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1 Introduction

Current distribution networks are undergoing technical advances. These technical advances influence the technology, the business and the regulation of the networks as well as the network operation and planning. The aim of the IDE4L Project is to define, develop and demonstrate the entire system of distribution network automation, IT Systems and applications for active network management. The challenges of the DSOs are to handle these applications for active network management and a growing capacity of renewable energy sources (RES).

The active network management changes the operation of distribution networks. The customer of a network company may be a consumer or a prosumer of electricity. In addition to energy, RES producers provide ancillary and flexibility services, predominantly via Technical Aggregator. These services are required in order to maintain secure and safe operation of the whole power system. Aggregators integrate small-scale DERs together to optimize their operation in the electricity market (Commercial Aggregator), and to provide services to TSOs and DSOs (Technical Aggregator).

In the network planning these technologies are often discussed for the integration of RES or electric vehicle (EV) in the distribution networks. The basic aims in the planning of active distribution network are to enhance the reliability and PQ of distribution network and to increase the hosting capacity for RES in the existing distribution network. And active distribution network will make infrastructure/methods/processes available to enable flexible DERs participation to the market.

The scope in this deliverable is the network planning of active distribution networks. Therefore, the benefits of an active distribution network are shown in the different time steps. In the Operational Planning is shown how to handle with uncertainties and congestions. The Target Network Planning shows the benefits of a cost-minimal network under consideration of active network components in the long-term network planning. And in the Expansion Planning shows the road map from the present network structure to the cost-minimal network of the Target Network Planning.

The goal of this deliverable is to assess the benefits of active networks and flexibility use under the IDE4L concept. This is shown on the demonstration network of Unareti, using optimization techniques that allow making full use of the flexibility of the users. Real consumption and production data have been used, and the flexible devices and consumption patterns have been estimated from available studies and field data. The assessment has been made for different scenarios that mirror the possible evolution of the integration in this study network of flexible devices, distributed generation resources and electric vehicles, among others.

The document is organized as follows. The general goals of the deliverable and task are given in Chapter 1. A background of the planning and optimization methods used in this study is given in chapter 2. The demonstration network is presented in chapter 3. The assumptions of the flexibility that is to be considered in the performed study are presented in chapter 4. Furthermore, future scenarios for the Expansion and Target Network Planning for the development of network customers has been made, which are presented in chapter 5. The investigations to show the benefits of active networks are based on these assumptions and are presented in chapter 6. A conclusion section ends the document. An annex has been added to include data, simulation methods and results not given in the main body of the document.
2 Planning method

2.1 Planning principles

The main aim of the network planning is to ensure a safe and reliable network operation in the future. Additionally, the network operator is prompted to reduce the network costs by the national regulators. These both aims make the network planning process to be a complex problem.

To guarantee a safe and reliable network operation, the network operator has to ensure the technical constrains to be obeyed. These constrains are defined as the voltage stability, the current limit of each conductor, the boundaries of the short-circuit current and the limit of interruption hours per year of the network customers.

The limits of the voltage stability in medium and low voltage networks are defined in the European standard EN 50160. This standard defines the allowed voltage boundary of $\pm 10\%$ of the nominal voltage $V_n$ at all of the network customers. If the planning process concentrates on medium or low voltage networks separately, the network planner has to consider a lower voltage boundary due to the missing voltage control in the secondary substation level. Therefore, the network planner defines a voltage boundary for each voltage level individually:

$$V_{\text{min}} \leq V \leq V_{\text{max}} \quad (2.1)$$

The current limit of the conductors is based on the thermal behavior of the conductors. The maximum current is restricted by the maximum thermal limit of the conductors. Therefore, the current limit is described by:

$$I \leq I_{\text{therm}} \quad (2.2)$$

Faults have to be detectable at all times. Therefore, the short circuit current at each substation has to be enough higher than the peak load at substations. However, the short circuit current has to be lower than maximal switching capacity of circuit breakers.

$$I_{\text{sc, min}}'' \leq I_{\text{sc}}'' \leq I_{\text{sc, max}}'' \quad (2.3)$$

The network planner has to consider a reliable supply of the network customers in the planning process of its networks. To ensure this, there are different planning principles in different European countries. In Germany, medium voltage networks are mainly planned as ring networks. The redundancy of ring networks ensures a supply of the network customers in case of one single fault in these networks. In Finland, the network planner has to ensure that the interruption time of a supply per year should less than 36 hours.

To obey the technical constrains, the network planner has to consider all network customers consisting of loads and DERs. Therefore, the network planner uses the worst case planning principle. This principle considers only the maximum and minimum load of the networks as well as the maximum and minimum feed-in of the DERs. Due to the less simultaneity of the loads and the different types of DER, the network expansion is often over dimensioned. To avoid this, the network planer could analyze its network stochastically. In the IDE4L project, the network planner does not only consider the worst cases but also time series to modeling the single customers. Therefore, it is important to model consistent time series for all customers considering all their dependencies. Due to the time series, it is necessary to calculate multiple load flows in the planning process. Therefore, er more calculation time is expected.

Besides the technical constrains, the planning process of distribution networks could be influenced by different other effects. In urban regions in Europe, the distribution networks are built as cable networks and in rural regions the share of overhead lines is higher than in urban regions. The cable share of the networks is different in the different nations of Europe (see Table 2.1)
The planning of distribution networks orientates at the building development in this regions. The routing of cables and partly also of overhead lines are orientating at streets. These allowed an easier maintenance and reparation of them.

For an existing network it is necessary to define an optimal operational planning. Operational planning is defined in IEC 61968-IRM in the following way: “Operational planning and optimization actors perform simulation of network operations, schedule switching actions, dispatch repair crews, inform affected customers and schedule the importing of power. They keep the cost of imported power low through peak generation, switching, load shedding or demand response”. An enhanced operational planning reduces the operational costs and therefore the need of new investments. In the smart grid paradigm this operational planning includes the consumers’ flexibility. This flexibility will likely be increased in the following years by the progress of control devices and communications and must also be taken into account by the network operator in the planning tasks. This flexibility may also imply savings for the users, when shifting flexible loads to hours of lower prices. This flexibility is higher when the number of users increases, so the role of the (commercial) aggregator in the future will have an increasing importance, both as flexibility manager and as an intermediary between users and network operators.

### 2.2 Overview of planning methods.

The network planning is split into three steps, which have different time horizons. Due to the different time horizons, the measures are different, which the planner could use. An overview of the steps of the network planning is given in Figure 2.1.

In the Operational Planning, as the first step, the network operator plans the day-ahead operation. The degrees of freedom are the operation of the active network components and the schedule of maintenance measures. The operational planning is challenged by the uncertainties of the load and generation forecasts additionally.

The second step is the Expansion Planning. The Expansion Planning describes development of the network. Due to the age-rated change of network equipment and the change of the network customers, the network planner has to rebuild the network. The development of the network customers is one of the biggest challenges in the Expansion Planning, which the network planner has to deal with.

The aim of the Target Network Planning is to identify cost-minimal network structure. In order to avoid inefficiencies in the Target Network, the Target Network Planning does not consider the present network. This fact determines the time horizon of the Target Network Planning, which is from 30 to 40 years in the future. Therefore, it is assumed that each component has to be changed. The present network has not to be
considered. The challenge of the Target Network Planning is to deal with a number of uncertainties of the development of the network customers.

In the following, the approach of the three steps of the planning process is described.

![Diagram of planning steps]

**Figure 2.1.1 Overview of the planning steps.**

### 2.2.1 Target network planning.

The aim of the Target Network Planning is to determine the cost-minimal network structure for future scenarios. To ensure optimal network structures, the Target Network Planning does not consider the present network and uses a so-called “Green-Field-Approach”. Therefore, the time horizon of the Target Network Planning has to be longer than the lifetime of the components that are built in the network. This guarantees that each component will be rebuilt. This means for electrical networks a time horizon of 40 to 50 years in future. Due to the long time horizon, the development of the customers is highly uncertain and it is necessary to evaluate different development scenarios for the future. The derivation of the scenarios and the scenarios themselves, which are evaluated in this project, are described in chapter 4.

In the planning process the Target Network Planning is needed to get a long-term vision of the network. The results of this planning step are used to derive planning principles or to provide information to the Expansion Planning. In the Expansion Planning the road map to the Target Network is created.

Due to the aim of a cost-minimal network structure, the target function $TF$ of the Target Network Planning could be formulated as:

$$TF = \min(\hat{C}_{\text{CAPEX}} + \hat{C}_{\text{OPEX}})$$

(2.4)

Besides the target function, the Target Network Planning has to guarantee the technical constrains obeyed, which are described in the previous chapter.

For a computer-based Target Network Planning, heuristic approaches could be used. A heuristic approach could not guarantee an optimal solution, but due to the dimension of the optimization problem, a perfect optimal solution is not practical.
The presented approach is based on an ant-colony system. Therefore, the planning problem of ring networks is redrafted in a spanning tree problem, which could be solved by the ant-colony system. The redraft of this problem is described in chapter 8.3.1. The ant-colony system designs multiple candidate networks, which will be evaluated afterwards technically and economically. If a candidate network is not valid technically, this candidate network will be got rid of for the following planning process. After the technical evaluation, it follows the economic evaluation. In this step, the investment cost will be calculated by the information of the network components. The active network components and their behavior are the input parameters of this approach. Due to different variations of their behavior, the benefits in the network planning could be shown.

Due to the small geographical field of observation, it is necessary to consider the geographical conditions in this area. For an easy maintenance and repair of the network, the single components of the network are built at location with a simple reachability. Therefore, the cable routing is orientated at streets. In the IDE4L project, the presented approach uses the data of the OpenStreetMap project [OSM] to identify the possible cable routes. Afterwards, the street data and the geographical data of the network are joined together. The information about the network customer and the cable routes is an important input parameter of the following optimization problem.

The simulation of the network operation considers the active and reactive power control of DERs and controllable loads (i.e. electric vehicle, heating). The reactive power control of the DERs is used to solve violations with the allowed voltage limits. In the presented approach, this is modeled with a \( \cos(\varphi(P)) \)-characteristic. A different network stakeholder, so called aggregator, could do the control of the active power of the DERs and the controllable load. The different stakeholders have different interest on the control of these components. The interest of the network operator is to reduce congestion in its network to reduce the network expansion. A market stakeholder wants to increase his profits. These different interests are evaluated by different variations to show the consequences in the network planning. The different interests have an impact on their behavior, and this is modeled by different time series, which are used in the technical evaluation. The time series are described in chapter 3.3.

The result of the Target Network Planning is the so-called Target Network. The Target Network represents the network structure, which is cost minimal for the given input parameter. The network structure includes the cable routing and their types as well as the CAPEX and OPEX costs of the network.

The benefit of the active network components and their control will be evaluated based on the consideration of the Target Networks for the different scenarios and variations.
2.2.2 Expansion planning.

The expansion planning task attempts to answer the question which investments to the network should be done and when. The idea is to create a roadmap of investments from the existing network today to the final (and assumedly optimal network) in the future.

The principal problem of the expansion planning is to minimize the required amount of investments (discounted to present year) that is required in archiving the desired target network. The investment plan takes into account the increment/decrement of the network loading, development of operational constraints, new planning solutions and new emerging technologies. The expansion planning is tightly knitted with target network planning, as its primary input is the target network state in future.

The expansion planning algorithm is composed of four separate parts which work independently as part of the larger algorithm. The separate parts (or modules) and their relation to one another are depicted on figure 2.2.2.2. The algorithm generates possible development steps and checks that technical constraints are fulfilled at every step. When adequate number of consecutive steps is formed, the algorithm finds the route of least cost through the possible development steps.
The Expander is the part of the algorithm that compares the current network status to the target network status and then makes investment decisions. This part contains the decision problem part of the algorithm. The Expander always looks the network at the n\textsuperscript{th} development step and makes decision how to improve the network towards target for the step n+1. The number of desired steps to reach target network is assumed to be given.

The Validator is the part of the algorithm which checks that the technical requirements for the distribution network are fulfilled at each proposed planning step. Technical requirements in this context mean the limit values for nodal voltages, branch currents, maximum outage time, and so on. The values may be based on existing limitation (for example: EN 50160 for connection voltage limits), or they can be separately specified in the DER scenarios.

The Allocator assigns cost values for each generated planning step and also finds the possible transitions (and their costs) between generated planning steps planning steps. The costs associated with a certain network state are divided into investment costs (transition cost from n:th network state to the n+1:th state) and operational costs (cost of network usage during the transition from n:th to n+1:th state). The cost calculation is based either to literature values (for example, the component values defined by regulator) or they may again be separately defined in the DER scenario.

The Router is the optimization part of the algorithm. It selects the route through the planning steps proposed by the previous parts of the algorithm. This is a generic dynamic programming pathfinding problem, which is
solved using a modified Dijkstra’s algorithm. Modified, in this case, means that the algorithm takes into account the time dependency of costs, a feature that is not part of original Dijkstra’s algorithm.

2.2.3 Operational planning.

As already mentioned, Operational planning is defined in IEC 61968-IRM in the following way: “Operational planning and optimization actors perform simulation of network operations, schedule switching actions, dispatch repair crews, inform affected customers and schedule the importing of power. They keep the cost of imported power low through peak generation, switching, load shedding or demand response”.

Of all these tasks, only the optimal scheduling and the flexibility related tasks (switching, load shedding or demand response) are considered here. They have also to do with network constraints (congestion, over/undervoltages) management. The time scope of this task is typically the day ahead and the time up to one hour before the real time. One important issue is the regulatory framework of the future Smart Grid. In the studies performed here, an ideal and simplified regulation will be assumed, as closest as possible to the more agreed rules of the European electricity markets, trying to minimize the number of required hypothesis. One of the simplifications is to merge the roles of retailers and market agents into the aggregators.

The aim of the work is to develop and test future methods for optimal exploitation of demand response and flexibility with different levels of RES presence. These methods consist in an enhanced strategy of market participation from the aggregator side and the optimal exploitation of customers’ flexibility for solving network congestions and constraints.

A method for optimal participation of an aggregator managing consumers and DER in the electricity market has been designed. This method minimizes the cost of the electricity for this aggregator, taking into account the declared flexibility of its customers.

