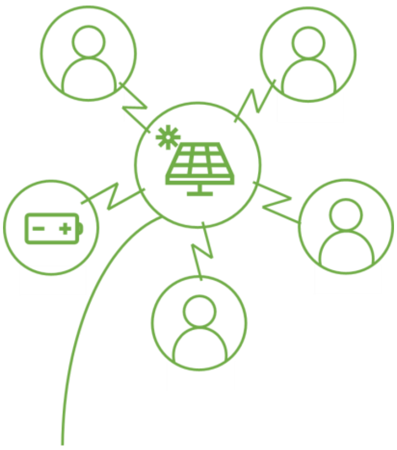
2024

ASPECDS - ASsessment of the Potentials of Energy Communities for Expanding Renewable-based Electricity Generation in Distribution Systems

Modeling of Energy Communities – a technical perspective. Overview on methodology and findings



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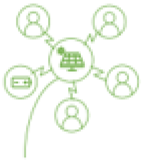
1 INTRODUCTION: THE AIM OF THE RESEARCH



Our research aimed at revealing how and to what extent energy communities (ECs) can contribute to increasing the photovoltaic (PV) hosting capacity of distribution grids. The hosting capacity is determined by technical factors, which are described – at least in Hungary – in a distribution network code. This study shows that – despite these constraints – there exist solutions which can help increase the PV hosting capacity, and that ECs could drive or incentivize the application of such solutions.

We have investigated the impact of favorable PV arrangements that could be incentivised by energy communities; the impact of centralised and distributed batteries with different storage control algorithms; the impact of demand-side management (DSM); reactive power control, as well as the combined impact of these being applied at the same time. We concluded that all the devices and procedures analyzed in this research can contribute to increasing the PV hosting capacity of the grid. This is achieved by avoiding excessive voltages, but it is important to take into account which type of measures lead to an (un)acceptable loading of the MV/LV[1] transformer. Apart from voltage rise limits, in many cases it is the *nominal power* (power rating) of the transformer that poses the most stringent limit under current regulation, despite the fact that a PV capacity higher than the transformer rating does not usually imply an *actual* overload of the transformer, since a certain level of consumption is usually present on the grid as well.

Our research on energy communities aims at investigating the *technical potential* of energy communities to *increase the PV hosting capacity of the distribution network*. The research also investigates other potential benefits of energy communities, such as:

- *tackling voltage issues of the grid*
- *reducing PV generation curtailments (and at the same time reducing the number of customer complaints)*
- *reducing technical network losses as a result of higher local consumption*
- *increasing local consumption (energy autonomy).*

This analysis has been carried out on two LV distribution networks: one supplying 4 LV circuits, the other supplying one LV circuit. It was assumed that an Energy Community comprises the consumers supplied by one MV/LV transformer. We used a three-phase, unbalanced, four-wire technical model and a load-flow calculation performed on it. Grid-friendly features were modelled, and different PV and battery locations were tested. The simulation time span was 1 year, obtained by scaling up the results of 24 days (1 weekend and 1 weekday per month). The technical analysis was expanded for alternative grid solutions that could potentially achieve a certain PV hosting capacity, one that was found to be achievable by energy community incentives as well. The goal of this step was to establish the economic comparability of each alternative solution.

[1] Medium Voltage, Low Voltage

2 MODELLING

2.1 Key characteristics of the modelled networks

2.1.1 Unbalance, LV transformer, MV grid, extrenal grid

The external network is modelled by an ideal voltage source at HV[2] level (infinite short circuit power), a HV/MV transformer and an equivalent MV network impedance. This was chosen so that the voltage across this equivalent impedance be the same as the voltage across the MV line impedance caused by the simulated MV/LV transformer current as well as the currents of other similar MV/LV transformers (not simulated in detail) assumed along the MV line. The mapping of the external network sections corresponds to practical network topologies, where the MV-LV sections are already radial in design, i.e. they have a single feed/connection to the HV system.

The detailed low-voltage network model and load flow calculation covers a single LV transformer area or a single circuit of it. Two network scenarios[3] are investigated:

1. A detailed model of all four circuits of a network which represents a prosperous urban agglomeration in Hungary, including the entire transformer area (called "R" network hereafter)
2. The CIGRÉ LV model, which is the international benchmark model and includes a single circuit.

Hungarian LV transformers usually feed an average of 4 circuits. Therefore, for the CIGRÉ model it is assumed that the transformer supplies three additional circuits identical to the one modelled, i.e. the current flowing through the LV transformer is four times the simulated feed-in current. The impedance of the LV transformer is multiplied by the number of circuits in order to obtain the correct voltage drop, taking into account the combined effect of all the circuits. For the "R" network, the total feed-in current is already calculated by the model, which contains 4 circuits.

It is assumed that the MV line supplies several MV/LV transformers of the same type and current, spaced evenly. During modelling, the current of only one of these transformers is calculated (as described above), with a multiple of this current flowing through each line section in proportion to the number of transformers downstream the line. Accordingly, only one calculated current flows through the last line section. To determine the total endpoint voltage drop/rise correctly, the impedance of the MV line must therefore be multiplied by a multiplier depending on the number of transformers. Further assuming that the HV/MV transformer feeds several identical MV lines, but only one MV line current is calculated as above, the HV/MV transformer impedance is multiplied by the number of MV lines to obtain the same voltage drop/rise.

At the point of the ideal voltage source (**slack**), the **voltage is kept at its nominal value**.

[2] High Voltage

[3] Introduced in details at section 2.2 Topologies

2.1.2 Consumer presmises beyond the public supply network

For the sake of the simulations, we used a simplified structure of low voltage networks.

In real networks the *connection point* of the consumers (the property boundary) is connected to the *public grid (mains)* via a so-called *service line* (*connection line*) at the so-called *branch point (joint)*. Within the property boundary, additional wires with typically smaller cross-sections are used to reach the meter, and beyond that internal wires (*sub circuits* and *final sub circuits*) are used to reach the inverter that connects the solar panels to the grid.

The inverter can only operate on the basis of the voltage it measures (e.g. to regulate its output according to a preset P(U) characteristic), while the voltage requirements mandatory for grid operators mostly apply at the *branch point* or at the *connection point*, and some of the requirements apply directly at the inverters:

- The regulation for blocking LV zones from further PV installation[4] includes a requirement for both the voltage at the *connection point* and at the *branch point*. Accordingly, simulations were performed with and without the *service lines* for the base case defined later. In terms of voltages, we found that there was no significant difference between the information content of the two sets of simulations.
- A further provision states that "the combined voltage drop along the service line and the unmetered wiring shall not exceed 2% of the nominal voltage of the public distribution system." Since no data on the service lines and the unmetered wiring were available, we can only conclude that assuming realistic lengths, cross-sections and injected power, the 2% voltage difference is a plausible upper limit.

Based on the above results we conclude that it is sufficient to model the public (mains) grid without the need to model the wires beyond the *branch point*. Further, it is sufficient to analyze the voltages at the nodes of the public network and to **set the blocking limit at 107.5%**.

Although the breakpoints of the inverter P(U) characteristics must be set to 250 V and 253 V according to the current distribution network code, the equivalent of these values at the *branch point* can be set to 248.26 V (instead of 253 V) and 3 V less, i.e. 245.26 V instead of 250 V, in accordance with the 107.5% value used for the blocking limit. With this modification we consider the inverters as if they were connected directly to the public grid, but with lower voltage tolerances. As a result we still represent the real operation in a simplified way, without unnecessary modelling complexity.

2.1.3 Network unbalance between phases

The network model and the load-flow calculation procedure is designed as a **four-wire** system, in order to take into account the voltage drop on **the neutral conductor** and thus accurately represent the network unbalance. The unbalance in the grid due **to generation** was modeled by setting the power threshold, above which a PV considered a three-phase unit, to 4 kW. Although the current distribution

[4] See section 2.3 for further details

network code now only allows PV inverters above 2.5 kW inverter power to be three-phase, previous regulations allowed single-phase PV inverters up to 5 kW to be connected to the grid.

2.2 Topologies

Detailed simulations were carried out on an international benchmark network (CIGRÉ), and on the „R" network representing a prosperous urban agglomeration, as described below.

2.2.1 Consumers, producers, batteries and other devices

The **consumers** modelled include both large and small consumers. The largest single consumer on the „R" network consumes about 4.5% of the total annual consumption in this system. The aggregation of five nodes in total, placed within 60 m radius of this consumer, accounts for 10% of the annual consumption. For the CIGRÉ network, the first large aggregated consumer consumes 48.85% of the annual consumption of the network.

