Advanced Architectures and
Control Concepts for
MORE MICROGRIDS

Specific Targeted Project
Contract No: PL019864

WPH. Impact on the Development of Electricity Infrastructure

DH2. Report on economic, technical and environmental benefits of Microgrids in typical EU electricity systems

Annex H2.B.
Microgrids in Southern Europe scenarios: Impact studies for typical Greek and Italian distribution networks

Final Version

December 2009

Document Information

Annex H2.B to "Deliverable DH2. Report on economic, technical and environmental benefits of Microgrids in typical EU electricity systems": **Microgrids in Southern Europe scenarios: Impact studies for typical Greek and Italian distribution networks.**

Task Title: TH2. Quantifying the impact of Microgrids on investment and replacement strategies of future national electricity infrastructure.

Date: December 2009

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Access:	__	**Project Consortium**
	__	**European Commission**
	x	PUBLIC

Status:	_	For Information
	__	**Draft Version**
	__	Final Version (internal document)
	_	Submission for Approval (deliverable)
	x	Final Version (deliverable, approved on…)

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ACRONYM LIST

AM	Active Management
CHP	Combined Heat and Power
DG	Distributed Generator
DNO	Distribution Network Operator
DSM	Demand Side Management
DSO	Distribution System Operator
FC	Fuel Cell
F&F	Fit-and-Forget approach (or passive management – PM – approach)
HV	High Voltage
ICE	Internal Combustion Engine
ICT	Information and Communication Technology
LV	Low Voltage
MG	Microgrids
MT	Microturbine
MV	Medium Voltage
OH	Overhead Lines
PM	Passive Management
PV	Photovoltaic
RES	Renewable Energy Sources
TSO	Transmission System Operator
UG	Under-Ground (cables)

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1. Introduction

This Annex presents the work performed by NTUA and ERSE (former CESI Ricerca) to assess the impact of Microgrids on distribution network infrastructures in Greece and Italy, respectively.

Both studies (and in particular the Italian case) include the presence of photovoltaic (PV) systems, thus being representative of typical Southern Europe scenarios and completing the set of evaluations illustrated in Annex H2.A more relevant to Northern and Central Europe scenarios with cogeneration-dominated Microgrids.

The Annex is organized as follows:

- Chapter 2 introduces a model for investment deferral assessment, which is exemplified in the analyses carried out for Microgrids operating in a typical Greek distribution network;
- Chapter 3 summarizes typical main characteristics of the Italian distribution system, introduces a specific software tool developed by ERSE for distribution network planning, and presents a number of analyses to assess the impact on distribution network design from different penetration levels of microgeneration and microgrids, also including different design and management strategies.
- Chapter 4 contains concluding remarks regarding the southern Europe analyses.

2. Distribution network analyses for Greece

2.1 Methodology for investment deferral assessment

2.1.1 The value of investment deferral

In many cases, the costs of upgrading the network by traditional procedures can reach extremely high costs, especially in congested metropolitan areas. Therefore, by using DG technologies to supply locally the needs of the loads, the investment on strategic expensive network upgrades can be deferred. The value of the deferral of these investments depends on the investment costs and the time by which these investments are deferred. This deferral time depends, in turn, on the size of the DG being installed and the rate at which the local load grows. This topic is explored next.

2.1.2 Summary of the nomenclature

Below is provided a summary of the main symbols used in this Chapter.

n_b: Number of buses in the network
g: Index of group of feeders for upgrade
I_k: Current in feeder (A)
γ_{ik}: Sensitivity of the current I_k, in branch (or feeder) k by an increment (or reduction) of load i (A/kW)
P_{di}: Active load at bus i (kW)
σ_i: Growth rate of load i (kW/year) or (kW/month)
P_{DGi}: Active power injection by a DG at bus i
τ_k: Deferral time for feeder k (years or months)
τ_g: Deferral time for feeder g (years or months)
ρ: Real interest rate (%/year)
C_g: Investment cost on group of feeders g (€)
B_i: Benefit to utility by DG at bus i (€)

2.1.3 Impact of DG on the Distribution network currents

When a new DG is installed to operate under a certain equivalent capacity factor, the currents in some of the feeders are reduced, according to the size of the DG and its location throughout the network. If the demand across the network continues to grow, certain time will pass before the feeder currents reach the values found before the DG started to operate. The benefit to the distribution utility is immediate: it will take more time for the current on those loaded transformers or feeders to reach the technical limits at which new investments have to be put in place. The benefit is even more evident when the current reduction defers or avoids already scheduled investments. Therefore, one of the first steps towards the quantification of the benefit of transformers or feeders investment deferral is to measure the impact of the DG output on the currents across the distribution network.

2.1.4 Methodology [1]

Let γ_{ik} be the sensitivity of the current in feeder k, I_k, by an increment of load i, represented by P_{di}. So γ_{ik} is defined as:

$$\gamma_{ik} = \frac{\partial I_k}{\partial P_{di}} \qquad (1)$$

Figure 2.1 shows the basic flowchart with the steps for the calculation of the γ_{ik} factors. Ideally, the γ_{ik} factors should remain constant for different small values of P_{di} but due to the nonlinearity of the system, slight changes are observed. It was perceived for the network under study that by varying from 0.01% to 2% of the bus load, the factors changed by up to 0.1% of their total value, which was considered substantially small. A value equal to ***0.2%*** of the load was chosen for the calculation of the factors. Such value is related to the integration step, which was also considered suitable (small enough) to carry out the numerical integration without compromising its accuracy, as it will be described later. The validation loop is done only once for the network under study.

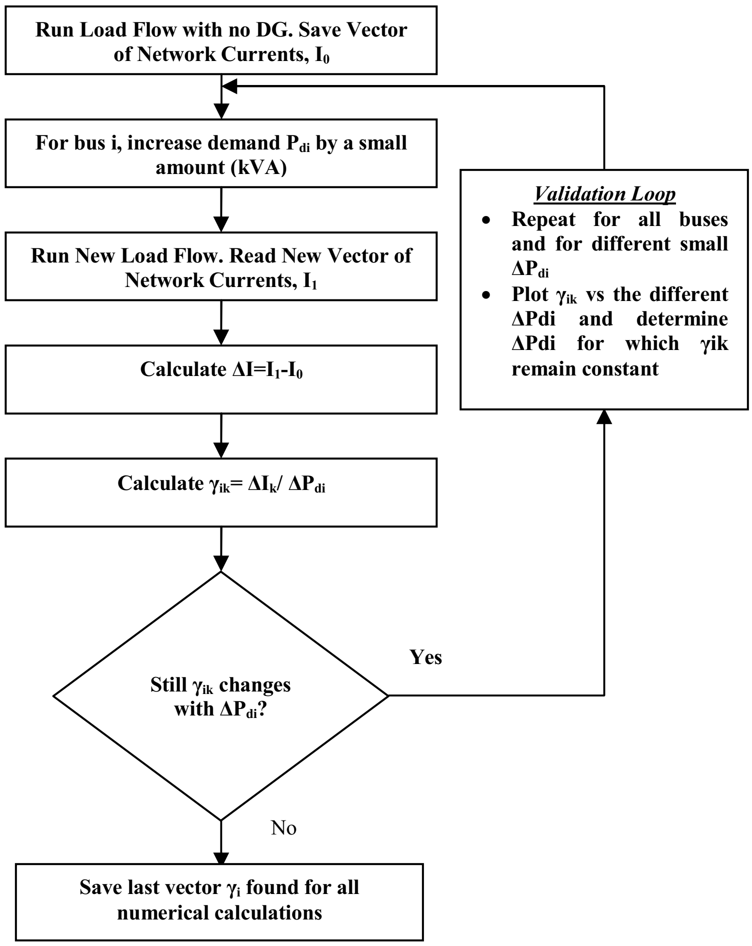


Figure 2.1 Flowchart with the steps for the calculation of the γ factors in [1]

Continuing with the methodology, for every increase on network loads, there will be an increase in the different feeder currents, according to the location of the demand relative to that of the feeder. The increase in current I_k, by a load increment P_{di} is equal to:

$$dI_k = \sum_i \gamma_{ik} dP_{di} \qquad (2)$$

If the demand P_{di} is growing in time at a certain rate, the increase in current I_k, by a load increment dP_{di} is equal to:

$$dP_{di}=\sigma_i dt \qquad (3)$$

Therefore, the differential of the feeder current I_k with respect to time is given by:

$$dI_k = \sum_i \gamma_{ik}(P_d)\sigma_i(t)dt \qquad (4)$$

because according to the nonlinearities of the distribution load flows, γ_{ik} depends on P_d, that is, on the state of operation and σ_i may itself depend on the time, that is, there may be periods when the demand grows faster than in others. Therefore expression (4) characterizes the rate of growth of feeder currents with time.

When a given DG with equivalent capacity S_{DGm} is installed at bus m, the feeder currents drop by a certain amount given by:

$$\Delta I_{km} = \gamma_{mk}^{DG} S_{DGm} \qquad (5)$$

Expression (5) can however be calculated exactly by running two load flows, one with the DG at bus and other one without it.

The time τ_k can be interpreted as a capacity deferral time in the sense that it will take τ_k more months or years for the current in feeder k or substation transformers to reach the technical limits at which new investments are needed. The following integral has to be solved numerically step by step, where at every time interval, new values of γ_{ik} and σ_i must be calculated.

$$\int_0^{\tau_k} \sum_{i=1}^{nb} \gamma_{ik}(P_d)\sigma_i(t)dt = |\Delta I_{km}| \qquad (6)$$

These situation and concept are better explained in Figures 2.2 and 2.3.

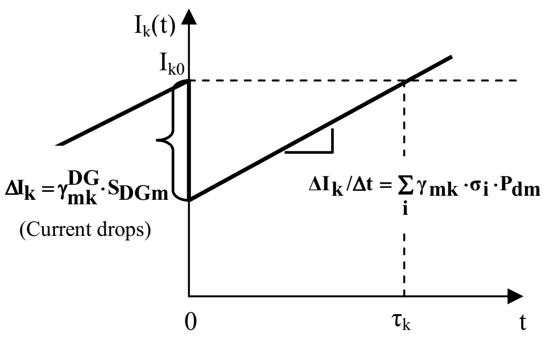


Figure 2.2 Deferral time by a drop in the feeder current

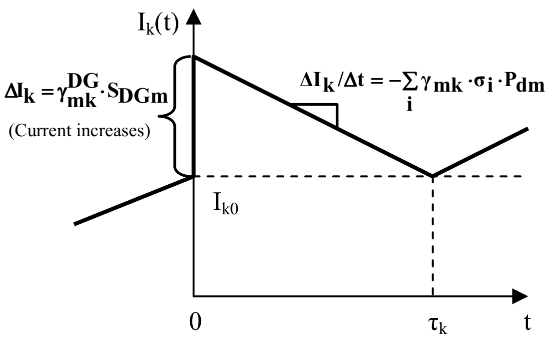


Figure 2.3 Deferral time when a DG increases the feeder current

2.1.5 *Quantification of the investment deferral benefit*

The presence of DG postpones the need for investment on certain portions of the network by a time span given by τ_k. Therefore, the planned expenditures for a particular feeder can be held up for months or years. As a result, the economic benefits to the utility are immediate and are related to the temporal value of money.

The time by which a given investment on a feeder or a group of feeders is delayed is given by the lowest deferral time of the feeder or any of the feeders belongings to that particular group. To calculate the deferral time for a group, τ_{gi}, (in months or years) due to the presence of a DG at bus i, the deferral time is first calculated for all feeders according to (6). The deferral time for a particular group is then the minimum deferral time for all feeders belonging to that group. In other words:

$$\tau_{gi} = \left\{ \min(\tau_{ki}), \quad \forall k \in g \right\} \qquad (7)$$

The total benefit, B_i, to the utility given by the microgrid located at bus i is the sum of all benefits obtained in all groups of feeders [6] .

$$B_i = \sum_g C_g \left(1 - \frac{1}{e^{\rho \tau_{gi}}} \right) \qquad (8)$$

2.2 *Case study analyses*

2.2.1 *Assumptions*

In order to implement the described methodology and obtain the desired meaningful generalized quantification, some assumptions had to be made, which are described next.

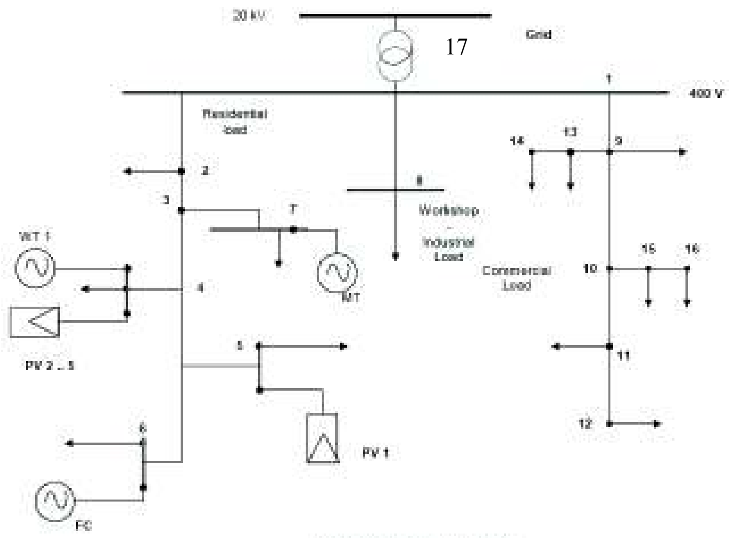
To simplify the analysis and the in numerous load flows run, the effect of the voltage regulators was ignored. Also, the load growth rate was supposed to be 0,3kW/month for all buses, although different rates can be supposed for different buses. Lower growth rates yield larger benefits as all investments can be deferred for longer periods. Some other load growth rates for the calculations were 0,1kW/month, 0,5kW/month, 0,3kW/month and 1kW/month. In addition, an important economic quantity is the real interest rate, ρ. The real interest rate was supposed to be firstly 5% and in other cases/scenarios 3%, 7%, respectively. Also, the cost of replacing a transformer of 400kVA by other of 500kVA is assumed to be constant for a short period of time. This price is about 15,000€.

The analysis of the deferral benefit was calculated by running a lot of different scenarios (DGs at the system with minimum, maximum and average capacities and other combinations). In all scenarios, a ΔP_{di} equal to 0.2% of the load was chosen for the calculation of the γ_{ik} factors. Such value is related to the integration step of (6), which was also considered small enough to carry out the numerical integration without compromising its accuracy.

In all cases it is assumed the power coefficient at the buses is 1 ($\cos\varphi=1$). Nonetheless, different DGs technologies are likely to operate at power factors different from unity, although utilities favor or even require the operation of the DGs at leading power factors (are required to produce reactive power). The reason is that distribution network loads are mostly reactive and the consumption of reactive power by the DGs degrades the network's power factor, with all the consequences that this implies.

2.2.2 Case study network description

With above in mind, the methodology presented here was applied to the 17-bus test distribution network [7]. It is a typical Hellenic LV network. Figure 2.4 presents an outline of the network (not to scale). The network comprises three feeders, one serving a primarily residential area, one industrial feeder serving a small workshop, and one commercial feeder. A variety of distributed energy resources (DER), such as one Micro Turbine (MT), one Fuel Cell (FC), one directly coupled Wind Turbine (WT) and several PVs are installed in the residential feeder. It is assumed that all DER produce active power at unity power factor, i.e. neither requesting nor producing reactive power.



The study case network.

Data for the units used

Unit ID	Unit Name	Minimum Capacity (kW)	Maximum Capacity (kW)
1	Microturbine	2	30
2	Fuel Cell	1	30
3	WT 1	0.1	15
4	PV 1	0.05	3
5	PV 2	0.05	2.5
6	PV 3	0.05	2.5
7	PV 4	0.05	2.5
8	PV 5	0.05	2.5

Line data of the MICROGRID

Sending Bus	Receiving Bus	R(pu)	X(pu)
0	1	0.0025	0.01
1	2	0.0001	0.0001
2	3	0.0125	0.00375
3	4	0.0125	0.00375
4	5	0.0125	0.00375
5	6	0.0125	0.00375
3	7	0.021875	0.004375
1	8	0.033125	0.00875
1	9	0.0075	0.005
9	10	0.015	0.010625
10	11	0.02125	0.005625
11	12	0.02125	0.005625
9	13	0.010625	0.005625
13	14	0.010625	0.005625
10	15	0.023125	0.00625
15	16	0.023125	0.00625

Figure 2.4 17-bus test distribution network

2.2.3 Simulations and results

After considering all the assumptions described above, hundreds of load flows have be run in order the total benefit to be calculated. Many scenarios have been run for that purpose. Following the described methodology the total benefit was calculated. In all scenarios, the current between buses 17-1 significantly reduced (of course, depending on the capacity of the DG), therefore the deferral time and also the total benefit will increase markedly.

So, strategically located DG in the microgrid operating during peak load periods can defer or do away with the need to undertake expensive network upgrades. As electricity is produced near the loads especially during peak load hours, power flow are essentially reduced (as long as the total DG capacity does not exceed the local load), thus postponing the need to upgrade some overloaded feeders or transformers. In our cases, next tables show the deferral time and the total benefit of replacing 5000 transformers of 400kVA by 5000 transformers of 500kVA with investment cost of ~15000€ for various σ and ρ, according to the above methodology. Also, next pictures show some other interesting results for example, the deferral time and total benefit increase with DG penetration.

The analysis of the deferral benefit was calculated by running different scenarios (DGs at the system with minimum, maximum, average capacities and other combinations). Particularly, ten (10) cases have been studied according to the level of RES production (highest, lowest and average) and the electricity prices according to the Amsterdam Power Exchange prices. The first case is that where no DG sources are considered. The studies have been run for the months January, April, July and October (05:00 in the morning – lowest load demand and 19:00 in the afternoon – highest load demand), [8], [9].

Next tables and Figures provide the relevant results.

Case Study- Bus N^{o}17 (k=17)

JANUARY (05:00 in the morning)

σ_i=300Watt/Month, ρ=5%/year

Calculation of the γ_{i17} (sensitivity of the current I_{17}, in branch (or feeder) 17 by an increment or reduction of load i (A/kW)			
Number of Bus (i)	***γ_{i17} (A/kVA)***	***σ_i (Watt/Month)***	***$\Sigma\gamma_{i,17}\cdot\sigma_i\cdot dt$ (Ampere)***
1	1.4573	300	***7.14654·dt***
2	1.4575	300	
3	1.4845	300	
4	1.4962	300	
5	1.5016	300	
6	1.5056	300	
7	1.5119	300	
8	1.4935	300	
9	1.4722	300	
10	1.486	300	
11	1.4988	300	
12	1.5045	300	
13	1.4796	300	
14	1.4835	300	
15	1.4933	300	
16	1.4958	300	

JANUARY

$P_{Total\ Load\ Demand,\ min}$*=55,201kW (05:00 in the morning)*

ESTIMATION OF DEFERRAL TIME AND QUANTIFICATION OF THE INVESTMENT DEFERRAL BENEFIT							
σ_i=300Watt/Month, ρ=5%/year, and $\Sigma\gamma_{i,17}\cdot\sigma_i\cdot dt$=7,14654 (Ampere) Investment Cost (C) for 500kVA Transformer = 15000€							
Scenarios		BUS 17 (Connection with Bus 1 via Transformer) Injection from the Grid		BUS 17 Difference of Currents (A) $\lvert I_{without\ DG} - I_{with\ DG}\rvert$	*Deferral Time, τ, (Months)*	Deferral Benefit, B (€)	*Total Benefit from Replacing 5000 Transformer of 400kVA (€)*
		S(kVA)	I(A)				
1	*Without DG*	55.5136	80.12692	0	***0***	0	***0***
2	*With DG (avg-APX-avg-RES)*	53.8081	77.66533	2.461590	***0.352194***	21.99595	***109,979.8***
3	*With DG (avg-APX-max-RES)*	47.6155	68.72708	11.39984	***1.631039***	101.5944	***507,971.8***
4	*With DG (avg-APX-min-RES)*	55.1602	79.61695	0.509970	***0.072964***	4.559575	***22,797.87***
5	*With DG (max-APX-avg-RES)*	53.8081	77.66533	2.461590	***0.352194***	21.99595	***109,979.8***
6	*With DG (max-APX-max-RES)*	47.6155	68.72708	11.39984	***1.631039***	101.5944	***507,971.8***
7	*With DG (max-APX-min-RES)*	55.1602	79.61695	0.509970	***0.072964***	4.559575	***22,797.87***
8	*With DG (min-APX-avg-RES)*	53.8081	77.66533	2.461590	***0.352194***	21.99595	***109,979.8***
9	*With DG (min-APX-max-RES)*	47.6155	68.72708	11.39984	***1.631039***	101.5944	***507,971.8***
10	*With DG (min-APX-min-RES)*	55.1602	79.61695	0.509970	***0.072964***	4.559575	***22,797.87***

JANUARY (19:00 in the afternoon)

σ_i=300Watt/Month, ρ= 5 %/year

Calculation of the γ_{i17} (sensitivity of the current I_{17}, in branch (or feeder) 17 by an increment or reduction of load i (A/kW)			
Number of Bus (i)	***γ_{i17} (A/kVA)***	***σ_i (Watt/Month)***	***$\Sigma\gamma_{i,17}\cdot\sigma_i\cdot dt$ (Ampere)***
1	1.4603	300	***7.19274·dt***
2	1.4606	300	
3	1.4932	300	
4	1.5073	300	
5	1.514	300	
6	1.5187	300	
7	1.5265	300	
8	1.5041	300	
9	1.4783	300	
10	1.495	300	
11	1.5105	300	
12	1.5174	300	
13	1.4872	300	
14	1.4919	300	
15	1.5039	300	
16	1.5069	300	

JANUARY

$P_{Total\ Load\ Demand,\ max}$=207,965kW (19:00 in the afternoon)

