# The role of alternative network response options in minimising the costs of DG integration into power networks

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*Project objectives*

The IMPROGRES project aims to identify possible improvements in the direction of a socially optimal outcome of market and network integration of distributed generation (DG) and electricity production from renewable energy sources (RES-E) in Europe with a focus on efficient interactions between distribution networks and embedded DG, fossil-based and from renewable energy sources (RES). To that effect the project sets out to:

- identify current interactions between DG/RES businesses, distribution system operators (DSOs) and energy markets directed at coping with increased DG/RES penetration levels;
- develop DG/RES-E scenarios for the EU energy future up to 2020 and 2030;
- quantify, for selected network operators, the total future network costs that have to be incurred to accommodate increasing shares of DG/RES according to the DG/RES-E scenarios;
- identify cost minimising response alternatives to accommodate increasing penetration levels of DG/RES for the same network operators, as compared to prevailing conventional DSO practices;
- recommend policy responses and regulatory framework improvements that effectively support improvements towards a socially optimal outcome of integrating DG/RES in European electricity networks and markets.

*Project partners*

- Energy research Centre of the Netherlands (ECN), The Netherlands (coordinator)
- Liander NV, The Netherlands
- Fraunhofer Institute for Wind Energy and Energy System Technology (IWES), Germany
- MVV Energie, Germany
- Risø National Laboratory for Sustainable Energy, Technical University of Denmark
- (Risø DTU), Denmark
- Union Fenosa Distribucion, Spain
- Universidad Pontificia Comillas, Spain
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# CONTENTS

# LIST OF FIGURES

# LIST OF TABLES

# ACRONYMS

| | |
|---|---|
| **ANM** | Active Network Management |
| **BAU** | Business-as-usual |
| **CHP** | Combined Heat and Power |
| **DG** | Distributed Generation |
| **DSM** | Demand Side Management |
| **DSO** | Distribution System Operator |
| **HV** | High Voltage |
| **ICT** | Information and Communication Technologies |
| **LV** | Low Voltage |
| **MV** | Medium Voltage |
| **PV** | (Solar) Photovoltaics |
| **RES** | Renewable Energy Sources |
| **TC** | (MV/LV) Transforming Centre |

# EXECUTIVE SUMMARY

Increasing DG/RES penetration levels are expected to affect a wide range of electricity system costs components. The most relevant ones are deemed to be distribution costs, since the size of distribution assets can no longer depend only on flows caused by peak demand; generation, since DG will replace part of the former production of conventional generation and the generation mix will change as well; balancing, due to the unpredictability and variability of some DG technologies and external cost, since emissions of different polluting substances are significantly lower when electricity is produced using clean renewable technologies.

Within the IMPROGRES project the evolution of the different types of costs with increasing shares of DG, ceteris paribus, has been determined. The set of system variables that are kept constant (level of demand, fuel prices, $CO_2$ prices, etc.) are known as the background or storyline where DG impact is measured. Two different storylines have been considered, one corresponding to the year 2008 and another one corresponding to the expected situation in the year 2020. For each storyline several scenarios have been analysed: no-DG, 2008 DG, 2020 DG Medium and 2020 DG High.

Three distribution areas which have a high potential for the integration of DG/RES have been studied. These are located in Spain, the Netherlands and Germany. These areas have different characteristics in terms of the type of load existing in the area (rural/urban, etc.), the type and amount of DG present, as well as unit costs and other parameters of design of the grid.

The computation of system costs has been mainly carried out with the aid of software models owned by IMPROGRES project partners. In order to assess distribution costs, two reference network models have been employed to compute the optimally adapted distribution network for each of the previously defined scenarios. These reference network models take into account the cost of investments, operation and maintenance and losses when developing the minimum cost grid that is able to cope with the flows that are expected in each case. They also take into account DG to reduce costs if possible as well as to compute the extra costs that the latter may cause.

Simultaneously, variable generation costs and social welfare in the dispatch are computed using an economic dispatch model named COMPETES, assuming perfect competition and taking into account the substitution effect associated with the presence of DG in a set of operation scenarios representative of the operation of the system during the whole year. Fixed generation cost are computed from the result of the dispatch computed by COMPETES and using levelized costs so as to determine the amount of capacity from each conventional generation technology required to provide this energy. External cost are computed from the total production from each technology computed by COMPETES and according to the unit emission factors corresponding to each technology. All these cost factors are scaled to take into account the effect that the low capacity credit corresponding to certain technologies may have both on the production and on the amount of capacity installed of each technology (the latter for conventional ones).

Furthermore, balancing costs are computed considering characteristic increases in balancing costs per unit of energy produced from wind in each type of area, and for the corresponding wind penetration level in the corresponding country, taking into account total wind production in the area. Finally, transmission network costs, only considered for the Dutch case study, were estimated by the network operators in the area based on their own planning studies.

Firstly, a business-as-usual analysis was performed in WP4 of the IMPROGRES project. This means that a completely passive behaviour of loads and DG was assumed, as it is mostly the case nowadays. Results showed that overall system costs tend to increase as more DG is connected. Notwithstanding, the impact on each of the different cost factors is unequal. Both fixed generation costs and distribution costs increase significantly due to the growing DG penetration levels. This is caused by the need to have back-up capacity due to the lowest capacity credit of DG/RES and the need to reinforce the networks so as to cope with the increased power flows. On the contrary, variable generation costs and externalities decrease owing to the fact that DG production substitutes (in terms of energy) part of the more polluting and expensive centralised generation. Balancing costs tend to increase as well, although they are less relevant as compared to the remaining cost components.

In order to be able to make comparisons among regions, the total impact of DG on system costs was normalised with the installed capacity of DG. DG-related distribution network incremental costs for DG penetration levels below 100% are in the range 45-70 €/$kW_{DG}$ for the Spanish case. Those in the Dutch case are in the range 95-164 €/$kW_{DG}$. Finally, those in the Mannheim area lie between 200-675 €/$kW_{DG}$. Differences in the former values for different areas may be partly caused by the use of different unit costs of network elements in different areas or the different assumptions about the behaviour of demand and generation

Assumptions made for WP4 analyses were rather conservative. Hence, it was considered that DG-driven incremental costs could be significantly mitigated under alternative conditions. In WP5 the same methodology described above was applied this time assuming that advanced response options are implemented. One alternative scenario has been defined for every original scenario studied in WP4. In this alternative scenario, a combination of several response options has been implemented. Response options that were modelled are twofold: advanced generation control and demand side management.

- The Kop van Noord Holland area is a region very favourable to the location of medium-sized wind farms and CHP units. Maximum DG production is expected to surpass consumption. In this area, the advanced response options considered comprise shifting demand of greenhouses from periods with low DG production to those where most CHP units are running, curtailing wind output at specific times (a few hours per year) and controlling CHP production thanks to the possibility to store heat or resort to gas boilers.

- The Mannheim area is residential. There, solar PV panels on roofs and micro-CHP units are expected to become widespread. By 2020, the production of PV panels connected at LV may have surpassed the maximum instantaneous consumption at this voltage level. Thus, limiting maximum DG production at certain times was deemed the most promising alternative. A 20% reduction has been assumed sensible.

- The Aranjuez region is a mostly residential and industrial area where there are a few medium-sized wind farms and industrial CHP plants. Additionally, some PV farms will have been connected by 2020 at MV level. Nonetheless, peak demand is the most relevant cost driver. Hence, advanced response options considered include both a reduction in peak LV demand which partly/mainly result from a shift in time of peak demand due to a change in tariffs applying in the region, though some demand response is also considered, and changes to CHP and PV production patterns which are also the result of active generation control and changing tariffs.

The results show that increasing DG penetration levels may cause distribution network costs to rise in spite of implementing advanced response options. An exception to this occurs in the Spanish case study, where network costs could decrease when low or moderate amounts of DG are connected. In this case, DG production during peak demand periods would reduce the rating of upstream network elements and, consequently, capacity requirements. Notwithstanding, the implementation of advanced response options could noticeably mitigate the negative impact of DG on distribution costs. Cost savings range from above 30% in the Dutch area to about 2% in the most unfavourable scenario of the Spanish case study (see Figure 1). The benefits of active network management (ANM) greatly depend on a myriad of parameters: DG penetration levels, relative location of loads and DG, DG technologies, assumptions made regarding load and DG behaviour and the nature and degree of implementation of these response options.

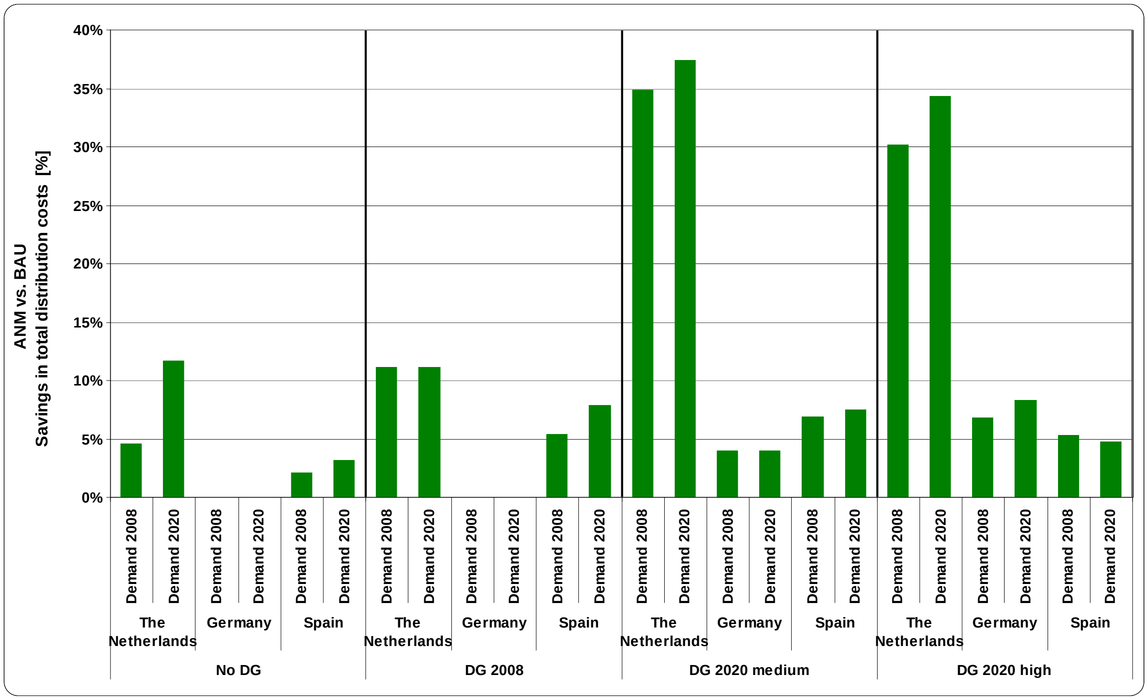


Figure 1: Savings in total distribution network costs after the implementation of advanced response options as compared to a BAU situation [%].

Generally, distribution cost savings were higher for those areas where a higher degree of controllability of load and especially DG was assumed. The highest benefits were obtained for the Dutch case study in the 2020-DG penetration level scenarios. It should be taken into account that DG penetration rates in these scenarios are extremely high whilst the planning assumptions considered in WP4 were extremely conservative. Therefore, it is reasonable that cost savings brought about by advanced response options are high when compared to those results for other areas. Per cent cost savings in the remaining scenarios (all but those in the Dutch area for 2020-DG penetration levels) all remain in the range of 5-10% of total distribution costs. Moreover, cost savings usually correspond to network investments in assets located upstream of DG within the network or in assets located at the same voltage level as DG.

Adding the remaining cost factors to distribution network costs, it was observed that the implementation of advanced response options caused overall system cost reductions for all case studies (before considering its implementation costs). However, it is worth noticing that most savings caused by the implementation of ANM correspond to reductions in network costs. On the contrary, fixed and variable generation costs, as well as externalities, tend to grow as a consequence of the lower contribution of DG/RES. However, it can be seen that the limited curtailment or shifting of DG/RES production produces significantly larger savings (in grids) than the associated costs.

In any case, curtailing intermittent DG/RES production should only be resorted to in rare occasions. Energy storage and demand response should be considered first in order to minimise the loss of resources caused by curtailing technologies such as wind or solar

PV. However, it was not possible within this project to analyse the influence of demand response or storage on intermittent DG/RES production spillage. Thus some simplifications needed to be done.

The amount of savings achieved per each kW of DG installed greatly depends on the particular characteristics of each region. Whilst overall cost savings present smaller variations among scenarios and are kept within similar ranges for the German (10-12 €/kW of installed DG) and Dutch regions (7-9 €/kW of installed DG), savings in the Spanish case study (2-5 €/kW of installed DG) were significantly lower and presented considerable volatility among scenarios. More detail is presented in Table 1.Therefore, implementing the set of response options that best fits each distribution area instead of applying the same to all areas seems to be advisable.