For both grids, the "real-sky" **PV production curves** are based on **real** PVGIS (Photovoltaic Geographical Information System) hourly data curves, which are interpolated to a quarter-hour resolution. For each simulation, we assign PVs to consumers in different ways to achieve different solar penetration rates. We interpret ***PV penetration*** according to the domestic rating method that was most commonly used until recently in Hungary: namely the PV was rated to meet the household's annual energy consumption. Accordingly, 100% penetration means that PVs on the grid produce the annual consumption of the consumers connected to the grid. The PVGIS database was also used to generate the **clear-sky** production curves.

In some scenarios (centralized or distributed) **batteries** are also assigned to consumers. Table 1 shows the storage capacities considered in the simulations. The methodology for power and capacity rating is described in Chapter 4.1.

Table 1.: Battery rated powers and capacities used for simulations

Grid	Version	Circuit 1	Circuit 2	Circuit 3	Circuit 4
R	**Rated power, kW**	**190**	**74**	**65**	**75**
	Capacity, kWh (Maximal energy)	1.230	500	438	532
	Capacity, kWh (4 hours)	**760**	**296**	**260**	**300**
CIGRÉ	**Rated power, kW**	**127**			
	Capacity, kWh (Maximal energy)	**584**	-	-	-
	Capacity, kWh (4 hours)	508	-	-	-

For modeling **electric car chargers** (EV - Electric Vehicle) and **heat pumps** (Heat Pump - HP) we used Hungarian statistics. For EVs we have found only national penetration figures, for PVs, HPs and batteries we also had data broken down to various types of settlement. In the statistics, penetrations are given projected to the number of households. The CIGRÉ benchmark description does not cover PV, HP, EV and batteries, thus these devices are not included. For EVs and HPs, the current penetrations have been rounded upwards, ensuring that at least one device of each type can be analyzed on the grid by default. Thus the final penetrations are as follows:

Table 2.: Base case penetrations used for simulations

Final penetration in base case	Number of devices and penetration projected on load [%]				Non-flexible loads (households&SME)
Grid	PV	HP	EV	Boiler	
Prosperous agglomeration "R"	116 (46,77%)	4 (1,6%)	1 (0,4%)	106 (42,74%)	232+16
CIGRÉ	3 (50%)	1 (16,67%)	1 (16,67%)	1 (16,67%)	6+0

2.2.2 International benchmark network – CIGRÉ

The **residential** part of the **CIGRÉ** European Low Voltage Network Model was used as the international benchmark network. This network **is cabled**. For the CIGRÉ network, **the residential consumption** was defined by maximum consumption, a power factor and a 24-hour profile curve. This residential profile was used for all 24 days on the CIGRÉ network. These were supplemented by few additional **flexible loads** by default. A single **electric vehicle charger**, one **boiler** and one **heat pump** were added to this network. The number of flexible loads was increased in the "electrification" scenario.

2.2.3 Prosperous urban agglomeration network – „R"

The prosperous urban agglomeration model implements an **overhead line** network, assuming a larger (95 mm^2) wire cross-sections, as typical for more affluent rural areas.

The model was based on a real network, for which we had a list of **consumers'** annual consumption for normal (residential and commercial) consumers and separately for controlled consumption. ***To generate*** the load curves for such consumers, we used a set of ***real quarterly measurements*** from which we sampled the quarterly consumption taking into account the total annual consumption values. The sampling follows a random heuristic that approximates well the expected state of the grid. As a result, the residential consumption curves are all different, providing a good representation of the real network conditions. Whole days are selected from the measured consumption and assigned to nodes. Residential consumers below 5000 kWh annual consumption were assigned ***as single-phase***, while those above 5000 kWh ***as three-phase*** loads to the nodes of the modelled network.

Due to the lack of time-series measurements for commercial **consumers** (SME - Small and Medium Enterprise), the load ***profile curve for trade sector*** used by DSOs was applied. SME consumers are always represented as ***three-phase loads***.

Consumers **are randomly assigned to a network node** and single phase consumers are **also randomly assigned to a phase**. **Three-phase** loads **are not balanced**: 45%, 25% and 30% of the total consumption is allocated to each phase.

For households, we selected a range of **fixed power** EV chargers and heat pumps. **EV chargers** were selected from 3.7 kW (1 phase), 7 kW (1 phase) or 11 kW (3 phase) options. For **heat pumps** we chose from 2 kW (1 phase), 3 kW (1 phase) or 6 kW (3 phase) types. The corresponding load curves were generated using a self-developed procedure that takes into account usage statistics. Fixed capacities of boilers are not included, the maximum installed capacities were derived from the consumption curve data instead. The average maximum power is 2.15 kW, while the absolute maximum is 5.2 kW.

This absolute maximum is somewhat high for a boiler, but these measurements are results from real profiling measurements. It is possible that in fact there were two devices behind the controlled meter.

2.2.4 Small settlement (village) networks

According to the original research plan we also performed simulations on sample networks of small (village) communities: selecting one more and one less affluent community and modeling their networks. Here we came to the conclusion that assuming both current and expected development in the next few years, the simulations show **a voltage issue only at unrealistically high PV penetrations**. We therefore **refrained from further detailed analysis of these networks**, as no new insights were expected for these networks compared to the networks discussed above.

2.3 Interpretation of the LV "blocking limits"

Section 8.7.1 of the Hungarian Distribution Network Code specifies the conditions when a part of the grid must be "blocked" against further PV installation, i.e. when no more solar panels can be connected to a circuit. The following three conditions are related to voltages – if any of the upper limits would be violated, the permission of further PV installations will be refused.

a) The voltage shall remain within ±7,5% of the nominal voltage for 95% of the averaged values for any 10 minutes period on any day during a one-week measurement, for each point of connection of the network.
b) The voltage shall remain within ±10% of the nominal value during any 10 minutes period and at any point on the network.
c) All voltages shall be between 80% and 115% of the nominal value in any one minute average.

We focused on the first condition in our quarter-hourly resolution model. Instead of 10 minutes we only have data of 15 minutes granularity, but the condition of 95% of the time is interpretable: 5% of the 96 quarter hours rounded upwards results in the following condition: **if the voltage of any phase exceeds 107.5% of the nominal phase voltage (248.26 V), for at least 5 quarter hours on any simulated day, we consider the circuit blocked.**

Another blocking condition defined by the grid code is related to the total power of the solar inverters installed (or under installation) in the area supplied by a MV/LV transformer: if this exceeds the *rated (nominal) power* of the MV/LV transformer, the transformer area is blocked.

Apart from this condition, we also record the actual power flowing through the transformer during the simulations, so that we can observe when the transformer is actually being overloaded. The worst case assumption – according to the grid code – would be if there was no consumption during maximal PV production; however, in reality the transformer can be overloaded only at larger PV penetrations due to the existing consumption.

3 SCENARIOS: SIMULATION CASES

Three different algorithms for the **allocation of PVs** on the grid were tested based on the current HP, EV, boiler[5] device allocations in the first scenario. The later scenarios already apply the algorithm selected based on the results of the first scenario. The algorithms tested are:

a) **Annual consumption based**: this method matches each customer's PV rating to the annual consumption of the respective customer, as has been the practice in Hungary until recently. The algorithm starts to allocate PV generation to the largest consumer and proceeds to other customers in descending order of their annual consumption, until the desired PV penetration is reached.

b) **Equal**: allocates equal sized PVs to the customers, starting from the one with largest annual consumption. The initial size of PVs is 10 kW, and if the desired total penetration is not achieved this way, all the PVs are scaled up equally.

c) **Uniform**: this algorithm uniformly distributes PVs between 2 and 18 kW to the consumers, and if the desired total penetration is not achieved this way, all PVs are scaled up proportionally.

d) **Concentric**: Used in one scenario only. Same as "equal" algorithm, but PV are assigned to customers based on their distance from the transformer, in ascending order.

