks matched the network structural indicators of DSOs in the European Union (presented in section 3.2).

When adjusting the RNM input parameters, the building density and the number of consumers per building can help to increase or decrease the consumer density, which in the end modifies the network length per supply point. The percentage of MV consumers with respect to the total number of consumers is both a RNM input parameter and a structural indicator, so it can be directly adjusted to the desired value. Since in the synthetic network there is only one HV/MV substation the size of the covered area determines the number of demand points supplied by the substation and this needs to coincide with the structural indicator (number of MV supply points per HV/MV substation). The distribution function of the consumer peak demands and the simultaneity factors impact on the two following structural indicators: i) required installed capacity of MV/LV substation per LV consumer, and ii) the number of LV consumers per MV/LV substation, so they have been adjusted iteratively. The network underground ratios per voltage level inside settlements are RNM input parameters that can help to adjust the total underground ratios. Finally, the MV/LV transformer capacities in the RNM installation library can be directly adjusted to the typical values obtained for the EU DSO structural indicators, which are broken down in rural and urban areas.

Figure 4-1 shows the different steps followed by the proposed methodology to construct synthetic representative distribution networks.

Large-scale networks represent the grid downstream of a single HV/MV substation, including LV & MV consumers, LV & MV feeders and MV/LV substations. Three grids have been built corresponding to urban, semi-urban and rural areas. The label of large-scale is due to the high number of buses present in each network of this kind. They are geo-referenced, because the topological coordinates of each single bus are provided.

1. The first step is to take the European DSO network structural indicators from the DSOs database and to use them as a reference to validate the obtained EU synthetic network. These indicators represent those network parameters that the built distribution network needs to have in order to be considered a representative proxy of a European network.
2. The next step for each representative network is to obtain a street map image, which will help to identify and select the location of buildings. Different images were considered for each type of area (urban, semi-urban or rural), trying to represent the typical consumer density in these types of locations. For example, in the urban network the centre of a city was selected, while in the rural network a countryside region with small settlements and farms was chosen. To gather the geographical coordinates (X,Y) of the buildings the street map image has to be

[6] https://www.openstreetmap.org/

processed, setting a density of buildings inside blocks (which determines the spacing between buildings) and the size of the area (which determines in the end the number of consumers supplied by the HV/MV substation).

3. Then the main parameters characterizing the consumers need to be defined: voltage level (LV or MV), geographical position coordinates (X, Y) and peak demand. In order to obtain these parameters, the percentage of MV consumers in the supplied area, the number of consumers per building, and an estimate of the distribution function of the consumer peak demands are specified. First, the percentage of MV consumers is used to fix the proportion of LV & MV consumers, determining their voltage levels at the grid connection points. This ratio was obtained as a structural indicator. Then, the number of consumers per building is used to place several consumers in each building, locating them in the same geographical coordinates. Therefore consumer coordinates are based on the coordinates of the buildings collected through the street map image processing. Finally, the distribution function of the consumer peak demands is used to set the peak demand of each particular consumer depending on its voltage level. The distribution function of the consumer peak demands and the number of consumers per building are adjusted at each iteration of the proposed methodology, see Figure 4-1.
4. A RNM input file is also provided, defining simultaneity factors, settlement underground ratios, and identifying the standard network installations that the RNM will use to build the synthetic networks.
5. Once all the aforementioned data are gathered, the Greenfield Reference Network Model (RNM) is run to obtain a first proxy synthetic network. Such a network is mainly dependent on the pre-specified consumer data, location of the HV/MV substation and the standard installation library included in the model. The Greenfield RNM uses as the main control variables: simultaneity factors, settlement underground ratios, and the catalogue of standard network installations.
6. Finally the resulting structural indicators that correspond to the obtained RNM synthetic network are measured and compared to the EU DSO structural indicators, which are used as reference. If the two sets of indicators are reasonably close the synthetic network can be chosen as a representative proxy of the target network.
7. In practice, it is always necessary to iterate this process several times, readjusting the RNM input parameters until the convergence to the target structural indicators is achieved.

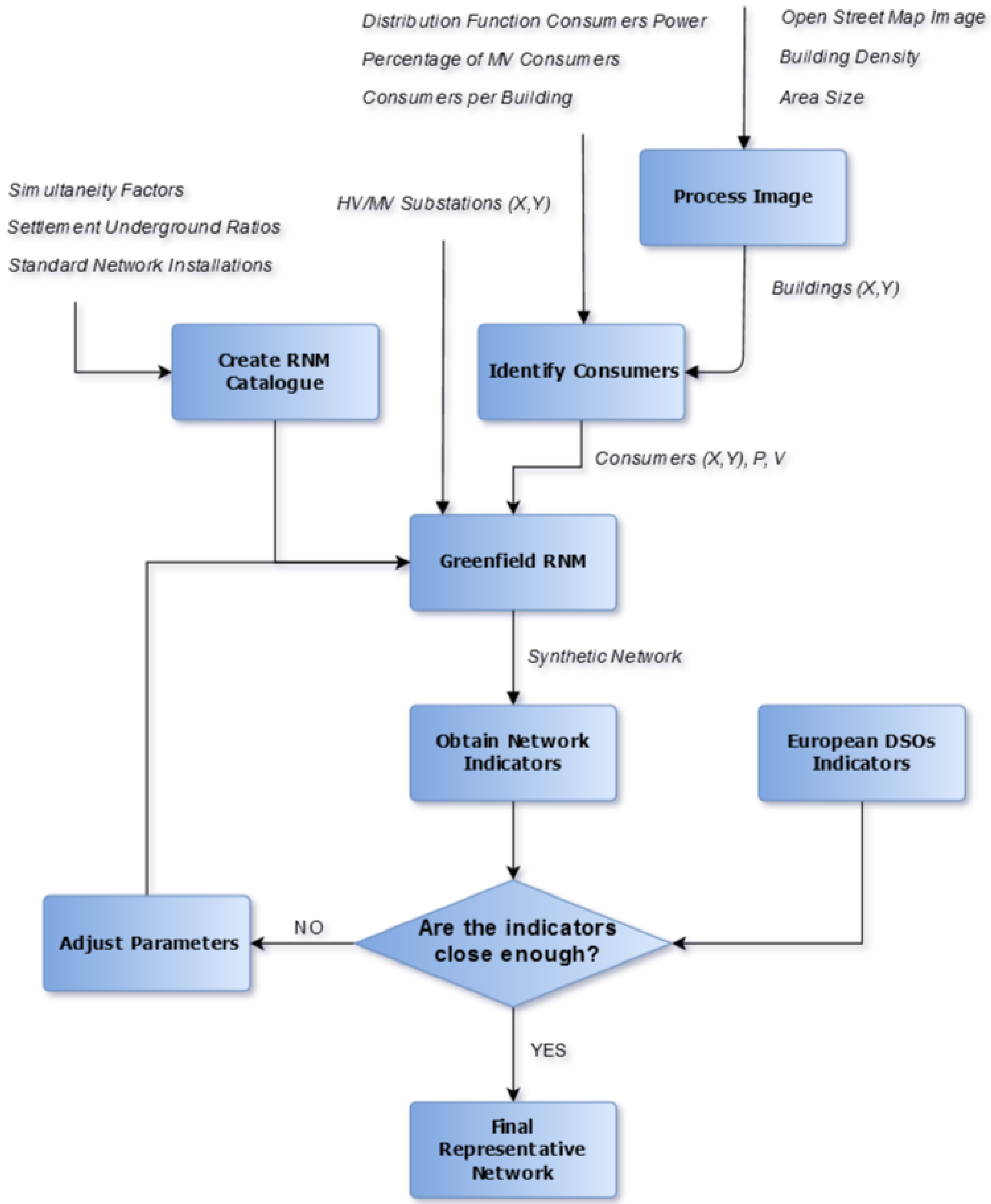

Figure 4-1 Schematic view of the methodology used to build the representative distribution networks

4.2 Realistic synthetic networks based on RNM

To build the synthetic networks using the RNM, the location of the customers have to be identified. For this purpose street map images need to be downloaded and processed. For the urban area, the center of a city was selected. In the rural area a region with small settlements and farms was chosen. Finally, the semi-urban area was taken as an intermediate one, representing the outskirts of a city.

The following figures show how the street map images were processed to obtain the location of consumers. Starting with a real street map image, in the urban area first the streets of the city were identified as shown in Figure 4-2.

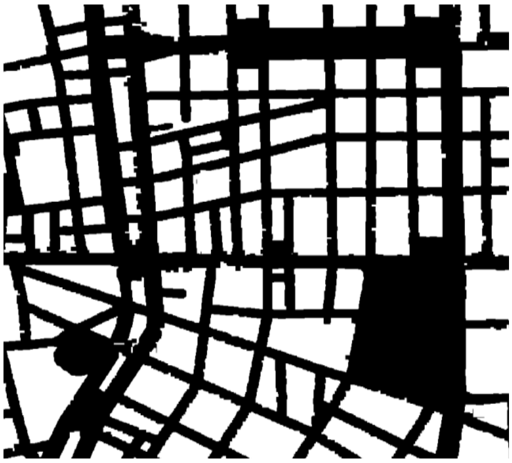

Figure 4-2 Street map image processing: identification of streets in the urban network

Then, the block of buildings was recognized, and finally the location of consumers was selected placing them around blocks of buildings as shown in Figure 4-3 where the blue points represent the buildings. All the consumers inside a building were placed in the same coordinates, as they correspond to a single bus from the network point of view.

Figure 4-3 Street map image processing: building location in the urban network

A similar process was carried out in the semi-urban and rural areas, but directly identifying blocks of buildings, instead of starting with the streets. As shown in Figure 4-4 the outskirts of a city were modeled in the semi-urban area.

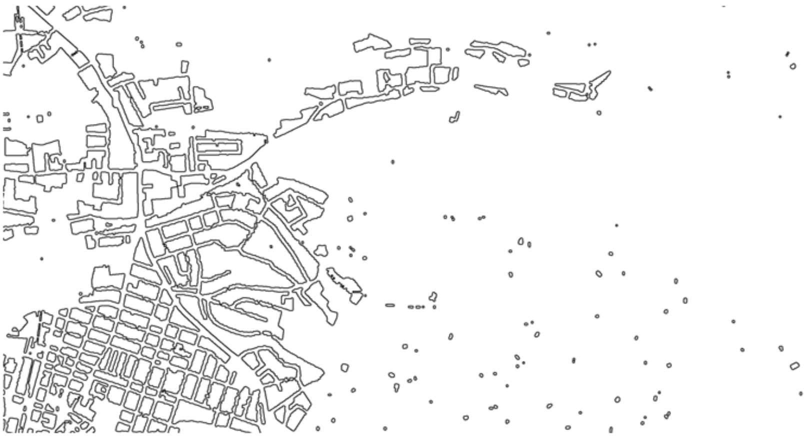

Figure 4-4 Street map image processing: semi-urban network

As shown in Figure 4-5, the rural area selected includes small settlements and farms around the settlements.

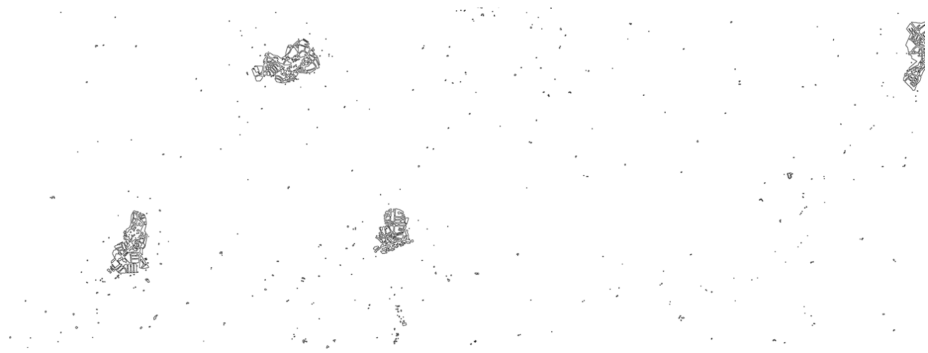

Figure 4-5 Street map image processing: rural network

Once the location of consumers was obtained, this information was complemented with the peak demand of each consumer, and with the RNM input catalogue. All this information was then used as input to the RNM in order to obtain the synthetic networks of each area.

Table 4-2 shows the median, the 0.05 and the 0.95 percentile of the values collected in the DSO Observatory database. The 0.05 and 0.95 percentiles were chosen with the aim of covering the full diversity of DSOs, but removing outliers. The values that were used as reference for the RNM to build the networks are marked in light blue. In general the median is the more relevant value, however for underground ratios, a great diversity exists, and therefore in this case the three values have been considered.

Network indicators	0.05 percentile	Median	0.95 percentile
Number of LV consumers per MV consumer	26	354	1550
LV circuit length per LV consumer (km)	0.0104	0.023	0.0542
LV underground ratio	22.20%	79%	99.80%
Number of LV consumers per MV/LV substation	24.9	90	209.2
MV/LV substation capacity per LV consumer (kVA)	2.37	3.8	9.12
MV circuit length per MV Supply Point (km)	0.27	0.73	1.46
MV underground ratio	14.40%	56%	100%
Number of MV Supply Points per HV/MV substation	61	178	580
MV/LV transformer substation capacity (kVA)	400-1000 Urban		
	100-400 Rural		

Table 4-2 DSO Database network indicators

4.2.1 Representative large-scale networks

Table 4-3 shows the calculated indicators that correspond to the constructed representative networks (Urban, Semi-Urban, Rural). The first column is the indicator name the next three columns are the values of each indicator for the constructed representative networks. It is worth noticing that the European DSO indicators in the database are not broken down in urban, semi-urban and rural areas because this information was not provided with that level of detail by the DSOs, with the exception of the typical MV/LV substation capacities. This implies that some variations exist between representative network (Table 4-3) and target (Table 4-2) indicators, for example, as it is the case of purely urban networks.

Network indicator	Urban	Semi-urban	Rural
Number of LV consumers per MV consumer	335	350	386
LV circuit length per LV consumer (km)	0.004	0.008	0.027
LV underground ratio	86%	42%	4%
Number of LV consumers per MV/LV substation	101	87	51
MV/LV substation capacity per LV consumer (kVA)	6.499	6.995	5.209
MV circuit length per MV Supply Point (km)	0.2	0.3	0.8
MV underground ratio	100%	74%	15%
Number of MV Supply Points per HV/MV substation	164	201	172
MV/LV transformer substation capacity (kVA)	400 630 1000	100 250 400 630 1000	100 250 400

Table 4-3 Indicator name and representative network ratios

Annex A: Indicator box plots, reports the box plots of the first eight indicators listed in Table 4-3. These box plots provide a graphical benchmarking between the values obtained through the DSOs data and the values measured from the representative networks that have been built through the methodology explained in section 4.1.4.

The following sections show the graphical representation and the main data of the three large-scale geo-referenced networks obtained through the RNM. The choice of using the following such networks depends much on the different possible configurations, (topologies, voltage levels, number of consumers, etc.) which may be used in real situations.

4.2.1.1 Urban (#1)

Figure 4-6 shows the large-scale network in an urban settlement, including MV feeders (blue lines), LV feeders (black thin lines), as well as MV/LV substations (red circles) and the HV/MV substation (blue triangle). All MV feeders are underground.

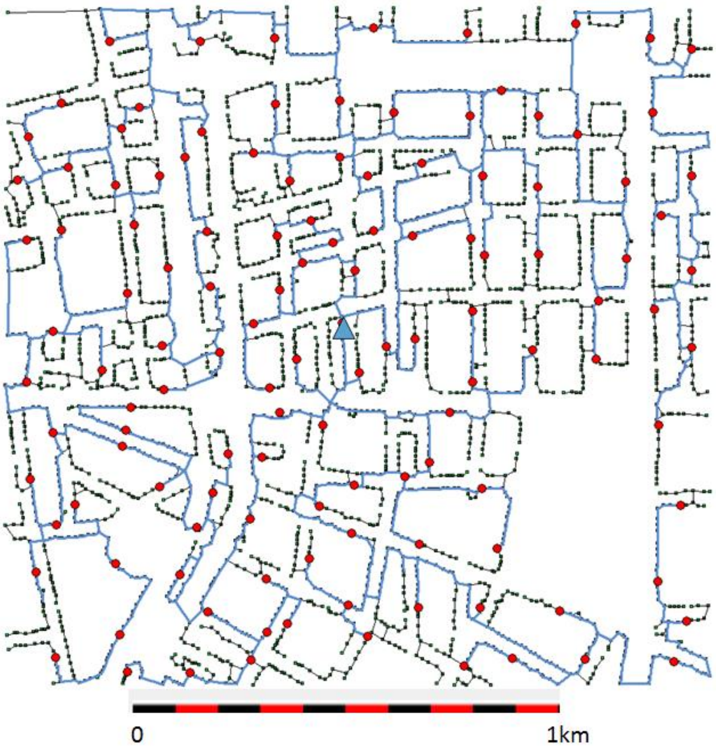

Figure 4-6 Urban network

Aggregated data are provided in the following to give an idea of the size of the considered distribution network and of its main characteristics. All the representative distribution networks built within the DSOs Observatory project will be publicly downloadable on the SESI webpage[7].

[7] http://ses.jrc.ec.europa.eu/distribution-system-operators-observatory

The number of MV consumers is much lower than the number of LV consumers, in the proportion showed by the reference indicators.

Aggregated inputs

	No.	Peak Power (MW)
LV Consumers	12735	56.78
MV Consumers	38	5.7

Since we are modeling a city centre, no MV overhead conductors are present.

	Overhead	Underground
LV km	7.38	46.49
MV km	0	31.20

Even though there is one single HV/MV substation and 126 MV/LV substations, the relation between the total capacity of MV/LV substations and HV/MV substations is close to one, as the reference indicators shows (please see Figure B-9).

	No.	Capacity (MVA)
MV/LV substation	126	82.76
HV/MV substation	1	80

In the following table the label "type ID" indicates the type of electrical line, according to the labels specified in section 4.2.2.6. Types LV_UO_1/2 refer to overhead and types LV_UU_1/2 to underground. Most LV feeders are underground, but there are also a few LV overhead feeders, corresponding to electrical lines in façades.

Low voltage network

Voltage (kV)	Type ID	Length (km)
0.4	LV_UO_1	2.929
0.4	LV_UO_2	4.45
0.4	LV_UU_1	38.956
0.4	LV_UU_2	7.533

The number of transformers for each rated power is close to the probabilities set by the reference indicators in Figure 4-12.

Medium to low voltage transformers

Voltage (kV)	Rated Power (kVA)	Number
20/0.4	1000	34
20/0.4	630	52
20/0.4	400	40

The types of MV electrical lines are MV_U_1/2, which are underground.

Medium voltage network

Voltage (kV)	Type ID	Length (km)
20	MV_U_1	27.163
20	MV_U_2	4.032

Figure 4-7 shows the five (colored) MV feeders. The HV/MV substation is represented by a triangle. Each feeder is painted with a different color. Black lines represent loops in the MV network normally open for increasing the reliability of supply in case of network outages.

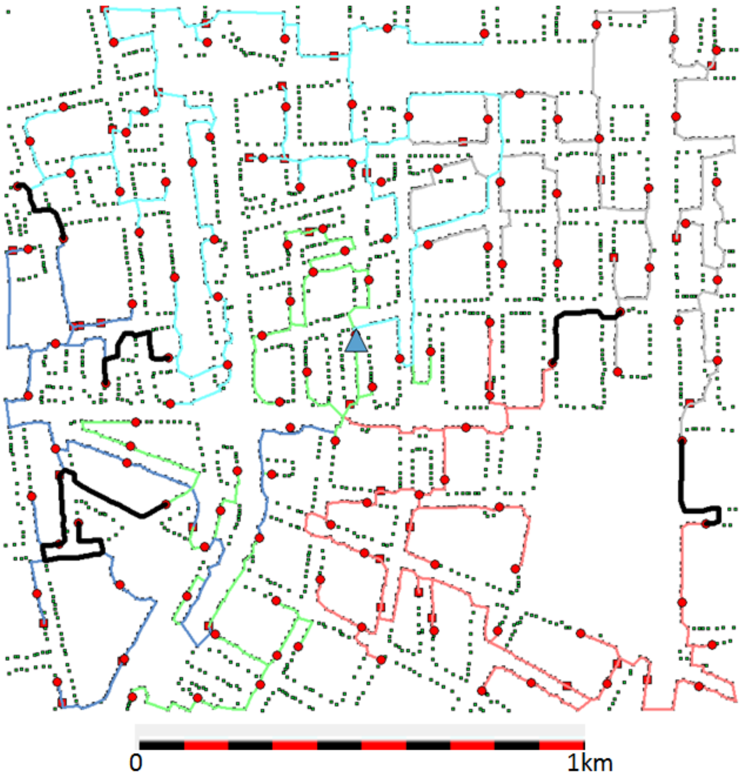

Figure 4-7 Urban MV feeders

The following table presents information broken down per MV feeder.

Feeders parameters

	LV network [km]	MV network [km]	MV/LV Substations
MV Feeder #1	8.00	4.97	15
MV Feeder #2	11.49	5.86	25
MV Feeder #3	11.81	6.21	26
MV Feeder #4	11.01	5.34	31
MV Feeder #5	11.57	6.98	29
Loops	0.00	1.84	0

High to medium voltage substations

Voltage (kV)	Rated Power (MVA)	No.
132/20	80	1

4.2.1.2 Semi-urban (#2)

Figure 4-8 shows the large-scale network with a semi-urban configuration, including MV feeders (blue lines), LV feeders (black thin lines), as well as MV/LV substations (red circles) and the HV/MV substation (blue triangle). It represents the outskirts of a city.