Table 1: Cost savings achieved through ANM as compared to a BAU situation for the different types of system costs. Values expressed in €/kW of installed DG and year [€/kW$_{DG}$/year].

| | 2008 demand | | 2020 demand | |
|---|---|---|---|---|
| | 2020 DG medium | 2020 DG high | 2020 DG medium | 2020 DG high |
| *The Netherlands* | | | | |
| Variable generation costs | 0 | 0 | 0 | 0 |
| Fixed generation costs | -2.1 | -2.3 | -1.6 | -2.3 |
| Distribution costs | 9.7 | 7.4 | 8.8 | 7.6 |
| Balancing costs | 0 | 0 | 0 | 0 |
| External costs | 0.1 | 0 | 0 | 0 |
| Transmission costs | 1.2 | 3.9 | 0 | 3.9 |
| Total costs | 8.9 | 9 | 7.2 | 9.2 |
| *Germany* | | | | |
| Variable generation costs | -0.3 | -0.2 | -0.3 | -0.3 |
| Fixed generation costs | 0.1 | 0 | 0 | 0 |
| Distribution costs | 9.8 | 10.8 | 9.3 | 12.6 |
| Balancing costs | 0 | 0 | 0 | 0 |
| External costs | 0.1 | 0.1 | 0.1 | 0.1 |
| Total costs | 9.7 | 10.7 | 9.1 | 12.4 |
| *Spain* | | | | |
| Variable generation costs | -0.3 | -0.2 | 0 | 0 |
| Fixed generation costs | 0.2 | 0.1 | 0 | 0 |
| Distribution costs | 4.5 | 2.3 | 4.8 | 2 |
| Balancing costs | 0 | 0 | 0 | 0 |
| External costs | 0 | 0 | 0 | 0 |
| Total costs | 4.3 | 2.2 | 4.8 | 2 |

Moreover, an estimation of the implementation costs in each area was carried out. When incorporating this estimation to the previous results, it is obtained that the case for ANM is generally positive. In the Dutch and German areas, the case for ANM is clearly positive, especially in the former. However, this is not the case in Spain where implementation costs are in the same range or even higher than the cost savings computed. It must be noted that these calculations constitute a rather simplified approach in several aspects. For example, the implementation costs had only been roughly estimated. This allowed us to draw some preliminary conclusions, albeit a definite decision about the acceptance or rejection of ANM would require a more detailed and profound cost-benefit analysis. Since significant differences across regions can be found depending on their particular characteristics, this analysis should be made on a region specific basis.

Furthermore, there are many other advantages of the implementation of response options that could not be quantified in WP5 such as the contribution of energy efficiency and DG/RES to security of supply (using endogenous resources), barriers to building new network assets (which could in fact make ANM the only solution), contribution of smart metering to improve continuity of supply, provision of ancillary services by DG and/or loads, etc. Additionally, a generalised use of ANM could push the development of the ICT technologies and drive unit implementation costs down. On the other hand, shaving load peaks or curtailing DG production may imply some loss of comfort or incomes for consumers and DG operators respectively. This could involve paying them some kind of compensation or lucrum cessans. These issues should be addressed in future research.

# 1. INTRODUCTION

Previous work carried out within WP4 of the IMPROGRES project quantified how system costs are affected by the connection of distributed generation (DG) considering a passive behaviour of loads and DG units [1]. WP4 covered distribution (and transmission for one case study) network costs, balancing costs, fixed generation costs, variable generation costs and the cost of externalities. More details about the methodology followed can be found in D5 of the IMPROGRES project.

The computation was carried out for three real distribution areas located in The Netherlands, Germany and Spain. A brief description of these areas is provided below:

- The Kop van Noord Holland region (The Netherlands) is a rural/sub-urban distribution area serving approximately 80000 customers over an area of about 990 $km^2$. Domestic loads are mostly densely located in the southern part the region. The remaining area is full of DG installations, which comprises numerous CHP units and wind farms. In fact, DG capacity is already comparable to peak demand nowadays. Moreover, generation is expected to overtake demand by 2020 due to the major increases foreseen both in wind and CHP, mainly at MV (medium voltage) level. Consequently, at times, local generation may exceed demand. This will presumably have great impacts at HV (high voltage), MV and even at transmission level.
- The Mannheim area studied (Germany) comprises mostly residential consumers. Overall, over 6100 customers in an area of 20 $km^2$ are included. The effect of a considerable development of domestic PV (photovoltaic) panels and domestic CHP units connected at LV level, from a current nearly negligible penetration level, is analysed. In the meantime, demand is expected to remain virtually unchanged. In this region, there are a few large MV consumers and numerous low voltage (LV) loads. Hence, both the MV and LV grids will be considered in the analysis. It is deemed probable that future DG production may exceed consumption at LV level during some (short) periods. Therefore, this distribution area could greatly benefit from an active integration of DG.
- The Aranjuez area (Spain) covers an area of 3400 $km^2$ with approximately 61600 consumers. Most loads in this region are connected within towns at LV, albeit several hundreds are at MV and a few at HV. Industrial zones are present in the outskirts of Aranjuez, which is the main town in the area. This sub-urban grid is comprised of a sub-transmission grid, a MV grid and a LV grid. Current installed DG capacity, low when compared to peak demand, is concentrated in a few units. Annual demand growths of around 4% are expected. Additional DG is expected too, including PV farms at MV and new wind and CHP units at HV level. Network reinforcements are deemed needed to cope with this DG and load growth. However, due to the existence of important procedural barriers, a more active integration of DG would be greatly beneficial.

For each case study region, a set of scenarios was defined considering two levels of demand (2008 and 2020), and four DG penetration levels (no DG, 2008 DG, 2020 DG medium and 2020 DG high). In WP4, BAU paradigm was assumed, i.e. DG and loads played a completely passive role. Therefore, DG/RES was not respondent at all to network and system needs.

WP5 of the IMPROGRES project intends to assess the impact that advanced operation and planning practices, such as demand response or active network management, would have on total system costs. In order to achieve this goal, the effect that these practices can have on a number of system cost components has been quantified through the use of various tools in the first place. This has been done by applying the methodology followed in WP4 to the same distribution areas and the corresponding scenarios. However, in this case, the behaviour of loads and DG is no longer considered completely passive owing to the implementation of advanced response options. Afterwards, a rough estimation of the implementation costs of the selected response options has been carried out so as to perform a simplified cost-benefit analysis.

The remainder of this document is organised as follows. Firstly, Section 2 briefly describes the kind of response options that have been considered in the analyses. Section 3, which constitutes the core of this report, presents the modelling of the different response options and provides the costs computation results for the three case studies. Finally, the results are analysed in detail and conclusions are drawn in Section 4.

# 2. RESPONSE OPTIONS CONSIDERED

This section details the response options that have been taken into account for each case study region. These were selected by the distribution system operators (DSOs) operating each distribution area and participating in the project. Once these response options had been identified and their potentials quantified according to the particular features of each case study, they were modelled in order to compute their impact on different cost components. Thus, for example, talking about distribution costs, response options were modelled mainly by modifying the simultaneity factors or active power associated with each type of load and /or DG technology.

Due to the limitations of the modeling tools, only two kinds of market responses have been analysed:

Advanced generation control through bilateral contracts between producers and DSOs or economic incentives such as prices with some locational/temporal differentiation.

Demand side management by means of interruptibility contracts or economic incentives (prices).

One alternative scenario has been defined for every original scenario studied in WP4. In this alternative scenario, a combination of several response options has been implemented. More details on the modeling of these scenarios for each case study region will be provided in next section.

# 3. IMPACT OF ADVANCED PRACTICES ON DIFFERENT COST COMPONENTS

This section of the document provides, for each of the three distribution areas, the impact of the combination of advanced responses that is considered for this area on the different cost components analyzed in deliverable D5 of the project. System costs have been computed for different penetration levels of DG assuming that the aforementioned advanced response options have been implemented. The methodology and most input data used in this analysis are also those already considered in D5. Those aspects of the analysis that are new are described in the following subsections. Results from this analysis are discussed and compared with the ones obtained in WP4 in order to draw relevant conclusions.

Section 3.1 focuses on the Kop van Noord Holland area (The Netherlands). Section 3.2 corresponds to the Mannheim area (Germany) and section 3.3 to the Aranjuez area (Spain).

## 3.1 Kop van Noord Holland area

The Kop van Noord Holland region is a very attractive area for DG investors. The main reasons for this are the high availability of wind resources in the area and the large number of horticultural greenhouses which may benefit from installing CHP units to meet their thermal demand and feed electricity into the grid. This has caused that installed DG capacity in 2008 was already close to peak demand in the region. Additionally, DG capacity is expected to significantly exceed demand in 2020.

### 3.1.1 Distribution Costs

**Modelling of those advanced practices with the highest impact in the area**

Previous results obtained in WP4 of the IMPROGRES project showed that a passive integration of DG, known as a fit-and-forget approach, led to considerable positive impacts of DG on distribution network costs. In the scenarios studied within WP4, very extreme, conservative, assumptions were made regarding the behaviour of DG. During peak demand periods, DG was assumed not to be producing; whereas during valley hours, it was assumed to be producing at rated capacity. Consequently, actively integrating DG through the implementation of advanced response options should certainly reduce this impact.

Response options considered aim at improving the integration of DG and load, i.e. reducing load and increasing generation at peak load hours and increasing load and reducing generation at valley hours. More specifically, three response options have been finally modelled:

1. Wind curtailment: Limiting the connection power of wind farms to a level below the installed capacity (passive curtailment), or reducing the output of wind farms at moments of congestion (active curtailment).

   The DSO Liander deemed reasonable to limit instantaneous wind production to 60% of the installed capacity at those periods when it largely exceeds demand. Figure 2 shows that production of on-shore wind farms in the Netherlands currently surpasses 80% of installed capacity in about 15% of the hours in a year.

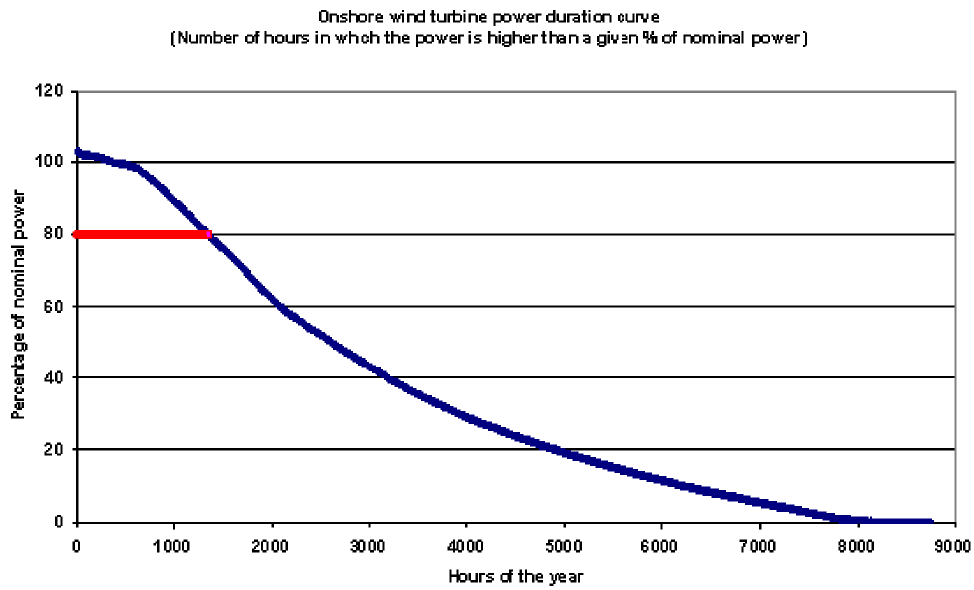


Figure 2: Wind duration curve for 2.5 MW onshore wind turbine in The Netherlands (source wind data: P. Eecen, ECN)

2. Temporary adjustment of the output of CHP units: These adjustments shall take place at specific times, like those where wind speed or demand is high. CHP production can be either increased or decreased.

   CHP production can be modified to some extent to reduce the amount of grid capacity required. However, this possibility is limited due to its influence on horticultural processes in the area. The heat produced simultaneously with electricity cannot be freely disposed of due to the need to comply with global efficiency regulatory requirements. On the other hand, heat requirements of the greenhouses can be met through cogenerated heat or by means of additional boilers. Considering this and the feedback got from meetings held with stakeholders, the maximum feasible increase in minimum CHP production was deemed to be about 20% of original output while the maximum reduction of peak CHP output at times of maximum net demand was deemed to be about 30% of that considered in D5.

3. Demand response: this measure is aimed at reducing peak demand and increasing consumption when production is at its maximum. In practice, only horticulturist loads shall be managed. The responsiveness of domestic loads in the region is deemed negligible. Moreover, less technological and social barriers may be encountered when managing horticulturists' demand than that of households. Response by the former type of consumers may involve shifting demand of greenhouse lighting from peak load periods to times of peak generation of CHP and wind.

Table 2 provides the amount of DG capacity that is assumed to be manageable for each one of the previous response options in the different scenarios. The shift in demand would represent an increase in the maximum net generation snapshots and a similar decrease in the maximum net demand ones.

Table 2: Summary of the modeling of response options considered in the Kop van Noord Holland area

| | Wind curtailment [MW] | Rise in CHP generation [MW] | Reduction in CHP generation [MW] |
|---|---|---|---|
| Relevant snapshot | Maximum generation | Minimum generation | Maximum generation |
| 2008 DG | n.a | 30 | 40 |
| 2020 DG medium | 80 | 120 | 180 |
| 2020 DG high | 200 | 150 | 265 |

| | **2008 demand** | **2020 demand** |
|---|---|---|
| Shift in demand of horticulturists [MW] | 15 | 100 |

**Numerical results**

Table 3 shows the amount of network assets of each type in the optimal network computed for each scenario in the Kop van Noord Holland area. Generally, more network assets in terms of network length and transformation capacity are required when DG penetration levels increase. A trade-off between installing 150 kV conductors and 50 kV ones exists for the HV grid. The former type of conductors have greater capacities but higher investment costs and vice versa. Therefore, total HV network length should be assessed taking this into account.