Tabble 3.: Introduction of scenarios

<table>
<tr><th>Scenario no.</th><th>Scenario name</th><th>Scenario goals and description</th><th>Excepted results</th></tr>
<tr><td>1</td><td>Base_variants_demo</td><td>1) Does the existence of voltage problems depend on the PV allocation method? <annual consumption-based | equal | uniform>
2) Which PV allocation method and sky curve <clear | real> is to be applied in further scenarios, based on current HP, EV, boiler distribution?</td><td>PV allocation method and sky curve chosen: annual consumption based, real-sky</td></tr>
<tr><td>2</td><td>Base-case</td><td>At what PV penetration levels are blocking limits reached without applying inverter regulation (e.g. P(U) curtailment)?</td><td>R_penetration_1.2
CIGRÉ_penetration_1.2</td></tr>
<tr><td>3</td><td>Hosting_capacity_central_PV</td><td>How much PV capacity can be installed using distributed PV (30% for R, 10% for CIGRÉ) and central PV, i.e. how much central PV capacity may still be installed without P(U) control before reaching the blocking condition?</td><td>R_penetration_1.3
CIGRÉ_penetration_1.3</td></tr>
</table>

[5] Electric Storage Water Heater

Scenario no.	Scenario name	Scenario goals and description	Excepted results
4	Hosting_capacity_central_BESS	After allocating distributed PV (30% for R, 10% for CIGRE) using the base case allocation method, how much additional distributed PV capacity may be installed without reaching the blocking condition, using central (or distributed) storage?	R_penetration_1.4 CIGRÉ_penetration_1.4
5	Hosting_capacity_concentric_PV	What is the maximal hosting capacity using the concentric PV allocation algorithm?	R_penetration_1.5 CIGRÉ_penetration_1.5
6.a,b	Hosting_capacity_distributed_control	What is the maximal hosting capacity when applying a) DSM, b) DSM+QU control? (Actions of low investment cost: a Q(U) control can be activated in the inverter and DSM – a consumption rescheduling solution – can also be activated either manually or by installing low cost hardware.)	R_penetration_1.6 CIGRÉ_penetration_1.6
7	Hosting_capacity_distributed_nocontrol	Using the PV penetration from scenario 6a, but no control of any type (no DSM, no Q(U), no P(U)): how serious is the voltage problem and how large are the power flows (is the transformer overloaded)?	R: number of voltage limit violations (max violation per day) CIGRÉ: number of voltage limit violations
8	Hosting_capacity_distributed_nocontrol_PU	Using the PV penetration from scenario 6a and P(U) control according to the grid code: how much is the curtailed energy?	R: kWh (% of generation) CIGRÉ: kWh
9.a 9.b	Hosting_capacity_distributed_controlBESS, Hosting_capacity_distributed_control_central_BESS	Using methods that can be supported by ECs (DSM + Q(U) + battery control) with distributed PV and batteries, what is the maximal PV hosting capacity? a) distributed storage, b) central storage	R_penetration_1.9 CIGRÉ_penetration_1.9
10	Hosting_capacity_distributed_nocontrolBESS	Using the PV penetration from scenario 9a, but no control of any type (no DSM, no Q(U), no P(U)): how serious is the voltage problem and how large are the power flows (is the transformer overloaded)?	R: number of voltage limit violations (max violation per day) CIGRÉ: number of voltage limit violations

Scenario no.	Scenario name	Scenario goals and description	Excepted results
11	Hosting_capacity_ distributed_nocontrolBESS_ PU	Using the PV penetration from scenario 9a and P(U) control according to the grid code: how much is the curtailed energy?	R: kWh (% of generation) CIGRÉ: kWh
12	Electrification_Base	Future electrification scenario: as a result of economic development, a 10% increase in the number of EVs with their chargers, +10% HPs and one new large consumer consuming 10% of the previous annual consumption of the community is simulated. What is the PV hosting capacity in this case?	R_penetration_1.12 CIGRÉ_penetration_1.12
13	Electrification_central_BESS	What is the PV hosting capacity for the case in scenario 1.12 but with an additional central storage?	R_penetration_1.13 CIGRÉ_penetration_1.13
15	Alternative_grid_solutions_ OLTC	Can the hosting capacity obtained from an EC-driven solution (+8% increase compared to base case using storage) achieved by a BAU alternative solution: replacing the MV/LV transformer with an OLTC transformer?	Yes/no. If yes, what is the cost compared?
16	Alternative_grid_solutions_ Linechange	Can the hosting capacity obtained from an EC-driven solution (+8% increase compared to base case using storage) achieved by a BAU alternative solution: replacing the lines with larger cross-section cables?	Yes/no. If yes, what is the cost compared?

4 DESCRIPTION OF THE CONTROL FUNCTIONS USED FOR SIMULATIONS

4.1 Battery control algorithm and battery rating

Two types of algorithms were used **for** battery **control**: an **individual** and a **community-oriented** algorithm. As a voltage-dependent battery control would only indirectly relate to the control of energy flow (and thus to the energy community approach), both variants are simple power flow-based algorithms:

- The **individual algorithm** aims at limiting the aggregated power flow of a given PV generation and its associated consumer load. Two nonzero thresholds (a positive and a negative tolerance) are applied in order to utilize the storage capacity in a more optimal way: power flows within these threshold limits are not triggering battery charge nor dischare. The thresholds/tolerances have a seasonal character.
- The **community algorithm** aims at reducing the power flowing to or from the MV grid through the MV/LV transformer. This method is similar to the individual algorithm but takes into account the aggregated power of an entire LV circuit. The storage(s) are located on the designated circuits. Season-dependent tolerances were applied here as well.

The reason for introducing (seasonal) thresholds is that power balancing with zero tolerances does not lead to the optimal result, since the part of the grid under consideration operates with very different energy balances at different times of the year. Operating the battery with zero thresholds in a permanently energy-deficient/-surplus enviroment for a longer period is detrimental to the voltage quality of the network, mostly because this kind of storage control does not intervene at the most favourable time of the day. **On winter days** (October - March), PV generation rarely exceeds consumption. In the zero-tolerance case, the storage is discharged as soon as PV production drops, most likely already in the late afternoon, and it would be depeted by the evening hours. It would be preferable to discharge during the period of highest consumption (evening) and reduce the peak consumption. To this end, we have introduced **the winter values of the seasonal tolerance**: the storage is charged as soon as there is a power surplus on the part of the network under test, but the discharge is started only when the power deficit exceeds half of the power rating of the storage. **On summer days** (April to September), the no-tolerance control mostly leads to near-full batteries, as PV production exceeds consumption during the day and only a relatively small part of the stored energy can be discharged at night. Thus, in the case of no-tolerance charging, the charging is already completed in the morning hours, not leaving any capacity for the peak production hours. Therefore, we have introduced **the summer values of the seasonal tolerance**: the storage is discharged as soon as there is a power deficit on the part of the network under test, but the charging is started only when the power surplus exceeds half of the power rating of the storage.

It has to be noted that the elaboration of an optimal battery control strategy was beyond the scope of this project.

The above two algorithms were tested in several combinations for central and distributed batteries.

The ratings (power and capacity) of the batteries used in the simulations can be found in Table 1.

The battery **total power rating** was based on the community approach: the total power (kW) of the batteries was set equal to the maximum (quarter-hour) reverse power flow on the transformer over 24 days, for the base-case scenario.

For the **total capacity (kWh)** we examined two approaches:

a) *Maximal energy rating:* the capacity was found by selecting the summer day with the most produced energy (this was the day with the maximal reverse flow), and assuming that the community would *store all the locally produced energy during this day*. This is based on the idea that if all this energy could be stored in the battery, there would be no reverse flow. This approach was **used in the CIGRÉ** model, and during the simulations most of the capacity was indeed used.
b) *Four-hour* storages were considered. The two-hour storage (as most prevalent domestic solution in Hungary) has been found to be too small (for the purpose of increasing PV hosting capacity), while our international perspective suggests that in Western Europe, storage with a four-hour capacity are more common. This approach was **used for the R model**, since the maximal energy rating method would lead to extremely high capacities. (For the CIGRÉ network, the difference between the two ratings was only 15%.)

It is important to note, that these power and capacity settings are not optimized for each scenario, for the sake of comparability. In some cases the power and capacity values turned out to be over-rated.

After obtaining the total battery power and capacity ratings, these were **split and located** according to the respective scenarios. For central storage scenarios, the total power and capacity was divided among the simulated circuits in proportion to the power flows on these circuits during the selected summer day. For distributed storage scenarios the rated power and capacity was distributed to consumers (loads) with three-phase PVs in proportion to their PV rating.

In the simulation we did not see the need to use a narrowed **State of Charge range**, i.e. we assumed a net storage capacity[7]. The **efficiency of** the storage was assumed to be **100%** in the simulations.

4.2 DSM algorithm

The DSM algorithm is used to model **the rescheduling of consumption for flexible loads** (boiler, EV chargers and HP). A given percentage of consumption for non-sunny hours is shifted to sunny hours between 10 and 15 o'clock. This fits well for loads that switch on and off and do not regulate their power consumption. We also applied a deadband between 8...10 and 15...17 hours when the consumption is not modified.

Flexible consumption **on the "R" network** is determined by the **boiler**s. According to actual Hungarian control paradigm approximately 75% of boiler load is concentrated at off-peak and 25% at peak periods. It was assumed in the simulations that this ratio could be reversed. We estimated a lower share of **EV charger** and **HP load** (about 15%) that can be rescheduled, as cars are not always home at

[7] If limited (forbidden) charging ranges are to be taken into consideration, 125% of the given storage capacities needs to be used

midday and heat pump consumption is concentrated at night in winter due to heating demand. Also, during summertime the HP consumption is concentrated in the sunny hours when it is used for cooling. By default, the **CIGRÉ network** only includes 1 boiler, 1 EV charger and 1 HP. In total, the amount of the rescheduled flexible off-peak consumption was **70%** on the "**R" network** and **40%** on the **CIGRÉ network**. In some scenarios, the DSM is used in combination with battery control or with reactive power control. In such cases, **the DSM algorithm has the precedence to pre-reconfigure the consumption and then other controls are run in a second step.**

An indication of the shifted EV charger and HP powers are given based on their rating.