ESTIMATION OF DEFERRAL TIME AND QUANTIFICATION OF THE INVESTMENT DEFERRAL BENEFIT							
σ_i=300Watt/Month, ρ=5%/year, and $\Sigma\gamma_{i,17}\cdot\sigma_i\cdot dt$=7,19274 (Ampere) **Investment Cost (C) for 500kVA Transformer = 15000€**							
Scenarios		**BUS 17 (Connection with Bus 1 via Transformer) Injection from the Grid**		**BUS 17 Difference of Currents (A) $\lvert I_{without\ DG} - I_{with\ DG}\rvert$**	***Deferral Time, τ, (Months)***	**Deferral Benefit, B (€)**	***Total Benefit from Replacing 5000 Transformer of 400kVA (€)***
		S(kVA)	**I(A)**				
1	***Without DG***	212.3981	306.57028	0	***0***	0	***0***
2	***With DG (avg-APX-avg-RES)***	141.3821	204.06745	102.5028	***14.25087***	864.7517	***4,323,758.0***
3	***With DG (avg-APX-max-RES)***	144.8317	209.04652	97.52376	***13.55864***	823.9223	***4,119,612.0***
4	***With DG (avg-APX-min-RES)***	148.8055	214.78227	91.78801	***12.76120***	776.7418	***3,883,709.0***
5	***With DG (max-APX-avg-RES)***	141.3821	204.06745	102.5028	***14.25087***	864.7517	***4,323,758.0***
6	***With DG (max-APX-max-RES)***	144.8317	209.04652	97.52376	***13.55864***	823.9223	***4,119,612.0***
7	***With DG (max-APX-min-RES)***	148.8055	214.78227	91.78801	***12.76120***	776.7418	***3,883,709.0***
8	***With DG (min-APX-avg-RES)***	172.3250	248.72971	57.84057	***8.041521***	494.2683	***2,471,341.0***
9	***With DG (min-APX-max-RES)***	175.8086	253.75791	52.81237	***7.342455***	451.9547	***2,259,774.0***
10	***With DG (min-APX-min-RES)***	179.8218	259.55047	47.01981	***6.537121***	403.0559	***2,015,280.0***

APRIL

$P_{Total\ Load\ Demand,\ min}$=48.954kW (05:00 in the morning)

ESTIMATION OF DEFERRAL TIME AND QUANTIFICATION OF THE INVESTMENT DEFERRAL BENEFIT							
σ_i=300Watt/Month, ρ=5%/year Investment Cost (C) for 500kVA Transformer = 15000€						$\Sigma\gamma_{i,17}\cdot\sigma_i\cdot dt$=6,98226 (Ampere)	
Scenarios		**BUS 17** (Connection with Bus 1 via Transformer) Injection from the Grid		**BUS 17** Difference of Currents (A) $\lvert I_{without\ DG} - I_{with\ DG}\rvert$	*Deferral Time, τ, (Months)*	Deferral Benefit, B (€)	*Total Benefit from Replacing 5000 Transformer of 400kVA (€)*
		S(kVA)	I(A)				
1	*Without DG*	49.2000	71.01403	0	*0*	0	*0*
2	*With DG (avg-APX-avg-RES)*	46.1769	66.65070	4.363330	*0.624917*	39.00648	*195,032.4*
3	*With DG (avg-APX-max-RES)*	39.0728	56.39667	14.61736	*2.093500*	130.2747	*651,373.6*
4	*With DG (avg-APX-min-RES)*	49.2000	71.01403	0	*0*	0	*0*
5	*With DG (max-APX-avg-RES)*	46.1769	66.65070	4.363330	*0.624917*	39.00648	*195,032.4*
6	*With DG (max-APX-max-RES)*	39.0728	56.39667	14.61736	*2.093500*	130.2747	*651,373.6*
7	*With DG (max-APX-min-RES)*	49.2000	71.01403	0	*0*	0	*0*
8	*With DG (min-APX-avg-RES)*	46.1769	66.65070	4.363330	*0.624917*	39.00648	*195,032.4*
9	*With DG (min-APX-max-RES)*	39.0728	56.39667	14.61736	*2.093500*	130.2747	*651,373.6*
10	*With DG (min-APX-min-RES)*	49.2000	71.01403	0	*0*	0	*0*

APRIL

$P_{Total\ Load\ Demand,\ max}$*=184.433kW (19:00 in the afternoon)*

ESTIMATION OF DEFERRAL TIME AND QUANTIFICATION OF THE INVESTMENT DEFERRAL BENEFIT							
σ_i=300Watt/Month, ρ=5%/year Investment Cost (C) for 500kVA Transformer = 15000€						$\Sigma\gamma_{i,17}\cdot\sigma_i\cdot dt$=7.1508 (Ampere)	
Scenarios		**BUS 17** (Connection with Bus 1 via Transformer) Injection from the Grid		**BUS 17** Difference of Currents (A) $\lvert I_{without\ DG} - I_{with\ DG}\rvert$	*Deferral Time, τ, (Months)*	**Deferral Benefit, B (€)**	*Total Benefit from Replacing 5000 Transformer of 400kVA (€)*
		S(kVA)	I(A)				
1	*Without DG*	187.8943	271.2021	0	***0***	0	***0***
2	*With DG (avg-APX-avg-RES)*	181.0926	261.3846	9.8175	***1.372923***	85.56274	***427,813.7***
3	*With DG (avg-APX-max-RES)*	178.5482	257.7121	13.490	***1.886502***	117.4442	***587,221.0***
4	*With DG (avg-APX-min-RES)*	187.8943	271.2021	0	***0***	0	***0***
5	*With DG (max-APX-avg-RES)*	181.0926	261.3846	9.8175	***1.372923***	85.56274	***427,813.7***
6	*With DG (max-APX-max-RES)*	178.5482	257.7121	13.490	***1.886502***	117.4442	***587,221.0***
7	*With DG (max-APX-min-RES)*	187.8943	271.2021	0	***0***	0	***0***
8	*With DG (min-APX-avg-RES)*	181.0926	261.3846	9.8175	***1.372923***	85.56274	***427,813.7***
9	*With DG (min-APX-max-RES)*	178.5482	257.7121	13.490	***1.886502***	117.4442	***587,221.0***
10	*With DG (min-APX-min-RES)*	187.8943	271.2021	0	***0***	0	***0***

JULY

$P_{Total\ Load\ Demand,\ min}$*=55.354kW (05:00 in the morning)*

ESTIMATION OF DEFERRAL TIME AND QUANTIFICATION OF THE INVESTMENT DEFERRAL BENEFIT							
σ_i=300Watt/Month, ρ=5%/year Investment Cost (C) for 500kVA Transformer = 15000€						$\Sigma\gamma_{i,17}\cdot\sigma_i\cdot dt$=6.98946 *(Ampere)*	
Scenarios		**BUS 17** (Connection with Bus 1 via Transformer) Injection from the Grid		**BUS 17** Difference of Currents (A) $\lvert I_{without\ DG} - I_{with\ DG}\rvert$	*Deferral Time,* τ*, (Months)*	Deferral Benefit, B (€)	*Total Benefit from Replacing 5000 Transformer of 400kVA (€)*
		S(kVA)	I(A)				
1	*Without DG*	55.6688	80.35105	0	***0***	0	***0***
2	*With DG (avg-APX-avg-RES)*	49.9935	72.15932	8.191730	***1.172012***	73.07218	***365,360.9***
3	*With DG (avg-APX-max-RES)*	45.9018	66.25354	14.09751	***2.016967***	125.5322	***627,661.0***
4	*With DG (avg-APX-min-RES)*	55.6688	80.35105	0	***0***	0	***0***
5	*With DG (max-APX-avg-RES)*	49.9935	72.15932	8.191730	***1.172012***	73.07218	***365,360.9***
6	*With DG (max-APX-max-RES)*	45.9018	66.25354	14.09751	***2.016967***	125.5322	***627,661.0***
7	*With DG (max-APX-min-RES)*	55.6688	80.35105	0	***0***	0	***0***
8	*With DG (min-APX-avg-RES)*	49.9935	72.15932	8.191730	***1.172012***	73.07218	***365,360.9***
9	*With DG (min-APX-max-RES)*	45.9018	66.25354	14.09751	***2.016967***	125.5322	***627,661.0***
10	*With DG (min-APX-min-RES)*	55.6688	80.35105	0	***0***	0	***0***

JULY
$P_{Total\ Load\ Demand,\ max}$=208.543kW (19:00 in the afternoon)

ESTIMATION OF DEFERRAL TIME AND QUANTIFICATION OF THE INVESTMENT DEFERRAL BENEFIT							
σ_i=300Watt/Month, ρ=5%/year Investment Cost (C) for 500kVA Transformer = 15000€						$\Sigma\gamma_{i,17}\cdot\sigma_i\cdot dt$=7.08999 (Ampere)	
Scenarios		BUS 17 (Connection with Bus 1 via Transformer) Injection from the Grid		BUS 17 Difference of Currents (A) $\lvert I_{without\ DG} - I_{with\ DG}\rvert$	*Deferral Time, τ, (Months)*	Deferral Benefit, B (€)	*Total Benefit from Replacing 5000 Transformer of 400kVA (€)*
		S(kVA)	I(A)				
1	*Without DG*	213.0016	307.4413	0	***0***	0	***0***
2	*With DG (avg-APX-avg-RES)*	201.3001	290.5517	16.88960	***2.382175***	148.1495	***740,747.500***
3	*With DG (avg-APX-max-RES)*	202.3603	292.0820	15.35930	***2.166336***	134.7868	***673,933.800***
4	*With DG (avg-APX-min-RES)*	212.3535	306.5059	0.935400	***0.131932***	8.243514	***41,217.5700***
5	*With DG (max-APX-avg-RES)*	139.5421	201.4116	106.0297	***14.95484***	906.1526	***4,530,763.0***
6	*With DG (max-APX-max-RES)*	140.5706	202.8962	104.5451	***14.74545***	893.8507	***4,469,254.0***
7	*With DG (max-APX-min-RES)*	150.2932	216.9295	90.51180	***12.76614***	777.0344	***3,885,172.0***
8	*With DG (min-APX-avg-RES)*	201.3001	290.5517	16.88960	***2.382175***	148.1495	***740,747.500***
9	*With DG (min-APX-max-RES)*	202.3603	292.0820	15.35930	***2.166336***	134.7868	***673,933.800***
10	*With DG (min-APX-min-RES)*	212.3535	306.5059	0.935400	***0.131932***	8.243514	***41,217.5700***

OCTOBER

$P_{Total\ Load\ Demand,\ min}$=*46.291kW (05:00 in the morning)*

ESTIMATION OF DEFERRAL TIME AND QUANTIFICATION OF THE INVESTMENT DEFERRAL BENEFIT							
σ_i=300Watt/Month, ρ=5%/year **Investment Cost (C) for 500kVA Transformer = 15000€**						***$\Sigma\gamma_{i,17}\cdot\sigma_i\cdot dt$=*6.97341 *(Ampere)***	
Scenarios		**BUS 17 (Connection with Bus 1 via Transformer)** **Injection from the Grid** **S(kVA)**	**I(A)**	**BUS 17 Difference of Currents (A)** $\lvert I_{without\ DG} - I_{with\ DG}\rvert$	***Deferral Time, τ, (Months)***	**Deferral Benefit, B (€)**	***Total Benefit from Replacing 5000 Transformer of 400kVA (€)***
1	***Without DG***	46.5101	67.13158	0	***0***	0	***0***
2	***With DG (avg-APX-avg-RES)***	39.6082	57.16951	9.96207	***1.428579***	89.02101	***445,105.0***
3	***With DG (avg-APX-max-RES)***	41.8087	60.34569	6.78589	***0.973109***	60.69620	***303,481.0***
4	***With DG (avg-APX-min-RES)***	46.5101	67.13158	0	***0***	0	***0***
5	***With DG (max-APX-avg-RES)***	39.6082	57.16951	9.96207	***1.428579***	89.02101	***445,105.0***
6	***With DG (max-APX-max-RES)***	41.8087	60.34569	6.78589	***0.973109***	60.69620	***303,481.0***
7	***With DG (max-APX-min-RES)***	46.5101	67.13158	0	***0***	0	***0***
8	***With DG (min-APX-avg-RES)***	39.6082	57.16951	9.96207	***1.428579***	89.02101	***445,105.0***
9	***With DG (min-APX-max-RES)***	41.8087	60.34569	6.78589	***0.973109***	60.69620	***303,481.0***
10	***With DG (min-APX-min-RES)***	46.5101	67.13158	0	***0***	0	***0***

OCTOBER

$P_{Total\ Load\ Demand,\ max}$=174.397kW (19:00 in the afternoon)

ESTIMATION OF DEFERRAL TIME AND QUANTIFICATION OF THE INVESTMENT DEFERRAL BENEFIT								
σ_i=300Watt/Month, ρ=5%/year Investment Cost (C) for 500kVA Transformer = 15000€						$\Sigma\gamma_{i,17}\cdot\sigma_i\cdot dt$=7.14654 (Ampere)		
Scenarios		BUS 17 (Connection with Bus 1 via Transformer) Injection from the Grid		BUS 17 Difference of Currents (A) $\lvert I_{without\ DG} - I_{with\ DG}\rvert$	Deferral Time, τ, (Months)	Deferral Benefit, B (€)	Total Benefit from Replacing 5000 Transformer of 400kVA (€)
		S(kVA)	I(A)				
1	Without DG	177.4827	256.1742	0	0	0	0
2	With DG (avg-APX-avg-RES)	146.7058	211.7516	44.42260	6.215959	383.5096	1,917,548.0
3	With DG (avg-APX-max-RES)	136.4278	196.9165	59.25770	8.291803	509.3875	2,546,938.0
4	With DG (avg-APX-min-RES)	144.4766	208.5340	47.64020	6.666191	410.9039	2,054,520.0
5	With DG (max-APX-avg-RES)	115.9559	167.3680	88.80620	12.42646	756.8900	3,784,450.0
6	With DG (max-APX-max-RES)	105.7761	152.6747	103.4995	14.48246	878.3849	4,391,925.0
7	With DG (max-APX-min-RES)	113.7481	164.1812	91.99300	12.87238	783.3293	3,916,646.0
8	With DG (min-APX-avg-RES)	177.4827	256.1742	0	0	0	0
9	With DG (min-APX-max-RES)	167.0241	241.0786	15.09560	2.112295	131.4392	657,195.80
10	With DG (min-APX-min-RES)	175.2141	252.8998	3.274400	0.458180	28.60892	143,044.60

THE MOST IMPORTANT CASES

***STUDY CASES** REGARDING THE MAXIMUM AND MINIMUM TOTAL DG GENERATION AS COMPARED WITH ABOVE 10 SCENARIOS*				*Injection from the Grid*		*Total DG Generation*	*Deferral Time*	*Deferral Benefits*	*Total Benefit from Replacing 5000 Transformers of 400 kVA*
				P(kW)	*Q(kVar)*	*P(kW)*	*τ (months)*	*B(€)*	*(€)*
1	JANUARY	05:00 (morning)	NO DG	55.5136	0.386	0.000	0	0	0
2			MAX - P_{DG}	47.6155	0.293	7.840	1.631	101.6	507,971.8
3			MIN - P_{DG}	55.1602	0.382	0.350	0.073	4.559	22,797.87
4		19:00 (afternoon)	NO DG	212.398	5.679	0.000	0	0	0
5			MAX - P_{DG}	141.382	2.752	68.83	14.25	864.7	4,323,758.0
6			MIN - P_{DG}	179.821	4.179	31.50	6.537	403.1	2,015,280.0
7	APRIL	05:00 (morning)	NO DG	49.2000	0.303	0.000	0	0	0
8			MAX - P_{DG}	39.0728	0.203	10.07	2.093	130.3	651,373.6
9			MIN - P_{DG}	49.2000	0.303	0.000	0	0	0
10		19:00 (afternoon)	NO DG	187.894	4.444	0.000	0	0	0
11			MAX - P_{DG}	178.548	4.030	9.020	1.886	117.4	587,221.0
12			MIN - P_{DG}	178.548	4.030	9.020	1.886	117.4	587,221.0
13	JULY	05:00 (morning)	NO DG	55.6688	0.388	0.000	0	0	0
14			MAX - P_{DG}	45.9018	0.276	9.700	2.017	125.5	627,661.0
15			MIN - P_{DG}	49.9935	0.319	5.630	1.172	73.07	365,360.9
16		19:00 (afternoon)	NO DG	213.001	5.711	0.000	0	0	0
17			MAX - P_{DG}	139.542	2.704	71.24	14.95	906.1	4,530,763.0
18			MIN - P_{DG}	212.353	5.677	0.620	0.132	8.246	41,217.57
19	OCTOBER	05:00 (morning)	NO DG	46.5101	0.271	0.000	0	0	0
20			MAX - P_{DG}	39.6082	0.203	6.860	1.428	89.02	445,105.0
21			MIN - P_{DG}	46.5101	0.271	0.000	0	0	0
22		19:00 (afternoon)	NO DG	177.482	3.965	0.000	0	0	0
23			MAX - P_{DG}	105.776	1.649	70.12	14.48	878.4	4,391,925.0
24			MIN - P_{DG}	177.482	3.965	0.000	0	0	0

JANUARY (05:00 in the morning)

$P_{Total\ Load\ Demand,\ min}$ = 55.201kW

Injection from the Grid (best scenario, max - P_{DG}): S = 47.6155kVA, I = 68.72708A

Investment Cost (C) for 500kVA Transformer = 15000€

σ: growth rate of load i (kW/year) or (kW/month) and ρ: real interest rate (%/year)

σ (Watt/ month)	$\Sigma\gamma_{i,17}\cdot\sigma_i$	***Deferral Time, τ (month)***	***Deferral Benefit, B (€) ρ = 3 %***	***Total Benefit from Replacing 5000 Transformers of 400 kVA (€) ρ = 3 %***	***Deferral Benefit, B (€) ρ = 5 %***	***Total Benefit from Replacing 5000 Transformers of 400 kVA (€) ρ = 5 %***	***Deferral Benefit, B (€) ρ = 7 %***	***Total Benefit from Replacing 5000 Transformers of 400 kVA (€) ρ = 7 %***
100	2.32977	4.893118	182.3742	911,870.9	302.7234	911,870.9	544.3544	2,721,772.0
300	6.98931	1.631039	61.03945	305,197.2	101.5944	507,971.8	142.0392	153,926.5
500	11.6488	0.978624	36.65353	183,267.7	61.03945	305,197.2	85.38562	426,928.1
700	16.3083	0.699017	26.19024	130,951.2	43.62499	218,125.0	61.03945	305,197.2
1000	23.2977	0.489312	18.33797	91,689.87	30.55083	152,754.2	42.75374	213,768.7

JANUARY (19:00 in the afternoon)

$P_{Total\ Load\ Demand,\ max} = 207.965$kW

Injection from the Grid (best scenario, max - P_{DG}): S = 141.3821kVA, I = 204.06745A

Investment Cost (C) for 500kVA Transformer = 15000€

σ: growth rate of load i (kW/year) or (kW/month) and ρ: real interest rate (%/year)

σ (Watt/ month)	$\Sigma\gamma_{i,17}\cdot\sigma_i$	Deferral Time, τ (month)	Deferral Benefit, B (€) ρ = 3 %	Total Benefit from Replacing 5000 Transformers of 400 kVA (€) ρ = 3 %	Deferral Benefit, B (€) ρ = 5 %	Total Benefit from Replacing 5000 Transformers of 400 kVA (€) ρ = 5 %	Deferral Benefit, B (€) ρ = 7 %	Total Benefit from Replacing 5000 Transformers of 400 kVA (€) ρ = 7 %
100	2.39758	42.75262	1,520.518	7,602,592	2,447.57	12,237,850	3,310.863	16,554,317
300	7.19274	14.25087	525.0001	2,625,000	864.7517	4,323,758	1,196.529	5,982,644
500	11.9879	8.550524	317.2419	1,586,209	525.0001	2,625,000	729.8186	3,649,093
700	16.7830	6.107517	227.2922	1,136,461	376.9038	1,884,519	525.0001	2,625,000
1000	23.9758	4.275262	159.4686	797,343	264.838	1,324,190	369.4593	1,847,297

APRIL (05:00 in the morning)

$P_{Total\ Load\ Demand,\ min}$ = 48.954kW

Injection from the Grid (best scenario, max - P_{DG}): S = 39.0728kVA, I = 56.39667A

Investment Cost (C) for 500kVA Transformer = 15000€

σ: growth rate of load i (kW/year) or (kW/month) and ρ: real interest rate (%/year)

σ (Watt/ month)	$\Sigma\gamma_{i,17}\cdot\sigma_i$	Deferral Time, τ (month)	Deferral Benefit, B (€) ρ = 3 %	Total Benefit from Replacing 5000 Transformers of 400 kVA (€) ρ = 3 %	Deferral Benefit, B (€) ρ = 5 %	Total Benefit from Replacing 5000 Transformers of 400 kVA (€) ρ = 5 %	Deferral Benefit, B (€) ρ = 7 %	Total Benefit from Replacing 5000 Transformers of 400 kVA (€) ρ = 7 %
100	2.32742	6.2804	233.6794	1,168,397.0	387.4397	1,937,198.0	539.5989	2,697,995.0
300	6.98226	2.0935	78.30116	391,505.8	130.2747	651,373.6	182.0673	910,336.3
500	11.6371	1.2561	47.02986	235,149.3	78.30116	391,505.8	109.5071	547,535.3
700	16.2919	0.8972	33.60783	168,039.1	55.97120	279,856.0	78.30116	391,505.8
1000	23.2742	0.6280	23.53339	117,667.0	39.20181	196,009.0	54.85383	274,269.1

APRIL (19:00 in the afternoon)

$P_{Total\ Load\ Demand,\ max} = 184.433$kW

Injection from the Grid (best scenario, max - P_{DG}): S = 178.5482kVA, I = 257.7121A