The other developed method is an optimized strategy of management of congestions and other network constraints. This technique is based on the optimal power flow algorithm and aims to exploiting the flexibility of customers (demand or generation, in general), while minimizing the RES curtailment. In this way, the uses of the existing network are optimized as well as the investments of future network expansion. These last points, however, go beyond the scope and timeframe of the operational planning.

In accordance with the definition of (commercial) aggregator used in this project, the aggregator has the role of a retailer, a balance responsible party and flexibility manager. In this way, the aggregators purchase the energy for their customers and evaluate their flexibility in order to participate in the market in an optimal way, obtaining the energy at the minimal cost. They must, consequently, forecast their customers’ demand and generation, the future market prices, and the flexibility. The procurement of energy can be done by means of bilateral contracts or in a power pool. Due to the regulation of the Italian market (where the study case is located), and the assumptions made along IDE4L project, all the energy will be bought in the mandatory power pool. This does not imply a lack of generality of the study, because the benefits that could be obtained by making use of the flexibility would yield similar results under different assumptions. Hedging against risks in futures, forward or option markets could be another source of benefits for the aggregator, but this will be not considered here.

On the other hand, the flexibility of the consumers can be also used by the DSO to solve the network problems that would yield to load or (renewable) generation curtailments.

Summarizing, in this study, the benefits of making use of demand response, or demand flexibility will take place in two points:

- In the purchase of energy in an organized electricity pool. The benefits in this case consist in a lower average price paid for the energy.
- In the management of the network constraints, avoiding over/undervoltages and line congestions making use of the flexibility

The users of the Unareti network are described in detail elsewhere in this document, but their main features will be enumerated here:
• The consumers are connected to the LV and MV networks.
• The aggregation level is per MV network, where it is more likely that congestion management methods, managed by the DSO might be used.
• A number of consumers have PV generation, both in the LV and in the MV level.
• One part of the consumers load will be flexible, while the rest of it cannot be modified without affecting the consumers’ comfort.
• The flexibility of the consumers will be summarized in different ways:
  o Electric vehicles: The vehicles (or at least apart of them) considered will be efficiently managed and the charging will be made in a smart way, without changing the users’ schedule.
  o Electrical appliances: The use of these appliances can be made in a predefined range of (off-peak) hours.
  o HVAC loads: The use of their flexibility is more reduced, and all the energy taken in one hour must be obtained in the next few hours.

Therefore, the aggregators will participate in the market for the sake of their customers in the following way. First, the aggregator receives or produces forecasts of load, solar production and market prices; these forecasts are for the whole of the represented consumers. With these forecasts, the aggregator submits a purchase bid to the electricity pool before the gate closure. The bid made at the cap price of the system for the purchase of energy, or at zero price, if there is a sell of energy. This could take place if the whole energy production is larger than the forecasted consumption.

After the market clearing, and due to the conditions under which the bid submission has been made, the bid is accepted and the aggregator assign the power to the different consumers, in the study, the demand/generation is disaggregated per MV node. This is sent to the DSO together with the available flexibility of the customers connected to every MV node and the cost of this flexibility.

Then, the DSO, at a given moment after the gate closure, calculates the possible congestions and network problems that could be arisen by this market solution. If any network constraint is violated, the available flexibility is used to avoid load or generation curtailment. This measure has a cost for the DSO, which will have to be compared with the cost of load curtailment.

Considering the day-ahead framework, the general scheme of the operations, actors and time sequence proposed for the day-ahead market process is shown in Figure 2.2.3. This scheme could be extensible to the intraday markets and real time operation with minor changes.

In Figure 2.2.3.1 MO stands for Market Operator, Agg stands for Aggregator and C/DER stands for Consumer/Distributed Energy Resource (generation facilities). The following process is proposed:

• **Customer needs/flexibility:** This is the agreement between aggregator and its customers (consumers/DERs) about their needs and possible flexibility. This arrangement is made long before the daily market.

• **Energy bids:** Based on needs and forecasts (prices, weather), the aggregator prepares and submits a bid for the whole of its customers to the Market Operator for the daily market. Flexibility bids can be included at this stage or in a later stage.

• **Market clearing:** From the different supply and demand bids, the MO sets the marginal price for energy and production/consumption bids that have been accepted. This provisional schedule is communicated to the DSO and the market agents, such as the aggregator. The congestions in the network have not been taken into account at this stage.

• **Feasibility check:** The DSO checks whether the provisional schedule complies with the network constraints.

• **Needs of flexibility:** If there are congestions, flexibility bids are use in order to solve them.

• **Flexibility bids:** Based on the available flexibility, flexibility bids are prepared by the aggregator and submitted to the DSO.
• **Flexibility clearing**: With the bids submitted, the DSO corrects the provisional schedule and prepares the feasible schedule, which is communicated to the market agents, among them, the aggregator.

• **Distribution network scheduling**: The aggregator sends the feasible schedule results to its customers, who fit their settings to this feasible schedule.

![Diagram](image)

**Figure 2.2.3.1. Scheme of the operations, actors and time sequence.**

A further simplification could be that the aggregator submits the energy and flexibility bids at the same time and the DSO would solve the constraints using the flexibility bids of the aggregator, sent together with the energy bids.

The role of the aggregator and DSO are still being discussed, and therefore the regulatory framework of the whole system is not known. For this reason, the simplest assumptions have been made for this regulation, trying to make them as close as possible to the current regulatory conditions. In this sense, the assessment made here is an upper estimate of the benefits that the customer flexibility may provide. Some conditions have been flexibilized and in order to better exploit the advantages of demand side flexibility.

- Perfect competence conditions. The aggregator is small enough not to have market power.
- There is an hourly net balance between generation and demand.
- The network tariffs are not included here because they can largely change between countries, and they are difficult to generalize.
- The DSO can decide over the flexibility of the consumers connected to the network through the aggregator, who is in direct contact with the final user.

Under these assumptions, the economic benefits of the flexibility are not transmitted directly to the customers. They are benefits for the aggregators, which allow them to offer better conditions to their customers, and this would lead to a generalized decrease of the energy prices to the final customer. The transfer of these benefits could be made in many ways, depending on the tariff policy of the aggregators.

The cost of the congestion management process is compared to the curtailment needed for solving a given problem. This flexibility would allow optimizing investments in the network. This comparison is beyond the scope of this study.
3 Case network.

The planning methods and algorithms developed, improved or adapted along the ide4l project will be checked in one of the study cases of the project, namely, the Unareti network. This network has been chosen because it is the one with more information available.

From the network, consumption and PV available data, series of hourly production and consumption have been created, as well as an estimate of the flexible loads. A summary of the main figures is given in this section, which has been divided in three: network data, available consumption and production data energy profile.

Although some of this information may be available in other deliverables of the IDE4L project, it has been included here for better readability of this deliverable.

In this section of the report only a rough description of available data and obtained profiles will be given. More details are included in the Annexes.

3.1 Network study case.

The study case is the Unareti field demonstrator, shown in Figure 3.1.1. It is a MV network with a rated voltage of 15 kV. The low voltage customers are aggregated per MV node.

![Figure 3.1.1 Diagram of the Unareti network.](image-url)
3.2 Available data.

Number and type of customers

The customers of the study network are divided into domestic customers, non-domestic customers in LV, non-domestic customers in MV and public lighting. There are a number of customers with photovoltaic arrays and there is also one charging point for electric vehicles that is not being used now.

The available data consisted in rated and contracted values for the consumers and the PV arrays, and measurements from selected customers in LV as well as in MV. A summary of the most important features is given below.

Consumption of domestic customers

Data come from a sample of 18 to 21 consumers, whose average hourly measured consumption and a boxplot of the obtained values are given in figure 3.2.1.

Boxplot of the hourly aggregated consumption. Average values of 15 measured sample customers

Figure 3.2.1. Measured average measured consumption

PV production

Among the monitored consumers there are 13 with a PV array totalizing 27.9 kW of installed power. 5 of them have a battery with a capacity of 860 Wh and a rated power of 3 kW. Figure 3.2.2 shows the hourly average values of the total production in p.u. over the installed power. Apart from the contracted power, there is no information about the features of PV devices present in the network, or how are they oriented.

Figure 3.2.2 Normalized (over installed power) total solar production of the given sample.
MV loads consumption.

There are also 9 nodes of MV consumers with a contracted power of 3844 kW from whom there are available data. Figure 3.2.3 shows the average hourly consumptions of the monitored customers, normalized to the maximum measured power. It may be remarked that most of the consumers present a similar behavior with two daily peaks, one in the morning and other in the afternoon. One follows a flatter profile, and two have a flat consumption at day hours. Finally, one node shows two peaks when the consumption of most of consumers decreases.

![Figure 3.2.3 Average values of MV customers along the measurement period.](image)

Market prices.

Apart from consumption and production data, market prices for Italy in the year 2014 have been used, specifically the Prezzo Unico Nazionale (PUN), since this is the price that the demand pays. These prices and a boxplot of the daily pattern are shown in Figure 3.3.6.

![Figure 3.2.4 Prices in the Italian electricity market along 2014.](image)
3.3 Energy profiles.

From the available data, a series of hourly consumption values for a year has been made, following the methodology of [grigg1999]. This consists in using a set of daily and weekly profiles that are applied to the peak consumption to obtain a yearly pattern. The year has 52 weeks, i.e. 360 days or 8736 hours. The consumption series have been obtained for the domestic demand, non-domestic demand in LV and MV users. There are also series for the public lighting and the PV production. The values of the profile coefficients are given in the appendix. The hours are given in UTC.

Domestic demand.

The daily patterns are different for weekdays and weekend and they have been obtained for each season as shown in Figure 3.2.5. The consumption is in p.u. over the average seasonal consumption.

![Daily patterns of domestic LV consumers. Solid line: weekdays; dashed line: weekends.](image)

*Figure 3.2.5 Daily patterns of domestic LV consumers. Solid line: weekdays; dashed line: weekends.*

The total daily consumption for the different days in a week for winter and summer seasons is shown in Figure 3.2.6.

![Accumulated consumption per day in the week for the whole of customers](image)

*Figure 3.2.6 Accumulated consumption per day in the week for the whole of customers*

The Figure 3.2.7 shows the weekly consumption pattern for the whole year. The consumption peak takes place during summer because of the use of electrical cooling system. During winter, the heating is taken from a district heating system. The resultant aggregated consumption in the network is also shown in this figure.
3.2.7. Values are given in p.u. over the peak consumption in the right and over the average consumption in the left.

Figure 3.2.7 Weekly pattern and overall consumption of domestic LV consumers

Non domestic LV demand

There are no data for non-domestic LV demand. Hence, these profiles have been obtained from similar consumers from the measured values of the MV consumers. To obtain an approximated share of the users existing in the network, two aspects are considered: 1) Share of non-residential in total buildings floor area by subsector in Italy, [Entranzed2.1], [Entranzedatatool] and 2) The Google map of the Brescia’s network. The share of different consumers in the study network and the final aggregated hourly consumption for a year are shown in Figure 3.2.8.

Figure 3.2.8 Share of non-residential in total buildings floor area and hourly consumption pattern.

Public lighting

The public lighting has been given the value of zero during the sunlight hours, and the full contracted during the night. The sunrise and sunset hours have been calculated for every day of the year in UTC. Again, a year of 364 days has been considered.

MV loads

From the available data, a daily and weekly pattern of all the MV customers has been obtained. The daily patterns have been divided into weekdays and weekend patterns. In the next figure, the average hourly total consumption of the customers is represented, in kWh, as well as the accumulated daily consumption during the week. The figure in the left is in p.u. over the average consumption in weekdays and weekends.
IDE4L Deliverable 2.3

PV production

Only a limited amount of data for the PV production is available. For this reason, an aggregated hourly photovoltaic production curve for one year has been created with program SAM (System Advisor Model) [sam2016] and checked with the available data. From this program, a pattern for whole year (364 days) is obtained and shown in Figure 3.2.10.

4 Modeling assumptions for the present network.

4.1 Flexibility.

Demand response means mainly shifting consumptions from one moment to another moment, but do not result in energy savings over time. It provides flexibility of different kinds [eu2012], [ecorys2014], like portfolio optimization, preventive and curative congestion management and also may contribute to system balancing, ancillary services and system adequacy and security. The potential of the demand response and the use of its flexibility is large [gils2014], and can be characterized in different ways, as shown later.

Along this section, flexibility will be used in the following ways: 1) to optimize the participation of customers in markets and 2) as an alternative mean to solve network congestions.

In the Unareti study case, the sources of flexibility are the electric vehicles, heating and cooling devices, the electrical appliances and other sources of flexibility coming from industrial processes of non-domestic customers in LV and MV. The total demand of the study network and the flexibility that they can provide is given in the following table.

The assumed decomposition into flexible and non-flexible demand per kind of load is given in the following table (the percentage of load reflected here is not the 100%, electric vehicles and lightening is missing).
This flexibility can be characterized basically as [gils2014]:

- Electric vehicles.
- Devices that can be used all along the day or in a large number of hours (washing machines or other similar appliances)
- Devices with a payback time of a few hours (heating and cooling devices).

Due to the special character of the electric vehicles, its description is made in a separate section.

**Domestic demand.**

No data of the devices and their use by the customers are available, and for this reason results from the surveys [est2010] and [palmer2014] have been taken. From them, the flexibility of the appliances and the number of appliances present in the homes of the domestic customers are shown in the table shown in the appendix. This gives an average percentage of flexible demand from electrical appliances (without heating and cooling devices) of 29.8%.

In the case of LV non-domestic loads, flexibility comes from devices supplying cold and ventilation services (ventilation, air conditioning and cooling appliances from food retailing, cold storages, etc.). Flexible loads consumption is approximated by multiplying the annual non-domestic demand by the shares of DR processes per type of non-domestic building. It is assumed that the flexible part of current non-domestic loads is 100% available for DR.

A sample of the hourly values of non-flexible and flexible demand for a few days randomly chosen is given in Figure 4.1.1, where the flexible demand follows here the overall demand, i.e. without optimizing it.

Details of how these values have been found are given in the Appendix.

**MV loads**

MV loads in Brescia network correspond to small industries, workshops and commercial buildings. Flexible consumption for DR is provided from devices supplying commercial ventilation, electrical heating, cold storage, pumps and air conditioning. They are estimated by multiplying each MV demand with average
demand shares of the processes considered for DR. A sample week showing the fixed and flexible demand is given in Figure 4.1.2. Again, it has been considered that 100% of flexible demand can be used.

