Evaluation of Benefits of Active Demand

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Responsible author(s)	Óscar Lago, Pedro Linares
Other authors	Marco Baron, Annelies Delnooz, Christian Linke, Andreas Cronenberg
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Executive Summary

This document has as main objective the evaluation of benefits of Active Demand (AD) programs, and the comparison between the benefits to be obtained in different power systems. There will be another one within the project which will look also at the costs of deploying such a program.

Theoretically, Active Demand programs can have impacts on system operation, system expansion and market efficiency (the last only applicable in liberalized market environments). By enabling customers to respond to price signals that reflect to a certain extent real operational costs (generation and/or network costs), savings in system operation can be achieved. Demand peaks, both local peaks in a particular area, and system peaks can be reduced, so the need for network investment, installed capacity in peaking units and capacity reserves is also reduced. Lastly, market-driven AD programs can allow an active participation of the demand side in the market and thereby achieve significant improvements in market efficiency.

Taking into account a survey carried out among stakeholders, and also the expectations pointed out by the project team in D1.1, the benefits of AD considered in this report are reduced energy costs (reduction in costs due to lower prices or lower consumption and reduction in ancillary costs), reduced price volatility, more consumer choice, reduced loss of intermittent generation, improved quality of service (lower congestion and blackouts, improved grid operation), reduced network losses, reduced network investments, more security of supply (through higher contribution of DG and lower energy use) and reduction in pollutant emissions.

However, not all these benefits could be quantified. In this report only the reduced generation costs, reduced pollutant emissions, reduced balancing costs, reduced network losses and reduced network investments due to the implementation of AD are quantified, using a simple methodology for different European countries. In order to quantify those benefits, four AD scenarios of reduction in peak demand and energy consumed were studied.

The results obtained show that generation costs and network investments are the items which contribute most to AD benefits. Savings in generation costs are between 0.51% and 4.78% of the total system costs. The largest savings in generation are obtained in Spain and the lowest in Belgium.

Finally, we should point out that, since electricity markets and their regulation in all EU member states are not exactly the same, the conditions for implementing AD based services may be different, at least under present circumstances. Consequently, there may be markets where the conclusions of this report may not be exactly applicable..

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1. Introduction

1.1. Scope of the document

This document attempts to evaluate some of the benefits that might be obtained from the implementation of Active Demand (AD). The evaluation of benefits is important mainly for two reasons.

First, to determine the social interest of pushing forward AD programs. Given that AD has not arisen spontaneously in electricity markets, due to different barriers, its development will probably require some support from regulators or public administrations. But in order to determine whether this support is deserved, the benefits should be compared against the costs.

Second, the evaluation of the benefits of AD will be of interest in order to price the different AD products that may be developed. This price should be based on the willingness to pay for the AD services provided, and this in turn will depend on the benefits that these services provide for the different agents.

Therefore, we set on to try to estimate the benefits provided by AD services for the agents involved. The document first reviews the benefits identified in the literature. Then it summarizes the findings of WP1 and WP5 about the expectations of the different stakeholders. In the following section the state of the art of the evaluation of quantitative benefits of AD programs is surveyed. This state of the art is then used to propose a methodology for the evaluation of the quantitative benefits identified within the ADDRESS project. It should be noted that some of the benefits will be evaluated in other Work Packages. The report concludes with the application of the methodology proposed to some case studies and with the interpretation of the results obtained.

The results will later enter the construction of the cost/benefit tool specified in Task 5.4. Non-economic consumer benefits will be investigated through the targeted interviews and analyzed in relation to social psychological models of energy use behavior (sub-task 5.1.1 and Task 5.2). These models (both for consumers and for other players) will be validated using results from the field test conducted in WP6.

Since the electricity markets and regulation in all EU member states are not exactly the same, the conditions for implementing AD based services may be different, at least under present circumstances. Consequently, there may be markets where certain alterations to the conclusions of this report may become necessary taking into account these markets specific requirements. However, in this report it is not possible to cover all market conditions and service variations.

1.2. Structure of the document

The document comprises the following sections:

- A review of the benefits of Active Demand.
- Benefits identified within the Address project.
- How to assess the benefits of AD.

- Methodology proposed for the evaluation of AD benefits.
- Evaluation of quantitative benefits.

1.3. Notations, abbreviations and acronyms

AD	Active Demand
CPP	Critical-peak pricing
DSO	Distribution system operator
RTP	Real-time pricing
TOU	Time-of-use
TSO	Transmission system operator

Table 1: abbreviations

1.4. Acknowledgements

We would like to thank Adela Conchado, for her previous work on the assessment of benefits of Active Demand; Jitske Burgers, for her review of the document, and of course, all partners in WP5.1 for their contribution to the assessment of the results for their own countries. We also acknowledge the funding of the CENIT-GAD project in Spain under which some of the methodological developments were carried out.

2. A review of the benefits of Active Demand

In the present energy context, in which growing concerns on environmental sustainability and security of supply need to be tackled as cost-effectively as possible, active demand management can play an important role (IEA, 2008; EC, 2005). Demand Side Management (DSM) measures directed to promote more efficient appliances, and also an efficient use of electricity, might be key features in the future of the energy sector. In the case of the power sector, given that the cost and impacts of electricity consumption vary over time, a more efficient use not only means reducing consumption, but also managing this consumption in time – at least at the hourly level.

Of course, for DSM measures to bring benefits not only in terms of energy efficiency, but also in economic efficiency, we must verify if the current situation features market failures or barriers which prevent an efficient allocation of resources[1]. This is unfortunately the case of most energy markets (Linares and Labandeira, 2010), and also of the residential power market: in most power systems, residential customers do not receive proper signals for the temporal management of their consumption. Up until now the major reason is the lack of technologies that allow, on the one hand, giving consumers these signals, and on the other hand, measuring their hourly consumption. This information asymmetry constitutes a market

[1] If there are no market failures or barriers, we may assume that the current situation is the optimal one, and therefore any additional measure will only worsen its economic efficiency.

failure, as the consumers' decisions do not account properly for the cost of producing electricity in the different time periods.

Solving this market failure is the major objective of Active Demand programs (AD, also known as demand response programs). There are many types of AD programs, but in essence, all of them consider sending price or volume signals (which may be equivalent depending upon the circumstances, as in Weitzman, 1974), which will vary in time, to consumers, so that they may respond to them by adjusting or shifting their loads. This would mean, in most cases, a reduction in peak load times, followed by an increase of demand in off-peak, with the corresponding flattening of the demand curve. This would in turn imply an increase in the efficiency of the power generation and transmission and distribution systems.

Although AD is not a new concept – in fact, it would be the "natural" mechanism in a perfectly competitive market –, it has been gaining interest recently, as power systems become more congested, smart grids develop, and the penetration of renewable energy increases. While most AD programs in past years have consisted on interruptible or curtailable services from large customers, nowadays the development of smart meters, home automation and advanced communication and control technologies enables more sophisticated forms of AD even at the household level, with domestic customers being able to adapt their demand in response to time-varying price signals.

The current interest in AD is materialized in numerous research projects besides this one[2], trials and initiatives[3]. Some countries and regions have carried out studies to assess the cost-effectiveness or potential for advanced metering and AD[4], and many countries have started deploying smart meters or have set roll-out targets[5] (Haney et al., 2009), which will facilitate the implementation of AD programs and broaden their possibilities.

However, like all regulations or programmes oriented to the correction of market failures, it seems advisable to carry out a cost-benefit analysis, so that the costs of these programmes are not higher than the efficiency gains achieved. Hence, although AD programs can result in significant benefits for power systems (e.g. US DOE, 2006), they can also entail non-negligible costs, especially if an advanced metering, communication or remote control infrastructure is put in place to facilitate automatic demand response. For this reason, assessing the benefits of AD is a must to determine the interest of AD programs, both from the perspective of regulators and market agents.

However, the assessment of benefits a priori is not trivial: it is difficult to estimate how demand patterns would change, and understanding the effects of such changes on intrinsically complex power systems requires a thorough analysis. A range of studies have analyzed these effects both qualitatively and quantitatively, providing valuable insights and

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2 Some R&D projects related to AD: GAD (www.proyectogad.es) in Spain, Smart-A (www.smart-a.org) in Europe, Demand Response Research Center (http://drrc.lbl.gov) in the USA and IEA Demand Side Management Programme (www.ieadsm.org) internationally.

3 Faruqui and Sergici (2009) presented a survey of the 15 most recent experiments with dynamic pricing at the household level. RRI (2008) reviewed the current status of AD in the USA, and Goldfine et al. (2008) the major developments in AD programs and initiatives.

4 E.g. FERC (2006) for the USA, NERA (2008) for Australia, Vasconcelos (2008) for the European Union, Navigant (2005) for Ontario (Canada).

5 In Europe, the penetration rate of smart meters is about 85% in Italy and 25% in France. UK, Spain, Ireland, the Netherlands, Norway and France have set deployment targets to achieve nearly 100% smart meter installation by 2020 (Faruqui et al., 2009)

constituting a useful starting point for future studies.

The purpose of this section is to present the state of the art of the analysis and assessment of the economic impacts of AD on power systems. Since the evaluation of implementation costs is not too complex, the focus will be on the evaluation of benefits.

2.1. Categorization of demand response programs

Being aware of the broad range of AD programs is important to understand the potential benefits that can be achieved and to put the variety of studies that have analyzed them in context. This section provides some background on the different designs and applications of AD programs.

There are many types of AD programs, which can be classified according to various criteria. Table 2 summarizes some classifications proposed in the literature. As shown in Table 2, AD can have reliability or economic purposes (RMI, 2006). Depending on the factor that triggers demand response, programs can be emergency-based or price-based (Faruqui and Hledik, 2007). With a similar meaning, but referring to the source of the trigger signal, they can be called system-led and market-led programs respectively (IEA, 2003). According to the type of signal provided (quantity or price), there are load response and price response programs (RMI, 2006). According to the method used to motivate AD, incentive-based programs or time-based rates can be distinguished (FERC, 2006; US DOE, 2006). Finally, there are direct load control programs, in which load reductions are controlled by a system operator, or passive load control programs, in which load reductions are controlled by customers (DTE Energy, 2007).

Table 2: Categorization of AD programs

Classification criteria	Dualities		Source
Purpose	Reliability	Economics	(RMI, 2006)
Trigger factor	Emergency-based	Price-based	(Faruqui and Hledik, 2007)
Origin of signal	System-led	Market-led	(IEA, 2003)
Type of signal	Load response	Price response	(RMI, 2006)
Motivation method	Incentive-based	Time-based rates	(FERC, 2006; US DOE, 2006)
Control	Direct load control	Passive load control	(DTE Energy, 2007)

To simplify, the whole range of AD programs may be reduced to two types, which correspond to each of the columns in Table 2. On the one hand, AD aiming to improve system reliability is generally implemented through emergency-based, system-led, load-response, incentive-based, direct-load control programs. On the other hand, AD aiming to reduce system costs is generally implemented through price-based, market-led, price-response (using time-based rates), passive load control programs.

Load response programs include direct load control, curtailable load, interruptible load and scheduled load. Price response programs include time-of-use (TOU) tariffs, dynamic pricing (such as critical-peak pricing (CPP) or real-time pricing (RTP)) and demand bidding (RMI, 2006). In general, in load response programs demand is remotely controlled upon conditions contracted with customers, while in price response programs, customers respond on their discretion to time-varying prices (Haney et al., 2009).

Some other factors that would influence the characteristics of AD programs, summarized in Table 3, are the following:

- The incentives to undertake AD and the program design differ significantly between liberalized market environments and centralized regulated environments (Borenstein et al., 2002; IEA, 2003).
- Similarly, it is important to consider if the promotion and financing of AD -or the installation of enabling technologies- is assumed by the regulator or is left to the initiative of market agents (NERA, 2008).
- The targeted segment of customers, from large industries to small commercial or domestic loads, is another relevant factor.
- Finally, the installation of enabling technologies critically determines AD options. For example, direct load control programs require remote control capabilities and real-time pricing requires an advanced metering infrastructure.

Table 3: Some other differentiating factors of AD programs

Other criteria	Dualities	
System/market structure	Vertically-integrated regulated system	Liberalized market
Promotion and financing	By regulator	By market agents
Targeted customers	High-voltage (industrial and large commercial)	Low-voltage (small commercial and domestic)
Automation of response	Manual response (without enabling technologies)	Automatic response (with AMI and/or other smart devices)

2.2. Potential benefits of demand response

AD has a broad range of potential benefits. The benefits that will materialize in practice will depend on the purpose, design and performance of the AD program implemented, as well as on other factors such as the structure of the market/system and the enabling technologies in place.

AD programs can have impacts on system operation, system expansion and market efficiency (the last only applicable in liberalized market environments). In this section, the potential benefits arising in those three aspects of power systems will be identified and described from a theoretical point of view (and summarized in Table 4). Some further considerations about the distribution of benefits among different agents and about smart metering will be pointed out as well.

2.2.1. Power system operation

AD programs where customers are able to respond to price signals that reflect to a certain extent real operational costs (generation and/or network costs) can achieve savings in system operation.

If prices reflect the cost of generation, part of the demand in times of high generation costs may be avoided or shifted to less expensive periods, resulting in some savings in the production of electricity.

If the cost of environmental impact is conveniently internalized in energy prices, the response of demand will also consider the impact on the environment (Spees and Lave, 2007). However, the change in net emissions will be very dependent on the generation mix. In systems in which marginal electricity in peak hours is produced from technologies emitting less CO2 than marginal technologies in off-peak hours (e.g. on-peak gas and off-peak coal, as occurs in many power systems), shifting some peak demand to off-peak could imply an increase in CO2 emissions, at least in the short-term (Holland and Mansur, 2007). Nevertheless, if not only shifting but also conservation effects from AD are taken into account, the overall emissions are likely to be reduced (Conchado and Linares, 2009b).

Another positive effect of AD on the operation of generation systems is facilitating the real-time balance of supply and demand, which is especially important when intermittent generation has large shares of production (Zibelman and Krapels, 2008). In fact, AD is considered as a major option to decrease problems caused by the variable and uncertain output of intermittent renewable sources (Kärkkäinen and Ikäheimo, 2009).

This contribution of AD to real-time balancing, coupled with the fact that AD can help to compensate supply shortages with load reductions in case of generation outages, may entail a reduction in the requirement of operating reserves for a certain level of short-term reliability of supply (or to increase short-term reliability of supply for a certain level of operating reserves) (Earle et al., 2009).