Table 3: Network elements. Kop van Noord Holland area

| | | HV network [km] | | | HV/MV Substations | | MV network [km] |
|---|---|---|---|---|---|---|---|
| | | Total | 150 kV | 50 kV | number | Capacity [MVA] | |
| 2008 Demand | No DG | 61.35 | 27.99 | 33.36 | 4 | 288 | 678.82 |
| | 2008 DG | 75.84 | 27.75 | 48.09 | 4 | 354 | 744.18 |
| | 2020 DG (medium) | 117.13 | 41.29 | 76.02 | 10 | 848 | 967.17 |
| | 2020 DG (high) | 80.88 | 80.88 | 0 | 6 | 1200 | 1118.75 |
| 2020 Demand | No DG | 64.26 | 64.26 | 0 | 5 | 760 | 811.72 |
| | 2008 DG | 71.55 | 71.55 | 0 | 5 | 760 | 1090.16 |
| | 2020 DG (medium) | 120.37 | 44.98 | 75.39 | 6 | 812 | 944.71 |
| | 2020 DG (high) | 80.5 | 80.5 | 0 | 7 | 1280 | 1095.21 |

Similarly to the results obtained in WP4, distribution network costs increase with DG penetration levels. This occurs in spite of the fact that advance response options have been implemented and is due to the very high levels of DG penetration existing in the scenarios considered. Moreover, Figure 3 shows that the increase in costs with the penetration level is more moderate for the highest level of demand. This can be explained by the fact that net generation in the DG maximum production snapshot (which is the dominant one in these scenarios) is smaller the higher consumption is. Therefore, network capacity requirements decrease as demand grows.

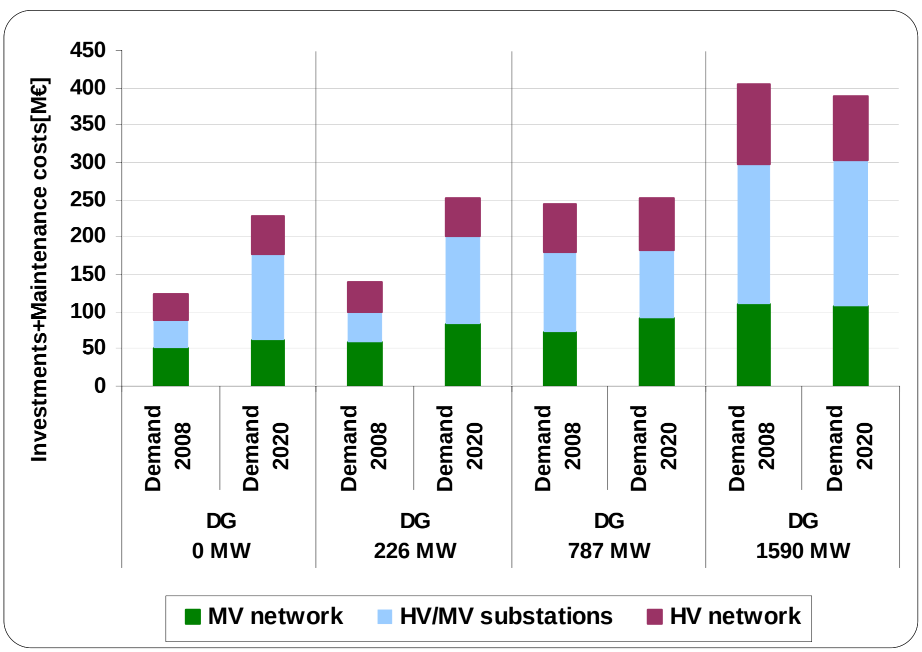


Figure 3: Investment and maintenance costs for the different scenarios in the Kop van Noord Holland area

However, these results ought to be compared with those of WP4 in order to be able to determine whether the implementation of advanced response options can be beneficial in terms of cost reduction. Figure 4 shows the comparison of total investment and maintenance costs for the 2008 and 2020 storylines before and after the implementation of the considered advanced response options.

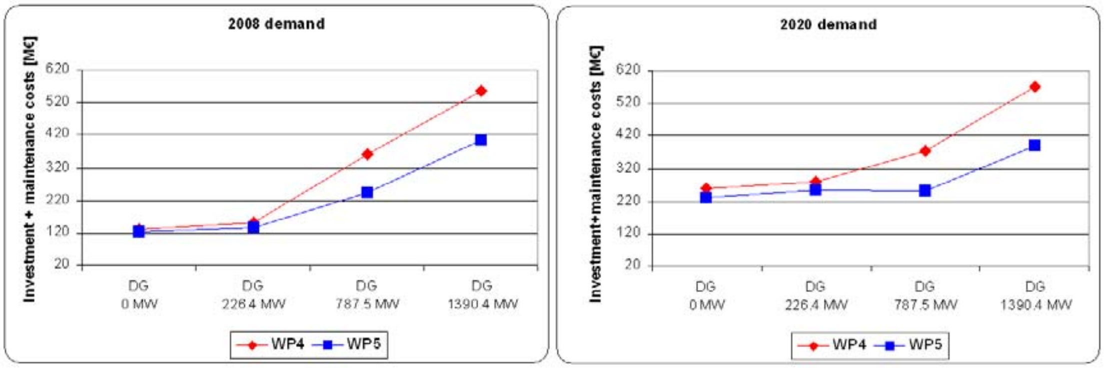


Figure 4: Comparison between distribution investment and maintenance costs for the different scenarios in the “business as usual” framework (WP4) and those obtained when applying ANM practices (WP5) in the Kop van Noord Holland area

It can be seen that response options can bring about significant costs reductions, especially for high DG penetration levels. As displayed in Table 4, the largest fraction of these savings is generally attained by reducing the transformation capacity required to allow the flow of DG production from MV to HV level. For some scenarios, the cost of network conductors increase with respect to WP4 values. Nevertheless, this effect can be considered negligible compared to that corresponding to the remaining cost components.

Table 4: Investment and maintenance cost savings yielded by the implementation of advanced response options (in M€). Kop van Noord Holland area

| | Demand 2008 | | | | Demand 2020 | | | |
|---|---|---|---|---|---|---|---|---|
| | DG 0 MW | DG 226.4 MW | DG 787.5 MW | DG 1390.4 MW | DG 0 MW | DG 226.4 MW | DG 787.5 MW | DG 1390.4 MW |
| Total | 5.96 | 14.16 | 117.31 | 152.11 | 30.35 | 26.22 | 122.93 | 182.88 |
| HV network | 0.00 | 7.26 | 4.32 | 1.98 | 8.96 | 6.39 | 30.31 | -18.99 |
| HV/MV substations | 0.00 | 2.46 | 70.81 | 141.83 | 17.57 | 27.49 | 84.39 | 141.81 |
| MV network | 5.96 | 4.44 | 42.18 | 8.30 | 3.82 | -7.66 | 8.23 | 60.06 |

In Figure 4, the only point where network costs do not increase with DG penetration corresponds to the scenario with 2020 demand levels and 2020 moderate DG levels. This can be explained using the maximum net loading at the transmission substation in each scenario. Maximum net loading is defined (neglecting energy losses) as the highest of peak net demand and peak net generation in each scenario. This information is provided in Table 5, where maximum net loading appears in red. It can be seen that, owing to the implementation of advanced response options, the maximum net loading of the transmission substation for the aforementioned scenario is reduced in spite of increasing DG penetration.

Table 5: Maximum net loading at transmission substation. Kop van Noord Holland area

| | | | Net loading | |
|---|---|---|---|---|
| | | | Snapshot | |
| | | | Max load - min gen | Min load - max gen |
| Scenario | Demand 2008 | No DG | 207.08 | 91.19 |
| | | DG 2008 | 176.82 | -95.63 |
| | | DG 2020 medium | 86.718 | -439.32 |
| | | DG 2020 high | 56.281 | -831.75 |
| | Demand 2020 | No DG | 499.43 | 202.69 |
| | | DG 2008 | 469.17 | 15.87 |
| | | DG 2020 medium | 379.068 | -327.82 |
| | | DG 2020 high | 348.631 | -720.25 |

Figure 5 shows that there is a strong correlation between maximum net loading (in absolute value) and distribution network costs. Note that this correlation is due to some particular features of the Dutch case study, i.e. DG and loads are both mostly connected at the MV level and geographically close. The relevance of the loading of the transmission substation is significantly lower in other case studies due to the existence of significant differences in the relative location of DG and loads.

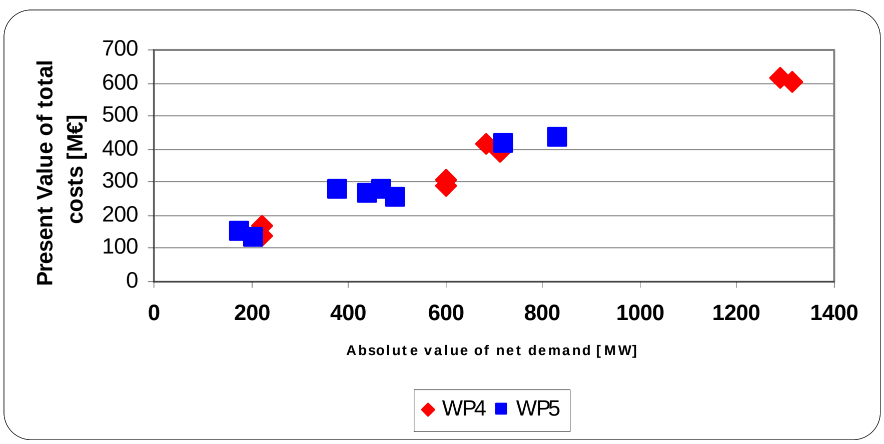


Figure 5: Distribution network costs versus net loading at the transmission substation in the Kop van Noord Holland area

In Figure 6, cost savings achieved by implementing ANM practices are expressed as a percentage of the optimal cost of the distribution network computed in D5. Cost reductions obtained are about 10% for scenarios with low DG penetration levels, whereas they are up to above 37% for those scenarios with large DG penetration levels. Nonetheless, one must bear in mind that cost savings achieved in this case study are very large partly due to the fact that assumptions made concerning DG behaviour in D5 were very conservative (especially the assumption that all DG units are operating at their rated capacity and at the same time the load is at its minimum).

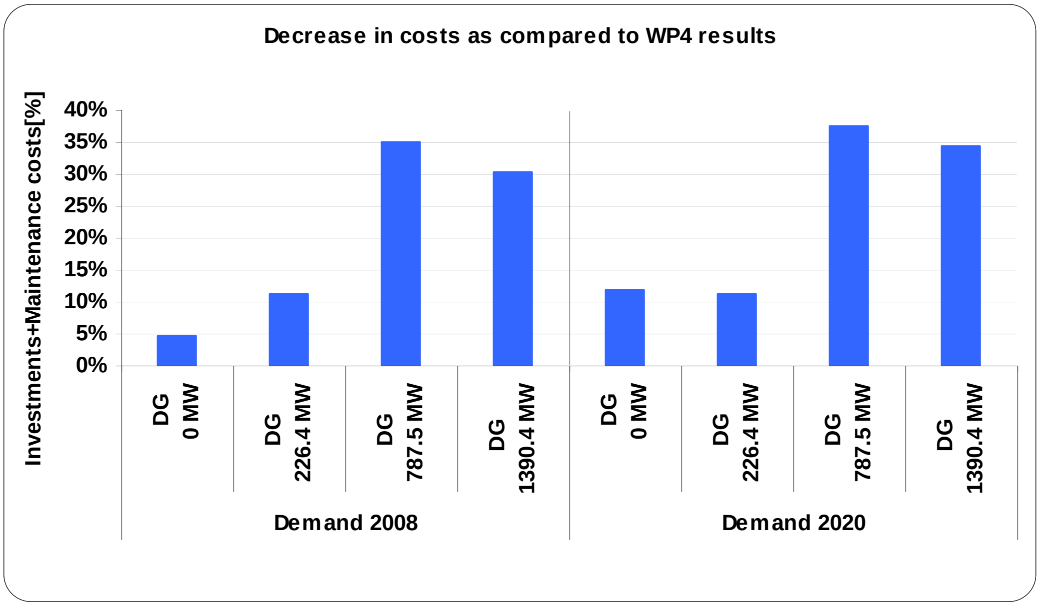


Figure 6: Savings in investment and maintenance costs with respect to WP4 results (in % of the costs obtained in WP4) due to implementing ANM measures. Kop van Noord Holland area

Finally, incremental costs per kW of DG connected have been computed and compared to the ones that had been obtained in D5. Incremental costs are defined as the ratio of the increase in costs in each scenario, with respect to the one with the same level of demand and no DG, to the amount of installed DG capacity. These are depicted for both 2008 and 2020 storylines in Figure 7. Incremental costs increase with DG penetration in both cases, albeit a noticeable reduction in the values computed is attained due to the implementation of advance responses.