4.2 Electric vehicles.

In the Unareti network there are two charging points with capacity of 33 kW each. At present there are no electric vehicles in this network. There is no information about charging profiles in charging points, so in this preliminary analysis it is assumed that the domestic customers charge all electric vehicles at home.

Electric vehicles are part of the responsive demand, and three kinds of charging have been considered:

- Dumb charging
- Tariff (two-tier), where the cheaper one begins in late evening.
- Smart charging, fitting the energy to the market price profile.

The size and other features (storage capacity and charging time) of the vehicle have been taken in agreement to the considerations made in EU project MERGE (D 1.1) for a first approximation. The considered assumptions are:

- Average charging rate - Standard: 3 kW
- Average distance travelled between two charge events: 40km
- Vehicle energy consumption: 0.16kWh/km
- Charger efficiency: 90%
- Charge time duration: 2.13 hours per charge.

Although the charging rate is low, it must be taken into account that a higher rate would exceed the capacity of a domestic customer. This consideration is made in D2.1 of MERGE. This is valid for all the 4 types of vehicles considered in MERGE (Quadricycle, Passenger vehicle, Goods-carrying vehicle up to 3500 kg and, Goods-carrying vehicle for more than 3500 kg).

The arrival pattern of the vehicles has been taken from D1.10 of EU project Green e-Motion in Italy. This pattern has been made after a survey of a number of vehicles in Italy and other countries. The number of sampled vehicles and the percentage of arrivals along different time slots in the day are given in the following table. The analysis made in this project is ample and consider different types of vehicles (particular, company owned, municipal, rented, etc.). Since there are no data for the Unareti network, and now there are no electric vehicles, a more detailed study is not possible.
It can be seen that there are only three different days, weekday, Saturday and Sunday. The number of charges in the weekdays is almost the same and in the weekend is 80% of the weekdays. In the project there are no seasonal or monthly patterns. In the simulation it has been considered that the vehicles are charged once per arrival. The energy consumed in the whole of the network is calculated taking into account the arrivals and the charging time.

With these considerations, the following profiles can be obtained. A yearly series of hourly values have been obtained, but in the Figure 4.2.1 only a few days will be shown, as an example.

5 Future scenarios

5.1 Definition of the scenarios.

5.1.1 Green distributed

The names of DER scenarios are: Green distributed, Green centralized, and Combined. Scenarios The Green distributed scenario represents a timeline in which the political will is to significantly increase RES in distribution grids and at the same time improve energy efficiency (e.g. heat pumps, insulation requirements, electric vehicles, etc.) and decrease the use of fossil fuels (e.g. replace oil-based heating with heat pumps). Because demonstration networks are located in office building or residential housing areas, only viable RES scenario in medium and low voltage network is small-scale PV (few kW up to few hundred kW). PV units for end customers are made economically viable either by new technical innovations or support schemes. The number of PV units and heat pumps will rapidly increase in the coming years. The number of electric vehicles is first increasing slowly until technical breakthrough of battery technology is found around year 2035 according to IEA when the share of electric vehicles about all passenger vehicles increases very rapidly. Changes in existing buildings are assumed to be very low (only through renovations), but new buildings are naturally much more energy efficient than average characteristics of buildings. Annual net energy demand of new buildings is approaching towards zero because of efficiency requirements of buildings and installation of PV at rooftops.

5.1.2 Green centralized

The Green centralized scenario represents a timeline where RES is centralized and mainly connected to high and extra high voltage networks. DG units in medium and low voltage networks are scarce and therefore do not have major impact on long-term distribution network planning. Also changes in DERs like heat pumps
and electric vehicles, and energy efficiency requirements of buildings are much more moderate than in Green distributed scenario. The net demand of customers remains almost at the same level as today. The role of distribution grid is considered to be a reliable link between centralized production and end customers, thus regulation puts great emphasis on grid reliability. Network regulation gives direct incentive to DSOs to consider outages in network planning e.g. in the form of high outage costs in power quality incentive within determination of allow profit of DSO. Distribution automation solutions like FLISR probably become a viable solution to enhance the performance of distribution network.

5.1.3 Green combined
The Green combined scenario is, as is evident, the combination of both previous scenarios. The high penetration of EVs and DG units is present in distribution grid along with heightened reliability criterions.

5.1.4 Methodology to create scenarios.
The DER scenarios are defined by identifying the key components of future grid usage. These include Distributed generation, EV charging, heating and cooling demand of residential and non-residential buildings, storages and household appliances. Each of these is modelled separately according the assumptions of existing technological and political trends in each scenario. The complete scenario is then formed by adding the individual scenario components together.

5.2 PV production
The amount of distributed generation is modelled as the share of customers who have a grid connected PV unit. In larger sense the distributed generation can be also different kind like micro wind turbines or such but in the scope of this project only PV generation is considered. The amount of PV generation can be evaluated either by global projections, such as one depicted in figure 5.2.1, or if know by the local governmental goals and predictions, or by the history of DG penetration. In this study we have chosen the last approach.

![Figure 8: Regional production of PV electricity envisioned in this roadmap](image)

**Figure 8.** Regional production of PV electricity envisioned in this roadmap

**Figure 5.2.1.** Global predictions on PV penetration.
The history of PV installations in the Unareti grid, and the linear regression coefficients used in the projections are depicted in figure 5.2.2.
The amount of PV installation in the grid through the planning horizon is depicted in figure 5.2.3.

Assumptions:
- PV production follows the reference years curve
- The installations in the future are of same size as installations today.
5.3 EV charging

EV charging is identified as the amount of home charging stations. EV numbers in the scenarios is based on projections on market shares of new EVs by [evolution2014, iea2011]. The powertrain development scenarios used in this study are depicted in figure 5.3.1. The very strict regulation (first plot in figure) is assumed to apply in Green Distributed and Green Combined scenario and the no-change-in-regulation is assumed to apply for Green Centralized scenario. The average amount of vehicles is assumed to remain constant in the planning zone trough the planning horizon.

The EVs in Green Distributed and Green Combined scenario are primarily Battery EVs as Fuel Cell EVs are not considered as a potential technology for passenger cars. This creates a higher power need per vehicle from grid point of view. In Green Centralized scenario most of the passenger cars are hybrid EVs, as without governmental incentives BEVs cannot compete pricewise with HEVs.

![Future of powertrain market remains uncertain](image)

Figure 5.3.1. Prediction of various powertrain developments under varying climate goals.

The amount of EV home charging in Green distributed and Green combined scenario are depicted in figure 5.3.2. The turning point of EV share is assumed to happen at 2030 when the Total cost of ownership of EV becomes significantly lower than the total cost of ownership of ICE the saturation of EVs is reached around 2035-2040. The penetration of EVs is largely due to the high governmental incentives for EV ownership. In Green Centralized scenario the EV penetration starts much later and the saturation is not reached in the planning horizon.
Assumptions:

- Introduction of EVs does not affect the driving behaviour or the average amount of vehicles per household
- Trip lengths and departure/arrival times of [merge112010] apply
- EV is primarily charged at home, after daily trips.
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- The commercial charging has no effect on the grid

## 5.4 Heating and cooling demand

The heating and cooling demand is evaluated with thermodynamic models of average buildings. Generalized models by [bettenghauser2013] are used in order to evaluate the heating / cooling need of a certain building type. The need for cooling is translated into electrical power either directly (Direct electrical heating/cooling) or by dividing it with COP (heat pumps).

The number of heat pumps in the grid is evaluated by the projections of [bettenghauser2013]. In the Green centralized scenario most of the customers are changing the current fossil fuel based heating solutions into either direct electric heating or into district heating whereas in the Green Distributed and Combined scenario most of the customers are selecting heat pumps as primary source of heating and cooling energy.

The Heating and cooling demand is estimated from the GIS data of the existing grid. The buildings associated with a certain substation are calculated manually from network plots. The figure 5.4.1 depicts one LV network and the building associated with it. The building types are identified with satellite images.

![Figure 5.4.1 LV network (sample) of Unareti.](image)

As previously stated the heating and cooling demand for Green Distributed and Combined scenario are primarily heat pumps and district heating. Linear growth is assumed. In green Centralized scenario the heating and cooling is primarily direct heating and district heating. (Figure 5.4.2).
Assumptions:

- The average house model [bettenghauser2013] applies for the buildings in grid area
- Models for heat propagation by [pandakov2015] apply
- The optimal temperature is constant over the year
- The flexibility of heating can be modelled as +/- 1 degree in realized temperature
- The amount of buildings does not change

5.5 Storages

An additional possibility to shift the electrical delivery or feed-in in the network is to use energy storages. Storing electrical energy is a big challenge. Due to the fact that electrical energy cannot store directly, the electrical energy have to convert in kinetic, heating, or chemical energy. In Distribution Systems the power of storages are small (up to less MW). Therefore, the common storage types are heat or chemical storages. The heat storage are described in chapter 5.4. This chapter is concentrate on chemical storages like batteries. Batteries are mainly used in combination with PV plants or as uninterruptible power supply to increase the power quality.

In the Scenarios are assumed that at 40 Percent of the PV plants have a battery storage included. Based on the existing storage types each battery has a power of 3 kW and a storage capacity of 860 Wh. The development of the storage capacity of each scenario is shown in figure 5.5.1.
6 Results.

In this section, the main results of the simulation studies for the considered scenarios are given and commented. These studies are the Target network planning, the Expansion planning and the Operational planning.

6.1 Target network planning.

The result of the Target Network Planning is the target network. It represents the cost-minimal network considering all the technical constraints for the given scenario. The result shows the target network for the demonstration network area of Unareti. The considered future scenarios are described in the previous chapter 4. In each scenario, the four control strategies of the controllable loads and storages (Original, Market, Capacity) are investigated. These different scenarios and control strategies have an influence on the result of the Target Network Planning.

In the cost evaluation, the investment and operation costs of the network components as well as the costs of the losses are considered. Costs for the implementation of the remote control of the customers are not considered in the investigations. These controllable customers have to be connected with ICT to the control center. It causes additional costs.

The aim of this investigation is to quantify the influence of these control strategy variations on the network planning. In the following, the results of the different scenarios are presented.

Results Green Distributed

The Green Distributed Scenario has the largest number of PV plants installed. Due to the different control strategies and consequently different load behaviors of EV, storages and heat pumps, the network structures and their costs are different. Figure 6.1.1 shows the annual network costs dependent on the control strategy.

The control strategy “market” allows the maximization of the benefits of the network customers. Therefore, the behavior of the network customers is influenced by the same market signal. Hence, the simultaneous behavior increases the peak load. The total network cost of this target network is higher than in the variation “original”, which does not consider the control of the customers.
The network cost is lowest in the variation “capacity”. The aim of the customer control is to reduce the peak load in the network. This means that each customer can be controlled individually. Due to the individual control, the network cost of this variation is the lowest.

![Network Cost Graph](image)

**Figure 6.1.1 Annual Network costs of the demonstration area in scenario Green Distributed**

Figure 6.1.2 shows the Target Networks of the Unareti demonstration area under consideration of different control strategies. These Target Networks have a different number of rings. In the variations “Original” and “Capacity”, all customers are connected by two cable rings, while in the variation “Market” one secondary substation is connected by a separate ring.

![Network Structures](image)

**Figure 6.1.2 Network structures of the demonstration area in scenario Green Distributed**

**Results Green Centralized**

Due to the moderate penetration of heat pumps, EVs and DER, their impact on the medium voltage networks is less in comparison to the Green Distributed Scenario. Therefore, the result of the Target Network Planning, the Target Network, is lesser than in the Green Distributed Scenario. Consequently, the network costs are also less. The annual network costs for the three control strategies are shown in Figure 6.1.3. The network costs of these three variations differentiate less from each other also due to the lower number of controllable devices in this scenario.
IDE4L is a project co-funded by the European Commission

Figure 6.1.3 Annual Network costs of the demonstration area in scenario Green Centralized

Figure 6.1.4 shows the network structures of the three target networks. In this scenario, all target networks consist of two rings. The routing of the three target networks is different.

Results Green Combined

The Green Combined Scenario is the combination of the both previous scenarios. The installed capacity of DER is between those scenarios. The number of EVs and heat pumps is the same as the Green Distributed Scenario. The annual network costs are shown in Figure 6.1.5. In this scenario, the variation in the network costs of the target networks is higher than in the other scenarios.
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Figure 6.1.5 Annual Network costs of the demonstration area in scenario Green Combined

Figure 6.1.6 shows the target networks of the Unareti demonstration area of the different control variations. The target networks, which are designed for the variations, have a different number of rings. In the variations “Original” and “Capacity” all customers are connected by two cable rings, while in the variation “Market” three rings are necessary to connect all customers.

General discussion

Due to the fact that the demonstration area of Unareti is urban network, the influence of the RES generation is small in comparison to other studies. However, the result of the Target Network Planning shows in general the effect of the control strategies of network customers. Due to the higher simultaneity of the load behavior, the network costs in the variation “market” are the highest in all three scenarios. However, the network costs could be reduced, if the network operator controls the controllable elements like storages, heat pumps and EVs. This is shown in the variation “capacity”, which has the aim to homogenize the load and feed-in in the network.

This could be also shown in the KPIs. The KPI for the Target Network Planning is defined in D7.1 of the IDE4L-Project:

\[
KPI_{TNP} = \frac{Costs_{BAU} - Costs_{SG}}{Costs_{BAU}} \times 100\%
\]  

(6.1)

With:

- \(Costs_{BAU}\) are the costs “Business as Usual” and presents the annual network costs of the variation “Original”.
- \(Costs_{SG}\) are the costs “Smart Grid” which presents the annual network costs of the other both variations “Market” and “Capacity”.

Therefore, the KPIs could be deviated and they are shown in Table 6.1.
### Table 6.1.1 KPIs of the Target Network Planning

<table>
<thead>
<tr>
<th>Scenario</th>
<th>Market</th>
<th>Capacity</th>
</tr>
</thead>
<tbody>
<tr>
<td>Green Distributed</td>
<td>- 4.09%</td>
<td>2.08%</td>
</tr>
<tr>
<td>Green Centralized</td>
<td>- 1.66%</td>
<td>- 0.34%</td>
</tr>
<tr>
<td>Green Combined</td>
<td>- 6.71%</td>
<td>2.36%</td>
</tr>
</tbody>
</table>

6.2 Expansion planning.

The results of expansion planning show the optimal steps to develop the existing grid to the Target network discussed in previous chapter. Expansion planning uses the results of the target network planning as input, thus similar optimization schemes are examined and an optimal development plan is constructed for all cases.

