Improvement of the Social Optimal Outcome of Market Integration of DG/RES in European Electricity Markets

Case studies of system costs of distribution areas

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Project objectives

The IMPROGRES project aims to identify possible improvements in the social optimal outcome of market integration of distributed generation (DG) and electricity production from renewable energy sources (RES-E) in European electricity markets. This will be achieved by:

- Identification of current interactions between DG/RES businesses, distribution system operators (DSOs) and energy markets in coping with increased DG/RES penetration levels.
- Developing DG/RES-E scenarios for the EU energy future up to 2020 and 2030.
- Quantifying the total future network costs of increasing shares of DG/RES for selected network operators according to the DG/RES-E scenarios.
- As a comparison to regular DSO practices, identify cost minimising response alternatives to increasing penetration levels of DG/RES for the same network operators.
- Recommend policy responses and regulatory framework improvements that effectively support the improvements of the socially optimal outcome of market integration of DG/RES in European electricity markets.

Project partners

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- Liander, The Netherlands
- Institut für Solare Energieversorgungstechnik (ISET), Germany
- MVV Energie, Germany
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Executive Summary

The promotion of the use of renewable energy sources (RES) and combined heat and power (CHP) at European level has led to increasing penetration levels of distributed generation (DG). Work Package 4 of the IMPROGRES project aims at computing the economic impact that the integration of growing shares of DG in several areas with high potential for the installation of this type of generation may have on overall system costs in general and each specific cost component related to the supply of electricity in particular. The European Electricity Directive (European Communities, 2003) defines DG as generation plants connected to the distribution systems.

Report D5, corresponding to the work developed within WP4, has first defined a suitable methodology to compute the impact of DG on system costs. Cost factors deemed to be affected by DG are distribution, 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 emission of different polluting substances are significantly lower when electricity is produced using clean renewable technologies.

In order to assess the impact on these cost components of DG, several penetration levels of DG, measured as the ratio of DG in each area to local contracted demand, have been defined. Then, we have determined the evolution of the different types of costs with increasing shares of DG, when all other aspects of the system functioning and development are kept unchanged and equal to those corresponding to a specific point in time. This set of system variables that are kept constant 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 he expected situation in the year 2020.

Areas where the installation of DG is considered have a high potential for the integration of DG/RES and 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 of generation installed or expected to be installed and the penetration levels considered, as well as unit costs and other parameters of design of the grid. The area in Spain is located in *Aranjuez*. It is an urban and semi-urban area with about 60.000 customers and mainly wind and CHP capacity currently installed. In the future, PV capacity is also expected. DG is concentrated in a few specific places. Up to 35% DG penetration levels are expected for 2020. High voltage, medium voltage and low voltage distribution networks are considered. The area in the Netherlands is a semi-urban area with 80.000 customers and very large in size (675 km2). It is located in *Kop van Noord Holland*. DG installed and expected is mainly wind and CHP and DG penetration levels, which are already very high, will probably reach 200% of the contracted load in 2020. Only high voltage and medium voltage distribution networks are considered. This entire grid must be built underground. The area in Germany is located in *Mannheim*. This is a residential area with about 6000 customer where generation expected is PV and micro-CHP located within the same households of consumers. DG penetration levels are nowadays negligible but are expected to reach about 30% of contracted load in 2020. Only medium voltage and low voltage distribution networks are considered.

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. 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 the unit emission factors corresponding to each technology. Al these cost factors but distribution cost 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). Finally, 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.

Based on the analyses carried out, one can conclude that main cost drivers when developing the distribution grid an area are relative levels of demand and DG, the relative location of demand and DG, the simultaneity factors of demand and DG and the unit investment costs and price of energy used. Flows in the grid are lower the more balanced production by DG and consumption by local load are. Thus, for low penetration levels of DG (compared to load) costs tend to decrease the more power produced by DG/RES (that is, the higher the DG penetration level is). For very high DG penetration levels, costs tend to increase with the penetration level. In order for DG to decrease power flows, generation must be located close to load. Thus, for a certain penetration rate, reduction in costs will be higher the closer generation and demand are located to each other. The same applies to the operation profile. Reduction in distribution costs will be higher (re increase lower) the more similar the operation profiles of demand and generation are (mainly the simultaneity factors and the time when maximum generation output or load consumption occurs). Last but not least, total distribution costs will be lower the lower unit investment costs and the price of energy losses are.

Talking about generation costs, one must make a clear distinction between fixed and variables costs. The former tend to increase as a result of the installation of DG because the unit investment costs of this generation capacity are higher than that of conventional generation. On the other hand, variable generation costs tend to decrease with the integration of DG/RES because the cost of producing power from conventional generation replaced by DG/RES is higher than that of the latter type of generation. Besides, CO_2 emissions and external costs (caused by the emission of other type of pollutants) is also higher for conventional generation capacity than for DG/RES one.

Despite this general trend, certain differences between DG/RES technologies exist. Thus, the investment costs for CHP generation tend to be lower than those of wind, which in turn are lower than those of solar power. At the same time, fuel costs and emissions tend to be higher for CHP than for wind or solar power. Consequently, the higher the fraction of total CHP capacity, the lower investment costs and the higher variable cost will be. The higher the fraction of solar capacity, the higher investment cost will, since this is, by far, the most expensive technology amongst the ones considered. This effect is reinforced by the fact that the capacity credit of solar is clearly below that of the wind, which is clearly below that of CHP capacity.

The balance between variable and fixed generation cost caused by DG/RES, which are, by far, the largest part of the total cost impact of DG, depends on several aspects, like the prices of electricity and CO_2 that are considered, the amount of electricity produced by each DG technology in the area and unit investment costs considered.

In general, with the exception of those scenarios where energy prices are quite high, the increase in fixed generation costs caused by DG will be larger than the corresponding decrease in variable costs. So, overall, total generation costs tend to increase as a result of the installation of DG/RES. All those effects have been observed when computing results for the three considered areas.

Differences between the evolution of variable costs and those of the social welfare in the dispatch depend on whether an increase in demand as a consequence of the installation of DG/RES occurs. Note that installing additional DG causes a shift in the supply curve to the right, which may in turn cause a decrease in the market electricity price. If demand is assumed to be elastic (as it actually is, though the actual elasticity of demand may be quite small at the moment), some consumers may increase its energy consumption as a result of this decrease in price. If an increase in demand occurs, the increase in social welfare in the dispatch will be higher than the decrease in variable costs (this is the case with the DG installed in the Dutch area). If not, both changes will be opposite in sign but will have the same magnitude (this is the case of the DG installed in the German area).

As mentioned earlier, external costs will decrease as a result of the installation of DG, though the impact of these reduction will in general be smaller than other effects of installing DG. Balancing costs, on the other hand, will increase with the amount of DG installed, though the magnitude of this increase, of course, will depend on the percentage of DG capacity that corresponds to wind, which is the main technology responsible for an increase in balancing costs because of its unpredictability.

Overall, supply costs and socio-economic costs will increase with the installation of new DG units for almost any DG/RES penetration level. An exception may be low penetration levels, where the impact of generation costs may be smaller than that of other cost components like distribution costs, which may decrease with DG/RES. Another, more significant, exception may be those scenarios where energy and CO_2 prices are very high. In this case, the decrease in variables costs (or increase in social welfare) may surpass the increase in generation investment costs.

Finally, we provide a global estimate of the impact of DG/RES in each of the areas considered on distribution cost and other types of costs. 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. Thus, unit costs considered for the German area are significantly higher than those in the Dutch and the Spanish ones. The fact that assumptions about the behaviour of demand and generation differ widely among areas may also cause non-negligible differences. These assumptions concern the fraction of DG installed capacity that is producing power at peak load time and the amount of power consumed in periods when DG production is highest. In the analyses here presented, conservative assumptions were made, according to planning practices by DSOs and the regulation in some countries. If the behaviour of DG better adapted to conditions in the system, incremental costs caused by DG could be significantly reduced.

Fixed and variable generation costs are the most important cost factor regarding the impact that DG/RES may have on it. The relative importance of variable and fixed generation costs may mainly depend on the level of energy prices and the unit investment costs for DG/RES technologies. In the considered snapshots, these costs range between 58 (for the Dutch and Spanish areas) and 98 (for the

German area) €/(kW DG installed *year), in the case of fixed generation costs, and between -117 and -22 €/(kW Dg installed*year), both values obtained for the Dutch area, in the case of variable costs. Changes in the social welfare are in the same order of magnitude as changes in variable generation costs.

Lastly, changes in external costs and balancing costs caused by DG/RES are much smaller than those in the previous cost factors: these range between 0 and 2 €/(kW DG installed*year) for balancing costs and between 0 and -6.3 €/(kW DG installed*year) for external costs (very small positive values are possible if demand increase as a result of the installation of DG).

Total system costs tend to increase as a result of the integration of DG/RES. Thus, changes in the total socio-economic impact range between close to 0 values for relatively low DG penetration levels in the Netherlands and 114 €/(kW DG installed*year) in Germany for relatively high DG penetration levels.

1 Introduction

The promotion of the use of renewable energy sources (RES) and combined heat and power (CHP) at European level has led to increasing penetration levels of distributed generation (DG). Work Package 4 of the IMPROGRES project aims at computing the economic impact that the integration of growing shares of DG in several areas with high potential for the installation of this type of generation may have on overall system costs in general and each specific cost component related to the supply of electricity in particular. The European Electricity Directive (European Communities, 2003) defines DG as generation plants connected to the distribution systems.

Policies of promotion of renewables prompted by an increasing awareness of the impact that the production of energy may have on the environment have resulted in a significant increase in the amount of the DG installed in most European countries in recent years. In some countries, like Germany, Denmark or Spain, energy produced from renewables represents a significant fraction of total energy production. In fact, Germany has already achieved the objective for the integration of renewables that had been set by the EU for the year 2020.

We all know that DG/RES has a significant impact on the functioning of many different cost factors of the production of electricity, namely generation (fixed and variable), distribution, balancing, external and transmission costs. Besides, it may alter the result of the dispatch in terms of the amount of power consumed. This work package integrates the theoretical calculation and assessment concerning the increase of DG in the mid- to long-term future from Work Package 3 with case studies of network operators. Therefore three network operators in respectively the Netherlands, Germany and Spain have cooperated in this work package to calculate and assess the costs of increasing DG shares according to the topology of their own network. This assessment creates strong links between theoretical (model-based approaches) and the current practise of DSOs. Finally, the overall impact of DG/RES on total system cost has been assessed and analysed for each of the case study areas.

Previously, WP3 has worked out DG/RES-E scenarios for the EU energy future per DG/RES-E generation technology and per country up to 2020 (with projections up to 2030) based on the simulation model GreenNet. One of the major issues in this context is, on the one hand, to develop a clear picture of e.g. intermittent and non-intermittent DG/RES sources, small-scale and medium scale CHP, etc. and, on the other hand, to model the DG/RES-E grid integration on very disaggregated level.

WP2 has assessed the interactions between DG operators, distribution system operators (DSOs) and the electricity markets, which have changed due to the increase in the penetration of DG/RES technologies. The increase of DG levels in electricity networks has led to different responses from DSOs, some facilitating the increase of DG but many others trying to limit this increase, perceiving this development as a threat to their day-to-day business. Electricity market places have originally been established to facilitate trade mainly for large-scale producers. But electricity (spot)-markets and balancing markets of today give increasing possibility for small-scale generation to participate in the market place.

The structure of report D5 corresponding to the work developed within WP4 of the IMPROGRES report is as follows. Section 2 of the report provides the general framework that has been used to compute the impact of DG/RES in the three considered areas on different cost components as well as on total system costs. Mayor cost components are identified together with scenarios and analyses to be carried out. Section 3 describes the three different distribution areas that have been considered for the assessment of the impact of DG installed within them. It also characterizes the scenarios that have bee employed corresponding to each of them. Section 4 provides a description of the methodology and assumptions that have been applied to compute the impact of DG on each different cost component. Unlike section 2 which was of a general nature, this section focuses on the specific characteristics of the method that is well suited to compute cost of each type. Section 5 presents the numerical results corresponding to the application of the methodology presented in section 4 to the case studies of the areas identified and described in section 3 in the general context established in section 2. Finally, section 6 provides some conclusions and presents the analysis to be carried out in WP5.

2 General approach to the study

In this section we describe the research methodology used in this report. We start by briefly describing the possible impact of DG/RES on the overall electricity system (Section 2.1). This is discussed in order to explain the specific type of system impacts included in our research. Thereafter we turn to the general picture that we aim to provide when it comes to the quantification of the impact of integrating more and more DG/RES in the electricity system (Section 2.2). Here we discuss the way in which the results obtained need to be interpreted. Finally, we turn to the scenario approach we take when looking at the issue of quantifying DG/RES integration costs (section 2.3). Since our quantifying approach is based on three specific case study areas, an important part of this final section concerns the scenarios constructed for the three case study areas.

2.1 DG/RES impact on electricity system

Cost factors affected by the integration of DG/RES-E mainly include the costs of reinforcing the network for it to be able to cope with changes in line flows caused by the operation of this new generation capacity; fixed and variable costs and revenues of the rest of generation in the system (conventional generation) and load; polluting gases emissions and their associated costs, as well as other external costs and, last but not least, fixed and variable costs of balancing services. Some of these cost factors may change significantly as a result of the integration of DG/RES-E while others may only be negligibly affected. The next paragraphs provide a qualitative assessment of the effect that integrating distributed and renewable generation may have on each of these types of costs.

Network DG/RES-E integration cost may be of two types: transmission costs and distribution costs. Peak network flows and total losses, which are the two main drivers behind network reinforcements, may significantly change as a result of the installation of DG/RES-E capacity in an area. What is more, the size and sign of line flows increases may vary widely depending on the characteristics of generation and load existing in the area. Thus, if DG/RES location and operation profile is similar to that of demand in the area, and the resulting net demand or generation is smaller in magnitude than the one existing before the installation of this generation, line flows in the system will decrease when DG/RES begins to operate and the network cost impact of integrating it in the system operation is likely to be negative. On the other hand, if new DG/RES is located far from the existing load, its operation profile differs significantly from that of the latter and/or the amount of DG installed is significantly larger than that of existing load, line flows may probably increase and, correspondingly, the associated cost impact is likely to be positive (increase in costs). This project has analyzed in detail the impact of integrating DG on the distribution network costs in the three different considered areas. However, the transmission cost impact of DG/RES has only been analyzed qualitatively in those areas where it was deemed to be significant. This was due to the complexity of the corresponding analysis and the lack of the tools that are required to perform it.

Fixed and variable costs and revenues of conventional generation in the system and load are also impacted by the installation of DG/RES. The latter type of generation ranks first in the merit order thus replacing conventional generation units that otherwise would be marginal. Given that fuel costs of DG/RES units tend to be quite small, variable production costs tend to decrease as a result of the installation of this generation. CO2 emissions cost has been deemed to be included in the final energy price. Thus, it has been deemed part of total generation costs. The magnitude of the variable generation cost impact of DG/RES greatly depends on fuel costs, being larger the higher conventional fuel cost are. Three different fuel cost levels have been considered within the project (2008, the one estimated for a 2020 low fuel cost scenario and a third one corresponding to a 2020 high fuel cost scenario). Fixed generation costs are also affected by the installation of DG/RES, since the latter may be able to provide, not only part of the energy that was produced before by conventional plants, but also a fraction of their firm generation capacity (with some level of confidence). However, the capacity credit of RES generation tends to be clearly below that of conventional generation. Besides, the unit construction cost of the latter is lower than that of the former. Consequently, fixed generation costs tend to increase as a result of the installation of RES/DG. Lastly, the system demand level may also change because of the entry into operation of DG/RES, since total supply costs will certainly vary and at least part of the demand in the system cannot considered to be completely inelastic. Thus, consumer revenues may also be affected by DG/RES.

The cost of those externalities of electricity production other than CO2 emissions is also affected by additional DG/RES being installed. Since the composition of the generation mix and the operation profile of each generation technology changes due to the integration of DG/RES, external costs will also change. These externalities comprise not only emission directly related to electricity production but also those that take place earlier in the value chain (construction of power plants, transportation of fuel, etc). Due to the fact that RES/DG technologies normally are less pollutant, external costs are expected to decrease as a result of the installation of DG.

Balancing costs are those incurred when counteracting power imbalances caused by sudden changes in system conditions (generation output, load consumption, power plants or line outages, etc). System balancing costs may also be affected by more DG/RES being in operation. Since part of this generation is regarded as highly volatile and, up to a certain point, unpredictable, the impact of this generation on balancing costs could be deemed to be positive. Our analysis has aimed at obtaining a good estimate of the impact of intermittent RES/DG generation on this type of cost. In this regard, we have focused on wind generation, which is the only one that might largely affect the amount of regulation reserves that are required.

It should be noted that in general, the costs and benefits caused by the integration an increasing amount of DG/RES are allocated to different electricity market actors in different areas. Even though the development that causes integration costs and benefits takes place in a limited geographical area, the consequences can be felt by actors far outside this area. Table 1 provides an overview of the actors and areas affected for every considered cost category.

Table 1: Allocation of costs and benefits of DG/RES integration

Cost category	**Actor(s) affected**	**Area impacted**		
		Area	**Country**	**EU**
Distribution network cost	DSO	X		
Transmission network cost	TSO		X	
Generation cost	Electricity producers		X	X
Balancing cost	Electricity producers[1]		X	X
External cost	Society (citizens)		X	X

[1] In some countries, some electricity producers are not responsible for balancing costs. Here we actually refer to all actors that are considered to be programme responsible parties.

2.2 General presentation

For each of the system cost elements that can be impacted by the increased penetration of DG/RES in the energy system, as described above, we aim to provide a quantification. This quantification however is clearly limited in scope. Since our focus is on the impact of an increased DG/RES penetration in a particular area in the countries of Germany, the Netherlands and Spain, the results presented in this report are only valid for DG/RES developments in these areas. Therefore, these results cannot be deemed representative of the impact of increasing DG/RES shares on country level on the cost of the electricity system. In order to get a clear understanding of what is actually computed within the scope of WP4, we provide an illustration of our results in Figure 1. This figure shows the impact of DG/RES in the Spanish case study area on the different cost categories previously identified for three different levels of DG/RES penetration. All other variables but DG/RES capacity are deemed to be those corresponding to the year 2008.

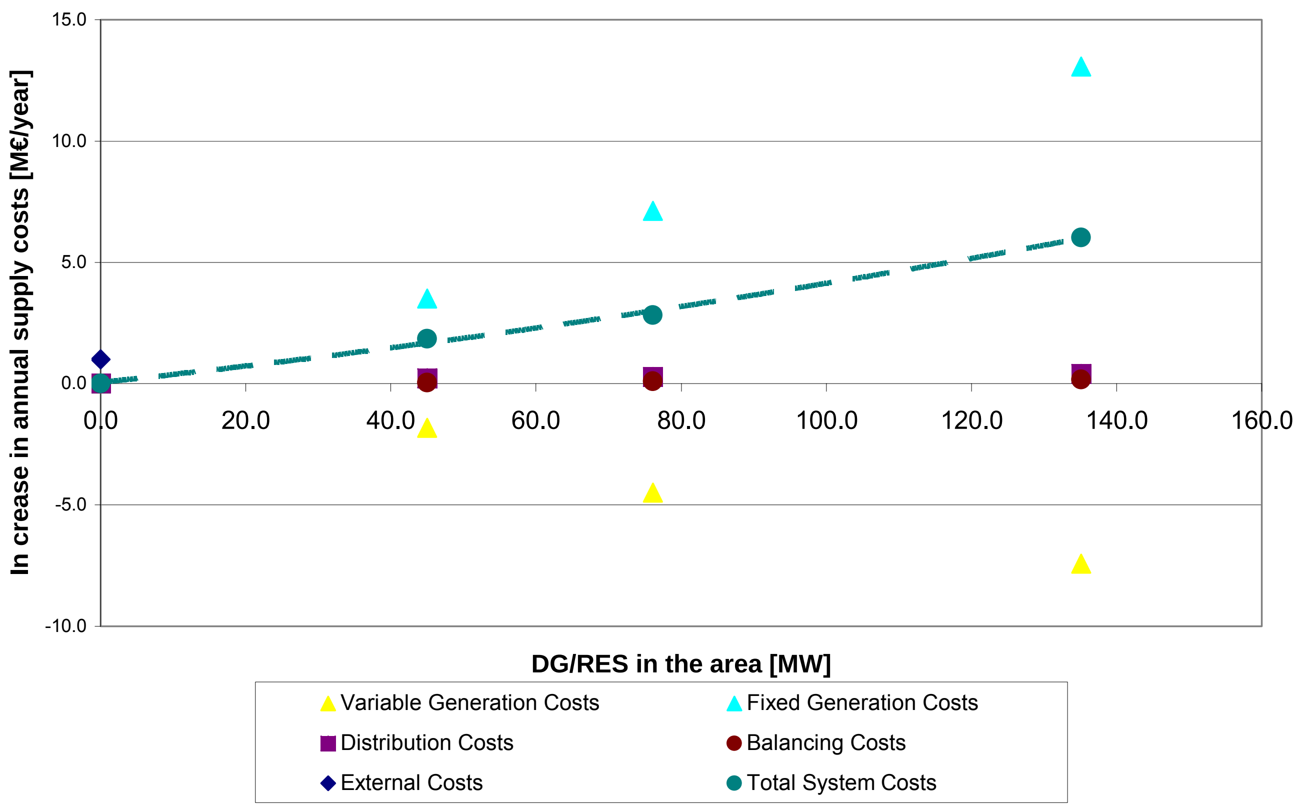


Figure 1: evolution of total annual supply costs with the amount of DG installed in the Aranjuez distribution area, in Spain, assuming all other variables are those corresponding to the year 2008

In this report we have obtained the depicted data points for each cost category. The figure should be interpreted as follows. First of all, it should be noted that the depicted data points have been obtained within a certain methodological research approach and with the assistance of a number of assumptions. Given this, we observe that an increase in DG/RES capacity in the Spanish case study area from 0 MW to 45 MW leads to an additional fixed generation cost of 3.5 million € per year. This means that compared to the situation where no DG/RES is present in the case study area, total fixed generation costs are 3.5 million € per year higher. A further increase in the amount of DG/RES in this same area from 45 MW to 76.1 MW gives rise to an additional fixed generation cost of 3.6 million € per year. As can be seen from the figure, the number of data points that could be computed for every cost category is limited. The limited number of data points being available means that no firm conclusions can be drawn with respect to the actual shape of the relationship between the amount of DG/RES on the one hand, and the consequential integration cost. In Figure 1 we therefore have drawn a broken line that could give the underlying relationship between the data points that were computed. For example, while we have depicted a rather smooth line connecting the data points, it might for example be plausible that specifically the shape of the relationship between the amount of DG/RES and the *network* integration costs is 'step-wise' shaped, with only some new DG/RES units actually triggering substantial network upgrade investments and other DG/RES units being able to connect at no or much lower cost.

Another way of presenting this computed data is to relate the amount of DG/RES in the case study area (in MW) to the contracted load in this same case study area. In other words, this would involve expressing the amount of DG/RES in the area as a percentage of the contracted load in this area. The level of load contracted by each consumer refers to the maximum amount of power each consumer is allowed to withdraw from the grid based on the energy and grid charges it is paying. By doing this we construct what we define as a DG/RES penetration rate. In the context of the earlier example of the Spanish case study area: an increase in the DG/RES penetration rate from 0% to 11% gives rise to an increase in yearly fixed generation costs of 3.5 million €. Finally, we can also present the cost impact caused by the increase in DG/RES in another way. This can be done by relating the total change in network cost to the amount of DG/RES that has been added within the case study area. This gives rise to a cost figure in € per unit (in kW) of DG/RES capacity added within the case study area. In the earlier example, an increase in the DG/RES penetration rate in the Spanish case study area from 0% to 11% gives rise to an additional fixed generation cost of €78.1 per kW of installed DG/RES capacity per year. Figure 2 presents the same results as provided in Figure 1 above, but this time using the latter type of presentation. A specific and false interpretation of this figure is that the relationship as presented in this figure also applies to DG/RES developments within a country. Within the earlier example: our research explicitly does not say that an increase in DG/RES penetration *in the whole country* (Spain) from 0% to 11% leads to an average increase in total S*panish* fixed generation costs of €78.1 per additionally installed kW of DG/RES capacity. In other words, our case study area results are not directly to be extrapolated to the country level. There are some cost categories, like generation costs, external costs or balancing costs, whose change when an increase in DG capacity in the whole country is considered is analogous to that when new DG is installed in a certain area (provided additional DG capacity installed is of the same type in both cases and assuming congestion in the grid does not affect the value of the new DG capacity). However, there are other cost categories, mainly distribution costs, whose value mainly depends on the inner characteristics of the particular distribution area where this generation is installed.

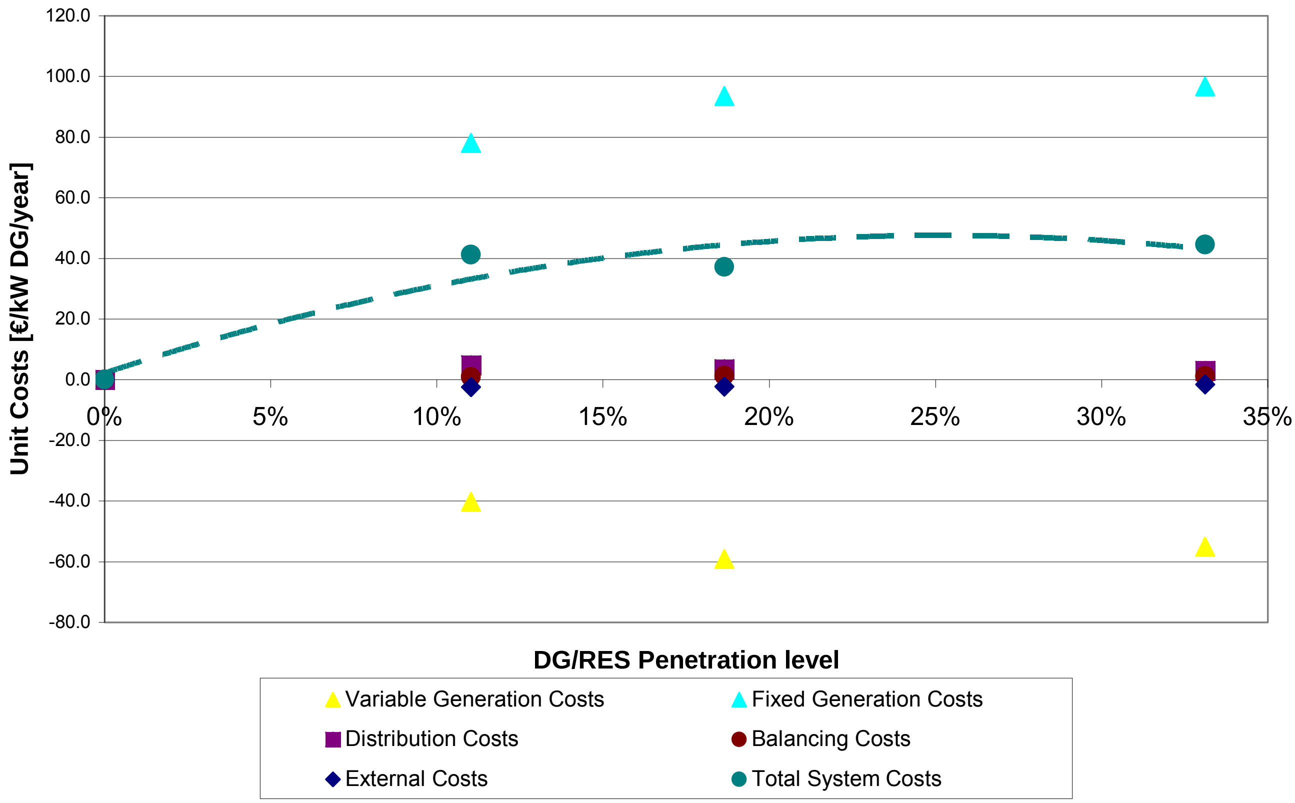


Figure 2: evolution of total annual supply costs with the amount of DG installed in Aranjuez distribution area, in Spain, assuming all other variables are those corresponding to the year 2008. Numbers are provided as unit costs

An identical figure as for the Spanish case study area above can be constructed for the other analyzed case study areas in Germany and the Netherlands as well. However, a comparison of the obtained figures for the three case study areas is not straightforward. Although technically the results of the three case study areas can be depicted in one figure, the actual comparison might be misleading. The reason for this is that such a figure does not do justice to the very much different context of the different areas. As will become apparent from this report, a large number of area and country specific characteristics have an impact on the actual cost impact as calculated in this report. Examples of such are the:

- The electricity generation mix in the country
- The characteristics of electricity load in the country and in the case study area
- The type of network considered (rural vs. urban, density of load and generation units)

This brings us back to the main goal of this report, namely: to assess what the driving, underlying factors are when it comes to the integration costs of DG/RES. In discussing the obtained results we try to include the impact of the above type of factors on results.

2.3 General scenario framework

In section 2.1 we have described the relationship between the amount of DG/RES in a area and the integration costs is dependent on a large number of factors. However, the real world is even more complex: certain influential factors change over time. For example, the generation cost impact of adding another X MW of DG/RES to the network in the Spanish case study area will be different for the current electricity system (2008) compared to a future (2020) electricity system. From 2008 to 2020, the total load in the case study area as well as in the Spanish electricity system will grow. In addition, the overall electricity generation mix in the area will be changing over time. To properly take into account these dynamics, we have adopted an approach based on the separate consideration of the effect of DG/RES in different background scenarios (which refer to the level of system load, the composition of the overall generation mix in the system, the fuel price, etc.). We will refer to these background scenarios as storylines. As explained in Table 2, storylines differ in the electricity generation mix in each country, the level of demand, the generation investment costs, the fuel prices and the price of CO2 emission rights. As a general scenario framework we basically adopt two different storylines where the one storyline is representing the current electricity system (say in 2008), and the other is representing the electricity system expected for the year 2020. Table 2 provides a description of the two adopted storylines.

Table 2: Overview of storylines

	Storyline	
Electricity system element	**'Current electricity system: 2008'**	**'Future electricity system: 2020'**
Electricity generation mix in the area (Europe)	• Electricity generation mix in 2008	• Estimated electricity generation mix in 2020, with more efficient technologies
Electricity demand	• Electricity demand level in 2008 (both at case study and country level, with location specific load in case study area)	• Estimated electricity demand level in 2020 (both at case study and country level, with location specific load in case study area)
Investment cost	• Current level of investment cost in electricity generation assets	• Estimated 2020 level of investment cost in electricity generation assets
Fuel prices	• Fuels prices as observed in 2006[2]	• Estimated fuel prices for 2008
Price of CO_2 emission rights	• Current level of CO_2 emission rights	• Assumed 2020 level of CO_2 emission rights

Due to limited availability of resources and the large complexity in computing the impact of DG/RES integration on the various cost categories, we have limited the number of data computations for each storyline. For each storyline we have identified four stages, or levels of penetration, of DG/RES. The stages only differ with respect to the amount and composition of DG/RES that is assumed to enter the

[2] We have used 2006 fuel price levels since 2008 fuel price levels were not yet fully available at the time of computing the results.

case study areas identified in Germany, the Netherlands and Spain. Table 3 provides a description of the identified stages of DG/RES integration, or levels of penetration of DG/RES.

Table 3: Overview of DG/RES scenarios

Stage	DG/RES scenario	Description	Background storyline	
			'Current electricity system: 2008'	'Future electricity system: 2020'
1	'No DG'	No DG/RES in case study area	2008 / 1	2020 / 1
2	'2008'	Amount of DG/RES in case study area as realized in 2006	2008 / 2	2020 / 2
3	'2020 low'	Low estimate for amount of DG/RES in case study area in 2020	2008 / 3	2020 / 3
4	'2020 high'	High estimate for amount of DG/RES in case study area in 2020	2008 / 4	2020 / 4

As described in the table, the different identified stages correspond to different amounts of DG/RES capacity (which may also correspond to slightly different compositions of the generation mix) that was realized or is expected in the case study area. First of all, stage 1 corresponds to the situation where no DG/RES is connected to the distribution network in the case study area. This situation has been applicable to each of the case study areas at different moments in the past. This stage with zero DG/RES is necessary as a counterfactual for the other stages. Since we are primarily interested in the *incremental* impact of adding more and more DG/RES, we need to have a starting point. In our research we have actually computed all cost impacts (in absolute terms) for these four DG/RES stages. However, in subsequent reporting we focus on the incremental cost impacts (i.e. the cost impact in relative terms). For example, by subtracting the total distribution network costs in stage 1 from the total distribution network costs in stage 2 we obtain the incremental cost impact of adding the amount of DG/RES associated with stage 2. Thus, results in the remainder of this report refer to the increase in costs corresponding to a certain category, for each stage of DG/RES in a certain area, with respect to the stage where no DG/RES is in place in the area. Here, it must be stressed that some combinations of DG and load installed, like future high DG installed capacity and 2008 load level, are not going to happen in reality in the corresponding area. However, they are useful in order to assess the effect of DG for extreme penetration levels.

3 Case studies

This section is focused on the selection and description of the tree case studies, corresponding to three areas within the European system, which have been analyzed in WP4 of the IMPROGRES project. Areas considered correspond to areas with high potential for the integration of DG/RES. First, section 3.1 defines the three areas that have been considered for the analysis of the impact of the integration of DG/RES on system costs, as well as the main characteristics of these areas. Afterwards, section 3.2 characterizes the set of scenarios considered within each area when analyzing the impact that integrating DG/RES may have on the development and operation of the total system.

3.1 Selection of case studies and main characteristics of them

A general description of the three case studies is provided in this section. Particular attention is paid to the differential aspects that may explain the different impacts that DG may have in different areas due to the DG technologies present, the type of demand, load density, etc. In order to account for the effects of different DG technologies and types of distribution networks, three distribution areas are analyzed within the IMPROGRES project. These are located in the Netherlands, Germany and Spain. The corresponding DSOs are Liander (formerly Continuon), MVV Energy and Unión Fenosa Distribución respectively. Throughout this section, each case study area will be described, placing emphasis on the differential characteristics that may explain possible deviations in network costs as DG penetration levels increase: area size, DG technologies present, demand types, etc.

3.1.1 Spanish case study

The Aranjuez area, comprising the south of Madrid province and the northern part of Toledo province, has been selected as one of the case study areas within the project. This area has a surface area of 3400 km^2. Currently, there are approximately 61600 consumers located within it. 99.55% of these consumers are connected to the LV network, 0.44% to the MV and 0.01% to the HV. Therefore, most loads located in the area are connected at low voltage level, mainly within towns, although several hundreds are at medium voltage level and a few at high voltage. The largest settlement in the area is Aranjuez, with over 52000 inhabitants (October 2008). An industrial zone exists in the outskirts of the town. Figure 3 shows a tentative picture of the HV and MV network for this area where the different towns can be seen within a thin polygonal line.

This sub-urban distribution grid is nowadays comprised of a sub-transmission grid at 132 and 45 kV, (though most of the circuits at sub-transmission level are built at 45kV, the DSO in the area, Unión Fenosa, is considering the possibility of upgrading the 45kV grid to 132 kV in the near future), a medium voltage grid at 15 kV, and a low voltage grid at 400V. This network currently comprises 1 132/45kV substation with two transformers, 6 45/15kV substations totalling 11 transformers and 1075 15kV/400V substations amounting to 599 transformers. At HV level, the network includes 8 circuits at 45kV and 48 circuits at 15kV. The structure of the 45kV grid is a ring, as it can be seen in Figure 3.

The total amount of load contracted in the area is around 275 MW, which results in a maximum simultaneous load fed by HV/MV substations of over 140 MW. Regarding DG, at the moment there is only one 10 MW wind farm and three industrial CHP units in the area adding up to 35 MW of total generation capacity.

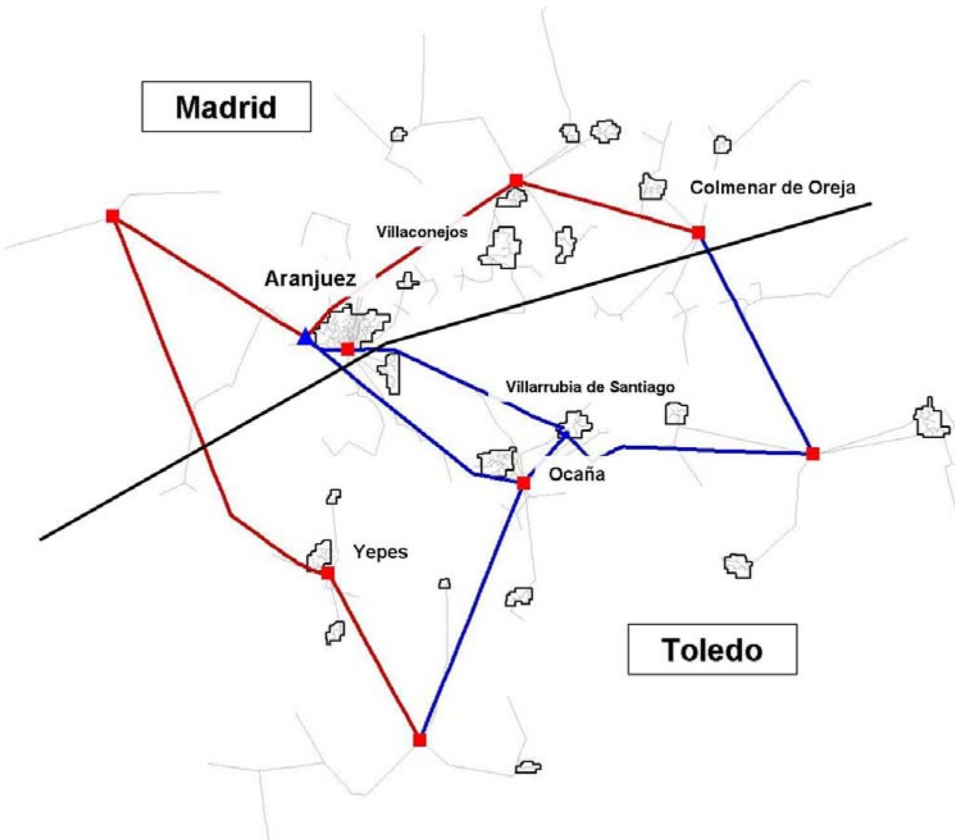


Figure 3: Aranjuez area distribution network

Figure 4 shows the hourly demand profile throughout the year in the Aranjuez area (green line). The yellow curve in the same figure represents the evolution of weekly average demand and the red one that of the seasonal average demand. Due to night supply tariffs applied in this area (consuming power during the night is encouraged through reduced tariffs) the hours with highest demand are concentrated between 11 and 12p.m. in Thursdays during winter months. This is shown in Figure 5, which provides the distribution of the 5% of hours in the year with the highest load (438). Separate figures have been drawn to represent the distribution of these peak load hours throughout the day, the week and the year. Finally, Figure 6 shows that, despite the fact that the peak load in the area is 140 MW, only in 1% of the hours net demand exceeds 110MW. This is because of the presence of DG in this area, which contributes to partially supply peak load.

This case-study area has been considered for its analysis within the project because of two main reasons. First, the level of DG penetration in the area was not negligible at all in the year 2008 and it is expected to significantly increase in the future. Annual demand increases of around 4% are expected, accompanied by a relevant increase in the DG installed capacity. PV generation to be installed in the area in the medium term future may range between 11 MW_p and 40 MW_p. This will be installed at medium voltage level. Additionally, new wind generation capacity (between 20 MW and 40 MW) and CHP capacity (only one additional 10MW unit is foreseen in the high scenario) are also expected or, at least, deemed possible.

The second reason for considering this area is the fact that the reliability of this area is nowadays highly dependent on the operation of DG units. Major problems that currently exist in the area are voltage collapse with n-1 failures and line overloads in peak load hours when DG is disconnected. If one trip of a network element occurs in the ring making the 45kV HV network in the area, all the demand must be supplied with power through a single feeder, which may become too long, thus suffering from voltage stability problems during peak load hours. DG may be of great help in this regard by providing voltage support in these hours. Additionally, as shown in Figure 6, DG may already help to significantly reduce maximum line flows in peak hours, thus avoiding line overloads.

The DSO in this area deems it necessary to build new network reinforcements in order to cope with the production of intermittent DG expected in the future as well as with the expected increase in load while maintaining security and quality levels. Given that procedural barriers are important, a more active integration of DG in the system would be greatly beneficial.

