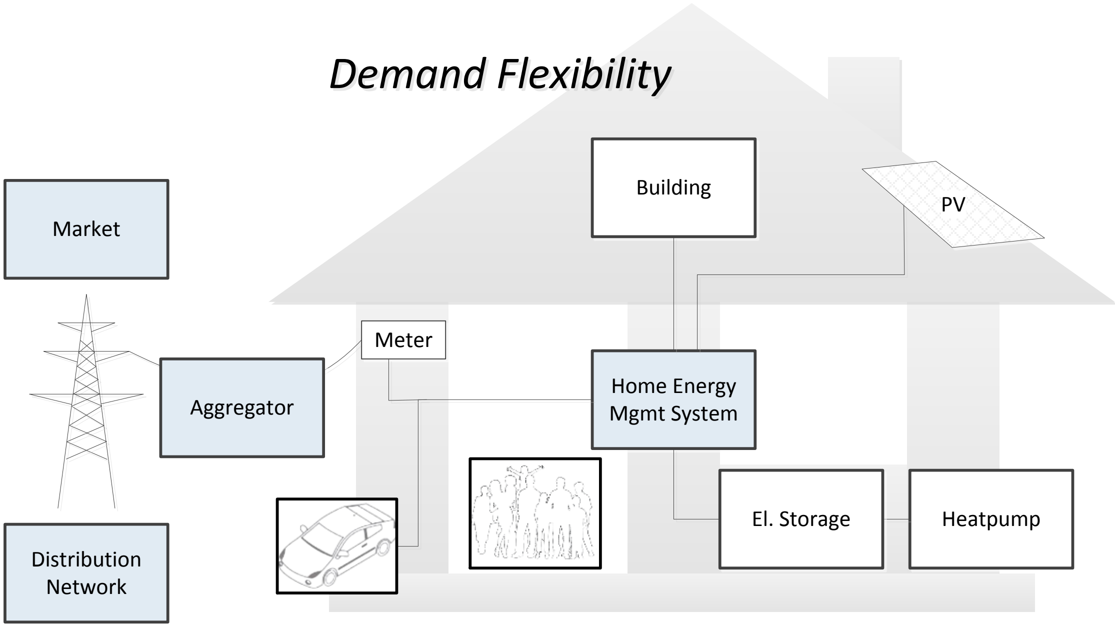

IEA DSM Task 17

Valuation Analysis of Residential Demand Side Flexibility

Demand Flexibility in Households and Buildings

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Contents

Foreword

Context

Task 17 of the IEA DSM program is to provide an analysis of the use of demand response, distributed generation and storage for energy systems operation [1]. The project consists of four subtasks. Subtask 10 describes the context and covers the current role and the interactions of flexible consumers and producers in the energy system. Subtask 11 covers the changes and impacts on grid and market operation once optimally using demand flexibility and includes valuation of demand side flexibility. Subtask 12 collects experiences and describes best practices in several countries. Subtask 13 ends with the conclusions. This document is the result of Subtask 11. Figure 0-1 illustrates the approach and the project structure.

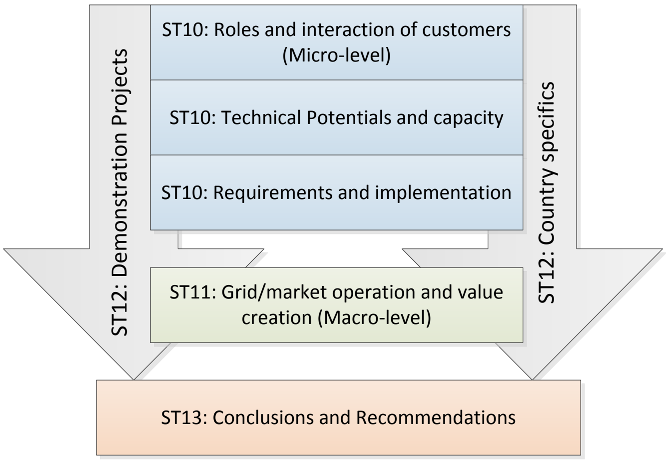


Figure 0-1 General approach of Task 17

Aim of the document

This document discusses the contribution of flexibility to the value stream in the electric energy system. Based on the definition of actors and their roles, it analyses the valuation of demand side flexibility. Related methodologies on cost benefit analysis with focus on demand flexibility are presented. This overview of standard methods is used for value evaluation and brief discussion of main benefits and costs.

Structure and methodology

The information in this report relies on the knowledge of country experts obtained from interviews and direct contributions as well as from papers, discussions and presentations at workshops. Contribution of flexibility and their value is analyzed for different actors and services. A comparative study on cost-benefit evaluation methods are listed in the second part.

Executive Summary

The document starts with background about the ongoing transition of the energy system and demand response integration. Use cases on how flexibility can create value are discussed in details with respect to each actor and their corresponding roles, with some examples given. These use cases are markets, network operators, customers and the society. Coordination schemes and their introduction and design of markets are presented and analyzed.

A detailed study on existing valuation schemes and cost-benefit analysis frameworks with a summary and overview of boundary conditions and scenarios is part of chapter 4. This is supported by an extensive number of existing valuations of smart grid projects with a particular focus on residential demand response.

The document continues on the subtask 10 deliverable that describes actors and their roles, as well as potentials which can be further translated into commercial and grid operation cost/benefit analyses.

Abbreviations

ADR	Aggregated demand response
AGG	Aggregator
ADR	Aggregated Demand Response
BRP	Balance Responsible Party (EU)
BA	Balancing Authority (US)
BEES	Battery Electrical Energy Storage
B2B	Business to Business
BEMS	Building Energy Management System
DF	Demand Flexibility
DNO	Distribution Network Operator
DR	Demand Response
DSF	Demand Side Flexibility
W23DSM	Demand Side Management
DSO	Distribution System Operator
DF	Demand flexibility
DER	Distributed Energy Resource
DG	Distributed Generation
EE	Energy Efficiency
FSP	Flexibility Service Provider
HEMS	Home Energy Management System
ISO	Independent System Operator
MO	Market Operator
PTU	Program Time Unit
SCADA	Supervisory Control and Data Acquisition
SGCG	Smart Grids Coordination Group
TNO	Transmission Network Operator
TSO	Transmission System Operator
VPP	Virtual Power Plant
VPN	Virtual Private Network

Definitions

Aggregated Demand Response
Can be understood as aggregating a large number of small resources and utilizing statistical behavior to increase availability and reliability, which would not be possible when using a single resource individually.

Aggregator
Definition from the Smart Grids Task Force – Expert Group 3:
"A legal entity that aggregates the load or generation of various demand and/or generation/production units. Aggregation can be a function that can be met by existing market actors, or can be carried out by a separate actor. EED: aggregator means a demand service provider that combines multiple short-duration consumer loads for sale or auction in organised energy markets." [2]

Flexibility Service Provider (FSP)
An FSP makes use of aggregated devices delivering flexibility in supply or demand. For instance it could be an aggregator who offers services with the portfolio of flexible resources to different stakeholders/actors in electricity system operation.

Flexibility Operator
Is the entity that uses the provisioned flexibility (e.g. facilitated by an FSP) on a market (e.g. BRP or DSO).

Balance Responsible Party (BRP), Balancing Authority (BA)
A legal entity that manages a portfolio of demand and supply of electricity and has commitment to the system operator in an ENTSO-E control zone to balance supply and demand in the managed portfolio on a Program Time Unit (PTU) basis according to energy programs. Legally, all metered nodes in the power system have program responsibility; this responsibility currently ultimately is delegated to the BRP.

Customer Energy Management System (CEMS) / Home Energy Management System (HEMS)
A customer or home energy management system coordinates with energy-using equipment (such as HVAC, water heaters, lights, pumps, local generation, and storage to control their operation to conveniently meet the needs of the household occupants. It may also include energy efficiency functions that help reduce the overall energy needs of the home. This automation system is an important enabler for demand response. Additionally it enables the possibility to receive a DR signal or tariff/price signal to provide a number of automated services that optimize operation to reach cost and energy efficiency with the constraints of the transmission and distribution system.

Demand side management (DSM)
"The planning, implementation, and monitoring of activities designed to encourage consumers to modify patterns of energy usage, including the timing and level of electricity demand. Demand side management includes demand response and demand reduction." [2] In this context, it is assumed to include Energy Efficiency as well as Demand Response as DSM operational objectives. The presence of a consumer-side generation or storage system (such

as PV and battery) does not necessarily imply the active management of these resources at the demand side. Only active participation of these resources by responding to a signal or other strategy to alter the shape of the load profile is considered as a ‘managed’ demand or an ‘active’ demand side management,

Demand Response (DR)

DR can be defined as a change in the consumption pattern of electricity consumers (e.g. load shifting, load decrease) in response to a signal (e.g. changes of electricity price) or due to other incentives or objectives (e.g. increase of the overall system performance, reliability of supply) [3],[4]. It includes the active response of generation and storage systems at the consumer-side (‘behind-the-meter’), by changing their ‘original’ generation pattern. Demand response, a term seen from the utility perspective, thus also includes generation in terms of negative demand.

Distributed Energy Resource (DER)

Subsumes devices on both sides of the electric meter in the distribution network (as opposed to central generation units) that are able to provide or consume energy (e.g. PV system, storage). Additionally it is capable of reacting to certain control signals or provides services (e.g. on/off, power reduction, voltage control) requested from energy management systems or other system controls. With respect to this definition, a DER can be considered as a Demand Response Resource if it is under control to response to higher control objectives and varies from its static generation or demand pattern.

Demand (Side) Flexibility (DF, DSF)

Adapted from the definition from the Flexibility Roadmap (Copper Alliance, Ecofys 2015).

“Flexibility is the ability of demand-side power system components to produce or absorb power at different rates, over various timescales, and under various power system conditions in response to a signal or triggered by a local event at the residential premises. Demand-side flexibility options include varying consumption. Opportunities for varying demand exist in many energy intensive industrial processes, irrigation and municipal water pumping, wastewater treatment, air and water heating and cooling (HVAC) systems, and electric vehicle charging. Energy efficiency investments (such as better insulation in buildings) can contribute to flexibility by freeing up traditional resources (such as HVAC units in this case) to offer greater temporal variability”

Definition from Eurelectric, Jan 2014:

“On an individual level, flexibility is the modification of generation injection and/or consumption patterns in reaction to an external signal (price signal or activation) in order to provide a service within the energy system. The parameters used to characterize flexibility in electricity include: the amount of power modulation, the duration, the rate of change, the response time, the location etc.”

Definition from Rocky Mountain Institute, August, 2015 [5]

“Demand flexibility uses communication and control technology to shift electricity use across hours of the day while delivering end-use services (e.g., air conditioning, domestic hot water, electric vehicle charging) at the same or better quality but lower cost. It does this by applying automatic control to reshape a customer’s demand profile continuously in ways that either are invisible to or minimally affect the customer, and by leveraging more-granular rate structures that monetize demand flexibility’s capability to reduce costs for both customers and the grid.

Importantly, demand flexibility need not complicate or compromise customer experience. Technologies and business models exist today to shift load seamlessly while maintaining or even improving the quality, simplicity, choice, and value of energy services to customers."

Distributed Generation (DG)
Smaller size generation (as opposed to bulk generation and dispersed) connected to the distribution network on medium and low voltage levels. Typical nominal powers are ranging from 1-50MW to 5-100kW in the respective network level. DG can be controlled locally or be part of central dispatched control operations.

Dispersed Generation
Smallest generation connected to the distribution network on low voltage levels and, opposed to bulk generation, not connected to a control center. Typical nominal powers are ranging from 1-5kW in the LV network level. Dispersed generation is best forecasted in an aggregated way; no mechanisms for direct control generally are implemented into current SCADA-systems so direct DSO control is not possible. Small, distributed generation systems like residential PV-units are also coined dispersed generation to emphasize the fact, that they are free-running.

Distribution Network Operator (DNO)
DNO maintains the distribution networks infrastructure in an asset based, investment manner. The DNO role is completely regulated and no commercial operation is possible.

Distribution System Operator (DSO)
DSO is responsible for the reliable operation of the distribution system.

Energy Efficiency (EE)
Thermodynamically, energy efficiency means the efficiency of a physical or chemical conversion process. Energy efficiency measures are ranked under demand side management (DSM), so utility driven. The definition from the Smart Grids Task Force – Expert Group 3 is:
"An actual reduction in the overall energy used, not just a shift from peak periods. Energy efficiency measures are a way of managing and restraining the growth in energy consumption. Something is more energy efficient if it delivers more services for the same energy input, or the same services for less energy input." [2]

Variable Output Renewable Generation
Generator which uses a primary energy source which is variable in its nature, e.g., photovoltaic systems, wind power generators, small hydro plants. The variability and predictability of these generators depends on their type and environmental conditions.

Prosumer
A utility customer that produces electricity. Roof top PV installations and energy storage battery systems are examples of homeowner investments that allow people to do both - consume and produce energy - for use locally or export during certain parts of the day or the year.

1 Introduction

1.1 Background

This is the second deliverable of task 17 phase 3 “Integration of Demand Side Management, Energy Efficiency, Distributed Generation and Storage” within the IEA/DSM program. Every subtask has a deliverable. In the first deliverable, after a general introduction on power and energy systems, the interfaces, roles and potentials of providing flexibility are discussed. In the second deliverable, identified technologies are assessed regarding their financial viability and maturity. In the third deliverable, an analysis of finished projects is performed and best practices are discussed. The fourth deliverable finally contains conclusions and recommendations.

Currently, in a number of European countries, connection of large scale wind and DG-RES leads to problems on the electricity market (negative prices for electricity in case of massive wind supply in periods of low consumption) and problems with voltage level and stability (especially in rural areas with large PV-production and low local demand). Furthermore, substitution of energy transports and storage of gas and liquid fuels by electricity leads to additional capacity problems in existing electricity grids. Examples of the latter are EVs and heat pumps. The need for increasing the DER-system embedding potential is currently urgent. In some countries, it is already necessary to curtail renewable electricity producing systems and it has to be paid for exporting generated electricity to the main grid.

On the other hand, most electricity market designs are not tailored for the current increase of the number of prosumers, infeed from lower voltage levels and even discourage the delivery of flexibility. Most electricity markets currently are geographically organized in and aligned to control zones, that match the high voltage transmission network, while the infeed of renewables takes place on the distribution system MV- and LV-levels. From this perspective, parallel markets with the scope of the distribution system would be required, although the liquidity of these markets might be too small.

Within the electricity sector and the current legislation and regulation, the DSOs are mostly affected and placed in the position to utilize end-user flexibility. This theme has been the subject of a number of national and international research projects. In addition, on the EU-level and in the US, inventories of project portfolios have been made. The introduction of renewable energy resources in competitive energy market environments can be seen not to have the effects originally targeted. Goal in this subtask is combining all this information in a common methodology for deriving quantitative information on these issues and how the flexibility uncovered in subtask 10 can be utilized to counteract inefficiencies. Smart Grid technologies currently are in the infancy phase.

1.2 Integration of demand response

In Figure 1-1 the increased coordination need between several actors (in grey letters) in regard of the integration of flexibility and different flexibility use cases are depicted based on different roles (red numbering).

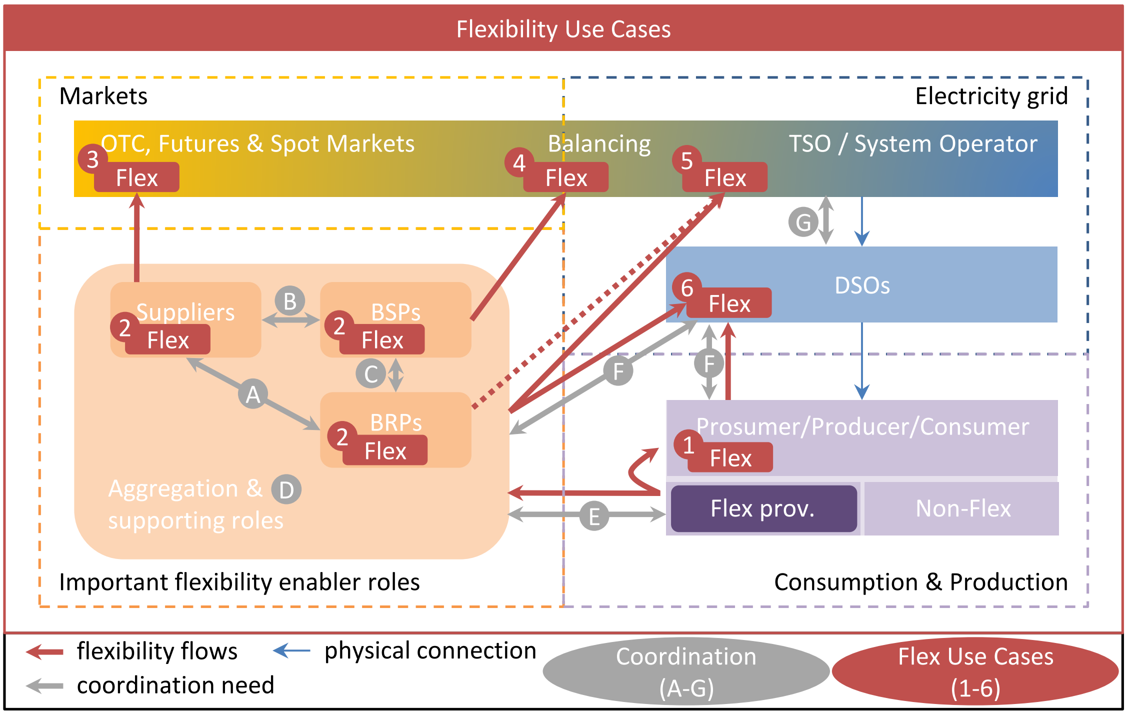


Figure 1-1: Flexibility use cases for different roles and coordination need

The following use cases for flexibility are recognized and will be analyzed:

1. Coverage of own consumption of the prosumer, minimization of grid costs and provision of flexibility to the aggregator
2. Portfolio optimization of the supplier, BSP and BRP
    a. Utilizing price differences at the energy markets
    b. Minimizing imbalance settlement costs
    c. Participation at the balancing markets
3. Value of flexibility for the integration of renewable energy in the spot markets
4. Balancing of the system (Frequency and voltage control at TSO level)
5. Grid services with flexibility for the TSO (black start, island operation, etc.)
6. Grid services with flexibility for the DSO

2 Contribution of flexibility to value streams

2.1 Overview flexibility in the electricity system

Flexibility can be used for several use cases like balancing, optimizing of the trading costs and minimizing costs from the imbalance settlement or for the customer to increase his own consumption, whereby these use cases can be associated with different roles/actors. However, when using the flexibility for one use case several other actors may be influenced by this activation either positive or negative.

2.1.1 Flexibility in different market designs

Comparison of U.S. and European market design in regard of system operators

Market design in Europe

In Europe, one important driver for the integration of the markets and for the facilitation of demand response is the aim of the internal energy market. Currently the electricity system in Europe faces several challenges to implement the internal energy market. An overview about the current market implementation and planned changes are shown in Figure 1-1.

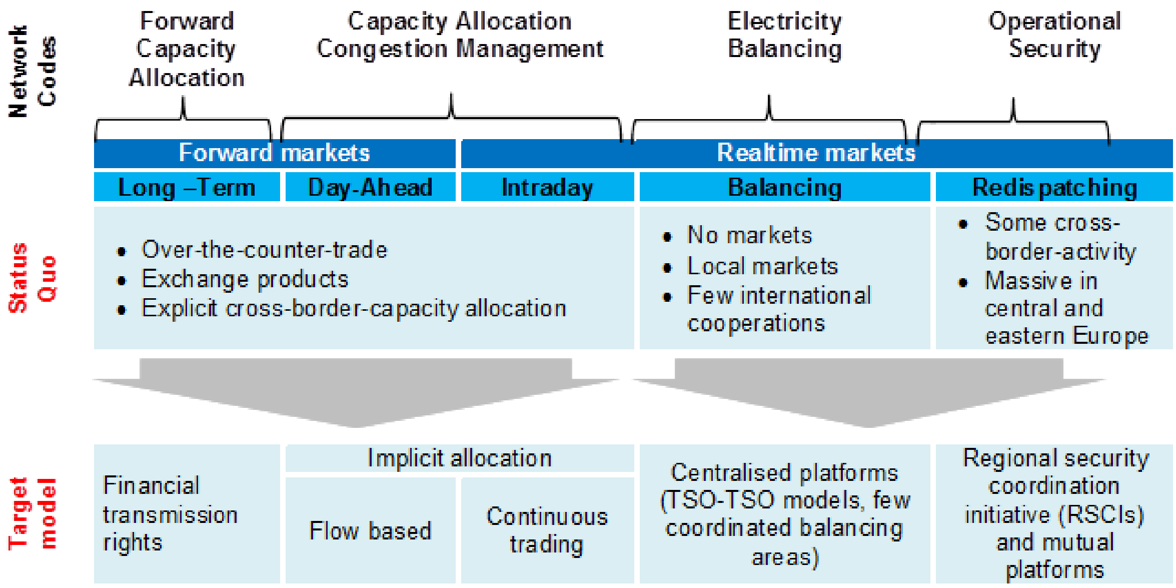


Figure 2-1: Relation between network codes, the status quo and target model of forward and real-time markets [6]

Market design in the U.S.

The interdependency is one main reason for the complexity of the flexibility valuation. This can be seen in the system design of the U.S. that is shown in Figure 2-2. All design parameters that are influenced by flexibility are bordered in wine red. It can be seen by the high amount of the colored parameters that the flexibility provision influences several factors of the energy system and the valuation of flexibility has to consider several interdependent elements. This is why the definition and implementation of interfaces between the actors/roles is important for the valuation of flexibility, especially in respect of the introduction of the new role of the aggregator. Coordination schemes between relevant actors/roles are described in chapter 3. Moreover, the enhanced use of flexibility from smaller units that are very often decentralized further increases the communication and coordination need between the actors. When looking at the energy system operation, several use cases for flexibility can be derived. In Figure 1-1, an assignment of flexibility use cases to different actors/roles is shown and in this chapter, a detailed overview about the flexibility use cases is given.

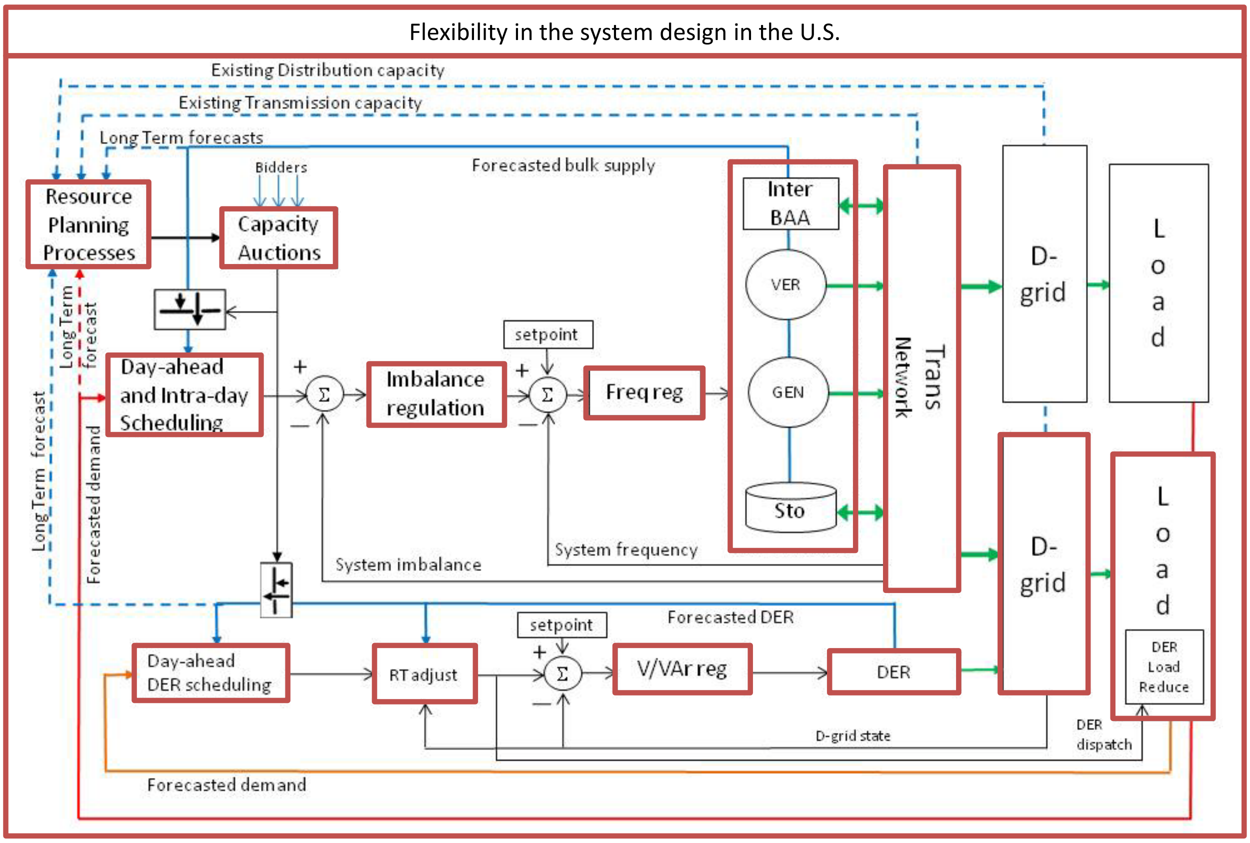


Figure 2-2: Example for the system operation in the U.S. with impact from flexibility (adapted [7])

European and U.S. market design in comparison

Operating reserve contains any kind of reserve that is used to support active power balance in the U.S. system, where the network frequency is kept at 60 Hz (in Europe at 50 Hz). The classification of this reserve can be done in several ways. One of them is presented in the following. Operating reserve can be separated in two categories: Non-event reserve, which means continuous and non-distinguishable events, and event reserve, which means severe and rare events. The further categories, which can be seen in Figure 2-3, are divided by speed. Similar to European balancing services, the contingency reserve, which is used for instantaneous events, is separated in primary, secondary and tertiary reserves. [8]

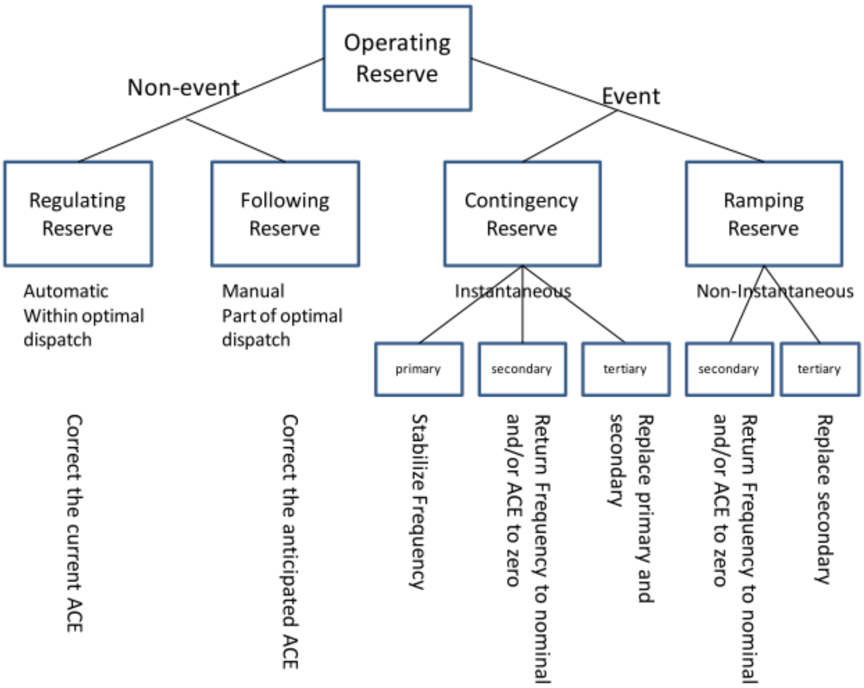


Figure 2-3: Operating reserve in the U.S. market design [8]

In this convention, primary, secondary and tertiary contingency reserves can be identified with other terms of reserve deployment, which can be seen in Figure 2-4. Primary contingency reserves can be identified with frequency response, secondary with spinning and non-spinning reserves and tertiary with supplemental operating reserve.

