Key economic factors influencing the adoption of the ADDRESS Smart Grids architecture

D5.3

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Executive Summary

The degree of adoption of Active Demand (AD) programs will be largely influenced by their costs and benefits, and more particularly, by the costs and benefits that accrue to each agent in the power system. For example, saving money is cited as the most important reason for engaging in AD programs in Spain (although in the Brittany Islands in France other reasons such as security of supply and protection of the environment appear to be as important as money savings due to the particular situation of the islands).

Regulators will (or should) be driven mostly by the results of social cost-benefit analyses. Here the key elements seem to be the long-term investments (of which the largest seem to be the communication costs) and benefits (regarding mostly avoided investments in networks and power plants).

Distributor System Operators (DSOs), as the parties typically responsible for deploying Medium and Low Voltage network infrastructure, will be mainly concerned by the costs, particularly by those that may be more difficult to transfer to consumers, that is, communication and control and network automation costs.

Aggregators, in turn, will be motivated by the business opportunity that appears whenever there are significant savings (benefits) to be shared with the consumer. In particular, given the structure of most electricity markets, the most relevant benefits here will be those related to the generation markets (daily, intradaily or balancing).

However, for all these costs and benefits to take place, the keystone is the consumer. What are the key economic factors that may influence the adoption of AD programs by consumers? Again, the consumers, if reasonably rational, will also conduct their own cost-benefit analysis (not precluding of course the inclusion of other non-economic factors, such as the desire to save energy or protect the climate, among others). The benefits will come basically from changes in the budget devoted to electricity consumption, that is, there will be benefits if the expense in electricity decreases. The cost, in turn, will have two parts. Firstly, the direct cost to be paid by the consumers (typically, the adaptation of appliances and plugs in their homes). Secondly, the cost that is passed-on by DSOs and aggregators in return for the infrastructure to be deployed (smart meters, telecommunication services, among others).

The goal of this report is to present a review of both previous estimates of the costs and benefits of AD programs, and of the major results obtained within the ADDRESS project, in order to identify the key economic factors that may drive the adoption of the ADDRESS architecture, both from the system and from the individual stakeholder point of view.

At the system level, the benefits assessed have been: reduced energy and pollution costs, reduced network investments, reduced network losses, and reduced costs of balancing. The total figures obtained per country range from 400 to 2,200 million Euros per year, which amount to 1.5 – 6.5% of each country's system typical costs. Of these savings, most correspond to a reduction in fuel and emission costs, and a much lower share belongs to network benefits and savings in balancing. The actual numbers vary based on the power system configuration in each country and on the scenario of penetration of AD. The four scenarios considered, originally proposed in deliverable D1.2 (Application of the ADDRESS architecture in four specific scenarios), differ in the peak load reduction and total energy reduction (the assumptions are

described in section 3.2), This is shown in the following figure[12].,

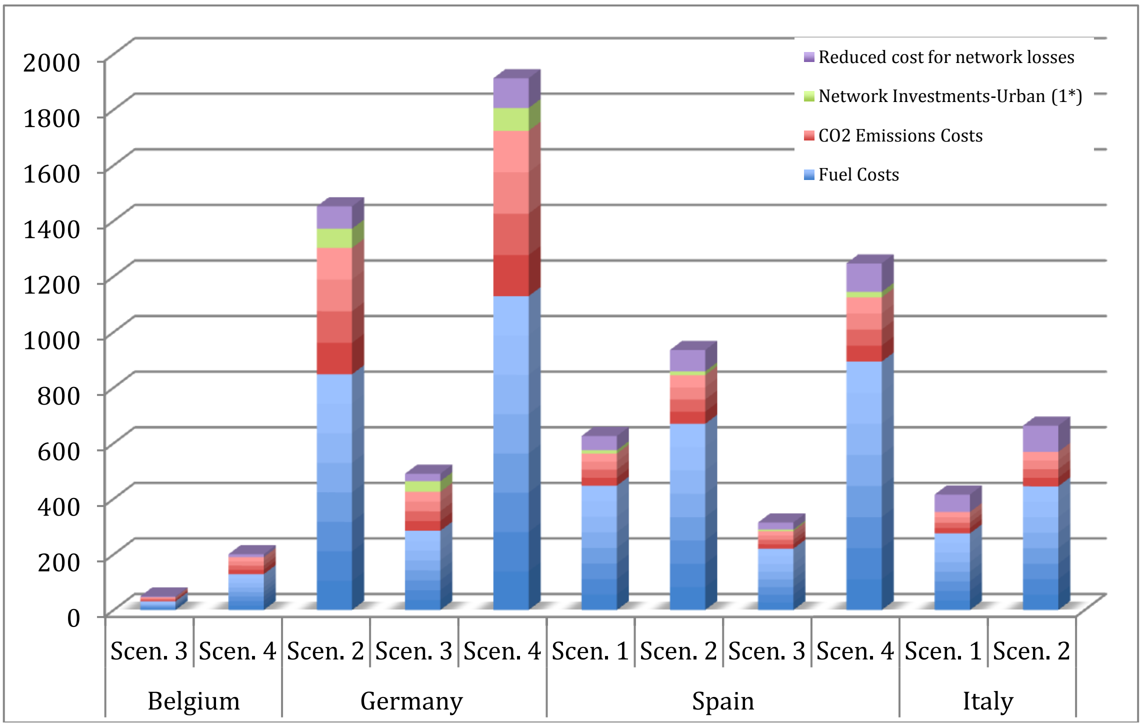

Figure ES-1. Annual savings in million Euros from different AD scenarios

These are not negligible benefits, although of course they should be compared against the costs of setting up the infrastructure required for AD programs to take place. Here the estimation is even more difficult, as there are few real cases in which all the infrastructure required for the ADDRESS architecture has been installed (it should be highlighted that this architecture is not only the deployment of smart meters), and even in these cases it is not clear whether the costs quoted are already commercial (the low level of penetration of these technologies suggests that current costs are much higher). In addition, given that this infrastructure can be used for other purposes, and not only AD, it is difficult to allocate the costs to AD programs in order to compare them with the benefits[3].

However, as mentioned before, these system-level benefits may be interesting as drivers for regulators' or policy-makers' decisions, but will not determine whether the rest of stakeholders will actually engage in AD programs. In this regard it would be more important to assess the individual benefits and costs for each stakeholder.

This presents an important difficulty: the attribution of the costs and benefits of AD programs will depend both on the regulatory context and market conditions. The regulatory context may determine for example to what extent the savings achieved by DSOs or TSOs (Transmission

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1 For the sake of simplicity, the figure only shows reduced network investments for urban areas given that this is where most consumers reside. Benefits for rural areas have also been estimated, and can be seen in the tables in section 3. These benefits for rural areas can be higher or lower than for urban areas depending on the country.

2 The figure does not show savings from network investments in Italy. This is because the methodology followed to calculate them is not comparable, because a network reference model was not available for Italy. Some results (with this different methodology) are shown in section 4.

3 This of course brings the question of how to share the costs among the different applications of the smart grid.

System Operators) through AD programs must be passed on to consumers. The market conditions can allow for example the sharing of benefits between aggregators and consumers.

This report presents two different estimations in this regard. A first one, in which the total social benefits are divided by the number of consumers affected. This should provide an indication of the benefits available for sharing between the agents. Depending on the country and on the scenario considered for the penetration of AD programs, we have estimated these total benefits to be between 6 and 48 Euros per consumer per year. Again, the variation of these benefits between countries and scenarios is shown below[4][5].