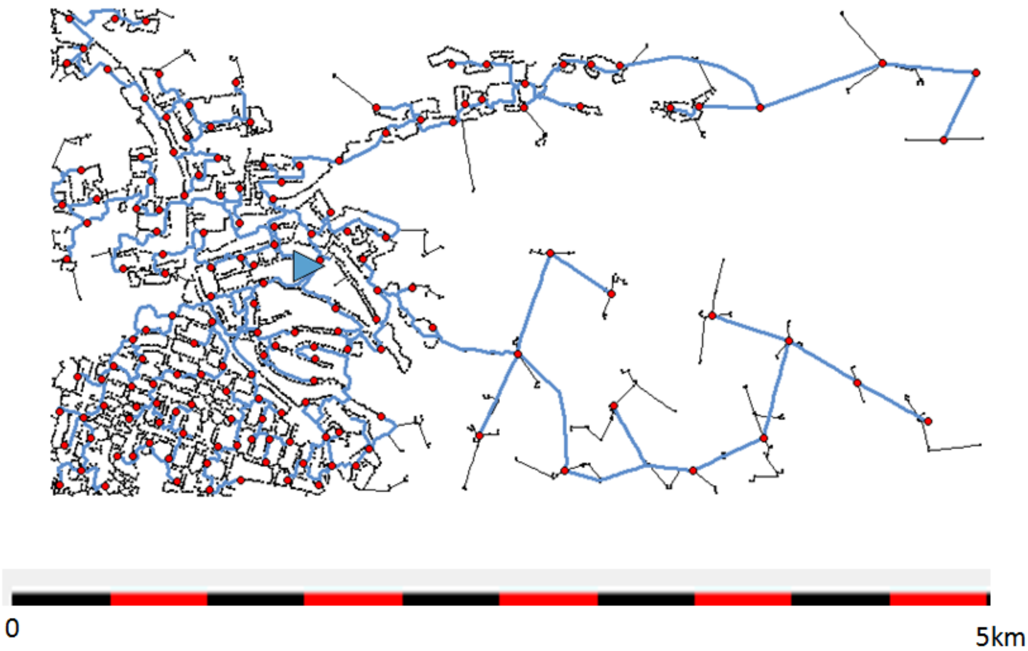

Figure 4-8 Semi-urban network

The proportion of MV to LV consumers is similar to the urban area case. In the semi-urban area there are however some MV overhead electrical lines. Again, the total installed capacity in MV/LV substations and HV/MV substations are close.

Aggregated inputs

	No.	Peak Power (MW)
LV Consumers	13998	68.5
MV Consumers	40	6

	Overhead	Underground
LV km	67.21	47.75
MV km	13.24	37.16

	No.	Capacity (MVA)
MV/LV subs.	161	97.91
HV/MV subs	1	120

All the types of electrical lines defined in section 4.2.2.6 are used in the semi-urban area, including overhead-pole, overhead-façade and underground.

Low voltage network

Voltage (kV)	Type ID	Length (km)
0.4	LV_IO_1	7.43
0.4	LV_IO_2	1.217
0.4	LV_UO_1	32.25
0.4	LV_UO_2	26.314
0.4	LV_UU_1	43.128
0.4	LV_UU_2	4.623

The rated power of MV/LV transformers in the semi-urban area covers a wider spectrum than in the urban area, in which sizes where higher.

Medium to low voltage transformers

Voltage (kV)	Rated Power (kVA)	No.
20/0.4	1000	38
20/0.4	630	57
20/0.4	400	54
20/0.4	250	8
20/0.4	100	4

Types MV_O_1/2 refer to overhead, while types MV_U_1/2 refer to underground.

Medium voltage network

Voltage (kV)	Type ID	Length (km)
20	MV_O_1	12.033
20	MV_O_2	1.204
20	MV_U_1	36.296
20	MV_U_2	0.859

Figure 4-9 shows the ten MV feeders. The HV/MV substation is represented by a triangle. Each feeder is painted with a different color. Black lines represent loops in the MV network.

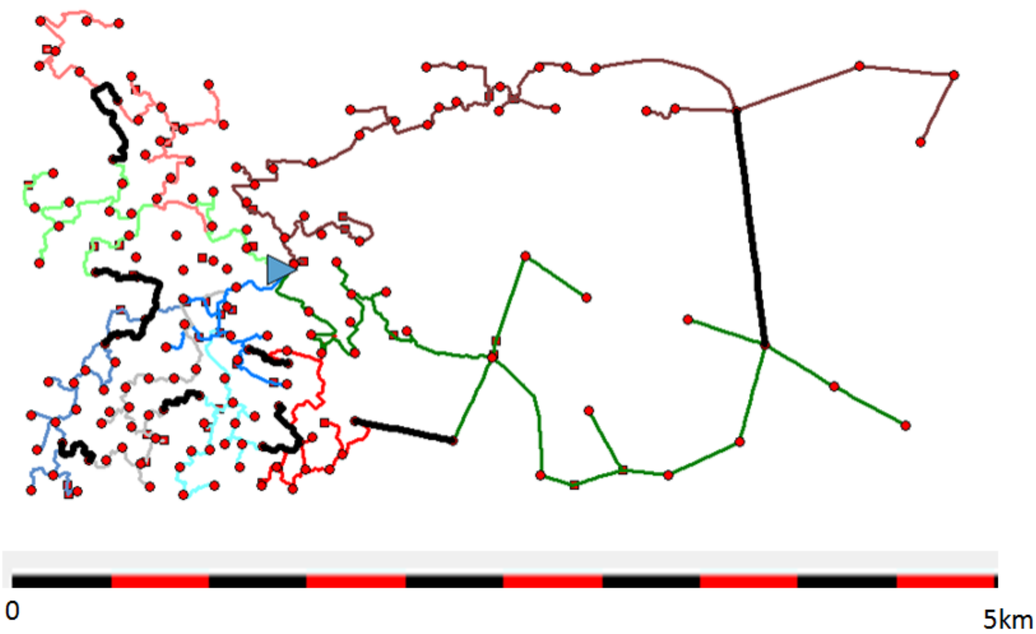

Figure 4-9 Semi-urban MV feeders

The following table shows information broken down per MV feeder.

	LV network [km]	MV network [km]	MV/LV Substations
MV Feeder #1	11.58	4.35	16
MV Feeder #2	12.39	4.94	16
MV Feeder #3	10.17	3.43	16
MV Feeder #4	11.81	4.49	16
MV Feeder #5	9.33	3.31	15
MV Feeder #6	9.51	2.50	10
MV Feeder #7	9.59	3.95	12
MV Feeder #8	19.94	8.59	30
MV Feeder #9	14.19	8.18	21
MV Feeder #10	6.45	1.97	9
Loops	0.00	4.67	0

High to medium voltage substations

Voltage (kV)	Rated Power (MVA)	Number
132/20	120	1

4.2.1.3 Rural (#3)

Figure 4-10 shows the rural large-scale network, including MV feeders (blue lines), LV feeders (black thin lines), as well as MV/LV substations (red circles) and a HV/MV substation (blue triangle). It represents a distribution network supplying electricity to several small settlements and farms in the countryside.

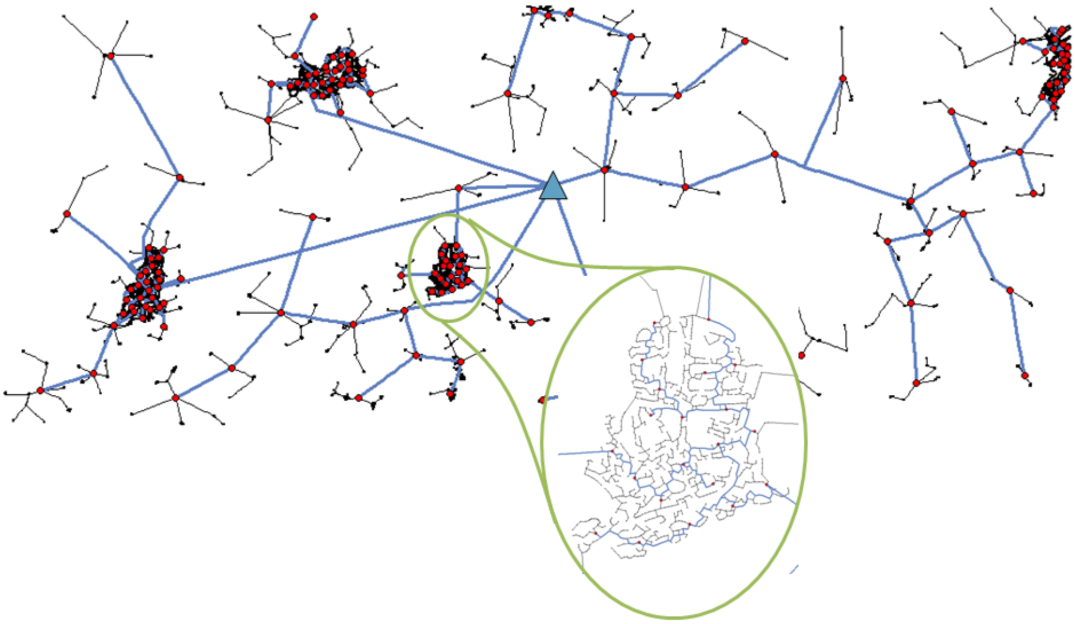

Figure 4-10 Rural network

As opposed to the previous distribution networks, in the rural network most of the electrical lines are overhead, both in MV and LV.

Aggregated inputs

	No.	Peak Power (MW)
LV Consumers	7727	25.28
MV Consumers	20	3

	Overhead	Underground
LV km	201.97	9.49
MV km	111.24	19.88

	No.	Capacity (MVA)
MV/LV subs.	152	40.25
HV/MV subs	1	80

As in the semi-urban network, all the types of LV electrical lines are used in the rural network, being LV_IO_1/2 (overhead-pole) the most common one.

Low voltage network

Voltage (kV)	Type ID	Length (km)
0.4	LV_IO_1	96.994
0.4	LV_IO_2	25.732
0.4	LV_UO_1	66.871
0.4	LV_UO_2	12.476
0.4	LV_UU_1	9.384
0.4	LV_UU_2	0.124

Only small size transformers (up to 400kVA) are used in the rural area.

Medium to low voltage transformers

Voltage (kV)	Rated Power (kVA)	Number
20/0.4	400	42
20/0.4	250	79
20/0.4	100	29

Most MV electrical lines are overhead, being type MV_O_1 the most common one.

Medium voltage network

Voltage (kV)	Type ID	Length (km)
20	MV_O_1	107.608
20	MV_O_2	3.624
20	MV_U_1	19.885

Figure 4-11 shows the six MV feeders. The HV/MV substation is represented by a triangle. Each feeder is painted with a different color. Black lines represent loops, normally open, for increasing reliability of supply in the MV network.

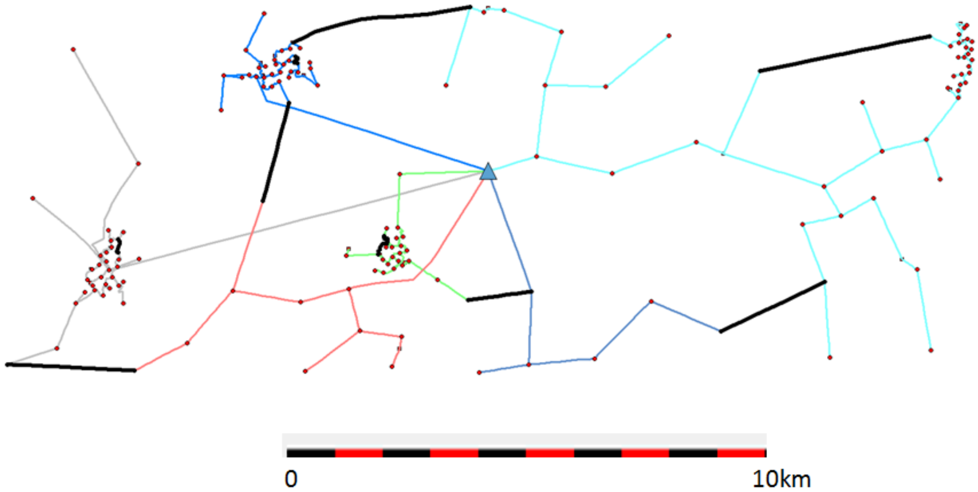

Figure 4-11 Rural MV feeders

The following table shows information broken down per MV feeder.

	LV Network [km]	MV Network [km]	MV/LV Substations
MV Feeder #1	11.54	9.95	6
MV Feeder #2	21.61	15.21	10
MV Feeder #3	43.94	24.93	33
MV Feeder #4	26.26	10.00	25
MV Feeder #5	67.51	38.09	47
MV Feeder #6	40.73	14.95	31
Loops	0.00	17.99	0

High to medium voltage substations

Voltage (kV)	Rated Power (MVA)	Number
132/20	80	1

4.2.2 Feeder-type network topologies

These topologies include two sub-categories: MV feeders and LV feeders.

The MV feeder networks (#4-11) have been built to be able to analyze the impact on the continuity of supply (i.e. duration and frequency of supply interruptions) depending on the network configuration and on the degree of automation of the distribution network. Therefore, for each network, two versions are being provided, one network with a low degree of automation and another one with a high degree of automation. Under a low degree of automation all the protection equipment (switches, breakers, etc.) are manually operated. Under a high degree of automation, some of the switches and breakers are remotely controlled. Typically, the tele-controlled protection equipment is regularly spaced along the MV feeders to maximize reliability improvements.

Also the MV urban and semi-urban topologies have been built taking into account the European DSO indicators. The main parameters required for this task have been: the feeder lengths, the number of MV/LV substations per HV/MV substation and the MV/LV transformer substation capacity. These indicators were broken down in urban and rural. Unfortunately only a fraction of DSOs provided this information, so that these models have been built using the available information.

The MV/LV transformer capacity is used to determine the transformation capacity of each MV/LV transformer substation. As it is shown in Figure 4-12 and Figure 4-13, the typical transformation capacity[8] is higher in urban networks than in rural network.

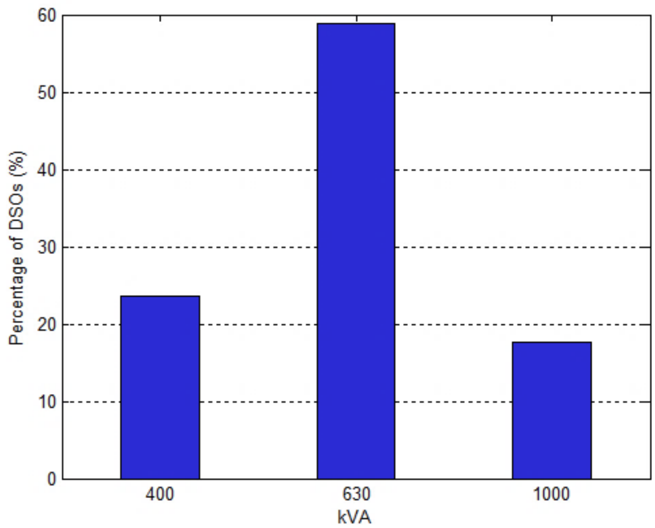

Figure 4-12 Typical transformation capacity of the MV/LV secondary substations in urban areas

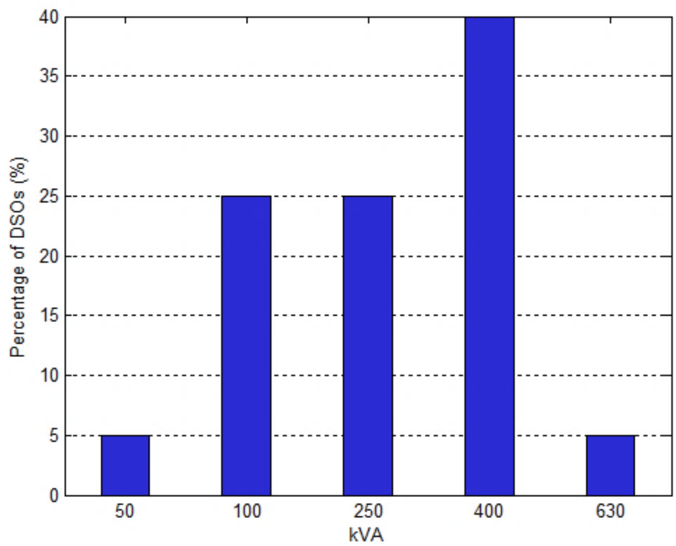

Figure 4-13 Typical transformation capacity of the MV/LV secondary substations in rural areas

[8] To improve the readability of the document we decided to report here the two figures already presented in section 3.2.1.

The average number of MV/LV substations per feeder is used to determine how many MV/LV substations are connected at each feeder. As it is shown in Figure 4-14 and Figure 4-15, the number of MV/LV substations per feeder is higher in rural areas than in urban areas.

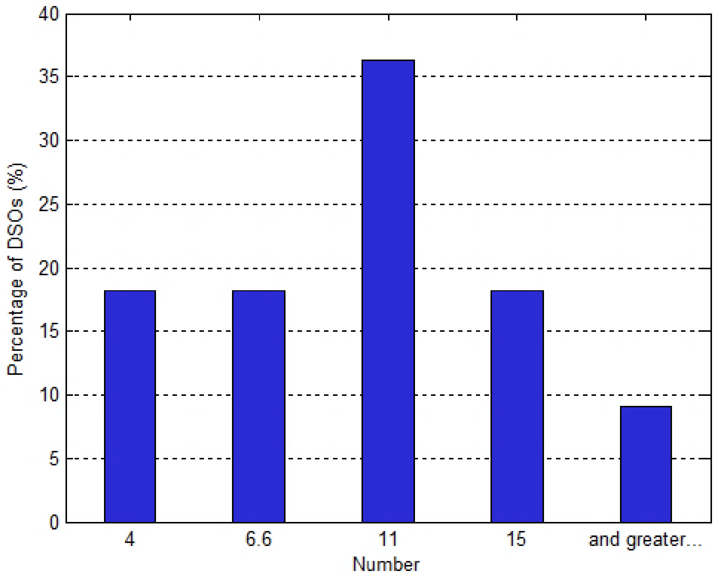

Figure 4-14 Average number of MV/LV substations per feeder in urban areas

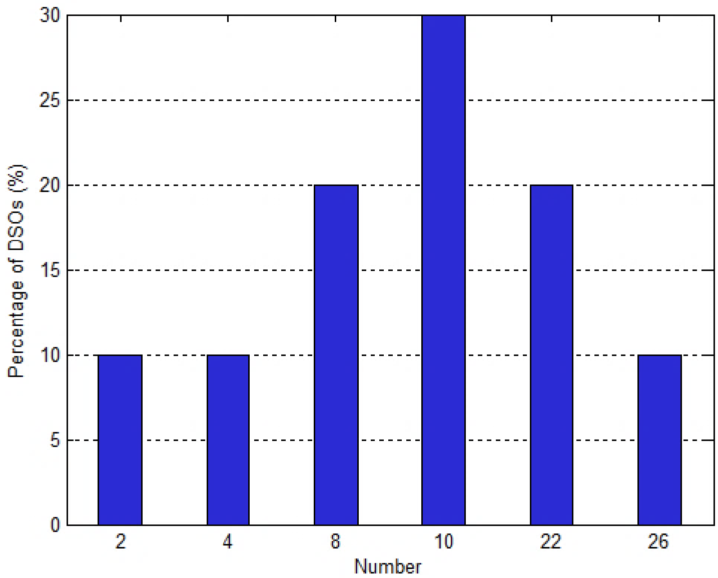

Figure 4-15 Average number of MV/LV substations per feeder in rural areas

The MV feeder length is used to determine the total length of the feeders in the representative network, which indirectly results in a distance between MV/LV substations. As it is shown in Figure 4-16 and Figure 4-17, the typical MV feeder length is higher in rural areas than in urban areas.

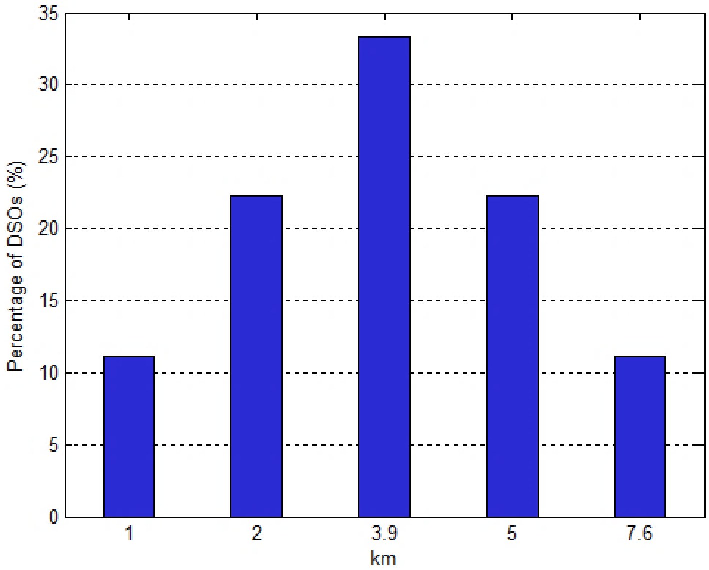

Figure 4-16 Average length per MV feeder in urban areas

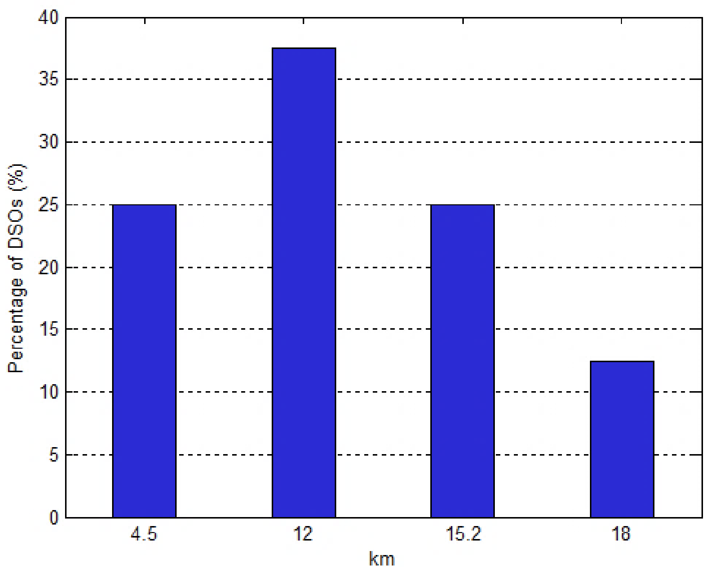

Figure 4-17 Average length per MV feeder in rural areas

4.2.2.1 Urban MV network: two substations interconnected (#4 & #5)

This network represents two HV/MV substations with feeder support connecting each other. This configuration is representing MV feeders in an urban MV network.

