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SMART GRIDS INVESTMENT SUPPORT STRATEGY FOR THE EU FUNDING PERIOD 2014-2020

REPORT 1 (PHASES 1 AND 2)

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EXECUTIVE SUMMARY

The general objective of the project is the definition of a Smart Grid assessment framework for JASPERS officials to support national authorities of beneficiary countries (i.e. new EU Member States) identifying the most relevant Smart Grids investments. Poland and Romania will be considered as case studies to illustrate the proposed assessment framework.

The project has been organized into two different parts and accordingly two different reports have been produced.

This first report describes the analysis that has been carried out to define the scope and the assessment criteria for Smart Grid investments, in line with the tasks foreseen in the first part of the assignment (phases 1 and 2). In the second part of the assignement (phases 3 and 4), the work has instead focused on applying the proposed methodology to project case studies in Poland and Romania and to prepare relevant documents to support submission of Projects' applications (e.g. standard contracts, tender documents etc.). Phases 3 and 4 are described in a second report.

In summary, this first report describes the main two outcomes of the work carried out in the first part of the assignment:

- Definition of eligibility criteria and of a detailed Smart Grid project assessment framework
- Set-up of a Smart Grid project assessment tool (in excel)

Moreover, this first report also presents possible regulatory mechanisms to support the implementation of Smart Grid investments, drawing from best practices and on-going discussions at European level, and presenting the current regulatory context for Smart Grids in Poland and Romania as case studies.

ELIGIBILITY CRITERIA AND PROJECT ASSESSMENT FRAMEWORK

The proposed assessment framework comprises three eligibility criteria for Smart Grid investments. The basic criteria for eligibility are the following:

1. Assessment of Smart technical characteristics – Is the proposed investment a Smart Grid project?

2. Assessment of project impacts (based on key performance indicators-KPI) – Does the project deliver expected positive impacts in line with energy policy goals?

In addition to these two basic criteria, major projects (under the meaning of article 100 of EU regulation 1303/2013, which provides provisions for the European Regional Development Fund, the European Social Fund and the Cohesion Fund) need also to demonstrate their economic viability (positive societal cost-benefit analysis - CBA):

3. Economic viability (economic cost-benefit analysis CBA) – Does the project deliver net positive monetary benefits for society?

As a final step, it is then proposed to rank eligible projects according to a cost-effectiveness index, which encapsulates the national energy priorities (KPIs score), the total project cost and the project size (number of project users).

The report provides a step-by-step approach to assess each of the eligibility criteria presented above, as detailed in the following.

The assessment of **the first eligibility criterion** requires defining a set of minimum technical requirements that Smart Grid investments need to fulfil. The assessment of the technical eligibility criterion is carried out in three steps:

- Ensure that all assets included in the project are “Smart”, according to the definition of Smart Assets and of the list provided in the report.

- Ensure that Smart assets in the project are combined together to deliver Smart functionalities. The report provides a mapping of smart assets-smart functionalities to guide this assessment. In combining smart grid assets, interoperability and open communication protocols shall be ensured.

- Ensure that Smart assets and functionalities in the project are not already conventionally deployed in the project area. A term of reference is the existing regulatory asset base of TSOs/DSOs of the country under consideration, which provides a concrete indication of the baseline functionalities of standard power system investments. This assessment is country dependent. The goal of this requirement is also to identify Smart Grid investments which are not already included in regulatory cost-recovery mechanisms and thus might need European funds to be implemented.

The assessment of the **second eligibility criterion** is carried out via the evaluation of a set of key performance indicator (KPIs) which measure the project's impact on the power system. The KPIs are calculated as a difference between the Business as Usual (BaU) case and the Smart Grid scenario.

The KPIs are designed to assess the impact of the project according to key European energy policy goals: sustainability, integration of distributed energy resources, security and quality of supply, energy efficiency. The report includes guidelines and formulas for the calculation of each KPI.

On the ground of the value of the KPIs, different qualitative impact levels can be defined (low, medium, high) acoording to predefined thresold values. Threshold values needs to be defined at national level according to local context and national policy priorities. A project would fulfil the KPI eligibility criterion if it provides sufficient impact on all or on some of the KPIs.

As the improvement of energy performance is a key expected outcome of Smart Grid investments, guidance is also provided in ranking Smart Grid investments according to their specific energy performance. To this end we have identified most pertinent energy performance indicators and analysed which Smart Grid assets and functionalities are expected to provide the highest impact.

Finally, **the third eligibility criterion** is about demonstrating that the project is economically viable and thus delivers net positive economic benefits to society. Only major projects (in line with article 100 of the EU Regulation no 1303/2013[1]) are required to fulfil this criterion.

For the assessment of this criterion, the report describes a full CBA methodology, including formulas for the monetization of the benefits.

The proposed economic indicators that need to be calculated under this criterion include:

- Net present value of the net benefit of the project for the whole power system
- Internal rate of return
- Cumulative investment by asset/functionality category

Once eligible projects have been identified, **it is then proposed to rank them according to a cost-effectiveness index**, which is expressed as follows:

$$Cost\ effectiveness = \frac{\text{KPI score}}{Total\ Project\ Cost} * number\ of\ project\ users$$

[1] For major projects, the regulation prescribes to carry out an economic cost-benefit analysis (CBA).

The evaluation of the KPI score requires combining the values of the different KPIs (assessed in the previous eligibility criterion) into a single global indicator. This assessment requires defining weights for the different KPIs and is typically subjective in nature. A simple and transparent option is to carry out a weighted average of the KPI scores as reported below:

$$Score = \frac{\sum_{kpi} score(kpi) * weight(kpi)}{Max\ theoretical\ score}$$

We stress that this assessment should be the responsibility of national authorities on the ground of political priorities.

SMART GRID PROJECT ASSESSMENT TOOL

The proposed eligibility criteria and assessment framework have then been implemented in a user-friendly project assessment tool (Excel), which is intended to provide step-by-step guidance in carrying out the assessment.

The different modules of the tool aim at guiding JASPERS officials, national authorities and project promoters across the different steps of the assessment for each of the eligibility criteria.

The modules are organized as follows:

- Description of the evaluation criteria
- Description of the project
- Calculation of the costs
- Estimation of the KPI
- Description of the context (Only major projects)
- Calculation of benefits (Only major projects)
- Synthesis Evaluation

The different modules can be used independently and modifications/inputting of new information can be done easily on each of the tool's modules (the tool comes with a detailed user manual).

The tool can be used to perform automatically some standard calculations (e.g. discounting; sum of costs) but it is sufficiently flexible to allow the detailed verification of the evaluation hypothesis and to tailor the assessment to the specific characteristics of the project and of the local context.

REGULATORY FRAMEWORK

Finally, the report also describes possible regulatory mechanisms to support the implementation of Smart Grid investments, drawing from best practices and on-going discussions at European level. The analysis focuses on three main aspects:

> Specific incentive programs to support innovation investments
> Output-based regulation (e.g. reward/penalties with reference to predefined targets like quality of supply, outage time etc.)
> European initatives on smart grid data management (data management models/roles and responsibilities, specific actions on data privacy and cybersecurity).

The regulatory analysis also presents an overview of the regulatory frameworks in Poland and Romania. On the one hand the report describes the most relevant legislative and regulatory initatives supporting Smart Grid investments in Poland and Rmania; on the other hand it highlights the present challenges and needs of the power system and the on-going initatives in Smart Grids in both countries.

This analysis provides the context to run the case studies for Poland and Romania that are described in the second report.

INTRODUCTION

The present report has been prepared by Tractebel Engineering, sub-consultant to COWI Belgium member of the COWI Consortium, under the JASPERS Framework Contract - Lot 3 Energy, and in response to the Terms of Reference included under Letter of Contract CC5529/PO70396 of 7 February 2014 on Smart Grids Investment Support Strategy for the EU Funding Period 2014-20.

The assignment is composed of 13 different tasks grouped in 4 phases:

Phase 1: Scope and assessment criteria for Smart Grids investments

> **Task 1**: Technical scope of the typical smart grids investments and their impacts in the power system, in particular for the integration of renewable energy sources and improved energy efficiency.

Task 2: Identification of regulatory requirements to implement investments in smart grids.

Task 3: Criteria for the eligibility of investments – physical, financial and socio-economic conditions.

Task 4: Criteria for the assessment of expected energy performance of the systems after investments.

Task 5: Elaboration of typical costs by types of elements in smart grids projects.

Phase 2: Cost-benefit analysis model
Task 6: Identification of expected economic and financial return of the investments.

Phase 3: Application and implementation procedures
Task 7: Preparation of an Applicant's Guide and sample Application, including elaboration of standard documents (standard contracts and tender documents).

Task 8: Review and selection criteria for the applications.

Task 9: Required structure for Project Implementation Units.

Task 10: Supporting documents for the supervision and control mechanisms of design, construction and commissioning.

Phase 4: Case studies and dissemination
Task 11: Case study: POLAND.

Task 12: Case study: ROMANIA.

Task 13: Dissemination.

An overview of the different phases is shown in figure 1, which also shows how the present report fits with the planning (highlighted in red).

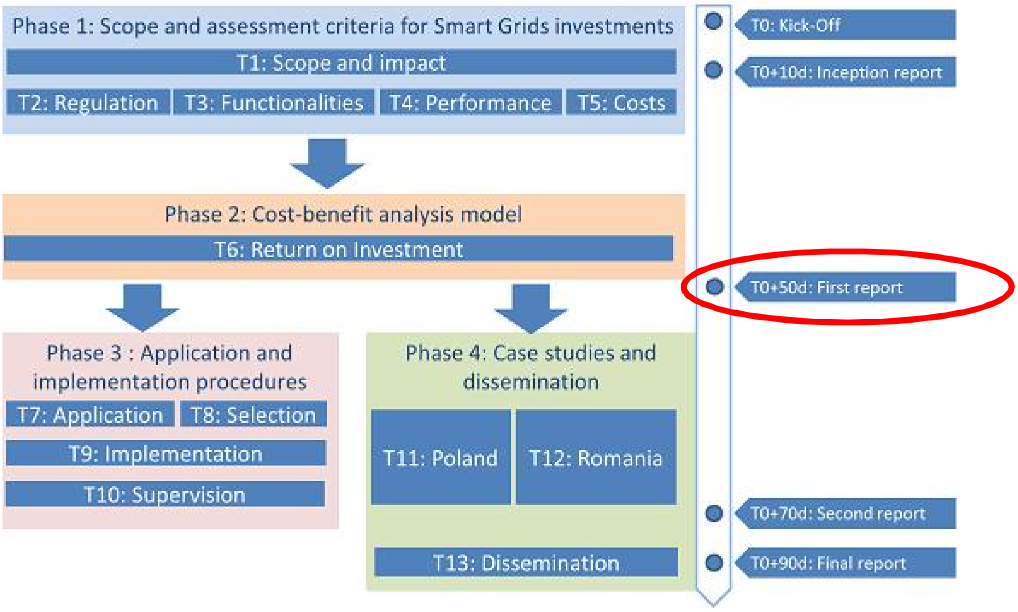

Figure 1: Overview of interdependencies of project tasks and planning

The scope of this first report covers the first two phases of the assignment and illustrate the analysis carried out to define the scope and the assessment criteria for Smart Grid investments (phase 1) and to define a cost-benefit analysis framework (phase 2).

The final report is composed of the first and second reports.

1 TECHNICAL SCOPE OF SMART GRID INVESTMENTS

The objective of this chapter is to define the technical perimeter of Smart Grid investments that will be then used in the different steps of the proposed assessment framework.

In particular the minimum functional requirements for eligible Smart Grid investments will be defined in terms of their technical characteristics (definition of smart assets and smart functionalities) and of their impacts on the power system (key performance indicators). This chapter corresponds to tasks 1 and 4 of the assignement (see introduction).

Definition of Smart Grids

The Energy Infrastructure Regulation, adopted in May 2013[2], considers as Smart Grid infrastructure "any equipment or installation, both at transmission and medium voltage distribution level, aiming at two way digital communication, real-time or close to real-time, interactive and intelligent monitoring and management of electricity generation, transmission, distribution and consumption within an electricity network"[1].

Literature review

In defining the Smart Grid assets, functionalities and impacts, we have built on the approaches followed by public organizations promoting Smart Grids projects and investments. Particular attention has been given to the initiatives undertaken by European authorities, like the Smart Grid Task Force of the European Commission, the recently adopted Energy Infrastructure Regulation and the European Electricity Grid Initiative (EEGI) in the framework of the SET-Plan.

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[2] REGULATION (EU) No 347/2013 OF THE EUROPEAN PARLIAMENT AND OF THE COUNCIL of 17 April 2013 on guidelines for trans-European energy infrastructure and repealing Decision No 1364/2006/EC and amending Regulations (EC) No 713/2009, (EC) No 714/2009 and (EC) No 715/2009

We have also analysed the implementation of the ARRA Smart Grid funds launched by the US Department of Energy (DOE) in 2009. The funding program has come to a close in 2013 and interesting lessons learned have also been drawn for refining the methodology proposed in this assignment.

Manufacturers' products and smart grid demonstration projects have been considered to guarantee the commercial availability of the selected assets and functionalities. When needed, technical publications have been used to bring details to the assets and functionalities descriptions. Focus has been put on assets or functionalities commercially available. The complete list of bibliographic sources can be found in 01.

1.1 Smart Grid assets

The goal of this subsection is to define from a technical point of view the scope of Smart Grid investments and the criteria to differentiate Smart Grid assets.

Different sources have been used to describe the selected Smart grid assets. The main source is the DOE's report *"User Guide for the U.S Department of Energy Smart Grid Computational Tool"*[1]. Description of assets commercialized by main Smart Grid vendors has also been used.

In general terms, we define that an asset is smart if

> It has (possibly two way) communication capabilities and can be included in a digital control loop

> It is controllable/accessible remotely and/or has local intelligence to automatically adapt to operating conditions

Table 1 reports the list of smart assets considered in this study. When duly justified, other assets could be included in the list by project promoters.

Five categories have been considered to classify smart grid assets:

a) Transversal

b) Transmission

c) Distribution – Control room

d) Distribution automation – Substations/field

e) Distributed Energy resources & Consumer

Asset's category	Name	Description
Transversal	Equipment health sensor	Monitoring devices that automatically measure and communicate equipment characteristics that are related to the "health" and maintenance of the equipment. These characteristics can include, but are not limited to temperature, dissolved gas, and loading. These devices can also automatically generate alarm signals if the equipment characteristics reach critical or dangerous level.
Transmission	Phase shifting transformer	Transformers that enable phase angle control between the primary (source) and the secondary (load) sides to create a phase shift between the primary side voltage and the secondary side voltage. The purpose of this phase shift is to control the real power flow through interconnected and meshed power system.
	Flexible AC Transmission Systems - FACTS devices	An electronic system and other static equipment that provide control of one or more AC transmission system parameters to enhance controllability and increase power transfer capability.
	Phasor measurement units	The phasor measurement units associated with phasor data concentrators, communications technology, and advanced software applications enable system operators to collect and analyse synchronized real-time measurements (voltages, currents) of multiple remote measurement points on the transmission system.
	Tools for advanced analysis and visualization	Advanced tools installed in dispatch centres to analyse grid information or help human operators

Table 1- Smart Grid Assets

Asset's category	Name	Description
Distribution – Control Room	Distribution management system - DMS (SCADA; outage management system; GIS)	A Distribution Management System (DMS) is a utility IT system capable of collecting, organizing, displaying and analysing in real-time distribution systems. A DMS can help to plan and execute distribution system operations to increase system efficiency, optimize power flows, and prevent overloads by taking into account all the measured information. A DMS can interface with other applications such as geographic information systems (GIS), outage management systems (OMS), and customer information systems (CIS) as well Distributed Energy Resources (DERs) information systems for a full view of distribution operations.
	Software tools for planning that take into account the available flexibility in the system provided by Distributed Energy Resources (DERs)	Distribution planning software which uses planning calculation models taking into account DERs and demand flexibility behaviour.

Table 1 (continued)- Smart Grid Assets

Asset's category	Name	Description
Distribution automation – Substation/field	Advanced fault detectors	This technology is a micro-processor based relay, with communication capabilities for coordinated operations, possibly allowing integration in substations Remote Terminal Unit (RTU) or DMS. These devices are relays able to adapt the settings of equipment according to different contexts. They allow for higher precision and greater discrimination of fault location and type by incorporating context awareness logic and/or coordinated measurement among multiple devices. It typically includes micro-processor based relays and switches (SCADA driven at substation level or at DMS), with communication capabilities, measurement units (three phase voltage and current, feeder configuration, running status of the DG units…). The protection scheme can then select the suitable protection approach when a default occurs. Adaptive protection relays include different types of protection: directional overcurrent relay, earth fault protection, default isolation, dynamic reconfiguration.
	Grid sensors (e.g. load monitoring, load balancing)	This technology can measure and communicate line, feeder and/or device variables, including for e.g. loading data, via a communication network in real- or near real-time.
	Voltage regulators (including on-load tap changers)	Voltage regulators are assets that can automatically increase or decrease the voltage on a distribution circuit to help keeping the voltage within a pre-determined band. Voltage regulators cannot adjust power factor. In this category are included transformers with on-load tap changers. They typically monitor the voltage at the location where they are connected (or along the feeders if voltage sensors are deployed), comparing it to a programmed set point. If the voltage deviates too far from the set point, the voltage regulator can adjust its output voltage by moving the tap on the secondary side up or down.
	Capacitor regulators	This technology can control capacitor banks either remotely via a human operator or as part of an automation control loop. Capacitor banks are used for voltage regulation and power factor adjustment.
	Automated feeder and line switches	Feeder and line switches that can be included in automation sequence or remotely controlled. They are equipped with remote communication capability and can be interfaced with automation controllers to send their status (open/close) and receive opening/closing commands. It can be used in network reconfiguration after a default has been isolated.
	Automatic fault reclosers	Reclosers that allow for remote control and monitoring and/or integration in automation sequence for fault restoration. A fault recloser is a circuit breaker that can automatically close the breaker after it has been opened due to a fault. Reclosers are used on overhead distribution systems to detect and interrupt momentary faults.
	D-FACTS devices (Distributed flexible AC transmission system)	Application of FACTS devices in distribution grids.

	Local substation control units/ Programmable Logic Controller (PLC) or RTU	These are microprocessor-controlled electronic devices, installed in substations that interface physical objects (automated switches, breaker…) to a remote control unit which can operate either locally or with a DMS wia a two ways communicating. They allow data transmission as well as control of connected objects. PLC stands for Programmable Logic Controller and is usually used for local remote control whereas RTU stands for Remote Terminal Unit and is typically used in SCADA architecture.

Asset's category	Name	Description
Distributed Energy resources & Consumers	Local energy management system (EMS)	A local controller able to integrate different inputs (e.g. price, weather forecasts) and define the optimal operation of the controlled DER (Distributed Generation -DG, energy demand, Electric Vehicle - EV). It is equipped with two way communication capabilities for remote monitoring and control. It can carry out autonomously local optimization or receive external commands as part of a centralized control architecture. An Energy Box for example, is a local EMS.
	Smart converters (for DG –grid interface)	Power-electronics converters (e.g. converters) interfacing distributed generation to the grid. They provide advanced controlling functionalities to the associated distributed generator like: control of active generation, volt/var control, frequency control; etc.. These devices are equipped with two way communication for remote monitoring and controllability (e.g. for sending control set-points).
	Microgrid controller	Micrograms are electrical systems that include multiple loads and distributed energy resources that can be operated in parallel with the grid or as an electrical island. A microgrid controller enables and controls micrograms. It could especially ensure frequency and voltage control within the microgrid or even perform technical and costs optimization of the operations.
	Adaptive protection relays (for DGs)	These devices are relays able to adapt the settings of equipment according to different contexts. These devices could also operate to protect DER from islanding (i.e.: injecting energy when there is no power flowing due to a default).They allow for higher precision and greater discrimination of fault location and type by incorporating context awareness logic and/or coordinated measurement among multiple devices. It typically includes micro-processor based relays and switches (SCADA driven at substation level or at DMS), with communication capabilities, measurement units (three phase voltage and current, feeder configuration, running status of the DG units…). The protection scheme can then select the suitable protection approach when a default occurs. Adaptive protection relays include different types of protection: directional overcurrent relay, earth fault protection, default isolation, dynamic reconfiguration. They can be integrated in the Smart converter interfacing the DG to the grid.
	Distributed electricity storage for energy and power applications	This type of energy storage devices is connected at the distribution level. They can be used to shift generation/consumption to peak/off-peak periods, both for bulk market purposes or for solving local issues on distribution grids (current/voltage constraints).
	Smart charging stations and vehicle to grid (V2G)	Electric Vehicle (EV) charging stations equipped with communications technology and able to adapt charging period according to grid information and external signals/commands. Vehicle to Grid (V2G) describes a system in which EVs are allowed, besides consuming electricity from the grid, to feedback energy to the local power

		grid. This process requires on-board bidirectional chargers. For this last functionality, commercial maturity is still unproven.
	Virtual Power Plant (aggregation) Platform (central and local units)	A virtual power plant platform is a software that can activate, control, monitor and/or evaluate the loads or generation capacity of a cluster of distributed energy resources installations (such as micro-CHP, wind-turbines, small hydro, demand response etc.). Such software relies on Energy Management Systems installed on DERs that are enabled for two ways communications with the platform. Thanks to its flexibility and reactivity, this type of platform can offer various services to the system (local energy balancing, ancillary services…), that can be useful for transmission and distribution needs as well as for generation portfolio optimization.
	Smart Meter	These electricity meters automatically process, transfer, manage and utilize metering data. They are equipped with two way data communication systems.
	Energy web portals/ in-home displays	These devices provide energy and related information to the consumer. The information can be available either locally or can be communicated to and from utilities or third party energy service providers. The consumer can then adapt its behaviour accordingly.
	Smart appliances	These appliances can be remotely controlled and/or can automatically optimize their energy/cost performance. They could also have a two ways communication with a Local Energy Management System (e.g. energy box).