Regarding network operation, if network-driven AD actions are promoted (either through prices or through other agreed incentives), demand can respond to alleviate network constraints or to avoid outages in case of contingencies (Affonso et al., 2006). Moreover, AD can contribute to reduce lines losses (Shaw et al., 2009). AD programs can even provide ancillary services for electricity network system operators, such as voltage support, active/reactive power balance, frequency regulation and power factor correction (Crossley, 2008). All these effects on networks can mean an increase in network reliability and quality of supply.

2.2.2. Power system expansion

As already mentioned, AD can potentially reduce demand peaks, both local peaks in a particular area and system peaks.

At local level, since networks are dimensioned for the highest expected demand, demand clipping can mean a reduction in the need for network reinforcement for a certain level of reliability (or an increase in long-term network reliability for the same level of investment).

At the system level, leveling the demand pattern reduces the need for installed capacity in peaking units. Moreover, it reduces the need of investment in capacity reserves (Braithwait et al. 2006) for a certain level of reliability of supply (or increases long-term reliability of supply for a certain level of capacity reserves).

Another effect of AD on the expansion of generation systems, which can be considered a benefit in countries where renewable energy is encouraged, is that it enables higher penetration of intermittent sources (by facilitating supply and demand balancing).

2.2.3. Functioning of power markets

In liberalized environments, market-driven AD programs, most frequently implemented in the form of time-varying tariffs, can allow an active participation of the demand side in the market and thereby achieve significant improvements in market efficiency.

This gives consumers the opportunity to maximize their utility by adjusting their demand in response to price signals. If price signals are accurate (in the sense that they reflect actual costs), only those consumers for whom consuming electricity at a certain time is worth at least as much as the cost it represents at that time would consume, resulting in a more efficient allocation of resources (EEI, 2006).

On the supply side, increasing the elasticity of demand would mitigate the generators' capacity to exercise market power (IEA, 2003: 54; Braithwait et al., 2006), which would also entail a reduction in the magnitude and number of price spikes (Kirschen, 2003; Borenstein et al., 2002).

Prices would also be moderated by the smoothing of the demand profile (IEA, 2003). However, it should be noticed that price reductions only represent wealth transfers from generators to consumers and not real savings for the society as a whole (Braithwait et al., 2006).

AD may allow generators and retailers to reduce the cost of imbalances (IEA, 2003). Similarly, AD can also be seen as a way of hedging against price and production volatility (PLMA, 2002) and extreme system events difficult to predict (Violette et al., 2006a).

With the implementation of AD programs, retailers may increase their business opportunities and offer contracts to customers better suited to their demand profile. At the same time, consumers can benefit from a greater choice of contracts and save money if their consumption profile is favorable to the system (in the sense that demand is low in times of high cost).

2.2.4. Summary of benefits

Table 4 summarizes the potential benefits of AD that have been mentioned, categorized according to the activity of power systems where they originate. Notice that benefits are assigned to the activity where they originate regardless of the activity that finally receives them (the distribution of benefits among agents will be discussed below). In line with this, benefits included in Table 4 are only those that represent actual savings or gains in efficiency for the society as a whole, and not wealth transfers among agents.

Table 4: Potential benefits of AD

	Operation	Expansion	Market*
Transmission and Distribution	▪ Relieve congestion ▪ Manage contingencies, avoiding outages ▪ Reduce overall losses ▪ Facilitate technical operation [a]	▪ Defer investment in network reinforcement or increase long-term network reliability	
Generation	▪ Reduce energy generation in peak times: reduce cost of energy and -possibly- emissions [b] ▪ Facilitate balance of supply and demand (especially important with intermittent generation) → Reduce operating reserves requirements or increase short-term reliability of supply	▪ Avoid investment in peaking units ▪ Reduce capacity reserves requirements or increase long-term reliability of supply ▪ Allow more penetration of intermittent renewable sources [c]	▪ Reduce risk of imbalances ▪ Limit market power ▪ Reduce price volatility
Retailing*			▪ Reduce risk of imbalances ▪ Reduce price volatility ▪ New products, more consumer choice
Demand	▪ Consumers more aware of cost and consumption, and even environmental impacts ▪ Give consumers options to maximize their utility: opportunity to reduce electricity bills or receive payments	▪ Take investment decisions with greater awareness of consumption and cost	▪ Increase demand elasticity

* Only applicable in liberalized systems
[a] Keep frequency and voltage levels, balance active and reactive power, control power factor, etc.
[b] Depends on the electricity mix
[c] It can be considered a benefit in systems where renewable generation is encouraged

2.2.5. Further considerations

2.2.5.1 Distribution of benefits among agents

The benefits arising in generation or network activities will not necessarily be received by generation companies and network operators, respectively. The distribution of benefits among the agents is a key issue that needs to be properly assessed considering the particular regulatory framework in place when performing an economic evaluation of an AD program.

In general terms, under a centralized paradigm, the benefits would be directly transferred to consumers through lower tariffs. In liberalized systems, if there is an incentive-based remuneration scheme, benefits arising in distribution would be earned by distribution companies in the short-term, and would be transferred to customers in the long-term through lower access tariffs. On the contrary, the savings arising in the generation system would be transferred directly to customers through lower energy prices (if markets are efficient), meaning at the same time a reduction in the revenues of generation companies. In any case, a more efficient use of energy due to AD should translate into benefits for consumers (ERGEG, 2007).

According to IEA (2003), the distribution of benefits among agents in liberalized environments entails a dispersion of the incentives to undertake AD in the following way:

- Base-load generators have little incentive and see AD only as a means of hedging to unplanned outages, whereas peaking generators view AD as direct competition.
- System operators may be interested in AD to facilitate supply and demand balance and to improve reliability.
- Network operators can use AD to relieve network congestion, improve local reliability or quality of supply or reduce network investments, but their incentives would depend crucially on their regulated remuneration scheme.
- Retailers can be interested in AD as a means to balance their contracted supply with the demand of their consumers.
- Consumers may use AD to reduce their electricity expenses, their incentives to respond basically depending on the incentives they are offered by retailers or utilities.

2.2.5.2 Smart metering and other enabling technologies

The potential benefits of AD can be broadened or amplified with the installation of enabling technologies. Indeed, most of the benefits mentioned in Table 4 can only be realized if an advanced metering and/or control infrastructure is in place. Thus, the implementation of dynamic tariffs requires an Advanced Metering Infrastructure (AMI), including the installation of “smart meters” and communication systems, and managing network contingencies through load interruptions or curtailments requires remote control devices.

In the literature, smart metering and demand response are usually related concepts. Many studies that have evaluated the cost-effectiveness of smart meters include the benefits associated to demand response in their assessment (e.g. CapGemini, 2007; Ofgem, 2006; Frontier Economics, 2006; Haney et al. 2009). In fact, the benefits of AD dominate the societal benefits that have been attributed to smart metering in recent business cases (Neenan and Hemphill, 2008). Other studies that analyze smart metering from a regulatory perspective can also provide interesting clues about demand response (e.g. EEI, 2006; ERGEG, 2007).

However, it should be noticed that the deployment of smart meters would entail some operational benefits not related to AD, such as savings in meter reading and network fault detection. These should be taken into account when performing a cost-effectiveness analysis of advanced metering infrastructures, but will not be included in this review.

Haney et al. (2009) mention the following operational benefits of smart meters:

- Improvement in the efficiency of metering services: avoided cost of meter reading, better outage detection, faster response times to outages, improved quality of supply recording and accurate billing.
- Reduction in customer service costs due to a lower level of customer complaints.
- Non-technical losses reduction.
- Others such as greater level of choice in terms of payment options, improved consumption information or micro-generation facilitation.

Smart meters also enable detailed locational data and more efficient pricing to network users of usage and system charges (IEA, 2003: 110). Moreover, the knowledge of demand patterns that can be gained with smart metering may allow more efficient network investment and operation (just because of the value of information, even without considering AD). Finally, smart meters may provide greater scope for innovative tariffs and more competition in retailing (Frontier Economics, 2006).

There are other technologies (apart from smart meters) that can contribute to AD, such as smart thermostats[6], lighting control systems, under-voltage and under-frequency relays or thermal storage systems (Batlle and Rodilla, 2008). Lockheed Martin Aspen (2006) examines in detail the current status of enabling technologies for homes and small business for either reliability-based or price-based AD programs, and SCE (2006) presents an inventory of emerging demand response technologies.

3. Benefits identified within the ADDRESS project

Within the ADDRESS project, benefits have been identified through two processes (which were carried out more or less in parallel). First, a survey was carried out among stakeholders, in which they expressed their beliefs about the existence of different benefits and of their relevance. The results of this survey have been published as Internal Report 5.1. Second, WP1 has dealt also with the identification of possible expectations or stakes of stakeholders, and has compiled them in Deliverable 1.1. We now review in detail the benefits identified, drawing largely from these documents.

3.1. Survey of stakeholders (IR5.1)

The survey asked stakeholders about their beliefs on whether 25 previously identified factors were likely to increase/decrease/not change with the introduction of AD programmes.

These factors are listed below:

6 The Smart Thermostat Program is an interesting pilot in California that tested smart thermostats to control air conditioning of 5.000 residential customers (KEMA-XENERGY, 2003)

Losses on the grid
Overloads/congestion on the grid
Investments in the grid
Investments in generation
Management of distributed generation (such as renewable energies)
Quality and security of supply
Revenue from sales
Cost of purchases
Balancing activities and costs
Participation in ancillary services markets
Management of emergency situations
Coordination required between players
Power system voltage stability
Comfort (for consumers)
Commercial relationships with consumers
Consumer trust in energy retailers
Climate change (pollutant emissions)
Information on system status
Smart metering
Corporate image
Competitiveness
Opportunity for consumers to receive new services
Consumer awareness of energy use
Provision of accurate and timely consumption information
Energy savings (volume of energy purchased)

The major conclusions of the survey regarding these factors are described in the box.

Consensus was reached on four factors. A majority view was reached on thirteen factors and a mixed response was received for eight factors.

Consensus was reached about the following four factors:

- smart metering will increase
- AD will increase the opportunities for consumers to receive new services
- consumer awareness of energy use will increase with AD
- AD will provide accurate and timely consumption information

A majority reported that Active Demand would have the following effect on thirteen factors:

A majority predicted that the following three factors would decrease with AD:

- overload/congestion on grid (except TSO who predicted increase);
- investments in generation (except a generator and DSO association who predicted it would increase);
- pollutant emissions (except the TSO who predicted that they would increase) [We note that this counterintuitive answer may be motivated by the particular generation mix on the national territory of the TSO interviewed.]

A majority predicted that the following ten factors would increase with AD:

- management of distributed generation (although some academics predicted it would decrease or remain unchanged);
- quality and security of supply (except a generator and energy retailer who predicted it would decrease);
- revenue from sales (except two research/consultancy institutions who predicted it would decrease);
- balancing activities and costs;
- need for greater coordination between players (all but a DSO association who predicted that this would decrease)
- commercial relationships with consumers (except one DSO who predicted that these would remain unchanged);
- information on system status predicted to increase especially by network operators (DSOs and TSO) and retailers;
- corporate image;
- competitiveness;
- energy savings (volume of energy purchase) (except retailers who were likely to predict that energy savings would be unchanged or decrease).

There was a mixture of responses for the following eight factors:

- the TSO and one DSO thought losses on the grid would increase whilst DSO/retailer/research institutions and the generator reported that losses on the grid would decrease;
- there was no consensus about whether investments in the grid would increase or decrease (DSOs and TSOs were likely to predict investments would either not change or increase whilst academics/research institutes and generator predicted that investments would decrease);
- the manufacturer, retailer/DSO and TSO thought that the cost of purchases would increase whilst a retailer and two academic/research organisations thought it would decrease;
- respondents were as likely to think that participation in ancillary services markets would increase as to decrease and one research institute predicted no change;
- DSOs, TSO and two research/consultancy institutions thought that there would be an increase in effort required to manage emergency situations whilst a retailer and generator thought this would decrease and a DSO and one academic institution predicted no change;
- there was uncertainty about whether power system voltage stability would increase, decrease or remain

Economic advantages identified by academic/research, retailer, DSO and metering organisations included:

- reduced energy costs at peak demand periods (research)
- reduced volatility of energy prices, lower investment in generation and other infrastructure, better planning of investments with more predictable demand (retailer)
- reduced investment in grid updating and expensive power reserve so reduced costs for energy (academic)
- local benefits from demand response such as deferred investment in new system infrastructure, extended equipment life and avoidance of equipment overloading (research)
- when active demand helps match production with consumption, citizens can avoid paying high flat rates to cover ecological and economical costs [*sic*] (academic)
- reduced need to invest in the network (DSO)
- reduction in electrical invoices (academic)
- provision of new electrical services (pre-payment tariffs) (academic)
- reduced cost depending on tariff models (retailer/DSO, academic)
- improved demand profile for the system (research)
- increased awareness about cost of energy use (manufacturer)
- ability to receive real time information and price signals on energy consumption (DSO)

Economic disadvantages included:

- high cost of managing and monitoring loads (academic)
- cost of implementation (research)
- concern about how settlements would work within/between retailers/distributors who have different drivers to enact DSM even if they share long term goals (retailer)
- penalties for energy over-consumption (retailer/DSO)

Technical/economic advantages included:

- better security of supply which would reduce power outages (retailer and academic)
- an improvement in quality of supply (DSO, academic, research)
- better fit between generation and consumption leading to more efficient generation frameworks (DSO)
- better use of electrical infrastructures (academic)
- reduced need for network reinforcement (DSO)
- reduced losses on transmission and distribution system (research)
- reduced voltage interruptions (metering, generator)
- reduced operation and maintenance costs (metering)
- increase in network safety (research)
- minimisation of shut downs (retailer/DSO)
- increased penetration of RES (academic)
- increased system energy efficiency (academic)

Technical/economic disadvantages included:

- difficulties for an aggregator (or other actor) to guarantee any promised use of AD (academic)
- AD framework would require more communication - more infrastructured communications, hardware, algorithms (DSO, research)
- AD framework requires better coordination - not easy to coordinate communications, hardware and algorithms (DSO)
- grid instability (with bad control of AD) (research)
- more complicated generation and load balance (DSO)
- necessity to have knowledge of network status in real-time (DSO)
- network reliability may decrease whilst new tools and equipment are tested and implemented (DSO)
- decreased impact of new electrical infrastructures (academic)
- reduced energy dependency and reliance on intermittent local resources [*sic*] (academic)

The corporate advantages were:

- better security of supply that would reduce power outages and bad publicity (retailer)
- increase in potential business for retailers (DSO)

The only corporate disadvantage to be identified was:

- loss of autonomy (retailer/DSO)

Environmental advantages were principally identified by academic/research organisations. There were no environmental disadvantages of AD.