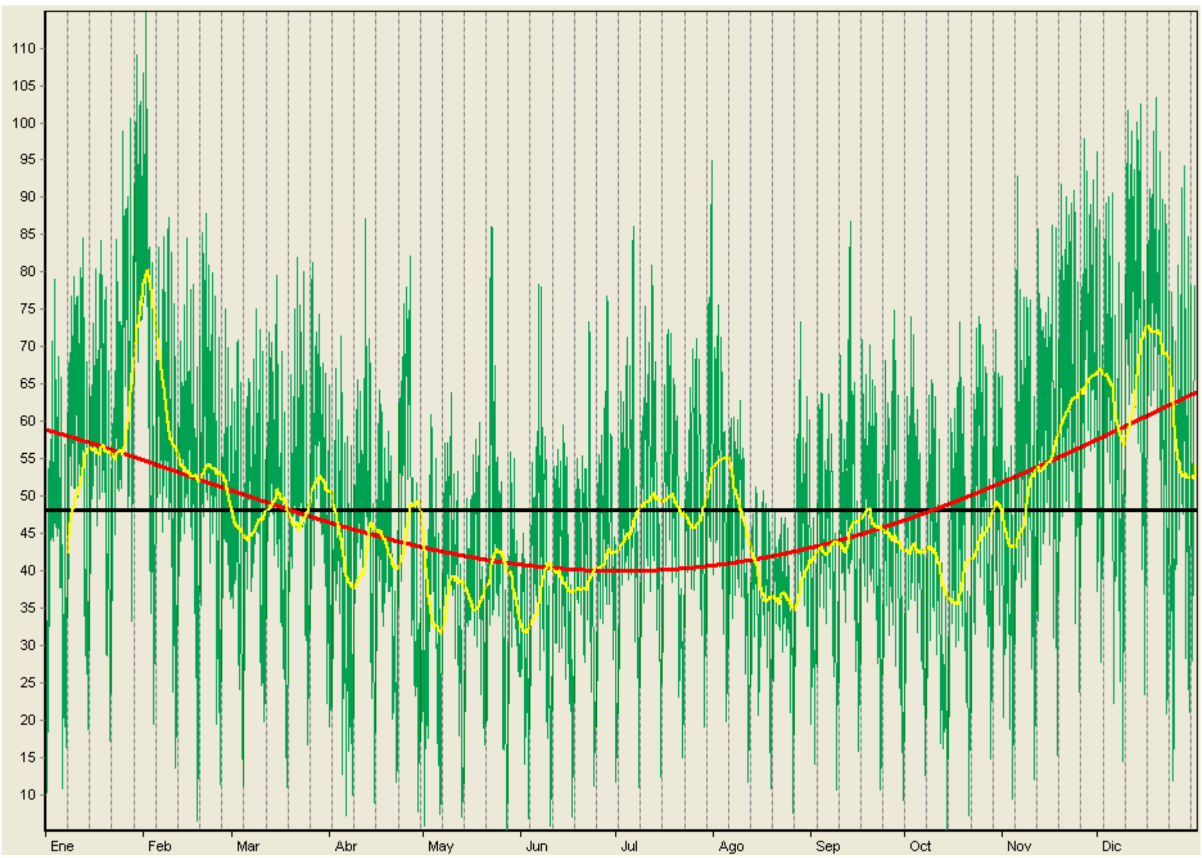


Figure 4: Annual demand profile in Aranjuez area distribution network

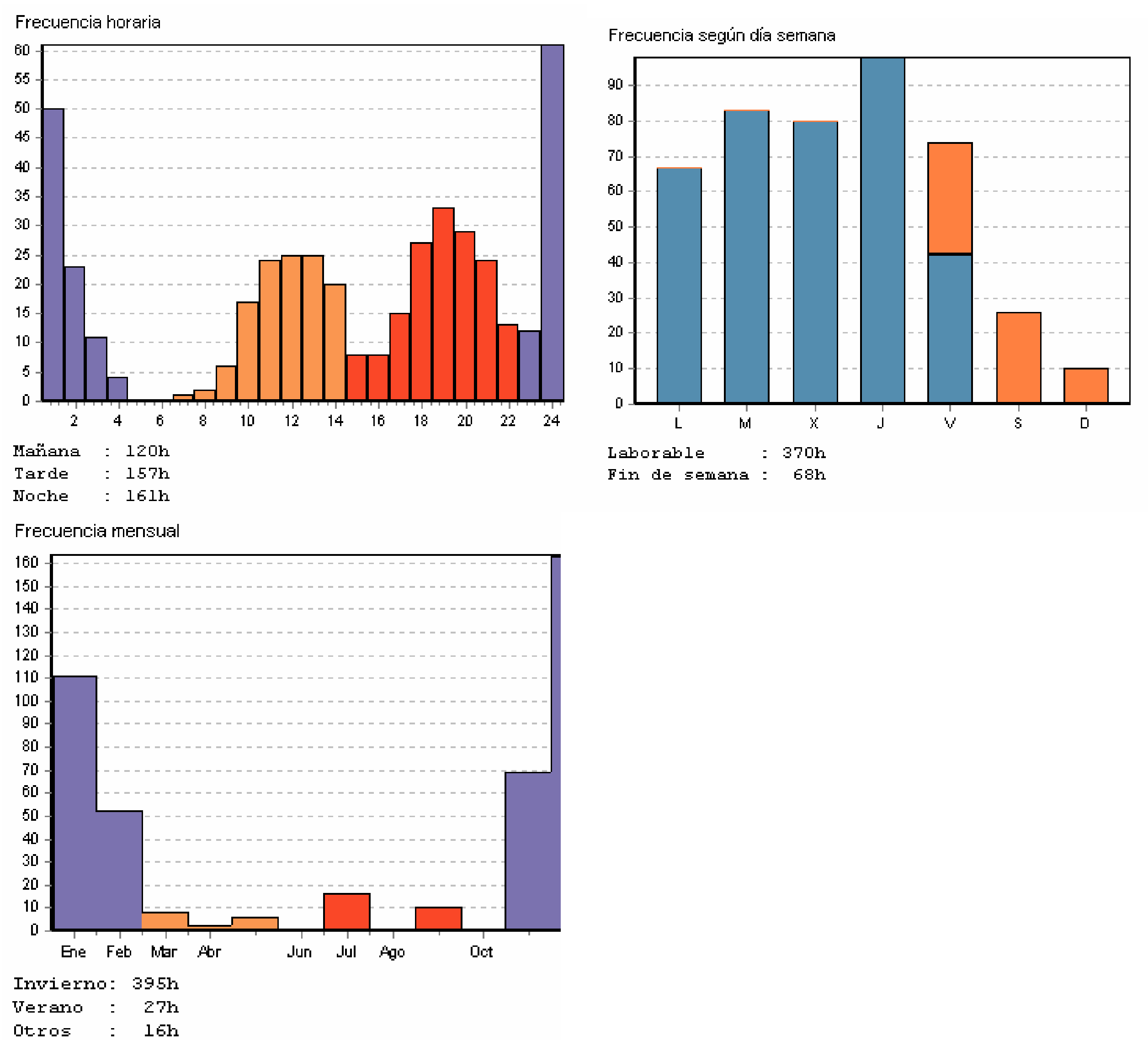


Figure 5: Number of hours with highest demand in Aranjuez area distribution network

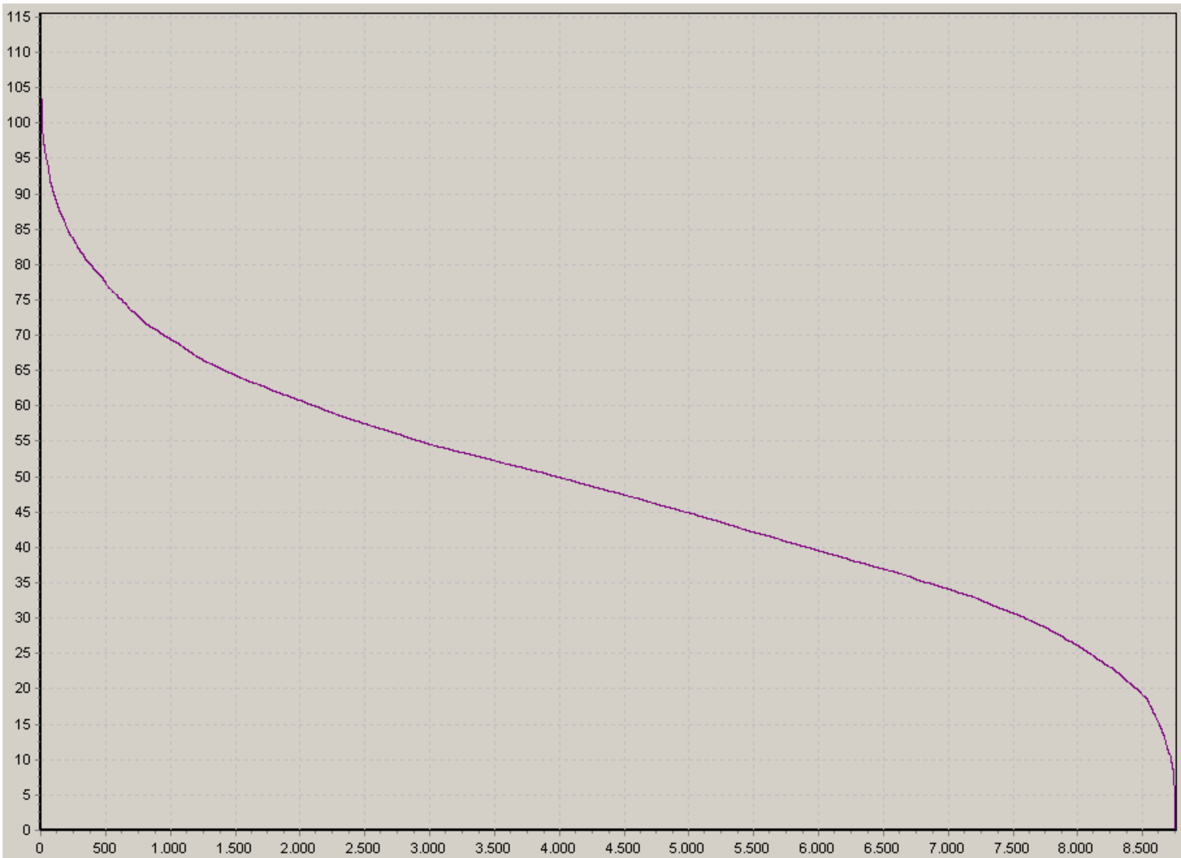


Figure 6: net Load duration curve

3.1.2 Dutch case study

The Kop van Noord-Holland area is a rural/sub-urban distribution area located in the province of Noord-Holland and serving approximately 80000 customers over an area of about 675 km^2 (see Figure 7). The most densely populated areas are located in the southern part of the area whereas horticultural exploitations are present all over the area and installed wind capacity in the northern part of the area. DG in the area comprises a large number of CHP units that provide heat for greenhouses and a number of wind farms. Figure 7 provides graphical representations of the province Noord-Holland and the area of the case study:

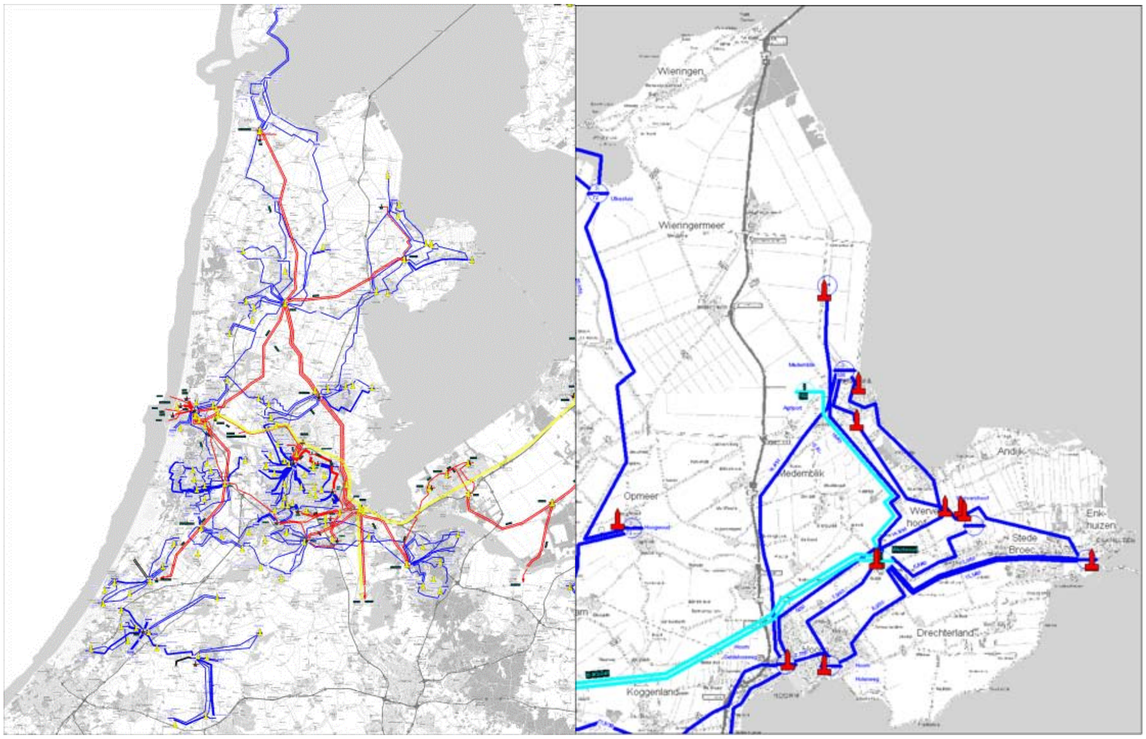


Figure 7: Left total province Noord-Holland; right the area of the case study named Kop van Noord-Holland

The picture on the left shows the total province Noord-Holland where the HV-grid is marked. Characteristic for the area of the case-study at the upper right of the province is that it is the area where the grid ends. The transport of energy depends on two cables along one way to the HV-grid further in the province, in the right picture the light blue connection (capacity today 2 x 240 MVA, extension in progress). This transmission connection ends at the transmission substation 'Westwoud'.

In the right picture the total HV-grid in 2008 is showed: the light blue connections are 150 kV and the dark blue connections are 50 kV. The red markers are transport stations 50 kV and 150 kV. The currently existing total distribution network comprises a low voltage 400V, a medium voltage grid, part of which is connected at 3kV, while the other is connected at 10kV, and a high voltage grid, which is part 50kV and part 150kV. Nowadays, DG in Kop van Noord consists of more than100 MW of wind energy and around 120 MW of combined heat and power (CHP) units. Contracted load in the area in 2008 was around 300 MW. Both current and future DG shall connect mostly to the medium voltage grid, except some large wind farms that are directly connected to the high voltage grid.

The reason to analyse this area within the IMPROGRES project was that, not only is DG today already comparable to contracted demand, but also a considerable growth is expected in the amount of installed DG in the medium term future. The DSO Liander expects DG to develop at a higher rate than demand, hence resulting in local generation exceeding local demand at certain times. Major developments are foreseen both in wind energy and CHP. It is deemed likely that by 2020 wind capacity will be doubled and CHP will reach nearly 600 MW. However, should a strong policy support and favourable market conditions for these technologies be in place, even a further growth of DG is considered possible. Under a high penetration scenario, up to 500 MW of wind and more than 800 MW of CHP could be connected to the distribution network by 2020. As a result of differences between demand and

generation profiles within this area and the large amount of generation installed net demand will experience great fluctuations: from 700 MW positive (thus importing power) to over 1000 MW negative (thus exporting it).
This will presumably have great impacts at high voltage and even at transmission level. In the study, the consequences of such a great penetration of DG will be assessed both for the medium voltage, considering only 10 kV for the sake of simplicity, and high voltage grids, considering both 50 kV and 150 kV. All small customers are combined to MV points of total simultaneous load.
In 2008, we start with about 1300 MV points of load and about 150 MV points of DG. To analyse this case study area we have assumed that the transmission substation Westwoud has enough capacity to transport the maximum import or export of the case study area. The investments in the direct connection from outside the area to Westwoud will be considered part of the transmission grid costs of the area.
Currently, customers with DG/RES only have to pay for the connection to the grid caused by DG. They do not need to pay for investments in the grid neither for the transport of energy produced by DG. Greenhouses in the area usually have a connection to the grid both to import power when CHP is out of order and to export power in situations where there is a surplus of power. So it can be very attractive for there exploitation to export as much as possible when energy price is high and to import energy when energy price is low. This, of course must comply with restrictions related to health needs. Fluctuations and uncertainties in the price of energy lead to the extreme situation where grid companies have to develop the grid so that it is able to cope with all greenhouses importing energy at their maximum contract-value and. Also, with that where all of them are exporting their maximum energy production. Grid companies are obliged by current regulation to deal with both extreme situations. When this should not be possible, grid companies have to extend the grid in a reasonable time.
Besides CHP, windmills should also be expected to produce from zero up to their maximum capacity. Thus, their output is deemed unpredictable and uncontrollable by DSOs. These characteristics combined with major plans for installation of greenhouses, CHP and windmills make this area very interesting for studying consequences of integrating DG/RES.
Liander notice that the studied grid in the area is since January 2008 no longer the responsibility only from Liander. Since then the legal situation is changed: the control of all grids of 110 kV and higher voltage are transferred to TenneT, the national TSO.

3.1.3 German case study

The German distribution area considered in the study comprises three residential areas in Mannheim: Wallstadt, Feudenheim, and Vogelstang. The DSO in the area is MVV Energie AG. Overall, more than 6100 customers are located in this case study area. For private customers, the only information available is the standard values of their power consumption profile. Peak demand is around 15 MW distributed over an area of 20 km^2. As a rule, the laying of the cable is carried out both sides along the course of the roads. In the central zones (study areas) MVV Energie owns a meshed network. Current DG penetration level is nearly negligible. This area is shown in Figure 8.
Installed DG capacity nowadays amounts to 362 kW$_p$ of solar PV and 6 kW of domestic micro CHP. Our study aims at analyzing the effect on distribution costs of a considerable increase in domestic solar PV panels and domestic CHP units connected at the low voltage grid. An important growth in PV capacity is foreseen, reaching between 10 MW$_p$ and 15 MW$_p$ by 2020. Moreover, between 25% and 50% of households could be equipped with a micro CHP unit of 1.1 kW by that time. Therefore,

installed CHP electric capacity may be in the range of 1.7 MW and 3.4 MW. In the meantime, demand is expected to remain virtually unchanged. Given the nature of the distribution area, where load is connected at LV and MV levels, only the medium and low voltage grids have been considered in our analysis.

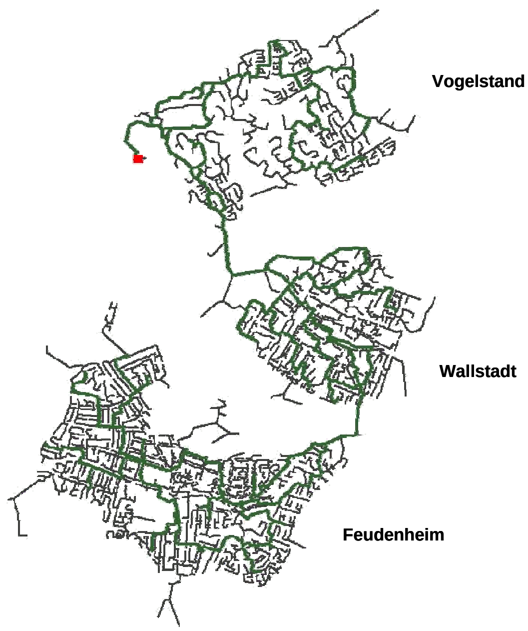


Figure 8: Mannheim area distribution network

DG installed capacity is nowadays rather low and has no impact on the system. In the future, an increase in DG production may lead to some overloads in critical assets. All DG is expected to be installed in the LV grid, where the simultaneity factor of consumers is rather low at the time when output from DG reaches its maximum. Thus, some reinforcements may be deemed necessary. This will be determined in section 5. This distribution area could greatly benefit from DG and, arguably, from an advanced control of generation output and demand.
Thinking of the current grid, one possibility to make it compatible with future power flows would be upgrading the transformer station from currently rated power 400 kVA to 800 kVA. This would be required if the maximum computed DG production in the future scenario is reached over a long period. If overloads occur over a short period of time, the transformer station installed could be 630 kVA.

3.2 Characterization of the set of scenarios considered for each area

As explained above, this subsection provides the main features of the set of scenarios to be considered when computing the impact of the integration of DG/RES in each area on the development and functioning of the global European system. Scenarios for each area must be representative of the different situations that may occur in areas of the same type when DG/RES capacity is installed in them. As already discussed within section 2, six different scenarios have been defined for each area that are representative of different possible combinations of load and DG/RES that may occur in this area or others similar to it. These 6 scenarios result from combing 2 different levels of load and 3 different levels of DG/RES. Levels of load correspond to the real situation in the area in the year 2008 and the expected level in the year 2020. Levels of DG/RES correspond to the real situation in the area in the year 2008, the expected one in 2020 in a low/medium DG/RES penetration scenario and the level expected for the year 2020 if penetration of DG/RES turns out to be high. In order to be able to compute changes to the expansion of the system and operation caused by DG/RES, not only the total amount of load and DG/RES is relevant, but also their geographical distribution and operation profile. No specific data about the location of load and generation shall be provided, since these data are deemed confidential by distribution companies. However, some graphical representations of these distribution areas have been provided in subsection 2.1 of this report and others are provided in this subsection. As for the operation profile, numbers representing the simultaneity factors of load and each generation technology at the times of maximum net demand and maximum net generation in each area are also provided. Thus, for each of the scenarios defined for an area, figures provided include installed capacity of load and DG/RES for each generation technology; the graphical representation of load, generation and the grid within the area and the simultaneity factors of load and generation in the two snapshot considered for each scenario (maximum demand and maximum generation). Simultaneity factors are provided simultaneously for the three areas in the last subsection within

3.2.1 Spanish area

As mentioned in section2.3, the number of scenarios to be considered in our analyses for the Spanish (and the remaining) areas is 6. These correspond to all the possible combinations of two different levels of demand (2008 level and the expected 2020 level) and three different levels of generation (2008 level, 2020 level assuming low DG penetration and 2020 level assuming high DG penetration). Table 4 provides the figures corresponding to the 2008 and 2020 load and DG levels that have been considered in the study.

Table 4: Installed capacity of load and DG for each technology. Spanish case [MW]

Network user	2008	2020 medium scenario	2020 high scenario
Load	407.97	641.12	641.12
DG CHP	35	35	45
DG PV	0	11.099	40.099
DG Wind	10	30	50

In order to compute the 2020 load level, 2 different load growth rates have been considered in the Aranjuez area, one for that part of the area belonging to Toledo province and the other one for the remaining part of the area, which belongs to Madrid province. On the one hand, load in Madrid is expected to increase at an annual rate of between 1.5 and 4.4% in winter and 1.9 and 5.6 % in summer. On the other, load in Toledo is expected to increase at an annual rate between 1.8 and 9.8% both in winter and in summer. This is shown in Table 5.

Table 5: load growth rates in the Aranjuez area

Demand growth (%)	Winter		Summer	
	High	Low	High	Low
Madrid	4,4	1,5	5,6	1,9
Toledo	9,8	1,8	9,8	1,8

Generation in the area in the 2008 scenario is provided in Table 6 together with its type and its connection point (location). Increases from the 2008 level in the generation capacity expected to be installed in the year 2020 both in the medium DG penetration scenario and in the high DG penetration scenario are provided, together with their type and location in Table 7 and Table 8, respectively.

Table 6: 2008 generation in the Aranjuez area

Capacity (kW)	Type	Conection point
5.760	CHP	ARZ
8.800	CHP	SUL
20.000	CHP	ALF
10.000	Wind Power	VRS

Table 7: Generation expected in a medium penetration scenario in he Aranjuez area

Capacity (kW)	Type	Conection point
4.000	PV	NOB
1.500	PV	OCA 702
3.000	PV	OCA 704
99	PV	OCA 709
2.000	PV	OCA 703
500	PV	OCA 709
20.000	Eólica	CDO

Table 8: Generation expected in a high penetration scenario in the Aranjuez area

Capacity (kW)	Type	Connection point
4.000	PV	NOB
1.500	PV	OCA702
3.000	PV	OCA 704
99	PV	OCA 709
2.000	PV	OCA 703
500	PV	OCA 709
20.000	Wind power	CDO
20.000	Wind power	ARZ
2.000	PV	ARZ 708A
2.000	PV	ARZ 708A
2.000	PV	ARZ 708A
1.000	PV	ARZ 708A
3.000	PV	ARZ 706
1.000	PV	CDO 701
4.000	PV	CDO 709
4.000	PV	CDO 710
10.000	CHP	NAJ
5.000	PV	VRS 706
5.000	PV	VRS 706

Figure 9 depicts the location of loads and DG for the different scenarios in the Aranjuez case study area as increments, i.e. all network users that exist at 2008 are also present in the 2020 medium penetration scenario. Additionally, all network users present in the 2020 medium penetration scenario are also present in the 2020 high penetration scenario.

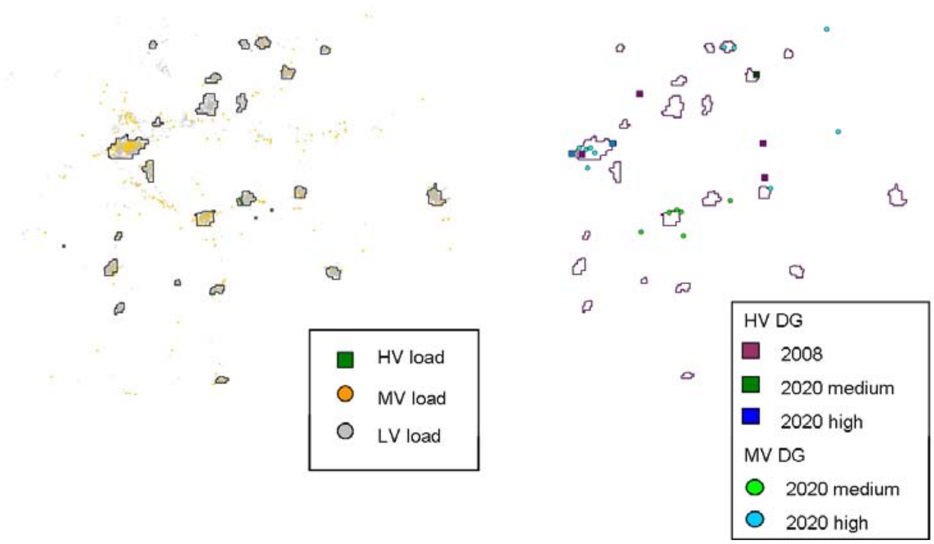


Figure 9: Location of loads and DG in the Aranjuez area. Spain

3.2.2 Dutch area

As mentioned in section2.3, the number of scenarios that have been considered in our analyses for the Dutch case study area is 6. These correspond to all the possible combinations of two different levels of demand (2008 level and the expected 2020 level) and three different levels of generation (2008 level, 2020 level assuming low DG penetration and 2020 level assuming high DG penetration). Table 9 provides the figures corresponding to the 2008 and 2020 load and DG levels that have been considered in the study.

Table 9: Installed capacity of load and DG for each technology. Dutch case [MW]

Network user	2008	2020 medium scenario	2020 high scenario
Load	317.27	856.15	856.15
DG CHP	116.402	573.152	886.302
DG Wind	109.995	214.345	503.345

Next, the main characteristics of the 2008, 2020 medium penetration scenario and 2020 high DG penetration scenario will be discussed. Numbers here provided are not exactly the same as those used in figures and tables in the description below because the latter are not 100% accurate.

3.2.2.1 2008 Scenario

Figure 10 shows current main concentrations of demand and DG/RES as roughly situated in the area. The yellow numbers is simultaneous demand, the blue numbers are representing sums of installed CHP and the green numbers represents summations of installed wind capacity.

Until 2006 there was a relative slow development of windmills and greenhouses combined with CHP. In 2006 started the development of a huge area with greenhouses and CHP called Agriport1. The '55'-demand and the '95' CHP is the situation of 'Agriport 1' in 2008, about 40% of the total project. In the practical situation, Agriport1 has one HV-connection with united customers, but in the case study we have decided to take into account all individual customers, so the model can optimize the total grid and total consequences.

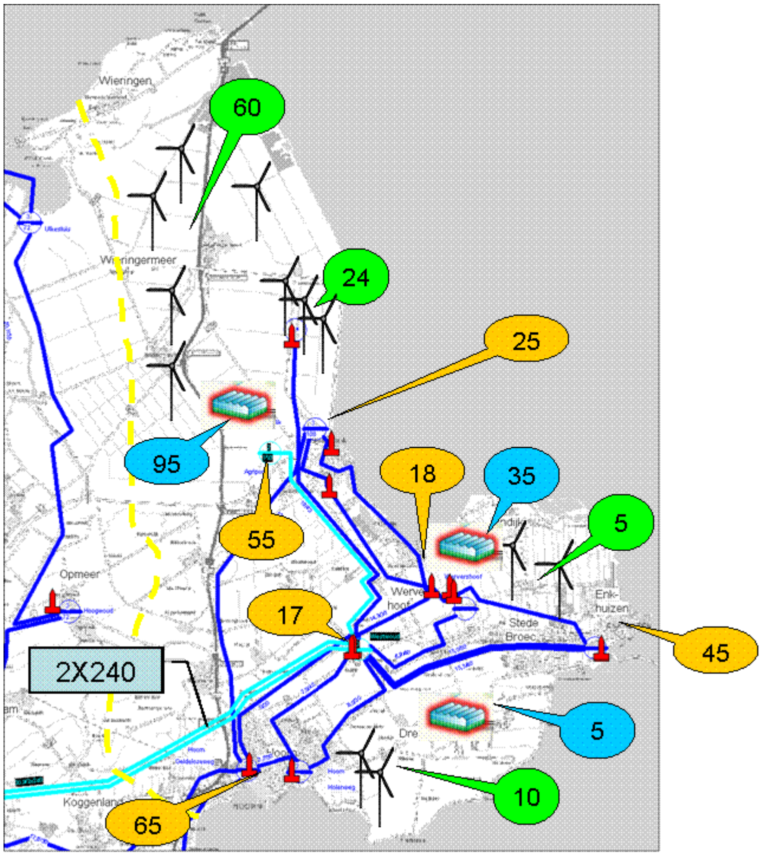


Figure 10: Situation in 2008 in the Dutch area

The installed wind capacity comprises one relatively large farm (24 MW) with a HV-connection and further all scattered single windmills or small wind farms, mainly situated in the north part of the case area.

3.2.2.2 2020 medium DG penetration scenario

The most important characteristics of the 2020 medium scenario are the following. Important to mention is that this scenario is perceived as a very likely scenario as confirmed in a stakeholder meeting with interested parties. The development of Agriport1 is completed then. And above in the middle of the case area next to Agriport1 a second project Agriport2 will be developed. In Agriport1 and Agriport2 are each planned 240 MW installed CHP capacity in individual units in a range from 2 until 7 MW. The customers in Agriport will probably contract together capacity leading to about 300 MW simultaneous demand. In 2.2 we have explained under which circumstances it is possible that these customers will demand 300 MW. On the other hand it is possible that they together want to export the total production, about 480 MW. Furthermore in the right side of the area there is another area with a large development of greenhouses, called Grootslag. For this area 92 MW of installed CHP capacity and 60 MW of simultaneous demand are expected.
Wind energy will double from 2008 to 2020. Wind farms will be mostly concentrated in the north of the area. In addition to an increase in the number of wind farms, the capacity of the individual windmills will grow to 3 MW. Other developments in demand and production are not substantial and

follow lower growth percentages. Figure 11 still shows the situation of the grid in 2008. It is evident that this grid is not sufficient to facilitate this scenario. In 4.3 it will be showed which investments have to be done to facilitate this scenario.

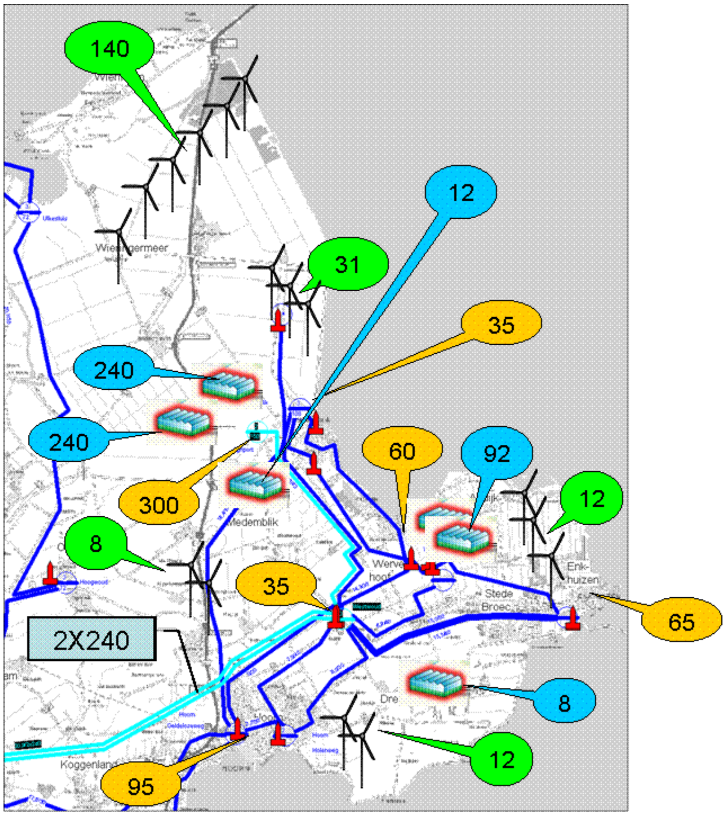


Figure 11: representation of the Dutch distribution area in the 2020 medium DG penetration scenario

3.2.2.3 2020 high DG penetration scenario

In the already mentioned stakeholder meeting, the interested parties have considered this high scenario as a possible scenario when the policy support and market circumstances will be favourable for DG/RES.

Figure 12 depicts this area in the 2020 high DG penetration scenario. Further expansion of CHP is possible if the good market circumstances for greenhouses continue. For this scenario we presume the development of Agriport3, a third large area of greenhouses in the neighbourhood of Agriport1 and Agriport2. Again, with a total installed capacity of CHP from 240 MW and a growth in the simultaneous demand from 90 MW. In this scenario also Grootslag will grow some more.

The growth of wind energy will be substantially higher because of the possibility of wind-farms off-shore in the Ijsselmeer and the Markermeer, the water east from the case area. We assume two farms each with capacity of 100 MW. On-shore we assume a further growth with 100 MW, again for the main part concentrated in the north of the case area. Other developments show normal growth percentages.

It is evident that the grid of 2008 still showed in the figure will not be able to manage such an amount of generation capacity. When we analyse the consequences of these scenarios with the knowledge about regulation and possible market circumstances as described in 2.2, the future grid will probably have to deal with enormous fluctuations. In Table 10 we have summarized the most extreme situations in 2008, 2020 medium and 2020 high scenario.

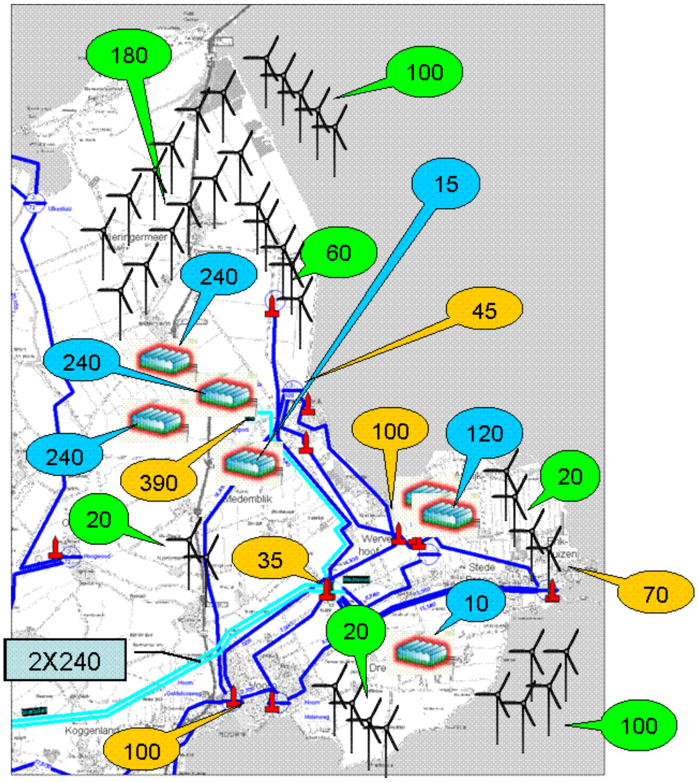


Figure 12: graphical representation of the Dutch distribution area in the 2020 high DG penetration scenario.

Table 10: main figures corresponding to the different likely scenarios

MW/MVA	today	low	high
Maximum demand	225	600	750
Minimum demand	75	100	125
Installed capacity wind	100	200	500
Installed capacity CHP	130	600	875
Balance in Westwoud maximum	225	600	750
Balance in Westwoud minimum	-155	-700	-1250
Difference	380	1300	2000

In 2008 the grid can deal with the most extreme situations, from import 225 MW to export a capacity of about 150 MW. In the medium and high scenarios the extreme values rise to 750 MW import and maximum about 1300 MW export. The calculations for an optimal grid take these extreme values into account. In 2008 there is backbone grid that can deal with flows up to 240 MVA. In the most extreme situation there should be a backbone grid in 2020 that can deal with flows over 1000 MVA. Both

Liander and TenneT are studying what will be the best structure for the future grid. In the highest scenarios it will be necessary to expand the ultra high voltage grid, 380 kV, now only situated in the south of the province, to the north of the province, even into the case area. This expansion then will be necessary not only for the developments in the case area, but also for DG/RES-developments in the rest of the province Noord-Holland.

3.2.3 German area

As mentioned in section 2.3 and equally to other case study regions, the number of scenarios that have been considered in our analyses for the German case study area is 6. These correspond to all the possible combinations of two different levels of demand (2008 level and the expected 2020 level) and three different levels of generation (2008 level, 2020 level assuming low DG penetration and 2020 level assuming high DG penetration). Table 11 provides the figures corresponding to the 2008 and 2020 load and DG levels that have been considered in the study.

Table 11: Installed capacity of load and DG for each technology. German case [MW]

Network user	2008	2020 medium scenario	2020 high scenario
Load	63.68	71.75	71.75
DG CHP	0.006	1.691	3.38
DG PV	0.362	10	20

Figure 13 shows the evolution of PV generation capacity in the Mannheim area. At the end of the year 2008 there were 6,7 MW of PV capacity installed, while the annual energy production was 5.400 MWh. In the last years, the PV electricity generation has experienced a seventy-fold increase, but it does not have a notable influence on the MVV grid yet.

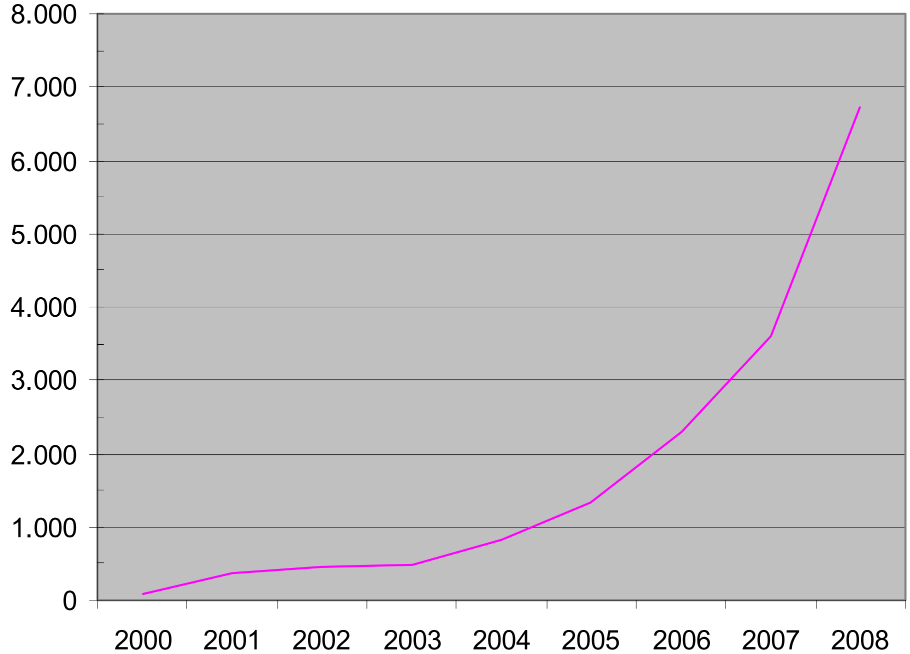


Figure 13: Development of installed PV generation capacity in the Mannheim area

The technical potential for PV electricity generation (roof units) in Mannheim amounts to 296 MWp which would result in an annual PV electricity generation of 267.000 MWh.[3] Within the IMPROGRES project, the MVV Energie case study region is deemed representative of the situation in urban residential areas with a high potential for the installation of DG. Table 12 and Table 13 show the installed capacity and the future potential of PV and micro-CHP in the three residential districts that have been analysed within the Mannheim area.

Table 12: Currently installed capacity and potential for PV in the Mannheim area

Modellparameter PV

District	Housing area (m²)	Electric potential factor (W/m²)	electric potential factor (W/m²)	Status quo (kW)	Future Low DG (MW)	Future High DG (MW)	Future High DG (MWh/a)	Voltage level
Feudenheim	1.906.487	2,375	4,75		5	9	8.150	LV
Wallstadt	1.042.411	2,375	4,75		2	5	4.456	LV
Vogelstang	1.278.686	2,375	4,75		3	6	5.466	LV
Total	**4.227.584**			**362**	**10**	**20**	**18.073**	

The calculation of the electric potential factor is based on an accurate determination of the potential of roof areas which are available for PV electricity generation in Mannheim. The potential factor of the area is computed dividing the potential of the installed load P [kWp] by the total surface of the chosen area. This factor is normally expressed in [W/m²].

[3] Hochrechnung des technischen Photovoltaik-Potentials für das Stadtgebiet Mannheim, Nicolai Herrmann März 2007

Table 13: Currently installed capacity and potential for micro-CHP in the Mannheim area

Modellparameter Micro -CHP

District	Housing area (m²)	number of house service connections*	Status quo (kW)	Future Low DG (kW)	Future High DG (kW)
Feudenheim	1.906.487	1.547		425	851
Wallstadt	1.042.411	3.387		931	1.863
Vogelstang	1.278.686	1.212		333	667
Total	**4.227.584**	**6.146**	**6**	**1.691**	**3.380**

The potential for Micro-CHP generation has been obtained assuming that each unit has an installed capacity of 1,1 kWel. In the Future Low DG scenario 25% of the houses have been assumed to have a Micro-CHP unit installed, while in the Future High DG scenario 50% of the houses have been deemed to have a unit installed. Figure 14 depicts the location of loads and DG for the different scenarios in the Mannheim case study area as increments, i.e. all network users that exist at 2008 are also present in the 2020 medium penetration scenario. Additionally, all network users present in the 2020 medium penetration scenario are also present in the 2020 high penetration scenario.

Figure 14: Location of loads and DG in the Mannheim area. Germany

3.2.4 Operation profile of load and DG in each area and snapshot

Load power consumption and DG production profiles. Consequently, the simultaneity factors considered for each snapshot are also a key parameter for an adequate network design. Simultaneity factors can be defined as the fraction of the installed capacity of DG or contracted power of consumers that is realized at a specific moment. For instance, a DG simultaneity factor of 0.9 for a maximum generation minimum demand snapshot means that under those conditions, DG would be producing at

90% of its installed capacity. Simultaneity factors presented here are those corresponding to the maximum net demand (also known as peak load) snapshot and the maximum net generation snapshot. Numerical values used in our analyses for simultaneity factors are shown in Table 14. The peak demand simultaneity factors for load are time coincident with the minimum output simultaneity factors for DG. They all correspond to the situation (snapshot) where net demand in the system is at its maximum level. The valley demand simultaneity factors for load are time coincident with the maximum output simultaneity factors for DG. They all correspond to the situation where net generation in the system is at its maximum level.

Table 14: Input data simultaneity factors of consumers and DG in the two considered snapshots

	Netherlands	Germany	Spain
LV demand-peak	n.a.	0.23	0.7
MV demand-peak	0.7	0.64	0.6
HV demand-peak	n.a.	n.a.	1
PV-min output	n.a.	0	0
Wind-min output	0	n.a.	0
CHP-min output	0	0.3	0.3
LV demand-valley	n.a.	0.15	0.15
MV demand-valley	0.24 (2008) 0.12 (2020)	0.15	0.6
HV demand-valley	n.a.	n.a.	1
PV-max output	n.a.	1	1
Wind-max output	1	n.a.	0.7
CHP-max output	1	1	0.75

Comparing the simultaneity factors used for consumers, it can be seen that these are significantly higher in the Spanish case. This is caused by the particular behaviour of demand in this area, which is prompted by the night period tariff for LV loads that is in place there. Under this tarification scheme, the energy price from 11:00 pm to 8:00 am is much lower than that during the day. Consequently, the highest power consumption takes place at 11:00 pm in winter when all the electric heating devices are turned on at exactly the same time. On the other hand, DSO Liander opted for a very conservative planning approach by assuming that DG made no contribution at all to cover the peak demand, whereas during valley hours DG was deemed to be producing at its maximum. Nonetheless, WP5 of the IMPROGRES project analyses the impact on system costs (and therefore also that on network costs) of the implementation of advanced market responses. Simultaneity factors considered there will be those that are most advantageous for the system, within reasonable limits. Therefore, the value of these factors will be less influenced by current network planning practices by each particular DSO or the particular regulation applied in each area.

4 Methodology for the computation of the different cost components

This section discusses the approach or methodology used to compute the impact of DG/RES on cost components: distribution, in section 4.1, and other cost components in section 4.2. The latter include generation (variable and fixed costs) in subsection 4.2.1, balancing costs in subsection 4.2.2, transmission costs in subsection 4.2.3 and external costs in subsection 4.2.4. In addition, we also discuss the impact of an increasing amount of DG/RES on the social welfare. The term social welfare originates from welfare economics and represents the total of consumer surplus and producer surplus, where the latter can also be referred to as producer profits. The character of the impact of DG/RES on social welfare (mainly consumer surplus) is quite different from that on the aforementioned cost components and should therefore be handled with care. The approach behind the social welfare impact is discussed in section 4.2.5. Once the process of computation of the impact of DG/RES on the separate cost is discussed, the process of computation of the overall cost impact of DG/RES on system costs is explained in section 4.2.7.

Finally, at this point we should stress that the major focus in the research that has led to this report has been placed on the impact of DG/RES integration on the distribution network cost, and less so on the computation on the other cost components affected by the integration of more and more DG/RES in electricity systems. This is reflected in the thoroughness and level of detail in the impact analysis for these other cost components. All in all, comparisons between the results on the distribution cost impact on the one hand, and on the impact on other cost components on the other hand, should therefore be treated with care.

4.1 Distribution integration costs for DG/RES

Distribution network planning has traditionally been made by forecasting the future growth in demand for a number of years and estimating the peak load that network capacity should cover. Technical and reliability constraints are usually taken into account. Nonetheless, article 14.7 of the European Electricity Directive (European Communities, 2003) states that DG and demand-side measures shall be considered as an alternative to network expansion. Thus, it is implicitly stated that DG must have an impact on the development of distribution grids.

Under low penetration levels, DG offers the possibility to defer network investments (provided, the operation profile of load and generation is similar) whereas higher levels of penetration may have considerable impacts on the costs, both capital and operating costs, of the distribution activity. However, it is still uncertain to what extent this may be realised. Therefore, further analysis is deemed necessary to clarify these topics. This process will probably require the use of new tools that integrate DG as an additional element connected to the distribution network. These are the so called reference network models. Additionally, the regulation of electricity distribution might be also adapted in order to account for the growing presence of DG in the grids. A further assessment of the impacts of DG on distribution regulation can be found in (Cossent et al., 2008 and Gómez et al., 2007).

This section aims at describing the process followed to compute the actual effect of DG over distribution network costs. Two reference network models have been used to determine the optimal distribution network needed to satisfy certain conditions of load and DG. In this Work Package, network planning is done under a business as usual (BAU) paradigm, i.e. the grid is dimensioned so as to be able to cope with the most demanding situation possible by itself. Nonetheless, in WP5 of the IMPROGRES project, alternatives to network reinforcements such as demand response or active network management will be analysed and compared with the result shown in this document. The network models that have been used are described in section 4.1.1. The approach followed is described in section 4.1.2.

4.1.1 Description of the planning tool

In this section, the main software tools and methodology used in order to carry out the analyses will be detailed. These software tools comprise two reference network models: PECO model and incremental model.

4.1.1.1 Reference network models

Reference network models allow their users to characterize distribution areas and design a distribution network that connects electricity end-consumers and generators given their geographical location, peak load or production and voltage level (Peco, 2004). The reference network should minimize investment costs, maintenance costs and energy losses, subject to reliability and technical constraints. As a result, the reference network or optimally adapted network may be used as a benchmark for actual distribution networks. This has been done by regulators in Sweden (the Network Performance Assessment model is described in Larsson, 2005) and Spain (concerning regulation is RD 222/2008). Generally, two different approaches can be found when designing the optimal network: greenfield models and expansion planning models. The former approach builds an optimal network from scratch, hence disregarding historic evolution of the networks. The latter approach takes the current network as the starting point and then builds the reinforcements necessary to cope with both horizontal (new network users) and vertical (changes in the capacities of existing users) future growths in demand and DG production.

Readers should be aware of the differences of these models with the optimised deprival value or the depreciated optimised replacement cost methodologies followed in New Zealand (New Zealand Commerce Commission, 2002) and Australia (Johnstone, 2003) respectively. A reference network model builds bottom-up a new optimal grid, whereas the “scorched node” models, so-called in opposition to scorched earth or reference network models (Turvey, 2006), remove elements from the existing network to identify surplus assets or excess capacity. Reference network models allow regulators to assign an economic value to network assets in the process of determining the allowed revenues of DSOs. The concept of reference network is also used in Strbac and Allan, 2001, Levi et al., 2005 and Paulun et al., 2008 for performance based regulatory purposes, albeit the approach followed in those cases is quite more simplified than in the reference network models described below.

Regardless of the reference network model being used, special attention must be paid to the input parameters. These may have a great impact on the resulting network costs; hence they should be correctly tuned. Otherwise, the reference network obtained could not be used as a benchmark of real networks. Generally, input data include, at least, consumers’ and transmission substations details (location, consumption data, etc.), distribution area modelling parameters (simultaneity factors, parameters for the identification of populated areas and selection of overhead or underground networks, load and loss factors, voltage levels…), economic and optimization parameters (price of energy losses, rate of return, quality of service indices), and a standardized equipment database.

In the present study, two network models, characterized below, have been used to compute distribution network costs in the three areas: the PECO model and the incremental model. Both models have been developed at the Institute for Research in Technology of the Comillas Pontifical University.

PECO model

The PECO model is able to build an optimal distribution network from scratch, thus belonging to the greenfield-type group[4], for very large areas comprising up to several million customers. Carrying out a very detailed modelling and being capable of dealing with very large problems, this model is a helpful tool for regulators in order to determine the remuneration of the distribution activity or setting distribution tariffs. The model has been already used for these purposes in Chile, Argentina and Spain. Network planning is performed through the interaction of two modules: a geographic information system (GIS) and a planning optimization algorithm. Data and information flows between these modules are shown in Figure 15.