Table 1 (continued)- Smart Grid Assets

1.2 Smart Grid functionalities

The implementation of Smart Grid assets per se is not sufficient to have a Smart Grid project. It is necessary in fact to combine the different Smart Grid assets (e.g. voltage and capacitor controllers) together in such a way to have Smart functionalities (e.g. automatic volt-var control).

In this section, we present the list of Smart functionalities impacting the different levels of the power system (consumption, distribution, transmission, generation) and carry out a mapping among Smart Grid assets and functionalities to highlight possible combinations of Smart Grid assets delivering Smart functionalities.

In the proposed methodology, Smart Grid assets are eligible to be included in Smart Grid investments if, apart from possessing intrinsic "Smart" characteristics (as defined in section 1.1), they are also effectively combined together to implement Smart functionalities. This aspect will be further detailed in chapter 3.

The defined list of functionalities builds on the main approaches followed at European level. In particular we have taken into account the list of functionalities defined by the EC Smart Grid Task Force and that has been used to evaluate Smart Grid projects of common interest in the framework of the EC Energy Infrastructure Regulation[34]. We have also considered the list of functionalities proposed by EPRI in the US, which have been used by the US Department of Energy to assess Smart Grid projects under the recovery act fund[5].

Table 2 reports the description of the considered Smart functionalities. Smart functionalities have been grouped according to the following three categories:

a) Transmission

b) Distribution

c) Consumer & Distributed Energy resources

We remark that, it is assumed that communication infrastructures and data management applications are necessary enablers for the implementation of the smart functionalities listed below. Therefore, the implementation of a smart functionality (e.g. load measurement and visualization /smart metering) shall include the corresponding data communication infrastructure (e.g. fibre optic.

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[3] Source: Smart Grids Task Force Expert Group 4 – Infrastructure Development "Definition of an assessment framework for projects of common interest in the field of smart grids" Brussels, July 2012, available from http://ec.europa.eu/energy/gas_electricity/smartgrids/taskforce_en.htm

[4] Source: European Commission Task Force for Smart Grids, 2010. "Expert Group 3: Roles and responsibilities". http://ec.europa.eu/energy/gas_electricity/smartgrids/doc/expert_group3.pdf

[5] Source: Methodological Approach for Estimating the Benefits and Costs of Smart Grid Demonstration Projects, EPRI, 2010

GPRS) and data management system (e.g. metering data management system), which are necessary for its correct functioning.

Functionality's category	Name	Description
Transmission	Dynamic line rating	Dynamic line rating can be achieved through real time determination of an element's (e.g., line, transformer etc.) ability to carry load based on actual electrical and environmental conditions (e.g. temperatures, wind…).
	Enhanced power flow control	Flow control requires techniques that are applied at transmission level for controlling active and reactive power flows. This functionality is enabled by tools such as flexible AC transmission systems (FACTS), phase shifting transformers, series capacitors.
	Wide area monitoring and visualization and control	Wide area monitoring and visualization requires time synchronized measurement units (phasor measurement units), communications, and information processing that makes it possible for the condition of the bulk power system to be observed and understood in real-time so that preventive (pre-incident) and post-incident actions can be taken.

Table 2 –Description of Smart Grid functionalities

Functionality's category	Name	Description
Distribution	Real-time load monitoring and visualization	This function provides real-time measurement and management of customer consumption (at end consumer level or substations/feeder level), generation level from DERs and possibly other collected measurements from grid sensors (including smart metering systems)
	Automatic fault management	Automated fault management consists in the implementation of processes for automatic fault location and service restoration (FLISR). . This functionality aims at isolating the area affected by a fault and finding and activating the best sequences of actions (manual/automatic circuit breakers...) in order to minimize the fault impact (e.g. on outage time; on number of users affected by the fault etc.). The sequence can be activated automatically or performed by a human operator.
	Dynamic network reconfiguration for optimization of grid operations	This functionality consists in being able to remotely adapt the topology of the distribution grid to different operational conditions in order to minimize losses or to carry out maintenance. It is achieved via remotely controllable feeder switches connected to RTU in substations. In the control room, at DMS level, a decision support system is needed to guide the operator to select alternative grid configurations.
	Power flow control (dispatchability of DER, D-FACTs)	This functionality requires techniques that are applied at distribution level for active power flow and reactive power control via: dispatchability of DERs by grid operator (for active and reactive power control) and via D-FACTS.
	Planning distribution grids taking into account the flexibility of distributed energy resources	This functionality refers to new planning tools that integrated the available flexibility/dispatchability of distributed energy resources (e.g. demand response, storage; DG curtailment) in the planning process of DSOs, as an alternative to traditional reinforcement investments.
	Proactive maintenance of equipment and identification of incipient faults	Proactive maintenance of equipment and identification of incipient faults is defined as on-line monitoring and analysis of equipment. It includes equipment performances and operating environment monitoring in order to detect abnormal conditions (e.g., high number of equipment operations, temperature, or vibration). Asset managers and operations personnel can then be automatically notified to respond to increasing risks of equipment failure.

	Automated VOLT/VAR control (including conservation voltage reduction)	It consists in implementing coordinated control of voltage and reactive power on the feeder. Voltage control is realized through an on load tap changer on the substation transformer. VAR control is realized through a controller of capacitor banks. The control loop is run by a RTU in the substations. The objective of the control loop is typically to keep the voltage in the limits while freeing up feeder capacity through reactive compensation (automatic volt-var control). Another option is to act on the voltage control loop to carry out conservation voltage reduction. The idea is to decrease the voltage as low as possible, to reduce consumption, but still complying within voltage limits admitted on distribution grid for all customers.

Table 2 (continued)–Description of Smart Grid functionalities

Functionality's category	Name	Description
Distributed Energy resources	Adaptive protection for distributed energy resources (e.g. anti-islanding)	This function is usually implemented in the converter of the DER equipment to protect it from islanding (i.e. producing electricity when the power is no longer flowing into the grid due to default occurrence). It includes electrical islands detection and proper disconnection from the power system.
	Automatic provision of ancillary services (Voltage, frequency and reactive power control)	Automated voltage and reactive power (VAR) control requires the use of smart converters. To modulate its power, the DER can operate autonomously in response to local events or in response to signals from a central control system. In the latter case, the DER will need to be equipped with a two way communication system for remote controllability and observability.
	Optimized dispatching (local or remote)	This functionality can include power generation, communications and control systems that optimize the output and performance of the DERs based on different variables forecasts (weather, prices…). It can also coordinate the DER's operation with other smart grid systems when this functionality is part of an aggregation function.
	Aggregation function	Aggregation function consists here to operate DERs through a VPP platform that monitors and controls each of the assets. This functionality relies on forecasting for intermittent generation; on operational conditions and often on optimization calculation to manage the asset. Optimization allows the portfolio to operate at the lowest operational costs while providing various services to the power system (energy balancing, primary and secondary reserves…).
	Micro-grid operation of distributed energy resources	This functionality is achieved by automated separation and subsequent reconnection (autonomous synchronization) of an independently operated portion of the T&D system (i.e. microgrid) from the interconnected electric grid.
	Smart charging of EVs and vehicle to grid (V2G) services	This functionality is an electric vehicle charging that can be modulated in time and in power in response to a signal sent by the power system or a VPP Platform. It can also intelligently integrate two-way power flows enabling electric vehicle batteries to become a useful utility asset. Nevertheless this last functionality is not commercially available yet.

Table 2 (continued)–Description of Smart Grid functionalities

Functionality's category	Name	Description
Consumer	Real-time load measurement and visualization.	This functionality provides real-time measurement of customer consumption of load through smart metering systems and in-home displays/web portals.).
	Automatic and/remote customer electricity use optimization	This functionality consists in the use of energy management systems to automatically manage energy assets (smart appliances, DG, EVs, etc.) at consumers' premises and. Optimization can be carried out toward multiple goals such as cost, reliability, convenience and environmental impact. This functionality includes applications like demand response.

Table 2 (continued)–Description of Smart Grid functionalities

1.2.1 Mapping Assets and Functionalities

Figure 2 reports the mapping of most common combinations assets-functionalities.

It is important to keep in mind that this mapping is general and aims at covering possible main links, to provide guidance in the identification of the main functionalities of a given project. However we remark that a given asset in a project will not necessarily have all the functionalities identified in the mapping. In the same way, for a given functionality not all the identified assets are necessary to implement it.

This framework will be used to define minimum impact requirements for eligibility of Smart Grid investments (chapter 2). The project assessment tool described in chapter 4 includes a dedicated module to guide the mapping Assets-functionalities.

ASSETS	FUNCTIONALITIES	Transmission			Distribution							Smart integration of DER						Consumers	
		Dynamic line rating	Enhanced power flow control	Wide area monitoring and visualization	Real-time load monitoring and visualization	Automatic fault management	Dynamic network reconfiguration.	Power flow control (dispatchability of DERs, D-facts)	Planning distribution grids with the flexibility of DER	Proactive maintenance of equipment	Automated Volt/VAR control	Adaptive protection for DER (e.g. anti-islanding)	Grid ancillary services (Voltage frequency reactive power control)	Optimization of DER output and operation (e.g. forecasting, energy mgmt)	Aggregation function	Microgrid operation	Smart charging of EVs and vehicle2grid services	Real-time load measurement and visualization.	Automatic and/remote customer electricity use optimization
Transmission grid	FACTS devices.		x																
	Phase shifting transformer		x																
	Phasor measurement units			x															
	Software for advanced analysis and visualization	x	x	x															
Distribution grid Control room	Distribution management system (DMS)				x	x	x	x		x	x								
	Software tools for distribution planning taking into account flexibility of DERs								x										
Distribution automation –Substation/field	Advanced fault detectors (e.g. adaptive settings; higher selectivity)					x						x							
	Grid sensors (e.g. load monitoring and load balancing)	x			x	x	x	x	x										
	Equiment healt sensors									x									
	Voltage regulators										x								
	Capacitor regulators										x								
	Automated feeder and line switches					x	x												
	Automatic fault reclosers					x													
	D-FACTS devices.							x											
	Local substation control units/PLC or RTU				x	x	x			x	x	x	x	x			x		
Distributed energy resources & Consumers	Local Energy Management System (EMS)												x	x	x	x			
	Smart converter (e.g. interface DG-grid)							x	x		x		x	x	x	x			
	Microgrid controller							x								x			
	Adaptive protection relays					x						x							
	Distributed Electricity storage for energy/power applications							x	x				x	x	x				
	Smart Charging stations and vehicle-to-grid application							x	x						x		x		
	Virtual Power Plant (aggregation) Platform								x						x	x			
	Smart Meters				x			x	x								x	x	x
	Energy web portal /in-home display																	x	x
	Smart appliances																	x	x

Figure 2 – Proposed mapping assets-functionalities to guide the assessment of minimum technical requirements

In figure 3, we provide an example of implementation of a smart asset (smart protection relays) to deliver a smart functionality (adaptive protection scheme of distributed generation).

1. **Adaptive protection of distributed generation**

> **Today**: DG relays typically rely only on local information

If there is a fault at the transformer, the LV feeder is disconnected, but the load could still be powered by the distributed generation (islanding).

DG relays have a very sensitive frequency band: if there is an under-frequency situation, the DG relay would disconnect possibly increasing the gravity of the frequency problem.

> **Smart Scenario**

DG relays communicate with RTU in the substation ("smart relays"), receiving information on grid conditions.

Adaptive settings of frequency band depending on grid conditions so that the DG unit can still inject power and therefore prevent from increasing the gravity of the frequency problem.

Disconnection of DG if substation relay is open, which prevents it from islanding.

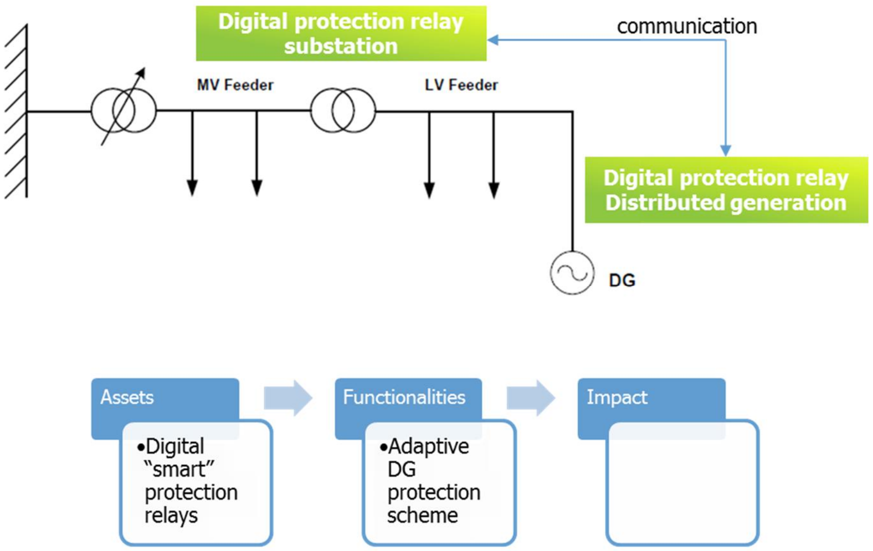

Figure 3– Example of mapping Smart assets (smart protection relays) -Smart functionality (adaptive protection scheme for distributed generation)

1.2.2 Assessing the impacts of Smart Grids investments: key performance indicators

To discriminate smart grid projects, impacts on the power system have to be taken into account. To this end, in this section a number of key performance indicators (KPIs) are proposed to measure these impacts. The selected KPIs should reflect the contribution of smart grid projects to key energy policy goals that have triggered Smart Grid implementations in Europe. The indicators are grouped in five different domains:

> Improved sustainability of the power system
> Increased integration of distributed energy resources
> Improved security and quality of supply
> Increased energy efficiency of the power system
> Increased economic profitability

The full list of KPIs is reported in table 4.

The KPIs are expressed in terms of relative variations of certain power system values with an without the Smart Grid project..

The list of KPIs builds on the approaches followed at European level. In particular we take into account the list of indicators defined by the EC Smart Grid Task Force and that has been used to evaluate Smart Grid projects of common interest in the framework of the EC Energy Infrastructure Regulation. The work of the GRID+ consortium to define KPIs for the European Electricity Grid Initiative (EEGI) of the SET Plan is also considered.

We have also considered the report of the Energy networks association in UK *"Assessing the impact of Low Carbon Technologies on Great Britain's Power Distribution Networks"*[6] and the definitions provided by the U.S. DoE in its report *"User Guide for the U.S. DoE Smart Computational Tool"*[3].

Full methodologies to quantify these KPIs are provided in section 4.3.

6

Defining EEGI Project and Programme KPIs, GRID+, October 2011

Assessing the impact of Low Carbon Technologies on Great Britain's Power Distribution Networks, Energy networks association in UK, 2009

Guidebook for ARRA Smart Grid Program Metrics and Benefits, DOE, December 2009

Measuring the "Smartness" of the Electricity Grid, B. Dupont, Student Member, IEEE, L. Meeus, and R. Belmans, Fellow, IEEE
https://lirias.kuleuven.be/bitstream/123456789/285643/1/MeasuringSmartness

KPI's category	Name	Description

KPI's category	Name	Description
Sustainability	Reduced greenhouse gas emissions	Some Smart Grid Functionalities can lead to decrease the amount of central generation that supplies the load (through reduced electricity consumption, reduced electricity losses, more optimal generation dispatch) and/or a reduced peak generation. Also, smart grid functionalities can increase the hosting capacity for renewable energy sources and reduce their curtailment level, thus increasing their share in the energy mix. These impacts can be translated into a reduction in GHG emissions produced by fossil-based electricity generators.
	Reduced local SOx, NOx emission	See above

Table 4 –description of key performance indicators to assess impact of Smart Grid functionalities

Integration of decentralized energy resources	Increased hosting capacity of distributed generation	The hosting capacity of a network is the maximum generation capacity that can be safely connected to the grid without this latter can flow when all the units are injecting at nominal power without causing hazardous conditions voltage, current violation…). Typically the hosting capacity referf to a "fit and forget" situation where safe conditions are considered with respet to a worst case scenario. To increase the hosting capacity of DG on the distribution grid various smart functionalities can have an impact:higher observability and controllability for the grid by using grid-side resources (voltage/capacitor regultors) and by using DERs (dispatchability of distributed generation; demand response, use of storage etc.)
	Increased hosting capacity for Electric Vehicles and other new loads	The same functionalities as listed above but also smart charging of EV can allow the distribution network to handle more EV as well as new loads (heat pumps..) connected to the grid.
	Increased number of generation hours provided by DG	In line with the increased DG hosting capacity, number of generation hours provided by DG can be increased thanks to smart grids functionalities. This indicator is complementary to the "increased hosting capacity of DG" KPI, and measures the actual increase of energy injected in the grid by distributed generators.

Table 4 (continued) –description of key performance indicators to assess impact of Smart Grid functionalities

KPI's category	Name	Description
Security and quality of supply	Increased generation's share from renewable sources in the generation mix	This indicator considers the impact of smart functionalities on a higher hosting capacity for the renewable-based distributed generation (see previous indicator) and also the reduction of curtailed renewable energy sources (RES) thanks, for example, to a reduction of grid congestions.
	Reduced peak demand	Peak demand can be significantly reduced thanks to demand response applications (shifting consumption from peak to off-peak periods) enabled by local EMS and VPP platforms. Reducing peak load is a major challenge since peak load periods can bring strong constraints on the system from generation (peak capacity is more expensive than other generating assets and increases CO2 emissions) to distribution (higher network capacity required, higher level of electrical losses…).
	Reduced duration and frequency of interruptions per customer (SAIDI; SAIFI)	SAIDI is the average duration of energy supply interruption per customer. SAIFI focuses on interruptions frequency per customer. To reduce these indicators, duration of defaults identification and isolation should be reduced in order to minimize the area impacted. Duration of reconfiguration after default is the other impacting aspect for interruption duration. Automatic faults management and incipient faults identification are the most relevant smart functionalities n to reduce SAIDI and SAIFI.
	Increased the voltage quality performances	This KPI is evaluated here through estimation of the number of maximum line voltage violations reached during a given period on the distribution system (Vmax). The main smart functionalities to improve voltage quality performance are voltage and reactive power control on the distribution side and Automatic provision of grid ancillary services (voltage frequency and reactive power control) on the DER side.
	Extended asset life time	Mechanical stress on equipment can be reduced (and therefore their life time can be extended) by functionalities like automatic fault management, proactive maintenance of equipment and identification of incipient faults on the distribution side as well as adaptive protection on the DER side.
	Reduced expected Energy Not Supplied (ENS)	The Energy Not Supplied (ENS) is the consequence of grid defaults or congestions that prevent generated load to be supplied to customers. This indicator is generally calculated over a year and is directly related to reduction of SAIDI and SAIFI values.

Table 4 (continued) –description of key performance indicators to assess impact of Smart Grid functionalities

Table 4 (continued) –description of key performance indicators to assess impact of Smart Grid functionalities

KPI's category	Name	Description
Energy Efficiency of the Power System	Reduced technical losses in transmission and in distribution networks	Technical losses depend mainly on technical characteristics of network equipment (resistance, impedance…) and on the amount of power flowing (there a quadratic relation between power flowing and losses) through these latter. Some smart functionality, that can be deployed on the distribution network, on DG and at consumption points, can significantly contribute to optimize this second aspect. On the distribution side, level of active power flow control can optimise load repartition on the Network, reducing peak load locally and therefore losses. Voltage and Reactive Power Control contribute to reduce technical losses thanks to improved voltage and frequency stability. From a DER perspective, automatic provision of grid ancillary services can reduce technical losses in particular through participation to VOLT/VAR regulation. From consumption perspective, the way load peak on the feeder is managed is key since technical losses increase with active power consumption. Additionally, increased self-consumption that reduces distance between generation and consumption delivery points could also lead to reduced technical losses.
	Reduced non-technical losses in transmission and in distribution networks	Non-technical losses refer to inaccurate billing, including energy theft. Smart meters can lead to a reduction in electricity theft through earlier identification and prevention of theft.
	Energy savings	On the demand side, energy savings can be mainly achieved with real-time load measurement and visualisation for consumers and automatic consumption use optimization. Both functionalities rely on the installation of a local Energy Management System at the consumers' premises. On the grid side, energy savings could also be achieved via conservation voltage reduction.
	Reduced congestions in the system's electrical lines	Level of congestions in the system depends on electrical lines capacity, electrical demand at specific periods of the year/day and associated load repartition on the network. Smart functionalities like dynamic line rating, active power flow control, dispatch ability of DG, consumption use optimization are key for reducing congestions in the system.

1.2.3 Mapping functionalities and KPIs

Figure 4 reports the mapping of common combinations functionalities-impacts/KPI.

The goal is to assess the contribution of Smart functionalities included in a Smart Grid investment against the different energy policy goals and to guide the selection of projects that contribute the most to positive impacts on the field.

This framework will be used to define minimum impact requirements for eligibility of Smart Grid investments (Task 3). The project assessment tool described in task 6 includes a dedicated module to guide the mapping functionalities - KPIs.

We stress that the mapping is intended to provide guidance in identifying which implemented Smart functionality might contribute to achieve different impacts. Depending on the specific project and local conditions, a given functionality might not necessarily have all the impacts identified in the mapping. In the same way, for a given impact not all the identified functionalities are necessary to realise it. Moreover the mapping includes indirect impacts, i.e. impacts of a certain functionality on a KPI (e.g. increase of generation hours by DGs) which in turn has a positive impact on another KPI (e.g. reduction of GHG emissions, assuming a higher share of generation from renewable-based DG). These indirect impacts need to be carefully assessed on a project-by-project basis, to avoid overestimating benefits.