- a reduction in CO_2 emissions and contaminating gases (academic/research)
- increase in renewable energy production (research)
- increase in environmental awareness (research)
- save energy depending on tariff models (retailer/DSO, academic)

Communication/social advantages:

- improvement of information to consumers using Automatic Meter Management with new communication systems to manage appliances (academic)
- skilled consumers would probably understand, accept and use without troubles or 'fear' the novelty of AD (consumer group)
- improved service to consumers (metering)
- public use infrastructure - society able to use electricity network in a more efficient way (DSO)
- energy independence (e.g. in Morocco)

Communication/social concerns included:

- how to ensure consumer support for actions (retailer)
- need to ensure transparency of the process involved in AD (consumer group)
- need to enable consumers to check and control the truthfulness of their own consumption data (consumer group)
- large amount of prices and calculations that may diminish comfort (research) [We note a more general definition of comfort here. Having to consider a large number of prices and associated decisions may be seen as inconveniencing consumers thus leading to loss of comfort.]
- privacy issues (research)
- possible lack of reliability from the consumers (academic)
- consumer impact such as reduced comfort (research)
- belief that citizens would be reluctant to participate in AD because they have had decades of cheap, unlimited, abundant energy and did not believe in a possible shortage (academic)
- AD framework would require better understanding of how energy is spent (DSO)

There were no regulatory advantages identified for AD. The regulatory disadvantages of AD were:

- common regulation across EU energy markets required - necessary rather than a disadvantage (DSO)
- perverse effects if regulation fails (research)
- need to identify, analyse and solve present regulatory constraints (DSO)

- Reduced energy costs (including reserve requirements)
- Reduced energy losses
- Reduced volatility of prices
- Lower investment needs (or deferral of investments): both in generation and grids
- New services for consumers
- More security of supply (through reduced energy use or changes in supply)
- Improvements in quality of supply (including voltage interruptions, black-outs, etc.)
- Pollutant emissions reductions

It should be remarked that we are trying to be as comprehensive as possible. But when it comes to assessing the social benefits of AD, care must be taken about double-counting some of them, as will be further addressed later in the report.

3.2. Identification of benefits from D1.1

The second take at the identification of benefits within the ADDRESS project was that of WP1. In fact, WP1 does not speak clearly about benefits, but about expectations of the players, and services provided by AD. We will perform a similar analysis as before, trying to convert these expectations and services into quantifiable benefits.

The starting point is the assessment of the stakes, needs and expectations of the players with regard to AD. This is shown in D1.1 Appendices for each agent. As an example, we include here the results for the retailer:

Player role	**“Retailer”**
Principal function(s) in the system	To purchase electricity on the wholesale market To supply electricity to its customers
Contextual constraints	To meet the declared consumption programme. To respect supply contracts with its customers.
Main Stake	To maximise its profits under constraint of risk management
Short-term needs generated by the stakes	Forecasting and setting of the sales conditions and prices. Forecasting and negotiation of the purchasing conditions and costs. Maximising the margin between purchases and sales.
Long-term needs generated by the stakes	Structuring strategically its portfolio of consumers and wholesale suppliers
Expectations with respect to Active Demand	To minimise consumption when the margin is negative and maximise consumption when margin is positive → requires a modification in power consumption on a given time span at a given time To minimise deviations from declared consumption programme and from

	contracted purchase volume → requires a modification in power consumption at very short term (intra-day) Month(s) ahead: to help structure long-term purchasing contracts so as to maximise margin → requires a recurring periodic modification in power consumption for a given time span over a given period (seasonal)

As may be seen, the closest concept to the benefits provided by AD is what is termed here expectations. As an example, a possible benefit of AD for retailers, consistent with the idea of benefit as presented in literature (see previous section) would be to minimise deviations from the declared consumption programme. These benefits are created by the use of AD services, which in turn arise because of the use of AD products.

The final step undertaken by WP1 was to define AD products (scheduled and conditional reprofiling, SRP and CRP) able to provide these services.

Again, the example of the retailer is used to show the type of services which may be provided by AD products.

Player	Principal services	Type of AD Product
Retailer	Short-term load shaping in order to Optimise Purchases and Sales.	SRP
	Management of Energy Imbalance in order to minimise deviations from declared consumption programme and reduce imbalance costs.	SRP
	Reserve capacity to manage short-term Risks.	CRP

So, from this review of D1.1 we end up with three concepts: expectations, services and products. Which one is closest to the idea of benefits?

As advanced before, it seems that it is expectations. Services refer mostly to technical concepts and instruments, means to produce changes in the welfare of the agents, but not changes as such. As for AD products:

- AD products may have different applications (provide different services) when used by different players, and therefore their benefits will also be different
- Some AD products may provide simultaneously different services, which complicates the measurement of benefits.

We may extend this idea to also say that AD services may also provide different benefits, depending on the player who uses them and the circumstances under which they are used.

Therefore, we will use the expectations of the different players as a proxy for the benefits provided by AD. These are shown in the following table (for a detailed description of the expectations we refer the reader to D1.1 appendices):

Player	Expectations

Retailer	To minimise consumption when the margin is negative and maximise consumption when margin is positive → requires a modification in power consumption on a given time span at a given time To minimise deviations from declared consumption programme and from contracted purchase volume → requires a modification in power consumption at very short term (intra-day) Month(s) ahead: to help structure long-term purchasing contracts so as to maximise margin → requires a recurring periodic modification in power consumption for a given time span over a given period (seasonal)
Centralised producer	Provide them more flexibility for participating in frequency control services → requires a modification in power consumption available at very short notice (a few minutes) Optimise the profits generated by commercial activity by buying AD flexibility as a function of the market prices → requires a modification in power consumption at short term (intra-day).
Decentralised electricity producer	Reduce imbalance costs → requires a modification in power consumption at short term (intra-day). Optimise the profits generated by commercial activity by buying AD flexibility as a function of the market prices → requires a modification in power consumption at short term (intra-day). Provide more flexibility for participating in frequency control services → requires a modification in power consumption available at very short notice (a few minutes).
Producers with regulated tariffs	Reduce imbalance costs → requires a modification in power consumption at short term (intra -day). Optimise the profits generated by commercial activity by buying AD flexibility as a function of the market prices → requires a modification in power consumption at short term (intra -day). Provide more flexibility for participation in frequency control services → requires a modification in power consumption available at very short notice (a few minutes). Reduce the investment costs of future generation facilities → requires a modification in power consumption available at long term (a few months or years) Avoiding loss of excess generation in valley hours → requires a modification in power consumption available at medium term (day(s) ahead)

Production aggregator	Reduce imbalance costs → requires a modification in power consumption at short term (intra -day). Optimise the profits generated by commercial activity by buying AD flexibility as a function of the market prices → requires a modification in power consumption at short term (intra -day). Provide more flexibility for participating in frequency control services → requires a modification in power consumption available at very short notice (a few minutes).
Traders	Optimise short-term purchases and sales by trading AD flexibility as a function of the market prices and to reduce market volatility and risk → requires a modification in power consumption at short term (intra -day).
Brokers	Extend the range of products proposed to market participants → requires modification in power consumption at different notices.
Balancing Responsible Parties	Assist in meeting balancing functions → requires a modification in power consumption at short term (intra -day).
DSOs	Power flow control / Network congestion solution Network restoration / Black start Frequency control / Power reserve Voltage control and reactive power compensation Islanded operation / micro-grids Reduction of system losses Optimised development and usage of the network
TSOs	Power flow control / Network congestion solution Network restoration / Black start Frequency control / Power reserve Power system voltage stability Islanded operation / micro-grids Reduction of system losses Optimised development and usage of the network
Large consumers	Minimise purchases when prices are high

Now, as we did with the outcome of IR5.1, we need to discuss whether these expectations are benefits or not.

To this end, we may start by grouping the expectations into more general concepts:

- Minimize deviations and imbalance costs
- Maximize margins (buy low, sell high)
- Flexibility to provide ancillary services
- Flexibility in operation (avoid start-up, ramps)
- Avoid loss of generation (for intermittent sources)
- Extended range of consumer products

- Reduce network congestion
- Improve network operation (black starts, frequency and voltage control)
- Reduction of network losses
- Reduction of network investments
- Minimize energy costs

It is quite intuitive to assimilate these expectations with benefits, in the sense that if the expectations are realized they will produce these. In fact, they are quite similar to those put forward by the stakeholders (with some notable absences).

3.3. Summary of benefits to be assessed

In this section we summarize the benefits identified within the ADDRESS project and we classify them. As mentioned before, there is a large coincidence between the benefits identified by the stakeholders and the expectations pointed out by the project team in D1.1. The final common list is the following:

- Reduced energy costs: we may distinguish here two categories
    - A reduction in costs due to lower prices or lower consumption
    - A reduction in ancillary costs: imbalances, reserves, start-up costs, etc
- Reduced price volatility
- More consumer choice
- Reduced loss of intermittent generation
- Improved quality of service (lower congestion and blackouts, improved grid operation)
- Reduced network losses
- Reduced network investments
- More security of supply (through higher contribution of DG and lower energy use)
- Reduction in pollutant emissions

Another important discussion, already hinted along the report, is how these benefits are attributed among the players, and to what extent they may result in net social benefits. We address this question below, by describing each of the benefits. For example, of the expectations listed before, we have taken out the maximization of margins, since this is merely a transfer among players, and therefore provides no net benefits.

It is also interesting to note here that some benefits may be shared among players: for example, a reduction in the final cost to consumers resulting from a better management of their loads may be partly (and legitimately) appropriated by the aggregator, since it may be creating value by combining different consumer profiles and using them in the system.

3.3.1.1 Reduced energy costs

As mentioned before, we will distinguish here two types of costs.

The first one is the deterministic energy cost. This basically includes the cost of the fuel, and the cost of its transformation into electricity. Active demand programs may reduce total electricity demand, when the energy payback (as described in D1.1) is lower than the load reduction requested. This reduction in demand will in turn produce two effects:

- A first one, the reduction of the total cost of producing electricity
- A second one, in liberalised markets, a potential reduction in the price of electricity. This second effect is not a benefit, but merely a transfer from producers to consumers (or also from consumers paying AD measures to other free-riding consumers).

The final beneficiary of this cost reduction is the consumer, although their realization of this benefit will depend on the market structure and regulation. For example, oligopolistic power markets will not necessarily send the full reduction signal to consumers. The same will happen in regulated markets if cost reductions are not reflected in tariffs.

The second type of cost is that associated to the non-deterministic elements of electricity supply. AD services may reduce the need for reserves, ancillary services, or start-ups, by better adjusting in real time supply and demand. This in turn will reduce the aggregated cost of electricity production. In this case, although the final beneficiary may be the consumer, other players may share some of these benefits. First, as a compensation for mediating in the participation of consumers; and second, by reducing uncertainty and risk by aggregation of multiple consumers.

3.3.1.2 Reduced price volatility

This benefit is similar to the non-deterministic element cited before, although it originates in a different reason, basically the need to use different technologies for electricity supply. By making the demand curve flatter, and more reliant on baseload technologies (usually with more stable variable costs) AD services will reduce price volatility. For risk-neutral consumers this would not be a benefit, since the only relevant issue would be the average cost. However, for the usual risk-averse consumer, price volatility has a cost.

As before, the benefits of this reduction in price volatility may be shared among consumers and the agents facilitating it.

3.3.1.3 More consumer choice

AD products and services may increase the possibilities for consumers to receive electricity services. However, it is difficult to conceptualize this as a benefit, even less to quantify it. In fact, sometimes more consumer choice might increase transaction costs and even result in higher costs. Therefore, we will not consider it here.

3.3.1.4 Lower loss of intermittent generation

By modifying the demand profile, AD services may prevent the loss of intermittent, primary energy sources such as wind or the sun. This is a real benefit for society, which can be measured as an opportunity cost (of the alternative which replaces this intermittent energy source), and which is usually received by the intermittent energy producer.

3.3.1.5 Improved quality of service

The quality of service provided by networks may also be improved by resorting to AD services: there may be lower congestion and blackouts, better frequency and voltage control, etc. However, what would be the benefit? In theoretical terms, this improvement is certainly a benefit, but only as long as consumers are willing to pay for it. If quality requirements are imposed, with no participation of the consumers, it is difficult to know the value of this quality for them, and therefore the benefit of this improvement. But still, a proxy can always be obtained, since AD may allow for attaining the same quality level with a lower cost (and this difference will be the benefit).

As with other regulated services, another issue is how the benefits are translated into tariffs, and therefore how they are shared between consumers and system operators.

3.3.1.6 Reduced network losses

By reducing congestion, and by adapting better to the network capacity, AD services may reduce network losses. This benefit is rather straightforward, as it may be calculated at the avoided cost of producing this electricity. The same issue about regulated services applies as before.

3.3.1.7 Reduced network investments

Similarly, AD services, by reducing peak loads, may reduce the need or defer investments in the networks. Again, this is a relatively straightforward benefit, measured as the reduction in investments required with and without AD services. We will still have the issue of how to share the benefits among players: for example, if all benefits are transferred to consumers, with no share for the system operators, these will have no incentive to use AD as an alternative to network investments. As for the last two benefits, the way SOs are paid is critical for this issue.

3.3.1.8 More security of supply

Besides the reduction of fuel costs implied by the reduction in energy use and the larger participation of intermittent energy sources, these same effects may increase security of supply, by reducing the reliance on imported energy sources.

If fuel markets were perfectly competitive, then this security of supply would be reflected in its costs, and there would be no need to quantify this benefit. This is not usually the case, and therefore there may be additional benefits from an improved security of supply. Unfortunately, it is quite difficult to estimate these benefits.

3.3.1.9 Reduction in pollutant emissions

Finally, lower energy use, and a modified demand profile may (not always in the case of the second) result in a reduction in pollutant emissions. If the social cost of these emissions is internalized, then the benefit will be seen directly by the players. If not, this social benefit will not accrue any of them.