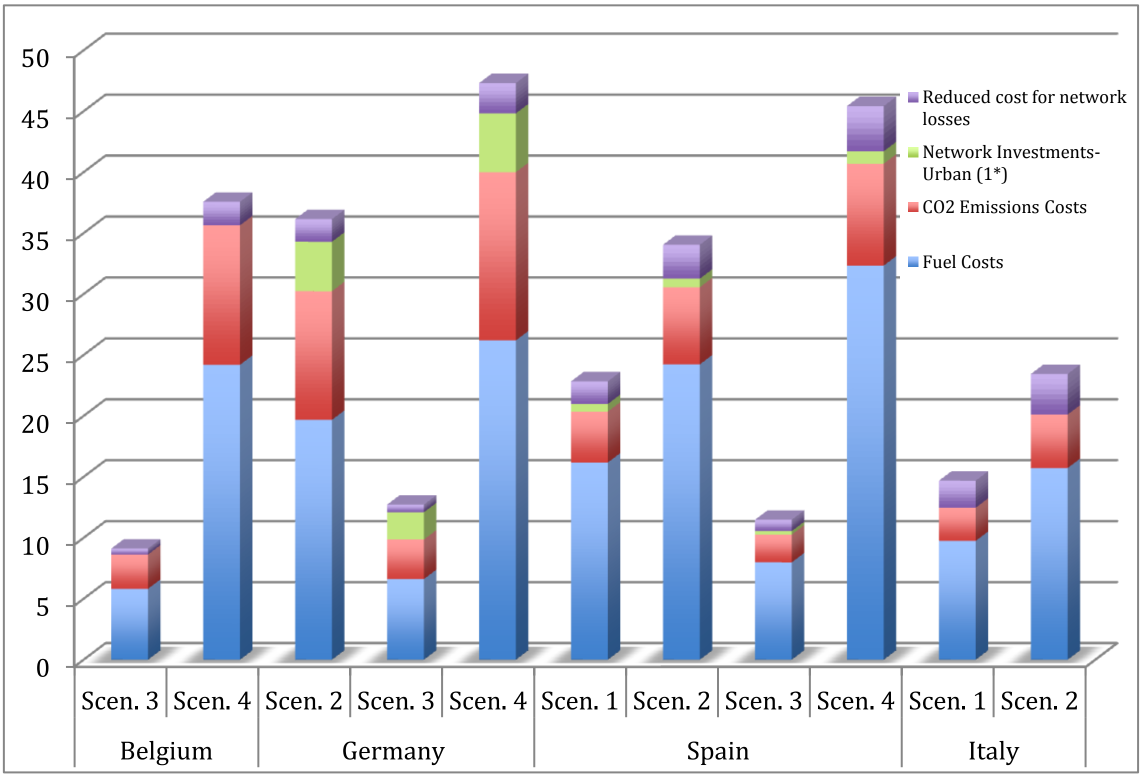

Figure ES-2. Savings per consumer, in Euros per year

As mentioned before, this does not mean that a consumer would actually enjoy these savings. Therefore, the report also presents a second estimation, in which the current regulatory and market context is taken into account, and in which the benefits to be achieved by each individual stakeholder from different AD services have been calculated. These calculations are further described in deliverable D5.4 (Report outlining business cases for Customers, Aggregators and DSOs in the scenarios detailed in WP1)[6], and are based on several

[4] Again, the figure only shows the benefits for a urban area, not for a rural one. See the earlier footnote for comments about this.

[5] The figure does not show savings from network investments in Italy. This is because the methodology followed to calculate them is not comparable, because a network reference model was not available for Italy. Some results (with this different methodology) are shown in section 4.

[6] This is a confidential document. Access can be provided by the consortium upon request. Request shall be made to the Project Coordinator.

assumptions which can be consulted in that document[7].

For example, if we add the benefits to be obtained from the provision of load reduction, tertiary reserve, management of energy imbalances, or short-term load shaping, aggregators would receive between 3 and 11 Euros per year, whereas consumers would receive between 3 and 7 Euros per year. It should be noted that these numbers do not need to be added to the total social benefits presented earlier because they are private benefits from a subset of AD services.

We acknowledge that these are not large figures, which might even go unnoticed to consumers and therefore not engage them much. Here the general caveats for this study should be reminded again: we have not been able to quantify all of the potential benefits of AD programs (e.g., better management of network congestions and emergencies); we are assuming current prices for electricity (these prices might increase in the future); and we are also assuming the current system flexibility needs for the scenarios, whereas in reality flexibility needs might increase significantly in a scenario with a larger penetration of renewable energy.

As an example of benefits not considered here (and not directly comparable to figures ES-1 and ES-2), deliverable 5.4 estimates the value of capacity-related services, obtaining figures of up to 54 €/year for Spain, or Italy. For the UK, where a deeper study was undertaken, residential consumers could obtain up to 237 Euros per year, and commercial ones up to 4740 Euros/year. These, if achievable, are clearly stronger drivers for action for consumers.

In addition, and based on the field tests carried out within the project, and also on evidence from other pilot projects, it is clear that automation of consumer response such as the one envisaged by the ADDRESS architecture would make easier the engagement of consumers.

Therefore, when all these elements are considered, the future for AD in Europe looks indeed possible.

[7] E.g., AD calls are limited to one call of 1 hour per day; there is no cost for the aggregator; the same flexibility is considered for all active consumers, etc.

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1. Introduction

1.1. Scope of the document

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 (AD) management can play an important role (e.g. 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 of economic efficiency, we must verify if the current situation features market failures or barriers which prevent an efficient allocation of resources[8]. 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 for this is the lack of technologies that allow, on the one hand, sending consumers these signals, and on the other hand, measuring their hourly consumption. This information asymmetry constitutes a market 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 AD 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 during off-peak periods, 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.

8 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.

The current interest in AD is materialized in numerous research projects besides this one[9], and also trials and initiatives[10]. Some countries and regions have carried out studies to assess the cost-effectiveness or potential for advanced metering and AD[11], and many countries have started deploying smart meters or have set roll-out targets[12] (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.

Indeed, the degree of adoption of AD programs will be largely influenced by their costs and benefits, and more particularly, by the costs and benefits that accrue to each agent in the power system. The goal of this report is to present a review of both previous estimates of the costs and benefits of AD programs, and of the major results obtained within the ADDRESS project, in order to identify the key economic factors that may drive the adoption of the ADDRESS architecture.

1.2. Structure of the document

This document synthetizes and puts together in a consistent way information already available in other documents of the ADDRESS project. Sections 2 and 3 come from an Internal Report "Evaluation of Benefits of Active Demand". Section 4 draws from a parallel deliverable, D5.4, (Report outlining business cases for Customers, Aggregators and DSOs in the scenarios detailed in WP1), in which the assessment of stakeholder benefits is explained in depth.

The document comprises the following main sections:

Section 2 reviews the potential costs and benefits of AD programs, based on previous estimates carried out in the literature, and identifies which of those seem to be more significant and will therefore become key economic factors for the adoption of AD programs. Although they may not be extrapolated directly to the business model developed within the ADDRESS project (see

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[9] 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.

[10] 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.

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

[12] 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).

section 4), we believe they provide a useful reference against which to compare the results obtained in the project.

Section 3 presents the results obtained for these benefits within the ADDRESS project, and for the scenarios considered. In this section the benefits are calculated from a social or regulatory point of view.

In Section 4, benefits are also calculated, but this time from the point of view of the different stakeholders. Therefore, this section highlights the economic factors that would drive the decisions of individual agents.

Finally, Section 5 presents the conclusions of the document.

1.3. Notations, abbreviations and acronyms

Table 1: Abbreviations.

EC	European Commission
EU	European Union
PC	Project Coordinator
TM	Technical Manager
QM	Quality Manager
QA	Quality Assurance
QAS	Quality Assurance System
QMO	Quality Management Office
QAP	Quality Assurance Plan
TB	Technical Board
MB	Management Board
GA	General assembly
WP	Workpackage
WPL	Workpackage leader
DOW	Description of Work
QO	Quality Objective
AD	Active Demand
DSO	Distribution System Operator
TSO	Transmission System Operator
AMI	Advanced Metering Infrastructure
DSM	Demand Side Management
KPI	Key performance indicator

1.4. Acknowledgements

We would like to thank Annelies Delnooz (VITO), Andreas Croenenberg and Christian Linke (CONSENTEC) and Marco Baron (ENEL) for their significant contribution to this report: providing data, running models for their countries for the assessment of the system-level benefits, and also helping us interpret them.

We would also like to acknowledge the insightful comments provided by the Technical Board and from the whole ADDRESS team on earlier versions of this work.

2. Key economic factors of active demand: Previous estimates of costs and benefits

In this section we review the potential costs and benefits of AD programs based on previous estimates carried out in the literature, and we identify which of those seem to be more significant and will therefore become key economic factors for the adoption of AD programs. Although they may not be extrapolated directly to the business model developed within the ADDRESS project (see section 4), we believe they provide a useful reference against which to compare the results obtained in the project. In later sections we will present the results obtained in the project both for the entire power system, and also for the individual stakeholders.

First we classify the AD programs, since it helps understand their motivations and therefore the benefits expected. We then move on to presenting benefits and costs.

2.1. Categorization of demand response programs

It is important to be aware of the broad range of potential AD programs to understand the prospective benefits that can be achieved and to place the various studies that have been used to analyze them into 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 either classified as 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 deemed 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 and 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) and passive load control programs.

