SEVENTH FRAMEWORK
PROGRAMME

THEME [ENERGY.2012.7.1.1] Integration of Variable Distributed Resources in Distribution Networks

Sustainable

(Deliverable –2.4)

KPI Assessment Methodology

Lead Beneficiary:

ICCS/NTUA

December 2013

Table of Contents

List of Figures

List of Acronyms and Abbreviations

CHP	Combined Heat and Power
CL	Controllable Load
DG	Distributed Generation
DoW	Description of Work
DSM	Demand Side Management
DSO	Distribution System Operator
DTC	Distribution Transformer Controller
Energy Box	Smart Meter
EV	Electric Vehicle
IED	Intelligent Electronic Device
HV	High Voltage
KPI	Key Performance Indicator
LV	Low Voltage
MV	Medium Voltage
NWP	Numerical Weather Predictions
OLTC	On-Load Tap Changing
OPF	Optimal Power Flow
RES	Renewable Energy Sources
RTU	Remote Terminal Unit
SCADA/DMS	Supervisory Control and Data Acquisition / Distribution Management System
SSC	Smart Substation Controller
STOR	Storage Device
TSO	Transmission System Operator
TVPP	Technical Virtual Power Plant
uG	Microgeneration
VHV	Very High Voltage
VPP	Virtual Power Plant

Authors

Authors	Organization	E-mail
Nikos Hatziargyriou	ICCS/NTUA	nh@power.ece.ntua.gr
Stavros Papathanassiou	ICCS/NTUA	st@power.ece.ntua.gr
George Korres	ICCS/NTUA	gkorres@cs.ntua.gr
Pavlos Georgilakis	ICCS/NTUA	pgeorg@power.ece.ntua.gr
Aris Dimeas	ICCS/NTUA	aris.dimeas@power.ece.ntua.gr
Despina Koukoula	ICCS/NTUA	kdespina@power.ece.ntua.gr
Kai Struntz	TUB	kai.strunz@tub-berlin.de
João A. Peças Lopes	INESCP	jpl@fe.up.pt
Luis González Sotres	UPC	luis.gonzalez@iit.upcomillas.es
Sami Abdelrahman	UNIMAN	sami.abdelrahman@postgrad.manchester.ac.uk
Pedro Godinho Matos	EDPD	pedro.godinhomatos@edp.pt
Diogo Lopes	EDPD	diogo.alveslopes@edp.pt
António Aires Messias	EDPD	aires.messias@edp.pt

Access:

Project Consortium	
European Commission	
Public	X

Status:

Draft version	
Submission for Approval	
Final Version	X

1. Executive Summary

This deliverable provides the KPIs and the KPIs' assessment methodology for the pilot installations and the proof of concept demonstration networks of the SuSTAINABLE project. Starting with the KPIs defined within the EEGI framework (Level 1 and Level 2 KPIs), the document focuses on the Level 3 KPIs that will be used to evaluate quantitatively the benefits of the methods and functionalities developed within Sustainable and applied on the actual pilot and demonstration networks.

The Level 3 KPIs are adopted from the DoW and are optimized, as follows:

1) Deferred Transmission and Distribution Capacity Investment;
2) Reduction of Technical Losses
3) Allowable maximum DG power without branch overload and voltage limit violations;
4) Share of electrical energy produced by Renewable sources;
5) Voltage and Power Quality performance indices;
6) Reduction of Carbon Emissions;
7) Reduction in RES cut-off due to congestion;
8) Optimized use of Assets

A detailed definition and calculation formulas are also provided in the present document. Finally, a number of indices to evaluate the accuracy and quality of the developed algorithms is provided as a Level 4 KPIs.

2. Introduction

Description of the **Task 2.4 "Definition of use case requirements and proof-of-concept scenarios characterization" from the Description of Work (DoW):**

This task will prepare the proof-of-concept and validation activities by specifying the requirements in terms of distribution network models, parameters, and scenarios and identifying a HV/MV substation and one or more MV/LV substations, with significant amounts of DG, where the demo will be run. It will detail actual regulatory schemes in study cases. Finally, the proof-of-concept and validation KPIs will be identified, namely the ones referred in the following table.