4. How to assess the benefits of AD

A proper quantitative assessment of AD benefits requires first an estimation of the changes induced by AD signals (prices or volumes, mostly the first) in the demand, and secondly a thorough analysis of the effect of those changes on power systems. A review of studies that have approached each of these issues will be presented in the following sections.

4.1. Estimating changes in demand

Most of the benefits associated to AD programs are directly dependent on the changes in demand achieved with them. Thus, in order to evaluate AD benefits, the shifting and conservation effects in the load profiles of the participating customers need to be properly assessed. Generally, each customer segment needs to be evaluated separately to take into account differences in load patterns and in sensitivities to prices.

Of course, the need for this analysis will depend on the type of signals sent. If these are volume signals, then the change in demand is given (although there still may be space for a discrete, yes-no decision on whether to accept the change in demand requested). If the signal is a price one, then the relevance of the analysis is more justified.

Notice that the level of detail in which demand changes are assessed needs to be consistent with the methodology that would be applied to estimate AD benefits. For some simple studies based on estimates, measuring variations in discrete demand blocks (e.g. on-peak and off-peak) may be sufficient, whereas complex analyses using simulation techniques would frequently require hourly or sub-hourly demand patterns before and after AD.

It is also worth noticing the difficulties in predicting changes in demand. The response of consumers is uncertain and can be influenced by multiple factors, such as climate, tariff design (prices), customer type (available electric devices, incomes, level of consumption, etc.), enabling technologies, the way in which critical prices or system alerts are notified, feedback information about consumption reported to consumers, awareness and education campaigns launched, etc. (Kohler and Mitchell, 1984; Faruqui and George, 2005; Herter, 2007; EEE, 2006; Summit Blue, 2006; Darby, 2006).

Next, three different ways to approach the assessment of the effects of AD on consumption patterns will be presented: (i) using estimates from previous studies or experiences (mainly price elasticities of demand, (ii) developing an econometric demand model or (iii) simulating demand with a bottom-up model. An interesting review of methods to evaluate demand response using a different classification than the one proposed here can be found in Woo and Herter (2006).

4.1.1. Price elasticity estimates

Using price elasticity estimates based on previous studies or experiences is one possible and simple approach to evaluate changes in demand. The price elasticity of demand expresses the demand increment in percentage terms in response to a one percentage point increase in price.

In the context of AD, three types of elasticity are commonly used: own-price elasticity, cross-price elasticity and elasticity of substitution. Own-price elasticity expresses the demand change in one period for a 1% increment in the price of that period, whereas cross-price elasticity expresses the variation of demand in one period for a 1% increment in the price of other period (generally, between on-peak and off-peak periods). The elasticity of substitution expresses the demand shifted from on-peak periods to off-peak periods given a 1% increment in the relative price on-peak to off-peak (King and Chatterjee, 2003).

Some authors have compiled price elasticity measures observed in different types of AD programs and different regions, or have presented their own estimates. Next, Table 5 presents some elasticity values for different target customers and time-varying tariffs adapted from US DOE (2006).

Table 5: Summary of price elasticity estimates (adapted from US DOE, 2006)

Target customers	Type of program	Own-price elasticity	Elasticity of substitution	Region

Residential (and small commercial)	TOU		0.07 to 0.21 (0.14 average)	US
	TOU / CPP	-0.1 to -0.8 (-0.3 average)		US - International
	CPP		0.04 to 0.13 (0.09 average)	California
	RTP	-0.05 to -0.12 (average -0.08)		Illinois
Medium or large commercial and industrial	RTP	-0.01 to -0.28		Georgia
		-0.01 to -0.27		UK
		<-0.01 to -0.38		N-S Carolina
			0.10 to 0.27	Southwest US
			0.02 to 0.16 (0.11 average)	New York

A number of studies have applied this kind of price elasticity estimates to evaluate changes in demand when assessing AD benefits. For example, Berg et al. (1983) uses hourly own-price and cross-price elasticities (both short-run and long-run values), whereas Navigant (2005) applies elasticities of substitution to compute the load shifts in the demand profile of different segments of consumers.

4.1.2. Econometric demand models

Econometric models try to derive the level of demand from some explicative factors based on microeconomic theory. The usual formulation is the maximization of the utility for consumers of their electricity consumption. The explicative factors most frequently used are the electricity price and the incomes (or budget) of the consumer. Social and demographic conditions, dwelling characteristics or technological aspects can be taken into account as well. Econometric models are developed from data of real experiences, and then used to evaluate other programs. Price-elasticity estimates are generally obtained from this type of model.

Some early examples of this approach are the studies of Lawrence and Braithwait (1979) and Hausman et al. (1979), which develop an econometric demand model to analyze the effect of TOU tariffs. In both studies, demand is given by the maximization of the consumer utility function subject to a budget constraint. Demand in different periods is considered as a different product, in such a way that load shifting can be modeled as the substitution between two products.

Similar studies analyzing TOU pricing can be found in Caves et al. (1984), Parks and Weitzel (1984) and Hill (1991). More recently, the model proposed by Reiss and White (2005) enables the evaluation of different tariff designs (not only TOU).

From a different perspective (and based on a real RTP experiment), Allcott (2008) estimates hourly residential demand as a utility function depending on household characteristics, daily prices and some load substitution and shifting parameters (based on temperature and dummy variables).

Econometric demand models can provide an accurate representation of the demand if the most relevant factors affecting consumption are included and the parameters expressing how demand changes with respect to those factors are properly assessed. However, since these parameters are adjusted for a given set of data under some particular conditions, econometric demand models may not be valid when the underlying conditions change. Thus, the main limitation of this type of models is that their results may be very dependent on the underlying conditions and difficult to extrapolate.

A final consideration is that econometric models that overlook the heterogeneous nature of electric loads may not be sufficiently accurate to evaluate AD actions. The utility of consumption strongly depends on its final use (the specific electric device used) and on circumstantial aspects (the service provided by the electric device in the time of consumption). Moreover, the capacity to reduce or shift demand also depends strongly on the technical potential of the electric devices in use. Therefore, including technological considerations into the demand model can improve the representation of AD actions.

4.1.3. Bottom-up demand models

Bottom-up demand models, unlike econometric models, aim to capture the specific loads that constitute the demand. The demand profile is obtained by aggregation of elemental loads (that may represent individual customers or the consumption of each appliance).

There are some interesting studies that have modeled electric demand using this approach but without considering any demand response action. It is the case of Cappasso et al. (1994) and Boonekamp (2007) for domestic demand. Even if these models would not be valid to evaluate AD programs, their contributions may be useful to develop models adapted to AD evaluation.

Other studies have incorporated into their bottom-up models the possibility to shift or reduce demand as a consequence of direct load control. The work of Paatero and Lund (2006) is a good example. The authors try to overcome the lack of detailed data about domestic consumption by using statistical data easily available, and incorporate stochastic processes to take into account the random nature of the demand.

Finally, some studies have considered the response of demand to prices explicitly. Conchado and Linares (2009a) suggest allocating simplified consumption cycles of electric appliances into the demand curve of individual consumers, and shift or reduce the consumption of each appliance according to its technical potential with the objective of minimizing the cost of consumption. In a different way, Lu et al. (2004) model thermostatically controlled loads by means of equivalent electric circuits that represent their heat transfer properties, and non-thermostatically controlled loads as tasks in a queue system.

4.2. Assessing benefits

The assessment of AD benefits can be approached from a range of possible methods, such as those based on avoided costs, resource planning, welfare analysis, value of system reliability, transmission planning and forward capacity auctions identified by Heffner (2007). The suitability of each method will depend on the type of benefit to be assessed, and there is no single approach able to capture accurately the whole range of effects of AD on power systems.

In this section, a survey of the state of the art of the quantification of AD benefits will be presented, distinguishing between two types of studies: those based on estimates and those based on simulation techniques. Both approaches have advantages and disadvantages.

Studies based on estimates are simple and transparent but may fail to represent accurately the complexity of power systems. In contrast, analyses with simulation techniques allow for detailed representations of power systems but are more complicated and difficult to track back and compare.

4.2.1. Studies based on estimates

In this type of studies, AD benefits are derived analytically from some estimates, necessarily making simplifications about consumer and market behavior to express all relationships in algebraic terms. Generally, only a few periods (such as on-peak and off-peak) are considered for the analysis.

An illustrative example of this type of study is found in Baer et al. (2004), who evaluate the GridWise initiative in the USA. Given a set of input data (market penetration and price-elasticity of demand by end-use sector, wholesale peak and off-peak prices in a baseline scenario, projected generating reserve margin in 2025, discount rate, etc.), the system peak-load reduction is calculated. From this estimate, generation capital cost deferrals are computed by multiplying peak-load reduction by the capital cost of peaking units (gas-fired combustion turbines or diesel generators). Similarly, the operating and fuel costs associated to deferring new capacity are calculated by multiplying peak-load reduction by the fuel costs and operation and maintenance costs of the avoided peaking units. T&D capital cost deferrals are directly estimated as a function of generation capacity deferral.

Another example of study based on estimates is a cost-benefit analysis of advanced metering in France by CapGemini (2007). Three scenarios representing different technology levels are considered, and it is assumed that the level of demand response depends on the technological capabilities implemented. The final estimates of benefits are allocated to generators, distributors and suppliers, which is very useful for regulatory design.

Other similar studies have been presented by Faruqui et al. (2009) for the European Union, Ofgem (2006) for the UK, Siderius and Dikstra (2006) for the Netherlands, Faruqui and George (2002) for the USA, Navigant (2005) for Ontario, or ESC (2004) for Australia.

The strong points of this approach are its simplicity and transparency. The results can be easily tracked back to the original assumptions, and it facilitates comparing the results of alternative AD designs. The drawback, however, is that it may not represent with enough level of detail the complex behavior of the market and the numerous interactions occurring in power systems. Moreover, since stochasticity is not considered (only point estimates of the parameters are used), the dependence of the results on the assumptions is magnified with respect to other methods (Neenan and Hemphill, 2008).

4.2.2. Analyses with simulation techniques

Instead of using estimates, AD benefits can be evaluated using models that simulate the behavior of power systems. Since simulation models allow for a detailed representation of the expansion and/or operation of generation systems and networks, or the performance of the market, this approach seems to be the most accurate for the evaluation of AD benefits.

Using simulation models, AD benefits are generally computed as the difference in the results between two simulations, one for a baseline scenario without AD and another for a scenario with AD.

Most of the studies assessing AD benefits with simulation techniques have focused on the impacts on the generation system or the wholesale market, but there are some studies addressing network impacts as well. A review of these studies is presented in this section, showing first those with focus on the generation system and wholesale market, and next those focusing on network impacts. At the end of the section, Table 6 provides a brief summary of the purpose, scope and methodology of the studies mentioned.

4.2.2.1 Generation system and wholesale market

When modeling generation systems, whether AD is evaluated in a regulated environment or in a liberalized market affects the simulation framework. The model can be developed from the viewpoint of a utility (e.g. Berg et al., 1983) or from a market perspective, either assuming perfect competition (e.g. Borenstein, 2005) or imperfect competition (e.g. Allcott, 2008).

AD is sometimes included endogenously into the simulation models, either by considering price-elastic demand-side bids in market equilibrium models (e.g. Su and Kirschen, 2009) or introduced as an available resource under centralized market approaches (e.g. Violette et al., 2006b). Some other studies determine the demand exogenously, assuming certain load reductions (e.g. Brattle, 2007) or evaluating ex-ante the changes in demand (e.g. Linares and Conchado, 2009).

Some authors have analyzed AD benefits considering the stochasticity of future outcomes for key variables, as Andersen et al. (2006), who uses Monte Carlo simulations (following Violette et al., 2006b) to evaluate the potential of AD not only in average but also in extreme situations.

In order to consider network congestion, it is possible to include in the generation model a representation of the transmission network and simulate the power flow through lines. AD impacts can then be assessed by computing locational marginal prices (LMP), as done by Neenan et al. (2005) or Brattle (2007). Walawalkar et al. (2008) also use LMP in their economic welfare analysis, but compute them by means of an econometric model.

The potential of AD to facilitate real-time balancing on supply and demand in systems with large penetration of wind generation has been investigated by Sioshanshi and Short (2009) and Silva (2009). The former quantify the reduction of wind spillages if demand is elastic to real-time prices that reflect wind availability and network constraints, whereas the latter evaluates the contribution of AD to balancing considering it as a reserve resource that can be scheduled to minimize system costs.

4.2.2.2 Networks

The quantification of potential impacts of AD in the network system has not been sufficiently investigated. Only a few studies have been found providing estimates of AD network benefits.

The impact of AD on the investments of distribution networks has been evaluated by Conchado and Linares (2009b) using a detailed network expansion simulation model and assuming certain reductions in the peak demand of participating customers.

Regarding network operation, the reduction in distribution losses due to domestic load-shifting has been assessed by Shaw et al. (2009), evaluating how the network power flow profiles can be changed by load-shifting and assuming that the overall potential for loss reduction is a function of the preexisting losses and the demand patterns.

A method to quantify the value of AD to alleviate network congestion has been proposed by Stanojević and Silva (2009). Using an AD model (that includes thermal load management and appliance shifting at the domestic level) integrated in a DC-OPF model allows for estimating the reduction of congestion costs due to the modification of the demand patterns.

In a similar way, the study by Stanojević et al. (2009) shows how the modification of daily demand patterns can improve the utilization of existing network capacity by reducing network critical loading and congestion in a stressed distribution network. The model used combines the dispatch of the generation units with a multi-period optimal power flow where AD is applied to minimize the re-dispatch.

Table 6 summarizes the purpose, scope and methodology of the references mentioned throughout this section.