General assumptions in these calculations:
- Voltage limits: 1.05 to 0.95 pu
- Component overload limit: > 100% of nominal
- Constant interest rate of 4%
- Component prices, operational expenses, and scenarios are same as in Target Network Planning
- Network useful life is 20 years, for all components.

The following figures show the logical topology of the Unareti grid in the different stages of the planning horizon, with the amount of invested money into the grid assets.

**Results Green Distributed**

![Diagram](image)

*Figure 6.2.1: Development steps of Unareti grid and investment costs in Green Distributed scenario with Market optimization*
Figure 6.2.2: Development steps of Unareti grid and investment costs in Green Distributed scenario with Capacity optimization

Figure 6.2.3: Development steps of Unareti grid and investment costs in Green Distributed scenario without optimization
Results Green Centralized

Figure 6.2.4: Development steps of Unareti grid and investment costs in Green Centralized scenario with Market optimization

Figure 6.2.5: Development steps of Unareti grid and investment costs in Green Centralized scenario with Capacity optimization
Figure 6.2.6: Development steps of Unareti grid and investment costs in Green Centralized scenario with no optimization

Results Green Combined

Figure 6.2.7: Development steps of Unareti grid and investment costs in Green Combined scenario with Market optimization
Figure 6.2.8: Development steps of Unareti grid and investment costs in Green Combined scenario with Capacity optimization

Figure 6.2.9: Development steps of Unareti grid and investment costs in Green Combined scenario with no optimization
The results presented in the figures 6.2.1 thru 6.2.9 it is evident that for the Unareti network under the assumptions of all the DER scenarios, it would seem that the limiting constrain of the network is the aging of the network. The point where the investments are made is in 2040 when the whole target network is constructed at once. From replacement investment point of view this is quite beneficial as the existing grid is utilized fully during its lifetime. This however has the unfortunate effect that the results of the expansion planning study are inconclusive. Since there is no direct benefit of delaying the required investments the study cannot quantify the amount of benefit that would be gained from ANM functionalities in the form of investment time planning.
6.3 Operational planning.

The results of the simulations with the improved smart operational planning will be shown and commented in this section. Results have been obtained for a whole year (52 weeks, i.e. 8736 hours) for the data presented in the previous section and for the scenarios considered.

The final assessment of the benefits of market-oriented (smart) strategies for the operational planning is made using the proposed KPIs, namely, reduction of energy cost and the ratio between minimum and maximum electricity demand within a day. Other metrics have been used to properly quantify the advantages of the proposed strategy. The KPIs are calculated for the different scenarios, comparing the obtained results from the optimized strategy with a Business as Usual (BaU) assumption where no optimization is made and where the possible flexibility of the load is not used.

The scenarios studied are the already described: Green Centralized (GC), Green Distributed (GD) and Green Combined (GCo). The most relevant differences among them are related with the penetration level of Photovoltaic in the distribution networks (MV and LV), the way of heating and the flexibility related to it, as well as the storage management. In this case, while in the GD scenario each consumer uses the stored energy coming from the PV for individual consumption after sunset. In the GC scenario, though, the storage capacity is used for shifting load trying to profit from the market price differences.

Since the participation of an aggregator trying to minimize its energy purchase expenses has been modeled, the followed assumptions, partially commented elsewhere are summarized here:

- The aggregator has the function of retailer, flexibility manager and balancing responsible for the customer it represents.
- These customers are LV domestic and non domestic and MV customers. Some of them have generation (PV) facilities. The production of this generation is subtracted from the demand. They have also storage facilities, which can be used as they wish. A single aggregator represents all the consumers of the Unareti network.
- All the users participate with their declared flexibility, following the instructions of the aggregator.
- The obtained benefits are the aggregator’s benefits. This can be transferred to its customers via tariffs or by means of some incentive. The description and modeling of these incentives is beyond the scope of this report.
- The aggregator behaves as a price taker. No market power hypotheses have been considered.
- The prices considered here are the same for the simulated years. Although the price level might not modify the relative overall conclusions, the price pattern does. It might be that in the future a more flat pattern will take place (less difference between consumption in peak and valley hours). Also higher electricity prices would make more attractive the savings for use of flexibility for the same relative benefit.
- Generally speaking, what is calculated here is an upper limit (in relative terms, not in absolute terms) of the benefits that could be obtained from the full use of flexibility when participating in the electricity markets.

The total yearly demand in the scenarios is, per category:

- Non-flexible LV domestic demand: 5183 MWh.
- Total non domestic LV demand: 6426 MWh
- Total MV demand: 8241 MWh

The flexible LV domestic demand varies per scenario and year.
The proportions of the charging strategy of electric vehicles considered in the different years are shown in the following table. They do not change between the GC, GD and GCo scenarios.

<table>
<thead>
<tr>
<th>Charging strategy</th>
<th>2015</th>
<th>2020</th>
<th>2025</th>
<th>2030</th>
<th>2035</th>
<th>2040</th>
<th>2045</th>
<th>2050</th>
</tr>
</thead>
<tbody>
<tr>
<td>Smart</td>
<td>--</td>
<td>55%</td>
<td>60%</td>
<td>57%</td>
<td>72%</td>
<td>74%</td>
<td>74%</td>
<td>76%</td>
</tr>
<tr>
<td>Tariff</td>
<td>--</td>
<td>25%</td>
<td>25%</td>
<td>28%</td>
<td>18%</td>
<td>18%</td>
<td>18%</td>
<td>18%</td>
</tr>
<tr>
<td>Dumb</td>
<td>--</td>
<td>20%</td>
<td>15%</td>
<td>15%</td>
<td>10%</td>
<td>8%</td>
<td>8%</td>
<td>6%</td>
</tr>
</tbody>
</table>

Before showing the obtained KPI, some examples are presented here, where the different results are compared for the BaU situation and for different scenarios. Results are shown for the same day in order to allow a better comparison.

The total demand in the sample day, for the year 2050 in the three scenarios (GC; GD and GCo) are shown in the following picture, compared to the BaU case.

![Aggregated demand for a sample day in the three scenarios for 2050.](image)

In this figure it can be seen that the flexibility is greater in the distributed scenario. The demand without optimization follows the price shape (demand is highly correlated with price if no demand management is made) and it reaches a peak in the first hour of the day, when the cheap charging tariff for EV begins. The optimized strategy is reversed to the price shape: consumption is larger when the prices are lower and vice versa.

As an example, the next figure shows what is the consumption of electric vehicles in year 2050 in the three considered scenarios. It can be seen the dumb, tariff and smart charging, as well as the BaU result. The dumb charging follows the BaU charging scheme, the tariff customers produce a peak in the beginning of the low tariff and the smart charging takes place when the prices are lower.

![Aggregated EV consumption for a sample day in the three scenarios for 2050.](image)
The overall results, assessed by means of the proposed KPIs are shown below.

**Reduction of energy cost**

This KPI was defined in the following way.

\[ \text{COST} = \text{COST}_{\text{SmartGrid}} - \text{COST}_{\text{BaU}} \]

where the costs are calculated for a whole year, in our cases of 364 days.

The costs in both assumptions and the differences are shown in the following table. The first one shows the total costs, the second the KPI and the third the relative value, calculated in this way

\[ \text{KPI}_{\text{rel}} = \frac{\text{KPI}}{\text{COST}_{\text{BaU}}} \]

<table>
<thead>
<tr>
<th>Scenario / Year</th>
<th>Energy Cost [€/year]</th>
<th>2015</th>
<th>2020</th>
<th>2025</th>
<th>2030</th>
<th>2035</th>
<th>2040</th>
<th>2045</th>
<th>2050</th>
</tr>
</thead>
<tbody>
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<td>Green-centralized</td>
<td>1287291</td>
<td>1327224</td>
<td>1370421</td>
<td>1499838</td>
<td>1617783</td>
<td>1700264</td>
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<tr>
<td>BaU - centralized</td>
<td>1320379</td>
<td>1372040</td>
<td>1427023</td>
<td>1576015</td>
<td>1728236</td>
<td>1802139</td>
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<td></td>
<td></td>
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<tr>
<td>Green-combined</td>
<td>1468516</td>
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<td>1621396</td>
<td>1673854</td>
<td>1827522</td>
<td>1948856</td>
<td>1938540</td>
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<td></td>
</tr>
<tr>
<td>BaU - combined</td>
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<td></td>
<td></td>
</tr>
<tr>
<td>BaU - distributed</td>
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<td>1504494</td>
<td>1527634</td>
<td>1644052</td>
<td>1906172</td>
<td>2057355</td>
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</table>

<table>
<thead>
<tr>
<th>KPI</th>
<th>Reduction of energy cost [€/year]</th>
<th>2015</th>
<th>2020</th>
<th>2025</th>
<th>2030</th>
<th>2035</th>
<th>2040</th>
<th>2045</th>
<th>2050</th>
</tr>
</thead>
<tbody>
<tr>
<td>Green-centralized</td>
<td>33088</td>
<td>44816</td>
<td>56602</td>
<td>76177</td>
<td>89121</td>
<td>93302</td>
<td>101875</td>
<td>104288</td>
<td></td>
</tr>
<tr>
<td>Green-combined</td>
<td>44781</td>
<td>56745</td>
<td>76265</td>
<td>91369</td>
<td>130213</td>
<td>154309</td>
<td>156465</td>
<td>166075</td>
<td></td>
</tr>
<tr>
<td>Green-distributed</td>
<td>37131</td>
<td>54455</td>
<td>63210</td>
<td>83710</td>
<td>128995</td>
<td>140521</td>
<td>149669</td>
<td>165868</td>
<td></td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>KPIrel</th>
<th>Reduction of energy cost [%]</th>
<th>2015</th>
<th>2020</th>
<th>2025</th>
<th>2030</th>
<th>2035</th>
<th>2040</th>
<th>2045</th>
<th>2050</th>
</tr>
</thead>
<tbody>
<tr>
<td>Green-centralized</td>
<td>2.5</td>
<td>3.3</td>
<td>4.0</td>
<td>4.8</td>
<td>5.2</td>
<td>5.4</td>
<td>5.7</td>
<td>5.8</td>
<td></td>
</tr>
<tr>
<td>Green-combined</td>
<td>3.0</td>
<td>3.6</td>
<td>4.5</td>
<td>5.2</td>
<td>6.7</td>
<td>7.3</td>
<td>7.5</td>
<td>7.9</td>
<td></td>
</tr>
<tr>
<td>Green-distributed</td>
<td>2.7</td>
<td>3.6</td>
<td>4.1</td>
<td>5.1</td>
<td>6.8</td>
<td>7.3</td>
<td>7.7</td>
<td>8.1</td>
<td></td>
</tr>
</tbody>
</table>

It can be seen that the highest difference is for the GC scenario because it allows for higher flexibility. Depending of the different years the GCo may provide better improvements. This depends on the amount of flexible devices that are being added along the time. In any case the difference between both scenarios is small. The KPI values show that the benefits for the aggregator (and its consumers) in the case of full use of their flexibility are far for being negligible.

**Ratio between minimum and maximum electricity demand.**

The other KPI proposed in the project is the ratio between minimum and maximum electricity demand within a day (MMDR), whose mathematical expression is:

\[ \text{MMDR} = \frac{\sum_{j=1}^{N} \frac{D_{\text{max},j}}{D_{\text{min},j}}}{N} \]

where N is the number of days (364 in our case), and \( D_{\text{max},j} \) and \( D_{\text{min},j} \) are the maximum and minimum hourly demand of day \( j \). The values obtained for this KPI for the smart and BaU scenarios are given in the following table.
It this table, it can be seen that the use of flexibility leads to higher differences between peak and base load. This might be an undesirable consequence of profiting of the prices differences. However, the high consumption hours of these users are opposed to those of the general consumption mirrored in the price shape. A higher use of the flexibility from other users and aggregators would lead to a more flat price pattern and therefore there will be less incentive for load shifting and in this way the KPI will take lower values.

The values of $\frac{D_{\text{max},j}}{D_{\text{min},j}}$ for each day $j$ along the simulated days are shown in the next figure for the GD scenario. It can be seen that the optimized demand presents higher values.

---

**Congestion management**

With the optimal strategy of market participation from the aggregator side developed, no congestion appears in the Unareti study network (shown in Figure 3.1.1), in any of the three scenarios considered: Green Distributed, Green Centralized and Green Combined.

Then, in order to show the performance of the algorithm, the most unfavorable scenario, regarding potential congestions has been chosen. This scenario is the base (“original”) Green Distributed Scenario in 2050. In this scenario, dumb charging is considered for the electric vehicles.
The customers of this study network are divided into three main types: domestic (including EVs), non-domestic customers in LV (including public lighting) and MV customers. There is a PV plant connected to this MV network at node 0545, rated 141 kW, and a number of LV customers with PV arrays, with a total of 957.54 kW installed.

In this study case, the sources of flexibility are heating and cooling devices, the electrical appliances and other sources of flexibility coming from industrial processes of non-domestic customers in LV and MV. The assumed decomposition into flexible and non-flexible demand per kind of load is the same that appears in section 4.1.

With the demand and generation series of data, congestion may occur in hour 8489 of the year, that is, in the hour 17 of a December day (day 354). The congestion is produced in the underground line connecting PL0002 and SS1056, in the second section of line 3 (green line in Figure 3.1.1), giving an overload of 102% (6.2 MVA is the rated limit of apparent power allowed).

It is assumed that the aggregator collects the flexibility from its customers and aggregates it by type of customer (domestic, non-domestic and MV). Given that no real flexibility bids were available, flexibility bids have been built based on data of and electricity prices for each type of customer taken from EUROSTAT database [eurostat2016].

From [eurostat2016], using data from the second semester of 2015, the average base price (price without taxes and levies) in Italy for medium standard industrial consumers (those with an annual electricity consumption between 500 and 2000 MWh) was around 0.09 €/kWh, and the average base price for household consumers (with annual electricity consumption between 2 500 and 5 000 kWh) was around 0.15 €/kWh. Regarding LV non-domestic consumers, an intermediate value has been obtained by linear interpolation. The average value of the Prezzo Unico Nazionale (PUN) in 2015 has been taken as reference since this is the price that the demand, and hence the aggregators, should pay. This average value of the PUN was 0.052 €/kWh. All these prices are shown in Table 6.3.1.1.