- EV: 3,7 kW (1 phase), 7 kW (1 phase) or 11 kW (3 phase) chargers
- HP: 2 kW (1 phase), 3 kW (1 phase) or 6 kW (3 phase)
- boiler: profile values are available. The average of maximum powers 2,15 kW, largest: 5,2 kW.

The figure below represents the DSM algoritm for one day (20th of June) on the „R" network:

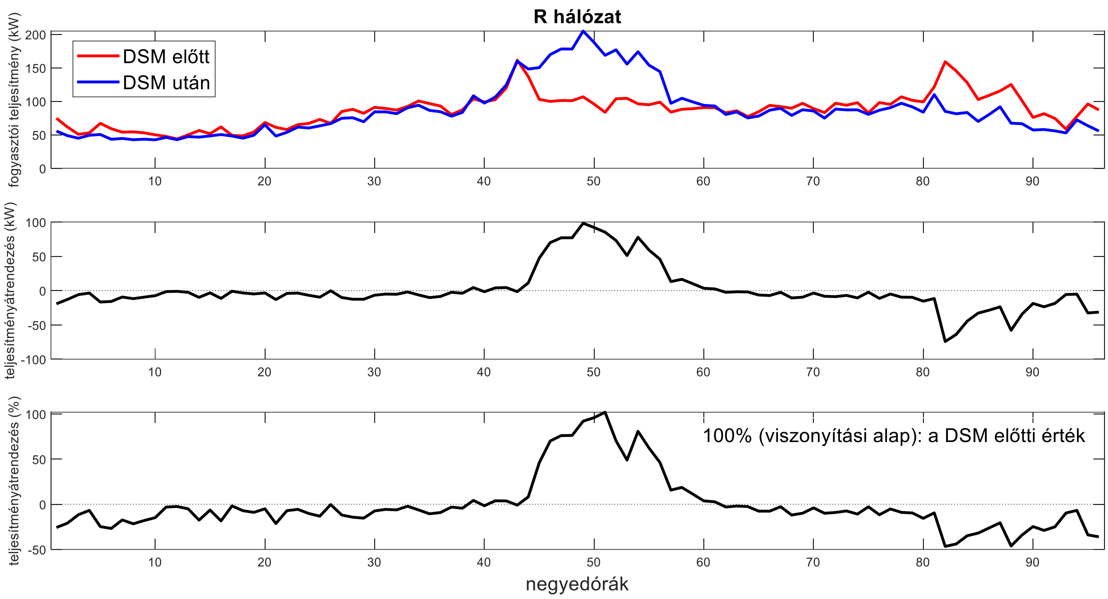


Figure 1.: DSM algorithm for one day on „R" network (red: before DSM, blue: after rescheduling)

4.3 P(U) control

P(U) control is a currently applied **inverter control** solution imposed by the DSO in order to reduce **the output of** the inverter at times when the grid voltage is too high. The characteristic's breaking points defined in the Grid Code are as follows: the output power must be reduced gradually (linearly) starting from 250 V, and be fully curtailed at and above 253 V. Not all inverters use this characteristic yet on the Hungarian grid, but all of them must be switched off at voltages higher than 253 V. There is also a stepwise approximation of the linear characteristic. For three-phase inverters, the characteristic **curtails symmetrically based on the highest phase voltage**.

Neither the connection wire nor the wire sections between the meter and the inverter were included in the simulations, therefore the best approximation for the P(U) characteristic according to the Grid

Code was by using modified breakpoints. Instead of the breakpoints at 250 V and 253 V, the 107.5% value (same as the blocking limit) was used as un upper limit, resulting in $\frac{400V}{\sqrt{3}} * 1{,}075 = 248{,}26\,V$ (instead of 253 V) and 3 V less, i.e. 245.26 V instead of 250 V. This characteristic was used in the simulations to investigate how much curtailed energy would be lost for PV owners under different types of conditions without the energy community driven control functions.

4.4 Q(U) control

Q(U) control is **a voltage-dependent reactive power control**, a symmetrical linear saturated characteristic with breakpoints, matching the concept of linear P(U) characteristic in the Grid Code. It can reduce the curtailed energy, because PV inverters can decrease voltage by consuming reactive power when their apparent rating is not being fully used to produce active power. Inverters can also feed reactive power into the grid which can be useful if the voltage is too low. The former is obviously important for increasing PV production, while the latter can be useful in the case of too much consumption. The reactive capacity of inverters is limited by the apparent power rating. No limit on cosfi was applied in the simulations. It was assumed that inverters are able to operate at night when there is no effective (PV) generation at all.

In the final solution, the breakpoints of the above Q(U) characteristic were fitted to the upper breakpoint Un*107.5%, similar to P(U). For the lower breakpoint, we kept the 3 V linear band in both directions. The breakpoints for the low voltages were symmetrical to the nominal voltage.

5 KPI SET USED FOR EVALUATION

5.1 Numerical stored results

Stored numerical results of the simulation were:

- Blocking limit: a counter named "**max violation high**" is introduced, showing the number of quarter hours of a day per node, when the voltage exceeded 107.5% of the nominal value. The maximum of these values across all days and nodes is recorded during a simulation. If the value of the counter reaches 5, that circuit is considered blocked. During the simulation runs the PV penetration is gradually increased and the penetration level at which the counter first reaches or exceeds 5 is considered the blocking limit.
- Another important indicator is PV **generation**, which gives an indication of how much green energy can be produced under given conditions.
- In addition to the **total** annual **consumption**, we also extract the **maximum quarter-hour consumption per phase aggregated over the grid.**
- We calculate **the grid loss** of the low voltage lines.

5.2 VAVDI, VAVFI

We also look at the number and cumulative duration of over- and undervoltages. For this purpose, we have defined new indicators based on the SAIFI (System Average Interruption Frequency Index) and SAIDI (System Average Interruption Duration Index), called VAVDI and VAVFI:

- **VAVDI** (Voltage Average Violation Duration Index) shows the average duration of a voltage violation per consumer per year. It is measured in hours/consumer/year.
- **VAVFI** (Voltage Average Violation Frequency Index) shows the average number of voltage violations per consumer per year on a given network. The unit of measurement is events/consumer/year.

The above indicators are calculated separately for both over- and undervoltages: **VAVDI high, VAVFI high, VAVDI low** and **VAVFI low**. We consider voltages above 107.5% of the nominal voltage, i.e. 248.26 V, as too high (the same limit is used for blocking) and 92.5% of the nominal voltage, i.e. 213.62 V as too low.

5.3 Energy autonomy indicators

For each scenario, we calculated the degree of self-sufficiency of the community and its individual members, and also their ability to consume the energy produced locally. Three indicators were developed for this aspect:

- **Self-consumption [%]:** the percentage of consumption of each customer that was covered by its locally produced solar energy within <u>a quarter of an hour</u> (percentage of production that was not fed into the grid). Average value across all customers. Consumption includes battery charging.
- **Transformer self-consumption [kWh]:** the amount of energy flowing through the MV/LV transformer in either direction <u>for one year</u>. It indicates the extent the MV network is being used by the energy community (which is assumed as the LV transformer supply area), either for consumption or for feed-in.
- **Self-production ratio / energy community self-consumption [%]:** an indicator calculated for the whole LV network, expressing the percentage of the energy produced on the local LV network <u>during a year</u> being consumed by the energy community (i.e. the percentage of the the production that was not fed into MV by the energy community).

5.4 Inverter curtailments

To assess the level of inverter curtailments , the following indicators were used, which are only relevant in scenarios using P(U) control:

- **Total number of inverters disconnected** [number of units]
- **Average number of times an inverter is switched off per year** [events/inverter]
- **Amount of energy curtailed by inverters** [kWh], which shows how much green energy could not be produced due to inverter controls
- **Average amount of energy lost (curtiled) by an inverter per year** [kWh/unit]

5.5 Transformer loads

The **transformer load** is evaluated **by phases** regardless of flow direction. The maximal loading on each phase without overloading is one third of the nominal three-phase power. In the case of overloading, it was examined whether it is permissible or not, since a certain amount of overload is acceptable from the point of view of the transformer ageing/lifetime degradation. Such overloading situations also occur during real operation. The permissible overloading depends on its duration and on the preceding loading history. To make assessment more simple, we considered the maximal loading below 110% as normal, between 110% and 130% as acceptable (higher than distribution code blocking limit, but acceptable for short periods of time) and above 130% unacceptable. Furthermore, we calculate if the installed PV power exceeds the transformer's power, and the ratio of the installed PV peak power to the transformer rated power.