Investment Cost (C) for 500kVA Transformer = 15000€

σ: growth rate of load i (kW/year) or (kW/month) and ρ: real interest rate (%/year)

σ (Watt/ month)	$\Sigma\gamma_{i,17}\cdot\sigma_i$	*Deferral Time, τ (month)*	*Deferral Benefit, B (€) ρ = 3 %*	*Total Benefit from Replacing 5000 Transformers of 400 kVA (€) ρ = 3 %*	*Deferral Benefit, B (€) ρ = 5 %*	*Total Benefit from Replacing 5000 Transformers of 400 kVA (€) ρ = 5 %*	*Deferral Benefit, B (€) ρ = 7 %*	*Total Benefit from Replacing 5000 Transformers of 400 kVA (€) ρ = 7 %*
100	2.3836	5.659507	210.737	1,053,686.0	349.5812	1,747,906.0	487.121	2,435,609.0
300	7.1508	1.886502	70.5772	352,886.4	117.4442	587,221.0	164.164	820,820.0
500	11.918	1.131901	42.3863	211,931.5	70.57727	352,886.4	98.7150	493,575.6
700	16.685	0.808501	30.2881	151,440.8	50.44629	252,231.5	70.5770	352,886.4
1000	23.297	0.565951	21.2081	106,040.7	35.33024	176,651.2	49.4390	247,195.1

JULY (05:00 in the morning)

$P_{Total\ Load\ Demand,\ min}$ = 55.354kW

Injection from the Grid (best scenario, max - P_{DG}): S = 45.9018kVA, I = 66.25354A

Investment Cost (C) for 500kVA Transformer = 15000€

σ: growth rate of load i (kW/year) or (kW/month) and ρ: real interest rate (%/year)

σ (Watt/ month)	$\Sigma\gamma_{i,17}\cdot\sigma_i$	*Deferral Time, τ (month)*	*Deferral Benefit, B (€) ρ = 3 %*	*Total Benefit from Replacing 5000 Transformers of 400 kVA (€) ρ = 3 %*	*Deferral Benefit, B (€) ρ = 5 %*	*Total Benefit from Replacing 5000 Transformers of 400 kVA (€) ρ = 5 %*	*Deferral Benefit, B (€) ρ = 7 %*	*Total Benefit from Replacing 5000 Transformers of 400 kVA (€) ρ = 7 %*
100	2.32982	6.0509	225.2012	1,126,006.0	373.453	1,867,269.0	520.2188	2,601,094.0
300	6.98946	2.0169	75.44589	377,229.4	125.532	627,661.0	175.4504	877,252.2
500	11.6491	1.2101	45.31318	226,565.9	75.4458	377,229.4	105.5179	527,589.4
700	16.3087	0.8644	32.38054	161,902.7	53.9287	269,643.6	75.44580	377,229.4
1000	23.2982	0.6050	22.67372	113,368.6	37.7705	188,852.5	52.85205	264,260.3

<u>JULY (19:00 in the afternoon)</u>

$P_{Total\ Load\ Demand,\ max}$ = *139.5421*kW

Injection from the Grid (best scenario, max - P_{DG}): S = 139.5421kVA, I = 201.4116A

Investment Cost (C) for 500kVA Transformer = 15000€

σ: growth rate of load i (kW/year) or (kW/month) and ρ: real interest rate (%/year)

σ (Watt/ month)	$\Sigma\gamma_{i,17}\cdot\sigma_i$	*Deferral Time, τ (month)*	*Deferral Benefit, B (€) ρ = 3 %*	*Total Benefit from Replacing 5000 Transformers of 400 kVA (€) ρ = 3 %*	*Deferral Benefit, B (€) ρ = 5 %*	*Total Benefit from Replacing 5000 Transformers of 400 kVA (€) ρ = 5 %*	*Deferral Benefit, B (€) ρ = 7 %*	*Total Benefit from Replacing 5000 Transformers of 400 kVA (€) ρ = 7 %*
100	2.36333	44.86453	1591.5	7,957,498.0	2,557.542	12,787,711.0	3,453.984	17,269,921.0
300	7.08999	14.95484	550.45	2,752,263.0	906.1526	4,530,763.0	1,253.096	6,265,482.0
500	11.8166	8.972907	332.73	1,663,690.0	550.4526	2,752,263.0	764.9356	3,824,678.0
700	16.5433	6.409219	238.43	1,192,152.0	395.2748	1,976,374.0	550.4526	2,752,263.0
1000	23.6333	4.486453	167.30	836,510.0	277.7987	1,388,994.0	387.4723	1,937,361.0

OCTOBER (05:00 in the morning)

$P_{Total\ Load\ Demand,\ min} = 46.291$kW

Injection from the Grid (best scenario, max - P_{DG}): S = 39.6082kVA, I = 57.16951A

Investment Cost (C) for 500kVA Transformer = 15000€

σ: growth rate of load i (kW/year) or (kW/month) and ρ: real interest rate (%/year)

σ (Watt/ month)	$\Sigma\gamma_{i,17}\cdot\sigma_i$	*Deferral Time, τ (month)*	*Deferral Benefit, B (€)* ρ = 3 %	*Total Benefit from Replacing 5000 Transformers of 400 kVA (€)* ρ = 3 %	*Deferral Benefit, B (€)* ρ = 5 %	*Total Benefit from Replacing 5000 Transformers of 400 kVA (€)* ρ = 5 %	*Deferral Benefit, B (€)* ρ = 7 %	*Total Benefit from Replacing 5000 Transformers of 400 kVA (€)* ρ = 7 %
100	2.32447	4.285738	159.8573	799,286.4	265.4812	1,327,406.0	370.3534	1,851,767.0
300	6.97341	1.428579	53.47618	267,380.9	89.02101	445,105.0	124.4813	622,406.5
500	11.6223	0.857148	32.10862	160,543.1	53.47618	267,380.9	74.81323	374,066.1
700	16.2712	0.612248	22.94175	114,708.8	38.21675	191,083.8	53.47618	267,380.9
1000	23.2447	0.428574	16.06291	80,314.56	26.76196	133,809.8	37.45337	187,266.9

OCTOBER (19:00 in the afternoon)

$P_{Total\ Load\ Demand,\ max} = 174.397$kW

Injection from the Grid (best scenario, max - P_{DG}): S = 105.7761kVA, I = 152.6747A

Investment Cost (C) for 500kVA Transformer = 15000€

σ: growth rate of load i (kW/year) or (kW/month) and ρ: real interest rate (%/year)

σ (Watt/ month)	$\Sigma\gamma_{i,17}\cdot\sigma_i$	Deferral Time, τ (month)	Deferral Benefit, B (€) ρ = 3 %	Total Benefit from Replacing 5000 Transformers of 400 kVA (€) ρ = 3 %	Deferral Benefit, B (€) ρ = 5 %	Total Benefit from Replacing 5000 Transformers of 400 kVA (€) ρ = 5 %	Deferral Benefit, B (€) ρ = 7 %	Total Benefit from Replacing 5000 Transformers of 400 kVA (€) ρ = 7 %
100	2.38218	43.44739	1,543.911	7,719,554.0	2,483.855	12,419,275.0	3,358.141	16,790,707.0
300	7.14654	14.48246	533.3783	2,666,892.0	878.3849	4,391,925.0	1,215.164	6,075,819.0
500	11.9109	8.689478	322.3415	1,611,708.0	533.3783	2,666,892.0	741.3808	3,706,904.0
700	16.6752	6.206770	230.9574	1,154,787.0	382.9499	1,914,750.0	533.3783	2,666,892.0
1000	23.8218	4.344739	162.0461	810,230.3	269.1030	1,345,515.0	375.3876	1,876,938.0

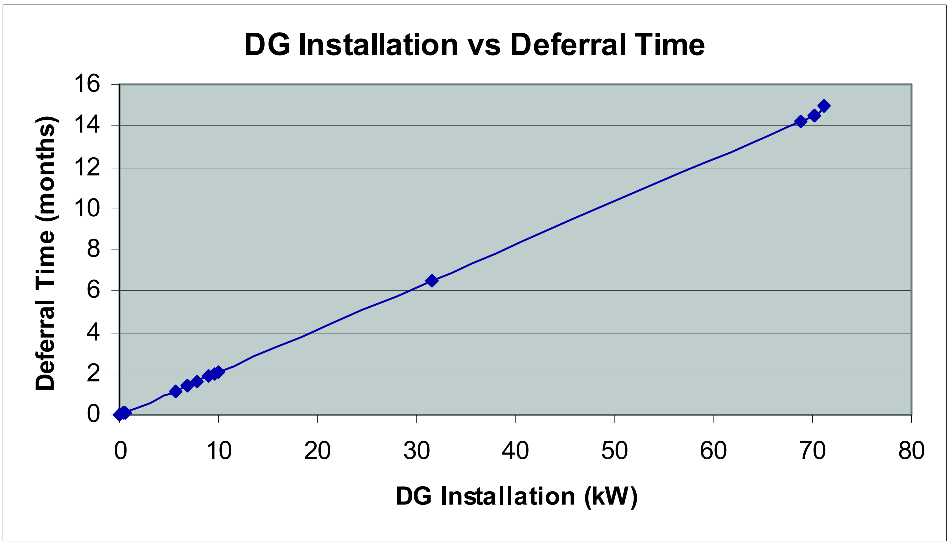


Figure 2.5 Deferral time as a function of DG capacity

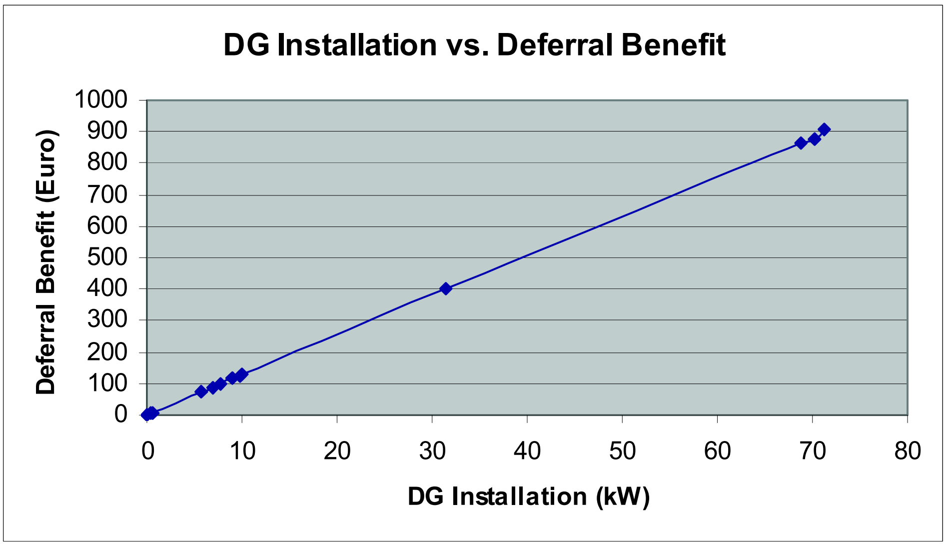


Figure 2.6 Deferral benefit as a function of DG capacity

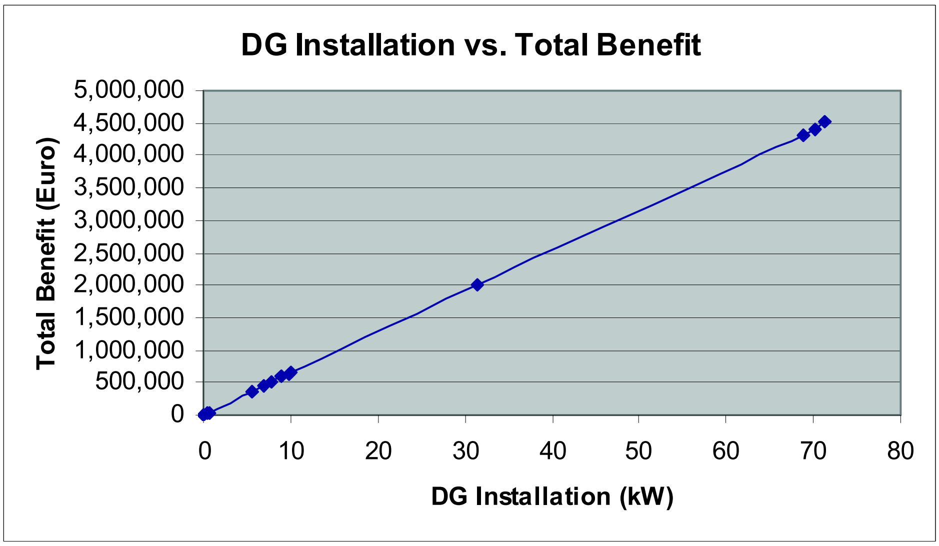


Figure 2.7 Total benefit as a function of DG capacity

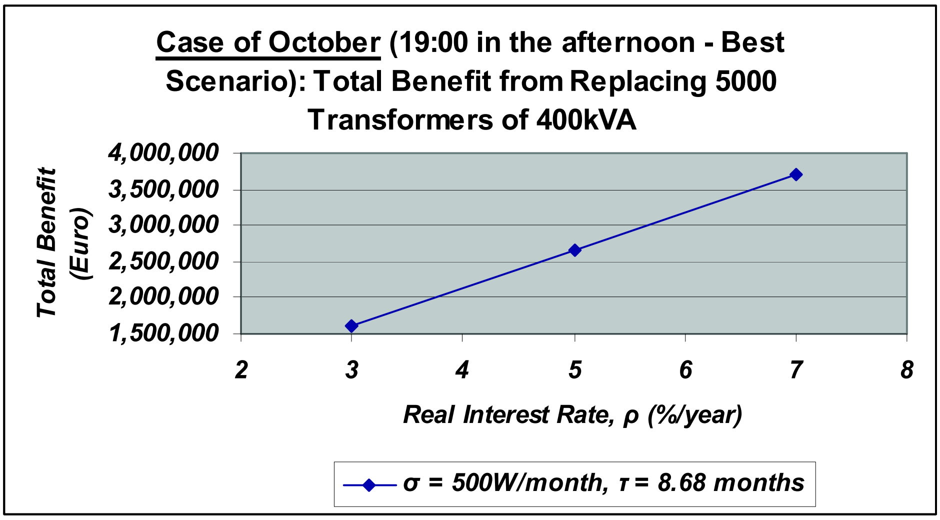


Figure 2.8 Case of October

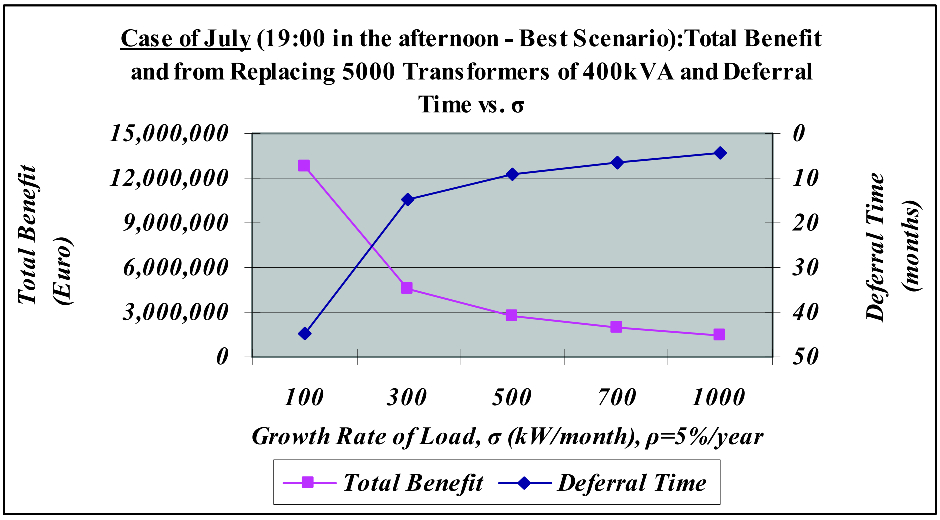


Figure 2.9 Case of July

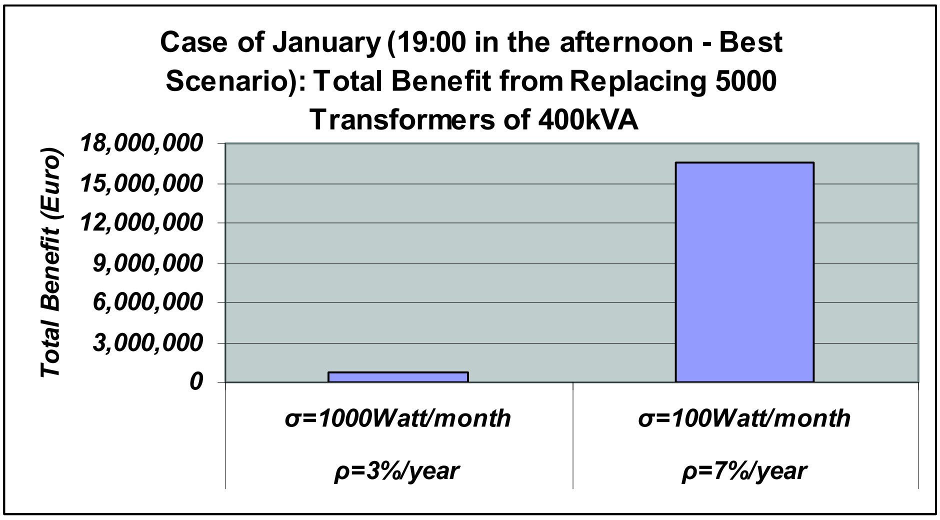


Figure 2.10 Case of January

2.2.4 Conclusions on the analyses run for Greece

This Chapter presented one way for quantifying the deferral benefits created by DG operating in a microgrid. A given microgrid can postpone or even eliminate the need for investments on transformers (strategies better known as "non-wire solutions").

After several necessary assumptions were made, an idea of the magnitude of this benefit was obtained.

It was found that the deferral time and total benefit increase when the DGs production of a microgrid are installed near load pockets and during peak load period. This almost obvious result was not only confirmed but also quantified.

Moreover, by using DG technologies to supply locally the needs of loads, investments on expensive network upgrades can be deferred. The value of the deferral of these investments depends on the investment costs and the time by which these investments are deferred. This deferral time depends, in turn, on the size of the DG being installed and the rate at which the local load grows.

Although a quantification of the deferral benefit is extremely complex, we can see that the equations are linear. In other words if σ_i and ρ_i are changed then the results are changed proportional.

However, only when all the economic benefits of a microgrid are understood and quantified can all the advantages be exploited to their full extent.

Clearly, the presence of dg postpones the need for investment on certain portions of the network by a time span.

3. Distribution network analyses for Italy: Assessment of the impact of PV-based Microgrids on investment and replacement strategies in a typical Italian distribution network

3.1 The Italian electricity distribution network

The Italian distribution system is mainly composed of three different levels:
- High Voltage network (132 kV, 150 kV);
- Medium Voltage network (15 kV, 20 kV);
- Low Voltage network (400 V).

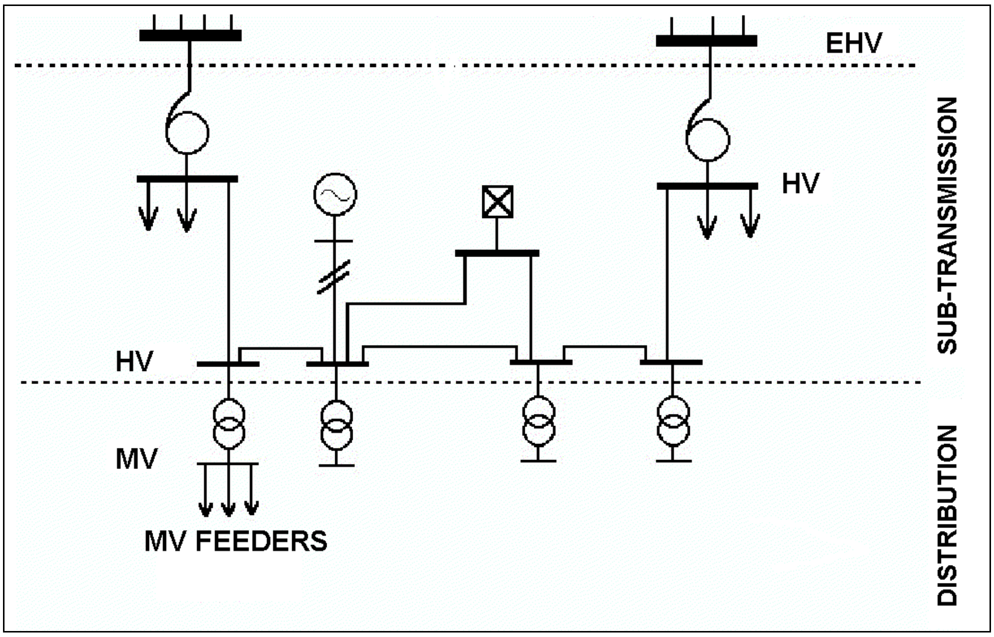


Figure 3.1 Structure of the Italian distribution system

Generally, only MV and LV levels are considered Distribution system in the strict sense of the word. The total length of the HV sub-transmission or primary distribution network (132, 150 kV) is about 45200 km. The overall extension of LV + MV distribution network is around 1090000 km (334000 km MV lines, 756000 km LV lines), with approximately 65 % overhead lines and 35 % underground cables at the MV level, and approximately 20 % overhead lines and 80 % underground cables at the LV level. Primary substations are about 1900; secondary substations are about 410000.

3.1.1 Medium Voltage network (15-20 kV)

In Medium Voltage (MV) networks or Secondary Distribution (15-20 kV), primary substations lower the voltage level from HV to MV and feed the secondary distribution network. Both MV and LV networks are built meshed, connecting different primary or secondary substations, but they are operated radially. Overhead networks are mainly adopted in rural areas, where load densities are low. They are generally realized with open-wire circuits. The MV network starts from a substation with a typical tree structure feeding MV/LV secondary substations and MV customers with "input-output" connections. For main lines, in case of a fault, a back-up supply is possible from adjacent primary substations or from a different bus-bar of the same substation. The conductor cross section of main feeders is kept constant (not tapered) in order to supply the system from both substations. The sub-feeders (laterals) have smaller sections, and generally have no back-up supply.