Call Requirements: KPI

- Technically and economically viable deployment of smart grids solutions:

1) Deferred Transmission and Distribution Capacity Investment;
2) Reduction of Technical Losses

- Integrating a large share of distributed renewable generation units in distribution networks, Substantial increase of the hosting capacity for medium- and small-size renewable sources (mainly wind and PV farms) in existing medium- and low-voltage networks, Allow distribution networks to be operated with reverse flows of electricity at times of high renewable electricity generation and low load:

3) Allowable maximum DG power without branch overload and overvoltage risks;
4) Share of electrical energy produced by Renewable sources;
5) Voltage and Power Quality performance indices;
6) Reduction of Carbon Emissions;
7) Reduction in RES cut-off due to congestion;
8) Ratio of Renewable Generation and Load

- Effective planning of necessary network reinforcements, Better observability of distributed resources:

9) Percentage of nodes with DG monitored in real time;
10) Allowable maximum injection of DG without congestion risk;
11) Optimized use of Assets

This task will establish the scenarios to be implemented in WP5 and WP6 where the current conditions of pilot sites will be complemented with the tools developed along the SuSTAINABLE project. Two main validation sites will be used with high potential for extracting objective conclusions regarding our proposed objective – the InovGrid in Portugal and Rhodes Island in Greece. Also, for more complex functionalities, proof-of-concept demonstrations (simulations) will be held at pilot sites in Germany, UK, Greece (Meltemi) and the Laboratory facilities of INESCP, ICCS and the SENSE lab at TUB.

This document includes the KPI assessment methodology for the tools of SuSTAINABLE project. For the KPIs the EEGI framework is adopted as described in the following figure.

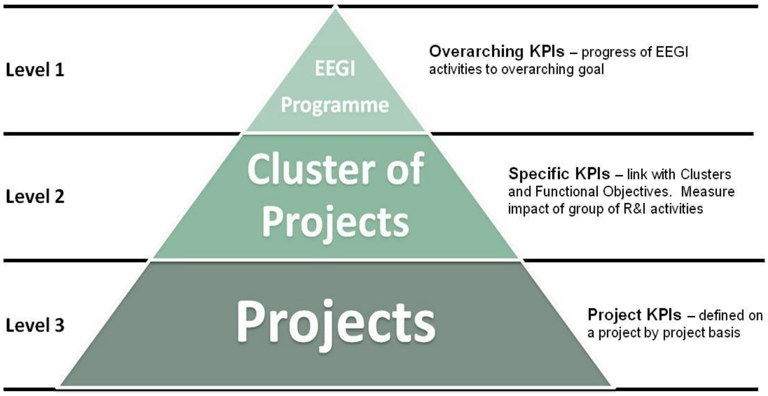


Figure 2 EEGI KPI developed framework for impact KPIs

As adopted from [1] KPIs are distinguished in three levels:

- **The Level 1 "Overarching KPIs"** consists of a limited set of network performance indicators which trace clear progress brought by EEGI activities towards its overarching goal;
- **The Level 2 "Specific KPIs"** are indicators defined at Cluster level to quantify the expected impacts of a group of R&I activities in view of meeting the R&I roadmap overarching goal;
- **The Level 3 "Project KPIs"** are proposed by each R&I project in view of detailing further the contribution of each R&I project to level 2 KPIs

Chapter 2 of this document contains the list of KPIs as defined in Grid+ and the Sustainable project.

Chapter 3 provides the list of relevant Level 3 KPIs for each of the Sustainable functionalities.

Chapter 4 provides a description of the KPIs and the formulas for their calculations.