Reliability-based programs include direct load control, curtailable load, interruptible load and scheduled load. Economics-based, 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 reliability-based programs demand is remotely controlled upon conditions contracted with customers, whereas 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, as will be shown in the document

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 (e.g. in some contexts, distribution network losses reductions would benefit generators rather than DSOs). 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, 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 mean of hedging against 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 mean 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 depend 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 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. Given that the objective of this document is to assess the benefits of active demand programs and not of the whole smart grid architecture, these will not be included in this review (although they would of course be required to perform a cost-effectiveness analysis of the smart grid and AMI).

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 provide detailed locational data and enable a more efficient pricing of transmission and distribution networks use of use of system charges for network users (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[13], 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.

2.3. Costs of active demand. Previous estimates

This section draws mostly from EPRI (2011), which is probably the most comprehensive review of the costs of smart grids and active demand programs. Unfortunately, there is not much evidence of real costs of these technologies, even less in the public domain. And even the little information available should be treated with caution, given that most technologies are still in a pre-commercial basis, and costs would be expected to decrease.

It should be reminded also that not all these costs are attributable to Active Demand programs: the smart grid will be used for several purposes, and it is very difficult to separate its costs among the different functionalities. For example, network automation may contribute mostly to a better management of the grid, whereas smart meters will present other benefits different from facilitating active demand (e.g., remote billing). Therefore, this section should be handled with care, and total costs should not be compared directly to the benefits estimated in section 3.

2.3.1. Demand management and smart metering-related costs

The implementation of demand management programs requires significant investments in communication facilities, smart meters, and adaptation of households which need to be fitted with devices that allow customers to manage their demand levels taking into account electricity prices and the technical requirements of the system. The communication infrastructure must allow bidirectional communication between the final consumers and the electric system. The smart meters must allow time discrimination of readings and remote reading, so connection to the existing communication infrastructure must be possible. The final customers must have price signal displays, as well as smart appliances that allow demand management depending on these price signals. Besides price displays, which may show hourly electricity prices or any

[13] 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).

other suitable code to differentiate between high and low prices, the final customers may receive information about their demand profiles and energy bills through the web (Stromback et al. 2011).

The drawback of enabling enhanced communication among the different agents present in the electricity system would be higher operation costs related to data management and infrastructure maintenance.

2.3.1.1 Costs of communication and control infrastructures and meters

As mentioned previously, in order to allow customers response to the electricity prices by means of an efficient demand management, it is necessary to have in place a bidirectional communication infrastructure so that system operators, distribution grid operators, and retailers have a greater control over their resources and may feed the consumers with the appropriate signals that allow an optimal resource use.

Different studies have estimated the costs of rolling out smart meters on a country basis. Infrastructure costs (remote metering and management systems) depend on the studied country. In Austria (PWC 2010), the costs estimations of rolling out smart meters (Table 5) have been carried out for each agent involved (final consumers, generators, network operator, and retailers) under four scenarios. Scenario 1 assumes 95% replacement rate of conventional meters for the 2011-2017 period, scenario 2 assumes 95% replacement rate for the 2011-2015 period, while in the case of scenario 3 the replacement rate is 80% for the 2011-2020 period.

Table 5: Costs of rolling out smart metering in Austria (PWC, 2010)

NPV 6%, 20 years [M€]	Scenario 1 95% 2017	Scenario 2 95% 2015	Scenario 3 80% 2020
Consumers	0	0	0
Network operator	2299	2425.8	1843.1
Retailers	718.7	769.3	557.9
Generation costs	0	0	0
TOTAL	3017.8	3195.1	2401

Besides the rolling out costs, other studies estimate the costs related to communication and control infrastructure. In Spain, within the CENIT-GAD project (Conchado & Linares 2010), the costs of control centers, communication equipment, meters, load controllers, and user-interface devices were estimated under different scenarios of active demand management penetration at the residential level. Similarly, the costs of implementing a smart grid in the US by 2030 were also estimated within the EPRI study EPRI (2011). Among the estimated costs are those related to the AMI.Table 6 shows the expected costs to deploy an AMI in the US by 2030 at the distribution level. In the table the ranges of unitary costs and total costs of the necessary equipment are estimated.

Table 6: Investment and operation costs of the AMI needed for active demand management[14].(EPRI 2011)

	Unitary costs ($)		Number of units	Unit	Total costs* ($M)	
Investments						
Advanced Meter Infrastructure, residential meters	70	140	143928676	Customers	8935	16084
Installation of residential meters	7	15	143928676	Customers	834	1787
Advanced Meter Infrastructure, commercial and industrial meters	120	500	20971918	Customers	2600	10777
Installation of commercial and industrial meters	20	65	20971918	Customers	423	1374
Other AMI-related costs	-	-	165029286	Customers	1648	4472
Maintenance						
Infrastructure maintenance	3/yr	3/yr	165029286	Customers	4438	16270

***:** Note that the total costs are not necessarily the product of the unit costs and the number of units, since the number of units represents the maximum number of units to install, while a smart grid with fewer units is possible

The metering costs of the AMI and the infrastructure needed for remote metering and management at the residential level estimated in EPRI (2011) are in the ranges observed in the survey carried out by Capgemini (2007) shown in Table 7.

Table 7: Costs of remote metering and management in different countries (Capgemini 2007)

Country	Number of meters [Millions]	Cost per meter [€]	Total Project cost [M€]
Italy	30	70	2100
United Kingdom	27	193	5211
California	4,7	213	1001,1
Sweden	1	220	220
California 1	5,1	262	1336,2
California 2	1,4	357	499,8
Canada/Ontario	4,3	453	1947,9

It can be noted from Table 7 that the costs by meter of these systems change in different countries.

[14] The costs related to the communication infrastructure needed to manage the demand actively are included in
.

2.3.1.2 Costs related to the adaptation of households

Apart from an infrastructure that allows a greater control of the system in real time and the communication between the system and the customers, it is also necessary to automate the households in such a way that the appliances may be managed according to the price signals received. That requires the use of smart appliances, load management systems, in-house displays, and communication systems. These costs have been estimated for Spain within the CENIT-GAD project (Conchado & Linares 2010) and for the US in EPRI 2011. Table 8 shows an estimation of the costs incurred by a residential customer in order to make his home suitable for demand management.

Table 8: Costs of adapting households for active demand management (EPRI 2011)

		Unit cost ($)		Number of units	Unit	Total cost* ($M)	
Customer	**Investments**						
	Load management system	150	300	143928676	Customers	2159	4318
	Displays	50	100	143928676	Customers	1439	2878
	Smart appliances	10	20	143928676	Customers	222	443
	Communication systems for building automation	5000	20000	20178151	Buildings	5045	20180

*: Note that the total costs are not necessarily the product of the unit costs and the number of units, since the number of units represents the maximum number of units to install, while a smart grid with fewer units is possible

2.3.2. Costs related to network automation

Apart from the costs related to the communications of the transport and distribution substations, smart grid deployment requires an investment in systems that improve network reliability while reducing losses. Bouhouras et al. (2010) studied how the automation of MV/LV transformers requires the installation within the transformer of a computer, MV engines (20 kV) to open switches, or IEDs (intelligent electronic devices) in order to increase the quality of supply and reduce losses.

Additionally, EPRI (2011) determines the transmission and distribution costs associated to the deployment of a smart grid in the US by 2030, including the automation-related costs of the transmission and distribution networks. Table 10 lists those costs and shows their ranges.