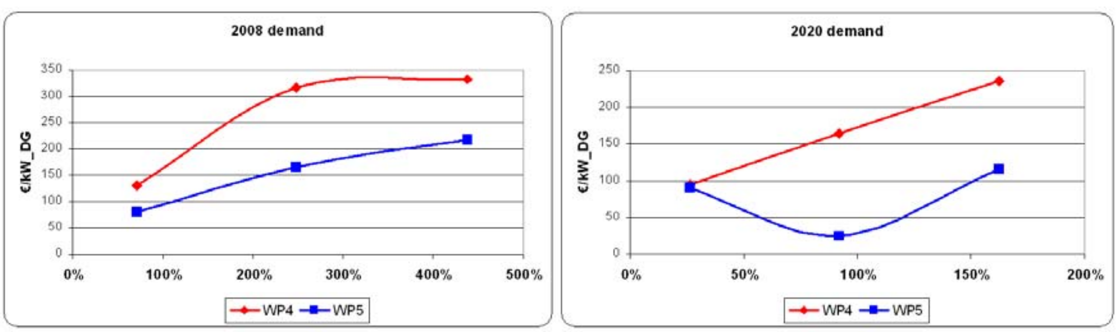


Figure 7: Comparison of incremental costs per kW of DG connected to the grid with (WP5) and without (WP4) implementing advanced response options. Kop van Noord Holland area

In order to have a more useful estimate of the costs involved per kW of DG, annual unit costs have been computed and represented in Figure 8. Conclusions from the analysis of these figures are analogous to those already provided for overall unit costs.

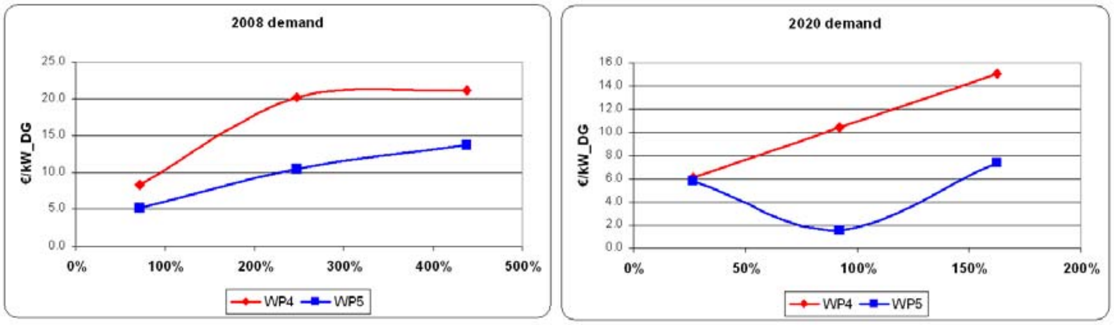


Figure 8: Comparison of incremental costs per kW of DG connected to the grid with (WP5) and without (WP4) implementing advanced response options (annual values). Kop van Noord Holland area

### 3.1.2 Other Costs

**Assumptions on energy demand and generation**

Since the COMPETES model is used for quantifying the generation impact there is a need for defining the impact on the periods of the day (4) and the seasons used (3: summer, winter and intermediate), in total 12 different periods. The COMPETES model assumes that each season is divided into 60 super-peak hours, 710 peak hours, 710 plateau, and 710 off-peak hours.

**First assumption: Limit the analysis to the peak generation situation**

Distribution network costs are determined by both snapshot conditions. However, it is assumed that the response options during the peak generation snapshot have more impact on the reduction in network cost then the options during peak demand. It is likely that in the snapshot with peak demand in combination with no generation, local peaks in grid utilization could be ‘shaved’ by increasing generation. However, it is assumed that both the duration and the amount of additional generation needed will be small compared to the snapshot of peak generation. This simplifies the analysis, but can lead to a small underestimation of the impact on generation costs.

**Second assumption: ranking of options**

In the 2020-High scenario, 500 MW of wind is expected, and 875 MW of CHP units. At most 590 MW of output reduction during peak generation is needed. This implies that when the CHP units are not producing for the market, no peak generation problems are expected, and there is no need to implement the two other response options (active wind curtailment and shifting of horticultural electricity demand). Response options are only relevant to consider for those hours (assumed 1500 hours/years) in which the horticultural CHP units are exporting excess electricity which is not used in the greenhouses. Active wind curtailment is the most expensive response option, and shifting CHP generation the lowest cost solution. In a relatively small number of hours, all three options are needed to prevent oversupply in the region, in a larger percentage of time two options will applied, and the largest percentage of time when a response option is needed, only one (the cheapest option) is applied.

We originally intended to calculate the number of hours per year that the different response options can be applied linking it to a wind power duration curve. However, the total electricity demand of the region throughout the year is unknown, and the snapshot has been calculated for the extreme situation of lowest demand. Therefore, we made educated guesses regarding the percentage of time that the different response options are needed. Since there is no need for response options if the CHP units are not exporting, these percentages have to be multiplied with the number of hours in which the CHP units will be running to find the number of hours in which the response option can be applied. The assumed percentages of the time that the individual response options would be applied on their own are shown in Table 6. In practice, wind curtailment and shifting demand in horticulture will only be needed in combination with the option of shifting generation of the CHP units. This results in much lower capacity factors which are shown in Table 11, after the different options have been discussed in more detail.

Table 6: Ranking of response options, amounts of MW potential capacity reduction involved and estimated percentage of time in which the option would be applied on its own. Source: Improgres team estimates

| | Maximum capacity [MW] | | Response option time [%] | |
|---|---|---|---|---|
| | 2020-LOW | 2020-HIGH | 2020-LOW | 2020-HIGH |
| 1. Active wind curtailment | 80 | 200 | 10% | 10% |
| 2. Shifting demand horticult. | 100 | 125 | 20% | 20% |
| 3. Shifting CHP generation | 180 | 265 | 30% | 30% |

**Reduction of CHP generation at times of high wind**

For the COMPETES analysis it is assumed that the 2008 level will be unaffected (0 MW reduction). The 1500 hours a year in which the CHP units are exporting electricity to the grid are assumed to be divided over the seasons as follows: summer: 250 hours, winter 500 hours, and spring/autumn 375 hours each. With the assumption that 30% of the exported generation will be shifted to other hours of the day, the calculated amounts of electricity export in the situation before the response options are applied and after are shown for the scenario 2020 High in

Table 7, and 2020 Low  in Table 8.

Table 7: CHP export to the grid in North Holland region in 2020 High scenario, before response options were applied and after [in GWh per season]. Source: Improgres team estimates

| | without response | | | with response options | | |
|---|---|---|---|---|---|---|
| | summer | winter | intermed | summer | winter | intermed |
| Super peak | 53 | 53 | 53 | 48 | 48 | 48 |
| Peak | 166 | 385 | 276 | 151 | 350 | 251 |
| Plateau | 0 | 0 | 0 | 20 | 40 | 30 |
| Off-peak | 0 | 0 | 0 | 0 | 0 | 0 |
| Total | 219 | 438 | 328 | 219 | 438 | 328 |

Table 8: CHP export to the grid in North Holland region in 2020 Low scenario, before response options were applied and after [in GWh per season]. Source: Improgres team estimates

| | without response | | | with response options | | |
|---|---|---|---|---|---|---|
| | summer | winter | intermed | summer | winter | intermed |
| Super peak | 36 | 36 | 36 | 33 | 33 | 33 |
| Peak | 114 | 264 | 189 | 104 | 240 | 172 |
| Plateau | 0 | 0 | 0 | 14 | 27 | 20 |
| Off-peak | 0 | 0 | 0 | 0 | 0 | 0 |
| Total | 150 | 300 | 225 | 150 | 300 | 225 |

**Demand response**

Greenhouse lighting is expected to be the largest contribution in the future growth in electricity demand in the Kop van Noord Holland. Having the lighting on at times of peak wind and CHP generation will reduce the required grid capacity. Especially when operation of the CHP is linked to day-ahead market prices, one expects a low level of simultaneity (the lighting will normally be operated at those times of the nights when electricity prices are low).

In the 2020 Low scenario we expect 100 MW of demand response capacity available and in the 2020 High scenario 125 MW. Using the assumption that demand response is only needed in 20% of the time in which the CHP units are running results in amounts of energy shifted as shown in

Table 9.

Table 9: Demand response in the grid in North Holland region in 2020 Low and High DG scenarios, after response options were applied [in GWh per season]. Source: Improgres team estimates

| | 2020 low | | | 2020 high | | |
|---|---|---|---|---|---|---|
| | summer | winter | intermed | summer | winter | intermed |
| Super peak | 1.2 | 1.2 | 1.2 | 1.5 | 1.5 | 1.5 |
| Peak | 3.8 | 8.8 | 6.3 | 4.8 | 11.0 | 7.9 |
| Plateau | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| Off-peak | -5.0 | -10.0 | -7.5 | -6.3 | -12.5 | -9.4 |
| Total | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |

**Wind curtailment**

According to the D5 report, investment cost in the distribution grid in North Holland are about 20 €/kW DG/year. When wind farm producers get a 50 €/MWh tariff plus 50 €/MWh subsidy (or assuming that the value of an additional MWh wind generation is 100 €/MWh in 2020. Reducing grid capacity with 1 kW leads to an average cost saving which has the same value as losing 200 kWh of wind generation due to curtailment.

With a wind duration curve it is possible to quantify the lost amount of wind power due to curtailment. In figure 1 a wind duration curve is shown for a large onshore wind turbine in the Netherlands (Source: P. Eecen, ECN). Per kW of onshore wind in the Netherlands about 3500 kWh per year is produced (in a windy region, close to the coast, with a large wind turbine). When onshore wind power higher than 80% of installed capacity is curtailed, this results in curtailment of 200 kWh per year per kW installed wind (in that case about 6.4% of wind energy generation would be lost).

For this analysis we assume that curtailment takes place at the relatively high amount of about 40% of the installed wind power capacity (80 MW of curtailment in 2020 Low and 200 MW in 2020 High scenario). However, since wind curtailment is only needed during 10% of the 1500 hours in which the CHP units are exporting, the amount of wind energy lost is only about 2% of total wind production. The amount of GWh lost due to wind curtailment is shown in

Table 10.

Table 10: Wind curtailment in GWh per season for 2020 Low and High DG scenarios. Source: Improgres team estimates

| | 2020 low | | | 2020 high | | |
|---|---|---|---|---|---|---|
| | summer | winter | intermed | summer | winter | intermed |
| Super peak | -0.5 | -0.5 | -0.5 | -1.2 | -1.2 | -1.2 |
| Peak | -1.5 | -3.5 | -2.5 | -3.8 | -8.8 | -6.3 |
| Plateau | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| Off-peak | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| Total | -2.0 | -4.0 | -3.0 | -5.0 | -10.0 | -7.5 |

Table 11: Overview of response options, their potential capacity in MW, time that they are actually applied [as % of the year] and the electricity curtailed or shifted [in GWh/year]. Source: Improgres team estimates

| | 2020 Low [MW] | 2020 High [MW] | Cap factor [%] | 2020 Low [GWh/yr] | 2020 High [GWh/yr] |
|---|---|---|---|---|---|
| Wind curtailment | 80 | 200 | 1.7 | 11.9 | 29.8 |
| Demand response | 100 | 125 | 3.4 | 29.8 | 37.2 |
| CHP output reduction | 180 | 265 | 5.1 | 81.0 | 119.3 |

**Overview of all cost categories**

The previous section described the impact of response measures on the distribution costs. Similar to the analysis described in WP4, deliverable 5, also in the case with active network management the other cost components were also quantified, primarily with the use of the Competes model. The results are shown in

Table 12 below, divided into three sections: first, the business as usual case without active network management measures, second the case with active network management and at the bottom, the difference between these two cases. An increase in the fixed generation cost is due to the reduction in output of CHP units in the distribution grid area during the peak hours. As a consequence more generation capacity is required outside the distribution grid area. Remarkably, the total net benefits (or cost savings) of the introduction of active network management for all four scenarios turn out to be close to 8 €/year per installed kW of distributed generation.

Table 12: Evolution of the impact of DG in the Kop van Noord Holland area on total annual supply costs with the DG penetration level. Results for the 2008 and 2020 demand levels in €/kW installed DG/year1

| Demand scenario for 2020: | Demand 2008 | | Demand 2020 | |
|---|---|---|---|---|
| DG assumed in 2020 [MW]: | 787 | 1390 | 787 | 1390 |
| *1. Business as Usual situation* | | | | |
| Variable Generation Costs | -34.8 | -22.9 | -53.1 | -49.3 |
| Fixed Generation Costs | 60.7 | 62.1 | 58.0 | 61.5 |
| Distribution Costs | 20.3 | 21.2 | 10.4 | 15.0 |
| Balancing Costs | 0.4 | 0.5 | 1.2 | 1.6 |
| External Costs | -3.4 | -4.3 | -4.1 | -4.5 |
| Transmission Costs | 3.3 | 11.4 | 0.0 | 9.5 |
| *Total Costs* | *46.5* | *68.0* | *12.3* | *33.9* |
| *2. Active Network Management* | | | | |
| Variable Generation Costs | -34.8 | -22.9 | -53.1 | -49.3 |
| Fixed Generation Costs | 62.8 | 64.4 | 59.6 | 63.8 |
| Distribution Costs | 10.6 | 13.8 | 1.6 | 7.4 |
| Balancing Costs | 0.4 | 0.5 | 1.2 | 1.6 |
| External Costs | -3.5 | -4.3 | -4.1 | -4.5 |
| Transmission Costs | 2.1 | 7.5 | 0.0 | 5.6 |
| *Total Costs* | *37.7* | *59.0* | *5.1* | *24.7* |
| *3. Cost Savings Active Network Management* | | | | |
| Variable Generation Costs | 0.0 | 0.0 | 0.0 | 0.0 |
| Fixed Generation Costs | -2.1 | -2.3 | -1.6 | -2.2 |
| Distribution Costs | 9.7 | 7.4 | 8.8 | 7.6 |
| Balancing Costs | 0.0 | 0.0 | 0.0 | 0.0 |
| External Costs | 0.0 | 0.0 | 0.0 | 0.0 |
| Transmission Costs | 1.2 | 3.9 | 0.0 | 3.9 |
| *Total Cost Savings* | *8.8* | *9.1* | *7.2* | *9.2* |

From

[1] Business as Usual is the situation before implementation of response options, as described in WP4, deliverable 5, table 46.