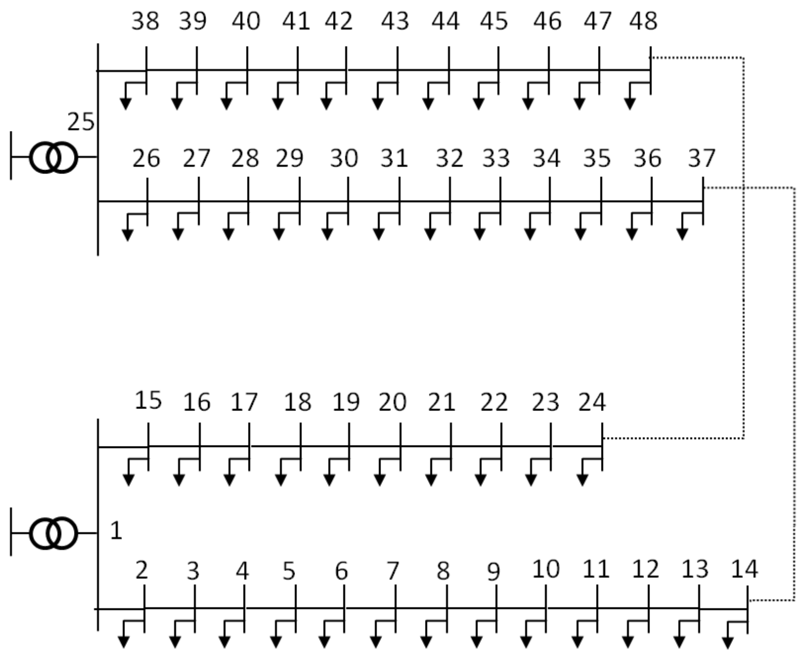

Figure 4-18 Two substation urban network

The representative MV network comprises two substations connected to buses 1 and 25, respectively. Two feeders per substation were modeled, with 10, 11, 12 and 13 MV/LV substations each. Two normally open loop branches (24-48, 14-37) connect the end of the feeders, respectively. Therefore, in case of failure of any feeder branch, one substation can supply part of the loads of the other substation. This configuration would also cope with HV/MV transformer failures as every feeder can be supplied through two alternative HV/MV substation transformers.

The feeder length and the number of MV/LV substations, as well as the distribution function of the transformer capacity has been selected based on the European DSO indicators.

	Feeder length [km]	MV/LV Substations
MV Feeder #1	4.2	13
MV Feeder #2	4.0	10
MV Feeder #3	4.5	12
MV Feeder #4	4.5	11
Loop branches	0.6	0

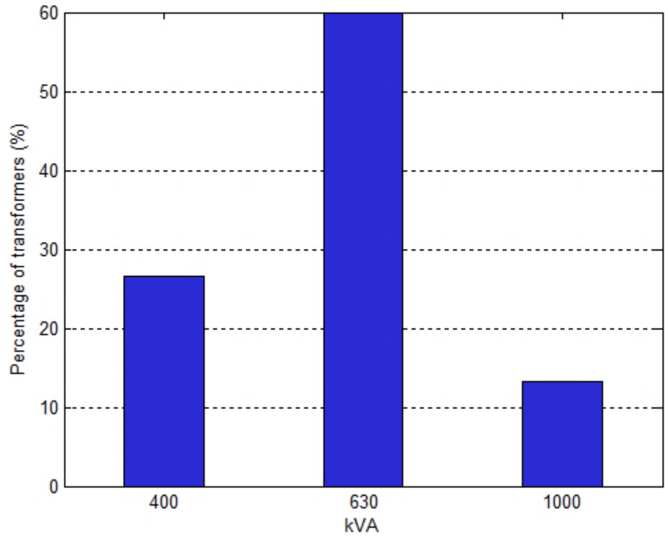

Figure 4-19 MV/LV Transformer capacity

In the buses modeling the MV/LV transformers, it has been assumed a load of 75% of the capacity of the transformer, with a 0.95 power factor. A power flow has been run with these parameters, and the operational constraints have been verified.

4.2.2.2 Urban MV network: one substation and one switching station (#6 & #7)

This network represents three MV feeders of a HV/MV substation. The ends of the MV feeders are connected to a switching station. This configuration is also representative of urban MV networks.

The HV/MV substation is connected to bus 1. There are three feeders with 10, 11 and 12 MV/LV substations each. The ends of the feeders are connected to a switching station in bus 35, through normally open branches (34-35, 23-35, 13-35). There is a support feeder connected to the switching station (1-35), to provide an alternative way to supply electricity in the case of any feeder branch failure. This support feeder has been represented as normally closed (instead of normally open), so that bus 35 is not isolated from the rest of the other buses and the power flow can be executed[9].

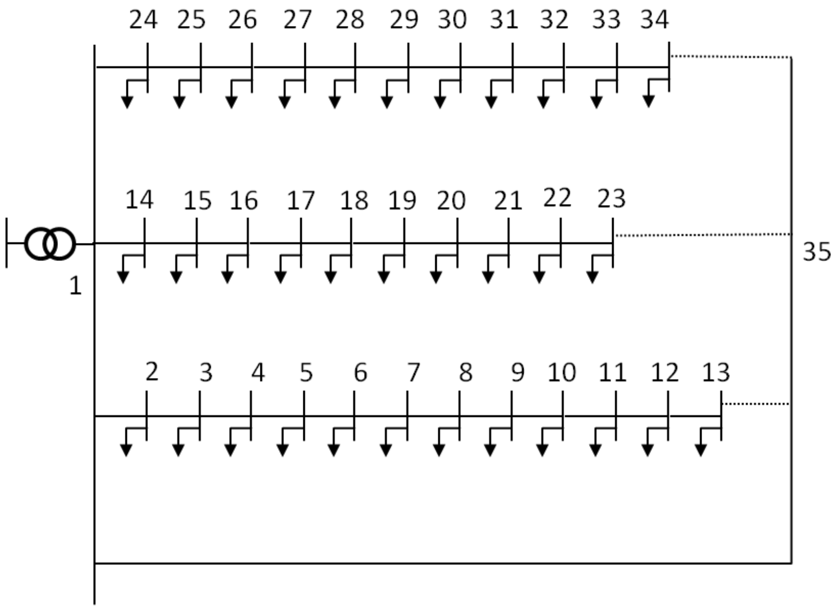

Figure 4-20 Urban switching station

In this case, the reference indicators are 3.9 km feeder length, 11 MV/LV substations per feeder, and 400kVA, 630kVA and 1000kVA as the MV/LV transformation capacity, being 630kVA the most common one.

	Feeder length [km]	MV/LV Substations
MV Feeder #1	4.01	12
MV Feeder #2	3.69	10
MV Feeder #3	4.21	11
Support feeder	0.42	0
Loop branches	0.83	0

[9] Otherwise bus 35 would be isolated and its voltage would not be defined.

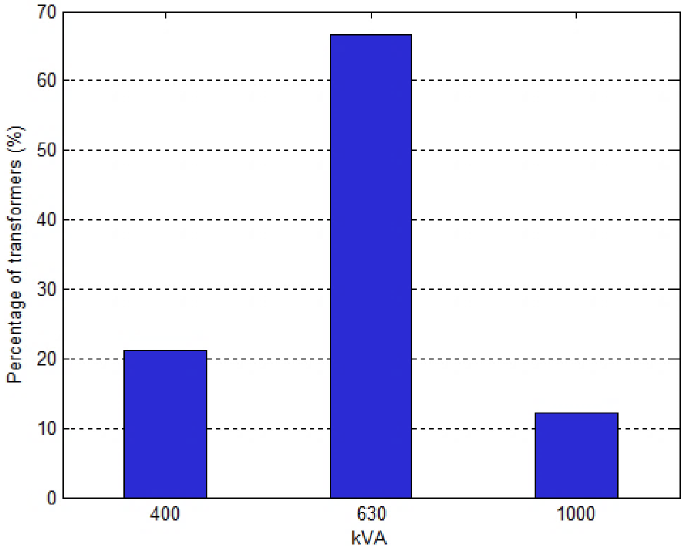

Figure 4-21 MV/LV Transformer capacity

In the buses modeling the MV/LV transformers, it has been assumed a load of 75% of the capacity of the transformer, with a 0.95 power factor. A power flow has been run with these parameters, and the convergence of the power flow has been tested, checking voltage and thermal limits.

4.2.2.3 Semi-urban MV network: substation ring (#8 & #9)

This network represents a substation ring with two feeders of a HV/MV substation connected by a loop. It is modeling a semi-urban MV network.

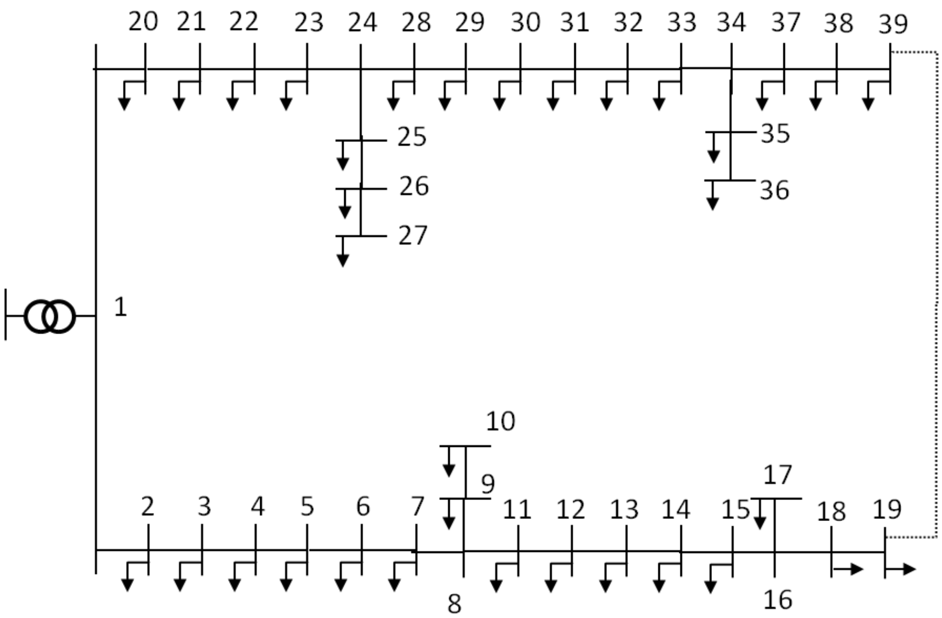

Figure 4-22 Semi-urban substation ring

The transformer of the HV/MV substation is connected to bus 1. There are two main feeders with 16 and 18 MV/LV substations each. A few secondary feeders are radially connected to the main feeders. The two ends of the feeders are connected by a normally open loop branch (19-39), which allows recovering part of the load in the case of any feeder branch failure.

The feeder length and the number of MV/LV substations per feeder have been increased compared to the urban networks, to take into account that according to the European DSO indicators, both indicators increase in rural networks. The values are an intermediate point between the values of the urban and rural indicators. The MV/LV transformer capacity is also reduced compared to the ones in the urban networks, but not as much as in rural networks.

	Feeder length [km]	**MV/LV Substations**
MV Feeder #1	6.08	16
MV Feeder #2	7.87	18
Loop branch	0.10	0

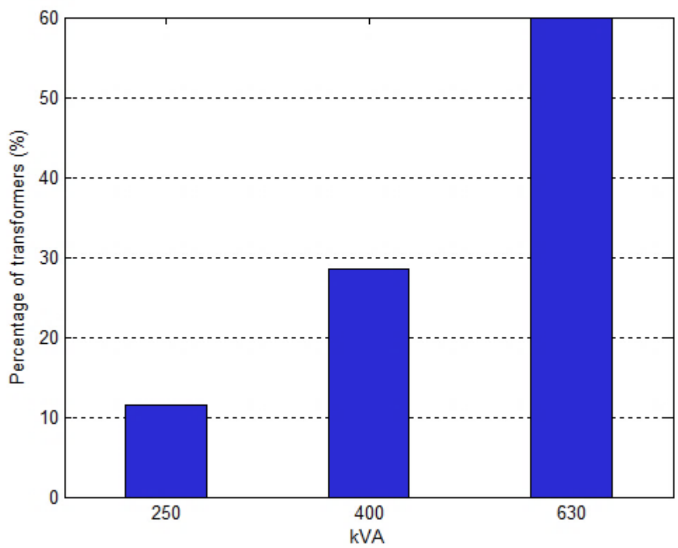

Figure 4-23 MV/LV Transformer capacity

In the buses modeling the MV/LV transformers, it has been assumed a load of 75% of the capacity of the transformer, with a 0.95 power factor. A power flow has been run with these parameters, and the convergence of the power flow has been tested, checking voltage and thermal limits.

4.2.2.4 Rural medium voltage network (#10 & #11)

This representative rural MV network represents a HV/MV substation with several radial feeders, some of them connected by loop branches (black lines).

This network has been built using the Reference Network Model, first modeling both the LV & MV consumers and feeders, and then extracting only the MV network. Nearby consumption points are modeling small settlements and isolated consumptions are representing farms.

The HV/MV substation is represented by a triangle. Each feeder is painted with a different color. The black lines represent loop branches normally open connecting different MV feeders.

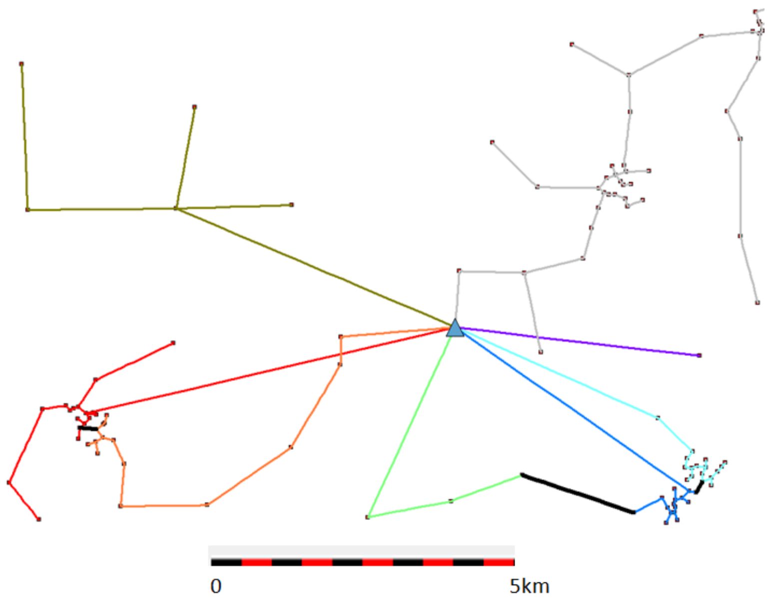

Figure 4-24 Rural MV network

The following tables and figures show the network indicators.

Network Indicator	Value
MV circuit length per MV Supply Point	0.705
MV underground ratio	0
Number of MV Supply Points per HV/MV substation	115

	Feeder length [km]	**MV/LV Substations**
MV Feeder #1	12.00	17
MV Feeder #2	9.31	15
MV Feeder #3	6.11	3
MV Feeder #4	6.84	15
MV Feeder #5	6.38	17
MV Feeder #6	4.07	1
MV Feeder #7	20.42	42
MV Feeder #8	13.48	5
Loop branches	2.42	0

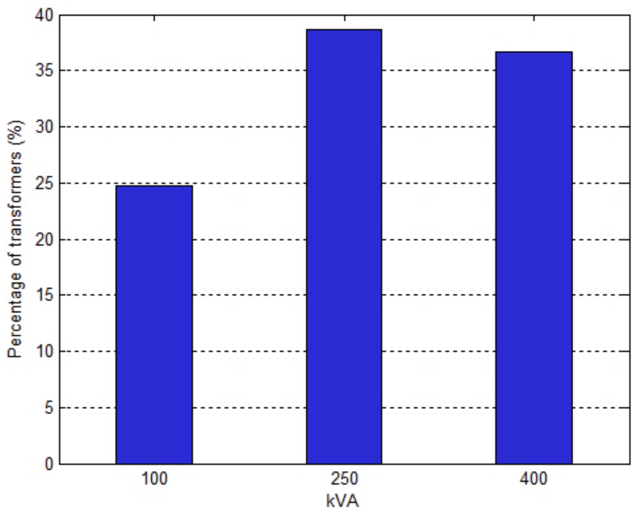

Figure 4-25 MV/LV Transformer capacity

The network comprises 118 buses. Therefore, only aggregated data of the rural medium voltage network is presented in this section.

Two protection equipment tables corresponding to a low and high degree of automation are available on the SESI webpage[10]. When the degree of automation is low (#10), all protection equipment are manually operated. When the degree of automation is high (#11), there are tele-controlled switches in buses 31, 42 and 55; as well as tele-controlled breakers at the beginning of the feeders.

[10] http://ses.jrc.ec.europa.eu/distribution-system-operators-observatory

Aggregated inputs

	No.	Peak Power (MW)
MV Supply Points	115	19.9

	Overhead	Underground
MV km	81.03	0

	No.	Capacity (MVA)
HV/MV subs	1	80

Medium voltage network

Voltage (kV)	Type ID	Length (km)
20	MV_O_1	81.03

High to medium voltage substations

Voltage (kV)	Rated Power (MVA)	No.
132/20	80	1

4.2.2.5 LV feeders

The representative LV feeder networks were built with the aim of analyzing the impacts of DG on single LV networks, such as the installation of photovoltaic distributed generation units. Network #12 models an urban LV grid while network #13 models a semi-urban LV grid. In the semi-urban area, distances are longer and there are more LV consumers per feeder.

4.2.2.5.1 Urban low voltage network (#12)

This network represents a MV/LV substation with LV feeders. This configuration is modeling a high density urban LV network. This network has been built using the Reference Network Model.

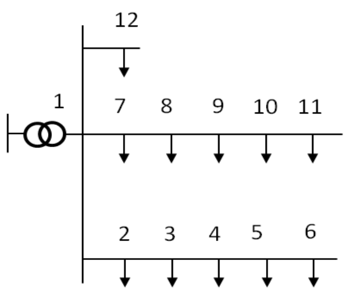

Figure 4-26 Urban LV network

The following table shows the network indicators.

Network indicator	Value
LV network length per LV Consumer	0.0024
LV underground ratio	1
Number of LV consumers per MV/LV substation	107
LV consumer peak power [kVA]	5.9

4.2.2.5.2 Semi-urban low voltage network (#13)

This network represents a MV/LV substation with LV feeders. This configuration is modeling a semi-urban LV network. It is based on representative feeder 2 in (Rigoni 2014).

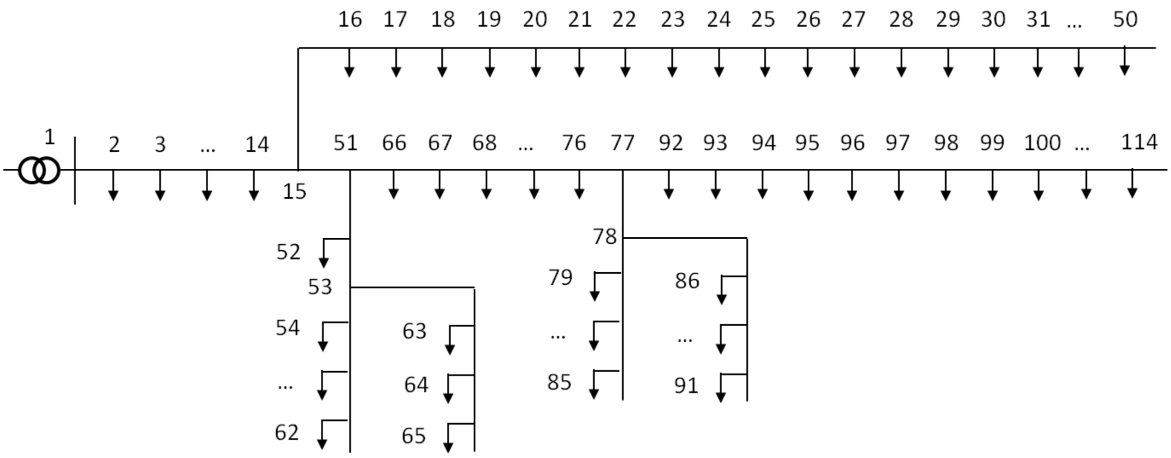

Figure 4-27 Semi-urban LV network

The following table shows the network indicators.

Network indicator	Value
LV circuit length per LV consumer	0.011
LV underground ratio	1
No. of LV consumers per MV/LV substation	108
LV consumer peak power [kVA]	3.70

This network is composed of 115 buses. The following tables show the aggregated data.

Aggregated inputs

	No.	Peak Power (MW)
LV Consumers	108	0.259

	Overhead	Underground
LV km	0	1.154

	No.	Capacity (MVA)
MV/LV subs.	1	0.400

Low voltage network

Voltage (kV)	Type ID	Length (km)
0.4	LV_UU_2	1.154

Medium to low voltage substations

Voltage (kV)	Rated Power (kVA)	Number
20/0.4	400	1

4.2.2.6 Standard equipment used to build the networks

A brief summary of the standard equipment used to build the representative networks is given in the following.