Table 10: Network automation costs (EPRI 2011)

		Unit costs ($)		Number of units	Unit	Total costs* ($M)	
Transmission and substation-related costs	**Investments**						
	Dynamic-Thermal Circuit Rating	10000	20000	11340	Number of substations with DTCR/12 km of line	113,4	226,8
	Substation and transmission line sensors	50000	100000	66450	Number of substations (new and existing)	1872	3532,7
	Current limiters in transmission networks	500000	500000	58017	Number of substations	580,3	580,3
	Flexible alternative current transmission systems	-	-	330	Number	4175	4925
	Communication systems within substations	50000	75000	67150	Number of substations	2777	4166
	Communication systems with substations	14400	14400	67150	Number of substations	799,5	799,5
	Phasor measurement units	125000	125000	1950	Number	244	244
	Intelligent electronic devices	110000	150000	67150	Number of substations	6110	8332
	Cyber security	100000	2200000	1454	Number of utilities	3729,2	3729,2
	Back Office systems for information management	1000000	20000000	1454	Number of utilities	32258	32258
	Maintenance						
	Increment in maintenance costs	50000/yr	50000/yr	67150	Number of substations	20022	20022

Distribution	**Investments**						
	<u>Distribution automation</u>						
	Communications with the feeding lines for AMI and smart distribution circuits	20000	20000	531600	Number of feeding lines	5776	5776
	Smart reclosers and relays	50000	50000	531600	Number of feeding lines	19617	19617
	Current limiters in distribution networks	80000	80000	66450	Number of substations	9059	9059
	Switches, reclosers, monitored capacity banks, regulators, and circuit improvements	308000	308000	531600	Number of feeding lines	99392	99392
	Voltage and reactive power controllers in feeding lines	60000	258000	531600	Number of feeding lines	19362	83258
	Smart reclosers	100000	150000	531600	Number of feeding lines	13290	19935
	Remote-controlled switches	50000	75000	531600	Number of feeding lines	1330	1994
	Direct load control (no AMI)	100	100	123949916	Number of customers	1859	1859
	ElectriNet controllers	50000	100000	531600	Number of feeding lines	3163	6326
	<u>Transformers</u>						
	Universal smart transformers with storage	37500	100000	1500000	Number	12563	12688
	Universal smart transformers with photovoltaic inverters	7500	50000	1500000	Number	12437	12937
	<u>Controllers for the local energy network</u>						
	Controllers for energy management in local networks (Energy Management Systems)	50000	100000	531600	Number of feeding lines	3163	6327

*: Note that the total costs are not necessarily the product of the unit costs and the number of units, since the number of units represents the maximum number of units to install, while a smart grid with fewer units is possible.

2.4. Key economic factors influencing the adoption of AD programs

As we have seen, the deployment of AD programs presents significant costs and benefits. These costs and benefits will drive the adoption of these programs from the point of view of the different stakeholders.

Regulators will (or should) be driven mostly by the results of social cost-benefit analyses. Here the key elements seem to be the long-term investments (of which the largest seem to be the communication costs) and benefits (regarding mostly avoided investments in networks and power plants).

DSOs, as the parties typically responsible for deploying Medium and Low voltage network infrastructure, will be mainly concerned by the costs, and particularly by those that may be more difficult to transfer to consumers, that is, the communications and control and network automation costs.

Aggregators, in turn, will be motivated by the business opportunity, that appears whenever there are significant savings (benefits) to be shared with the consumer. In particular, given the structure of most electricity markets, the most relevant benefits here will be those related to the generation markets (daily, intradaily or balancing).

However, for all these costs and benefits to take place, the keystone is the consumer. What are the key economic factors that may influence the adoption of AD programs by consumers? Again, the consumer, if reasonably rational, will also conduct her own cost-benefit analysis (not precluding of course the inclusion of other non-economic factors, such as the desire to save energy or protect the climate, among others). The benefits will come basically from changes in the budget devoted to electricity consumption, that is, there will be benefits if the expense in electricity decreases. The cost, in turn, will have two parts. Firstly, the direct cost to be paid by the consumer (typically, the adaptation of appliances and plugs in her home). Secondly, the cost that is passed-on by DSOs and aggregators in return for the infrastructure to be deployed (smart meters, telecommunication services, among others).

In the following sections we will present the order of magnitude of the different costs and benefits mentioned, first at the system level (that is, from a regulatory or social point of view), and then at the stakeholder level.

3. Evaluation of benefits within the ADDRESS project at the system level

3.1. Identification of benefits at the system level

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 Deliverable 1.1 (ADDRESS technical and commercial conceptual architectures). 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, among others
- 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 of pollutant emissions

Another important discussion, already hinted along the report, is how these benefits are distributed among different 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, we have not considered the maximization of profits or market shares in the expectations list, 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 consumers costs 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.

3.1.1.1 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:

- The reduction of the total cost of producing electricity and
- a potential reduction in the price of electricity in liberalized markets. 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 direct all savings 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. These players can be compensated for mediating the participation of consumers, and for reducing uncertainty and risk by aggregating multiple consumers.

3.1.1.2 Reduced price volatility

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

3.1.1.3 More consumer choice

AD products and services may increase the possibilities for consumers to receive electricity services, such as more information related to their consumption, or ideas for energy efficiency, etc., which in turn can result in more choices among providers. 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.

3.1.1.4 Lower loss of intermittent generation

By modifying the demand profile, AD services may prevent the loss of intermittent power generated from primary renewable energy sources such as wind or the sun (reducing the curtailment of their production). 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. Another way of looking at this issue is that the increased benefit might result in a larger penetration of renewables, which contributes both to the achievement of policy targets in this area and to a reduction in carbon emissions from the electricity system.

3.1.1.5 Improved quality of service

The quality of service provided by networks may also be improved by resorting to AD services, which can lead to fewer congestions and blackouts, better frequency and voltage control, among others. However, what would be the economic 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 will be difficult to quantify value of the service quality improvements for them. Regardless, a proxy could still 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.

3.1.1.6 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: this reduction in losses may be translated or not into tariffs for the end consumer, depending on the regulation of the system.

3.1.1.7 Reduced network investments

Similarly, AD services for the reduction of peak loads may reduce network reinforcement investment needs. Again, this is a relatively straightforward benefit, measured as the reduction in investments required with and without AD services. Nevertheless, the issue of how to share the benefits among players will still arise. For example, if all benefits are transferred to consumers, with no share for the transmission or distribution system operators, operators will have no incentive to use AD as an alternative to network investments. Thus, the mechanism by which DSOs or TSOs are paid is critical for this issue.

3.1.1.8 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, the security of supply would be reflected in the fuel 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, such as reduced price volatility and risk, lower monetary transfers to foreign energy-producing countries, better management of scarce energy resources, and, in some cases, even lower physical risk of energy shortages. Unfortunately, it is quite difficult to estimate these benefits.

3.1.1.9 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.

3.2. Evaluation of benefits at the system level

In order to quantify AD benefits, AD is going to be treated as an exogenous input for the evaluation of the benefits. Therefore, four different AD scenarios for energy and peak load reductions are assumed[15] for the 2020 load curve based mostly in the results presented by Faruqui & Sergici (2010). Table 11 shows three different assumptions. Peak load reduction, which refers to the decrease of the power demanded in peak hours (which are defined differently for each countries, but are in general terms those hours with maximum demand). The payback effect is the amount of peak load reduction that is shifted to other hours (and therefore not reduced when looking at the

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

overall load curve). Finally, energy reduction is the absolute amount of energy consumption that is forgone (e.g, when the peak load reduction is not shifted to other times, but just lost)..

Table 11: Scenarios of reduction in energy and peak load.

	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%

These scenarios represent the characteristics of different countries. 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 12 shows the scenarios studied for each of the countries assessed by the different partner institutions within this project.

Table 12: Scenarios assumed in each country

	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)

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 cases were not enough data was available, the total demand growth was assumed for residential demand.

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). In addition, 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. 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.

3.3. Reduced energy costs and reduction in pollutant emissions

The benefits of AD in terms of reduced energy costs and CO2 emissions reduction (given that most of these emissions arise from the generation of electricity) have been assessed based on the expected power systems of 2020, since this is when AD is expected to be implemented. The costs of fuel and the CO2 emissions in the scenarios with and without AD have been compared.

Referring to the power system simulation, a good methodology would be to use a sophisticated approach such as a detailed simulation with a power system model able to represent realistically how the different power plants are dispatched (e.g., Linares et al., 2008) but since this methodology was not available for all countries assessed (basically because of the lack of access to this kind of models) a simpler methodology is proposed and described below. As will be mentioned later, the simpler methodology achieves reasonable results when compared to the sophisticated one.

3.3.1. Methodology

A similar approach has been used by all partners to estimate the reduction in energy costs and in the emission of pollutants in the different AD scenarios. This approach consists on supplying 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 had to be placed on the distribution of wind, solar and hydro production.

This simple methodology provides similar results to those produced by sophisticated power generation expansion models (e.g., Linares et al., 2008) for Spain for the demand scenarios with and without AD. Table shows that the fuel costs differences between both models are at most 0.11%, whereas it is at most 1.24% for CO2 emissions.

Table 13: Difference obtained between the simple approach and the sophisticated Op. Model for the scenarios with and without AD in Spain

	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%

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+CO2 emission costs) to expansion model costs (fuel costs+CO2 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 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.

Table 14: Expansion Model Costs to Operation Model Costs Ratio

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

3.3.1.1 Energy mix

The electricity generation mix will have a large influence in the results. Thus, is key to define the different energy mixes used in this study. 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. As mentioned earlier, these are assumptions about the expected state of the power system in 2020. In some cases this will correspond to 2010 figures (when increases are not expected, or when there is no information that allows us to guess future figures).