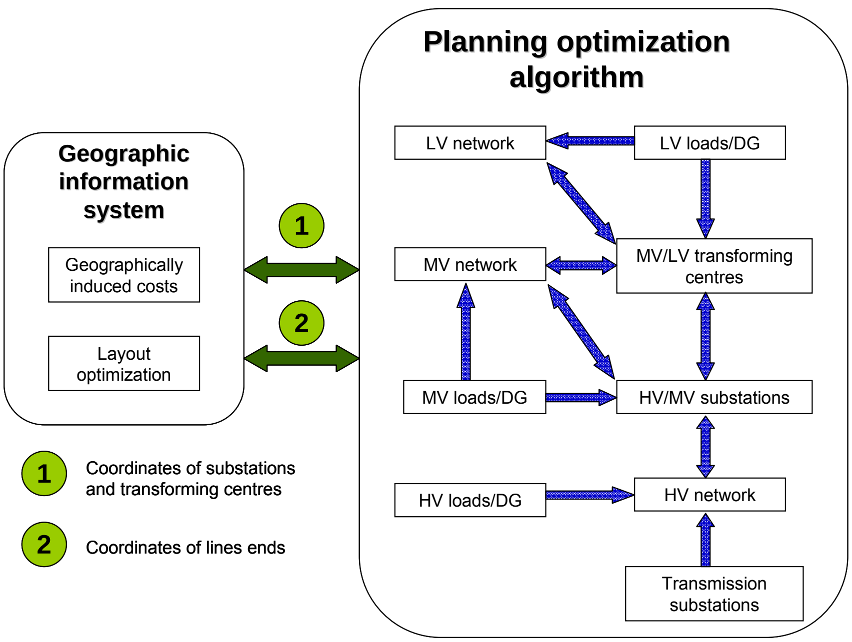


Figure 15: Description of the PECO model algorithm

Coordinates of consumers, distributed generators and transmission substations are given so that the model builds MV/LV transforming centres, HV/MV substations, and the LV, MV and HV networks. Firstly, settlements, street maps and industrial areas are determined according to the load density and number of customers of each kind. These influence the costs of the components according to their location, for example, whether underground or overhead lines may be built, or forcing line layouts follow the street maps. Moreover, orography, so as to skirt very steep or high zones, and forbidden ways trough, such as protected natural areas, may also be provided. Then, network elements from a standardized equipment database are deployed minimizing investments, operation and maintenance

[4] The PECO model may also obtain an optimal distribution network given the existing HV/MV substations and/or MV/LV transforming centres. This would be an intermediate approach between a greenfield model and an expansion planning model.

costs, and energy losses subject to technical constraints (voltage drop, capacity) and reliability constraints.

More specifically, LV networks are designed radially, whereas MV networks are operated in radial configuration although feeders meshing the network, breakers, maintenance crews, signalizers, etc. might be installed if required to comply with the continuity of supply indices fixed. The continuity indices are computed by simulating the failure of network elements according to a given failure rate and considering repair times depending on the location (urban or rural) and type of network (overhead or underground). The continuity of supply indices used in this model are TIEPI[5] and NIEPI[6], taken from the Spanish regulation, and refer to the number and duration of interruptions suffered by each kW of consumers' contracted power. An IEEE standard defines these same indexes as SAIDI and SAIFI. These parameters are very similar to SAIDI[7] and SAIFI[8], used in performance regulation of distribution utilities in other countries. In order to avoid possible cream skimming, both zonal and individual indices are taken into account. Finally, the HV network is designed according to an N-1 criterion.

Optimization is carried out in several steps using heuristic algorithms. The objective function is the present value of investments plus annual maintenance and energy losses costs computed with a weighted average cost of capital (WACC) specified as an input to the model. The WACC is considered the same for all costs. The PECO model considers only one nominal voltage value at LV and MV, but two different nominal voltage values may be used for HV networks. In order to compute the required distribution network capacity the model takes into account the initial demand and an estimate of its future vertical growth. A description of an early version of the PECO model and its algorithms can be found in Román et al., 1999.

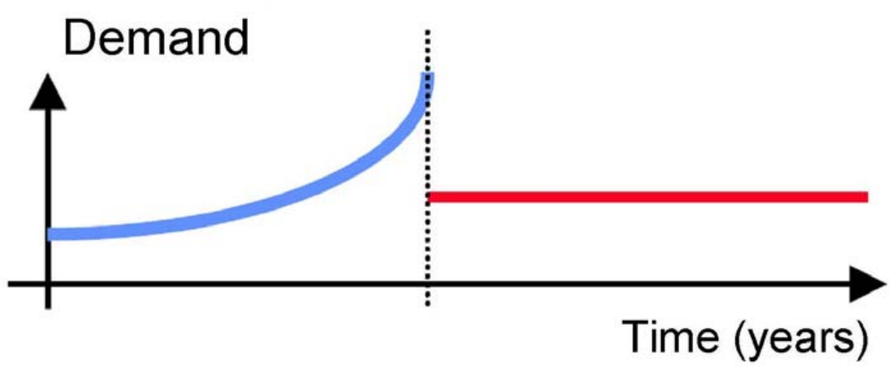


Figure 16: Energy losses computation

Energy losses are computed for the initial year by running a power flow with the given loads and DG. For the following years, it is considered that Joule losses grow proportionally to the square demand whereas iron losses in transformers are kept constant. The evolution of demand over the whole time horizon is estimated as shown in Figure 16. During a number of years, demand increases at a constant rate. However, since uncertainties are greater the further from the initial point we look at, it is deemed

[5] Tiempo de Interrupción Equivalente de la Potencia Instalada
[6] Número de Interrupciones Equivalente de la potencia instalada
[7] System Average Interruption Duration Index
[8] System Average Interruption Frequency Index

reasonable to model demand at a constant level once the maximum demand is reached. This level is set between the maximum level of demand and the initial point.

Data output comprise the amount of elements of each kind built in the optimal network and their extent of use, energy losses (peak capacity and annual energy losses), the continuity of supply indices obtained in each area with the resulting network, and the present value of network costs differentiating between types of costs and network layers, i.e. transforming centres, distribution substations, LV network, MV network or HV network. Additionally, the use of the GIS module enables graphic representation of all towns, street maps, network elements, and network users with their exact geographical location plus information concerning power flows, reliability indices, losses, extent of use, etc.

Incremental model

The incremental model is able compute the costs derived from the connection of new loads and/or DG over a period of time. The flow diagram corresponding to the functioning of the incremental model is provided in Figure 17 Being provided with an initial network and the loads and DG it serves, the incremental model first checks that the given grid is able to cope with the existing demand and builds the optimal reinforcements, if necessary, for the initial situation. Next, the increments in loads and DG are introduced and the required reinforcements computed. The incremental model plans the network expansion for each voltage level minimizing the present value of system costs considering both technical and quality requirements. The objective function includes investments in new network elements and upgrades of existing ones, operation and maintenance costs, and energy losses. The present value is calculated according with the WACC methodology (defined exogenously), being it the same for all cost components.

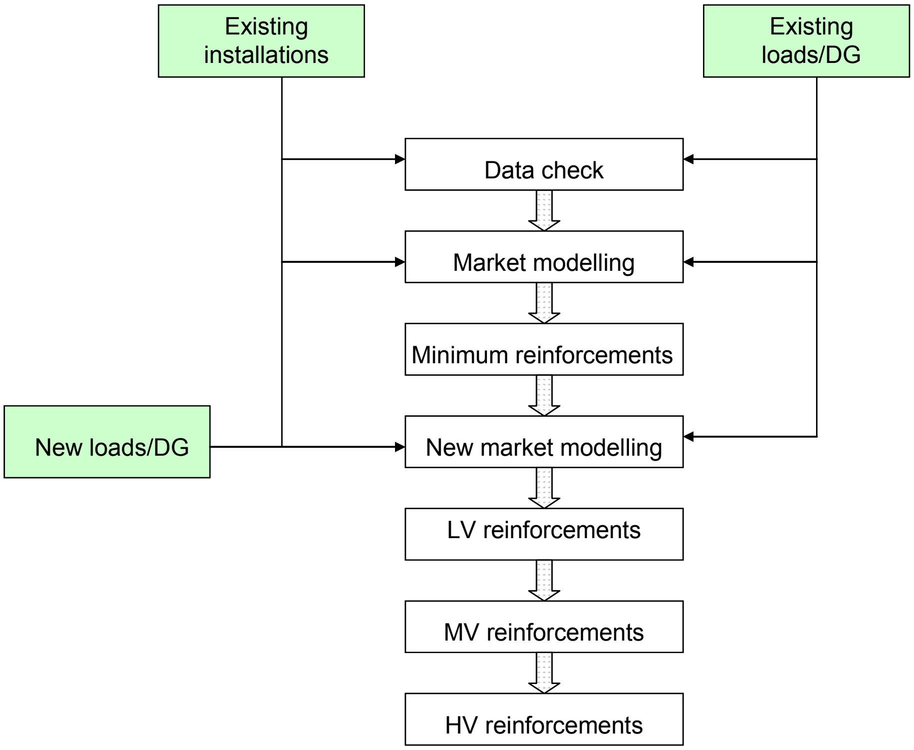


Figure 17: Incremental model flow diagram

The incremental model requires extensive input data, since it must be fed with the same information as the PECO model plus the information about the initial network (including not only the electrical lines but also transformers, protective equipments…), existing loads/DG and incremental (new) loads/DG. Horizontal and vertical increases in loads and/or DG can be considered. Horizontal increases refer to the installation of new consumers or producers in different nodes from any other in the system, whereas vertical increases are changes in the amount of power produced or consumed in nodes where load or generation already existed. It is important to remark that both the real existent grid and a network obtained with the PECO model can be entered as the initial grid when using the incremental model. This might be useful when the companies' inventories are incomplete or untrustworthy. For example, the Spanish regulation states that when LV distribution networks are not properly inventoried, the LV network considered for regulatory purposes will be obtained with the model from scratch.
Additionally, the incremental model includes a GIS module similar to that of the PECO model so as to modify network costs depending on the location of towns, industrial zones, street maps, forbidden areas or orography. Output data consist of the number, type and investments and maintenance costs of former network elements plus minimum reinforcements (those necessary for the initial grid to be able to cope with original demand and generation before considering vertical or horizontal increases) and incremental reinforcements (those caused by new demand and generation), as well as energy losses in both scenarios (before and after the reinforcements have been undertaken). Moreover, the resulting continuity of supply indices are provided. Finally, it is possible to represent graphically all network elements and information about them, as well as power flows and network users.

4.1.2 Algorithm applied within the project

Two reference network models have been described in the previous section. This subsection explains how both models have been jointly used in order to assess the impact of DG on distribution network costs. The actual location of consumers and DG together with their characteristics in each of the distribution areas considered have been provided by DSOs participating in the project. However, the actual network is not considered. A "brand-new" distribution network has been obtained from scratch in order to avoid distortions in the computation of the impact of DG on network costs that are caused by the historical evolution of networks.

Traditionally, distribution networks have been designed and dimensioned according to a peak demand scenario. Energy losses minimization and quality of service related investments were also taken into account. Nonetheless, under significant DG penetration levels, it is necessary to consider two situations that may potentially influence the planning process. Not only will the peak (net) demand situation be considered but also the peak (net) generation one. The terms of scenario and snapshot need to be defined so as to avoid misunderstandings:

- Scenario: Characteristics of demand and DG that already exist, or are likely to exist in the future, in a certain distribution area and that the distribution network in this area must cope with. Hence, a scenario is defined by the level of installed capacity and location of DG and demand.
- Snapshot: Energy consumption and production of loads and DG in a specific situation within a particular scenario.

A scenario, according to this definition, may be comprised of one or more snapshots. Generally, herein two snapshots, i.e. maximum demand-minimum generation and minimum demand-maximum generation, will be analysed for each scenario, e.g. current demand future DG medium penetration. The data used to build the scenarios and representative snapshots have been provided by the DSO in the corresponding country for each case study. Some scenarios have been built considering actual current consumers and DG, whereas others correspond to estimates of demand growth and new DG connections for the year 2020. Forecasts are based on existing applications for connection, consultations with national stakeholders, historical values, etc. Altogether, up to eight scenarios have been analysed for every case study corresponding to combinations of two levels of demand (current and future) and four DG penetration levels (no DG, current DG, future DG medium and future DG high). Overall, results were obtained for at least 14 snapshots per case study (the scenarios without DG did not require to analyse the maximum net generation snapshot).

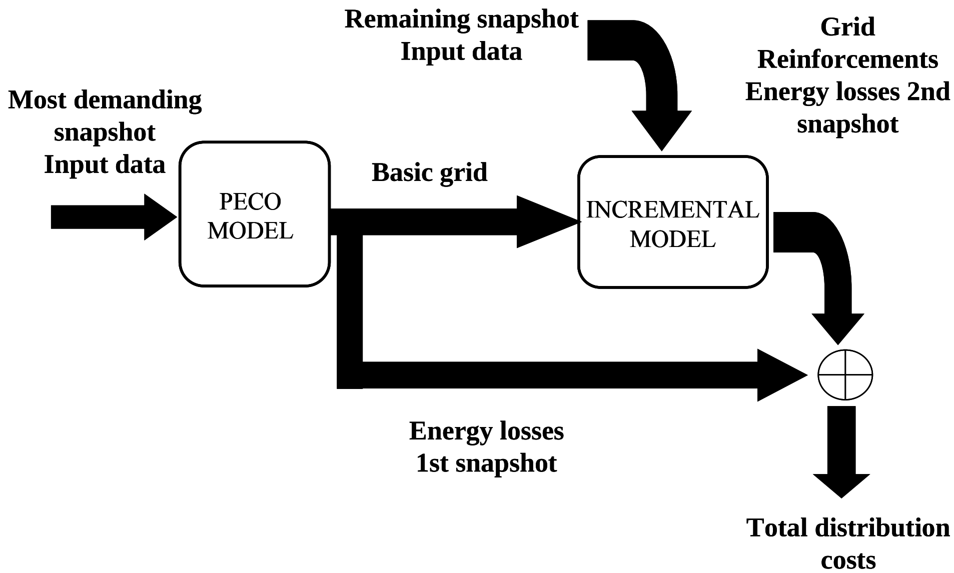


Figure 18: Methodology to assess the impact of DG on distribution network costs

Firstly, the most demanding scenario must be identified. This is the most relevant to define the network topology. Then, the minimum cost network able to cope with the flows in this snapshot is computed with the from-scratch model. The network obtained in the previous step is then fed into the incremental model together with the demand and DG data corresponding to the remaining snapshot. The minimum cost grid reinforcements needed to cope with this second snapshot are determined. Thus, it is ensured that the distribution network resulting from this process is able to cope with any situation that may take place under any particular set of conditions of load and DG. The outputs from both models are combined in order to calculate total distribution network costs. Investment costs are the sum of those of the initial network and the reinforcements. Maintenance costs are directly obtained as those associated with the computed network investments. Finally, energy losses over the planning horizon are computed by taking into account the power losses occurring in the two snapshots considered. Energy losses can only be roughly estimated due to the great uncertainties that exist about the behaviour of demand over a number of years. However, it is a relevant cost factor that cannot be neglected. This process is graphically depicted in Figure 18.

For the German and Dutch case studies, where DG penetration levels reach very high values, the network was computed from scratch with the two models previously described for each one of the scenarios considered. However, in the Spanish case a different approach was deemed necessary. Given that in the Spanish case DG penetration was much lower, the impact of DG on network costs was comparatively less important. Hence, results could be distorted by the fact that the models used provide quasi optimal, albeit not optimal, solutions. The discrete nature of decisions and the use of heuristic algorithms (note that the models can be applied to very large systems) could distort the computation of the cost impact of DG in the Spanish case. Therefore, an initial network was obtained from scratch for each level of demand while DG/RES in the system was deemed to be zero. Costs caused by the connection of DG in each scenario were computed, using the incremental model, as those corresponding to the reinforcements to the peak-demand-no-DG network that were caused by DG.

This methodology was deemed adequate and has yielded reasonable results for assessing the impact of DG on distribution network costs in real situations. Its main characteristics are listed below:

- Reference network models are able to compute distribution costs for very large problems adding up to millions of customers.
- Building a network from scratch avoids considering the effect of historical network evolution or the existence of surplus assets.
- The influence on costs of different levels of DG for a given level of demand as well as that of changes in the level of demand for the same DG production level has been assessed.
- The characteristics of the three case studies differ significantly among them, thus enabling us to study the impact of DG in different kinds of distribution networks:
    - In The Netherlands, we have considered a rural/sub-urban area with underground cables and DG connected at HV and MV levels.
    - In Germany, we have considered a residential area with underground cables and DG connected at LV level within households.

In Spain, we have considered a suburban area with both underground cables and overhead lines and DG connected at HV and MV levels.

4.2 Other cost components and computation of total costs

4.2.1 Generation costs

We deploy the electricity market simulation model of ECN, COMPETES[9], for the calculation of the impact of DG/RES on overall generation cost for the set of areas and scenarios considered in the study.[10] The model represents the complete EU electricity market, including all electricity generation units per country and taking into account the interconnections between the different countries. All electricity generation technologies present in a certain country are explicitly modeled. Hence, the complete electricity generation mix in the EU is covered. For each unit the marginal cost of producing electricity is set as a model input. This includes the fuel cost, the operation and maintenance cost, and the cost of CO_2 emissions on an €/MWh basis. The model can solve the equilibrium result for the electricity price level, total demand and production and the level of international electricity exchange. This study assumes perfect competition. That is to say, ranking the marginal cost per generation unit and its associated production capacity, an electricity supply curve is constructed on a country by country basis. Given an electricity demand curve for each country, the model calculates the optimal price and demand levels. Optimal here refers to social optimal levels: the level at which overall market welfare (being the total of consumer and producer surplus) is maximized. Network capacity between countries is accounted for. Figure 19 illustrates the computation of the optimal price level and associated amount demand and production.

[9] Journal publications documenting COMPETES and its applications to market coupling, transmission management and investment, and climate policy include (Hobbs et al, 2008; Hobbs and Rickers, 2004; Hobbs et al, 2005; Hobbs et al, 2004; Lise et al, 2008; Neuhoff et al, 2005). Additional applications are documented in (Wals et al, 2004).
[10] Appendix 2 contains a more elaborate description of the model.

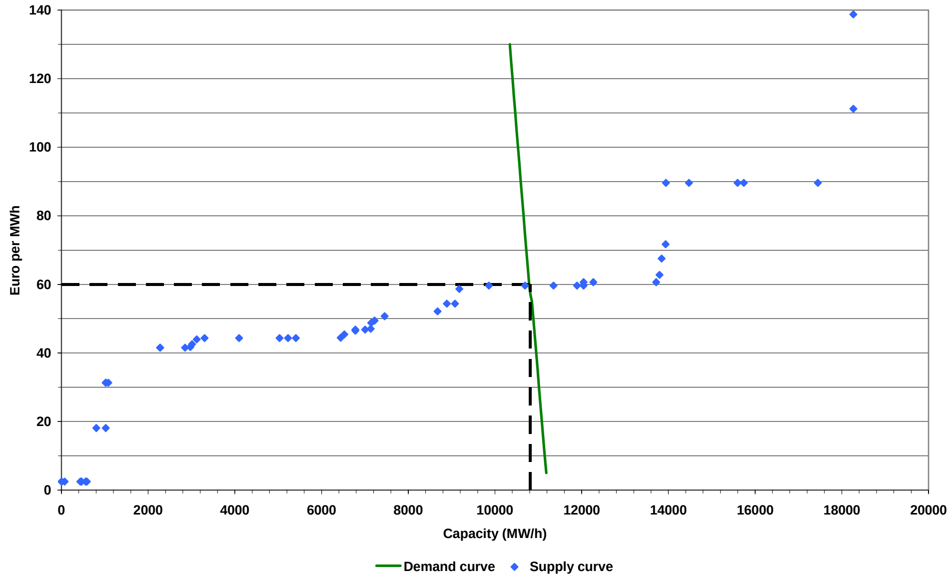


Figure 19: Illustration of demand and supply curves for the case of the Netherlands (source: ECN)

The blue dots represent the electricity supply curve for the Netherlands, where each individual dot represents a different electricity generating unit. Here the Netherlands is taken as an example, but such a figure could be constructed for any other EU country included in the model. The depicted demand and supply curve can be interpreted as an average for a whole year. In reality, both the demand and supply of electricity can vary over hours of the day, month or season. Although the model used in the analysis has also provided specific results for a set of snapshots representing different hours of the year, we focus on the presentation and reporting of total yearly values. In the illustrative examples we mainly use average values representing for example average hourly demand and supply curves. As can be seen in the above figure, each generating unit has its own distinct variable cost of producing electricity. The green demand curve represents the current average hourly demand for electricity in the Netherlands. The model confronts the demand curve with the electricity supply, taking into account the demand and supply curve in other electricity systems and the ability to exchange electricity between countries, and finds the optimal electricity price. In this example, the equilibrium price is about €60 per MWh while average hourly demand is about 11 GWh. In this optimal situation, the total variable cost of electricity generation in the Netherlands is represented by the surface below the blue dotted supply curve. This is shown in Figure 20.

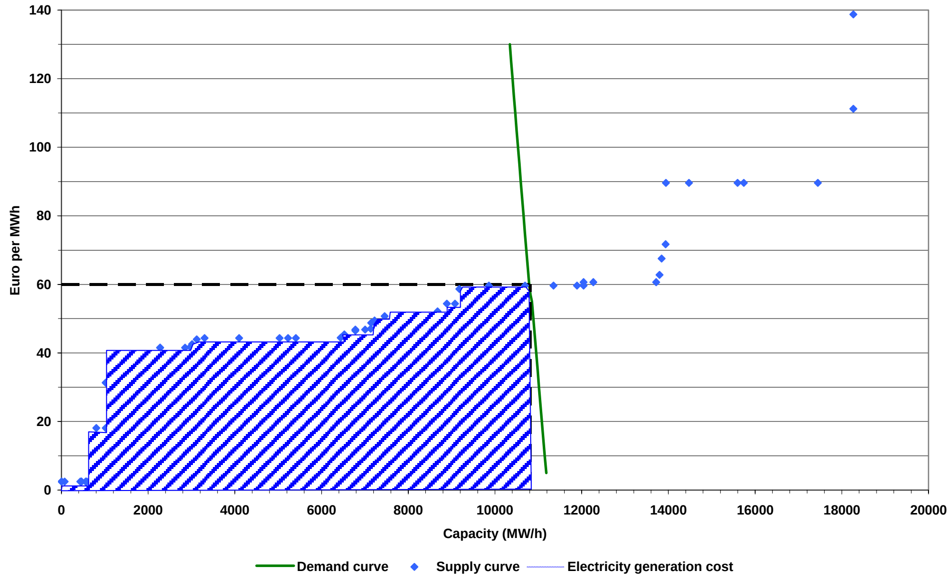


Figure 20: Illustration of total variable electricity generation cost for electricity producers (source: ECN)

4.2.1.1 Calculating the variable generation cost impact

The penetration of DG/RES into electricity systems implies that new electricity generation units with particular marginal electricity generation costs are added to the existing electricity generation mix, i.e. are added to the electricity supply curve. This causes the electricity supply curve to shift rightward. This is illustrated in Figure 21, where the supply curve for the Dutch electricity system is shown for two different amounts of DG/RES in the Dutch case study area. One supply curve represents stage 1, where no DG/RES is present in the case study area at all, whereas the other supply curve represents stage 4, where about 1400 MW of DG/RES have been installed in the case study area. Hence, the supply curve shifts to the right with an amount of 1600 MWe of installed, capacity[11].

[11] This amounts to about 790 MWh of additional electricity production.

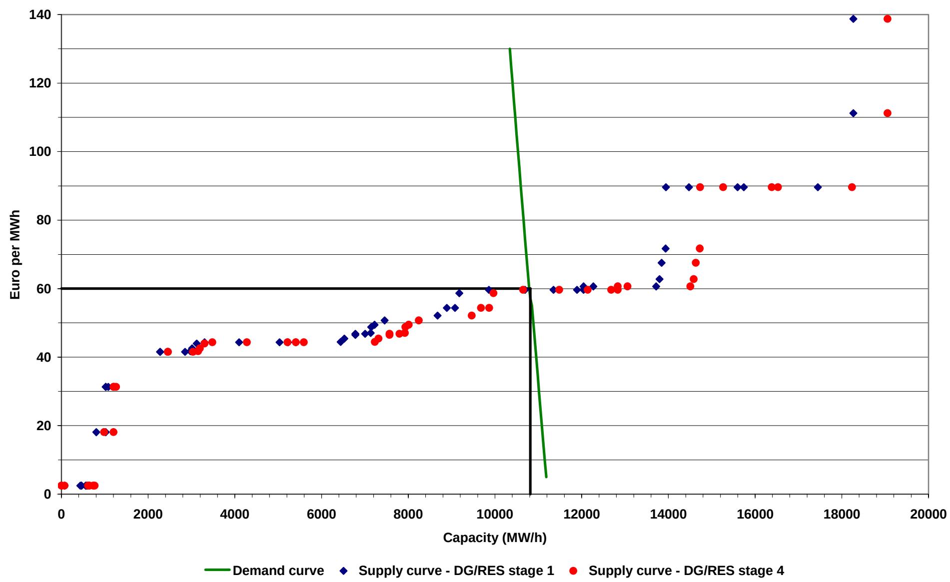


Figure 21: Illustration of a shift in the Dutch electricity supply curve due to the integration of an additional 1600 MW in the case study area (source: ECN)

Due to the shift in the supply curve, the total cost incurred by electricity producers is changing. In fact, total generation costs decrease since cheaper wind turbines (i.e. no fuel cost) have been added to the electricity generation mix. This change in variable generation costs can be attributed to the integration of about 1600 MW of DG/RES in the Dutch case study area. An indirect variable generation cost impact of this integration takes place outside the Dutch electricity system: a shift in the national electricity generation mix can cause a change in the electricity supply and demand situation in neighbouring electricity systems as well. Therefore, we assess the change of the total variable generation costs for all EU member states instead of the change in national variable generation costs.

4.2.1.2 Calculating the fixed generation cost impact

With fixed generation costs we refer to the cost of capital invested in generation assets. We adopt a levelised investment cost approach in order to obtain the fixed generation cost impact of DG/RES integration in electricity systems. This means that we derive a fixed generation cost expressed in € per produced electricity unit from a number of input parameters concerning investment.[12] Below we mathematically show how we calculate the fixed generation cost per technology expressed in € per produced MWh. The input data assumptions with respect to the calculation of the fixed generation costs are given in Appendix 2.

$$Fixed\ \ generation\ \ \cos t\ \ (€/MWh) = \frac{1000\ x\ investment\ \ \cos t\ \ (€/kW)}{\left(economic\ \ lifetime\ \ (years)\ \ x\ \ \left(capacity\ \ factor\ \ x\ \ 8760\right)\right)}$$

[12] The sum of the variable generation cost and the fixed generation cost can be interpreted as the long-rum marginal cost of producing electricity.

Output of the Competes model includes the actual electricity production level for each technology in each EU member state. For example, the model explicitly provides the total amount of electricity produced by CCGT, wind turbines, CHP units etcetera within the EU. By comparing different DG/RES situations with different electricity supply curves and different levels of electricity prices and electricity production, we obtain the incremental changes in electricity production per technology. For example, in one of the considered scenarios for the case of the Netherlands, the increase in the amount of DG/RES in the case study area from 0 MW to about 1600 MW results in an increase in the total amount of wind-based electricity generation and an decrease in the amount of CCGT-based electricity generation. Wind-based electricity production increases in about 1200 GWh per year, while CCGT-based electricity generation decreases in about 800 GWh per year.[13] Obviously, the *increase* in electricity production from a certain technology requires an investment in this type of technology at a specific moment in time. By multiplying the incremental change in technology specific electricity production with the fixed generation cost indicator we obtain an estimate for the investment cost for that technology. A *decrease* in the amount of electricity produced by a certain technology can be associated with an avoided investment in this technology. By multiplying the increment change in the electricity produced by that technology with the fixed generation cost indicator for that technology we obtain an avoided investment cost. By taking together the total estimates for the additional required investment costs and the total estimates for the avoided investment costs we obtain an estimate for the overall fixed generation cost impact that emerges due to the increasing penetration of DG/RES in the case study area. This result can be expressed in million euros per year or can be related to the amount of DG/RES that initiated this cost impact. In the latter case we obtain a fixed generation cost impact in terms of euro per additionally installed kW of DG/RES capacity per year. Note that the fixed generation cost impact, as well as the earlier described variable generation cost impact are computed for the whole European electricity system. Although it is likely that the largest impact of DG/RES penetration in a area within a country has the largest impact on generation costs within that country, it is also likely that the electricity generation dispatch in neighboring electricity systems is affected through the change in exchange electricity flows.

4.2.1.3 Additional storyline

For the computations of the generation cost impact we have analyzed an additional storyline compared to the storylines presented in section 2. In Table 15, the three analyzed storylines are presented.

Table 15: Overview of storylines

Electricity system element	**Storyline** **'Current electricity system: 2008'**	**'Future electricity system: 2020'**	**'Future electricity system: 2020 with low prices'**
Electricity generation mix in the area	• Electricity generation mix in 2008	• Estimated electricity generation mix in 2020, with more efficient technologies	

[13] Note that more technologies show an increase or decrease in yearly electricity production due to the increased amount of DG/RES within the system. Since this is only an example we highlight two specific technologies here.

Electricity demand	• Electricity demand level in 2008 (both at case study and country level, with location specific load in case study area)	• Estimated electricity demand level in 2020 (both at case study and country level, with location specific load in case study area)	
Investment cost	• Current level of investment cost in electricity generation assets	• Estimated 2020 level of investment cost in electricity generation assets	
Fuel prices	• Fuels prices as observed in 2006[14]	• Estimated fuel prices for 2008	• Fuels prices as observed in 2006[15]
Price of CO_2 emission rights	• Current level of CO_2 emission rights	• Assumed 2020 level of CO_2 emission rights	• Current level of CO_2 emission rights

The third storyline is based on the future electricity system storyline but assumes a lower fuel price and a lower price for CO_2 emission rights. To be more precise, it assumes fuel and CO_2 emission rights prices in 2020 to be at the level of 2008, the first storyline. In short, the third storyline is a mixture of the storylines for the current electricity system (2008) and the future electricity system (2020). The inclusion of this third storyline was deemed necessary due to the possible sensitivity of generation cost impact results to changes in the fuel price and the price of CO_2 emission rights.

4.2.2 Balancing costs

Our analysis is based on the one performed in GreenNet and makes use of information obtained from existing bibliography about the computation of balancing costs. Various sources of information have been consulted. Finally, we have decided to consider the estimation of balancing costs produced by Holttinen et al. in (Holttinen et al., 2008). Balancing costs caused by DG/RES are here assumed to be solely associated to wind production. The contribution of other types of DG/RES to balancing costs (solar, CHP, etc.) is deemed to be negligible, since the output of generators using these technologies is thought to be either controllable (CHP) or, at least, predictable in the short term with some level of accuracy (solar).

Balancing cost per MWh of wind generation

Figure 22, which has been obtained from the study carried out in (Holttinen et al., 2008), provides an estimation of balancing costs caused by wind power in three different types of areas:

1. Highly flexible areas (in dark green, labelled ‘Low’): those that have a vast amount of economical resources to balance of sudden and/or unexpected changes of wind production.

[14] We have used 2006 fuel price levels since 2008 fuel price levels were not yet fully available at the time of computing the results.

[15] We have used 2006 fuel price levels since 2008 fuel price levels were not yet fully available at the time of computing the results.

2. Partially flexible areas (labelled 'Average'): those that have some resources to respond to sudden and/or unexpected changes in wind output.
3. Inflexible areas (in pale green, labelled 'High'): those that have few resources to cope with wind output excursions and unpredicted changes.

Balancing costs in Figure 22 are expressed as unit costs per MWh of wind energy produced in each type of area. These unit costs correspond to each year of operation (they are annual figures) and depend on the wind penetration level expressed as the ratio of wind capacity to peak demand in the corresponding system. The three curves illustrated in this figure allow one to determine the bandwidth of balancing costs, which coincide with those provided within (Holttinen et al., 2008). For high wind shares, specific unit costs range between 1 and 5.5 €/MWh of wind energy produced. It should be noted that curves reflect balancing costs based on results of the system analysis. Imbalance charges (prices) in real systems may –depending on the market design and system characteristics – be significantly higher.

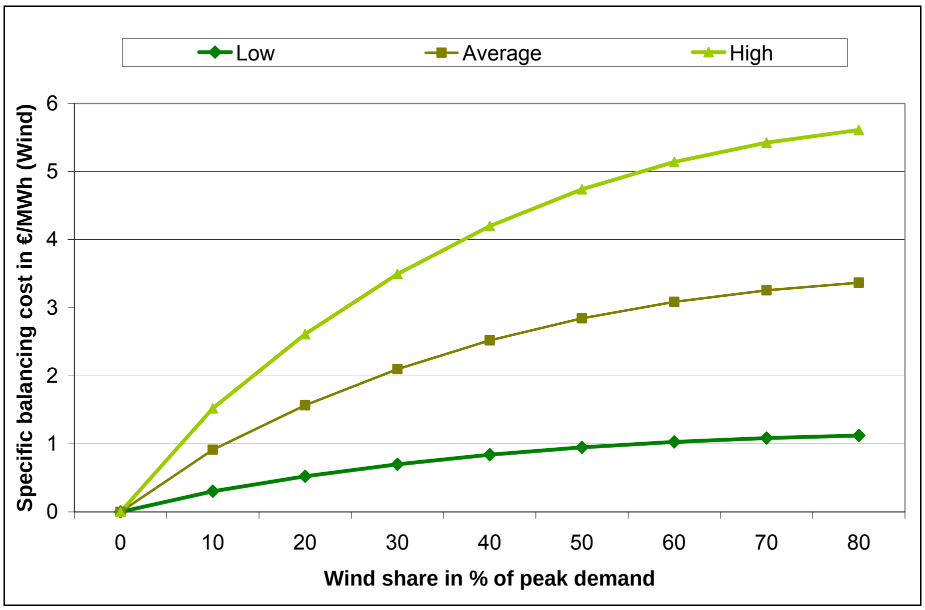


Figure 22: Balancing cost per MWh of wind generation as a function of national installed wind capacity as percentage of national peak electricity demand for three levels of flexibility in electricity generation. Model implementation of balancing costs of wind power in GreenNet based on a comparison of study results in Holttinen et al. (2008)

In order to compute balancing costs for each of the 3 case study areas considered in the IMPROGRES project, according to the methodology that has just been outlined, first of all we must determine the flexibility level of each of these areas. Germany has been deemed to be a system with low flexibility ('high' balancing cost scenario). This is due to the fact that interconnection capacity of the German system with neighbouring areas is not remarkably high and generation resources in Germany, apart from wind, mainly are conventional thermal (not very flexible) plants. Therefore, when computing balancing cost for the German area, one must consider the pale green cost curve in Figure 22, labelled 'High'. On the other hand, the Spanish and the Dutch systems are deemed to have a medium level of flexibility. Spain is largely isolated from the rest of Europe but it has significant water resources (though this depends on the amount of water reserves available in the system, which varies much from one year to another). The Netherlands is highly interconnected to the rest of Europe and has a large share of relatively flexible gas-fired power plants. Therefore, when computing balancing costs for the

Spanish and Dutch areas we should focus on the 'Average' cost curve. In any case, the amount of wind capacity installed, now or in the future, in the considered German area is null. Thus, impact on balancing costs of RES/DG generation in this area has been deemed to be zero.

From cost per MWh wind generation to cost per installed kW DG

Once we know the balancing cost curve to use for the country that each area a is located within, among the three ones available, we must determine the penetration level of wind in this country for each of the scenarios considered s. Balancing costs are incurred at country level, since deviations of wind farms from their scheduled output may be balanced by any other unit in the system. Therefore, scenarios relevant to compute the unit impact of wind in an area on balancing costs are national scenarios, instead of scenarios that refer to the considered area. Scenarios differ both in the level of demand existing in the country (current or future load) and in the amount of wind capacity installed at national level (current level of wind capacity and future levels both in the low and in the high penetration scenarios). Thus, the wind penetration level for each country c and scenario s, $LWP_{c,s}$, can be expressed as:

$$LWP_{c,s} = \frac{WPI_{c,s}}{PL_{c,s}}$$

where $PL_{c,s}$ and $WPI_{c,s}$ are the level of peak demand and the amount of wind power installed in area c and scenario s, respectively.

From the wind share expressed as a percentage of peak demand in the country, and knowing the balancing cost curve to use, or the mathematical expression relating the national wind penetration rate and the unit balancing cost of wind that should be considered, one can easily obtain the unit balancing cost per MWh of wind energy produced in each area a of country c and for each scenario s as:

$$UBC^{e}{}_{a,s} = f_{flex\_type}(LWP_{c,s})$$

Taking into account the unit balancing cost per MWh of wind power produced in each area a and scenario s, $UBC^{e}{}_{a,s}$, as well as the total annual wind production in this area for this same scenario, $WP_{a,s}$, one can compute the total balancing cost in area a for scenario s as:

$$TBC_{a,s} = UBC^{e}{}_{a,s} \bullet WP_{a,s}$$

Lastly, dividing the total balancing cost in area a and scenario s by the RES generation capacity installed locally, $RPI_{a,s}$, one can compute the unit balancing cost per MW of installed RES capacity, $UBC^{c}{}_{a,s}$. Given that balancing costs provided in cost curves in Figure 22 are annual, unit cost so computed would be annual as well.

$$UBC^{c}{}_{a,s} = \frac{TBC_{a,s}}{RPI_{a,s}}$$

Thus, we could compute annual unit balancing costs per capacity installed for each of the considered scenarios and could represent the potential evolution of these costs with the DG/RES penetration level for each level of demand.

4.2.3 Transmission network costs

The deployment of large shares of DG/RES may probably have an impact on the development of the electricity transmission network. Thus, the net demand to be supplied within each of the three distribution areas considered in the project is affected by the amount of energy produced within these areas. Effects of DG/RES on transmission costs may be of two types.

1. As a consequence of the change in the balance between generation and demand in each area, flows in the main transmission system also change. Therefore, reinforcements to the main transmission grid that are required will also change because of the installation of DG.
2. Given that the net amount of power to be supplied to each area (respectively shipped from this area to others) changes with the level of DG penetration, reinforcements to the grid required to connect this area to the rest of the system shall also change. Thus, if the peak absolute value of the net demand in the area increases, connection capacity required will be larger. On the other hand, if the peak absolute value of the net demand decreases, less interconnection capacity that initially expected will be required.

Reinforcements of type 1 have not been assessed within our analysis because we did not have available the tools required, nor the necessary data, to perform the corresponding computations, which would have to consider a network model the whole interconnected EU system. On the other hand, some rough estimate of the reinforcements required to connect the distribution area to the rest of the system was obtained in those cases where these reinforcements were deemed to be important enough. Since only in the Dutch area the penetration level of DG was high enough to significantly affect the peak net demand (or generation) in the corresponding area, we focused our analysis on the Kop van Noord Holland area. Computations in this regard that have been included in our document were carried out by the DSO in this area (Liander).

4.2.4 External costs

External cost refers to those costs of electricity generation that are not borne by actors in the electricity market (i.e. electricity producers, consumers, network operators etc). Although the external costs are not represented by an actual financial flow in the electricity system we think it is important to include this cost impact in our analysis of the total costs (and benefits) of integrating DG/RES in the electricity system since environmental concerns are an important driver for the realization of more DG/RES-based electricity generation. Below we briefly describe our approach in computing the external cost impact. It is important to note that

In our definition, the external costs concern the environmental impact of electricity production, excluding the external costs of CO_2 emissions since the CO_2 impact of electricity production has been included in the generation costs. The underlying assumption behind this approach is the assumption that the price for CO_2 emission rights fully reflects the environmental damage caused by CO_2 emissions. If we would include the negative impact of CO_2 emissions in the external costs as well we would be double-counting. External costs considered here do not only relate to the corresponding damaging emissions of electricity generation units, such as NO_x emissions, but also to the emissions that have been emitted earlier in the value chain. For example, the external costs of producing and

transporting gas from a gas field to a gas-fired power plant are included in the external cost of gas-fired electricity generation.
In order to compute the impact of DG/RES on external costs we have used external cost indicators that have been identified for different electricity generation technologies. The indicators are based on (Kuik, 2007) and own calculations, where the indicators computed by Kuik indicators are based on the ExternE methodology. Table 16 presents the computed external cost indicators.

Table 16: external cost indicators for different technologies and CO2 prices (source: Kuik 2007, own calculations)

	CO_2 price assumption	
Technology	**€20/ton CO_2 [€ / MWh]**	**€50/ton CO_2 [€ / MWh]**
Nuclear	1,68	1,68
Coal (pulverised)	10,16	15,15
Coal-CCS	14,08	17,28
Gas	1,43	1,67
Gas-CCS	1,70	1,96
Wind offshore	0,55	0,55
Wind onshore	0,99	0,99
PV	3,89	6,11
CHP	0,96	1,11
Micro CHP	0,96	1,11
Waste refusal	0,99	0,99

As has been explained earlier when discussing the approach used in computing the generation cost impact, the electricity market model Competes provides detailed information on the amount of electricity production per electricity generation technology in every DG/RES penetration case. For each of the four stages of DG/RES integration we have computed the optimal level of electricity production, with separated data on the electricity generation per technology. Since all other system conditions, apart from the amount of DG/RES, have been identified within the storyline, we infer that all changes in the total amount of electricity production per technology are indirectly caused by the increased penetration of DG/RES in the electricity system. By calculating the incremental change in electricity production from the one DG/RES integration stage to the next for each generation technology and multiplying this figure with the external cost indicator we obtain an external cost impact estimate for each electricity generation technology. Summing these results across all generation technologies provides an estimate for the overall impact of integrating more and more DG/RES in the electricity system on the costs of externalities, i.e. the environmental impact.

4.2.5 Social welfare

The term social welfare originates from welfare economics and represents the total of consumer surplus and producer surplus, where the latter can also be referred to as producer profits. Below we explain the concepts of consumer surplus and producer surplus by using an example based on actual results.

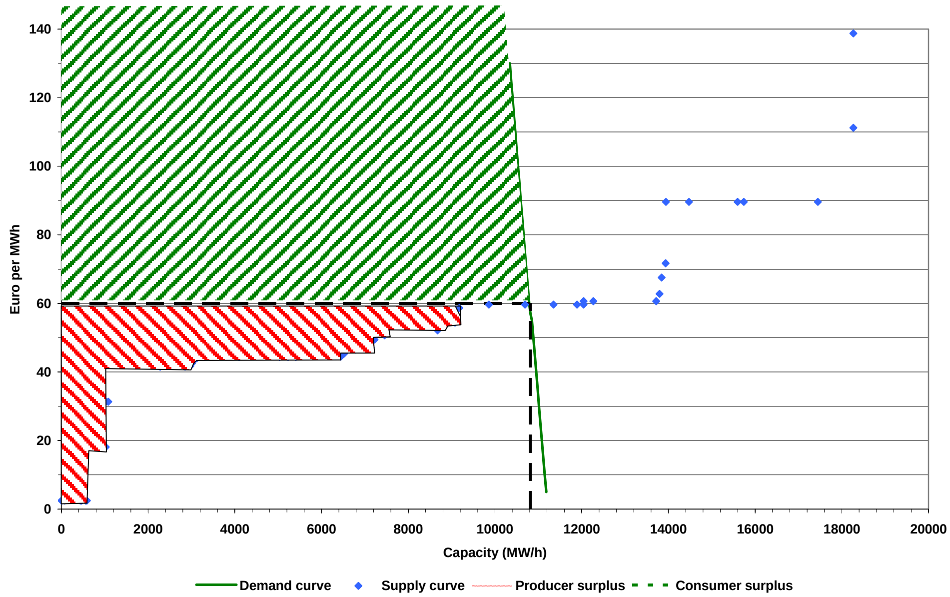


Figure 23: Illustration of the concepts of consumer and producer surplus for the case of the Netherlands (source: ECN)

The producer surplus is also known as the total profit for electricity producers and computed as the difference between the variable generation costs incurred by electricity producers for each unit of electricity produced on the one hand, and the revenue (i.e. the electricity market price) received for each produced unit of electricity. The total of electricity producer profits is graphically represented by the red marked area in Figure 23. Note that the basic demand and supply curves reflect a marginal analysis: it presents the consumers' willingness to pay and producers' willingness to accept costs of electricity production for additional units of electricity. In this general demand and supply framework, the electricity supply curve is only based on the variable generation costs. This means that the fixed generation costs are not included in the figure. In reality off course, also the investment costs of generation need to be covered by total electricity revenues. Ideally, total producer profits sufficiently cover these investment costs.

The concept of consumer surplus is technically defined as being the difference between the consumers' valuation for every unit of electricity consumed (i.e. the willingness of people to pay for the consumption of one unit of electricity) and the actual cost of every unit of electricity consumed (i.e. the electricity market price). In Figure 23, which depicts, for the considered case example, the electricity supply curve, the demand curve and the equilibrium price and electricity production level, the total amount of consumer surplus is indicated by the green marked area. The concept of consumer surplus is relatively more difficult to grasp than the concept of electricity producer profits since it does not reflect an actual financial flow in the electricity system. Due to a measurement problem, it is a more difficult indicator in its application in practice. For example, it is difficult to obtain the people's actual willingness to pay for electricity consumption. It is therefore difficult to construct the actual demand curve for electricity. Although a specific valuation, i.e. electricity demand curve may be assumed, the total amount of consumer surplus is then bound to be sensitive to the actual elasticity of demand assumed. In the graphical example this is reflected in the slope of the demand curve. When the demand curve is much flatter (less steep) the total level of consumer surplus will turn out much lower. However, due to our overall methodology based on an analysis of *incremental* changes, caused by integrating more and more DG/RES, in electricity system components we think that it is useful to use both producer profits as well as consumer surplus in our analysis. This can be explained with the figure below.