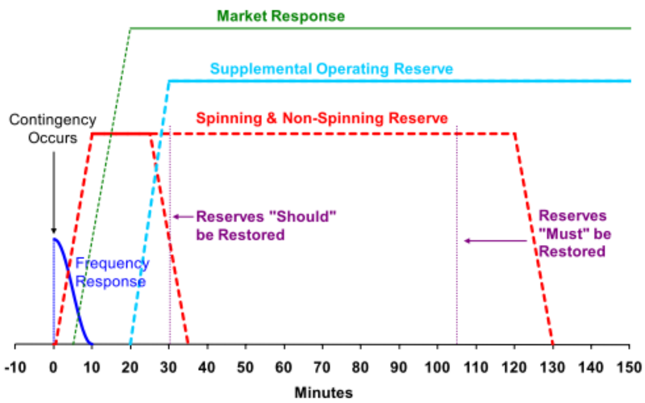


Figure 2-4: Reserve deployment [8]

Generally, some products of the US market system closely resemble European products. However, they are named differently. This resemblance can be seen in Figure 2-5, where the relation between the NERC (North American Electric Corporation) and the UCTE (wound up in 2009, when all operational tasks were transferred to ENTSO-E [9]) terminology is given. As already mentioned, frequency responsive reserve is a primary reserve and therefore part of contingency reserve. Secondary control reserve corresponds to regulating reserves as well as to spinning and non-spinning reserves. Spinning reserves are units that are already connected to the grid, whereas non-spinning reserves as well as supplemental reserves are extra capacity units that need to be connected to the grid. Supplemental reserves (tertiary contingency reserves) are deployed with slower response than spinning/non-spinning reserves and can be identified with tertiary control reserve. [8]

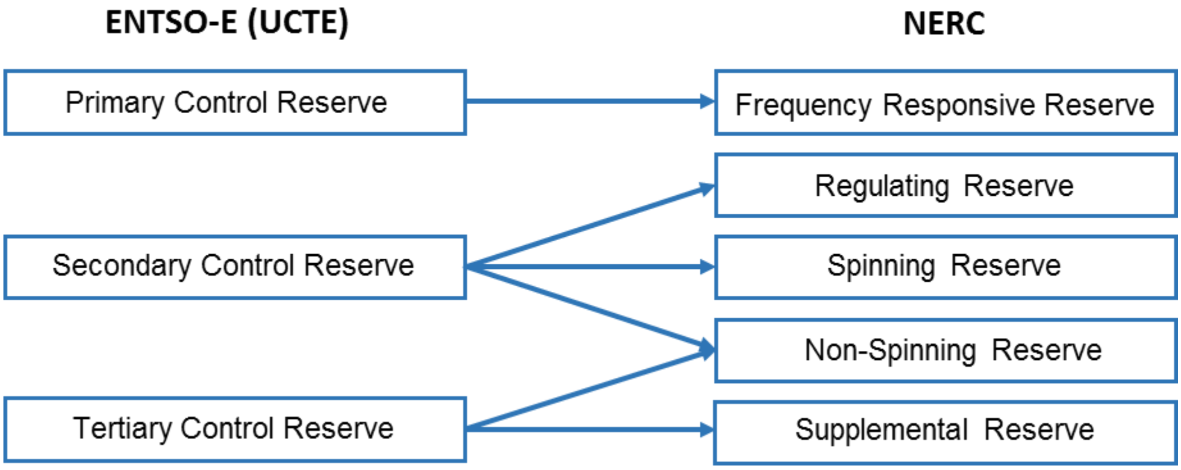


Figure 2-5: Terminology of ENTSO-E and NERC (adapted [8])

The most obvious difference between the two market systems is that in the U.S. system it is distinguished between "normal balancing" and disturbance events whereas this distinction is not made within ENTSO-E. [8]

Pricing schemes in the U.S. and Europe

Regarding the pricing schemes used for congestion management, the U.S. and Europe use two different approaches: Nodal and zonal pricing. Nodal pricing, which is implemented in the U.S., uses a uniform price for its auctions and can therefore also be identified with the term locational marginal pricing (LMP). [10] Market clearing prices are calculated for nodes, which represent the grid locations at which energy is injected by generators or withdrawn by loads. The prices then represent the locational value of energy and is therefore dependent on losses or congestion. The nodal price consists of three components: Marginal cost for generation, marginal cost of losses and marginal cost for transmission congestion. [11]

In most of the European countries, zonal pricing, where particular nodes are bundled to zones with a common price, is implemented. In this pricing scheme, inter-zonal congestion is considered by real-time markets. However, a uniform price is used for the respective zones despite of the congestion inside of it. A zone is typically a country or state (for reducing the complexity of pricing settlement), but there are also countries who are divided in several zones (e.g. Denmark, Norway). One problem with this pricing scheme is that, after the zones of the real-time market have been cleared, TSOs need to order redispatches if they sees their zonal transmission lines in danger to get overloaded. In [10], the zonal pricing approach is therefore identified with two stages. In the first stage, where the zonal prices are calculated, only inter-area/cross-border congestion is considered. In the second stage, intra-zonal congestion is dealt by the use of redispatch (see Chapter 2.3.2). If redispatch is market-based as in the Nordic countries (counter-trading), changes after the first clearing stage are compensated as in pay-as-bid auctions. The compensation schemes used to relax intra-zonal transmission congestion can affect the way producers make offers on the real-time markets. [10]

2.1.2 Overview about flexibility use cases

Categorizing DR into the purpose or service it is targeted for will follow market, network, or consumer value generation purposes. The first one is 'energy' oriented versus the 'power' oriented second one. Naturally these both objectives could interfere when they are counteracting or when e.g., a physical limit or constraint has to be kept [12]. The third purpose for demand flexibility is solely local for self-optimization at building or household level. This could change during the operation of the distributed DR resource, e.g. heat pump operation with self-generated electricity, during seasonal changes (e.g. no PV generation in winter). Moreover, deviations from the schedules from a balance responsible group (BRP) are settled with an imbalance settlement regime. Depending on the type of the balance system design and the imbalance settlement, also the balance responsible party can support the transmission system operator by counteracting the direction of the control error and by this reducing the balancing need of the transmission system operator. In Figure 2-6 an overview about the business cases is given and hence, an overview about the value of flexibility in the electricity system. Moreover, in smaller systems as for example islands more ancillary services are needed than in highly interconnected and mashed networks like in Central Europe. In grey, relevant flexibility use cases are depicted. The use cases that are highlighted in dark-grey are more relevant for prosumers and are closer to implementation. These use cases will be described in the following.

Use cases and value from prosumers‘ flexibility				
Market Business Cases	Grid Business Cases for TSO	Grid Business Cases for DSO	Customer Business Cases	Value for society
Long-term and day-ahead OTC & spot prices	Deferred or reduced grid investments	Deferred or reduced grid investments	Optimization of energy costs	Integration of renewable energies
Intraday OTC & spot prices	Reduction of losses	Reduction of losses	Increase of own consumption	Achievement of climate objectives
Balancing markets for frequency control (primary, secondary and tertiary)		Upkeep of supply in cases of system incidents	Reduction of grid connection/capacity costs	Price mitigation and lower electricity prices
Reduction of imbalance settlement costs	Reduction of balancing need	Limit power from upstream grid (↓grid tariffs)	Securing power supply	Lower grid costs
Risk mitigation	Redispatch	Island operation	Improvement of power quality	Independent electricity supply
Capacity markets	Island operation, black start and inertia	Higher system reliability	Reactive power management	Reliable electricity supply

Figure 2-6: Overview about use cases and the value from prosumer’s flexibility; dark grey are use cases that are already possible or that are possible in the near future

Portfolio optimization of the aggregator

Operators of flexible loads optimize the value of flexibility by the participation of this flexibility on different markets. An example for the portfolio optimization using the example of Austria is shown in Figure 2-7. Thereby, the aggregator is connected via information and communication technology (ICT) with the flexible units of the virtual pool of demand response units. He sets the schedule for the flexible units based on the approximated available flexibility. Especially for the participation in very short-term markets, the aggregator needs feedback from the flexible units on the status. This interaction between the aggregator and the customer is described in Chapter 3.1.

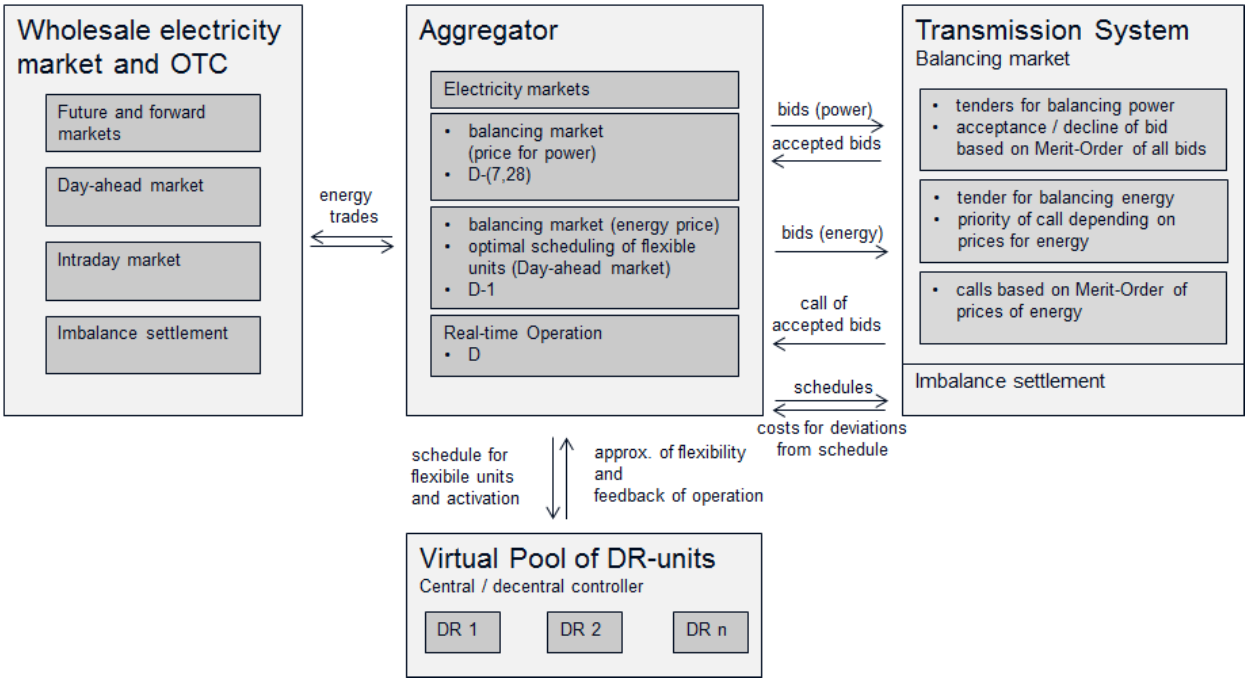


Figure 2-7: Portfolio optimization for electricity and balancing markets from aggregator perspective using the example of Austria

The aggregator will optimize the market participation of the flexibility based on price forecasts and based on the roles that the aggregator fulfills. When the aggregator is only a BSP and only aggregating flexibility for the balancing markets the optimization will differ from an aggregator that participates as a supplier also on the energy markets. In the following, the different markets and use cases for the aggregator are explained.

2.1.3 Demand response dynamics of use cases

Depending on the DR characteristics, the aggregator can operate the flexibility on the markets. One huge difference regarding the availability of flexibility is the differentiation if the flexibility from prosumers is controlled automatically or manually. For several use cases, it is important to react within minutes or even seconds. This reaction time will be only possible with automatically controlled units. This does not indicate that the aggregator or another actor has the possibility to control these devices directly. It can be also implemented with price signals (see the document of IEA Task 17 Subtask 10 - Roles and Potentials). Several examples for demo projects with demand response are collected in the document of IEA Task 17 Subtask 12 - Case Studies.

The characteristics from the use cases differ e.g. in timing, spinning/non-spinning and capacity regarding flexibility to be able to participate on markets. Some characteristics as for example the timing of the use cases are shown in Table 2-1. Therefore, depending on the use case, different demand response technologies are able to provide their flexibility for each use case.

Table 2-1: DR and DG application dynamics classification adapted from [13].

Name	Description	Actor/role that uses flexibility	Scope	Time Resolution	Forecast Horizon	Value
Scheduling and trading	Production and purchase of residual load	Supplier	Market	daily, hourly and PTU	long-term, day-ahead / intraday	kW
Load/generation following	A given $E_{predicted}(t)$-profile has to be followed by a BRP	BRP	Market	Intra-PTU[1]	12-36 PTUs	kW
Residual load levelling	Attempt to reach a more flat distribution of residual load over time	Supplier, (DSO)	System/ HV, (MV, LV)	several PTUs	12-36 PTUs	kW
Primary spinning reserve	Triggered by measured frequency deviations demand or supply are varied (e.g. via a droop-curve)	TSO	System/ HV	Seconds	Minutes	kW
Passive imbalance compensation in re-active system management of balancing market	The system-wide imbalance is counteracted using the monitored power of responsive generation or demand of a BRP	BRP/TSO	System/ HV	Intra-PTU, minutes	PTUs	kW
Active imbalance compensation	The system-wide imbalance is counteracted by supplying power after issuing bids to the system operator	BRP/ Prosumer /TSO	System/ HV	Intra-PTU	1-2 PTU	kW
DG-RES self-consumption	The locally varying output of DG-RES is balanced locally by flexible generation or demand response	Prosumer	MV/LV	Minutes	Minutes	kW
Voltage regulation	Monitoring the frequency, the active-reactive power ratio is adjusted	DSO	MV/LV	Seconds	Seconds	kW
Ramp-up/down assistance	Compensate start-up/shutdown behavior of large installations	BRP / TSO	System	PTU	Days	kW
Connection capacity management	Manage loads/generators to stay below a certain connection capacity	DSO	LV/MV	Minutes	Days	kW
Self-healing	React to events by reconfiguration e.g., in case of critical system state	DSO	MV/LV	Minutes	Minutes	kW
Curtailment/load shedding	Reduce consumption in case of overproduction in a certain grid segment	TSO / DSO Prosumer	HV/MV	Minutes	Days	kW

[1] The imbalance settlement period (PTU) is typically in the order of 15 minutes to 1 hour.

2.2 Markets

2.2.1 Long-term markets – future and forward markets

In terms of the dynamics in the electricity supply system and due to system stability reasons, demand and supply need to match for any instance in time; otherwise, the system is in imbalance. In liberalized electricity systems, market mechanisms being implemented to maintain the balance are increasing. Starting with long-term bilateral contracts between market parties (forward markets, over-the-counter markets) or on the power exchanges (future markets), traders start trading up to five years before delivery. Thereby, future markets oppose less risk for the trading parties, but in the bilateral forward markets, the parties are freer in the design of the products and not limited to the available products of the power exchange.

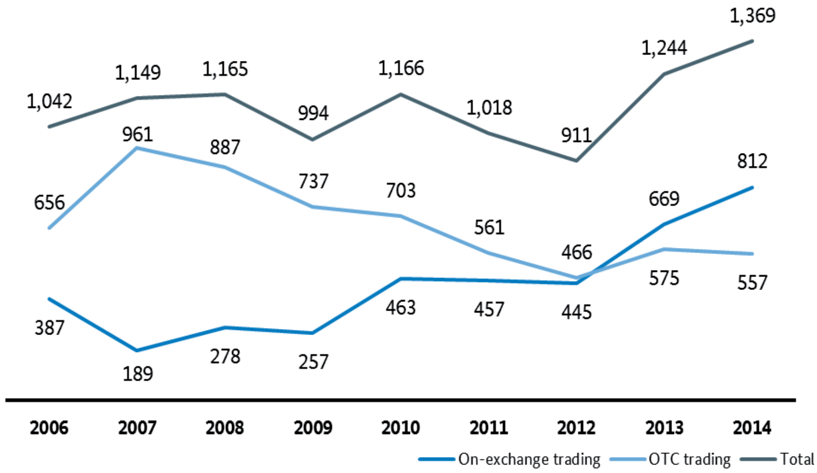


Figure 2-8: OTC clearing volume and forward trading in Phelix futures on EEX in TWh [19]

In Europe, the importance of the power exchanges is increasing. The trading volumes and the share of the future markets – for example on EEX compared to the OTC markets – increased continuously in the last years [14]. In 2014, the share of the Phelix futures markets was nearly 60%, whereby until 2011 the volumes of the OTC markets exceeded the volumes on the exchange by far.

Long-term, a substantial part of the forecasted demand can be covered by supply, based on forecasting tools for economic development - i.e. demand, temperature, etc. Obviously, such long-term acquiring strategies bear diverse risks, so not all of the forecasted demand will be met on these markets. Hence, other markets, closer to the day of operation offer to be more predictable and therefore less risky. Day-ahead markets enable additional trading to be sure to meet the portfolio's day-ahead program responsible profile and intraday markets enable further portfolio adaptations.

2.2.2 Day-ahead markets

This market provides a platform for commercial trade between supply and demand to align the portfolios one day ahead of delivery. The price on the day-ahead market gives a good impression of the actual value of electricity, considering all external parameters, for instance unplanned outages of power plants that are known day-ahead. Therefore, for example in Finland, households have contracts with their retailer based on day-ahead spot market prices.

The objective is to use the day-ahead price patterns to fit the consumers to the spot market. However, access for smaller consumers is needed to boost and incentivize DR. On day-ahead markets, the main actors are traders and retailers.

European internal energy market and market coupling

One aim of the internal energy market is to facilitate the cross-border trade between the European countries. An overview about the planned issues for market integration is shown in Figure 2-1 (see Chapter 2.1). An important step in this direction is the European electricity market coupling with implicit auctions with flow-based capacity calculation. In general, congestions of the transmission grid between bidding zones can be handled with explicit or implicit auctions:

- Explicit auctions: Spot market trading and capacity allocation are carried out separately.
- Implicit auctions: Spot market trading and capacity allocation are carried out in one step.

The capacity allocation can be calculated with different methodologies:

- more static calculation of the available transfer capacity (ATC)
- dynamic calculation of the capacity with power flow-based

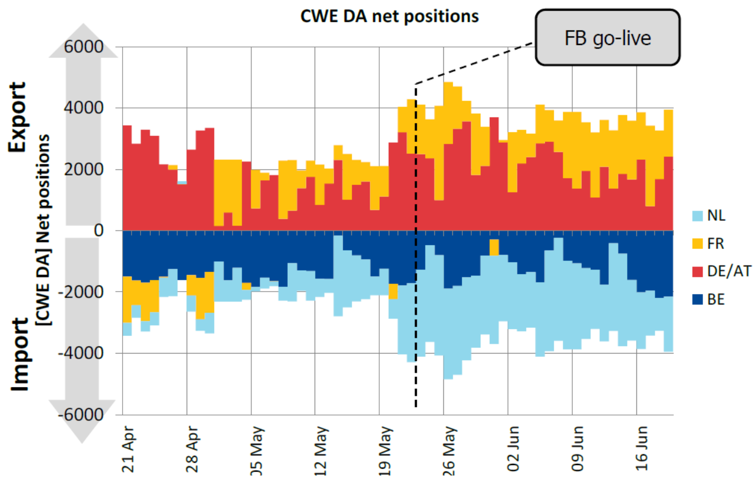


Figure 2-9: Import and export before and after the introduction of flow-based trading [6]

The market coupling in combination with power flow-based capacity calculation enables a better exploitation of the available transmission grid capacity and increases the possibility for cross-border trade as can be seen in Figure 2-9. Market coupling can increase the social welfare[2] as it increases the possibility for cross-border trading and a decrease of electricity prices (see for example [15] for more details). Market coupling promises to increase the available transmission capacity, mainly by the reduction of inefficient cross-border capacity usage due to e.g. oppositely directed or speculative allocation of capacity [16].

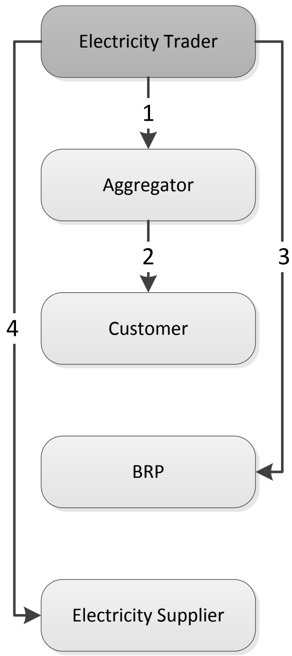
In central-western Europe, market coupling based on ATC was implemented in 2010. In February 2014, price coupling was implemented in northwestern Europe (Price Coupling of

[2] The social welfare is determined by the sum of three components: the consumer surplus, the producer surplus and the income due to congestions by the TSOs.

Regions-Initiative (PCR)). Since May 2015, flow-based market coupling was implemented in the central western area (CWE).

Example use case: Spot markets
An electricity trader buys or sells electricity on the spot market and uses price differentials to make profit. Therefore, the trader utilizes price spreads between high and low prices on the day-ahead and intraday markets. He uses the flexibility of his customers to supply the traded energy. The following steps are needed for this use case:

1. Electricity trader / Customer capable of load shifting or energy saving uses flexibility if viable
2. Aggregator provision and activation of flexibility
3. Electricity trader informs BRP of schedule / changed schedule
4. Electricity trader deals with the available energy



2.2.3 Intraday market

Recently the intraday markets have gained a large portion of volume and interest since the fluctuating renewable energy sources are hard to predict day-ahead. The intraday market offers a platform that permits balancing energy supply and demand within a short time horizon. For demand flexibility it is a reasonable advice to target DR programs, which are as close to operation as possible [17].

There exist two different designs for intraday markets: continuous intraday markets and auctions. In the continuous intraday market, the traders can submit their orders closer to real-time than in markets that use auctions. Typically in continuous auctions this is possible to until 1 h (Nordic markets) to 5 minutes (APX Power NL) before real-time. For example at EPEX Spot, there exist two markets for Germany: an auction that closes day-ahead and a continuous intraday market, where it is possible to trade until 30 minutes before real-time (intraday gate closure time).

To give renewable energies an incentive, it is important to allow negative prices. Moreover, very high/low caps respectively floors give an incentive for flexibility. In Europe, the typically allowed prices are between 9999 and -9999€/MWh as for example in the Netherlands, Belgium and in Germany, Austria, Switzerland and France.

2.2.4 Imbalance settlement

The BRPs are settled based on their deviations from their planned schedules for every imbalance settlement period (PTU). During this settlement, the BRPs' deviations are priced with the imbalance settlement prices. The connection between the electricity markets, the imbalance settlement and the balancing markets can be seen in Figure 2-10.

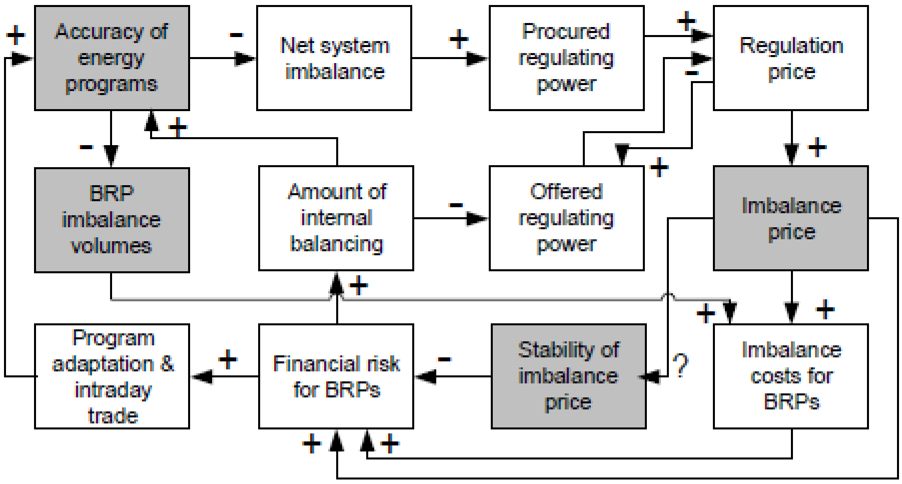


Figure 2-10: Causal diagram of the balancing system, including the four identified performance indicators for balance responsibility and imbalance settlement (grey) [18]

For the imbalance settlement, the imbalance settlement period (PTU) plays an important role. It specifies the time interval for which control reserves are allocated to balance groups. Within a PTU, the power may be varied as long as the overall energy in the PTU is the same. The PTUs are diverse in Europe and vary between 15 minutes and 1 hour. A cost benefit analysis for the harmonization of the PTUs was performed by ENTSO-E [19]. The results highly depend on the assumptions; hence, the final decision for the harmonization was not made yet.

To minimize imbalance costs in a market based electricity system, BRPs have benefits in monitoring their portfolios in order to know their current real-time imbalance with a resolution of a PTU. Having the deviation in their generation/demand (ΔS/D) compared to the program issued in the right direction regarding the national or system segment imbalance leads to benefits. If possible, BRPs monitor their power profiles and adjust operation, production but also possibly demand in real-time. However, their contributions are reconciled based on the meter readings from telemetry devices collected a few days later. For reconciliation, time dependent kWh(t)/energy data, with a PTU time resolution, is most important. As renewable energy resources are embedded at an increasing rate, generation and load forecasts are becoming ever more important. These forecasts are of course most important for planning day-ahead and hence better forecast the BRP schedules. Such forecasts are also become increasingly more important intraday as they could allow a reduction of balancing energy and hence cut down costs.

There exist two system management regimes in general:

- Proactive: The BRPs are incentivized to stick to their schedules; the TSO can calculate possible deviations and uses also slower reserves to reduce the control error
- Reactive: The BRPs are allowed and incentivized to deviate from their schedules; the imbalance settlement can be used to reduce the needed balancing energy

Depending on the system management regime, an aggregator with balance responsibility can either support its BRP by

- reducing the deviations in a more proactive system management regime

- In a reactive system management regime, it can help the BRP to support the TSO by reducing the control error and reducing its imbalance settlement costs or even offsetting the costs.

For example, in Belgium, a reactive system management is implemented and the forecasted imbalance settlement price for the next PTU is published shortly before each PTU. This means that the BRP can reduce the balancing need of the control area by counteracting.

Furthermore, there exist day-after markets where the BRPs can settle their imbalances among themselves. For example in Germany the price for this day-after trading is the day-ahead spot price, but this price setting can lead to negative effects (see [20]).

Example Use Case: Minimizing imbalance costs
The balance responsible party is able to minimize deviations of its balance group from the schedule with the help of flexibility. This reduces the balancing costs that the balancing group has to pay for their deviation. Additionally, the end user flexibility allows for an improved balancing of energy production and consumption in the balancing group. If the BRP detects deviations from the schedule, he buys the needed flexibility from an aggregator to a lower price than the balancing energy. The aggregator then activates his pool of consumers for delivery. Hydroelectric power plants might also profit from this arrangement, as they could be part of a pool. The following steps are needed for this use case:

1. Meter responsible delivers data to energy flows to the BRP
2. BRP checks if there are large deviations from the schedules and contacts the aggregator
3. Aggregator activates flexibility from his customers

2.3 TSO

The TSO needs different system services as shown in Figure 2-11. Moreover, the costs for Germany in the year 2014 are shown there to give a feeling for the comparative height of these costs. In most countries, prosumers can provide system services only to a limited extent.

For example, the service “interruptible loads” can only be provided by loads that are connected to the high-voltage grid. The balancing markets are opened to demand response in several countries. And in some countries like Switzerland even prosumers are able to participate.

For several system services the integration of prosumers still has to be enabled as some of these services can currently only be provided by larger units. As prosumers are not directly situated in the transmission grid, the system service by prosumers needs an interaction between the TSO and the DSO (see Chapter 3.2).

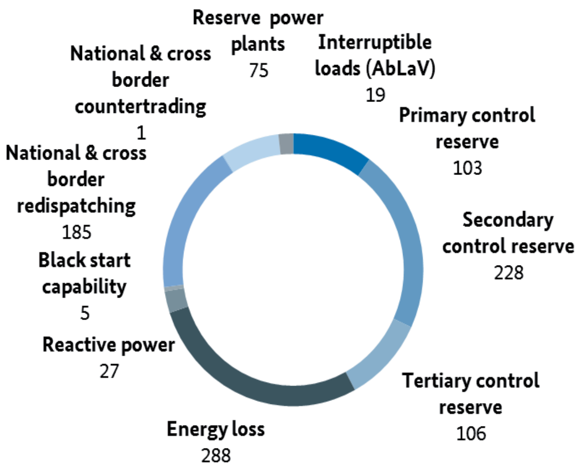


Figure 2-11: Breakdown of costs for German TSOs’ system services in the year 2014 [20]

2.3.1 Balancing markets

Ancillary service markets are organized and operated by the TSO. These services are used to keep supply and demand in balance in order to keep the frequency in system stable to a set point, e.g. in Europe that is 50Hz. By this unplanned, instantaneous outages of power plants, or sudden jumps resulting from the bidding times at the spot markets or the fluctuation of demand or infeed of renewables due to sudden and unanticipated weather changes can be balanced by the TSO very close to real-time. The volume that needs to be balanced by the TSO can be reduced when the BRPs balance themselves on the intraday markets. To reduce the costs and the volume of the needed activation of balancing energy further, the implementation of cross-border balancing markets is facilitated by the European regulation.

The balancing markets are divided based on the underlying load-frequency processes as can be seen in Figure 2-13:

- Frequency Containment Reserve (FCR): typically controlled decentral with a reaction time of less than 30 seconds; market is power based
- automatic and manual Frequency Replacement Reserves (FRR): mainly controlled centrally by the TSO, reaction times are between 5 Minutes (aFRR) and 15 minutes (mFRR)
- Replacement Reserves (RR): Controlled centrally and reaction times longer than 1 hour

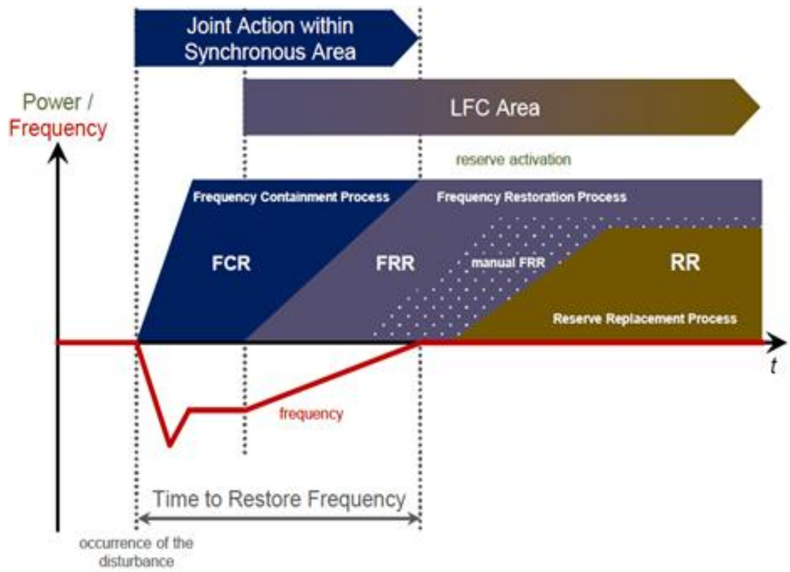


Figure 2-12: Representation of load-frequency control processes in Europe [21]

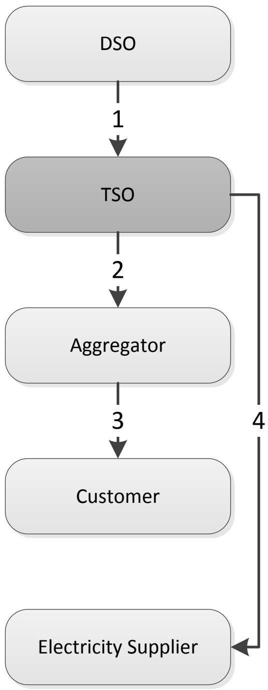
In the last years the prequalification criteria were adjusted to include demand response in the balancing markets. For example in Germany and Austria pooling was made possible and the minimum bid sizes were lowered. Furthermore, the minimum size of the technical units was reduced. This is why the participation of aggregators in these markets increased in the last years. Very often aggregators include larger customers in their pools. Mainly in demo projects the integration of prosumers in these balancing markets was tested as the market entry barriers for these small customers are still high. The prosumers need to be connected to the pool with ICT and the acceptance and awareness of the customers is important for a successful business model.