Table 6: Summary of the purpose, scope and methodology of the references mentioned for the quantification of AD benefits with simulation techniques

Reference	Summary
Allcott, 2008	Following Borenstein (2005), evaluates the effects of RTP in the PJM market, using a two-stage model that simulates the entering of new units in the first stage and the day-ahead market in the second stage. AD is incorporated changing the slope of the demand.
Andersen et al. (2006)	Assess the short-term value of AD in the Nordic Market using the partial equilibrium model Balmorel coupled with Monte Carlo simulations to include extreme situations, and address market power mitigation simulating supply function equilibrium competition in the Danish system
Berg et al., 1983	Simulate the impact of TOU pricing on generation operation and expansion under a utility perspective, using price elasticities to evaluate changes in demand.
Borenstein, 2005	Evaluates the impact of RTP on long-run efficiency in a competitive electricity market with simplified simulations (representative parameters for US).
Brattle, 2007	Estimates short-term impacts of day-ahead demand curtailment on locational marginal prices in the PJM market, using a model that simulates the generation dispatch together with the transmission network load flow.
Conchado and Linares, 2009b	In their assessment of AD benefits and costs for Spain, the authors analyze the impact of AD in the expansion of distribution networks by means of a model able to quantify the cost of reinforcements in real networks for expected increases in demand.
Linares and Conchado, 2009	Simulate the effect of RTP (at the residential level) in the Spanish electricity market with a detailed generation expansion model. AD effect on the load profile is estimated ex-ante with a bottom-up model of domestic electricity demand.
Neenan et al., 2005	Evaluate several time-varying tariffs for large customers in New England using a prospective price formation simulation model able to compute how locational marginal prices are impacted by load changes.
Shaw et al., 2009	Provide a quantitative estimate of the possible reduction in losses associated to domestic demand shifting in Great Britain using a

	spreadsheet model.
Silva, 2009	Estimates the value of smart domestic appliances to reduce balancing costs in European countries with high penetration of wind generation by simulating the annual system operation based on simultaneous scheduling of both generation and AD, including AD as part of the standing reserve providers.
Sioshanshi and Short, 2009	Explore how RTP prices could contribute to diminish wind spillages by increasing the flexibility of demand in response to wind availability or to system constraints that limit wind generation, using a unit-commitment model with DC power-flow of the Texas power system.
Stanojević et al. (2009)	Analyze the potential of DSM to mitigate network congestion, increase the utilization of network assets and avoid wind spillages by means of a multi-period DC-OPF applied to a urban distribution network, considering historical time series data for demand and wind output.
Stanojević and Silva (2009)	Evaluate congestion costs in constrained electricity networks (with high penetration of wind generation) by incorporating DSM options (thermal load management and appliance shifting algorithms) into a DC-OPF model.
Su and Kirschen, 2009	Quantify the effect of increased participation of the demand side in the electricity market using a centralized complex-bid market-clearing mechanism that considers the load shifting behavior of consumers who submit price-sensitive bids. Algorithm tried only in a test system.
Violette et al., 2006b	Use a resource planning approach to assess the value of AD in a 19-year horizon from an utility perspective, considering 100 Monte Carlo scenarios (case study for a region in the USA).
Walawalkar et al., 2008	Perform an economic welfare analysis of AD in the PJM electricity market with a simulation of demand-side bidding, analyzing the tradeoff between the distortions introduced by the subsidies provided to responsive consumers and the social welfare gains.

4.2.2.3 Benefits not addressed in literature

Some of the benefits detailed in section 3.3 have not been addressed by the literature to our knowledge. These are:

- Reduced price volatility
- More consumer choice
- Improved quality of service (lower congestion and blackouts, improved grid operation)
- More security of supply (through higher contribution of DG and lower energy use)

The reason will probably be the high difficulty of doing this. As explained previously, the assessment of the benefits of reduced price volatility and more consumer choice requires strong assumptions about risk aversion, transaction costs, decision models, etc., which require a much deeper approach from the consumer side.

The benefits of an improved quality of service should not be that difficult to estimate, provided that the alternative route is taken: to estimate the reduction in costs to provide a given quality level.

Finally, security of supply is a very complex issue, which lies quite far from the scope of this type of studies. For those interested, a recent reference is Jansen and Seebregts (2010).

5. Methodology proposed

In this section, and based on the existing literature, we propose a methodology for assessing the benefits identified of AD services. Due to the difficulty implied, we will not address price volatility, consumer choice and security of supply.

An important note is that we will only address net social benefits, but not their distribution among agents, particularly for non-regulated players. For example, we may estimate the reduction in energy costs, but not how this reduction is shared among consumers and aggregators, since that belongs mostly to the free working of the market, and will largely depend on the varying objectives, business models and marketing strategies of aggregators and, more generally, non-regulated players.

Benefits will be estimated per MWh of AD, and also, when required, for a country (this will require estimating AD contribution rates, but is needed to compare against the costs of AD implementation).

The general approach for the evaluation of benefits will be to simulate the system (be it power generation, distribution and transmission, or the whole economy) with and without AD services, under the scenarios considered more plausible.

5.1. Reduced energy costs

The benefits of AD in terms of reduced energy costs may be assessed with three different, and progressively more complicated, approaches.

The first approach would be a simple estimation, presented in the following steps:

- take as given a change in the demand curve,
- estimate the moment in which these changes would take place,
- ascertain which is the marginal technology producing in each moment,
- and therefore estimate the reduction in fuel costs achieved by the reduction of demand

This is a very simple approach, but of course presents some problems:

- first, it is not that easy to know when changes in demand will take place, and therefore to know which is the marginal technology avoided by resorting to AD. In complex systems, the marginal technology might change with the introduction of AD, thus making the estimation even more complicated
- second, this is only valid for the deterministic case. The estimation of the changes in ancillary services, reserves, balancing costs, etc, cannot be achieved by such a simple procedure
- finally, it assumes that AD changes will not be responsive to prices

A better approach is to simulate the operation (and expansion, in the case of long-term effects) of the power generation system with more sophisticated models, such as unit-commitment, operation or expansion models such as those developed in literature and currently used in most power systems. If we need to estimate changes in balancing costs, reserves, etc., unit commitment models are better suited for the task. If instead we need to assess long-term changes then expansion models will be required.

These models may deal with AD as an exogenous input, or ideally, as an endogenous one, allowing AD to respond to the changes in the system. Let we make this clearer. If we treat AD as exogenous, then the system will react to the change in the demand profile by changing the operation of power plants, which will also result in a change in prices (and therefore in energy costs). But this change in prices might also alter the incentives for AD, entering then into a loop. In order for this loop to be closed to reach an equilibrium, AD should be introduced endogenously in the model, to allow it to react to the changes it induces.

Therefore, it seems that this more sophisticated approach will be able to estimate better the reduction of energy costs implied by AD. But there is still another problem with this estimation, namely that it is a partial equilibrium one: it assumes that demand for electricity remains given (not always, if some elasticity of demand is modelled), but more importantly, that the changes in electricity demand and prices do not produce in turn changes in other parts of the economy (e.g. substitution effects with other fuels). This can only be gauged by using a general equilibrium (CGE) model. Unfortunately, there are also some drawbacks for this: this type of models is not able to represent correctly the electricity sector, and even less AD programs, so it is difficult to use them for this purpose.

So, to summarize: the best approach would be to use power system models to estimate changes in energy costs due to the introduction of AD. Within the ADDRESS project this can be done for Spain~~,~~ France, and probably Belgium. These models might be accompanied by estimations with general equilibrium models, which can give a broader picture and some hints about the general economic effects. These models are available for Spain, Sweden and Germany within the ADDRESS project.

Finally, if there are no power system models, some simpler estimations may be attempted, although these will only be valid for simpler systems, and for only a limited range of energy costs. This would be the alternative for the rest of partners involved.

For balancing, a first idea is to use the average balancing price as an indication of the value of AD for this purpose (assuming that its participation in this market will not change essentially its prices). However, this leaves apart the estimation of absolute benefits. In order to do that, we should estimate the participation of AD in these markets, and this is a very difficult issue.

5.2. Reduced loss of intermittent generation

As mentioned before, AD may reduce the spillage of intermittent generation, by shaping the load to adapt to this production. This effect may only be assessed with sophisticated power system simulation models (similar to the ones mentioned before) but with an added twist: they need to account for the stochasticity of intermittent generation, because this is the major reason for the spillage of the energy produced. Ideally, we need to simulate the operation of intermittent generation and of the rest of the system, and introduce AD as an additional alternative to respond (ex-post) to the changes in intermittent generation. These models are only starting to be developed: the paper by Sioshanshi and Short already cited is a first attempt, and more sophisticated models are being developed currently at Comillas University to study this effect.

Given that this will be an issue only for power systems with a large penetration of renewable energy, and with limited reserve capacity, here we propose to identify first the relevant cases in Europe (Spain is a clear one) and only evaluate this benefit in these cases.

5.3. Reduction in pollutant emissions

Given that most pollutant emissions arise from the generation of electricity, the estimation of the change in pollutant emissions due to the introduction of AD will have to rely on the simulation of the generation system. Here the same discussion presented in 5.1 applies: this estimation can be done directly from the analysis of the reduction of energy costs, since it is based on the change in technologies for the production of electricity. So we can propose a simple estimation, a simulation with power system models (stochastic if available), or the use of CGE models, depending on their availability. The only requirement is for these models to be able to compute pollutant emissions. Fortunately, this is the usual case for most of the current models. Therefore, we propose the same case studies as for the reduction of energy costs.

5.4. Reduced network losses

The assessment of the reduction of network losses can also be attempted with two different approaches: a simple, back-of-the-envelope one in which we assume a constant, linear rate of transmission losses (which is clearly not the case for electricity), and multiply this rate by the reduction in energy transported. However, this is really providing us with only a small part of the total effect: since electricity losses are not linear, the impact of AD will probably be much greater, by reducing demand in peak hours, when losses are larger.

Therefore, and in order to assess this impact correctly we need to use power flow models (AC, or in their absence, DC) to study the real impact on losses of the introduction of AD.

These power flow models are usually widely available within distribution companies such as those participating in the project, and also in universities. Therefore, they might be used for all countries participating in the ADDRESS project.

However, an important point is that these models are also going to be used within WP3 to evaluate the benefits for DSOs, and therefore we may not need to duplicate efforts here.

Once losses have been quantified, we will need to monetize them. One possibility would be to use the market price as an indicator of the value of this electricity.

Given the difficulty of this estimation, the effects on networks (also including investments and quality of service) will only be assessed by those partners who own reference network models.

5.5. Reduced network investments

The introduction of AD also makes it easier for the network to become adapted to the demands of the consumer. Therefore, introducing AD may prevent or defer new investments in the grid. This reduced need for investments can be estimated again in a simplified way: looking at the reduction of peak demand, identifying the lines to be reinforced or built in the current situation, and analysing each of them. However, in this case the sheer number of power lines makes the simplified estimation almost infeasible if we want it to be representative.

Therefore, it seems advisable to use reference network models, available in some countries (Spain, Germany) to assess the difference in the network building requirements with and without AD programs. These models of course have their own shortcomings: first, they usually start from an optimal network design, which is not the usual case. In the real world, the introduction of AD services may result either in larger benefits (when lines are more overloaded than in the optimal situation) or in lower ones (if current lines have spare capacity). Second, they are not always able to represent environmental or political constraints to build new power lines. Third, the requirement of data is usually huge, and therefore applying them to a whole country (for distribution networks) is unrealistic.

A reasonable compromise would be to use reference models for specific areas, which may be deemed representative of the network, and try to extrapolate from these results.

Again, care should be taken not to duplicate work of WP3.

5.6. Improved quality of service

This is a rather unexplored field, and therefore its estimation will be more complex. In principle, the same power flow models used for estimating network losses might be used, to assess the impact of AD on congestion, voltage or frequency control, or blackouts. Two problems arise:

- First, the correct definition of quality of service, which may vary across countries and which, in fact, may include additional elements to the ones mentioned.
- Second, quality of service is essentially a stochastic variable, which therefore requires a more adequate treatment than the one usually provided by current load flow models.

Anyway, we can be confident in that the long-term benefits of quality of service can be quantified when assessing the need for network investments, since these investments usually take into account quality of service constraints. In the short term this estimation is much more difficult.

As mentioned before, an alternative which may sort out some of these problems would be instead to try to calculate the avoided costs of attaining the same level of quality as before, but with the participation of AD. Then, we should study to what extent AD services substitute for other resources. Instead of relying of large models this would imply the use of more technical models, which may be more accessible sometimes.

Finally, the same caveat applies regarding the possible duplication of work with WP3.

6. Evaluation of quantitative benefits

In order to quantify AD benefits, AD is going to be treated as an exogenous input (see section 5.1) for the evaluation of the benefits. Therefore, four different AD scenarios of reductions in energy and peak load are assumed[7] for the 2020 load curve based mostly in the results presented by Faruqui & Sergici (2010). Table 7 shows the percentage of residential load that is assumed to be reduced during peak periods (Peak load Reduction), the percentage of the reduced demand that will be allocated to off-peak periods (Payback effect) and the residential load reduction for each scenario.

[7] Deliverable 1.2 has presented four scenarios in which to assess the impacts of AD.

	Peak load Reduction	Payback effect	Energy Reduction
Scenario 1	20%	20%	10%
Scenario 2	25%	20%	15%
Scenario 3	10%	20%	5%
Scenario 4	35%	20%	20%

Table 7: Scenarios of reduction in energy and peak load

These scenarios have been applied to different countries, depending on their characteristics. Scenario 1 is the AD Scenario considered for South European cities where electricity is extensively used for cooling during summer months. Scenario 2 is the AD Scenario considered for the South European countryside areas, these areas have significant agricultural load and demand for cooling in summer. Scenario 3 is the AD Scenario considered representative of the North European suburban villages where electricity demand is dominated by lighting and other uses, not heating or cooling. Finally, Scenario 4 is the scenario considered for mid-latitude European communities where electricity is used for heating in winter and cooling in summer. All scenarios have been considered for Spain in order to provide a reference. Table 8 shows the scenarios studied for each of the countries assessed by the different partner institutions within this project.

	Country (Partner)
Scenario 1	Italy (ENEL), Spain(Comillas)
Scenario 2	Germany(Consentec), Italy (ENEL), Spain(Comillas)
Scenario 3	Belgium (VITO), Germany (Consentec) , Spain(Comillas)
Scenario 4	Belgium (VITO), Germany (Consentec) , Spain(Comillas)

Table 8: Scenarios assumed in each country

France and Sweden were going to be assessed in this study, too, but, unfortunately, EDF and Vatenfall could not participate in this assessment.

In order to calculate the hourly (quarterly, in the case of Vito) load curve in year 2020 (Consentec assumed it remained the same as in 2010), partners scaled up the hourly consumption in the reference year (last year with available data) so that the total energy consumed equaled the total amount expected for 2020. In the case of residential demand the same procedure was applied. In case there were not enough data available the same demand growth than for the total demand was assumed for residential demand.