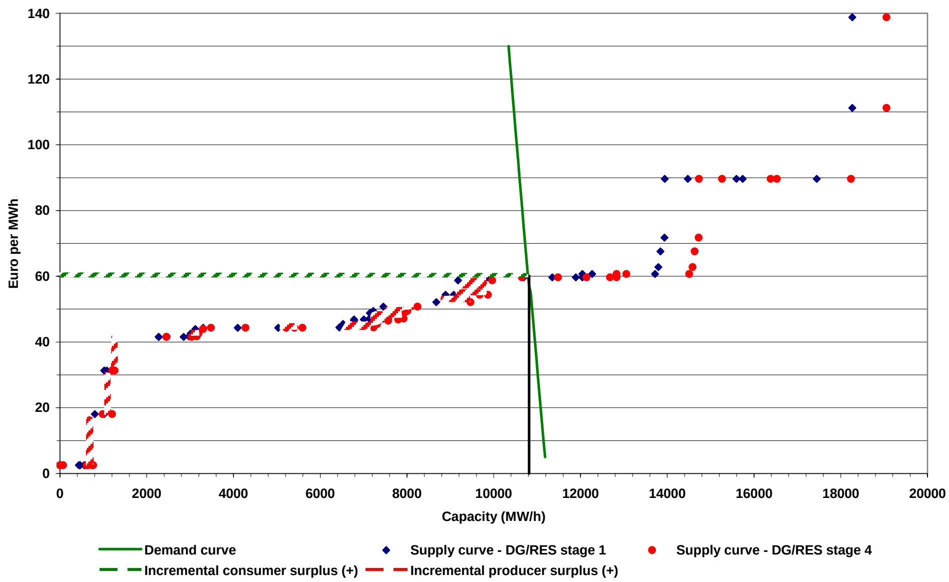


Figure 24: Illustration of the incremental impact of DG/RES penetration on consumer and producer surplus for the case of the Netherlands (source: ECN)

Figure 24 contains the electricity supply curves for two stages of DG/RES penetration in the case study area in the Netherlands. The electricity supply curve for stage 1 represents the Dutch electricity supply curve in the case where no DG/RES is present in the Dutch case study area, whereas the electricity curve for stage 2 represents the Dutch electricity supply curve where about 1600 MW of DG/RES is integrated in the Dutch case study area. Due to the penetration of electricity generation with low variable costs (e.g. wind-based generation), the electricity supply curve shifts rightward. This integration of 1600 MW has an impact on both the consumer and producer surplus. The producer surplus is increased. This is indicated by the red marked areas. As a result of the integration of relatively low-cost generation technologies, the total generation costs for electricity producers decreases. Together with the fact that in this particular case for the Netherlands the electricity market price is hardly affected by the increase in DG/RES, the producer profits increase. This increase in producer profits is more or less equal in size to the decrease in generation costs. In the case of the Netherlands the increase in 1600 MW DG/RES leads, according to our results, to a very small decrease in the electricity market price. This gives rise to a small increase in total consumer surplus, as indicated by the green marked area in the figure. As it can be seen from this illustrative example, the incremental value change in total consumer surplus is less prone to different assumptions with respect to price elasticity of demand (i.e. the relative steepness of the demand curve) than the absolute value of total consumer surplus.
All in all, we like to assess the impact of DG/RES penetration on social welfare, so both consumer and producer surplus. We note that the interpretation of the concept of producer surplus is more straightforward than that of consumer surplus. Nevertheless, by focussing on incremental changes

instead of absolute value we believe that valuable insights can be gained with respect to the impact of DG/RES penetration on electricity systems from a social perspective. We will however be careful in comparing results for the impact on social welfare with results for the impact on the more technical cost components such as distribution network cost and balancing cost.
The results for the social welfare impact of DG/RES penetration are again provided by the Competes model. Given that the total value for producer profits and consumer surplus for the whole European electricity system are provided by the model for every stage of DG/RES integration in the three different case study areas, we can compute the incremental impact on both indicators in a straightforward manner.

4.2.6 Correcting for the capacity credit of DG/RES

An important element in calculations on electricity system cost impacts due to the increasing penetration of DG/RES, more in particular non- or less controllable DG/RES such as wind and CHP, is the capacity credit. This is related to maintaining generation adequacy in the face of larger amounts of wind-based electricity generation being part of the overall generation mix. This has been accounted for in the calculations of the variable generation costs, fixed generation costs, external cost, consumer surplus and producer surplus.
For the fixed generation cost impact calculations, we rely on the detailed data provided by the COMPETES model runs. Model results provide data on the change in the deployment of electricity generation units in the different DG/RES penetration stages. By linking this detailed information to levelized yearly investment costs we obtain the fixed generation cost impact. By taking into account the impact of additional DG/RES on generation from each of the different power plant types, a more precise determination of the impact takes place compared to a single capacity credit figure.
Ideally, the correction of the other cost components calculated with the Competes model outputs (variable generation costs, external costs, consumer surplus and producer surplus) should be based on additional model runs. As stated above, in the performed model runs exact information is obtained on the type of units that change their deployment as a result of the additional DG/RES capacity entering the market. For the units that witness a negative change in deployment (i.e. they no longer producer electricity, or produce electricity during less hours of the year) it could be assumed that these units will not be invested-in in the first place, or will be taken out of service prematurely. This could be simulated in new model runs where these units are taken out of the generation capacity mix. This would result in cost impacts for variable generation costs, external costs, consumer surplus and producer surplus that have a link with the figures acquired in the first set of model runs, with the difference being related to the capacity credit of the no- or less controllable DG/RES technologies. In fact, the 'second-round' results would have to be scaled-down compared with the first-round results. In the research reported on in this report, performing a second set of model runs proved not to be feasible due to resource limitations. As a second-best approach, the results acquired in the first set of model runs have been corrected for the capacity credit in the following manner. We have used individual country and technology specific capacity credits (where possible) to obtain a weighted average capacity credit for each DG/RES penetration stage. This implies that the weighing has been based on the actual amount of new DG/RES capacity added in the case study area. The obtained capacity credit then varies over the DG/RES penetration stages and is used as a scaling factor to correct the first-round results on variable generation costs, external costs, consumer surplus and producer surplus. Table 17 presents the assumed capacity credit ratios for each DG/RES technology for the different case study areas.

Table 17: Overview of assumed capacity credit values (source: Greennet (EEG), ECN)

Technology	Case study area					
	Spain		The Netherlands		Germany	
	2008 electricity system	2020 electricity system	2008 electricity system	2020 electricity system	2008 electricity system	2020 electricity system
Wind	22%	17%	16%	12%	9%	7%
CHP	60%	60%	60%	60%	-	-
Micro-CHP	-	-	-	-	35%	35%
PV	0%	0%	-	-	0%	0%

4.2.7 Total system costs

In this report we firstly assess and present the different impacts of increasing DG/RES penetration on an individual basis. However, at the same time we aim to get an understanding of the overall social impact, taking all separated impacts together. Table 18 lists the different type of impacts analyzed in this report. When assessing the overall impact of DG/RES integration, we provide first the impact on the overall supply cost, without taking into account the impact of DG/RES on the amount of demand served. Then we provide the overall socio-economic impact of DG/RES taking into account social welfare of consumers and generators in the dispatch and how it changes as a result of the introduction of DG/RES. Reasons for this distinction are the inherent nature and the approach used in computing the different components. Especially, the interpretation of the impact of DG/RES penetration on consumer surplus led us to adopt this approach. For each of the case study areas we discuss the two perspectives.

Table 18: Allocation of costs and benefits of DG/RES integration

Cost category	Actor(s) affected	Perspective	
		Supply cost	Socio-economic
Distribution network cost	DSO	√	√
Transmission network cost	TSO	√	√
Generation cost	Electricity producers	√	
Balancing cost	Electricity producers[16]	√	√
External cost	Society (citizens)	√	√
Producer surplus (dispatch)	Electricity producers		√
Consumer surplus (dispatch)	Electricity consumers		√

[16] In some countries, some electricity producers are not responsible for balancing costs. Here we actually refer to all actors that are considered to be programme responsible parties.

4.2.7.1 Computation of the impact of DG/RES in each area on the overall supply cost

This section discusses the computation of the impact on the total supply cost of integrating the DG/RES that exists in each area. This total supply costs includes all cost components in the energy supply chain: generation (fixed and variable costs), transmission, distribution, balancing and external costs. Thus, computing the change in total supply costs caused by DG/RES bolts down to adding up all these cost components in two situations, with and without DG/RES in the considered area, and, then, determining the difference between the aggregate costs in both cases.

In other words, the impact of DG/RES on supply costs can be computed according to the following expression:

$$\Delta SupC = \Delta VGC + \Delta CGC + \Delta DC + \Delta BC + \Delta EC$$

where $\Delta SupC$ stands for increase in the supply cost, ΔVGC represents the increase in variable generation costs, ΔCGC stands for increase in capital generation costs, ΔDC for increase in distribution costs, ΔBC for increase in balancing costs and ΔEC for increase in external costs

4.2.7.2 Computation of the socio economic impact of DG/Res in each area

When computing the global socio-economic impact of DG/RES, one should consider, in one way or another, all the cost components and benefits that have been discussed previously. Distribution, balancing, external and fixed generation costs must each be considered on their own in the computation of the total system cost impact of DG because they relate to costs that are not accounted for by any other cost component. On the other hand, the impact on variable generation costs is very much related to that on the profits made by consumers and producers in the dispatch. Thus, their inclusion in the computation of the total system costs DG impact must be carefully considered.

In a liberalised sector where demand may exhibit some elasticity, though small, (this is the case of most EU countries), the objective in the dispatch is maximizing the social welfare or aggregate benefits of producers and consumers. Therefore, the impact of DG/RES on variable generation costs is only useful as long as it represents a proxy to its impact on social welfare. In fact, if demand elasticity does not change, the change in social welfare between 2 operation situations is the same as the change between variable generation costs and we could include one or the other in the computation of the overall impact of DG (but not the 2 of them at the same time). Note that generators' surplus is the result of deducting generation costs from generator revenues (energy they sell times the energy price). So the impact (change) in generators' surplus already takes into account the corresponding change in generation costs. However, as previously mentioned, part of the demand is expected to react to energy prices, thus making changes in variable generation costs different from changes in the social welfare in the dispatch.

Then, the computation of the overall impact of DG on total costs should be carried out according to the following expression:

$$\Delta SC = -\Delta CS - \Delta PS + \Delta CGC + \Delta DC + \Delta BC + \Delta EC$$

where ΔSC stands for increase in system costs due to DG/RES, ΔCS for increase in consumers' surplus in the dispatch, ΔPS for increase in producers' surplus in the dispatch,.

Given that we aim to compute the change in total costs, surplus increases (of generators and consumers) should be considered with a negative sign while cost increases should be considered with a positive one. Changes in generation variable costs should not be considered because the DG impact on these costs is already being implicitly considered when computing the DG impact on generators' surplus. An alternative expression for the impact of DG/RES on the social surplus in the dispatch (that of producers and consumers) follows:

$$\Delta SS = \Delta CS + \Delta PS = (\Delta UD - \Delta EMV) + (\Delta EMV - \Delta PC) = \Delta UD - \Delta PC$$

where ΔSS is the increase in the social surplus in the dispatch, ΔUD is the increase in the utility that demand obtains from energy consumed, ΔEMV is the increase in the aggregate market value of energy (energy price times the total amount of energy bought or sold in the market) and ΔPC is the increase in the energy production cost.

5 Numerical results

Previous sections have described the three case studies analysed within the IMPROGRES project and the methodology followed in order to assess the impact of DG on distribution network costs, generation costs, external costs, balancing costs and transmission costs. Results corresponding to the application of the above explained methodology to each of the 3 areas are provided separately (sections5.1, 5.2 and 5.3). Results computed are presented both numerically and graphically through cost curves (or bar graphs). Both total integration costs (absolute) and unit costs per kW of DG in the system are provided.

5.1 Spanish area

This is a sub-urban area comprising several medium and small towns and some industrial zones in the area of Aranjuez, which is the largest settlement in the case study area. Existing DG is comprised of industrial CHP units and a wind farm connected at the high voltage level. Nonetheless, further developments of DG are bound to take place by 2020 in this area. New generators will be connected both at HV (wind and CHP) and MV (solar PV) levels. The DSO in the area (Unión Fenosa) assumes that DG shall contribute to partially cover peak demand. An exception to this is solar PV, due to the fact that peak load in the area occurs at night because of the application of special rates for consumption during this period of time. Noticeable vertical demand growths are considered in the Aranjuez area when defining the future demand (see Table 65).

5.1.1 Distribution costs

As explained when presenting the methodology followed to compute distribution costs, these include investments costs, maintenance costs and the cost of energy losses. More than eight scenarios with different patterns of electricity consumption and DG have been evaluated for the Spanish case study, since it was deemed appropriate to identify trends in the impact of DG/RES on distribution costs with the DG/RES penetration level. However, numerical results provided here correspond just to the eight scenarios that had been defined a priori. Next, the most relevant results yielded by the reference network models for the Aranjuez area are presented. These comprise the main figures corresponding to network elements that are installed to cope with the integration of DG in the system operation, e.g. length of lines, per type of line, installed transformation capacity and broken down costs.

Table 19: Amount of network elements of each type in the Aranjuez area. Spain

		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	167.4	87.2	80.1	8	260	716.2	418	248.7	694.3
	2008 DG	199.9	108.7	91.2	8	260	716.2	418	248.7	694.3
	2020 DG (medium)	207.7	116.5	91.2	8	260	718.5	418	248.7	694.3
	2020 DG (high)	216.7	125.5	91.2	8	260	730.8	418	248.7	694.3
2020 Demand	No DG	196.7	150.1	46.6	10	380	702.7	587	375.8	706.4
	2008 DG	223.5	176.9	46.6	10	380	702.7	587	375.8	706.4
	2020 DG (medium)	229.5	182.9	46.6	10	380	705.4	587	375.8	706.4
	2020 DG (high)	242.0	195.4	46.6	10	380	719.1	587	375.8	706.4

Table 19 shows the total amounts of network assets of each type in the optimally adapted distribution grids for each of the scenarios considered. As described in section 3, an initial network has been computed in this area from scratch for each of the two scenarios corresponding to both levels of demand and no DG. Costs derived from the connection of DG in each scenario S were computed with the incremental model starting from the grid that is adapted to the situation where demand level is the same as that in S and no generation exists. According to this approach, the integration of DG would result in investment and maintenance costs that are equal or higher than those in the scenario without DG. Possible network costs caused by DG would correspond to connection lines and any necessary network reinforcements. Most network reinforcements arising from the connection of DG correspond to HV lines and, to a lesser extent, MV lines. Reinforcements were computed as the minimum cost ones that were necessary to cope with flows in the corresponding minimum demand maximum generation snapshot. Table 19 provides the breakdown of network costs per type of asset and voltage level.

Increases in the required amount of network assets due to the integration of DG have been computed with respect to the no-DG scenario for the corresponding level of demand. Figure 25 shows the increases in the total length of transmission lines and transformation capacity that are required to cope with flows caused by DG in each scenario. Neither HV/MV substations nor MV/LV transforming centres have been included in Figure 25 because no extra transformation capacity was added due to the connection of DG. Increases have been expressed as percentages of the aggregate cost of the corresponding assets in the no-DG same demand scenario.

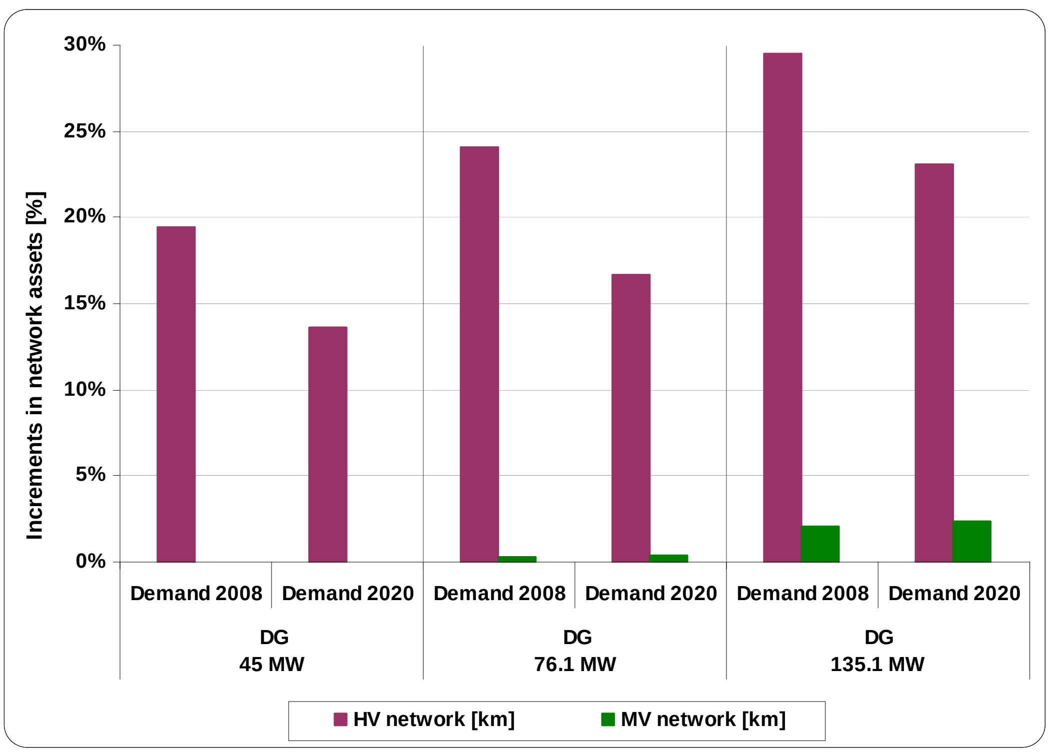


Figure 25: Increases in total amounts of network assets in each scenario with respect to the amounts required in the corresponding no-DG scenario. Values have been expressed as percentages of the aggregate cost of the corresponding assets in the no-DG same demand scenario. Spain

Table 20: Breakdown of network costs per type of asset and voltage level. Spain

		2008 Demand				2020 Demand			
		No DG	2008 DG	2020 DG (medium)	2020 DG (high)	No DG	2008 DG	2020 DG (medium)	2020 DG (high)
Investment [M€]	Total	67.8	70.0	70.7	71.9	85.0	87.1	87.7	89.1
	HV network	13.5%	16.3%	17.0%	17.7%	14.7%	16.8%	17.3%	18.0%
	HV/MV substations	15.8%	15.3%	15.1%	14.9%	22.0%	21.5%	21.4%	21.0%
	MV network	38.0%	36.8%	36.5%	36.6%	32.0%	31.2%	31.0%	31.1%
	MV/LV TCs	13.4%	13.0%	12.9%	12.7%	15.6%	15.2%	15.2%	14.9%
	LV network	19.2%	18.6%	18.5%	18.1%	15.7%	15.3%	15.2%	15.0%
PV Maintenance [M€]	Total	43.1	44.4	44.8	45.4	50.8	52.0	52.3	53.0
	HV network	11.3%	13.8%	14.4%	14.9%	11.2%	13.1%	13.6%	14.2%
	HV/MV substations	15.7%	15.2%	15.1%	14.9%	16.6%	16.3%	16.2%	16.0%
	MV network	47.3%	46.0%	45.7%	45.7%	41.9%	41.0%	40.8%	40.8%
	MV/LV TCs	22.1%	21.5%	21.3%	21.0%	27.1%	26.6%	26.4%	26.0%
	LV network	3.6%	3.5%	3.5%	3.5%	3.1%	3.0%	3.0%	3.0%
PV Total [M€]	Total	124.7	128.2	129.0	131.1	155.0	158.2	158.9	161.1
	HV network	11.5%	14.0%	14.6%	15.2%	12.2%	14.0%	14.4%	15.1%
	HV/MV substations	16.7%	16.4%	16.2%	15.9%	20.9%	20.7%	20.6%	20.2%
	MV network	39.5%	38.8%	38.5%	38.7%	33.6%	33.2%	33.1%	33.2%
	MV/LV TCs	17.6%	17.0%	16.9%	16.6%	20.7%	20.1%	20.0%	19.7%
	LV network	14.7%	13.9%	13.8%	13.6%	12.6%	12.0%	11.9%	11.7%

As shown in Table 20, investment and maintenance costs increase as more DG is connected. This is especially true for the cost of the HV network. Nonetheless, relative increases in costs are significantly smaller than in previous case studies. This is mainly caused by the fact that DG penetration levels reached are lower than in other distribution areas and DG production at peak load times is higher than in these areas.

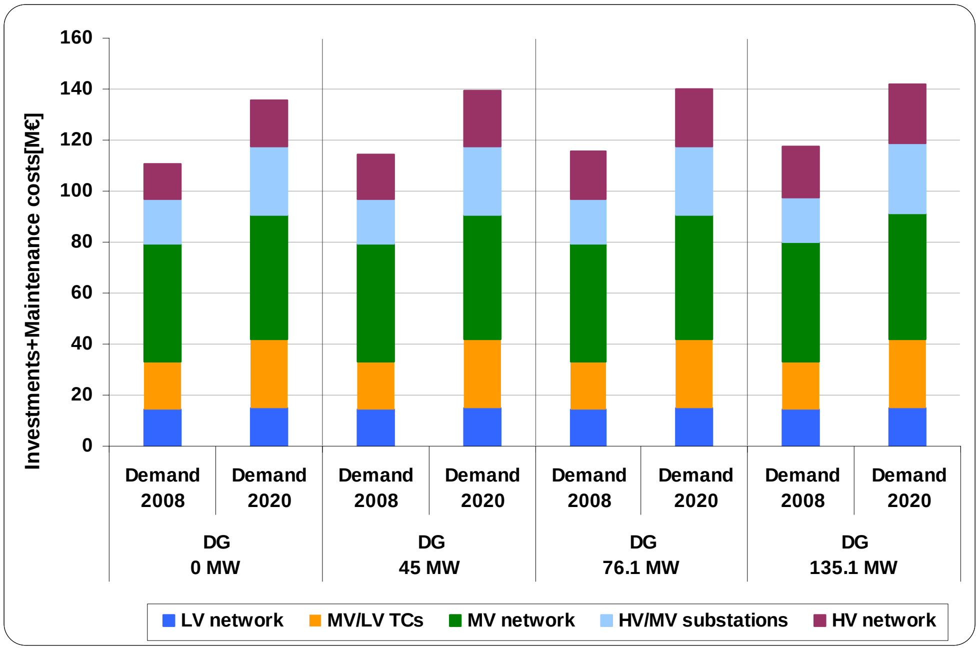


Figure 26: Investment and maintenance costs in the Aranjuez area, Spain.

In the Aranjuez distribution area, investment and maintenance costs corresponding to the MV network account for the largest fraction of total costs, as displayed in Figure 26. These represent around 35%-40% of total network costs. On the other hand, HV/MV substations and MV/LV transforming centres amount to 15%-20% of total investment and maintenance costs each. Finally, HV and LV networks generally represent less than 15% of total costs each. This distribution area is, by far, the largest one in terms of surface and the one where the concentration of loads is lowest. Therefore, as expected, the size of the network, and its cost, for a given demand level are higher than in the Dutch or German areas. Furthermore, contrary to what happened in the previously analysed case study areas, there are not significant differences between the evolution of costs with the DG penetration level for the two demand levels that were considered. What is more, Figure 26 tells us that differences in network costs between those scenarios that have the same DG capacity but different demand levels remains virtually the same across all DG installed capacities considered.

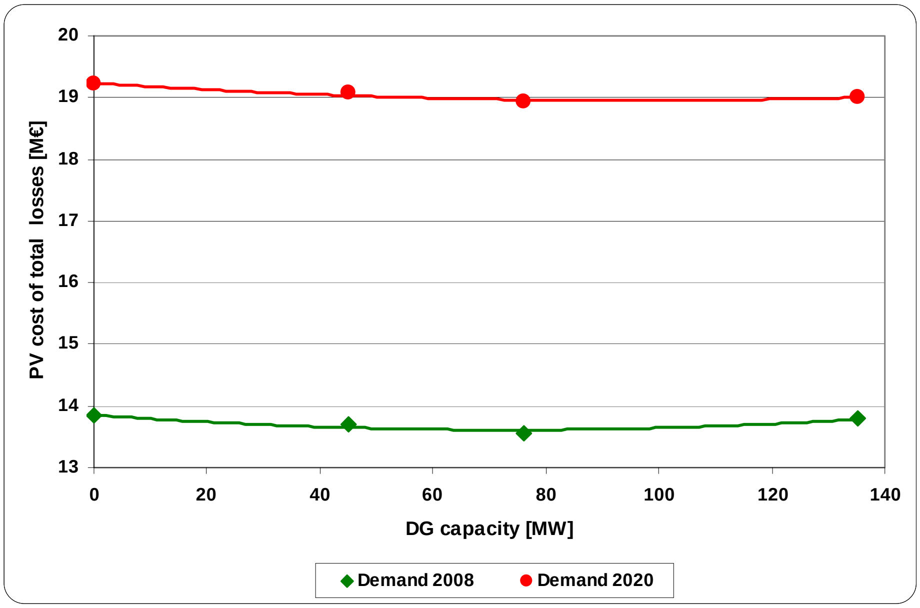


Figure 27:: Evolution of total losses cost. Aranjuez, Spain.

The evolution of the present value of losses when demand is kept constant and increasing values of DG are considered, which is depicted in Figure 27 for the 2008 and 2020 demand levels, is quite similar to the U-shaped curves described in (Méndez et al., 2006). Curves in (Méndez et al, 2006) depict the level of energy losses as DG production increases, when the network, load and DG capacities are kept constant. In our analysis, the topology of the network could change significantly from one scenario to another. However, due to the approach followed in the Spanish case and the particular characteristics of this area, the final optimally adapted network turned out to be very similar in all scenarios. Network reinforcements mainly corresponded to connection lines. This contributed to energy losses following a U-shaped curve similar to that predicted in literature for a given system (generation, load network) and different operating conditions. On the other hand, cost curves of losses that were obtained are rather flat. Hence, no significant deviations in losses cost from the no DG scenarios could be found.

Table 21: Breakdown of total costs in the investment, maintenance and losses components. Spain

	2008 Demand				2020 Demand			
	No DG	2008 DG	2020 DG (medium)	2020 DG (high)	No DG	2008 DG	2020 DG (medium)	2020 DG (high)
PV total [M€]	124.7	128.2	129.0	131.1	155.0	158.2	158.9	161.1
Investment	54.3%	54.6%	54.8%	54.8%	54.8%	55.1%	55.2%	55.3%
Maintenance	34.6%	34.7%	34.7%	34.6%	32.8%	32.9%	32.9%	32.9%
Losses	11.1%	10.7%	10.5%	10.5%	12.4%	12.1%	11.9%	11.8%

As shown in Table 21, the present value of total network costs increases in size with the level of DG penetration, albeit, as it has already been mentioned, at a lower rate than in the other distribution areas. Investments are clearly the most relevant cost factor. Maintenance costs are noticeably lower than the cost of investments, although they amount to a higher percentage of total costs than in previous cases (areas). Finally, the cost of energy losses account for the smallest share of all (around one fifth of investments), though they are bigger than in the German and Dutch areas.

Table 22: evolution of total incremental distribution cost per unit of DG installed in the Aranjuez area with the dg penetration level. Results for the 2008 and 2020 storylines are provide separately

	2008 Storyline			
DG Penetration Level	2008 DG	2020 DG (medium)	2020 DG (high)	2020 DG (extra high)
Total PV [€/kW DG]	76.03	55.63	46.96	61.13
Investment [€/kW DG]	50.46	37.97	30.50	40.54
Maintenance + Losses [€/kW DG]	25.57	17.66	16.46	20.59

	2020 Storyline			
DG Penetration Level	2008 DG	2020 DG (medium)	2020 DG (high)	2020 DG (extra high)
Total PV [€/kW DG]	69.80	50.17	44.68	42.77
Investment [€/kW DG]	48.35	35.29	30.27	28.30
Maintenance + Losses [€/kW DG]	21.45	14.88	14.42	14.47

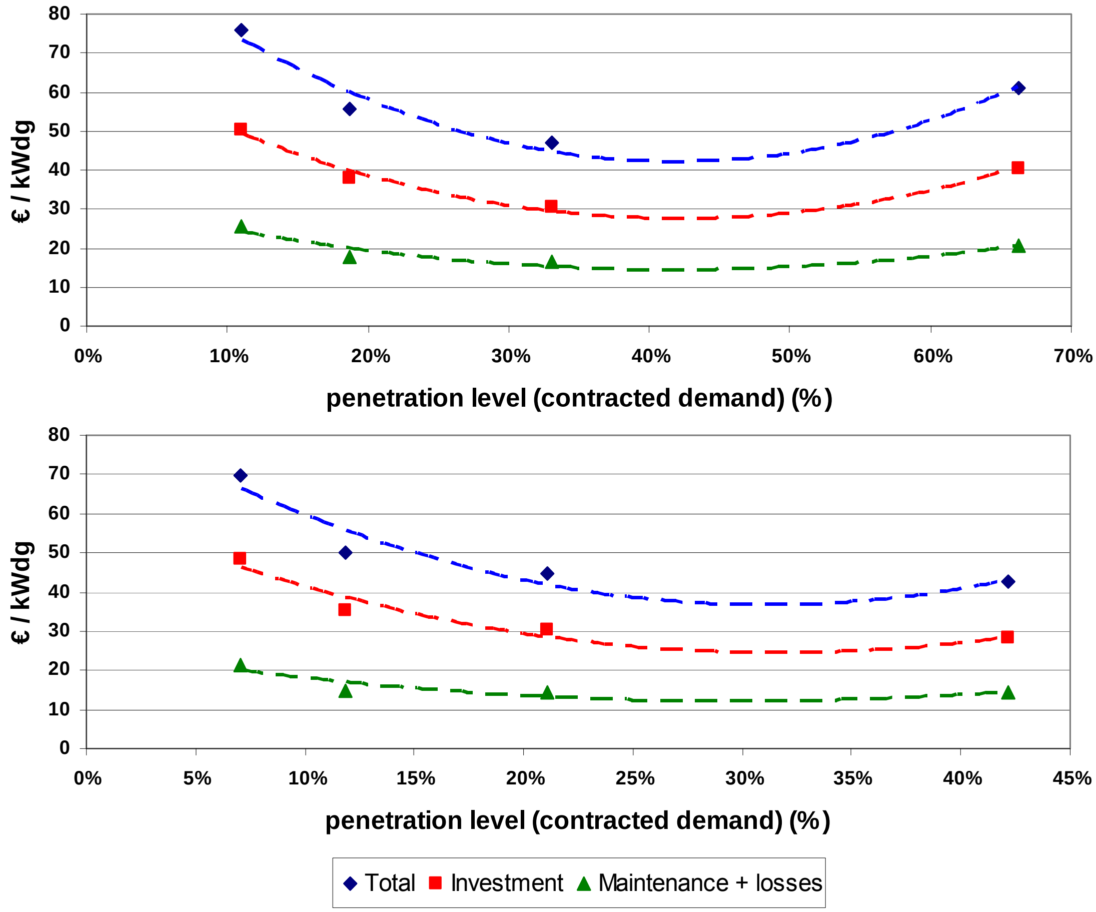


Figure 28: Incremental costs per installed kW of DG in the Spanish area both considering the 2008 storyline (upper graphic) and the 2020 one (lower graphic)

Figure 28 and Table 22 show the total unit network costs of installing DG for all the considered scenarios or DG/penetration levels. Incremental cost impacts shown here refer to the overall cost incurred by the system throughout the useful life of the grid, which is deemed to be between 30 and 40 years, in line with the estimates obtained for the useful life of assets provided at the end of Appendix 1. Results for each of the two considered storylines have been displayed separately so as to avoid confusion. Two additional scenarios were obtained for the Spanish area by doubling the installed generation capacity of those generators that were present in the future high DG penetration scenarios for both demand levels. These correspond to the two points that are more to the right in both graphics within Figure 28. Lines drawn correspond to the 2nd order curves that best fit the points computed. They are aimed at identifying a tentative general trend in cost impacts. Besides, they can serve as an aid to see which points are related to each other. However, in practice one would expect a stepwise change when additional grid capacity is needed, as opposed to a continuous development like the one shown in curves. What is more, given the low number of points that have been used to draw these curves, we cannot claim that they correspond to the actual trend followed by costs. This is why these curves have been drawn using a dashed line.

According to this figure, the connection of DG leads to a decrease in network costs up to a certain point, from where costs begin to increase with the penetration level. As we have already explained in sections 3.1.1 and 3.2.1, most new generators in the Aranjuez area are located close to each other and near populated areas as well. In other words, they are located close to the network required to serve load. Therefore, large DG capacities can be connected without major reinforcements. Nonetheless, unit network costs per kW of DG installed start increasing for penetration levels above 40% (see Figure 28). In any case, costs for the highest penetration level considered are still below those computed for DG penetration levels that are close to zero. The most plausible reason for the observed evolution of network costs lies in the fact that scenarios in the Spanish area were built by increasing the capacities of DG units, keeping their number and location constant. As explained by (Gómez et al., 2007), the concentration of DG capacity within the network is an important factor affecting distribution network costs. Total costs per unit of installed DG capacity for the Spanish case study range from 47 €/kW_{DG} to 76 €/kW_{DG} for the DG penetration scenarios corresponding to the 2008 storyline and from 43 €/kW_{DG} to 70 €/kW_{DG} for the 2020 storyline.

Finally, Table 23 and Figure 29 provide annual incremental costs of distribution, with respect to the corresponding no DG scenario, for different levels of penetration of DG. Similarly to what was done for total costs, results for annual ones are displayed separately for each of the two storylines. The evolution of annual unit distribution costs caused by DG with the level of DG penetration is completely analogous to that of the corresponding not annual, but overall, unit costs. However, computing annual cost is necessary in order to compare these to other cost components and come up with a single estimate of the overall impact of DG on system costs for each scenario.

Table 23: Unit annual incremental distribution costs associated with the integration of DG in the Aranjuez area (Spain)

	2008 Storyline			
DG Penetration Level	2008 DG	2020 DG (medium)	2020 DG (high)	2020 DG (extra high)
*Total PV [€/kW DG *year]*	4.84	3.54	2.99	3.89
*Investment [€/kW DG*year]*	3.21	2.42	1.94	2.58
*Maintenance + Losses [€/kW DG*year]*	1.63	1.12	1.05	1.31
	2020 Storyline			
DG Penetration Level	2008 DG	2020 DG (medium)	2020 DG (high)	2020 DG (extra high)
*Total PV [€/kW DG *year]*	4.44	3.19	2.84	2.72
*Investment [€/kW DG*year]*	3.08	2.25	1.93	1.80
*Maintenance + Losses [€/kW DG*year]*	1.36	0.95	0.92	0.92

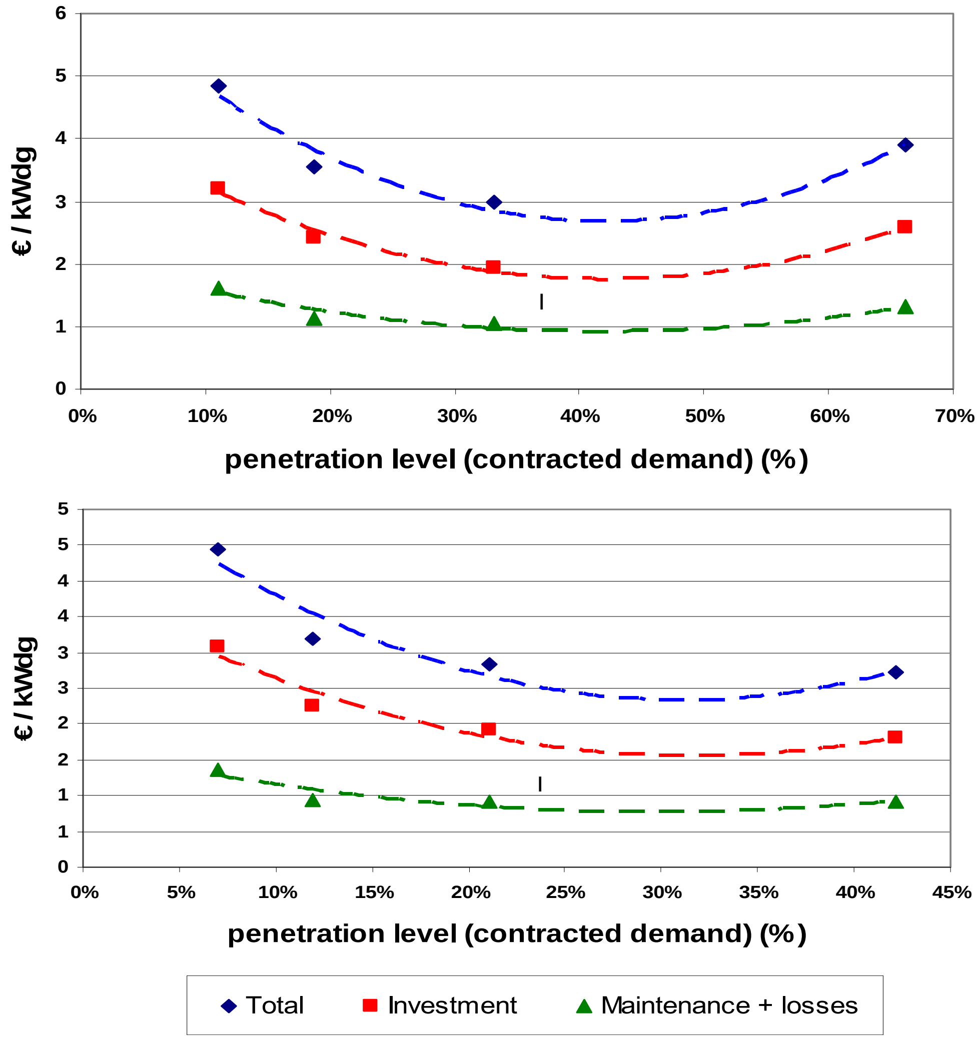


Figure 29: graphical representation of annual incremental distribution costs for the Aranjuez area (Spain). Evolution of these costs with the level of penetration of DG. Results for the 2008 storyline are depicted in the upper graphic and those for the 2020 storyline are depicted in the lower one

5.1.2 Generation costs

Table 24 and Table 25 and Table 26 present the results on the generation cost impact of DG/RES penetration in the Spanish case study area. Note that the cited cost figures reflect the total increase (or decrease) in generation cost for all the EU system, and not just for the Spanish electricity system. Results presented correspond to the generation cost impact in the different scenarios considered (combinations of demand, DG and price levels). The results are presented in both absolute terms (m€/year) and in terms related to the amount of additional DG/RES capacity integrated in the case study area (€/$kW_{DG/RES}$/year). Table 24 presents the impact on variable generation costs whereas Table 25 presents the impact on fixed generation costs. The results in the tables should be interpreted as follows. The penetration of the additional amount of DG/RES associated with the 'Future high DG' stage of DG/RES integration in the 2008 electricity system causes a decrease in variable generation costs of €7.4 million per year. When this cost figure is related to the actual amount of DG/RES capacity we obtain a decrease in variable generation cost of €55 per $kW_{DG/RES}$ per year. Looking at the same level of DG/RES penetration ('Future high DG') within the same storyline (the 2008 electricity system), we observe an increase in fixed generation costs of €13.1 million per year, which corresponds to about €97 per $kW_{DG/RES}$ per year.

Table 24: Assessment of variable generation cost impact of DG/RES in the Spanish system area (Aranjuez) (source: ECN)

Storyline	Unit	No DG	Status quo DG	Future low DG	Future high DG
2008 electricity system	[m€/year]	0,0	-1,8	-4,5	-7,4
	[€ / kW DG / year]	0,0	-40,2	-59,0	-55,0
2020 electricity system – low prices	[m€/year]	0,0	-1,6	-4,2	-7,7
	[€ / kW DG / year]	0,0	-36,0	-55,7	-57,2
2020 electricity system – high prices	[m€/year]	0,0	-2,0	-5,3	-9,7
	[€ / kW DG / year]	0,0	-45,1	-69,7	-71,5

Table 25: Assessment of fixed generation cost impact of DG/RES in the Spanish system area (Aranjuez) (source: ECN)

Storyline	Unit	No DG	Status quo DG	Future low DG	Future high DG
2008 electricity system	[m€/year]	0,0	3,5	7,1	13,1
	[€ / kW DG / year]	0,0	78,1	93,5	96,7
2020 electricity system – low prices	[m€/year]	0,0	2,6	5,9	11,1
	[€ / kW DG / year]	0,0	57,7	77,1	81,8
2020 electricity system – high prices	[m€/year]	0,0	2,4	4,8	8,9
	[€ / kW DG / year]	0,0	52,2	63,1	66,2

Table 26: Assessment of total generation cost impact of DG/RES in the Spanish system area (Aranjuez) (source: ECN)

Storyline	Unit	No DG	Status quo DG	Future low DG	Future high DG
2008 electricity system	[m€/year]	0,0	1,7	2,6	5,6
	[€ / kW DG / year]	0,0	37,9	34,5	41,8
2020 electricity system – low prices	[m€/year]	0,0	1,0	1,6	3,3
	[€ / kW DG / year]	0,0	21,7	21,4	24,7
2020 electricity system – high prices	[m€/year]	0,0	0,3	-0,5	-0,7
	[€ / kW DG / year]	0,0	7,1	-6,6	-5,3

The analysis shows that the increasing penetration of DG/RES-E in the Spanish case study area gives rise to a *decrease* in the total yearly variable cost of electricity generation and an *increase* in the fixed generation cost of the generating technologies. This is explained by the fact that an increased amount of electricity is produced by low variable cost technologies such as wind turbines and PV. Electricity production from these technologies in fact replaces more expensive variable cost technologies elsewhere in the system (mainly gas-based, on both a distributed (CHP) and central level). However, the capital cost of the latter technologies tends to be relatively lower than the capital cost of the introduced distributed technologies (wind and PV).

Looking at the total generation cost impact we find that in almost all the DG/RES integration stages the fixed generation cost impact dominates the variable generation cost impact, implying a net increase in total generation costs for an increase in DG/RES in the system. Only in the 2020 electricity system storyline with high electricity prices the variable generation cost impact dominates the fixed generation cost impact. This is mainly caused by the CO_2 price in this storyline is assumed to be much higher than in the other storylines. This raises the variable generation cost impact.

5.1.3 Balancing costs

Annual unit balancing costs computed for the Spanish area using the methodology outlined in section 4.2.2 are provided in Figure 30 and Table 27. In both cases, results for the 2008 and 2020 storylines have been depicted separately. Dots in the figure represent the DG penetration rate and annual unit balancing cost for each of the DG/RES penetration scenarios considered. Values for these points are provided in the table. These points (or dots) can be used to figure out the evolution of balancing costs with the DG penetration level, which is expressed as the ratio of installed DG to contracted load. Cost impacts in Figure 30 are expressed in €/kW of installed DG per annum. Lines drawn in Figure 30 correspond to the 2nd order curves that best fit the points computed. They are aimed at identifying a tentative general trend in cost impacts. However, given the low number of points that have been used to draw these curves, we cannot claim that they correspond to the actual trend followed by costs. This is why these curves have been drawn using a dashed line.

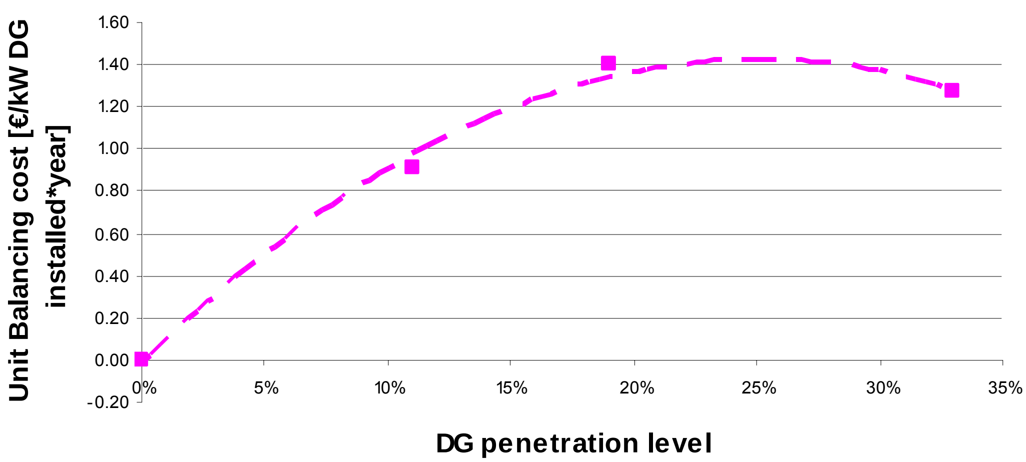
Both for the 2008 and the 2020 storylines, the impact of DG/RES in the Aranjuez area on system balancing costs increases with the DG penetration level until it reaches its maximum level and begins to decrease. The maximum unit cost impact for the 2008 storyline is 1.4 €/kW of DG installed and it corresponds to a DG penetration level of 19%. That for the 2020 storyline is 1.82 €/KW of DG installed and it corresponds to a DG penetration level of 12%.

The unit impact of DG on balancing costs is higher for the 2020 storyline than for the 2008 because the national penetration level of wind power capacity with respect to peak demand is deemed to be higher in 2020 in the Spanish system. Thus, when similar DG/RES penetration rates in the Aranjuez area are considered, balancing costs incurred per unit of energy produced from wind are higher for those scenarios belonging to the 2020 storyline than for scenarios corresponding to the 2008 storyline.

Within each story line, the evolution of the unit impact of DG on balancing costs with the DG penetration level in the area depends solely on the ratio of total energy produced from wind in the area to the total capacity of DG/RES installed in the area.