Table 15: Installed capacity. Load factor and energy generated for the different technologies in different countries

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	-	-	-	-	-

*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[16]. 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 . 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 , using an expansion model (see Annex B). The model simulates the necessary investment from now until 2020 in order to meet demand.

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

Comillas (Spain), Consentec (Germany) and Enel (Italy) considered that the estimated energy produced in 2020 by wind plants is equally distributed through all hours of the year. Vito (Belgium) assumed the historical values of generated wind energy for 2010, published by the Belgian TSO, Elia[17], and scaled them to the expected installed capacity in 2020.

For the distribution of solar generation, Consentec (Germany) took seasonal and daily effects into account, Comillas (Spain) and Enel (Italy) assumed a flat profile, and Vito (Belgium) used synthetic load profiles for sun energy generated via the HOMER energy modeling software for hybrid renewable energy systems[18].

In the case of hydroelectricity generation, Comillas (Spain) assumed that the energy predicted to be generated in 2020 is distributed through the peak hours (in Spain, hydro is a regulating technology) and Consentec (Germany) considered that hydropower generation is the same through all hours of the year. Enel (Italy) carried out a mixed approach, they assumed that the predicted Pumped Hydro generation in 2020 will be distributed through peak hours whereas natural Hydro generation remains unchanged through all hours of the year.

Geothermal generation was only considered by Enel (Italy). It was assumed that geothermal power is equally distributed through all the hours of the year.

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.

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[16] "Previsioni di domanda energetica e petrolifera italiana 2009/2020" http://www.unionepetrolifera.it/it/pubblicazioni/2009

[17] Available at http://www.elia.be/repository/pages/465892cca4e349af8abb76414fa54f13.aspx

[18] Available at www.homerenergy.com

Data available for fuel costs, CO2 emissions, efficiencies, O&M costs and subsidies for the different technologies in the different countries are shown in the following table:

Table 16: Thermal energy requirements, Fuel costs, Emissions, O&M costs, Subsidies

	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 17: Price of CO2 for the different countries

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

3.3.2. Results

Following the simple approach, the costs and emissions for the reference scenario are shown in Table 18.

Table 18: Fuel Costs, CO2 Costs and Total Costs in the Base Scenario

		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

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.

Table 19: Reductions in Fuel Costs and CO2 emissions costs

	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 20: Reductions in Fuel Costs, CO2 Costs and Total Costs in each Scenario

	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%

As seen in Table 20, the order of Scenarios (when available for a determined country) from the maximum reduction to the minimum reduction in Fuel Costs and CO2 emissions is Scenario 4, Scenario 2, Scenario 1 and Scenario 3. The percentages of reduction, both fuel costs and CO2 emissions, vary from country to country, Germany gets a 6.84% reduction in Fuel Costs and 6.84% reduction in CO2 emissions in Scenario 2 and Italy gets a 4% and 2.5% respectively for the same Scenario. The maximum Fuel and CO2 reductions were achieved in Germany in Scenario 4 and the minimum Fuel and CO2 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 variation of benefits for the different scenarios depends of course on the peak load and energy reduction assumptions (with Scenario 4 being the one assuming larger reductions in peak load and energy, and Scenario 3 being the less favorable), but also on the power system configuration of each country: countries with more hydro will realize lower benefits from AD (given that the system is flexible), and those with more coal will see larger reductions in carbon emissions.

These results are consistent with previous studies. In order to assess the operation costs savings during peak periods for 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 which may be cited is the paper by Andersen et al. (2006) for Denmark and the Nord Pool. In this case the reduction of operation costs due to reducing peak load in 1000 MW (being peak demand about 22000 MW) during hours with electricity prices higher than NOK 1000/MWh was about 0.4% of the operation costs, which is smaller than the reductions obtained in this study.

3.4. Reduced network investments

In order to assess network investment savings associated to AD in different scenarios of Peak demand reduction, reference network models such as those available for Germany (Consentec) and Spain (Comillas) for specific representative areas (described below) were used. Reference network models are models that calculate the optimal network configuration for a given area (and also its cost), and, when run under different scenarios (such as peak load changes) can provide therefore the differences in costs between alternative network configurations.

3.4.1. Methodology

Consentec determined the network structure using the “model network analysis[19]. This is

[19] 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

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).

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 peak demand is assumed to be 5% in the base case, but then this increase is corrected based on the peak-load reduction assumed in each of the AD scenarios. For example, if peak-load reduction is assumed to be 20%, then the incremental residential peak demand is reduced to 4%.

3.4.2. Input data

Table 6: Network characteristics for the Rural/Semi-Rural and Urban areas

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 22: Unitary costs 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

3.4.3. Results

Table 23: Costs of the network for the Rural/Semi-Rural and Urban areas.

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

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 75: Savings in the different Scenarios respect to Reference Scenario for the rural/semi-rural 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%

As in the case of Fuel Costs and CO2 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, which again is reasonable given the peak-load reduction assumptions for each of them.

For most of the network components, the investments in the AD 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 (this may be due to the different optimal configuration, which requires a different weight of LV and HV lines). Despite this, and as would be expected, given that the peak load is reduced in all of them, the total network investments in the AD 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 in most cases higher for Germany than for Spain, both for urban and rural areas. This of course results from the differences in the distribution of consumers and their loads in the areas studied, but also from the differences in the costs of network elements in both countries (Germany features higher network costs than Spain). Savings are also higher for urban areas, which seems reasonable given the higher density of consumers and loads in these areas (and therefore the larger effect of AD programs).

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

Table 8: Reductions in Fuel Costs, CO2 emission costs and Network Investments.

	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	-	-

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).

3.5. 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 previous sections.

3.5.1. 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 both approaches 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 27).

Comillas, Consentec and Vito determined the average electricity price in their countries taking into account the total energy generated with each technology during 2020 and the marginal cost of each technology (Table 9). Accordingly, 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[20]), 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[21]. 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%.

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

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

Table 97: Contribution of each peak technology during a year

	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	-	-	-	-	

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

2*: Fuel+CO2

3.5.2. Results

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

Table 108: Cost of network losses avoided

[redacted]	Belgium			Germany				Italy			Spain				
[redacted]	Total	Reduction		Total	Reduction			Total	Reduction		Total	Reduction			
	Ref.	Sc. 3	Sc. 4	Ref.	Sc. 2	Sc. 3	Sc. 4	Ref.	Sc. 1	Sc. 2	Ref.	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 %)

As seen in Table 10, 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% in Belgium (Scenario 3) and Germany (Scenario 4), respectively. These reductions are larger than the results obtained in Shaw et al. (2009) for the UK using a complex methodology but in this case conservation actions were not simulated, only shifting loads were assumed. 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 .

Of course, the network losses and average electricity prices assumed have a large influence in the final savings obtained. The higher the energy price (the opportunity cost of the energy lost), the larger will be the savings. The higher the current losses of the system, the larger will be the savings induced by AD programs when reducing the amount of energy consumed (and therefore transported by the network).

Comparing savings in network losses with the other savings (Table 11), savings in network losses are around ten times smaller than savings in fuel costs and five times smaller than savings in emissions.

Table 119: Reductions in Fuel Costs, CO2 emission costs, Network Investments and Network losses.

	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

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).

4.1. Reduced costs of balancing

AD may have an interesting contribution to the reduction of the balancing costs of the system. Since supply must be equal to demand in real time, some generation units must be able to increase or reduce their output in response to demand variations. 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 into 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.

4.1.1. 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 based its calculation for Germany on data of 2009 and Comillas based it for Spain on data of 2010.
In Italy the transmission system operator, who is responsible for balancing, does not pay for the availability service but only the activation of the reserve energy. Hence, in this case the methodology proposed is not applicable.

4.1.2. 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[22.] 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, respectively.
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€.

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

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€.

Table 30: Avoided costs of Positive minute reserve

	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

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.

4.1.3. Negative minute reserve

Consentec stated that the contribution of AD to the negative balancing service only extends 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.

Table 31: Avoided costs of Negative minute reserve

	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

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

4.2. Summary of results

The following table presents the Fuel Costs avoided, CO2 emission costs avoided, Network Investments avoided, Network losses avoided and balancing costs avoided, in M€.

Table 32: Reductions in Fuel Costs, CO2 emission costs, Network Investments, Network losses and Balancing costs, in M€

	Belgium		Germany			Spain				Italy	
	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			Scen. A	Scen. B	Scen. C	Scen. A	Scen. B	Scen. C	Scen. 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		

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).