In particular, Table 4-4 shows the parameters of the LV feeders, Table 4-5 shows the characteristics of the MV/LV transformers, and Table 4-6 shows the parameters of the MV feeders. R and X are the resistance and reactance per phase of the power lines respectively in ohms/km. B is the susceptance in $ohms^{-1}$/km. Rsc and Xsc are the short-circuit resistance and reactance of the transformers in unitary units referred to the rated power and voltage of the respective transformer.

Voltage (kV)	Type ID	Name	Type	Rated current (A)	R (ohms/km)	X (ohms/km)
0.4	LV_IO_1	3x 50mm^2	Overhead - pole	150	0.65	0.1
0.4	LV_IO_2	3x 150mm^2	Overhead - pole	305	0.2	0.1
0.4	LV_UO_1	3x 25mm^2	Overhead - façade	100	1.4	0.1
0.4	LV_UO_2	3x 95mm^2	Overhead – façade	230	0.32	0.1
0.4	LV_UU_1	3x 95mm^2	Underground	255	0.39	0.075
0.4	LV_UU_2	3x 240mm^2	Underground	420	0.14	0.08

Table 4-4 Low voltage feeders

Voltage (kV)	Rated Power (kVA)	Rsc (p.u.)	Xsc (p.u.)
20/0.4	1000	0.012	0.04
20/0.4	630	0.012	0.04
20/0.4	400	0.012	0.04
20/0.4	250	0.012	0.04
20/0.4	100	0.012	0.04

Table 4-5 Medium to low voltage transformers

Voltage (kV)	Type ID	Name	Type	Rated current (A)	R (ohms /km)	X (ohms /km)	B (ohms[1] /km)
20	MV_O_1	LA80 (60-AL1/14-STIA)	Overhead	250	0.42	0.39	-
20	MV_O_2	LA180 (147-AL1/34-ST1A)	Overhead	425	0.18	0.36	-
20	MV_U_1	3x 120mm^2	Underground	300	0.21	0.11	7.57E-05
20	MV_U_2	3x 400mm^2	Underground	515	0.07	0.09	1.17E-04

Table 4-6 Medium voltage feeders

Table 4-7 shows the parameters of the high to medium voltage substations.

Voltage (kV)	Rated Power (MVA)	Rsc (p.u.)	Xsc (p.u.)
132/20	80	0.003	0.10

Table 4-7 High to medium voltage substations

The parameters of the equipment are part of the RNM catalogue (R. Cossent 2011), which is based on manufacturer data[11] [12] [13].

The reactance of the MV overhead power lines has been obtained with the formula (1).

$$X=2\pi f(0.5+4.605 \text{ Log } D/r)x10^{-4} \text{ ohms/km} \quad (1)$$

where: X: Reactance in ohms/km

[11] Nexans, 6-36Kv Medium Voltage Underground Power Cables.
[12] Ormazabal, Distribution Transformers up to 5MVA.
[13] Eaton, Power Distribution Systems

f: Frequency in Hertz = 50

D: Geometric average distance between line conductors in mm.

r: Conductor radius in mm.

5 Evaluation of policy options based on RNM

This section presents some simulation examples using the built representative networks to analyse the impact of DER penetration and network automation on the technical performance of these distribution networks. These analyses have been mainly done to present illustrative examples of the potential applications of the representative networks built in the DSOs Observatory project. 24 hour profiles were modelled or assumed for consumers and for the distributed generation connected to the networks. Power flows for each hour were computed as well.

In the analysis, the impact of two RES technologies was analyzed: solar and wind. In particular, the penetration levels expected in years 2020 and 2030 were considered. Figure 5-1 shows the expected solar penetration[14] in the EU Member States, according to the study prepared by the European Photovoltaic Industry Association (EPIA) (EPIA 2012). It is based on new EPIA scenarios for the penetration of PV electricity in 2030:

- the Baseline scenario envisages a business-as-usual case with 4% of EU electricity demand provided by PV in 2020 and 10% in 2030;

- the Accelerated scenario foresees PV meeting 8% of the demand in 2020 and 15% of the demand in 2030 and based on current market trends;

- the Paradigm Shift scenario is based on the assumption that all barriers are lifted and that specific boundary conditions are met, which foresees PV supplying up to 12% of EU electricity demand by 2020 and 25% in 2030.

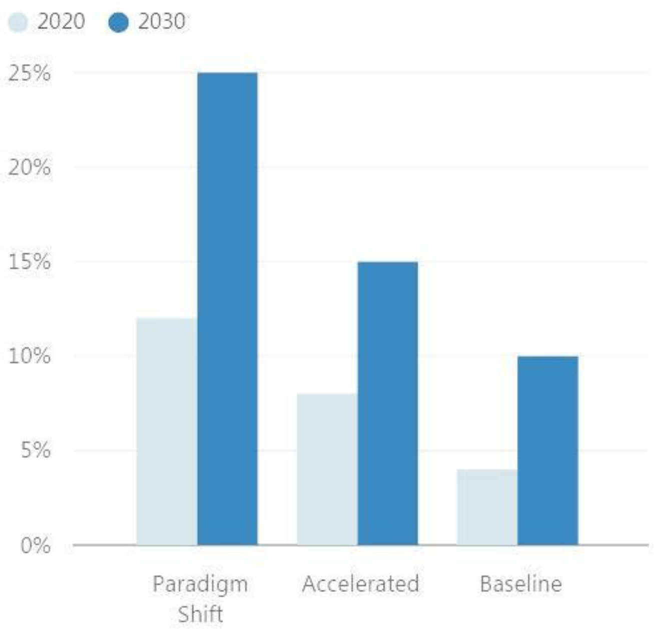

Figure 5-1 Expected solar PV penetration in 2020 and 2030 (EPIA)

[14] It is measured as the percentage of EU electricity energy demand provided by PV.

In our analysis, the penetration of solar generation is set according to the accelerated scenario. This scenario was selected because it is believed to represent a realistic view of market development in Europe until 2030 given the targets fixed in the 2030 framework. It roughly assumes that the same market conditions observed in 2011 will be maintained throughout the coming two decades. The amount of electricity that a PV installation generates clearly depends on the weather conditions. To this aim three types of days can be considered: rainy, cloudy and sunny. In order to model the most stressing situation for the network, the condition of peak generation, i.e. the sunny day, was selected.

In the case of wind generation, it is important to take into account that only a fraction of the energy is produced onshore, and not all of that is connected to the distribution networks. According to scenarios described in the literature (J. Wilkes 2014) (EWEA 2011), the expected wind penetration was set to 14.9% in 2020 and 28.5% in 2030, 80% of that onshore, and 57.4% connected to MV (which corresponds to 6.8% and 13.1% for 2020 and 2030 respectively). Regarding hourly profiles, there is much variability in the energy that can be produced by a wind turbine. The wind production of a particular installation[15] was selected in order to analyze a real wind hourly production (EnerNex 2011). Three types of profiles were identified corresponding to a minimum, middle and maximum production days. The maximum production day was selected in order to consider the condition of peak generation as the more stressing situation for the distribution network. Both the large-scale rural and urban representative networks were selected to carry out the impact analyses. In rural networks, due to the existence of longer distances, voltage problems are the most stringent operational constraints, while in urban networks, with shorter distances and higher density of consumers, congestions are the most frequent operational problem.

5.1 Selected scenarios

The main scenarios considered were a demand only scenario with no RES (Sc. 0 in the following), and two more scenarios, corresponding to the expected RES penetration[16] in years 2020 (Sc. 1 in the following) and 2030 (Sc. 2 in the following). As shown in Figure 5-2 an additional scenario (Sc. 3 in the following) has been considered, corresponding to twice the DG penetration in 2030 (2030 x2). The penetration levels in 2020 and 2030 are based on the literature, as previously described.

The PV panels were modeled as located on residential consumers, and each PV unit was placed in the same location of an existing consumer. When setting the annual energy production of a PV unit, an onsite PV size limit was considered. This onsite PV size limit was interpreted as a restriction on the size of the PV, based on the annual consumption of the consumer. In particular, in the rural network, it was modeled that the annual energy production of the PV units could be 50%, 100% and 200% of the respective consumed energy. For example 50% onsite PV size limit means that each PV unit is annually producing 50% of the consumer annual energy (only in the consumer premises

[15] Wind data was obtained from the National Renewable Energy Laboratory (NREL), which is operated by the Alliance for Sustainable Energy, LLC (ALLIANCE) for the U.S. Department of Energy (DOE).

[16] The penetration is measured as the percentage of EU electricity energy demand provided by PV and wind, respectively.

in which they are installed). On the other hand, in the urban network, the onsite PV size limit was extended to a finer range comprised between 60% and 200%.

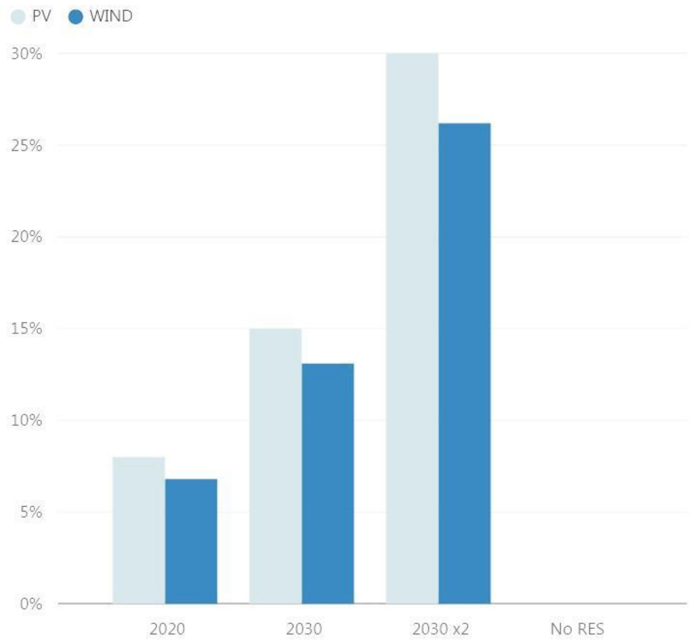

Figure 5-2 RES penetration scenarios

5.2 Results of the simulations

A power flow was run for each hour of the day. The 24 power flows were classified into three time tiers, 1) 10h-14h corresponding to peak PV generation hours, 2) 18h-20h corresponding to peak demand hours, and 3) the rest of the hours.

Residential consumers have much variability in their consumption, having usually short periods of peak demand and a lower demand during the rest of the time. Therefore, in the case of these customers, there is a significant difference in using the average consumption versus using real individual consumptions, and this can have a considerable impact on the power flow results. In order to capture the variability of LV residential consumers and to get more realistic results, the Load Profile Generator was used to generate the hourly profiles of residential consumers (Pflugradt 2013). A total of 72 profiles were obtained and they were assigned to individual consumers. Each of these profiles contains 24 values, one for each hour. A separated power flow was then run for each hour.

Commercial load profiles are based on (Jenkins 2014). Four commercial load profiles were considered in the analysis. In the case of the commercial consumers there is usually a stable consumption during working hours. Moreover, the total number of commercial consumers connected to the representative distribution networks is much smaller than the total number of residential consumers. Therefore, in this case, capturing the heterogeneity in the consumption is less important, and fewer profiles have been considered in the analysis.

5.2.1 Impact of solar PV on distribution networks

In each power flow, the reference voltage at the slack bus was set with the criteria of fixing the median of the bus voltages in the network to 1.0 p.u. Therefore, half of the buses had a voltage lower than 1.0 p.u. and half of the buses had a voltage higher than 1.0 p.u. In this way, voltages were controlled as close as possible to 1.0 p.u. in order to minimize voltage impacts.

Figure 5-3 shows the bus voltages in the network during the peak PV hours for the 100% onsite PV size limit (that is, each installed PV is producing all the energy that the consumer requires during the year) in the four scenarios. As shown in Figure 5-3, most of the bus voltages are in the range 0.95 - 1.05 in the first three scenarios (Sc. 0. Sc. 1 and Sc. 2) but present a significant higher voltage spread than Sc. 0, being the voltage spread slightly higher in Sc. 2 than in Sc. 1.

Finally, it can be observed that there are many more buses suffering under-voltages and over-voltages conditions in Sc. 3 when compared with the other scenarios. Despite the fact that the allowed operational voltage limits are ±10% of the nominal values according to standard EN 50160, the planning criteria followed by DSOs are usually more restrictive. For example, in (Long Island Power Authority 2010) voltage drops are limited to ±5%. These security margins are necessary because, due to the traditional passive operation paradigm, the voltage spread in operating conditions can increase significantly with respect to the considered planned conditions.

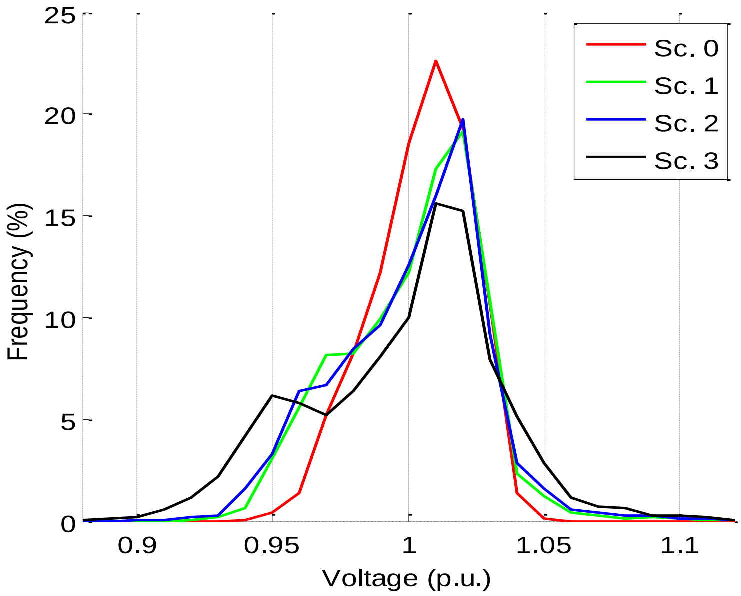

Figure 5-3 Bus voltages in the rural network for a 100% PV size limit (Peak PV hours)

Figure 5-4 shows the bus voltages during the peak demand hours. During these hours (18-20 h) the PV generation is almost negligible and then the bus voltages are very similar in all the scenarios, not being significantly influenced by the PV production.

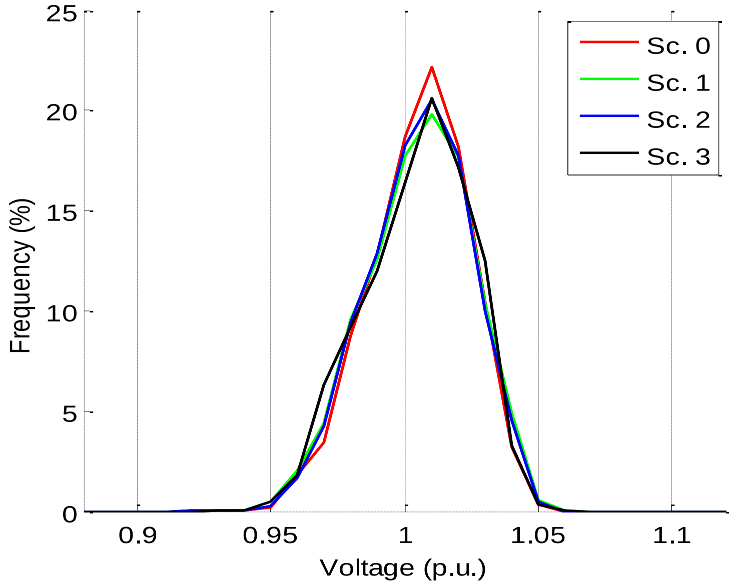

Figure 5-4 Bus voltages in the rural network for a 100% PV size limit (Peak demand hours)

Figure 5-5 shows the voltage spread in the rural network depending on the scenario and on the onsite PV size limit implemented. The voltage spread is measured as the difference between the maximum voltage and the minimum voltage across the network in per unit (p.u.). Only with a 50% onsite PV size limit voltage spreads are below the ±10% limit (0.2p.u.) in Sc. 1 and in Sc. 2. As the DG penetration increases, the voltage spread increases. The voltage spread depends strongly on the onsite PV size limit.

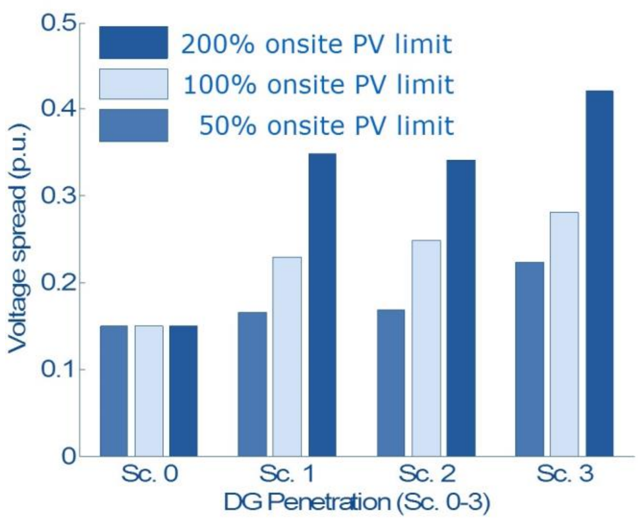

Figure 5-5 Voltage spread in the rural network

5.2.1.1 Economic impact assessment of RES penetration on network voltages

In order to monetize the impact of RES penetration on network voltages, we have used a penalty cost function. This penalty function is used mainly to quantify from an economic perspective the impact of voltage spreads on the considered network, as shown in Figure 5-6. It assumes a cost of zero when the bus voltage is within the range 0.95 - 1.05 p.u.; a 3€/kWh cost[17] for voltages outside de ±10% limit; and a quadratic function for the intervals 0.9 - 0.95 p.u. and 1.05 - 1.1 p.u. (a graphical representation is shown in Annex D: Cost functions). From the graph two main causes can be identified as responsible for increasing network costs due to voltage levels outside operational limits. One of these is the penetration of RES, which increases voltage costs as it can be observed by comparing the results obtained for the different scenarios. The size of the PV units would be a second cause of these costs, which could be limited by devising a more efficient onsite PV size limit strategy. This effect can be observed when comparing the different onsite PV size choices, within a given scenario. In some cases, the impact of the onsite PV size limit on voltage costs is even greater than the impact due to an increase in RES penetration. For instance, Sc. 1 with a 200% onsite PV size limit has a higher voltage cost than Sc. 2 with a 100% onsite PV size limit. This means that, in this particular case, the question is not only how much renewable generation is connected to the system, but also how this is distributed throughout the whole network.

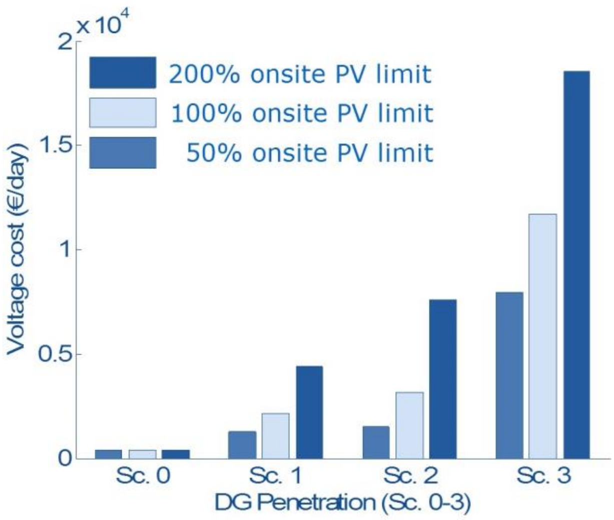

Figure 5-6 Voltage cost impact on the rural network

Figure 5-7 and Figure 5-8 shows through the colored dots where the voltage levels are outside the established limits in the rural network. Two snapshots corresponding to 14:00 p.m. in Sc. 0 and in Sc.1 have been selected. Nodes with voltages below 0.95 p.u. (undervoltages) are identifed by red circles, and with voltages above 1.05 p.u. (overvoltages) by blue circles. Figure 5-7 shows that in Sc. 0 only some nodes with undervoltages can be identified.

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[17] This cost is associated to the cost of the non-served energy due to a consumer supply interruption.

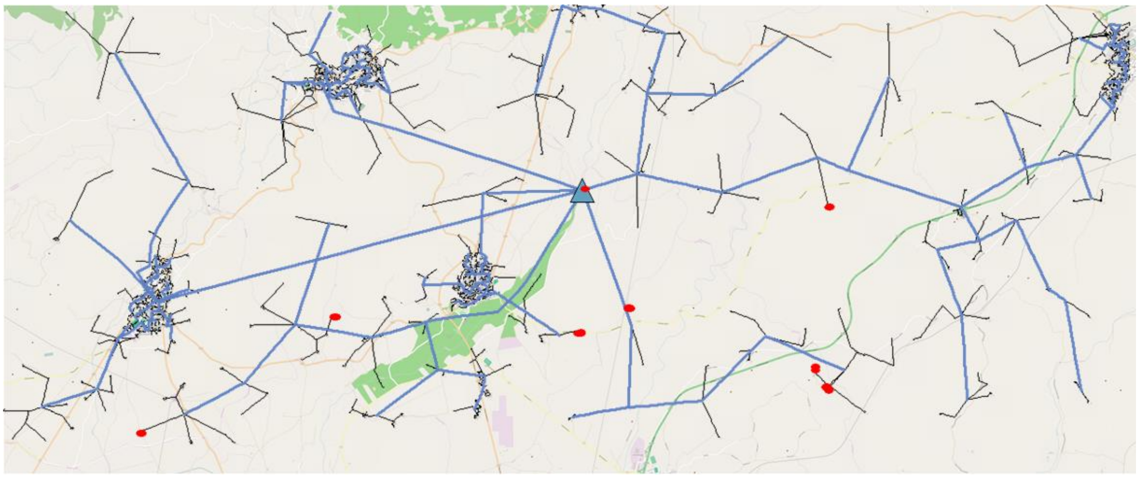

Figure 5-7 Voltage map of the rural network at 14:00 in Sc. 0

Figure 5-8 shows the voltage map in Sc. 2 with a 200% onsite PV size limit. In some buses in which there were low voltages in Sc. 0, such problems have spread to the nearby buses. In other cases, the local generation have raised voltages, eliminating the previous undervoltage problems.