Table 27: Unit balancing costs for different load and DG levels in Aranjuez area (Spain)

	2008 Storyline No DG	*2008 Storyline 2008 DG*	*2008 Storyline 2020 DG Low*	*2008 Storyline 2020 DG High*
Wind power capacity country [GW]	9.2	9.2	9.2	9.2
Total gross demand [TWh]	260	260	260	260
Peak load factor	1.31	1.31	1.31	1.31
Pwind/PL,max	0.24	0.24	0.24	0.24
Specific cost per MWh Wind [€/MWh]	1.77	1.77	1.77	1.77
DG penetration level in area [%]	0%	11%	19%	33%
Annual wind production area [MWh]	0	23000	60000	97000
Installed DG Capacity in area [MW]	0	45	76.1	135.1
*Unit balancing cost [€/(kW DG*year)]*	0.00	0.91	1.40	1.27
	2020 Storyline No DG	***2020 Storyline 2008 DG***	***2020 Storyline 2020 DG Low***	***2020 Storyline 2020 DG High***
Wind power capacity country [GW]	18.9	18.9	18.9	18.9
Total gross demand [TWh]	364	364	364	364
Peak load factor	1.31	1.31	1.31	1.31
Pwind/PL,max	0.35	0.35	0.35	0.35
Specific cost per MWh Wind [€/MWh]	2.31	2.31	2.31	2.31
DG penetration level in area [%]	0%	7%	12%	21%
Annual wind production area [MWh]	0	23000	60000	97000
Installed DG Capacity in area [MW]	0	45	76.1	135.1
*Unit balancing cost [€/(kW DG*year)]*	0.00	1.18	1.82	1.66



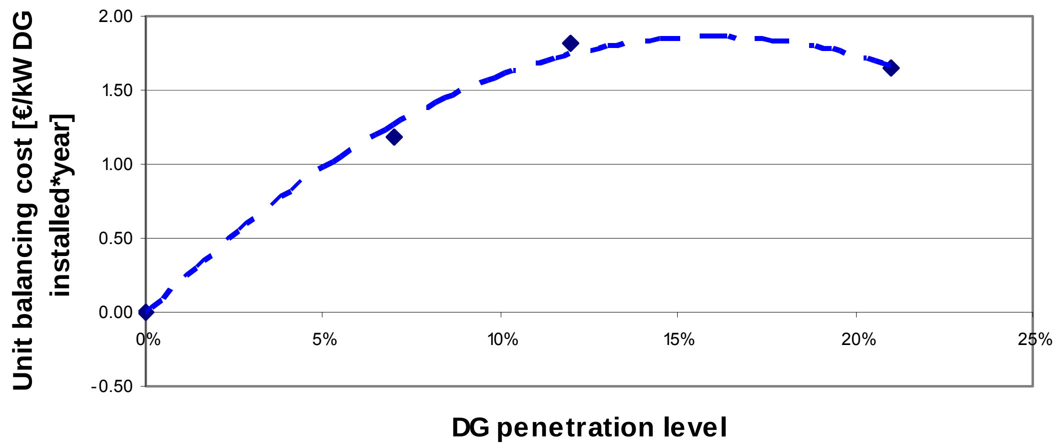


Figure 30: evolution of unit balancing cost (per MW of installed DG capacity) with the level of DG/RES penetration for 2 different levels of load in the Spanish area (current load and future load)

5.1.4 External costs

Table 28 provides numerical results corresponding to the impact of DG/RES on external costs. The impact on the external cost is directly related to the shift in the overall generation mix. We remind the reader at this point that the external costs reflect the cost of environmental and health damage (for example caused by emissions from electricity generating units). These costs however exclude the damage done by direct CO_2 emissions in the electricity generation sector since these are assumed to be covered by the price of CO_2 emissions rights that need to be paid by emitters which are already included as part of the variable generation costs. In Table 28 we again present results for the three distinguished storylines and the different levels of DG/RES integration in the Spanish case study area. The external cost impact is given both in absolute terms (million € per year) and in terms related to the amount of DG/RES capacity installed in the case study area (€ per $kW_{DG/RES}$ per year).

Table 28: assessment of the impact of DG/RES in the Spanish system area (Aranjuez) on external costs (source: ECN)

Storyline	Unit	No DG	Status quo DG	Future low DG	Future high DG
2008 electricity system	[m€/year]	0,0	-0,1	-0,2	-0,2
	[€ / kW DG / year]	0,0	-2,4	-2,2	-1,5
2020 electricity system – low prices	[m€/year]	0,0	0,0	0,0	0,0
	[€ / kW DG / year]	0,0	0,2	0,2	0,4
2020 electricity system – high prices	[m€/year]	0,0	0,0	0,0	0,1
	[€ / kW DG / year]	0,0	0,4	0,4	0,7

Within the 2008 electricity system storyline a shift from gas-based electricity generation to more DG/RES generation, the external cost are reduced since the gas-based units pushed out of the merit order are relatively ‘dirty’. Results of the analyses are different for the 2020 electricity system storyline since the gas-based units that are replaced by DG/RES units are much cleaner than their 2008 peers.

Overall, this can even give rise to a small increase in the external cost of total electricity production. However, this increase is so small that it must be noted that it is possible for somewhat different assumptions on the actual external cost indicators for the different technologies to turn the small increase into a small decrease. Note two things with respect to this observation. First, also 'clean' technologies have significant external cost (especially in the production of materials used etc.). Second, part of the considered DG/RES technologies penetrating the case study area are fossil-fuel based (CHP). All in all, we could state that in a 2020 electricity system it does not seem very likely that additional DG/RES integration of the type studied here (a combination of wind, CHP and PV) will cause a very large reduction in external costs.

5.1.5 Transmission costs

An estimate of the impact on transmission costs of the penetration of DG/RES in the Spanish area has not been carried out because penetration of DG/RES is not thought to be high enough so as to significantly change connection capacity requirements.

5.1.6 Total electricity supply costs

Table 29 and Figure 31 show the impact on total supply costs of the installation of DG in the Aranjuez area for different DG penetration levels. Results for the 2008 and 2020 storylines are provided in separate tables and graphics. Besides total supply costs, the evolution of the different cost components with the DG penetration level is also provided, though the impact of DG on each cost component has already been discussed in previous subsections. Table 29, Table 33 and Figure 31 provide, for each DG/RES scenario that has been defined within a certain storyline in the Spanish area, the unit impact of DG/RES (per kW of DG/RES installed) on each of the cost components considered, as well as the unit impact on total supply costs. Numerical results provided are annual.
The general trend followed by total costs with increasing levels of DG in the Spanish area is quite similar in the 2008 and 2020 backgrounds. In both cases, this trend is dominated by fixed and variable generation cost components. As mentioned in section 5.1.2, impact of DG on fixed costs is positive (these costs increase) because the unit investment costs of DG generation technologies (renewables and CHP) are higher than those of conventional generation that is partially replaced by the former. Besides, the low capacity credit of some of the generation installed in the Aranjuez area (this is the case of solar and wind power) results in conventional generation capacity still having to provide most of the firm generation capacity in the system. Thus, the decrease in conventional generation capacity caused by the installation of DG in the Aranjuez area is well below the amount of DG generation capacity installed.
On the other hand, the impact of DG on variable generation cost is negative (these costs decrease) because fuel costs and other operation costs incurred by new DG are clearly below those of conventional generation. Besides, the amount of CO2 emitted by DG (at least by some technologies, like solar or wind) is almost negligible, compared to significantly larger amount of CO2 emitted when producing conventional generation energy that is now replaced by DG generation one. Figures for the 2020 scenario correspond to the case where fuel and CO2 prices in the 2020 horizon are deemed to be moderate. The evolution of fixed generation costs is analogous to that of variable ones. However, for a certain DG penetration level, the former are larger than the latter. This is in line with what could be expected nowadays, since the difference in variable generation costs between DG and conventional generation that is marginal in the market is not enough to compensate for the higher investment costs

born by DG producers. Thus, the former must receive some kind of compensation in the form of support payments allowing them to profit from the installation of generation from these technologies. The evolution of total costs in each storyline with the level of DG penetration depends mainly on the composition of the generation mix that exists in the area. Thus, both the capacity credit and the unit investment costs of CHP generation are clearly below those of wind and, specially, solar generation. Consequently, an increase in the CHP generation capacity shall lower unit fixed generation costs while am increase in solar shall clearly increase fixed generation costs. The trend of variable generation costs is somewhat the opposite. Increasing the CHP capacity will increase unit average variable production costs while increasing wind or solar capacity will lower unit variable costs.

The unit DG/RES impact on total supply costs is positive for every DG penetration level that has been considered (overall costs increase because of the introduction of DG). However, it seems to reach a maximum, which is around 15% DG penetration level for the 2020 storyline and 25% for the 2008 storyline. As explained, this mainly depends on the composition of the generation mix in the area in each scenario.

Table 29: Evolution of the impact of DG in the Aranjuez area on total supply costs with the DG penetration level. Results for the 2008 and 2020 storylines are provided in separate tables

Scenarios	2008 DEMAND No DG	Current DG	Future DG (medium)	Future DG (High)
DG penetration level [%]	0%	11%	19%	33%
Cost concepts				
Variable Generation Costs [€/kW installed DG/year]	0.0	-40.2	-59.0	-55.0
Fixed Generation Costs [€/kW installed DG/year]	0.0	78.1	93.5	96.7
Distribution Costs [€/kW installed DG/year]	0.0	4.8	3.5	3.0
Balancing costs [€/kW installed DG/year]	0.0	0.9	1.4	1.3
External Costs [€/kW installed DG/year]	0.0	-2.4	-2.2	-1.5
Total cost [€/kW installed DG/year]	0.0	41.3	37.2	44.5

Scenarios	2020 DEMAND No DG	Current DG	Future DG (medium)	Future DG (High)
DG penetration level [%]	0%	7%	12%	21%
Cost concepts				
Variable Generation Costs [€/kW installed DG/year]	0.0	-36.0	-55.7	-57.2
Fixed Generation Costs [€/kW installed DG/year]	0.0	57.7	77.1	81.8
Distribution Costs [€/kW installed DG/year]	0.0	4.4	3.2	2.8
Balancing costs [€/kW installed DG/year]	0.0	1.2	1.8	1.7
External Costs [€/kW installed DG/year]	0.0	0.2	0.2	0.4
Total cost [€/kW installed DG/year]	0.0	27.5	26.6	29.5

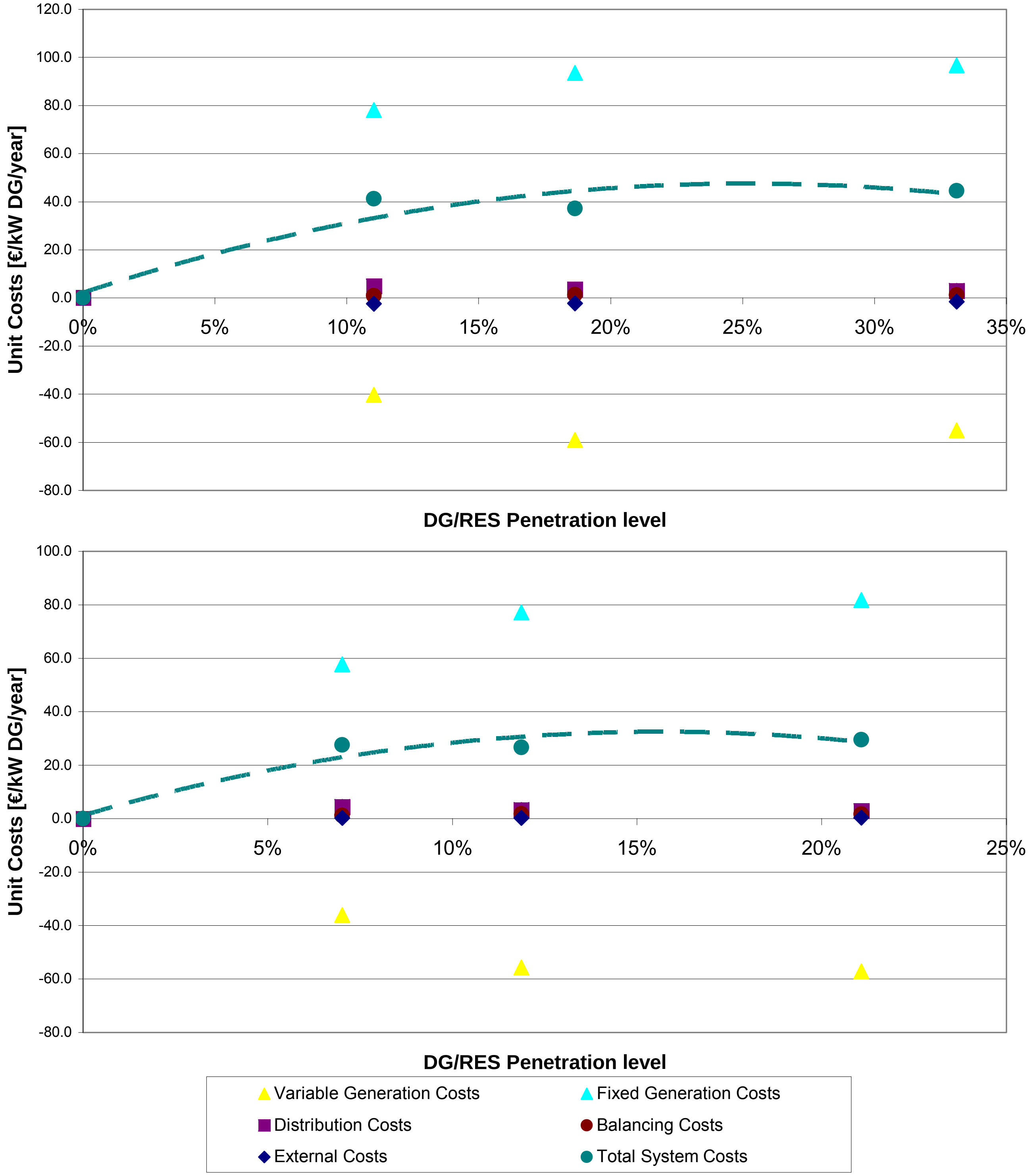


Figure 31: Evolution of the impact of DG in the Aranjuez area on total supply costs with the DG penetration level. Results for the 2008 (upper graphic) and 2020 (lower graphic) storylines are provided in separately

5.1.7 Social Welfare

Table 30, Table 31 and Table 32 present the impact of introducing DG/RES in the Spanish case study area on the welfare of consumers, producers and the aggregate of them, respectively. Results presented correspond to the welfare impact in the different scenarios considered (combinations of demand, DG and price levels). These results have been presented both in absolute terms (m€/year) and in the form of unit impact per kW of DG installed. Welfare impacts presented are annual values.

Table 30: assessment of the impact of DG/RES in the Spanish system area (Aranjuez) on consumer surplus (source: ECN)

Storyline	Unit	No DG	Status quo DG	Future low DG	Future high DG
2008 electricity system	[m€/year]	0,0	0,0	0,3	4,0
	[€ / kW DG / year]	0,0	0,0	3,7	29,5
2020 electricity system – low prices	[m€/year]	0,0	0,0	0,0	0,0
	[€ / kW DG / year]	0,0	0,0	0,0	0,0
2020 electricity system – high prices	[m€/year]	0,0	0,0	0,0	0,0
	[€ / kW DG / year]	0,0	0,0	0,0	0,0

Table 31: assessment of the impact of DG/RES in the Spanish system area (Aranjuez) on producer surplus (source: ECN)

Storyline	Unit	No DG	Status quo DG	Future low DG	Future high DG
2008 electricity system	[m€/year]	0,0	1,8	4,3	4,2
	[€ / kW DG / year]	0,0	40,2	56,1	31,3
2020 electricity system – low prices	[m€/year]	0,0	1,6	4,2	7,7
	[€ / kW DG / year]	0,0	36,0	55,7	57,2
2020 electricity system – high prices	[m€/year]	0,0	2,0	5,3	9,7
	[€ / kW DG / year]	0,0	45,1	69,7	71,5

Table 32: assessment of the impact of DG/RES in the Spanish system area (Aranjuez) on social welfare (source: ECN)

Storyline	Unit	No DG	Status quo DG	Future low DG	Future high DG
2008 electricity system	[m€/year]	0,0	1,8	4,5	8,2
	[€ / kW DG / year]	0,0	40,2	59,8	60,8
2020 electricity system – low prices	[m€/year]	0,0	1,6	4,2	7,7
	[€ / kW DG / year]	0,0	36,0	55,7	57,2
2020 electricity system – high prices	[m€/year]	0,0	2,0	5,3	9,7
	[€ / kW DG / year]	0,0	45,1	69,7	71,5

The results with respect to the consumer surplus impact relate to the price impact DG/RES has. Whenever the penetration of low-variable cost DG/RES decreases the electricity price level, the consumer surplus is bound to increase. Through interconnections with neighboring electricity systems the price decrease might even give rise to increased consumer surplus abroad. In the case of the DG/RES integration in the Spanish case study area we observe that increasing DG/RES penetration only has an impact on the Spanish electricity price in the storyline representing the current Spanish

electricity system. Hence, consumer surplus increases only in this situation. In the other situations the average yearly price level is not affected by the increase in DG/RES in the case study area.
At the same time, the penetration of relatively low variable cost DG/RES technologies in the Spanish electricity system causes an increase in producer surplus (i.e. electricity producer profits). This is evident since we earlier saw that the variable generation cost decrease due to DG/RES penetration and the average electricity price level is not affected in the majority of cases. In other words, electricity producer revenues stay more or less equal while variable generation costs go down, implying an increase in profits.
As a consequence, the total impact on social welfare (on an EU basis) due to increased DG/RES penetration in the Spanish case study area is always positive in the analyzed cases. The total impact varies from €1.6 million (in the lowest DG/RES penetration stage, in the storyline representing the 2008 electricity system) to €9.7 million (in the highest DG/RES penetration stage, in the storyline representing the 2020 electricity system with high prices). This is equivalent to about €40 to €71 per $kW_{DG/RES}$ per year.

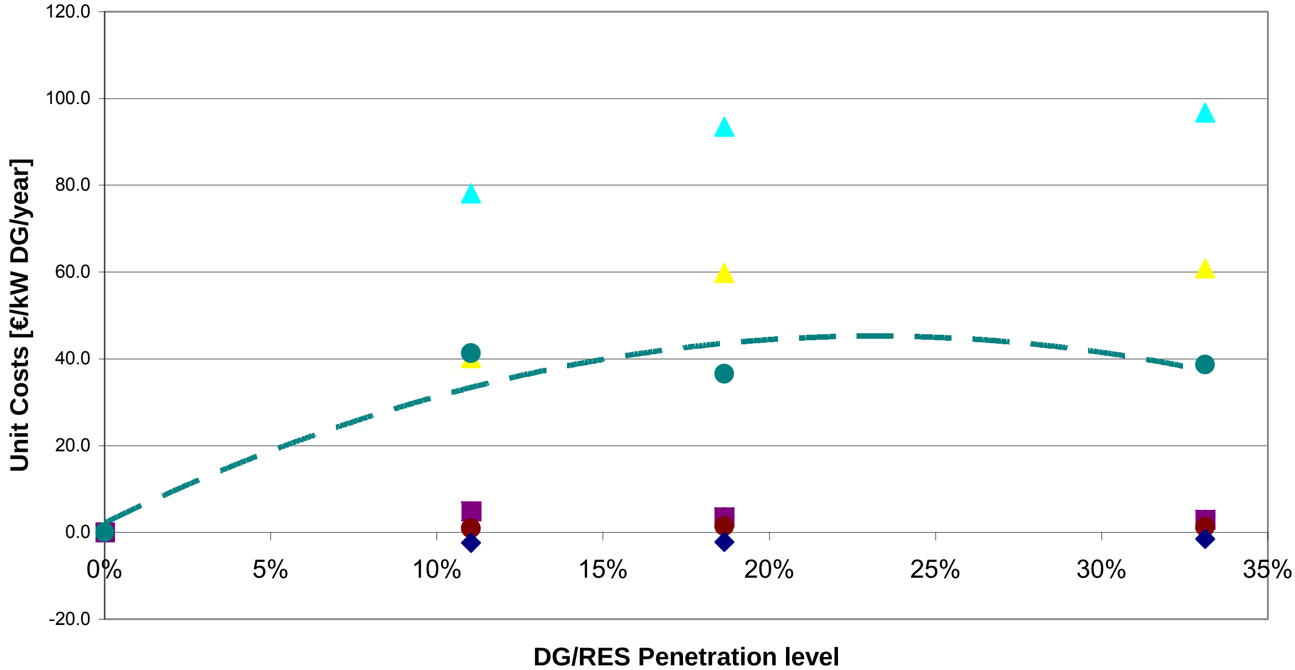
5.1.8 Overall socio-economic cost

This subsection provides a quantification of the total impact on the socio economic cost of the system being penetrated by DG/RES in the Aranjuez area. The methodology followed to compute the overall cost impact of DG is explained in section 4.2.7. Table 33 and Figure 32 provide, for each DG/RES scenario that has been defined within a certain storyline in the Spanish area, the unit impact of DG/RES (per kW of DG/RES installed) on each of the cost components considered, as well as the unit impact on total socio economic system cost. Numerical results provided are annual.
The evolution and general trend of socio-economic costs is rather similar to that followed by total supply costs. Changes in the social surplus and capital generation cost dominate changes in the remaining cost components. The only difference lies in the fact that for high penetration levels in the 2008 storyline, demand served in the system increases as a result of the introduction of DG in the Aranjuez area. This yields a benefit for the system corresponding to the difference between the utility that extra demand extracts from energy and its cost. Consequently, in these scenarios there is a decrease in the socio-economic impact of DG with respect to the impact on supply costs.
Results on total system costs obtained for the different scenarios show a relatively low dispersion around the curve used to fit them. However, one must take into account that these results correspond to situations that not only differ in the amount of DG capacity installed but also in the relative composition of the generation mix, which may vary from one scenario to another within the same storyline.

Table 33: computation of overall impact of DG/RES in the Aranjuez area on the socio economic cost of producing and consuming electricity in the system. Results for the 2008 storyline are provided in the upper table while those for the 2020 story line are provided in the lower one

Scenarios	2008 DEMAND			
	No DG	Current DG	Future DG (medium)	Future DG (High)
DG penetration level [%]	0%	11%	19%	33%
Cost concepts				
Social Cost Dispatch [€/kW installed DG/year]	0.0	-40.2	-59.8	-60.8
Fixed Generation Costs [€/kW installed DG/year]	0.0	78.1	93.5	96.7
Distribution Costs [€/kW installed DG/year]	0.0	4.8	3.5	3.0
Balancing costs [€/kW installed DG/year]	0.0	0.9	1.4	1.3
External Costs [€/kW installed DG/year]	0.0	-2.4	-2.2	-1.5
Total cost [€/kW installed DG/year]	0.0	41.3	36.5	38.7

Scenarios	2020 DEMAND			
	No DG	Current DG	Future DG (medium)	Future DG (High)
DG penetration level [%]	0%	7%	12%	21%
Cost concepts				
Social Cost Dispatch [€/kW installed DG/year]	0.0	-36.0	-55.7	-57.2
Fixed Generation Costs [€/kW installed DG/year]	0.0	57.7	77.1	81.8
Distribution Costs [€/kW installed DG/year]	0.0	4.4	3.2	2.8
Balancing costs [€/kW installed DG/year]	0.0	1.2	1.8	1.7
External Costs [€/kW installed DG/year]	0.0	0.2	0.2	0.4
Total cost [€/kW installed DG/year]	0.0	27.5	26.6	29.5



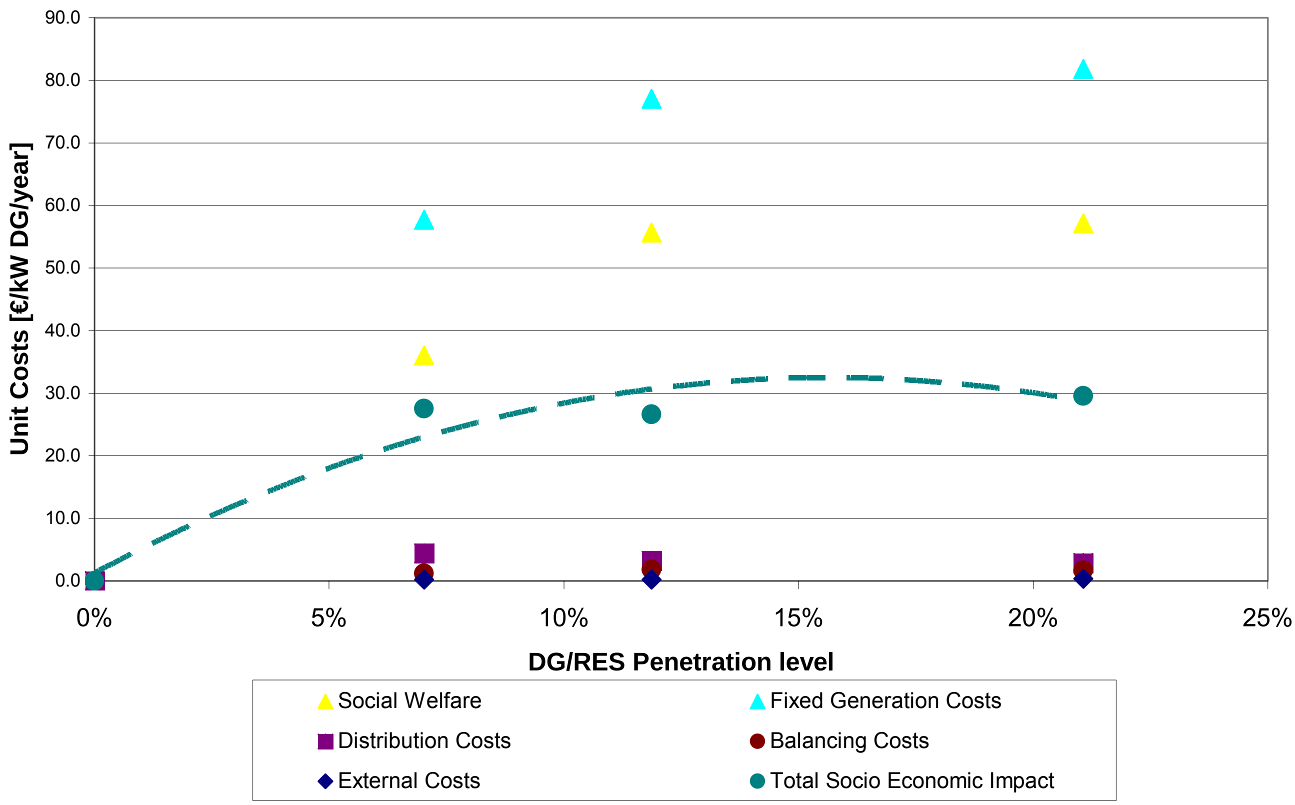


Figure 32: evolution of total socio economic impact of Dg in the Aranjuez area with the level of penetration of DG in the area. Results for the 2008 storyline are provided in the upper graphic while those for the 2020 story line are provided in the lower one

5.2 Dutch area

This area is a rural sub-urban one with some industrial zones and numerous horticultural exploitations. Nowadays, DG installed capacity is already high compared with the electricity demand. Nevertheless, major developments of DG are expected, since this is an attractive area for new wind farms and the use of CHP for greenhouses. The DSO in this area, Liander, advised us to consider a snapshot where DG makes no contribution to cover peak demand and another one where DG produces at its maximum and demand is at its minimum. Both horizontal and vertical increases of demand and DG were considered.

5.2.1 Distribution costs

Next, both numerical results and the resulting networks produced by the network reference models are provided for the Kop Van Noord Holland area. Costs considered include: investment, energy losses and maintenance. Eight scenarios with different patterns of electricity consumption and DG have been evaluated for the Dutch case study. These comprise the main figures corresponding to network elements that are installed to cope with the integration of DG in the system operation, e.g. length of lines, per type of line, installed transformation capacity and broken down costs.

Table 34: Network elements for the Kop van Noord area. Netherlands

		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	752.11
	2008 DG	92.4	27.65	64.75	4	428	777.14
	2020 DG (medium)	82.21	82.21	0	5	1160	1321.68
	2020 DG (high)	128.29	128.29	0	9	2120	1255.31
2020 Demand	No DG	74.53	74.53	0	6	880	858.17
	2008 DG	71.55	71.55	0	5	920	1005.42
	2020 DG (medium)	166.95	68.13	98.82	11	1458	1155.97
	2020 DG (high)	82.8	82.8	0	7	2160	1488.94

Table 34 shows the amount of network assets of each type in the computed network for each scenario. Note that there might be more than one transformer per substation as the incremental model algorithms may decide to upgrade an existing installation instead of building a new one in order to reduce costs. This is the reason why, in some cases, the final installed capacity of a substation may be higher than that shown in Table 67, in Appendix 1.

Increments in total amounts of network assets, due to the introduction of DG, have been computed, for each type of network asset, with respect to the no-DG scenario for the corresponding level of demand. Figure 33 shows the increases in network length and transformation capacity that are required to cope with a certain DG penetration level. These are expressed as percentages of the total amount of assets for the corresponding no-DG scenario.

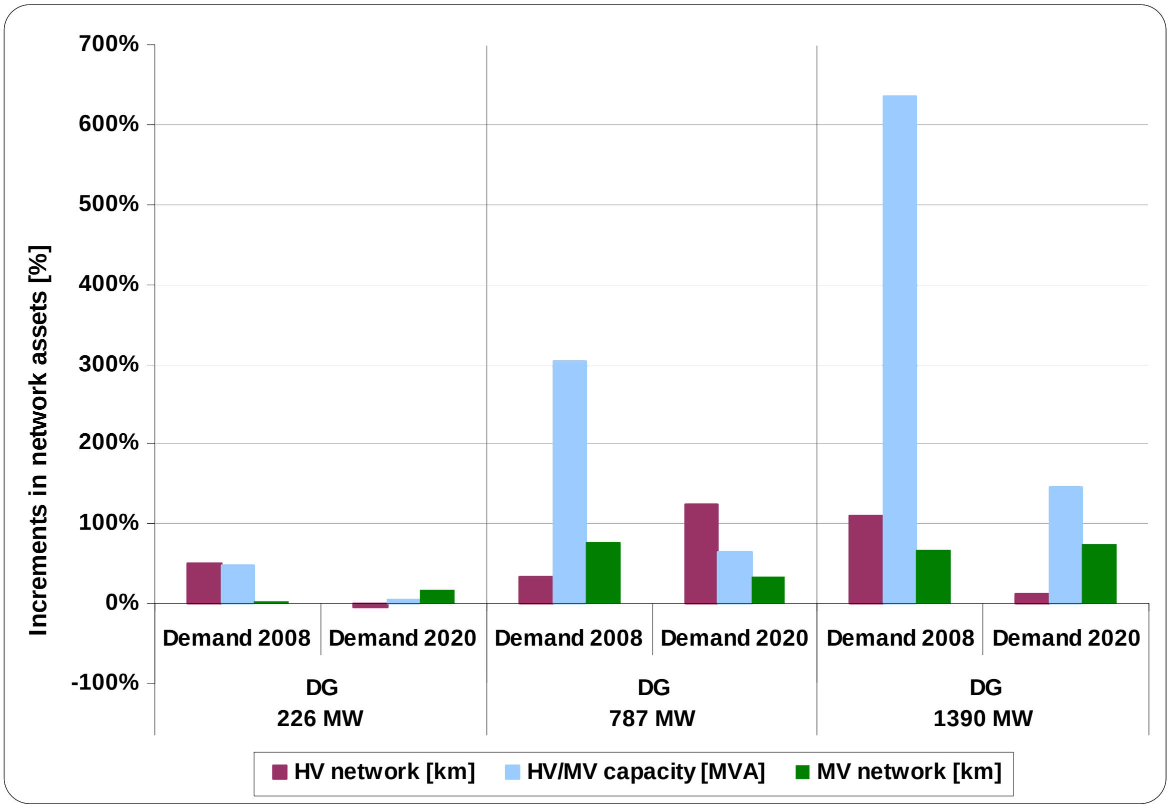


Figure 33: Increments in network assets, with respect to the no-DG scenarios, expressed as percentages of the amounts for the no-DG scenario in the Dutch area

Among the potential benefits of DG, the possibility to defer network investments is frequently mentioned. However, this effect cannot be appreciated in Table 34 or Figure 33. This can be explained by the very high levels of DG penetration existing in the scenarios considered and the fact that DG makes no contribution at all to cover peak demand. On the contrary, maximum DG output takes places at times when demand is at its minimum level. Therefore, greater network capacity and length are required as DG penetration grows. Naturally, this is reflected in the evolution of distribution network costs.

Table 35: Breakdown of total network costs per network level. Netherlands

		Present Demand				Future Demand			
		No DG	Present DG	Future DG (medium)	Future DG (high)	No DG	Present DG	Future DG (medium)	Future DG (high)
Investment [M€]	Total	91.88	109.54	252.28	382.55	180.56	194.75	261.59	394.93
	HV network	28.26%	32.54%	20.26%	20.86%	25.03%	22.76%	27.97%	12.60%
	HV/MV substations	26.45%	25.38%	46.18%	56.59%	48.18%	48.01%	44.27%	56.47%
	MV network	45.29%	42.09%	33.56%	22.54%	26.79%	29.23%	27.76%	30.94%
NPV Maintenance [M€]	Total	36.96	43.35	108.97	173.18	78.41	84.59	111.88	176.42
	HV network	25.18%	28.56%	16.49%	16.21%	20.27%	18.43%	23.15%	9.86%
	HV/MV substations	34.68%	33.48%	55.49%	65.38%	58.53%	58.31%	53.89%	64.53%
	MV network	40.14%	37.96%	28.02%	18.42%	21.21%	23.27%	22.96%	25.61%
NPV Losses [M€]	Total	10.03	15.44	28.26	45.74	27.70	28.97	42.45	62.22
	HV network	1.60%	6.11%	2.04%	2.37%	2.31%	1.47%	7.28%	2.99%
	HV/MV substations	60.72%	52.69%	83.73%	56.35%	61.33%	61.36%	86.48%	46.89%
	MV network	37.68%	41.20%	14.23%	41.29%	36.36%	37.17%	6.24%	50.13%
NPV Total [M€]	Total	138.87	168.33	389.51	601.47	286.67	308.31	415.91	614.70
	HV network	25.52%	29.09%	17.88%	18.12%	21.53%	19.57%	24.56%	10.97%
	HV/MV substations	31.12%	29.97%	51.51%	59.10%	52.28%	52.09%	51.16%	59.11%
	MV network	43.37%	40.94%	30.61%	22.78%	26.19%	28.34%	24.27%	29.93%

Table 35 shows the total investments and maintenance costs for each scenario broken down according to the different network levels. For example, in the current demand and current DG scenario, total network investments amount to 109.5 M€; 32.5% corresponded to expenses in the HV network, 25.4% to the substations and 42.1% to the MV network. This table shows that network costs increase as DG penetration grows, albeit at a lower rate the higher demand is. This can be straightforwardly explained by the fact that, for higher demand levels, 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 with the level of demand.

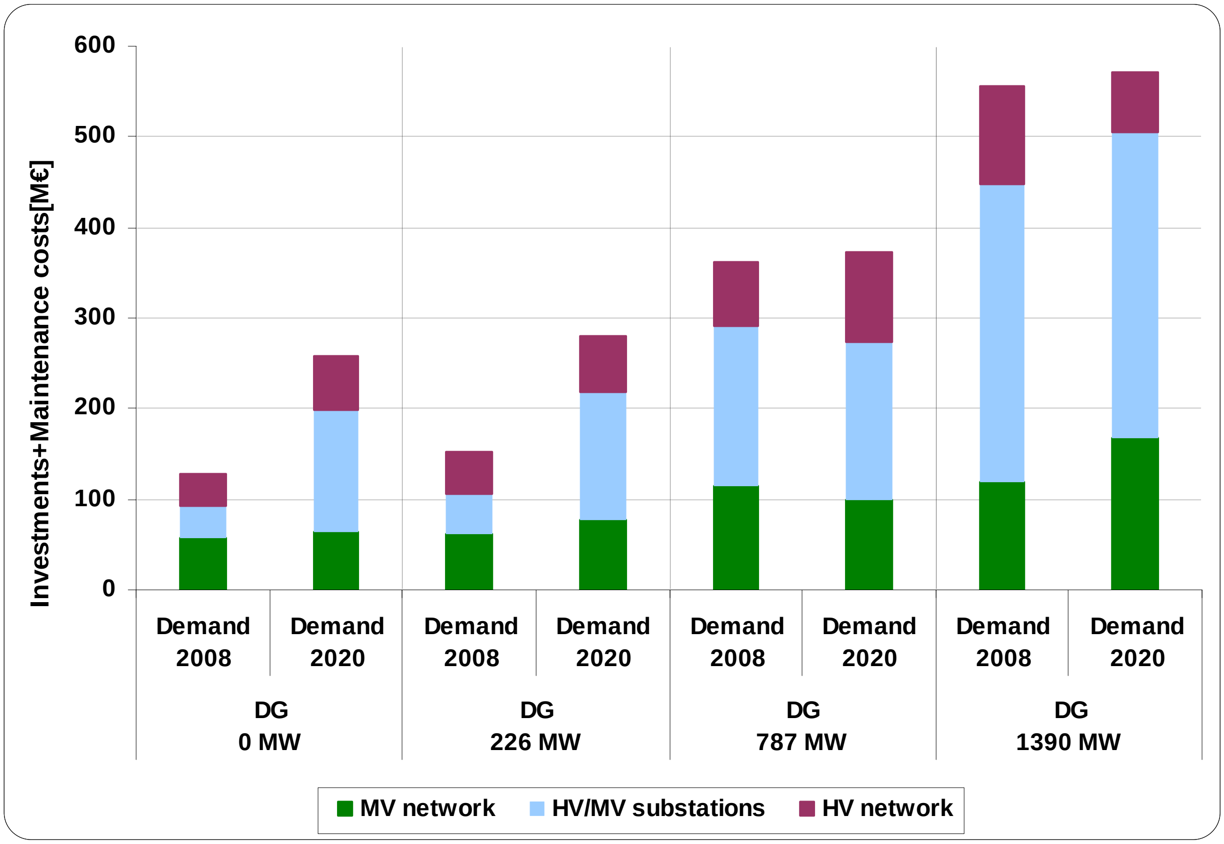


Figure 34: Investment and maintenance costs. Kop van Noord Holland, Netherlands.

In the Kop van Noord Holland case study, HV/MV substations are generally the most important investment and maintenance cost component (see Figure 34). This is even more remarkable for high DG penetration levels. There are several reasons behind this. On the one hand, investment decisions are discrete, which sometimes leads to a surplus of capacity (having spare capacity is better than not having enough). On the other hand, assumptions regarding relevant snapshots are rather extreme for this case study as DG contribution to meet peak demand is deemed zero. These facts, together with the uneven geographical location of loads and DG units, force the incremental model to reinforce several substations to be able to face any possible situation where new DG or demand is present.
Furthermore, Figure 34 shows the evolution of investments and maintenance costs (directly dependent on the models used) due to increases in DG and demand. In the scenarios with lower DG penetration, investments are mainly demand-driven and increasing demand results in an increase in distribution costs. On the contrary, a larger proportion of investment and maintenance costs for future DG scenarios are DG-driven. In the latter one, increasing demand may even result in a reduction of network costs. In the medium future DG penetration scenario costs amount to almost the same for both demand conditions, whereas in the high future DG penetration scenario the tendency is reversed and investment and maintenance costs are greater for the present demand level. As previously mentioned, the underlying reason is that higher consumption takes place at DG maximum output periods.

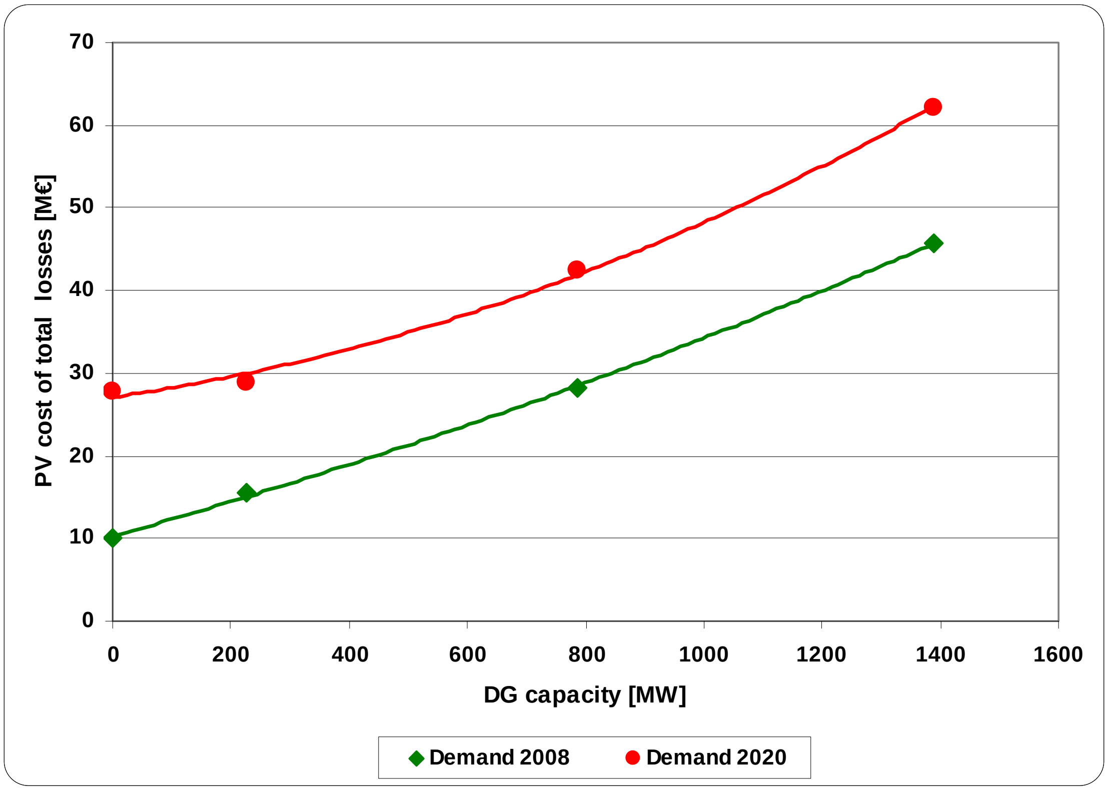


Figure 35: Evolution of total losses cost. Kop van Noord Holland, Netherlands.

The evolution of the present value of energy losses for each level of demand with the increase in installed DG capacity is shown in Figure 35. The evolution of the cost of losses is very similar to that of investment and maintenance costs. Despite not being homogenously distributed, network costs seem to be lower the more similar demand and generation in the system are. Another relevant feature of Figure 35 is that it shows that present values of the cost of energy losses are generally around ten times lower than investments plus maintenance costs.

Table 36: Breakdown of total costs per type of cost. Netherlands

	2008 Demand				2020 Demand			
	No DG	2008 DG	2020 DG (medium)	2020 DG (high)	No DG	2008 DG	2020 DG (medium)	2020 DG (high)
NPV total [M€]	138.87	168.33	389.51	601.47	286.67	308.31	415.91	614.70
Investment	66.16%	65.07%	64.77%	63.60%	62.99%	63.17%	62.89%	64.25%
Maintenance	26.62%	25.75%	27.98%	28.79%	27.35%	27.44%	26.90%	28.70%
Losses	7.22%	9.17%	7.26%	7.61%	9.66%	9.40%	10.21%	10.12%

Table 36 shows the present value of total costs and how much of them corresponds to each type of cost. For instance, in the current demand and current DG scenario, present value of total costs amounted to 168.3 M€; 65.1% due to investments, 25.8% to maintenance and 9.2% to energy losses. The aforementioned effect that network costs steadily increase as DG penetration grows, albeit at a lower

rate for the higher demand level, is shown again. Moreover, investments are the most significant cost factor, followed by maintenance, two times lower, and energy losses, from 6 to 9 times lower.
In order to compute the impact of DG on network costs, total costs in each scenario were compared to costs in those scenarios where no DG was present and the level of demand was the same. The difference between the costs in those two scenarios divided by total DG installed capacity is equal to the per unit incremental costs driven by DG.