Then, in order to obtain the modified load curve for each AD scenario, the residential load in peak hours is reduced and part of this reduction is allocated to off-peak (this is the payback). Finally, if the energy reduced through peak load reduction (including the payback) is less than the total energy reduction set for each scenario, a further reduction coefficient is applied to all hours, so that the final energy reduction in residential demand is at least equal to the one specified for the scenario.

In order to make the reductions in peak hours and allocation to off-peak hours mentioned before, the partners defined either a reference value for peak hours and off-peak hours or a time frame for peak hours (see Annex A). The demand which must be shifted during a day is allocated among off-peak hours taking into account the contribution of each hour to the off-peak.

6.1. Reduced energy costs and reduction in pollutant emissions

The assessment of the benefits of AD in terms of reduced energy costs and CO_2 emissions reduction (given that most of these emissions arise from the generation of electricity) has been done simulating the generation systems for 2020, since this is when AD is expected to be implemented. The costs of fuel and the CO_2 emissions in the scenarios with and without active demand will be compared.

Referring to the generation system simulation, a good methodology would be to use a sophisticated approach such as a generation system model (e.g., Linares et al., 2008) but since this methodology in not available for all countries assessed a simple methodology is proposed.

6.1.1. Methodology

All partners have used a simple approach in order to estimate the reduction in energy costs and in the emission of pollutant emissions due to the application of AD scenarios. This approach consists of covering the hourly demand (quarterly for Vito) in each of the considered AD scenarios with the minimum fuel and emissions costs (in the case of Vito (Belgium), with the minimum fuel costs, emissions costs, Operation & Maintenance costs and subsidies), taking into account the energy mix installed. Special attention must be paid to the distribution of wind, solar and hydro production.

This simple methodology obtains results similar to the sophisticated approach for Spain for the demand scenarios with and without AD. Table 9 (expanded in Table 33) shows that the difference between fuel costs for the simple approach and fuel costs for the operation generation model varies between +0.07% and -0.11% of the fuel costs for the operation model and that the difference between the CO_2 emissions for the simple approach and the CO_2 emissions for the sophisticated approach varies between +0.55% and 1.24% of CO_2 emissions. The table shows the results for the different scenarios considered in this study (which will be explained in section 3).

	Ref. Scen.	Scenario 1	Scenario 2	Scenario 3	Scenario 4
Fuel Costs Variation	0.07%	-0.05%	0.06%	0.02%	-0.11%
CO2 Emissions Variation	0.84%	1.20%	0.55%	0.96%	1.24%

Table 9: Difference obtained between the simple approach and the sophisticated Op. Model for the scenarios with and without AD in Spain

Moreover, in order to determine the influence of AD on generation investments, an expansion model (Linares et al., 2008) has been used for Spain. This model estimates the necessary investment from now until 2020 in order to cover demand in 2020, in each of the Scenarios, with the minimum operation and investment costs.

The operation model costs (fuel costs+CO_2 emission costs) to expansion model costs (fuel costs+CO_2 emission costs+investment costs) ratio in 2020 for all the escenarios with and without AD, studied for Spain has been calculated. As seen in Table 10 (expanded in Table 34) the value of the ratio is 1.17 for both the Reference Scenario and Scenario 3, and 1.16 for Scenario 1, 2 and 4. That is, the reduction in generation investment costs represent from 16 % to 17 % of the reduction in operation costs in all scenarios considered.

	Refer. Scen.	Scenario 1	Scenario 2	Scenario 3	Scenario 4
Ratio Exp./Op.	1.17	1.16	1.16	1.17	1.16

Table 10: Expansion Model Costs to Operation Model Costs Ratio.

6.1.1.1 Energy mix

The electricity generation mix will have a large influence in the results, so it is important to state first what this generation mix is. The capacity installed for each technology in each of the participant countries and the energy generated per year by hydro power plants, solar energy and wind are shown in the following table:

Technology	INSTALLED CAPACITY [MW]			LOAD FACTOR			ENERGY [GWh]		
	Belgium	Germany	Spain	Belgium	Germany	Spain	Germany	Italy	Spain
Nuclear	3282	13354	7251	0.83	0.9	0.9	-	-	-
National Coal	-	24300	4689	-	0.9	0.9	-	55000	-
Imported Coal	5887.0	20400	1928	0.73	0.9	0.9	-		-
CCGT/Natural Gas	3742.6	26600	*	0.80	0.82	0.9	-	222250	-
Cogeneration	3859.5	-	7132	0.69	-	0.374	-	-	-
Hydro	-	5800	16662	-	-	-	22900	49500[1]	19166

Mini-hydro	87.6	-	1938	0.44	-	0.324	-		-
Biomass	637.9	6200	578	0.66	0.75	0.509	-	10000	-
Wind	3157.8	51000	16187	-	-	-	111700	19000	33538
Solar	1366.5	17900	3270	-	-	-	15200	31050	1287
Fuel-Oil	-	5650	310	-	0.9	0.9	-	11440	-
Gas Other	2534	-	-	0.59	-	-	-	-	-
Other Renewables	-	-	-	-	-	-	-	21800[2]	-
Other	825	-	-	0.78	-	-	-	-	-

Table 11: Installed capacity. load factor and energy generated for the different technologies in different countries

*CCGT installed for each scenario varies: Base Scenario (39031 MW), Scenario 1 (37891 MW), Scenario 2 (37323 MW), Scenario 3 (38640 MW), Scenario 4 (36754 MW).

[1]Pumped Hydro included (5500 GWh)

[2]Biomass: 10 GWh, Geothermal: 6,8 GWh and Municipal solid waste: 5 GWh.

Vito extracted the installed capacity and load factor data for Belgium in 2020 (included in the table above) from the Environmental Costing Model, the reference model used in Flanders for long-term energy, emission and policy scenarios.

Enel determined the 2020 energy mix based on the estimation performed by Unione Petrolifera[8]. The energy produced by PV has been updated due to the new feed-in tariff "Quarto Conto Energia"

Consentec used the data for 2020 in Germany included in the Table 11. The technology Natural Gas also comprises cogeneration units, so that the load factor has been decreased to reflect that the electricity production (partly) depends on the demand of heat. The same has been done for Biomass where the relative amount of cogeneration units is even greater.

Comillas determined the energy mix for Spain in 2020, included in Table 11, using the Expansion Model (see Annex B). That model simulates the necessary investment from now until 2020 in order to meet demand.

6.1.1.2 Distribution of wind, solar and hydro and costs of the different technologies

Comillas (Spain), Consentec (Germany) and Enel (Italy) distributed the estimated energy produced in 2020 by wind plants equally through all hours of the year. Vito (Belgium) used the historical values of generated wind energy for 2010, published by the Belgian TSO, Elia[9], and they rescaled them for the installed capacity in 2020.

For the distribution of solar generation, Consentec (Germany) took seasonal and daily effects into account , Comillas (Spain) and Enel (Italy) distributed it equally through all hours

[8] "Previsioni di domanda energetica e petrolifera italiana 2009/2020" http://www.unionepetrolifera.it/it/pubblicazioni/2009
[9] Available at http://www.elia.be/repository/pages/465892cca4e349af8abb76414fa54f13.aspx

of the year and Vito (Belgium) used synthetic load profiles for sun energy generated via the HOMER energy modeling software for hybrid renewable energy systems[10].

In case of hydro generation, Comillas (Spain) distributed the energy predicted to be generated in the year 2020 through the peak hours (in Spain, hydro is a regulating technology) and Consentec (Germany) distributed the hydro power plants generation equally through all hours of the year. Enel (Italy) carried out a mixed approach, they distributed the predicted Pumped Hydro generation in the year 2020 through the peak hours and the natural Hydro generation equally through all hours of the year. Moreover, Enel (Italy) distributed geothermal generation equally through all the hours of the year.

As mentioned, other technologies were dispatched according to their fuel and emissions costs (or fuel costs, emissions costs, Operation & Maintenance costs and subsidies). The cheapest technologies are assumed to be dispatched first.

Data available for fuel costs, CO_2 emissions, efficiencies, O&M costs and subsidies for the different technologies in the different countries are shown in the following table:

[10] Available at www.homerenergy.com

	MWh_{th}/MWh		FUEL COSTS [€/MWh.]		FUEL COSTS[€/MWh. produced]			EMISSIONS [ton/MWh.]				O&M costs [€/MWh]	Subsidies [€/MWh]	FUEL+O&M+Subsidies [€/MWh produced]	
	Belgium	Spain	Belgium	Spain	Belgium	Spain	Italy	Belgium	Germany	Italy	Spain	Belgium	Belgium	Belgium	Germany
Nuclear	2.86	3.15	2	1.71	5.72	5.39	-	0	0	0	0	13.3	0	19.02	26.5
National Coal	-	2.65	-	13	-	34.45	19	-	0.93	0.96	0.93	-	-	-	24
Imported Coal	2.45	2.5	15.6	13	38.22	32.50		0.83	0.91		0.91	1.3	0	39.52	33.5
CCGT/Natural Gas	1.82	1.99	33	25	60.06	49.75	45	0.37	0.41	0.36	0.38	1.3	0	61.36	49
Cogeneration	1.84	1.82	29.7	25	54.648	45.50	-	0.4	-	-	0.55	3.0	10	67.648	-
Biomass	3.7	3.7	30.6	12.79	113.22	47.32	63	0.1	0	-	0	5.3	65	183.52	47
Fuel-Oil	-	2.56	-	20.46	-	52.38	92	-	0.77	0.6	0.77	-	-	-	52
Gas Other	1.98	-	33	-	65.34	-	-	0.4	-	-	-	5.0	0	70.34	-
Other	2	-	25	-	50	-	-	0.4	-	-	-	3.0	0	53	-

Table 12: Thermal energy requirements, Fuel costs, Emissions, O&M costs, Subsidies

PRICE OF CO2 EMISSIONS [€/ton]			
Belgium	Germany	Italy	Spain
35	35	35	35

Table 13: Price of CO_2 for the different countries

6.1.2. Results

Following the simple approach the costs and emissions for the reference scenario in the simple approach are shown in Table 14.

		Fuel Costs [M€]	CO2 Emissions [Mton.]	Total Costs [M€]
Belgium(3*)	Base Scenario	1973	26.4	2903
Germany(2*)	Base Scenario	12514	190.0	19165
Spain(1*)	Base Scenario	12917	96.4	16290
Italy(1*)	Base Scenario	11134	127.5	15954

Table 14: Fuel Costs, CO_2 Costs and Total Costs in the Base Scenario

1*: Fuel Costs=Fuel Costs and Total Costs= Fuel Costs+CO2 costs

2*: Fuel Costs=Fuel Costs+O&M-Subsidies and Total Costs= Fuel Costs+O&M-Subsidies+CO2 costs

3*: Fuel Costs=Fuel Costs and Total Costs= Fuel Costs+O&M-Subsidies+CO2 costs

The avoided costs in each of the Scenarios considered are shown in the following table.

	Belgium		Germany			Spain				Italy	
Reductions [Mio€]	Scenario 3	Scenario 4	Scenario 2	Scenario 3	Scenario 4	Scenario 1	Scenario 2	Scenario 3	Scenario 4	Scenario 1	Scenario 2
Fuel Costs	30.6	129.0	848.0	285.0	1129.0	447.1	669.6	220.7	893.7	275.6	444.7
CO2 Emissions	15.4	60.9	455.0	140.0	595.0	115.5	175.0	63.0	231.0	76.9	124.1

Table 15: Reductions in Fuel Costs and CO_2 emissions costs.

	Fuel Costs Reduction [%]				CO2 Emissions Reduction[%]				Total Costs Reduction[%]			
	Belgium	Germany	Italy	Spain	Belgium	Germany	Italy	Spain	Belgium	Germany	Italy	Spain
Scen.1	-	-	2.4%	3.46%	-	-	1.6%	3.42%	-	-	2.2%	3.45%
Scen.2	-	6.78%	4%	5.18%	-	6.84%	2.5%	5.19%	-	6.80%	3.5%	5.18%
Scen.3	1.57%	2.27%	-	1.71%	1.70%	2.30%	-	1.87%	1.71%	2.29%	-	1.73%
Scen.4	6.99%	9.02%	-	6.92%	7.07%	9.11%	-	6.85%	7.39%	9.05%	-	6.90%

Table 16: Reductions in Fuel Costs, CO_2 Costs and Total Costs in each Scenario.

As seen in Table 16, the order of Scenarios (when available for a determined country) from the maximum reduction to the minimum reduction in Fuel Costs and CO_2 emissions is Scenario 4, Scenario 2, Scenario 1 and Scenario 3. The percentages of reduction, both fuel costs and CO_2 emissions, vary from country to country, Germany gets a 6.84% reduction in Fuel Costs and 6.84% reduction in CO_2 emissions in Scenario 2 and Italy gets a 4% and 2.5% respectively for the same Scenario. The maximum Fuel and CO_2 reductions were achieved in Germany in Scenario 4 and the minimum Fuel and CO_2 reductions were achieved in Belgium in Scenario 3 (only Scenario 3 and Scenario 4 were available for Belgium) and they were 1.57% and 1.70%, respectively.

The operation costs reductions obtained are close to the results obtained by previous studies. In order to assess the operation costs savings during peak periods in PJM due to a 3% curtailment of load in peak periods, Brattle (2007) determined that the savings obtained due to curtailments were between 4% and 7% of the initial peak operation costs during curtailed hours. Another study was the paper by Andersen et al. (2006) for Denmark and the Nord Pool, in this case reduction of operation costs due to peak clipping of 1000 MW (being peak demand about 22000 MW) during hours with electricity prices higher than NOK 1000/MWh were about 0.4% of the operation costs, these reductions were a little bit smaller than the reductions obtained in this study.

6.2. Reduced network investments

As has been mentioned in section 5.5, in order to assess the benefits of AD concerning the reduced network investments for different scenarios of reduction in Peak demand, it seems advisable to use reference network models such as those available for Germany (Consentec) and Spain (Comillas) for specific areas which are deemed representative of the network.

6.2.1. Methodology

Consentec determined the network structure using the "model network analysis"[11]. This is a long-term greenfield approach, which means that the results obtained are valid in the long-term. Comillas used a "Greenfield model" in order to determine current network structures. Then, in order to determine reinforcements in the network in a 10 year horizon, an "Expansion model" was used.

Two different areas were studied for Germany and Spain. A rural area that comprises about 10.6 Million inhabitants and an urban area with a size similar to a city of about 3.4 Million inhabitants were studied by Consentec. Comillas studied an urban area located in Madrid (65526 consumers) and a town located near Madrid (semi-rural area with 61577 customers).