3. SuSTAINABLE Project - KPIs Overview

3.1 Level 1 KPIs Assessment

In the Grid+ project, two main KPIs define a global level of assessment. These KPI are:

A.1 Increased network capacity

Increased Network Capacity [NC] is the amount of electrical power that can be transmitted or distributed in the selected frame, for example, to connect new RES generation, to enhance an interconnection, to solve congestion, or even all the transmission capacity of a TSO. In other words, it concerns the possibility to increase the usage of a given electrical network in order to accept higher levels of integration of distributed generation and consumption, using also available distributed storage units, by exploiting dynamic monitoring and exploiting flexibility in terms of injected power into the grid from generation units and also responsiveness from active loads.

A.2 Increased system flexibility

Increased System Flexibility (SF) is the amount of electrical power (generation or load) that can be modulated to the needs of the system operation within a specific unit of time. It results from higher levels of controllability of distributed energy resources (generation, load and storage) that allow the management of these resources either locally or in a coordinated manner to enhance the capabilities and efficiency of operation of given electrical network.

The calculation methods for the Level 1 KPIs are described in Annex A of [1] and will be adopted by SUSTAINABLE.

3.2 Level 2 KPIs Assessment

A second level of six, more detailed KPIs was defined in Grid+ in order to further monitor the increasing network capacity and/or system flexibility. The following table, copied from [1], lists these impact KPIs and their links with the R&I clusters and the three pillars of EU energy policy.

KPI describing the Expected network capacity & flexibility increases		**Related R&I cluster(s)**	**Compliance with EU policy goals**			**TSO/DSO**	
			Sustainability	**Market competitiveness**	**Security of Supply**	**TSO**	**DSO**
B.1	*Increased RES & DER hosting capacity*	Power Technologies Integration of DER & new uses Network operation Market Designs	X	X	X	X	X
B.2	*Reduced energy curtailment of RES and DER*	Grid Architecture Network Planning Power Technologies Integration of Smart Customers Integration of DER & new uses Network Operation Market Designs	X	X	X	X	X
B.3	*Power Quality and Quality of Supply*		X	X	X	X	X
B.5	*Increased flexibility from energy players*			X	X	X	X
B.4	*Extended asset life time*	Asset Management			X	X	X
B.6	*Improved competitiveness of the electricity market*	Integration of Smart Customers Integration of DER & new uses Network Operation Market Designs		X		X	X
B.7	*Increased hosting capacity for Electric Vehicles and other new loads*	Network Planning Integration of DER & new uses Network Operations	X	X	X		X

The five R&I clusters for DSO are identified as follows:

C1. Integration of smart customers

D1. Active demand for increased flexibility

D2. Energy Efficiency from integration with Smart Homes

C2. Integration of DER and new users

  - D3. DSO Integration of small DER
  - D4. System Integration of medium DER
  - D5. Integration of Storage in Network Management
  - D6. Infrastructure to host EV/PHEV
- C3. Network Operations
  - D7. Monitoring and Control of MV Network
  - D8. Automation and Control of MV Network
  - D9. Network Management Tools
  - D10. Smart Metering Data Processing
- C4. Network Planning and asset management
  - D11. New Planning Approaches for Distribution Networks
  - D12. Asset Management
- C5. Market Design
  - D13. New Approaches for Market Design Analysis

The following table relates the R&I clusters with the KPIs describing the Expected network capacity & flexibility increases.

KPI describing the expected network capacity & flexibility increases	**Related R&I cluster(s)**
B1. Increased RES & DER hosting capacity	C2. Integration of DER & new users (D3) C3. Network operation (D8, D9) C5. Market Design
B2. Reduced energy curtailment of RES and DER	C1.Integration of Smart Customers (D1) C2. Integration of DER & new users (D3) C3. Network Operation (D7, D8, D9, D10) C4. Network Planning (D11) C5. Market Design
B3. Power Quality and Quality of Supply	
B5. Increased flexibility from energy players	

3.3 Level 3 KPIs Assessment

In order to identify in a quantified manner the benefits that can be obtained from the adoption of the Sustainable functionalities, a more focused and detailed set of KPIs is defined, leading to the third level. These KPIs are the following:

1) Deferred Transmission and Distribution Capacity Investment;
2) Reduction of Technical Losses
3) Allowable maximum DG power without branch overload and voltage limit violations;
4) Share of electrical energy produced by Renewable sources;
5) Voltage and Power Quality performance ;
6) Reduction of Carbon Emissions;
7) Reduction in RES cut-off due to congestion;
8) Optimized use of Assets

3.4 Level 4 KPIs Assessment

Some of the functionalities, like state estimation and forecasting, are enabling functionalities providing the background of the rest of the functionalities and having an overall clear, but indirect impact on the main KPIs. It is important to evaluate the performance of these functionalities, therefore specific quality indices are suggested for this purpose. These indices, termed Level 4 KPIs, are the following:

9) Forecasting Accuracy

10) State Estimation Quality

4. SuSTAINABLE Functionalities Impact on Project KPIs

The Sustainable project will develop the following set of functionalities:

SF1. Advanced local forecasting tools to predict renewable generation

SF2. Advanced local forecasting tools to predict load consumption

SF3. Advanced local distribution grid monitoring / state estimation

SF4. Advanced coordinated voltage control exploiting controllable generation, flexible loads, storage devices and conventional OLT and capacitors (or DFACTS if they exist);

SF5. Technical virtual power plant (TVPP) concept-as support to the interaction between DSO and TSO, providing coordinated actions

SF6. Provision of differentiated quality of supply (QoS)

SF7. Network reinforcement planning considering management of distributed flexibility

SF8. Power quality planning for flexible distribution systems

SF9. Planning of Advanced System Protections

These functionalities are described in detail in D2.3 “**Definition of Overall System Architecture”**

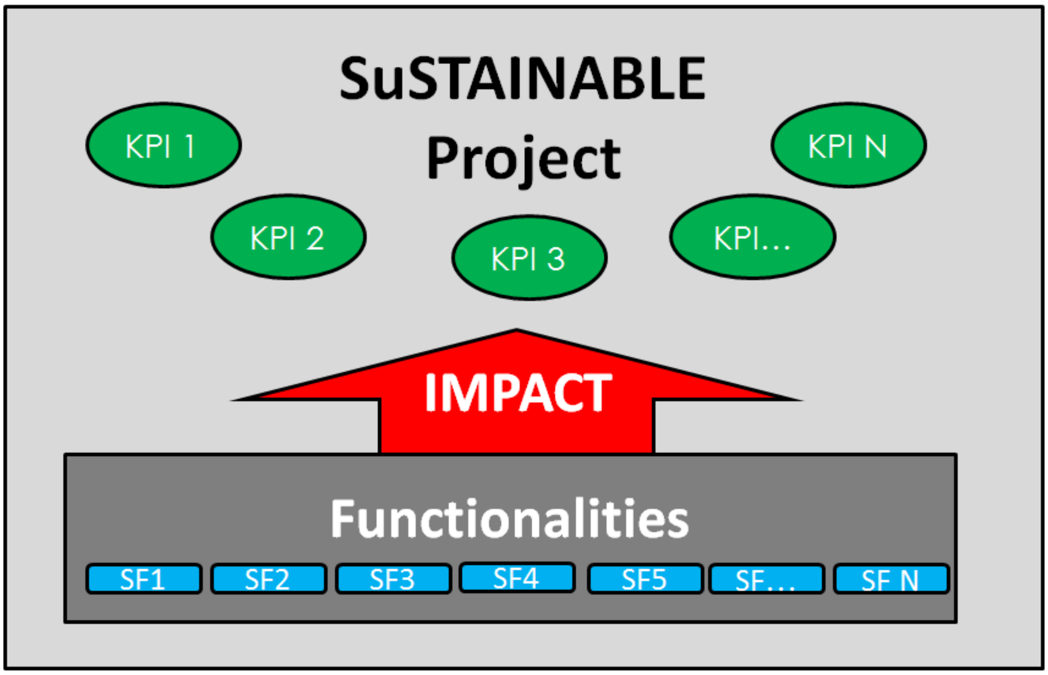


Figure 2. Impact of Sustainable functionalities on project KPIs

The following Table relates the KPIs identified with the functionalities under development in the Sustainable project.