FUNCTIONALITIES	KPI	Sustainability		Integration of DERs			Security and Quality of Supply						Energy Efficiency of the Power System			
		Reduction of greenhouse gas emissions	Reduction of local SOx, NOx emission	Increase of hosting capacity of distributed generation	Increase of hosting capacity for Electric Vehicles and other new loads	Increase of number of generation hours provided by DG	Increase of generation's share from renewable sources in the generation mix (including reduction of curtailed renewable energy)	Reduction of peak demand	Reduction of duration and frequency of interruptions per customer (SAIDI; SAIFI)	Increase of the voltage quality performances	Extended asset life time	Reduction of the expected energy not supplied	Reduction of technical losses in transmission and in distribution networks	Reduction of non-technical losses in transmission and in distribution networks	Reduction of electricity consumption	Reduction of congestions in the system's electrical lines
Transmission	Dynamic line rating	x	x				x					x				x
	Enhanced power flow control	x	x				x						x			x
	Wide area monitoring and visualization								x	x	x					
Distribution	Real-time load monitoring, visualization	x	x	x	x	x	x	x	x		x		x	x		x
	Power flow control (dispatchability of DERs; DFACTS)	x	x	x	x	x	x	x			x		x			x
	Automated volt/VAR control	x	x	x		x	x			x			x			x
	Automatic fault management								x		x	x				
	Dynamic network reconfiguration								x				x			
	Planning distribution grids taking into account the flexibility of DER	x	x	x	x	x	x									
	Proactive maintenance of equipment								x		x					
Smart integration of DER	Optimization of DER output and operation (e.g. forecasting, energy mgmt)	x	x	x	x	x	x									x
	Grid ancillary services (Voltage frequency reactive power control)	x	x	x		x	x			x			x			x
	Adaptive protection for DGs (e.g. anti-islanding)			x		x			x		x					
	Aggregation function	x	x	x	x	x	x	x								x
	Micro-grid operation			x		x			x			x				
	Smart charging of EVs and vehicle2grid services	x	x		x			x								
Consumers	Real-time load measurement and visualization.	x	x					x	x				x	x	x	
	Automatic and/remote customer electricity use optimization	x	x			x	x	x					x		x	x

Figure 4 – Proposed mapping functionalities-KPIs to guide the assessment of minimum technical requirements

In figure 5, we provide an example of implementation of smart assets (load tap voltage controller and voltage sensor) and functionalities (conservation voltage reduction) and the corresponding mapping assets-functionality-impact.

1. **Grid Voltage Control – Conservation voltage reduction**

> **Today:** Load tap voltage controller: typically no automatic adjustment based on end-of –line voltage measurement.

> **Smart Scenario**: Voltage controller in the substation receives real-time voltage measurement from the feeder's end and automatically adjust the transformer's tap in order to reduce voltage while keeping it above minimum admissible value. This in turn leads topositive impacts such as energy savings and reduced losses.

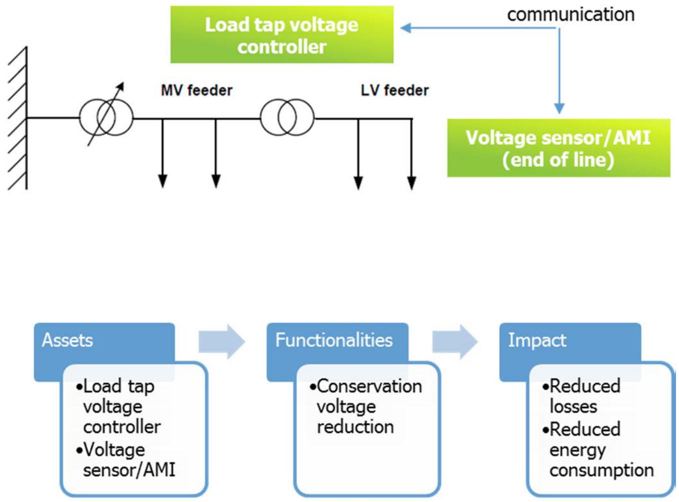

Figure 5 – Example of mapping smart assets- smart functionalities- impact for Grid Voltage Control – Conservation voltage reduction

1.3 Ranking of Smart Functionalities according to energy performance KPIs

On the ground of the list of KPIs defined in task 1, in this section we first identify those KPIs specifically related to sustainability and energy efficiency (energy performance KPIs). This corresponds to task 4 of the assignment (see introduction).

On the ground of the identified energy performance KPIs, we have then carried out a qualitative ranking of most pertinent Smart Grids functionalities according to their sustainability/energy efficiency performances, according to three levels of performance: low, medium and high (table 5).

Energy performance KPI Smart Functionality	Energy savings	Reduction of technical losses	Reduction of non-technical losses	Reduction of congestions	Reduction of peak load
Real-time load measurement and visualization (consumer's side)	++	+	+++*		+
Automatic and/or remote customer electricity use optimization	+++	+		++*	+++
Smart EV charging				++*	++
Volt/Var control (including conservation voltage reduction)	++*	++*		++*	
TSO/DSO Enhanced power flow control (including dispatchability of DGs, dynamic grid reconfiguration, FACTS etc.)		++*		++*	
(DSO) Real-time load monitoring and visualization		++*		+	
Dynamic line rating				++*	
Optimization of DER output and operation		+			+

Table 5 – Ranking of Smart functionalities according to their energy performance (sustainability and energy efficiency)

*Strongly depends on local conditions and grid configuration

We remark that the output of this task mainly aims at identifying which Smart Functionalities could have an impact on energy performance. However the expected level of impact strongly depends on the local context and should be assessed case by case.

The following KPI are proposed:

> Energy savings
> Reduction of technical losses
> Reduction of non-technical losses (energy theft)
> Reduction of congestions
> Reduction of peak load

The methodology to quantify the KPIs is provided in section 5.1.

a) Energy Savings

Associated Smart Functionality and impact:

Functionality: Real-time load measurement and visualization

> Possibility for consumers to have access to real-time (or with sufficiently frequent update) of electricity consumption can provide a reduction of energy consumption in the range 2-10%. This functionality is implemented via in-home displays or dedicated on-line energy dashboards providing consumers with indicators of their energy performance. Data are collected via smart meters. However capturing this benefit depends on direct action by the consumers and thus the effect is expected to decrease with the level of engagement of the consumer after the first phase of the project.
> **Impact: Medium**

Functionality: Automatic and/or remote customer electricity use optimization

> Use of automatic tools to automatically optimize consumers' electricity consumption. In this case the impact on energy efficiency is typically in order of 5-10% but above all can be sustained over time as it does not depend on consumers' direct involvement. The optimization function can be implemented via smart thermostats, energy boxes etc. Smart meters are used to collect consumption data. The positive impact on consumption comes from the overall optimization of consumption leading to less energy consumed and not from load shifting (possibility to differ electricity consumption at peak times), which does not directly reduce the electricity consumed.
> **Impact: High**

Functionality: Volt/Var control (including conservation voltage reduction)

> Possibility to control dynamically the voltage at a feeder to reduce the voltage at customers' premises (while respecting the minimum voltage level) and reducing power consumption.

- **Impact: Medium, but it depends on local conditions and on grid configuration.**

b) Reduction of technical losses

Functionality: (DSO) Real-time load monitoring and visualization

- Possibility to monitor the load flow in the distribution grid and assess actions to reduce grid losses (either in the planning phase or in the operational phase).
- **Impact: could be significant, but it depends on local conditions and on grid configuration.**

Functionality: Enhanced power flow control

- Thanks to advanced controllability capabilities (FACTS devices, dispatchability of DGs, etc.), the power flows can be optimized in order to minimize power losses.
- **Impact: medium, but it depends on local conditions and on grid configuration.**

Functionality: Volt/Var control (including conservation voltage reduction)

- The volt/var functionality can be provided either by grid assets (e.g. voltage and capacitor regulators) or by distributed energy resources (e.g. via smart converters). The goal is to control the reactive power flow in the feeders and reduce the current in the lines (and thus the losses) for the same amount of delivered active power.
- **Impact: could be significant, but it depends on local conditions and on grid configuration.**

Functionalities: Real-time load measurement and visualization/ Automatic and/or remote customer electricity use optimization

- A reduction of energy consumption thanks to manual or automatic optimization of the energy consumption leads also to a reduction of energy losses as indirect effects. Another positive impact on electricity losses is due to load shifting from peak to off-peak periods.
- **Impact: Low/medium (mainly indirect).**

c) Reduction of non-technical losses

Functionality: Real-time load measurement and visualization

- Real-time load measurement via smart meters allows DSOs to identify supplied electricity not correctly billed.
- **Impact: High (depending on the level of non-technical losses in the project area).**

d) Reduction of congestions

Functionalities: (DSO/TSO) Dynamic line rating; Power flow control; real-time load monitoring and visualization; voltage and reactive control; Automatic and/or remote customer electricity use optimization (for demand response)

> Thanks to better grid management and optimization of power flows, these functionalities allow to free grid capacity and reduce congestions, allowing a better dispatching of the power plants.
>> **Impact: Medium/High**

Functionalities: Automatic and/or remote customer electricity use optimization (for demand response); Smart EV charging

> Thanks to optimization on the demand side, these functionalities could allow to reduce congestions thanks to demand side management.
> **Impact: Medium. The effect might also be higher and concentrated at local level, on specific portion of the distribution grid. This depends on local conditions and on grid configuration.**

e) Reduction of peak load

Functionalities: Real-time load measurement and visualization/ Automatic and/or remote customer electricity use optimization; Smart charging of EVs;

> These functionalities act on the demand side to reduce energy consumption and/or to shift load from peak to off-peak periods. A reduction of peak load has positive effect in terms of economic efficiency of the electricity system (e.g. reduced use of expensive peaking units).
>> **Impact: High**

Functionality: Optimization of DER output and operation

> Output of distributed generation/storage to partly match/be synchronized with local consumption, thus reducing the peak load at the interface DSO/TSO (in the primary substation).
> **Impact: Depends on penetration of Distributed generation and local characteristic of the grid. Low impact at present.**

2 CRITERIA FOR ELIGIBILITY OF INVESTMENTS

In this chapter, we present the criteria for the eligibility of Smart Grid investments (this corresponds to task 3 of the assignment). We stress that the proposed criteria are intended for ex-ante evaluation, on the ground of estimations to be carried out before project implementation.

The basic criteria for eligibility are the following:

1. Assessment of Smart technical characteristics – Is the proposed investment a Smart Grid project?

2. KPI-based assessment of project impact– Does the project deliver positive impacts in line with energy policy goals?

3. Cost-effectiveness (comparison of KPI scores with project cost) – Does the project deliver positive impacts in a cost-effective way?

In addition to these three basic criteria, major projects (in line with article 100 of EU regulation no 1303/2013) need also to demonstrate their economic viability (positive societal CBA):

1. Economic viability (economic CBA) – Does the project deliver net positive monetary benefits for society?

In the following sections we analyse in detail the proposed eligibility criteria.

2.1 Assessment of Smart technical characteristics

The EC Smart Grid Task Force[7] has proposed a classification of power system investments in three levels of grid features:

> Basic functions
> Supplementary functions
> Emerging (smart) functions

The purpose of the assessment proposed in this section is to define more precisely the minimum functionalities required for an investment to fall in the third category.

Building on the mapping of Smart Grid assets and functionalities presented in chapter 1, minimum technical requirements are defined in order to ensure that Smart Grid assets are actually combined together to provide a smart functionality.

The idea is that the implementation of individual Smart assets (e.g. equipment health sensor) is not sufficient if it is not integrated in a Smart functionality (e.g. predictive maintenance). Moreover, it is also necessary to ensure that Smart assets and smart functionalities in the project cannot be considered as “conventional solutions” in the country or region where the projects should take place.

Accordingly, the assessment of the technical eligibility criterion is thus carried out in three steps:

> Ensure that all assets included in the project are “Smart”, according to the definition of Smart Assets and of the list provided in section 1.1.

> Ensure that Smart assets in the project are combined together to deliver Smart functionalities. The mapping smart assets-smart functionalities presented in section 1.2 is proposed to guide this assessment. Interoperability of smart assets shall be guaranteed. Open communication standards shall be adopted to ensure future scalability of the deployed functionalities.

> Ensure that Smart assets and functionalities in the project are not already conventionally deployed in the project area. A term of reference is the existing regulatory asset base of TSOs/DSOs of the country under consideration, which provides a concrete indication of the baseline functionalities of standard power system investments. This assessment is country dependent. The goal of this requirement is also to identify Smart Grid investments which are not already included in regulatory cost-recovery mechanisms and thus might need European funds to be implemented.

The different steps for the assessment of the technical eligibility criterion are summarized in figure 6.

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[7] Source: see [4]

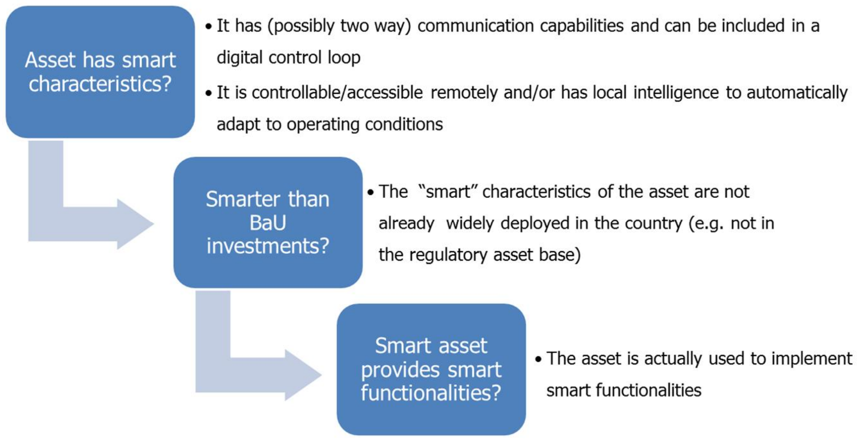

Figure 6– Steps for the assessment of the technical eligibility criterion

2.2 KPI-based assessment of project impacts in line with energy policy criteria

A second criterion for a Smart Grid project to be eligible for funding is that it should deliver the positive impacts that public authorities seek when supporting Smart Grid investments.

To carry out this assessment, we use the set of technical key performance indicators (KPIs) defined in chapter 1. The KPIs are designed to assess the impact of the project according to key European energy policy goals: sustainability, integration of distributed energy resources, security and quality of supply, energy efficiency. For each KPI, guidelines and formulas for their calculation are provided in chapter 4.

As mentioned, the proposed KPIs take into account the work done by the EC Smart Grid Task Force[8] and by the GRID+ consortium in the context of the SET Plan European Electricity Grid Initiative (EEGI)[9].

Global approach

Each KPI reflects the impact of a Smart Grids project on a Power System's indicator. It is a relative value that is calculated based on the value of the considered indicator in a Business As Usual situation (cf. formula below):

$$KPI\ (\%) = \frac{V[SG] - V[BAU]}{V[BAU]} * 100\%$$

[8] Source: see [1] and [5]

[9] Source: see [2]

Where:

$V[SG]$ is the value of the indicator once the project has been deployed

$V[BAU]$ is the value of the indicator in a Business As Usual situation

The Business As Usual considered here is the "do minimum" situation. This scenario takes inot account only the power system investments necessary to keep current power system performances (SAIDI, SAIFI, ENS, voltage quality performance, hosting capacities, RE share…) The BaU scenario should take into account consumption and peak load growth as they are forecasted by the public authorities of the region.

The impact of the project can be assessed qualitatively as proposed in table 6, by comparing KPI values to predefined impact threshold values and translting KPI values in qualitative scores (1=limited impact; 2=moderate impact; 3 high impact).. Threshold values of the KPIs draw on available results from Smart Grids pilot projects and on information about the local context of the project implementation. More details will be provided in the second report when discussing case studies for Poland and Romania (tasks 11 and 12 of the assignment).

Several publicly available reports synthesize such return on experiences from Smart Grids projects. The most notable ones include:

> "*Smart Grid projects in Europe: Lessons learned and current developments – 2012 update*" from the European Commission Joint Research Centre[10]
> "*Smart Energy made in Germany - Interim results of the E-Energy pilot projects towards the Internet of Energy*" published by B.A.U.M. Consult GmbH in February 2012[11]
> *"Smart Grid Investment Grant Progress Report II"* released by the U.S. Department of Energy in October 2013[12]

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[10] Source: http://ses.jrc.ec.europa.eu/sites/ses.jrc.ec.europa.eu/files/documents/ld-na-25815-en-n_final_online_version_april_15_smart_grid_projects_in_europe_-_lessons_learned_and_current_developments_-2012_update.pdf

[11] Source : http://www.e-energy.de/documents/E-Energy_Interim_results_Feb_2012.pdf

[12] Source: http://lists.nrel.gov/t/96865/225989/32040/0/

KPI value	Qualitative impact assessment	Description	Score (KPI)
KPI>a	High positive impact	Significant positive impact assessed with sufficient level of confidence	3
b<KPI<a	Moderate positive impact	Positive impact assessed with sufficient level of confidence	2
KPI<b	Low impact	Only limited impact assessed with sufficient level of confidence	1
0	No Impact	No impact or impact could not be assessed with sufficient level of confidence	0

Table 6: Possible outcomes of qualitative impact assessment based on KPIs and threshold values

The evaluation of the KPI score requires combining the values of the different KPIs (assessed in the previous eligibility criterion) into a single global indicator. This assessment requires defining weights for the different KPIs and is typically subjective in nature. A simple and transparent option is to carry out a weighted average of the KPI scores as reported below:

$$Score = \frac{\sum_{kpi} score(kpi) * weight(kpi)}{Max\ theoretical\ score}$$

We stress that this assessment should be the responsibility of national authorities on the ground of political priorities. The project assessment tool proposed in chapter 4 has a specific module to guide the KPI assessment.

Finally, in assessing the impact of Smart Grid investments, it should be noted that:

- A Smart Grid investment could have contradictory scores on different KPIs. For example, a higher penetration of DERs might result in an increase in the level of technical losses.
- The improvement of a certain KPI might be outside the control of the project promoter. For example, an improvement of the KPI "Share of electricity generated from renewable sources" might also depend on investments by external actors (e.g. generation companies investing in renewable energy sources).

> Translating KPI values in the qualitative impacts (high, moderate, low) should be done at national level depending on local contexts and on the level of reliability of the information provided by project promoters to support the KPI calculation.

2.3 Cost-effectiveness

This criterion intends to assess the cost-effectiveness of the project in delivering the positive impacts assessed under the previous eligibility criterion with the KPI approach.

The cost-effectiveness of the project can be expressed as the ratio between the KPI score and the cost of the project considering the number of grid users affected by the project (in order to keep into account the project size):

$$Cost\ effectiveness = \frac{\text{KPI score}}{Total\ Project\ Cost} * number\ of\ project\ users$$

The total cost of the project cost can be evaluated according to the methodology for assessing the costs of Smart Grid investments presented in chapter 3. The tool proposed in chapter 4 has a specific module to guide the project cost evaluation.

The cost-effectiveness of a project shall be assessed against a predefined threshold or in comparison with other competing projects (projects which are relatively more cost-effective are eligible). We stress that assessing the KPI score and the cost-effectiveness of a project should be done at national level depending on local contexts and political priorities.

The tool proposed in chapter 4 has a specific module to guide the cost-effectiveness assessment.

2.4 Assessment of net societal benefits – economic CBA

For major projects (, a fourth criterion of eligibility is its economic viability, i.e. the project should provide a net economic benefit for society. This criterion is assessed via an economic CBA (see chapter 4). Moreover the project promoter should detail concrete and measurable actions to mitigate possible risks that emerged in the sensitivity analysis.

The proposed economic indicators that need to be calculated under this criterion include:

> Annualised NPV net benefit of the project for the whole power system
> Internal rate of return
> Individual benefits Cumulative investment by asset/functionality category
> Estimation of expected impacts of net benefits on tariffs

The tool proposed in chapter 4 has a specific module to guide the full CBA assessment.

3 TYPICAL COSTS BY TYPES OF ELEMENTS IN SMART GRIDS PROJECTS

This chapter aims at providing a methodology for identifying and estimating the total cost of Smart Grids investment projects (this corresponds to task 5 of the assignment).

First of all, a methodology to identify Smart Grid investment costs (and separate them from baseline costs) has been defined, based on the minimum technical requirements presented in chapter 1. .

A standard economic model (in excel) has then been developed to characterize and compute the costs associated to eligible Smart Grid assets. The model includes standard cost evaluation components (CAPEX, OPEX, lifetime…) and technical metrics for estimating the penetration of Smart Grids assets (e.g. in terms of the number of grid users, substations, transformers, line kilometers etc. equipped with smart functionalities).

3.1 Methodology to separate baseline costs from Smart Grids implementation costs

Two different rules to separate baseline costs from smart grids implementation costs are applied. Their application depends on the project promoter position. If the promoter is a regulated player, regulated asset base should be defined. If the promoter is a deregulated player no asset base is considered.

3.1.1 Baseline costs to guarantee the current performances of the system over time

Before identifying Smart Grid implementation costs it is necessary to frame a baseline situation of the power system. As it is described in chapter 2, the Business as Usual (BAU) situation includes only traditional investments which are necessary to keep the initial performances of the system over the project period (“do minimum” investment scenario).

3.1.2 Methodology for a regulated player

Regulated players' assets base is already financed through regulated tariff. Therefore, as described in chapter 3, if some assets in the regulatory asset base have already smart functionalities, this should be taken into account in the further evaluation of the project's assets to avoid any double payment. Project's assets should then be considered as smart grid asset only if they offer additional functionalities compared to the smart assets in the regulatory asset base.

Figure 7 reports an example of assets cost evaluation. Smart assets in the regulatory asset base and their associated smart functionalities are reported in orange. The assets and associated functionalities of a submitted smart grid project are represented in green.