Table 12 it can be concluded that the total annual cost savings to society amount to around 8 € per kW installed DG per year. Most of these savings are a result of a reduction in distribution network costs. Not included in these figures are the ICT costs for ANM. But this is estimated to be about 1 €/kW, or less then 0.1 €/kW/year, and therefore can be omitted.

## 3.2 Mannheim area

The German case study corresponds to an urban, residential area. At the moment, DG penetration is scarce. Nonetheless, a great deployment of solar PV panels on rooftops and domestic micro-CHP is expected to have taken place by 2020.

### 3.2.1 Distribution Costs

**Modelling of those advanced practices with the highest impact in the area**

At first, one may think that DG in urban areas may allow DSOs to defer network investments and reduce energy losses thanks to the fact that it is located very close to loads. However, results obtained in WP4 showed that this was not the case under the passive approach adopted. Peak demand was higher than DG capacity in all scenarios. Notwithstanding, DG capacity connected at LV, which mainly consists of PV, was considerably higher than peak demand at LV in some scenarios due to the very low simultaneity factors associated with LV consumers. This required significantly reinforcing the network to cope with flows in the maximum net generation snapshots for large DG penetration levels. Therefore, response options adopted in this case study are aimed at reducing DG production in the maximum net generation snapshots corresponding to the future DG scenarios.

A 20% reduction in maximum DG production resulting from ANM practices was considered possible. This can be partly achieved through directly controlling DG units when network conditions require doing so, provided that the necessary control equipment is deployed. Furthermore, another share of this reduction can be achieved in a passive way. This is mainly due to the fact that micro-CHP maximum production is likely to take place in winter evenings, when the cogenerated heat is used for heating and sanitary hot water purposes, whereas peak PV production will take place at noon during sunny summer days. Moreover, PV panels placed on rooftops will probably lack tracking systems, have a heterogeneous orientation and get dirty due to the pollution from different sources present in urban areas. All these factors may cause a deviation of their peak production from rated capacities of the installations (generally considered as that of the inverter).

**Numerical Results**

Table 13 shows the total network length and transformation capacity in the optimal grid obtained for every scenario under WP5 assumptions. For very low DG penetration levels, the impact of DG on the total amount of network assets is negligible. On the other hand, it can be observed that significant reinforcements to the LV grid and, particularly, to MV/LV transforming centres may be associated with DG for the 2020 DG penetration levels.

Table 13: Total amount of network assets for the different scenarios that have been considered in the Mannheim area

| | | MV network [km] | MV/LV transforming centres | | LV network [km] |
|---|---|---|---|---|---|
| | | | number | Capacity [MVA] | |
| 2008 Demand | No DG | 45.97 | 49 | 9.9 | 110.03 |
| | Present DG | 45.97 | 49 | 9.9 | 110.03 |
| | Future DG (medium) | 53.39 | 61 | 11.805 | 116.19 |
| | Future DG (high) | 64.15 | 83 | 18.665 | 142.07 |
| 2020 Demand | No DG | 57.44 | 51 | 10.93 | 109.38 |
| | Present DG | 57.44 | 51 | 10.93 | 109.37 |
| | Future DG (medium) | 46.74 | 62 | 12.41 | 115.57 |
| | Future DG (high) | 43.02 | 82 | 18.235 | 147.22 |

Figure 9 shows that increases in network assets provided in

Table 13 result in higher investment and maintenance costs. Increases in the size of the LV network are the ones that cause the highest increase in costs. Furthermore, similarly to results in WP4, in those scenarios where the DG penetration level is that expected for 2020, network costs are lower the higher demand is. Maximum net instantaneous generation is the dominant cost driver in the latter scenarios. Hence, increasing load in those situations reduces power flows and capacity requirements.

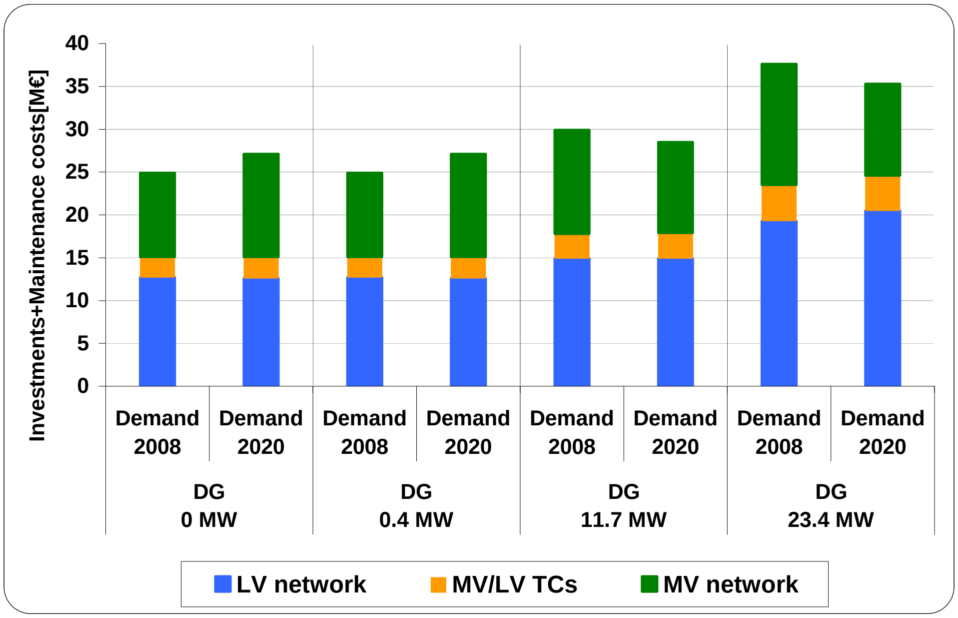


Figure 9: Investment and maintenance costs for the different scenarios in the Mannheim area

Figure 10 provides the total investment and maintenance costs for the scenarios within the 2008 and 2020 storylines both in a “business as usual” framework (that considered in WP4) and in the one where ANM practices have been implemented (WP5). As expected, the evolution in WP5 of investment and maintenance costs with the DG penetration level is similar to that in WP4. However, non-negligible cost savings are achieved by implementing ANM practices. Given that advanced response options taken into account relate to increasing DG controllability, savings are greater for high DG penetration levels.

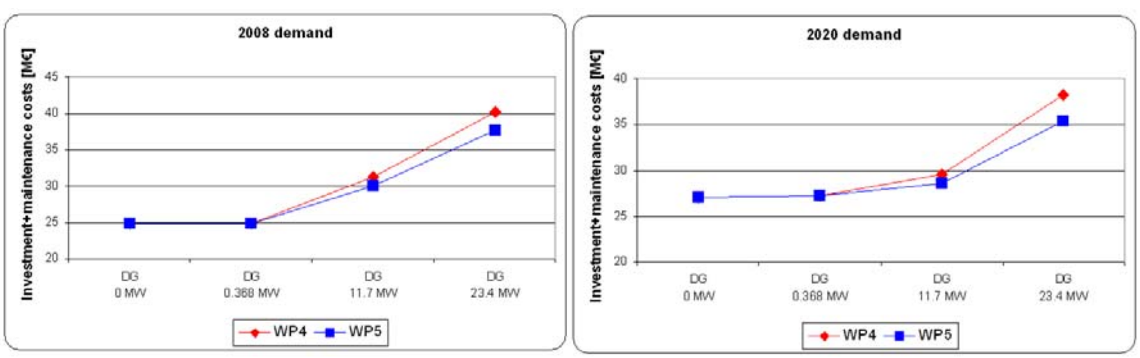

Figure 10: Comparison between distribution investment and maintenance costs for the different scenarios in the “business as usual” framework and those obtained when applying ANM practices in the Mannheim area

Cost savings achieved when implementing ANM practices correspond mainly to the LV network and, to a lesser extent, to the MV/LV transforming centres, as shown in Table 14. This is consistent with previous results showing that most DG-driven costs corresponded to reinforcements to the LV network and MV/LV transforming centers. Results for scenarios with null or very low DG penetration levels are not shown in Table 14, since changes in costs associated with DG in these scenarios were zero or negligible.

Table 14: Distribution investment and maintenance cost savings caused by the implementation of ANM practices in the Mannheim area (quantities are expressed in M€)

| | Demand 2008 | | Demand 2020 | |
|---|---|---|---|---|
| | DG 11.7 MW | DG 23.4 MW | DG 11.7 MW | DG 23.4 MW |
| Total | 1.27 | 2.50 | 1.10 | 2.93 |
| MV network | 0.00 | 0.00 | 0.00 | 0.00 |
| MV/LV transforming centres | 0.39 | 1.02 | 0.33 | 0.98 |
| LV network | 0.88 | 1.48 | 0.77 | 1.95 |

Figure 11 shows cost savings caused by ANM practices when they are expressed as a percentage of the efficiently incurred distribution network costs when ANM practices are not implemented. The implementation of these practices (decreasing peak generation by 20% a few hours per year) would yield cost reductions of between 4% and 8% of total original distribution costs.

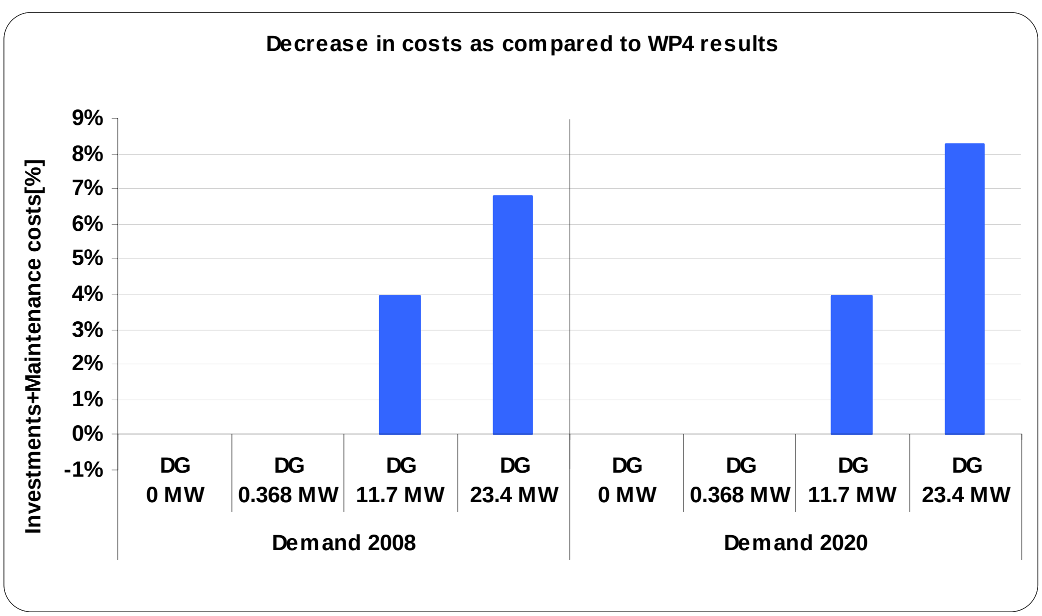

Figure 11: Savings yielded byANM practices in the Mannheim area in distribution investment and maintenance costs with respect to WP4 (busines as usual) results (savings are expressed as a percentage of the costs obtained in WP4)

Finally, incremental costs per kW of DG connected have been computed and compared to the ones that had been obtained in D5. Incremental costs are defined as the ratio of the increase in costs in each scenario, with respect to the one with the same level of demand and no DG, to the amount of installed DG capacity. These are depicted for both 2008 and 2020 storylines in Figure 12 (present value of costs) and Figure 13 (annualized values). One can conclude that incremental costs tend to increase with the DG penetration level, though a moderate reduction can be attained thanks to the implementation of advanced response options.