For example the Swiss company Tiko includes heat pumps and boilers in its pool to participate in the balancing markets [21]. In 2015, more than 5,500 customers participated in their pool. As these devices are based on heating, the pool does not participate in the balancing market during summer.

The balancing markets have grown historically; they are based on the characteristics of each country's electricity system. Therefore, the configuration of the parameters of the balancing markets is very diverse when the balancing markets are analyzed in detail (see [22] for further details on these parameters). With respect to participation in this market, different gate-closure times exist. For tertiary and secondary balancing markets, these can be days, a week, or even more ahead. In some countries, balance responsible parties or resource providers have an obligation to offer a percentage of their portfolio to the reserves market. For example in Italy all power plants with more than 10 MW have an obligation to participate in the balancing markets [23]. The times for providing balancing can be separated into products that are time slices (e.g. in Austria 4h slices). Balancing for the selected time slice or interval (e.g. from 0h to 4h or from 4h to 8h) has to be provided for 5 weekdays or for the weekend (2 days). The market for bidding closes usually the week before (e.g., on Tuesday for the next week). For secondary reserve, the slices can be different (e.g. peak from 8 a.m. until 8 p.m. during weekdays and off-peak in Austria). Ramp up requirements for tertiary balancing needs to be for example within 10 minutes. The aggregator has to guarantee that the portfolio is capable of meeting this requirement (pre-qualification for participating). For the secondary and the tertiary reserve market, residential pooled DR resources are already participating, where for the primary balancing market technical requirements are too high as to meet with distributed DR as an asset. Typically, the costs from the balancing are partly passed along to the BRPs with the imbalance settlement and partly they are socialized e.g. by recovering the costs in the grid costs.

Example Use Case: Balancing markets and activation of balancing energy

Aggregators can participate in the balancing markets when they fulfill the role of a BSP or when they are part of a BSP.



Balancing capacity: The pool has to participate in the tendering of positive or negative balancing capacity for each product. In most countries, the TSO remunerates the provision of capacity.

When the bid is accepted, then the BSP has the obligation to reserve the capacity and to deliver balancing energy. According to the Network Code of Electricity Balancing, the TSO calls the balancing energy based on merit order rule. This means for the BSP that the call probability decreases, when the price of the bid is higher and due to this is situated further back on the merit order.

The TSO uses flexibility for the provision of control energy instead of conventional control reserve supply. The following steps are needed for this use case:

1. TSO determines if control reserve is necessary and if so, buys it from the aggregator
2. Aggregator activates flexibility from his customers and TSO reports changes of schedules to the BRP and gets compensation for provided control energy

2.3.2 Redispatch

Redispatch is a requirement to adapt the active power feed-in from power plants by the TSOs with the aim to avoid or eliminate congestions of the transmission grid. This measure can be applied universally and internally in control areas. By lowering the effective power supply of one or more power plants while increasing the active power feed of one or more other power plants, the total active power feed remains in total virtually unchanged with less burden of a bottleneck.

In principal, an aggregator could participate in redispatch with small units like prosumers. However, the barriers to enter these markets are high. Currently TSOs use power plants with a capacity of several MW for redispatch. For example in Germany these are more than 50 MW per unit [24].

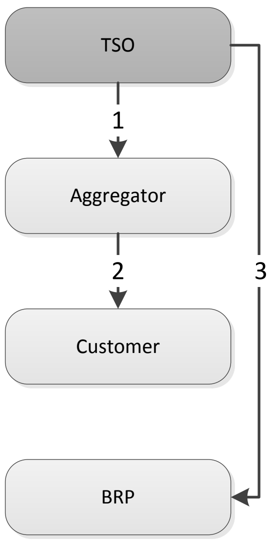
Bilateral contract between aggregator and TSO – France:

The French aggregator Voltalis [25] is one of the few European aggregators who mostly contracts residual customers. They then receive a device (“Bluepod”), which is able to reduce the heating device operation of the household in short time intervals. This happens when the Bluepod receives a signal from the aggregator, which in turn receives a dispatch signal from the TSO. Voltalis only has a bidirectional contract with the TSO for dispatch and therefore does not participate in energy markets. He gets a remuneration from the TSO; customers only profit by a reduction of their consumption. Customers are able to push a button on the Bluepod to operate their heating devices in a normal way at any time (“opt-out”) [26].

Example use case: Redispatch

Network operators can use the provided flexibility for their redispatch by procurement of the flexibility from an aggregator. This requires an aggregator who has access to customers in different sections of the network with varied network loads. The aggregator than activates his pool to reduce network loads in the affected network sections. The following steps are needed for this use case:

1. TSO notices aggregator about the needed network relieve
2. Aggregator activates his pool to deliver the requested flexibility
3. TSO communicates changes to the BRP



2.3.3 Capacity mechanisms

Capacity mechanisms are used to secure the peak demand of the future energy system during all times. DR can reduce the peak demand and reduces with this the needed capacity during peak times. Different capacity markets can be implemented – an overview can be seen in Figure 2-13. Depending on the design, they can intervene and influence the free market. The European Commission “will examine in particular whether

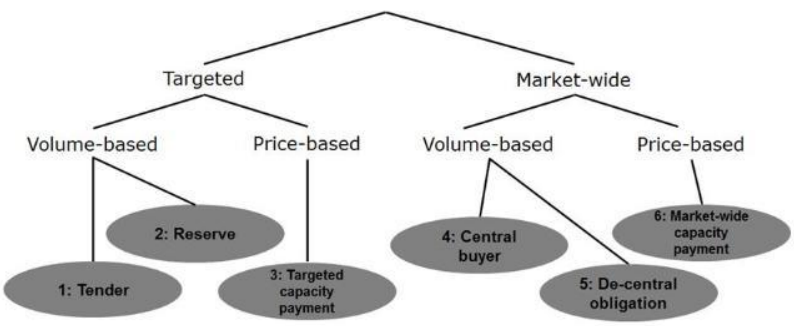


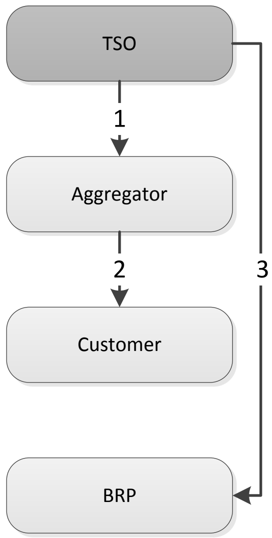
Figure 2-13: Overview about capacity mechanisms [29]

capacity mechanisms ensure sufficient electricity supply without distorting competition or trade in the EU's Single Market" [27]. For sure, the highest capacity mechanisms are implemented in several countries. One example is the capacity market of the U.S. regional transmission organization PJM. PJM allows DR to participate in this market to reduce peak consumption as well as the increase of generation by new generators and upgrades for existing generators. Thereby, PJM takes into account the locations of the units to reduce congestions.

In Germany, the reserve power plants and the interruptible loads are measures to ensure the available capacity in all parts of the country.

Example use case: Capacity markets

The TSO is responsible for the balance of energy production and consumption in his control-area. If the BRPs fail to comply with their schedule, the TSO is in charge to procure the energy deficit. This can be exceptionally costly if the shortcomings occur in a peak time or if the energy production is already at maximum capacity possible, which might lead to a network overload. An aggregator might offer his flexibility to reduce the shortage with reducing the consumed energy.



The energy producers could reduce their costly back-up plants, and therefrom lowering their expenses. The following steps are needed for this use case:

1. TSO identifies insufficient energy supply
2. Aggregator provides and activates flexibility
3. TSO adjusts schedules for BRP

2.4 DSO

2.4.1 Deferred or reduced grid investments

CAPEX: The use of DR flexibility can help the DSO to avoid or defer reinforcement costs for the grid. As an example, a DSO who has to handle an increasing demand and low voltage issues in the distribution grid would not have to make an investment in an asset (which might even end up being stranded) but rely on demand response. Especially investments in long-lived assets and capital investments due to the uncertainty of local demand and the feed-in of renewables can be deferred. [28]

OPEX: The DSO can also make use of its customers' flexibility to reduce the maintenance costs of his grid. Generally, the DSO operates planned outages to ensure network maintenance. The outages take place at a time of low load so that security of supply is not jeopardized. Customer flexibility can help the DSO to get independent from these low-load periods and therefore optimize his operational planning. [28]

The Improgres project [29] showed the benefits of demand response for the integration of distributed generation in four different implementation scenarios. Three distribution areas (in Germany, the Netherlands and Spain) were selected. The resulting benefits, which can be seen in Figure 2-14, are significant. To see the real value of DR for the DSO, these benefits need to be compared to costs for smart metering infrastructure and the costs for DR activation. [28]

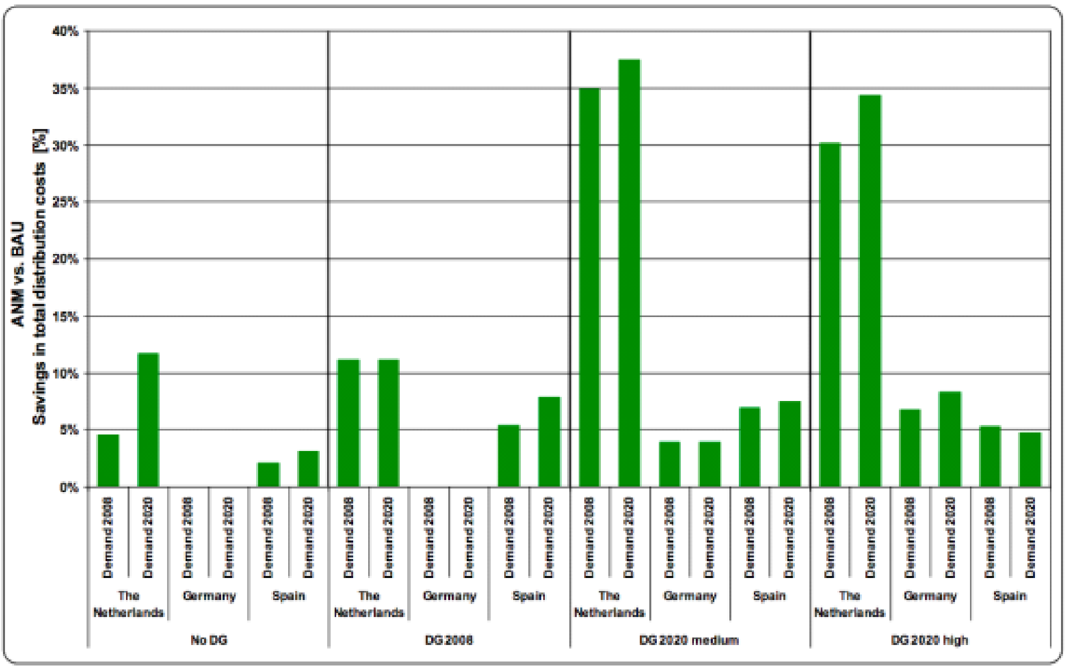
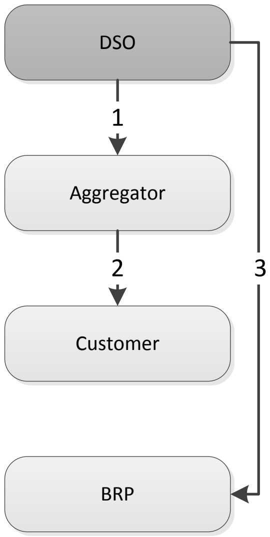


Figure 2-14: Distribution network savings compared to business-as-usual scenario due to implementation of DR (IMPROGRES project, 2010) [30]

Example use case: Network Management

The DSO clears net network costs with his customers. Network costs are partially driven by peak loads. Peak loads lead to costly investments for grid development and additionally the DSO has to compensate other DSOs for occurring peaks. To avoid these costs, the DSO buys flexibility instead from an aggregator. Another possible way of business is to optimize the overall grid status. The following steps are needed for this use case:

1. DSO notices network peaks and activates an aggregator
2. Aggregator activates his pool of customers to deliver the requested flexibility
3. DSO communicates the changes in the schedules to the BRP



2.4.2 Reduction of losses

In many countries, the grid operators are responsible for grid losses (in some countries, this is the supplier's responsibility). Therefore, the DSO has the incentive to reduce its grid losses in order to reduce its overall costs. Table 2-2 presents an overview of typical values for grid losses in the distribution grid. In peak times, the total losses may even exceed 20% [31].

Table 2-2: Typical losses in the distribution grid [32]

Component	Estimated loss as a percentage of energy sold	
	Typical Urban	Typical rural
Subtransmission lines	0.1	0.7
Power transformers	0.1	0.7

Distribution lines	0.9	2.5
Distribution transformers no load	1.2	1.7
Distribution transformers load	0.8	0.8
Secondary lines	0.5	0.9
Total	**3.6**	**7.3**

It can be seen that there are high losses in the distribution lines that result from the resistance of the cables. [31] The losses are proportional to the product of resistance and the squared current magnitude:

$$P = I^2 * R$$

By reducing the current magnitude (peak demand reduction) on the conductors using residential demand side flexibility, losses could be mainly reduced.

In Table 2-3, country examples for total grid losses in the transmission and distribution grid are given:

Table 2-3: Country examples for grid losses [33]

Country	Transmission grid	Distribution grid
France	2.3%	5.0%
Austria	1.5%	4.5%
Czech Republic	1.5%	7%
Slovakia	1%	8.3%
Romania	2.6%	13.5%

Although several demonstration projects could show the benefits of demand response, many DSOs still tend to use “traditional” and cost-intensive supply-side solutions. This may be because they are familiar with them and see them as less risky. NRAs should therefore establish a regulatory framework in which DSOs are incentivized to make use of demand response flexibility. An example for a framework that provides incentives for innovations on the distribution level is the one of the NRA in the UK (Ofgem). The network price is based on the RIIO-ED1 methodology (Revenue = Innovation + Incentives + Output) and sets outputs that DSOs need to deliver for their customers and the associated allowed revenues. [28]

2.5 Customer

2.5.1 Optimization of energy costs

With the implementation of DR, customers will get access to new technologies. These technologies (e.g. smart meters or smart home systems) can help them to get a better overview of their energy consumption. Customers might therefore get aware of devices that need a lot of energy and rather rely on energy-efficient devices or try to consume less energy as a whole. Furthermore, customers can profit from an increasing overall energy efficiency: Demonstration projects showed that due to the use of DR, customers could benefit from total energy savings of 10-15% [34].

Another way to optimize customers’ energy costs is to increase the own consumption of a customer if he owns an appropriate storage system (see Chapter 2.5.2). Furthermore, the implementation of DR can have an influence on energy prices, which will be discussed in Chapter 2.6.2.

2.5.2 Increase of own consumption

As the share of distributed generation is increasing, more and more customers can make use of flexibility. These customers are able to provide their (DR) flexibility to another market party. On the other hand, they can use their flexibility to balance themselves. If a prosumer owns a storage system - additionally to his generation plant (e.g. a PV system) - he could become less dependent on his supplier. In an idealized case, he could cover his own consumption without feeding electricity in the distribution grid most of the time. As a result, running costs can be minimized. The principal costs for a customer are then the installation and maintenance costs of its system.

In Figure 2-15, a typical prosumer consumption/generation profile is presented. During the day, the power generation of the PV system is very high and the prosumer has to feed in his surplus back into the grid. Then again, in the evening, when consumption is high, the PV generation is very low. The prosumer therefore has to take the needed electricity from the grid. If the prosumer owned a storage additionally, he would not have to feed in the surplus of his PV system back into the grid (except when the storage capacity is reached), but could use it later on except for the storage losses.

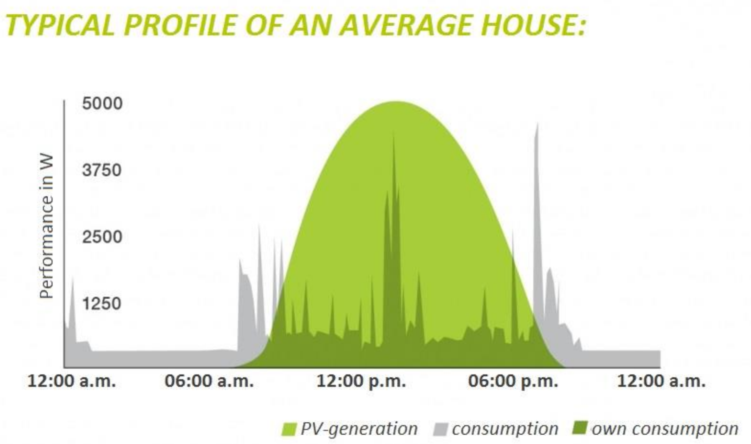


Figure 2-15: Power consumption and generation with solar energy system [35]

2.5.3 Reduction of grid connection/capacity costs

The grid price has to cover the maintenance and operating costs of a grid operator for its electricity grid. If DR flexibility can be implemented successfully to lower the peak demand (load shifting), DSOs' costs for the grid will probably decrease (see also chapter 2.4): Investment costs may be reduced/switched to a later point of time. If DR flexibility is used for energy efficiency programs, also grid losses can be reduced. If the DSO is able to lower his total costs due to an efficient implementation of DR flexibility, customers can profit by lower connection and capacity costs.

Example of DSO savings due to DR – Sweden:

In Sweden, the possible economic impact of residential demand response on DSOs' costs have been investigated [36]. Distribution load data from 2007 to 2012 from the selected DSO Sala-Heby Energi Elnät AB was used to establish the average daily load curve in the distribution system. The resulting load curve can be seen in Figure 2-16. The broken line presents the simulated resulting curve due to the use of DR.

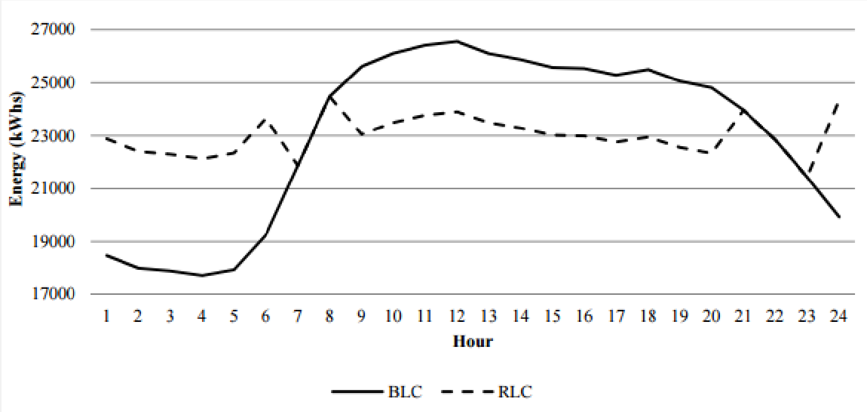


Figure 2-16: Average load profile (BLC – basic load curve, RLC – resulting load curve) [36]

Three essential cost factors for the DSO have then been investigated in regard of potential benefits enabled by demand response: postponement of future investments, power losses and grid fee to feeding grid. Two scenarios were considered. In the first scenario, a DR peak-load shifting to off-peak times of 10% was assumed. In the second scenario, the best case was assumed in which the load curve can be flattened during the whole day using DR flexibility. Resulting savings for the selected DSO are presented in Figure 2-17. As long as power loss is treated as an "uncontrollable cost" and is directly passed on to the customer (as it is in Sweden), DSOs do not have high incentives to implement load management. [36]
The fee that has to be paid by the DSO to the regional grid (mostly owned by Vattenfall, Fortum and E.ON) can be generally designed in three ways. It can be a fixed fee that cannot be influenced by DR or a variable fee either dependent on a subscribed maximum level of power (can be influenced by load shifting) or on the energy transferred (cannot be changed by load shifting but by overall reduction). Grid fees are treated again as uncontrollable costs in Sweden and therefore directly passed to the customer. Because of that, DSOs would not profit from savings. In the future, it will therefore be necessary to incentivize DSOs in nevertheless implementing DR. [36]
According to the simulation, the highest savings would be able to be achieved in the investment sector. The distribution grid has to cope with a rising demand – if the load curve can be flattened due to DR, the DSO will only have to face a fraction of the original peak load. [36]
In total, annual savings up 620 $ per customer (best case, scenario 2) or 33 $ per customer (scenario 1) could possibly be achieved due to using DR for load shifting.

Power losses	Scenario 1	Scenario 2
Reduction in kWh over the year	346,756	1,635,036
Reduction in mean arithmetic loss	3.99 %	18.81 %
Annual difference in USD	40,260 $	180,133.28 $
Annual difference in USD per customer	3.05 $	13.64 $
Reduction in annual cost (%)	8.08 %	36.14 %

Grid fee to feeding grid	Scenario 1	Scenario 2
Optimized value (kWh) for subscribed maximum power	38,499	19,770
Decrease in subscribed maximum power (%)	8.99 %	46.70 %
Annual difference in USD	63,385.92 $	701,608.64 $
Annual difference in USD per customer	4.80 $	53.11 $
Reduction in annual cost (%)	4.86 %	46.23 %

Postponing future investments	Scenario 1	Scenario 2
Difference in USD	326,064 $	7,320,640 $
Postponed investment years	2	43
Annual difference in USD per customer	24.68 $	554.13 $

Figure 2-17: Savings for the DSO Sala-Heby Energi Elnät AB/customer due to DR (adapted from [36])

2.6 Society

2.6.1 Achievement of climate objectives and integration of renewables

Climate targets of a country mostly directly include the integration of renewables. As these two business cases are therefore closely linked to one another, they will be treated within one section.

European climate objectives

The European Union (EU) gives country-specific climate targets that are mandatory for its member states. These targets need to be fulfilled to reach the European climate targets as a whole. For 2020, these targets are also called the "20-20-20" goals [37]. Member states have binding energy targets to reach the European energy goals by the year of 2020, which are

- 20% less greenhouse gas emissions (than in 1990),
- A share of 20% renewables of EU energy,
- An increase of 20% in energy efficiency.

The European energy strategy for 2030 [38] has already been established too. Its goals are

- 40% less greenhouse gas emissions (than in 1990)
- A share of 27% renewables of EU energy
- At least 27% of energy savings compared to the business-as-usual scenario

It is obvious that these objectives are closely linked to one another. The implementation of renewables can mainly support the decrease of greenhouse gas emissions (e.g. by using solar plants). Hereby, it is important not to neglect the greenhouse gas emissions resulting from the production of such systems. On the other hand, security of supply and energy efficiency must not be jeopardized by the integration of renewables.
An achievement of these climate goals should entail main benefits for society. They should further increase the European energy security (as less energy imports will have to be made), create new jobs and should make Europe more competitive as a whole. Specific benefits that could already be reached due to the energy efficiency process or are expected to be achieved in the near future are [39]:

- New buildings consume 50% less energy than in 1980
- Efficient appliances and technologies are expected to save European consumers 100 billion € per year in their energy bills by 2020 (even more with the additional installation of smart meters)
- Each percent increase of energy efficiency leads to 2.6% less gas imports to the EU
- Job increase in the innovation sector, as new technologies need to be developed (→ business opportunities for European companies)

Figure 2-18 shows the share of renewables in the gross final energy consumption of European member states in 2013 and their country-specific goal for 2020. Figure 2-19 shows the general progress of European member states regarding the European 20-20-20 goals.

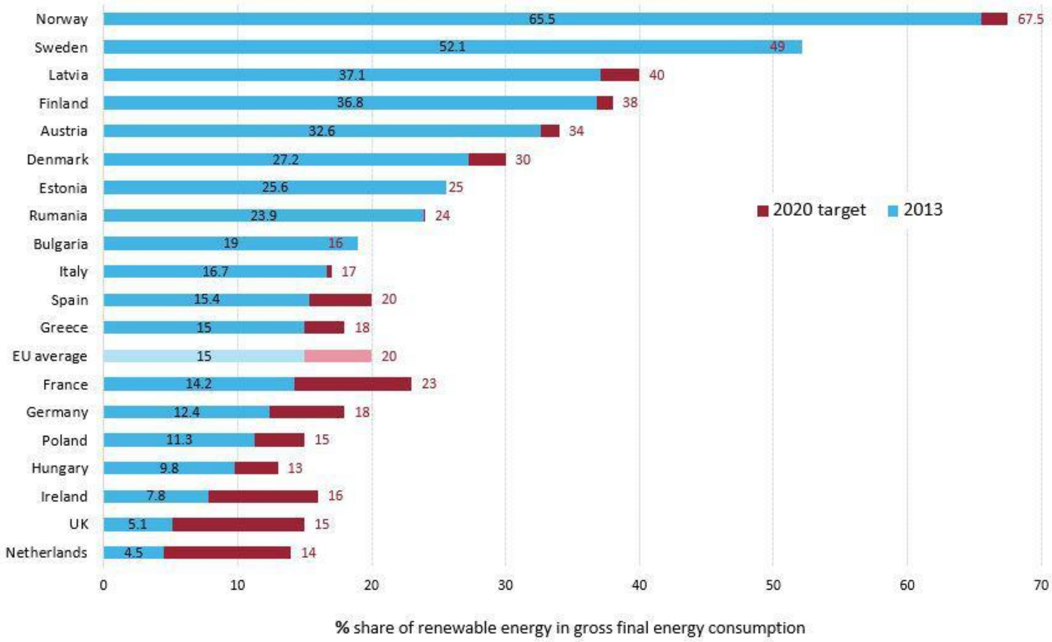
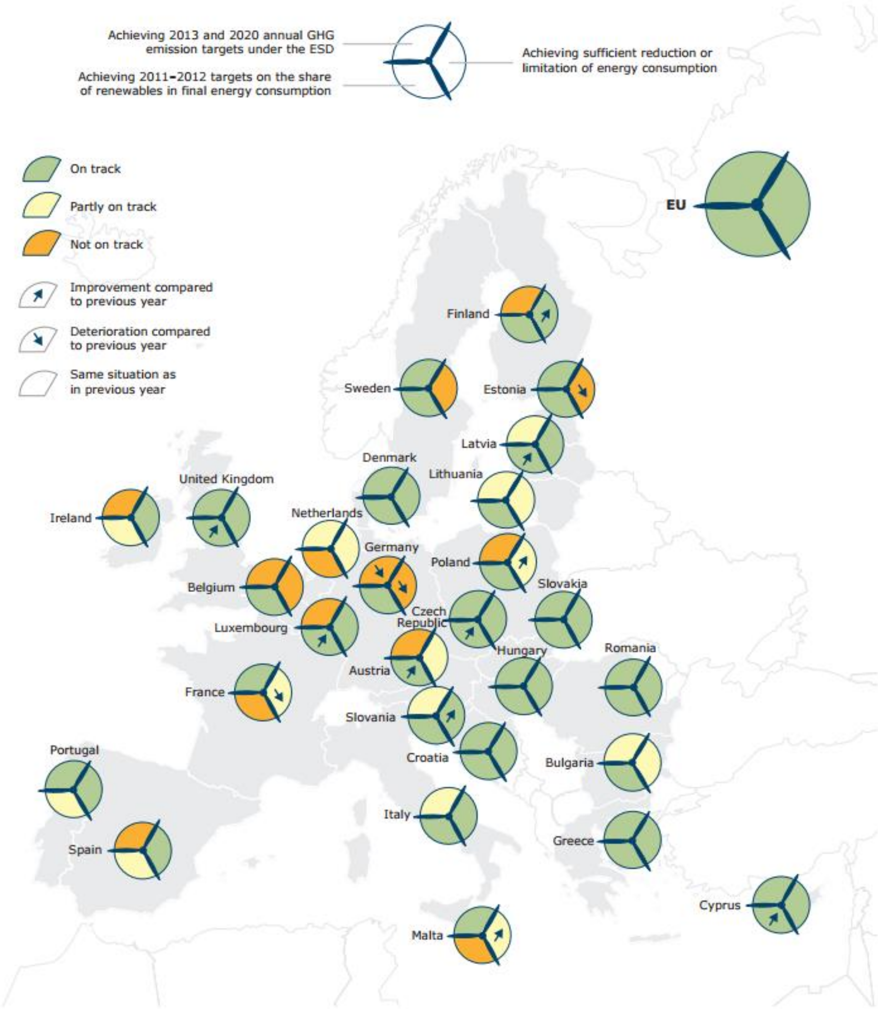


Figure 2-18: Share of renewables in gross final energy consumption of European member states [40]

The integration of DR programs can mainly contribute in achieving climate targets. Renewable energy sources are volatile; DR flexibility can therefore help to integrate the resources successfully while maintaining system security. If distributed and renewable generation plants lead to a different production than forecasted, the consumption can be adjusted correspondingly due to demand response. For example, unexpected large grid feed-ins of renewables can be compensated.