6 RESULTS

6.1 Overall results table

Simulation results are represented in Rables 4 and 5 below. A more detailed evaluation is provided in the later parts of the current chapter.

Table 4.: Prosperous urban agglomeration network („R”) simulation results

	R network, transformer:	400 kVA		=52,6% PV		Annual consumption: 879,4 MWh								
		PV (kW)	PV increase	PV penetr. (%)	Tr. max. load (%)	Self-cons. (%)	Tr Self-cons. (MWh, %)	Self Prod. Ratio (%)	Remarks	Loss / Cons.	VAVDI low (h/home/a)	VAVDI high (h/home/a)	VAVFI low (#/home/a)	VAVFI high (#/home/a)
2	Base	**535**		70	**100**	**23**	**905**	**49**		1,63%	0,85	1,61	3,41	5,28
3	Central PV (plus 30% distributed)	583	+ 9%	76,5	113	11	+ 5%	45	350 kW central, 233 kW distributed PV	1,09%	0,80	0,00	3,20	0,00
5	Concentric	720	+ 35%	94	143	12	+ 18%	39		1,83%	0,71	7,09	2,82	21,82
4a	Central Storage	596	+ 11%	78	87	25	-20%	62	4 h battery capacity	1,31%	0	2,54	0	3,78
4b	Distributed Storage, EC (centralized) control	596	+ 11%	78	87	25	-21%	62	4 h battery capacity	1,26%	0	2,54	0	3,78
4c	Distributed Storage, individual control	580	+ 8%	76	90	24	-9%	56	4 h battery capacity	1,45%	0,83	0,57	3,31	0,66
4d	Distributed Storage, 50-50% central/individual	580	+ 8%	76	107	24	-32%	70	4 h battery capacity	0,98%	0	1,45	0	4,13
6.a	DSM	580	+ 8%	76	93	29	-12%	57		1,43%	8,74	0,40	12,66	1,38
6.b	DSM + Q(U)	664	+ 24%	87	110	33	-5%	52	Tr. overloading, otherwise 760+ kW (100+ %) PV	1,83%	0,10	0,00	0,19	0,00
7	6a PV penetration, no controls	580	+ 8%	76	109	24	+ 4%	47		1,82%	0,83	11,20	3,31	27,35
8	6a PV penetration, P(U) control	580	+ 8%	76	95	24	+ 4%	47	P(U) curtailment: annual production of a 4,4 kW PV	1,77%	0,83	0,00	3,31	0,00
9a	DSM + distributed storage (EC or 50-50 ctrl.)	596	+ 11%	78	90	30	-38%	73	4 h battery capacity	0,90%	6,71	1,08	13,22	3,21
9b	DSM + central storage	617	+ 15%	81	72	31	-30%	68	4 h battery capacity	1,11%	1,05	1,38	3,94	3,59
12	Electrification base case	535	+ 0%	70	98	17	+ 33%	52	Voltages too low (+37% consumption)	2,18%	182,0	1,5	239,4	4,9
12b	Elektrifikáció base + DSM	535	+ 0%	70	123	21	+ 4%	74	+37% consumption ==> PV penetration = 51%	1,66%	223,1	0,0	225,4	0,0
13	Electrification + central storage	603	+ 13%	79	85	19	+ 5%	69	PV ==> 58%. Voltages too low. (4h battery)	1,62%	46,5	1,2	71,5	2,1
15	OLTC	596 OK	+ 11%	78 OK	126	25	+ 6%	46	Is 78% PV possible with alternative solutions?	1,94%	0	0	0	0
16	Line upgrading (larger cross-section)	596 OK	+ 11%	78 OK	114	25	+ 6%	45	Is 78% PV possible with alternative solutions?	1,29%	0	0	0	0

Table 5.: International bechnmark network (CIGRÉ) simulation results

	CIGRÉ network, transformer:	500 kVA		=34% PV		Annual consumption: 1 674 MWh								
		PV (kW)	PV increase	PV penetr. (%)	Tr. max. load (%)	Self-cons. (%)	Tr Self-cons. (MWh, %)	Self Prod. Ratio (%)	Remarks	Loss / Cons.	VAVDI low (h/home/a)	VAVDI high (h/home/a)	VAVFI low (#/home/a)	VAVFI high (#/home/a)
2	Base	**348**		24	**86**	**10**	**1 374**	**91**		3,66%	407	4	221	5
3	Central PV (plus 30% distributed)	645	+ 85%	44	88	4	+ 9%	63	500 kW central, 145 kW distributed PV	2,87%	408	0	221	0
5	Concentric	630	+ 81%	43	88	23	+ 8%	66		3,76%	385	5	208	8
4a	Central Storage	537	+ 54%	37	88	14	-11%	88	"Maximal energy" battery capacity rating	3,73%	304	8	187	17
4b	Distributed Storage, EC (centralized) control	536	+ 54%	37	88	14	-11%	88	"Maximal energy" battery capacity rating	3,42%	304	7	185	10
4c	Distributed Storage, individual control	435	+ 25%	30	86	11	-9%	94	"Maximal energy" battery capacity rating	2,69%	141	6	92	9
4d	Distributed Storage, 50-50% central/individual	463	+ 33%	32	88	12	-10%	93	"Maximal energy" battery capacity rating	2,89%	210	6	131	8
6.a	DSM	348	+ 0%	24	88	10	0%	92	There are almost no controllable loads.	3,57%	364	2	204	3
6.b	DSM + Q(U)	652	+ 87%	45	85	17	+ 7%	68		6,09%	0	5	0	8
8	6a PV penetration, P(U) control	348	+ 0%	24	88	10	0%	92	P(U) curtailment: annual production of a 1,74 kW PV	3,63%	387	0	208	0
9a	DSM + distributed storage (EC or 50-50 ctrl.)	464	+ 33%	32	86	12	-11%	93	"Maximal energy" battery capacity rating	2,78%	180	5	120	8
9b	DSM + central storage	536	+ 54%	37	86	15	-11%	88	"Maximal energy" battery capacity rating	3,60%	259	6	153	7
10	9a PV penetration, no controls	348	+ 0%	24	88	12	+ 1%	80	Scn.11: P(U): annual production of a 1,74 kW PV (2,3%) curtailed	4,35%	386	62	208	74
12	Electrification base case	--	--	--	--	--	--	--	Even w/o electrification the loads are at their limits (low voltages)					
13	Electrification + central storage	--	--	--	--	--	--	--	Even w/o electrification the loads are at their limits (low voltages)					
15	OLTC	464	+ 33%	32	88	12	+ 1%	80	Is 32% penetration possible with alternative solutions?	3,11%	0	0	0	0
16	Line upgrading (larger cross-section)	--	--	--	--	--	--	--	Largest cross-section cables are used already.					

6.2 Base case

In the simulations, we have assumed that a district is blocked under any of the following two conditions:

- According to the Grid Code: if there are too many voltage problems on the network (voltage exceeds 107.5% of the nominal value at any node for at least 5 quarter hours on any day)
- According to the Grid Code: when the installed PV capacity reaches the transformer capacity. This results in a blocking limit of **52.6% PV penetration (400 kW PV power)** on the „R" grid and **34% (500 kW)** on the CIGRÉ grid.

We also considered a realistic transformer overloading condition: if at a given installed PV capacity the transformer is overloaded to an unacceptable extent (it can tolerate about 130% for a maximum of 2 hours).

In the prosperous urban agglomeration (**"R" grid**), we found the blocking limit based on voltage problems **at 70% PV penetration** without any controls (no PU(U), no Q(U), no battery, no DSM) in the base case. This amount of PV capacity is not allowable with the original 250 kVA transformer, which is the rating of the actual operating transformer, rated for existing consumption in the area. Therefore, during the simulations we assumed the next available transformer rating, which is 400 kVA. Although the assumed base-case solar capacity (**535 kW**) still exceeds the maximal allowed 400 kW (transformer capacity based blocking limit), but the **transformer is not overloaded**. Further evaluation shows that **at 76% PV penetration** (without controls) **the transformer becomes overloaded**. If the MV/LV transformer was rated 630 kVA, we would not hit the transformer power limit. Additionally, due to the lower impedance associated with a larger transformer, the voltage drop on the transformer would also be lower and therefore the base case blocking PV penetration would increase slightly (by 1 ... 5 percentage points).