Both undervoltages and overvoltages occur inside settlements and outside settlements. Even though PV generation was located randomly on the network, the undervoltages and overvoltages do not tipically appear in the same area. Instead, they are normally concentrated in some areas. For example, in this rural network there are two settlements with undervoltages, one settlement with overvoltages, and one settlement which simultaneously has undervoltages and overvoltages. In those cases some planning remedial actions can be proposed to improve the network performances. For instance, in the settlements which only have one type of problem, undervoltages or overvoltages, voltage regulators or transformers with on-load tap changers could be installed to alleviate those voltage problems.

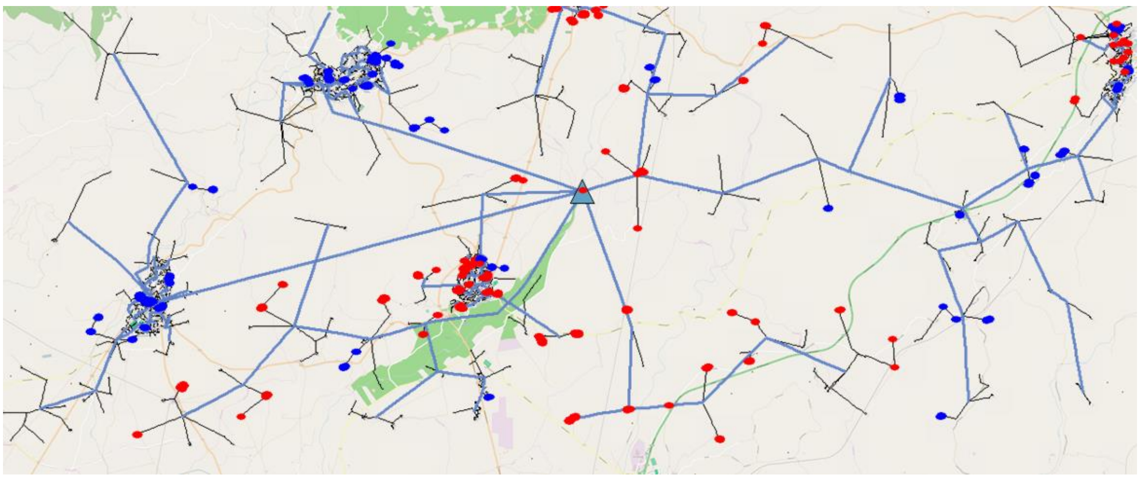

Figure 5-8 Voltage map of the rural network at 14:00 in Sc. 2, with a 200% onsite PV size limit

Figure 5-9 shows the aggregated load/generation profiles of consumers, PV, and wind in Sc. 2. The values are positive for consumption and negative for generation. The total net demand is near zero for the peak PV hours. In Sc. 3, with even higher DG penetration levels, the net demand becomes negative in peak PV hours, which implies the existence of reverse power flows in the HV/MV substation during those hours. Such conditions need to be avoided since they can cause high losses in the system and can have an impact on protection equipment.

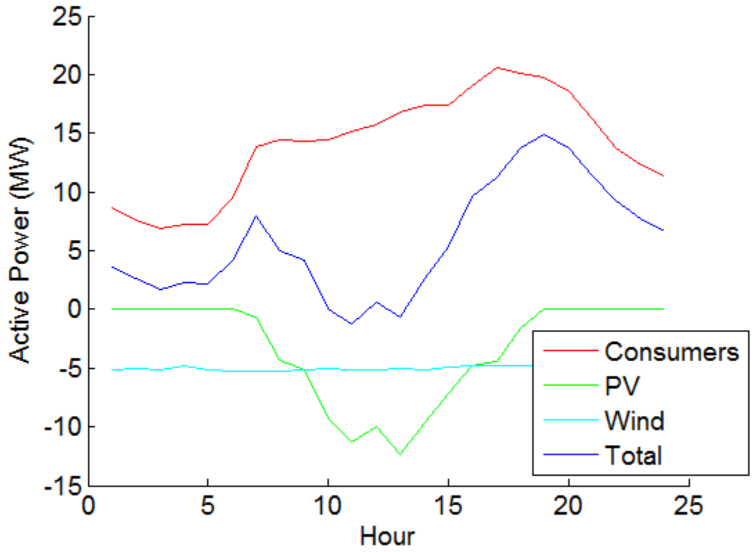

Figure 5-9 Aggregated profiles in year 2030

The aggregated profiles in Figure 5-9 are the same for each scenario independently of the size of the PV units (i.e. independently of the onsite PV size limit). This means that with a 50% onsite PV size limit, more PV units would have to be installed to reach the same total penetration level than with a 100% onsite PV size limit.

The percentages of consumers which have installed a PV in each scenario and onsite PV size limit are shown in Table 5-1. For instance, the 50% onsite PV size limit, for a global level of PV penetration of 8% (Sc. 1), means that 17% of total consumers install PV producing the 50% of their total electricity energy demand. The percentage of consumers in Sc. 1 and Sc. 2 installing PV for a 100% onsite PV size limit is 8.8% and 16%.

	SC. 0	SC. 1	SC. 2	SC. 3
50% onsite PV size limit	0.0%	17.0%	31.3%	57.6%
100% onsite PV size limit	0.0%	8.8%	16.1%	31.3%
200% onsite PV size limit	0.0%	4.4%	8.3%	16.1%

Table 5-1 Percentage of consumers installing PV for each scenario and onsite PV size limit

Thus, the expected penetration levels of 2020 and 2030 can be achieved with different onsite PV size limit choices. When deciding to implement a given onsite PV size limit choice one has to take into account that different choices can have different impact on the network and on the needed investments. Smaller PV units have less negative impact on the network performances but more consumers need to be encouraged to install PV to reach the same penetration level. Additionally, a higher number of active network users could require a bigger effort for DSOs in terms of management and operation efficiency. This has implications, for instance, regarding the obligations set on generators regarding observability and/or controllability which are frequently defined depending on the size of DG units. For example, if one sets an observability requirement for all units above 1MW, and assuming a total installed capacity of 10MW, it becomes relevant whether such capacity corresponds to 10 units of 1MW (thus observable) or 100 units of 0.1MW (which are not observable according to the hypothesized requirements). On the other side, big size (and less sparse) units create more problems to the network but a smaller amount of them is needed to reach the established penetration targets. As conclusion of this analysis, it can be observed that the assessment of RES penetration on network impacts cannot be derived only from the aggregated load/generation profiles, such as the one shown in Figure 5-9. As emphasized, the number of PV units and their concentration/distribution on the network, given by the percentage of consumers with PV units (in our case), is also a relevant parameter, which has been modeled through several onsite PV size policies. As already shown in Figure 5-6, the expected network impacts (in terms of costs) would highly depend on those onsite PV policies. Figure 5-10 shows the number of overloads[18] in the rural network in each scenario and for each onsite PV size limit. As it happened with bus voltages, the RES penetration and the onsite PV size limit are causes for congestions. In this particular case, there are no overload problems in any scenario with a 50% onsite PV size limit. Some overloads occur for a 100% onsite PV size limit, and the number of overloads increases significantly for a 200% onsite PV size limit in the three scenarios. Despite seeming unrealistic, the limit of 200% onsite PV size could be driven by generous net-metering policy with additional compensation for excess production or by community net-metering programs (which allow compensating the consumption of some customers with the excess production of their neighbours/associates).

[18] The number of overloads is calculated as the network branches in which the power flow exceeds the maximum allowed operational limit times the number of hours in which this condition happens.

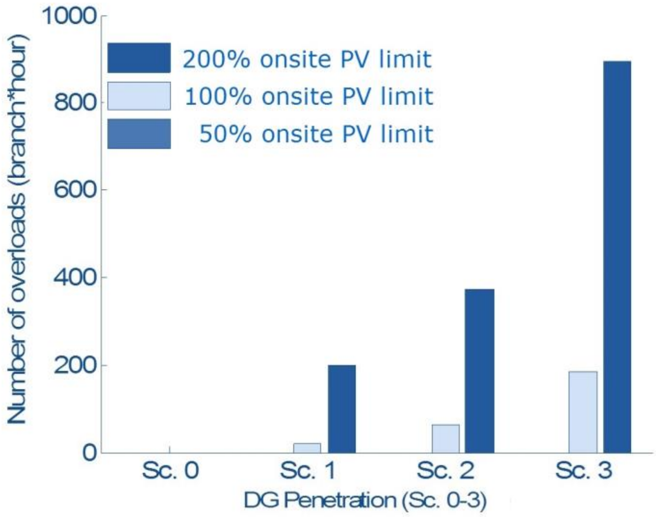

Figure 5-10 Number of overloads in the rural network

5.2.1.2 Economic impact assessment of RES penetration on network overloads

As previously done, the impact of RES penetration on network overloads have been monetized by means of a penalty cost function. The utilization factor can be defined as the power through the branch (conductor or transformer) divided by the branch capacity[19]. When the utilization factor of a network branch is below one the branch is not overloaded and the associated penalty cost is zero. For higher utilization factors the penalty cost increases linearly with a slope of 3€/kWh, which is related to the cost of the non-served energy in case of an interruption. Figure 5-11 shows the calculated network overload costs. Again, the onsite PV size limit is critical. Significant overloads only appear in the rural network for a 200% onsite PV size limit, meaning that overloads in the rural network only occur for high PV sizes.

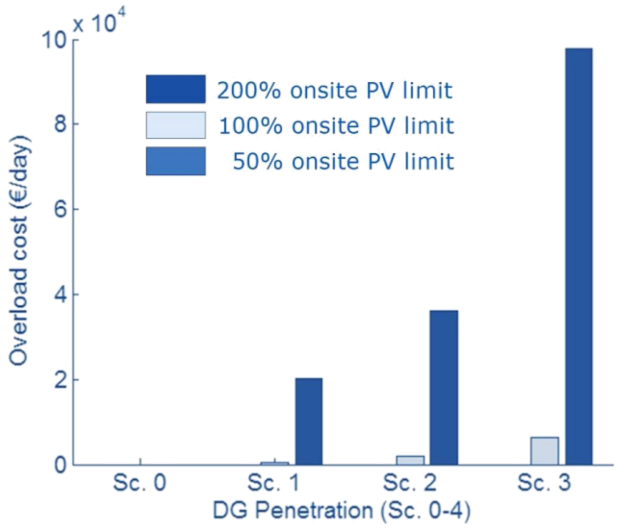

Figure 5-11 Network overload costs in the rural network

[19] Despite its name, some power lines require a higher capacity to deal with voltage problems, and therefore in that case a low utilization factor doesn't mean that the line is infra-utilized.

In order to analyse overloads, it was deemed relevant to perform a similar analysis on the urban network. Since this network shows a higher concentration of consumers, it is less prone to voltage problems than it is to overloads. The scenario analysed corresponds to Sc. 2, with an onsite PV size limit in the range of 60-200%. Figure 5-12 shows the number of overloads in the urban network depending on the onsite PV size limit. For a 60% limit there are no overloads. Starting at 80% onsite PV size limit, some overloads appear in the network. As the onsite PV size limit increases, that is per each consumer with installed PV a greater percentage of energy is produced, overloads increase exponentially.

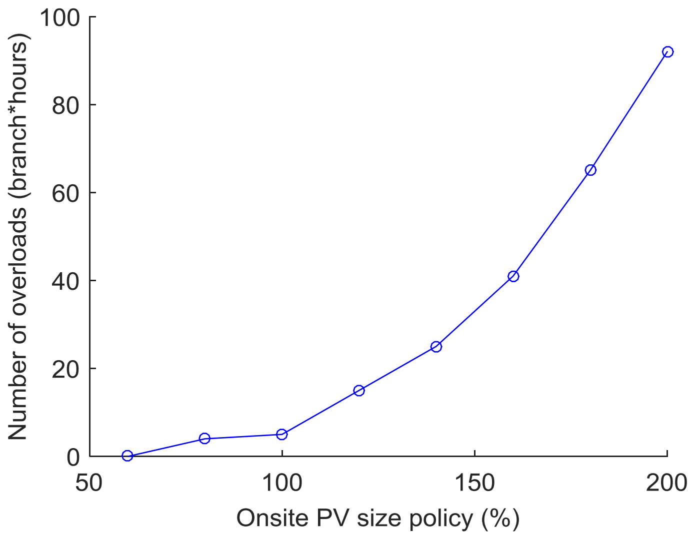

Figure 5-12 Number of overloads (branch*hour)

By comparing this result with the ones in the previous section it can be concluded that voltage problems occur in the rural network even for very low onsite PV size imposed limits. On the contrary, overloads only appear in urban networks when the size of PV installations is much larger.

5.2.2 Storage units to mitigate voltage spreads in the network

Figure 5-13 shows the voltage spread in the rural network in Sc. 1 for a 100% onsite PV size limit, when storage is installed to mitigate the effect of distributed generation. The starting point, with no storage installed, is over the ±10% limit (0.2 p.u.). When storage is installed the voltage spread decreases. 28kWh storage units would be the limit to keep the voltage spread below 0.2p.u. Storage units were connected to buildings with a previous PV installation, instead of being designed for individual consumers. As it can be observed in Figure 5-13, even for 100kWh storage units, the voltage spread would be only slightly below the ±10% limit.

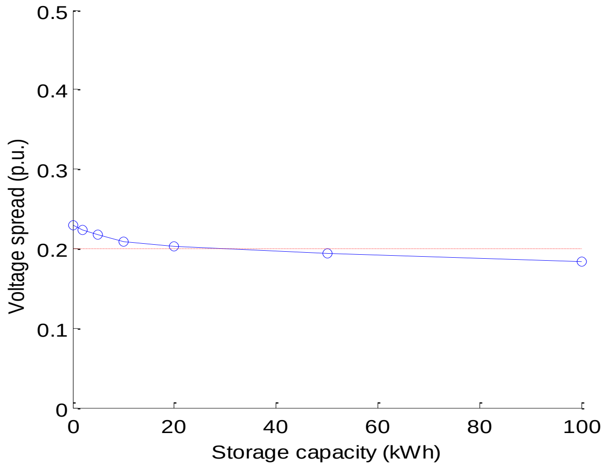

Figure 5-13 Voltage spread in Sc. 1 with increased storage unit capacity

This analysis highlights the advantages of increasing the allowed voltage spread, whenever it is technically feasible (i.e. if it does not harm or result in a wrong operation of the installed equipment and consumer devices). Especially in countries in which the voltage spread is currently more restrictive than the ±10% of EN 50160, the relaxation of this constraint could significantly facilitate the integration of more distributed generation.

Figure 5-14 shows how the network voltage and the overload costs decrease as storage capacity increases in storage units. In this graph the overload cost is low, as there are little congestions in this scenario (this can be checked in Figure 5-10 and Figure 5-11). Besides, it can be observed that the marginal benefit of storage decrease with the storage size.
Storage was modeled as only installed in PV premises, not in wind park sites. Therefore, even for 100kWh storage, there is a significant remaining voltage cost (in Sc. 0 the voltage cost was 370 €/day).

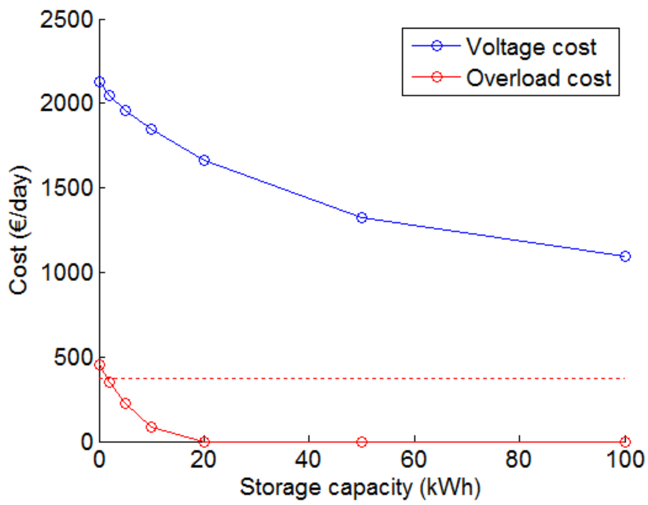

Figure 5-14 Voltage and overload cost in Sc. 1, for a 100% onsite PV size limit, with increased storage unit capacity

The high costs per kWh[20] for batteries suggest however that other solutions should be considered to mitigate voltage spread in the distribution network.

5.2.3 Reliability analysis

In the following, a reliability analysis is carried out (Rodriguez, et al. 2016) to calculate the reliability indexes in the selected representative networks. The model simulates a fault that leads to an outage for each of the electrical power lines of the network, and then models the operation of the switches and breakers to locate and isolate the fault and to restore the service.

The sequence of steps carried out for each fault consists of:

1. Determining affected loads
2. Applying smart grid solution
3. Sending maintenance crews
4. Manual switching
5. Visual inspection
6. Reparation

Through this approach, the customers' interruptions and the relative durations are calculated. By aggregating these numbers for all the possible faults, SAIDI[21] and SAIFI[22] indexes are gathered.

[20] At the moment there are different kind of technologies for storage and several estimates on their prices. Generally those solutions that are considered scalable are still far for being considered cheap (Luo 2015).
[21] SAIDI is the System Average Interruption Duration Index. It measures the duration of the interruptions.
[22] SAIFI is the System Average Interruption Frequency Index. It measures the frequency of the interruptions.

In brief, the time to restore service in a feeder is comprised for each load from some of all of the following elements:

$t = t_{operator} + n_{steps,j} * t_{operator,j} + t_1 + \Sigma_{steps,i} [t_{2,i}+t_{3,i}] + t_4 + t_5$,

where:

$t_{operator}$ (min) is a fixed term to account for the response time of the operator in the control centre

$n_{steps,j}$ is the number of switching actions performed by the operator in the control centre to isolate the faulty segment among two telecontrolled elements

$t_{operator,j}$ is a fixed term to account for the time required for each switching action performed by the operator in the control centre (min)

t_1 is a fixed term to account for the time required for fault detection and sending a maintenance crew (min)

t_2 is a fixed time for each step of the dichotomic search process (operation of the switches, getting into the car, etc) (min)

$t_{3,i}$ is a variable time proportional to distance to travel in step i, considering a certain speed s_3 (min)

t_4 is a variable time for fault localization along a segment, proportional to distance to cover, considering a certain speed s_4 (min)

t_5 is a fixed time to repair a fault in a branch of the feeder (min)

Figure 5-15 Parameters used in the simulations to obtain SAIDI and SAIFI

Three network configurations have been analyzed in terms of reliability. The network configurations correspond to three representative networks already presented in section 4.2.

They are:

1) Urban medium voltage network (section 4.2.2.1);
2) Semi-urban medium voltage network (section 4.2.2.3);
3) Rural medium voltage network (section 4.2.2.4).

Simulation step	Parameter s - speed; t - time	Value
Regulatory threshold to consider long-duration interruptions of supply	$t_{max,reg}$ (min)	3
Response of the control centre for Fault Detection, Isolation and Service Restoration (FDIR) with smart grid solution	$t_{operator}$ (min)	0.5
	$t_{operator,j}$ (min)	0.2
Response of maintenance crew	t_1 (min)	14
Operation of load break switches in underground networks with secondary substations connected in input-output	t_2 (min)	8
	s_3 (km/h)	37
Visual inspection of overhead lines	s_4 (km/h)	6
Fault reparation	t_5 (min)	120

Table 5-2 Parameters of the reliability simulations

Figure 5-16 shows SAIFI as the percentage of tele-controlled switches in the networks (referred to the total number of switches in the network) is increased. It is worth mentioning that when there are 0% tele-controlled switches, there are still some manual switches or breakers in the networks, so 0% tele-controlled switches is not equivalent to 0% automation. For each degree of automation and representative network, tele-controlled switches have been placed regularly spaced along the feeders.

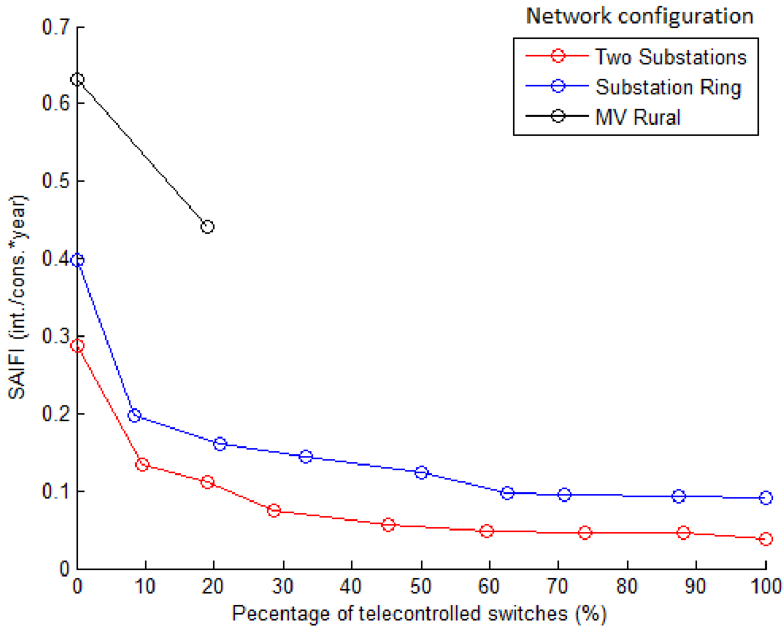

Figure 5-16 SAIFI as a function of the percentage of tele-controlled switches

As expected, the reliability of supply index corresponds to a higher improvement in the urban two substations configuration than in the other two configurations considered because of its topology. The worst result for the reliability of supply is obtained in the MV rural network.