Table 37: evolution of total incremental distribution cost per unit of DG installed in the Kop van Noord Holland area with the dg penetration level. Results for the 2008 and 2020 storylines are provide separately

	2008 Storyline			
DG Penetration Level	2008 DG	2020 DG (medium)	2020 DG (high)	2020 DG (extra high)
Total PV [€/kW DG]	130.13	318.27	332.71	275.84
Investment [€/kW DG]	78.01	203.68	209.05	174.95
Maintenance + Losses [€/kW DG]	52.12	114.59	123.65	100.88
	2020 Storyline			
DG Penetration Level	2008 DG	2020 DG (medium)	2020 DG (high)	2020 DG (extra high)
Total PV [€/kW DG]	95.58	164.12	235.93	207.87
Investment [€/kW DG]	62.67	102.89	154.18	134.87
Maintenance + Losses [€/kW DG]	32.91	61.23	95.32	73.00

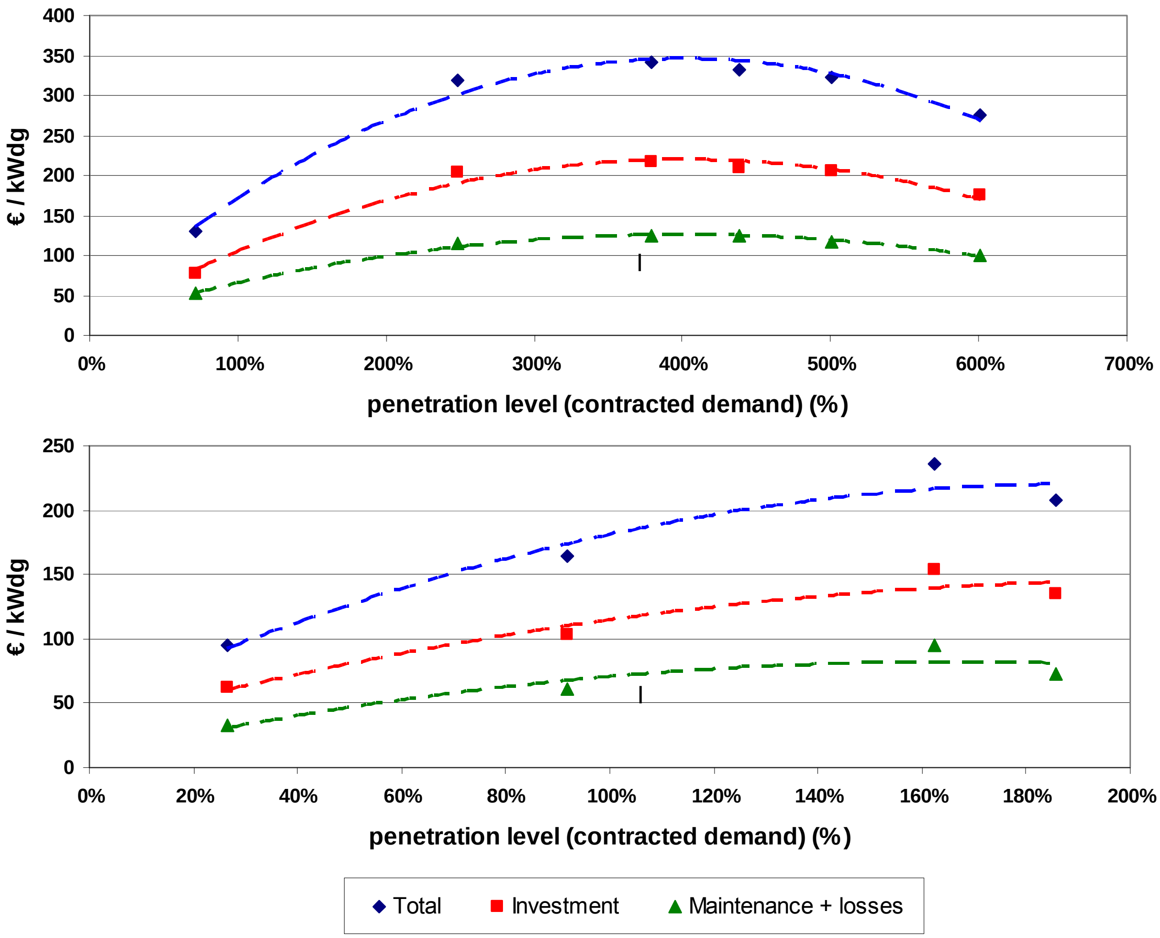


Figure 36: Incremental distribution costs of DG per installed kW of generation in the case study area in the Netherlands. Results for the 2008 (upper graphic) and 2020 (lower graphic) storylines are shown separately

Figure 36 and Table 37 represent the change in overall incremental costs per kW of DG as penetration levels increase. DG penetration is defined as the ratio of installed DG capacity to total consumers contracted demand. Contracted demand does not correspond to the actual peak demand, but it results from applying a scale factor equal to the inverse of the simultaneity factor to peak demand. Since both peak and valley demand situations were considered, the contracted power was deemed a more adequate variable. Incremental cost impacts shown here refer to the overall cost incurred by the system throughout the useful life of the grid, which is deemed to be between 30 and 40 years, in line with the estimate for the useful life of assets provided at the end of Appendix 1. Results for the 2008 (upper graphic) and 2020 (lower graphic) storylines are shown separately.

Two additional scenarios are included in Figure 36 for illustrative purposes. These were computed for the present level of demand (upper graphic). One was computed for a DG penetration level between the future medium and the future high ones. The other one was computed considering the same number and location of generators as in the future DG high scenario but considering plants with larger capacities than those in the future high DG scenario. The curves represented are the second degree polynomials that best fit the points obtained. Coefficients of determination are above 0.95 in all cases. They are aimed at identifying a tentative general trend in cost impacts. However, given the low number of points that have been used to draw these curves, we cannot claim that they correspond to the actual trend followed by costs. This is why these curves have been drawn using a dashed line.

Figure 36 shows that, for the Kop van Noord area, DG unit incremental costs follow an ascending pattern both in the 2008 and the 2020 storyline until they reach their maximum level. For costs in the 2008 storyline, this maximum is between 350% and 400% DG penetration level and its value is about 350€/kW_{DG}. On the other hand, for the 2020 storyline, this maximum level seems to be around the 200% DG penetration level and it seems to be about 235 €/kW_{DG}. Once they surpass this maximum level, unit incremental costs begin to decrease. In this case, no differentiation per technology can be made as the DSO Liander considered that network ought to be designed with no contribution from DG to meet peak demand, whereas DG, regardless of its kind, produced their rated power during valley hours. However, experience proves that there are certain technologies that may produce higher network benefits, or cause lower network costs, than others. Declining per unit DG-driven network costs obtained in the right hand side part of the curve for the 2008 storyline are probably due to economies of scale. Despite this decreasing trend in distribution costs for very high DG penetration levels, one cannot claim that total network costs should also decrease. As explained in section 5.2.5, the cost of reinforcements to the transmission grid that allow the connection of the distribution area to the rest of the system are significantly higher for high DG penetration levels than for lower ones. Consequently, overall transmission + distribution costs are liable to follow an upward trend.

Table 38: Unit annual incremental distribution costs associated with the integration of DG in the Kop van Noord Holand area (The Netherlands)

	2008 Storyline			
DG Penetration Level	2008 DG	2020 DG (medium)	2020 DG (high)	2020 DG (extra high)
*Total PV [€/kW DG *year]*	8.28	20.25	21.17	17.55
*Investment [€/kW DG*year]*	4.96	12.96	13.30	11.13
*Maintenance + Losses [€/kW DG*year]*	3.32	7.29	7.87	6.42
	2020 Storyline			
DG Penetration Level	2008 DG	2020 DG (medium)	2020 DG (high)	2020 DG (extra high)
*Total PV [€/kW DG *year]*	6.08	10.44	15.01	13.23
*Investment [€/kW DG*year]*	3.99	6.55	9.81	8.58
*Maintenance + Losses [€/kW DG*year]*	2.09	3.90	6.07	4.65

Finally, Table 38 and Figure 37 provide annual incremental costs of distribution, with respect to the corresponding no DG scenario, for different levels of penetration of DG. The evolution of annual unit distribution costs caused by DG with the level of DG penetration is completely analogous to that of the corresponding not annual, but overall, unit costs. However, computing annual cost is necessary in order to compare these to other cost components and come up with a single estimate of the overall impact of DG on system costs for each scenario. Similarly to what was done for total unit costs, results for the 2008 and 2020 storylines are provided separately.

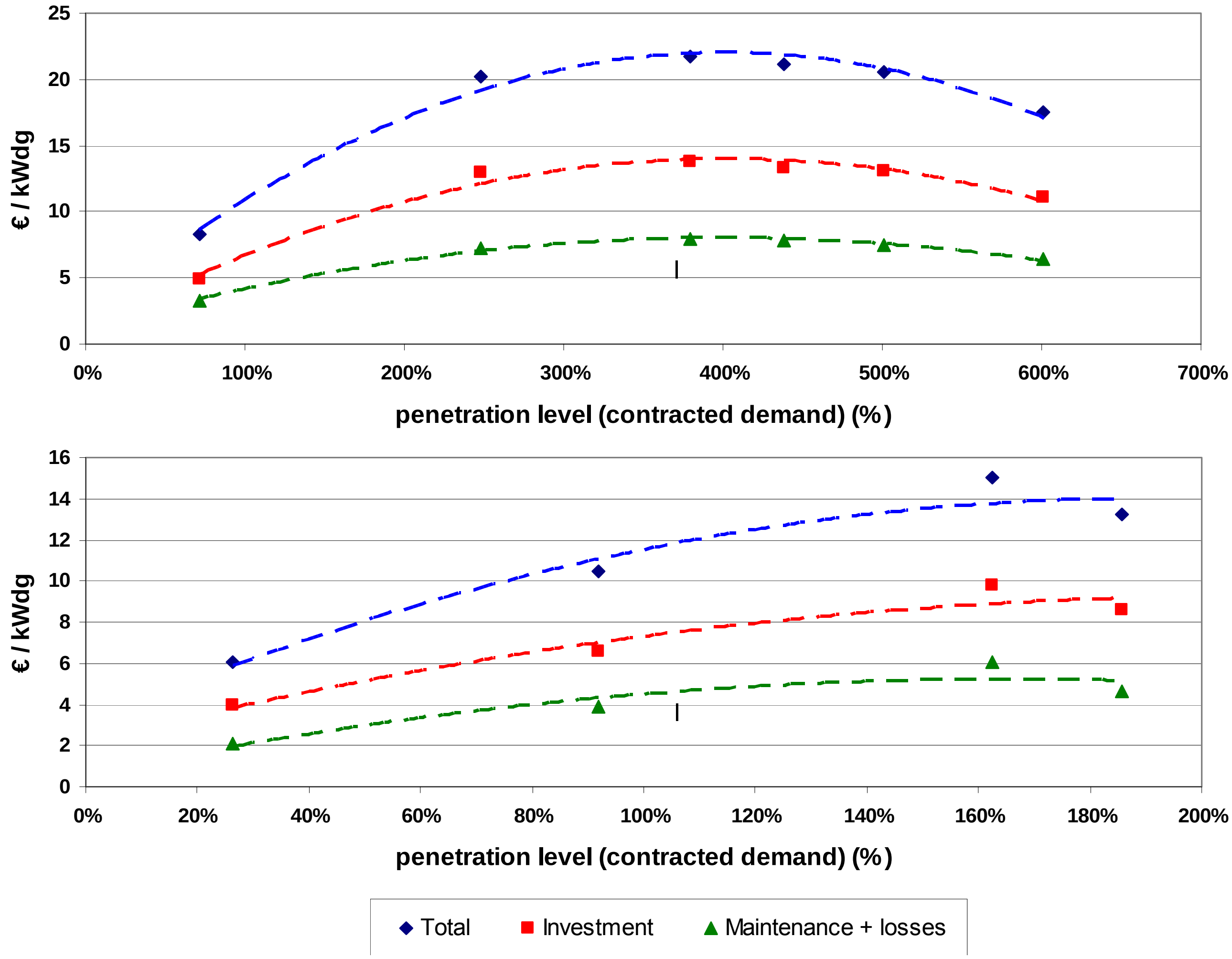


Figure 37: graphical representation of annual incremental distribution costs for the Kop van Noord Holand area. Evolution of these costs with the level of penetration of DG

5.2.2 Generation costs

Table 39, Table 40 and Table 41 present the results on the generation cost impact of DG/RES-E penetration in the Dutch case study area. Note that the cited cost figures reflect the total increase (or decrease) in generation cost for all the EU system, and not just for the electricity system in the Netherlands. This is especially relevant for the Dutch case study area since the Netherlands has a relatively high interconnectivity with neighboring electricity systems. This means that effects in the Dutch electricity system, caused by an increasing amount of DG/RES units connected to the Dutch electricity system, can easily give rise to effects in German and Belgian electricity systems as well. Results are presented for three different storylines and different levels of DG/RES integration.

Table 39: Assessment of variable generation cost impact of DG/RES in the Dutch system area (Kop van Noord Holland) (source: ECN)

Storyline	Unit	No DG	Status quo DG	Future low DG	Future high DG
2008 electricity system	[m€/year]	0,0	-16,0	-27,4	-36,4
	[€ / kW DG / year]	0,0	-70,8	-34,8	-22,9
2020 electricity system – low prices	[m€/year]	0,0	-16,3	-41,8	-78,3
	[€ / kW DG / year]	0,0	-72,0	-53,1	-49,3
2020 electricity system – high prices	[m€/year]	0,0	-5,7	-5,8	-22,1
	[€ / kW DG / year]	0,0	-25,3	-7,4	-13,9

Table 40: Assessment of fixed generation cost impact of DG/RES in the Dutch system area (Kop van Noord Holland) (source: ECN)

Storyline	Unit	No DG	Status quo DG	Future low DG	Future high DG
2008 electricity system	[m€/year]	0,0	15,3	47,8	98,8
	[€ / kW DG / year]	0,0	67,5	60,7	62,1
2020 electricity system – low prices	[m€/year]	0,0	15,1	45,7	97,8
	[€ / kW DG / year]	0,0	66,7	58,0	61,5
2020 electricity system – high prices	[m€/year]	0,0	13,2	42,8	90,1
	[€ / kW DG / year]	0,0	58,2	54,4	56,7

Table 41: Assessment of total generation cost impact of DG/RES in the Dutch system area (Kop van Noord Holland) (source: ECN)

Storyline	Unit	No DG	Status quo DG	Future low DG	Future high DG
2008 electricity system	[m€/year]	0,0	-0,8	20,4	62,4
	[€ / kW DG / year]	0,0	-3,4	25,9	39,2
2020 electricity system – low prices	[m€/year]	0,0	-1,2	3,8	19,5
	[€ / kW DG / year]	0,0	-5,3	4,9	12,3
2020 electricity system – high prices	[m€/year]	0,0	7,5	37,0	68,0
	[€ / kW DG / year]	0,0	33,0	47,0	42,8

For the case of the Netherlands, where more and more CHP and wind-based electricity generation is entering the electricity system and the distribution level in the case study area, we find that variable generation costs decrease. This has to do with the fact that, a substantial part of the new generation has very low variable costs compared to conventional generation existing before. The somehow erratic evolution of the impact of DG with the price of emissions and fuel has to do with the fact that, for very high prices, the introduction of DG results in an increase in the level of global demand that contributes to a relative increase in the global variable generation cost.

At the same time, we observe an increase in fixed generation costs. The latter implies that the yearly fixed generation costs (i.e. the annualized investment costs) for the new DG/RES units entering the system are higher than the yearly fixed generation costs of the generation units that run less hours a year as a consequence of the increased amount of DG/RES in the system. The net impact on fixed generation costs is negative: the yearly fixed generation costs increase across all storylines and in all DG/RES integration stages. The actual value varies from €13 million to €99 million per year. In terms of additional fixed generation costs related to the amount of additional kW of DG/RES capacity the range is given by €54 to €67 per $kW_{DG/RES}$ per year.

Although the separated impact on variable and fixed generation cost is unambiguous, the picture given by the total generation cost impact is less clear. We can not draw the conclusion that increasing DG/RES penetration always increases or decreases total generation costs. In the storylines representing the 2008 electricity system and the 2020 electricity system with low prices, total generation costs decrease for small DG/RES penetration levels but increase for larger ones. On the other hand, for the storyline representing the 2020 electricity system with high prices the increase in fixed generation always exceeds the decrease in variable generation costs. In other words, increasing the amount of DG/RES in the case study area always gives rise to an increase in overall generation costs.

5.2.3 Balancing costs

Annual unit balancing costs computed for the Dutch area using the methodology outlined in section 4.2.2 are provided in Figure 38 and Table 42. In both cases, results for the 2008 and 2020 storylines have been depicted separately. Dots in Figure 38 represent the DG penetration rate and annual unit balancing cost for each of the DG/RES penetration scenarios considered. Values for these points are provided in the table. These points (or dots) can be used to figure out the evolution of balancing costs with the DG penetration level, which is expressed as the ratio of installed DG to contracted load. Cost impacts in Figure 38 are expressed in €/kW of installed DG per annum. Lines drawn in Figure 38 correspond to the two-samples centered moving average curves that best fit the points computed. They are aimed at identifying a tentative general trend in cost impacts. However, given the low number of points that have been used to draw these curves, we cannot claim that they correspond to the actual trend followed by costs. This is why these curves have been drawn using a dashed line.

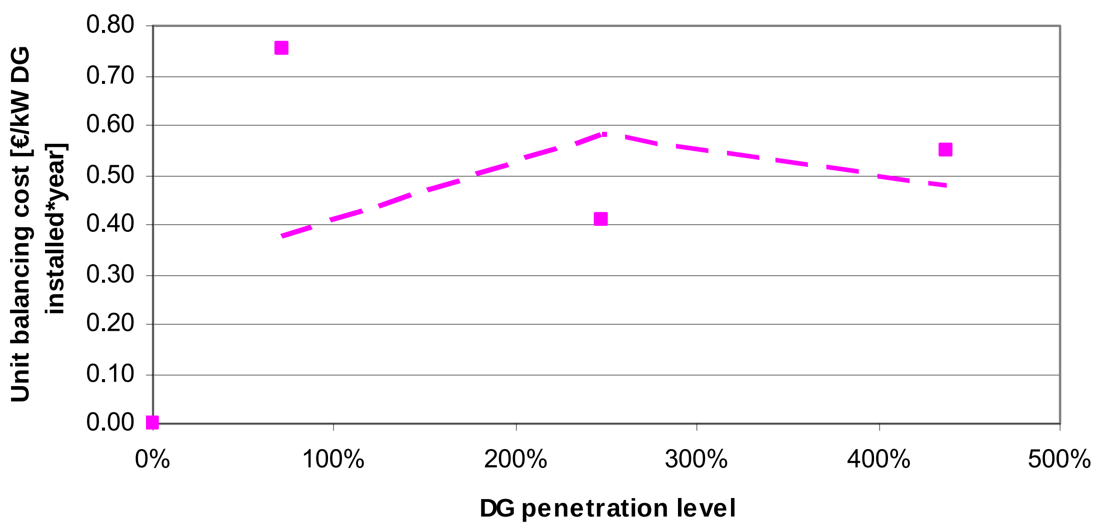
Both for the 2008 and the 2020 storylines, the impact of DG/RES in the Kop van Noord Holland area on system balancing costs seems to increase with the DG penetration level until it reaches its maximum level and then tends to decrease, though this trend does not seem to be so clear as that identified in the case of the Aranjuez area. The maximum unit cost impact for the 2008 storyline is 0.75 €/kW of DG installed per annum and it corresponds to a DG penetration level of 71%. That for the 2020 storyline is 2.24 €/KW of DG installed per annum and it corresponds to a DG penetration level of 26%.

The unit impact of DG on balancing costs is higher for the 2020 storyline than for the 2008 because the national penetration level of wind power capacity with respect to peak demand is deemed to be higher in 2020 in the Dutch electricity system. Thus, when similar DG/RES penetration rates in the Kop van Noord Holland area are considered, balancing costs incurred per unit of energy produced from wind are higher for those scenarios belonging to the 2020 storyline than for scenarios corresponding to the 2008 storyline.

Within each story line, the evolution of the unit impact of DG on balancing costs with the DG penetration level in the area depends solely on the ratio of total energy produced from wind in the area to the total capacity of DG/RES installed in the area.

Table 42: Unit balancing costs for different load and DG levels in Kop van Noord Holland area (The Netherlands)

	2008 Storyline No DG	***2008 Storyline 2008 DG***	***2008 Storyline 2020 DG Low***	***2008 Storyline 2020 DG High***
Wind power capacity country [GW]	1.3	1.3	1.3	1.3
Total gross demand [TWh]	116	116	116	116
Peak load factor	1.39	1.39	1.39	1.39
Pwind/PL,max	0.07	0.07	0.07	0.07
Specific cost per MWh Wind [€/MWh]	0.70	0.70	0.70	0.70
DG penetration level in area [%]	0%	71%	248%	438%
Annual wind production area [MWh]	0	244200	465031	1092161
Installed DG Capacity in area [MW]	0	226.4	787.5	1389.65
*Unit balancing cost [€/(kW DG*year)]*	0.00	0.75	0.41	0.55
	2020 Storyline No DG	***2020 Storyline 2008 DG***	***2020 Storyline 2020 DG Low***	***2020 Storyline 2020 DG High***
Wind power capacity country [GW]	6.7	6.7	6.7	6.7
Total gross demand [TWh]	143	143	143	143
Peak load factor	1.39	1.39	1.39	1.39
Pwind/PL,max	0.30	0.30	0.30	0.30
Specific cost per MWh Wind [€/MWh]	2.07	2.07	2.07	2.07
DG penetration level in area [%]	0%	26%	92%	162%
Annual wind production area [MWh]	0	244200	465031	1092161
Installed DG Capacity in area [MW]	0	226.4	787.5	1389.65
*Unit balancing cost [€/(kW DG*year)]*	0.00	2.24	1.23	1.63



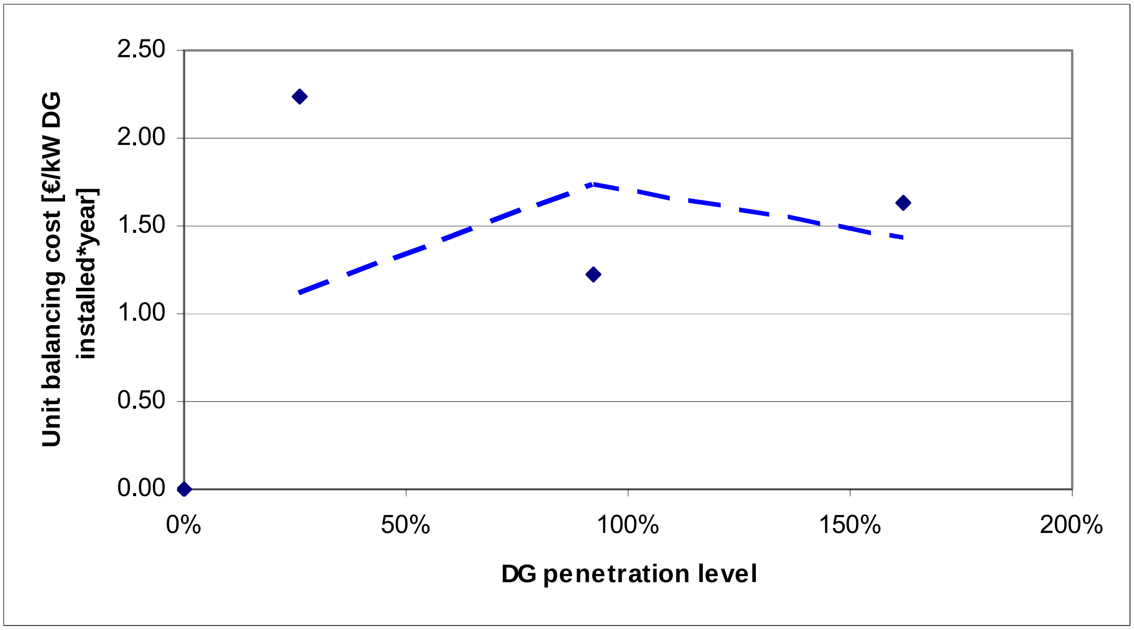


Figure 38: evolution of unit balancing cost (per MW of installed DG capacity) with the level of DG/RES penetration for 2 different levels of load in the Dutch area (current load and future load)

5.2.4 External costs

Table 43 provides numerical results corresponding to the impact of DG/RES integration in the Dutch case study area on external costs. As was explained earlier the driver of external cost impact results is the change in the deployment of specific electricity generation technologies and units. Generally, DG/RES-based electricity generation has relatively lower external cost per unit of electricity produced than conventional electricity generation technologies that will be producing less electricity in the situation where more and more DG/RES enters the electricity generation mix.

Table 43: assessment of the impact of DG/RES in the Dutch system area (Kop van Noord Holland) on external costs (source ECN)

Storyline	Unit	No DG	Status quo DG	Future low DG	Future high DG
2008 electricity system	[m€/year]	0,0	-1,0	-2,7	-6,8
	[€ / kW DG / year]	0,0	-4,5	-3,4	-4,3
2020 electricity system – low prices	[m€/year]	0,0	-1,0	-3,3	-7,2
	[€ / kW DG / year]	0,0	-4,5	-4,1	-4,5
2020 electricity system – high prices	[m€/year]	0,0	-2,3	-7,4	-11,9
	[€ / kW DG / year]	0,0	-10,0	-9,4	-7,5

The results presented in Table 43 show that total external costs in the case of DG/RES penetration in the Dutch case study area decrease when the amount of DG/RES increases. Total external costs decrease with about €1 million to €12 million per year, depending on the actual amount of DG/RES additionally connected to the electricity system and depending on the considered storyline (i.e.

generation mix, demand level and level of fuel prices). When these total yearly figures are related to the actual amount of DG/RES capacity we find that the decrease amounts to €3 to €10 per $kW_{DG/RES}$ per year. The largest decrease in external costs is observed for the storyline representing the 2020 electricity system with high prices.

5.2.5 Transmission costs

As mentioned in section 4.2.3, the impact of DG/RES in the case study area for The Netherlands on the cost of connecting this area to others has been considered in our study. Reinforcements expected by the DSO in the area for the different scenarios considered are depicted in Table 44 together with their cost.

Table 44: cost of reinforcements to be made to the interconnection area between the Kop van Noord Holland area and the rest of the system in the different DG/RES-demand scenarios

demand	***DG***	***m€ Westwoud Station***	***m€ Westwoud Oterleek***	***Remark***
2008	NO	10	36	
2008	DG 2008	10	36	
2008	DG 2020 medium	15	72	
2008	DG 2020 high	45	250	380 kV/150 kV
2020	NO	15	72	
2020	DG 2008	15	72	
2020	DG 2020 medium	15	72	
2020	DG 2020 high	45	250	380 kV/150 kV

Based on this information, we have computed the increase in connection capacity costs caused by the installation of DG in each scenario (with respect to the corresponding no DG scenario). This is provided in Table 45. Annual figures have been computed considering a discount rate of 5.66% and a useful life of lines of 40 years.

Table 45: Total increase in transmission interconnection capacity costs due to DG in each scenario (with respect to the corresponding no-DG scenario)

Demand scenario	***Unit***	***No DG***	***Status quo DG***	***Future low DG***	***Future high DG***
2008	*[m€]*	0.0	0.0	41.0	249.0
	[m€/year]	0.0	0.0	2.6	15.8
	[€/kW DG/year]	0.0	0.0	3.3	11.4
2020	*[m€]*	0.0	0.0	0.0	208.0
	[m€/year]	0.0	0.0	0.0	13.2
	[€/kW DG/year]	0.0	0.0	0.0	9.5

5.2.6 Total electricity supply costs

Table 46 and Figure 39 show the impact on total supply costs of the installation of DG in the Kop van Noord Holland area for different DG penetration levels. Results for the 2008 and 2020 storylines are provided in separate tables and graphics. Besides total supply costs, the evolution of the different cost components with the DG penetration level is also provided, though the impact of DG on each cost component has already been discussed in previous subsections. Table 46 and Figure 39 provide, for each DG/RES scenario that has been defined within a certain storyline in the Dutch area, the unit impact of DG/RES (per kW of DG/RES installed) on each of the cost components considered, as well as the unit impact on total supply costs. Numerical results provided are annual.

The general trend followed by total costs with increasing levels of DG in the Dutch area seems to be basically the same in the 2008 and 2020 backgrounds. In both cases, this trend is dominated by fixed and variable generation cost components. As mentioned in section 5.1.2, impact of DG on fixed costs is positive (these costs increase) because the unit investment costs of DG generation technologies (renewables and CHP) are higher than those of conventional generation that is partially replaced by the former. Besides, the low capacity credit of some of the generation installed in the Kop van Noord Holland area (this is the case of wind power) results in conventional generation capacity still having to provide most of the firm generation capacity in the system. Thus, the decrease in conventional generation capacity caused by the installation of DG in this area is well below the amount of DG generation capacity installed. The evolution of fixed generation costs is quite similar in both storylines.

The impact of DG on variable generation cost is negative (these costs decrease) because fuel costs and other operation costs incurred by new DG are clearly below those of conventional generation. Besides, the amount of CO2 emitted by DG (wind capacity that exist in the area) is almost negligible, compared to significantly larger amount of CO2 emitted when producing conventional generation energy that is now replaced by DG generation one. Figures for the 2020 scenario correspond to the case where fuel and CO2 prices in the 2020 horizon are deemed to be moderate.

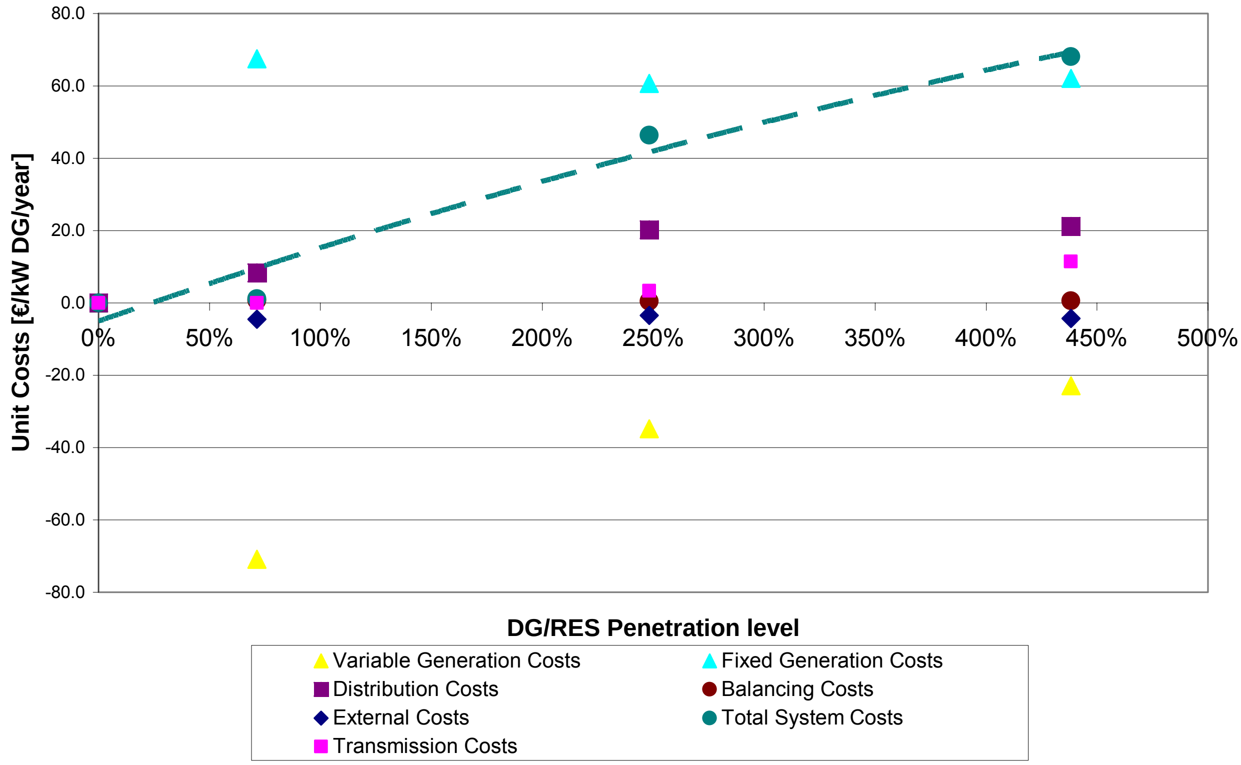
The main difference between the evolution of fixed and variable generation costs with the DG penetration level lies in the fact that, in both storylines, demand served in the high penetration scenarios increases with respect to that in low penetration ones (decrease in energy prices prompts some loads to increase their power consumption). This extra energy consumed will be provided partly by DG/RES capacity and partly by expensive marginal conventional generation capacity, which will increase variable costs. Besides, in the higher DG penetration scenarios extra DG mainly is CHP power, whose variable costs of CHP are much more similar to those of conventional generation than costs of wind generation. This two effects combined mean that average decrease in variable costs per unit of DG/RES installed will be lower in high penetration than in low penetration scenarios. The average unit variable cost of generation in scenarios where demand increases must necessarily be higher than that in scenarios where demand does not. Consequently, the average (negative) impact of DG on variable costs in high DG penetration scenarios will be smaller than that in low penetration ones. This is much more significant in scenarios corresponding to the 2008 storyline, where the increase in demand with the level of DG is much higher than for scenarios in the 2020 storyline. The latter effect has to do with the fact that the reduction in prices caused by DG in 2008, where fuel prices were very high, is deemed to be higher than the reduction caused by DG in the 2020 business as usual background, where prices are expected to be lower. The evolution of unit fixed generation costs is quite stable with the level of DG penetration. This is probably related to the similar unit investment costs of wind capacity and CHP. Lastly, one must stress here that the impact of the cost of reinforcements of connection to the

transmission grid on overall socio-economic costs for the higher DG/RES penetration scenarios is non negligible.
All in all, the evolution of total costs in each storyline with the level of DG penetration depends mainly on the composition of the generation mix that exists in the area, as explained in subsection 5.1.6 for the Aranjuez area, and the changes in demand prompted by changes in the DG penetration level.
The unit DG/RES impact on total supply costs is positive for every DG penetration level that has been considered but the very low ones both in the 2008 storyline and in the 2020 storyline (overall costs increase because of the introduction of DG). The general trend seems to indicate that for sufficiently high DG penetration rates the unit impact always becomes positive (costs increase). Another important consideration to make lies in the fact that high DG penetration rates considered in the 2008 storyline are much higher than those in the 2020 storyline. This may impact unit distribution costs, among other cost components.

Table 46: Evolution of the impact of DG in the Kop van Noord Holland area on total supply costs with the DG penetration level. Results for the 2008 and 2020 storylines are provided in separate tables

Scenarios	2008 DEMAND			
	No DG	Current DG	Future DG (medium)	Future DG (High)
DG penetration level [%]	0%	71%	248%	438%
Cost concepts				
Variable Generation Costs [€/kW installed DG/year]	0.0	-70.8	-34.8	-22.9
Fixed Generation Costs [€/kW installed DG/year]	0.0	67.5	60.7	62.1
Distribution Costs [€/kW installed DG/year]	0.0	8.3	20.3	21.2
Balancing costs [€/kW installed DG/year]	0.0	0.8	0.4	0.5
External Costs [€/kW installed DG/year]	0.0	-4.5	-3.4	-4.3
Transmission Costs [€/kW installed DG/year]	0.0	0.0	3.3	11.4
Total cost [€/kW installed DG/year]	0.0	1.2	46.4	68.1

Scenarios	2020 DEMAND			
	No DG	Current DG	Future DG (medium)	Future DG (High)
DG penetration level [%]	0%	26%	92%	162%
Cost concepts				
Variable Generation Costs [€/kW installed DG/year]	0.0	-72.0	-53.1	-49.3
Fixed Generation Costs [€/kW installed DG/year]	0.0	66.7	58.0	61.5
Distribution Costs [€/kW installed DG/year]	0.0	6.1	10.4	15.0
Balancing costs [€/kW installed DG/year]	0.0	2.2	1.2	1.6
External Costs [€/kW installed DG/year]	0.0	-4.5	-4.1	-4.5
Transmission Costs [€/kW installed DG/year]	0.0	0.0	0.0	9.5
Total cost [€/kW installed DG/year]	0.0	-1.5	12.4	33.9



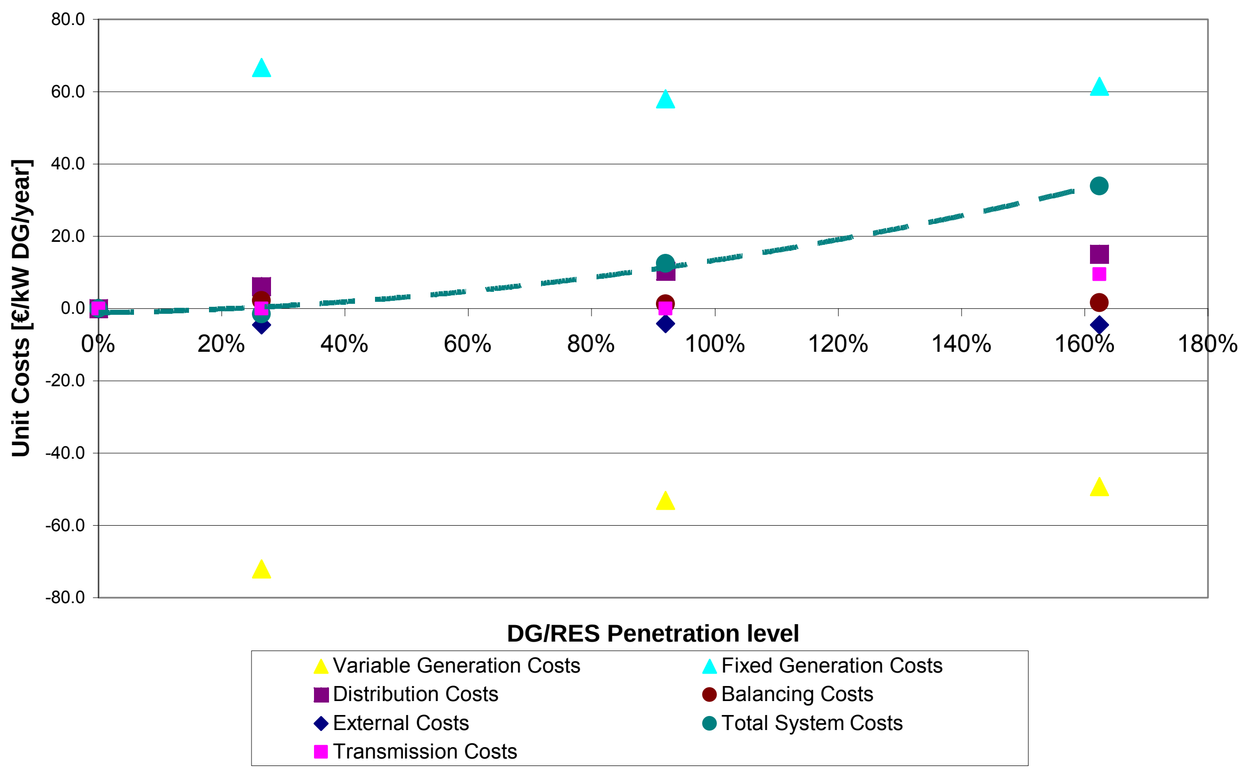


Figure 39: Evolution of the impact of DG in the Kop van Noord Holland area on total supply costs with the DG penetration level. Results for the 2008 (upper graphic) and 2020 (lower graphic) storylines are provided in separately

5.2.7 Social Welfare

Table 47, Table 48 and Table 49 present the impact of integrating DG/RES in the Dutch case study area on the welfare of producers and consumers. Given the large number of interconnections that exist between the electric system in The Netherlands and others, the fact that DG/RES-E penetrates the Dutch system has consequences for other electricity systems in the EU as well. The reported impact on consumer and producer surplus is a total for the whole EU, and is not only reflecting the impact only in the Netherlands. The penetration of more and more DG/RES in the Dutch case study area causes a decrease in the average electricity price level on the Dutch market. Due to interconnections with neighboring electricity systems, also the electricity demand and supply situation abroad is affected. Results presented correspond to the welfare impact in the different identified storylines (which vary in generation mix, demand level and level of prices), for different stages of DG/RES integration in the case study area.

Table 47: assessment of the impact of DG/RES in the Dutch system area (Kop van Noord Holland) on consumer surplus (source: ECN)

Storyline	Unit	No DG	Status quo DG	Future low DG	Future high DG
2008 electricity system	[m€/year]	0,0	0,4	79,1	275,6
	[€ / kW DG / year]	0,0	1,7	100,4	173,4
2020 electricity system – low prices	[m€/year]	0,0	0,2	11,5	78,7
	[€ / kW DG / year]	0,0	0,8	14,6	49,5
2020 electricity system – high prices	[m€/year]	0,0	62,7	208,8	395,6
	[€ / kW DG / year]	0,0	277,0	265,2	248,9

Table 48: assessment of the impact of DG/RES in the Dutch system area (Kop van Noord Holland) on producer surplus (source: ECN)

Storyline	Unit	No DG	Status quo DG	Future low DG	Future high DG
2008 electricity system	[m€/year]	0,0	15,7	-36,1	-184,7
	[€ / kW DG / year]	0,0	69,4	-45,9	-116,2
2020 electricity system – low prices	[m€/year]	0,0	16,1	32,6	15,2
	[€ / kW DG / year]	0,0	71,3	41,4	9,6
2020 electricity system – high prices	[m€/year]	0,0	-42,4	-154,3	-280,1
	[€ / kW DG / year]	0,0	-187,2	-196,0	-176,2

Table 49: assessment of the impact of DG/RES in the Dutch system area (Kop van Noord Holland) on social welfare (source: ECN)

Storyline	Unit	No DG	Status quo DG	Future low DG	Future high DG
2008 electricity system	[m€/year]	0,0	16,1	43,0	90,9
	[€ / kW DG / year]	0,0	71,1	54,6	57,2
2020 electricity system – low prices	[m€/year]	0,0	16,3	44,1	93,9
	[€ / kW DG / year]	0,0	72,1	56,0	59,1

2020 electricity system – high prices	[m€/year]	0,0	20,3	54,5	115,5
	[€ / kW DG / year]	0,0	89,8	69,2	72,7

Overall social welfare in the European electricity system increases in all scenarios and in all cases as a result of the installation of DG/RES in the Dutch case study area. This is mainly caused by an increase in consumer surplus, which in turn can be explained by the decrease in electricity prices. The impact on consumer surplus seems robust: consumer surplus increases in all cases. The impact of increasing the amount of DG/RES in the case study area on producer surplus is ambiguous however. In some of the analyzed cases the decrease in electricity prices is not able to compensate the electricity producers for the decrease in variable generation costs, resulting in a negative producer surplus impact. However, especially for the cases that assume a 2020 electricity system with low prices this is not the case: there electricity prices still decrease resulting in less electricity revenues, but the decrease in revenues is exceeded by the decrease in variable generation costs. For society as a whole the penetration of DG/RES in the Dutch case study area seems beneficial. The increase in total welfare varies from €16 million per year at low DG/RES penetration levels to more than €100 million per year at higher penetration levels.

5.2.8 Overall socio-economic cost

This subsection provides a quantification of the total impact on the socio economic cost of the system being penetrated by DG/RES in the Kop van Noord Holland area. The methodology followed to compute the overall socio-economic impact of DG is explained in section 4.2.7. Table 50 and Figure 40 provide, for each DG/RES scenario that has been defined within a certain storyline in the Dutch area, the unit impact of DG/RES (per kW of DG/RES installed) on each of the cost components considered, as well as the unit impact on total socio economic system cost. Numerical results provided are annual.

The evolution and general trend of socio-economic costs in the 2008 storyline is rather similar to that followed by total supply costs. Changes in the social surplus and capital generation cost dominate changes in the remaining cost components. The only difference lies in the fact that for high penetration levels both in the 2008 and the 2020 storylines, demand served in the system increases as a result of the introduction of DG in the kop van Noord Holland area. This yields a benefit for the system corresponding to the difference between the utility that extra demand extracts from energy and its cost. Consequently, in these scenarios there is a decrease in the socio-economic impact of DG with respect to the impact on supply costs. Lastly, as explained when computing overall supply costs, one must stress here that the impact of the cost of reinforcements of connection to the transmission grid on overall socio-economic costs for the higher DG/RES penetration scenarios is non negligible.

Results on total system costs obtained for the different scenarios show a relatively low dispersion around the curve used to fit them. However, one must take into account that these results correspond to situations that not only differ in the amount of DG capacity installed but also in the relative composition of the generation mix, which may vary from one scenario to another within the same storyline.