		Smart Funct 1	**Smart Funct 2**	**Smart Funct 3**
KO	**Smart Asset 1**	**X**		
	Smart Asset 2		**X**	**X**
OK	**Smart Asset 3**	**X**		**X**

Figure 7: Example of identification of Smart Grid costs vs baseline costs

In the example, Smart Asset 1 is part of the Smart Grid project but does not bring any additional smart functionality to the power system. Therefore, under the proposed framework, it should not be eligible to be included in the Smart Grid project. On the other hand Smart asset 3 enables additional smart functionalities compared to the comparable asset already included in the regulatory asset base. The cost of Smart asset 3 can then be included in the costs of the Smart Grid project.

3.1.3 Methodology for a deregulated player

For a deregulated player, it is proposed that only the minimum functional requirements set up in chapter 2 are considered to evaluate whether an asset is eligible to be considered as smart and therefore included in the Smart Grid project cost.

3.2 Standard economic model for estimating the costs related to Smart Grids assets

Cost calculations consider incremental values between the Smart Grid and the BaU scenarios. Two main categories of costs are considered:

> The cost associated to smart assets in the Smart Grid scenario (e.g. cost of smart meters)

> The traditional investments that can be deferred or avoided in the Smart Grid scenario compared to the traditional scenario (e.g. avoided cost for the replacement of traditional meters)

Table 7 explains which investment costs are quantitatively estimated in the project assessment tool.

Investments	$\mathbf{Y_1}$	$\mathbf{Y_2}$	**...**	$\mathbf{Y_N}$
BAU	I_1	I_2	...	I_N
Smart Grid project	SG_1	SG_2	...	SG_N
	I'_1	I'_2	...	I'_N
Costs of Smart Grid Project	$\mathbf{SG_1}$	$\mathbf{SG_2}$	**...**	$\mathbf{SG_N}$
Deferred/avoided Investments for the System in the Smart Grid scenario	$\mathbf{I_1\text{-}I'_1}$	$\mathbf{I_2\text{-}I'_2}$		$\mathbf{I_N\text{-}I'_N}$

Table 7: Example of identification of Smart Grid costs vs baseline costs

Where:

> $\mathbf{I_k}$ is the traditional investment (e.g. grid reinforcement) made at year k in the BAU situation

> $\mathbf{SG_k}$ is the Smart Grid assets investment made at year k when the Smart Grid project is implemented

> $\mathbf{I'_k}$ is the traditional investment made at year k when the Smart Grid project is implemented

The last two lines of table 7 show which investment costs need to be actually quantified in the project assessment tool.

3.2.1 Technical penetration metrics for Smart Grid assets

A number of technical parameters have also been defined to capture the level of penetration of smart assets and functionalities associated to a Smart Grid project (see table 8) and to help quantifying KPI. They are necessary to quantify the KPIs in chapter 4 and are a necessary input for the project assessment tool presented in chapter 4. They are grouped into the same categories as the smart functionalities identified in chapter 1.

Power System's level	Parameters
Transmission	Share of transmission lines operating under dynamic line rating
Distribution	Share of feeders/substations equipped with smart protection assets
	Share of feeders/substation equipped with smart monitoring assets
	Share of feeders/substations equipped with smart flow control assets
Distributed Energy Resources & Consumer	Share of decentralized generation with two ways communication from the total DG installed capacity
	Share of charging capacity of vehicles that can be controlled
	Share of energy demand served by smart meters
	Share of load with dynamic tariffs
	Share of available flexible demand consumption out of the total power demand

Table 8: Technical parameters defining the penetration levels of smart assets and functionalities

3.2.2 Standard economic model for estimating the costs related to Smart Grids assets

The quantification of the total cost of the project is carried out in three steps:

> Assessment of unit cost per smart asset,

> Assessment of the total cost per smart asset over the project period

> Assessment of the total project's cost.

First, the project promoter needs to provide, for each smart asset, values for the different asset cost elements that are listed below:

> Asset lifetime in years

> $CAPEX[€/unit]$: CAPEX per asset unit (not annualised)

> $OPEX$[€/y/unit]: OPEX per asset unit and per year after its deployment

> $Install\ Cost[€/unit]$: Installation Cost per unit

> $Decom\ Cost[€/unit]$: Decomissioning Cost per asset unit

Three additional types of costs are included:

> **Personnel costs** over the deployment period: they should be filled as OPEX

> **Pre project studies costs**: All preliminary analysis should be considered as a unique CAPEX in year 1.

> **Post project studies costs**: Results analysis and results dissemination should be considered as a unique CAPEX in the final year of the assessment period.

Then a first model has been developed to estimate the total cost per smart asset over the project period. The detailed formula is written below:

$$C_{asset,k} = (a^* + OPEX) * CQ_k + abs(CQ_k - CQ_{k-1}) * (Install\ Cost\ \mathbf{or}\ Decom\ Cost)$$

Where:

$C_{asset,k}$[€]: Total cost for given asset at a year k taking into account all the units installed, already in activity and decommissioned

a^*: Constant or fixed annuity for each asset investment. For each asset unit, a stream of yearly unchanging payments for the asset's lifetime is considered here. It takes into account the CAPEX per asset unit, the discount rate and asset lifetime.

$CQ_k[unit]$: Cumulated Quantity deployed at year k

The last term of the formula should be read as follows:

If $CQ_k - CQ_{k-1} > 0$ (ie number of assets deployed increases) then the formula is: $(CQ_k - CQ_{k-1}) * Install\ Cost$

If $CQ_k - CQ_{k-1} < 0$ (ie number of assets deployed decreases) then the formula is: $(CQ_{k-1} - CQ_k) * Decom\ Cost$

This formula should be applied for each asset and for each year. It is used then in the projects assessment tool to estimate the global cost of a smart grid project.

Since the methodology used to estimate total project's cost over its deployment period is the same as for the gross benefit calculation, the methodology is presented together with the global economic model of the assessment tool in chapter 4.

Finally, we not that in the project assessment tool, the calculation of the residual value of project assets is performed by considering the remaining annuities occurring after the last year of the project reference period.

Other approaches for the calculation of the residual value, when duly justified, could be considered by national authorities[13].

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[13]For example the "Commission draft Delegated Act" (still a draft at the time of submission of this report) includes guidance on the residual value (see p. 16 Art. 18) and suggests the calculation of the residual value as the net present cash flows after the project reference (using the socio-economic benefit in the last year of the project as a proxy) http://ec.europa.eu/regional_policy/what/future/pdf/preparation/fiche_29_draft_delegated_act_2014_02_04.pdf

4 PROJECT ASSESSMENT

This chapter describes in detail the formulas to evaluate the impact of Smart Grid investments. This corresponds to task 6 of the assignment.

First of all, we describe the approaches to evaluate the KPIs defined in chapter 1 and that are used for the assessment of the cost-effectiveness of the project. This analysis is intended for both small and large scale projects.

Secondly, we describe how to build on the evaluation of the KPIs to actually monetize the benefits that need to be included in the full CBA of the project. Additionally, guidelines to carry out a full CBA are provided. Such a CBA is needed only for major projects.

Finally we describe the project assessment tool (annex C1) that has been developed in the course of this assignment and that is intended to guide the assessment of Smart Grid investments, according to the eligibility criteria presented in chapter 2.

The project assessment tool can be used to assess both small and large scale projects. The user’s manual of the tool is reported separately as an appendix to this report (annex B1).

4.1 KPIs calculation methodology

4.1.1 Calculation methodology for indicators related to the KPIs

As describe in task 3, the generic formula for KPIs calculation is the following:

$$KPI\ (\%) = \frac{V[SG] - V[BAU]}{V[BAU]} * 100\%$$

Where:

$V[SG]$ is the value of the indicator once the project has been deployed

$V[BAU]$ is the value of the indicator in a Business As Usual situation

Table 9 describes in detail the methodology and formula to estimate the delta: $V[SG] - V[BAU]$ of all the proposed KPIs.

Category	KPI	Parameters to be considered for the calculation of *V[SG]-V[BAU]*	Metrics	Methodology / sources to be used
Sustainability	Reduced greenhouse gas emissions	• **Increased share of renewable in the energy mix** • **Energy savings** • **Reduced peak demand (considering only the part that is shifted)** • **Reduced technical losses.** $\boldsymbol{GHG_{peak}}$:GHG emissions by peak power plants [kg/MWh] $\Delta \boldsymbol{GHG_{peak/off\ peak}}$ = GHG emissions by peak power plants [kg/MWh]-GHG emissions by semi basic power plants [kg/MWh] $\boldsymbol{GHG_{average}}$: average GHG emissions [kg/MWh]	kg	$\Delta GHG_{\frac{peak}{off}peak}$ $* Reduced\ Peak\ Energy\ Demand$ $+\ Increased\ \ energy\ generated$ $from\ RE\ \ * GHG_{peak}\ \ [kg/MWh]$ $+ Reduced\ Energy\ demand$ $* GHG_{average}$
	Reduced SOx, NOx emission	Cf. above $\boldsymbol{SOx/NOx_{peak}}$:SOx/NOx emissions by peak power plants [kg/MWh] $\Delta \mathbf{SOx/NOx_{peak/off\ peak}}$ = SOx/NOx emissions by peak power plants [kg/MWh]-SOx/NOx emissions by semi basic power plants [kg/MWh] $\mathbf{SOx/NOx_{\ average}}$: average SOx/NOx emissions [kg/MWh]	kg	$\Delta \frac{SOx}{NOx}{}_{\frac{peak}{off}peak}$ $* Shifted\ Peak\ Energy\ Demand$ $+\ \ Increased\ \ energy\ generated$ $from\ RE$ $* SOx/NOx_{\ peak}\ \ \ [kg/MWh]$ $+ Reduced\ Energy\ demand\ [MWh$ $* \mathrm{SOx/NOx}_{\ average}$
Integration of DER	Increased hosting capacity for distributed generation	• **Active, reactive power flow and voltage observability and control**: o Share of feeders and substations equipped with monitoring assets o Share of feeders and substations equipped with smart flow control assets (D-FACTS, voltage regulators…) • **DERs injection flexibility of active and reactive power** o Share of DG equipped with two ways communications o Share of operational flexibility provided by DG (active and reactive power) o Share of stored energy in vehicles that can be controlled (Vehicle to Grid) • **Adaptive protection**	MW	[hosting capacity of DG]SG - [hosting capacity of DG][BAU]

		o Share of DG equipped with adaptive protection relays • **Consumption use optimisation**: o Share of available flexible demand out of total power demand		
	Increased hosting capacity for Electric Vehicles and other new loads	• **Smart Charging of EV and Vehicle To Grid** o Share of charging capacity of EV that can be controlled • **Active, reactive power flow and voltage observability and control**: o Share of feeders and substations equipped with monitoring assets o Share of feeders and substations equipped with smart flow control assets (D-FACTS, voltage regulators…) • **DERs flexibility in terms of active and reactive power injection** o Share of DG equipped with two ways communications o Share of operational flexibility provided by DG • **Consumption use optimisation**: o Share of available flexible demand out of total power demand	MWh	[hosting capacity of EV]SG - [hosting capacity of EV][BAU]
	Increased number of hours of generation provided by DG (including storage)	• **Active, reactive power flow and voltage observability and control**: o Share of feeders and substations equipped with monitoring assets o Share of feeders and substations equipped with smart flow control assets (D-FACTS, voltage regulators…) • **DERs flexibility in terms of active and reactive power injection** o Share of DG equipped with two ways communications o Share of operational flexibility provided by DG • **Adaptive protection** o Share of DG equipped with adaptive protection relays • **Storage optimization**: o Share of energy storage out of the daily electrical demand • **Consumption use optimisation**: o Share of available flexible demand out of the total power demand	MWh	[Number of hours of generation provided by DG]SG- [Number of hours of generation provided by DG][BAU]
	Increased energy share generated from renewable sources	Cf. Increased number of hours of generation provided by DG (including storage)	%	(1+increase hosting capacity for DG-RES)*hosting capacity for DG-RES[BAU]*load factor*hours of production*(1- current curtailment of RES* (1-reduced curtailment of RES))
	Reduced peak	• **DER & Consumers**: o Relative impact on a household/building consumption of a local EMS	MW	Peak Demand [MWh][BAU] *share of power equipped with local

Security and Quality of Supply	demand	o Share of total consumption that is consumed by households equipped with local EMS		EMS*reduced peak demand of a single household per Local EMS installed [%/unit]
	Reduced SAIDI	• **Automatic fault management and incipient faults identification:** o Share of feeders/Substation equipped with smart monitoring assets for remote observability and for incipient faults identification o Share of feeders/Substation equipped with smart protections assets, remote switches etc.	min/customer	[SAIDI]SG-[SAIDI][BAU]
	Reduced SAIFI	• **Incipient faults identification:** o Share of feeders/Substation equipped with smart monitoring assets for remote observability and for incipient faults identification o Share of feeders/Substation equipped with smart protections assets, remote switches etc.	1/customer	[SAIFI]SG-[SAIFI][BAU]
	Increased voltage quality performances	• **Voltage and reactive power control:** o Share of feeders/Substation equipped with smart monitoring assets of voltage level o Share of feeders/Substation equipped with voltage/capacitor regulators • **Automatic provision of grid ancillary services (voltage and reactive power control) by DER:** o Share of DG equipped with smart converters o Share of operational flexibility that can be provided by DG	Volt	[Vmax]SG-[Vmax][BAU]
	Extended asset life time	• **Automatic fault management, proactive maintenance and incipient faults identification:** o Share of feeders/Substation equipped with smart monitoring assets for remote observability and for incipient faults identification • Share of feeders/Substation equipped with smart protections assets, remote switches etc. **Adaptive protection** • Share of DG equipped with adaptive protection relays	years	[Average asset lifetime]SG-[Average asset lifetime][BAU]
	Reduced expected energy not supplied	• **Reduced peak demand** • **Dynamic line rating:** o Share of transmission lines operating under dynamic line ratings • **Increased installed capacity of DG** • **Reactive and Active power flow control** o Share of feeders/substations equipped with smart power flow control • **Consumption use optimization**	MWh	[ENS]SG-[ENS][BAU]

		o Share of available flexible demand from the daily peak load		
Energy Efficiency	Reduced technical losses in T&D	• **Active, reactive power flow and voltage observability and control**: o Share of feeders and substations equipped with smart flow control assets (D-FACTS, voltage/capacitor regulators…) • **DERs flexibility in terms of active and reactive power injection** o Share of operational flexibility that can be provided by DG o Share of DG equipped with smart converters, • **Consumption use optimisation**: o Reduced peak demand o Share of self-consumption from the total energy consumed	MWh	[Technical losses]SG-[Technical losses][BAU]
	Reduced non-technical losses in T&D	• **Active, reactive power flow and voltage observability and control**: o Share of feeders and substations equipped with monitoring assets • **Real-time load measurement and visualization:** o Share of energy demand served by smart meters	MWh	[Non-technical losses]SG-[Non-technical losses][BAU]
	Energy savings	• **DER & Consumers**: o Relative impact on a household/building consumption of a local EMS o Share of total consumption that is consumed by households equipped with local EMS	MWh	Total Consumption [MWh][BAU]*share of consumption equipped with local EMS*Energy savings of a single households per Local EMS installed [%/unit]
	Reduced congestions in the system's electrical lines	• **Dynamic line rating:** o Share of transmission lines operating under dynamic line ratings • **Active Power Flow control:** o Share of feeders/substations equipped with smart flow control • **DERs flexibility in terms of active and reactive power injection** o Share of DG equipped with two ways communications o Share of operational flexibility that can be provided by DG (for balancing and ancillary services) o Share of stored energy in vehicles that can be controlled (Vehicle to Grid) • **Consumption use optimisation**: o Share of available flexible demand from the total power consumed	MWh	[level of congestion]SG-[level of congestion][BAU]

Table 9: Quantification of the proposed Key performance indicators

4.2 KPI detailed descriptions

4.2.1 Reduced greenhouse gas emissions

Some smart functionalities can lead to a decreased amount of central generation that supplies the load (through reduced electricity consumption, reduced electricity losses, more optimal generation dispatch) and/or a reduced peak generation. These impacts can translate into a reduction in GHG emissions produced by fossil-based electricity generators. Reduced GHG emissions are thus a consequence of other KPIs that can be improved by a smart grid project:

- Increased share of renewable energy (RE) in the energy mix
- Energy savings
- Reduced peak demand
- Reduced technical losses.

The KPIs listed above are impacted mainly by smart functionalities that are described in the related paragraphs below.

More generally, increased share of generation with a lower CO_2 content is another parameter that can be a consequence of the consumption switch from a peak period to an off-peak period thanks to consumption use optimization.

The calculation of the KPI is done for the average annual amount of GHG emitted.

For an exact value, a technical and economic simulation should be run. Otherwise the simplified formula below can also be used based on other pilot projects results:

$$\Delta GHG_{\frac{peak}{off}peak} * Shifted\ Peak\ Energy\ Demand\ [MWh] + Increased\ \ energy\ generated\ from\ RE\ * GHG_{peak}\ [kg/MWh] + Reduced\ Energy\ demand\ [MWh] * GHG_{average}$$

Where:

$$\boldsymbol{Reduced\ Peak\ Energy\ Demand\ [MWh]} = Peak\ Energy\ Generated\ [MWh] * (1-(1-rpd[\%]) * \frac{(1+TL[\%]*(1-rtl[\%]))}{1+TL[\%]})$$

NB: We consider here only the part o the peak demand that is shifted

$\boldsymbol{TL}[\%]$: Current Technical Losses (initial year of the assessment reference period)

$\boldsymbol{rpd}[\%]$: Reduced Peak Demand (see section 4.1)

$\boldsymbol{rtl}[\%]$: Reduced Technical Losses (see section 4.1)

$\boldsymbol{Peak\ Energy\ Generated}\ [MWh]$: Current Energy generated by marginal peak units

$$\textbf{\textit{Increased energy share generated from RE}}[MWh] = \textit{Peak Energy Demand}\ [MWh] * (1 + TL[\%] - (1 - ISRE_{peak}[\%]) * (1 + TL[\%] * (1 - rtl[\%])))$$

$ISRE_{peak}[\%]$: Increased energy share generated from renewable sources that can be guaranteed at peak period

$$\textbf{\textit{Reduced Energy demand}}\ [MWh] = \textit{Total Energy Demand}\ [MWh] * (1 + TL[\%] - (1 - es[\%]) * (1 + TL[\%] * (1 - rtl[\%])))$$

$es[\%]$: Energy Savings

$GHG_{average}$: average GHG emissions [kg/MWh]

GHG_{peak} :GHG emissions by peak power plants [kg/MWh]

$$\Delta GHG_{peak/off\ peak} = \textit{GHG emissions by peak power plants}\ \left[\frac{kg}{MWh}\right] - \textit{GHG emissions by base/by semi base power plants}\ [kg/MWh]$$

4.2.2 Reduced SOx, NOx emission

The amount of SOx, NOx can be reduced due to same factors listed for the KPI: Reduced GHG emissions. The average annual amount of SOx, NOx emitted is considered for the calculation of the KPI. For an exact value, a technical and economic simulation should be run. Otherwise the simplified formula below can also be used based on other pilot projects results:

$$\Delta \mathrm{SOx/NOx}_{\mathrm{peak/off\ peak}} * \textbf{\textit{Reduced Peak Energy Demand}}\ [MWh] + \textbf{\textit{Increased energy generated from RE}} * SOx/NOx_{peak}\ [kg/MWh] + \textbf{\textit{Reduced Energy demand}}\ [MWh] * \mathrm{SOx/NOx}_{\mathrm{average}}$$

Where:

SOx/NOx_{peak}: $\textit{SOx/NOx emissions by peak power plants}\ [kg/MWh]$

$\Delta SOx/NOx_{peak/off\ peak} = \textit{SOx/NOx emissions by peak power plants}\ [kg/MWh] - \textit{SOx/NOx emissions by semi basic power plants}\ [kg/MWh]$

$SOx/NOx_{average}$: $\textit{Average SOx/NOx emissions}\ [kg/MWh]$

4.2.3 Increased hosting capacity for distributed generation

The hosting capacity of a network is the maximum generation capacity it can manage, when all the units are supplying at nominal power, without causing unacceptable damages (voltage, current violation…).

To increase the hosting capacity of DG on the distribution grid various smart functionalities can have an impact. These functionalities are reported below

To quantify the increased hosting capacity for distributed generation, the previous functionalities can be considered through the following quantitative parameters:

> Active, reactive power flow and voltage observability and control:

Share of feeders and substations equipped with monitoring assets

Share of feeders and substations equipped with smart flow control assets (D-FACTS, voltage regulators…)

> DERs flexibility in terms of active and reactive power injection

Share of DG equipped with smart converters (for interface DG-grid)

> Share of operational flexibility provided by DG (active and reactive power control; Adaptive protection)

Share of DG equipped with adaptive protection relays

> Consumption use optimisation:

Share of available flexible demand out of total power demand

The potential for increasing hosting capacity depends also on the initial configuration of the distribution grid: density of consumption, network topology etc.

To have an exact value for this hosting capacity, a load flow should be run. The following steps can be implemented as suggested in the GRID+ report reported in appendix A:

1/On the highest voltage node, install a generator with no generated active power and a 0.9 inductive power factor. 2/Increase the generator power until the voltage, in any node, reaches its maximum admissible value, or the current in any branch reaches its maximum admissible value. 3/The corresponding power is the hosting capacity.

Relevant pilot projects results could be used as an alternative to network simulations.

4.2.4 Increased hosting capacity for Electric Vehicles and other new loads

The KPI "Increased hosting capacity of electric vehicles" largely depends on the same smart functionalities as the increased hosting capacity of DG. Smart Charging of Electric Vehicles (EV) and Vehicle-To-Grid functionalities should be also considered.