As mentioned before, a long-term network planning model is used by Consentec and two different models (Mateo et al., 2011) are used by Comillas, one ("Greenfield model") in order to determine the current network and the other one ("Expansion model") for future planning in the different demand scenarios.

The model used by Consentec uses as inputs the data of the distributed energy plants, the surface of the areas and the number of customers, based on the year 2010. The load curve of the domestic demand was modified for each Scenario (2, 3 and 4 for Germany) like in paragraph **Errore. L'origine riferimento non è stata trovata.**.

The "Greenfield model" used by Comillas needs as inputs the quantity and location of current data of peak demand and generation in order to determine the current network. Once this has been determined, the network structure and the incremental residential peak demand of current clients for a 10 year horizon are used as inputs for the "Expansion model". The incremental residential demand is assumed to be 5% in the base case, but then the increase is different for each of the AD scenarios considered, taking into account that in each of the AD Scenarios in Table 7 a reduction of that increase is assumed.

[11] Consentec Gmbh, IAEW, RZVN, Frontier Economics. Untersuchung der Voraussetzungen und möglicher Anwendung analytischer Kostenmodelle in der deutschen Energiewirtschaft. Gutachten im Auftrag der Bundesnetzagentur, 20. November 2006

6.2.2. Input data

Reference Scenario	Urban		Rural/Semi-rural	
	Germany	Spain	Germany	Spain
LV-line length [km]	22655	184.34	117744	747.19
MV/LV transformer	8937	322	72345	521
MV-line length [km]	6523	153.02	112603	754.85
HV/MV transformer stations	97	3	769	7

Table 17: Network characteristics for the Rural/Semi-Rural and Urban areas

	Urban		Rural/Semi-Rural	
	Germany	Spain	Germany	Spain
LV-line length [€/km]	90000	32600	90000	18200
MV/LV transformer [€/transformer]	28000	19900	28000	19000
MV-line length [€/km]	110000	43400	110000	27200
HV/MV transformer stations [€/transformer]	2500000	2170000	2500000	1700000

Table 18: Unitary costs for the Rural/Semi-Rural and Urban areas

6.2.3. Results

Reference Scenario	Urban		Rural/Semi-rural	
	Germany	Spain	Germany	Spain
LV-line length [Mio€]	2039	6.04	10597	13.63
MV/LV transformer [Mio€]	250	6.41	2026	9.83
MV-line length [Mio€]	718	6.70	12386	20.54
HV/MV transformer stations [Mio€]	241	6.52	1922	11.88
TOTAL (Mio€)	3248	25.66	26931	55.89

Table 19: Costs of the network for the Rural/Semi-Rural and Urban areas

Urban	Scenario 1	Scenario 2		Scenario 3		Scenario 4	
	Spain	Germany	Spain	Germany	Spain	Germany	Spain
LV-line length [Mio€]	-2.70%	-0.52%	-3.38%	-0.27%	-1.53%	-0.61%	-3.94%
MV/LV transformer [Mio€]	-1.21%	-6.80%	-1.37%	-3.70%	-0.69%	-7.93%	-2.49%
MV-line length [Mio€]	-2.48%	-3.45%	-2.48%	-1.87%	-0.77%	-4.04%	-4.02%
HV/MV transformer stations [Mio€]	0.00%	-6.80%	0.00%	-3.71%	0.00%	-7.94%	0.00%
TOTAL (Mio€)	-1.59%	-2.20%	-1.79%	-1.20%	-0.73%	-2.50%	-2.60%

Table 20: Savings in the different Scenarios respect to Reference Scenario for the urban area.

Rural/Semi-rural	Scenario 1	Scenario 2		Scenario 3		Scenario 4	
	Spain	Germany	Spain	Germany	Spain	Germany	Spain
LV-line length [Mio€]	-0.86%	0.78%	-1.13%	0.44%	-0.34%	0.9%	-1.36%
MV/LV transformer [Mio€]	-0.89%	-6.56%	-1.09%	-3.73%	-0.34%	-7.78%	-1.47%
MV-line length [Mio€]	-0.12%	-2.99%	-0.12%	-1.50%	-0.06%	-3.69%	-0.19%
HV/MV transformer stations [Mio€]	0.00%	-6.42%	0.00%	-3.38%	0.00%	-7.82%	0.00%
TOTAL (Mio€)	-0.41%	-1.02%	-0.51%	-0.99%	-0.17%	-2.49%	-0.66%

Table 21: Savings in the different Scenarios respect to Reference Scenario for the rural/semi-rural area

As in the case of Fuel Costs and CO_2 emissions, the order of Scenarios (when available for a determined country) from the maximum to the minimum total costs savings is Scenario 4, Scenario 2, Scenario 1 and Scenario 3.

For most of the network components, the investments in peak reduction Scenarios are less than in the Reference Scenario, except for the length of LV-lines in rural areas of Germany which increases compared to the Reference Scenario. Despite this, the total network investments in the peak reduction Scenarios decrease compared to the reference Scenario for both, rural/semirural and urban areas in Germany and Spain.

The total monetary reductions in percentage terms compared to the reference Scenario are bigger in all the scenarios for the rural areas in Germany than for the rural areas in Spain. In urban areas, the percentage of monetary reductions is bigger in Germany than in Spain for Scenarios 2 and 3.

The avoided costs in each of the Scenarios considered are shown in the following table. Network investment costs have been annualized so that they can be comparable with fuel and CO2 emission costs reductions, which have been calculated in an annual basis. Therefore, the reductions are in M€ per year.

	Belgium		Germany			Spain				Italy	
Reductions [M€]	Scen. 3	Scen. 4	Scen. 2	Scen. 3	Scen. 4	Scen. 1	Scen. 2	Scen. 3	Scen. 4	Scen. 1	Scen. 2
Fuel Costs	31	129	848	285	1129	447.1	669.6	220.7	893.7	275.6	444.7
CO2 Emissions Costs	15	61	455	140	595	115.5	175	63	231	76.9	124.1
Network Investments-Urban (1*)	-	-	69	38	82	12	13.5	5.5	19.7	-	-
Network Investments-Rural (1*)	-	-	245	126	302	3.1	3.9	1.2	5	-	-

Table 22: Reductions in Fuel Costs, CO_2 emission costs and Network Investments.

1*: The avoided network investments in Germany and in Spain were scaled for the whole countries because they were originally calculated for small areas within the countries. The avoided network investments in Germany were originally calculated for a rural area that comprises about 10.6 Million inhabitants (48 Million German people live in rural areas) and an urban area with a size similar to a city of about 3.4 Million inhabitants (33 Million German people live in big cities). In Spain, avoided network investments were calculated for an urban area located in Madrid (65526 consumers of the 19.34 Million urban consumers in Spain) and a town located near Madrid (semi-rural area with 61577 customers of the 8.29 Million rural consumers in Spain).

6.3. Reduced network losses

The reduction in the energy consumed due to AD through the studied period entails a reduction of the electricity that has to be generated and therefore a reduction in the network losses as has been mentioned in section 5.4.

6.3.1. Methodology

In order to assess the reduction in network losses due to AD, a sophisticated methodology would be to reproduce the power flow in the networks in the demand scenarios with and without AD in a similar way as Shaw et al. (2009) did. However, since this methodology cannot be reproduced in all the countries assessed, a simpler approach is proposed. As will be seen in the results section, the results obtained with the simple approach and the sophisticated approach are very close.

Regarding the simple approach, a constant network losses rate will be assumed and this rate will be multiplied by the reduction in energy transported in each of the AD Scenarios for 2020. The rate of losses will be determined for the different countries taking into account that actually the network losses rate is not linear (losses are proportional to the square of load).

Once losses reductions have been quantified, they will be monetized. The market price will be used as an indicator of the value of the electricity.

Enel established the average price of electricity in Italy for 2020 taking into account the National Single Price ("Prezzo Unico Nazionale", PUN) in the last five years, which is set as weighted average of the electricity prices over the various geographical zones in Italy, and assuming a 2% yearly inflation. The resulting 2020 electricity price is 92,76 €/MWh.(Table 23).

Comillas, Consentec and Vito determined the average electricity price in their countries taking into account the contribution of each technology to the peak during year 2020 and the marginal cost of each technology (Table 23). Therefore, the average electricity price for 2020 is 63,85 €/MWh in Spain (the average electricity price in the Spanish electricity market was 44.57 €/MWh in 2010[12]), 60.5 €/MWh in Germany and 48.81 €/MWh in Belgium.

For the quantification of transmission and distribution losses Vito used their report concerning the energy balance of Flanders in 2009[13]. Linking the gross electricity production to the network losses they obtained a percentage of 4.7% of transmission and distribution losses. Comillas and Enel assumed a rate of losses of 9% and Consentec a rate of losses of 6%.

[12] Data obtained in the web page of the Spanish Market Operator. Available at http://www.omel.es/

[13] Available at http://www.emis.vito.be/sites/default/files/pagina/voorlopig_rapport_2009%28sept_2010%29.pdf

	Belgium		Germany		Spain		Italy
Technology	Number of Peak hours	Price (1*) [€/MWh]	Relative amount [%]	Price (1*) [€/MWh]	Number of Peak Hours	Price (2*) [€/MWh]	Estimated electricity price 2020 [€/MWh.]
Imported Coal/Anthracite	5578.00	49.69	10.458	65.35	835	64.35	92.76
CCGT/Natural Gas	3313.50	47.25	48.704	63.35	7488	63.75	
National Coal/Lignite	-	-	39.925	56.55	-	-	
Nuclear	-	-	0.913	26.5	-	-	
Cogeneration	-	-	-	-	437	64.75	
Gas Other	49.25	48.30	-	-	-	-	
Other	1.25	42.00	-	-	-	-	

Table 23: Contribution of each peak technology during a year

1*: Fuel+CO2+O&M-Subsidies

2*: Fuel+CO2

6.3.2. Results

The reduced costs for network losses are determined in the following table:

	Belgium			Germany				Italy			Spain				
	Total	Reduction		Total	Reduction			Total	Reduction		Total	Reduction			
	Reference	Sc. 3	Sc. 4	Reference	Sc. 2	Sc. 3	Sc. 4	Reference	Sc. 1	Sc. 2	Reference	Sc. 1	Sc. 2	Sc. 3	Sc. 4
Energy consumption [GWh]	93176	598.2	2376.1	541000	20844	6948	27792	390000	7518	11277	370731	8921	13381	4460	17841
Transmission losses	0.047	0.047	0.047	0.06	0.06	0.06	0.06	0.09	0.09	0.09	0.09	0.09	0.09	0.09	0.09
Cost for network losses [Mio€]	213.8	1.37 (0.64 %)	5.04 (0.64 %)	2089	80.49 (3.85 %)	26.83 (1.28 %)	107.3 (5.14 %)	3255	62.8 (1.93 %)	94.1 (2.89 %)	2130	51.3 (2.41 %)	76.9 (3.61 %)	25.6 (1.20 %)	102.5 (4.81 %)

Table 24: Cost of network losses avoided

As seen in Table 24, the reduction in losses due to AD varies from country to country in each of the Scenarios considered, going from 0.64 % to 5.14%, respectively to Belgium in Scenario 3 and Germany in Scenario 4. These reductions are larger than the results obtained in Shaw et al. (2009) for the UK using a complex methodology (see paragraph **Errore. L'origine riferimento non è stata trovata.**) but in this case conservation actions were not reproduced. Shaw et al. (2009) got a 0.7% losses reduction with a 10% residential load reduction in peak hours (similar to Scenario 3 but considering a 100% payback effect) and a 1.4% losses reduction with a 15% residential load reduction in peak hours .

The network losses and average electricity prices assumed have a big influence in the final savings obtained. In the case of Spain, these savings are similar to those obtained for Germany for the same scenario, although the reduced energy consumption is much bigger in Germany for the same scenario.

Comparing savings in network losses with the other savings (Table 25), savings in network losses are around ten times smaller than savings in fuel costs and five times smaller than savings in emissions.

	Belgium		Germany			Spain				Italy	
Reductions [M€]	Scen. 3	Scen. 4	Scen. 2	Scen. 3	Scen. 4	Scen. 1	Scen. 2	Scen. 3	Scen. 4	Scen. 1	Scen. 2
Fuel Costs	31	129	848	285	1129	447.1	669.6	220.7	893.7	275.6	444.7
CO2 Emissions Costs	15	61	455	140	595	115.5	175	63	231	76.9	124.1
Network Investments-Urban (1*)	-	-	69	38	82	12	13.5	5.5	19.7	-	-
Network Investments-Rural (1*)	-	-	245	126	302	3.1	3.9	1.2	5	-	-
Reduced cost for network losses	2.58	10.3	80	27	107	51.3	76.9	25.6	102.5	62.8	94.1

Table 25: Reductions in Fuel Costs, CO_2 emission costs, Network Investments and Network losses.

1*: The avoided network investments in Germany and in Spain were scaled for the whole countries because they were originally calculated for small areas within the countries. The avoided network investments in Germany were originally calculated for a rural area that comprises about 10.6 Million inhabitants (48 Million German people live in rural areas) and an urban area with a size similar to a city of about 3.4 Million inhabitants (33 Million German people live in big cities). In Spain, avoided network investments were calculated for an urban area located in Madrid (65526 consumers of the 19.34 Million urban consumers in Spain) and a town located near Madrid (semi-rural area with 61577 customers of the 8.29 Million rural consumers in Spain).

6.4. Reduced costs of balancing

AD furthermore may have an interesting contribution to the reduction of the balancing costs of the system as mentioned in paragraph 5.1. Since supply must be equal to demand in real time, some generation units must be able to increase or reduce their output in the time. This real time balance requires that the units entrusted to increase or reduce their output have some capacity available in order to carry out the real time balance. Having capacity available to correct the systems imbalances is a cost for electricity systems.

Being aware of the real time operation of electricity systems, balancing costs can be divided in availability costs and activation costs of reserve energy in order to balance the real-time operation of systems. Since the activation of reserve energy is an energy cost, it will not be attributed to the balancing activities because it has already been taken into account in the energy costs.

As mentioned, balancing units must be able to have some capacity available to increase or reduce their output. Regarding this, availability costs can be divided into positive minute reserves in the case of generation units that can increase their output rapidly and negative minute reserves in the case of generation units that can decrease their output rapidly.