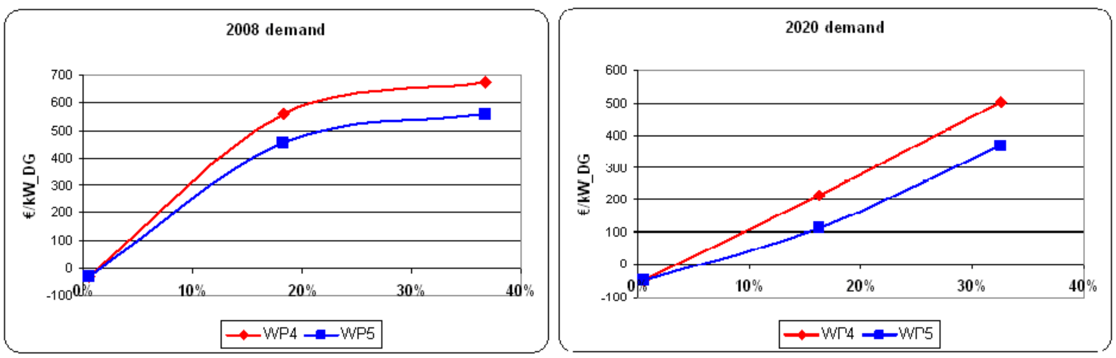


Figure 12: Comparison of incremental costs per kW of DG connected to the grid with and without implementing advanced response options. Mannheim area

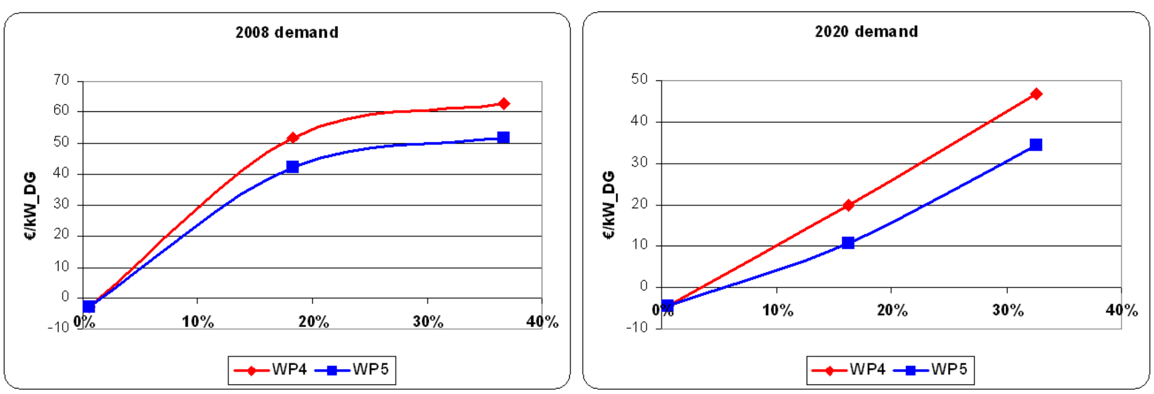


Figure 13: Comparison of incremental costs per kW of DG connected to the grid with and without implementing advanced response options (annual values). Mannheim area

### 3.2.2 Other Costs

**Assumptions on energy demand and generation**

For the distribution system optimization it was assumed that a 20% reduction in maximum peak generation can be achieved. Most of the micro-CHP generation will be in winter, while the peak in solar photovoltaic generation is in summer. But there will be some hot tap water production by the micro-CHP units, and a small part of heat generation will be on a summer day. Because of this negative correlation, the expected number of hours per year that the CHP units are operating while at the same time the PV modules produce close to maximum power is expected to be only a few tens of hours per year. Active network management in this case will imply shifting CHP generation from the middle of the day to other periods of the day. To be on the safe side it is estimated that 100 hours per year will be sufficient. Given the 2020 low capacity of 1.69 MW, and the 2020 high capacity of 3.38 MW of micro-CHP units this implies shifting 169 MWh from the summer peak to summer off-peak hours for the 2020 Low case, and 338 MWh from summer peak to summer off-peak for the 2020 High case.

Table 15: Evolution of the impact of DG in the Mannheim area on total annual supply costs with the DG penetration level. Results for the 2008 and 2020 demand levels in €/kW installed DG/year

| Demand scenario for 2020: | Demand 2008 | | Demand 2020 | |
|---|---|---|---|---|
| DG assumed in 2020 [MW]: | 11.7 | 23.4 | 11.7 | 23.4 |
| *1. Business as Usual situation* | | | | |
| Variable Generation Costs | -40.2 | -40.2 | -44.6 | -44.6 |
| Fixed Generation Costs | 98.1 | 98.1 | 98.2 | 98.2 |
| Distribution Costs | 52.0 | 62.8 | 20.0 | 46.8 |
| Balancing Costs | 0.0 | 0.0 | 0.0 | 0.0 |
| External Costs | -6.3 | -6.3 | -1.2 | -1.2 |
| *Total Costs* | *103.6* | *114.4* | *72.5* | *99.3* |
| *2. Active Network Management* | | | | |
| Variable Generation Costs | -39.9 | -40.0 | -44.3 | -44.3 |
| Fixed Generation Costs | 98.0 | 98.1 | 98.2 | 98.2 |
| Distribution Costs | 42.2 | 52.0 | 10.7 | 34.2 |
| Balancing Costs | 0.0 | 0.0 | 0.0 | 0.0 |
| External Costs | -6.4 | -6.4 | -1.3 | -1.3 |
| *Total Costs* | *93.9* | *103.7* | *63.3* | *86.8* |
| *3. Cost Savings Active Network Management* | | | | |
| Variable Generation Costs | -0.3 | -0.3 | -0.3 | -0.3 |
| Fixed Generation Costs | 0.0 | 0.0 | 0.0 | 0.0 |
| Distribution Costs | 9.8 | 10.8 | 9.3 | 12.6 |
| Balancing Costs | 0.0 | 0.0 | 0.0 | 0.0 |
| External Costs | 0.1 | 0.1 | 0.1 | 0.1 |
| *Total Cost Savings* | *9.7* | *10.7* | *9.2* | *12.5* |

The total annual cost savings were found to be approximately similar with the Dutch case study area at a level of about 10 €/kW installed DG/year, despite the large differences in scale (MW-sized units in case of the Netherlands, and kW-sized units for Germany). The ICT cost for ANM are estimated to be about 200 € per household, which is equivalent to about 50 €/kW installed DG, or approximately 2.5 €/kW installed DG/year. Consequently, when the ICT cost are taken into account the net benefits are only about 8 €/kW installed DG/year, or 20 € per household per year.

## 3.3 Aranjuez area

The Spanish case study covers a large area comprising several towns. In 2008, DG presence was limited to a few industrial CHP plants and a wind farm connected at HV level. By 2020, a few new CHP plants and wind farms with similar characteristics are expected to have been built. Moreover, several smaller PV plants will be connected at the MV network.

### 3.3.1 Distribution costs

**Modelling of those advanced practices with the highest impact in the area**

Results obtained in WP4 (D5) denoted that demand was a more relevant cost driver than DG, since conditions in peak demand snapshots proved to be much more demanding than those in peak generation ones. Consequently, advanced response options considered in this case study are aimed at increasing DG production and lowering demand in the maximum net demand snapshots. Considered response options include the following:

- Reducing LV peak demand due to a change in retail tariffs, including the removal of night-period tariffs[2] and the implementation of new tariffs with time differentiation, contracts signed between DG and retailers or demand aggregators and energy efficiency gains. The simultaneity factor of LV demand is estimated to decrease from 0.7 to 0.56.
- Increasing DG output in the peak net demand snapshot thanks to several factors:
  - the change of peak demand from night to day (where industrial CHP units are working and there is solar radiation for PV plants to produce),
  - bilateral contracts between DSOs and DG
  - and the creation of congestion management schemes with participation of DG.

As a result of the application of these measures, the simultaneity factor for CHP units in the maximum net demand snapshot has been raised to 0.6, whilst the one corresponding to solar PV has been raised to 0.5.

**Numerical Results**

The amount of network assets of each type computed for each scenario is provided in Table 16. There is DG connected at HV level in all scenarios but those without DG. However, it is only in the 2020-DG scenarios that there is DG connected at MV level too. DG located at MV level comprises a few solar PV farms. It can be observed in Table 16 that, owing to this DG and the implementation of advanced response options (formerly solar PV was not producing at all at peak net load snapshots), a non-negligible reduction in the necessary amount of HV/MV transformation capacity is achieved.

[2] Peak demand in this distribution area took place during night winter hours since there were numerous electric heaters, installed in order to benefit from night-period tariffs, that started at exactly the same time (coincident with the change in the tariff). Removing the night-period tariff will cause peak demand to shift from night to day.

Table 16: Total amount of network assets for the different scenarios that have been considered in the. Aranjuez area

| | | HV network [km] | | | HV/MV substations | | MV network [km] | MV/LV transforming centres | | LV network [km] |
|---|---|---|---|---|---|---|---|---|---|---|
| | | Total | 132 kV | 45 kV | Number | Capacity [MVA] | | Number | Capacity [MVA] | |
| 2008 Demand | No DG | 206.42 | 129.07 | 77.35 | 8 | 240 | 677.74 | 389 | 209.1 | 682.97 |
| | 2008 DG | 176.46 | 122.3 | 54.16 | 8 | 240 | 681.31 | 390 | 208.89 | 680.1 |
| | 2020 DG (medium) | 172.47 | 118.31 | 54.16 | 8 | 230 | 680.15 | 388 | 209.78 | 687.85 |
| | 2020 DG (high) | 169.92 | 136.55 | 33.37 | 8 | 230 | 703.71 | 389 | 209.9 | 684.27 |
| 2020 Demand | No DG | 190.59 | 145.58 | 45.01 | 10 | 350 | 676.7 | 575 | 360.89 | 701.81 |
| | 2008 DG | 199.79 | 153.54 | 46.25 | 11 | 350 | 634.87 | 557 | 324.05 | 694.35 |
| | 2020 DG (medium) | 222.49 | 176.16 | 46.33 | 9 | 300 | 721.64 | 551 | 324.55 | 699.1 |
| | 2020 DG (high) | 183.03 | 134.56 | 48.47 | 8 | 300 | 843.54 | 550 | 324.25 | 699.84 |

Figure 14 depicts the present value of distribution investment and maintenance costs in all the scenarios that have been analyzed. Due to the limited excursion of total costs across scenarios, it is difficult to draw conclusions from this diagram. Further comments will be made based on the next figures.

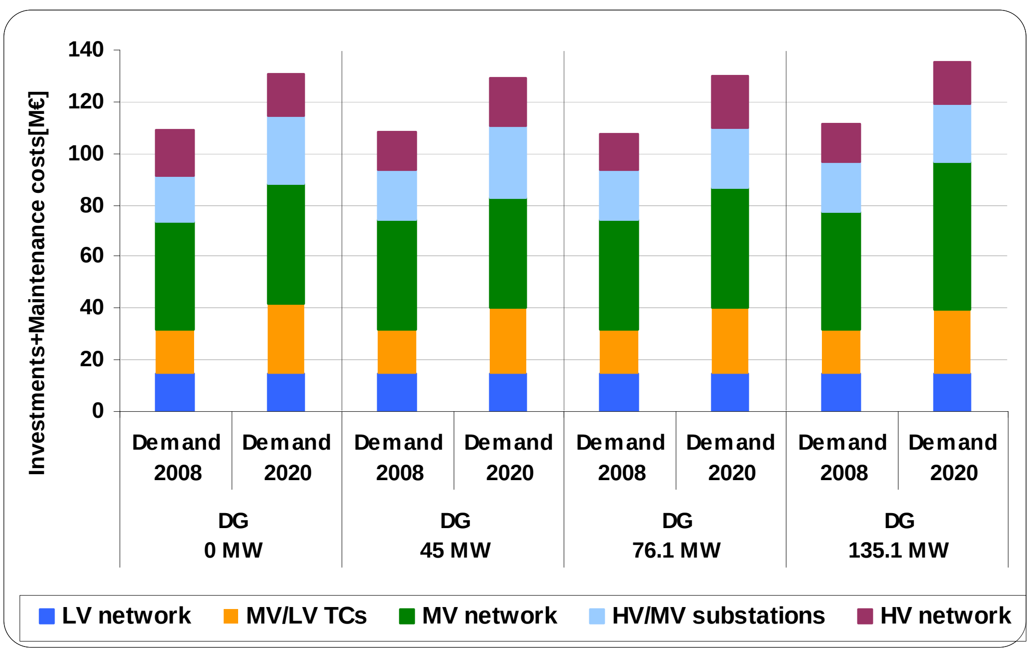


Figure 14: Investment and maintenance costs. Aranjuez area

Figure 15 provides the total investment and maintenance costs for the scenarios within the 2008 and 2020 storylines both in a “business as usual” framework (that considered in WP4) and in the one where ANM practices have been implemented (WP5). Cost savings attained in the no-DG scenarios (corresponding to the top left points of both graphics in Figure 14) were achieved through the implementation of demand side management measures, whereas those in the remaining scenarios correspond to the combined effect of demand side management and enhanced DG control or enhanced DG reaction to system conditions. Furthermore, assuming the implementation of ANM practices, the present value of distribution investment and maintenance costs for low or moderate DG penetration levels is lower than that for those scenarios without DG. This can be attributed to the reduction in distribution capacity needs due to the netting effect of DG production at peak net load times.