<table>
<thead>
<tr>
<th>Type of consumer</th>
<th>Electricity price (€/kWh)</th>
</tr>
</thead>
<tbody>
<tr>
<td>LV Domestic consumers</td>
<td>0.15</td>
</tr>
<tr>
<td>LV Non-domestic consumers</td>
<td>0.12*</td>
</tr>
<tr>
<td>MV consumers</td>
<td>0.09</td>
</tr>
<tr>
<td>PUN</td>
<td>0.052</td>
</tr>
</tbody>
</table>

Table 6.3.1.1. Average base prices of electricity in Italy in 2015 (*obtained by interpolation).

Then, the ratios of the base price for each type of consumer and the PUN have been taken to obtain the flexibility prices in 2050. For the hour of congestion, flexibility prices and market price are depicted in Table 6.3.1.2.

<table>
<thead>
<tr>
<th>Type of consumer</th>
<th>Flexibility price (€/kWh)</th>
</tr>
</thead>
<tbody>
<tr>
<td>LV Domestic consumers</td>
<td>0.16816</td>
</tr>
<tr>
<td>LV Non-domestic consumers</td>
<td>0.13453</td>
</tr>
<tr>
<td>MV consumers</td>
<td>0.10090</td>
</tr>
<tr>
<td>Market price (PUN)</td>
<td>0.05838</td>
</tr>
</tbody>
</table>

Table 6.3.1.2. Flexibility prices and market price in hour 8489 of year 2050.

With the prices shown in Table 6.3.1.2, MV flexibility would be the first one in being selected, followed by the flexibility from LV non-domestic consumers. Domestic flexibility would be the last one in being used.
The solution of the congestion management algorithm is that the DSO should purchase flexibility products in order to solve the congestion in line 3. Total amount of flexibility needed reaches the value of 92.9 kW, which is distributed among different nodes of line 3 as indicated in Table 6.3.1.3. The total cost of this flexibility is 9.37 €/h, but total cost of energy is not increased in this amount due to a lower power at the primary substation node (10.0099 MW in the original case and 9.9015 MW in the final case). Total cost of energy in the original case is 584.30 €/h and total cost of energy in the final case (after applying the algorithm) is 587.43 €/h (+ 3.13 €/h).

<table>
<thead>
<tr>
<th>Node</th>
<th>Flexibility (kW)</th>
</tr>
</thead>
<tbody>
<tr>
<td>749</td>
<td>15.1</td>
</tr>
<tr>
<td>937</td>
<td>43.8</td>
</tr>
<tr>
<td>1070</td>
<td>24.5</td>
</tr>
<tr>
<td>1180</td>
<td>9.5</td>
</tr>
</tbody>
</table>

Table 6.3.1.3. Flexibility used per node.

The loading of each branch of the line 3 before and after applying the congestion management algorithm is shown in Figure 6.3.1.1. With the algorithm, congestion is solved, but the congested branch (line number 4 in Figure 6.3.1.1) is 100% loaded. By applying security factors and purchasing more flexibility the final loading could be further decreased.

6.4 Summary.

The present set of studies have shown the benefits of making use the smart grid possibilities, in particular the full use of the customers’ flexibility. The study has been performed in a real study network under three scenarios that represent the likely evolution of renewable penetration, smart devices and control strategies from the present time to 2050. The regulatory framework considered is similar to the current, with the minimal changes to allow the deployment of flexibility and the full advantages of its possibilities.

The results show that investment savings of up to 2.36% in the future network can be obtained by fully use of the possibilities of the smart grid in the target network planning. Expansion planning studies however were inconclusive due to the relatively strong grid and small grid area. In all study cases the existing grid could be utilized to its full extent leaving little to be optimized in this respect.
The use of flexibility under favorable regulatory conditions and willingness of the customers of making full use of it may produce decrease in energy purchase costs of up to 8.1% in the most favorable case in the limit study case year, 2050, which is an attractive result. These results must be looked at considering that the prices of the energy have not changed along time for the study. Prices can change in two ways, firstly, by an increase in the average level and secondly by changing the daily and seasonal pattern that they have now. In the first case, the results in relative value will remain the same, and only the average price of the energy will say what the value the absolute gain is. Higher energy prices will make more attractive the smart grid solution, since the savings are larger.

The second change is more difficult to ponder and is related with the second result given in the report. Very likely, the increase in flexibility use and the higher number of DER, PV in particular, storage devices and electric vehicles will change the demand pattern as well as the price patterns. This effect is shown in the peak consumption displacement observed in the optimized results. These results produce in many cases differences between maximum and minimum consumption larger than in a BaU scenario. Under this situation the benefits of the flexibility use may differ from the obtained results, but this effect cannot be considered with the available data of this study case.

7 Conclusion.

The aim of this deliverable has been to make a benefit assessment of the planning methods using a smart grid approach following the IDE4L concept. This assessment has been made in three different planning levels: target network planning, expansion planning and operational planning.

The results for these different time scopes (long term, mid term and short term, respectively) show the benefits of the optimal network that would make full use of the smart grid potentialities, the optimal steps to be taken in the network expansion and the smart procurement of energy in the market for aggregators. All these benefits represent savings in the final electricity costs, via energy purchase or access tariff. They would eventually lead to a decrease in energy cost to the final customers.

Flexibility is here understood as the capability of consumers to distribute their consumption along the day in order to get an economic advantage, and that can be used to optimize the network operation.

The results have been obtained for three scenarios: Green distributed, Green Centralized and Green Combined. In all cases, the assumed renewable share is the same for the whole system but the distributed scenarios assumes a greater involvement of individual users in the smart grid. The combined scenarios are a midpoint between the other two. These scenarios map the likely evolution of power systems until 2050 under the considered hypotheses. Results for selected years between today and 2050 have been obtained.

The advanced planning methods have been applied to the Unareti test grid. Available data for this grid include grid topology and data, measurements of consumption of selected users, contracted powers and PV installed power. This grid includes MV users and LV domestic and non domestic users. The study has been made for the MV grid, where the LV consumers have been aggregated. This represents a probable field for the implementation of the smart grid paradigm.

From the available data and making reasonable assumptions (explained in this document), the available flexibility of users and the changes in consumption has been made. In this way, different consumption and production series of hourly values have been made for every studied year as well as the energy consumed in a flexible way.

State-of-the-art planning tools developed by the project partners and modified when necessary, have been made. More advanced tools like probabilistic modeling of consumers have not been considered because the lack of proper data would yield unreliable results.
Simulation results show that there are benefits coming from the use of smart planning methods at the three levels. These benefits are moderate, but there is room still for greater improvements if the controllability, storage and number of EV increase. It must be taken into account the even if the relative gain is small, the size of the system to which these methods would be applied would produce large absolute gains.

Target network planning that takes into account the flexibility of the users may yield savings up to 2.36% and the results raise a possible conflict between a market oriented strategy of the users and the aim of leveling the load pattern instead, more economical from the point of view of investment in networks.

Operational planning results show that for 2050, savings up to 8% could be obtained if the flexibility of users is fully exploited. Again, the use of market prices as the only incentive leads to a more concentrated consumption in the low price hours and (as for the Target grid planning) to a higher dimensioned grid.

About this problem, it must be mentioned that current energy prices for the Italian network have been considered. This assumption conditions the results very strongly.

Firstly, a rise in the price level will yield higher absolute savings and vice versa. More importantly, the progressive increase of flexibility will likely change the price pattern that will tend to flatten. This means that the benefits for the smart scheduling will decrease, but that the needed investments for redimensioning the grid will also decrease. An assessment of these effects is not easy to make because to guess how the price pattern will be in the future is extremely complex and out of the scope of the project.

Finally, this development will be only possible within a favorable regulatory framework that supports these beneficial trends towards the smart grid.

In this way, the role of the aggregator should be clearly defined in order to allow this agent the full use of the customers’ flexibility – for example, allowing the combination of distributed generation and consumption.

Also the capacity of the distributors to make use of customers’ flexibility should be encouraged, making again use of the aggregator as a mediator between consumers and DSO. Therefor, an efficient use of flexibility in customers could be achieved with the maximum simplicity. A market for this flexibility should be designed in coordination with the existing markets, facilitating the participation of the maximum number of customers and agents in general.

Publications issued from this project


8 References.


Entranze project Deliverable D2.1. The challenges, dynamics and activities in the building sector and its energy demand in Italy. Available at http://www.entranze.eu/


“EVolution - Electric vehicles in Europe: gearing up for a new phase?”, Amsterdam Roundtable Foundation and McKinsey & Company The Netherlands, April 2014

Green e-Motion project Deliverable D1.10. European global analysis on the electromobility performance. Available at http://www.greenemotion-project.eu


IA-HEV Hybrid and electric vehicles. The electric drive delivers (2015)


Merge project Deliverable D 1.1 MOBILE ENERGY RESOURCES IN GRIDS OF ELECTRICITY. (2010). Available at http://www.ev-merge.eu

Merge project Deliverable D 2.1 MODELLING ELECTRIC STORAGE DEVICES FOR EV (2010). Available at http://www.ev-merge.eu

Merge project Deliverable D 3.2 (1). Evaluation of the impact that a progressive deployment of EV will provoke on electricity demand, steady state operation, market issues, generation schedules and on the volume of carbon emissions (2011)


9 ANNEXES

9.1 A. Data and measurements not included in the main body.

Low voltage domestic demand measured data.

A number of measurements came from a group of 18 customers of this network. The measurements consist in 5 minutes average values of consumed power and PV production. The period when these measurements have been collected is from 10/26/2014 to 4/15/2015, i.e., 172 days.

A second set of measurements came from a group of 21 customers (considering the 18 customers from the first measurements). They consist in 5 minutes average values as the first measurements, but these measurements have been collected from 01/05/2015 to 31/10/2015, i.e., 184 days.

From all data, only measurements of 15 customers have been taken, because of unreliable or missing data for problems in the LV network at the moment of the measure.

The total number of consumers in the network is 3951 and they have a total contracted power of 20507 kW.

MV measured data

The measurements came from each one of the 9 medium voltage customers of the Unareti network. They are 15 minutes average values of consumed power. The period of the consumption measurements was collected from 01/11/2014 00:00:00 to 30/04/2015 23:45:00, i.e., 181 days.

From the data, only the customer in node 545 injects power to the MV network, a PV plant produces this energy and the maximum injected power is 84kW.
There are missing measurements for the MV load in SS1462 where no data of March is found. Besides, the contracted power is 50kW but this does not coincide with the maximum consumption data (92 kW). In this case, 160kW of contracted power has been considered.

<table>
<thead>
<tr>
<th>Substation</th>
<th>Max. Consumption (kW)</th>
<th>Contracted Power (kW)</th>
</tr>
</thead>
<tbody>
<tr>
<td>297</td>
<td>630</td>
<td>1000</td>
</tr>
<tr>
<td>732</td>
<td>92</td>
<td>160</td>
</tr>
<tr>
<td>749</td>
<td>78</td>
<td>112</td>
</tr>
<tr>
<td>1070</td>
<td>123</td>
<td>187</td>
</tr>
<tr>
<td>1180</td>
<td>182</td>
<td>600</td>
</tr>
<tr>
<td>545</td>
<td>154</td>
<td>500</td>
</tr>
<tr>
<td>1006</td>
<td>438</td>
<td>625</td>
</tr>
<tr>
<td>1512</td>
<td>103</td>
<td>500</td>
</tr>
<tr>
<td>1462</td>
<td>96</td>
<td>160</td>
</tr>
<tr>
<td>Total</td>
<td>--</td>
<td>3844</td>
</tr>
</tbody>
</table>

Maximum consumptions and contracted power of medium voltage loads in Unareti test grid.

The following figures show a boxplot of the obtained values per hour and the hourly average values of the total consumption in p.u. for the sampling period.

Since there are not data for a whole year (only 181 days), it is not possible to build a complete yearly pattern, thus, the monthly consumption used has been scaled according to the monthly consumption of Italy in 2014 (Terna Rete Italia 2015).

PV data.

There are also 957.54 kW of PV connected to the network, whose installed power and their storage capacity is shown in the following table.

<table>
<thead>
<tr>
<th>Installed PV power (W)</th>
<th>2960</th>
<th>1290</th>
<th>1290</th>
<th>1290</th>
<th>4220</th>
<th>1290</th>
<th>1290</th>
<th>1290</th>
<th>5000</th>
<th>1290</th>
<th>1290</th>
<th>4110</th>
</tr>
</thead>
<tbody>
<tr>
<td>Storage</td>
<td>No</td>
<td>No</td>
<td>Yes</td>
<td>Yes</td>
<td>No</td>
<td>No</td>
<td>Yes</td>
<td>No</td>
<td>No</td>
<td>Yes</td>
<td>No</td>
<td>Yes</td>
</tr>
</tbody>
</table>

Existing storages in Unareti test grid.

In order to form a hourly production series for the PV, since there is not enough data to produce it from measurements, a PV model has been run in the program SAM [sam2016] with the following data:

- Radiation data for a year come from [eplus2016].
- Model PVWatts (simplified). Standard panel, rated power 4 kW of SAM. Tilt of 45º (roughly the latitude of Brescia). Losses of 14.08% (default in SAM). Rooftop panels.
- 50% of the panels are oriented to South, 25% are oriented to East, and 25% are oriented to West.

The model has been fitted to the available data of the six month available values.