Source: EEA.

Figure 2-19: Progress of European member states regarding climate targets of 2020 [41]

Demand response and energy efficiency

To achieve improved energy efficiency, customers need to understand their use of electricity better. They need to be given new tools to manage their consumption and finally reduce it by using their energy resources in a more efficient and coordinated way. In [42], four ways for the coordination of demand response and energy efficiency are given:

- *Combined program offerings:* Often, DR programs are provided separately from energy efficiency programs. Combining these two, customers could get a better understanding for their electricity use and its optimization.
- *Coordinated marketing and education:* Demand response and energy efficiency may be complicated to understand for customers. Providers of DR/energy efficiency programs should therefore put effort in marketing and offering education programs.
- *Market-driven coordinated services:* Some private firms may find a market among customers who are interested in reducing their energy bills. Therefore, these firms might initiative coordination between energy efficiency and demand response.
- *Building codes and appliance standards:* Establishing building codes and appliance standards can help to integrate demand response and energy efficiency features in a cost-efficient way.

While DR flexibility can relieve the load on the grid in peak times, energy efficiency leads to a general relief on the load of the grid (as less energy is needed for the same services). As a

result, society benefits from an increasing security of supply, a positive impact on the environment (due to resource savings) and reduced electricity bills.
Figure 2-20 shows the possible impact of demand response and energy efficiency on the expected peak electric demand (solid purple line) in the U.S. The dotted line shows the expected peak electric demand without participation of energy efficiency and DR programs. Although the perspective of this presentation is from 2010, it shows very well the influence and scale of DR and energy efficiency programs.

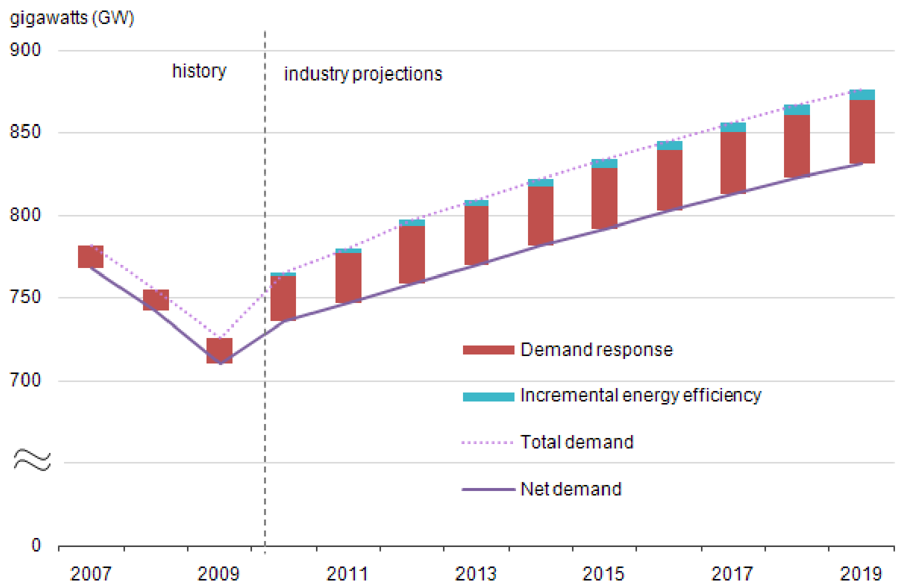


Figure 2-20: Expected influence of DR and energy efficiency on net demand in the U.S. [43]

Figure 2-21 shows the energy savings in the U.S. due to demand response in 2014. Due to these savings, it can be seen that DR flexibility can be used to improve energy efficiency. It can be seen that the highest amount of energy savings could be achieved in the residential sector. The highest savings in the peak demand were however achieved in the industrial sector. A residential customer could save about 40$ in 2014, while the incentives of commercial and industrial customers were a lot higher: Commercial customers could save about 600$, industrial about 9,000$ in 2014.

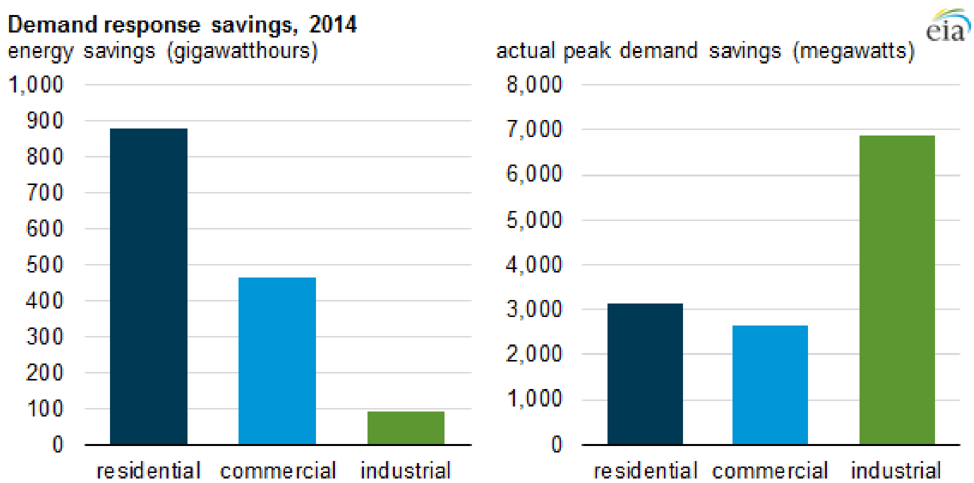


Figure 2-21: U.S. energy savings due to demand response [44]

2.6.2 Price mitigation and lower electricity prices

The main components of the electricity price are the grid tariff, VAT and the energy price (which has to be paid to the supplier). An example can be seen in Figure 2-22. Obviously, VAT will not be changed due to the use of DR flexibility. The possibility of lower grid tariffs is discussed in chapter 2.5.3.

To incentivize customers who are willing and able to provide DR flexibility to shift their demand to off-peak times, electricity suppliers are able to offer flexible tariffs (price-based DR). The energy price is then not constant but higher in peak and lower in off peak times (and also depending in the balancing position of the respective supplier/BRP).

If a supplier/BRP uses demand side flexibility of its customers to balance its own position, he can save the costs for imbalance penalties. Furthermore, resources can be saved if the peak demand is reduced. This might result in lower energy prices in general.

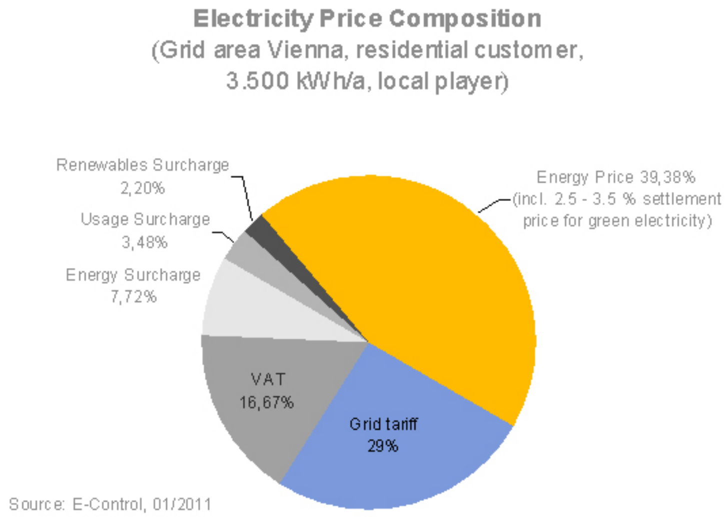


Figure 2-22: Electricity price composition in the Vienna grid area [45]

2.6.3 Lower grid costs

In the energy efficiency directive 2012/27/EU it is stated that grid tariffs should support the implementation demand response by incentivizing customers for respective measures:

> *"Conditions for, and access to, demand response should be improved, including for small final consumers. Taking into account the continuing deployment of smart grids, Member States should therefore ensure that national energy regulatory authorities are able to ensure that network tariffs and regulations incentivise improvements in energy efficiency and support dynamic pricing for demand response measures by final customers.* [46]*"*

Figure 2-23 shows the share of network costs in European electricity prices in percentage. In general, small customers will have to pay higher prices as they are connected to a lower voltage level than larger customers. In 2011, the share of network costs in the total electricity price was between 20 and 50% for the average European retail customer. Network costs cover capital costs, organization and management, procurement of network losses, customer service and overhead costs (associated with network service delivery). The network price for a retail (household) customer consists in most European countries of a fixed charge (€), a capacity charge (€/kW) and an energy charge (€/kWh). [47]

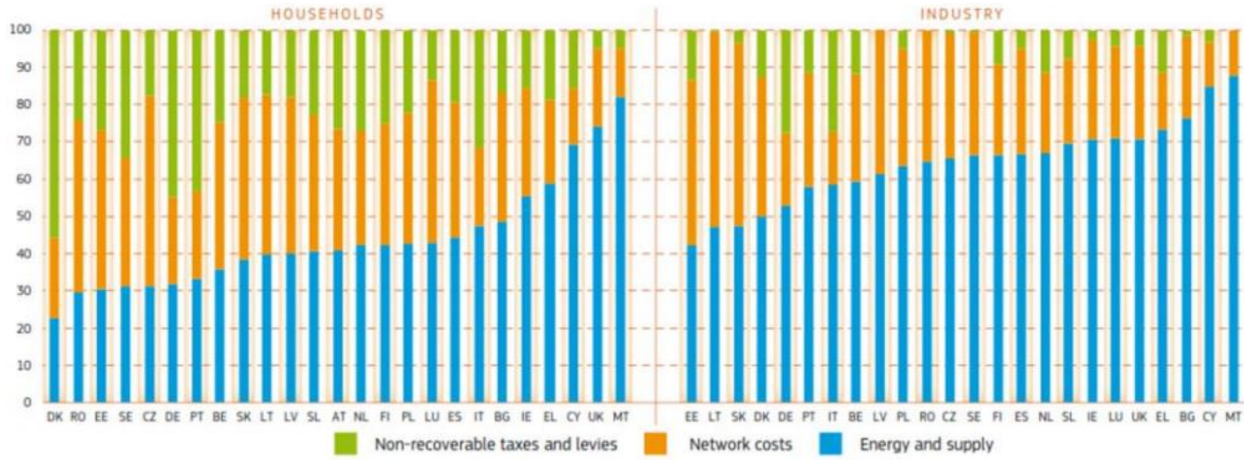


Figure 2-23: Share of network costs in retail electricity prices in Europe (2011) [47]

To incentivize customers to use their demand side flexibility for valley filling, load shifting and peak shaving, network tariffs need to be adapted. Regulated retail prices and volumetric tariffs may incentivize customers to reduce their consumption in general but not to reduce it in peak times.

Four possible tariff types and the resulting incentives are presented in [47]:

- **Fixed volumetric:** The customer has to pay a fixed price (€/kWh) depending on the amount of energy he consumes. He is therefore incentivized to reduce his overall consumption. As the peak consumption will not be mainly affected, impacts on the network costs will be low.
- **Capacity-based**: The customer has to pay for the capacity that has been made available (€/kW). He is therefore incentivized to reduce its peak demand (→ lower network costs). However, he might not reduce its overall consumption but only shift it to off-peak hours (except when it is a time-of-use tariff, in which the capacity-based price also depends on the time of consumption).
- **Time-of-use volumetric:** This type of tariff is again energy-based. In contrast to the first tariff model, this model includes two prices: A low price (€/kWh) in off-peak hours and a high price (€/kWh) in peak hours. Customers are therefore incentivized to reduce their overall and especially their peak-time consumption, which can influence network costs.
- **Two-part tariff:** This model consists of a power component (€/kW) and an energy component (€/kWh). Customers are incentivized to shift their consumption to off-peak hours and reduce their overall consumption.

The implementation of the presented tariffs can help customers to optimize their overall electricity costs by adapting their consumption while the DSO profits from a more even load on his grid. Dynamic pricing and resulting coordination between market actors has still to be investigated and is a topic of current research.

3 Coordination schemes for flexibility utilization

To successfully use demand side flexibility on energy markets and enable all of its benefits requires an intense coordination between different actors/roles of the power system. These coordination requirements will be presented and analyzed in the following. Actors and roles of the power system were already defined in IEA Task 17 Subtask 10 - Roles and Potentials of Flexible Consumers and Prosumers and will be used according to these definitions in this chapter.

3.1 Influence of the independent aggregator and resulting interactions

An interaction that has to be analyzed carefully is the one between independent aggregator (independent from supplier) and other market parties. This interaction is of great significance as the actions of these parties mainly influence each other.
Figure 3-1 shows the interactions of the independent market parties with other actors/roles. The aggregator is directly contracted with customers who are able and willing to provide demand side flexibility (demand facilities). The aggregator is then allowed to sell the aggregated flexibility on the energy markets. The grey arrows show the impacts of this transaction on other market parties who are not directly involved in the process of demand response. These impacts need to be regulated by contracts or operational relationships. [48] The main impacts between the market parties are shortly describes in the following:

- **Aggregator ↔ BRP/supplier**: When the aggregator activates DR of its contracted customers, this has a main impact on the BRP/supplier as his balancing position is changed. He may therefore receive either an imbalance penalty or payment. Furthermore, the BRP/supplier gains financial risk because part of the energy that he injected will not be consumed by its customers if DR is activated. [48]
- **Aggregator ↔ customer:** The customer’s load profile is changed due to demand response. This again can influence BRPs/suppliers if customers’ consumption is higher/lower than it was taken into account by these market parties which can result in additional imbalances. [48]
- **Aggregator ↔ TSO/DSO:** The activation of DR can lead to network constraints and jeopardize the security of supply. Therefore, a new information framework will be needed. The costs for this framework should be carried by the aggregator. [48]

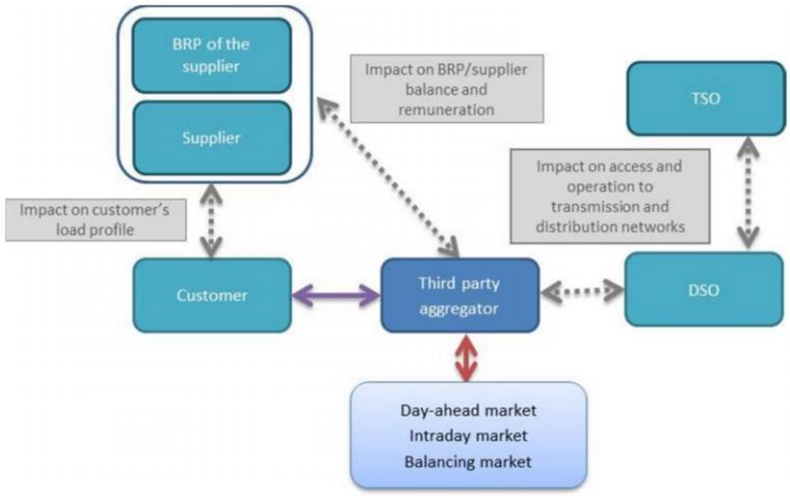


Figure 3-1: Independent aggregator and its relation to other market parties [48]

ENTSO-E's network code on electricity balancing (NC EB)

The NC EB [49] Article 27 gives rules related to balancing. It is stated that TSOs (in cooperation with other TSOs and DSOs) are responsible for defining terms and conditions for BRPs and BSPs.

Thereby, "*the terms and conditions for balancing service providers shall allow the aggregation of demand side response, the aggregation of generation units, or the aggregation of demand side response and generation units within a responsibility area or scheduling area when appropriate to offer balancing services* [49]*"*. The exact conditions necessary for aggregating demand side response have to be given by the TSO. Terms and conditions have to include the requirements for a BSP to act independently from a BSP. Also the financial settlement between BRP and BSP in case of independent aggregation has to be defined by the TSO.

ACER's recommendations

The agency for the cooperation of energy regulators (ACER) provided a document with recommendations [50] for the adoption of the NC EB. Within this document, it is proposed to introduce a new article in the network code to specify to role of the independent BSP (aggregator). The providers of DR may have to face significant barriers in entering the balancing service markets. These barriers should be identified and eliminated by European member states and their respective NRAs so that independent BSPs can participate in an equal playing field for balancing services. [50]

To enable an increasing share of DR provision independent from energy suppliers on the balancing service markets, ACER proposes harmonization requirements [50]:

- A BSP should be able to provide demand response flexibility without having a contract with the supplier or BRP of its demand facility.
- The provision of demand side flexibility independently from energy suppliers should be balance responsible.
- TSOs are responsible to adjust the final position and determine the allocated volume for the BRP of the independent BSP and the one of the supplier.
- TSOs have to determine the financial settlement between the BRP of the independent BSP and the one of the energy supplier.

Possible interactions between the market parties

In this section, possibilities to compensate or coordinate the impacts of the independent aggregator on other market parties will be addressed.

- *Independent aggregator ↔ BRP/supplier:* The aim of this interaction is to compensate the imbalances of the BRP/supplier that have been caused by the aggregator. In [48], three market models are presented that allow BRPs/suppliers to recover all resulting additional costs. The basic principle is that the BRP's/supplier's imbalances that were caused by the aggregator are compensated by the TSO. Furthermore, BRPs are financially compensated for the electricity that has been rerouted by the aggregator for its use on the electricity markets.
    - *Corrected model:* The metering data from BRP's/supplier's customers is corrected by the amount of electricity used by the aggregator. The customers have to remunerate their BRP/supplier at the contracted rates. They are in turn remunerated by the aggregator. A positive aspect of the implementation of this system is that the additional effort on BRP's/supplier's side is minimized. However, the correction of metering data may lead to a lack of transparency on the customer's side.
    - *Regulated model:* In this model, the BRP/supplier is directly compensated by the aggregator. The regulated price that has therefore to be paid by the aggregator has to cover the commodity/means of flexibility that is subscribed ex-ante by a BRP/supplier. A possible barrier of this model is that the regulated price may not exactly cover the additional costs for the BRP/supplier, as it has not to be the same price as contracted with the customer.
    - *Contractual model:* The aggregator and the BRP/supplier have to set up a contract to agree on the compensation process. For this model, standardized frameworks can be helpful for simplification of the process. This model can lead to market power concerns of the BRP/supplier, as customers may tend to contract with BRPs/suppliers who are contracted to an aggregator.

  In order to use DR efficiently, the aggregator needs to provide information to the BRP/supplier. The BRP/supplier needs to know if customers change their consumption specifically or because they are activated by the aggregator. While the first case needs the BRP/supplier to react to keep its position balanced, a reaction/different electricity injection would destroy the effect of DR in the second case [48]. Therefore, a stable and transparent communication system is needed between the two market parties.
- *BRP/supplier ↔ customer:* It may be necessary to renegotiate an already existing contract between a BRP/supplier and its customer, if this customer wants to participate in a DR program. This step is prerequisite to guarantee that customers who do not participate in DR programs do not have to come up for DR related costs. [48]
- *Aggregator ↔ customer:* The aggregator needs information and communication technology (ICT) to stay connected to its customers. To use the flexibility of a customer on the markets, the aggregator needs feedback from his contracted flexible units to gain information about their status. The gaining resulting from the use of flexibility needs to be allocated in a fair way.

  Another aspect that has to be considered in the aggregator/customer interaction is that some prosumers might want to use their flexibility to balance themselves (e.g. using the flexibility of a photovoltaic system to compensate its own consumption). Conflicts between interests of the aggregator and of the prosumer can be the result. To avoid such conflicts, regulations need to be contractually set between these two parties. To establish them, future investments and projects will have to be conducted.

- *Aggregator/Customers ↔ DSO (/TSO):* Regarding DR flexibility, there are two possibilities for the DSO. On the one hand, he can use flexibility for his grid, like for example for congestion management. On the other hand, the DSO is affected by DR flexibility activation, even if it does not use it for its grid. The DSO is then involved in the process because the activation of DR flexibility influences the state of its grid.
  DR flexibility activation that is not used for the distribution grid: As DR is located in the distribution grid, the DSO needs to be actively integrated in the process of DR activation. He has to guarantee secure operation of the distribution grid and has therefore to conduct congestion management. For this, he needs information about the activation of DR provided by the aggregator. On the other hand, he needs to inform the aggregator of the availability of the distribution grid. The state of the grid can be displayed in a transparent way by a traffic-light system. In the red state (critical state), activation of DR should not be possible for the aggregator and he should therefore not be able to offer bids on the electricity markets. [48]
  Another approach is that the activation of a DR bid by the TSO first needs to be approved by the DSO. Therefore, a screening of market bids has to be accessible for the DSO. In case of approval of a bid, the DSO has to guarantee that network operation in the distribution and transmission grid are not jeopardized and so no additional costs occur for network operators. TSOs and DSOs have to ensure fair and transparent market conditions to make the use of DR as efficient as possible (e.g. for the use of solving local congestions). [48]
  Active use of flexibility by the DSO: According to [51], market mechanisms should only be applied to DR in case of the balancing challenge. Local challenges (transformer loading, voltage) should be faced by using bilateral contracts between network operators and customers who are able to provide DR flexibility. These bilateral contracts might interfere with the contracts of aggregator and customer so that a framework has to be established in future projects. Different market models can be used to gain the highest value possible for network operators. These models will be introduced in chapter 3.2.
- *Interaction regarding general data exchange:* The data exchange that is necessary between the mentioned market parties can be carried out by the parties themselves. On the other hand, a new (independent) actor could be instructed to establish and administrate a common information platform. This actor would be responsible for collecting data from the involved market parties and provide them to other market parties (comparable with the role of the metering data responsible – see IEA Task 17 Subtask 10 – but now as an independent actor). With an independent actor as the provider of important data, transparency and information equality for all market parties might be easier to achieve.

Example for the interaction of the aggregator with other market parties – France:
The NEBEF mechanisms (Notification d’Echange de Blocs d’Effacement, Notification of Exchange of Blocks of Load Shedding) allow demand response bids to participate on energy markets. Since 2014, the independent aggregator is allowed to integrate customers supplied by other market parties in its portfolio. The NEBEF mechanism establishes hereby the transfer of energy from a BRP/supplier to the aggregator until its use on the markets. To use the NEBEF services, a market party has to become a demand side management operator (in accordance to the NEBEF rules and fixed by a contract with RTE, the French

TSO) and have a balance perimeter [52]. To guarantee security of supply over a long term, the capacity mechanism will be implemented in France. Using this mechanism, customers will have to get capacity certificates for the the amount of their portfolios to the consumption peak. This can either be fulfilled by the possession of real assets or by buying capacity certificates to a holder of flexibility. Certificates are obligatory for generation and demand side capacity connected to a transmission or distribution grid. The use of flexibility on electricity underlies two contractual relationships. As the system is an example for a regulated model, aggregators can contract customers without involvement of their respective BRP/supplier. The aggregator then has to compensate the BRP/supplier, while the customer has to pay what is indicated on its meter. The aggregated flexibility is proposed as "energy block" on the energy markets. [53]
Regarding the interaction between aggregator and DSO/TSO, several demonstration projects are conducted in France. The aim of these projects is to establish the services that can be provided to the DSO due to demand response, optimal market conditions and framework for the optimal use of flexibility and the evolving role of the DSO. A cost/benefit analysis shall give an overview about the financial and qualitative output of a tested solution. [53]

3.2 Interaction between TSO and DSO

The aim of the interaction of TSOs and DSOs is to gain the most possible value from flexibility, while fulfilling all of their roles in the best possible way and keeping costs low for society/customers.
Most of the electricity generation takes place at the distribution level. Furthermore, the increasing share of small and distributed generation plants is challenging DSOs and in succession also TSOs in maintaining system stability. To face these challenges, a high level of interaction between transmission and distribution system operators is needed. According to [54], the TSO/DSO cooperation can be separated in three categories:

- *Resource access:* TSOs and DSOs need to coordinate their resource access and inform each other about decisions they made on this point. Otherwise, resource lacks are possible.
- *Regulatory stability:* TSOs and DSOs should coordinate their approaches and timescales concerning regulatory principles in order to be able to operate their respective grids in an optimal way.
- *Grid visibility and data:* The interaction of TSOs and DSOs should underlie a sufficient, transparent and non-discriminatory data exchange from both sides.

Flexibility can be used in two ways: System balancing or network management (congestion management and voltage control). This may lead to conflicts in the use of flexibility sources. Both TSOs and DSOs are responsible for network management, while the TSO is also responsible for balancing. In systems with a high share of distributed generation and demand response, these market parties need to get access to balancing markets. This implicates that DSOs are also involved in the balancing process. They need to participate in the definition of prequalification criteria and provide the necessary metering data to the TSO. [54], [51]
Some points should be considered to avoid conflicts between TSOs/DSOs and to allow all market parties access to different markets [54]:

- The way flexibility is measured should be harmonized between TSOs and DSOs.
- TSOs and DSOs should take investments to establish a way to use flexible resources in a coordinated way so that the highest value is achieved. Possibilities for this are a single market place [55] for flexibility bids - to support local congestions and balancing - or

separated local congestion markets where a high interaction between TSO and DSO is necessary to avoid double biding and ensure system security. For these two market designs, several coordination schemes are possible. They are currently investigated in the SmartNet project [56].

- TSOs and DSOs should establish a way so that both of them can use reactive power from RES to support voltage levels in a coordinated way.

General prerequisites for a TSO-DSO interaction [54]

- Technical requirements concerning network-planning procedures and the implementation of new technologies should be planned in coordination.
- TSOs and DSOs should establish a joint information platform where data can be provided from both sides. New information technologies should be observed and jointly decided on. Communication between the system operators should be held transparent and the most effective possible.
- Joint staff training can help to easier the interaction between TSOs and DSOs.

NRA and EU engagement

The interaction between TSOs and DSOs also requires the involvement of NRAs and – on an international European level – even European engagement. NRAs should easier the cooperation of TSOs and DSOs by allowing them to use flexibility for local and central market purposes. TSOs and DSOs need to be allowed to contract (e.g. by bilateral contracts) flexibility resources to conduct congestion management. Furthermore, NRAs should approve technical/economical solutions that were established in the TSO-DSO cooperation in order to facilitate communication and fulfill their roles in the best possible way. The European commission should encourage a fast implementation and compliance of the network codes. Furthermore, they need to guarantee that the network codes are reviewed and adapted to current system needs periodically. [54]

ENTSO-E's network code on load frequency control-and reserves (NC LFCR)

The NC LFCR [57] already includes rules for the interaction and cooperation of TSOs and DSOs in European member states concerning reserve providing units connected to the DSO grid. It is says that

> *"TSOs and DSOs shall collaborate and use reasonable endeavours to facilitate and enable the delivery of active power reserves by reserve providing groups or reserve providing units located in distribution networks.* [57]*"*

According to the NC LFCR, the DSO (either reserve connecting or intermediate) will be responsible for processing the application of a reserve providing unit/group within two months after the provision of the notification. He is furthermore responsible for the publication of all necessary data like the type of active power reserves, voltage levels and connection points of the reserve providing groups/units. During the prequalification process, TSO and DSO will have to cooperate closely. According to the network code, DSOs shall have the right to exclude and set limits to the delivery of active power reserves in its distribution grid. These processes have to be handled in a transparent and non-discriminatory way (based on technical arguments). Furthermore, TSOs and DSOs shall cooperate and jointly define temporary limits for the delivery of active power reserves at any point of time before its activation. They have to agree on communication procedures/methodologies related to prequalification and delivery of active power reserves. [57]

In an **ISGAN discussion paper** [51], general use cases that would profit from a TSO-DSO cooperation are presented. Several country examples for this cooperation cases are given. In the following, the cases will be presented shortly. The TSO-DSO cooperation will be presented with the examples of Austria and the USA.

- *Congestion of transmission-distribution interface:* The transformer between transmission and distribution grid acts as the boundary between both grids. Due to a high share of distributed generation, the transformer can become critically loaded. If it is operated by the DSO, he can use demand side management or take other measures to decrease the loading. If the transformer is operated by the TSO, a cooperation between the grid operators is necessary.
    - *Austria:* Congestion is prevented in the network-planning phase. There is no extension planned of the TSO-DSO cooperation at this point.
    - *USA:* The transformer is operated by the DSO. Distribution and transmission planning departments cooperate to ensure that capacity and station configurations are adequate.
- *Congestion of transmission lines:* This case is very similar to the first one. Transmission lines can get critically loaded due to increased loading or distributed generation.
    - *Austria:* Congestions of transmission lines are again prevented in the network-planning phase. Furthermore, load can be switched to the DSO level in some cases (faults or maintenance).
    - *USA:* The TSO manually provides load curtailment information to the DSO. The DSO then determines the particular load blocks to execute the amount of load curtailment given by the TSO.
- *Voltage support (TSO ↔ DSO):* DSOs and TSOs can support the voltage on the grid of the other party. For example, the DSO can support voltage on the transmission grid by activating DR in the distribution grid.
    - *Austria:* To fulfill the needs of TSO and DSO, the tap setting (setting of the transformer) is negotiated between the two control rooms of the grid operators. Automated control is not used very often but expected to be implemented more often in the future.
    - *USA:* The TSO manages the voltage support needs and therefore carries out tap changers and switching of DSO substation capacitors. The voltage measured at DSO level is used for the management of capacitor controllers with special management systems.
- *Balancing challenge:* An increasing share of distributed generation leads to more errors in the forecasts of demand and consumption and it gets more challenging to balance the grid. Flexibility on the distribution grid could be used by the TSO to counteract resulting imbalances.
    - *Austria:* From a legal perspective, resources located in the distribution grid are allowed to participate in the balancing markets, if they fulfill the prequalification criteria. TSOs are solely responsible for the definition of these criteria; there is no interaction between TSO and DSO.
    - *USA:* The DSO only performs load curtailment for the DSO (see “congestion of transmission lines”). In the future, the data exchange between TSO and DSO will have to improve to enable other possibilities of cooperation, as the TSO holds a clear information advantage.
- *(Anti-)Islanding, re-synchronization & black-start:* Due to distributed generation, some parts of the grid can be balanced instantaneously with a higher probability. If this part of

the grid is separated from the rest, islanding occurs. If a part of the distribution grid, which is balanced, is locally separated from the transmission grid (at a transformer), measures have to be established to detect the situation or conduct a re-synchronization. In severe cases, this can be a black-start, which is of course not needed very often in Europe. Therefore, this use case can be seen as a “special” one.