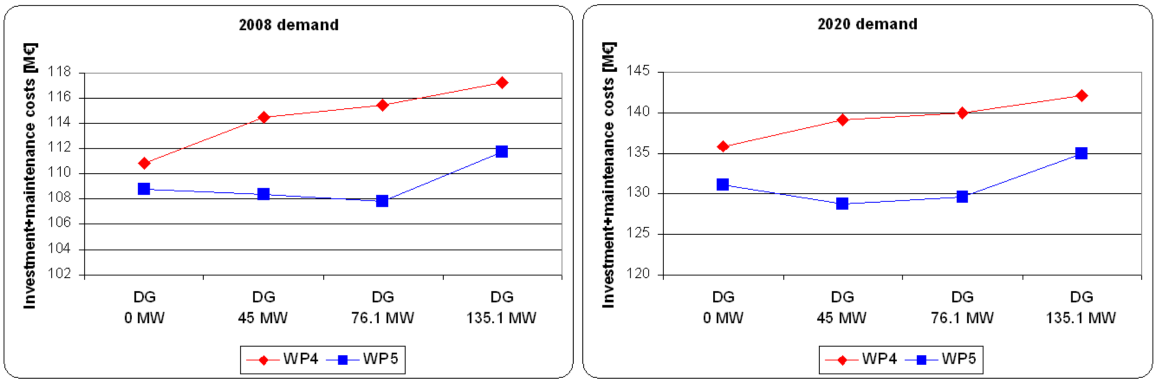


Figure 15: Comparison between distribution investment and maintenance costs for the different scenarios in the "business as usual" framework and those obtained when applying ANM practices in the Aranjuez area

The distribution of costs savings across network voltage levels varies from one scenario to another. This is due to the discrete nature of network investment decisions and the fact that algorithms used are heuristic and therefore, do not provide, truly optimal solutions. Notwithstanding, some general trends can be identified according to results on cost savings by voltage level provided in Table 17. For the 2008-demand scenarios (2008 storyline), most cost savings correspond to the HV and MV networks. On the other hand, for the 2020-demand scenarios, some considerable savings correspond to the HV/MV substations. Generally, cost savings achieved in the LV network and the MV/LV transforming centres are, more or less, uniform across all scenarios.

Table 17: Distribution investment and maintenance cost savings caused by the implementation of ANM practices in the Aranjuez area (quantities are expressed in M€)

| | Demand 2008 | | | | Demand 2020 | | | |
|---|---|---|---|---|---|---|---|---|
| | DG 0 MW | DG 45 MW | DG 76.1 MW | DG 135.1 MW | DG 0 MW | DG 45 MW | DG 76.1 MW | DG 135.1 MW |
| Total | 2.10 | 6.06 | 7.59 | 5.58 | 4.67 | 10.36 | 10.35 | 7.12 |
| HV network | -3.20 | 2.58 | 3.87 | 4.42 | 1.55 | 3.51 | 2.22 | 7.52 |
| HV/MV substations | -0.67 | -1.79 | -1.56 | -1.56 | 0.69 | -1.19 | 4.18 | 4.93 |
| MV network | 4.20 | 3.40 | 3.57 | 1.15 | 1.81 | 6.17 | 1.95 | -7.48 |
| MV/LV transforming centres | 1.70 | 1.65 | 1.65 | 1.60 | 0.46 | 1.60 | 1.86 | 1.88 |
| LV network | 0.06 | 0.22 | 0.05 | -0.02 | 0.16 | 0.26 | 0.14 | 0.26 |

Cost savings can be expressed as a percentage of the investment and maintenance costs efficiently incurred in the corresponding WP4 scenario. Cost savings vary between

2% and 8 % of corresponding WP4 costs (see Figure 16). Savings attained through demand side management measures are higher the higher the level of demand is. Moreover, the highest cost reductions through DSM are obtained for moderate DG penetration levels.

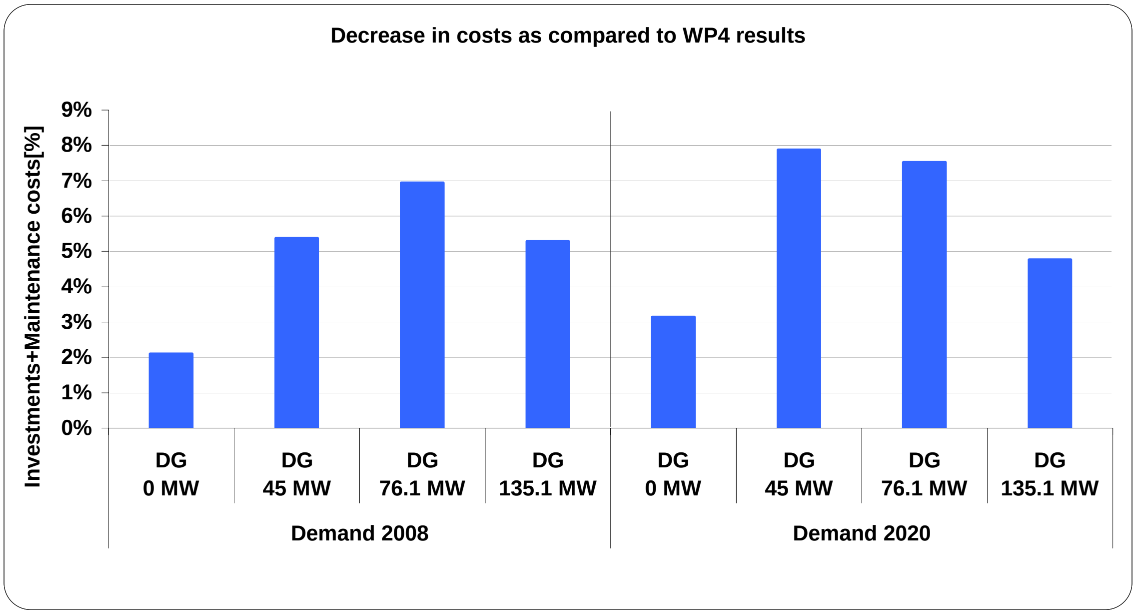


Figure 16: Savings yielded byANM practices in the Aranjuez area in distribution investment and maintenance costs with respect to WP4 (busines as usual) results (savings are expressed as a percentage of the costs obtained in WP4)

Finally, incremental costs per kW of DG connected have been computed and compared to the ones that had been obtained in D5. Incremental costs are defined as the ratio of the increase in costs in each scenario, with respect to the one with the same level of demand and no DG, to the amount of installed DG capacity. These are depicted for both the 2008 and 2020 storylines in Figure 17 (present value of costs) and Figure 18 (annualized values). Contrary to results computed in WP4 (D5), negative unit incremental costs have been obtained here for low and moderate DG penetration levels. This means that DG may produce a decrease in distribution costs in the area for low to moderate DG penetration levels (with respect to the no DG situation) if actively managing this DG is possible (as a reaction to system conditions).

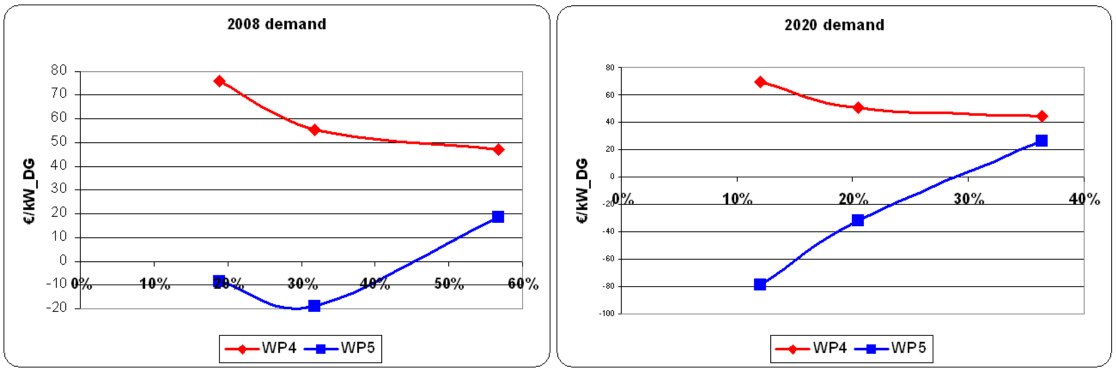


Figure 17: Comparison of incremental costs per kW of DG connected to the grid with and without implementing advanced response options in the Aranjuez area

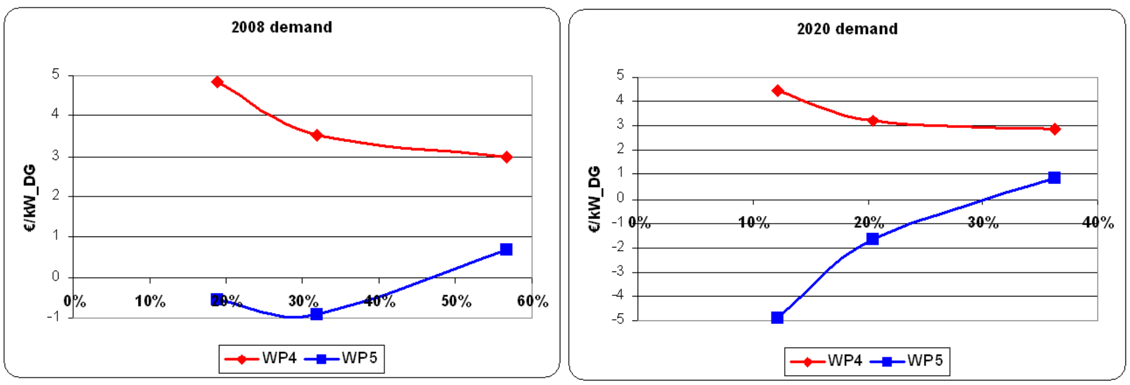


Figure 18: Comparison of incremental costs per kW of DG connected to the grid with and without implementing advanced response options in the Aranjuez area (annual values)

### 3.3.2 Other Costs

To quantify the amount of the other cost items, additional assumption regarding the impact of the active network management measures need to be made. For the snapshot calculation simultaneous peak demand from LV loads is assumed to be reduced from 0.7 to 0.56 due to measures to dissuade heating systems to operate starting from 23.00 hours when the night tariff starts. This implies a reduction in the simultaneous peak of 13 MW with the 2008 demand levels, and 21 MW at 2020 demand levels.

There are two basic alternatives in achieving the heating power reduction during peak load hours. In the peak shaving alternatives, only in a limited number of hours of the annual system peak load is shifted to other hours. From the load distribution function (see figure 6 in Deliverable D5) this requires shifting heating load on approximately 80 hours per year3. Load shifting only during the annual peak hours implies shifting 530 MWh at 2008 demand levels and 830 MWh at 2020 demand.

However, when a change in night tariffs results in adjusted behaviour so that the heaters are run more in daytime than in night time, this effect will take place on every time the heater is used, and not only during the annual peak hours as was the case in the first alternative. From the seasonal change in the demand profile (figure 4, D5) it can be seen that the average load factor in the middle of the summer is about 40%, while over the whole year the average load factor is about 48%. Therefore about 16% of the annual electricity consumption is the level higher than the level during the middle of the summer. Assuming that half of this extra winter demand will be for heating and the other half for other uses which depend on the season, an estimated 8% of total electricity demand in the Aranjuez area is for heating. In this second alternative, 6.73 GWh of electricity demand is supposed to be shifted from the off peak to the shoulder hours with 2008 demand levels, and 10.61 GWh in case of the 2020 demand levels. These values of the second alternative have been used to determine the other cost levels.

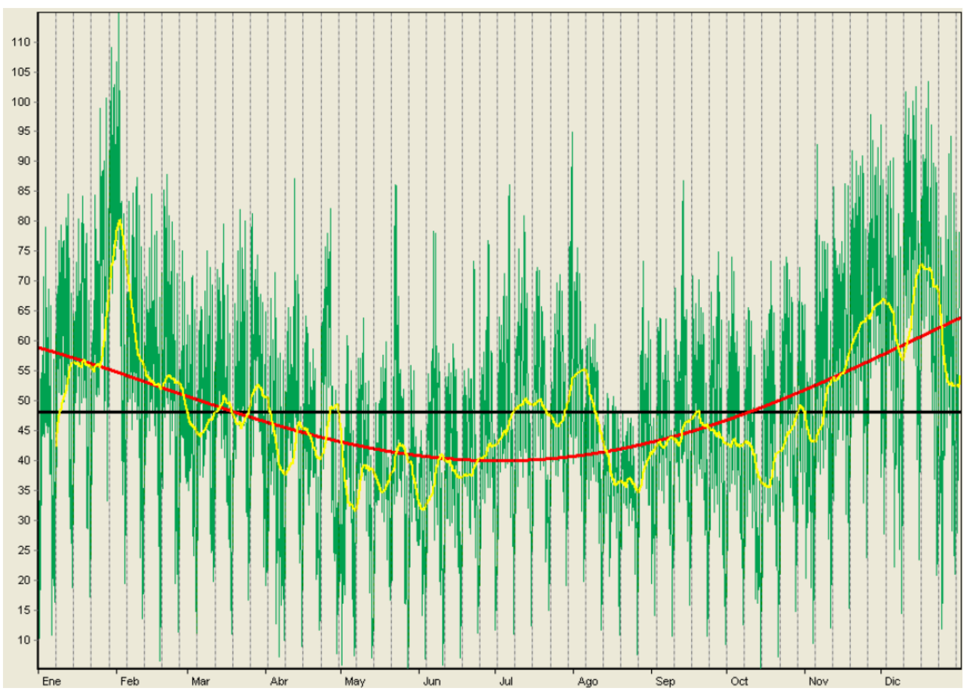


Figure 19: Annual demand profile in Aranjuez area distribution network

In the new situation, after active network management has been implemented, the system peak load will change during the day. For the network snapshot, it is necessary to include the contribution from generation during the day. But the times of operation of the CHP do not have to change due to active network management: they can continue to operate during daytime. For the non-network costs the impact of active network management only takes place due to the load shifting.

[3] 80 hours per year the capacity will be reduced. In a power duration curve, the first hour the maximum reduction takes place, while in the last hour, almost no reduction takes place. Assuming a linear relation, the average capacity reduction over the 80 hours is half of the capacity reduction of the first hour.