![Figure 9.1.2. Comparison between synthesized series and data.](image)

**Contracted power per node and type in the study network**

<table>
<thead>
<tr>
<th>Node</th>
<th>P total (kW)</th>
<th>P domestic (kW)</th>
<th>P non domestic (kW)</th>
<th>PV (kW)</th>
<th>Pub. Lighting (kW)</th>
<th>MVload (kW)</th>
<th>No. Cust.</th>
</tr>
</thead>
<tbody>
<tr>
<td>60</td>
<td>1876.6</td>
<td>1506.45</td>
<td>370.15</td>
<td>62.59</td>
<td>53.6</td>
<td>0</td>
<td>487</td>
</tr>
<tr>
<td>117</td>
<td>733.85</td>
<td>376.2</td>
<td>357.65</td>
<td>12.7</td>
<td>32</td>
<td>0</td>
<td>133</td>
</tr>
<tr>
<td>145</td>
<td>1347</td>
<td>1112.1</td>
<td>234.9</td>
<td>45.74</td>
<td>32</td>
<td>0</td>
<td>357</td>
</tr>
<tr>
<td>297</td>
<td>521.6</td>
<td>44.55</td>
<td>477.05</td>
<td>145.68</td>
<td>0</td>
<td>1000</td>
<td>34</td>
</tr>
<tr>
<td>338</td>
<td>1627.95</td>
<td>1249.6</td>
<td>378.35</td>
<td>43.77</td>
<td>32</td>
<td>0</td>
<td>422</td>
</tr>
<tr>
<td>378</td>
<td>207.9</td>
<td>179.3</td>
<td>28.6</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>63</td>
</tr>
<tr>
<td>468</td>
<td>213.3</td>
<td>9.9</td>
<td>203.4</td>
<td>5.89</td>
<td>0</td>
<td>30</td>
<td>13</td>
</tr>
<tr>
<td>545</td>
<td>470.9</td>
<td>324.5</td>
<td>146.4</td>
<td>6</td>
<td>0</td>
<td>500</td>
<td>101</td>
</tr>
<tr>
<td>585</td>
<td>370.05</td>
<td>228.8</td>
<td>141.25</td>
<td>14.2</td>
<td>3.3</td>
<td>0</td>
<td>83</td>
</tr>
<tr>
<td>603</td>
<td>257.45</td>
<td>59.4</td>
<td>198.05</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>18</td>
</tr>
<tr>
<td>604</td>
<td>614.4</td>
<td>407</td>
<td>207.4</td>
<td>34.35</td>
<td>0</td>
<td>0</td>
<td>132</td>
</tr>
<tr>
<td>605</td>
<td>403.8</td>
<td>257.4</td>
<td>146.4</td>
<td>7.18</td>
<td>17.6</td>
<td>0</td>
<td>84</td>
</tr>
<tr>
<td>732</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>625</td>
<td>1</td>
</tr>
<tr>
<td>749</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>1125</td>
<td>1</td>
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<tr>
<td>827</td>
<td>703.16</td>
<td>51.15</td>
<td>652.01</td>
<td>157.18</td>
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<td>0</td>
<td>39</td>
</tr>
<tr>
<td>870</td>
<td>730.7</td>
<td>515.35</td>
<td>215.35</td>
<td>29.61</td>
<td>32</td>
<td>0</td>
<td>176</td>
</tr>
<tr>
<td>937</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>125</td>
<td>1</td>
</tr>
<tr>
<td>952</td>
<td>346.75</td>
<td>217.8</td>
<td>128.95</td>
<td>5.82</td>
<td>0</td>
<td>0</td>
<td>71</td>
</tr>
<tr>
<td>987</td>
<td>1354.3</td>
<td>770.55</td>
<td>583.75</td>
<td>7.04</td>
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<td>0</td>
<td>258</td>
</tr>
<tr>
<td>1006</td>
<td>434.9</td>
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<td>434.9</td>
<td>0</td>
<td>0</td>
<td>625</td>
<td>18</td>
</tr>
<tr>
<td>1023</td>
<td>758.15</td>
<td>559.35</td>
<td>198.8</td>
<td>16.76</td>
<td>36</td>
<td>0</td>
<td>188</td>
</tr>
<tr>
<td>1024</td>
<td>907.6</td>
<td>523.05</td>
<td>384.55</td>
<td>21.19</td>
<td>0</td>
<td>0</td>
<td>178</td>
</tr>
<tr>
<td>1056</td>
<td>1384.3</td>
<td>1123.65</td>
<td>260.65</td>
<td>232.97</td>
<td>53.6</td>
<td>0</td>
<td>296</td>
</tr>
<tr>
<td>1070</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>1875</td>
<td>1</td>
</tr>
<tr>
<td>1073</td>
<td>508.95</td>
<td>0</td>
<td>508.95</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>23</td>
</tr>
<tr>
<td>1136</td>
<td>1079.2</td>
<td>745.25</td>
<td>333.95</td>
<td>8.86</td>
<td>17.6</td>
<td>0</td>
<td>209</td>
</tr>
<tr>
<td>1143</td>
<td>784.85</td>
<td>732.05</td>
<td>52.8</td>
<td>50.12</td>
<td>23.1</td>
<td>0</td>
<td>220</td>
</tr>
<tr>
<td>1180</td>
<td>521.5</td>
<td>19.8</td>
<td>501.7</td>
<td>31.67</td>
<td>0</td>
<td>1625</td>
<td>35</td>
</tr>
<tr>
<td>1187</td>
<td>136.3</td>
<td>0</td>
<td>136.3</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>3</td>
</tr>
</tbody>
</table>
### Data of the Unareti network.

**Coefficients used to form the yearly load pattern**

The next table shows the weekly peak load in percent of annual peak. The week number 1 is assumed to be the first week of the calendar year, then the peak occurring in the week before to the last week of July.

<table>
<thead>
<tr>
<th>Week</th>
<th>Peak Load</th>
<th>Week</th>
<th>Peak Load</th>
</tr>
</thead>
<tbody>
<tr>
<td>1</td>
<td>68.7</td>
<td>27</td>
<td>63.0</td>
</tr>
<tr>
<td>2</td>
<td>68.1</td>
<td>28</td>
<td>87.9</td>
</tr>
<tr>
<td>3</td>
<td>70.7</td>
<td>29</td>
<td>97.1</td>
</tr>
<tr>
<td>4</td>
<td>70.7</td>
<td>30</td>
<td>100.0</td>
</tr>
<tr>
<td>5</td>
<td>71.2</td>
<td>31</td>
<td>67.1</td>
</tr>
<tr>
<td>6</td>
<td>73.3</td>
<td>32</td>
<td>74.4</td>
</tr>
<tr>
<td>7</td>
<td>74.8</td>
<td>33</td>
<td>75.8</td>
</tr>
<tr>
<td>8</td>
<td>68.5</td>
<td>34</td>
<td>47.4</td>
</tr>
<tr>
<td>9</td>
<td>67.4</td>
<td>35</td>
<td>50.6</td>
</tr>
<tr>
<td>10</td>
<td>65.8</td>
<td>36</td>
<td>62.1</td>
</tr>
<tr>
<td>11</td>
<td>64.2</td>
<td>37</td>
<td>55.4</td>
</tr>
<tr>
<td>12</td>
<td>65.4</td>
<td>38</td>
<td>56.7</td>
</tr>
<tr>
<td>13</td>
<td>62.0</td>
<td>39</td>
<td>57.8</td>
</tr>
<tr>
<td>14</td>
<td>58.1</td>
<td>40</td>
<td>59.7</td>
</tr>
<tr>
<td>15</td>
<td>57.6</td>
<td>41</td>
<td>60.6</td>
</tr>
<tr>
<td>16</td>
<td>58.0</td>
<td>42</td>
<td>58.6</td>
</tr>
<tr>
<td>17</td>
<td>62.3</td>
<td>43</td>
<td>62.6</td>
</tr>
<tr>
<td>18</td>
<td>62.4</td>
<td>44</td>
<td>63.5</td>
</tr>
<tr>
<td>19</td>
<td>59.2</td>
<td>45</td>
<td>66.5</td>
</tr>
<tr>
<td>20</td>
<td>59.4</td>
<td>46</td>
<td>67.1</td>
</tr>
<tr>
<td>21</td>
<td>58.5</td>
<td>47</td>
<td>67.7</td>
</tr>
<tr>
<td>22</td>
<td>57.1</td>
<td>48</td>
<td>70.1</td>
</tr>
<tr>
<td>23</td>
<td>65.6</td>
<td>49</td>
<td>65.4</td>
</tr>
<tr>
<td>24</td>
<td>68.9</td>
<td>50</td>
<td>71.3</td>
</tr>
<tr>
<td>25</td>
<td>56.5</td>
<td>51</td>
<td>69.9</td>
</tr>
<tr>
<td>26</td>
<td>53.7</td>
<td>52</td>
<td>71.9</td>
</tr>
</tbody>
</table>

**Normalized weekly peak loads of yearly load pattern.**

In the following Tables, the daily load in percent of weekly peak and the hourly load in percent of the daily peak are shown for each season of the year. From the first Table, it can be seen that the daily consumption is higher on weekend than weekdays with the peak always occurring on Sunday. Comparing the daily consumption between seasons, the summer peak load is the highest from Monday to Thursday.
IDE4L Deliverable 2.3

Seasonal peak loads.

<table>
<thead>
<tr>
<th></th>
<th>Winter Peak Load</th>
<th>Summer Peak Load</th>
<th>Spring Peak Load</th>
<th>Fall Peak Load</th>
</tr>
</thead>
<tbody>
<tr>
<td>Monday</td>
<td>89.9</td>
<td>95.6</td>
<td>89.3</td>
<td>88.5</td>
</tr>
<tr>
<td>Tuesday</td>
<td>88.5</td>
<td>93.0</td>
<td>89.7</td>
<td>85.1</td>
</tr>
<tr>
<td>Wednesday</td>
<td>87.7</td>
<td>96.9</td>
<td>84.7</td>
<td>88.5</td>
</tr>
<tr>
<td>Thursday</td>
<td>87.3</td>
<td>93.8</td>
<td>87.9</td>
<td>86.2</td>
</tr>
<tr>
<td>Friday</td>
<td>84.2</td>
<td>88.4</td>
<td>92.7</td>
<td>85.2</td>
</tr>
<tr>
<td>Saturday</td>
<td>93.8</td>
<td>96.9</td>
<td>94.6</td>
<td>97.6</td>
</tr>
<tr>
<td>Sunday</td>
<td>100.0</td>
<td>100.0</td>
<td>100.0</td>
<td>100.0</td>
</tr>
</tbody>
</table>

Normalized daily load profiles.

Consumption of MV loads

The following figures shows the weekly consumption in kWh of each MV load.
Assumption and data for the flexibility assessment in study network. Domestic demand.

The flexibility of the domestic demand is taken form HVAC devices and appliances (freezer, fridge, washing machine, dishwasher, clothes dryer). It has been considered that there are two kinds of flexibility [gils2014]: (1) flexibility linked to the HVDC devices, where the power can be shifted a maximum of two hours and (2) power that can be consumed in a given period (24 hours, or off-peak hours, for instance). In both cases, it has been assumed that this flexibility can be used without interfering in the comfort of the users. It has been also considered that the aggregator can use all the flexibility. This is, hence, an upper limit estimate.

The data needed to obtain this flexibility loads are the annual consumption, maximum power, frequency of use, ownership rate, the number of domestic customers in the network (3376 in Unareti network) and average load profiles of large appliances. Typical data taken from [gils2014], [est2010], [zimmermann2012], [palmer2014], [remodece2016] have been taken.

In the following figures, the average profile of the different devices are given, based on the previously cited studies.

![Figure 9.1.4 Average load profile of Fridge-freezer](image-url)
IDE4L Deliverable 2.3

Figure 9.1.5 Average load profile of washing machine

Figure 9.1.6 Average load profile of appliances

The daily weekly load patterns in p.u. for fridge-freezer and washing/drying appliances are shown in the next Table, [zimmermann2012]. The fridge-freezer shows a higher consumption on workdays. Conversely, the washing/drying appliances consume more on weekends.

<table>
<thead>
<tr>
<th>Day in week</th>
<th>Fridge-freezer</th>
<th>Washing m.</th>
<th>Dishwasher</th>
<th>Clothes dryer</th>
</tr>
</thead>
<tbody>
<tr>
<td>Workdays</td>
<td>1.00</td>
<td>0.88</td>
<td>0.92</td>
<td>0.67</td>
</tr>
<tr>
<td>Weekend</td>
<td>0.98</td>
<td>1.00</td>
<td>1.00</td>
<td>1.00</td>
</tr>
</tbody>
</table>

*White goods appliance weighting factors.*

In the next figures the seasonality effect on the consumption along the year in the fridge-freezer and washing/drying appliances are shown.

Figure 9.1.7 Cold appliances – Seasonality effect.
The mean yearly consumption per electrified household [enerdata2016] and the average annual consumption of each appliance are shown in the tables below, assuming that the Mean average consumption per household in Italy is 2338 kWh/hh.

<table>
<thead>
<tr>
<th>Type of appliance</th>
<th>Average annual consumption (kWh)</th>
<th>Ownership rate</th>
</tr>
</thead>
<tbody>
<tr>
<td>Fridge-freezer</td>
<td>383</td>
<td>0.99</td>
</tr>
<tr>
<td>Washing machine</td>
<td>209</td>
<td>0.97</td>
</tr>
<tr>
<td>Clothes dryer</td>
<td>209</td>
<td>0.1</td>
</tr>
<tr>
<td>Dishwasher</td>
<td>210</td>
<td>0.45</td>
</tr>
</tbody>
</table>

Annual consumption and ownership rate of white goods appliances.

Considering the relative contribution from the different loads-without electric heating in a year, the following breakdown per household is utilized as in (Energy Saving Trust. 2010). The flexible loads annual consumption from household appliances is on average a 29.8% (697 kWh) and with air conditioning, it is 924 kWh.

<table>
<thead>
<tr>
<th>Without electric heating</th>
</tr>
</thead>
<tbody>
<tr>
<td>Type of appliance</td>
</tr>
<tr>
<td>Cold appliances</td>
</tr>
<tr>
<td>Cooking</td>
</tr>
<tr>
<td>Lighting</td>
</tr>
<tr>
<td>Audiovisual</td>
</tr>
<tr>
<td>ICT</td>
</tr>
<tr>
<td>Washing machine</td>
</tr>
<tr>
<td>Clothes dryer</td>
</tr>
<tr>
<td>Dishwasher</td>
</tr>
<tr>
<td>Heating</td>
</tr>
<tr>
<td>Not known</td>
</tr>
<tr>
<td>Other</td>
</tr>
<tr>
<td>Air conditioning</td>
</tr>
<tr>
<td>Total</td>
</tr>
</tbody>
</table>

Consumption breakdown by appliances.
Non domestic LV loads

It has been considered in the evaluation of the non domestic LV loads flexibility, that the use of energy is shared as shown in the table below [saele2010] [gruber2008].