  - *Austria:* Some parts of the distribution grid could be used in the islanding mode. However, this mode is not used very often due to the high availability of the transmission grid. Black start capability is foreseen at TSO level (basic service) but not at the DSO level (and therefore not rewarded by the network tariff system).
  - *USA:* Islanding is prohibited. Therefore, the TSO has to develop measures to prevent this mode. The DSO provides balance loads for black-start loading. Data exchange occurs through human interaction.

- *Interoperability for coordinated protection:* If there occur any faults on the distribution or transmission grid, they may be detected in the grid of the other party by measurements. TSO-DSO interaction can thereby be helpful to detect faults in a short time. With a high share of distributed generation, faults may be fed by fault currents from different directions so that the location of the original fault may not be easy to determine. Then again, advanced coordination between TSO and DSO is helpful.
  - *Austria:* There is no interaction between TSO and DSO at this point yet.
  - *USA:* TSO and DSO conduct coordination studies together and circuit information is exchanged. Distribution automation can be enabled through the TSO by applying slower protection.

Example for TSO/DSO interaction – Switzerland:
A future model for the TSO/DSO interaction was investigated in [58] based on the delineation of barriers in the national Smart Grid Roadmap [59] when using flexibility. The TSO conducts congestion forecasts in three time intervals: 2-days-ahead, 1-day-ahead of the dispatch and intraday. Through these forecasts, the need for flexibility is defined in order to relieve network congestion. The demand can be linked with different markets according to the timeframe. Congestions in the DSO area must thereby not be compromised. Therefore, an additional DSO forecast about the local grid situation and need for flexibility on the DSO level is proposed. Such a forecast should be linked to the day-ahead forecast of the TSO. [33]
A coordination between the flexibility needed by the TSO and the flexibility which can be provided by resources in the distribution grid is crucial. In addition, the coordination mechanism must ensure that the flexibility contracted with the DSO does not interfere with flexibility contracted with the TSO or other more market-oriented actors. This does not necessarily mean that a resource can only be contracted once. However, it does mean that it only can be allocated to one actor at a specific time and a specific type of flexibility provision. This coordination model can be seen in Figure 3-2. More in depth studies are currently carried out in Switzerland to design a functional and simple coordination framework.

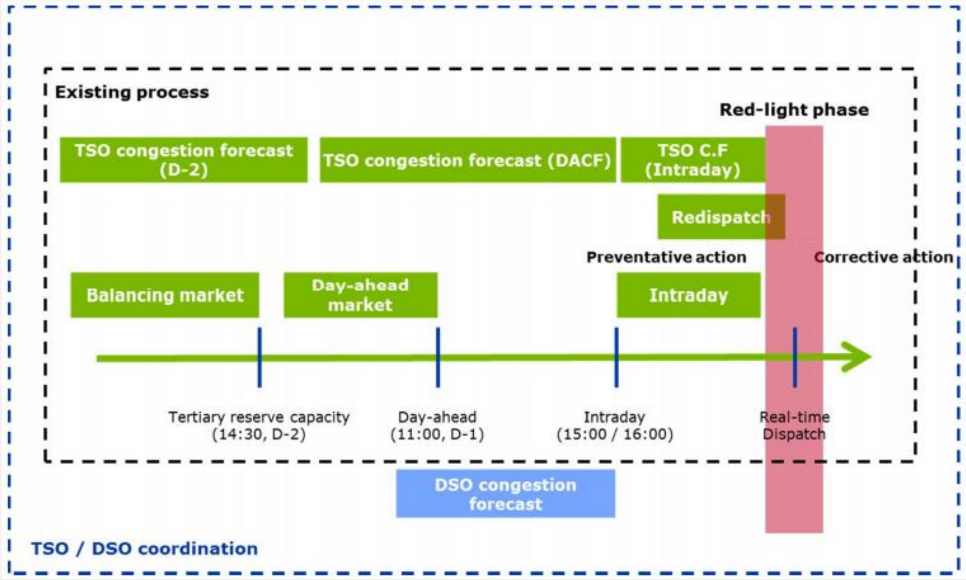


Figure 3-2: TSO/DSO coordination model [33]

4 Valuation analysis for demand side flexibility demonstration projects

The aim of this chapter is to demonstrate possibilities for conducting a valuation analysis for demand side flexibility demonstration projects and thereby defining important key parameters to be considered (such as boundary conditions). Valuation analyses shall finally give an insight in benefits that can be enabled by using demand response and in the extent of necessary investment costs of a project. Risks in the calculation of costs and benefits shall thereby be captured within a sensitivity analysis, which can display the outcome of a CBA due to a change of key parameters.

Therefore, already existing guidelines for the measurement of profitability are presented in chapter 4.1. In a next step, boundary conditions, which need to be defined and considered for conducting a CBA are listed and explained (chapter 4.2). Requirements for scenarios and sensitivity analyses are given. Problems and challenges that can occur in conducting a CBA have been worked out and are described in chapter 4.3. A general set of costs and benefits related to demand side flexibility demonstration projects is given in chapter 4.4. Finally, a short insight in demonstration projects that have already been valued by using different methodologies, is given (chapter 4.5).

4.1 Methodologies for measuring the profitability

A number of guidelines for measuring the profitability of demand side flexibility demonstration projects have been designed. They are applicable at technology readiness levels (TRLs) above 7. It has to be remembered that CBAs of research projects might give other results as compared to demonstration projects, whereas sensitivity analyses of research projects can already give significant results. A number of guidelines for measuring the profitability of demand side flexibility demonstration projects, which are of importance for Europe and the US, are described in this chapter.

4.1.1 EPRI method

EPRI (Electric Power Research Institute) developed a method for a CBA process for smart grid demonstration projects [60] which consists of 21 steps. These steps are summarized in four sections, which can then again be associated with three different phases (see Figure 4-1).

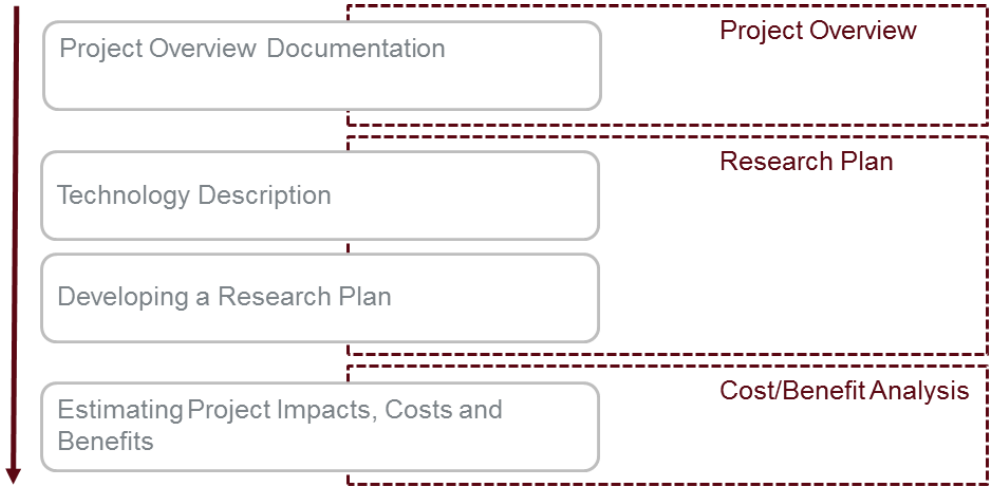


Figure 4-1: CBA framework defined by EPRI (based on [60])

Project overview

First, basic information about the project (name, budget, lead organization etc.) is given. Then the project purpose is illustrated: The current situation ("business as usual") is described and problems that should be solved due to the project as well as the objectives of the project are identified. The regulatory and market contexts of utilities need to be identified and additional project information needs to be given (geographic scope, basic project elements, etc.). At last, organizational information like the project timeline is given.

Research plan

This phase contains two sections.

- *Technology description:* All technologies, systems and devices used for the project need to be identified. The deployed systems need to be linked to smart grid functions that are enabled by them (linking of assets to functions). It is identified how the smart grid devices and systems are applied and which benefits and impact-related costs would therefore result. In a last step, physical impacts and performance metrics are described. They would need to be calculated for the identified benefits or to analyze the performance of the project.
- *Developing a research plan:* The very first steps of this section are the definition of the research problem and the required identification of physical measurements. Relevant external factors (like weather data) are listed. In the next step, a set of numbers/measurements for comparison with the baseline scenario needs to be identified (definition of baseline quantities or estimation methods). Formal hypotheses (true/false statements) about impacts associated with smart grid applications are constructed and be further tested through experimentation (these experiments need to be defined in the next step). The project timeline is specified and coordinated with the experiment plans. In the last steps, instructions for the data collection (e.g. time intervals, collection points), a specification for the data testing, screening, storage and retrieval as well as for algorithms for the calculation of impacts/impacts metrics are listed.

CBA
The measurement data for which guidelines have been defined in the previous section are used to estimate physical impacts. For a CBA physical impacts that cause economic costs/benefits are the most interesting. Thereby impact categories can be helpful, the proposed ones are “reliability”, “utility operations”, “system operations”, “utility assets”, “power quality” and “customer”. The impacts are then converted to monetary values.

4.1.2 JRC method

Based on the work of EPRI also JRC (Joint Research Centre) defined a general guideline used to identify the value of projects related to smart grids [61] which has been taken over and adapted for many other approaches (for example [62]). Due to its importance, it is illustrated shortly in the following. The framework of the CBA consists of three main steps, which can be seen in Figure 4-2.

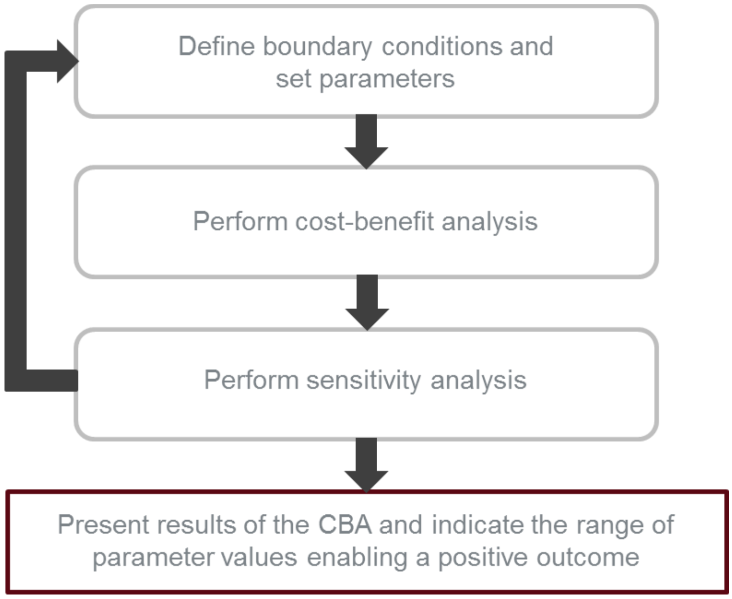


Figure 4-2: CBA framework defined by JRC (based on [61])

Boundary conditions
The local context and conditions of the rollout need to be documented as well as their impact on the major assumptions. Data sources are identified and their level of uncertainty is specified. Additionally, the span of years in which costs and benefits take place needs to be specified and argued why this period is appropriate. JRC gives a list of representative variables that should be considered and collected within the CBA timeframe as they potentially have impact on the investment. Some critical variables need to be analyzed carefully (see chapter 4.1.4).

Cost-benefit analysis (CBA)
The CBA consists of seven steps (see Figure 4-3).

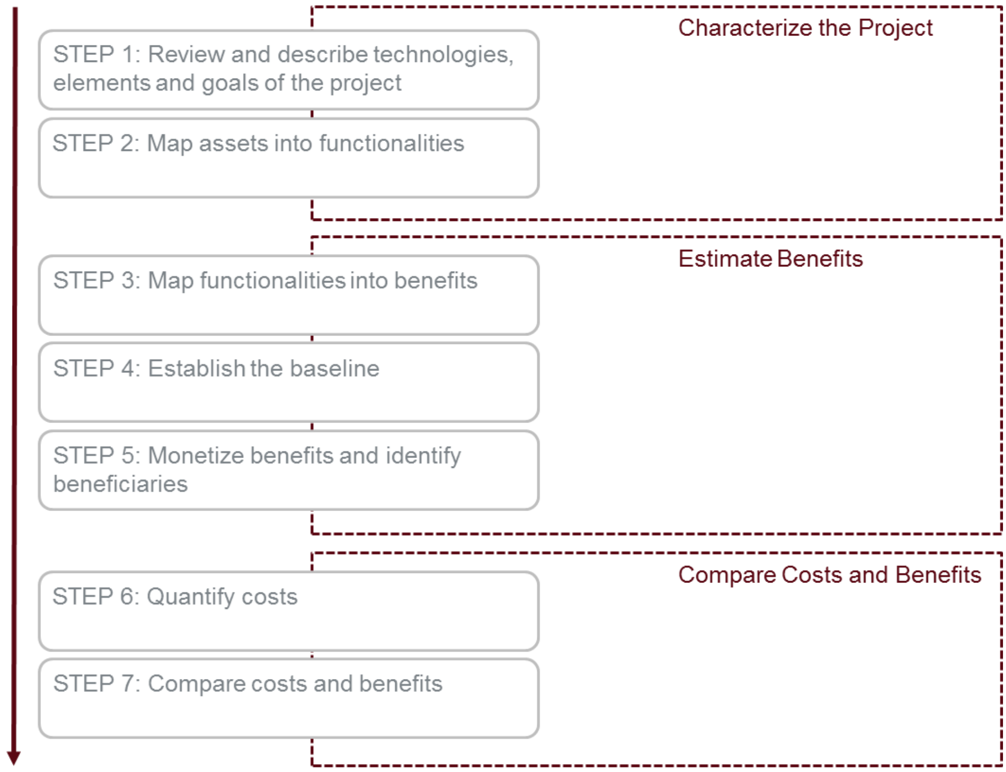


Figure 4-3: Steps of the CBA (based on [61])

1. In **step 1,** high-level goals are identified and it is stated how the installed technologies will have impact on them. It is important to point out who the stakeholders are and how their needs are addressed. Then the assets and their function are described and how the system is affected by them. The assets include technologies, devices and equipment, which have to be valued.
2. In **step 2,** assets are linked to their functionalities. Every asset is thereby looked at individually. The result is an assets-functionalities matrix.
3. In **step 3,** the functionalities are linked to benefits that give the functionalities-benefits matrix.
4. In **step 4**, the baseline is established which is then compared to all other scenarios. It is obvious that at least two scenarios should be evaluated and compared: One, where the project is implemented (test scenario) and one “Business as Usual” scenario (BaU), where no changes are made (no project implementation, baseline).
5. In **step 5,** the data needed for quantification and monetization of benefits (such as hourly load data etc.) are collected. If there have any key assumptions to be made, they should be clearly documented and the level of estimation uncertainty should be stated. The beneficiaries and their estimated corresponding share on a benefit should be identified in this step. It is useful to divide benefits into sub-benefits for the calculation of their value. JRC gives a list of possible benefits for smart grid projects and some suggested formulae to calculate the monetization of them.
6. In **step 6,** costs of the project are identified and quantified. Some of them may be easy to estimate or can be directly measured. Cost data is generally a combination of estimated costs and data directly from the scenario.
7. In **step 7,** costs and benefits finally are compared. There are different ways of conducting this step. The most common approaches are annual comparison, cumulative comparison, net present value or cost-benefit-ratio.

Sensitivity analysis

It is identified how much a variation of key variables affects the outcome of the CBA. The sensitivity analysis is necessary as specific factors (e.g. geographic or economic ones) have a major role in determining the importance of benefits. Furthermore, the CBA is based on estimations and forecasts that may significantly differ from values that have been actually realized. The sensitivity analysis should show the possible range of parameter values that cause a positive outcome of the CBA.

Qualitative impact analysis

The qualitative impact analysis should be used additionally to the recommended CBA and cover all non-monetary appraisals of a scenario (e.g. job creation, enabling of new services). According to [61], two main points should be included in the analysis:

- KPI (key performance indicator)-based scores of scenario merits on different objectives
- A qualitative appraisal of foreseen externalities and their social impact

After the specification of these two points, a way to aggregate necessary information has to be found. Expert judgement is necessary to estimate the overall impact of qualitative factors.

4.1.3 ISGAN method

ISGAN Annex 3 [63] has its focus on developing a general method for the valuation of smart grid projects as an internationally applicable solution by collecting existing CBA methods. In this process, existing problems of CBA methods are identified and eliminated. To bypass the difficulty of mapping assets into functionalities, JRC's method has been refined. Assets are now directly linked to benefit categories. Six toolkits (see Table 4-1) have been developed as a proposal for six different smart grid solution types and implemented in Microsoft Excel. The output is then a value in euros, which gives the benefit of the solution. The toolkits will be tested on real smart grid projects in the ongoing ISGAN task. Thereby these toolkits will be improved by adding, for example, the point of view from which the analysis is considered. Taking the scope only from the grid operator gives a perspective differing from taking the whole economy or society.

Table 4-1: Toolkits (ISGAN method) [63]

Toolkit/Goal	Input Parameter	Services/Benefits
1: CBA of storages connected to the transmission system	• Storage size (MWh, MW) and installation costs • Yearly hours of avoided higher request of conventional Automatic Grid Control (AGC) (h/y) • Specific cost for reinforcing the transmission grid ($/MW) • Specific cost for voltage regulation ($/MW) • Avoided curtailment of RES generation (MWh/y) • L/f control and AGC requirements • Marginal prices (day-ahead market (DAM), ancillary services market (ASM) and RES subsidies	• L/f control and synthetic inertia • AGC • Voltage regulation • Mitigation of RES curtailment (grid congestions) • Investment deferral (transmission capacity)
2: CBA of storages connected to the medium-voltage grid	• Storage size (MWh, MW) and installation costs • Specific cost for reinforcing the distribution grid ($/MW) • Specific cost for voltage regulation ($/MW) • Avoided curtailment of DG plants (MWh/y) • L/f control and AGC requirements • Marginal prices (DAM, ASM) and DG subsidies	• Voltage regulation • Increase of Hosting Capacity and investment deferral (distribution capacity) • Mitigation of DG

		curtailment (grid congestions) • L/f control and synthetic inertia • AGC
3: CBA of storages connected to the low-voltage grid	• Storage size (kWh, kW) and installation costs • Yearly number of avoided transient interruptions and voltage dips • Yearly number of avoided short and long interruptions • Mean duration of the interruptions • Rated power of MV/LV transformer (kVA) • Specific cost of transient interruptions and voltage dips ($/int) • Specific cost of short and long interruptions ($/int) • L/f control requirements	• Improve the continuity of service (SAIFI+SAIDI) • Improve the quality of supply • L/f control and synthetic inertia
4: CBA of a smart automation system applied to a MV distribution network	• Characteristics of Primary Substation (number of busbars, number of feeders) • Yearly number of avoided transient interruptions and voltage dips • Yearly number of avoided short and long interruptions • Value of interrupted power for each event (MW) • Specific cost of transient interruptions and voltage dips ($/int) • Specific cost of short and long interruptions ($/int) • Specific cost of automation solutions • Is it automation or remote control?	• Improve the continuity of service (SAIFI+SAIDI) • Improve the quality of supply

5:
CBA of a smart grid applied to a MV distribution network
	• Characteristics of Primary Substation
	  ○ number of busbars & number of feeders;
	  ○ rated power of HV/MV transformer & rated voltage
	• Hosting capacity with passive network
	• Equivalent hour of DG plants
	• Costs of connection DG plants
	• Info of the project:
	  ○ number of GD plants/storage involved in the project
	  ○ presence of control system (Y/N)
	  ○ bidirectional communication systems and standard protocols (Y/N)
	  ○ participation of DSO to ASM (Y/N)
		• Increase of Hosting Capacity and investment deferral (distribution capacity)
		• Mitigation of DG curtailment (grid congestions)

6: CBA of advanced metering infrastructure (AMI) applied to a distribution network	• Number of installed smart meters & Number of meters afferent to a concentrator • ToU price scheme (Y/N) • Annual number and type of remotizable operations different from readings • Remote transactions: consumption reading (registers and intervals), supply • activation/deactivation, change of the subscribed power, change of the ToU tariff, max allowed • power level reduction (Y/N) • Demand response (Y/N) • Cost of each type of remotizable meter operations ($) • Communications failure rates for meter readings and for meter operations (%)	• Reduction of demand curve • Reduction of meter reading and operations costs • Reduced electricity losses & increase of energy efficiency • Deferred distribution, transmission and generation capacity investments

4.1.4 PNNL method

The recommended valuation methodology for transactive energy systems (which means that electric energy is exchanged by the participants) by the Pacific Northwest National Laboratory (PNNL) can be seen in Figure 4-4.

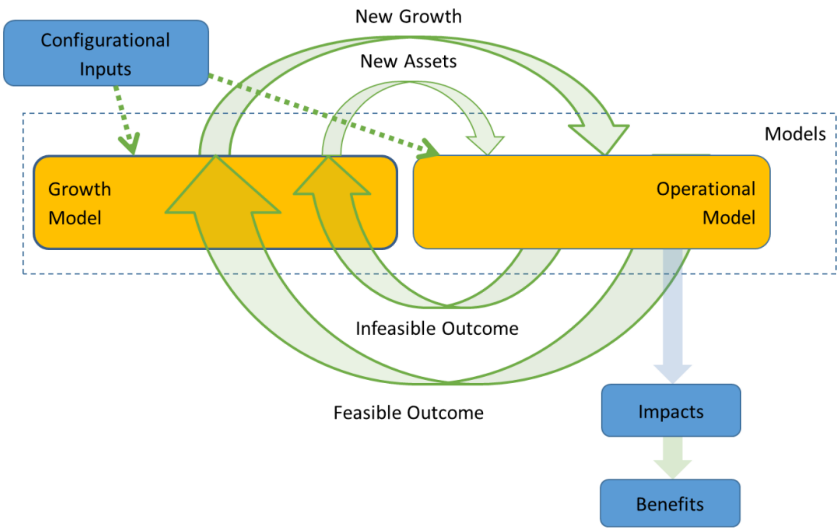


Figure 4-4: Recommended valuation concept [64]

Two models are used in this methodology [64]:

- *Operational model:* It models the performances of a system within a certain period in which main variables (policies, infrastructure, resources, and consumer population/behavior) remain relatively static. This time span is usually a year. If operations within this period are shown to be feasible, the operational model gives impacts and benefits that are being tracked. If operations are not feasible, the operational model has to be reconfigured.
- *Growth model:* This model defines how operations will change from one timeframe, in which a certain operational model is valid, to the next. Two types of growth have to be considered: New technology and "natural"/uncontrollable factors like changes in the energy consumption or retirements of infrastructure. The growth model keeps all acceptable responses to these challenges as well as their costs. If an operational model fails in producing a feasible outcome, one or more of these responses are being used. These alternatives are being tested by the operational models.

The basic method for the valuation of transactive energy systems consists of 17 steps, which can be seen in Table 4-2.

Table 4-2: Basic steps of the PNNL valuation method [64]

STEP	DESCRIPTION
1	Identify a treatment that is to be tested. This treatment is the principal difference between the initial baseline and test scenarios or how the two scenarios will evolve over time.
2	Define assets and market conditions to be used in analyses of baseline and test scenarios. The analyst specifies the source of input data, whether it is through research, results of pilot projects, or assumptions.
3	Identify the hypotheses concerning how the benefits of the baseline and test scenarios and their evolutionary pathways will differ. The hypotheses specify stakeholder(s) who will be affected. Hypotheses should also be specified temporally and geographically to the extent possible.
4	List the metrics that will likely prove and quantify, or alternatively disprove, the listed hypotheses. These are benefits. Benefits should be monetized whenever possible and assigned to a certain stakeholder.
5	Map how these benefits will be derived from other benefits. This process stops with benefits that can be learned from operational models; such benefits are called impacts.
6	Specify the requirements for the operational models that will inform the impacts. A useful operational model will reveal the hypothesized differences between the baseline and test scenarios as they evolve over time and will achieve the geographical and temporal granularity desired.
7	Select the specific operational models that will satisfy the requirements from item 6. Make clear where potential impacts are not included in the operational models and what assumptions, if any, are used instead.
8	Configure the operational models specific to the energy system under test and the treatment.
9	Configure the growth model specific to how a scenario will evolve/grow from time increment (typically a year) to the next, including demand growth and which new assets are available each year.
10	The baseline's and test scenario's evolutionary pathways in the model might be different if that was the treatment (item 1). At this point, the valuation is entirely set up and ready to be executed by following these next steps:
11	Confirm that the initial baseline and test scenarios violate no operational requirements (e.g., line constraints, reserve margins, environmental impact limits) when they are tested by the operational models for year 0.
12	Apply the growth predictions (i.e., load growth, annual equipment replacements, installed cost of DERs, inflation, etc.) within the growth model to both the baseline and test scenario pathways. Some growth predictions will cause assets to be implemented or replaced, which will introduce one-time costs for the new year.
13	Advance the growth model time increment (typically a year).
14	Test the new scenarios using the operational models.
15	Depending whether the new scenario violates one of the system's operational requirements, a) Violation case: Discard the scenario and formulate an alternative scenario by adding available asset(s) from those in the growth model to the scenario from which the violation case evolved. Return to item 13. This step may be repeated if there are multiple reasonable alternative asset candidates. New assets mean that one-time costs are introduced by the new scenario. b) No-violation case: Continue.
16	Return to item 11 until the desired time horizon has transpired, often 10–25 years.
17	Select baseline and test scenario pathways. These will often be the time series having minimum net present values.

The report [64] also gives a list of possible objectives of transactive energy projects with their involved technologies, participants in the transaction process, the measurement process and a basis for the monetization of the proposed objectives. Of course, this list is not exhaustive as different projects focus on different objectives (and therefore addressing other participants, using other technologies,…) that cannot be captured easily in whole within a single report. Several models that are needed for the valuation process are presented in general in the report. The methodology also proposes to observe benefits that cannot be directly monetized. Even though there are no markets for such benefits (e.g. occupant comfort, environmental benefits) to discover monetary values, there are methods to apply monetary values to these benefits by finding out how much customers would be willing to pay to achieve this benefit. [64]

- *Direct method:* Customers are being interviewed on how much they would be willing to pay to achieve a certain benefit. This method is rather challenging and time-consuming.
- *Indirect method:* The willingness of customers to pay for a certain benefit is estimated by assets for the equivalent utility that they are actually paying for.

Although these methods exist, not all costs and benefits can be monetized without problems. For example, costs/benefits derived from transactive energy building systems like changes in worker productivity due to a change in light intensity (visual comfort) cannot be turned in monetary values easily.

After conducting the proposed analysis, PNNL also recommends a sensitivity analysis to observe the impact of variations and risks (due to uncertainty, natural variability or modeling inaccuracy) of the input parameters on the outcome of the analysis. [64]

4.1.5 DOE/FERC method

The U.S. Department of Energy (DOE) and the Federal Energy Regulatory Commission (FERC) jointly developed a framework to evaluate the cost-effectiveness of demand response projects. As demand response has a different impact on different parties, five cost-effectiveness tests have been developed to evaluate demand response projects from different perspectives. The California standard practice manual is the recommended basis for the cost-effectiveness framework and was also the basis for defining and applying the tests. The focus of this methodology is not the valuation process itself, but the determination of which costs/benefits have to be considered for which perspective. [65]

The five tests that are presented in the report are [65]:

- *Participant cost test:* Costs (direct expenses due to demand-side measures) and benefits (like reduction of electricity bills) that occur to customers in DR projects are considered in this test.
- *Ratepayer impact measure (RIM) test:* The impact of DR programs on utility rates are considered in this test. The result of the test gives an indication about how customers that do not participate in a DR project are affected by it.
- *Program administrator cost (PAC) test:* This test is taken from the perspective of the program administrator and considers all relevant costs (like designing/planning a DR project) and benefits (like avoided energy/capacity costs) of his perspective.
- *Total resource cost (TRC) test:* In this test, all utility customers are considered, regardless, if they are participating in the DR project or not. All incurred costs are considered in this test. Benefits include avoided utility costs and any benefit experienced by program participants.
- *Societal cost test:* The costs and benefits considered are the same as in the TRC test. However, also additional costs/benefits can occur in this test: These are costs/benefits related with environmental impact or governmental service, which are experienced by society as a whole.

Table 4-3 gives a list of important demand response program costs and presents which of these costs are considered in which test.