For quantification, the following functionalities and associated parameters can be taken into account:

> Active, reactive power flow and voltage observability and control:

Share of feeders and substations equipped with monitoring assets

Share of feeders and substations equipped with smart flow control assets (D-FACTS, voltage regulators…)

> DERs flexibility in terms of active and reactive power injection

Share of DG equipped with smart converters (for interface DG-grid)

> Share of operational flexibility that could be provided by DG (active and reactive power control)Smart Charging of EV and Vehicle To Grid

Share of charging capacity of EV that can be controlled

> Consumption use optimisation:

Share of available flexible demand out of total power demand

The potential for increasing the hosting capacity of EV depends also on the initial configuration of the distribution network: density of consumption, network topology etc.

To have an exact value of the hosting capacity, a load flow should be run (cf detailed methodology in section 4.1).

4.2.5 Increased number of hours of generation provided by DG (including storage)

The KPI "Increased number of hours of generation provided by DG" largely depends on the same smart functionalities as the increased hosting capacity of DG.

For quantification, the following functionalities and associated parameters can be taken into account::

> Active, reactive power flow and voltage observability and control:

Share of feeders and substations equipped with monitoring assets

Share of feeders and substations equipped with smart flow control assets (D-FACTS, voltage regulators…)

> DERs flexibility in terms of active and reactive power injection

Share of DG equipped with smart converters (for interface DG-grid)

Share of operational flexibility that could be provided by DG (active and reactive power control)

> Adaptive protection

Share of DG equipped with adaptive protection relays

> Storage optimization:

Share of energy storage out of the daily electrical demand

> Consumption use optimisation:

Share of available flexible demand out of total power demand

To have an exact value for this indicator, an economic and technical dispatch simulation should be run. Otherwise, field tests results from other pilot projects can be used.

4.2.6 Increased energy share generated from renewable sources

This KPI assesses the increased share of RE in the energy mix thanks to (i) higher number of generation hours by RE-based DGs (e.g. PV) and (ii) reduced RE curtailment, for example thanks to reduce congestions.

For an exact value, an economic and technical dispatch simulation should be run. Otherwise the simplified formula below can also be used based on other pilot projects results:

$$(1 + increase\ hosting\ capacity\ for\ DG - RES) * current\ hosting\ capacity\ for\ DG - RES * present\ load\ factor * hours\ of\ production * (1 - present\ curtailment\ of\ RES * (1 - reduced\ curtailment\ of\ RES))$$

4.2.7 Reduced peak demand

Peak demand can be significantly reduced thanks to remote observability and optimized management of electrical consumption enabled by local EMS and VPP platforms. Reducing peak load is a major challenge since peak load periods can bring strong constraints to the system at generation (peak capacity is more expensive than other generating assets and increases CO2 emissions) and distribution level (higher network capacity required, higher level of electrical losses…).

As for the KPI Energy Savings, reduced peak demand can be estimated thanks to local Energy Management System (EMS) deployment in households that can help reducing the general consumption by moving it from peak period to off-peak period. The same quantitative parameters can be used.

The simplified formula below can also be used based on other pilot projects results:

$$\begin{aligned}&Current\ Peak\ demand\ [MW] *\\&share\ of\ consumption\ equipped\ with\ local\ EMS *\\&Reduced\ peak\ demand\ per\ Local\ EMS\ installed\ [\%/unit]\end{aligned}$$

4.2.8 Reduced SAIDI

SAIDI is the average duration of energy supply interruption per customer. To reduce this indicator, duration of defaults identification and isolation should be reduced in order to minimize the area impacted. Duration of reconfiguration after default also impacts interruption time. Automatic faults management and incipient faults identification can significantly reduce the value of these parameters. Boundary parameters like current fault occurrence probability, classification of the difference fault occurrence type, current duration of actions needed to repair can be used to quantify this KPI. (Parameters like the share of feeders/Substation equipped with smart protections assets).

To quantify reduced SAIDI, the previous functionalities can be considered through the following penetration metrics:

> Automatic fault management and incipient faults identification:

Share of feeders/Substation equipped with smart monitoring assets

Share of feeders/Substation equipped with smart protections assets

The assessment should be based on simulation analysis or on results of comparable pilot projects.

4.2.9 Reduced SAIFI

SAIFI reflects interruptions frequency per customer. The same boundary parameters as for SAIDI should be considered here. The main smart functionality to be taken into account here is the incipient faults identification.

To quantify reduced SAIFI, the previous functionalities can be considered through the following quantitative parameters:

> Incipient faults identification:

Share of feeders/Substation equipped with smart monitoring assets

Share of feeders/Substation equipped with smart protections assets used for incipient faults identification

To have an exact value for this indicator, a dynamic network simulation should be run.

4.2.10 Increased voltage quality performances

This KPI is evaluated here through estimation of the number of maximum line voltage violations reached during a given period on the distribution system (Vmax). The main smart functionalities to improve voltage quality performance are voltage and reactive power control on the distribution side and automatic provision of grid ancillary services (voltage frequency and reactive power control) on the DER side.

To quantify increased voltage quality performances, the previous functionalities can be considered through the following quantitative parameters:

> Voltage and reactive power control:

Share of feeders/Substation equipped with smart monitoring assets

Share of feeders/Substation equipped with voltage/capacitor regulators

> Automatic provision of grid ancillary services (voltage frequency and reactive power control) by DER:

Share of DG equipped with smart converters (for interface DG-grid)

The assessment should be based on simulation analysis or on results of comparable pilot projects. Alternative methodologies can be suggested by the project promoter (e.g. number of customer complaints could be another relevant indicator).

4.2.11 Extended asset life time

Mechanical stress on equipment can be reduced (and therefore their life time can be extended) by functionalities like automatic fault management, proactive maintenance of equipment and identification of incipient faults on the distribution side as well as adaptive protection on the DER side.

To quantify extended asset lifetimes, the previous functionalities can be considered through the following quantitative parameters:

> Automatic fault management, proactive maintenance and incipient faults identification:

Share of feeders/Substation equipped with smart monitoring assets

Share of feeders/Substation equipped with smart protections assets

> Adaptive protection

Share of DG equipped with adaptive protection relays

Empirical observations and other projects results can also be used.

4.2.12 Reduced expected energy not supplied

The Energy Not Supplied (ENS) is the consequence of transmission grid and generation defaults and congestions that prevent generated load to be supplied to customers. This indicator is generally calculated over a year. Reduced ENS can be estimated from other KPIs:

> Reduced congestions

> Reduced peak demand

> Increased installed capacity of DG

> Increased hours of DG injection

Main smart functionalities contributing to reduce ENS are the consumption use optimization providing flexible demand, dynamic line rating, and smart functionalities supporting hosting capacity of DGs, so that load can be met by local generation. .

Parameters for estimation are the followings:

> Dynamic line rating

  Share of lines equipped with dynamic line rating functionality

  > Active, reactive power flow and voltage observability and control :

  Share of feeders and substations equipped with monitoring assets

  Share of feeders and substations equipped with smart flow control assets (D-FACTS, voltage regulators…)

  > DERs flexibility in terms of active and reactive power injection

  Share of DG equipped with smart converters (for interface DG-grid)

  Share of operational flexibility that could be provided by DG (active and reactive power control)

> Consumption use optimization

  Share of available flexible demand out of daily peak load

To have an exact value for this indicator, a network simulation should be run. Otherwise, pertinent pilot projects can be used.

4.2.13 Reduced technical losses on T&D

Technical losses depend mainly on technical characteristics of network equipment (resistance, impedance…) and on the amount of power flowing (there is a quadratic relation between power flowing and losses) through it. Some smart functionalities, that can be deployed on the distribution network, on DG and at consumption points, can significantly contribute to optimize this second aspect.

On the distribution side, level of active power flow control can optimise load repartition on the Network, reducing peak load locally and therefore technical losses. Voltage and Reactive Power Control contribute to reduce technical losses thanks to improved voltage and frequency stability.

From a DER perspective, automatic provision of grid ancillary services can reduce technical losses in particular through participation to voltage regulation.

From consumption perspective, the way load peak is managed on the feeder is a key, since technical losses increase with active power consumption. Additionally, increased self-consumption that reduces distance between generation and consumption delivery points could also be taken into account.

To quantify the reduced technical losses, the previous functionalities can be considered through the following quantitative parameters:

> Active, reactive power flow and voltage observability and control:

    Share of feeders and substations equipped with monitoring assets

    Share of feeders and substations equipped with smart flow control assets (D-FACTS, voltage/capacitor regulators…)

> DERs flexibility in terms of active and reactive power injection

    Share of operational flexibility provided by DG (for balancing and ancillary services)

    Share of DG equipped with controllable converters, on load-tap changers

> Consumption use optimisation:

    Reduced peak demand

    Share of self-consumption from the total energy consumed

To have an exact value for this indicator, a load flow simulation should be run. Otherwise test results from other pilot projects can be used for calculation.

4.2.14 Reduced non-technical losses in T&D

Thanks to smart metering deployment and smart monitoring asset deployed on the distribution network, non-technical losses can be reduced.

To quantify the reduced non-technical losses, the previous functionalities can be considered through the following quantitative parameters:

> Active, reactive power flow and voltage observability and control:

Share of feeders and substations equipped with monitoring assets

> Real-time load measurement and visualization:

Share of energy demand served by smart meters

Test results from other pilot projects can be used for calculation.

4.2.15 Energy savings

Energy savings can be mainly achieved with real-time load measurement and visualisation for consumers and automatic consumption use optimization. Both functionalities rely on the installation of a local Energy Management System at home/in the building.

To quantify energy savings, the previous functionalities can be considered through the following quantitative parameters:

> DER & Consumers:

Relative impact on a household/building annual consumption of a local EMS

Share of total consumption equipped with local EMS

The simplified formula below can also be used based on other pilot projects results:

$$Current\ total\ Consumption\ [MWh] * share\ of\ consumption\ equipped\ with\ local\ EMS * Energy\ savings\ per\ Local\ EMS\ installed\ [\%/unit]$$

4.2.16 Reduced congestions in the system's electrical lines

Congestions occurence in the system depends on electrical lines capacity, electrical demand at specific periods of the year/day and associated load repartition on the network. Smart functionalities like dynamic line rating, active power flow control, dispatch ability of DG and consumption use optimization are keys for reducing congestions in the system.

To quantify reduced congestions in the system's electrical lines, the previous functionalities can be considered through the following quantitative parameters:

> Dynamic line rating:

Share of transmission lines operating under dynamic line ratings

> Active Power Flow control:

Share of feeders/substations equipped with smart flow control

> DERs flexibility in terms of active and reactive power injection

Share of DG equipped with two ways communications

Share of operational flexibility provided by DG (for balancing and ancillary services)

For a more precise value, results from other pilot projects in similar context should be used. Otherwise, an economic and technical dispatch simulation can be run.

4.3 KPI Monetization

For major projects, a full costs-benefits analysis has to be performed. This section details the considered list of benefits to be monetized. These beneftis are based on the KPIs defined in the previous sections..

4.3.1 Benefits list

Based on work carried out by EC JRC and EPRI on CBA (cf. 01), the list of benefits reported in table 10 have been selected for this study. A detailed description of each benefit is provided in the next subsections.

Power System's level	Benefits
Generation	Deferred Generation Capacity Investments
	Reduced generation costs (including reduced curtailment of RE and reduced electricity losses)
	Reduced GHG emission costs
Transmission & Distribution	Deferred capacity investments
	Reduced congestions cost
	Reduced equipment failure
	Reduced restoration cost
	Reduced operation cost on the distribution grid

Power System's level	Benefits
Society	Reduced cost of outages
	Reduced non-technical losses

Table 10– List of benefits considered in the CBA for this study

4.3.2 Definition of benefits

The estimation of benefits is carried out by monetizing the relative variation of KPIs between the SG scenario and the BaU scenario :

In the following sections, we provide formulas for the quantification of benefits. Notations should be understood as described below:

- $\boldsymbol{X_k}$: Projected value of $\boldsymbol{X}$ at year $\boldsymbol{k}$ in a smart grid configuration should be used for calculation
- $\boldsymbol{X}$: Present value of $\boldsymbol{X}$ can be used for calculation
- $\boldsymbol{X_k[BAU]}$: Projected value of $\boldsymbol{X}$ at year $\boldsymbol{k}$ in a **BAU** configuration should be used for calculation
- $\boldsymbol{x}$: KPI value should be used for calculation

To avoid heavy notations, the difference "$[SG] - [BAU]$" may not always appear clearly in the suggested formulas below. Factorizations have been made and relevant KPIs are used to estimate this difference.

As for the project costs, deferred investments are calculated based on constant annuity methodology. For each asset unit, a stream of yearly unchanging payments for the asset's lifetime is considered here. It takes into account the CAPEX per asset unit, the discount rate and asset lifetime.

4.3.3 Generation

Deferred Generation Capacity Investments

The size of a generating units portfolio in a country depends mainly on the gross electrical peak demand (including losses). Therefore Reduced peak demand and reduced electrical losses are the two KPIs to take into account for estimating the deferred generation capacity investments due to a smart grid project. When peak demand is reduced, the first deferred investment is made on peak generation units that are also the most expensive unit. That is why we consider here only peak generation capacity cost.

A simplified formula can be:

$$DGCI_k = a^*{}_{generation} * PGCIC * Peak\ Demand_k[BAU] * \left(1 + TL - (1 - rpd) * \left(1 + TL * (1 - rtl)\right)\right) * (1 + reserve\ margin[\%])$$

Where:

$DGCI_k[€]$: Deferred Generation Capacity Investment at year k

$a^*{}_{generation}$: Constant annuity for generation capacity investments

$PGCIC[€/MW]$: Peak Generation Capacity Investment Cost per installed MW (not annualised)

$Peak\ Demand_k[BAU][MW]$: Projected Peak Demand at the year k in the BAU situation

$TL[\%]$: Current Technical Losses in 2013

$rpd[\%]$: Reduced Peak Demand (see 1.3.11 for an estimation)

$rtl[\%]$: Reduced Technical Losses (see 1.3.6 for an estimation)

$Reserve\ Margin[\%]$: Reserve margin that is taken in the country to size the generation portfolio

Reduced generation costs (including reduced curtailment of RE and technical losses)

Smart Grid can reduce generation costs by shifting demand from peak period (higher generation costs) to off peak period (lower generation costs). Reduced technical losses and Energy savings are also impacts that lead to global reduced energy generated. The last impact that should be taken into account is the increase of renewable share in the energy mix during peak period due to reduced curtailment of RE. This could avoid starting costly peak units.

$$RGC_k = \Delta WEC_{peak/offpeak} * Reduced\ Peak\ Energy\ Demand_k + Increased\ energy\ generated\ from\ renewables_k * WEC_{peak} + Reduced\ Energy\ demand_k * WEC_{average}$$

Where:

$RGC_k[€]$: Reduced Generation Costs at year k

$\Delta WEC_{peak/offpeak}[€/MWh]$: Difference between peak and off-peak wholesale electricity cost

$WEC_{peak}[€/MWh]$: Peak wholesale electricity cost

$WEC_{average}[€/MWh]$: Average wholesale electricity cost

$\boldsymbol{Reduced\ Peak\ Energy\ Demand}_{k}[MWh] =$
$Peak\ Energy\ Generated_k[BAU]\ [MWh] * (1 - (1 - rpd[\%]) * \frac{(1+TL[\%]*(1-rtl[\%]))}{1+TL[\%]})$

NB: We consider here only the part of the peak demand that is shifted

Peak Energy Generated $_k$[BAU][MWh] : Projected Energy generated by marginal peak units at year k in the BAU situation

Increased energy share generated from renewable sources$_k$[MWh] =
$Peak\ Energy\ Demand_k[BAU] * (1 + TL[\%] - (1 - isre_{peak}[\%]) * (1 + TL[\%] * (1 - rtl[\%])))$

isre$_{peak}$[%]: Increased energy share generated from renewable sources that can be guaranteed at peak period thanks to smart grid project deployment

Reduced Energy demand $_k$[MWh] = $Total\ Energy\ Demand_k\ [BAU] * (1 + TL[\%] - (1 - es[\%]) * (1 + TL[\%] * (1 - rtl[\%])))$

Total Energy Demand$_k$ [BAU][MWh]: Projected Energy Demand at year k in the BAU situation

es[%]: Energy Savings thanks to smart grid project deployment

Reduced GHG emission costs

Reduced GHG emissions costs are a direct consequence of the KPI reduced GHG emission (see section 4.1).

A simple formula is therefore:

$$RGHG_k = rghge * GHG\ emissions_k[BAU] * CO2\ cost\ [€/kg]$$

Where:

$RGHG_k$[€]: Reduced GHG emission costs

$rghge$[%]: Relative reduction of GHG emissions thanks to smart grid project implementation

$GHG\ emissions_k[BAU][kg\ CO2_{eq}]$: Total GHG emissions of the generation portfolio at the year k the benefit is calculated in the BAU situation. The value should be given in kg CO2 equivalent.

4.3.4 Transmission & Distribution

T&D - Deferred capacity investments

Transmission

Since the same rules as for the deferred generation capacity investments are followed to size the transmission system, the same smart grid impacts should be considered for calculation. In addition Smart Grid deployment can lead to an increase of installed capacity of DG (RES, non RES and storage) guaranteed during peak period. This would also contribute to decrease the total power flowing through transmission system to limit it to Distribution system.

Smart Grid can also increase transmission capacity thanks to smart functionalities like dynamic line rating. It would then allow higher amount of power to flow in the transmission lines.

A simplified formula would be:

$$\boldsymbol{DTCI_k} = a^*_{\boldsymbol{Transmission}} * \boldsymbol{TCIC} * \left(\boldsymbol{Peak\ Demand_k}[\boldsymbol{BAU}] * \left(\mathbf{1} + \boldsymbol{TL} - (\mathbf{1} - \boldsymbol{rpd}) * \left(\mathbf{1} + \boldsymbol{TL} * (\mathbf{1} - \boldsymbol{rtl})\right)\right) * (\mathbf{1} + \boldsymbol{reserve\ margin}[\%]) + \boldsymbol{igc_{DG/peak}} * \boldsymbol{GC_{DG/peak}} + \boldsymbol{itc} * \boldsymbol{TC_k}[\boldsymbol{BAU}]\right)$$

Where:

$\boldsymbol{DTCI_k}[€]$: Deferred Transmission Capacity Investment at year k

$a^*_{\boldsymbol{Transmission}}$: Constant annuity for Transmission capacity investments

$\boldsymbol{TCIC}[€/\boldsymbol{MW}]$: Transmission Capacity Investment Cost per MW (not annualised)

$\boldsymbol{igc_{DG/peak}}$: Increased DG installed capacity that is guaranteed when peak units are running (refer to 1.3.3 for estimation guidelines)

$\boldsymbol{GC_{DG/peak}}$: DG installed capacity that is guaranteed when peak units are running in 2013

$\boldsymbol{itc}[\%]$: Increased Transmission Capacity thanks to Smart assets

$\boldsymbol{TC_k}[\boldsymbol{BAU}][\boldsymbol{MW}]$: Transmission Capacity at year k in a BAU situation

Distribution

The simplified formulation for calculation is described below:

$$\boldsymbol{DDCI_k} = \boldsymbol{DCIC} * \left(\boldsymbol{Peak\ Demand_k}[\boldsymbol{BAU}] * \left(\mathbf{1} + \boldsymbol{TL} - (\mathbf{1} - \boldsymbol{rpd}) * \left(\mathbf{1} + \boldsymbol{TL} * (\mathbf{1} - \boldsymbol{rtl})\right)\right) * (\mathbf{1} + \boldsymbol{reserve\ margin}[\%]) + \boldsymbol{idc} * \boldsymbol{DC_k}[\boldsymbol{BAU}]\right)$$

Where:

$DDCI_k[€]$: Deferred Distribution Capacity Investment

$DCIC[€/MW]$: Distribution Capacity Investment Cost per MW

$idc[\%]$: Increased Distribution Capacity thanks to Smart assets

$DC_k[BAU][MW]$: Distribution Capacity

Transmission - Reduced congestions cost

Reduced congestions level is the KPI leading to this benefit. Since congestions mostly occur during peak period, the peak wholesale electricity price is then used to monetize.

Estimation can be made as follows:

$$RCC_k = rcl * LC * WEC_{peak}$$

Where:

$RCC_k[€]$: Reduced Congestions Costs

$rcl[\%]$: Reduced level of congestions due to smart grid project deployment

$LC[MWh]$: Total energy congestions in MWh observed

$WEC_{peak}[€/MWh]$: Wholesale peak electricity cost

T&D - Reduced equipment failure

Reduced equipment failure is directly calculated from the KPI “extended asset lifetime” through the following formula which can be used for distribution and transmission:

$$REF_k = Q_{extended\ lifetime\ assets\ (k)} * eal * AL_{average} * Assets_{extended\ lifetime}\ costs$$

Where:

$REF_k[€]$: Reduced Equipment Failure at year k

$Q_{extended\ lifetime\ assets(k)}[unit]$: Number of assets whose lifetime have extended thanks to smart grid assets at year k

$eal[\%]$: Extended assets lifetime in percentage of their current lifetime

$AL_{average}[y]$: Average lifetime of the considered assets

$Assets_{extended\ lifetime}\ costs\ [€/unit]$: annualised costs of assets whose lifetime have been extended thanks to smart grid assets

T&D - Reduced restoration cost

Reduced restoration cost is calculated from the KPI reduced SAIDI that then reduces costs of intervention by line workers. This benefit is estimated for Transmission and Distribution simultaneously.