Table 50: computation of the overall socio-economic impact of DG/RES in the Kop van Noord Holland area. Results for the 2008 and 2020 storylines are provide separately

Scenarios	2008 DEMAND			
	No DG	Current DG	Future DG (medium)	Future DG (High)
DG penetration level [%]	0%	71%	248%	438%
Cost concepts				
Socio Economic Cost Dispacth [€/kW installed DG/year]	0.0	-71.1	-54.6	-57.2
Fixed Generation Costs [€/kW installed DG/year]	0.0	67.5	60.7	62.1
Distribution Costs [€/kW installed DG/year]	0.0	8.3	20.3	21.2
Balancing costs [€/kW installed DG/year]	0.0	0.8	0.4	0.5
External Costs [€/kW installed DG/year]	0.0	-4.5	-3.4	-4.3
Transmission Costs [€/kW installed DG/year]	0.0	0.0	3.3	11.4
Total cost [€/kW installed DG/year]	0.0	0.9	26.7	33.7

Scenarios	2020 DEMAND			
	No DG	Current DG	Future DG (medium)	Future DG (High)
DG penetration level [%]	0%	26%	92%	162%
Cost concepts				
Socio Economic Cost Dispacth [€/kW installed DG/year]	0.0	-72.1	-56.0	-59.1
Fixed Generation Costs [€/kW installed DG/year]	0.0	66.7	58.0	61.5
Distribution Costs [€/kW installed DG/year]	0.0	6.1	10.4	15.0
Balancing costs [€/kW installed DG/year]	0.0	2.2	1.2	1.6
External Costs [€/kW installed DG/year]	0.0	-4.5	-4.1	-4.5
Transmission Costs [€/kW installed DG/year]	0.0	0.0	0.0	9.5
Total cost [€/kW installed DG/year]	0.0	-1.6	9.5	24.1

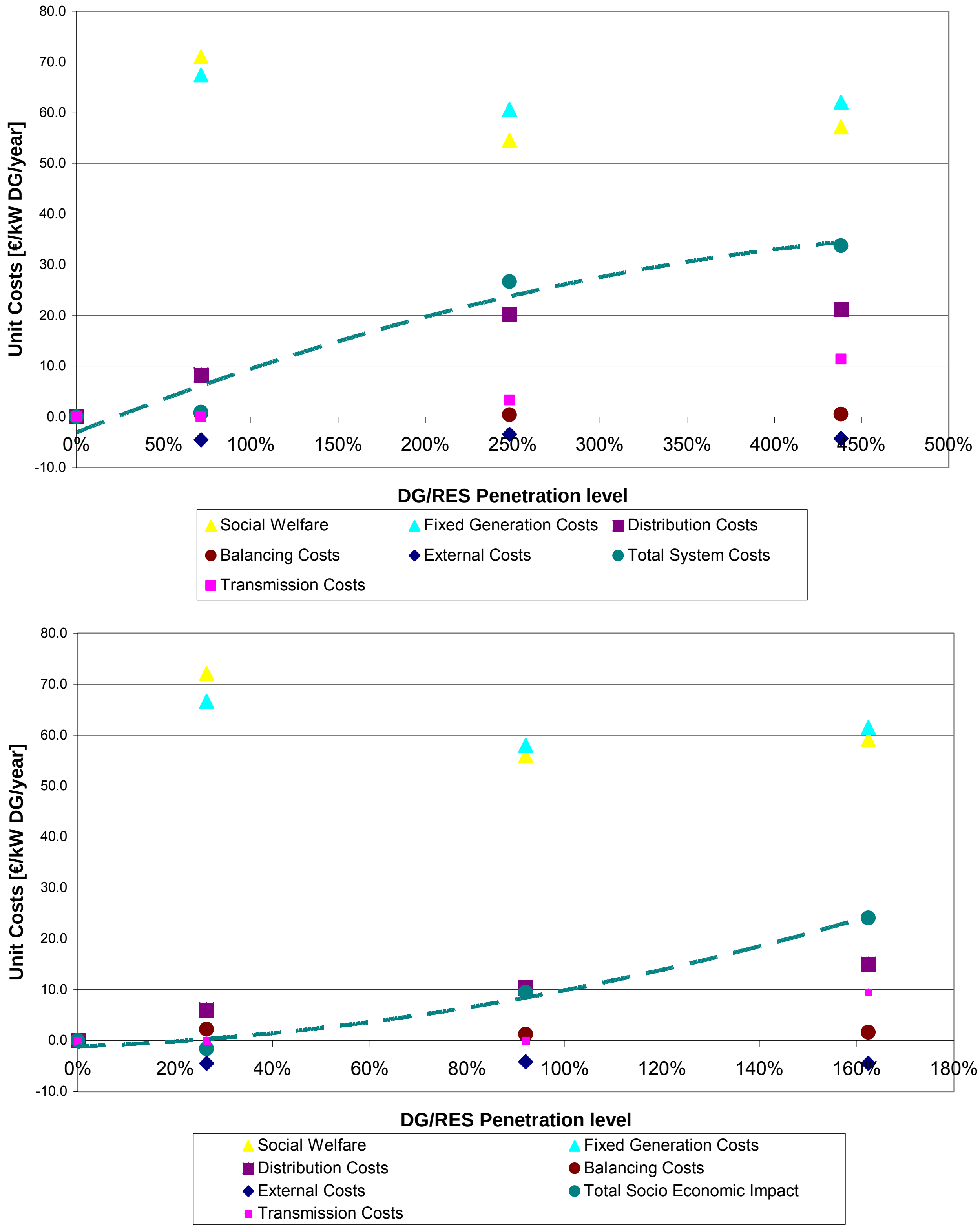


Figure 40: evolution of total socio-economic impact of DG in the Kop van Noord Holland area with the DG penetration level. Results for the 2008 storyline are provided in the upper figure. Those for the 2020 storyline are provided in the lower one

5.3 German area

The German case study corresponds to a purely residential area. In spite of the fact that DG penetration is almost negligible nowadays, DSO MVV Energy selected this area to study the development of solar PV panels and domestic CHP units. Assumptions are that CHP is producing at times of peak demand, whereas PV is not. Demand growth during the period 2008-2020 is very low and only takes place as vertical increments (see Table 65 in Appendix 1).

5.3.1 Distribution costs

Next, both numerical results and the resulting networks produced by the network reference models are provided for the Mannheim area. Costs considered include: investment, energy losses and maintenance. Eight scenarios with different patterns of electricity consumption and DG have been evaluated for the German case study. These comprise the main figures corresponding to network elements that are installed to cope with the integration of DG in the system operation, e.g. length of lines, per type of line, installed transformation capacity and broken down costs.

Table 51: Network elements for the Mannheim area. Germany

		MV network [km]	MV/LV transforming centres		LV network [km]
			number	Capacity [MVA]	
2008 Demand	No DG	46.0	49	9.9	110.0
	2008 DG	46.0	49	9.9	110.0
	2020 DG (medium)	53.4	50	14.3	122.5
	2020 DG (high)	64.2	49	25.9	151.0
2020 Demand	No DG	57.4	51	10.9	109.4
	2008 DG	57.4	51	10.9	109.4
	2020 DG (medium)	46.7	56	13.7	121.1
	2020 DG (high)	43.0	47	27.0	157.1

Table 51 provides an overview of the amount of assets of each type included in the optimal transmission network computed for the Mannheim area in each of the considered scenarios. Some of the transforming centres included in Table 51 may have more than one transformer, since, in some scenarios, the incremental model algorithms decided to reinforce existing transforming centres rather than building new ones for some scenarios.

Increments in network assets due to the introduction of DG have been computed with respect to the no-DG scenario for the corresponding level of demand. Hence, Figure 41 shows the increments in network length and transformation capacity that are required to cope with a certain DG penetration level. These have been expressed as percentages of the aggregate cost of the corresponding assets in the no-DG same demand scenario.

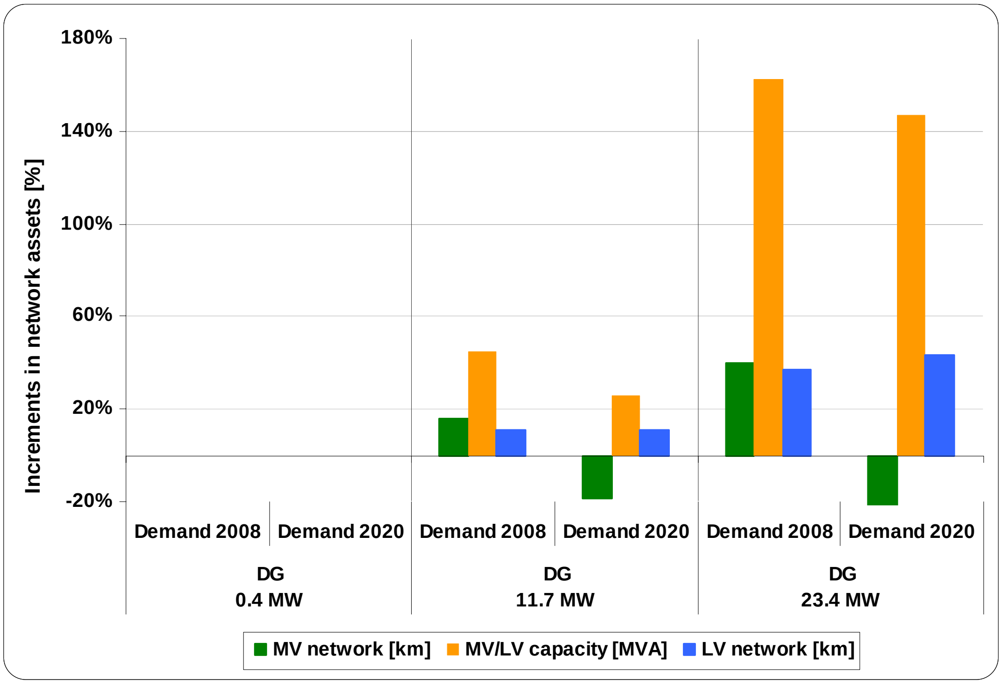


Figure 41: Increments in network assets with respect to the no-DG scenarios. They have been expressed as percentages of the total cost of these assets in the reference scenario. Germany

Once again, the possibility to defer investments thanks to the integration of DG is not realized in this case study. Herein, DG is connected at LV level at the same point as loads. This would generally mean lower power flows through the network and lesser network requirements. However, present penetration levels are very low and insufficient to cause significant savings. On the other hand, future penetration levels that are considered exceed peak demand at LV level and most installed capacity takes place for solar PV which, in this case, is deemed not to be producing at peak demand periods. Consequently, network length and transformation capacity steadily grows as DG penetration rises.

Table 52: Breakdown of total costs per network level. Germany

		2008 Demand				2020 Demand			
		No DG	2008 DG	2020 DG (medium)	2020 DG (high)	No DG	2008 DG	2020 DG (medium)	2020 DG (high)
Investment [M€]	Total	23.0	23.1	29.0	37.2	25.1	25.2	27.5	35.6
	MV network	40.6%	40.6%	39.9%	36.3%	45.4%	45.3%	37.1%	28.9%
	MV/LV TCs	7.5%	7.4%	8.3%	10.6%	7.3%	7.3%	8.7%	11.1%
	LV network	51.9%	52.0%	51.7%	53.0%	47.3%	47.3%	54.3%	60.0%
PV Maintenance [M€]	Total	1.8	1.8	2.3	2.9	2.0	2.0	2.1	2.7
	MV network	26.1%	26.1%	25.2%	21.4%	29.7%	29.7%	19.4%	14.8%
	MV/LV TCs	35.8%	35.8%	39.4%	43.1%	34.8%	34.8%	43.5%	43.5%
	LV network	38.1%	38.1%	35.5%	35.5%	35.5%	35.5%	37.2%	41.6%
PV Total [M€]	Total	26.0	26.0	32.5	41.8	28.4	28.3	30.9	40.1
	MV network	38.8%	38.7%	37.9%	34.3%	43.3%	43.3%	35.3%	27.4%
	MV/LV TCs	11.4%	11.2%	12.0%	13.8%	11.1%	10.9%	12.1%	14.1%
	LV network	49.8%	50.1%	50.1%	51.9%	45.6%	45.8%	52.6%	58.5%

Similarly to what happens in the Dutch case study, network costs increase as DG penetration level grows (see Table 52). This trend may be altered when load is comparable in size to generation, thus contributing to a significant decrease in flows. Nevertheless, demand growth in Mannheim is considerably smaller than that in Kop van Noord Holland, which originates very high penetration levels of DG in the LV network. Besides, as mentioned earlier, the contribution of DG in the low voltage network (mainly PV) to reduce net demand is quite small. In addition, one can see how the relative weight of MV/LV transforming centres increases for higher DG penetration levels. In these situations, net generation in the minimum demand and maximum DG production snapshots is dominant and leads to greater reinforcements of transformation capacity.

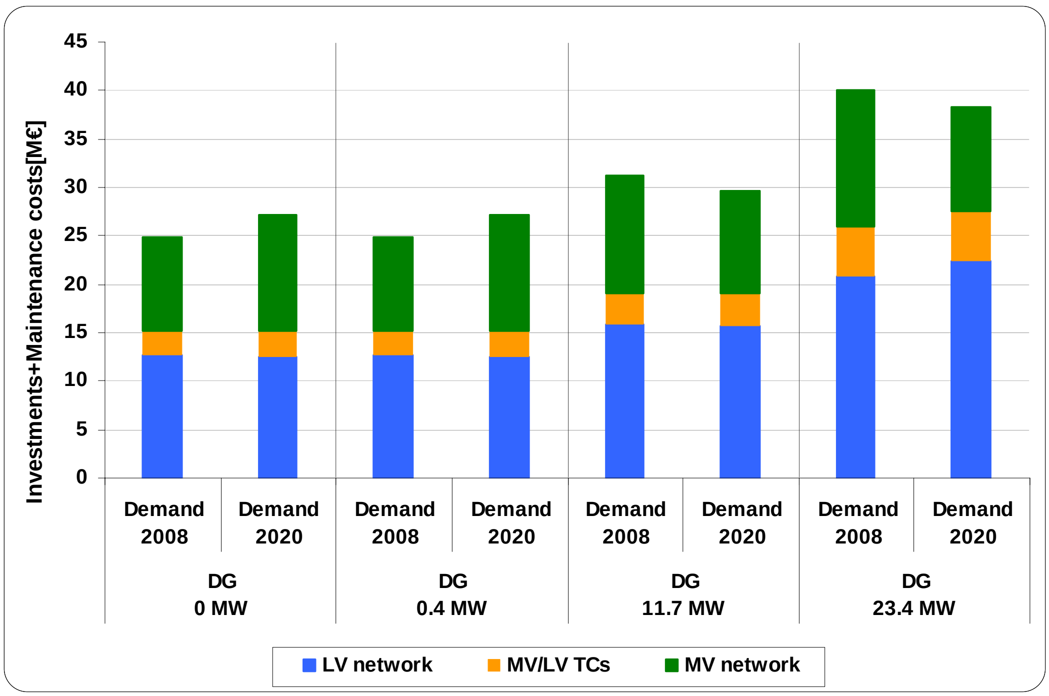


Figure 42: Investment and maintenance costs. Mannheim, Germany

In the Mannheim case study, LV networks are generally the most important investment and maintenance cost component (see Figure 42). This effect heightens for greater DG penetration levels. The cost of MV/LV transforming centres increases as well, whereas the cost of MV networks decreases (in relative terms). These results are reasonable since all DG units are connected at LV. Therefore, most reinforcements take place at this level. This effect is strengthened by the fact that most DG installed capacity correspond to PV solar, which, in this study, is supposed not to produce any power at all during maximum demand periods while it is deemed to be at its maximum during valley hours.

The evolution of investments and maintenance costs in the different scenarios is shown in Figure 42. In those scenarios with null or very low DG penetration, investments are essentially demand-driven. On the contrary, a larger proportion of investment and maintenance costs for future DG scenarios are DG-driven. Actually, for both future-DG-penetration scenarios, investment and maintenance costs when considering the 2020 demand are below those corresponding to the situation where demand is at its 2008 level. These savings in network costs are due to the fact that higher loads result in lower net production in the area at times when DG output is at its maximum.

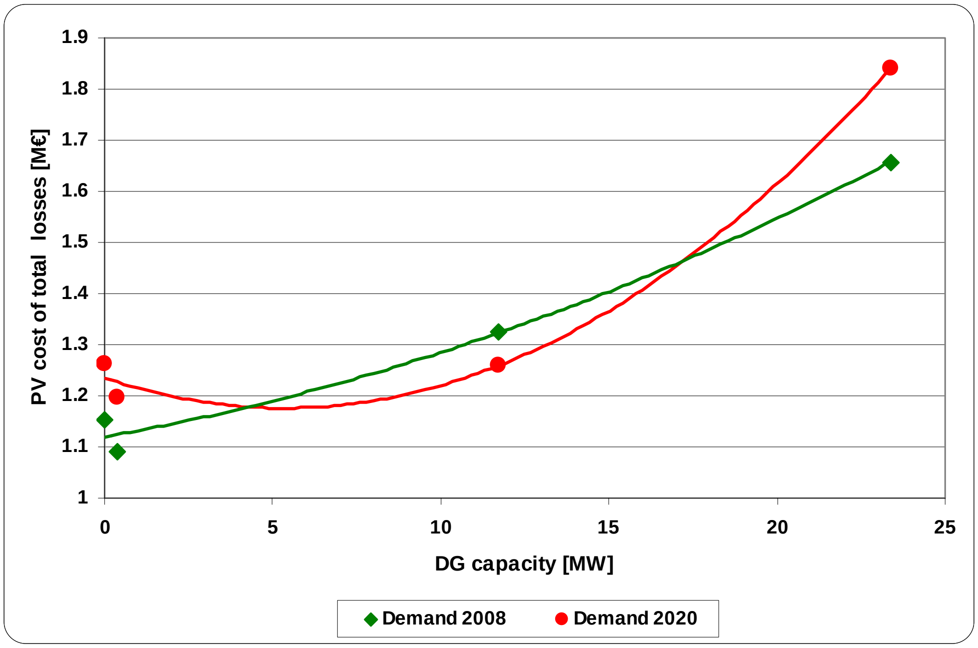


Figure 43: Evolution of total losses cost. Mannheim, Germany

The evolution of the present value of energy losses with DG penetration levels for each level of demand is shown in Figure 43. In this case, an initial reduction in the costs of losses is observed for low DG penetration levels with respect to the no-DG scenario. However, for the future DG penetration levels these tend to increase again. Considering an amount of DG equal to that in the future medium DG scenario, one can see how energy losses are lower for the 2020 demand level than for the 2008 level. Higher demand at LV level, where demand will be lower in the future than DG, results in lower DG penetration levels and, hence, lower flows than for 2008 demand. However, losses represent a small fraction of total distribution costs in this area (between 4 and 5% of total costs, as shown in Table 53). Thus, differences in the cost of losses do not yield significant benefits to the system and are unlikely to have a strong influence on the development of the grid. The present values of the cost of energy losses are about twenty times lower than investments plus maintenance costs in all the scenarios considered.

Table 53: Breakdown of total costs per type of cost. Germany

	2008 Demand				2020 Demand			
	No DG	2008 DG	2020 DG (medium)	2020 DG (high)	No DG	2008 DG	2020 DG (medium)	2020 DG (high)
PV total [M€]	26.0	26.0	32.5	41.8	28.4	28.3	30.9	40.1
Investment	88.5%	88.7%	89.0%	89.0%	88.6%	88.8%	89.0%	88.7%
Maintenance	7.1%	7.1%	6.9%	7.0%	6.9%	6.9%	6.9%	6.7%
Losses	4.4%	4.2%	4.1%	4.0%	4.4%	4.2%	4.1%	4.6%

Table 53 shows that the most relevant cost factor to take into account when developing the grid is investment costs, whereas energy losses and maintenance are much less influential cost factors. This is explained by the cost structure of network elements reported by DSO MVV Energy. Additionally, the economic value of energy losses reported by the German DSO is higher than in other case studies. However, the relative amount of energy losses is significantly smaller than in other areas. Hence, the relative importance of losses in the planning process may not be as big as in the Spanish and Dutch areas. High per unit changes in maintenance plus losses in the 2008 DG scenarios with respect to the no DG scenario cannot be considered representative, since the amount of DG in the area in 2008 was negligible. Total network costs present an upwards tendency as more DG is installed in the network. It can be seen that cost increases due to DG are higher for the 2008 demand level than for the 2020 when the DG penetration level is moderate. However, for high penetration levels, increases tend to be much more similar.

Table 54: evolution of total incremental distribution cost per unit of DG installed in the Mannheim area with the dg penetration level. Results for the 2008 and 2020 storylines are provide separately

	2008 Storyline		
DG Penetration Level	2008 DG	2020 DG (medium)	2020 DG (high)
Total PV [€/kW DG]	-29.18	558.57	674.52
Investment [€/kW DG]	137.70	508.48	606.19
Maintenance + Losses [€/kW DG]	-166.88	50.09	68.33

	2020 Storyline		
DG Penetration Level	2008 DG	2020 DG (medium)	2020 DG (high)
Total PV [€/kW DG]	-48.21	214.80	503.13
Investment [€/kW DG]	126.69	200.83	447.64
Maintenance + Losses [€/kW DG]	-174.91	13.97	55.50

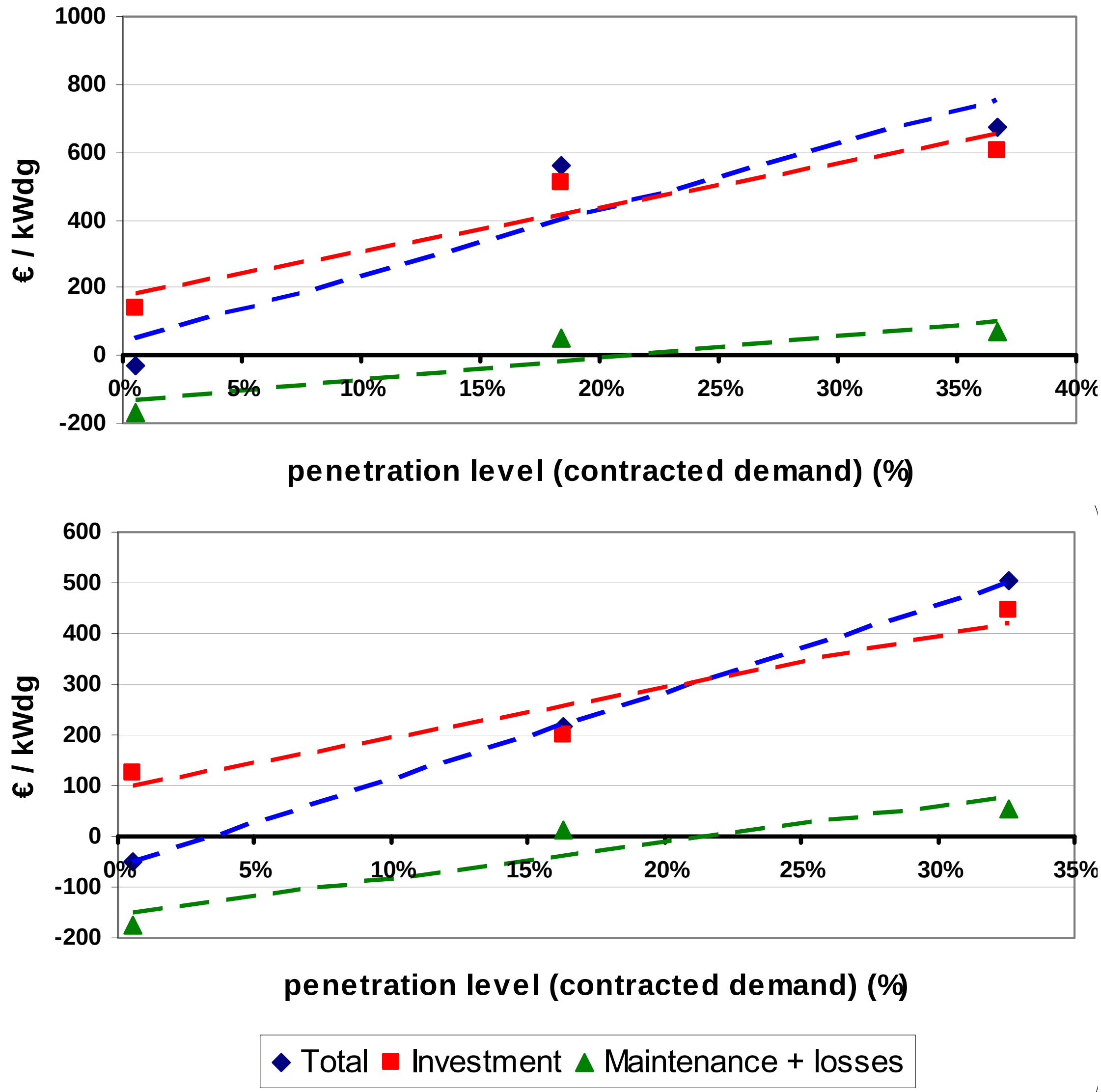


Figure 44: Incremental costs per installed kW of DG. Germany for 2008 (top) and 2020 (bottom)

The per-kW incremental costs caused by DG, measured with respect to the corresponding no DG scenarios, are plotted in Figure 44 for the different DG penetration scenarios considered. Results corresponding to the 2008 and 2020 storylines have been represented separately for clarity reasons. Straight lines that best fit the computed points corresponding to considered DG penetration scenarios have been included. These lines are aimed at identifying a tentative general trend in cost impacts. However, given the low number of points that have been used to draw these curves, we cannot claim that they correspond to the actual trend followed by costs. This is why these curves have been drawn using a dashed line.

DG-related costs tend to increase with the DG penetration level from -29 €/kW$_{DG}$ to 675 €/kW$_{DG}$ for DG/RES penetration scenarios corresponding to the 2008 storyline and from -50 €/kW$_{DG}$ to 500 €/kW$_{DG}$ for DG/RES penetration scenarios corresponding to the 2020 storyline. Negative values, when they occur, are due to a reduction in energy losses thanks to the existence of DG, whereas investments and maintenance remain very similar to those in the no DG scenarios. It should be mentioned that the actual reduction in the cost of energy losses is not very significant when compared to total costs. However, since DG capacity in the Mannheim area is very low nowadays, the per-kW cost reduction is very noticeable. Thus, values provided in Figure 44 for very low DG penetration levels may not be very representative of what may happen when a significant amount of DG is in place. Moreover, significant differences in the cost of losses have been found depending on the level of demand, being the corresponding unit values computed much smaller for future demand scenarios. This demonstrates that the integration of DG and demand is a relevant factor when minimizing network costs driven by the penetration of DG.

Finally, Table 55 and Figure 45 provide annual incremental costs of distribution, with respect to the corresponding no DG scenario, for different levels of penetration of DG. Annual cost impacts are displayed separately for the 2008 and the 2020 storylines for clarity reasons. The evolution of annual unit distribution costs caused by DG with the level of DG penetration is completely analogous to that of the corresponding not annual, but overall, unit costs. However, computing annual cost is necessary in order to compare these to other cost components and come up with a single estimate of the overall impact of DG on system costs for each scenario.

Table 55: Unit annual incremental distribution costs associated with the integration of DG in the Mannheim area (Germany)

	2008 Storyline		
DG Penetration Level	2008 DG	2020 DG (medium)	2020 DG (high)
*Total PV [€/kW DG *year]*	-2.72	51.97	62.76
*Investment [€/kW DG*year]*	12.81	47.31	56.41
*Maintenance + Losses [€/kW DG*year]*	-15.53	4.66	6.36

	2020 Storyline		
DG Penetration Level	2008 DG	2020 DG (medium)	2020 DG (high)
*Total PV [€/kW DG *year]*	-4.49	19.99	46.82
*Investment [€/kW DG*year]*	11.79	18.69	41.65
*Maintenance + Losses [€/kW DG*year]*	-16.28	1.30	5.16

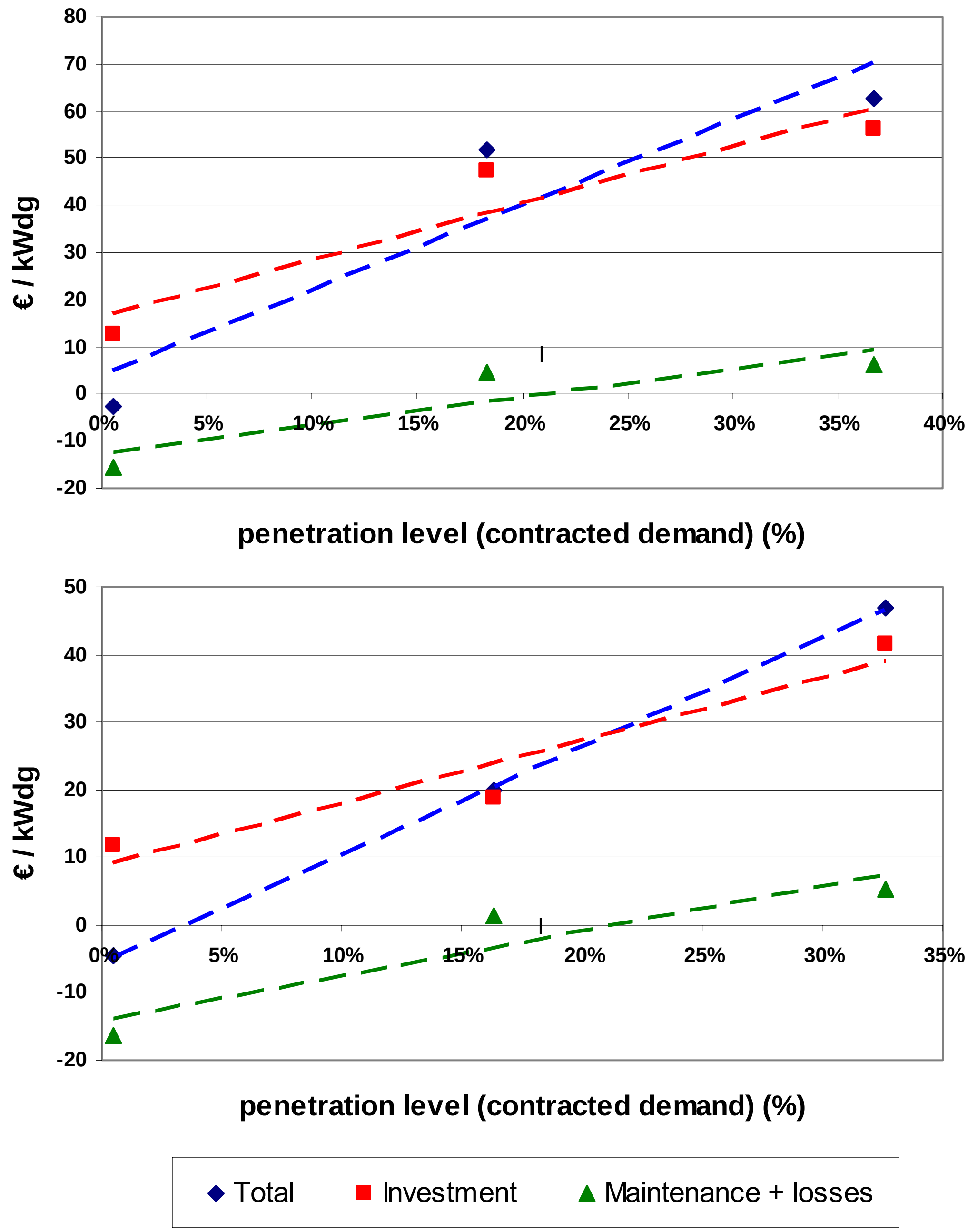


Figure 45: graphical representation of annual incremental distribution costs for the Mannheim area. Evolution of these costs with the level of penetration of DG for 2008 (top) and 2020 (bottom)

5.3.2 Generation costs

Table 56, Table 57 and Table 58 provide the results on the generation cost impact of DG/RES penetration in the German case study area. Note that the cited cost figures reflect the total increase (or decrease) in generation cost for all the EU system, and not just for the electricity system in Germany. Given the large number of interconnections that exist between the German system and others, the fact that DG/RES-E penetrates the former has consequences for other electricity systems in the EU as well. Results presented correspond to the generation cost impact in the different scenarios considered (combinations of demand, DG and price levels). These results have been presented both in absolute terms (million euro per year) and related to the amount of additional DG/RES installed in the first place (per $kW_{DG/RES}$ per year).

Table 56: assessment of variable generation cost impact of DG/RES in the German system area (Mannheim) (source: ECN)

Storyline	Unit	No DG	Status quo DG	Future low DG	Future high DG
2008 electricity system	[m€/year]	0,0	0,0	-0,5	-0,9
	[€ / kW DG / year]	0,0	-39,3	-40,2	-40,2
2020 electricity system – low prices	[m€/year]	0,0	0,0	-0,5	-1,0
	[€ / kW DG / year]	0,0	-43,1	-44,6	-44,6
2020 electricity system – high prices	[m€/year]	0,0	0,0	-0,1	-0,3
	[€ / kW DG / year]	0,0	-23,0	-12,4	-12,4

Table 57: assessment of fixed generation cost impact of DG/RES in the German system area (Mannheim) (source: ECN)

Storyline	Unit	No DG	Status quo DG	Future low DG	Future high DG
2008 electricity system	[m€/year]	0,0	0,0	1,1	2,3
	[€ / kW DG / year]	0,0	91,0	98,1	98,1
2020 electricity system – low prices	[m€/year]	0,0	0,0	1,1	2,3
	[€ / kW DG / year]	0,0	88,2	98,2	98,2
2020 electricity system – high prices	[m€/year]	0,0	0,0	0,3	0,6
	[€ / kW DG / year]	0,0	20,8	27,2	27,2

Table 58: assessment of total generation cost impact of DG/RES in the German system area (Mannheim) (source: ECN)

Storyline	Unit	No DG	Status quo DG	Future low DG	Future high DG
2008 electricity system	[m€/year]	0,0	0,0	0,7	1,4
	[€ / kW DG / year]	0,0	51,7	57,8	57,9
2020 electricity system – low prices	[m€/year]	0,0	0,0	0,6	1,3
	[€ / kW DG / year]	0,0	45,1	53,6	53,6
2020 electricity system – high prices	[m€/year]	0,0	0,0	0,2	0,3
	[€ / kW DG / year]	0,0	-2,2	14,8	14,8

Given that the amount of DG/RES capacity entering the German case study area is relatively small, for example compared to the DG/RES capacity entering the Spanish and Dutch case study area, the absolute impact of the penetration in terms of million Euro per year is small. Across the various cases, the decrease in variable generation costs varies from about €0 to €1 million per year. The increase in fixed generation costs varies between €0 and €2.5 million per year. However, we do observe robust results for the generation cost impact in the sense that variable generation costs decrease in all cases and fixed generation costs increase in all cases. The two impacts taken together we observe that total generations actually increase in all cases except one.

5.3.3 Balancing costs

Balancing costs corresponding to the German area have not been computed because they were deemed to be zero. This is due to the fact that wind generation capacity in the area, which is the one mainly responsible for increasing balancing costs, is zero currently and is also expected to be zero in the future, since this is an urban area.

5.3.4 External costs

The impact on external costs is directly related to the shifts that DG/RES penetration causes in the deployment of electricity generating units in the generation mix. In the case of Germany, the increased electricity production from CHP, PV and wind results in a decrease in electricity production from gas and coal-based units. Since the latter generally have larger external costs than the former, giving rise to a decrease in external costs. This is confirmed by the figures in Table 59.

Table 59: assessment of the impact of DG/RES in the German system area (Mannheim) on external costs (source ECN)

Storyline	Unit	No DG	Status quo DG	Future low DG	Future high DG
2008 electricity system	[m€/year]	0,0	0,0	-0,1	-0,1
	[€ / kW DG / year]	0,0	-4,7	-6,3	-6,3
2020 electricity system – low prices	[m€/year]	0,0	0,0	0,0	0,0
	[€ / kW DG / year]	0,0	-0,6	-1,2	-1,2
2020 electricity system – high prices	[m€/year]	0,0	0,0	0,0	0,0
	[€ / kW DG / year]	0,0	0,0	0,0	0,0

The absolute values for the decrease in external costs are very small, but when related to the amount of DG/RES capacity that caused this external cost effect we see that there is a positive effect that varies from €0 per $kW_{DG/RES}$ per year in the situation where the 2020 electricity system with high electricity prices is assumed and €6 in the situation where the 2008 electricity system is assumed. This observation can be explained by the fact that the gas-based electricity generating units that are operating in 2020 are relatively more efficient and cleaner than the gas-based electricity generating units in 2008.

5.3.5 Transmission costs

An estimate of the impact on transmission costs of the penetration of DG/RES in the German area has not been carried out because penetration of DG/RES is not thought to be high enough so as to significantly change connection capacity requirements.

5.3.6 Total electricity supply costs

Table 62 and Figure 46 show the impact on total supply costs of the installation of DG in the Mannheim area for different DG penetration levels. Results for the 2008 and 2020 storylines are provided in separate tables and graphics. Besides total supply costs, the evolution of the different cost components with the DG penetration level is also provided, though the impact of DG on each cost component has already been discussed in previous subsections. Table 62 and Figure 46 provide, for each DG/RES scenario that has been defined within a certain storyline in the German area, the unit impact of DG/RES (per kW of DG/RES installed) on each of the cost components considered, as well as the unit impact on total supply cost. Numerical results provided are annual.

The general trend followed by total costs with increasing levels of DG in the German area is quite similar in the 2008 and 2020 backgrounds. In both cases, this trend is dominated by fixed and variable generation cost components though, contrary to what happens in the other two areas, distribution cost have a non-negligible contribution to the evolution of total supply costs. This is mainly due to the fact that unit investment costs considered for distribution assets in the German area are significantly higher than those in the Spanish and the Dutch areas. The different characteristics (distribution and overall level) of demand in the area in the 2008 and the 2020 storylines results in distribution costs in the 2020 storyline increasing much more steeply that in the 2008 storyline (check section 5.3.1 for more details). As a consequence of this, and given that the evolution of generation costs in the 2008 and 2020 backgrounds, which will be commented upon in the following paragraphs, is completely analogous, unit impact of DG on total costs for the high DG penetration scenarios seems to be close to reaching a maximum value while that in the 2020 storyline seems to increase more steeply. In any case, both curves seems to increase until they reach a maximum and then remain more or less stable.

As mentioned in section 5.1.2, impact of DG on fixed costs is positive (these costs increase) because the unit investment costs of DG generation technologies (renewables and CHP) are higher than those of conventional generation that is partially replaced by the former. Besides, the low capacity credit of some of the generation installed in the Mannheim area (this is the case of solar power in this area) results in conventional generation capacity still having to provide most of the firm generation capacity in the system. Thus, the decrease in conventional generation capacity caused by the installation of DG in the Mannheim area is well below the amount of DG generation capacity installed.

On the other hand, the impact of DG on variable generation cost is negative (these costs decrease) because fuel costs and other operation costs incurred by new DG are clearly below those of conventional generation. Besides, the amount of CO2 emitted by DG (at least by some technologies, like solar) is almost negligible, compared to significantly larger amount of CO2 emitted when producing conventional generation energy that is now replaced by DG generation one. Figures for the 2020 scenario correspond to the case where fuel and CO2 prices in the 2020 horizon are deemed to be moderate. The evolution of fixed generation costs is analogous to that of variable ones. However, for a certain DG penetration level, the former are larger than the latter. This is even clearer in the case of Mannheim, where investment costs are deemed to be higher than in other areas (countries). In any case, this is in line with what could be expected nowadays, since the difference in variable generation costs between DG and conventional generation that is marginal in the market is not enough to compensate for the higher investment costs born by DG producers. Thus, the former must receive some kind of compensation in the form of support payments allowing them to profit from the installation of generation from these technologies.

The evolution of generation costs in each storyline with the level of DG penetration depends mainly on the composition of the generation mix that exists in the area. Thus, both the capacity credit and the unit investment costs of CHP generation are clearly below those of wind and, specially, solar generation. Consequently, an increase in the CHP generation capacity shall lower unit fixed generation costs while an increase in solar shall clearly increase fixed generation costs. The trend of variable generation costs is somewhat the opposite. Increasing the CHP capacity will increase unit average variable production costs while increasing wind or solar capacity will lower unit variable costs.

The unit DG/RES impact on total supply costs is positive for every DG penetration level that has been considered (overall costs increase because of the introduction of DG). However, it seems to reach a maximum, which is around 30% DG penetration level for the 2008 storyline and between 25 and 40% for the 2020 storyline. As explained, this mainly depends on the composition of the generation mix in the area in each scenario and, in the case of the German area, on the distribution of demand and generation, which clearly conditions distribution costs, a significant part of total costs here.

Table 60: Evolution of the impact of DG in the Mannheim area on total supply costs with the DG penetration level. Results for the 2008 and 2020 storylines are provided in separate tables

Scenarios	2008 DEMAND			
	No DG	Current DG	Future DG (medium)	Future DG (High)
DG penetration level [%]	0%	1%	18%	37%
Cost concepts				
Variable Generation Costs [€/kW installed DG/year]	0.0	-39.3	-40.2	-40.2
Fixed Generation Costs [€/kW installed DG/year]	0.0	91.0	98.1	98.1
Distribution Costs [€/kW installed DG/year]	0.0	-2.7	52.0	62.8
Balancing costs [€/kW installed DG/year]	0.0	0.0	0.0	0.0
External Costs [€/kW installed DG/year]	0.0	-4.7	-6.3	-6.3
Total cost [€/kW installed DG/year]	0.0	44.3	103.5	114.3
Scenarios	2020 DEMAND			
	No DG	Current DG	Future DG (medium)	Future DG (High)
DG penetration level [%]	0%	1%	16%	33%
Cost concepts				
Variable Generation Costs [€/kW installed DG/year]	0.0	-43.1	-44.6	-44.6
Fixed Generation Costs [€/kW installed DG/year]	0.0	88.2	98.2	98.2
Distribution Costs [€/kW installed DG/year]	0.0	-4.5	20.0	46.8
Balancing costs [€/kW installed DG/year]	0.0	0.0	0.0	0.0
External Costs [€/kW installed DG/year]	0.0	-0.6	-1.2	-1.2
Total cost [€/kW installed DG/year]	0.0	40.0	72.4	99.3

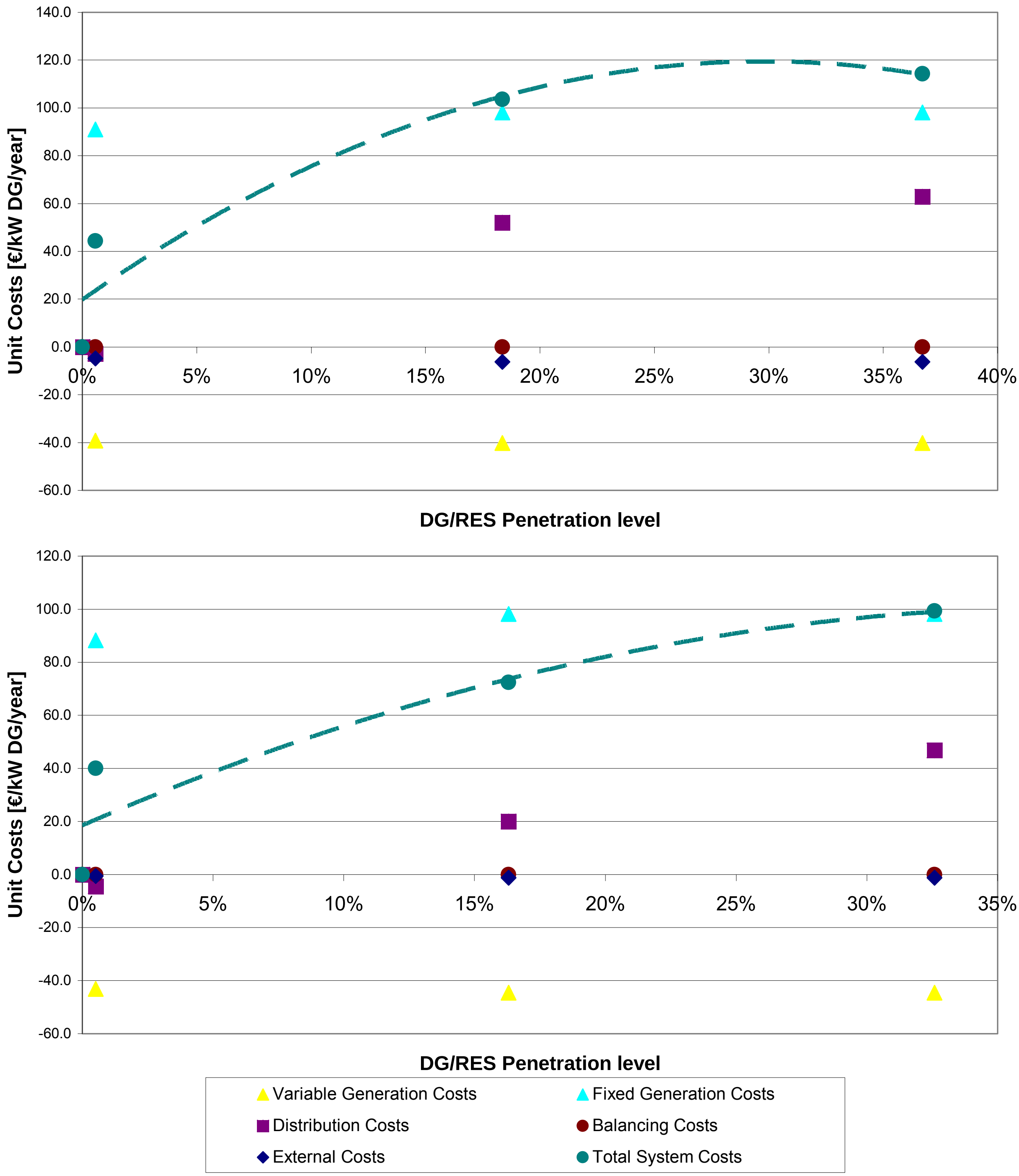


Figure 46: Evolution of the impact of DG in the Mannheim area on total supply costs with the DG penetration level. Results for the 2008 (upper graphic) and 2020 (lower graphic) storylines are provided in separately

5.3.7 Social benefit

Table 61, Table 62 and Table 63 show the impact of integrating DG/RES in the German case study area on the welfare of producers and consumers. The little amount of DG/RES that enters the system has only very limited impact on the average electricity price in only a very limited number of cases. This results only in an increase in consumer surplus in the storyline representing the 2020 electricity system with high prices. Relating the absolute effect in million Euro per year to the actual amount of DG/RES that is added to the electricity system gives rise to very high impact figures in terms of Euro per $kW_{DG/RES}$ per year.

Table 61: assessment of the impact of DG/RES in the German system area (Mannheim) on consumer surplus (source: ECN)

Storyline	Unit	No DG	Status quo DG	Future low DG	Future high DG
2008 electricity system	[m€/year]	0,0	0,0	0,0	0,0
	[€ / kW DG / year]	0,0	0,0	0,0	0,0
2020 electricity system – low prices	[m€/year]	0,0	0,0	0,0	0,0
	[€ / kW DG / year]	0,0	0,0	0,0	0,0
2020 electricity system – high prices	[m€/year]	0,0	0,0	2,1	4,3
	[€ / kW DG / year]	0,0	133,0	183,9	183,9

Table 62: assessment of the impact of DG/RES in the German system area (Mannheim) on producer surplus (source: ECN)

Storyline	Unit	No DG	Status quo DG	Future low DG	Future high DG
2008 electricity system	[m€/year]	0,0	0,0	0,5	0,9
	[€ / kW DG / year]	0,0	39,4	40,2	40,2
2020 electricity system – low prices	[m€/year]	0,0	0,0	0,5	1,0
	[€ / kW DG / year]	0,0	43,1	44,6	44,6
2020 electricity system – high prices	[m€/year]	0,0	0,0	-1,5	-2,9
	[€ / kW DG / year]	0,0	-76,3	-124,7	-124,7

Table 63: assessment of the impact of DG/RES in the German system area (Mannheim) on social welfare (source: ECN)

Storyline	Unit	No DG	Status quo DG	Future low DG	Future high DG
2008 electricity system	[m€/year]	0,0	0,0	0,5	0,9
	[€ / kW DG / year]	0,0	39,4	40,2	40,2
2020 electricity system – low prices	[m€/year]	0,0	0,0	0,5	1,0
	[€ / kW DG / year]	0,0	43,1	44,6	44,6
2020 electricity system – high prices	[m€/year]	0,0	0,0	0,7	1,4
	[€ / kW DG / year]	0,0	56,7	59,2	59,2

Given that the little DG/RES penetrating the case study area is not affecting average German electricity prices (and hence electricity producer revenues) but does reduce the variable generation costs, total producer surplus increases. Only in a 2020 electricity system with high fuel prices the small electricity price decrease causes electricity revenues to decrease and thereby off-setting the reduction in variable generation costs. In this situation the producer surplus decreases. Total welfare always increases in the case of Germany.