Table 4-3: Demand response program costs [65]

Cost	Participants cost test	RIM test	PAC test	TRC test	Societal cost test
Program Administrator Expenses	No	Yes	Yes	Yes	Yes
Program Administrator Capital Costs	No	Yes	Yes	Yes	Yes
Financial Incentive to Participant	No	Yes	Yes	No	No
DR Measure Cost: PA Contribution	No	Yes	Yes	Yes	Yes
DR Measure Cost: Participant Contribution	Yes	No	No	Yes	Yes
Participant Transaction Costs	Yes	No	No	Yes	Yes
Participant Value of Lost Service	Yes	No	No	Yes	Yes
Increased Energy Consumption	No	Yes	Yes	Yes	Yes
Lost Revenues to the Utility	No	Yes	Yes	No	No
Environmental Compliance Costs	No	Yes	Yes	Yes	Yes
Environmental Externalities	No	No	No	No	Yes

Table 4-4 gives a list of important demand response program benefits and presents which of these costs are considered in which test.

Table 4-4: Demand response program benefits [65]

Benefit	Participants cost test	RIM test	PAC test	TRC test	Societal cost test
Avoided Capacity Costs	No	Yes	Yes	Yes	Yes
Avoided Energy Costs	No	Yes	Yes	Yes	Yes
Avoided T&D Costs	No	Yes	Yes	Yes	Yes
Avoided Ancillary Service Costs	No	Yes	Yes	Yes	Yes
Revenues from Wholesale DR Programs	No	Yes	Yes	Yes	No
Market Price Suppression Effects	No	Yes	Yes	Yes	No
Avoided Environmental Compliance Costs	No	Yes	Yes	Yes	Yes
Avoided Environmental Externalities	No	No	No	No	Yes
Participant Bill Savings	Yes	No	No	No	No
Financial Incentive to Participant	Yes	No	No	No	No
Tax Credits	Yes	No	No	Yes	No
Other Benefits (e.g., market competitiveness, reduced price volatility, improved reliability)	Depends	Depends	Depends	Depends	Depends

For a more detailed description of each cost and benefit that is listed in Table 4-3 and Table 4-4, please refer to [65].

Some main factors should be considered when the cost-effectiveness framework is applied:

- Study period: An appropriate study period should include all years in which costs and benefits are expected to happen. This may not always be easily possible, as not all costs and benefits are expected to occur in the same period. It is essential that program administrators define a study period regarding the expected cost/benefit streams.
- Baselines: The definition of a baseline scenario is essential, as it is the comparison for the test scenario. However, the definition of the baseline is challenging as different customers vary in their behavior (end-use, usage patterns and their change over time,…) so that a standardized basic scenario cannot be easily found.
- Customer participation and response levels: The participation rate of customers in a demand response project has a main impact on benefits that are achieved due to the project. The participation levels may not always be easy to estimate and may change over time.
- Sensitivity analyses: Some key uncertainties can be treated within a sensitivity analysis. They should include avoided capacity costs, participant value of lost service and transaction costs and customer participation/response levels.
- Transparency: Models, estimations/assumptions, inputs and methodologies used by program administrators should be clear and transparently documented.

4.2 Boundary conditions and scenarios

A CBA consists of a comparison between scenarios. The baseline ("business as usual") should be compared with at least with one other scenario in which it is assumed that the project is going to be implemented (test scenario). Therefore boundary conditions, assumptions and critical variables need to be specified.

4.2.1 Boundary conditions, assumptions and critical variables

Boundary conditions should give an overview about the framework of a project. In the EPRI methodology as well as in the framework of JRC's CBA there are proposed parameters that have to be analyzed before the CBA can be conducted and scenarios can be defined.

According to [60], boundary conditions ("high level background discussion") should include:

- A description of the utility regarding ownership, structure type and service territory
- The context of the market structure
- Regulatory structure (wholesale regulation, retail regulation and other relevant regulations) and commissions, considering the dominant type of pricing

According to [61], local conditions need to be specified:

- Main parameters that are defining the local conditions and context for a smart metering roll-out have to be worked out.
- Major assumptions and how they are influenced by local conditions have to be described.
- Data sources and their level of uncertainty have to be specified.
- The time span, in which costs and benefits occur, has to be defined. It has to be argued why this time span is the most appropriate one.

Critical variables [61] need to be specified. The determination of these variables influences the quality of the scenario.

- *Synergies with smart grid capabilities:* It is possible that the new smart metering equipment enables side benefits if they are installed with additional smart grid capabilities. Two aspects should be considered: To what extent costs of envisioned smart grid investments can be reduced and how large the additional side benefits are.
- *Discount rate:* The time value of money and the uncertainty of future cash flows have to be considered properly when a smart grid project has to be valued. This has a major impact on the assessment of a scenario, as costs are often incurred in the beginning of a scenario, while benefits are provided in the long-term.
- *Schedule of implementation:* Due to the choice of the discount rate or other factors like the decrease of costs due to technology maturity, the implementation schedule has an impact on the outcome of the CBA. It is recommended to segment the implementation schedule in urban and rural implementations because the costs might differ in these areas. Installation peaks should be avoided to make the management of installation easier. This is not possible without further ado, as the peaks in the installation rate are on the customer sites.
- *Electricity demand and prices:* For the electricity demand, county-specific forecasts should be used, as it is dependent on many other factors (as for example population growth or electricity losses). The electricity price has a major impact on the outcome of the CBA, as the most significant benefits resulting from a DR project are often the

electricity savings. Both electricity demand and price are subject to the sensitivity analysis.

- *Technology maturity:* The fact that the costs for smart grid technologies can significantly decrease due to technology maturity has to be taken into account.
- *Carbon costs:* Carbon costs and CO_2 emission costs should be estimated throughout the scenario timeframe as avoided emission of CO_2 is likely be a significant benefit of a DR project.
- *Estimation of peak load transfer and consumption reduction:* Peak load transfer can reduce the need to install peak generation capacity, which can be expensive and highly polluting.
- *Selection of control groups:* The behavior of consumers using the new smart grid technologies influences the outcome of the CBA. There are some points that should be especially considered in the selection of the target group(s) of customers:
    - People who volunteer or refuse to take part in the project should not be added to the target group as they might have a particularly high or low interest to reduce their energy consumption.
    - All types of consumers should be considered, so consumers from different education levels and societal backgrounds should take part in the target group.
    - Social-demographic data should be used to extrapolate the results of the control group to a national level.
    - Some products/services might not be compatible with certain customer groups.

  The baseline is often realized by a control group, which should randomly selected from the target population.
- *Implementation parameters:* These parameters include the system architecture, design parameters and the technology that is used. Estimations for technology and its installation costs have to be made. The communication technology has to be defined.
- *Impact of the regulatory framework on set assumptions/parameters:* The specific roles of actors in the electricity market need to be defined as they can influence the distribution of costs and benefits.
- *Other variables* can be life expectancy of technologies, inflation rate, communication success rate…

The list of parameters can be extended for the project that is analyzed. It can be seen that the definition of one parameter often leads to the need of defining another one (e.g. definition of communication technology → estimation of communication success rate).

4.2.2 Baseline

To evaluate the costs and benefits of DR rollout, the general energy consumption of the costumers has to be evaluated at first (baseline). The baseline can be either simulated or measured. For the analysis of the demand side management potential in pilot projects it is best to use a control group as a baseline. For the analysis of the scaling possibilities the consumption of a larger group will be simulated. Two basic methods to model the residential energy consumption are available: a top-down and a bottom-up approach [66]. According to [65], [67], a baseline scenario has to fulfil the following criteria:

- *Representativeness:* The baseline needs to be a good approximation for customer’s patterns in absence of the DR project.

- *Acceptability:* The baseline has to be likely to be accepted by stakeholders, utilities and regulators.
- *Operational:* The data used for the baseline has to be collected in a way that it can be compared with data from the DR program.
- *Precise:* The baseline needs to be sufficiently precise (with respect to the key performance indicators).
- *Consistency:* It should be possible to apply the established baseline consistently across other DR project types (at least at DR projects that are offered to the same customer sector).

4.2.3 Scenarios

Within a scenario, critical variables, boundary conditions and assumptions have to be defined. For the definition of the scenario itself, at least the percentage of technology rollout, the rollout time (year of implementation) and number of considered functionalities have to be declared. [61]
Energy transition solutions are often meant to be viable in the (near) future. Forecasting future developments means uncertainty. Therefore, multiple scenarios need to be explored. Looking back at results of a CBA means looking back at the chosen scenario and determine if this still is a realistic scenario. A scenario can be tested with a sensitivity analysis.

4.2.4 Sensitivity and Multi-Scenario Analysis

The definition of a business case has to consider developments that may happen in the future. This is also the case with making a CBA for solutions to the energy transitions. Boundary conditions are subject to constant change. E.g.: the policy framework for the energy system and market. Therefore, it is important to include these future developments in the CBA. This can be done through the combination of a sensitivity analysis combined with a multi-scenario analysis.
In sensitivity analyses, independent variables that will change the outcome of the CBA are identified. These can be for example new policies changing the energy market, or an increase in solar or wind energy. Once these variables are identified, the multi scenario analysis can be used to determine how these variables will affect the outcome of the CBA. This can be done through a worst/best case scenario analysis, but also through predefined scenarios. If the variables are identified, it will be possible to define a break-even point for the solution. This will give a better insight in when a certain solution might start to be a viable solution in the energy transition. Furthermore, it helps monitoring future development in the energy transition and determining, as to which solution will fit the changing circumstances best.

4.3 Challenges for a CBA

Although there are general guidelines for conducting a CBA, performing it actually is not a trivial problem. Several aspects make the analysis difficult:

- A large number of technologies, programs and operational practices are involved in smart grid and DR projects [62]. These technologies show a large diversity [60]. A lot of them also offer a variety of ways in using them which all influences the ongoing of a project.
- The mapping of assets into functionalities as it is proposed by JRC is not always easily possible. Some assets may be linked to the same or more than one functionality. Furthermore, there are no standardized lists for the mapping of assets to functionalities. [63]

- Not all benefits can be converted to a monetary value easily. Qualitative benefits are in need of weighing factors that need to be specified and discussed by experts. Different weighing factors can mainly influence the outcome of the CBA.
- Not all external impacts can be properly estimated as for example the environmental impact. Furthermore, the outcome and success of a project are strongly dependent on the participation level of customers. Thereby it is very difficult to make a forecast about the level of response.
- The scope of markets and market participants is not easy to estimate [60]. Smart grid and DR projects have impacts on all the operational areas of the electricity value chain. Therefore there is a transfer of costs and benefits [62].
- Smart grid and DR projects mostly cover a long period of time, which makes traditional estimations in several areas (like the development of new and helpful technologies) difficult.
- In the definition of scenarios and the baseline it is important to consider if other smart grid or DR projects are planned in the near future which could mainly influence them and therefore the outcome of the CBA. Furthermore, the definition of the baseline itself can be challenging, as there is no “standardized customer behavior”.
- According to [64] there are a lot of factors which mainly influence the outcome of the CBA and are a reason why valuations of DR projects can differ. These factors are:
    - Clients and purposes (for whom is the analysis conducted?)
    - Assumptions and forecasts
    - Data sources and their reliability
    - Methodologies (what is included in the analysis?)
    - Model rigor/type and its quality
    - Skill of those conducting the analysis
    - Constraints used by the analysis
    - Time and location which are represented by the analysis
    - Time horizons which are addressed by the analysis
    - Perspectives (is a single or are multiple perspectives represented by the analysis?)
    - Transparency and documentation
    - Definition of value
    - Jurisdictional/regulatory environment of the analysis

4.4 Valuation of demand response projects

As a first step for the valuation of DR projects, general costs and benefits for this kind of projects have been worked out. They can be found in Table 4-5. The costs are hereby separated in implementation costs and ongoing costs. Benefits are characterized by the categories “consumer”, “supplier”, “market-wide effects”, “reliability”, “market performance” and “environmental”. It is obvious that assigning a monetary value to benefits (especially those listed in the categories “reliability” and “environmental”) is not a trivial problem.

Table 4-5: Costs and benefits of demand response [68][69][70][71]

Costs and Benefits of DR			
Benefits	Consumer		▪ Electricity cost reduction (bill savings & incentive payments) ▪ Improved service ▪ Reduced business losses ▪ Access to real-time information ▪ Options for customers
	Supplier		▪ More accurate and automated metering and billing → reduced costs
	Market-wide Effects		▪ Capacity increase ▪ Avoided infrastructure costs by improving TSO & DSO network investment efficiency ▪ Reduced electrical losses ▪ Potential of improved security of electricity delivery
	Reliability		▪ Reduced outages in the system and for the customer ▪ Diversified resources ▪ Risk management ▪ Managing demand-supply balance with high fRES
	Market Performance		▪ Market efficiency ▪ Reduced market power ▪ Lower costs of electric system and price reduction ▪ Reduced price volatility ▪ Reducing the generation margin
	Environmental		▪ Reduced CO_2 emissions ▪ Reduced pollution (e.g. NO_x, SO_2) ▪ Value in distributed power systems (higher share of fRES)
Costs	Initial Implementation	Consumer	▪ Enabling technology ▪ Response plan
		Supplier	▪ Program design ▪ Marketing ▪ Metering & communication ▪ Billing system ▪ Business integration ▪ Customer education
	Ongoing Operating	Consumer	▪ Inconvenience ▪ Lost business ▪ Rescheduling ▪ Onsite generation
		Supplier	▪ Administrative ▪ O&M ▪ Marketing ▪ Incentive payments evaluation

These presented costs and benefits can be found in each DR project and could therefore be a basis for the valuation process of these projects.

4.5 Existing valuations of Smart Grid Projects

Several DR projects that have been valued are presented in this section in order to get an overview about how different valuation methods can be applied to real projects and where there are still problems in the valuation process.

4.5.1 InovGrid

InovGrid [72] is a smart grid project led by the Portuguese distribution system operator EDP. The project has been analyzed as a case study of the CBA method proposed by JRC [62]. The separate steps are presented in the following.

STEP 1 – Describe the technologies, elements and goals of the project

The goal of InovGrid is to replace low voltage meters with so-called EDP boxes using automated meter management (AMM) standards. These boxes include functions of smart metering and have the capacity of interaction with other devices through an interface. Data is collected by local control equipment. The project aims to integrate distributed generation, the charging network of electric vehicles and DSM in the network operation. Table 4-6 shows the smart grid technologies that have been installed for the project. [62]

Table 4-6: Installed smart grid technologies of InovGrid [62]

Distribution Transformer Controller (DTC)	Local control equipment will be installed in distribution transformer stations, the main components being a measurement module, control module and communications module. The main functions are, collecting data from EB and MV/LV substation, data analysis functions and grid monitoring.
DTC Cell Module – Distribution Automation	Module that enables turning on and off remotely or locally, the various independent circuits of the MV-LV substation.
DTC Power Quality Module	Module that allows the recording and reporting of the quality characteristic values of the wave voltage (rms value, flicker, voltage dips, harmonics), providing information and generating alarm events

STEP 2 – Identify the smart grid functionalities

The assets that have been identified in step 1 were linked to functionalities. Six high-level characteristics have been considered:

- Enabling the network to integrate users with new requirements
- Enhancing efficiency in day-to-day grid operation
- Ensuring network security, system control and quality of supply
- Better planning of future network investment
- Improving market functioning and customer service
- Enabling and encouraging stronger and more direct involvement of consumers in their energy usage and management

These high-level characteristics contain 33 network functionalities that the assets have been linked to. A cutout of the resulting functionalities-benefits-matrix can be seen in Figure 4-5. [62]

Asset Functional Modules	Functional Modules Description	1. Facilitate connections at all voltages / locations for any kind of devices	2. Facilitate the use of the grid for the users at all voltages/locations	3. Use of network control systems for network purposes	4. Update network performance data on continuity of supply and voltage quality	5. Automated fault identification / grid reconfiguration reducing outage times	6. Enhance monitoring and control of power flows and voltages
Energy Box (EB)	Device to be installed in the consumer / producer that includes a measurement module, control module and communications module.	■	■	■	■	■	■
HAN Module	Communications and control module that allow to read the records of the local EB (eg, consumption, power consumption profile, historical events, quality of service), by connecting to other devices.	■					
Distribuition Transformer Controller (DTC)	Local control equipment will be installed in distribution transformer stations, the main components being a measurement module, control module and communications module. Is main fuctions are, collecting data from EB and MV/LV substation, data analysis functions and grid monitoring.	■	■	■	■	■	■
DTC Cell Module	Module that enables turning on and off remotely or locally, the various independent circuits of the MV-LV substation						
DTC Wave Quality Module	Module that allows the recording and reporting of the quality characteristic values of the wave voltage (rms value, flicker, voltage dips, harmonics), providing information and generating alarm events		■	■			■

Figure 4-5: Mapping of assets into functionalities (partial view) [62]

STEP 3 – Mapping of functionalities onto a standardized set of benefit types

The functionalities were linked to matching benefits. This can be seen in the resulting matrix in Figure 4-6. Four categories have been considered for benefits: economic, reliability, environmental and security. [62]

			1. Facilitate connections at all voltages / locations for any kind of devices	2. Facilitate the use of the grid for the users at all voltages/locations	3. Use of network control systems for network purposes	4. Update network performance data on continuity of supply and voltage quality	5. Automated fault identification / grid reconfiguration reducing outage times
Economic	Improved Asset Utilization	**Optimized Generator Operation**					
		Deferred Generation Capacity Investments					
		Reduced Ancillary Service Cost					
		Reduced Congestion Cost					
	T&D Capital Saving	**Deferred Transmission Capacity Investments**					
		Deferred Distribution Capacity Investments					
		Reduced Equipment Failures					
	T&D O&M Savings	**Reduced Distribution Equipment Maintenance Cost**					
		Reduced Distribution Operation Cost					
		Reduced Meter Reading Cost					
	Theft Reduction	**Reduced Electricity Theft**					
	Energy Efficiency	**Reduced Electricity Losses**					
	Recovered Revenue	**Detection of anomalies relating Contracted Power**					
	Electricity Cost Savings	**Reduced Electricity Cost**					
Reliability	Power Interruptions	**Reduced Sustained Outages**				■	
		Reduced Major Outages					
		Reduced Restoration Cost					
	Power Quality	**Reduced Momentary Outages**					
		Reduced Sags and Swells					
Environmental	Air Emissions	**Reduced CO2 Emissions**	■	■			
		Reduced Sox, Nox, and PM-10 Emissions	■	■			
Security	Energy Security	**Reduced Oil Usage**	■	■			
		Reduced Wide-scale Blackouts					

Figure 4-6: Mapping of functionalities into benefits [62]

STEP 4 – Establishment of the baseline

For each benefit, there are a number of possible baseline scenarios. It is important to select the baseline (BaU) that is regarded as the most representative for the grid if the project had not been implemented [62]. A comparison between the baseline and the smart grid scenario is given for the example of two benefits for InovGrid in Table 4-7.

Table 4-7: Setting of baseline for measuring the benefit [62]

	Benefit 1: Reduced distribution maintenance cost	**Benefit 2: Reduced technical losses**
„Business as usual“ (BaU) condition	Direct costs related to • Maintenance of transformers, secondary substations • Breakdown of transformers • Theft of transformers at secondary substations	Estimation of the total amount of losses (in %) at distribution and transmission level, corresponding to total monetized value for the considered period.
Smart grid condition	Estimated reduction in maintenance with InovGrid infrastructure • Remotely control and monitor asset condition and utilization, avoiding side visit related costs • Better information on power flow and distribution load, implying less breakdown of transformers • Sensors on the secondary substations that warn in case of the decreasing thefts	Estimated reduction in technical losses due to • Energy efficiency (consumption reduction and peak load transfer) • New capacity to control the reactive power level

STEP 5 – Quantification and monetization of identified benefits and beneficiaries:

The value of benefits can be seen as the monetary change between the BaU and the smart grid scenario:

$$Value\ (€) = [Condition]_{BaU} - [Condition]_{SG}$$

The BaU condition includes all costs related to local meter operations without the InovGrid infrastructure being installed. The benefit is then expressed as cost reduction due to the InovGrid infrastructure. The communication success rate was expected to be 95%. The resulting costs and savings for InovGrid can be seen in Figure 4-7 [62].

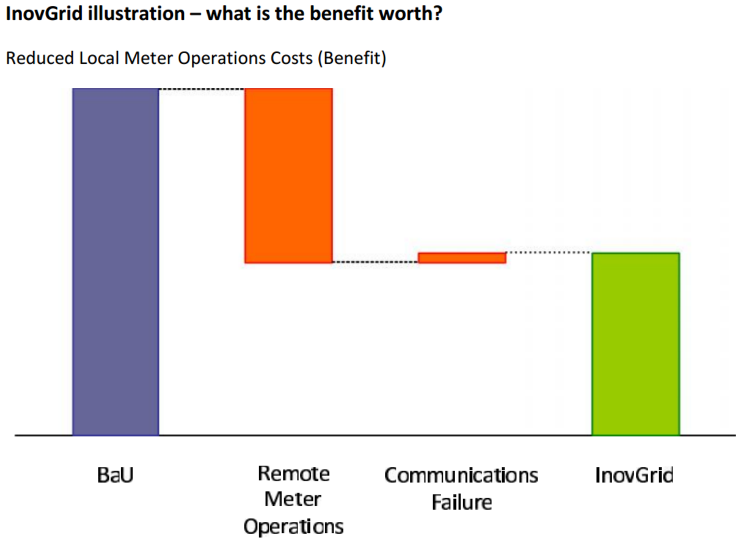


Figure 4-7: Estimated benefit of InovGrid [62]

Beneficiaries of the project have been identified. This can be seen in Table 4-8. It is extremely important to allocate benefits clearly to the beneficiaries to be able to observe the effects on the overall value chain.

Table 4-8: Beneficiaries of InovGrid [62]

DSO	ESCO	Consumer/Producer	Regulator	Economy
• Operation costs reduction • Loss reduction • Control and management optimization • Investment optimization	• New services • Innovative pricing • Estimation removal • Consumption profiles	• Micro production • Cost reduction • New services and tariffs • Better reliability	• Increases competition • Improves efficiency • Improves reliability • Better information	• Improved energy efficiency • Reduced fossil resources dependency • Reduced GHG emissions • Improved employment and exports

STEP 6 – Quantification and estimation of relevant costs

Sources of costs that were identified for the project InovGrid can be seen in Table 4-9. Either they have been estimated based on a market consultation or they were tracked in accounting.

Table 4-9: Sources of costs for the InovGrid project [62]

Type of cost	Tracked in accounting/estimated
Smart meter	Estimated
Conventional meter	Accounting
HAN and WAN module for smart meter	Estimated
Distribution transformer controller/concentrator	Estimated
Implementation/installation	Accounting
IT	Estimated
Operation & maintenance (equipments and systems)	Accounting
Communications	Estimated
Training & marketing	Estimated
Project management	Estimated
Meter reading	Accounting
Value of losses	Accounting
Theft	Estimated

STEP 7 – Comparison of costs and benefits

It has been decided to use annual comparison for the InovGrid project. Figure 4-8 shows indicative numbers for the project and does not represent the exact numbers of the InovGrid project.

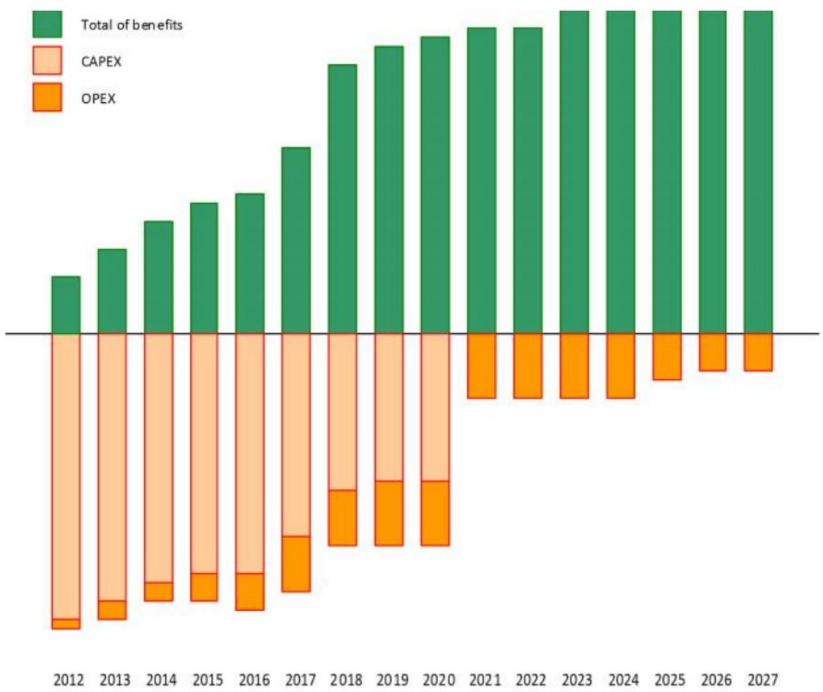


Figure 4-8: Annual comparison of costs and benefits [62]

4.5.2 A smart grid for the city of Rome

The focus of this project is not directly demand response but the value of the implementation of a smart grid in Rome (which then again enables demand response and distributed generation). The project is a scaling-up of the pilot project of Malagrotta [73]. The aim of the Malagrotta project was to introduce a prototype of a smart grid that may finally be expanded over the whole city of Rome and allow further distributed generation to participate to the grid than before. The focus is on advanced MV-grid automation, monitoring/remote control of the MV/LV-grid and new management criteria of the MV-grid [73].
The JRC CBA methodology has been executed to value the project “A smart grid for the city of Rome”. The framework parameters for the analysis are listed in Table 4-10.

Table 4-10: Parameters for the CBA [73]

Parameter	Unit	Value	Reference
Time horizon	Years	15-19	ACEA[3]
Real Financial Discount Rate (FDR)	%/year	3	EC, literature and own assessment
Real Social Discount Rate (SDR)	%/year	2.5	EC, literature and own assessment
Inflation rate	%/year	2	ECB inflation target
Average uncertainty in monetization of benefits	%	3	ACEA
Average rate of decrease of benefits related to in investments in infrastructure	%/year	5	ACEA
Average rate of decrease of benefits related to investments 1in software	%/year	1	ACEA
Average rate of electricity demand increase	%/year	1	TERNA and own assessment
Emission factor	Ton CO_2 eq/MWh_e	0.708	Covenant of Mayors
1 ton CO_2 equivalent average price in EU ETS	€	15	EC, literature and own assessment

After the declaration of the framework parameters, the separate steps of the CBA have been conducted.

STEP 1 – Describe the technologies, elements and goals of the project
The project is located in Rome. Its timeframe is from 2011 to 2019 (return on investment 2015-2029). Its goal is to show the effectiveness of new communication technologies under real conditions. Thereby system quality/continuity of the energy network and distribution network observability shall be improved. The positive impact of automation shall be assessed. Engineering features are given in Table 4-11. The project has been articulated in three sub-projects that are automation, medium/low voltage monitoring & remote control and new network management criteria. [73]

Table 4-11: Main features of the project [73]

MAIN FEATURES	PROJECT SMART GRID	ROME
LV CONSUMERS INVOLVED	1.200	~1.600.000
MV DISTRIBUTED GENERATION	4	~200
NUMBER OF HV/MV PRIMARY SUBSTATIONS	2	~70
NUMBER OF MV/LV SECONDARY SUBSTATIONS	76	~13.000

[3] The Malagrotta project, which was the starting point for the smart grid study for Rome, was a smart grid pilot project of ACEA.

STEP 2 – Identify the smart grid functionalities
The identification of assets and their functionalities has been done by ACEA. Therefore a "Driver" (custom-made indicator) has been developed as a result of a specific model considering among other variables [73]:

- Number of MV/LV users
- Probability of faults
- Cost for installing technical solutions
- Reduction in adverse events and the increase of quality of electricity supply

STEP 3 – Mapping of functionalities onto a standardized set of benefit types
The three "drivers" of the sub-projects were linked to their resulting benefits. Furthermore, grid sections that bring the most benefits in the shortest time were identified. Unfortunately, no details about this step are given in [73].

STEP 4 – Establishment of the baseline
All three sub-projects were compared with the baseline (first their separate implementation and then the implementation of all of them). Historical costs and benefits of other grid interventions have been considered in testing the robustness of resulting figures. The DSOs have a very important role in this step as they are directly involved in the realization of the project and can give access to important data. [73]

STEP 5 – Quantification and monetization of identified benefits and beneficiaries
The benefits were calculated considering the assumptions that have been made for the CBA as well as foreseeable boundary conditions. Benefits of all three sub-projects have been considered, including benefits accruing to ACEA from [73]:

- Regulated remuneration of the invested capital
- Regulatory penalties that have been avoided due to improvements in electricity supply
- Maintenance/intervention costs that have been avoided when grid faults take place

These benefits can be broken down into benefits accruing to the DSO resulting from the technologies that have been implemented in several years of the project. Finally, the calculated benefits for each sub-project and all sub-projects together can be seen in Figure 4-9.

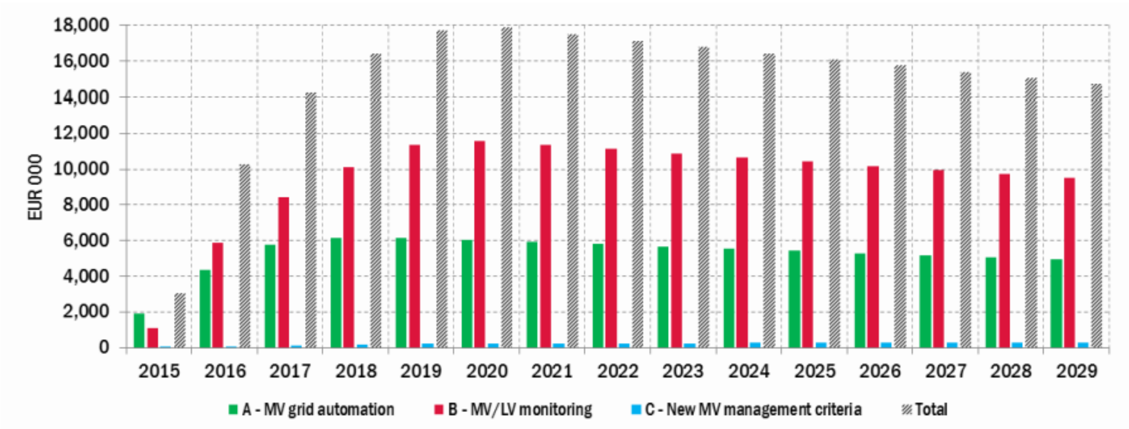


Figure 4-9: Resulting benefits of implementing a smart grid in Rome [73]

Further benefits resulting from the remuneration of invested capital or avoided greenhouse gases have been considered in a societal and/or the private investor analysis [73].