A simplified formula is suggested below:

$$RRC_k = rsaidi * SAIDI * Ncustom_k * cost\ of\ labour$$

Where:

RRC_k[€]: Reduced restoration costs

$rsaidi$[%] : Reduced SAIDI thanks to smart grid deployment project

$SAIDI[min/customer]$: Current System Average Interruption Duration Index in 2013

$Ncustom_k$: Number of customers that are impacted by the considered smart grid project at the year the benefit is calculated

$cost\ of\ labour[€/h]$: cost of labour for a line worker sent on the field after a fault occurrence

Distribution - Reduced normal operation cost on the distribution grid

Reduced operation cost is calculated from the reduction manual operations thanks to controllable smart assets. Therefore, there is less line workers sent on the field. Several smart devices allow avoiding manual operation: feeder switches, capacitor switches, other automated switches etc.

A simplified formula is suggested below:

$$RNOC_k = rn_{operation} * T_{operation} * N_{operation} * cost\ of\ labour$$

Where:

$RNOC_k$[€]**:** Reduced normal operation at year k

$T_{operation}[h]$: Average time for a manual operation on the distribution grid

$N_{operation}$: Average number of normal operations on the distribution grid over a year

$rn_{operation}$[%]: Reduced number of normal operations thanks to smart asset

4.3.5 Society

Reduced cost of outages

Reduced cost of outages is calculated from the KPI Energy Not Supplied and a specific cost for ENS (€/MWh) which may vary with the country.

$$RCO_k = rens * ENS * cost\ of\ ENS$$

Where:

$RCO_k[€]$**:** Reduced cost of outages at year k

$ENS[MWh]$: Energy not supplied

$rens[\%]$: Reduced energy not supplied

$cost\ of\ ENS[€/MWh]$: Cost of energy not supplied (value of lost load). The value is set up considering the economic loss that implies energy not supplied for society. It is usually higher than wholesale electricity marginal cost, but at European level there is no currently a harmonized approach for the monetization of the value of lost load.

Reduced non-technical losses

The KPI "reduced non-technical losses" is monetized using the retail electricity cost:

$$RNTL_k = rntl * NTL * CRE$$

Where:

$RNTL_k[€]$**:** Reduced non-technical losses at year k

$NTL[MWh]$: Non-technical losses

$rntl[\%]$: Reduced non-technical losses

$CRE[€/MWh]$: cost of retail electricity

4.3.6 Summary of benefits calculation

Table 11 sums up all the formulas used for the calculation of the benefits.

Power System's level	Benefits	Simplified formula	Notations
Generation	Deferred Generation Capacity Investments	$a^*_{generation} * \boldsymbol{Peak\ Demand_k}[\boldsymbol{BAU}] * \left(\boldsymbol{1} + \boldsymbol{TL} - (\boldsymbol{1} - \boldsymbol{rpd}) * (\boldsymbol{1} + \boldsymbol{TL} * (\boldsymbol{1} - \boldsymbol{rtl}))\right) * (\boldsymbol{1} + \boldsymbol{reserve\ margin}[\%])$	$a^*_{generation}$: Constant annuity for generation capacity investments $\boldsymbol{Peak\ Demand_k}[\boldsymbol{BAU}][\boldsymbol{MW}]$: Projected Peak Demand at the year k in the BAU situation $\boldsymbol{TL}[\%]$: Current Technical Losses in 2013 $\boldsymbol{rpd}[\%]$: Reduced Peak Demand (see 1.3.11 for an estimation) $\boldsymbol{rtl}[\%]$: Reduced Technical Losses (see 1.3.6 for an estimation) $\boldsymbol{Reserve\ Margin}[\%]$: Reserve margin that is taken in the country to size the generation portfolio
	Reduced generation costs	$\Delta \boldsymbol{WEC_{peak/offpeak}}[€/\boldsymbol{MWh}] * \boldsymbol{Reduced\ Peak\ Energy\ Demand}\ [\boldsymbol{MWh}] + \boldsymbol{Increased\ \ energy\ generated\ from\ renewables}\ [\boldsymbol{MWh}] * \boldsymbol{WEC_{peak}}[€/\boldsymbol{MWh}] + \boldsymbol{Reduced\ Energy\ demand}\ [\boldsymbol{MWh}] * \boldsymbol{WEC_{average}}$	$\Delta \boldsymbol{WEC_{peak/offpeak}}[€/\boldsymbol{MWh}]$: Difference between peak and off-peak wholesale electricity cost $\boldsymbol{WEC_{peak}}[€/\boldsymbol{MWh}]$: Peak wholesale electricity cost $\boldsymbol{WEC_{average}}[€/\boldsymbol{MWh}]$: Average wholesale electricity cost $\boldsymbol{Peak\ Energy\ Generated}\ [\boldsymbol{MWh}]$: Current Energy generated by marginal peak units $\boldsymbol{Reduced\ Peak\ Energy\ Demand}\ [\boldsymbol{MWh}] = Peak\ Energy\ Generated\ [MWh] * (1 - (1 - rpd[\%]) * \frac{(1+TL[\%]*(1-rtl[\%]))}{1+TL[\%]})$ NB: We consider here only the part of peak demand that is shifted $\boldsymbol{Increased\ energy\ share\ generated\ from}$

			$\boldsymbol{renewable\ sources}[\boldsymbol{MWh}] = Peak\ Energy\ Demand\ [MWh] * (1 + TL[\%] - (1 - isre_{peak}[\%]) * (1 + TL[\%] * (1 - rtl[\%])))$ $\boldsymbol{isre_{peak}}[\%]$: Increased energy share generated from renewable sources that can be guaranteed at peak period $\boldsymbol{Reduced\ Energy\ demand}\ [\boldsymbol{MWh}] = Total\ Energy\ Demand\ [MWh] * (1 + TL[\%] - (1 - es[\%]) * (1 + TL[\%] * (1 - rtl[\%])))$ $\boldsymbol{es}[\%]$: Energy Savings
	Reduced GHG emission costs	$\boldsymbol{Reduced\ GHG\ emissions}[\%] * \boldsymbol{GHG\ emissions}[\boldsymbol{kgCO2}] * \boldsymbol{CO2\ cost}\ [€/\boldsymbol{kg}]$	$\boldsymbol{GHG\ emissions}[\boldsymbol{kg\ CO2_{eq}}]$: Total GHG emissions of the generation portfolio. The value should be given in kg CO2
Transmission & Distribution	Deferred Transmission capacity investments	$\boldsymbol{DTCI_k = a^*_{Transmission} * (Peak\ Demand_k[BAU] * \left(1 + TL - (1 - rpd) * (1 + TL * (1 - rtl))\right) * (1 + reserve\ margin[\%]) + igc_{DG/peak} * GC_{DG/peak} + itc * TC_k[BAU])}$	$\boldsymbol{DTCI_k}[€]$: Deferred Transmission Capacity Investment at year k $\boldsymbol{a^*_{Transmission}}$: Constant annuity for Transmission capacity investments $\boldsymbol{igc_{DG/peak}}$: Increased DG installed capacity that is guaranteed when peak units are running (refer to 1.3.3 for estimation guidelines) $\boldsymbol{GC_{DG/peak}}$: DG installed capacity that is guaranteed when peak units are running $\boldsymbol{itc}[\%]$: Increased Transmission Capacity thanks to Smart assets $\boldsymbol{TC_k[BAU][MW]}$: Transmission Capacity at year k in a BAU situation
	Deferred Distribution capacity investments	$\boldsymbol{DDCI_k = DCIC * (Peak\ Demand_k[BAU] * \left(1 + TL - (1 - rpd) * (1 + TL * (1 - rtl))\right) * (1 + reserve\ margin[\%]) +}$	$\boldsymbol{DDCI_k}[€]$: Deferred Distribution Capacity Investment $\boldsymbol{DCIC}[€/\boldsymbol{MW}]$: Distribution Capacity Investment Cost

		$\boldsymbol{idc * DC_k[BAU]})$	per MW $\boldsymbol{idc}[\%]$: Increased Distribution Capacity thanks to Smart assets $\boldsymbol{DC_k[BAU][MW]}$: Distribution Capacity
	Reduced congestions costs	$\boldsymbol{rcl * LC * WEC_{peak}}$	$\boldsymbol{rcl}[\%]$: Reduced level of congestions due to smart grid project deployment $\boldsymbol{LC[MWh]}$: Total energy congestions in MWh observed in 2013 $\boldsymbol{WEC_{peak}[€/MWh]}$: Wholesale peak electricity cost
	Reduced equipment failure	$\boldsymbol{Q_{extended\ lifetime\ assets\ (k)} * eal * AL_{average} * Assets_{extended\ lifetime}\ costs}$	$\boldsymbol{Q_{extended\ lifetime\ assets(k)}[unit]}$: Number of assets whose lifetime have extended thanks to smart grid assets at year k $\boldsymbol{eal}[\%]$: Extended assets lifetime in percentage of their current lifetime $\boldsymbol{AL_{average}[y]}$: Average lifetime of the considered assets $\boldsymbol{Assets_{extended\ lifetime}\ costs\ [€/unit]}$: annualised costs of assets whose lifetime have been extended thanks to smart grid assets
	Reduced restoration cost	$\boldsymbol{rsaidi * SAIDI * Ncustom_k * cost\ of\ labour}$	$\boldsymbol{rsaidi}[\%]$: Reduced SAIDI thanks to smart grid deployment project $\boldsymbol{SAIDI[min/customer]}$: System Average Interruption Duration Index $\boldsymbol{Ncustom_k}$: Number of customers that are impacted by the considered smart grid project at the year the benefit is calculated $\boldsymbol{cost\ of\ labour[€/h]}$: cost of labour for a line worker sent on the field after a fault occurrence

	Reduced operation cost on distribution grid	$rn_{operation} * T_{operation} * N_{operation} * cost\ of\ labour$	$RNOC_k$[€]: Reduced normal operation at year k $T_{operation}[h]$: Average time for a manual operation on the distribution grid $N_{operation}$: Average number of normal operations on the distribution grid over a year $rn_{operation}$[%]: Reduced number of normal operations thanks to smart asset
Society	Reduced cost of outages	$rens * ENS * cost\ of\ ENS$	$ENS[MWh]$: Energy not supplied $rens$[%]: Reduced energy not supplied $cost\ of\ ENS$[€/MWh]: Cost of energy not supplied. The value is set up considering the economic loss that implies energy not supplied for society. It is usually higher than wholesale electricity marginal cost.
	Reduced non-technical losses	$rntl * NTL * CRE$	$NTL[MWh]$: Non-technical losses $rntl$[%]: Reduced non-technical losses CRE[€/MWh]: cost of retail electricity

Table 11: Monetization of proposed benefits

4.4 Economic model including sensitivity analysis

In this section we present the economic model integrating the costs (as defined within chapter 3) and the monetized benefits (as defined in section 4.1) for Smart Grid investments in order to quantify estimated NPV, IRR and payback time.

Since the cost-benefit analysis to be performed is aimed at assessing funding at EU level, we take a social welfare approach for benefits (and costs) evaluation (economic CBA)[14]. This means considering benefits of Smart Grids investments for the whole power system rather than only for one specific actor (e.g. the DSO).

To this end, peculiar aspect of an economic (societal) CBA needs to be considered: shadow prices; societal discount rate; transfers among actors to avoid double-counting.

The inputs and outputs of the economic model include:

Inputs: monetary value of benefits (section 4.1); project costs (as defined in chapter 3); discount rate; time horizon of the analysis.

Outputs: Economic indicators: NPV; IRR; payback time. The tool will also allow the visualization of a "Smart Grid" roadmap, presenting the level of installations of the Smart assets across the lifetime of the project

In the following it is assumed a project reference period of 25 years.

The different outputs of the economic model are detailed in the following sections.

4.4.1 Cumulated gross benefits and investments per type

For each type of gross benefits and Smart Grids implementation assets their discounted cumulated value over the project evaluation period will be graphically displayed.

The formula used for both is written below:

$$C_n = \sum_{k=0}^{T-1} \frac{c_{p,n}}{(1+i)^k}$$

Where:

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[14] Sources: European Commission DG Regio, "Guidelines to cost benefit analysis of investment projects", July 2008

European Investment Bank "The economic appraisal of investment projects at the EIB", March 2013

C_n: Discounted Total Cost for the asset n

$c_{k,n}$: Costs of the asset n at the year k. For the CAPEX part of the cost, a fixed annuity is considered.

T : Time period (in year) for which the project is evaluated.

i : Discount rate

NPV (Net Profit Value) benefit calculation

The same formula is applied for the gross benefits calculation.

4.4.2 Economic calculation (from society's perspective)

NPV is the sum of annualised cash flows on the project period evaluation.

The formula is shown below:

$$NPV = \sum_{k=0}^{T-1} \mathrm{CF}_k$$

Where T is the time period (in year) for which the project is evaluated.

Annualised Cash Flows at year n (CF_n) calculated by doing the difference between gross benefits and Smart Grids costs (CAPEX, OPEX, installation costs…) made at year n. This calculation takes into account a specific discount rate for society and the terminal value using the constant annuity methodology identified in task 5.

The economic Cash Flows takes into account all the gross benefits made on the power system thanks to the project implementation as well as all its Smart Grids implementation costs.

The selected discount rate will be specific for society and constant annuity methodology identified in chapter 3 will be used for the Smart Grids implementation costs and the deferred power system investments.

$$CF_k = \sum_n \frac{\mathrm{gb}_{k,n}}{(1+i)^k} - \sum_m \frac{\mathrm{c}_{k,n}}{(1+i)^k}$$

Where:

$\mathrm{gb}_{k,n}$: Gross benefit of the benefit n at the year k. For the deferred investments, this parameter is a fixed annuity.

$\mathrm{c}_{k,n}$: Costs of the asset m at the year k. For the CAPEX part of the cost, a fixed annuity is considered.

i: Discount rate.

Internal Rate of Return (IRR) calculation

The internal rate of return is an indicator that helps evaluating the risk carried by the project. Indeed, to implement a project, its discount rate should be significantly below the IRR. The closer the discount rate is to the IRR, the bigger is the risk carried by the project.

The formula to define IRR is written below using the same notation as in 4.2:

$$NPV = \sum_{k=0}^{T} \sum_{n} \frac{\mathrm{gb}_{k,n}}{(1 + \boldsymbol{IRR})^k} - \sum_{n} \frac{\mathrm{c}_{k,n}}{(1 + \boldsymbol{IRR})^k} = \mathbf{0}$$

Payback time

Payback time is the time from which the net present value of the project becomes positive. The longer is the payback time the bigger is the risk carried by the project.

In the project assessment tool, this value is presented by displaying a graph of the cumulated discounted Cash Flows over years.

Sensitivity analysis

Sensitivity analysis should reveal parameters (costs and KPIs) that have the strongest impact on the project performance and therefore expose the project to greater risks. Although sensitivity analysis is not included in the tool, a methodology is proposed below.

Sensitivity analysis is done on main calculation inputs: KPI and assets deployment. Focus should be made on:

- KPI that have the highest weight given by the project reviewer (following KPI evaluation methodology described in chapter 2)
- Assets most widely deployed
- Assets that have the highest cost

Linear variations on these parameters should be applied to assess the impact on the eligibility criteria (alignment with policy goal and cost effectiveness/economic benefit depending on the global project cost) and on the other risk indicators (IRR, Payback Time).

4.5 Project assessment tool

A number of modules (excel sheets) have been developed in the different tasks and integrated in a single CBA tool (Excel file), including:

- Mapping of Smart assets/functionalities into KPIs (task 1)
- Definition of calculation hypotheses and quantification of KPIs (chapter 4) (KPIs expressed in technical - e.g. MW; %- not monetary units)
- Quantification of costs (chapter 3)
- Monetization of benefits (chapter 4)
- Economic model for calculating economic indicators (NPV, IRR)

The different modules aim at guiding JASPERS officials, national authorities and project promoters across the different steps of the proposed methodological framework. Even if all the different modules are logically connected, not all links among the corresponding excel sheets have been automatized.

In fact, the goal of the tool is to perform automatically some standard calculations (e.g. discounting; sum of costs) but also to allow the punctual verification of the hypothesis that are behind the selection of assets, functionalities, KPIs, parameters and calculation hypotheses. The tool is therefore intended to be flexible and will thus require manual customizations to tailor the assessment to the specific characteristics of the project and of the local context.

The different modules could be used independently and modifications/inputting of new information could be done easily on each of the tool's modules. The goal is also to have a tool that could be used for a detailed analysis (with detailed descriptions filled for the context and the project) as well as for a quick evaluation (with no quantified benefits and global costs given as inputs). The detailed analysis would be done in the case of projects with a global cost superior to 50M€ and would include an estimation of the economic benefit of the project. The quick evaluation, sufficient for smaller projects, will evaluate these latter with a semi quantitative approach comparing their respective impacts and costs, determining their costs effectiveness.

The proposed overall architecture of the assessment tool, with all the different modules, is reported in figure 8. The modules are organized as follows:

- Description of the evaluation criteria
- Description of the project
- Calculation of the costs
- Estimation of the KPI
- Description of the context (Only for major projects)
- Calculation of benefits (Only for major projects)
- Synthesis Evaluation

The detailed user manual is reported in Appendix B.

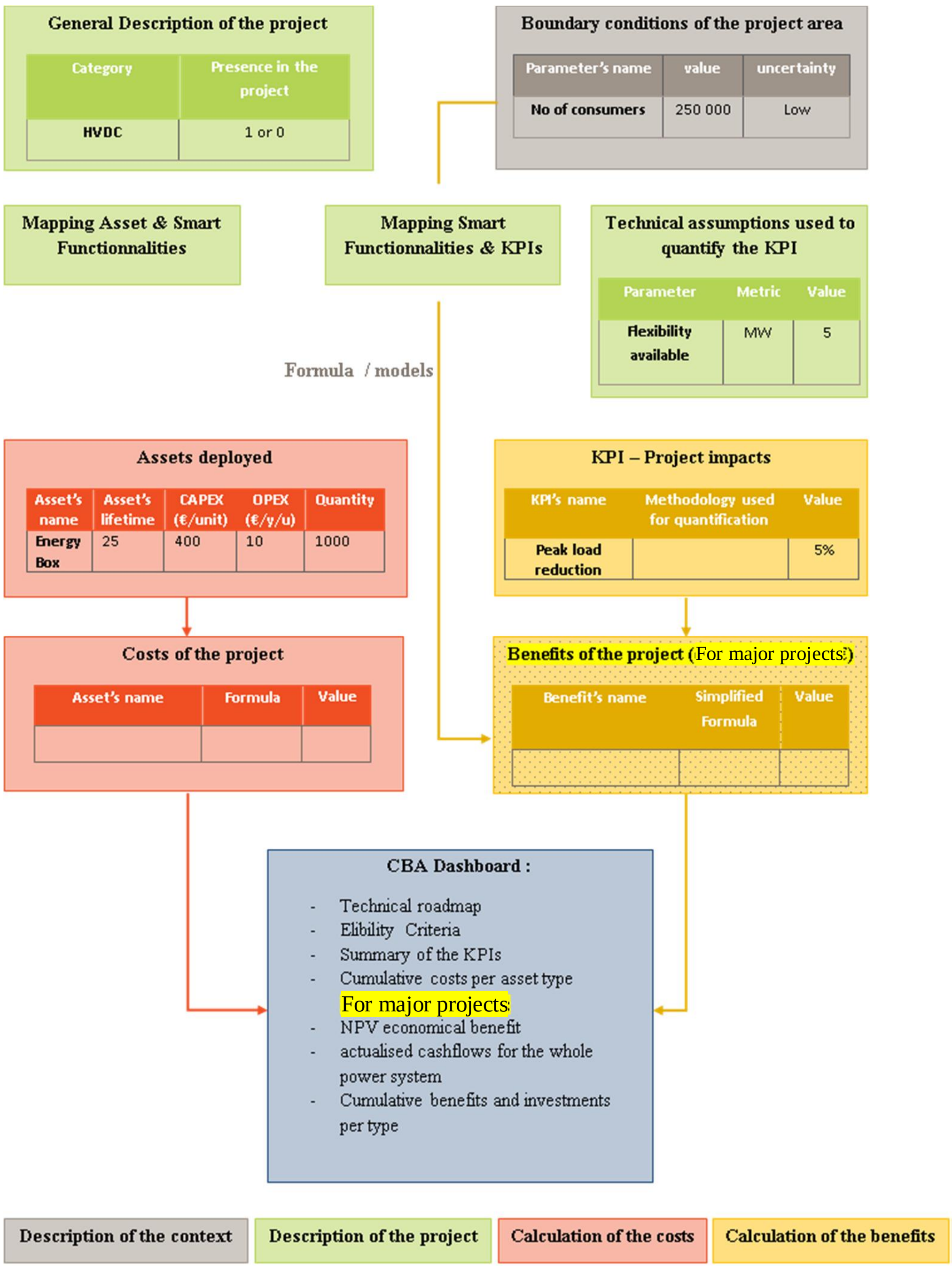

Figure 8–architecture of the assessment tool. Each bloc corresponds to an Excel sheet. Arrows represent dependencies between sheets.

The different steps to fill the tool are described in the following sections.

4.5.1 Reference ranges for the synthesis evaluation

This sheet should be filled by the projects reviewer before the project assessment phase. For each KPI based on national conditions and policy priorities, National Authorities need to fill in :

> Range values for low, medium and high impact
> Weights between 1 to 5 to define the level of priority of the KPI

An overview of the excel sheet is given in figure 9.

Description of the indicator	Present value of the indicator	Metrics	KPI's name	No impact	Low impact *Fill here the max value only (in %)*	Medium impact *Fill here the max value only (in %)*	High impact	Weight (from 1 to 5) for final evaluation
Average total amount of GHG emitted by generation over a year	200	Mt	Reduced green house gas emissions	0%	5%	15%	>15%	1

Figure 9–Extract of the sheet "reference range" of the tool. Yellow fields should be field by the projects reviewer.

4.5.2 Description of the project

There are four steps in the project assessment tool that are dedicated to the project description.

The first two steps are encoded in the excel sheet *"Project Description"*. This sheet provides a description of the context in which the project will be deployed as well as a general description of the main functionalities of the project.