6.4.1. Methodology and Results

In order to quantify the availability costs for the power systems considered within this study, the amount of both positive and negative balancing energy which can be provided by AD is multiplied by the average price paid in the balancing market for this service. This assumption is valid as long as AD does not set the price in this market, in which case more detailed assessments would be required.

Comillas and Consentec studied the economic outcomes for the reduction in the need of available energy due to the application of AD policies. Consentec bases its calculation for Germany on data of 2009 and Comillas bases it for Spain on data of 2010.

In Italy the transmission system operator, who is responsible for balancing, doesn't pay for the availability service but only the activation of the reserve energy. Hence, in this case the methodology proposed is not applicable.

Positive minute reserve

To determine the reduced cost regarding only the positive minute reserve, Consentec compared three different scenarios with different degrees of penetration of AD, which differ in the value of the spared costs for positive balancing energy in percentage[14]. Scenario A assumes an availability reduction of 100 % and therefore a total compensation of positive balancing energy through AD while scenario B and C have 75 and 50 % as an upper bound.

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[14] Consentec GmbH. Gutachten zur Höhe des Regelenergiebedarfs. Gutachten im Auftrag der BNetzA, 10.12.2008

The amount of positive balancing energy fluctuates between 2285 and 3508 MW for Germany with an average of 2749 MW. The average price paid for the availability of this power is 1,3 €/MW per hour leading to yearly costs of 31,25 Mio€.

Comillas assumes four scenarios of availability reduction. Scenario A assumes an availability reduction of 100%, Scenario B assumes a 75%, Scenario C assumes a 50% and Scenario D assumes a 25%.

The amount of positive balancing energy averages 727 MW for Spain. The average price paid for the availability fluctuates between 7,37 €/MW and 22,47 €/MW, being the average price 16,4 €/MW per hour leading to yearly costs of 104,44 Mio€.

	Scenario A		Scenario B		Scenario C		Scenario D
	Germany	Spain	Germany	Spain	Germany	Spain	Spain
Degree of penetration [%]	100	100	75	75	50	50	25
Avoided Availability costs [Mio€]	31.3	104.4	23.4	78.3	15.6	52.2	26.1

Table 26: Avoided costs of Positive minute reserve

Avoided costs of Positive minute reserve are bigger for all scenarios in Spain than those in Germany mainly because of the higher unitary availability costs.

Negative minute reserve

Consentec stated that the contribution of AD to the negative balancing service only extends to a reduction of the availability cost. Assuming a degree of penetration of 50 % (equivalent to Scenario C) and an amount of negative balancing energy with a media of 2647 MW another 40.15 Mio€ can be avoided.

Comillas determined that the amount of negative balancing energy averages 531 MW for Spain. The average price paid for the availability fluctuates between 7,37 €/MW and 22,47 €/MW, being the average price 16,4 €/MW per hour leading to yearly costs of 76,252 Mio€. The same scenarios as in the positive minute reserve case are going to be studied.

	Scenario A	Scenario B	Scenario C		Scenario D
	Spain	Spain	Germany	Spain	Spain
Degree of penetration [%]	100	75	50	50	25
Avoided Availability costs [Mio€]	76.25	57.19	40.15	38.13	19.06

Table 27: Avoided costs of Negative minute reserve

Avoided costs of negative minute reserve for Scenario C are bigger in Germany than in Spain.

Next table includes Fuel Costs avoided, CO_2 emission costs avoided, Network Investments avoided, Network losses avoided and balancing costs avoided in order to compare the figures:

	Belgium		Germany			Spain				Italy	
Reductions [M€]	Scen. 3	Scen. 4	Scen. 2	Scen. 3	Scen. 4	Scen. 1	Scen. 2	Scen. 3	Scen. 4	Scen. 1	Scen. 2
Fuel Costs	31	129	848	285	1129	447.1	669.6	220.7	893.7	275.6	444.7
CO2 Emissions Costs	15	61	455	140	595	115.5	175	63	231	76.9	124.1
Network Investments-Urban (1*)	-	-	69	38	82	12	13.5	5.5	19.7	-	-
Network Investments-Rural (1*)	-	-	245	126	302	3.1	3.9	1.2	5	-	-
Reduced cost for network losses	2.58	10.3	80	27	107	51.3	76.9	25.6	102.5	62.8	94.1
Reduced Balacing Costs			Scenario A	Scenario B	Scenario C	Scenario A	Scenario B	Scenario C	Scenario D		
Positive Minute Reserve			31.3	23.4	15.6	104.4	78.3	52.2	26.1		
Negative Minute Reserve					40.15	76.3	57.2	38.1	19.1		

Table 28: Reductions in Fuel Costs, CO_2 emission costs, Network Investments, Network losses and Balancing costs.

1*: The avoided network investments in Germany and in Spain were scaled for the whole countries because they were originally calculated for small areas within the countries. The avoided network investments in Germany were originally calculated for a rural area that comprises about 10.6 Million inhabitants (48 Million German people live in rural areas) and an urban area with a size similar to a city of about 3.4 Million inhabitants (33 Million German people live in big cities). In Spain, avoided network investments were calculated for an urban area located in Madrid (65526 consumers of the 19.34 Million urban consumers in Spain) and a town located near Madrid (semi-rural area with 61577 customers of the 8.29 Million rural consumers in Spain).

7. Conclusions

Fuel costs and CO_2 emissions experience the biggest reduction due to AD. Fuel costs reduction varies from 1.57 % to 9.02 %, respectively in Belgium in Scenario 3 and Germany in Scenario 4. Emissions reduction varies from 1.6% to 9.11%, respectively in Italy in Scenario 1 and Germany in Scenario 4. These reductions vary from country to country due to the different energy mix, but Germany gets the largest fuel and emissions reduction for the same Scenario.

In order to quantify the contribution of AD to the reduction of the total estimated costs for 2020 (Table 29), the costs saved in each AD Scenario for 2020 are divided by the total estimated costs for 2020 (without applying AD). Therefore, the figures shown in Table 30 are percentages of the total estimated costs for 2020.

Costs [Mio€]				
	Belgium	Germany	Spain	Italy
	Reference	Reference	Reference	Reference
Fuel Costs	1973	12514	12917	11134
CO2 Emissions	922	6650	3374	4820
Network Investments-Urban	-	3248	758	-
Network Investments-Rural	-	12119	753	-
Network losses	214	2089	2130	3255
Positive Minute Reserve	-	31.3	104.4	-
Negative Minute Reserve	-	80.3	76.3	-
Total Costs	3109	36732	20112	19209

Table 29: Estimated costs for 2020.

	Reductions for each Scenario/Total Costs of the system										
	Belgium		Germany			Spain				Italy	
Reductions [M€]	Scen. 3	Scen. 4	Scen. 2	Scen. 3	Scen. 4	Scen. 1	Scen. 2	Scen. 3	Scen. 4	Scen. 1	Scen. 2
Fuel Costs	1.00%	4.15%	2.31%	0.78%	3.07%	2.22%	3.33%	1.10%	4.44%	1.43%	2.32%
CO2 Emissions Costs	0.48%	1.96%	1.24%	0.38%	1.62%	0.57%	0.87%	0.31%	1.15%	0.40%	0.65%
Network Investments-Urban (1*)	-	-	0.19%	0.10%	0.22%	0.06%	0.07%	0.03%	0.10%	-	-
Network Investments-Rural (1*)	-	-	0.67%	0.34%	0.82%	0.02%	0.02%	0.01%	0.02%	-	-
Reduced cost for network losses	0.08%	0.33%	0.22%	0.07%	0.29%	0.26%	0.38%	0.13%	0.51%	0.33%	0.49%
Reduced Balacing Costs			Scenario A	Scenario B	Scenario C	Scenario A	Scenario B	Scenario C	Scenario D	-	-
Positive Minute Reserve	-	-	0.09%	0.06%	0.04%	0.52%	0.39%	0.26%	0.13%	-	-
Negative Minute Reserve	-	-			0.11%	0.38%	0.28%	0.19%	0.09%	-	-

Table 30: Percentage of the obtained savings with respect to the total costs

1*: The avoided network investments in Germany and in Spain were scaled for the whole countries because they were originally calculated for small areas within the countries. The avoided network investments in Germany were originally calculated for a rural area that comprises about 10.6 Million inhabitants (48 Million German people live in rural areas) and an urban area with a size similar to a city of about 3.4 Million inhabitants (33 Million German people live in big cities). In Spain, avoided network investments were calculated for an urban area located in Madrid (65526 consumers of the 19.34 Million urban consumers in Spain) and a town located near Madrid (semi-rural area with 61577 customers of the 8.29 Million rural consumers in Spain).

As seen in Table 30, the contribution of the different savings to the total costs differs from country to country. In most countries, the biggest reductions come from savings in fuel costs (although the magnitude of these depend on the fuel mix). Savings due to reductions in network investments or losses are much lower, although here there are significant differences between countries (with Germany featuring cost reductions much bigger than in Spain).

Table 31 show the savings obtained per customer due to AD. Fuel savings vary from 5.81 € to 32.34 € per customer, respectively in Belgium in Scenario 3 and Spain in Scenario 4. CO_2 emissions costs savings vary from 2.28 € to 13.81 €, respectively in Spain in Scenario 3 and Germany in Scenario 4. While network investments savings in urban areas vary from 0.29 € to 4.82 € per customer, respectively to Spain in Scenario 3 and Germany in Scenario 4, these savings are much higher in Germany than in Spain. Network investment savings in rural areas vary from 0.15 € to 11.552 € per customer, respectively to Spain in Scenario 3 and Germany in Scenario, being even higher the differences between Germany and Spain than in the urban areas.

	Belgium		Germany			Spain				Italy	
Reductions [€/Residential Customer]	Scen. 3	Scen. 4	Scen. 2	Scen. 3	Scen. 4	Scen. 1	Scen. 2	Scen. 3	Scen. 4	Scen. 1	Scen. 2
Fuel Costs	5.81	24.19	19.68	6.61	26.19	16.18	24.23	7.99	32.34	9.75	15.72
CO2 Emissions Costs	2.81	11.44	10.56	3.25	13.81	4.18	6.33	2.28	8.36	2.72	4.39
Network Investments-Urban	-	-	4.06	2.24	4.82	0.62	0.70	0.29	1.02	-	-
Network Investments-Rural	-	-	9.40	4.83	11.55	0.38	0.47	0.15	0.60	-	-
Reduced cost for network losses	0.48	1.93	1.86	0.63	2.48	1.86	2.78	0.93	3.71	2.22	3.33
Reduced Balacing Costs			Scenario A	Scenario B	Scenario C	Scenario A	Scenario B	Scenario C	Scenario D		
Positive Minute Reserve			0.73	0.54	0.36	3.78	2.83	1.89	0.94		
Negative Minute Reserve			-	-	0.93	2.76	2.07	1.38	0.69		

Table 31: AD savings per costumer [€/customer]

These figures on the benefits of AD programs will then be incorporated into business case analyses, in which they will be compared with the costs of deploying such a program. This analysis will be available in a separate report within the ADDRESS project.

8. References

8.1. Project documents

List of reference document produced in the project or part of the grant agreement

[DOW] – Description of Work

[GA] – Grant Agreement

[CA] – Consortium Agreement

8.2. External documents

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9. Revisions

9.1. Revision history

Version	Date	Author	Notes
0.1	27 May 2010	Pedro Linares	First draft
0.2	1 June 2011	Óscar Lago, Pedro Linares, Marco Baron, Annelies Delnooz, Christian Linke, Andreas Cronenberg	Draft with results incorporated
0.3	4 January 2012	Jitske Burgers	Review
1.0	21 June 2012	Óscar Lago, Pedro Linares, Marco Baron, Annelies Delnooz, Christian Linke, Andreas Cronenberg	First release

Annex A. Modified Load Curve

In order to make the energy reduction and energy shifting for each of the scenarios for the modified load curve, a reference value for peak hours and off-peak hours was defined for each country.

Reference value for peak hours and off-peak hours or the time frame for peak hours are defined in next table:

	Belgium	Spain	Italy
Peak Reference	11875 MW	49934 MW	8.00 h-20.00 h
Off-Peak Reference	10697 MW	39727 MW	20.01 h-7.59 h

Table 32: Reference value for peak and off-peak periods

Annex B. Sophisticated approach

In order to validate the results obtained using the simple approach, those results for Spain are going to be compared with the results obtained using sophisticated approaches for Spain. Comillas uses both a short- term operation model and a long- term expansion model (Linares et al., 2008). The short- term operation model uses a linear optimization algorithm in order to cover the demand minimizing the operation costs of the existing installed technologies in 2020 (Table 11). The long-term expansion model uses a linear optimization algorithm that promotes the necessary investment from now until 2020 to cover demand with the minimum costs (investment and operation costs)

Table 33 show the differences between the results obtained with the simple approach and those obtained with the operation model. Those differences are very low. Therefore, the simple approach seems an acceptable simplification.

	Reference Scenario			Scenario 1			Scenario 2			Scenario 3			Scenario 4		
	Simple	Sophist.	Dif	Simple	Sophist.	Dif	Simple	Sophist.	Dif	Simple	Sophist.	Dif	Simple	Sophist.	Dif
Fuel Costs [M€]	12917	12908	0,07%	12469	12475,3	-0,05%	12247	12240	0,06%	12696	12693,8	0,02%	12023	12036	-0,11%
CO2 Emissions [Mton.]	96,4	95,6	0,84%	93,1	92	1,20%	91,4	90,9	0,55%	94,6	93,7	0,96%	89,8	88,7	1,24%

Table 33: Results obtained using the simple approach and the operation model (sophisticated approach).

Moreover, in order to know the contribution of investments to the system costs, the costs obtained using the operation model and the expansion model are going to be compared (Table 34).

Costs [M€]	Reference Scenario			Scenario 1			Scenario 2			Scenario 3			Scenario 4		
Country:Spain	Operation Model (1*)	Expansion Model (2*)	Ratio	Operation Model (1*)	Expansion Model (2*)	Ratio	Operation Model (1*)	Expansion Model (2*)	Ratio	Operation Model (1*)	Expansion Model (2*)	Ratio	Operation Model (1*)	Expansion Model (2*)	Ratio
Total Costs[M€]	16253	19035	1,17	15697	18279	1,16	15420	17902	1,16	15975	18657	1,17	15142	17524	1,16

Table 34: Results obtained in the operation and expansion model

1*: Fuel Costs+Emission Costs
2*: Fuel Costs+Emission Costs+Investment Costs