Table 18: Evolution of the impact of DG in the Aranjuez area on total annual supply costs with the DG penetration level. Results for the 2008 and 2020 demand levels in €/kW installed DG/year

| Demand scenario for 2020: | Demand 2008 | | Demand 2020 | |
|---|---|---|---|---|
| DG assumed in 2020 [MW]: | 76 | 135 | 76 | 135 |
| *1. Business as Usual situation* | | | | |
| Variable Generation Costs | -59.0 | -55.0 | -55.7 | -57.2 |
| Fixed Generation Costs | 93.5 | 96.7 | 77.1 | 81.8 |
| Distribution Costs | 3.5 | 3.0 | 3.2 | 2.8 |
| Balancing Costs | 1.4 | 1.3 | 1.8 | 1.7 |
| External Costs | -2.2 | -1.5 | 0.2 | 0.4 |
| *Total Costs* | *37.2* | *44.6* | *26.6* | *29.6* |
| *2. Active Network Management* | | | | |
| Variable Generation Costs | -58.8 | -54.8 | -55.7 | -57.2 |
| Fixed Generation Costs | 93.4 | 96.6 | 77.1 | 81.8 |
| Distribution Costs | -0.9 | 0.7 | -1.7 | 0.9 |
| Balancing Costs | 1.4 | 1.3 | 1.8 | 1.7 |
| External Costs | -2.2 | -1.5 | 0.2 | 0.4 |
| *Total Costs* | *32.9* | *42.3* | *21.7* | *27.6* |
| *3. Cost Savings Active Network Management* | | | | |
| Variable Generation Costs | -0.3 | -0.2 | 0.0 | 0.0 |
| Fixed Generation Costs | 0.2 | 0.1 | 0.0 | 0.0 |
| Distribution Costs | 4.5 | 2.3 | 4.8 | 2.0 |
| Balancing Costs | 0.0 | 0.0 | 0.0 | 0.0 |
| External Costs | 0.0 | 0.0 | 0.0 | 0.0 |
| *Total Cost Savings* | *4.3* | *2.2* | *4.8* | *2.0* |

The costs savings in the Spain case study turn out to be somewhat lower than in the two other cases. The technology (ICT) cost amount to about 8 €/kW installed DG/year. This turns out to be higher than the total cost savings from Table 18.

# 4 OVERALL ANALYSIS AND CONCLUSIONS

When estimating the impact of implementing ANM practices on system costs, we have focused on advanced response options concerning advanced generation control and demand side management. The means through which these response options are implemented (bilateral contracting, price signals, etc.) do not affect the computation of system costs in section 3. The computation of system costs is only affected by the assumptions made regarding the change in the profile of controllable demand and generation and the amount of capacity under control. On the other hand, the computation of the implementation costs of each response option is indeed greatly affected by the choice of the means used to achieve the controllability of loads and/or DG. Thus, cost-benefit analysis carried out must have taken practical implementation choices of various types into account.

Three different distribution areas were analyzed. The following paragraphs describe these distribution areas and enumerate the response options assessed in each one of them:

- The Kop van Noord Holland area is a region very favourable to the location of medium-sized wind farms and CHP units used to provide heat to horticultural greenhouses. DG penetration rates are so high that maximum DG production is expected to surpass consumption. In this area, the advanced response options considered comprise shifting demand of greenhouses from periods with low DG production to those where most CHP units are running, curtailing wind output at specific times (a few hours per year) and controlling CHP production thanks to the possibility to store heat or resort to gas boilers.
- The Mannheim area is residential. There, solar PV panels on roofs and micro-CHP units are expected to become widespread. By 2020, the production of PV panels connected at LV may have surpassed the maximum instantaneous consumption at this voltage level. Thus, Demand Side Management has proven not to be useful in order to defer network investments. Limiting maximum DG production at certain times was deemed the most promising alternative. Nonetheless, due to the limited controllability of this technology, only a 20% reduction has been assumed sensible.
- The Aranjuez region is a residential and industrial semi-urban area comprising a few medium-sized wind farms and industrial CHP plants. Additionally, some PV farms will have been connected by 2020 at MV level. Peak demand is the most relevant cost driver, although DG is able to contribute to partially meet demand. Hence, advanced response options considered include both LV demand response and changes to CHP and PV production patterns. Changes to the DG production profile that have been modelled have been assumed to be the result, not only of active generation control, but also of the shift in time of peak demand due to a change in tariffs applying tin the region.

## 4.1 Computing system costs

### 4.1.1 Distribution costs

Next paragraphs summarize the results obtained in each of the areas regarding the effect of ANM measures on distribution costs.

- Kop van Noord Holland area: Despite the fact that costs can significantly increase with DG penetration levels, ANM practices proved to be able to significantly reduce the former. In the scenarios where no DG exists, Demand Side Management measures achieved a 5-10% reduction in distributions costs. Nonetheless, for high DG penetration levels, up to 35% of investment and maintenance cost have been avoided. Most cost savings are associated with investments in HV conductors and HV/MV substations. Such high values of cost cuts are mainly due to the wide range of response options considered and the extremely pessimistic planning assumptions that were used in the analyses carried out in WP4 (D5). The fact that all loads and most DG are connected at the same voltage level allows one to easily explain results obtained based on the absolute value of maximum and minimum net generation in the area. However, this explaining variable is no longer useful in other areas where the location of network users across voltage levels is more heterogeneous.
- Mannheim area: Savings in this area were only obtained for the 2020-DG scenarios, since advanced response options that have been assessed only involved limiting maximum DG production and very little DG capacity was installed in the area in 2008. Moreover, due to the fact that the level of controllability of DG assumed is very limited (only a 20% reduction was deemed possible), maximum cost cuts obtained were about 8 % of original costs. Differences between the two considered levels of demand were fairly small, since the expected load growth in the area is very low. Contrary to what happened in the Dutch case study, most cost savings have been achieved in the same voltage level where DG is connected. In this case, reinforcements to the LV network to accommodate DG were reduced when applying ANM practices and network costs were driven down.
- Aranjuez area: Cost cuts achieved when implementing ANM practices in this area range from 2% to nearly 8% of total original costs depending on the scenario. This is the only case study where DG could yield a reduction in distribution costs for moderate penetration levels if actively managed. This implies that, due to the netting effect of DG, some network investments could be avoided or deferred. Thus, negative unit incremental costs have been computed for medium penetration levels. However, cost savings brought about by the connection of DG are rather low when compared to total network costs. Demand Side Management measures can also produce some cost cuts in the light of the cost savings achieved for the no-DG scenarios. Finally, it must be acknowledged that the behaviour of some cost components, particularly LV conductors and MV/LV transforming centres, could not be explained. This may be presumably due to the lumpiness of investment decisions and the need to use heuristic algorithms to analyze large networks.

The results obtained show that increasing DG penetration levels may cause distribution network costs to rise in spite of implementing advanced response options. An exception to this occurs in the Spanish case study, where network costs could decrease when low or moderate amounts of DG are connected. In this case, DG production during peak demand periods would reduce the rating of upstream network elements and, consequently, capacity requirements. Furthermore, there is one scenario in the Kop van Noord Holland case study where distribution costs are lower than those for lower DG penetration levels. This can be explained taking into account the specific characteristics of the DG present in the Kop van Noord area and the fact that the maximum net loading of the transmission substation in the area could decrease when actively managed DG is installed.

All in all, the implementation of advanced response options could noticeably mitigate the negative impact of DG on distribution costs. Largest cost savings are above 30% of total distribution costs for the Dutch case study, whereas cost cuts of about 2% of total distribution costs were achieved in the Spanish distribution area in the most unfavourable scenario. Results denote that demand side management is able to reduce investment and maintenance costs in distribution networks. However, cost savings are much higher when DG is controlled to some extent too. Moreover, the magnitude of the positive effects of advanced response options assessed greatly depend on the characteristics of the considered distribution area (DG penetration levels, relative distribution of loads and DG, DG technologies, assumptions made regarding load and DG behaviour in D5, etc.) and the nature and degree of implementation of these response options. Therefore, implementing the set of response options that best fits each distribution area instead of applying the same to all areas seems to be advisable.

Generally, cost savings were higher for those areas where a higher degree of controllability of load and especially DG was assumed. The highest benefits were obtained for the Dutch case study in 2020-DG penetration level scenarios. It should be taken into account that DG penetration rates in these scenarios are extremely high whilst the planning assumptions considered in WP4 were extremely conservative. Therefore, it is reasonable that cost savings brought about by advanced response options are high when compared to those results for other areas. Per cent cost savings in the remaining scenarios (all but those in the Dutch area for 2020-DG penetration levels) all remain in the range of 5-10% of total distribution costs. Moreover, cost savings usually correspond to network investments in assets located upstream of DG within the network (The Netherlands) or in assets located at the same voltage level as DG (Germany).

To conclude with, it seems clear that the implementation of Demand Side Management and advanced generation control practices can have very positive effects on distribution network costs. This is particularly relevant in the face of the very high DG penetration levels that are expected in many distribution areas in the near future. However, a thorough cost-benefit analysis is required to make a final decision on the implementation of these measures.

### 4.1.2 Overall system costs

This subsection summarizes the results obtained in each of the areas regarding the effect of ANM measures on electricity system costs; excluding distribution costs which were already covered before. Due to resource limitations, total system costs were only obtained for the 2020-DG scenarios.

The first remarkable conclusion obtained in the study is that the implementation of advanced response options caused overall system cost reductions for all case studies (before considering its implementation costs). However, it is worth noticing that most savings are attained by decreasing the costs incurred in the electricity grids; mostly distribution networks. The transmission network costs were only deemed relevant in the Dutch case study. The particular results for each region can be summarised as follows:

- Kop van Noord Holland, The Netherlands: total savings amount to 7-9 €/kW of DG installed. Most savings are due to a reduction in distribution network costs and to a lesser extent transmission network costs. Transmission network related savings accounted for 50% of the cost decreases in distribution costs in some scenarios, whereas in others these were null. Furthermore, a slight increase in fixed generation costs was observed in all scenarios. This was caused by the lower contribution of CHP when it is curtailed or shifted, which required back-up capacity from other technologies outside the distribution area.
- Mannheim area, Germany: the analyses yielded overall system costs reductions of around 10-12 €/kW of DG installed. The cost reductions correspond almost exclusively to the distribution network. A slight increase in variable generation costs is obtained as more production from conventional technologies is needed, but it is nearly negligible when compared to distribution network cost savings.
- Aranjuez region, Spain: the benefits brought about by the advanced response options presentes large variations among scenarios. Values between 2€/kW of DG and 5 €/kW of DG were obtained. Distribution costs are generally the most important component, albeit these are significantly lower than in the other areas. Balancing costs are also reduced in some scenarios. On the other hand, variable generation costs increase in a small amount for the same reasons as in the German case study.

The results show that most savings caused by the implementation of ANM correspond to reductions in network costs. On the contrary, fixed and variable generation costs, as well as externalities, will grow as a consequence of the lower contribution of DG/RES. However, it can be seen that the limited curtailment or shifting of DG/RES production produces significantly larger savings (in grids) than the associated costs.

Moreover, the amount of savings achieved per each kW of DG installed greatly depends on the particular characteristics of each region. Whilst overall cost savings present smaller variations among scenarios and are kept within similar ranges for the German and Dutch regions, savings in the Spanish case study were significantly lower and presented considerable volatility among scenarios. These variations reflect the evolution of distribution network costs which were previously explained.

Finally, a rough estimate of the costs of implementing advanced response options in each area was provided. Adding these estimates to the previous results yields very different results in each region (see

Table 19). In the Dutch and German areas, the case for ANM is clearly positive, especially in the former. However, this is not the case in Spain where implementation costs are in the same range or even higher than the cost savings computed.

Table 19: Summary of average annualized costs and benefits of Active Network Management for the three case study regions (in €/kWDG/year). Source: Summary of Improgres findings: Based on 4 scenarios per country (Demand 2008; Demand 2020 times Medium and High DG)

| | Network cost savings €/$kW_{DG}$/year | Technology cost (ICT) €/$kW_{DG}$/year | Net benefits €/$kW_{DG}$/year |
|---|---|---|---|
| Spain | 3.3 | 7.9 | -4.6 |
| Germany | 10.5 | 2.5 | 8.0 |
| Netherlands | 8.6 | 0.1 | 8.5 |

It must be noted that these calculations constitute a rather simplified approach to a cost-benefit analysis. Therefore, a definite decision about whether ANM is positive or negative cannot be made. The implementation costs had only been roughly estimated in order to draw preliminary conclusions about the acceptance or rejection of ANM. Results indicate that ANM tends to be positive on the overall account, albeit a separate and detailed cost-benefit analysis may be required in each case. Furthermore, there are many other advantages of the implementation of response options that could not be quantified in WP5 such as the contribution of energy efficiency to security of supply, barriers to building new network assets (which could in fact make ANM the only solution), contribution of smart metering to improve continuity of supply, provision of ancillary services by DG and/or loads, etc.

Additionally, some of the ICT costs can be shared with other regions whose associated savings have not been included in the study. For example a DSO or a SO control centre would cover a wider territory than the ones analysed herein. It seems that generalising the use of ANM and pushing the development of the ICT technologies can drive unit implementation costs down. On the other hand, shaving load peaks or curtailing DG production may imply some loss of comfort or incomes for consumers and DG operators respectively. This could involve paying them some kind of compensation or lucrum cessans which have not been considered in these analyses. It has been assumed that DG/RES curtailment is only resorted to a few hours per year. Otherwise, it would be arguable whether the savings in network investments compensate for the curtailed production. These issues should be further addressed in future research.

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