Adopted MV network layouts are:

- radial;
- link-arrangement (line connecting 2 substations, with a normally-open automatic sectionalizer in the middle of the feeder);
- open ring.

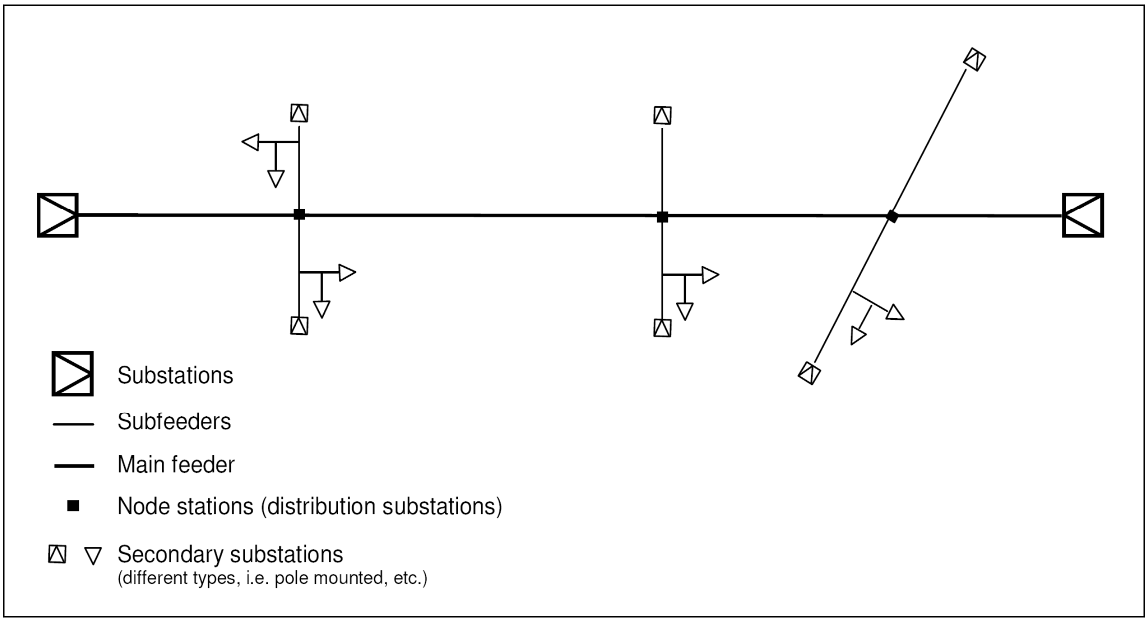


Figure 3.2 Overhead network structure

Underground networks are generally used in urban areas, where load densities are high. The typical structure is based on constant section feeders connected from a substation to another, and secondary substations connected in "input-output" configurations.

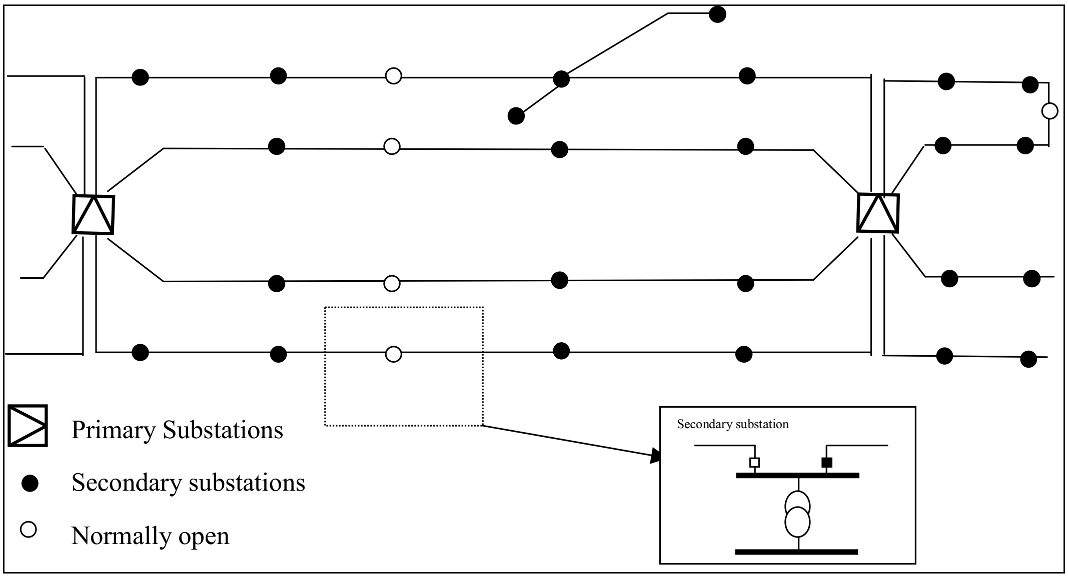


Figure 3.3 Underground network structure

MV lines parameters							
Type	**Conductors**	**Section** [mm^2]	**Current limit** [A]	**Resistance R** [Ω/km]	**Reactance X** [Ω/km]	**Capacitance C** [μF/km]
Underground cables	Aluminum paper insulated ARC4HLRX	95	200	0.320	0.125	0.350
	Aluminum paper insulated ARC4HLRX	150	280	0.206	0.117	0.420
	Aluminum paper insulated ARC4HLRX	240	360	0.125	0.110	0.500
Overhead lines	Copper	25	140	0.720	0.400	0.008
	Copper	35	190	0.520	0.430	0.009
	Copper	70	280	0.270	0.400	0.010
	Aluminum -Steel	150	350	0.230	0.340	0.010

Table 3. 1 Characteristics of MV conductors

HV/MV substations typically have two transformers and two bus-bars, each connected to a group of feeders with balanced total load; in case of failure of one transformer, the two bus-bars are connected together and the un-faulted transformer carries on the whole load.

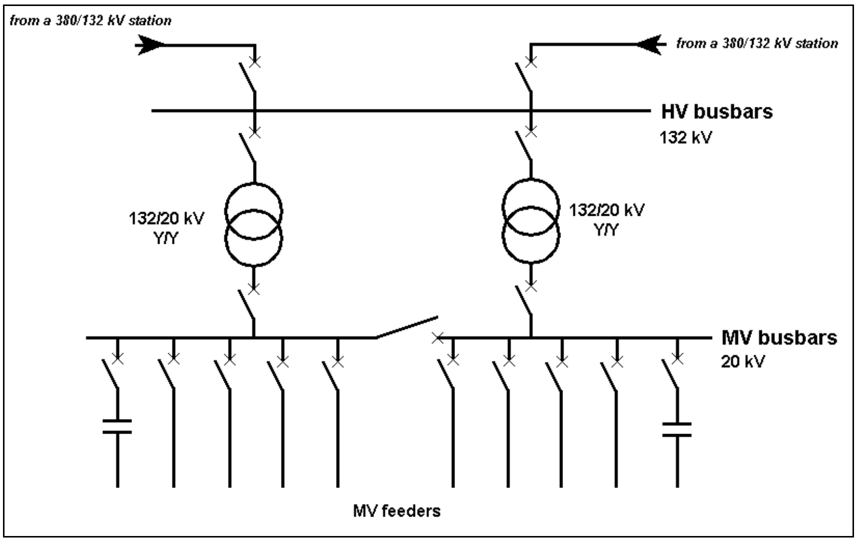


Figure 3.4 Typical layout of a primary substation

HV/MV transformers			
Size [MVA]	***V_{cc} %***	***No-load losses [kW]***	***Load losses [kW]***
16	13.0%	12	88
25	14.6%	16	122
40	15.5%	23	186
63	18.3%	32	282
100	16.8%	40	210

Table 3.2 Characteristics of primary substation transformers

The network is protected against faults by means of overcurrent protections with two or three thresholds and a directional earth-fault protection. Both protections activate an automatic recloser with fast and slow tripping capabilities. The neutral conductor is isolated or earthed through Petersen coil. Some automation, such as faulted branch identification, is implemented at this level.
Typical values of maximum component loading are:

- Normal operation:
    - transformers: 65 %
    - overhead lines: 60 %
    - underground cables: 50 %
- Emergency conditions (dual supply systems):
    - transformers: 130 %
    - overhead lines: 110 %
    - underground cables: 100 %

3.1.2 Low Voltage network (0.4 kV)

The Low Voltage grid is based on radial distribution.

In LV networks the following layouts can be found:

- link-arrangement connecting two secondary substations (most reliable in terms of availability, mainly adopted in urban areas and cable networks);
- open ring: the whole feeder is supplied from a single MV/LV secondary substation, starting from one bus-bar of the substation and ending in the same substation on a different bus-bar; the network is operated in open loop configuration with an automatic line sectionalizer in the middle of the feeder; each line is capable to carry on all the load, in case of an outage;
- tree structure with mains and secondary (laterals) feeders (no back-up supply, only adopted in light/medium density load (rural) areas with overhead lines).

The neutral is solidly earthed.
The distribution transformers are connected to the MV feeders in an "input-output" configuration, and supply the radial secondary subfeeders.

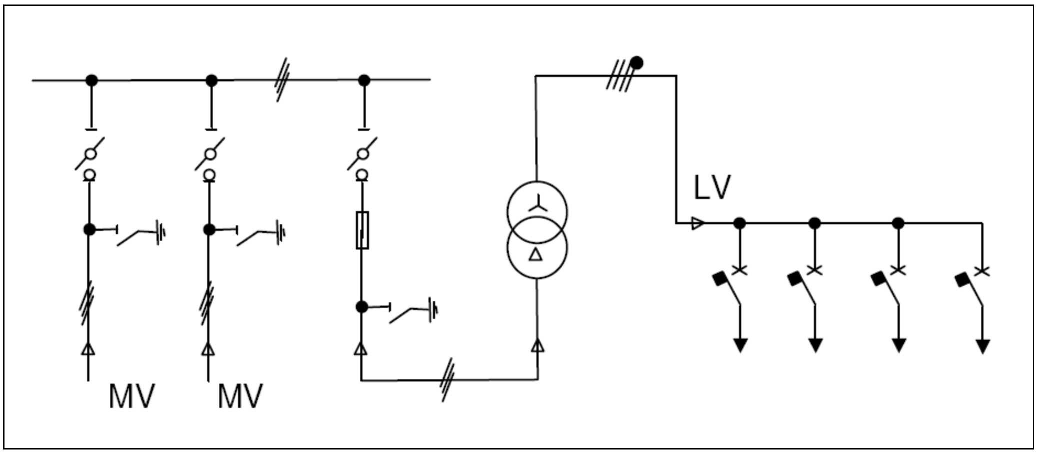


Figure 3.5 Typical layout of a secondary substation

Typical sizes of MV/LV transformers are 50, 100, 160, 250, 400 and 630 kVA. Transformers are generally delta-wye connected with neutral solidly grounded.

MV/LV transformers			
Size [kVA]	***V_{cc} %***	***No-load losses [W]***	***Load losses [W]***
50	4%	150	850
100	4%	250	1400
160	4%	360	1850
250	4%	520	2600
400	4%	740	3650
630	6%	900	5600

Table 3.3 Characteristics of secondary substation transformers

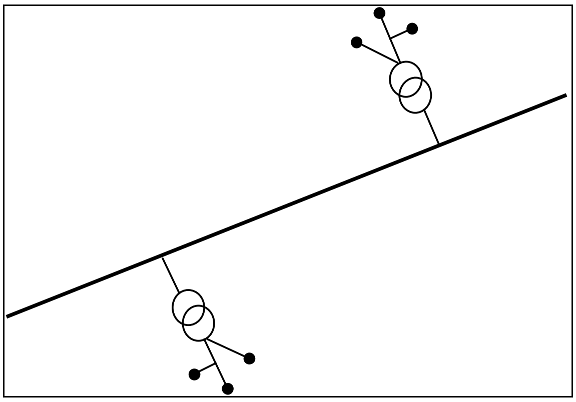


Figure 3.6 Typical rural LV network layout

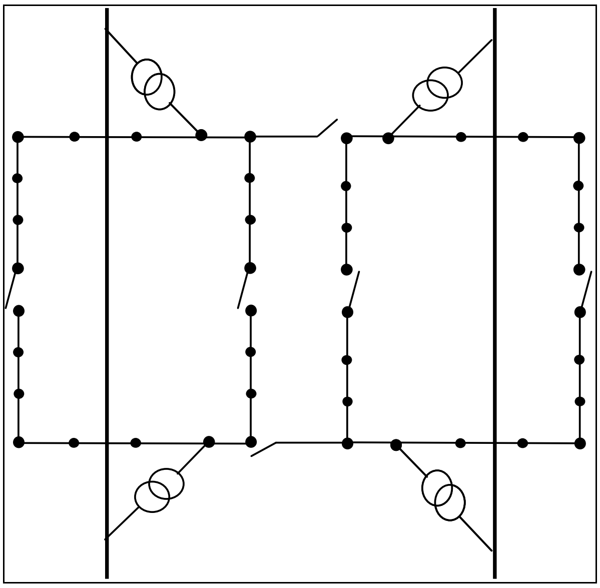


Figure 3.7 Typical urban LV network layout

Secondary substations typically have just one transformer.
For LV network, lines are realized with overhead cables or underground cables.

LV lines parameters				
Type	**Conductors**	**Current limit** [A]	**Resistance R** [Ω/km]	**Reactance X** [Ω/km]
Underground cables	Aluminium 3 X 150 + 50 N	305	0.206	0.075
	Copper 3 X 50 + 25 N	208	0.391	0.078
	Copper 3 X 25 + 25 N	145	0.734	0.081
	Copper 3 X 16 + 16 N	114	1.160	0.082
	Copper 1 X 6 + 6 N	78	3.060	0.090
Overhead lines - cables	Aluminium 3 X 70 + 54.6 N	191	0.443	0.100
	Aluminium 3 X 35 + 54.6 N	123	0.868	0.110
	Copper 4 X 10	80	1.900	0.120
	Copper 2 X 10	88	1.900	0.110
Overhead lines - bare conductors	Copper 1 X 35	180	0.519	0.313
	Copper 1 X 25	140	0.719	0.323
	Copper 1 X 16	105	1.117	0.345

Table 3.4 Characteristics of LV conductors

3.1.3 Voltage regulation

At MV level, voltage is controlled automatically through the on-load tap changer of the HV/MV transformers (± 12 × 1.5 %). For the on-load tap changer, two kinds of control techniques can be applied: constant voltage at the MV bus-bar or current compound.
At LV level, the MV/LV transformers are equipped with a manual no load tap changer. The tap is set in accordance to the maximum value on the MV bus-bar.
The allowed voltage range at the end of the LV feeder is ± 10 % V_{nom}.

3.2 The software tool "SPREAD" for network planning

SPREAD is a prototypal software package for the optimal planning of MV distribution network (the detail of the LV level is not considered), in presence of DG, taking into account expansion over time and usual technical constraints.
SPREAD has been developed jointly by *ERSE* (formerly *CESI RICERCA*) and the *University of Cagliari* (Italy) for research and study purposes; therefore it is not a commercial software package.

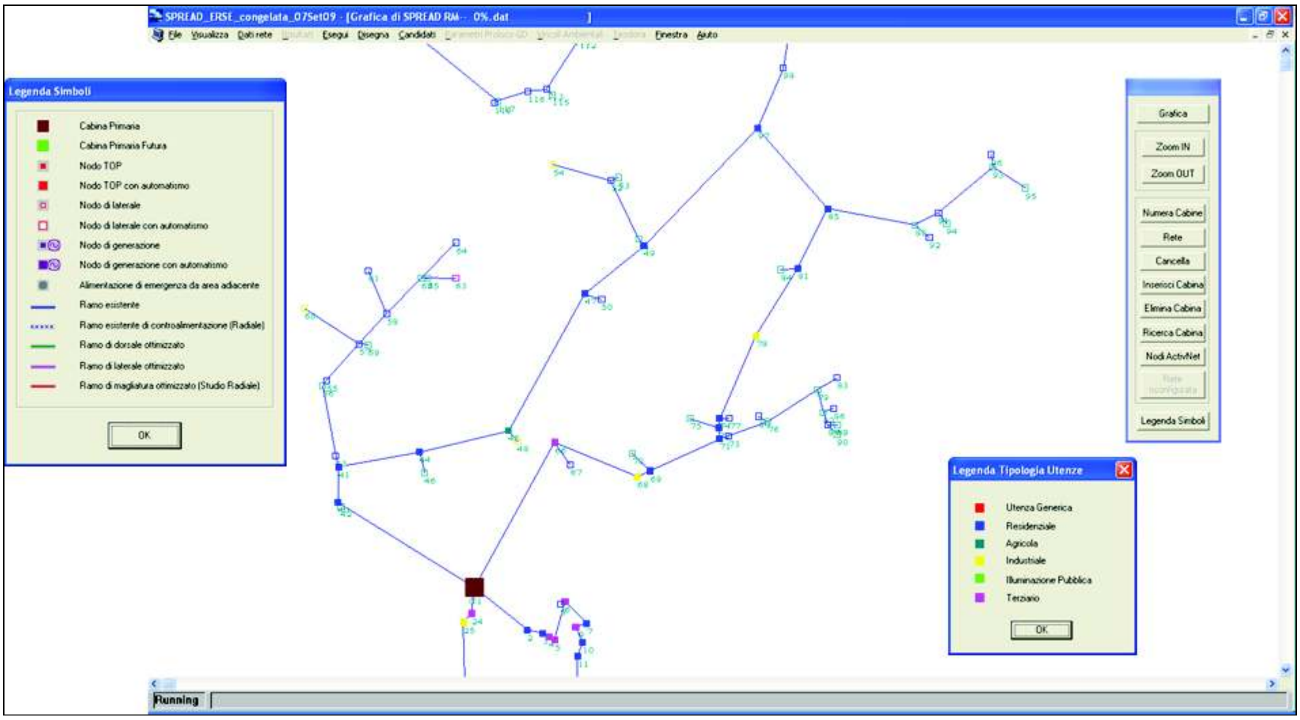


Figure 3.8 The planning environment in SPREAD

The tool is composed by two main optimization modules:

- a module for network planning, aimed at identifying the optimal network topology and size of transformers and conductors, under normal operation and (n-1) security criterion, also in presence of DG plants;
- a module for the optimal siting and sizing of DG on a given network.

The Network Topology Optimization module minimizes the generalized cost of the network, taking into account building, maintenance, upgrading costs and the cost of losses, in order to choose the best network configuration, with trunks and laterals, both in normal and in emergency conditions, and makes use of a heuristic optimization algorithm.

The required level of continuity of service is obtained by using an optimal configuration of *Automatic Sectionalizing Switching Devices*.

For each configuration examined and before cost calculation, the right conductor size for all the branches is chosen to verify all technical constraints, with reference to the planning horizon both in the normal operative state and in emergency conditions. In order to take into account the uncertainties introduced by DG in the planning process, a probabilistic approach has been adopted. The probabilistic load flow (*PLF*) implemented takes into account the probability density function (*pdf*) of loads and generators. For typical distribution planning studies, both loads and generators are represented by means of normal distribution referred to an average annual power absorbed or produced.

The optimization problem is formulated as the minimization of an Objective Function including the Net Present Value (*NPV*), over the given time horizon, of the cost for network upgrading (substation transformers, lines, circuit breakers, automatic sectionalizers) and the cost of power losses.

The solution has to satisfy the usual technical constraints:

- thermal limits of conductors;
- node voltage limits;
- continuity of supply indexes;
- short circuit levels (sizing of line circuit breakers) (also DG contribution is accounted).

The software implements a methodology that allows the planner to consider some of the most important functions of Active Network Management, namely Generation Curtailment, Load Shedding and Network Reconfiguration (reactive power dispatching for voltage control is still under development).

The resort to active management is dealt with on the basis of a probabilistic approach, that means that the DSO can give to customers or producers a certain probability to be shed or disconnected during the most critical hours, assuring the on line operation in the rest of the day. In many cases, the use of active controls is limited to emergency conditions (line faults), that implies a reduced probability of occurrence.

The simulation of active network management in the planning optimization methodology can allow postponing investments thanks to the maximum exploitation of the existing assets. On the other hand, active management, by maintaining the network close to its thermal capacity limits, generally results in an increase in losses.

For comparison purposes, the software implements also the conventional *"connect (fit) and forget"* planning policy, that implies the sizing of the distribution system so as to meet technical constraints in the most onerous conditions, both in steady state and emergency conditions: minimum load/maximum generation and maximum load/no generation.

In order to assess the impact of active management on distribution network operation, both loads and generators are modelled through their daily load / generation curves, assumed valid for all the days of the year. In this way, possible overload currents and/or voltage violations that could appear during the day can be assessed. The daily load (generation) curves are discretized into 24 intervals (each one of the duration of 1h); for each interval, the uncertainties on the loads (generators) power are considered by using suitable normal pdf, and the PLF is applied repeatedly for all the discretization intervals in order to choose the correct size of each conductor that verifies all the technical constraints.

3.3 Description and analysis of the study case

3.3.1 Test network

The test network is a portion of a real MV distribution network (20 kV nominal voltage) supplied by one primary substation with two HV/MV transformers rated 16 MVA, feeding 118 MV/LV nodes (52 trunk nodes and 66 lateral nodes).The network is radial with emergency tie connections.

Two areas can be identified. In the upper part of the network there are relatively long overhead lines feeding small loads (80 rural nodes); the cross section of the conductors is small because of the low load density. In the lower part of the network, urban/industrial loads (38 urban nodes) have to be supplied; here underground cables with bigger cross sections are used due to the high load density.

The planning period is 20 years and a constant power demand growth rate of 3% per year has been assumed. For actualized costs calculations, a discount rate of 8% per year has been used.