> *On the **<u>CIGRÉ</u>** network, we have experienced a **blocking limit** by voltage problems at 24% PV penetration in base case. This corresponds to **348 kW of installed PV.** At this point the maximal transformer load was 86%. The blocking limit by the nominal power of the transformer is not reached in the base case.*

6.3 Evaluation of very high blocking limits on „R" network

The base case simulations showed that the voltage limit has only been reached at a high PV penetration level of 70% in the **urban agglomeration network (R)**. This value seems to be very high compared to hosting capacities reported in other studies. A DSO was consulted on this issue.

a) We obtained data from a real LV district blocked from further PV installations. We found that the already installed PV capacity is **140%** of the transformer rated power. This is not allowed under current rules in the Grid Code, yet such grids exist. For a comparison, we checked the installed PV power over the transformer power for some simulated scenarios:
   - „R" grid: at 76% (580 kW) PV penetration the transformer rated power is exceeded by **45%**, at 78% penetration (596 kW) by **49%**
   - CIGRÉ grid: for 37% (536 kW) PV penetration, the installed PV power is **7.2%** higher than the transformer rating, while for **43%** (630 kW) PV penetration it is **26%** higher.

Our results are therefore not out of line with reality.

b) **Higher initial LV voltages:** in reality the DSO very often does not keep the phase voltage around its nominal value (230.94 V) on the LV side of the MV/LV transformer, as we do in our simulations. Instead, a higher starting voltage (243...245 V) is used. This causes the upper voltage limit to be hit much sooner (at lower PV capacity levels), so in reality a PV penetration lower than our simulation results is associated with the blocking limit. However, this voltage control principle is not applied generally in all cases, therefore – for the sake of comparability – we performed a test to see the consequences of non-nominal starting voltages:
c) We analysed the variation of the **maximum voltage along the grid at different PV penetrations** (30%, 40%, 50%, 60%, 70%, 80%) **and starting voltages** in the base case „R” grid. Using nominal starting voltage, the blocking limit was found to be at 70% PV penetration, which is the first time the 107.5% limit is reached. However, if the starting voltage is 245 V (106%), the voltage limits is already reached at 30..35% PV penetration. This is a value that is significantly closer to real-life experience.

Additional typical figures for the blocking limit based on information from a domestic DSO are as below:

- In 25% of MV/LV transformers, the installed residential PV power reaches 25% of the rated transformer power, and at 8% of the transformers the installed PV capacity reaches 50% of the transformer's rated power. 10,000 circuits comprise residential PVs, of which only 2,000 are problematic, meaning that problems are not usually found at average situations.
- Other causes for voltage problems can be: consumer and producer unbalance, high circuit loop impedance, PEN conductor with smaller cross-section than the phase conductor, large (electrical) distance of the residential PVs from the supply point, generation hot spots, consumption of only a small proportion of locally generated power locally, or high supply voltage on the LV side of the transformer.

6.4 Coordinated PV placement

The first efforts aimed at evaluating the possible increase in PV hosting capacity as a result of a coordinated PV placement strategy in the EC. To achieve this, we looked at two types of favourable arrangements:

- Community owned central PV installed at the start of the line
- Distributed, fixed-sized PVs (preferably 10 kW) were installed one-by-one based on the distance from the transformer ("Concentric" algorithm)

6.4.1 Central PV

We have found that by installing a central PV, the voltage-based blocking limit is not reached even at **76.5%** (583 kW installed PV) for the „R” grid, when the transformer overload limit is already approached. Note that this limit cannot be defined precisely. For this installation, the maximum transformer load is 113%. Thus with a central PV, a PV hosting capacity that can be achieved is 6.5% higher than in the reference base case scenario (where the PVs are installed in a distributed way at the largest consumers and scaled to match their annual consumption). The 583 kW PV represents an additional 9% installed capacity compared to the base case without applying P(U) control. However, this installed capacity is higher than the transformer rating, i.e. it does not comply with actual regulations.

> *The PV **hosting capacity** can be increased up to **44%** compared to the 24% PV penetration of the base case, with a central PV on the CIGRÉ grid, i.e. a total of **645 kW PV** can be installed. The transformer would then be subject to a maximum load of 88%. The voltage-based blocking limit has not been set here, because a new PV of more than 500 kW would certainly not be allowed by the grid code. The 44% PV penetration is not allowed under today's distribution regulations, it is blocked by the rated power of the transformer.*

6.4.2 Concentric PV installation

We found the **voltage-based** blocking limit being reached at **94% PV** penetration, i.e. at **720 kW** of installed PV peak power on the „R" grid by placing identical PVs starting from the transformer (concentric method). According to this result, on a voltage basis an additional +35% installed PV power could be accomodated on the grid with the concentric arrangement. However, the **transformer** is highly **overloaded.** Therefore we cannot really exceed **76% (580 kW**) installed PV capacity, similarly to the central PV scenario.

> *In the CIGRÉ network, with the concentric PV distribution method the voltage-based blocking limit is reached at **43% PV** penetration. Even in this case the transformer load would increase up to 88% only.*

6.5 Evaluation of energy community driven control functions

6.5.1 Battery

6.5.1.1 Central battery with community algorithm

In case of a central storage we can only implement a community algorithm that aims to minimize the energy flow towards the medium voltage grid when the solar panels are generating energy. In scenario 4.a, one central storage has been placed on each circuit of the networks, with the total power sized according to section 4.1. In terms of storage capacity, four-hour storage (R network) and maximum energy rating (CIGRÉ benchmark) was applied.

The first runs were performed **without applying the seasonal tolerance.** As expected, the PV hosting capacity achievable under the blocking constraints is improved by such storage units compared to the base case:

- „R" network, maximum energy capacity rating: increase from 70% to **72%**
- „R" network, 4 hours battery: increase from 70% to **72%**
- CIGRÉ network, maximum energy capacity rating: increase from 24% to **32%**
- CIGRÉ network, 4 hours battery: increase from 24% to **30%**

The **improvement on the R network** is quite **moderate**. This is due to the fact ***that the storage capacity is barely used,*** as it is mostly empty in winter and almost constantly full in summer. This makes it impossible to act in the desired ways.

For **CIGRÉ** network, **the storage results in a more significant improvement for** the PV hosting capacity, which can be explained by the ***fact that the nighttime consumption is sufficient to discharge the storage during the summer period***, and thus there is sufficient capacity to eliminate the voltage spikes from PV generation during the day.

In order to achieve a better use the capacity of the storage, we have introduced **<u>seasonal tolerance</u>**, which is described in detail in the description of the storage algorithm. With this change, the value of hosting capacity is further improved:

- „R" network, maximum energy capacity rating: increase from 70% to **78%**
- „R" network, 4 hours battery: increase from 70% to **78%**
- CIGRÉ network, maximum energy capacity rating: increase from 24% to **37%**
- CIGRÉ network, 4 hours battery: increase from 24% to **32%**

The modification results in **batteries being fully charged much less frequently on summer days and can intervene at critical times of the day**. Based on the evaluation of these results, the seasonal tolerance has been kept for all further storage simulations scenarios. The available penetration values also show that **for the "R" network, the larger storage does not make a significant difference compared to the smaller 4-hour capacity**, **and therefore the 4-hour capacity will be used for consequent scenarios. On the other hand, for the CIGRÉ network the battery with maximum energy capacity rating performs better and will be used in further simulations**.

With this solution the PV hosting capacity was increased to **78% PV** on the „R" grid, which represents **596 kW** PV and **+11.4%** hosting capacity compared to the base case. The maximal transformer load is 87% in this scenario.

> *Installing a central battery on the CIGRÉ grid results in the hosting capacity of the grid being increased from 24% of the base case to **37% PV penetration**, which would be **536 kW** of installed PV. The maximum transformer load would be 88%. According to current grid code regulation, with a central battery the allowable PV penetration on the CIGRÉ grid could be increased up to the rated transformer capacity (500kW).*

6.5.1.2 Distributed storage, community algorithm

In scenario 4.b the storage power and capacity defined once in scenario 4.a is set up on the grid in a distributed way at 3-phase producers. For the „R" network this covered 75-80, while for CIGRÉ 4 storage units. The operation of the central (community) algorithm is identical to the previous one, thus the total storage power and the total stored energy are also identical to case 4a.

In case all distributed batteries are controlled by the community method algorithm, identical results to the central storage scenario could be achieved on the „R" grid: a **78% PV** penetration limit (**596 kW**, +11.4% installed PV compared to the base case). The maximum load on the transformer is thus 87%, i.e. transformer overloading occurs at all.

> *The CIGRÉ grid also features the same result than the central storage scenario when distributed batteries are operated by the community algorithm with a community target. The achievable*

*PV hosting capacity is therefore **37%** where voltage based blocking is hit. Even then, the maximum actual transformer load would be 88%.*

The difference compared to scenario 4.a is found in the slightly different network loss values, since the same amount of energy is stored in and out at different points in the network.