To perform this analysis two versions of the networks have been built, one with a low degree of automation and one with a high degree of automation. The following table shows the percentage of tele-controlled switches considered for each of these networks.

Network configuration	**Low degree of automation**	**High degree of automation**
Two substations	0%	20%
Substation ring	0%	10%
MV Rural	0%	19%

Table 5-3 Percentage of tele-controlled switches in the networks

For a high degree of automation, the substation ring configuration has less tele-controlled switches than the two substation configuration, because the substation ring network refers to a semi-urban area.

However, in the MV rural network the percentage is high because it refers to the total number of switches in the network, which is usually very low, as there are few loops in that network, which makes the installation of a switch (manual or tele-controlled) less useful. In Figure 5-16 and Figure 5-17 the rural network has only two points because there are very few switches and loops in a rural network making meaningless considering higher degrees of automation.

Figure 5-17 shows the SAIDI in the selected representative networks. In all the networks SAIDI is below 60min. As with SAIFI, the lower degrees of automation achieve a significant reduction of the reliability indexes, but there is a saturation effect, meaning that the relative improvement of very high automation degrees is less significant. Such a result can be useful to perform cost-benefit analysis for network automation functionalities and technologies.

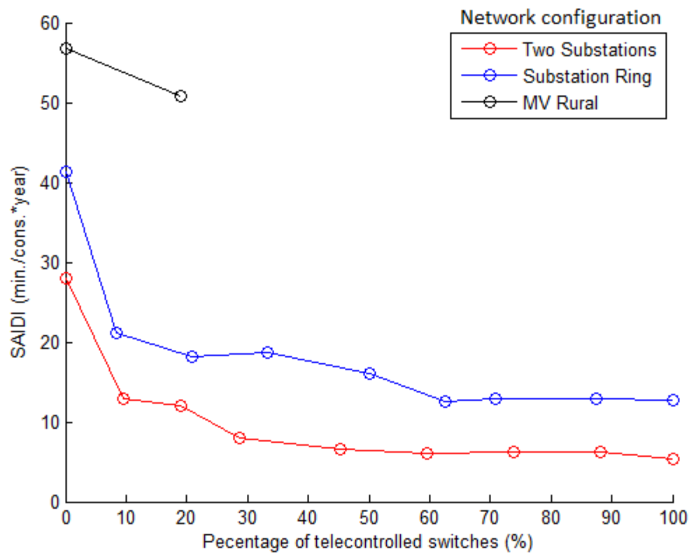

Figure 5-17 SAIDI as a function of the percentage of tele-controlled switches

6 Conclusions

This report presents the outcomes of the latest power distribution data gathering and assessment exercise carried out by the JRC. It aims to provide policy decision makers and other power system stakeholders with analyses and tools to better understand the energy transition challenges faced by electricity distribution system operators in Europe.

It is also intended to support research activities in this field by providing reliable input data and tools to carry out realistic simulations and comprehensive techno-economic studies on the emerging developments in the power distribution system.

The electricity grid represents indeed a critical asset for our society. Given the rapidly changing energy system, the scientific community needs to be able to rely on robust models and realistic data to contribute to answer the questions society and policy making are posing.

To the best of our knowledge, the report represents the most comprehensive data collection exercise on European distribution systems published so far. Given the vast number of Distribution System Operators active in Europe, the mapping effort was limited to the bigger distribution system operators, i.e. the 190 Distribution System Operators serving more than 100,000 customers and hence subjected to the unbundling requirements of the EU Electricity Directive. Of these Distribution System Operators, 79 responded to the JRC survey.

Based upon the collected data:

- 36 distribution system indicators were built, split in three categories: network structure, network design and distributed generation.
- A total of 13 different representative distribution networks with different voltage levels were built: 3 large scale geo-referenced networks (urban, semi-urban and rural) and 10 feeder-type networks with common topologies.

These indicators and models help to shed light on the different characteristics of some of the major European distribution networks. To get a sense of the potentialities of this approach, some applications were presented and discussed.

Two large-scale representative networks (rural and urban) were selected to analyse the impact of increasing levels of renewable energy sources penetration, photovoltaic panels and wind farms in particular, on the technical performance of the grid. The impact on network voltages and network overloads caused by these intermittent energy sources has been then monetised by means of a penalty cost function.

The analyses have shown that the number and size of photovoltaic units, as well as their connection/siting on the network are all relevant parameters which need to be carefully taken into account. In fact, preliminary results highlight how limiting the size of the generation units would mitigate voltage and congestion problems and maximise the renewable penetration/network investment ratio. The case studies suggest that smaller units spread throughout the network — compared to fewer bigger size (higher peak capacity) units connected to it — would mitigate operation problems and would allow deferring or avoiding future network reinforcements. A careful consideration of the local

conditions of each distribution area, as well as of the different connection patterns - including unit sizes, technologies and location within the network - is of paramount importance to minimise adverse impacts on system operation.

The installation of dispersed storage units combined with local photovoltaic plants represents another way to mitigate the voltage spread introduced by the increasing penetration of photovoltaics connected to the distribution network. However, the analysis carried out through the representative distribution networks indicates that a voltage spread reduction is only observed when big storage units are installed in combination with each installed photovoltaic unit. The relatively high cost of batteries suggests that other solutions should be considered to mitigate voltage spread in the distribution network (e.g. inverters).

Finally, a reliability analysis showed how the System Average Interruption Frequency Index might be improved (reduced) by increasing the installation of tele-controlled switches in the distribution network, that is, by increasing the level of automation of the considered distribution grid.

Representative distribution networks proved to be a valuable tool to simulate the impact of increasing shares of renewable energy sources on network voltages and network overloads. Representative distribution networks however, can also be useful in other types of analyses, e.g. scalability and replicability analyses, cost-benefit analyses, transmission and distribution systems inter-link and interdependencies analyses.

The JRC will continue to carry out its scientific and policy support activities in the power system fields to better understand and address the challenges DSOs face in the transition to a smarter energy system. In order to increase the knowledge base of the evolving electricity distribution sector, the results of these activities will be made publicly available[23].

This report can be then seen as the first step of a periodic mapping and modelling exercise, which the JRC aims to continue with the support of the relevant electricity system stakeholders, in order to help understanding the merits, challenges and options of the electricity system transition.

[23] More information on the project and the representative networks in Matlab/Matpower format will be available on: http://ses.jrc.ec.europa.eu/distribution-system-operators-observatory

Annex A: Indicator box plots

The following figures represent the box plot of the main used indicators as obtained from the DSOs Observatory database. Additionally the values used for the built representative distribution networks are shown. The circle represents the urban network, the star represents the semi-urban network and the diamond represents the rural network. The rest of the information refers to the values in the DSO Observatory database. In particular, the red line is the median, the blue box represents the interval comprised within the 0.25 and 0.75 percentiles, meaning that 50% of the DSOs have an indicator value which is contained in the box. The black lines represent the full range, including the minimum and the maximum values.

The ratio of the number of LV consumers per MV consumer has been set to the median for the three types of areas, given that there was not information broken down per type of area in the database.

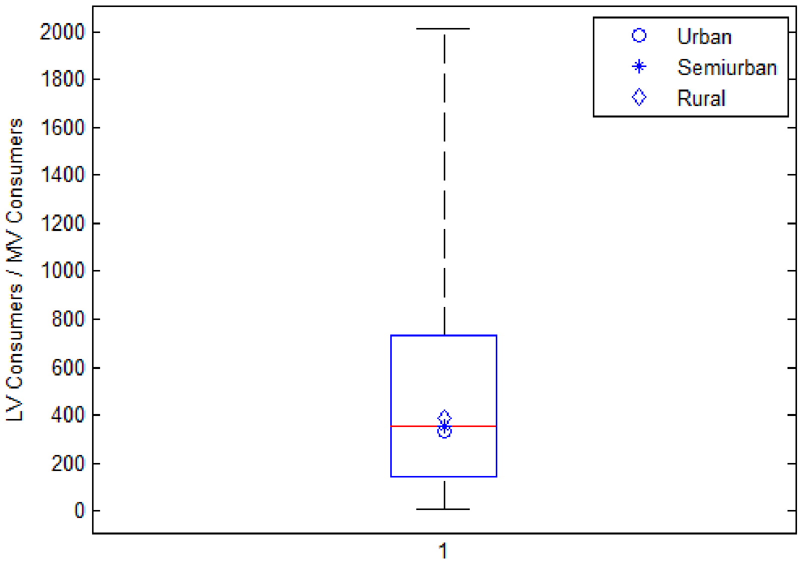

Figure A- 1 LV consumers per MV consumer

Finland is an example of rural networks. In Finland the average is 0.07 LV km / (LV Consumer), higher than the median. In the same way in the representative networks, the more rural the area is, the higher the value of LV km / (LV Consumers).

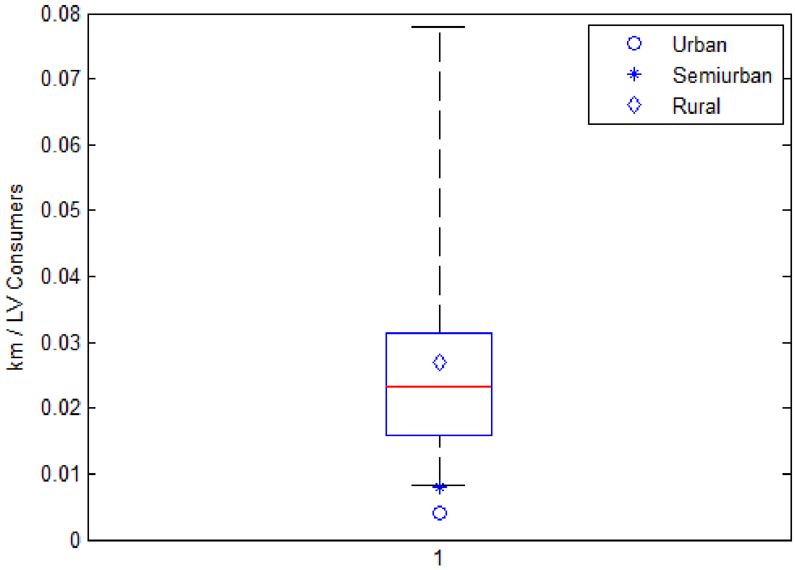

Figure A- 2 LV network length per LV consumer

In rural areas the LV underground ratio is lower than in semi-urban areas, and the LV underground ratio in semi-urban areas is lower than in urban areas.

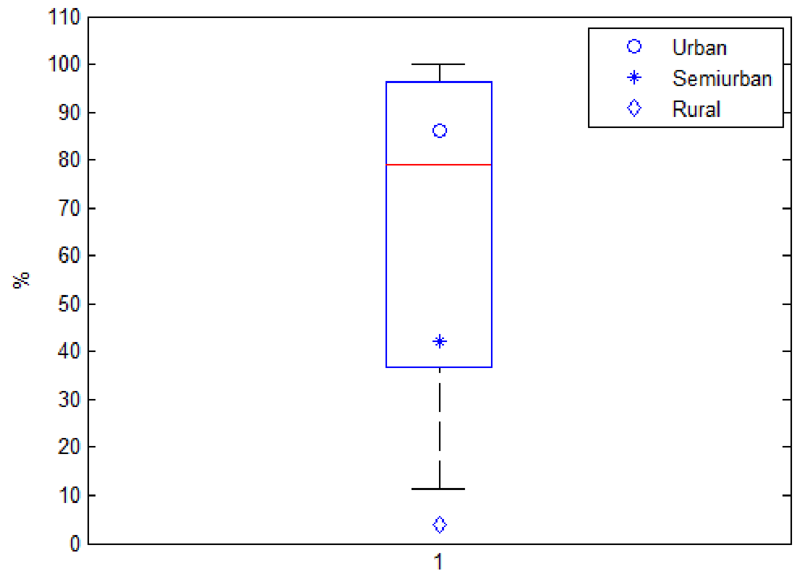

Figure A- 3 LV underground ratio (LV underground circuit length divided by total LV circuit length)

The number of LV consumers per MV/LV substation is higher in urban areas than in rural areas. This is due to the higher density in the urban areas and the higher dispersion in the rural areas. Typically in urban areas the constraint for connecting more consumers to the MV/LV substation is power capacity, while in rural areas the constraint is the number of nearby consumers.

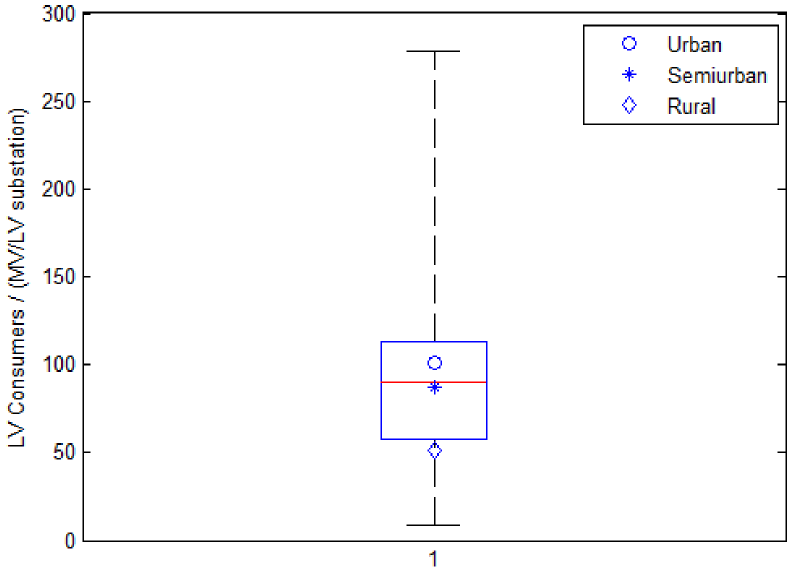

Figure A- 4 Number of LV consumers per MV/LV substation

The MV/LV transformer capacity per LV consumer is near the 0.75 percentile in the three types of areas.

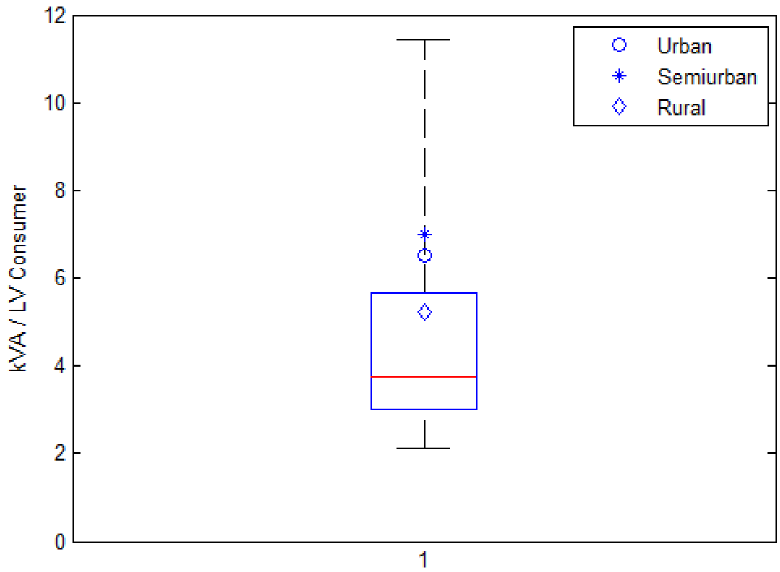

Figure A- 5 MV/LV transformer capacity per LV consumer

The MV circuit length per MV supply point is around 0.5 in The Netherlands, 0.65 in Belgium and 0.95 in Finland. In the same way the MV circuit length per MV supply point is higher in rural areas than in urban areas.

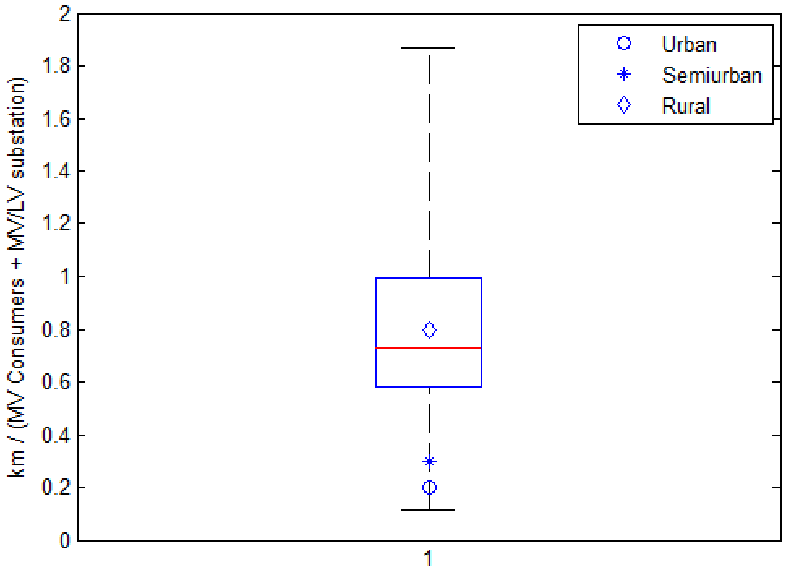

Figure A- 6 MV network length per MV supply points

Typically underground cables are more common inside settlements than outside settlements. Therefore, the MV underground ratio is lower in rural areas (which also include MV feeders connecting several settlements) than in semi-urban areas, and it is also lower in semi-urban areas than in urban areas. As the urban network represents the center of a city, we have modeled its MV network as fully underground.

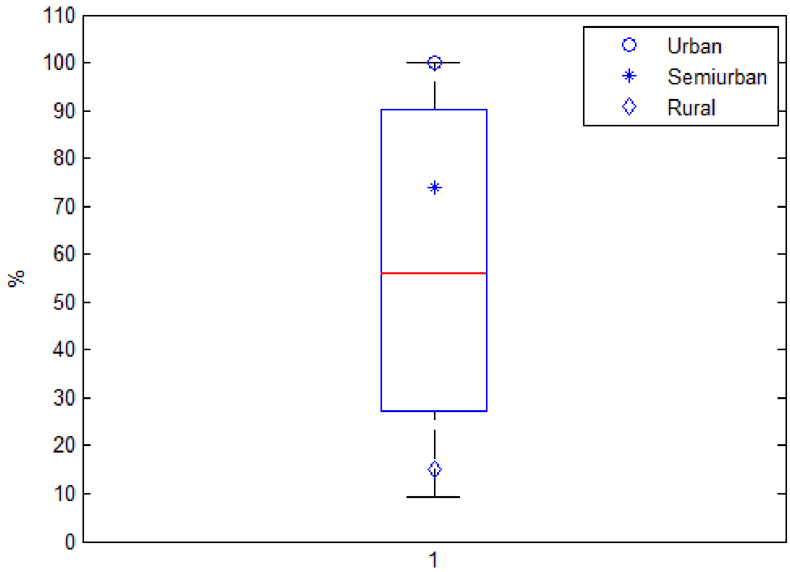

Figure A- 7 MV underground ratio (MV underground circuit length divided by total MV circuit length)

In the three types of areas, the number of MV supply points per HV/MV substation is near the median.

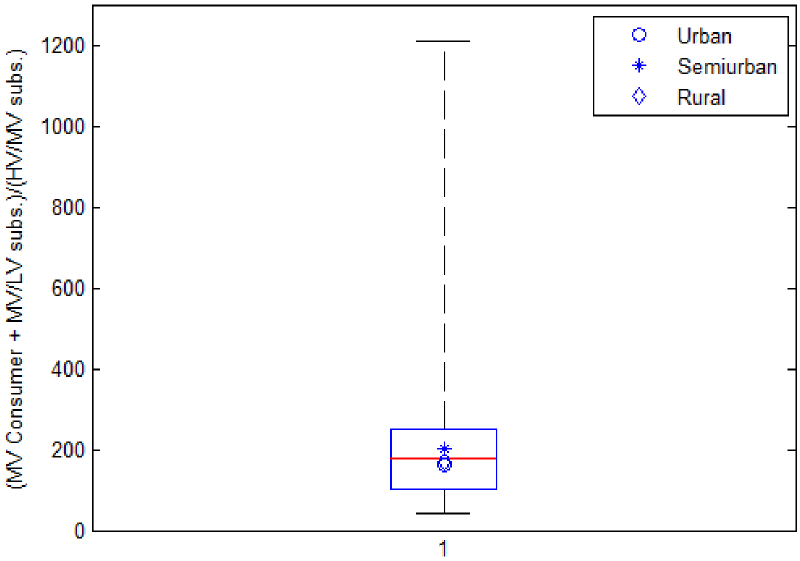

Figure A- 8 MV supply points per HV/MV substation.

Annex B: Other indicators

In this annex the remaining indicators not presented in the previous chapters are reported for the interested reader.