The active power delivered to the MV nodes, at the beginning of the study period, is about 16.4 MW, divided in 11.9 MW for the urban feeder and 4.5 MW for the rural one.

The unit cost of electricity losses is 0.22 €/kWh.

The total length of the network is 62.8 km, of which about 80% overhead lines (rural part) and 20% underground cable (urban part).

Five typologies of loads have been considered: residential, industrial, tertiary, agricultural and public lighting.

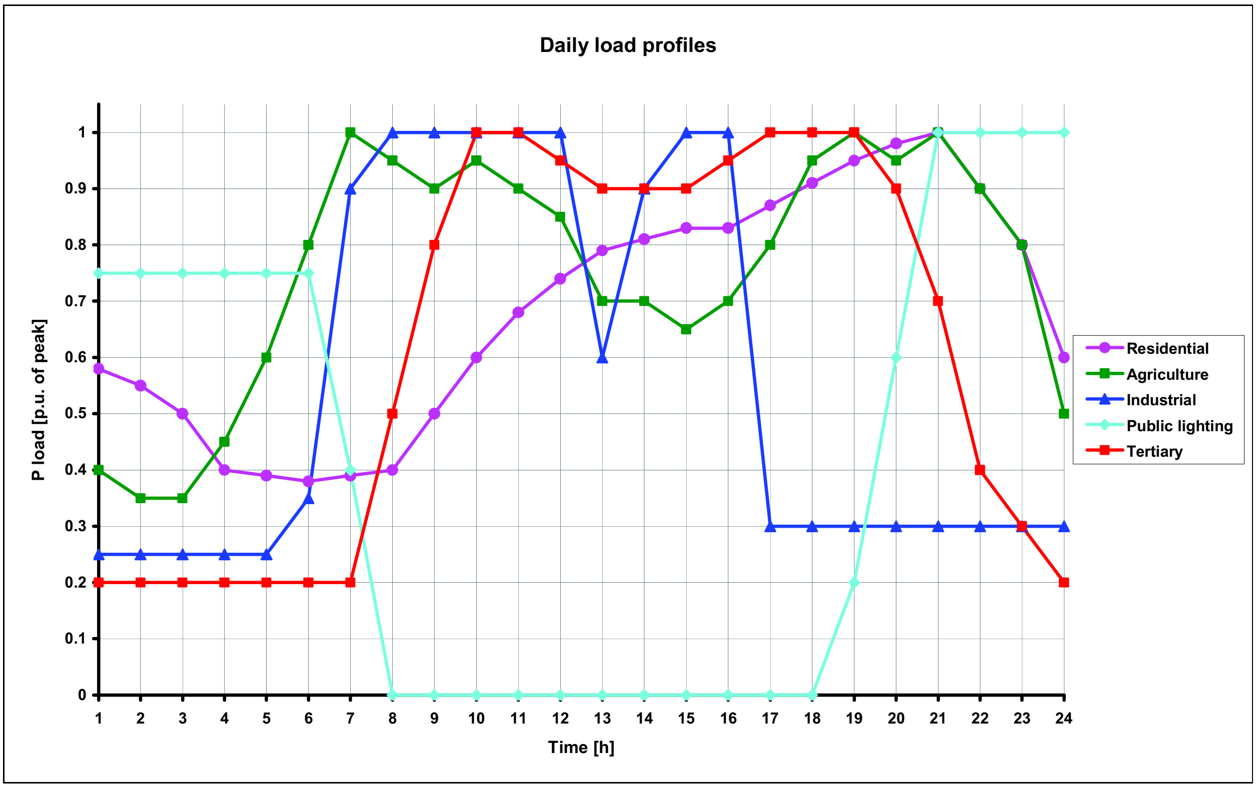


Figure 3.9 Daily load profiles

Node	Area type	P load [kW]	cosφ load	Feeder type	Load type
2	urban	640	0.71	trunk	Residential
3	urban	150	0.90	trunk	Residential
4	urban	89	0.91	trunk	Tertiary
5	urban	310	0.71	trunk	Tertiary
6	urban	290	0.71	trunk	Tertiary
7	urban	470	0.71	trunk	Residential
8	urban	270	0.91	lateral	Residential
9	urban	390	0.90	trunk	Tertiary
10	urban	301	0.90	trunk	Residential
11	urban	710	0.91	trunk	Residential
12	urban	360	0.90	trunk	Tertiary
13	urban	460	0.90	trunk	Residential
14	urban	10	0.90	lateral	Public lighting
15	urban	20	0.90	trunk	Residential
16	urban	30	0.90	trunk	Public lighting
17	urban	355	0.90	trunk	Residential
18	urban	500	0.71	trunk	Tertiary
19	urban	450	0.71	trunk	Tertiary
20	urban	360	0.71	trunk	Residential
21	urban	120	0.71	trunk	Residential
22	urban	200	0.71	trunk	Tertiary
23	urban	220	0.71	trunk	Residential
24	urban	410	0.71	trunk	Tertiary
25	urban	730	0.71	trunk	Industrial
26	urban	6	0.71	trunk	Public lighting
27	urban	6	0.71	trunk	Public lighting
28	urban	360	0.71	trunk	Industrial
29	urban	460	0.71	trunk	Industrial
30	urban	400	0.71	trunk	Industrial
31	urban	270	0.71	trunk	Industrial
32	urban	950	0.90	trunk	Industrial
33	urban	710	0.71	trunk	Industrial
34	urban	600	0.71	trunk	Industrial
35	urban	75	0.90	trunk	Public lighting
36	urban	50	0.90	trunk	Public lighting
37	urban	30	0.90	trunk	Residential
38	urban	10	0.71	trunk	Residential
39	urban	130	0.90	trunk	Tertiary
40	rural	84	0.90	trunk	Residential
41	rural	60	0.90	trunk	Residential
42	rural	72	0.90	lateral	Agricultural
43	rural	72	0.90	lateral	Residential
44	rural	84	0.90	trunk	Residential
45	rural	84	0.90	trunk	Agricultural
46	rural	72	0.90	lateral	Agricultural
47	rural	94	0.90	trunk	Residential
48	rural	128	0.90	lateral	Industrial
49	rural	18	0.90	trunk	Residential
50	rural	72	0.90	lateral	Residential
51	rural	104	0.90	lateral	Agricultural
52	rural	60	0.90	lateral	Residential
53	rural	72	0.90	lateral	Agricultural
54	rural	128	0.90	lateral	Industrial
55	rural	60	0.90	lateral	Residential
56	rural	11	0.90	lateral	Agricultural
57	rural	94	0.90	lateral	Residential
58	rural	104	0.90	lateral	Residential
59	rural	11	0.90	lateral	Agricultural
60	rural	244	0.90	lateral	Industrial
61	rural	11	0.90	lateral	Residential
62	rural	60	0.90	lateral	Agricultural
63	rural	6	0.90	lateral	Tertiary
64	rural	244	0.90	lateral	Residential
65	rural	11	0.90	lateral	Agricultural
66	rural	84	0.90	trunk	Tertiary
67	rural	72	0.90	lateral	Residential
68	rural	18	0.90	trunk	Industrial
69	rural	104	0.90	trunk	Residential
70	rural	72	0.90	lateral	Agricultural
71	rural	60	0.90	trunk	Residential
72	rural	60	0.90	trunk	Residential
73	rural	94	0.90	lateral	Residential
74	rural	60	0.90	trunk	Residential
75	rural	72	0.90	lateral	Agricultural
76	rural	84	0.90	lateral	Agricultural
77	rural	72	0.90	lateral	Residential
78	rural	266	0.90	trunk	Industrial
79	rural	84	0.90	lateral	Agricultural
80	rural	72	0.90	lateral	Residential
81	rural	94	0.90	trunk	Residential
82	rural	60	0.90	lateral	Agricultural
83	rural	28	0.90	lateral	Residential
84	rural	128	0.90	lateral	Agricultural
85	rural	18	0.90	trunk	Residential
86	rural	72	0.90	lateral	Residential
87	rural	94	0.90	lateral	Residential
88	rural	60	0.90	lateral	Agricultural
89	rural	72	0.90	lateral	Agricultural
90	rural	12	0.90	lateral	Agricultural
91	rural	104	0.90	lateral	Residential
92	rural	5	0.90	lateral	Residential
93	rural	94	0.90	lateral	Agricultural
94	rural	128	0.90	lateral	Agricultural
95	rural	60	0.90	lateral	Agricultural
96	rural	5	0.90	lateral	Residential
97	rural	23	0.90	trunk	Residential
98	rural	37	0.90	lateral	Residential
99	rural	0	0.00	lateral	Agricultural
100	rural	0	0.00	lateral	---
101	rural	0	0.00	lateral	Agricultural
102	rural	7	0.90	lateral	Agricultural
103	rural	7	0.90	lateral	Residential
104	rural	7	0.90	lateral	Residential
105	rural	0	0.00	lateral	---
106	rural	7	0.90	lateral	Agricultural
107	rural	0	0.00	lateral	---
108	rural	0	0.00	lateral	---
109	rural	7	0.90	lateral	Residential
110	rural	0	0.00	lateral	---
111	rural	7	0.90	lateral	Residential
112	rural	0	0.00	lateral	---
113	rural	0	0.00	lateral	---
114	rural	7	0.90	lateral	Residential
115	rural	7	0.90	lateral	Agricultural
116	rural	0	0.00	lateral	---
117	rural	0	0.00	lateral	Agricultural
118	rural	7	0.90	lateral	Agricultural
119	rural	7	0.90	lateral	Residential

Figure 3.10 Bus characteristics of the test network

HV/MV transformers			
Size [MVA]	Vcc %	No-load losses [kW]	Load losses [kW]
16	13.0	12	88
25	14.6	16	122
40	15.5	23	186
63	22.5	32	282
100	16.8	40	210

Table 3.5 Standard transformers for Primary Substations

	Section [mm^2]	R [Ohm/km]	X [Ohm/km]	C [microF/km]	Current limit [A]
Cable - A	240	0.125	0.110	0.500	360
Cable - B	150	0.206	0.117	0.420	280
Cable - C	95	0.320	0.125	0.350	200
Cable - D	120	0.253	0.124	0.315	260
Cable - E	150	0.345	0.238	0.193	190
Cable - F	95	0.193	0.129	0.290	310
Cable - G	95	0.352	0.150	0.268	140

Table 3.6 Characteristics of MV underground cables

	Section [mm^2]	R [Ohm/km]	X [Ohm/km]	C [microF/km]	Current limit [A]
Aerial - a	150	0.230	0.340	0.010	350
Aerial - b	70	0.270	0.400	0.010	280
Aerial - c	35	0.520	0.430	0.009	190
Aerial - d	25	0.720	0.400	0.008	140
Aerial - e	16	1.118	0.419	0.008	105
Aerial - f	20	0.871	0.413	0.008	120
Aerial - g	35	0.479	0.305	0.064	165

Table 3.7 Characteristics of MV overhead lines

Branch	Bus 1	Bus 2	Length [m]	Conductor type
1	1	2	946	Cable - B
2	2	3	384	Cable - B
3	3	4	153	Cable - B
4	4	5	92	Cable - B
5	5	6	417	Cable - B
6	6	7	322	Cable - B
7	6	8	55	Cable - C
8	7	9	124	Cable - B
9	9	10	208	Cable - B
10	10	11	248	Cable - B
11	11	12	451	Cable - B
12	12	13	726	Cable - D
13	13	14	57	Cable - E
14	13	15	399	Cable - F
15	15	16	398	Cable - F
16	16	17	362	Cable - B
17	17	18	160	Cable - B
18	19	18	190	Cable - B
19	19	20	206	Cable - C
20	20	21	1343	Cable - C
21	21	22	329	Cable - C
22	22	23	187	Cable - C
23	23	39	191	Cable - C
24	1	24	462	Cable - B
25	24	25	206	Cable - B
26	25	26	664	Cable - B
27	26	27	345	Cable - B
28	27	28	120	Cable - B
29	28	29	125	Cable - B
30	29	30	179	Cable - B
31	30	31	765	Cable - B
32	31	32	177	Cable - G
33	32	33	99	Cable - B
34	33	34	312	Cable - B
35	34	35	412	Cable - B
36	35	36	335	Cable - B
37	36	37	693	Cable - B
38	37	38	224	Cable - B
39	38	39	175	Cable - B

Table 3.8 Branch characteristics of the test network – urban area

Branch	Bus 1	Bus 2	Length [m]	Conductor type
40	1	40	1697	Aerial - c
41	40	41	400	Aerial - c
42	40	42	100	Aerial - e
43	41	43	150	Aerial - e
44	43	56	749	Aerial - e
45	41	44	550	Aerial - c
46	44	45	1050	Aerial - c
47	44	46	230	Aerial - d
48	45	47	1600	Aerial - c
49	45	48	200	Aerial - e
50	47	49	750	Aerial - c
51	47	50	100	Aerial - e
52	49	51	80	Aerial - e
53	49	97	1725	Aerial - c
54	51	52	770	Aerial - e
55	52	53	150	Aerial - e
56	52	54	650	Aerial - e
57	55	56	100	Aerial - e
58	55	57	450	Aerial - e
59	57	58	400	Aerial - e
60	57	59	100	Aerial - e
61	57	60	750	Aerial - e
62	58	61	500	Aerial - e
63	58	62	500	Aerial - e
64	62	63	500	Aerial - e
65	62	64	950	Aerial - e
66	62	65	200	Aerial - e
67	1	66	1806	Aerial - g
68	66	67	285	Aerial - e
69	66	68	1000	Aerial - c
70	68	69	150	Aerial - c
71	69	70	300	Aerial - e
72	69	71	890	Aerial - c
73	71	72	130	Aerial - c
74	71	73	50	Aerial - f
75	72	74	450	Aerial - c
76	72	75	305	Aerial - c
77	73	76	450	Aerial - f
78	74	77	100	Aerial - e
79	74	78	900	Aerial - c
80	76	79	700	Aerial - f
81	76	80	150	Aerial - e
82	78	81	850	Aerial - c
83	79	82	250	Aerial - e
84	79	83	300	Aerial - f
85	81	84	100	Aerial - e
86	81	85	700	Aerial - c
87	82	86	200	Aerial - e
88	82	87	350	Aerial - e
89	85	88	1100	Aerial - e
90	85	97	1126	Aerial - e
91	87	89	250	Aerial - e
92	87	90	450	Aerial - c
93	88	91	300	Aerial - e
94	88	92	200	Aerial - e
95	91	93	750	Aerial - e
96	91	94	100	Aerial - e
97	93	95	500	Aerial - e
98	93	96	150	Aerial - e
99	97	98	775	Aerial - e
100	98	99	1015	Aerial - e
101	99	100	150	Aerial - e
102	99	101	1200	Aerial - e
103	100	102	150	Aerial - e
104	100	103	2750	Aerial - e
105	101	104	1500	Aerial - e
106	101	105	80	Aerial - e
107	105	106	100	Aerial - e
108	105	107	180	Aerial - e
109	107	108	80	Aerial - e
110	107	109	1200	Aerial - e
111	108	110	320	Aerial - e
112	110	111	100	Aerial - e
113	110	112	2650	Aerial - e
114	112	113	600	Aerial - e
115	112	114	150	Aerial - e
116	113	115	100	Aerial - e
117	113	116	200	Aerial - d
118	116	117	665	Aerial - d
119	117	118	2000	Aerial - d
120	117	119	2865	Aerial - d

Table 3.9 Branch characteristics of the test network – rural area

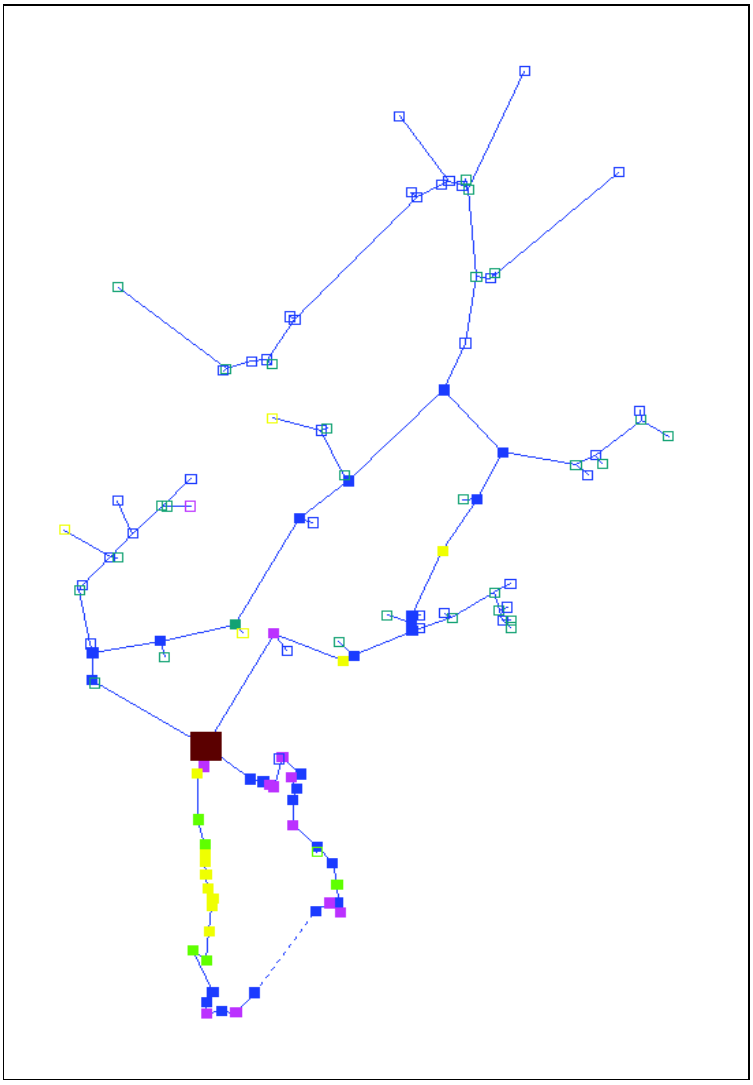


Figure 3.11 The study case MV network at the beginning of the planning period

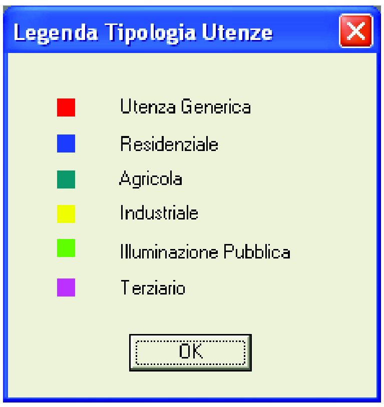


Figure 3. 12 Colour codes identifying the different load typologies

3.3.2 Assumptions and scenarios

The effect of different DG penetration levels and planning approaches on network upgrade costs and losses have been analyzed.

Several scenarios have been considered with increasing levels of penetration of photovoltaic generation on residential nodes; this choice is due to the fact that PV generation is presently strongly supported in Italy, with high feed-in tariffs for small plants connected to the LV level, so a significant development is expected in areas with predominant residential characteristics.

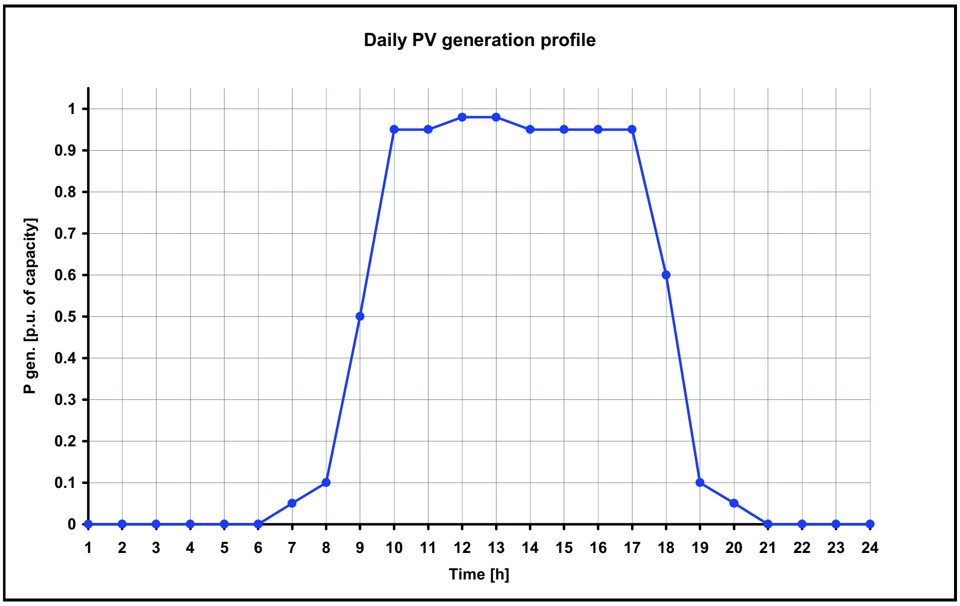


Figure 3.13 Daily profile for PV generators

The percent level of DG penetration has been defined as the ratio of installed capacity to peak load, referred to residential nodes only. The equivalent percent penetration levels referred to the total peak load of the network are shown in the following table:

DG penetration scenarios	
% of residential peak load	% of total peak load
20%	8%
40%	15%
60%	23%
80%	31%
100%	38%
120%	46%
140%	54%
160%	61%
180%	69%
200%	77%

Table 3. 10 DG penetration scenarios

DG plants have been assumed to operate at cosϕ = 1, the required reactive power is therefore supplied by the main grid.