STEP 6 – Quantification and estimation of relevant costs

The capital expenditures (CAPEX) and operational expenditures (OPEX) have been estimated. In the CBA by JRC it is recommended to consider the lifetime of assets and their resulting replacement costs. For this analysis it has been assumed that all assets have a lifetime of at least 15 years (duration of the project) so that no replacement costs have to be considered. The estimated costs for the project can be found in [73].

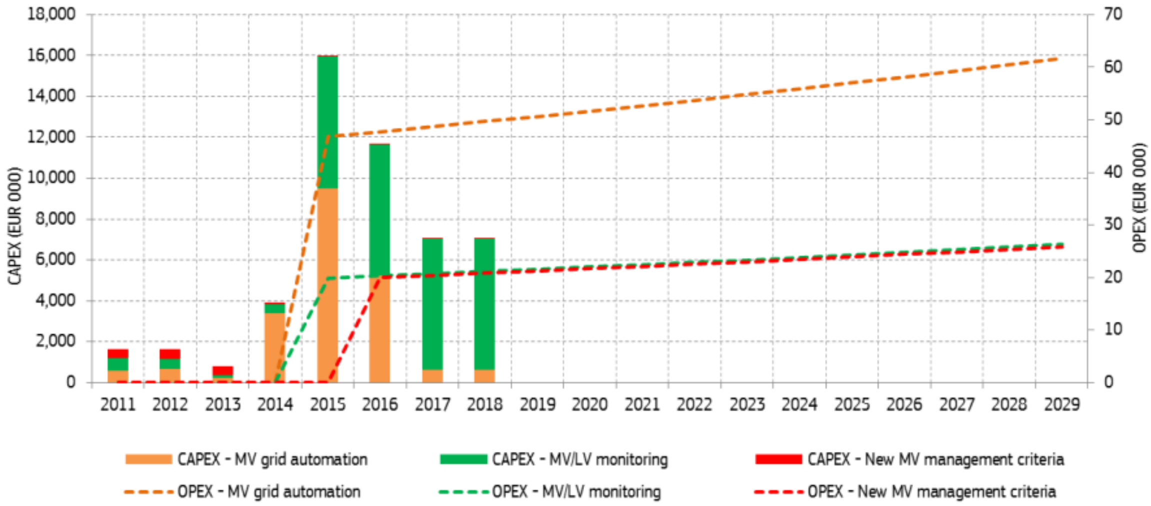


Figure 4-10: Estimated costs for the smart grid project [73]

STEP 7 – Comparison of costs and benefits

The net present value (NPV) is calculated as it represents the financial feasibility of a project. It can be calculated using the following formula [73]:

$$NPV = \sum_{j=1}^{n} \frac{CF_j}{(1+i)^j} - investment_{j=0}$$

n…number of years for which the cash flow is expected to be received
i…interest rate applied representing the opportunity cost of the capital
j…number of years from the moment the investment is fully disbursed by the DSO
Investment…the total capital and operational expenditure expected to be sustained by the DSO
A positive NPV means a positive cash inflow at the end of the considered period of a project.

Results

Private Investor CBA: The NPV and the internal rate of return (IRR) have been calculated for each sub-project. The results can be found in Table 4-12.

Table 4-12: NPV and IRR for the private investor CBA [73]

	Automation	MV/LV monitoring	New management criteria	Whole smart grid project
NPV	10.026 €	24.608 €	1,406 €	35,972 €
IRR	12.55 %	21.17 %	12.28 %	16.60 %

Societal Analysis: The reduction of air pollution was identified as the most likely positive social impact. The following factors have been used to turn societal benefits in monetary values [73]:

- MWh of generation that could be saved
- Resulting avoided tons of CO2-equivalent

- Average price of a ton of CO2 equivalent that has been avoided

The societal benefit has been calculated with the following formula [73]:

$$SB_i = \Delta CO_{2i} * EF * P_{CO_2}$$

SB…societal benefit resulting from avoided emissions

ΔCO_2…decrease of CO_2 emissions due to the project

EF…emission factor

P_{CO2}…estimation of monetary social value for one ton of avoided emissions

The results of the societal analysis are listed in Table 4-13.

Table 4-13: NPV and IRR for the societal analysis [73]

	Automation	MV/LV monitoring	New management criteria	Whole smart grid project
NPV	11.033 €	26.274 €	1,688 €	39,119 €
IRR	12.55 %	21.17 %	12.74 %	16.67 %

Finally, a sensitivity analysis has been conducted. The parameters that have been considered can be found in Table 4-14.

Table 4-14: Parameters for the sensitivity analysis [73]

Parameters for sensitivity analysis	Unit	Baseline Model Value	Values' Range
Real Financial Discount Rate (FDR)	%/year	3	0 ± 8
Real Social Discount Rate (SDR)	%/year	2.5	0 ± 5
Average uncertainty in monetization of benefits	%	3	-2 ± 17
Average rate of decrease of benefits related to investments in infrastructure	%/year	5	2 ± 11
Average rate of decrease of benefits related to investments in software	%/year	1	0 ± 8
Average rate of increase OPEX	%/year	0	0 ± 6
Average rate of increase CAPEX	%/year	0	0 ± 16
Emission factor	Ton CO_2 eq/MWh_e	0.708	0.50 ± 0.95
1 ton CO_2 equivalent average price in EU ETS	€	15	0 ± 50

4.5.3 Valuation of smart metering rollout in Europe

To specify the value of smart metering systems in Europe, EU member states have been instructed by the European Commission to conduct a CBA on this subject. General guidelines and recommendations (Recommendation 2012/148/EU) where given for the analysis so that comparable results could be achieved. The proposed CBA method was the JRC method (with a sensitivity analysis in addition). A set of minimum functionalities (categorized by their respective parties), costs and benefits to be considered in the analysis was given. These lists are non-exhaustive, so the countries were able to expand it with country-specific data. Some countries did the analysis before Recommendation 2012/148/EU had been released. Therefore, they did not follow the proposed methodology. [74]

Table 4-15 and Table 4-16 show the costs and benefits recommended to be considered in the analysis.

Table 4-15: Proposed costs to be considered in the analysis [74]

General category	Type of cost to be tracked for roll-out and to be estimated for the baseline
CAPEX	• Investment in the smart metering systems • Investment in IT • Investment in communications • Investment in in-home displays (if applicable) • Generation • Transmission • Distribution • Avoided investment in conventional meters (negative cost to be added to the list of benefits)
OPEX	• IT maintenance costs • Network management and front-end costs • Communication/data transfer costs (inc GPRS, radio communications) • Scenario management costs • Replacement/failure of smart metering systems • Revenue reductions (e.g. due to more efficient consumption) • Generation • Distribution • Transmission • Meter reading • Call center/customer care • Training costs
Reliability	• Restoration costs
Environmental	• Emission costs (CO_2 control equipment, operations and emissions permit)
Energy Security	• Costs of fossil fuels consumed to generate power • Costs of fossil fuels for transportation and operation
Other	• Cost of consumer engagement programs • Sunk cost of previously installed (traditional) meters, including recycling costs of old meters

Table 4-16: Proposed benefits to be considered in the analysis [74]

Benefit	Sub-benefit
Reduction in meter reading and operations cost	• Reduced meter operations costs • Reduced meter reading costs • Reduced billing costs • Reduced call center/customer care costs
Reduction in operational and maintenance costs	• Reduced maintenance costs of assets • Reduced costs of equipment breakdowns
Deferred/avoided distribution capacity investments	• Deferred distribution capacity investments due to asset remuneration • Deferred distribution capacity investments due to asset amortization
Deferred/avoided transmission capacity investments	• Deferred transmission capacity investments due to asset remuneration • Deferred transmission capacity investments due to asset amortization
Deferred/avoided generation capacity investments	• Deferred generation investments for peak load plants • Deferred generation investments for spinning reserves
Reduction in technical losses of electricity	• Reduced technical losses of electricity
Electricity cost savings	• Consumption reduction • Peak load transfer
Reduction in commercial losses	• Reduced electricity theft • Recovered revenue relating to 'contracted power' fraud • Recovered revenue relating to incremental 'contracted power'
Reduction of outage times	• Value of service • Reduced cost of client indemnification
Reduction of CO 2 emissions	• Reduced CO_2 emissions due to reduced line losses • Reduced CO_2 emissions due to wider spread of low carbon generation sources • Reduced CO_2 emissions due to truck rolls of field personnel
Reduction of air pollution	• Reduced fuel usage due to truck rolls of field personnel • Reduced air pollutants emissions due to reduced line losses • Reduced air pollutants emissions due to wider diffusion of low carbon • generation sources • Reduced air pollutants emissions due to truck rolls of field personnel

Four countries produced positive CBA outcomes [74], detailed key figures are discussed later:

- **Great Britain**: The CBA methodology that has been used was broadly consistent with the proposed methodology. The original list of costs and benefits has been expanded.
- **The Netherlands:** A CBA of smart metering produced by KEMA in 2010 has been used for the analysis. As this analysis has been released before Recommendation 2012/148/EU, these guidelines could not be followed. The core scenario of the CBA does not include all available smart metering functionalities (direct feedback). Furthermore, the legal situation in the Netherlands does not permit to install smart meters in a way that all the proposed functionalities are enabled. The analysis showed the importance of having clarity about the politics allowing customers to deactivate features of a smart meter (e.g. due to privacy issues) as this might influence resulting benefits.
- **Romania:** A CBA conducted by AT Kearny in 2012 has been considered. The analysis is regarded as consistent with the set of minimum functionalities that have been proposed by Recommendation 2012/148/EU. The analysis showed that areas with high commercial losses can provide a strong net benefit because of low cost forms of smart metering.
- **Switzerland:** Although Switzerland is not an EU member state, two CBAs[4][5] for the wide scale introduction of smart metering systems were conducted in 2012 and 2015 respectively. While the first study was performed in order to decide whether smart metering systems should be introduced by a specific regulation, the second study was performed in the framework of works conducted for the national Smart Grid Roadmap [59]. Even as the study in 2012 had been done in advance of the 2012/148/EU guidelines, the used methodology is very similar as the one suggested in the guidelines and delineated above. The methodology is based on the "Impact Assessment Guidelines[6]". The analysis includes five different scenarios varying different aspects as rollout speed, target value of smart meter and dynamic pricing abilities. In addition, benefits for electricity network and the balancing energy market are investigated. Taking indirect costs and benefits into account, the CBA of 2012 found net benefits for almost all scenarios, regardless how conservative the assumptions were. In time, more critical voices demanded a refresh of the results. The second CBA does not investigate benefits for the electricity network but instead take impacts of the exchange rate more into account. The second CBA also shows net benefits but lower ones than in the CBA of 2012. This is mainly due to the lower exchange rate and its impact on the value of electricity savings. Many indirect benefits could not be quantified but were qualitatively shown. That includes the management and accounting of self-consumption, better forecast and hence a lower demand for balancing energy.

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[4] BFE (2012) Folgeabschätzung einer Einführung von «Smart Metering» im Zusammenhang mit «Smart Grids» in der Schweiz

[5] BFE (2015) Smart Metering Roll Out – Kosten und Nutzen (Follow-up to BFE (2012)) (both to be found on www.bfe.admin.ch/smartgrids)

[6] European Union (2009) - Impact Assessment Guidelines

Negative/inconclusive CBA outcomes have been obtained by the following countries [74]:

- **Belgium:** A CBA, in which costs and benefits were aggregated on net present value basis, has been conducted for three areas.
    - *Brussels:* Four rollout scenarios have been considered by the analysis, which has been provided by Belgium-Brussels Capgemini Consulting for Brugel in 2011: basic, moderate, advanced and full smart metering rollout. Although the analysis has not been developed along the lines of EU's recommendations, most of benefits proposed in this document are captured in the analysis. The result was strongly negative, nevertheless high benefits have been predicted in consumption, commercial losses and meter reading.
    - *Flanders:* The basis of the analysis was a CBA conducted in 2012 by KEMA, which was updated in 2014. A uniform rollout of smart meters within 5 years and a segmented rollout within 6 years have been analyzed. Not all the proposed costs and benefits have been considered in this approach.
    - *Wallonia:* Two scenarios have been considered. In the first scenario, 80% of customers were fitted with smart meters by 2020. In the second scenario, a particular implementation of smart meters to specific customer segments has been regarded. Not all the proposed costs and benefits have been considered in this approach.
- **Czech Republic:** The recommended analysis has been conducted whereby the scenario "blanket" (implementation of smart metering) and "basic" (status quo) have been considered. As a rollout timeframe, 7 years have been chosen which makes a rollout of 80% by 2020 impossible. In [74] it is criticized that the breakdown of benefits is not obvious from the analysis and that there were some empirical assumptions made that would need to be reviewed as they mainly influence the outcome of the CBA.
- **Germany:** Several smart metering rollout scenarios have been valued in 2013. One of them is the "EU scenario" which foresees a rollout of 80% by 2022. The methodology used is broadly consistent with the proposed one. The gateway system that has been proposed for the smart metering rollout to manage data transfer results in high communication costs. In [74] it is stated that the benefits need further evaluation. Furthermore, the potential role of intelligent meters (low costs) should be further evaluated.
- **Hungary:** The CBA, which analyzes a smart metering rollout of 80% by 2021 as a core scenario, has been carried out in 2013. Three alternate scenarios have been considered:
    - A joint roll out by all DSOs, where the system of data management is developed by concerned companies (need for smart meter operator who is responsible for data collation/transfer).
    - A variation of the previous scenario. The transmission operator acts as the smart meter operator.
    - A variation of the previous scenario. Demand management functions are included in the smart meter setup.

  In future analyses it should be considered if the full benefits that have been caught by the analysis can be achieved by using lower-cost solutions.
- **Lithuania:** The CBA has been conducted in 2012. Three scenarios of smart metering rollout have been considered: base case (functionalities have been chosen considering the commission's recommendations), advanced functionality and multi metering. The analysis included more information than many other countries analyses as for example

capital/operating expenditure and smart metering rollout profiles over time. All sensitivities runs that have been performed by the consultant (considering demand growth, consumptions efficiency, smart metering equipment prices and electricity price) showed a negative outcome.

- **Portugal:** The CBA that has been conducted by KEMA in 2012 was broadly consistent with the recommended methodology. A smart metering rollout of 80% by 2020 under a rollout period from 2014 to 2022 has been considered. Customers do not get feedback in real time but indirect feedback through their monthly billing. Significant net benefits have been shown in the analysis. The DSO does not receive overall these benefits in the proposed scenario, which leads to constraints in the implementation process and should be further investigated.
- **Slovak Republic:** The scenario that has been analyzed by the Regulatory Office for Network Industries (URSO) in 2012 envisages a smart metering rollout of 23% in the low-voltage supply points by 2020. Within this scenario, there are two options: A linear implementation or a progressive implementation in which 70% of smart meters are installed within the first 4 years and the remaining 30% in another 4 years. The required scenario of 80% smart metering rollout by 2020 has not been analyzed yet. Some benefits like the avoided costs for standard meters have not been clearly identified in the CBA. Furthermore, some of the proposed benefits have not been included in the analysis (e.g. reduced costs of equipment breakdowns).

The detailed CBA results of the country-specific analyses can be found in Figure 4-11 and Figure 4-12. Only the results for the categories proposed by the European Commission (EC) are displayed in this presentation. Therefore, not the total result of the CBA is displayed for each country but only parts of it. This is the reason why – for example – Slovakia would have a positive CBA outcome in this presentation although the outcome of the whole CBA was negative. It can be seen that most of the countries did not consider exactly the categories that were proposed by EC, which results in no value for this section.

Cost type	GB	NL	RO	BE-BR	BE-FL	BE-WL	CZ	DE	HU	LT	PT	SK
Smart meters	4,851.3	549.4	648.2	166.5	1,278.7	1,245.3	1,417.5	7,328.0	510.1	161.1	364.0	55.4
Information Technology	992.5	38.7	13.0	49.2	275.0	232.7	628.5	3,324.1	46.7	18.9	51.0	13.7
Communications	2,967.5	786.9	157.8	89.6	75.0	172.9	349.0	6,589.2	220.5	52.1	217.0	34.3
In-home display	-	-	-	-	-	-	-	1,284.5	47.7	-	-	-
Generation	-	-	-	-	-	-	-	-	-	-	-	-
Transmission	-	-	-	-	-	-	-	-	-	-	-	-
Distribution	-	-	-	-	-	-	14.9	-	-	18.7	-	-
Training costs	-	-	-	4.0	-	10.1	-	420.7	-	0.2	-	-
Customer care and engagement programmes	466.3	234.9	-	17.5	200.0	68.8	14.7	-	117.8	3.2	121.0	-
Sunk costs	-	-	-	-	-	-	7.8	-	42.1	-	-	-
Security	-	-	-	-	-	-	22.9	-	-	-	-	-
Others not defined	-	-	-	-	50.0		38.8	-	0.1	-	-	-
TOTAL	9,277.5	1,609.9	819.0	326.8	1,878.7	1,729.8	2,494.0	18,946.5	985.1	254.1	753.0	103.3

Figure 4-11: Cost results of the conducted CBAs presented by the countries (€ Million, NPV Basis) [74]

	GB	NL	RO	BE-BR	BE-FL	BE-WL	CZ	DE	HU	LT	PT	SK
Benefits in Rec. 2012/148/EU												
Reduction in meter reading and operation	4,803	870	390	41	536	322	420	1,937	59.0	8	208	23
Reduction in O&M costs	-	-	90	10	200	8	-	-	-	-	-	6
Deferred distribution capacity investments	176	-	-	-	-	-	-	1,214	-	-	-	-
Deferred transmission capacity investments	-	-	-	-	-	-	-	355	-	-	-	-
Deferred generation capacity investments	1,004	-	-	-	-	-	-	2,892	-	-	-	-
Reduction in technical losses	384	-	96	5	10	-	-	-	18.1	14	34	8
Electricity cost savings	3,236	518	3	107	359	263	9	9,228	30.9	52	530	120
Reduction of comm. Losses	167	62	365	51	200	897	-	59	79.6	30	169	26
Reduction of outage times	118	32	-	3	75	-	-	16	-	-	7	-
Reduction of CO_2 emissions	225	-	-	16	-	-	-	-	-	2	-	2
Reduction of air pollution	61	-	-	-	-	-	-	-	-	-	-	-
Benefits not in Rec. 2012/148/EU												
Avoided investment in standard meters	-	-	140	9	314	-	728	2,966	-	22	147	-
Competitiveness and others	-	424	-	-	-	77	-	-	481.3	-	-	-
TOTAL BENEFITS	**10,174**	**1,906**	**1,084**	**242**	**1,694**	**1,567**	**1,156**	**18,667**	**668.9**	**128**	**1,095**	**186**

Note: same methodological or data source differences with COM(2014) 356 apply as per the cost tables.

Figure 4-12: Benefit results of the conducted CBAs in the country analysis (€ Million, NPV Basis) [74]

4.5.4 ECONGRID

The aim of ECONGRID [75] is to evaluate the implementation of smart grids throughout Austria. The applied methodology can be seen in Figure 4-13.

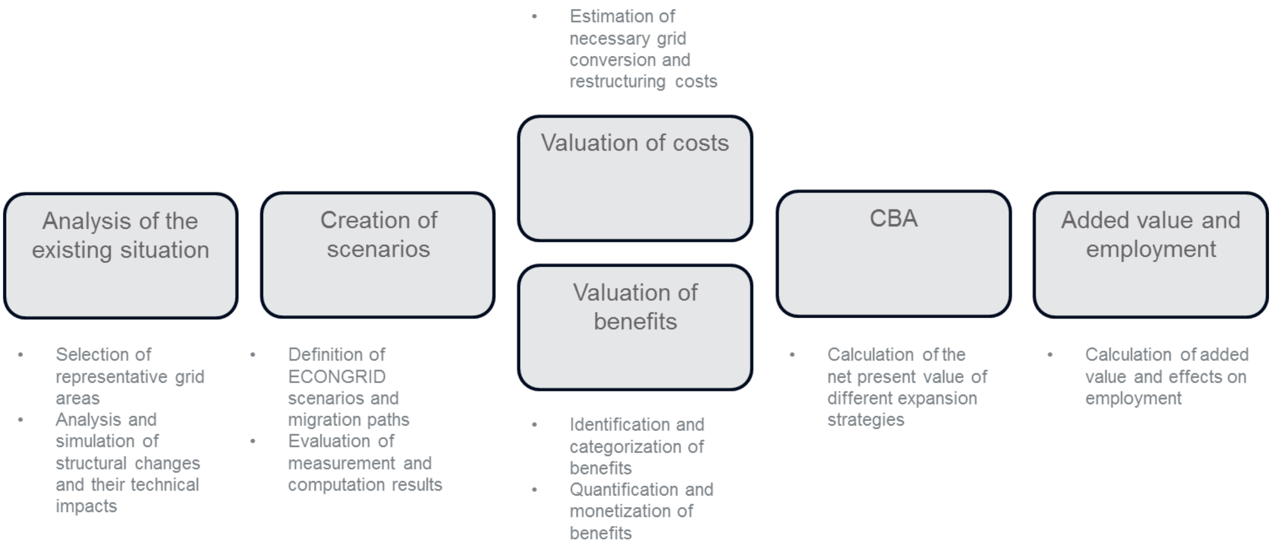

Figure 4-13: Valuation methodology of ECONGRID (based on [75])

As a first step, three representative, distribution grid areas have been selected to analyze the existing grid situation: An urban, a suburban and a rural area. Then three scenarios have been defined, which are valued within the analysis [75]:

- Current policy: This scenario is the closest one to the "business as usual" scenario. Nevertheless, already decided measures are considered in this scenario in a way that they will be implemented in the foreseen period.
- Renewable+: The further expansion of renewable energies is foreseen in this scenario.
- *Flex*demand: This scenario is the most important one regarding the focus of this report and will therefore be treated in more detail (in [75] all scenarios are treated with equal importance). It considers the increasing importance of demand side management (high potential of load transfer because of high integration of distributed energy generation). The estimated development of important parameters is given in Table 4-17.

Table 4-17: Parameter estimation for the Flexdemand scenario in 2020 and 2030 [75]

Scenario *Flex*demand		2020	2030
Supply side	Renewable energy sources:		
	PV	2,289 GWh	8,889 GWh
	Wind Power	7,064 GWh	8,864 GWh
	Hydropower	42,806 GWh	44,006 GWh
	Biomass	6,554 GWh	6,854 GWh
Demand side	Electric Mobility		
	Number of electric vehicles	51,901	584,388
	Number of PHEV	155,703	1,012,301
	Sum	207,604	1,596,689
	Number of vehicles with V2G storage	83,042	479,006
	Demand Response	400MW	500MW

As a next step, migration paths have been defined. These paths specify how framework parameters (expansion of renewables,…) are achieved in the scenarios. In general, the migration paths "smart" and "conventional" have been considered. For the scenario *Flex*demand, the additional path "smart plus", in which an ambitious use of smart technologies is foreseen, was considered.

Before costs and benefits can be calculated for each scenario, main technologies (including technical products but also processes and methods) need to be identified. These technologies include [75]:

- Information & communication technologies
- Substations (high and medium voltage)
- Switchboards in the medium voltage grid
- Grid development (medium and low voltage: Power amplification and capacity expansion)
- Grid protection (medium and low voltage)
- Control technology for the distribution grid
- Amplification of transformers, expansion of local grid stations
- Adjustable transformers in the local grid
- Transformer stations for electric mobility
- Fast-charging stations for electric mobility in the low voltage grid
- Distributed generation plants
- Distributed storages (with charge controller)
- Smart Meter
- Load control at the customer through the grid operator
- Load-, demand side- and feed-in-management at the customer
- Smart home technologies

After the identification of technologies, a set of necessary investment costs (from 2014 to 2030) has been defined. These costs were divided in five categories, namely "distribution grid", "smart technologies", "distributed generation", "storages" and "E-mobility". The respective costs can be found in Table 4-18.

Table 4-18: Cost categories for ECONGRID scenarios [75]

Distribution grid	Smart technologies	Distributed generation	Storages	E-Mobility
• Control technology • Transformer amplification • Transformers for electric mobility • Rear derailleur • Power amplification/capacity expansion for low and medium voltage • Substations • Grid protection	• Smart meter • Smart home technologies • Consumption control	• PV systems • Other distributed generation	• Distributed storages • Charge controller	• Electric filling stations • Charging station, measuring station, wall mounting • Measurement distributor • Access to the grid

The resulting costs for the *Flex*demand scenario can be found in Figure 4-14. For the calculation of investment costs, a large-scale application of distributed storages is only considered if the profitability of these storages can be guaranteed (costs for storages and charge controllers can be compensated by lower electricity procurement costs) [75].

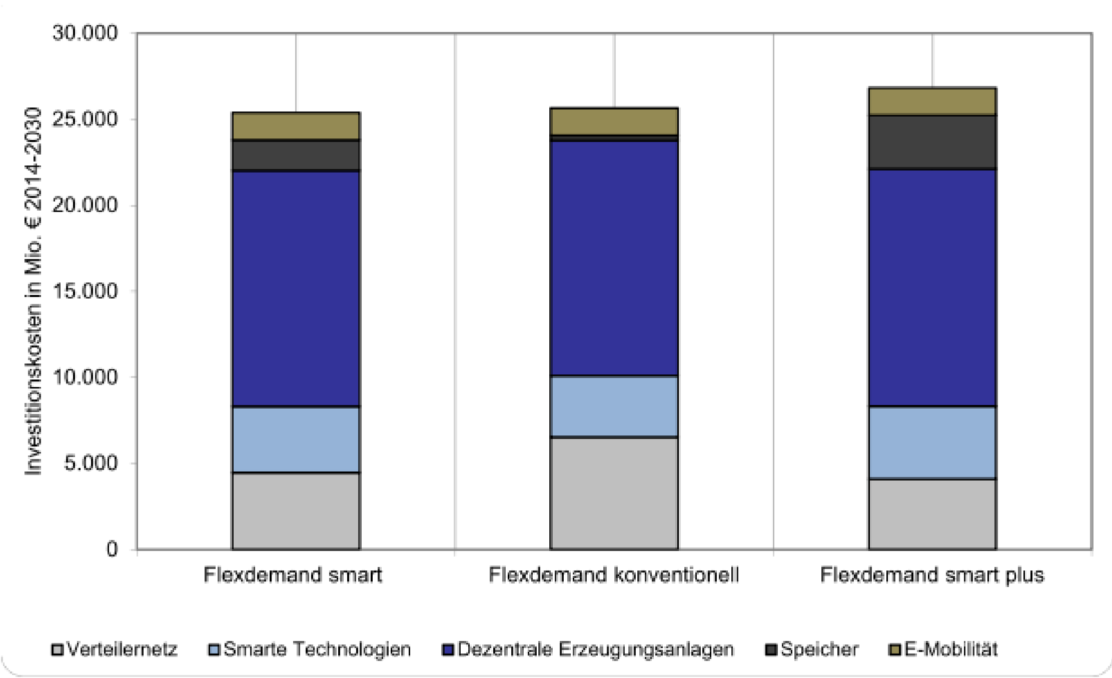

Figure 4-14: Investment costs (divided by category: grey – distribution grid, light blue – smart technologies, dark blue – distributed generation, dark brown – storages, light brown – E-mobility) of the *Flex*demand scenario regarding different migration paths [75]

To demonstrate which migration path should be the favored one for each scenario, differential costs between the different migration paths have then be calculated using the following formula:

$$Differential\ Costs = Costs\ Distribution\ Grid_{smart\ (plus)} - Costs\ Dristribution\ Grid_{conventional}$$

For the *Flex*demand scenario, the differential costs resulted in a positive value. This shows that the smart (plus) migration paths cause higher costs than the conventional path. A reason for this are among other things the expensive and rather short-lived components that are used for these migration paths. [75]
As a next step, benefits of the project have been identified. The benefits that are considered in the ECONGRID analysis are [75]:

- Optimized generation
- Delayed investments in generation capacities
- Delayed investments in the distribution grid
- Reduced operation, maintenance and restoration costs for the distribution grid
- Reduced metering costs
- Reduced grid losses
- Reduced electricity procurement costs
- Increased security of supply and voltage quality
- Reduction of CO2 emissions
- Reduction of air pollutants
- Reduced dependence on electricity imports

Again, the difference between the smart (plus) and the conventional migration path benefit has been calculated to examine which path should be favored in the implementation process:

$$Benefit_{smart\ (plus)} = Electricity\ Procurement\ Costs_{smart\ (plus)} - Electricity\ Procurement\ Costs_{conventional}$$

For the *Flex*demand scenario with the migration path “smart”, a total benefit of 2.3 billion € has been calculated. For the same scenario with the migration path “smart plus” a total benefit of 3.4 billion € has been calculated.
For the final CBA, the differential costs and benefits have been used. A positive net present value shows that a smart migration path should be favored. All scenarios showed a positive net present value. Regarding only the cost side, the current policy scenario should be the favored one. Also considering the benefit side showed that *Flex*demand with migration path “smart plus” is the most profitable scenario for electricity companies, customers and economy in whole. Benefits clearly exceed the costs in this scenario. [75]

The net present value for each scenario can be found in Figure 4-15.