Context of the project

Category	Indicator related to the context of the project	Present value of the indicator	Sources	Metrics
Sustainability	Average total amount of GHG emitted by generation over a year	200		Mt

Figure 10- 'Scope of the project'- yellow cells should be filled by the project promoter

The objective of this table is to input a set of parameters which represent the boundary conditions of the project. This is important to give a general overview of the context in which the submitted project will be deployed (see figure 10).

Moreover, the values of the parameters included in this sheet are used for quantification of the KPIs. For major projects, these values are also used for the benefits calculation.

Full description of these parameters can be found in the User Manual.

Listing smart assets and their functionalities

Asset's name	power flow control (including dispatchability of DERs)	Planning distribution grids taking into account the flexibility of DER	Proactive maintenance of equipment and identification of incipient faults.
Example 1	1		

Figure 12- 'Mapping Asset-Funct' - yellow cells should be filled by the project promoter

The second step of the project description is the mapping asset-functionalities that have been presented in chapter 1. It can be found in the Excel sheet "*Mapping Asset-Funct*". The purpose of this sheet is to evaluate whether the project shall be considered as a Smart Grid project. The project promoter should list here all the smart assets deployed in its project and map them with functionalities identified in chapter 1.

There is no pre-identified smart asset; the project promoter is free to name the assets of its projects. On the other hand, smart functionalities form already a pre-defined list that cannot be modified

An example of mapping is given in figure 12.

Mapping Smart functionalities with KPIs

Functionality name	Reduction of greenhouse gas emissions	Reduction of local SOx, NOx emission	Increase of hosting capacity of distributed generation
Enhanced power flow control		1	

Figure 13- 'Mapping Funct-KPI' - yellow cells should be filled by the project promoter

The objective of the sheet '*Mapping Funct-KPI*' is to describe which KPIs are impacted by the smart functionalities implemented in the project

Functionalities are automatically copied from the previous mapping sheet. An example of mapping is given in figure 13. Note that a single functionality can have impacts on several KPIs.

4.5.3 Calculation of the project's cost

The calculation of the cost of a submitted project is done in two steps.

Project's assets

Asset's name	Asset's lifetime (in years)	CAPEX (k€/unit)	Annual OPEX (k€/y/unit)	Installation cost (k€/unit)	Decommis-sioning cost (k€/unit)	Cumulated quantity Y1
Personnel costs			2			1
Example 1	40	0,15	0,0075	0,2	0,2	2

Figure 14 - 'Project's assets' - yellow cells should be filled by the project promoter

The sheet *'Project's asset'* gathers all the inputs necessary to the calculation of the total project's cost (see example in figure 14). The expected inputs to assess the cost of each asset have been described in chapter 3.

Three additional types of costs are included:

- **Personnel costs** over the deployment period: they should be filled in as OPEX, the unit being person/month.
- **Pre-project studies costs**: All preliminary analysis should be considered as a unique CAPEX in year 1.
- **Post project studies costs**: Results analysis and results dissemination should be considered as a unique CAPEX in the final year (year 25).

Costs

Asset's name	Metric	Constant annuity (a*)	Formula *CQk: Cumulated Quantity at year k* *Install Cost: Installation Cost* *Decom Cost: Decomissioning Cost*	**Y1**
Management Costs	k€		*OPEX*CQk*	2
Example 1	k€	0,00606	(a*+OPEX)*CQk+ABS(CQk-CQ(k-1))*(Install Cost or Decom Cost)	0,416

Figure 15- 'Costs' – this sheet shouldn't be modified

In the sheet *'Costs'*, several calculations are implemented to estimate the total project's cost (see figure 15). This sheet should not be modified by the tool's user. The following calculations are done:

> Yearly cost per asset
> Discounted cost per asset over the project period
> Discounted cost per year
> Total discounted cost over the project period

The estimation is based on the formulas described in chapter 3 and 4 respectively for the costs calculation per asset and for the economic model. The calculation is completely based on previous inputs.

4.5.4 Estimation of the KPI

In the sheet *"Project's impacts"* of the tool, the project promoter should give value for each KPI he had identified in the mapping functionalities – KPIs. Each value should come with sources and justification. Estimation approaches that were described for KPI quantification are suggested in this sheet for each KPI (see example in figure 16).

KPI's name	Impacted indicator	Unit	Impacting Parameters on the indicator	Suggested Formula	Nota - tions	Metho- dology	Value at the end of the project
Reduced electricity consumption	Annual electricity consumption	MWh	• DER & Consumers: o Relative impact on a household/building consumption of a local EMS o Share of consumption from households equipped with local EMS	Total Consumption [MWh][BAU]*share of consumption equipped with local EMS*Energy savings of a single households per Local EMS installed [%/unit]			5%

Figure 16- 'Project's impacts' - yellow cells should be filled by the project promoter

This step is key for the evaluation of the project and is used for the benefits' calculation when a CBA is required (project's cost> 50M€).

The same format is used in the sheet *'Secondary parameters'* that are used only for the benefits calculation (cf. chapter 4).

4.5.5 Calculation of benefits *(Only for major projects)*

There are two steps to quantify the benefits.

Boundary conditions

Parameter's name	Description	Benefits link	Metrics	Source *to be filled with a short description*	Uncertainty	Y1	Y25
Reserve margin		Deferred Generation investment cost	%		3	2%	

Figure 17- 'Boundary Conditions' - yellow cells should be filled by the project promoter. Grey cells are not to be filled

In the sheet '*Boundary Conditions*', all the additional inputs regarding the project's scope that are required for the benefits calculation are listed. These are the boundary conditions of the project area (e.g. number of consumers; number of substations; present costs of traditional investments in the system; energy context of the area: energy mix; baseline peak demand; peak investment costs etc.).They all have been listed previously in chapter 4 with benefits formula description. These inputs should be given by the project promoter (see example in figure 17).

For each value, sources should be given in the dedicated field. An uncertainty should be also associated to the value. Y1 stands for the first year of the project deployment and Y25 stands for the last year of the project period.

Scale for uncertainty is the following:

- 1: **high uncertainty**: No official sources, neither measured values to base the estimation on.
- 2: **medium uncertainty**: Either official sources are available but the value estimation relies on approximated values or project promoters' values are available for estimation but no official sources
- 3: **low uncertainty**: The value is measured or its calculation relies on measured values and official sources for this value are available

Calculation of the benefits

Benefit's name	Metric	Formula *See notations definitions in the user manual*	Constant annuity (a*)	**Y1**
Deferred Generation Capacity Investments	k€	a*_generation*PGCIC*[Peak Demand]_k [BAU]*(1+TL-(1-rpd)*(1+TL*(1-rtl)))*(1+reserve margin[%])	0,0404	0,0

Figure 18- 'Benefits' – The sheet shouldn't be modified

In the Excel sheet *"Benefits"* are calculated all the monetized KPI.. All calculations made there are based on the monetized KPI formulas and on the economic model described previously in this section (see figure 18).

The indicators calculated in this sheet are the following:

- Total discounted benefit per benefit type over the project period
- Total discounted gross benefit per year
- Annual discounted cash flows
- Total NPV over the project period taking into account gross benefit and total cost of the project

4.5.6 Synthesis Evaluation

The Excel sheet *"Synthesis evaluation"* synthetises all the outputs of the different tool modules. It includes:

For non-major projects:

- Technical roadmap: number of yearly deployments of asset units along project's lifetime

- Eligibility Criteria for the reviewed project (as defined in task 3) described in table 12:

Criteria	Description
Functional minimum requirements	Evaluation of the smartness of the project regarding the assets' functionalities deployed
Alignment with policy goals	A ranking of the KPIs allows evaluating if the project is in line with policy goals. The ranking of each KPI is described in task 3.
Cost effectiveness	Graph displaying the criteria alignment with policy goals vs the total project's cost per customer. It is a 2 dimensions graph.

Table 12 – Eligibility criteria description

- Summary of the KPIs

- Cumulative costs per asset type

- Society benefits:

  Reduced outages

  Reduced non-technical losses

For major projects

> Technical roadmap

> Eligibility Criteria for the reviewed project (as defined in task 3): The graph '*Cost Effectiveness'* becomes *'Economic Benefit'*. It displays the criteria alignment with policy goals vs the economic benefit of the project. The size of the bubble in the graph is proportionate to the difference: *[IRR]*-*[current discount rate]*. The smaller is the bubble, the bigger is the risk carried by the project.

> Summary of the KPIs

> Cumulative costs per asset type

> Cumulative benefits per benefits type

> NPV economic benefit

> Actualised cash flows for the whole power system

> Cumulative benefits and investments per type

> Society benefits:

Reduced electricity costs

Reduced outages

Reduced non-technical losses

5 REGULATORY REQUIREMENTS TO SUPPORT SMART GRID INVESTMENTS

This chapter is aimed at describing possible regulatory mechanisms to support the implementation of Smart Grid investments, drawing from best practices from other European countries. It corresponds to task 2 of the assignment.

The analysis also takes into account recent developments at European level, particularly in the context of the EC Smart Grid Task Force. It also presents an overview of the regulatory frameworks in Poland and Romania. This analysis provides the context to run the case studies in tasks 11 and 12. This will allow discussing which kind of regulatory evolutions might be considered in Poland and Romania (and possibly in other eastern European Member States) on the ground of the regulatory options pursued in (western) European countries.

5.1 Regulatory and energy policy context in Romania

In Romania, the main energy policy priorities for the modernization of the power system are the promotion of energy efficiency, the integration of renewable energy sources and the roll-out of smart metering systems.

a) Energy efficiency

Energy efficiency is a main policy priority in Romania. The main legislative initiative in this domain is the "*Governmental Ordinance (GO) No. 22/2008 regarding energy efficiency and promotion of the use of renewable energy to final consumers*". In particular, the ordinance prescribes that the final consumers of electricity, natural gas, water and heat must use individual meters purchased at competitive prices and to reflect accurately enough the energy consumption.

The Ordinance also proposes a number of incentives for the promotion and support of energy efficiency measures and indicates a number of tools and financing mechanisms to support energy efficiency investments:

- Models of contracts;
- Funds for subsidizing the provision of programs and measures regarding the improvement of the energy efficiency and to promote a market for the measures aiming to improve the energy efficiency.
- Measures including the promotion of energy auditing, financial instruments for energy savings and improvement of energy metering and billing information.

b) Integration of renewables

The *"Law regarding the system to promote renewable energy production No. 220/2008, as amended and supplemented"* creates the legal framework for the use of renewable energy sources with the goal of:

- reducing the costs of generation, transmission and distribution of renewable energy compared to using classic fuels and thus reducing the energy bill of the various consumer categories;
- reducing imports of primary energy and increasing security of supply, while ensuring national energy balance;
- fostering sustainable development at local and regional level and the creation of new jobs related the processes of exploiting renewable energy resources;
- reducing greenhouse gas emissions;
- attracting external sources to promote renewable energy investments;
- defining rules relating to guarantees of origin, administrative procedures and connection to the grid in terms of energy produced from renewable sources.

The law establishes the promotion of electricity from renewable sources through green certificates.

Additionally, the transposition of the Eureopan Directive 2009/28/EC regarding the promotion of using energy from renewable sources, has set a target of at least 24% of energy from renewable sources in the gross final consumption of power of Romania for 2020.

c) Smart Metering

Law for electricity and natural gas No.123/2012 - Title I Electricity creates the mandatory goals for ***Smart metering systems*** implementation in public electrical grids. In particular, the Law has a specific provision on *smart metering* in Art.66:

> *Art. 66. - (1) Until September 3, 2012, Romanian Regulatory Authority for Energy (ANRE) will assess the implementation of intelligent metering systems in terms of costs and benefits of long-term market profitability and feasible implementation deadlines.*
>
> *(2) Where the assessment referred to in para. (1) shows that the implementation of intelligent metering systems is advantageous for the functioning of the energy market, ANRE approved a timetable for the*

implementation of intelligent metering systems so that about 80% of customers have intelligent metering systems by 2020.

The implementation of these systems will be approved in the annual investment plans of distribution operators.

Presently, a small number of grid users are already equipped with smart metering systems. There are three categories of smart metering beneficiaries:

- One category represents about 2000 measuring points included in TSO's smart metering system (called OMEPA system) dedicated to very high voltage measuring points or to settlement points between operators and suppliers in the wholesale electricity market.
- The second category represents about 400 measuring points dedicated to new RES dispatching power plants (wind or solar).
- The third category is represented by a few thousands of residential customersinvolved in "pilot projects" developed by distribution operators.

Almost 9 million grid users still need to be equipped with smart meters.

The cost-benefit analysis carried out by the Romanian Government in 2011 provided a positive result. As a result, according to the above mentioned Energy Law, the eight Romanian public grid operators have to implement smart metering systems for about 7 million users (customers of the public electricity networks) in the next 7 years.

5.1.1 Romania Power System – present status and challenges

Romanian Power System is part of ENTSO-E (former UCTE) since the 10th of October 2004. The total land surface of the country is 238,391 sq. km and the total population is about 20 million inhabitants.

Romanian Electricity Market is integrated in the Electricity Market of the European Union. In line with EU legislation (Directive 2009/72/EC), the Romanian Energy sector is fully unbundled and structured in the following activities:

- Generation (9 major producers with more than 1 TWh / year and other small ones);
- Transmission and system operator (one system operator);
- Distribution (8 area distribution system operators and more than 60 suppliers for final consumers). The DSOs are: SC ENEL Distributie Muntenia SA, SC ENEL Distributie Banat SA, SC ENEL Distributie Dobrogea SA, SC E.ON Moldova Distributie SA, SC CEZ Distributie SA, SC FDEE Electrica Distributie Muntenia Nord SA, SC FDEE Electrica Distributie Transilvania Sud SA, SC FDEE Electrica Distributie Transilvania Nord SA.

The Romanian power system is regulated by ANRE (Romanian Regulatory Authority for Energy).

Total number of distribution networks users in 2012 was around 9 millions.

The electricity gross consumption in 2012 was 59.130 TWh and maximum peak around 9 GW.

In the last few years, the penetration of renewable energy sources has constantly increased, particularly solar and wind generation. Installed capacity (2012 values) is:

- Wind = 2619 MW
- Solar = 1055 MW
- Biomass = 97 MW

The Romanian Power System is currently facing the following problems:

- **Aging traditional generation**

80% of thermal power plants in Romania have been installed 40-45 years ago and now exceeds their lifetime;
31% of hydropower with an installed capacity of 6,450 MW have exceeded their lifetime; foreseen rehabilitation programs are targeting only a small share of the total;

- **Aging network and poor monitoring of assets**

67% of electricity distribution networks are in an advanced stage of wear.
Distribution networks' control and command functionalities have a limited penetration.
High operational costs of the grid (including technical and non-technical losses), particularly at low voltage (LV) level
Needs for development of reliable communciation infrastructure (e.g. optical fiber highways using power line poles)

- **Expected increase of power demand and of electricity prices**

- **Integration of RES to meet EU target**

Romania has a target of 24% of renewable energy by 2020

This requires new works for grid reinforcement due to the new RES generators (including the MV and LV networks).

5.1.2 Romania Power System – Relevant Smart Grid legislation and regulation

Relevant smart grid regulation

Transmission Grid Code (ANRE's Order no. 20/2004) and ***Distribution Grids Code*** (ANRE's Order no. 128/2008) have not any specification regarding smart grids. However the technical requirements for the network operators and for generators/big consumers are imposing high performance electrical equipments. This is expected to promote the use of new technologies such as SCADA, FACTS, smart metering, route with optical fiber etc. This would be a first step in smart grids implementation.

ANRE's Order no. 72/2013 for approving the Methodology for setting electricity distribution tariffs defined a bonus/malus framework for DSO efficiency. The regulator sets efficiency targets and reward/penalty for DSOs based on their performances on power losses reduction and OPEX (operational expenditures) optimization.

The regulatory framework presently in force allows grid operators to share with clients the gains from reduction (by optimization) of *grid losses* and of *OPEX*:

> *Art. 39. - The efficiency gain realized by the distribution operator to each voltage level from a grid losses index lower than the regulated target is left to the disposal of distribution operator in a proportion of 25% for medium and high voltage levels or 50% for the low voltage level.*

This bonus/malus scheme can represent for Distribution Operators a very important incentive to pursue efficiency improvements via smart grids investments.

Smart metering pilots

ANRE's Order no. 91/2013 on the implementation of smart metering systems set important obligations for public utilities in this field.

This regulation establishes the obligation for each of the eight concessionary distribution operators to achieve in 2014 at least four pilot projects in smart metering. The projects are funded through distribution tariffs. The regulation also prescribes mandatory and optional functionalities of smart metering systems.

Since February 2014, ANRE and the eight concessionary Distribution Operators have been working to define smart metering pilot projects to be launched in 2014.

5.1.3 Romania Power System – On-going Smart Grid initiatives

Some of the most significant on going Smart Grid initiatves in Romania are:

> Smart metering system implemented by the TSO (Transelectrica) for approximately 2,000 measuring points
> Tele-transmission via optic fiber installed on very high voltage power lines
> SCADA systems installed in very high voltage stations
> AMR (automated meter reading systems) installed in 110 kV networks of distribution operators
> SCADA systems installed in dispatchable power plants (conventional and renewable)
> In 2014, implementation of more than 32 pilot projects in smart metering, especially for householders and small commercial (from thousands to tens of thousands of customers).

5.2 Regulatory and energy policy context in Poland

In Poland, the main policy priorities for the modernization of the power system are the promotion of energy efficiency, the integration of renewable energy sources, the enhancement of secuirty of supply and the roll-out of smart metering systems.

a) Energy efficiency

Although the energy intensity of the Gross Domestic product (GDP) declined by 30% within the last 10 years, the efficiency of the Polish economy calculated as GDP (at euro exchange rate) per energy unit remains twice as low as the European average. Economic development is expected to bring a considerable increase in electricity consumption accompanied by a relative decrease in the use of other energy forms.
The main overarching energy policy objectives in this field are as follows:

> To achieve zero-energy economic growth, i.e. economic growth with no extra demand for primary energy;
> To reduce the energy intensity of Polish economy to the EU-15 level.

Specific objectives in this field are as follows:

> To enhance efficiency of power generation by building highly efficient generation units;
> To achieve a twofold increase (as compared to 2006) in power generation with the use of highly efficient cogeneration technology by 2020;
> To limit losses in transmission and distribution grids by modernising the existing and building new grid, replacing low efficiency transformers, and developing distributed generation;
> To increase efficiency of end-use of energy;
> To limit the total cost of meeting the peak demand.

In April 2011 a law on energy efficiency was passed – it requires entities operating in the energy industry to take action to improve the energy efficiency factor and obtain the so-called "white certificates"

b) Security of supply

The main objective is to ensure the supply of energy demand, taking into account the maximum possible use of domestic resources and environmentally friendly technologies. Most relevant specific objectives in the field are the following:

- **Meeting peak demand** - Building new generation capacity and/or implement demand side management measures to ensure adequate generation reserves at peak demand;
- **Cross-border connections** - Developing cross-border connections coordinated with extending the domestic transmission system as well as the systems in neighbouring countries, which will allow to exchange at least 15% of electricity used in Poland by 2015, 20% by 2020, and 25% by 2030;
- **Modernisation of the distribution grid to host distributed generation** - Modernisation and extension of the distribution grid which allows to improve the reliability of power supply and to develop distributed power generation using local sources of energy;
- **Reduction of failure and outages** - Modernisation of transmission and distribution grids to reduce failure frequency by 50% by 2030 as compared to 2005;

c) Integration of renewable energy sources

A key energy policy objective in this field is to increase the use of renewable energy sources in the final energy use to at least 15% in 2020 and further increase in the following years.

Concretely, the following renewable energy sources are expected to be developed in Poland in the following years:

- Biomass generation (mainly distributed generation)
- Off-shore and on-shore wind
- Small and large-scale hydro power units
- Photovoltaic
- Geothermal

d) Roll-out of smart metering systems

The Polish energy regulator has approved a timetable for the implementation of intelligent metering systems so that about 80% of customers have intelligent metering systems by 2020. The implementation of these systems will be approved in the annual investment plans of distribution operators.

5.2.1 Polish Power System – present status and challenges

Generation

In 2012 the total production of electricity in Poland amounted to 159.9 TWh and was lower by around 2% than in 2011. In the same period, the national energy consumption amounted to 157 TWh and was lower by 0.6% than in 2011. The major reason for the fall in national electricity consumption was a downturn in the economy evidenced by a decrease in the GDP growth in 2012 which, according to the initial estimate prepared by the Central Statistical Office (GUS), amounted to2% in 2012. In comparison, in 2011 the GDP growth was at the level of 4.3%. The share of the individual energy groups in the market, as well as the structure of these entities, did not change significantly in 2012. The three biggest capital groups cover approximately two third of the domestic electricity production. The share of the biggest generator PGE Polska Grupa Energetyczna SA in the electricity production amounted to around 38% in 2012. The share of TAURON Polska Energia SA was at 13% and EDF at 10%. The other significant generators are: ENEA SA, ZE PAK SA, GDF SUEZ, PGNiG, Dalkia, CEZ, Fortum and RWE.

Power networks and system operators

PSE is the single transmission system operator in Poland. The Polish Power System is part of the ENTSO-E (former UCTE) system.

At distribution level, at the end of 2012, 148 DSOs conducted distribution activities, including 5 legally unbundled distribution companies, and 143 DSOs which were not subject to the legal unbundling obligation (as they served less than 100.000 consumers). The ownership supervision over these groups is performed generally by the State Treasury. There is only one DSO that is owned by a company whose main stakeholders are not connected with the State Treasury: RWE.