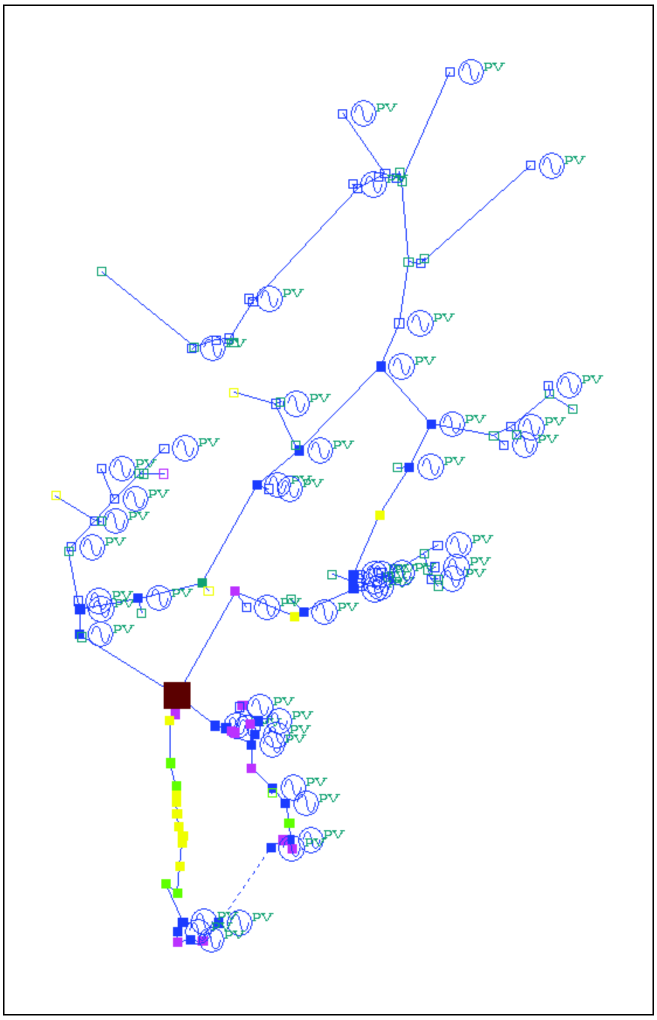


Figure 3.14 Assumed location of DG on the existing network

Different planning strategies have been adopted:

- a probabilistic planning, taking into account load and generation daily profiles discretized into 24 hourly intervals;
- a conventional "fit & forget", or worst case, criterion: the network is sized in order to meet technical constraints under extreme operating conditions, that is "maximum load – no generation" and "minimum load – maximum generation"; daily power profiles and the coincidence factor between loads and DG are not considered;
- a probabilistic planning with daily profiles and the possibility to consider at a design stage the resort to Active Management options (Demand Response or DSM) to solve violations; it has been assumed that residential customers participate to a load control program by accepting a maximum demand reduction of 50%.

In order to compare the different scenarios and planning strategies, the following parameters have been evaluated:

- investment costs for network upgrading
- losses costs;
- electricity losses;
- voltage profiles.

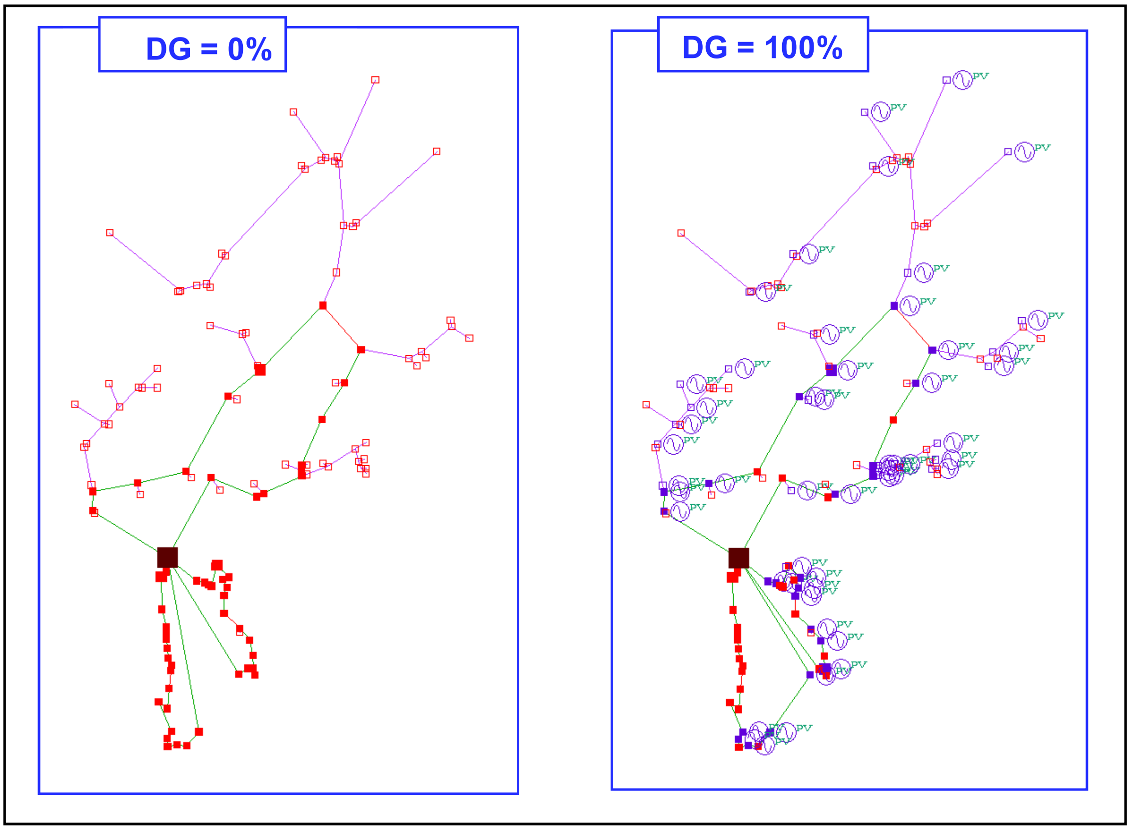


Figure 3.15 Example of different network topologies (without and with DG) optimization (DG penetration expressed in % of peak load)

3.3.3 Results: costs, losses, voltage profiles

In the following Figures all costs are given in percent with respect to the reference case of a network with no DG, planned according to the probabilistic approach and considering load and generation daily profiles.

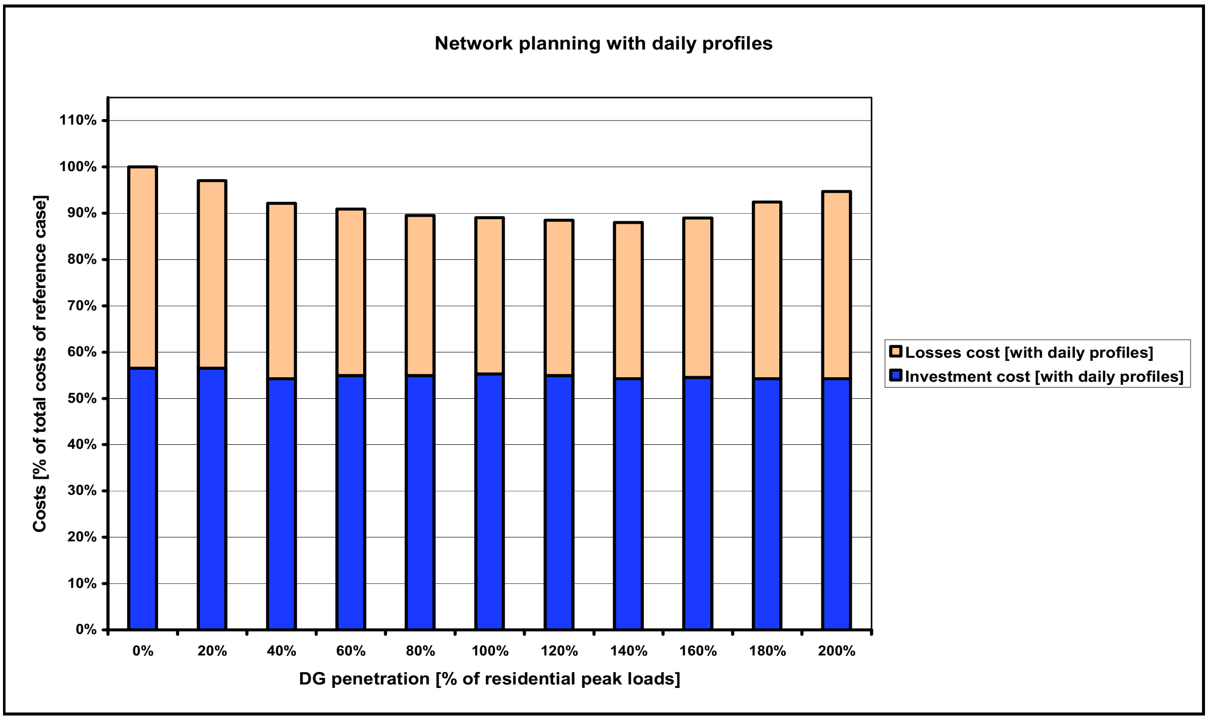


Figure 3.16 Costs of the network designed considering daily curves for loads and generators, for different levels of DG penetration

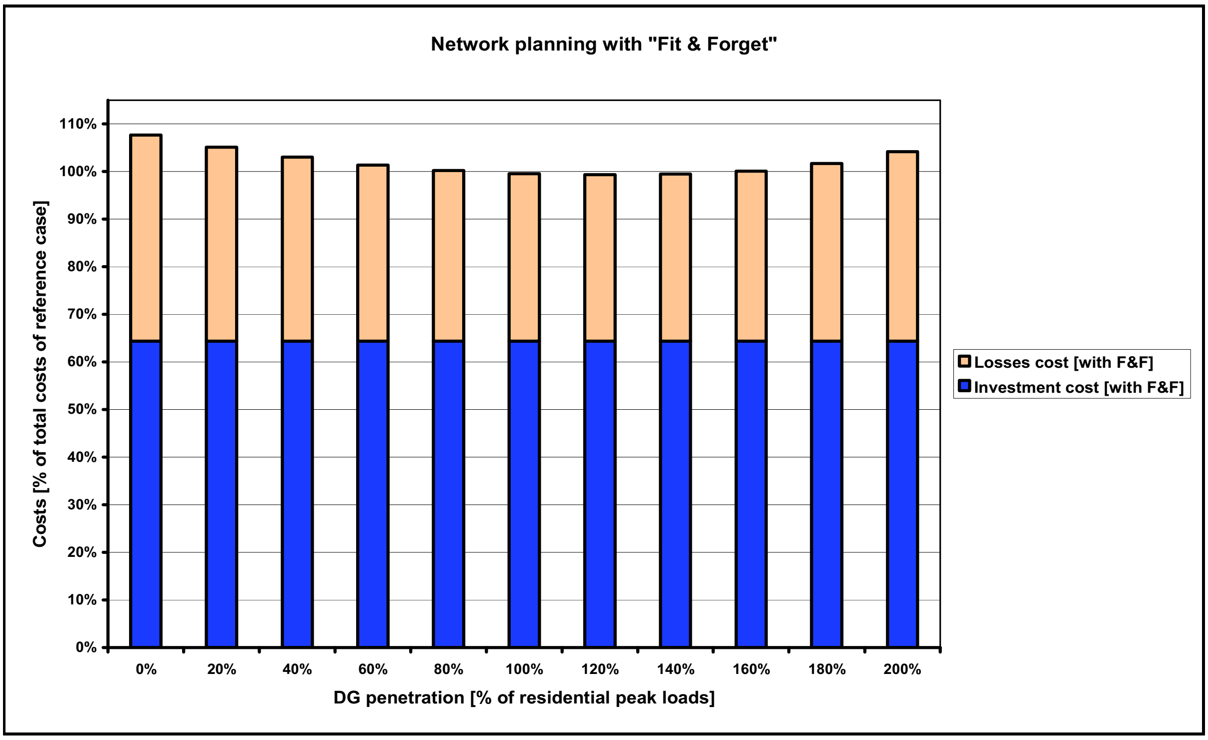


Figure 3.17 Costs of the network designed based on the traditional fit & forget approach, for different levels of DG penetration

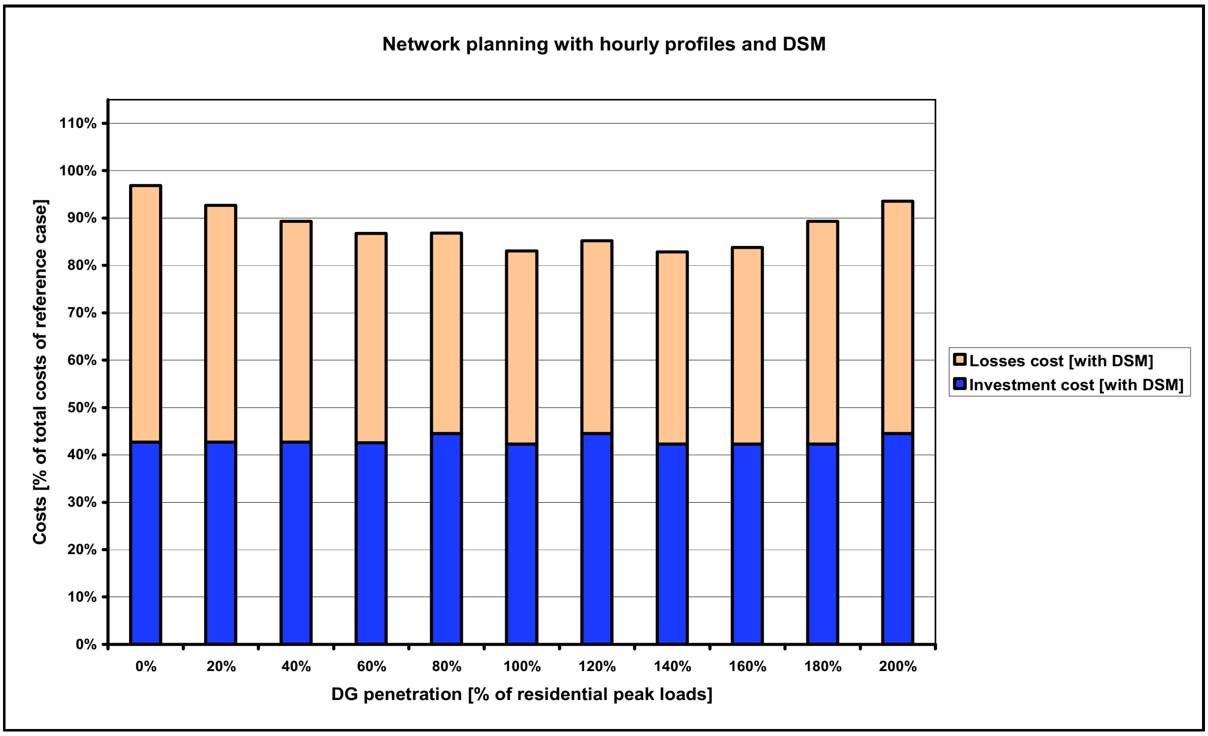


Figure 3.18 Costs of the network designed considering daily curves and possible load shedding actions, for different levels of DG penetration

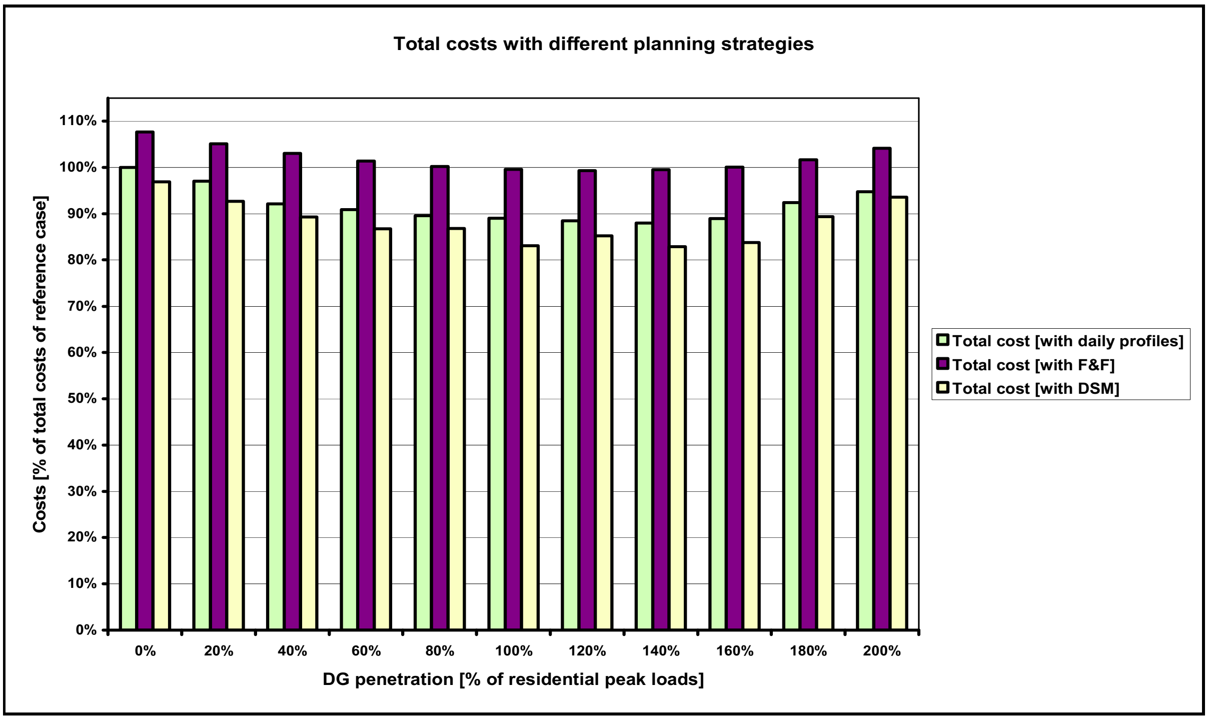


Figure 3.19 Comparison of total costs under different planning strategies

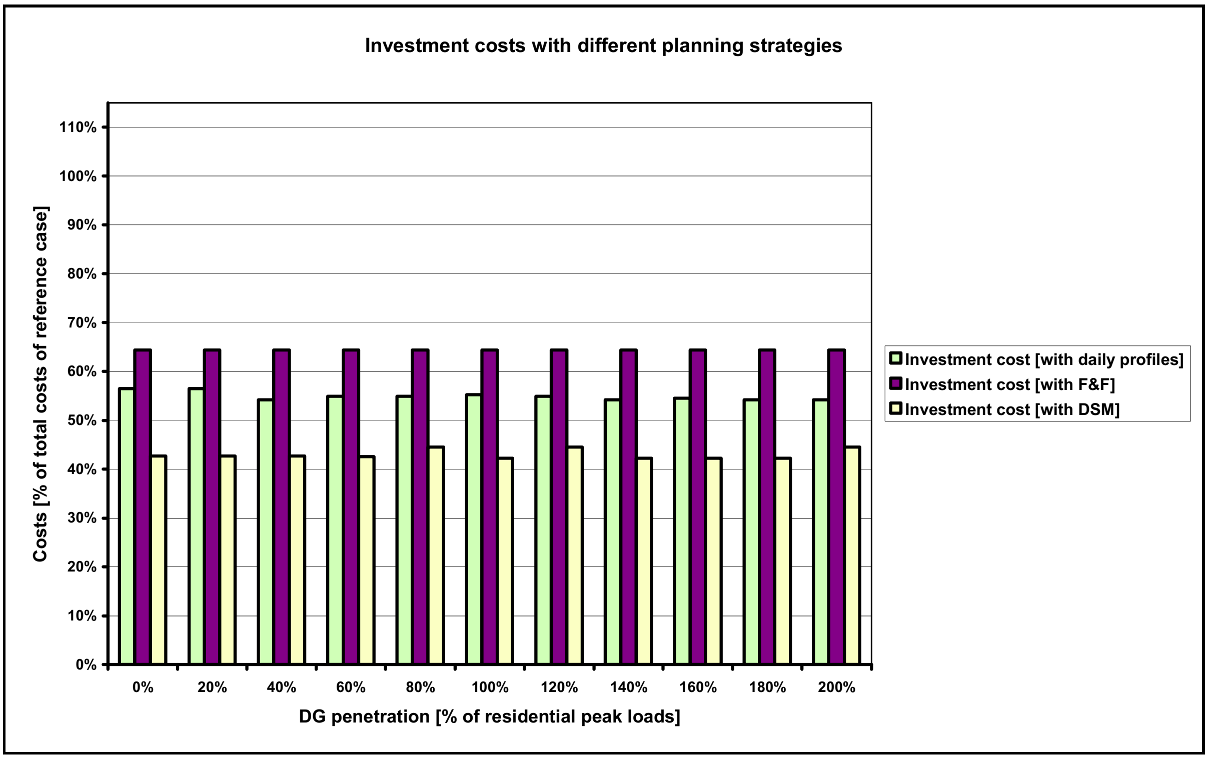


Figure 3.20 Comparison of investment costs under different planning strategies

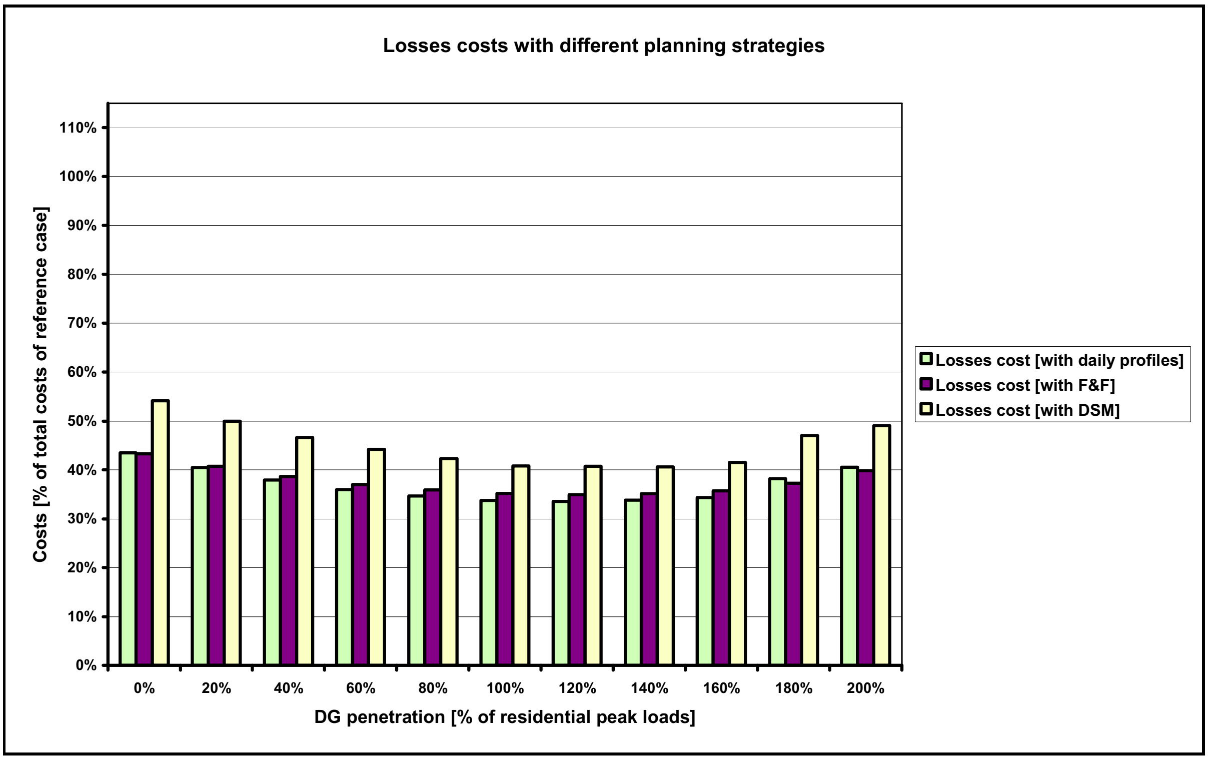


Figure 3.21 Comparison of costs of losses under different planning strategies

It can be observed that the conventional "Fit & Forget" planning approach leads to higher investment costs, due to the oversizing of lines and to the replacement of the HV/MV transformers.
The resort to Load Shedding actions helps to solve violations without reinforcing the network, so allowing to reduce investments; on the other hand, the high exploitation of existing network assets, near to thermal limits, allowed by Active Management, causes an increase in energy losses.
It must be noticed that, in this study case, Load Shedding is required only to solve violations (overcurrents in the urban part of the network, overcurrents and undervoltages in the rural one) in emergency conditions following a line fault, so the probability of cutting power to customers is low. The software tool SPREAD provides detailed information on critical conditions (faulted branch and violations occurred) and actions undertaken by Active Management (nodes involved and power shed for each time interval).