6.5.1.3 Distributed battery, individual algorithm

In scenario 4.c, we allocate the batteries using the same procedure as in scenario 4.b, but instead of a community algorithm we **control them with the individual algorithm** that is based on local PV production and local consumption, applying balancing operation with **seasonal tolerance**.

The achieved hosting capacities still represent **a significant improvement compared to the case without storage, but they are below the results achieved with the community algorithm**:

- "R" network (4-hour storage): **76%** (580kW) instead of 70% (4.b: 78%)
- CIGRÉ network (maximum energy capacity): **30%** instead of 24% (4.b: 37%)

The poorer results are due to the fact that **the individual algorithm only takes into account a small fraction of the consumption** (which is connected to the specific PV) and therefore charges more often and to a much higher SoC, and **is consequently less able to intervene during critical hours**, especially in summer. Thus even with lower penetration, the battery's SoC is much higher than with the community algorithm at a higher penetration. In addition, by looking at the share of full batteries it can be verified that they reach a 100% SoC much more often, leading to voltage problems during the summer.

The maximum load on the transformer using distributed storage and individual algorithm was 90% ("R") and 86% (CIGRÉ).

6.5.1.4 Distributed battery with 50% individual and 50% community algorithm

In Scenario 4.d, the **capacity and power of** each of the **distributed batteries** was **split** into two equal parts. One part **was operated with a community algorithm** identical to scenario 4.b , while the other part **was operated with an individual algorithm** identical to scenario 4.c .

As expected, the **results** obtained **are between results 4.b and 4.c**:

- „R" network (4-hour storage): **76%** instead of 70%
- CIGRÉ network (maximum energy rating): **32%** instead of 24%

Although the 76% **penetration of** the **„R" network is the same as in scenario 4.c**, the **loss and self-sufficiency indicators** obtained in case 4.d **are improved**.

Transformer maximum load: 107% ("R") and 86% (CIGRÉ).

6.5.2 Demand-side management, reactive power control

6.5.2.1 DSM only

We have found that DSM can increase the PV capacity of the grid to **76%** on the urban agglomeration grid: this level equals to the results of the scenarios using a more advanced PV layout or relying on distributed batteries with tolerance band (which is a more grid-friendly algorithm than the one applied in today's practice), as well as the mixed individual-community-based algorithm. This 76% limit corresponds to 580 kW PV and thus +8% installed PV capacity compared to the base case. At this scenario there is no transformer overload, the maximum load is 93%.

The same penetration without DSM would cause high VAVDI and VAVFI values and of course, the network would be blocked (because the number of quarter hours with overvoltage within a day at a specific node would reach 12 instead of 1 – which is the case with DSM). With applying P(U) control at this same PV penetration, **4,842 kWh** of solar PV energy would be lost, which corresponds to the annual production of a 4.4 kW PV.

> *DSM had no effect on the blocking limit in the CIGRÉ network, because there were only a few flexible consumers. However with applying P(U) control, at the level of 24% PV penetration achieved in this way (and in the base case), **1,914 kWh** of solar PV energy would be lost, which represents about 0.47% of the total annual PV generation on this grid, and corresponds to the annual generation of a **1.74 kW of PV**.*

6.5.2.2 DSM+Q(U)

By applying the combination of DSM and reactive power control, our results show **that the voltage-based blocking limit on the „R" grid is not reached even at 100% PV penetration (760 kW installed PV)**, meaning that there is no day with voltage above 107.5% of the nominal value for at least 5 quarter hours. **However**, **the transformer would already be significantly overloaded** at such a high PV penetration. Still, we found that allowing a technically feasible transformer overloading, the hosting capacity could be increased to 87% PV penetration (compared to 76% with DSM without reactive power control). This corresponds to 664kW PV**. The effect of the reactive control is apparently significant when compared to DSM**, but can only be used to a limited extent due to the current-based overloading of the transformer.

> *On the CIGRÉ network the voltage-based blocking limit is **45% PV penetration (652 kW)** for DSM + Q(U) control, which means 87% PV installation. Applying DSM+Q(U) at 45% PV penetration, the maximal transformer load would be 85%, so we would not reach the blocking limit. Since DSM in itself had no discernible effect on the blocking limit, the possibility of an increase from 24% in the base case to 45% is mostly due to the reactive power control. **The impact of the reactive control is therefore also significant** on the CIGRÉ network.*

6.5.2.3 DSM and distributed battery

Compared to the stand-alone effect of applying DSM, additionally installing distributed batteries to the „R" grid can **increase the PV penetration by 2%,** and vice versa: at 76% penetration with distributed batteries (individual or community+individual algorithm), adding **DSM can increase it by only 2%**. The hosting capacity can therefore be increased from 70% of the base case to **78%** (**596 kW** i.e. +11% installed PV compared to the base case) by DSM and distributed storage combined. The maximum transformer load during this period is 90% - **the transformer is not overloaded at all**. Further, the battery at the same penetration has significantly reduced the maximum load on the transformer (from about 111% to 90%). In other words the blocking limit caused by transformer overloading is found at a significantly higher PV penetration with distributed storage.

> ***32% PV penetration*** *is allowed by the to voltage-based blocking on the CIGRÉ network, which is equivalent to the result of a community-and-individual algorithm for distributed batteries. This result is not surprising as DSM alone had no impact on the PV penetration of the network.*

6.5.2.4 DSM and central storage

By installing a central storage with our proposed community algorithm, **PV hostincg capacity** can be increased to **81%**. Thus the DSM's surplus is 3% compared to 78% for the central battery in this scenario. This means **617 kW PV**, 15% more PV installed capacity compared to the base case. The maximum load on the transformer is only 72%, therefore the transformer loading condition represents a limit at a higher PV penetration than in the distributed storage scenario. (However the rated power of the transformer would still represent a blocking limit here.)

> *With central storage and DSM, the same PV penetration limit is found as in the scenario with a central battery but without DSM:* ***37%****. This still corresponds to 536 kW PV, whereby the maximum transformer load is reduced by 2% from 88% to 86% as a result of applying DSM.*

6.6 Electrification

Our results of electrification scenarios showed that the networks could not or not easily cope with additional consumption. As consumption increases, the occurrence of undervoltages on the network increases rapidly. New consumers (large consumers) connecting to the feeder represent a smaller issue than new loads (EVs and HPs in our scenarios) scattered across the grid.

> ***CIGRÉ network could not accommodate any additional consumers*** *at all, as it has already featured a too high number of voltages below 92.5%.*

One additional large consumer consuming 10% of the previous annual consumption of the network may be allowed to connect to the prosperous urban agglomeration network. One large consumer plus additional electric cars and heat pumps at 10% of the households would result in up to 30 quarter hours per day with a voltage below 92.5% (and 4 quarter hours per day with a voltage above 107.5% when the PV penetration equals the base case). This number of low voltage issues could in reality trigger customer complaints. Installing a central battery may reduce the maximum daily upper voltage limit to 0, but it is able to reduce the counter for low voltage level issues from 30 to only 27. In this scenario the blocking limit was found at 596 kW PV with a total of 6 upper and 22 lower voltage limit violations. (This would correspond to 79% PV penetration relative to base case consumption, and 58% relative to the increased consumption.)

The use of a central battery with a community algorithm can only facilitate the connection of new consumers to a limited extent. An increase in PV penetration is most helpful when new consumption occurs during sunny hours. However, PV penetration cannot even be increased significantly by applíing central batteries. The operation of batteries is also questionable from the aspect whether during moderate wintertime PV generation batteries might be charged to a level which can then provide sufficient supply Evs and HPs in the evening hours. Since additional electrification consumers (electric cars and heat pumps) are flexible consumers, DSM could further help electrification (no such research was performed as part of the current paper). Furthermore, applying reactive power control could be useful, as it was seen to be effective in avoiding too low voltages. The full power of PV inverters is available for reactive power control during non-sunny hours to increase the voltage if needed, while on the other hand their applicability in voltage reduction is more limited since effective power generation reduces the capacity currently available for reactive control.

6.7 Alternative grid solutions

Two alternative network solutions were considered: an on-load tap changer type transformer (replacement of the current transformer) and a line replacement. Specifically, the study investigated the possibility of achieving 78% PV penetration on the prosperous urban agglomeration network and 32% PV penetration on the CIGRÉ network – which are typical PV hosting capacity levels that could be achieved using energy community driven methods.

6.7.1 OLTC

Two types of operation were tested when assessing a replacement to an OLTC transformer:

- Maintaining the voltage at the nominal value on the low-voltage side of the transformer by varying the transformer ratio; and
- Maintaining the average of the minimum and maximum voltage by observing the maximum and minimum voltage along the circuits per phase.