Renewable energy sources: connection, access, dispatching and balancing

In order to promote the penetration of distributed generation, RES units with installed capacity lower than 5 MW are charged half of the connection fee (calculated on the basis of the actual costs of this connection). The electricity system operator, within its operation area, is required to ensure preferential transmission and distribution of electricity generated by RES and high-efficiency cogeneration, while preserving the reliability and security of the national electricity system. Additionally, the default supplier is obliged to purchase electricity generated from renewable energy sources offered by the electricity generators connected to the distribution or transmission grid situated on the territory that belongs to the supplier’s operation area. The energy is bought at the average price for electricity on the wholesale market in the preceding year.

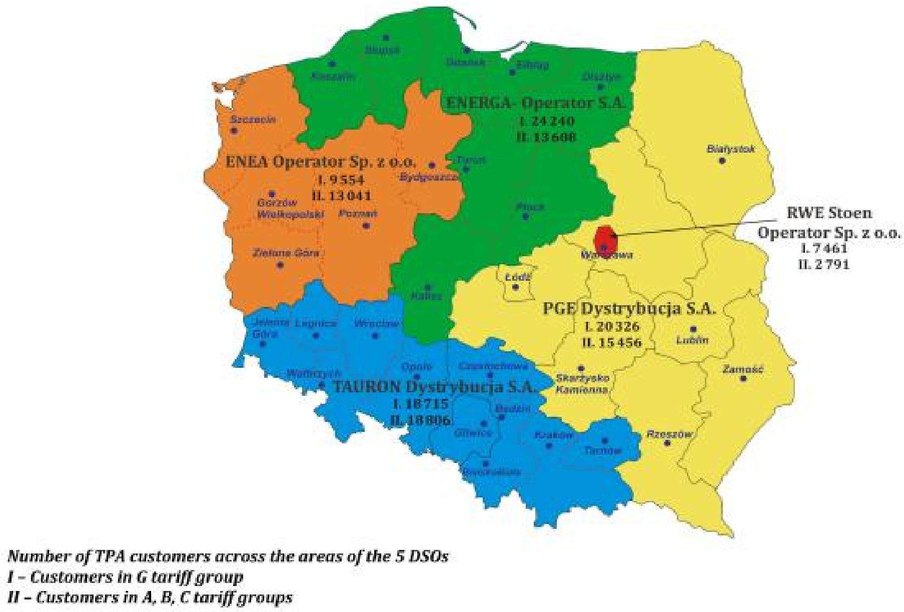

Figure 19 –Main electricity distribution system operators in Poland

5.2.2 Polish Power System – Relevant Smart Grid legislation and regulation

Energy efficiency law

The goal of increasing energy efficiency, given by the Law on energy efficiency 12) (Act on energy efficiency 15.04.2012, Ustawa, z dnia 15 kwietnia 2011 r.; o efektywności energetycznej, Dz. U. z 2011 r. Nr 94, poz. 551), creates possibilities of Smart grid and Smart metering projects implementation in order to fulfil the demanded factors.

The main objectives in the Energy Efficiency law are:

> To reduce peak demand for the power and to ensure balance in the National Power System;
> To develop a competitive electricity market through introduction of billing based on the current consumption profile with facilitation of change the provider;
> To provide information about the current energy and other commodity consumptions;
> To limit electricity prices increases for end-user through the implementation of new competitive forces in the electricity market.

In particular, the act sets up a national target for efficient energy management to achieve, by 2016, the final energy savings in the amount of not less than 9% of the average domestic consumption of this energy in a year, the averaging covers the years 2001-2005.

Regulation

It is worth stressing that primary energy legislation does not directly address the implementation of Smart Grids. Moreover, existing grid codes for distribution and transmission grids do not have any specific provisions for smart grids implementation. Currently, the Polish Energy Regulator (URE) is the main actor providing incentives for Smart Grids initiatives.

URE intends by 2015 to introduce quality-based regulation to incentivize investments in the modernization of the power system and to support smart grid projects.

The regulator is currently revising best practices for quality-based regulation and different options for introducing new support mechanisms, particularly for innovative investments such as smart grids and smart metering. The goal is to re-define the regulatory framework to promote investment in energy produced by “prosumers,” network reliability, and activation of demand-side resources and energy efficiency.

For smart metering, Polish authorities have considered that the implementation of intelligent metering systems cost-effective and have expressed their full support to smart metering roll-outs, as a first step for broader development in Smart Grids in Poland. However a full CBA document is not publicly available.

As mentioned before, 80% smart metering roll-out is foreseen by 2020.

5.2.3 Polish Power System – On-going Smart Grid initiatives

Hel Peninsula pilot project

The Hel Peninsula pilot project led by Energa is the first attempt in the Polish power sector at practical implementation and verification of the new Smart Grid applications.

The project’s first stage covers approximately 100,000 measuring devices in three selected locations. One of the areas selected for the deployment is a zone in its prevailing part of urban character, in the northern part of Poland, supplied from a primary substation (110/115 kV substation Władysławowo). The project will focus on medium and low voltage grids.

Main elements of the project include:

> IT system integrated with SCADA at the Regional Power Dispatch level
> telecommunication infrastructure
> automation, control, and measuring equipment in MV and LV grids
> Installation in the LV grid of distributed generation such as photovoltaic cells, wind turbines, as well as heat pumps, smart street lighting, and electric vehicle charging stations.

Key objectives of the project include:

- Improving supply reliability indicators and failure recovery time in the project's area, via practical implementation of fault location and grid reconfiguration algorithms, together with enhanced LV grid monitoring.
- Implementing voltage regulation and demand response for grid management
- Testing islanding operation of a portion of the distribution grid coordinating distributed generation.
- Testing the efficiency of demand side management (DSM) mechanisms and of electric vehicle smart charging

It is worth mentioning that the European Bank for Reconstruction and development has agreed to support ENERGA investment programme in Smart Grids in the period 2012-2015 with a loan of PLN 800 million (around 200M€). The investment programme foresees the implementation of smart grid solutions aiming at energy efficiency improvements and integration of distributed generation.

Smart Metering

As mentioned, ENERGA has been undertaking since 2009 a wide smart metering pilot project comprising approximately 100,000 measuring devices in three selected locations. In 2014, tens of projects in smart metering, especially for householders and small commercial (from thousands to tens of thousands clients), are being launched. The projects are financed via tariffs.

5.3 Best practices for regulatory support of Smart Grid investments in selected Member States

In 2010, the Council of European Energy Regulators published a set of recommendations for changing the regulatory framework to incentivize the modernization of the European energy systems [15]. Among proposed recommendations, the following two levers for providing incentives to Smart Grid investments are increasingly at the centre of the European debate over how to incentivize investments in Smart Grids:

- Specific incentive programs to support innovation investments
- Output-based regulation (e.g. reward/penalties with reference to predefined targets like quality of supply, outage time etc.)

Under traditional regulatory regimes, DSOs do not have an incentive to take an active role in Smart Grid developments. As an example, we consider the mismatch between DER penetration and DSO incentive:

- DER penetration determines cost increase for DSO

[15] ERGEG Position Paper on Smart Grids – Consultation Paper and Conclusions Paper (after public consultation), ERGEG, May 2010. http://www.energy-regulators.eu

> DER penetration determines reduction of grid revenues (e.g. auto-consumption)
> DSOs do not typically have direct incentives to go beyond the bare minimum in integrating DERs

In several European countries, the trend toward output-based regulation is pursued to align DSOs incentives with Smart Grid transformations and to ensure that DSOs take an active role in Smart Grid investments. Output-based regulation includes service outputs in the revenue drives of grid companies, i.e. bonus/penalty for DSO performances on e.g. losses, continuity of supply, amount of DG integration etc.. Another tool that is increasingly being pursued is to provide specific innnovation funds for DSOs to purse R&D/innovative/smart investments and take an active role in Smart Grid developments.

In the following, we will illustrate these on-going regulatory evolutions with some examples from regulation in the UK, Italy and France, where significant steps have been undertaken to promote Smart Grid investments (see table 13).

Member State	Bonus/penalty regulation for DSO performances	Innovation funds to support Smart Grid investmentss
Italy	Continutity of supply performances (SAIDI targets)	Additional 2% remuneration for Smart Grid projects improving hosting capacity of MV networks
France	Continuity of supply; controllable OPEX; quality of supply; R&D spending level; losses	Mandatory % of turnover to invest in R&D
UK	Indicators of performances in the following domains: • Customer satisfaction • Safety • Reliability (e.g. energy not supplied) • Conditions for connection • Environmental impact (e.g. lower electricity losses) • Social obligations	-Annual "Network Innovation Competition" to support innovative Smart Grid projects (£30M)- Companies able to pass through up to 90 per cent of innovation expenditure. -Low Carbon Network Fund- • First tier: Support for small-scale projects (budget less than (£0.5M) • Second tier: annual financing up to £64M for a small number of large-scale smart grid projects

Table 13 – Examples of output based regulation and smart grid incentive programs in UK, Italy and France

ITALY

Incentives for smart grid investments

The Italian regulator (AEEG) has put in place specific innovation schemes to support Smart Grid investments. In particular the regulator has issued three specific calls for Smart Grid projects that could benefit from regulatory support: active grid (integration of distributed generation), storage, and electro-mobility.

For example, under the active grid call, DSO investments in Smart Grids supporting the integration of distributed generation are awarded an additional remuneration of 2%. Approved Smart Grid projects are included in the regulated asset-base and remunerated under a traditional cost-plus regulation.

Smart Grid investments are eligible for extra-remunaration is if they contribute to mitigate reverse power flows in the MV grid caused by the high penetration of distributed generation. To this end, eligible projects need to be located in MV substations affected by reverse power flow for a certain number of hours per year. Projects are then selected according to their score on a specific indicator (so called "Psmart") which assess the project's impact in improving the hosting capacity of distributed generation without causing grid problems (voltage, current, frequency).

Output-based regulation

In Italy, output-based regulation is currently focused on continuity of supply. Since 2000, the Italian regulator has introduced a bonus/penalty scheme for DSOs based on indicators of continuity of supply, namely, the average duration of interruptions per consumer (SAIDI) - for long (longer than 3 minutes) unplanned interruptions.

The indicator is calculated separately in a number of areas (over 300) that have similar characteristics (e.g. in terms of population density) and that are managed by the same distribution company. The bonus/penalty scheme is calculated for each area on an annual basis, taking into account the performance target. This approach is also intended to leave flexibility to DSOs in finding most innovative and cost-effective approaches to reach the target.

For the next regulatory period (starting in 2016), the Italian regulator is considering to further extend output-based regulation to support Smart Grid investments. In particular, on the ground of the results of the incentive program for Smart Grid projects on active grid, the regulator is considering to set bonus/penalty according to DSO performances with respect to the reverse time flow index (share of yearly hours where the power flows in a MV substation is reversed) and the Psmart index.

FRANCE

Incentives for smart grid investments

In France the main public incentive program to support Smart Grid investments has been launched by the French agency for Environement and Energy Management (ADEME). ADEME launched two calls for expressions of interest in 2009-10 and in 2011, with the goal of providing financial support to Smart Grid projects. Key objectives of the ADEME calls include the integration of distributed energy resources (distributed generation, demand response, electric vehicles etc.) and the definition of new business models for Smart Grid actors. In the period 2010-2013, a total of 16 projects have been launched in the framework of the ADEME Smart Grid program. The total budget of projects amounted to 304 M€, with ADEME funding equals to 82.9 M€.

Another incentive for DSOs to purse R&D/innovative/smart investments is the obligation for system operators to mandatorily invest a percentage of their turnover in R&D.

Output-based regulation

In France, the network access tariff (**TURPE**) was created in 2000 by the French Regulator (CRE) in order to finance the operation and the investments in T&D networks. With the third tariff period 2009-2013, incentive mechanisms (reward/penalty) were introduced by CRE to encourage system operators to optimize their performance. These include performance targets for:

> the quality of supply (equivalent outage time)
> the controllable operating expenditure
> the quality of service (only for the DSO).

Current reflexions on the 4th TURPE revision are considering to further extend the bonus/malus scheme. At distribution level bonus/malus schemes should be set-up for the volume of losses and for R&D and innovative spending. This is expected to provide further incentives to DSOs to undertake innovative Smart Grid investments.

UK

Output-based regulation

Under the current RIIO system (Revenue=Incentive+innovation+Outputs)[16], the UK regulator OFGEM has set-up an ambitious framework to provide incentives to DSOs to pursue innovation and to take an active role in the management of the grid. Main envisioned targets that led to the revision of the previous regulatory framework starting in 2008 were:

> Reduction of 80% of greenhouse gas emissions by 2050
> Decarbonised electricity generation by 2030

Under the RIIO model, the Regulator has set outputs that network companies are expected to deliver in a number of domains:

> ensure safe and reliable services
> non-discriminatory and timely connection and access terms
> customer satisfaction
> limited impact on the environment
> delivery of social obligations.

DSOs incur in penalties if they do not meet performance standards.

Innovation funds for smart grid investments

In 2010, OFGEM established the Low Carbon Networks (LCN) Fund. The Fund runs for a period of five years (2010-15) and provides up to £ 320 million in financial support to incentivize distribution network operators (DNOs) in

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[16] https://www.ofgem.gov.uk/network-regulation-%E2%80%93-riio-model

undertaking innovation-based projects, facilitating the UK transition toward a low carbon economy.

The LCN Fund provides two tiers of funding. The first tier is intended to support DNO-led small-scale smart grid projects with budgets of less than £0.5 million. Under the Second Tier, OFGEM organises an annual competition for an allocation of up to £ 64 million to help fund a small number of large-scale smart grid projects.

Moreover, under the RIIO model, OFGEM has set-up an annual competition for electricity and gas network companies to benefit of an innovation allowance for research, demonstration and commercial implementation of innovative technologies and applications.

Some of the main features of the Innovation Allowance include:

> there is a limit of the allocation of innovation funding for each company:
> the innovation allowance is capped at 0.5-1% of allowed revenue
> level of cap depends on the quality of the justification set out in the company's innovation strategy
> Companies are able to pass through up to 90 per cent of innovation expenditure.

5.4 On-going European initiatives on Smart Grid data management regulation

Another key development that is necessary to support smart grid investments is a clear regulatory framework over data management. In particular the EC Smart Grid Task Force, which includes all main European Smart Grid stakeholders and is chaired by the European Commission, has presently three working groups devoted to data management models[17].

In June 2013, the EC Smart Grid Task Force has proposed three models to define roles and responsibilities in managing smart metering data:

> **DSO as market facilitator:** In this model the DSOs are in charge of operating Smart Metering data hub(s) and making data available to interested third parties. This is that de-facto model in countries with just one DSO (e.g. Ireland).

> **Central data hub (CDH):** In this model, a (regulated) third party is in charge of operating the Smart Metering Data Hub (the CDH does not perform metering), possibly at national level. This model has already been implemented in Denmark (since winter 2012/2013) and has already been approved in the UK.

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[17] EC Smart Grid Task Force Expert Group 3 -“Options on handling smart grids data”, June 2013, http://ec.europa.eu/energy/gas_electricity/smartgrids/taskforce_en.htm

> **Data access point manager (DAM):** In this model, there are no data hubs. The model foresees a new commercial role: the "Data access-point managers". These market actors are in charge of enabling authorized parties to retrieve data directly from the meters. There are no examples of this model to date.

Table 14 reports the current situation in terms of implementation of data management models in different Member States.

Data management Model	Countries in which model has already been selected	Countries leaning toward the model
DSO data hub	-	Netherlands, Belgium, Ireland
Central data hub	UK, Denmark	Italy; Poland; Sweden; Finland; Estonia
Data access manager	No examples to date	No examples to date

Table 14 Smart Grid data management models proposed by the Smart Grid Task Force and examples of adoption in selected Member States

In parallel, we remark that the EC Smart Grid Task Force is also working on providing inputs to the European Commission on data privacy and cyberseucirty[18]. It is expected that the EC will issue new recommendations on data-privacy and cybersecurity in the folowing months.

Data Privacy

In January 2013, the Smart Grid Task Force produced a first draft of a Data Protection Impact Assessment (DPIA) template for Smart Metering Systems. The adoption of a DPIA had been recommended by the European Commission (EC) for smart metering[19]. The template has to be made available to organizations and Member States. It is meant to be applied on a voluntary basis as a means for organizations to anticipate and manage the potential privacy risks that may arise from new implementations and programs.

[18] http://ec.europa.eu/energy/gas_electricity/smartgrids/taskforce_en.htm

[19] Source:see http://eur-lex.europa.eu/legal-content/EN/ALL/;jsessionid=yWxHTzVpPC40Hy3xhJ1JX2NfQQZ8CKpz1mddB1Qdhl3n1BLnd655!509556202?uri=CELEX:32012H0148

Cyber-security

Since 2012, the Smart Grid Task Force has been working on the assessment of best available technologies to address cyber security. This work is carried out in the framework of the EC Recommendation 2012/148/EU of 9 March 2012 on Smart Metering roll-out[20]. The Recommendation required to focus on the cyber security risks inherent to the common minimal functional requirements for smart metering and to identify optimal controls to mitigate each of these risks.

Following the on-going work in the EC Smart Grid Task Force, the EC might consider to adopt a Recommendation on minimum cyber security requirements for Smart Grids (possibly to be adopted in 2014).

[20] http://eur-lex.europa.eu/legal-content/EN/ALL/;jsessionid=yWxHTzVpPC40Hy3xhJ1JX2NfQQZ8CKpz1mddB1Qdhl3n1BLnd655!509556202?uri=CELEX:32012H0148

6 CONCLUSION

The general objective of the project is the definition of a Smart Grid assessment framework for JASPERS officials to support national authorities of beneficiary countries (i.e. new EU Member States) identifying the most relevant Smart Grids investments. Poland and Romania will be considered as case studies to illustrate the proposed assessment framework.

The project has been organized into two different parts and accordingly two different reports have been produced.

This is the first report which describes the work carried out in the first part of the assignment. It provides a complete methodology for smart grid project assessment, which is articulated in three main outputs:

- Detailed characterization of Smart Grid investments through the description of a detailed list of smart assets, smart functionalities and associated key performance indicators

- Definition of eligibility criteria for Smart Grid projects under the upcoming EU regulatory funding period 2014-2020.:

    - Assessment of Smart technical characteristics – Is the proposed investment a Smart Grid project?

    - Assessment of project impacts (based on key performance indicators-KPI) – Does the project deliver expected positive impacts in line with energy policy goals?

    - Economic viability (economic cost-benefit analysis CBA) – Does the project deliver net positive monetary benefits for society?[21]

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[21] This criterion applies only for major projects (under the meaning of article 100 of EU regulation 1303/2013)

> Definition of an excel project assessment tool, including a detailed list of formulas for the quantification of KPIs, costs and benefits.

Moreover, this report also presents possible regulatory mechanisms to support the implementation of Smart Grid investments, drawing from best practices and on-going discussions at European level, and presenting the current regulatory context for Smart Grids in Poland and Romania.

Romania and Poland are the case studies that are analysed more in detail in the second report (corresponding to phases 3 and 4 of the assignemnt) to illustrate the proposed methodology. The second report also provides speficic documents to support sumbission of projects' applications (standard tender documents, application guide, description of requirements for project implemnetation units etc.).

APPENDIX

Annex A1 REFERENCES

Sources for "Smart Assets"

Books & Publications

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Guidebook for ARRA Smart Grid Program Metrics and Benefits, DOE, December 2009

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"*Definition of an assessment framework for projects of common interest in the field of smart grids,* "EC Smart Grids Task Force Expert Group 4:, July 2012. http://ec.europa.eu/energy/infrastructure/consultations/doc/20120720_electricity_smartgridsassessment_framework_sgtf_eg4.pdf

"*Evaluation of Smart Grid projects within the Smart Grid Task Force Expert Group 4 (EG4)*", EC JRC, 2013. http://ses.jrc.ec.europa.eu/sites/ses.jrc.ec.europa.eu/files/documents/evaluation_of_smart_grid_projects_within_the_smart_grid_task_force_expert_group_4_eg4.pdf

Annex B1 – Project assessment Tool User Manual

Annex C1 – Project assessment tool

Two versions of the project assessment tool has been prepared for non-major projects (without the CBA assessment module) and for major projects (with the CBA assessment module.

The corresponding excel files are:

Annex C1- Jaspers- Smart Grid Assessment Tool_non-major projects.xlsx

Annex C1- Jaspers- Smart Grid Assessment Tool_major projects.xlsx

Annex D1 – List of acronyms

AIT	Average Interruption Time
AMI	Advanced Metering Infrastructure
BAU	Business As Usual
CAPEX	Capital Expenditures
CBA	Cost-benefit analysis
CDH	Central data hub
CHP	Combined Heat and Power
DAM	Data Access Manager
DER	Distributed Energy Resources
DG	Distributed Generation
DLR	Dynamic Line Rating
DMS	Distribution Management System
DR	Demand Response
DSM	Demand Side Management
DSO	Distribution System Operator
EC	European Commission
EEGI	European Electricity Grid Initiative
EIA	Environmental Impact Assessment
EMS	Energy Management System
ENS	Energy Not Supplied
EU	European Union
EV	Electric Vehicle
FACTS	Flexible Alternating Current Transmission Systems
FLISR	Fault Location/Isolation/Service Restoration
GHG	Greenhouse Gas
HV	High Voltage
HVDC	High Voltage Direct Current

ICT Information and Communication Technologies

IRR Internal Rate of Return

KPI Key Performance Indicator

LV Low Voltage

MV Medium Voltage

NPV Net Present Value

OECD Organisation for Economic Co-operation and Development

OHL Overhead line

OP Operational Programme

OPEX Operational Expenditures

PA Priority Axis

PV Photovoltaic

RES Renewable Energy Sources

RTU Remote Terminal Unit

SAIDI System Average Interruption Duration Index

SAIFI System Average Interruption Frequency Index

SCADA Supervisory Control and Data Acquisition

SG Smart Grid

STD Standard Tender Documents

TSO Transmission System Operator

V2G Vehicle to Grid

VPP Virtual Power Plant

WAMS Wide area monitoring system