Now this very same information is presented again but translated into savings per residential/commercial customer, in € per year and customer. These figures will be easier to compare to the results obtained for individual stakeholders, and also provide a good indication of the incentives that consumers may have for engaging into AD programs.

Table 33: Reductions in Fuel Costs, CO2 emission costs, Network Investments, Network losses and Balancing costs, in € per consumer and year

	Belgium		Germany			Spain				Italy	
	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 (1*)	-	-	4.06	2.24	4.82	0.62	0.70	0.29	1.02	-	-
Network Investments-Rural (1*)	-	-	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			Scen. A	Scen. B	Scen. C	Scen. A	Scen. B	Scen. C	Scen. 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		

5. Key economic factors for ADDRESS: Cost-benefit analysis for individual stakeholders

This section provides a brief summary of Deliverable 5.4 (Report outlining business cases for Customers, Aggregators and DSOs in the scenarios detailed in WP1)[23],, which has analyzed business cases for customers, aggregators and DSOs[24]. Our objective is to show how the costs and benefits identified in previous sections translate into the individual stakeholder level. We will only provide here the major results of this deliverable; more information can be obtained by referring to D5.4 itself.

This individual analysis has only considered a subset of the costs and benefits assessed in previous sections. Table 34 summarizes the services selected and some of their characteristics, including the challenges they help solve.

Table 34: AD services and challenges that they aim to solve

Service	Actor	Challenge
Management of energy imbalances (MEI)	BRP	Imbalances within own portfolio
Tertiary reserve (TR)	TSO	Imbalances at the system level
Short-term load shaping to optimise purchases and sales (SOPS)	Retailer	Price risk at the wholesale market
Load reduction (LR)	DSO	Local constraints in the distribution grid

These services are related to the benefits assessed at the system level (section 3) in the following way:

- MEI and TR would be part of the reduced costs of balancing (section 3.6)
- SOPS is partly related to the fuel cost reduction in peak times, although at the system level we have not accounted for price risk, given that there is not a social benefit or cost arising from this (within the context of the study), but rather just a transfer of this risk from one agent to another.
- LR would result from reduced energy costs (section 3.3) and reduced network investments (section 3.4). However, the correspondence is not direct, in that D5.4 does not calculate network costs but just estimates them.

Since the electricity markets in all EU member states are not exactly the same, the conditions for implementing active demand based services may be different at least under present circumstances. Although the services, relations, functionalities and results presented below are carefully compiled and well documented and consequently in general should be valid for most countries, there may be markets where certain alterations may become necessary taking into account their specific requirements. However in this document it will not be possible to cover

[23] This is a confidential document. Access can be provided by the consortium upon request. Request shall be made to the Project Coordinator.

[24] Producers may also benefit from AD actions. For example, renewable or baseload producers may benefit from AD by preventing them to curtail their production. Other producers may reduce the need to invest in peaking plants, which may also bring savings in terms of carbon emissions. Some of these benefits have already been assessed in section 3, and others (capacity-related) are included at the end of this section.

all market conditions and service variations. Therefore, these services were implemented[25] in different European countries (Spain, Italy, Finland and Belgium). Compared to the previous assessment in chapter 3, we substitute Germany for Finland, but the rest of the countries are the same, which facilitates the comparison of the results.

The economic analysis is based on the e^{3}value methodology [e^3 web], which is very well suited for network-based businesses where many participants interrelate with each other. In addition, this methodology focuses on the concept of economic value and it provides a graphical representation of all the actors needed to run the business under analysis. For all these characteristics, the e^{3}value methodology appears as a very good method to analyze the economic feasibility of AD services.

The application of the methodology to the four services in the different countries resulted in some graphical models (step 2), which were used as the starting point to build up the economic assessment tool. In particular, these models identified the money exchanges between the different actors, as well as the data requirements (step 3), which were summarized in [IR5.4].

While building the economic assessment tool, and due to the strong computational effort required for the analysis, a series of assumptions were made in order to allow the analysis to be carried out, both regarding actors and data. The major assumptions were:

- The aggregator performs, in addition to aggregation, the retailing and BRP activities, and it always takes the best decision possible, i.e. a perfect forecast of market prices and system and portfolio imbalances are assumed.
- In addition, no investment costs are considered, since the development of active demand is likely to happen in the future when, on the one hand, appliances will be smart (no need for smart plugs) and the customers themselves will probably buy the EnergyBox (or something equivalent) to monitor and manage their electricity consumption.
- Domestic retail price is the total price paid by domestic consumers to retailers for electricity, excluding taxes, and including T&D fees and other system costs, except in Finland, where T&D fees are paid as a separate item. Average retail price for non-domestic consumers is the average value of the retail prices paid by the remaining types of consumers (industrial, commercial, public, SMEs…).
- Active consumers were assumed to be able to either increase or decrease their consumption as an answer to active demand service request. Flexibility data were based on the assumptions taken in Task 5.1, where different percentages of demand flexibility and capacity for the four scenarios defined in [D1.2] were considered. In each of them, active consumers are flexible in a fixed percentage of total consumption in a given period. For the base case, the first scenario was considered: 20% peak load reduction and 20% payback when consumers are requested to reduce consumption.
- Based on the outcome from field tests carried out in WP6, Active consumers can be requested to provide one AD service per day at most to increase consumption and another one to reduce consumption. On the same grounds, the duration of AD service provision is assumed to be one hour, and the payback is made just after the end of the call. The energy required for the payback will be traded in the hour-ahead market.
- When, either because it is activating an AD service or due to the payback effect, the

[25] In this document, "implementation" refers to the modelling and the analysis of a business model or service, by taking into account the existing conditions in a given country or market and with the aim of performing the economic assessment within Task 5.4. Therefore, it has nothing to do with the ADDRESS field implementation carried out in WP6.

aggregator sells energy in the hour-ahead market, it will replace producers, so they will sell a lower amount of energy. On the contrary, if it is buying energy in the hour-ahead market (for the same reasons), that energy will be provided by producers.

In parallel with the economic assessment tool construction, historical data were collected from the selected countries, getting both some general data and some consumption and price profiles for the base year (2010). Data were also collected from other WP5 tasks (T5.1) and from the field test being performed in WP6.

During the economic assessment (step 4), each service was compared to the situation in which there was no AD action, so that the potential of AD provision could be estimated. Since the remuneration of active consumers will strongly depend on the evolution of AD markets, which is unknown at the moment, the total potential of each AD service in each country was calculated. Then, this potential must be used by the aggregator to reward consumers for their AD actions and to make its profit.

As in section 3, we have assumed that the penetration of AD is not relevant enough as to change the energy price in the market. If AD penetration is higher, then prices in peak times would decrease, hence reducing the incentive for these actions.

The results obtained are presented below.

5.1.1. Short-term load shaping to Optimize Purchases and Sales (SOPS)

Once the hourly metering infrastructure is in place, retailers (aggregators) will be able to ask their consumers to reduce their load to sell back part of it to the hour-ahead market when it expects the hour-ahead market price to be attractive.

6. Active consumers' annual CF difference (€/customer)	0.78	2.17	2.34	1.41

When the aggregator sells back part of its consumers' consumption in the hour-ahead market, it will offer a cheaper price than some producers. Therefore, active consumers will replace those producers in the hour-ahead market merit order and, hence, the cash-flow increase for the aggregator will come from a cash-flow reduction for producers.

6.1.1. Management of Energy Imbalances (MEI)

On the other hand, the deployment of metering infrastructure will allow any BRP (aggregator) to ask for demand increase or decrease from their consumers in order to reduce its balancing portfolio imbalances.

In this case, the aggregator will use active consumers' flexibility to reduce its portfolio's imbalance, thus reducing system balancing needs. As a result, producers will be asked to provide less balancing energy and, hence, they will obtain less money for that.

6.1.2. Load Reduction (LR)

One of the reasons for the installation of smart meters is to allow DSOs to have more detailed information about the situation in their respective grids. Thanks to this deeper knowledge of grid status, DSOs will be able to improve their operations, leading to an optimized use of distribution network assets.

One of the potential improvements is the creation of AD markets (where aggregators would bundle and offer small consumers' flexibilities), which would be called upon in the (few) periods in which the grid is under stress, so that demand can be locally reduced[26] and costly investments in grid reinforcements can be deferred (provided that regulation allows this).

In this case, the DSO uses AD to avoid grid problems and, thus, pays for it, so there is a strong reduction in DSO's cash-flow. However, AD actions will help the DSO improve its grid operation and, hence, this cash-flow reduction must be compared to the deferred grid reinforcement costs[27], in order for the DSO to assess the feasibility of setting up the AD service market. Of course, regulation must be appropriately designed, so that DSOs have an incentive to promote AD.