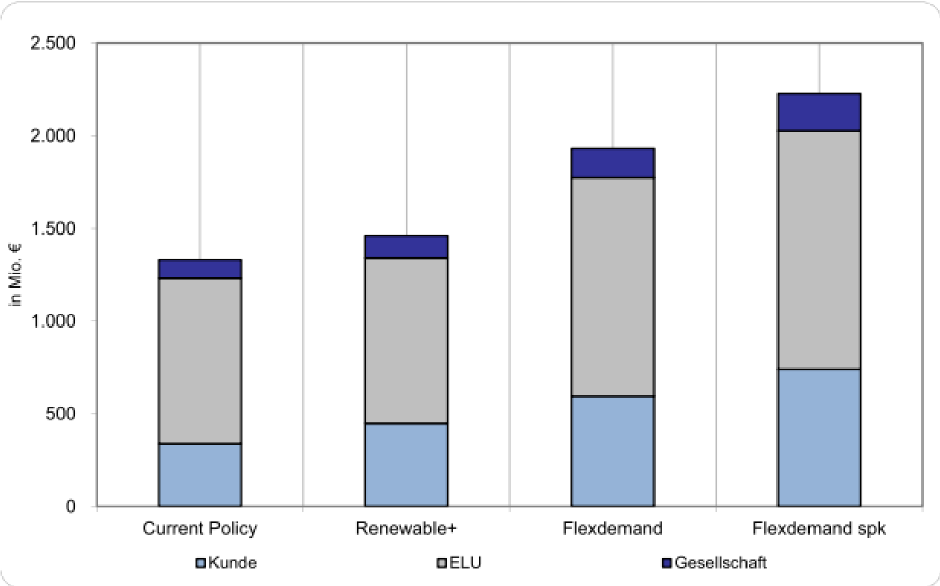

Figure 4-15: Net present value of ECONGRID scenarios (divided by categories: light blue – customer, grey – electricity companies, dark blue – society) [75]

As storage costs have a major impact on the outcome of the CBA, a sensitivity analysis has been conducted for this parameter. In this analysis, higher storage costs have been considered. It could be seen that the net present value of all scenarios remained positive. However, in the scenarios Renewable+ and *Flex*demand with migration path "smart plus", customers are affected in a negative way, as storage investment costs could no longer be compensated by lower electricity procurement costs. [75]

Finally, a macroeconomic analysis (for the period from 2014 to 2020) of the Current Policy and *Flex*demand (smart plus) scenario has been added to the CBA. Therefore, a labor and energy market model for Austria (LEMMA) has been used. The basis of this model is data published by Statistik Austria, which displays the production of different economic sectors in input-output-tables regarding the preliminary work of other sectors and the production factors capital and work. It could be seen that *Flex*demand (smart plus) offers the opportunity to create 6,444 new jobs, especially in the construction sector. Because of that, especially low-qualified workers can profit. The unemployment rate for low-qualified workers could be changed by -0.40%, for medium-qualified by -0.21% and for high-qualified by -0.08% in this scenario. [75]

4.5.5 IGREENGrid

This project [76] is led by eight European DSOs. The aim of the project is to increase the hosting capacity for distributed renewable energy sources (DRES). The main objective is to share knowledge and identify solutions for the possible and effective integration of DRES in six existing demo projects. These demo projects should be validated in their scalability/replicability by simulation in other environments [77].

The European Electricity Grid Initiative (EEGI) recommended a smart grid evaluation method, which is represented by a set of key performance indicators (KPIs) and has been adopted by IGREENGrid for the assessment of control techniques and solutions that are used in the integration of DRES. For the use of this methodology, it is necessary that benefits resulting from a smart grid solution can be quantified. For the IGREENGrid project, economic and technical benefits are quantified. [78]

Technical benefits [78]

The following scenarios have to be considered to receive technical benefits:

- *R&I (research and innovation) scenarios:* The demonstrators of these scenarios consist of the real field application of smart grid solutions. Therefore, essential parameters can be directly measured on the demonstrative network.
- *BAU (business as usual) scenario:* The parameters for the BAU scenario can be received either by simulations or by real field measurements. These measurements can be done on the same network but before the smart grid solution has been installed. Then a matching finder can be used to find the most similar BAU past condition to the situation measured for the R&I situation. For some demonstrators it is also possible to apply the smart grid solution interruptions so that one day the R&I situation and the other day the BAU situation can be measured.

Once the scenario parameters are collected, an "indicator algorithm" is used to calculate the benefit indicator K_x of a scenario. In the next step, the two benefit indicators K_{BAU} and $K_{R\&I}$ are compared and the KPI can be obtained by

$$KPI = K_{R\&I} - K_{BAU}.$$

As the different characteristics of demonstrators should be considered, performance indicators need to be normalized. If normalization factors cannot be applied, the KPI formula is adapted in the following way:

$$KPI_{\%} = 100\% * \frac{K_{R\&I} - K_{BAU}}{K_{BAU}}.$$

Economic benefits [78]

R&I solutions can have a negative impact on the network economy as installation, operation and maintenance costs may increase. These costs have again to be compared with the ones of the BAU scenario. Several different definitions of the BAU and R&I scenarios should therefore be taken into account and compared by CBA with respect to the KPI methodology.

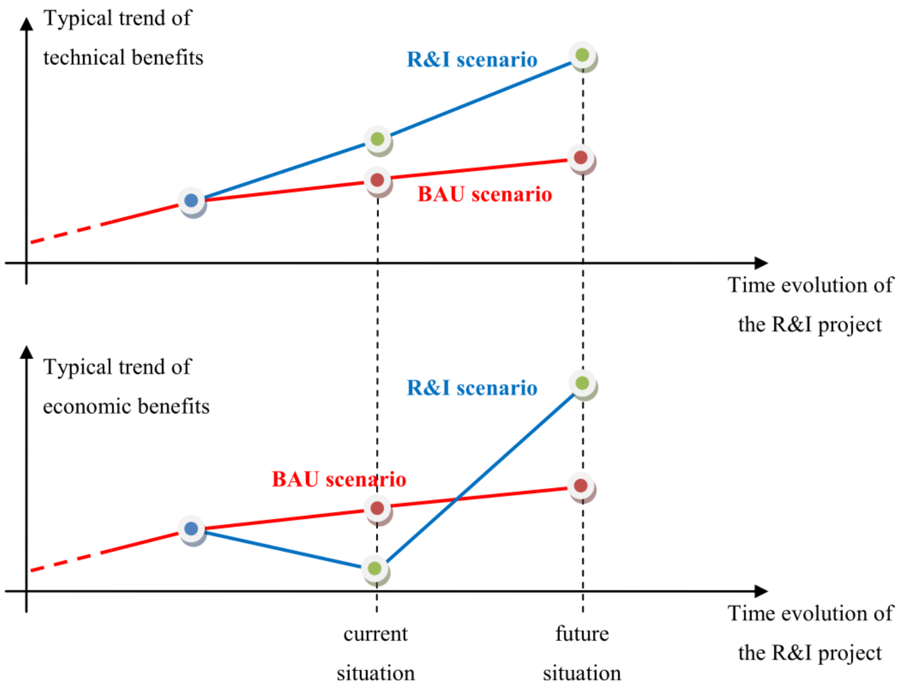

Figure 4-16: Technical and economic benefits of the IGREENGrid project [78]

Figure 4-16 shows the expected benefits of the IGREENGrid project. It can be seen that in the current situation, technical benefits of the R&I scenario are higher than the ones of the BAU scenario, whereas the economic benefits are lower but expected to increase in the future.

Definition of KPIs [78]

For the definition of KPIs, EEGI proposes to consider three respective levels, which can be seen in Figure 4-17.

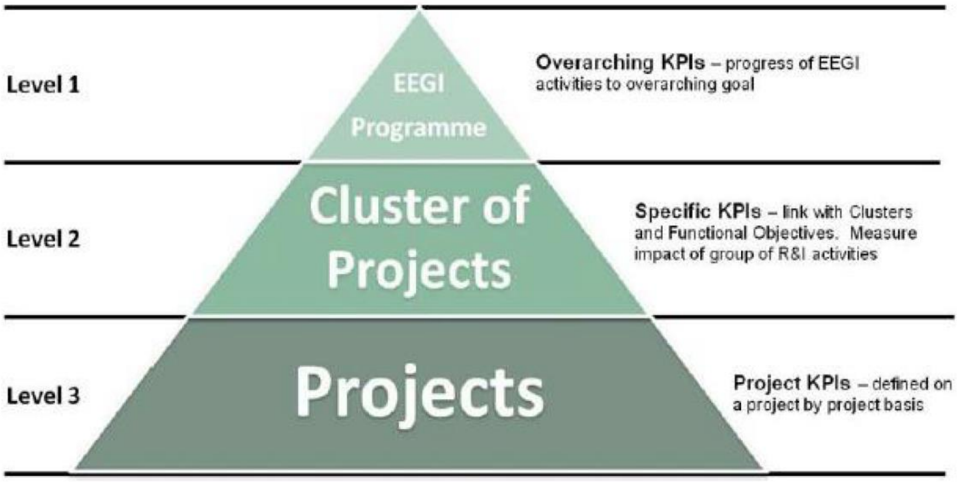

Figure 4-17: Levels for KPIs as proposed by EEGI [78]

The KPIs for the IGREENGrid project have been evaluated by using this model (second and third level KPIs have been regarded). Two main categories have been established for the KPIs, which depend on the relevance of one KPI in evaluating benefits in terms of DRES integration:

First category indicators: These indicators include the main technical aspects necessary for the integration of DRES.

- DRES hosting capacity
- Quality of supply
- Energy efficiency

Second category indicators: These indicators are fundamental to reach the goals of the first category but also represent additional goals. They are not closely linked to the KPIs proposed by EEGI but considered important for the valuation of the IGREENGrid project.

- R&I solution usage time
- Reverse power flow
- Forecasting accuracy
- Greenhouse gas emissions

4.5.6 S-chameleonStore

The aim of this project [79] is to evaluate a control and configuration platform for battery storage systems to handle the challenges of distributed renewable energy sources. Costs, risks and the potential of different battery storage types have to be pointed out. The method [79] that has been used for this and which is consisting of two parts is described in this section.

Economic analysis

The discounted cash flow (DCF) has been calculated as the sum of discounted costs and proceeds from the following parameters for each storage type [79]:

- Investment costs
- Running costs
- Operating costs
- (Technical) durability of components
- Depreciation period in accounting
- Repayment period of borrowed capital
- Equity and debt ratio and resulting costs
- Revenue parameters (energy prices, tariffs,…)
- Expected inflation
- Expected price increasing
- Taxes and duties of operators

For some of the parameters it has also been calculated which value would be necessary in order that the value of the DCF would be zero. Furthermore costs for the energy storage (€/kWh) have been considered. [79]

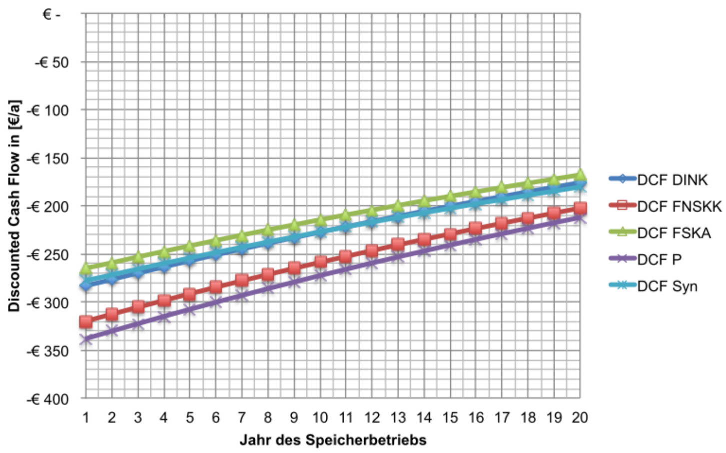

Figure 4-18: DCF of different consumer profiles for a lithium-ion storage with 2kWh storage capacity and a 2kWp PV system [79]

Figure 4-18 shows the DCF that has been calculated for lithium-ion batteries. It can be seen that the value of the DCF is negative. This is due to the storage costs of lithium-ion batteries, which are very high [79].

Environmental valuation

The focus of this valuation lies on three main points [79]:

- An estimation of the climate footprint of selected storage systems
- The criticality of resources
- The toxicity of resources

A life cycle assessment, as it can be seen in Figure 4-19, has been conducted.

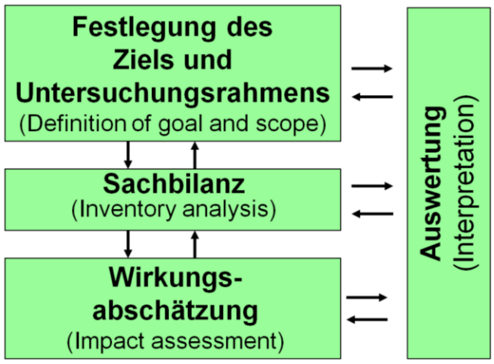

Figure 4-19: Phases of the life cycle assessment [79]

Definition of goal and scope: In this section, goal and framework of the project need to be defined. The scope of application, interest in knowledge and target groups have to be specified and already existing publications have to be taken into account. The product system and technical/geographic and time limits of the system need to be declared. [79]

Inventory analysis: The inputs (resource consumption) and outputs (emissions) of a product system are quantified [79].

Impact assessment: Out of the impacts on the environment which are obtained in the inventory analysis, potential effects on the environment are derived [79].

Interpretation: Sensitivity analyses have to be conducted to test the stability of results. Uncertainties in the results are estimated or quantified. To value the impacts on the environment that are caused by the battery storage system used in the project S-ChameleonStore, two scenarios have been defined [79]:

- In **scenario 1,** it has been determined how much PV or wind power needs to be installed to compensate the CO_2 emissions of the battery storage (Assumption: Electricity current gained by PV/wind power replaces conventionally generated current and the resulting CO_2 emission savings are credited to the battery storage).
- In **scenario 2,** it has been determined if a storage battery can be recommended to increase the hosting capacity of a grid segment regarding the CO_2 amortization.

In Table 4-19, the most important materials used for a lithium-iron-phosphate battery are listed. Their share of total CO_2 emissions is given. The most important materials of the battery make in sum about 85% of the total CO_2 emissions, the rest comes from other materials or transport.

Table 4-19: Materials and resources used for a lithium-iron-phosphate battery and their share of the total CO_2 emissions [79]

Material	Mass [kg]	Mass share [%]	Share of total CO_2 equivalent [%]
Steel	24.62	14.00	2.50
Aluminum	50.10	27.00	40.00
Copper	0.16	0.09	6.00
Polypropylene	7.61	4.00	0.10
Graphite	55.60	32.00	1.00
Lithium carbonate	14.92	9.00	41.00

4.5.7 PowerMatching City

The project is located in in Groningen (Netherlands). Its aim is the demonstration of a future energy system by providing connected households smart appliances, so that the energy consumption can be matched in real time depending on the available renewable generation and local network constraints [80].
A CBA has been conducted for this project; its framework can be seen in Figure 4-20.

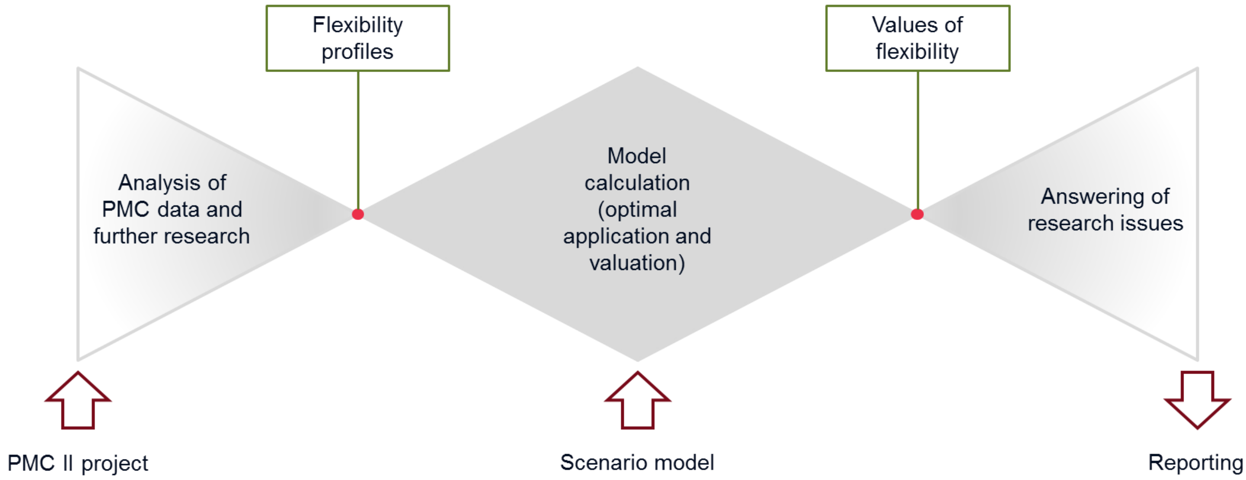

Figure 4-20: Overview of the CBA used by PowerMatching City (based on [81])

The flexibility profile consists of a representative standardized load profile on hourly basis for an average micro combined heat and power (micro-CHP), a heat pump and an electric vehicle for a Dutch household for both weekdays and weekend days. The CBA model includes a description of the temperature dependency of heat pumps and micro-CHP regarding its load and generation. [81]
The research questions have been determined at the beginning of the project. They are [81]:

- What is the flexibility that the different appliances can provide?
- What is the economic value of the provided flexibility for the Netherlands?
- What is the economic value per appliance for the Netherlands?
- What is the value of flexibility for the grid operator in terms of lower net costs?
- What is the value of flexibility in order to integrate renewable energy sources, in terms of a reduction in electricity generation costs and costs for imbalance?

For the analysis, the business as usual scenario has been compared with 5 other scenarios that demonstrate different situations of the year 2030. Their most important characteristics can be found in Table 4-20. The BAU scenario is a reference scenario, the scenarios D and E are the most ambitious ones regarding CO_2 reduction. The scenario E is characterized by 100% renewables and its high use of biomass.
The different scenarios were implemented in the CBA model. This model uses a simplified grid model and energy market model to assess the effect of using flexibility for both the grid and energy market. The benefits are based on comparing the situations with and without the use of flexibility. Flexibility is optimized based on the objective to minimize network peak loadings in the MV/LV-grid. [81]

Table 4-20: Overview of scenario characteristics (situation 2030) [81]

Scenario	BAU	A	B	C	D	E
CO_2 reduction	24%	40%	40%	55%	100%	100%
Share of renewable energy sources	18%	25%	25%	25%	25%	100%
Decentral use	100%	100%	<25%	100%	<25%	100%
Energy savings	10%	25%	10%	25%	50%	50%
Decentral potential	Low	Low	Low	Low	Low	High
Most important energy sources	Coal and natural gas	Natural gas	Coal and natural gas	Natural gas	Natural gas	Biomass
Penetration of electric vehicles 2030	9%	8%	9%	23%	30%	65%
Penetration micro-CHP	14%	14%	4%	14%	4%	80%
Penetration of electric heat pumps	4%	13%	13%	20%	55%	20%
Penetration of PV	13%	13%	3%	13%	3%	93%
Storage capacity of low voltage net	870 MW	870 MW	0 MW	870 MW	0 MW	28,000 MW
Storage capacity of high voltage net	0 MW	0 MW	0 MW	0 MW	0 MW	11,100 MW
Capacity of H2 production	0 MW	0 MW	0 MW	0 MW	6,500 MW	12,000 MW

The following benefits for the use of flexibility have been considered in the analysis [81]:

- Avoided of costs for CO_2 emissions
- Avoided costs for storage systems
- Avoided costs of energy losses
- Potential value on the balancing market
- Avoided net costs (HV/MV/LV)
- Avoided market costs for electricity generation
- Avoided costs of central generation

Figure 4-21 shows the resulting net present value for each scenario, for the period from 2015-2050[7]. On the one side (yellow bar), the value of simultaneously used flexibility is displayed. On the other side, it is assumed that the flexibility of each unit (micro-CHP, heat pump or electric vehicle) can be used separately.

[7] The situation from 2030 until 2050 is assumed to be steady-state. Meaning that within this period only replacement investments are considered.

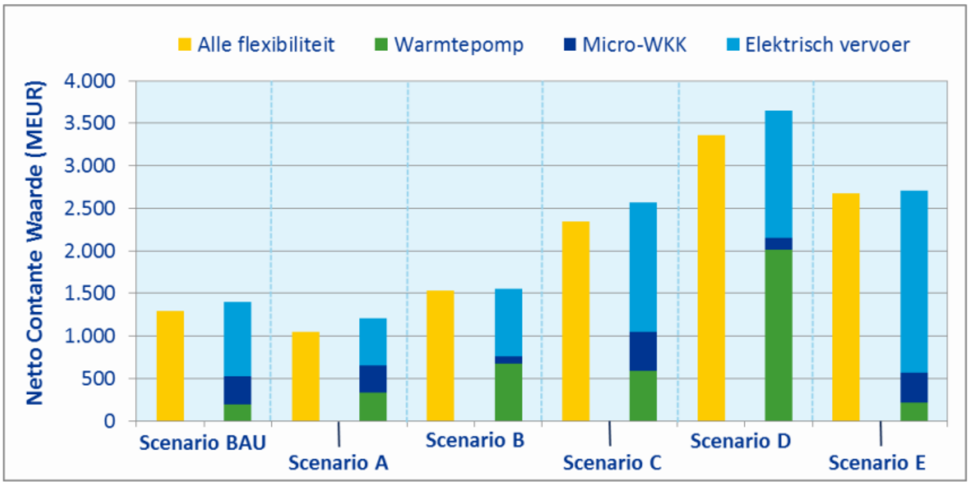

Figure 4-21: Overview of the net present value for each scenario [81]

4.5.8 Customer benefits evaluation (ComEd, SRP, HECO and APC)

The Rocky Mountain Institute made an approach to analyze DR projects with their focus on the economics of demand flexibility for residential customers. Two use cases and four specific scenarios have been analyzed [82], as it can be seen in Table 4-21.

Table 4-21: Use cases and scenarios for the valuation of demand flexibility [82]

	SCENARIO 1	**SCENARIO 2**
USE CASE 1: Bill savings provided by the shifting of energy use using time-varying energy and demand prices	Commonwealth Edison (ComEd), Illinois: Residential real-time pricing	Salt River Project (SRP), Arizona: Demand charges for solar PV customers
USE CASE 2: Increasing on-site consumption of solar PV in the absence of net energy metering	Hawaiian Electric Company (HECO): No compensation for exported PV proposal	Alabama Power Company (APC): Avoided cost compensation for exported PV

Fundamental value drivers for demand flexibility have been analyzed and categorized, which can be seen in Table 4-22.

Table 4-22: Value of demand flexibility in categories [82]

CATEGORY	DEMAND FLEXIBILITY CAPABILITY	GRID VALUE	CUSTOMER VALUE
Capacity	Can reduce the grid's peak load and flatten the aggregate demand profile of customers	Avoided generation, transmission and distribution investment; grid losses; equipment degradation	Under rates that price peak demand, lowers customer bills
Energy	Can shift load from high-price to low-price times	Avoided production from high-marginal-cost resources	Under rates that provide time-varying pricing, lowers costumer bills
Renewable energy integration	Can reshape load profiles to match renewable energy production profiles better	Mitigated renewable integration challenges	Under rates that incentivize onsite consumption, lowers customer bills

Assumptions

For the valuation and estimation of customer benefits, several assumptions had to be made. To establish a baseline, 15-minute sub metered home energy data that has been collected by the Northwest Energy Efficiency Alliance between 2012 and 2013 has been used to derive typical profiles for behavior-driven appliance use. Furthermore, estimations for non-flexible loads in a typical home (such as TV) have been made. For the estimation of rooftop solar PV generation, weather data and a modeling tool have been used to gain a 15-minute resolution to estimate the production. The potential of the four major electricity loads air conditioning, electric water heaters, electric dryers and electric vehicle charging has been modeled. [82]

Cost assumptions that have been made (2014 real dollars) can be found in Table 4-23.

Table 4-23: Cost assumptions [82]

LEVER	TECHNOLOGY REQUIRED	INCREMENTAL COST	LIFETIME
Domestic hot water (DHW)	Smart controls and variable-power heating elements	$200	10 years
Air conditioning (AC)	Communicating and/or “smart” thermostat	$225	10 years
Dryer	Communicating and/or “smart” cycle delay switch	$500	10 years
Electric vehicle (EV) charging	Communicating and/or “smart” charge timing controls	$100	10 years
Battery	7 kWh/2 kW battery bank	$3,000	10 years
Solar PV		$3.50/$W_{DC}$	25 years

To scale the bill savings that were calculated for one customer to other customers that are served by the same utility, the consumption of the modeled customer has to be scaled to the average residential consumption for each utility. For capital costs, the costs of cost-effective technology of the modeled customer have to be scaled to average residential consumption. The size of the PV market that could be unlocked by demand flexibility has been estimated by estimating the number and type of buildings that can support a PV system. The utility-wide peak load reduction potential has been estimated for use case 1. Therefore, the peak demand savings estimate has been scaled to average residential customer peak loads and number of eligible customers. [82]

Findings

- *Real-time pricing (ComEd):* Customers were given day-ahead estimates of hourly energy prices and were then able to adapt their energy assumption. It has been shown that nearly 20% of the total annual kWh can be shifted to lower-cost hours. Customers can save 12% of total bills which is about 250$/year (costs for the enabling technology are not yet considered in this calculation). Peak demand could be reduced by up to 940 MW with an appropriate participation of each eligible customer in ComEd territory. [82]
- *Residential demand Charges (SRP):* The project introduced a residential rate design option that results in a charge that is dependent on the peak 30-minute demand of a customer each month. Peak demand could be reduced by 48% which results in possible 41% savings of total bills or 1,000$/year (enabling technology is not considered in this calculation yet). Peak demand could be reduced by up to 673 MW. [82]
- *Non-exporting rooftop solar PV rate (HECO):* The idea of this scenario was to offer new PV customers a non-export option. Owners of rooftop PV etc. do not receive compensation or credit bill for the PV energy that they export in the grid. Results showed that on-site consumption of rooftop PV could be increased from 53% to 89%. If customers take advantage of demand flexibility, they can save additional 33% of total bills (which are about 1,600$/year) relative to the cost of solar PV without export compensation. Costs for enabling technology are not included in this calculation yet. [82]
- *Avoided cost compensation for exported PV (APC):* Avoided cost-compensation is offered for exported PV rather than crediting at the retail rate. A non-avoidable capacity charge of 5 $/kW-moth for behind-the-meter generation is imposed. Results showed that on-site consumption of rooftop PV could be increased from 64% to 93%. If customers take advantage of demand flexibility, they can save additional 11% of total bills (which are about 210$/year) relative to the cost of solar PV without export compensation. Costs for enabling technology are not included in this calculation yet. [82]

4.6 Conclusion and Outlook

Chapter 4.1 showed that there have already been several methods developed for the valuation of smart grid and DR projects. Nevertheless, the valuation process remains difficult when it is applied on a specific project. This is because all proposed methods introduce high-level parameters that may not play an equally important role in each project. Furthermore, the proposed valuation steps may not cover each important parameter of a project. Often the methods only introduce an abstract model of valuating a project but do not give details about the exact conduct of the analysis. Problems and challenges for conducting a CBA have been listed in in chapter 4.3.

In chapter 4.2, a set of parameters that define the boundary conditions of a project has been worked out. These parameters should be declared for each project that has to be valued in order to give an overview about its general framework. To test the outcome of a CBA, it is recommended to conduct multi-scenario and sensitivity analyses. Requirements for the baseline and the test scenarios are given in chapter 4.2.2 and chapter 4.2.3. The easiest way to get an estimation about the possible margin of a project is to compare a worst-case and a best-case scenario with the baseline.

In chapter 4.5, already existing valuations of DR projects have been shortly presented. It could be seen that (with the exception of InovGrid, which was a case study for the JRC method), there has never been a strict and general approach for the valuation process. On the contrary, accessible data has been used to build a specific analysis for each project. This makes the analysis for a single project easier but complicates the comparison of different projects, because there are no general guidelines how the analysis is conducted. Even though the smart grid project of Rome (chapter 0) used the analysis defined by JRC, the steps have not been performed in detail in the final report [73]. Some analyses only end with a listing of costs and benefits. They are not compared and therefore no conclusion about the value generated by the project is made.

Another problem is that most project valuations only observe quantitative benefits of a project. Qualitative benefits are – if they are considered at all – only mentioned as a “bonus” of a project. There is still the need for a method to combine a qualitative with a quantitative analysis.

To conclude it can be said that it is so far unavoidable to adapt the proposed CBA methodologies for each project that has to be valued. Nevertheless the introduced guidelines should be followed as good as possible in order to enable comparable results of different projects. The existing methodologies will need to be refined and extended in the future (like it is currently being done by the Energy Institute of Johannes Kepler University Linz [83]), in order to make their application easier. In addition, a toolset developed under the name of e3value (http://e3value.few.vu.nl/) facilitates multi-actor, multi-objective CBAs. As a first step, a common set of costs and benefits (as it has been proposed in chapter 4.4), should be considered in each valuation process so that comparable results can be found.

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