5.3.8 Overall socio-economic costs

This subsection provides a quantification of the total impact on the socio economic cost of the system being penetrated by DG/RES in the Mannheim area. The methodology followed to compute the overall cost impact of DG is explained in section 4.2.7. Table 66 and Figure 47 provide, for each DG/RES scenario that has been defined within a certain storyline in the German area, the unit impact of DG/RES (per kW of DG/RES installed) on each of the cost components considered, as well as the unit impact on total socio economic system cost. Numerical results provided are annual.

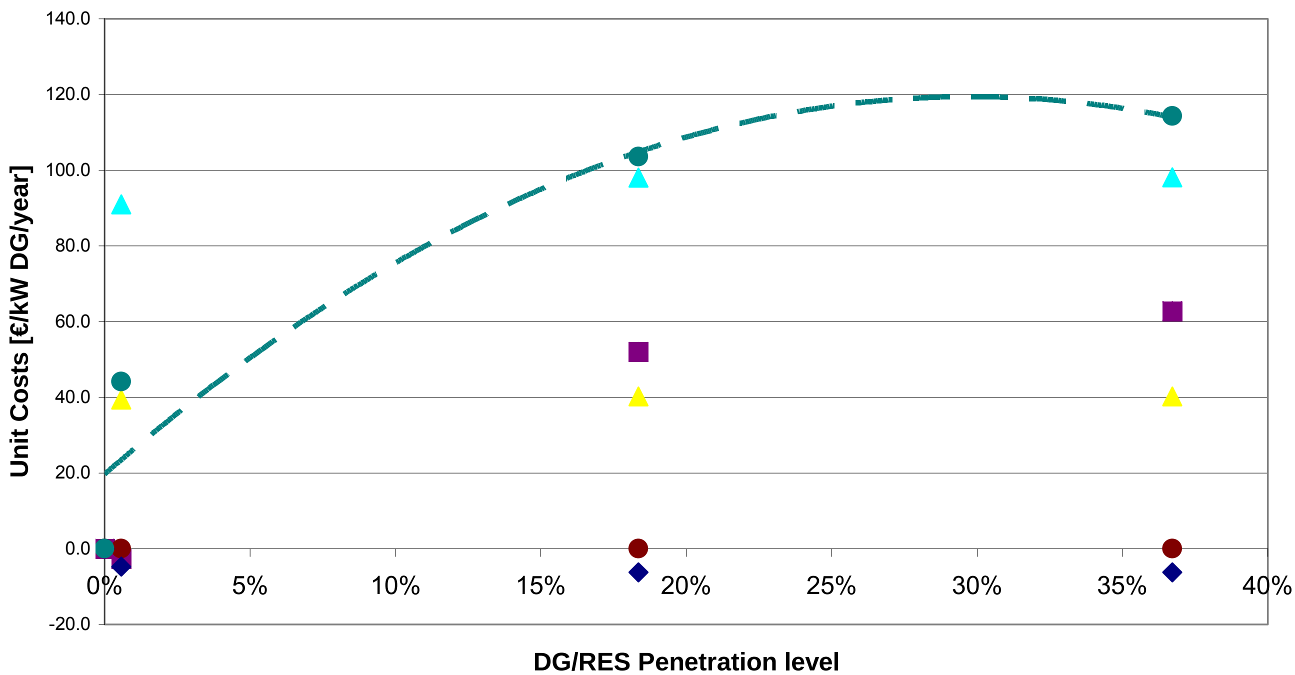
The evolution and general trend of socio-economic costs is exactly the same as that followed by total supply costs. Changes in the social surplus, capital generation cost and distribution costs dominate changes in the remaining cost components. The reason for supply and socio-economic costs being the same is the fact that demand in the system does not change as a result of the installation of DG in the Mannheim area. This probably has to do with the fact that the amount of DG installed in the area in high penetration scenarios is rather low compared to that in the remaining two areas (remember that changes in demand in previous sections occurred for high DG penetration levels in the Spanish and Dutch distribution areas). As a result of what has been said, the analysis of the evolution of socio-economic costs with the penetration of DG in the Mannheim area is the same as that for supply costs.

Results on total system socio-economic costs obtained for the different scenarios show a relatively low dispersion around the curve used to fit them. However, one must take into account that these results correspond to situations that not only differ in the amount of DG capacity installed but also in the relative composition of the generation mix, which may vary from one scenario to another within the same storyline.

Table 64: computation of overall impact of DG/RES in the Mannheim area on the socio economic cost of producing and consuming electricity in the system. Results for the 2008 storyline are provided in the upper table while those for the 2020 storyline are provided in the lower one

Scenarios	2008 DEMAND			
	No DG	Current DG	Future DG (medium)	Future DG (High)
DG penetration level [%]	0%	1%	18%	37%
Cost concepts				
Socio Economic Cost Dispatch [€/kW installed DG/year]	0.0	-39.4	-40.2	-40.2
Fixed Generation Costs [€/kW installed DG/year]	0.0	91.0	98.1	98.1
Distribution Costs [€/kW installed DG/year]	0.0	-2.7	52.0	62.8
Balancing costs [€/kW installed DG/year]	0.0	0.0	0.0	0.0
External Costs [€/kW installed DG/year]	0.0	-4.7	-6.3	-6.3
Total cost [€/kW installed DG/year]	0.0	44.2	103.5	114.3

Scenarios	2020 DEMAND No DG	Current DG	Future DG (medium)	Future DG (High)
DG penetration level [%]	0%	1%	16%	33%
Cost concepts				
Socio Economic Cost Dispatch [€/kW installed DG/year]	0.0	-43.1	-44.6	-44.6
Fixed Generation Costs [€/kW installed DG/year]	0.0	88.2	98.2	98.2
Distribution Costs [€/kW installed DG/year]	0.0	-4.5	20.0	46.8
Balancing costs [€/kW installed DG/year]	0.0	0.0	0.0	0.0
External Costs [€/kW installed DG/year]	0.0	-0.6	-1.2	-1.2
Total cost [€/kW installed DG/year]	0.0	40.0	72.4	99.3



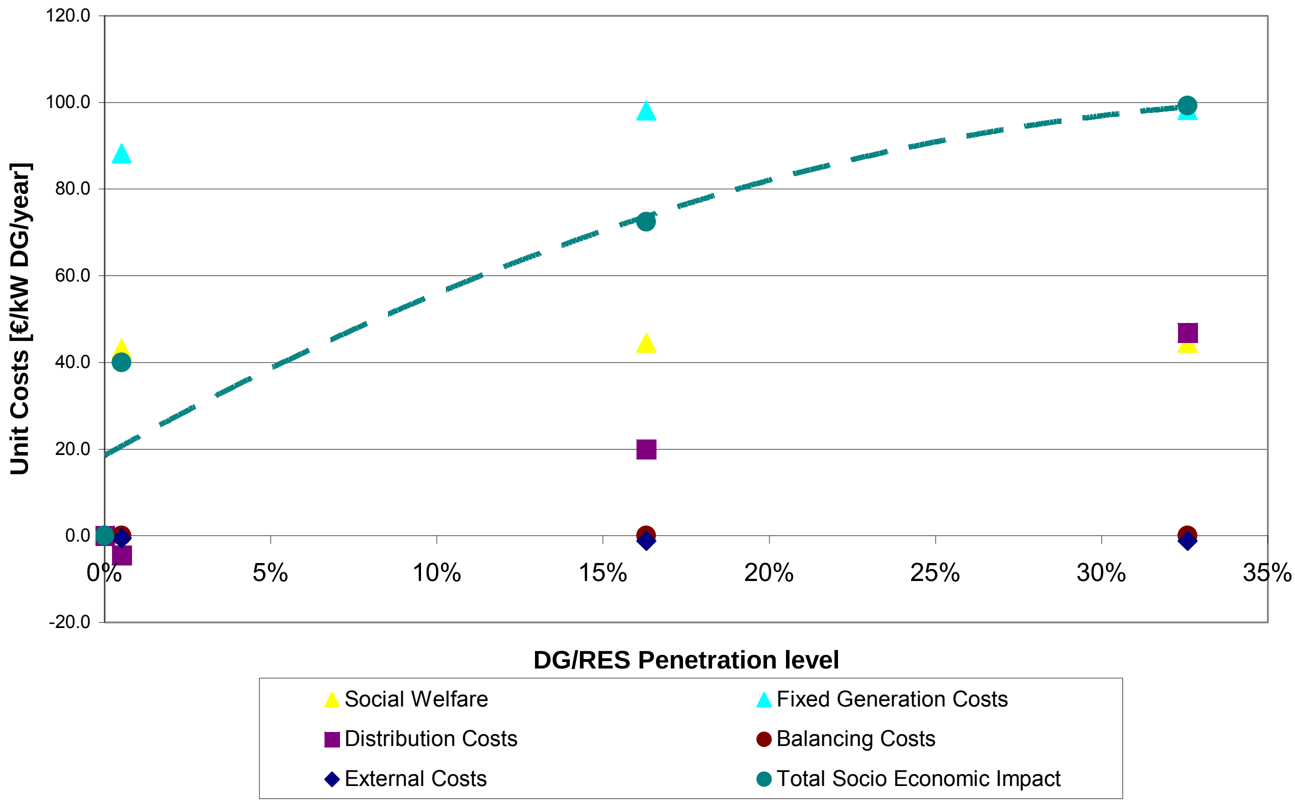


Figure 47: evolution of total socio economic impact of DG in the Mannheim area with the level of penetration of DG in the area. Results for the 2008 storyline are provided in the upper graphic while those for the 2020 story line are provided in the lower one

5.4 Analysis of results

This subsection provides a brief analysis of the results that have been computed for the different areas. Section 5.4.1 refers to distribution costs, which have been computed with great detail, while section 5.4.2 refers to the remaining cost components and total system costs.

5.4.1 Distribution costs

This section compares the numerical results obtained by the network reference model for the 3 distribution areas considered. Differences in the impact of DG on network costs due to the particular features of each area and assumptions made by DSOs of each area will be discussed. Distribution network costs for the 3 case study areas have been presented in section 5.

The distribution areas considered have quite different characteristics regarding their size, type of loads, network elements or DG technologies and capacities. All of them are areas with high DG potential nevertheless. According to current loads/DG levels and DSOs' estimates for 2020, high penetration levels of DG are expected for these areas in coming years. What is more, growth of DG capacity will largely exceed that of demand in the cases of Germany and The Netherlands. Generation in these areas consist of CHP units, which are present in all cases, solar PV, which is present in the Spanish and German areas, and wind power in the Dutch and Spanish areas. The average size of DG units and the voltage level at which they are connected also vary much among areas. In Spain and Germany, largest generators have a capacity between 1 and 10 MWs. Those in Spain are connected to HV and MV networks while those in Germany are connected at LV level. The capacity of most generators in the German area is about a few kWs. The size of units in the Dutch area ranges between few kWs and more then 20 MW, though most units are between 50 and a few hundred kWs

DG penetration levels, which are measured as the ratio of installed generation capacity to total load contracted by consumers, reach in the Kop van Noord-Holland area a maximum of 200%. The maximum DG penetration level in Mannheim is 37% and that in Aranjuez is 33%. However, these values should not be directly compared due to the use of different simultaneity factors for loads. Should DG penetration be measured as the ratio between DG capacity and peak demand, the former figures would become 715%, 83% and 49% respectively. The aforementioned penetration levels are considerably high by themselves. Additionally, DG may not be connected at the same network level as demand, which may lead to important network reinforcements so as to accommodate such large amounts of generation in a network where little demand is present. For instance, peak demand at the LV network for the German case amounts to 7.05 MW, whereas maximum DG production gets to over 23 MW.

The previous section showed that expected DG will result in higher costs of distribution network assets than those corresponding to the situation where no DG is present, i.e. additional km of lines and transformation capacity (see Figure 25, Figure 33 and Figure 41). The highest increases in network capacity due to DG, when expressed as percentages of the network capacity in the corresponding scenario with no DG, shall take place in the Dutch case study area. On the other hand, the lowest increases are likely to occur in the Spanish distribution area. This is coherent with DG penetration levels expected in each case study area.

As a consequence of this, total distribution network costs are deemed to increase with DG penetration in all cases. Investments are clearly the most relevant component in total costs, followed by maintenance costs and energy losses. This is even more remarkable for the German area. The relative share of each cost component in the optimally adapted network cost mainly depends on the costs structure of network elements and the value of energy losses reported by DSOs. On the other hand, these shares are barely affected by DG penetration (see Table 21, Table 36 and Table 53).

For low DG penetration levels, network costs are greater the higher the demand to be served is regardless of DG penetration, i.e. load is the main cost driver. However, only in the Spanish case area does this pattern remain appropriate for large penetration levels. In Figure 34 and Figure 42 the evolution of investment and maintenance costs for the Dutch and German cases is plotted, respectively. Therein, it is shown that network costs for large DG penetration levels are lower the higher demand is. In these scenarios, the maximum net generation snapshot becomes decisive to estimate network costs and optimal network dimensioning and design. The higher load is during maximum generation periods, the lower required investments are. Figure 48 clearly depicts this effect. It shows changes in investment and maintenance costs, with respect to the no-DG scenarios, as DG penetration increases. These are expressed as percentages of the costs of the corresponding (in terms of demand level) no-DG scenarios.

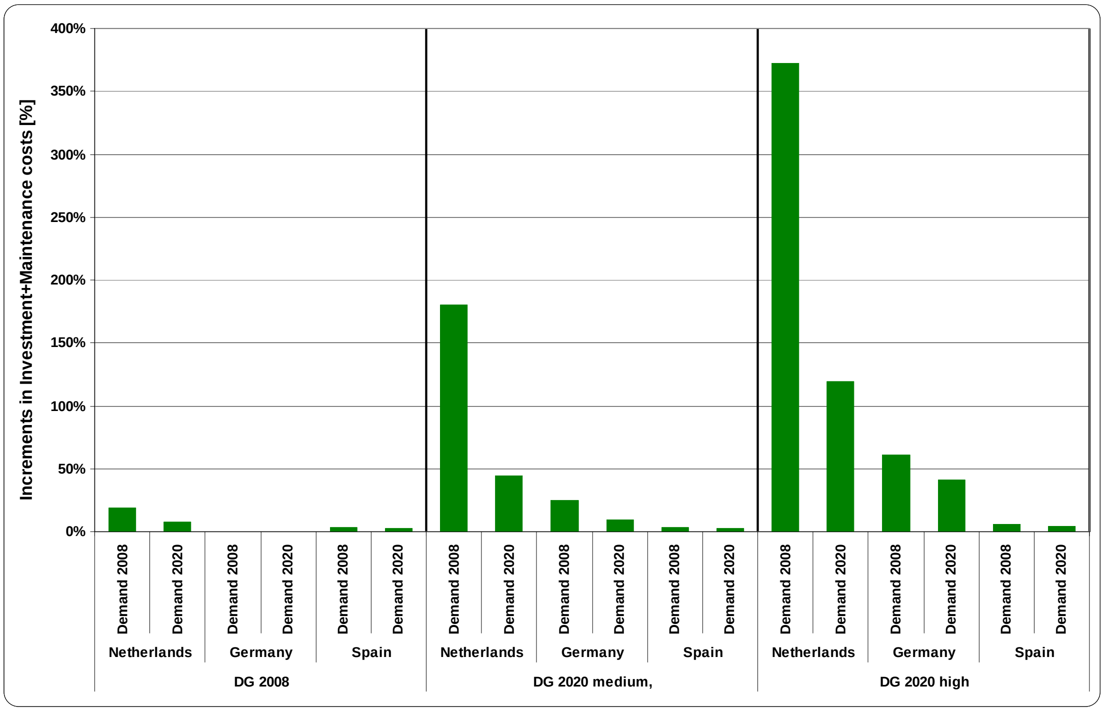


Figure 48: Investment and maintenance cost increases, with respect to the corresponding no-DG scenario, as percentage of the total cost in the no-DG scenario

Differences among areas in this regard may be explained by the fact that significantly lower penetration levels are reached in the Aranjuez area. Besides, assumptions made when computing the network for the Dutch case study were more conservative than those in other systems. This has a non-negligible impact on the results that have been obtained. Table 14 contains the simultaneity factors used in each snapshot for every distribution area. In the German and Dutch areas, DSOs considered worst case scenarios were DG made no contribution to meet peak demand, whereas DG produced at rated capacity at valley hours. Actually, this is not totally true for Germany, since CHP was deemed to be producing at 30% of its capacity during peak load hours. However, solar PV capacity is much greater than that of CHP in this area. On the other hand, Spanish DSO Unión Fenosa decided to analyse less conservative DG/load conditions.

It seems that as long as DSOs are not able to have some control over DG, or some assurance over its behaviour, potential benefits from the installation of DG will not be fully realized. Real benefits arise when DG contributes to meet peak demand and vice versa, when demand contributes to reduce net peak generation. However, considering more pessimistic scenarios lead to higher costs.

Incremental costs per kW of DG capacity connected to the network showed significant differences among the three case study areas, both in terms of the level of costs and in terms of the path followed by these costs for increasing DG penetration levels. Since the DG penetration levels reached in the Dutch case study were much greater than those in the remaining two case study areas, one shall focus on the lower DG penetration levels in this area for comparative purposes. Figure 49 depicts total incremental costs expressed in €/kW$_{DG}$, for different DG penetration levels, in the three distribution areas that have been analyzed. As mentioned before in the report, penetration levels have been measured as the ratio of installed DG/RES capacity to contracted load. This was deemed appropriate in order to be able to obtain identical penetration levels for the corresponding scenarios in WP4 (where conventional management of the grid is considered) and WP5 (where active network management is introduced). However, given that simultaneity factors of load, as well as other main features of the three considered distribution areas differ widely, comparable penetration levels in different areas may mean quite different things. Thus, one must be very careful when drawing conclusions from the comparison of results shown in Figure 49.

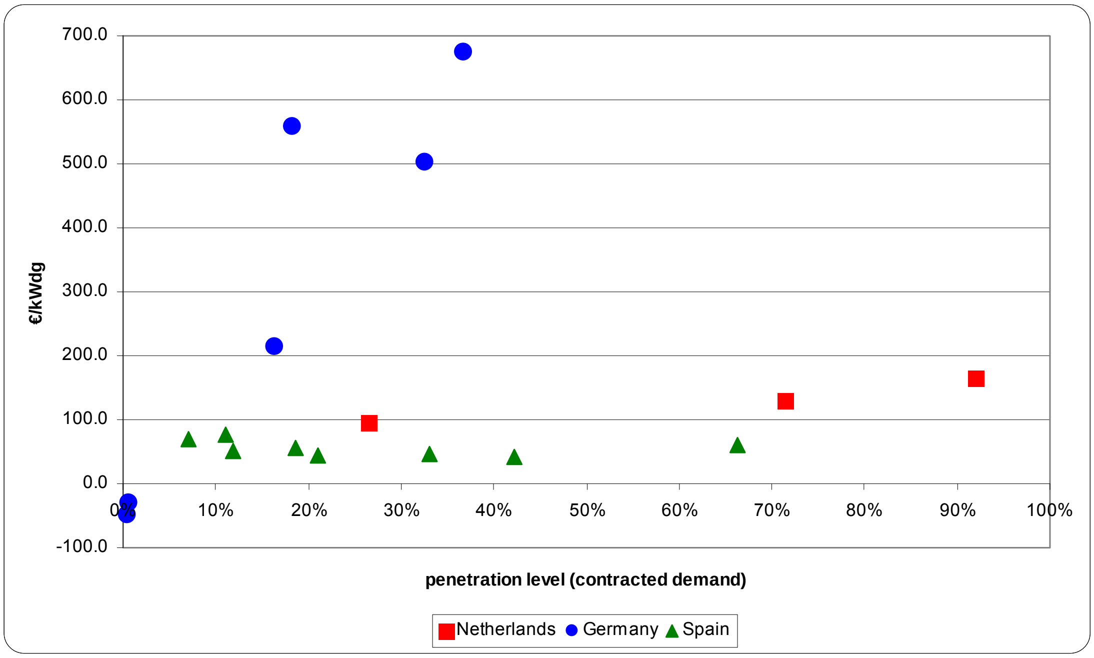


Figure 49: Incremental costs per installed kW of DG. Overview

At first, one may think that costs per kW of DG connected to the distribution network in the German area should be lower than those in other areas, since DG is connected very close to demand in Germany. However, costs for Germany are significantly higher than those in the other two areas, under similar DG penetration levels. As previously mentioned, DG simultaneity factors for peak demand periods used in the analysis of the German area are noticeably lower than those in the other two areas, which may lead to higher costs for the same DG penetration level. In the German case study area, DG output is very low at peak load times, whereas all DG units are producing at their maximum in valley hours (see Table 14). However, these may not be the only reasons for such great differences. The German DSO reported comparatively higher unit costs for network elements than the other 2 DSOs; especially LV lines and MV/LV transforming centres (see Table 66 and Table 67).

On the other hand, costs per kW of DG in The Netherlands are quite similar to those in Spain for comparable DG penetration levels. It is deemed reasonable that costs in the case of The Netherlands are higher than those in the Spanish case, since the whole Dutch network is built underground. Nonetheless, the impact of this on network costs is mitigated, to some extent, by the fact that DG is located closer to demand and other generators in the Dutch area than in the Spanish one. Therefore, the average utilization of network assets in The Netherlands case study area is higher than that in the Spanish area.

To summarize, main cost drivers when developing the distribution grid are relative levels of demand and DG, the relative location of demand and DG, the simultaneity factors of demand and DG and the unit investment costs and price of energy used. Flows in the grid are lower the more balanced production by DG and consumption by local load are. Thus, for low penetration levels of DG (compared to load) costs tend to decrease the more power produced by DG is (that is, the higher the DG penetration level is). For very high DG penetration levels, costs tend to increase with the penetration level. In order for DG to decrease flows, generation must be located close to loads. Therefore, for a certain penetration rate, reduction in costs will be higher the closer generation and demand are located. The same applies to the operation profile. Reduction in distribution costs will be higher (respectively, the increase in costs will be lower) the more similar the operation profiles of demand and generation are (mainly the simultaneity factors and the time when maximum generation output or load consumption occurs). Last but not least, total distribution costs will be lower the lower unit investment costs and the price of energy losses are.

5.4.2 Other costs components and total system costs

Talking about generation costs, one must make a clear distinction between fixed and variables costs. The former tend to increase as a result of the installation of DG because the unit investment costs of this generation capacity are higher than that of conventional generation. On the other hand, variable generation costs tend to decrease with the integration DG/RES because the cost of producing power from conventional generation replaced by DG/RES is higher than that of the latter type of generation. Besides, CO2 emissions and external costs (caused by the emission of other type of pollutants) is also higher for conventional generation capacity than for DG/RES one.

Despite this general trend, certain differences between DG/RES technologies exist. Thus, the investment costs for CHP generation tend to be lower than those of wind, which in turn are lower than those of solar power. At the same time, fuel costs and emissions tend to be higher for CHP than for wind or solar power. Consequently, the higher the fraction of total CHP capacity, the lower investment costs and the higher variable cost will be. The higher the fraction of solar capacity, the higher investment cost will, since this is, by far, the most expensive technology amongst the ones considered. This effect is reinforced by the fact that the capacity credit of solar is clearly below that of the wind, which is clearly below that of CHP capacity.

The balance between variable and fixed generation cost caused by DG/RES, which are, by far, the largest part of the total cost impact of DG, depends on several aspects, like the prices of electricity and CO2 that are considered, the amount of electricity produced by each DG technology in the area and unit investment costs considered. The higher prices are, the higher the impact of DG on variable costs will be, given that energy produced by DG/RES remains constant and total energy consumed remains constant as well. However, if the installation of DG/RES in an scenario where prices are very high prompts a change (increase) in the total energy consumption, the impact of DG/RES on variable costs will be less negative than that if demand had not changed. Therefore, an increase in prices causes two opposite effects: differences in prices with conventional generation contribute to a decrease in variable costs; increases in demand cause an increase in variable costs. The overall combined result of these two effects may depend on the specific case considered. Unit investments costs that are higher cause an increase in fixed capacity costs that is not matched by any change in variable costs (which does not need to be altered). Finally, the higher the fraction of CHP within the DG generation mix, the lower the

increase in generation costs and the decrease in variables costs will be. The larger the fraction of solar power the higher the increase in fixed generation costs will be.
In general, with the exception of those scenarios where energy prices are quite high, the increase in fixed generation costs caused by DG will be larger than the corresponding decrease in variable costs. So, overall, total generation costs tend to increase as a result of the installation of DG/RES. All those effects have been observed when computing results for the three considered areas.
Differences between the evolution of variable costs and those of the social welfare in the dispatch depend on whether an increase in demand as a consequence of the installation of DG/RES occurs. If an increase in demand occurs, the increase in social welfare in the dispatch will be higher than the decrease in the variable costs (this is the case with the DG installed in the Dutch area). If not, both changes will be opposite in sign but will have the same magnitude (this is the case of the DG installed in the German area).
As mentioned earlier, external costs will decrease as a result of the installation of DG, though the impact of these reduction will in general be smaller than other effects of installing DG. Balancing costs, on the other hand, will increase with the amount of DG installed, although the magnitude of this increase, of course, will depend on the percentage of DG capacity that corresponds to wind, which is the main technology responsible for an increase in balancing costs because of its unpredictability.
Overall, supply costs and socio-economic costs will increase with the installation of new capacity for almost any DG/RES penetration level. An exception may be low penetration levels, where the impact of generation costs may be smaller than that of other cost components like distribution costs, which may decrease with DG/RES. Another, more significant, exception may be those scenarios where energy and CO_2 prices are very high. In these cases, the decrease in variables costs (or increase in social welfare) may exceed the increase in generation investment costs.

6 Final remarks

Nowadays, electricity systems in Europe are facing considerable increases in the DG capacity. This new DG mainly consists of generation from RES or CHP. This kind of generation has experienced a huge development over the last years due to the high level of existing support payments. Support mechanisms resulting in the aforementioned payments have emerged as a consequence of the EU Energy Policy.

Furthermore, distribution utilities must be legally and functionally unbundled from other companies in other activities of the electricity sector. Hence, they cannot have any direct control over the location and behaviour of DG. This makes the integration of DG even more challenging. Nonetheless, there are still great uncertainties about the extent to which the installation of DG will affect overall system operation and planning.

This report has provided a quantification of the impact of DG on overall system costs (distribution network costs, generation costs, social welfare, balancing costs, external costs and, in the Dutch case, some estimate of transmission connection costs) in three different areas. Two reference network models have been applied to compute this impact in three real case studies corresponding to areas in The Netherlands, Germany and Spain. DSOs actually operating the distribution grid in each of the former areas, together with other partners in the project like ECN, Comillas and EEG, have provided the data required to carry out these analyses. The DG penetration level in the three distribution networks considered expected for the year 2020 is significantly higher than that existing in 2008. According to the information provided by DSOs, generation technologies that will mainly contribute to increases in DG penetration levels are CHP, PV solar and wind energy.

According to the analyses conducted, once all costs and benefits involved are considered, increasing the amount of installed DG in an area generally results in an increase in total system costs regardless of the type of area. However, the evolution of system costs with DG capacity significantly depends on the characteristics of generation and demand in each area. Thus, for example, distribution network integration costs are lower the closer generation is to demand and the more similar generation and demand profiles are.

6.1 Global estimate of the impact of DG/RES on cost components

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. The fact that assumptions about the behaviour of demand and generation differ widely among areas may also cause non-negligible differences. These assumptions concern the fraction of DG installed capacity that is producing power at peak load time and the amount of power consumed in periods when DG production is highest. In the analyses here presented, conservative assumptions were made, according to planning practices by DSOs and the regulation in some countries. If the behaviour of DG better adapted to conditions in the system, incremental costs caused by DG could be significantly reduced.

Fixed and variable generation costs are the most important cost factor regarding the impact that DG/RES may have on it. The relative importance of variable and fixed generation costs may mainly depend on the level of energy prices and the unit investment costs for DG/RES technologies. In the considered snapshots, these costs range between 58 (for the Dutch and Spanish areas) and 98 (for the German area) €/(kW DG installed*year), in the case of fixed generation costs, and between -117 and -22 €/(kW DG installed*year), both values obtained for the Dutch area, in the case of variable costs. Changes in the social welfare are in the same order of magnitude as changes in variable generation costs.

Lastly, changes in external costs and balancing costs caused by DG/RES are much smaller than those in the previous cost factors: these range between 0 and 2 €/(kW DG installed*year) for balancing costs and between 0 and -6.3 €/(kW DG installed*year) for external costs (very small positive values are possible if demand increase as a result of the installation of DG).

Total system costs tend to increase as a result of the integration of DG/RES. Thus, changes in the total socio-economic impact range between close to 0 values for relatively low DG penetration levels in the Netherlands and 114 €/(kW DG installed*year) in Germany for relatively high DG penetration levels.

6.2 Introduction to WP5

In order to significantly increase benefits brought about by DG/RES, or decrease its negative impact on system costs, DG and demand should respond to conditions in the system. Nowadays, DSOs and TSOs tend to consider DG as a passive agent due to the lack of responsiveness of DG/RES. However, DG/RES may actively contribute to the operation of the system. Because of the existence of flat support payments that do not vary according to other variables, DG/RES generally perceives poor incentives to modify its production pattern according to network and system conditions. The lack of incentives for DG/RES to provide reserves, the inexistence of use-of-system charges for these generators or the inability for most DG/RES to face real time, or at least day ahead, energy prices, are other causes of the lack of responsiveness of generation.

Additionally, the impact of DG on distribution costs tends to be neglected when computing the allowed revenues of the utilities (Cossent et al., 2009).

Consequently, System Operators do not rely on DG/RES for planning purposes for the time being. This occurs despite the fact that, in the case of Distribution, for example, Article 14.7 of EU Directive 2003/54 mandates DSOs to consider DG as an alternative to network expansion. Only in the UK is there an initiative of this kind, through the Engineering recommendation P2/6 (Energy Networks Association, 2006). Even in this case, there is no clear evidence that DSOs have relied on DG to defer or replace network investments.

In order to accomplish this, the following specific measures ought to be implemented:

- DG/RES should be encouraged to generate at peak times and/or modify their production considering the situation of the local distribution network and the global system.
- Quite analogously, demand should be encouraged to reduce its consumption at peak times and, in general, adapt it to the situation in the system
- The impact of DG/RES on network costs, either positive or negative, should be considered to compute the allowed revenues of DSOs, probably also TSOs, and network charges. Otherwise, system operators (at global or local distribution area level) could receive some windfall profits due to DG-related benefits or incur incremental costs that would not be recovered.

DSOs and TSOs ought to consider DG/RES for planning purposes. There is a clear need for new planning tools and regulatory mechanisms that encourage DSOs and TSOs to consider DG in network planning both when these generators may result in additional investments and when they may avert others. Everything related to the active management of load, generation and networks will be dealt with in the following Work Package within the IMPROGRES project, WP5, whose title is “Assessment of enhanced network response alternatives”.

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Appendix 1: Extra input data required to compute distribution costs

This Appendix presents in a comparative fashion the main input data for each one of the three case studies. The results of reference network models greatly depend on the input data provided. Therefore, parameters must be carefully chosen so as to better reflect the particularities of each distribution network. In this study, the most relevant parameters, such as consumers and DG location and size and simultaneity factors (fraction of the peak load or generation consumed or produced at a certain time), or the main characteristics of network elements available, have been provided by those DSOs operating the actual distribution networks. The remaining model parameters (location of towns, determination of street maps, underground burying criteria, etc.) have been adjusted according to the results obtained in previous studies carried out with these models.

Table 65 summarizes the number, size and location of the different network users that are present in each one of the distribution areas studied. Note that in the German case study, the HV grid is out of the scope of the analyses carried out within the project. The same applies to the LV grid in the Dutch case. Thus, a significant number of MV loads in the Netherlands are not actual consumers but transforming centres and their aggregated demand. Further details on the evolution of installed capacity or DG technologies have been provided in section **¡Error! No se encuentra el origen de la referencia.**3.

Geographical coordinates of every single network user have been fed into the model as well. The Spanish distribution area is, by far, the largest one with approximately 3400 km², followed by the Dutch area with around 990 km^2 and the German one, which covers only about 20 km^2. Despite the fact that geographical constraints such as prohibited areas or the existence of mountains can be considered by the models that have been used in the project, they were not deemed relevant for the case study areas. The geographical location of consumers and DG/RES units within each of the distribution areas is provided in subsection 3.2.

Dimensioning network capacity mainly depends on the operation profile of load and generation in each of the relevant snapshots to be considered. Given the difficulty to consider a large amount of scenarios in the analyses carried out in the project, only two situations, or snapshots, have been deemed relevant for the design and dimensioning of the grid. As mentioned in section4.1, these are the peak load (or maximum net demand) scenario and the peak generation (or minimum net demand) scenario. Simultaneity factors corresponding to these two snapshots in each area are provided in section 3.2.4.

Concerning network elements, the focus will be placed on HV/MV substations, MV/LV transforming centres and lines, which are the most relevant ones in terms of cost and reliability. Reference network models used in the analyses consider two different nominal voltage levels for HV grids, and only one nominal voltage level for MV and LV networks. Table 66 and Table 67 provide the main characteristics of those network elements that have been used by models to build the optimally adapted distribution grid in each area. Available asset types were chosen by the IMPROGRES DSOs based on assets used in existing networks and those available nowadays in the market that best suit their needs. Differences in costs among areas can be explained by differences in the grid nominal voltage in each case, whether underground or overhead elements are used in the area, or how wide the range of alternatives provided is.

Table 65: Input data. Number and capacity of consumers and DG

		Netherlands	Germany	Spain
2008	LV consumers	n.a.	6122	61304
	LV load [MW]	n.a.	30.66	282.29
	MV consumers	1307	14	268
	MV load [MW]	317.27	33.02	112.68
	HV consumers	0	n.a.	5
	HV load [MW]	0	n.a.	13
2020	LV consumers	n.a.	6121	61304
	LV load [MW]	n.a.	34.21	436.13
	MV consumers	1628	15	268
	MV load [MW]	856.15	37.54	191.99
	HV consumers	0	n.a.	5
	HV load [MW]	0	n.a.	13
2008	LV DG	n.a.	84	0
	LV DG capacity [MW]	n.a.	0.368	0
	MV DG	147	0	0
	MV DG capacity [MW]	202.75	0	0
	HV DG	1	n.a.	4
	HV DG capacity [MW]	23.65	n.a.	45
2020 medium penetration	LV DG	n.a.	3537	0
	LV DG capacity [MW]	n.a.	11.691	0
	MV DG	321	0	6
	MV DG capacity [MW]	756.5	0	11.099
	HV DG	1	n.a.	5
	HV DG capacity [MW]	31	n.a.	65
2020 high penetration	LV DG	n.a.	6149	0
	LV DG capacity [MW]	n.a.	23.38	0
	MV DG	425	0	16
	MV DG capacity [MW]	1130.4	0	40.099
	HV DG	3	n.a.	7
	HV DG capacity [MW]	260	n.a.	95

Table 66: Input data: lines/cables (O and U stand for overhead and underground respectively)

	Netherlands	Germany	Spain
HV lines/cables			
Nominal Voltage [kV]	50/150	n.a.	45/132
Number available	5		5 O 4 U
Rated current [A]	460-1600		606-1750
R [Ω/km]	0.021-0.1		0.04-0.12
X [Ω/km]	0.11-0.18		0.27-0.4
Investment cost [€/m]	275-700		38-127 O 270-348 U
MV lines/cables			
Nominal Voltage [kV]	10	20	15
Number available	3	6	7 O 5 U
Rated current [A]	215-360	267-388	133-540
R [Ω/km]	0.16-0.4	0.1-0.21	0.08-1.3
X [Ω/km]	0.11-0.12	0.11-0.13	0.1-0.4
Investment cost [€/m]	51-71	140-220	19-56 O 125-150 U
LV lines/cables			
Nominal Voltage [kV]	n.a.	0.4	0.38
Number available		8	4 O 4 U
Rated current [A]		124-361	100-415
R [Ω/km]		0.08-0.8	0.15-1.5
X [Ω/km]		0.08-0.09	0.07-0.1
Investment cost [€/m]		85-125	10-14 O 65-72 U

It is important to remark that both underground and overhead elements were considered for the Spanish distribution area, whereas only underground lines were available in the Dutch and German cases. Consequently, this leads to higher unit network costs in the latter two distribution areas. This being true, investment costs in Netherlands and Spain remain in the same order of magnitude, except for 150-132 kV substations. However, unit costs considered for the German case are significantly higher than those in the other two areas.

Table 67: Input data. HV/MV substations and MV/LV transforming centres

	Netherlands	Germany	Spain
HV/MV substations 1			
Nominal Voltage [kV]	50	n.a.	45
Number available	4		3
Capacity range [MW]	18-40		20-40
Investment cost[k€]	550-1000		600-1000
HV/MV substations 2			
Nominal Voltage [kV]	150	n.a.	132
Number available	2		8
Capacity range [MW]	120-280		20-150
Investment cost [k€]	11500-29500		1700-5200
MV/LV transforming centres			
Nominal Voltage [kV]	n.a.	20	15
Number available		6	7
Capacity range [kW]		100-630	15-1000
Investment cost [k€]		25-75	7-26

Network investments are also quite influenced by the continuity of supply requirements set by local or national regulation. As explained in section 4.1.1, the reference network models used in this study take into account TIEPI and NIEPI indices when assessing the quality of service level corresponding to a particular network in a certain area. Values required for these indices vary according to the location of consumers in one within five types of area: urban, sub-urban, rural, dispersed rural and industrial. The 80th percentile used to characterize zonal continuity of supply is defined as the minimum value of TIEPI or NIEPI that is not surpassed by 80% of the towns within a specific zone. Table 68 and Table 69 provide the values of continuity of supply indices that must be achieved at zonal/ individual level in our analyses.

Table 68: Input data. Continuity of supply zonal indices

	TIEPI [h]	TIEPI 80th percentil [h]	NIEPI
Urban	2	3	4
Sub-urban	4	6	6
Rural	8	12	10
Dispersed rural	12	18	15
Industrial zone	2	3	4

Table 69: Input data. Continuity of supply individual indices

	Low voltage		Medium voltage	
	TIEPI [h]	NIEPI	TIEPI [h]	NIEPI
Urban	6	12	4	8
Sub-urban	10	15	8	12
Rural	15	18	12	15
Dispersed rural	20	24	16	20
Industrial zone	6	12	4	8

For the Spanish case study, values of indices for all types of areas were fed into the model for it to divide the whole case study area into zones of different types. Mainly urban and industrial zones were identified by the model, since, in most zones, the concentration level of loads was remarkably high due to the presence of towns. On the other hand, in the Mannheim area only urban indices were considered, since the distribution network corresponds to a residential area. In order to avoid distortions caused by the low number of network users in this area (areas are identified by the number and density of customers), the remaining alternatives were not considered. Finally, the Dutch area of Kop van Noord is a mixture of rural and sub-urban areas. However, contrary to what generally occurs in Spain for this type of areas, the distribution network built in The Netherlands in this case is (almost) completely underground. Therefore, it was deemed reasonable to set tighter requirements of continuity of supply so that the resulting networks were as messed as real underground networks normally are. Only sub-urban and industrial zone continuity of supply indices were considered.

Additionally, limits on the voltage at the network nodes were imposed. These limits were set to the corresponding nominal value ± 5%. Finally, in order to compute the present value of those costs that are incurred annually, i.e. energy losses and maintenance costs, values of WACC used were within the interval 5.5%-8.5%, the useful life of lines and transformers was set at between 30 and 40 years, that of protection and control devices was set at 10 years and energy losses were valued at between 36 €/MWh and 66 €/MWh.

Appendix 2: The COMPETES model

To analyse the competition on wholesale electricity markets and between different national markets ECN developed the COMPETES model. COMPETES covers twenty European electricity markets, i.e. Austria, Belgium, Czech Re-public, Denmark, Finland, France, Germany, Hungary, Italy, Luxembourg, Netherlands, Norway, Poland, Portugal, Slovakia, Slovenia, Spain, Sweden, Switzerland, and the United Kingdom. Here Denmark is divided into two parts that belong to two different non-synchronised networks, while Luxembourg is added to Germany, because there is generally no congestion between them. The model assumes that these markets can influence the market prices in other markets.

The model is able to simulate strategic behaviour (oligopolistic competition) while considering the effect of transmission constraints between countries. This strategic behaviour is based on the theory of Cournot competition and Conjectured Supply Functions (CSF) on electric power networks . The strategic behaviour of the generation companies is reflected in the conjectures each company holds regarding the supply response of rival companies. These response functions simulate each company's expectations concerning how rivals will change their electricity sales when prices change in response to the company's actions; these expectations determine the perceived profitability of capacity withholding and other strategies. The Cournot model represents one possible conjecture: that rivals will not change their outputs; COMPETES can also simulate the other extreme: that a company's actions will not change price (price taking behaviour). CSFs can be used to represent conjectures between these two extremes. COMPETES can also represent different systems of transmission pricing, among them fixed transmission tariffs, congestion-based pricing of physical transmission, netting restrictions, and auction pricing of interface capacity between countries.

Virtually all generation companies in the twenty countries are covered by the input data of the model. The user can specify which generation companies are assumed to behave strategically and which companies will be allocated to the so-called 'competitive fringe' (i.e. the price takers). The model calculates the equilibrium behaviour of the generators - and the resulting out-comes - by assuming that they simultaneously try to maximise their profits. By considering the extremes of Cournot and perfectly competitive equilibria, as well as CSF equilibria between those extremes, the robustness of conclusions to assumptions about degrees of competitive behaviour can be assessed.

With regard to consumer behaviour, the present version of the model considers 12 different levels of demand, based on the typical demand during three seasons (winter, summer and autumn/spring) and four time periods (super peak, peak, shoulder and off-peak). The 'super peak' period in each season consists of the 240 hours with the highest sum of the loads for the twenty considered countries. The three other periods have equal numbers of hours and represent the rest of the seasonal load duration curve. Altogether, the twelve periods represent all 8760 hours of a year. The consumers are assumed to be price sensitive by using decreasing linear demand curves depending on price. The number and duration of periods and the price elasticity of demand in different periods are user-specified parameters.

Transmission of electricity among countries is constrained both by power transmission distri-bution factors (PTDF), which is a linearised "DC load flow" representation of the transmission network, and path-based restrictions, which reflect the contractually allowed flows among countries. The linearised load flow model recognizes the existence of controllable DC lines between nonsynchronized markets (UK, UCTE, and Nordpool). Interface constraints in the path-based restrictions include constraints between individual pairs of countries, as well as multi-country interfaces (for instance, aggregate exports from Germany to the Netherlands and to France are constrained). Note that the physical line capacity is generally larger than the contractually permitted amounts and this difference is also reflected in the COMPETES model.

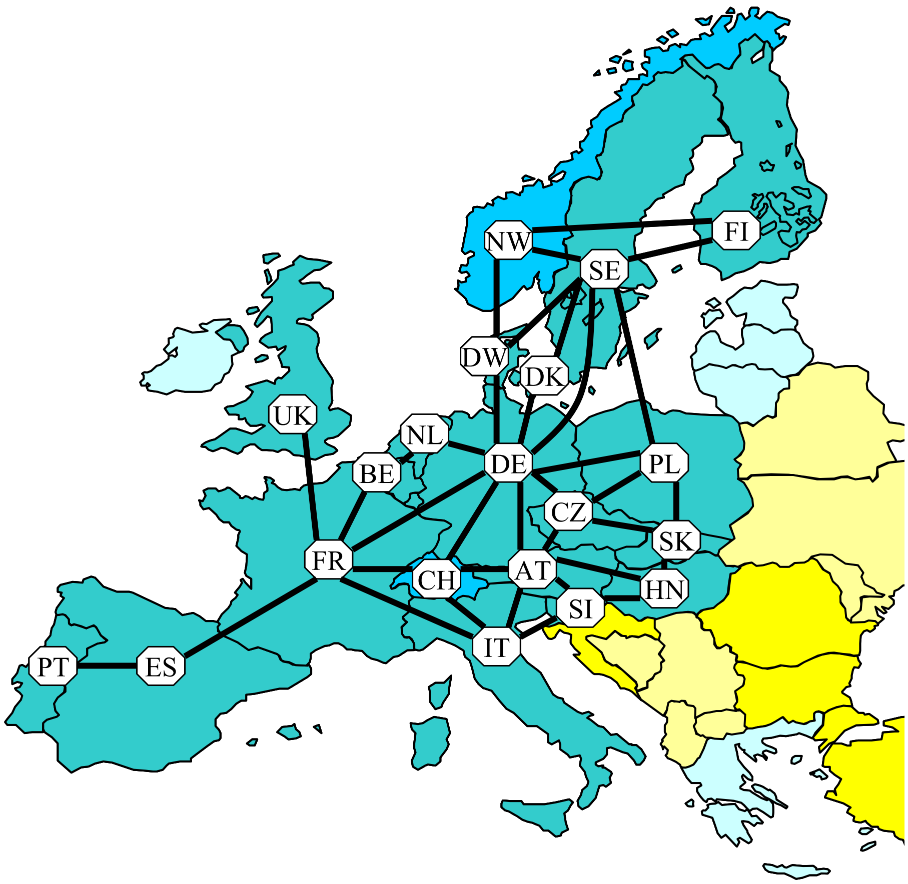

Figure 50: representation of the European network used by the COMPETES model

Abbreviations and acronyms

CHP	Combined Heat and Power (cogeneration)
DG	Distributed Generation
DSO	Distribution System Operator
EU	European Union
HV	High Voltage
LV	Low Voltage
MS	Member State
MV	Medium Voltage
PV	Photovoltaics
RES	Renewable Energy Sources
TSO	Transmission System Operator