According to our results, on the „R" grid a PV penetration of 78% (which is feasible in an energy community either supplied with a central battery, DSM and distributed batteries, or distributed batteries and community algorithm) cannot be achieved with the first approach.

The second version has proven to be very effective in avoiding voltage problems, but the transformer overload has been close to the feasibility limit with a maximum of 126%. (As a reference, in the case of batteries the maximum transformer load varied between 87% and 107% depending on the scenario, with no unacceptable overloads.)

> *The **first OLTC version was not effective** on the CIGRÉ grid **either**, as it could not achieve the 32% PV penetration tested. The **second OLTC version** proved to be effective: no voltage problem remained and the transformer was not overloaded (maximum transformer load was only 88%). Therefore, an OLTC transformer with this type of operation is **a real alternative solution** to achieve 32% PV penetration in the CIGRÉ network.*

We would like to emphasize that OLTC simulations may show a slightly better performance than in reality. The reason is that we did not apply discrete steps for the turns ratio (tap position) in our model. Also, we allowed to change the tap position every quarter hour if it was necessary, which in reality does not occur with such frequency.

We believe that a method similar to the second OLTC method (monitoring only the supply and endpoint voltages instead of all node voltages) would be nearly as effective. By measuring voltage at fewer points, the installation could also be implemented more simply at lower cost.

6.7.2 Replacement of lines

In the urban agglomeration network, the existing maximum cross-section overhead line type has been replaced by the maximum cross-section cable. This scenario has eliminated all voltage problems on the network, therefore it is considered to be a good alternative solution for voltage problems. Still, the transformer is overloaded in this scenario too (this issue cannot be mitigated by the wire replacement), but the resulting maximum transformer load of 114% still proves to be acceptable.

> ***There was no point*** *simulating larger cross-section cables in the CIGRÉ network, because the main wires of this system were already at their largest available cross-section.*

6.8 Cost estimation

In this chapter, we aim to provide guidance on how to compare the investment aspect of energy community solutions and alternative grid development solutions. The solutions under consideration have a wide range of cost elements. We summarize the main cost items apart from labour costs below:

- Alternative grid solutions:
    - OLTC:
        - Metering at LV transformer
        - 3-phase voltage metering at least at the end points (4 locations on „R” network, 1 location on CIGRÉ network), but preferably at each node. Data collection per 15 minute intervals and transfer to the OLTC according to the algoritm
    - Replacing the lines
        - Only evaluated at „R” grid, the cost of earthworks, laying new 240 mm2 cable and overhead line removal of an approximately 3.5 km length line
- Energy community solution cost elements:
    - Battery
        - Distributed, custom algorithm: software, control algorithm
        - Community algorithm:
            - 3-phase metering at the startpoint of the circuit
                - Central battery: software of a higher complexity level
            - Distributed: transmission of 3-phase voltage metering to the distributed batteries, local device to receive this data
                - Central control unit
            - Distributed charge control software
    - DSM
        - long-wave radio control: receiver is already available at many places, an update of the scheduling / control program is required
        - Plug-in timer - a few thousand HUF only
        - Smart home system, possibly smarter devices (smart boiler)
    - Q(U): needs to be activated in the inverters

A key input used for cost estimation is shown in Table 6. which contains the actual cost estimations and conventional development timeframes used by the industry, broken down to development per circuit:

Table 6.: Estimated costs and development timeframes used by the industry

	Necessary developement time	**Yearly number of feasible developments** (unit/transformer station)	**Cost** (MHUF/unit)
Transformer tapping/ MV busbar voltage adjustment	6 months	Once in large volume	0,1
OLTC	6-12 months	30	**6**
Circuit reorganization	18 months	30	12
Cross-section increase	24 months	50	**18**
New circuit establishment/support	24 months	40	12
Increasing transformer density	36 months	30	30

7 SUMMARY

The most important conclusions derived from the analysis of each scenario are as follows:

- Transformer upgrades can alleviate one of the most limiting conditions.
  According to current Hungarian Grid Code regulations, the total PV power connected to a transformer area cannot exceed the transformer rated power. Replacing the transformer (e.g. 250kVA to 400kVA or 630kVA) would result in some cases in significantly higher PV hosting capacity, before the voltage-based limiting condition is met.

- Blocking areas based on the rated power of the transformer is an overly conservative, strong condition. Allowing 10% more PV than the transformer rating would still be safe.
  The above condition (that limits PV hosting capacity to the transformer rated power) is a safe and easily verifyable way to protect the transformer from overloading. However,
    - *transformers may be significantly overloaded for short periods of time (depending on preceding loading conditions)*
    - *in practice there is always some non-negligible load even in high-production periods.*

- Replacing the transformer to an OLTC is an effective way to alleviate static[8] voltage problems.
  It does not contribute, however, to self-sustainability KPIs of an energy community. There are several ways to operate an OLTC – these differ in the measurement and instrumentation requirements. The OLTC control is most effective if measurements are available for multiple nodes of the LV system, not just at the transformer's LV side.

- The transformer and OLTC costs represent an investment level similar to a small number of PV installations (approx 5). If a suitable financial/contractual arrangement can be elaborated, it may be worth for an energy community to invest in transformer replacement (either higher capacity transformer or OLTC).
  Network investments (e.g. transformer uprating, replacement, line uprating or new constructions, etc.) are to be performed by DSOs, and the costs are covered by the network usage fee component of the consumer tariffs. These investments can experience significant delays because of several reasons (e.g. lack of workforce, capped network usage tariffs, etc.) Energy communities could accelerate this process in order to obtain a significant PV connection license several years earlier than in the case where this investment was to be made and scheduled by the DSO – assuming that a suitable agreement can be constructed.

- Combined centralised and decentralised PVs is the best PV deployment solution.
  However, installing a centralised PV is not feasible in some cases (e.g. due to restricted available space).

[8] This study exclusively focused on static voltage problems, not dynamic ones. Current DSO practice requires that sudden voltage changes (e.g. due to short-term PV production fluctuations caused by cloud coverage variations) be limited within 2% of the nominal voltage at any point of the LV system. Typically, most OLTCs and DSM cannot cope with the dynamic requirements, but Q(U) control and battery control can.

- Concentric PV installment is a highly efficient solution to gradually exploit the PV hosting potential of LV distributed systems.
  An energy community – having an appropriate contractual and accounting system among its members – could facilitate such a PV installation plan, which is an optimal way of gradually expanding its PV capacities in a grid-friendly way. Also, it is an efficient alternative to installing (partially) certalised PV, and is in alignment with the European Solar Rooftop Standard, (rooftops of all new residential and non-residential public buildings shall carry a PV).

- Batteries: lower transformer loads and MV grid usage can be achieved with higher or the same level of energy independence depending on consumption profiles by installing storage.
  - *A voltage-based central control is the optimal way of managing charging and discharging the battery, from a grid-compatility point of view. (It requires additional investments for voltage measurements at farther nodes of the line, data acquisition and communication).*
  - *Central battery controlled by a centralized control algorithm is the best overall solution among power-flow-based control algorithms. This option is followed by setting up distributed batteries but controlling them by a central algorithm. Setting up distributed batteries with a control algorithm that takes into account both individual power balance as well as community power balance (power flow over the transformer) is still an efficient way of increasing PV hosting capacity and at the same time ensuring increased energy autonomy. Finally, very similar results are obtained by individual control of distributed batteries, which still allows for significantly higher installed PV capacity than the base case, and can be introduced gradually.*
- Reactive power (Q(U)) control is a highly effective way to increase the PV hosting capacity by ensuring proper voltage regulation, assuming line types with certain line parameters (X/R ratio not too small).
  - *Difficulty: during sunny hours, the produced PV power and the required reactive power consumption together might be higher than the inverter rated power. Therefore, either an oversizing of some inverters or the curtailment of power generation by a small amount (still much less than with P(U) regulation) is necessary.*
    - *It is important to stress however, that not all PV inverters need to contribute to Q(U) control: although this has not been studied in detail, sample calculations suggest that it is sufficient to control the inverters farthest away from the transformer, and that about one third of the inverters should be involved.*
    - *An oversizing by 20% might be sufficient is many cases, 30% might suffice in most cases.*
    - *In the case of a suitable community-level financial settlement and contractual background, the energy community may be able to subsidise the oversizing of the involved residential PV inverters or compensate for the financial disadvantage of a small curtailment of their production.*
  - *Applying reactive power control leads to a slight increase of network losses.*
- DSM is a very effective way in handling voltage problems and increasing possible hosting levels of PV capacity, reducing the load on the MV grid, and thus ultimately improving energy independence and self-sufficiency

- *It requires a new approach instead of the current tariff system and the control/switching schedule currently used for off-peak "valley-filling".*
- *It could be extended to non-generating consumers (consumers without a PV), with additional positive impact.*