<table>
<thead>
<tr>
<th>Building</th>
<th>Heating [%]</th>
<th>Cooling [%]</th>
<th>Misc. [%]</th>
</tr>
</thead>
<tbody>
<tr>
<td>Hotel</td>
<td>35%</td>
<td>40%</td>
<td>25%</td>
</tr>
<tr>
<td>Restaurant</td>
<td>42%</td>
<td>31%</td>
<td>27%</td>
</tr>
<tr>
<td>School</td>
<td>47%</td>
<td>19%</td>
<td>34%</td>
</tr>
<tr>
<td>Hospital</td>
<td>31%</td>
<td>40%</td>
<td>29%</td>
</tr>
<tr>
<td>Supermarket</td>
<td>9%</td>
<td>18%</td>
<td>73%</td>
</tr>
<tr>
<td>Office</td>
<td>30%</td>
<td>28%</td>
<td>42%</td>
</tr>
</tbody>
</table>

Consumption breakdown of non-domestic customers in LV network.

The monthly patterns for heating and cooling loads, are shown in Figure 9.1.9.

![Figure 9.1.9 Heating (---) and cooling (+-) monthly patterns.](image)

MV loads

The flexibility of the MV loads is estimated by multiplying each MV demand by the average demand shares of the processes considered for DR [gils2014], [saele2010], [gruber2008].

Decomposition of the annual MV flexible demand per type of business and process is shown in the next Table. Electrical heating has been considered in a low share because of the district heating presented in the network and the monthly consumption of Italy in 2014 (Terna Rete Italia 2015).

<table>
<thead>
<tr>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td>Small Industry</td>
<td>0.6</td>
<td>20</td>
<td>2</td>
<td>18</td>
<td>11</td>
<td>48</td>
</tr>
<tr>
<td>Commercial C.</td>
<td>0.2</td>
<td>25</td>
<td>0</td>
<td>15</td>
<td>10</td>
<td>50</td>
</tr>
<tr>
<td>Workshop</td>
<td>0.6</td>
<td>20</td>
<td>2</td>
<td>18</td>
<td>8</td>
<td>51</td>
</tr>
<tr>
<td>Supermarket</td>
<td>7</td>
<td>10</td>
<td>0.6</td>
<td>12</td>
<td>1</td>
<td>60</td>
</tr>
<tr>
<td>Restaurant</td>
<td>0.2</td>
<td>20</td>
<td>0.2</td>
<td>12</td>
<td>1</td>
<td>56</td>
</tr>
</tbody>
</table>

Consumption breakdown of non-domestic customers in MV network.

9.2 DER scenarios

DER scenario data included in Excel files:
- detailedderscenario-a2a-distributed.xlsx
- detailedderscenario-a2a-centralized.xlsx
- detailedderscenario-a2a-combined.xlsx
9.3 Algorithms

9.3.1 Target network

The aim of the network planning is to find a network structure, which can supply all customers with the minimal network cost. Therefore, the objective function of the network planning is to minimize the network cost consisting of the investment costs and the operating costs. Classically, the computer-based network planning can be divided into two parts: Target Network Planning, which identifies the future cost-minimal network (target network) and the Expansion Planning, which has the task to create a roadmap to reach the future target network from the present network. In this chapter, the Target Network Planning is described.

To identify the cost minimal network, “Green-Field-Approach” is chosen. Therefore, the time horizon of the Target Network Planning is at least the lifetime of the network components. This means that the time horizon of the Target Network Planning should be 30 to 50 years in the future.

The Target Network Planning has the aim to identify the cost-minimal network for a given supply task in the long-term future, which can also satisfy the safe and secure supply of the network customers. Therefore, there are some boundary conditions to consider, which could be technical constraints (i.e. voltage stability, thermal limit, etc.) on the one hand, on the other hand the building development could be also restrict the network planning. These facts mean that the target network planning has high uncertainties, which are mostly modeled by different scenarios. These scenarios describe the development of the customer load as well as the development of the supply task and they are self-consistent.

The degrees of freedom of this problem are mainly the cable routing and the choices of the network component types (cable, transformer, switches, etc.) to be used. Consequently, this problem is a combinatorial optimization problem, which has a finite, but very large amount of solutions. To check the technical constraints of the planning problem, the non-linear power flow equations have to be solved. Therefore, the problem could be described as a mixed trigonometric-quadratic optimization problem.

To solve such a problem, different approaches are described in the literature. In the network planning process, heuristic approaches are used usually. In the IDE4L project a medium voltage network should be planned. In [Rotering2013] a method is presented, which could solve this problem by an ant-colony-system. The ant-colony system is a genetic algorithm based on an evolutionary process. The advantage of this approach is easy to implementation of parallelization instead of a single solution. Several solutions can be evaluated at the same time. This set of solutions, called population, can be adapted after each iteration by selection or mutation. The approach chooses the best solutions after each iteration. The best solutions are combined by crossovers and random mutations in order to ensure a wide solution space and not to converge to a local optimum.

The ant-colony system is based on the natural role model of foraging ants. It is observed that ants find the shortest way between their nest and the feed. This fact is used in the Target Network Planning. The Target Network Planning problem could be defined as a traveling salesman problem, because medium voltage networks have often a radial network structure.

Theoretically, all secondary substations and medium voltage customers could be connected with each other secondary substation, customer or the primary substation. In practice, the single substations or customers are connected with the nearby substations or customers. Therefore, the degrees of freedom could be highly reduced. For a reduction of the computation time, it is also useful to reduce the corresponding model in the optimization process. This can be done by the Delaunay Triangulation.
With the Delaunay Triangulation, a given area including nodes can be divided into triangles, so that the vertices of these triangles are created on the given nodes. The sides of the triangles are called edges and they connect the nodes. These edges represent the reduced amount of possible cable routes. An exemplary result of the Delaunay Triangulation is shown in Figure 9.3.1.1.

The fact that medium voltage networks are mostly build as ring networks, is used in the algorithm. So, it is possible to formulate the ring network planning problem in a problem of a minimal span tree. Therefore, another graph is placed on the top of the triangulation. The middle pints of each triangle becomes a node of this second graph as well as the primary substation. These nodes are also connected to the next adjacent nodes. The ant colony system is used on this graph. Due to this, the nodes are called ant nodes and the paths are called ant paths.

The ants are walking on the ant paths, starting on the ant nodes, which represent the primary substations, to find the shortest way. Firstly, the ants are looking for food without preferential direction. When an ant finds a feed, it returns to the nest and leaves a pheromone trail. Other ants are guided in this track, but also continue to explore other options. Since all ants are moving at the same speed, the pheromone level on shorter paths is higher. Consequently, these paths are preferred. The result is an optimal spanning tree surrounded by a ring cable network.

Due to the fact that medium voltage cables are laid along streets, in order to an easy maintenance of these cables, the presented algorithm uses the street map data of the OpenStreetMap [OSM2016] project to identify possible cable routes. OpenStreetMap provides the street data in the xml format. Typically in mathematics and computer science, this data is transformed into an Adjacency Matrix ($AM$), which maps the information to nodes and edges. The $AM$ describes adjacencies between two nodes. If two nodes $i$ and $j$ directly connected, the element $am_{i,j}$ of the $AM$ is 1. In the planning process, the distances between each node are needed. Therefore, the $AM$ are weighted by the distances between the nodes. This matrix is called the Weight Adjacency Matrix $WAM$.

$$WAM = \begin{pmatrix} v_{1,1} & \cdots & v_{1,n} \\ \vdots & \ddots & \vdots \\ v_{n,1} & \cdots & v_{n,n} \end{pmatrix}$$

(9.1)

With:

$$v_{i,j} = \begin{cases} \text{dist}(\text{node}_i, \text{node}_j) & \text{if node}_i \text{ and node}_j \text{ directly connected} \\ 0 & \text{if node}_i \text{ and node}_j \text{ not directly connected} \end{cases}$$

The model allows an exact display of the street data. In order to determine the exact distances between each substation, a high resolution of nodes is necessary.
The processed data consists on roads and road junctions. In the next step, the locations of the primary and secondary substations are mapped onto the street data. The several substations are connected to the next available node of the road graph. If the substations are directly placed close to the road, the extra cable length of the connection line can be neglected. In individual cases, where no nodes of the road graph is close to the substation, an additional connection have to be created.

In order to reduce the processing time of the algorithm, the resolution of the road graph will be reduced. Therefore, nodes, that have exactly two connections and no substations, are way nodes of the road. These two connections and this node could be substituted by one edge. In order to not lose information, the distance of the new edge is the sum of the distances of the substituted edges. The real road length $R_L$ consists of all distances of the associated nodes $ASN$ that belongs to that road.

$$ASN = \begin{pmatrix} node_1 \\ \vdots \\ node_m \end{pmatrix}$$

$$R_L = \sum_{i=1}^{m-1} WAM(ASN(i), ASN(i + 1))$$

The result of this simplification is a Reduced Weighted Adjacency Matrix $RWAM$, which contains all important information for the network planning. The dimension of the problem can be greatly reduced by this process.

After processing the street data, the needed information for the cable routing are identified. Therefore, a routine is needed, which finds the shortest connection between two nodes (substations) in the graph. This issue in graph theory is known as the Shortest Path Problem. This is the problem of finding a path between two vertices (or nodes) in the graph such that the sum of the weights of its constituent edges is minimized. The best known algorithm for this application is the Dijkstra algorithm. One of the main reasons for the popularity of this algorithm is that it is one of the most important and useful algorithms available for generating exact optimal solutions to large class of shortest path problems.

When all shortest paths are determined, a new graph result that only contains nodes and edges is used for connecting all substations with minimal weight. Since all possible shortest connection are considered, it is ensured that no solution has been overlooked and deleted accidentally.

$$\dim(RWAM) \ll \dim(WAM)$$
The ant-colony-system is an iterative heuristic approach and is shown in Figure 9.3.1.2. In each iteration, there are multiple colonies and each colony has multiple ants. Each ant represents a candidate network. The generation of each candidate network starts at the ant node of the primary substation. From this node the nearby ant nodes are connected over the ant paths with a minimal spanning tree. The enveloped of the Delaunay triangles of the connected ant nodes represent the medium voltage network ring structure. The connection of the triangles ends, if all secondary substations are connected to the medium voltage network ring. In the first iteration, the connection of the ant nodes is a random process. The process of the triangle connection is shown in Figure 9.3.1.3.
After the first iteration, the information of the previous iterations is used to improve the random process to get a better result. The information of the quality of a candidate network is saved in its pheromone level. This pheromone level is based on the technical and economic evaluation of the candidate networks. After the generation of the candidate network, the technical evaluation starts. Therefore, a load flow for 8760 hourly time steps is calculated to check the voltage limits and current limits of the network components. If the candidate network violates these limits, this candidate network will be deleted. Otherwise the candidate network will be evaluated economically.

The economic evaluation is based on the annuities of the investment costs including a fixed factor for the maintenance costs as well as annual costs of losses. The losses are estimated from the load flow calculation from the technical evaluation process.

References Target Network Planning

9.3.2 Expansion planning
The expansion planning algorithm is composed of four distinctive parts: Expander, Validator, Allocator, and Router. They each have a dedicated task in the expansion planning algorithm. In this chapter they are described. For the general description of the algorithm refer to chapter 2.3.

Expander
The expander is the key part of the Expansion planning algorithm. Its purpose is to make suggestions of the possible development steps. The Expander compares the current state of the network to desired target network and identifies the independent parts of the network that can be replaced. The network components are placed in a priority order of replacement from which the Expander selects the most urgent required replacement. When the replacement is selected the Expander compares the selected part of the network topology to the target networks topology and selects the pieces of the target network which will eventually replace the existing parts.

The expansion solutions generated by the expander are based on a heuristic set of rules made to maximize the effective use of the existing grid. For this functionality the expander sorts all the components into remaining useful age order so that first component to be replaced is the oldest in the network. Expander selects set of replacing topologies once any part of the network ceases to fulfill the planning criterions.
Figure 9.3.2.1 demonstrates the Expander behavior in case that the line between vertices 2 and 4 is selected to be replaced. Expander notes that the edge in question is not part of the target network and then checks that trough which vertices is the vertex 4 routed in the target network, which in this case is through vertex 3. It’s also important to note that in this example an alternative routing to the vertex could also be done via vertices 5 and 6 but since this expansion is more expensive than the first (longer cabling) the first one is selected.

General set of rules for the Expander are:

- If component is at the end of its useful life, find replacing topology form target network and validate
- If component has overload:
  - find replacing topology form target network and validate
  - switch to congestion managed profiles and validate
- If vertex has a voltage out-of-bounds
  - apply CVC for the whole network and validate
  - find replacing topology from vertex to root and validate

Validator

Validator makes sure that the network development suggested by the Expander is viable from technical perspective. The technical feasibility analysis in this part of the algorithm takes into account following variables:

- Voltage limits (according to EN 50160)
- Component overloading (maximum loading 100% of nominal)
- Useful life of components

Validator is based on OpenDSS [1] calculation software. It calculates hourly load flows for every hour of the planning reference year. The demand and generation profiles for the calculation are obtained from DER scenarios. Output of this algorithm part is topology data for the Expander to know which parts of the studied network expansion suffer either overloading or out-of-bounds voltage.

Allocator

Allocator is the part of the algorithm which compares the validated development steps into each other and determines the transition costs from one network state to another. The possible development steps form a directed graph from the current network state to the target network. Allocators task is to form this graph from the data saved in expansion stage so that the Router which does the final optimization to find the best sequence of development steps has required input data.
Each vertex of the network state graph has a cost associated with network operational costs during the time which the said development steps exists. This cost consists of estimated/calculated network losses, maintenance costs and other costs specified by the designer. Each edge of the graph consists of capital costs of transition to turn the network from origin node network into the target node network. Their calculation is based on component unit prices defined by the designer, essentially “which components need to be bought in order to transform the grid from one network to another”.

Allocator calculates all the network-cost graph only for physically feasible transitions. Meaning that skipping development steps is not allowed and that returning to a network state which is planned before the current state is forbidden.

![Network State Graph]

**Figure 9.3.2.2:** The transitions generated by the Allocator. Each of the black arrow is weighted with the CAPEX of the transition. Red arrows are forbidden transitions.