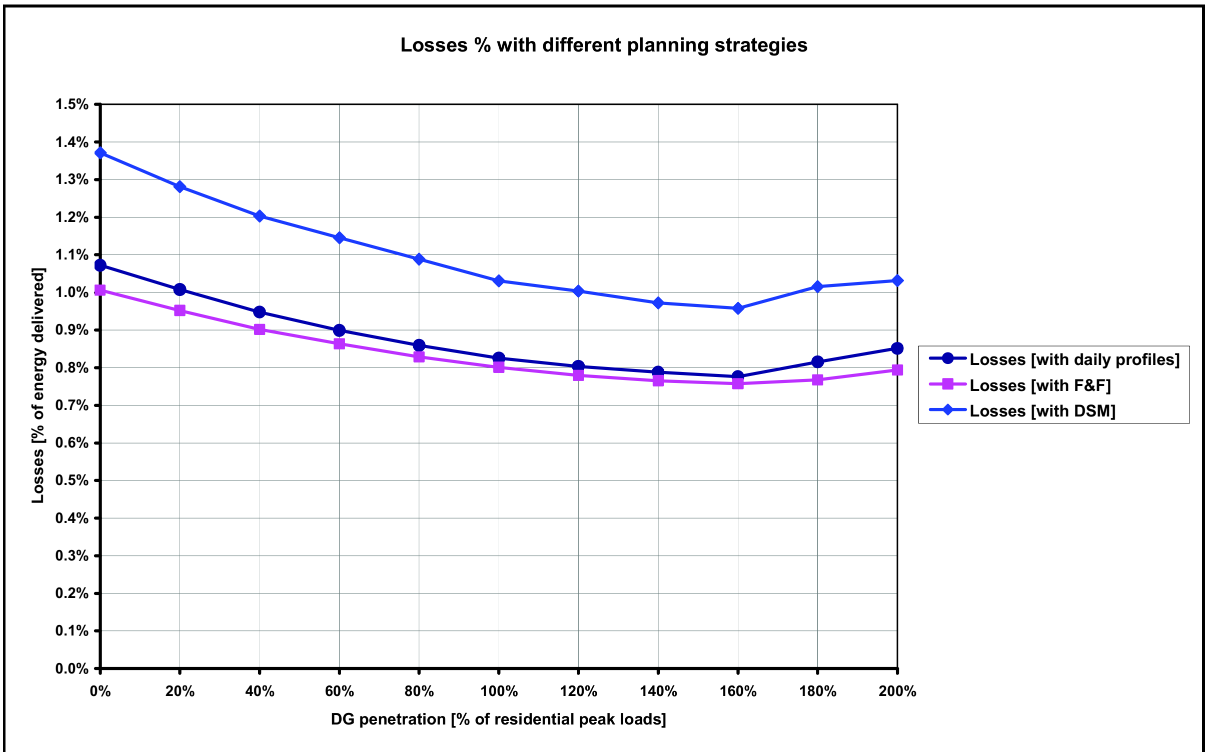


Figure 3.22 Comparison of electricity losses under different planning strategies, for increasing levels of DG penetration

The resort to Generation Curtailment actions has not shown to be effective in the considered scenarios; this is probably due to the low level of DG concentration assumed on the network (DG production is rather evenly spread over the network instead of being concentrated in few big DG units).

The following pictures show some examples of the improvement in voltage profiles due to the presence of DG along the feeders:

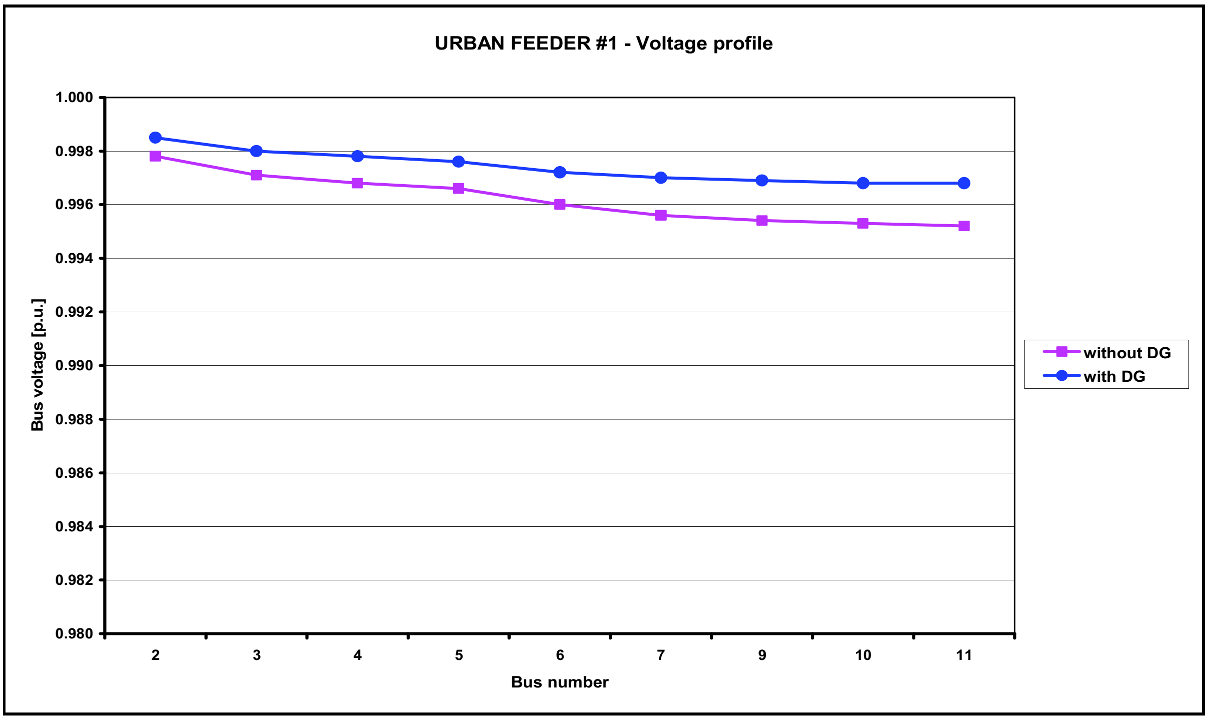


Figure 3.23 Voltage profiles along a urban feeder without DG and with DG (100% penetration)

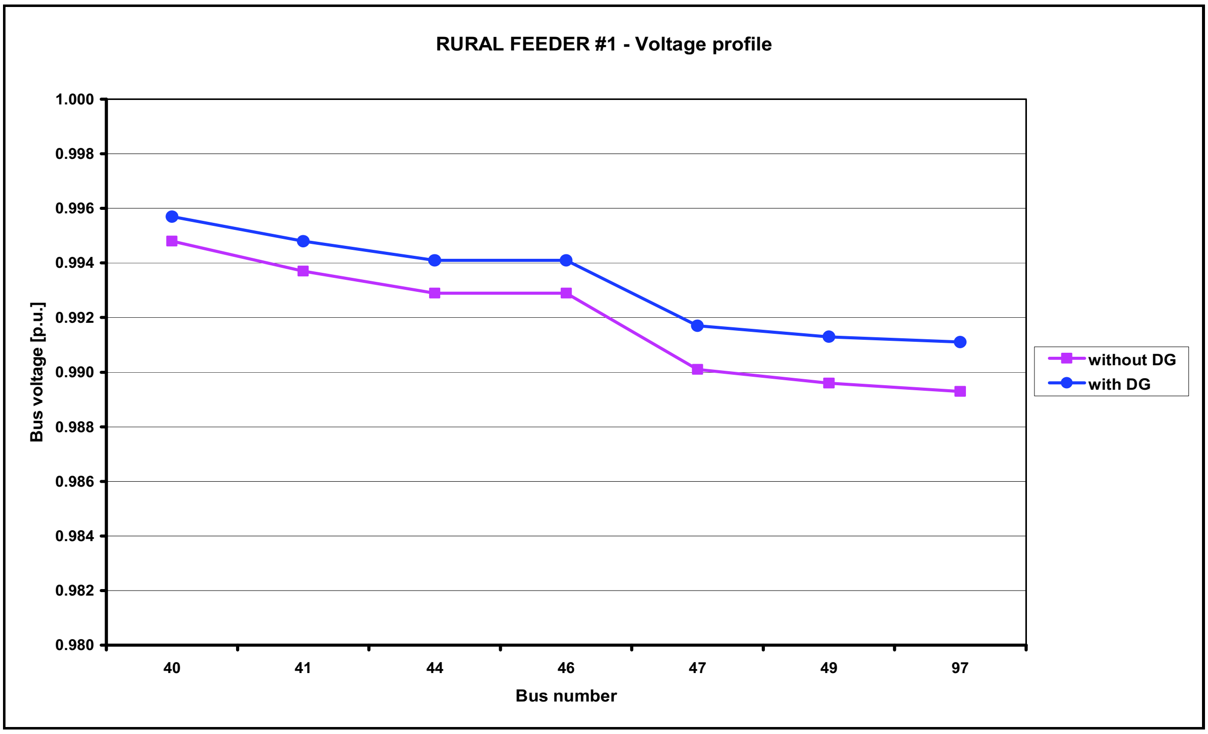


Figure 3.24 Voltage profiles along a rural feeder without DG and with DG (100% penetration)

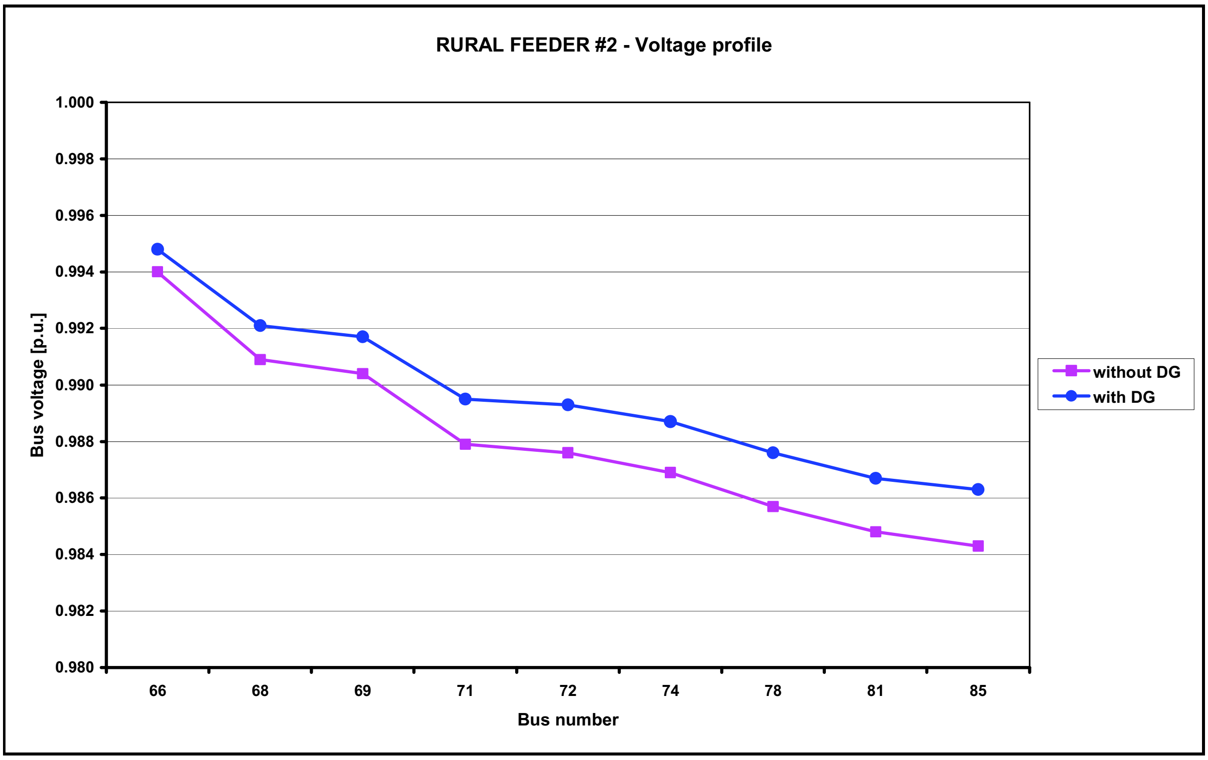


Figure 3.25 Voltage profiles along a rural feeder without DG and with DG (100% penetration)

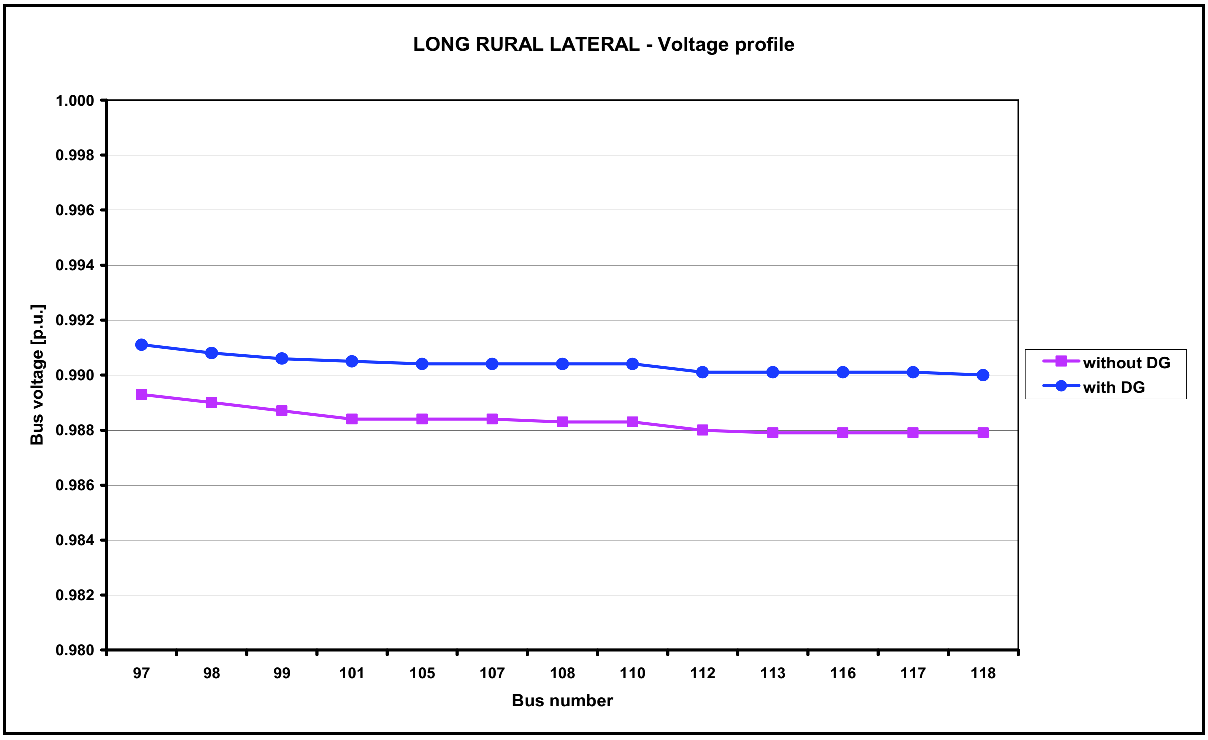


Figure 3.26 Voltage profiles along a lateral line without DG and with DG (100% penetration)

3.3.4 Assessment of the impact of microgrids on network planning

Microgrids have been assumed to be totally autonomous in terms of energy balance, thanks to the integration of responsive loads, controllable generators and storage systems. Each LV microgrid has been ideally represented, at the MV level, as a node behaving as a load coupled with a generator, both having a constant power equal to the average value of the corresponding daily curve; besides, the equivalent generator has been supposed to operate at the same cosϕ of the load, thus providing to the microgrid the required reactive power. In such way, each microgrid results in zero power flow (both active and reactive) at the corresponding MV/LV substation transformer. It is worth noting that, in order to provide reactive support, DG plants must be sized based on apparent power and not simply on active power.
A totally autonomous microgrid requires a DG penetration level of 100% in energy terms, i.e. in terms of ratio of energy delivered by DG to energy consumed by loads; given the assumed daily profiles, this implies an installed DG capacity of about 180% of peak load; consequently, the assessment of the benefits of microgrids has been made with comparison to the scenario of 180% DG penetration.
In the following picture are represented the “actual” daily profiles assumed for residential loads and PV generators, together with the equivalent constant average values used to simulate the microgrid behaviour at MV level, for a level of energy penetration of 100%:

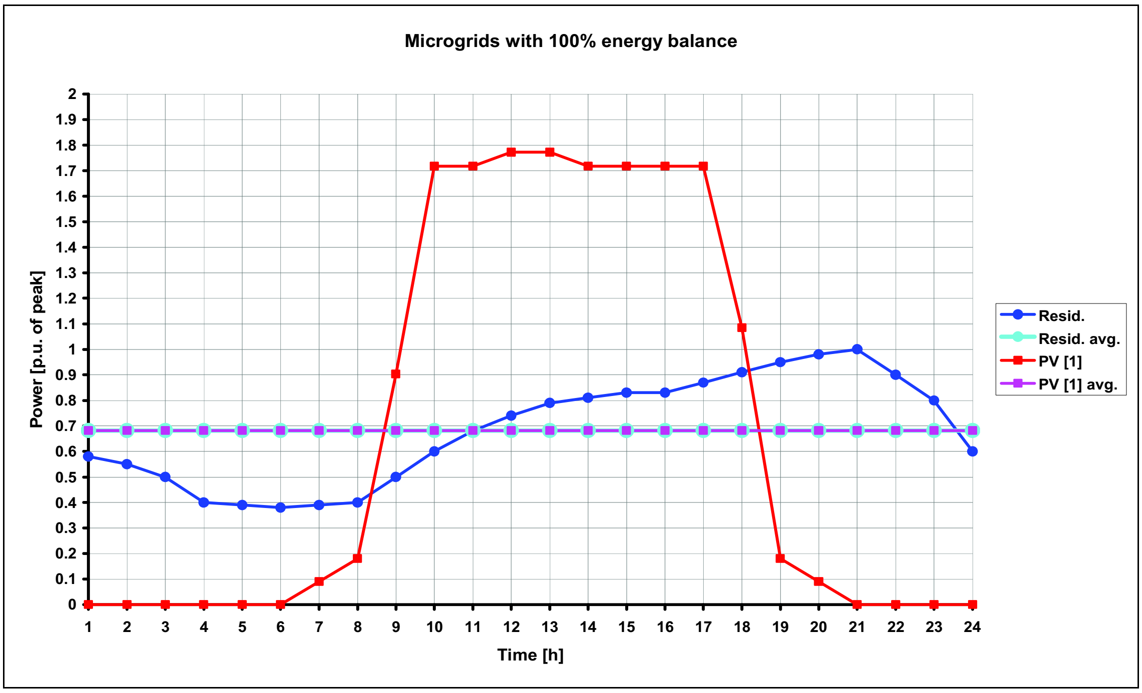


Figure 3.27 Ideal representation of the integration of responsive loads, controllable generators and storage in microgrids

The following pictures show the comparison of investment costs, losses costs, and energy losses (in % of total energy delivered to loads) for 3 different scenarios:

- base case without DG,
- 180% of "simple" DG power penetration,
- 180% of DG power penetration (100% in energy terms) in the form of integrated microgrids,

and for 3 different planning strategies:

- probabilistic approach with daily profiles,
- fit&forget,
- DSM.