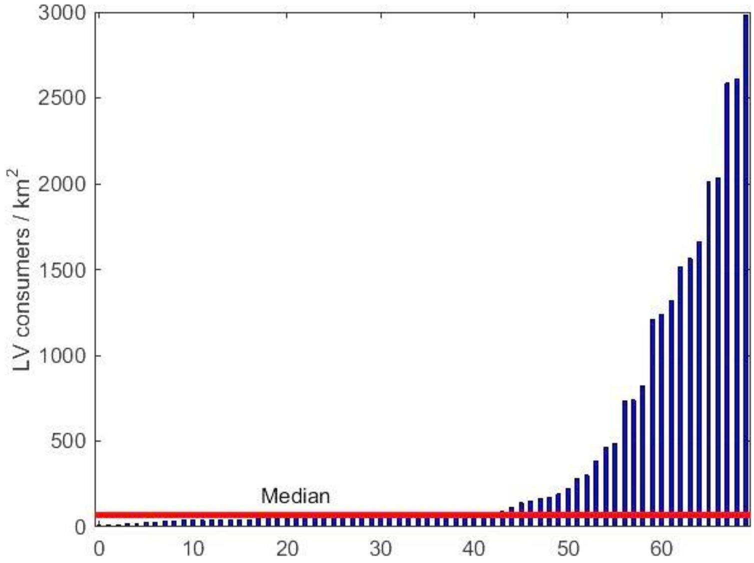

Figure B- 1 LV consumers per area

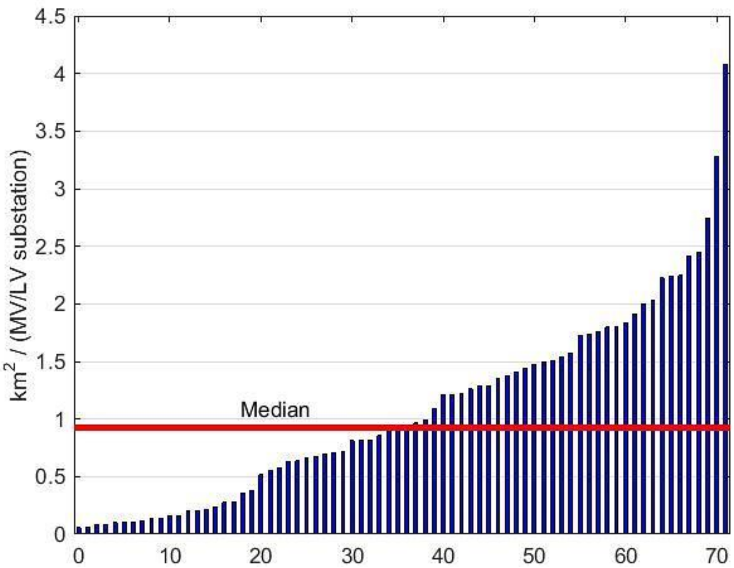

Figure B- 2 Area per MV/LV substation

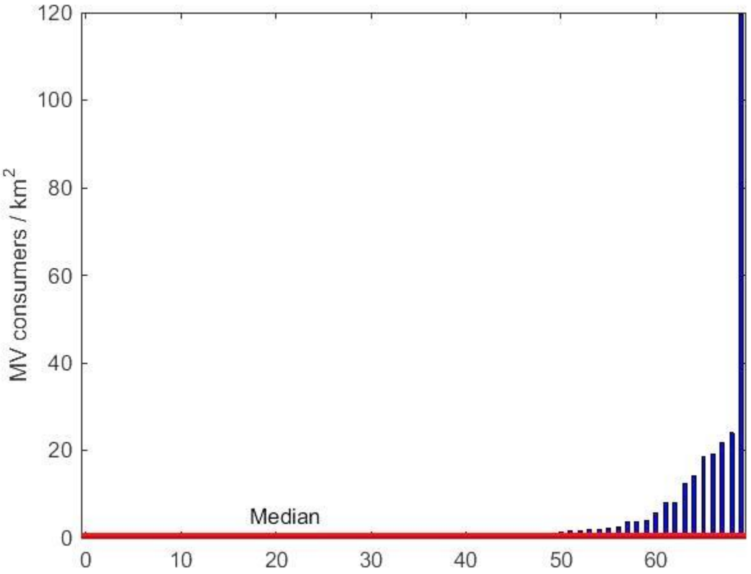

Figure B- 3 Number of MV consumers per area

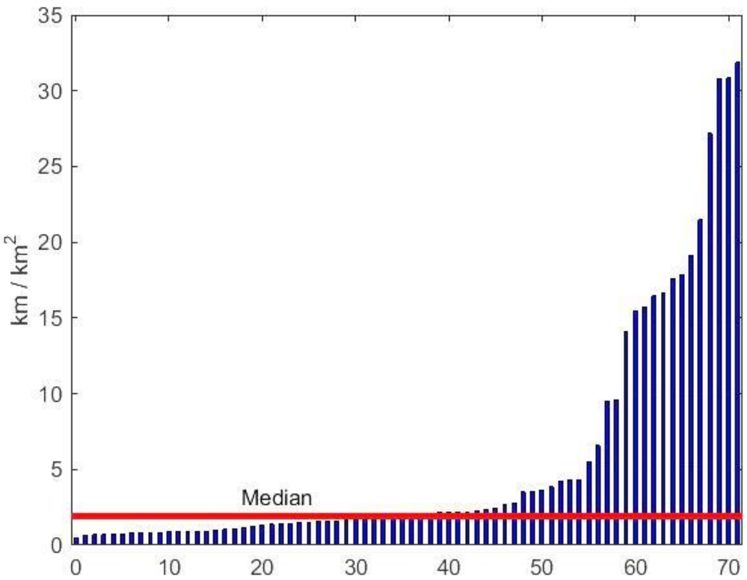

Figure B- 4 LV circuit length per area of distribution

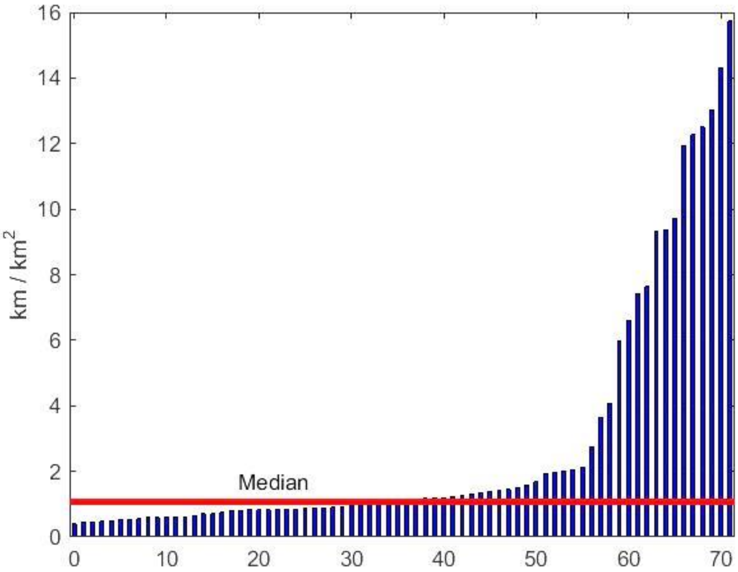

Figure B- 5 MV circuit length per area of distribution

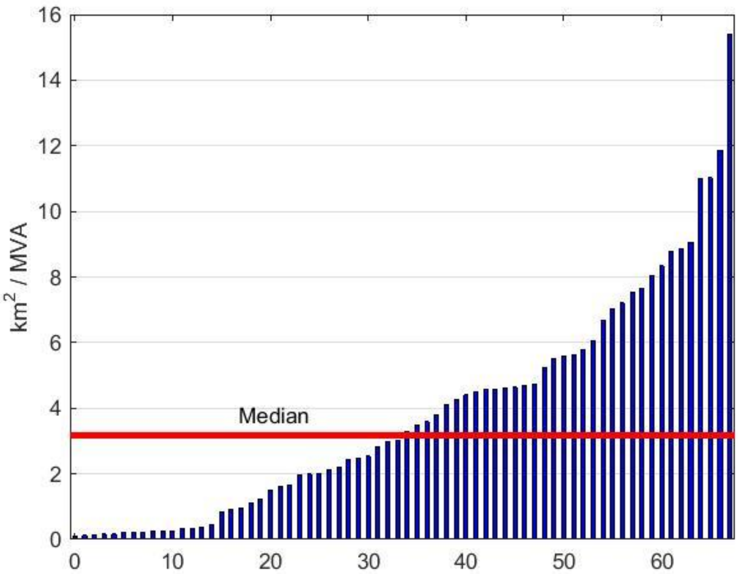

Figure B- 6 Area covered per capacity of MV/LV substation

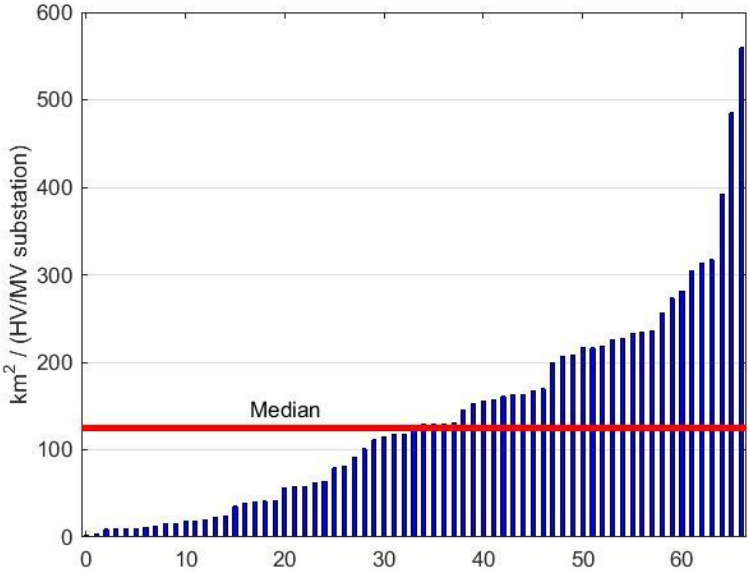

Figure B- 7 Area per HV/MV substation

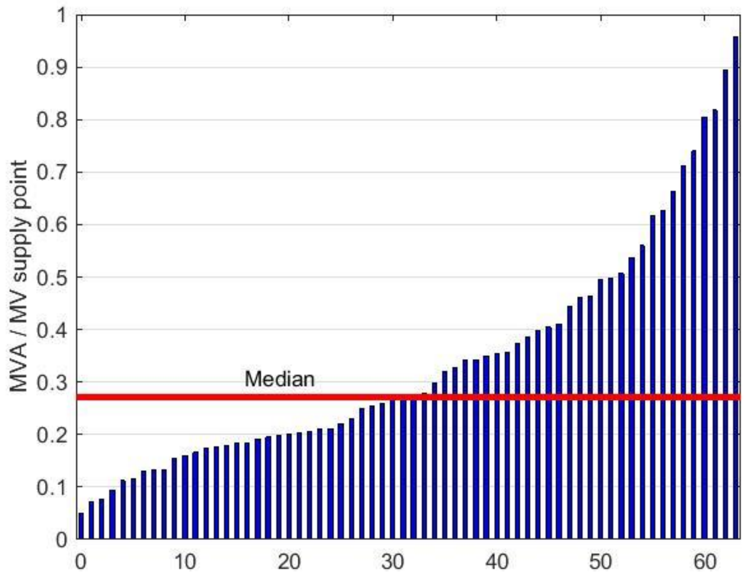

Figure B- 8 Capacity of HV/MV substation per MV supply point

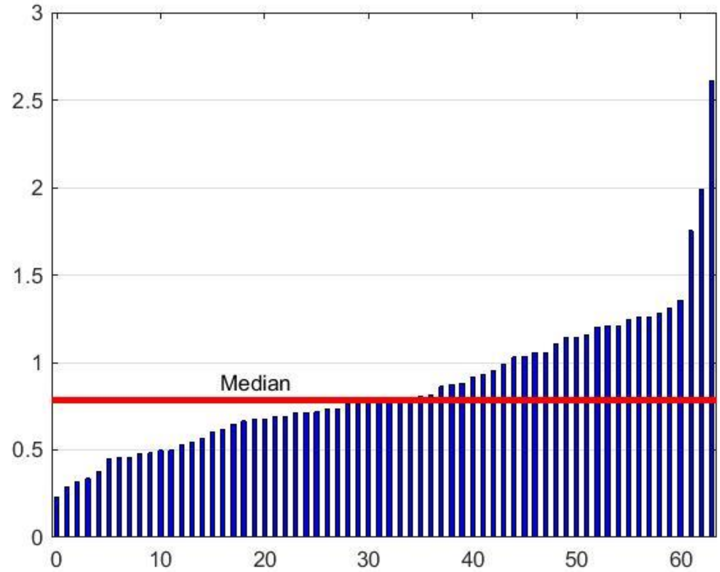

Figure B- 9 Ratio of capacity of MV/LV substations per capacity of HV/MV substation