Even if in this case AD does not compete with producers because service activation depends on grid status and not market prices, producers will still be affected by AD actions, since, when demand is reduced, it is sold back in the hour-ahead market, and, hence, producers will be selling less energy than in the case with no AD. On the contrary, when payback is made, producers will sell more energy, but such increase is not enough to compensate for the loss of profit resulting

[26] Here only load reduction has been considered, but of course AD can also be used to increase demand when needed (e.g, to prevent the curtailment of renewable or base-load generation, in which case producers would be the ones who profit from this)

[27] The amount to be saved will strongly depend on the distribution grid conditions (see subsection **Errore. L'origine riferimento non è stata trovata.** for some examples) and on the DSO confidence towards AD (the results of the services are difficult to predict due to customers' possibility to override AD activation, uncertainty of aggregator's system reliability, etc.). In the short-term, it is likely that DSOs still reinforce their networks, but, as AD markets evolve and DSOs gain confidence, they are expected to use AD to avoid reinforcements more frequently.

from the AD action.

6.1.3. Tertiary Reserve (TR)

Although present market access rules for providing balancing capabilities to the TSO are not suitable for small consumers, the development of AD markets may lead to a future in which different aggregators could consolidate the flexibilities of a number of small consumers to participate in these markets.

The aggregator will offer more competitive prices than some producers to the TSO, which will allow it to replace producers in balancing service provision.

6.1.4. All cases together

Since the investments required for the provision of each service are common, aggregators will probably not provide just a single service, but will look at the different markets (one market per service) to offer the most profitable one at each moment. Taking into account the constraints deriving from assumptions (one call per day to increase consumption and another call to reduce consumption), the aggregator estimates which will be the service that will provide the highest benefit when increasing consumption on a daily basis and activates it (and not the other three). Then, the aggregator repeats the same calculation to determine the service to be activated to reduce consumption.

Table 35 presents the changes in annual cash-flows and the number of calls for the different countries, when the four services are combined. As detailed above, the aggregator compares the four services in each hour and activates the most beneficial one. Therefore, these results are not the sum of the particular results, but the optimization of the four services at the same time.

Table 35: Changes in annual cash-flows per active consumer when the four services are applied together

Changes in annual cash-flows per active consumer with all the services together								
	Spain		Italy		Finland		Belgium	
	€	*% bill*	€	*% bill*	€	*% bill*	€	*% bill*
Aggregator	2.64	0.55%	4.23	1.00%	6.00	0.51%	5.29	0.62%
Active consumers	1.20	0.25%	2.01	0.47%	2.72	0.23%	1.57	0.18%
Aggregator + Active consumers	3.84	0.80%	6.24	1.47%	8.72	0.74%	6.86	0.80%
Annual energy bill (€)	480.38		424.84		1,185.24		859.16	
Number of AD calls	536		717		454		605	

The effects of the application of the four services together in the different actors' cash-flows are the same as in the application of each service on its own.

The case with the highest potential is, obviously, the one that combines the four services together, i.e. the one that selects the most profitable service to be provided in each day, but both TR and LR services offer potentials which are only slightly lower. Regarding the number of calls, both TR and MEI services are called quite often.

The country with the highest potential is Finland, Italy and Belgium have a similar potential, and Spain is the country with the lowest one. The main reason for this is that the market price levels are lower in Spain than in the rest of the countries and the amount of energy reduced by each consumer in Finland when the LR service is activated is much higher than in the rest of the countries under study.

The potential is made up of the savings that active consumers see for reducing their total electricity consumption and of the profit that the aggregator can make in the markets. The results for the different countries are presented in Table 35.

A sensitivity analysis was performed to see the effects that different price and demand conditions have on the results. In particular, the effect of two demand profiles (2010 and 2020) and the variation in electricity prices (volatility increase by 50%, mean electricity price increase by 50% and the appearance of price spikes in 1% hours) were assessed, as Table 36 shows.

Table 36: Results of the sensitivity analysis for different price and demand conditions

Changes in AD service potential with all the services together (€/active customer)				
	Spain		**Italy**	
	€	*% Δ*	*€*	*% Δ*
Base case 2010	3.83		6.24	
2010, +50% volatility	5.11	33.4%	6.99	12.2%
2010, +50% mean	5.18	35.2%	8.22	31.7%
2010, 1% spikes	13.72	258.2%	9.61	54.0%
Base case 2020	4.84	26.2%	7.64	22.6%
2020, +50% volatility	6.34	65.2%	8.43	35.2%

2020, +50% mean	6.08	58.5%	8.00	28.3%
2020, 1% spikes	16.52	330.9%	11.82	89.5%

The effect of payback was also analyzed and, as expected, as payback increases, the potential value associated to AD is reduced, even if the number of calls increases, as shown in .

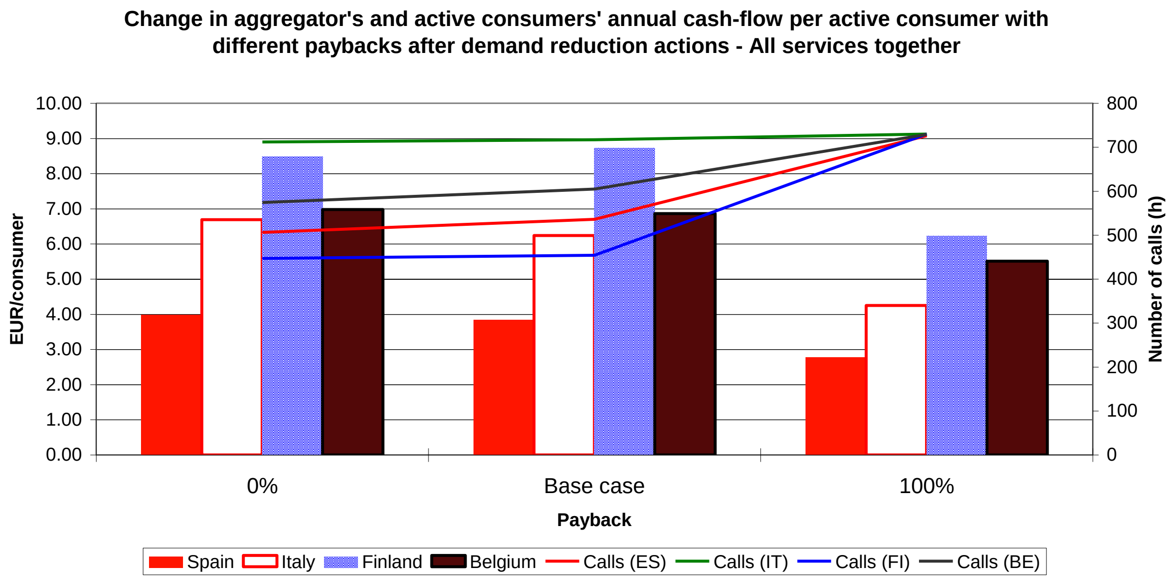

Figure 1: Effect of payback on AD potential

Therefore, the potential for providing the selected AD services in the countries analyzed will strongly depend on the future evolution of electricity markets and regulation. This way, positive changes in market regulation, increased customers' environmental awareness, changes in tariff structures/design and higher cost of energy fuels, among others could create the conditions needed by aggregators to launch AD programs and by consumers to engage in those programs.

However, there are some other "capacity-related" services whose potential can be attractive today. In these services, AD helps grid operators, either by reducing the allocation of grid use, by providing additional resources for balancing the system, or by deferring/avoiding network investments.

In Spain, the use of AD to reduce the contracted power can save an active consumer about 29.5 €/year. If an interruptibility service were implemented for small consumers as there is for big ones, they could obtain additional 24.7 €/year.

In Belgium, there is no contracted power, but active consumers could still obtain about 18 €/year if they were allowed to participate in the market for the provision of reserve services for tertiary control to the TSO.

In Italy, aggregators may provide the following services:

- Smart load reduction service to the DSO, so that the latter can be involved in the mitigation service that is currently active in Italy. By taking into account that the TSO pays the DSO for mitigation services 10 €/kWh for the first 4 hours and 3 €/kWh for the following hours, and if the DSO shares 90% of this amount with the aggregator, each consumer can get about 26.1 €/year for providing 0.2 kWh per call in about 40 calls.
- Smart load reduction as an interruptible load service, whose total cost for the system and

number of providers are a bit higher than in Spain, so that the potential for small consumers (if they are allowed to provide it) should be in the same range of about 25 €/year.