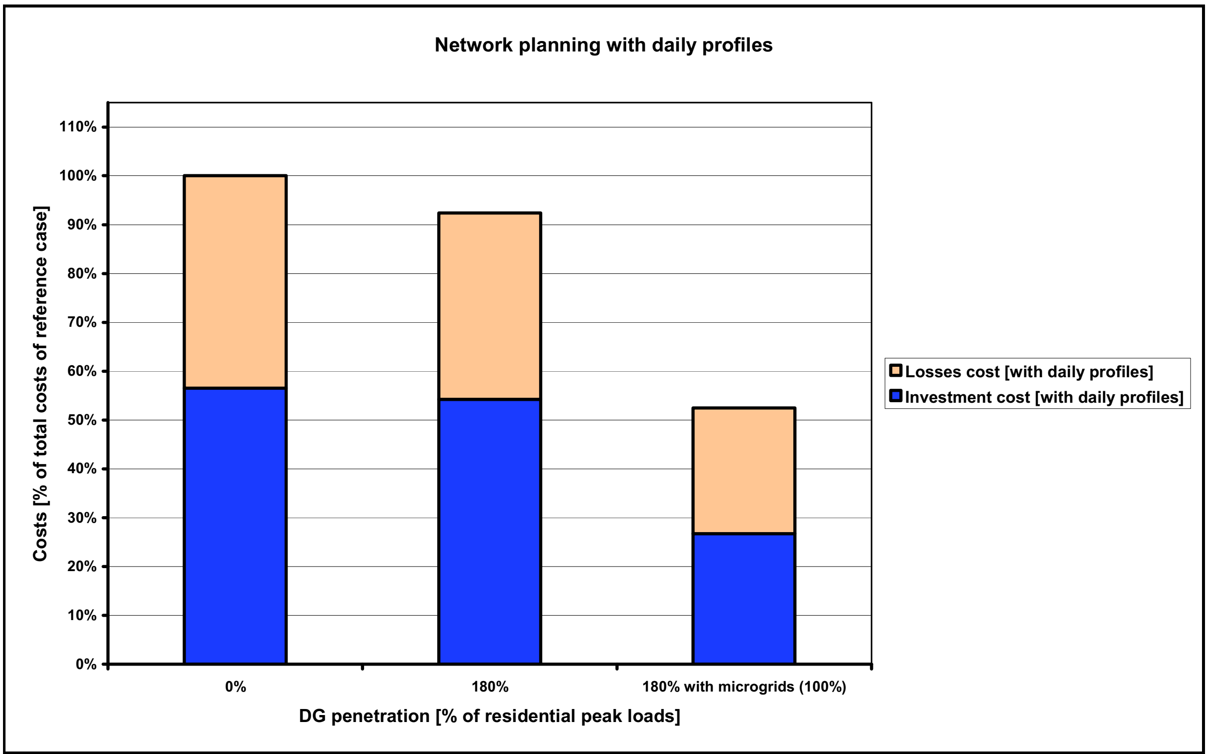


Figure 3.28 Costs of the network designed considering daily curves for loads and generators

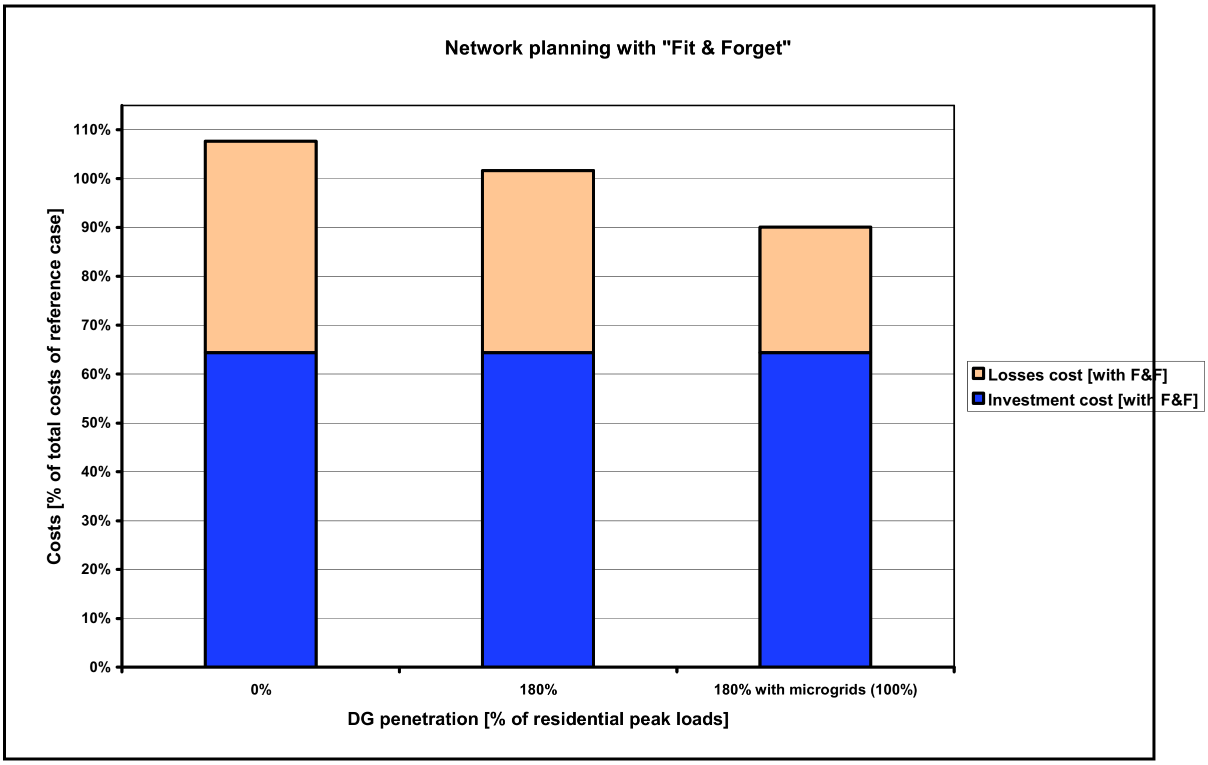


Figure 3.29 Costs of the network designed based on the traditional fit & forget approach

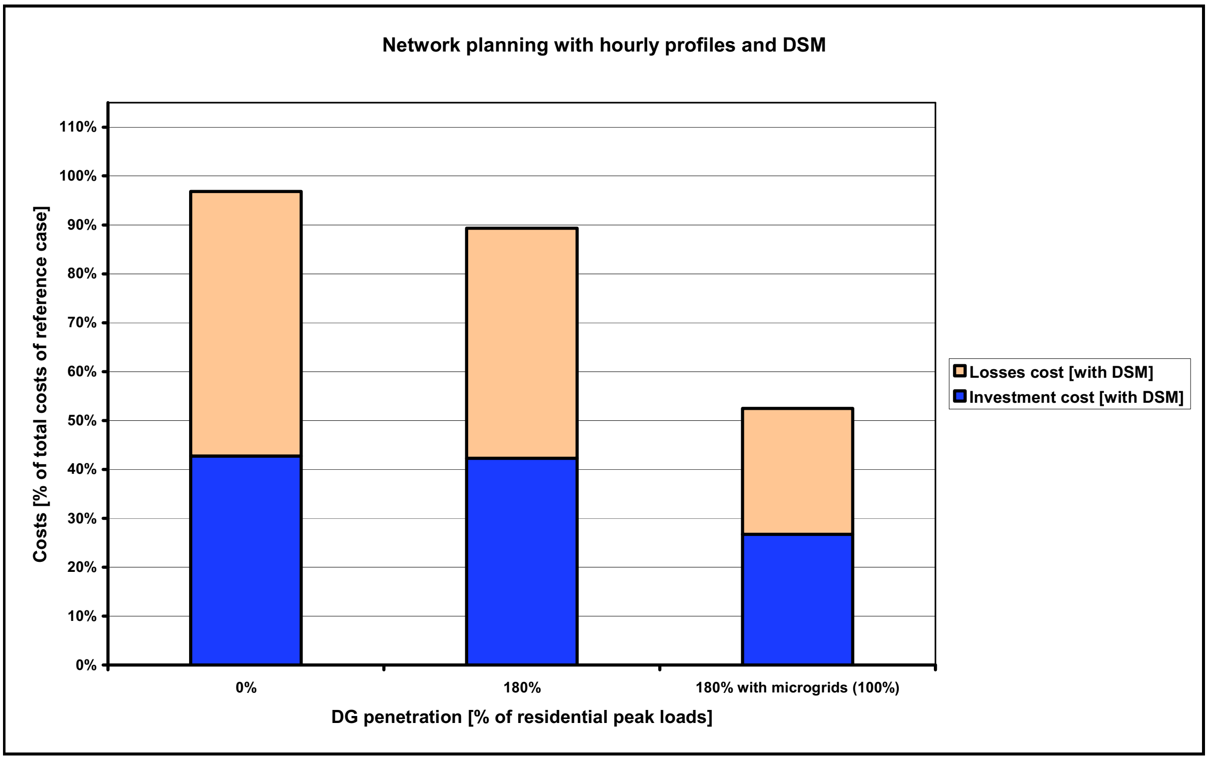


Figure 3.30 Costs of the network designed considering daily curves and possible load shedding action

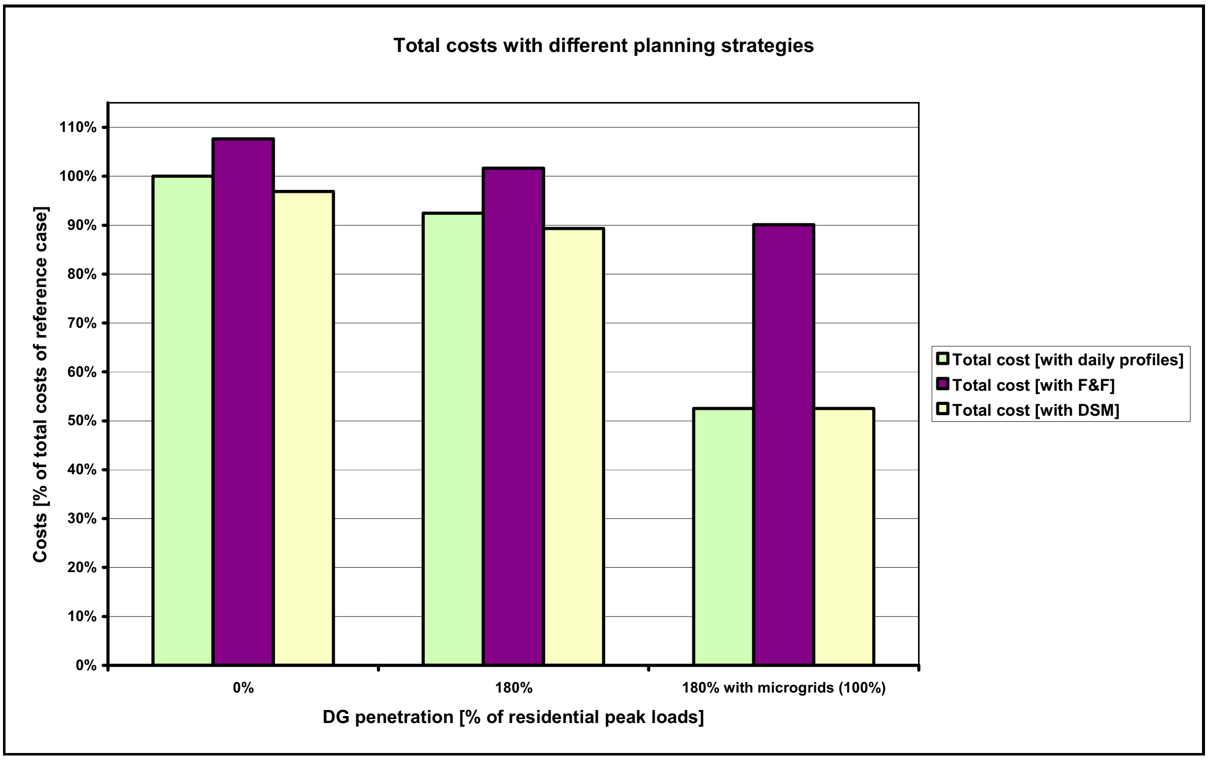


Figure 3.31 Comparison of total costs under different planning strategies

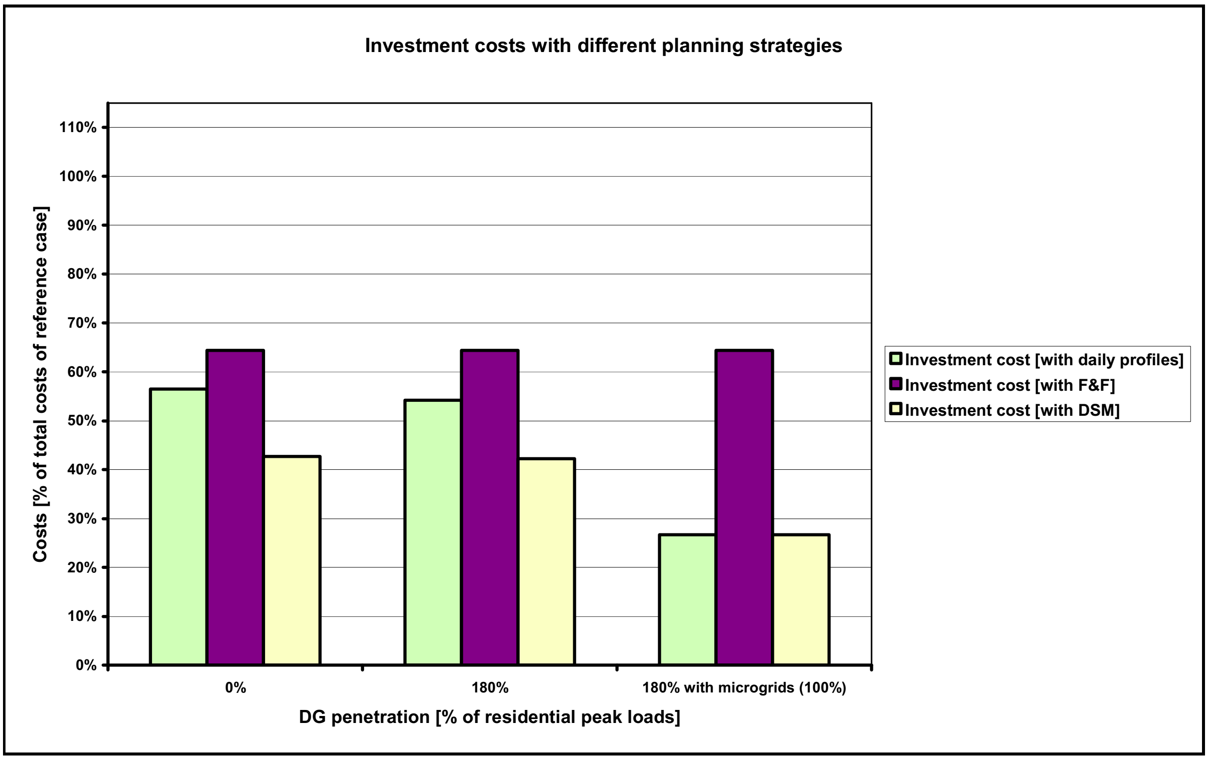


Figure 3.32 Comparison of investment costs under different planning strategies

Notice that, in presence of autonomous microgrid operation, load shedding actions are never necessary even in emergency conditions, so investment costs and losses are the same as in the case of planning with daily profiles (the resultant optimal network configuration is identical).

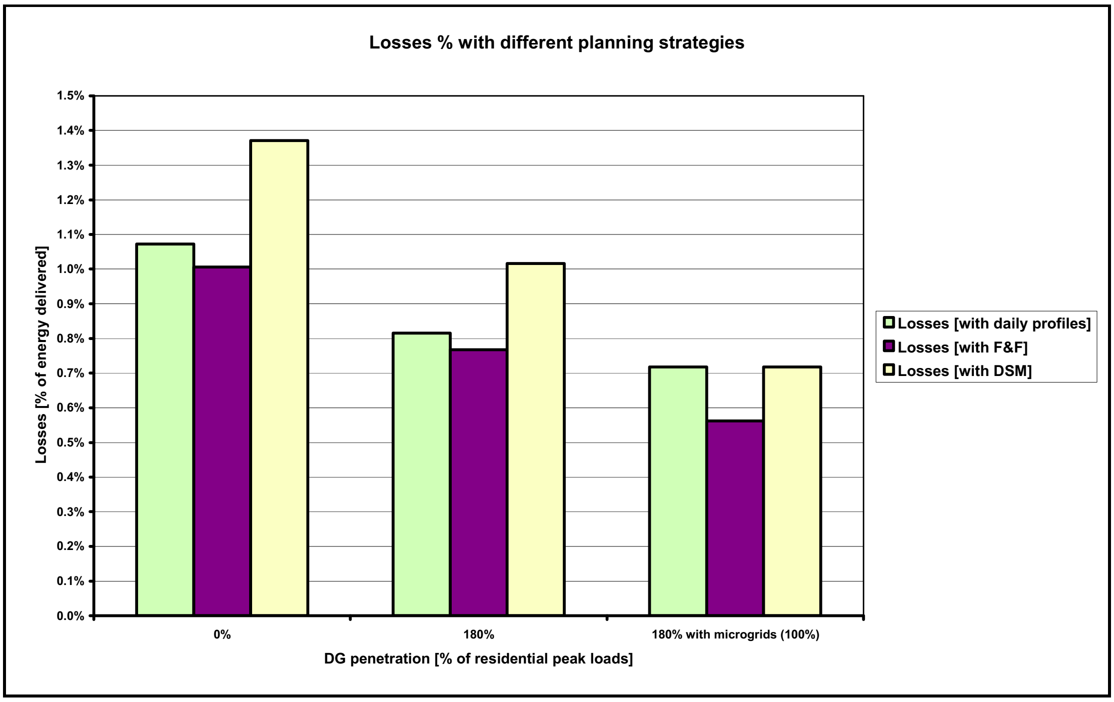


Figure 3.33 Comparison of energy losses under different planning strategies

3.4 Conclusions on the Italian network analyses

An analysis of the impact of DG and microgrids on investments in electricity distribution infrastructures has been conducted on a typical Italian MV network, by making use of a software for optimal planning developed by ERSE for research purposes. The software minimizes the cost of network (upgrading costs and cost of losses) over a given time horizon, taking into account the usual technical constraints (thermal limits of conductors, voltage levels, etc.).

The effect on network upgrade costs and losses of an increasing degree of penetration of PV generators in residential areas have been analyzed.

Different planning strategies have been adopted: a) probabilistic, with load and generation hourly profiles; b) conventional “fit & forget” (worst case); c) considering active management options at a design stage.

The comparison has been based on different parameters, namely investment costs for network upgrading, cost of losses, energy losses, voltage profiles.

The conventional "fit & forget" planning approach, based on a worst case scenario, leads to higher investment costs, due to the oversizing of lines and transformers.

When the presence of DG is correctly taken into account at a design stage, benefits can be obtained, at least until a certain degree of penetration, in terms of reduction in investment costs for network upgrading, required to face load growth, and in cost of losses.

If the possibility to resort to active management options is considered during the planning process, a further reduction in investment costs can be observed, but, conversely, the high exploitation of existing network assets causes an increase in energy losses.

Finally, the effect of the integration, at the LV level, of loads, generators and storage in the form of microgrids has been considered. Thanks to the microgrid concept, the secondary substation feeding the LV network can be seen as an "active" MV equivalent node, making it feasible to implement active management strategies not only to big individual MV customers, but also to groups of several small LV customers. In this case study, microgrids have been assumed to be totally autonomous in terms of energy balance (both active and reactive), thus resulting in zero power flow at the MV/LV substation transformer; this "ideal" behaviour leads to a further reduction in network upgrading costs and electricity losses.

It is important to underline that active management options and microgrid operation must be considered at the planning stage in order to take full advantage of their benefits.

4. Concluding remarks on distribution network analyses for Greece and Italy

This Annex report has described the results of the investigations performed within WPH, Task 2, about the impact of Microgrids operating in Southern Europe scenarios on distribution infrastructure development. More specifically, as opposed to Northern scenarios dominated by CHP systems, the two typical networks analysed for Greece and Italy envisage the presence of PV units (this was the only technology in the Italian case).
The results in the Greek case indicate that DG operating in a Microgrid can postpone or even eliminate the need for investments on upgraded transformers (strategies better known as “non-wire solutions”), with benefits increasing when the DG units are installed close to loads. The investment deferral time and relevant economic benefits show to be linear with the installed DG capacity, with a deferral benefit in the order of 12.5 €/kW_{DG} for typical load growth.
In the Italian case, different analyses have been run to identify and quantify the value of DG and Microgrids under different network design strategies and controllability levels. In all the analyses, the conventional “fit & forget” planning approach leads to the highest investment costs, while the possibility of controlling loads (active management and DSM) within Microgrids can decrease investment costs substantially, in the order of 30% of the F&F cost. However, this comes at the cost of 15÷20% additional losses, as the asset utilisation is optimised. Overall, active management of the network lead to 10÷20% less cost (investment and losses) relative to a F&F approach, while the maximum benefits brought by DG with AM with respect to the base case (network designed with no DG) occur for DG penetration of 100% and correspond to total cost savings in the order of 25%.
A specific study has also been carried out for an *energy-autonomous* Microgrid. In this case the total network cost in the presence of Microgrids with AM is basically halved with respect to a network designed with no DG, while the Microgrid autonomous operation with respect to the same DG penetration leads to an overall cost decrease by some 40% when AM is performed.
Overall, the results for network analysis in Southern countries (and substantial PV production, above all in the Italian case) line up with the ones for Northern countries. In particular, the outcomes of the analyses confirm that if the possibility to resort to active management options is considered during the planning or upgrade process, a further reduction in investment costs can be observed, although at the cost of additional energy losses due to the high asset exploitation.

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