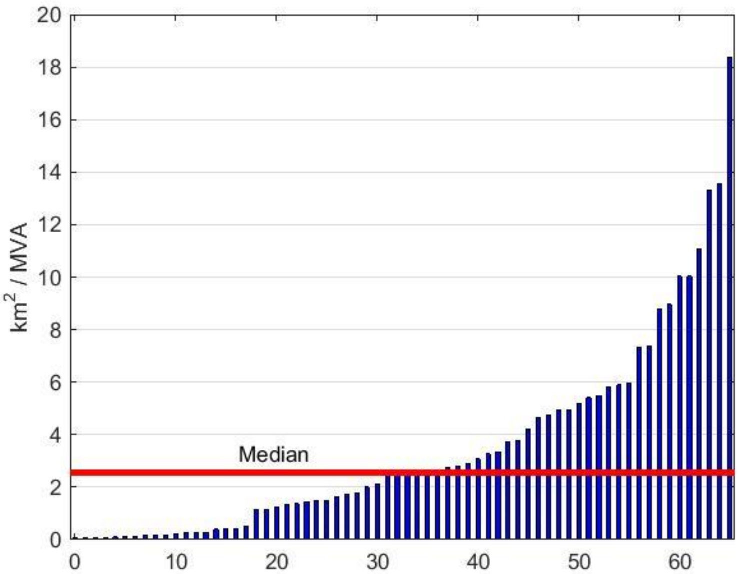

Figure B- 10 Area per capacity of HV/MV substations

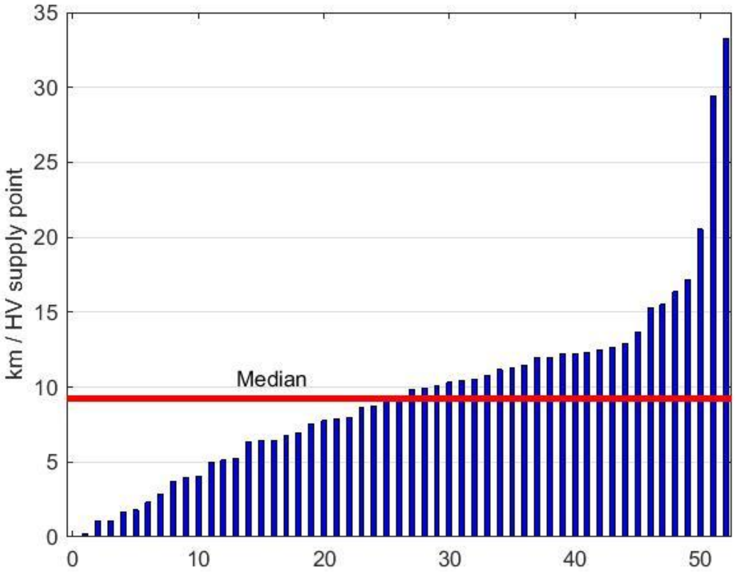

Figure B- 11 HV circuit length per HV supply point

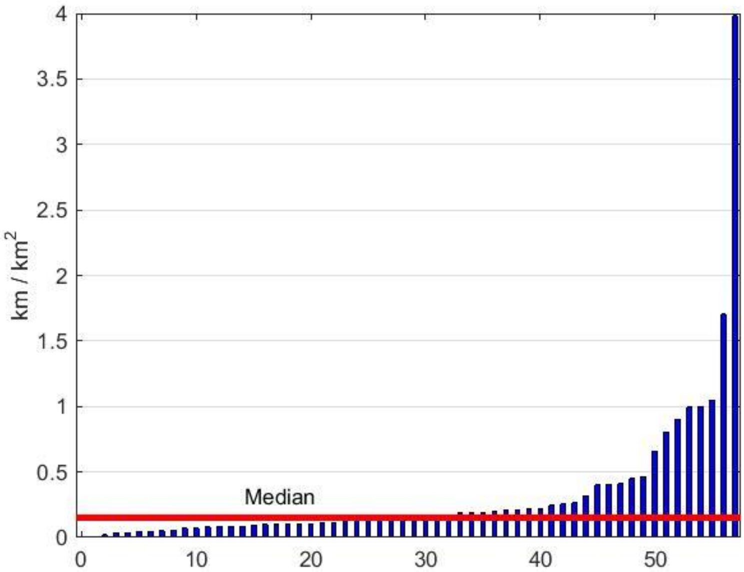

Figure B- 12 HV circuit length per area

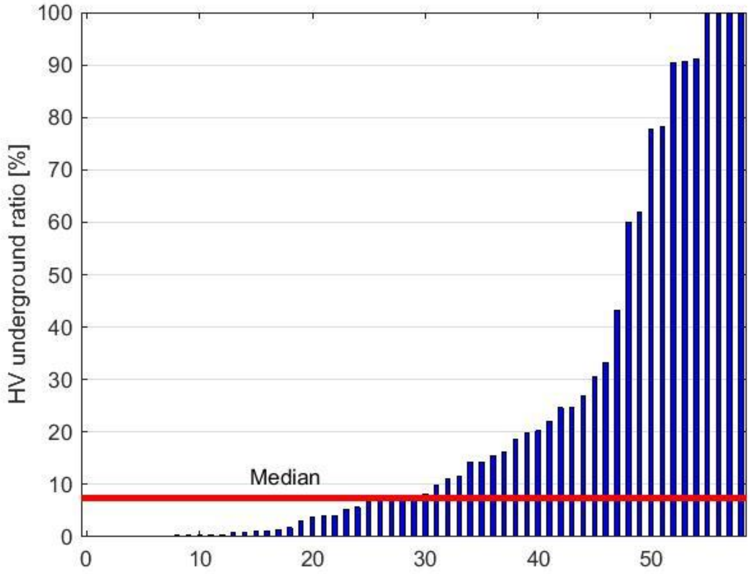

Figure B- 13 HV underground ratio

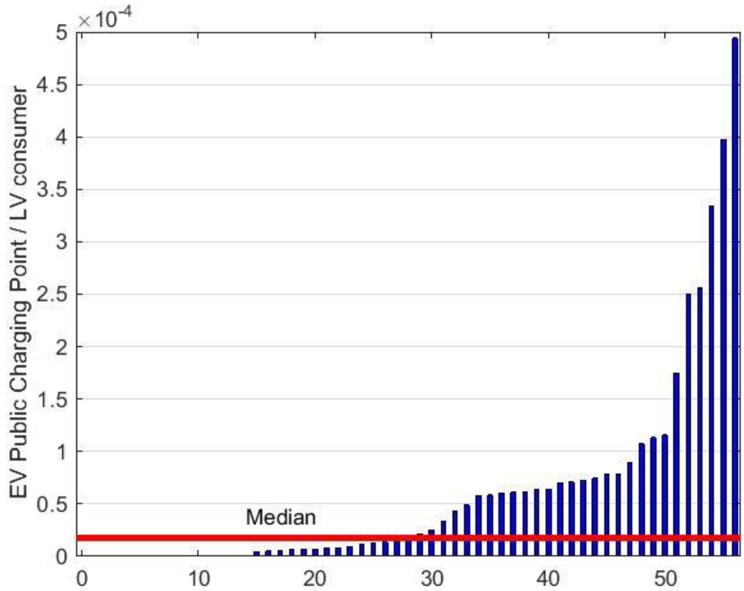

Figure B- 14 Number of electric vehicle public charging points per consumer

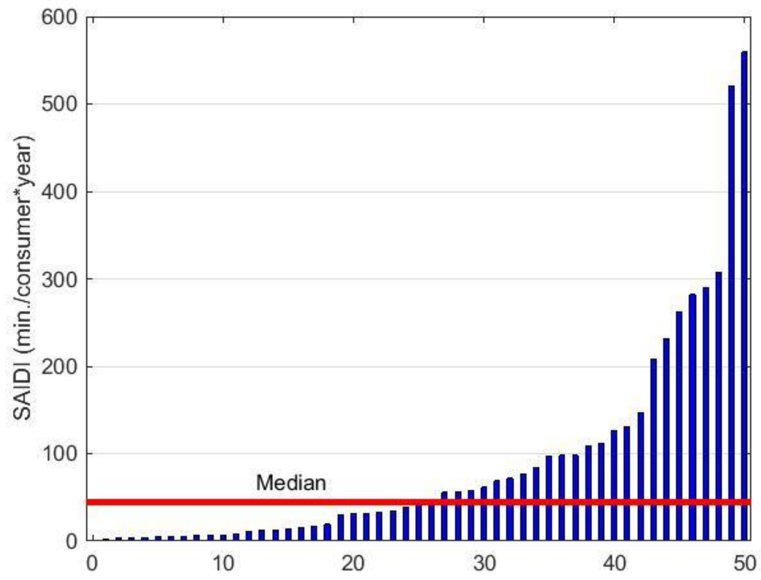

Figure B- 15 SAIDI for long unplanned interruptions

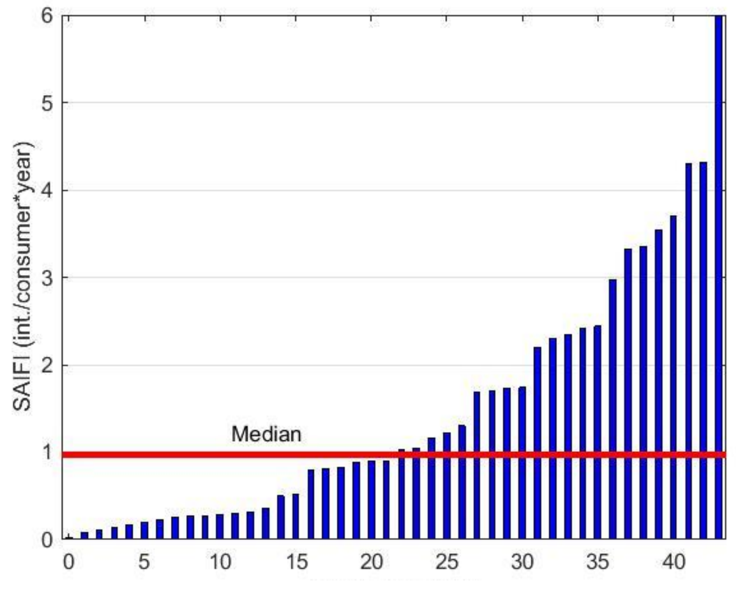

Figure B- 16 SAIFI for long unplanned interruptions

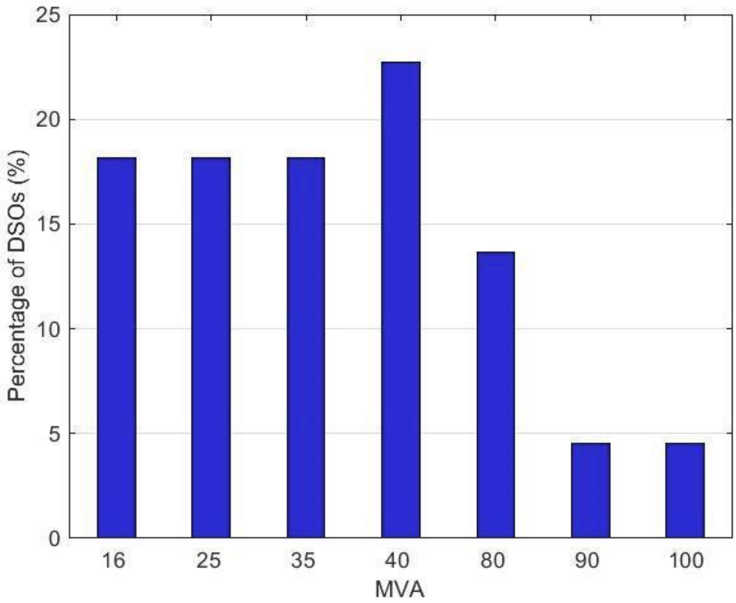

Figure B- 17 Typical transformation capacity of HV/MV substations

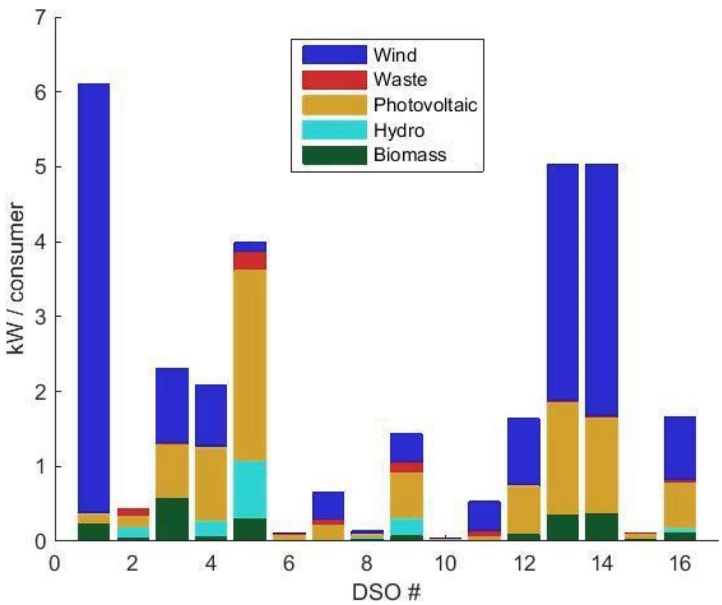

Figure B- 18 Total generation installed capacity per consumer

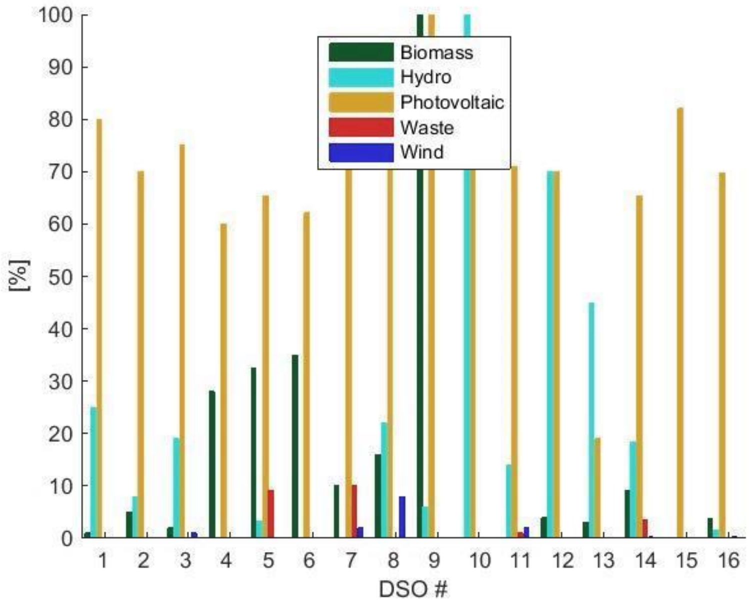

Figure B- 19 Percentage of generation connected to LV per technology

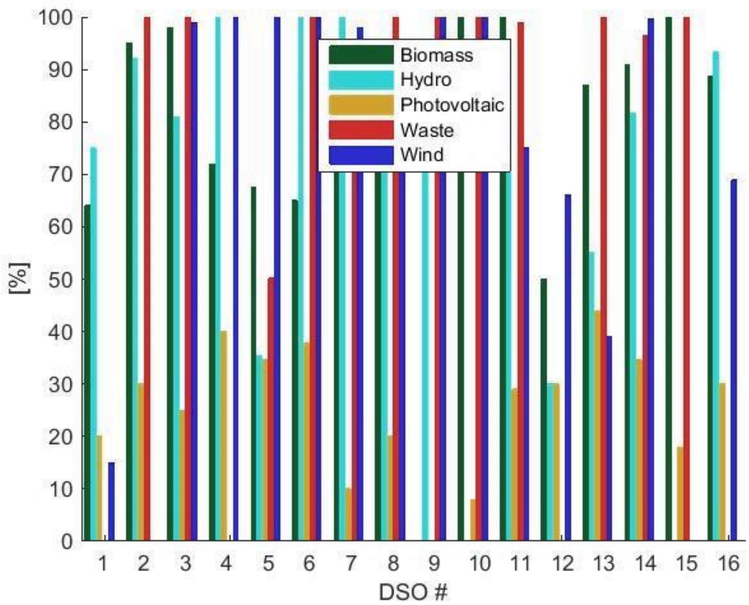

Figure B- 20 Percentage of generation connected to MV per technology

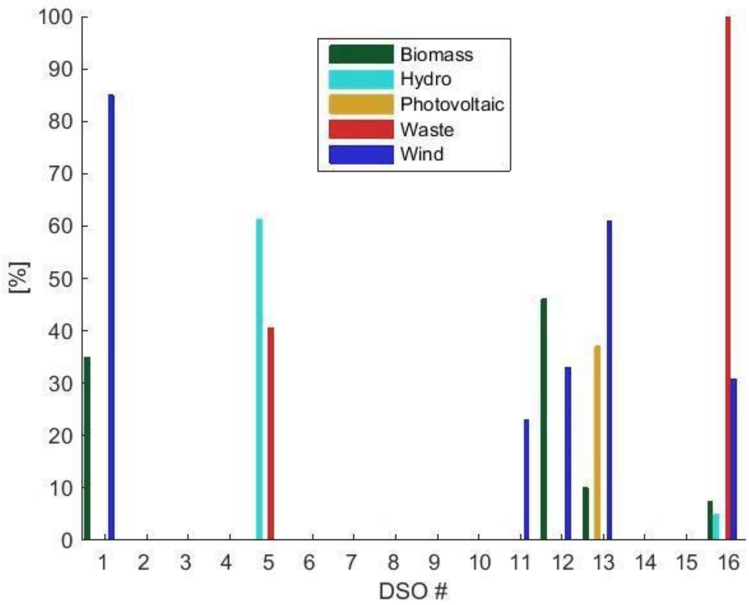

Figure B- 21 Percentage of generation connected to HV per technology

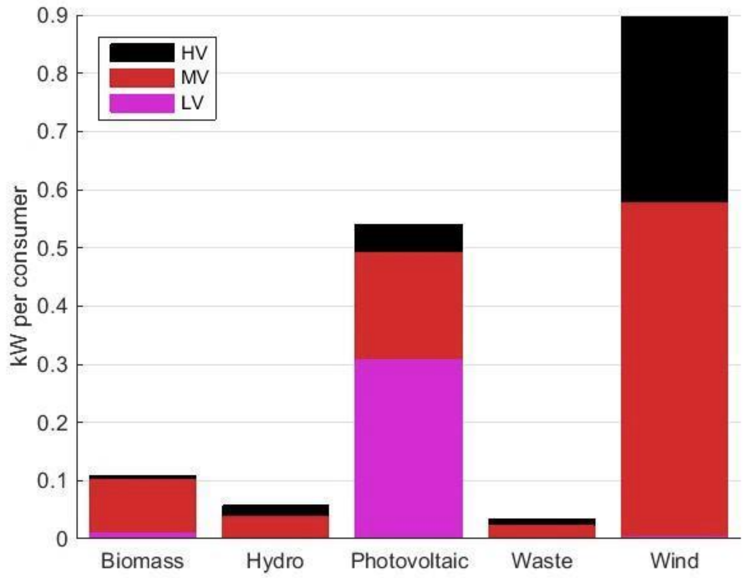

Figure B- 22 Total Installed Capacity/consumer connected to LV, MV and HV

Annex C: On-line survey

1. Identification

Company/Association	
Country	
Phone	
Fax	
Email	
Comments	

2. General information (Distribution Business - Basic Figures, Structure & Ownership)

A. Basic data

Legal Name of the DSO	
Country	
Regions and/or municipalities covered	
Distributed Annual Energy (on average) (GWh)	
Area of Distribution Activity (approximately) (km2)	

B. Distribution business

Ownership of the DSO	
A. Private	
B Public state owned	
C Public owned by municipality	
D Other	
Is the DSO part of a bigger group operating in the power industry?	
If yes, type of unbundling with respect to the parent company:	
Business in the power sector the company (or their group) operate besides distribution (e.g. generation, transmission, supply/retail)	

C. Customers

Total Number of Customers connected	
Number of LV (< 1 kV) Customers	
Number of MV (1- 36 kV) Customers	
Number of HV (> 36 kV) Customers	

D. Circuit length per voltage level (km)

Total	
LV (< 1 kV)	
of that Overhead	
of that Underground	
MV (1-36 kV)	
of that Overhead	
of that Underground	
HV (> 36 kV)	
of that Overhead	
of that Underground	

E. Technical data

Number of HV/MV Substations	
Total installed capacity of HV/MV Substations (MVA)	
Number of MV/LV Secondary Substations	
Total installed capacity of MV/LV Secondary Substations (MVA)	
Total installed capacity of generation connected (MW)	
Installed capacity of generation connected to LV networks (MW)	
Number of electric vehicle public charging points	

F. Reliability

Reliability indexes (annual value of each reliability index for long unplanned interruptions).

Reliability index	Value	LV**	MV**	HV**
SAIDI (min./customer)				
SAIFI (int./customer)				

Please fill in the following table in case your reliability indexes are not the proposed ones.

No.	Reliability Index*	Unit	Value	LV**	MV**	HV**
1						
2						
3						
4						
5						
6						

G. Comments

Please mention here any comments or suggestions you may have

3. Further Collaboration

Are you interested in providing more customized information with the purpose of building distribution networks representative of your company/country in a second phase of this project?

4. Additional data

Would you like to provide additional data? If is it so, please choose among the three categories (one or more):

- ☐ Network structure
- ☐ Distributed generation
- ☐ Reliability
- ☐ I can't provide additional data

Network structure

Network Data:

Typical transformation capacity of HV/MV Substations (MVA)	
Typical transformation capacity of the MV/LV Secondary Substations in urban areas (kVA)	
Typical transformation capacity of the MV/LV Secondary Substations in rural areas (kVA)	
Average number of MV/LV Secondary substations per feeder in urban areas	
Average number of MV/LV Secondary substations per feeder in rural areas	
Average length per MV feeder in urban areas	
Average length per MV feeder in rural areas	
Number of TSO-DSO interconnection points	
Voltage levels of the distribution networks (kV)	
Typical number of voltage levels concatenated in distribution (for example 1 LV level, 1 MV levels and 1 HV level)	
Degree of automation in the MV network [Type of smart grid automation equipment and penetration]:	
(e.g. Circuit breaker, Tele-controlled circuit breaker, Switch (on-load), Tele-controlled switch, Fault detector, Directional fault detector, Recloser, …).	

	Substations equipped with Monitoring/Automation Equipment*	Degree of penetration (low/medium/high)24	Percentage of substations equipped with these equipment (%)
1			
2			
3			
4			
5			
6			
7			
8			
9			
10			

[24] Low penetration is 0-5%, medium penetration is 5-20% and high penetration above 20%.

Distributed generation

Generation connected to distribution network (ONLY!)

	Total Installed Capacity [MW]	Total Gross Electricity Generation [GWh]	Connected to LV (1kV) [%]	Connected to MV (1-36 kV) [%]	Connected to HV (>36kV) [%]
Photovoltaic					
Wind					
Biomass					
Waste					
Hydro					

Reliability

Are the reliability indexes measured per type of area?

If yes, in what areas? What are the reliability indexes (annual value of each reliability index per type of area, for long unplanned interruptions)?

	Value
Urban-SAIDI (min./cust.)	
Urban-SAIFI (int./cust.)	
Rural-SAIDI (min./cust.)	
Rural-SAIFI (int.cust.)	

Please fill in the following table in case your reliability indexes or area type are not the proposed ones.

	Area type	Reliability Index	Units	Value
Area 1				
Area 2				
Area 3				
Area 4				

Conclusion

Thank you for responding to our questionnaire. Are there any other questions that we should have asked?

Do you wish to upload additional documents related to your activity? (maximum 1mb per file; you can upload multiple files)

Annex D: Cost functions

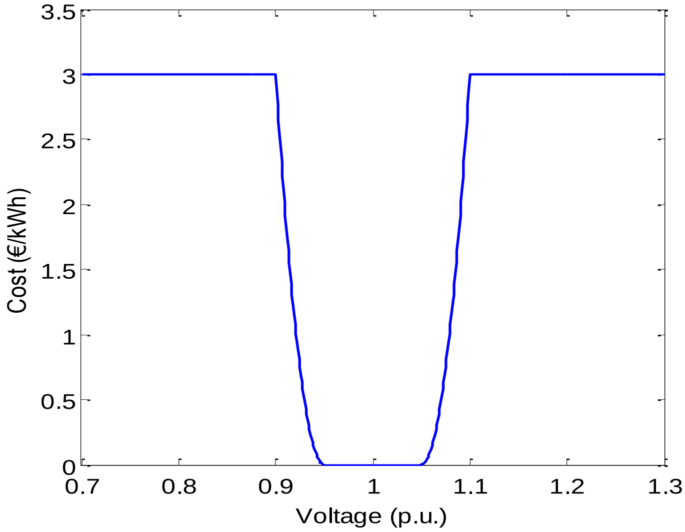

Figure D-1 Voltage cost function

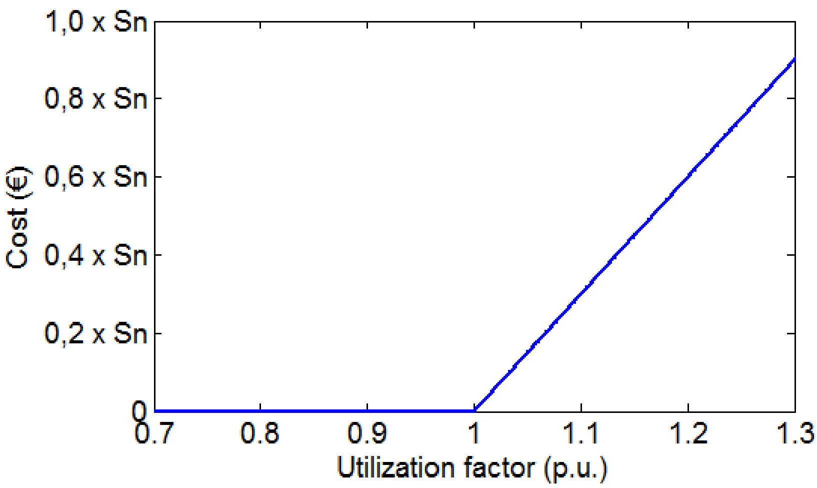

Figure D-2 Overload cost function[25]

[25] Sn is the nominal rating of the element in kVA.

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List of abbreviations and definitions

Benchmarking is the process of measuring an organization's internal processes then identifying, understanding, and adapting outstanding practices from other organizations considered to be best-in-class.

Circuit is a conductor or system of conductors through which an electric current is intended to flow.

Circuit breaker is an automatic switch that stops the flow of electric current in a suddenly overloaded or otherwise abnormally stressed electric circuit.

Demand response are changes in electric usage by end-use consumers from their normal load patterns in response to changes in electricity prices and/or incentive payments designed to adjust electricity usage, or in response to the acceptance of the consumer's bid, including through aggregation.

DSO is the abbreviation for distribution system operator.

Electric vehicle is an automobile that is powered entirely or partially by electricity.

Distributed generation is a method of generating electricity from multiple small energy sources very near to where the electricity is actually used. Directive 2009/72/EC defined distributed generation as "generation plants connected to the distribution system".

Fault detector is a device able to identify a defect in an electrical circuit due to which the current is diverted from the intended path.

Feeder is a voltage power line transferring power from a distribution substation to some point at which the power is broken into smaller circuits.

Fuse is a safety device that protects an electric circuit from excessive current, consisting of or containing a metal element that melts when current exceeds a specific amperage, thereby opening the circuit.

Low voltage network, in this document, is assumed to be the distribution network installations working with a nominal voltage lower than 1kV.

LV is the abbreviation for low voltage.

Median is the middle number in a given sequence of numbers, taken as the average of the two middle numbers when the sequence has an even number of numbers.

Medium voltage network, in this document, is assumed to be the distribution network installations working with a nominal voltage in the 1..36kV range.

Microgrid is a group of interconnected loads and distributed energy resources (such as distributed generators, storage devices, or controllable loads) within clearly defined electrical boundaries that acts as a single controllable entity with respect to the grid. A microgrid can connect and disconnect from the grid to enable it to operate in both grid-connected or island-mode.

MV is the abbreviation for medium voltage.

MV/LV substation is a power station where the voltage is stepped down from medium voltage to low voltage.

MV Supply points are the installations and loads directly supplied by the medium voltage network, i.e. MV/LV substations and MV consumers.

High voltage network, in this document, is assumed to be the distribution network installations working with a nominal voltage above 36kV. It is also commonly called sub-transmission network in the literature.

HV is the abbreviation for high voltage.

HV/MV substation is a power station where the voltage is stepped down from high voltage to medium voltage.

HV Supply points are the installations and loads directly supplied by the high voltage network, i.e. HV/MV substations and HV consumers.

Quality of service is the degree to which the performances of the elements of the electrical system result in power being delivered to consumers within accepted standards and in the amount desired. It can be classified in commercial quality, continuity of supply and waveform power quality.

Plug-in electric vehicle is any motor vehicle that can be recharged from an external source of electricity, and the electricity stored in the rechargeable battery packs drives or contributes to drive the wheels.

Recloser is a circuit breaker designed to trip when a fault is detected, then automatically reclose after a set amount of time in an attempt to clear transient faults on the feeder.

Reference Network Models are large scale distribution planning models, used in the regulation for estimating the efficient cost required for building the distribution networks.

Revenue regulation is a form of price control applied to companies that are considered to be regulated monopolies. Revenue regulation is designed to motivate regulated companies to increase their efficiency whilst ensuring their economic viability.

SAIDI is the abbreviation for System Average Interruption Duration Index. It is a measure of the duration of the interruptions.

SAIFI is the abbreviation for System Average Interruption Frequency Index. It is a measure of the frequency of the interruptions.

Simultaneity factor is a ratio used to calculate the peak of a higher voltage installation based on the peak of its lower voltage installations. It is required because the peaks of the installations do not occur all at the same time and therefore when they are added (e.g. to design an upstream installation), the peak of the aggregated profile is lower than the sum of the individual peaks.

Smart grid is an electricity network that can integrate in a cost efficient manner the behaviour and actions of all users connected to it - generators, consumers and those that do both - in order to ensure economically efficient, sustainable power system with low losses and high levels of quality and security of supply and safety.

Smart Meters are electronic measurement devices used by utilities to communicate information for billing customers and operating their electric systems. Smart meters enable two-way communication between the meter and the central system. Unlike home energy monitors, smart meters can gather data for remote reporting.

Storage is a set of technologies capable of storing previously generated electric energy and releasing that energy at a later time. Electrical Energy Storage (EES) technologies may store electrical energy as potential, kinetic, chemical, or thermal energy, and include various types of batteries, flywheels, electrochemical capacitors, compressed air storage, thermal storage devices and pumped hydroelectric power.

Substation capacity is the amount of power that the substation can transform. It can be expressed in kVA (kilovolt-amperes) or MVA (megavolt-amperes).

Switch is a device used to break or open an electric circuit or to divert current from one conductor to another.

Transformer is a device that converts an alternating (A/C) current of a certain voltage to an alternating current of different voltage, without change of frequency.

Underground ratio is defined as the percentage of the underground circuit length referred to the total circuit length (overhead and underground) of the respective voltage level.

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