- Voltage regulation and power flow control for the DSO, so that the annual investments of about 71 M€ in the LV networks could be significantly reduced. The amount that the DSO can actually save will strongly depend on the distribution grid conditions and on its own confidence towards AD. In the short-term, it is likely that DSOs still reinforce their networks, but, as AD markets evolve and DSOs gain confidence, they are expected to use AD to avoid reinforcements more frequently.

Annual electricity bill for Italian consumers is about 524 €, 95 € of which correspond to system costs that could be reduced by the provision of these services. Therefore, we could envisage that all domestic consumers could benefit from a reduction in their annual electricity bill, as long as AD markets are developed and, as expected, they are more cost efficient in providing these services.

There are several interesting possibilities for specific AD services in other countries than Spain, Italy, Finland and Belgium, but only the example of capacity related services in the UK is elaborated in deliverable 5.4. From the analysis, it can be concluded that:

- Although the minimization of DSO interconnection costs and investment deferral or avoidance is case sensitive (some applications would produce no value, whereas others can offer significant benefits), in cases with high capacity charges and fixed costs, or networks approaching their operational limits and subject to significant demand growth uncertainty, AD can provide around 237 and 4740 Euro per year for domestic and commercial customers, respectively. Another good point of the AD capacity services for DSOs is their low frequency, which in the base test case and with a 5% AD penetration was only 3.78h per year per customer (i.e. 8 HH calls per year in the UK). This service could be notably attractive for customers, as it could offer high gains for a service that would only be active a few hours during some years.
- The value for avoidance of transmission charges is less (£4.38 or about 5 € under ADDRESS consistent assumptions, £7.53 or about 9 € for domestic and £141-£145 or about 170 € for commercial) but still reasonably attractive, especially given the low number (around 15) of calls per year.

7. Conclusions

The degree of adoption of Active Demand programs will be largely influenced by their costs and benefits, and more particularly, by the costs and benefits that accrue to each agent in the power system. For example, saving money is cited as the most important reason for engaging in AD programs in Spain (although in the Brittany Islands in France other reasons such as security of supply and protection of the environment appear to be as important as money savings due to the particular situation of the islands).

Regulators will (or should) be driven mostly by the results of social cost-benefit analyses. Here the key elements seem to be the long-term investments (of which the largest seem to be the communication costs) and benefits (regarding mostly avoided investments in networks and power plants).

DSOs, as the parties typically responsible for deploying Medium and Low voltage network infrastructure, will be mainly concerned by the costs, particularly by those that may be more difficult to transfer to consumers, that is, communication and control and network automation costs.

Aggregators, in turn, will be motivated by the business opportunity that appears whenever there are significant savings (benefits) to be shared with the consumer. In particular, given the structure of most electricity markets, the most relevant benefits here will be those related to the generation markets (daily, intradaily or balancing).

However, for all these costs and benefits to take place, the keystone is the consumer. What are the key economic factors that may influence the adoption of AD programs by consumers? Again, the consumer, if reasonably rational, will also conduct her own cost-benefit analysis (not precluding of course the inclusion of other non-economic factors, such as the desire to save energy or protect the climate, among others). The benefits will come basically from changes in the budget devoted to electricity consumption, that is, there will be benefits if the expense in electricity decreases. The cost, in turn, will have two parts. Firstly, the direct cost to be paid by the consumer (typically, the adaptation of appliances and plugs in her home). Secondly, the cost that is passed-on by DSOs and aggregators in return for the infrastructure to be deployed (smart meters, telecommunication services, among others).

The goal of this report has been to present a review of both previous estimates of the costs and benefits of AD programs, and of the major results obtained within the ADDRESS project, in order to identify the key economic factors that may drive the adoption of the ADDRESS architecture, both from the system and from the individual stakeholder point of view.

At the system level, the benefits assessed have been: reduced energy and pollution costs, reduced network investments, reduced network losses, and reduced costs of balancing. The total figures obtained per country range from 400 to 2,200 million Euros per year, which amount to 1.5 – 6.5% of each country's system typical costs. Of these savings, most correspond to a reduction in fuel and emission costs, and a much lower share belongs to network benefits and savings in balancing. The actual numbers vary based on the power system configuration in each country and on the scenario of penetration of AD. The four scenarios considered, originally proposed in deliverable D1.2, differ in the peak load reduction and total energy reduction (the assumptions are described in section 3.2),

These are not negligible benefits, although of course they should be compared against the costs of setting up the infrastructure required for AD programs to take place. Here the estimation is even more difficult, as there are few real cases in which all the infrastructure required for the ADDRESS architecture has been installed (it should be highlighted that this architecture is not only the deployment of smart meters), and even in these cases it is not clear whether the costs quoted are already commercial (the low level of penetration of these technologies suggests that current costs are much higher). In addition, given that this infrastructure can be used for other purposes, and not only AD, it is difficult to allocate the costs to AD programs in order to compare them with the benefits[28].

However, as mentioned before, these system-level benefits may be interesting as drivers for regulators' or policy-makers' decisions, but will not determine whether the rest of stakeholders will actually engage in AD programs. In this regard it would be more important to assess the individual benefits and costs for each stakeholder.

This presents an important difficulty: the attribution of the costs and benefits of AD programs will depend both on the regulatory context and market conditions. The regulatory context may determine for example to what extent the savings achieved by DSOs or TSOs through AD programs must be passed on to consumers. The market conditions can allow for example the sharing of benefits between aggregators and consumers.

This report presents two different estimations in this regard. A first one, in which the total social benefits are divided by the number of consumers affected. This should provide an indication of the benefits available for sharing between the agents. Depending on the country and on the scenario considered for the penetration of AD programs, we have estimated these total benefits to be between 6 and 48 Euros per consumer per year.

As mentioned before, this does not mean that a consumer would actually enjoy these savings. Therefore, the report also presents a second estimation, in which the current regulatory and market context is taken into account, and in which the benefits to be achieved by each individual stakeholder from different AD services have been calculated. These calculations are further described in deliverable D5.4, and are based on several assumptions which can be consulted in that document[29].

For example, if we add the benefits to be obtained from the provision of load reduction, tertiary reserve, management of energy imbalances, or short-term load shaping, aggregators would receive between 3 and 11 Euros per year, whereas consumers would receive between 3 and 7 Euros per year. It should be noted that these numbers do not need to be added to the total social benefits presented earlier because they are private benefits from a subset of AD services.

We acknowledge that these are not large figures, which might even go unnoticed to consumers and therefore not engage them much. Here the general caveats for this study should be reminded again: we have not been able to quantify all of the potential benefits of AD programs (e.g., better management of network congestions and emergencies); we are assuming current prices for electricity (these prices might increase in the future); and we are also assuming the current system flexibility needs for the scenarios, whereas in reality flexibility needs might increase significantly in a scenario with a larger penetration of renewable energy.

As an example of benefits not considered here (and not directly comparable to figures ES-1 and ES-2), deliverable 5.4 estimates the value of capacity-related services, obtaining figures of up to 54 €/year for Spain, or Italy. For the UK, where a deeper study was undertaken, residential consumers

[28] This of course brings the question of how to share the costs among the different applications of the smart grid.

[29] E.g., AD calls are limited to one call of 1 hour per day; there is no cost for the aggregator; the same flexibility is considered for all active consumers, etc.

could obtain up to 237 Euros per year, and commercial ones up to 4740 Euros/year. These, if achievable, are clearly stronger drivers for action for consumers.

In addition, and based on the field tests carried out within the project, and also on evidence from other pilot projects, it is clear that automation of consumer response such as the one envisaged by the ADDRESS architecture would make easier the engagement of consumers.

Therefore, when all these elements are considered, the future for AD in Europe looks indeed possible.

8. References

8.1. Project documents

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

Deliverable 1.1. ADDRESS technical and commercial conceptual architectures.

Deliverable 1.2. Application of the ADDRESS conceptual architecture to four specific scenarios.

Deliverable 5.4. Report outlining business cases for Customers, Aggregators and DSOs in the scenarios detailed in WP1

8.2. External documents

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9. Revisions

9.1. Revision history

Version	Date	Author	Notes
0.1	31/05/2013	Pedro Linares	First release
0.2	15/06/2013	TB members review	Comments
0.3	30/06/2013	Pedro Linares	Updated version
0.4	8/07/2013	TM	Comments
0.5	12/7/2013	Pedro Linares	Updated version
0.6	15/07/2013	PC	Comments
0.7	18/07/2013	Pedro Linares	Updated version
1.0	19/7/2013	PC/QMO	Final approval