**Router**

Router is the optimizing part of the algorithm which finds the shortest path through network-cost graph generated by the Allocator. The shortest path should be understood as the path of lowest cumulative cost during the planning horizon. The Routes utilizes well-known Dijkstra’s algorithm [2] to determine the shortest route.

For the purposes of the algorithm the operational costs associated with the target vertex of an arbitrary edge on the network-cost graph is added to the edge weight leading to the said vertex. This is done since Dijkstra’s algorithm in its original form doesn’t consider that the vertex could have a weight associated to it.

Also, the time value of the costs associated to a certain transition is assessed by calculating their present value with discounted cash flow method [3].


9.3.3 Operational planning.

In this section the mathematical formulation of the process followed to obtain the optimal use of the flexibility for purchasing energy and solving congestion is made.

Scheduling problem

The optimization process consist in the minimization of the purchase cost of the energy for the aggregators. A simplified formulation is given below. The problem is a mixed linear integer optimization problem.

\[
\begin{align*}
\text{min} & \quad \sum_{t=1}^{N_h} \pi_t P_{t}^{\text{net}} \\
\text{subject to} & \quad \sum_{t=1}^{N_{\text{shift}}} P_{t}^{\text{shift}} \cdot d = E_{\text{shift}} \\
& \quad \sum_{t=1}^{N_{\text{ev}}} P_{t}^{\text{ev}} \cdot d = E_{\text{ev}} \\
& \quad P_{t}^{\text{flex}} = P_{t}^{d} - P_{t}^{\text{flex}} + \sum_{k=1}^{N_k} P_{t+k}^{\text{back}} \quad t = 1, \ldots, N_h \\
& \quad P_{t}^{\text{load}} = P_{t}^{\text{fix}} + P_{t}^{\text{shift}} + P_{t}^{\text{flex}} + P_{t}^{\text{ev}} + P_{t}^{B+} - P_{t}^{B^-} \quad t = 1, \ldots, N_h \\
& \quad E_{t}^{B} = E_{t-1}^{B} - \frac{1}{\eta} P_{t}^{B+} \cdot d + \eta^{-} P_{t}^{B^-} \cdot d - \Delta E \\
& \quad P_{t}^{\text{net}} = P_{t}^{\text{load}} - P_{t}^{\text{pv}} \quad t = 1, \ldots, N_h \\
& \quad P_{t}^{\text{flex}} = \sum_{k=1}^{N_k} P_{t+k}^{\text{back}} \quad t = 1, \ldots, N_h \\
& \quad -P_{\text{cont}} \leq P_{t}^{\text{net}} \leq P_{\text{gen}} \quad t = 1, \ldots, N_h \\
& \quad 0 \leq P_{t}^{\text{shift}} \leq P_{t}^{\text{shift,max}} \quad t = 1, \ldots, N_h \\
& \quad 0 \leq P_{t}^{\text{flex}} \leq P_{t}^{d} \quad t = 1, \ldots, N_h \\
& \quad 0 \leq P_{t}^{\text{load}} \leq P_{\text{cont}} \quad t = 1, \ldots, N_h \\
& \quad 0 \leq P_{t}^{B+} \leq P_{t}^{B+,\text{max}} \quad t = 1, \ldots, N_h \\
& \quad 0 \leq P_{t}^{B-} \leq P_{t}^{B-,\text{max}} \quad t = 1, \ldots, N_h \\
& \quad E_{t}^{B,\text{min}} \leq E_{t}^{B} \leq E_{t}^{B,\text{max}} \quad t = 1, \ldots, N_h \\
& \quad P_{t+k}^{\text{back}} = 0; \quad \forall \ k = 1 \ldots N_k \\
& \quad P_{Nh}^{\text{flex}} = 0
\end{align*}
\]

Nomenclature.

Indices

- \( t \): Time intervals, [h].
- \( k \): Maximum time until shifted load has to be balanced, [h].

Variables

- \( P_{t}^{\text{net}} \): Net power bid in the market in period \( t \), [kW].
- \( P_{t}^{\text{shift}} \): Shiftable demand in period \( t \), [kW].
- \( P_{t}^{\text{ev}} \): Electric vehicle demand in period \( t \), [kW].
- \( P_{t}^{\text{flex}} \): Net flexible power \( t \), [kW].
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$p_{t}^{flex}$ Flexible demand taken in period $t$, [kW].

$p_{t,k}^{payback}$ Payback energy in period $k$ of flexible power taken in period $t$ [kW].

$p_{t}^{load}$ Total demand in period $t$, [kW].

$p_{t}^{B+,B^{-}}$ Power from/to the batteries in period $t$, [kW].

$E_{t}^{B}$ Stored energy in period $t$, [kWh].

Constants and data

$E_{shift}$ Daily amount of shiftable energy [kWh].

$E_{ep}$ Daily amount of electric vehicle energy [kWh].

$p_{t}^{d}$ Maximum shiftable demand in period $t$, [kW].

$p_{t}^{fix}$ Fixed demand in period $t$, [kW].

$p_{t}^{pv}$ Photovoltaic generation in period $t$, [kW].

$p_{gen},P_{con}$ Installed capacity and contracted power, [kW].

$p_{t}^{shift,max}$ Maximum shiftable demand in hour $t$, [kW].

$\Delta E$ Energy losses in the storage system [kWh].

$\eta^{+},\eta^{-}$ Efficiencies of giving back/storing the energy of the batteries [kWh].

$d$ Duration of the market time slot [h]

$N_{shift}$ Number of hours allowed for load shifting.

$N_{h}$ Number of time slots of the optimization time

$N_{k}$ Number of hours allowed for the payback of the flexible load.

As a general consideration, the shiftable demand will be called that requires that a given amount of energy must be consumed in a number of predefined hours. This may consist in electrical appliances that can be connected at different moments or electric vehicles, which have a range of hours where they can be charged. The demand whose payback must be given in the following hours will be called flexible.

Equation (1) is the objective function and represents the cost of purchasing energy for the given prices. It is followed by the constraints of the process. Equations (2) and (3) formulate the condition that the shiftable power should be provided in a given number of hours. Equations (4) to (7) formulates the power balance in order to define $P_{t}^{net}$, the result of the optimization process. The condition that the flexible power should be paid back in the next $N_{k}$ hours is formulated in equation (8). The rest of the equations pose the limit of the variables, except the two last ones, which sets the initial and final conditions. It can be seen that the power

Although the time slot has been of one hour, according to the Italian market features, the formulation could be applied to any other time slot, $d$.

Congestion management

The main objective of the congestion management algorithm is to propose changes of scheduled generation/consumption values of DER units, through flexibility offers/bids to provide a feasible combination of schedules in the day ahead framework or in the in-tra-day markets.

As said before, the DSO, at a given moment after the electricity market gate closure (day ahead or intraday market), calculates the possible congestions and network problems that could be arisen by this market solution. If any network constraint is violated, the available flexibility is used to avoid load or generation curtailment. The algorithm is run for timeslots of one hour independently.
As inputs, the algorithm takes the network information (topology, voltage limits, lines ratings) and the market information (the provisional schedule and the market clearing price). The algorithm needs to know the aggregated generation/demand of each MV node from the market clearing and to have forecasts of DG connected at MV and LV networks of independent producers not included in any CA portfolio.

A Power Flow calculation is run first in order to check limit violations in the network (voltage, branch loading and power capabilities constraints of the network). If violations are detected, the algorithm will evaluate flexibility products offered by the aggregators, through an Optimal Power Flow (OPF).

The OPF is run to find the changes in the scheduled generation/consumption that should be applied using the available flexibility in order to satisfy all the network constraints with the least cost. It is formulated as single period AC Optimal Power Flow whose objective function to be minimized is the cost of the flexibility products. The OPF considers a high cost associated to load or generation curtailment in order to reduce them to the unavoidable cases. This cost could be the Value of Lost Load (VoLL), for example. The equalities are power flow equations in each node, and inequalities are voltage constraints, branch capacity constraints and power generation/consumption capabilities of DER. A solution will always be obtained because generation or load curtailment is always a feasible solution.

If changes in the preliminary schedule arise, the accepted bids would be communicated to the aggregators, and the final schedule would be saved in a text file. The algorithm flow chart is depicted in Figure 9.4.

![Figure 9.4. Congestion management algorithm flow chart.](image)

### 9.3.4  Flexibility and Optimization in Target network planning and Expansion planning

Since TNP and EP solve the planning problem on a higher abstraction level than Operational planning and with much more inherent uncertainties, we use simplified representation of the smart functionalities in order to model them efficiently on the planning studies.

This annex explains how the functionalities of congestion management, aggregator bidding and/or dynamic distribution pricing are represented in these planning tasks.
Market Optimization

Market optimization results in a customer load behavior which would be consistent with a spot market driven electricity price for end consumers. In this optimization scheme the end customer attempts to minimize his total cost of consumed energy thus resulting in moving of the shiftable loads to low-price hours from high-price hours. This functionality represents the aggregator trying to minimize the cost of electricity.

The amount of load shifted is dependent on amount of customer flexibility. The flexibility dictates the constraints for the optimization problem (explained further). The objective function of this optimization scheme thus becomes a scalar product between consumed hourly energies and hourly energy price vectors ($E_{\text{hourly}}$ and $c_{\text{energy}}$ respectively), resulting in linear function:

\[ f_{\text{Cost}}(E_{\text{hourly}}) = c_{\text{energy}} \cdot E_{\text{hourly}} \]

Example:

Capacity Optimization

Capacity optimization results in a customer behavior where the customer attempts to utilize a minimum power capacity. This means that during the optimization window the customer attempts to keep his profile as flat as possible. This optimization represents in a simplified way the capability of congestion management and dynamic distribution pricing to reduce the peak loading of the grid.

Again, as with Market optimization, the amount of reduction on peak demand and “flatness” of the profile is dependent on customer flexibility. The objective function for this optimization scheme becomes sum of squares of the hourly energies vector:

\[ f_{\text{Cost}}(E_{\text{hourly}}) = \sum_{n=1}^{N} E_{\text{hourly},n}^2 \]

Example:
**Flexibility of storage**

Storage is considered to be a “buffer” of the hourly consumption at the customer end. Storage can be charged by drawing energy from the grid and discharged by injecting energy to customer connection point. Idling losses of the storage are neglected. The storage optimization problem thus becomes:

\[
\text{minimize: } f_{\text{Cost}}(P_{\text{charging}})
\]

Subject to:

\[
C_{\text{minimum}} \leq C_n \leq C_{\text{maximum}}
\]

\[
-P_{\text{charging,max}} \leq P_{\text{charging,n}} \leq P_{\text{charging,max}}
\]

\[
\forall \ n \in [1, 2, ..., N]
\]

where:

\[
C_n = C_0 + \sum_{k=1}^{n} P_{\text{charging,k}} - P_{\text{demand,k}}
\]

\[
N = \text{card}(P_{\text{charging}})
\]

The first inequality constraint defines the bounds for the amount of energy that can be stored or drawn from the storage. In these calculation the lower limit is 0 and the upper limit is the nominal size of the storage. In case that some of the storage capacity would be reserved to some other use the limits can be arbitrary. The second inequality constrains defines the bounds for instantaneous power that can be drawn or injected to the grid. In these calculations these are the nominal power of the storage element.

**Flexibility of EVs**

EV is considered to be a “moving storage” meaning that that when the EV is being driven it is not available for charging (or discharging) into the grid. While the EV is driven it consumes the charge in the storage as per driving schedule that is assumed to be known. Thus the problem becomes:

\[
\text{minimize: } f_{\text{Cost}}(P_{\text{charging}})
\]
Subject to:

\[ C_{\text{safety\_limit}} \leq C_n \leq C_{\text{EV}} \]
\[ -P_{\text{charging\_max}} \leq P_{\text{charging\_n}} \leq P_{\text{charging\_max}} \]
\[ P_{\text{charging\_n}} = 0 \quad \text{if} \quad P_{\text{demand\_n}} \neq 0 \]
\[ \forall \ n \in [1, 2, ..., N] \]

where:

\[ C_n = C_0 + \sum_{k=1}^{n} P_{\text{charging\_k}} - P_{\text{demand\_k}} \]
\[ N = \text{card}(P_{\text{charging}}) \]

The two first inequality constraints are essentially same as in the case of simple storage optimization. The amount of energy stored in the EV must remain between predefined bounds at all times and the instantaneous power of charging and discharging cannot be higher than the nominal power of EV’s charger. In these calculations the lower limit is 0 effectively removing V2G functionalities.

The equity constraints say that when the EV is being driven (EV’s consumption is non-zero) the EV cannot be charged.

**Flexibility of Heating and Cooling loads**

The flexibility in heating and cooling demand is dictated by the allowed deviance from optimal indoor temperature of the customer’s house. In a certain sense the optimization problem is similar to storage optimization: the amount of energy stored in the system is the product of thermal mass and internal temperature of the house, the power injected to the system is the power of the heating/cooling system and the power drawn from the system is the heat loss of the house. Thus the optimization problem becomes:

\[ \text{minimize: } \sum_{n=1}^{N} \text{f\_cost}(P_{\text{heating\_n}}) \]

Subject to:

\[ Q_{\text{house\_min}} \leq Q_{\text{house\_n}} \leq Q_{\text{house\_max}} \]
\[ 0 \leq P_{\text{heating\_n}} \leq P_{\text{heating\_max}} \]
\[ \forall \ n \in [1, 2, ..., N] \]

where:

\[ Q_{\text{house\_n}} = Q_{\text{house\_0}} + \sum_{k=1}^{n} (P_{\text{heating\_k}} + P_{\text{loss\_k}}) \]
\[ Q_{\text{house\_min}} = T_{\text{min\_house}}, Q_{\text{house\_max}} = T_{\text{min\_house}} \]

### 9.4 Detailed Results. Target Network Planning

Table below shown the detailed results of the Target Network Planning.
The convergence behavior of the ant-colony-system is shown in Figure 9.4.1. This is presented of the Green Distributed Scenario and the control variation Original. The blue line in the figure shows the minimal annual network costs of each colony and each scenario. And the orange line shows the overall minimal network costs. The computation time for this calculation (75 ants; 8 colonies; 30 Iterations) is ca. 71 minutes.
Figure 9.4.1 Convergence behavior of the Ant-Colony system of the scenario green distributed (original)