Sustainable Functionalities impact on project KPIs

	KPI1. Deferred T&D Capacity Investment	KPI2. Reduction of Technical Losses	KPI3. DER Hosting	KPI4. Share of RES	KPI5. Power Quality	KPI6. Reduction of Carbon Emissions	KPI7. Reduction in DER cut-off due to congestion	KPI8. Optimized use of Assets
SF1. RES Forecasting			(X)	(X)	(X)	(X)	(X)	(X)
SF2. Load Forecasting			(X)	(X)	(X)	(X)	(X)	(X)
SF3. Monitoring/ State Estimation		(X)			(X)		(X)	(X)
SF4. Coordinated Voltage Control		X	X	X	X	X	X	
SF5. TVPP as support to DSO/TSO			X	X	X	X	X	
SF6. Provision of Differentiated QoS	X				X			
SF7. Flexibility based Reinforcement Planning	X		X	X		X		X
SF8. Power Quality Planning	X	X			X			
SF9. Advanced Protections Planning					X		X	X

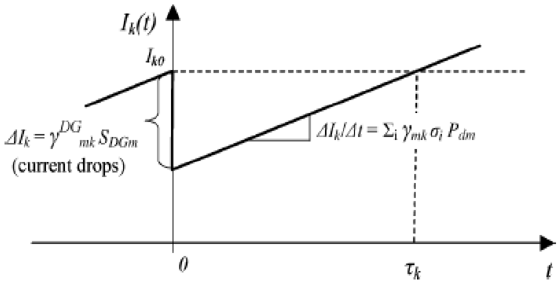
(x) Enabling functionalities having indirect impact on KPIs

NOTE: The set of Level 3 KPIs proposed in this deliverable and their corresponding links to the developed functionalities are defined according to the current project state of development and expected outcomes, they might be however modified throughout the project.

5. Definition of Sustainable KPIs

5.1. Deferred Transmission and Distribution Capacity Investment

The satisfaction of load increase requires an amount of transmission and distribution assets in order to avoid violation of operating limits. These limits concern overloaded transformers and lines, typically at urban networks, and voltages, typically at rural networks. Network expansion planning considering the connection of DER can defer investments in transmission and distribution assets, since load can be satisfied locally up to a certain amount.



The KPI

$$PV(\tau_g) = \frac{C_g}{e^{p+\tau_g}}$$

PV is the present value of deferred investment, C_g is the investment cost, τ_g is the deferral time, *p* is the real interest rate

This KPI is particularly useful for the functionality of network reinforcement planning considering management of distributed flexibility. The reinforcement planning functionality will be built as follows: The distribution network at the reference year is given. Moreover, the investments in distributed generation (location and size) within the planning horizon are also given. What is requested is to optimally expand (reinforce) the distribution network in the planning horizon so as satisfy the load at the minimum possible total cost and at the same time being able to host the whole planned DG capacity, considering smart grid (voltage control) functionality.

More specifically, the Deferred Transmission and Distribution Capacity Investment (DTDCI) KPI for the functionality of network reinforcement planning considering management of distributed flexibility will be computed by the following formula:

$$DTDCI = \left(\frac{NRC_{BL} - NRC_{SG}}{NRC_{BL}} \right) \cdot 100\%$$

where:

NRC_{BL} is the net present value of the network reinforcement cost for the baseline scenario, i.e., 1) without installation of DG in the planning horizon, and 2) without smart grid (DG voltage control) functionality. The NRC_{BL} will be computed by the multi-objective network reinforcement planning functionality considering no installation of DG in the planning horizon.

NRC_{SG} is the net present value of the network reinforcement cost for the smart grid case, i.e., 1) considering the installation of the whole scheduled DG in the planning horizon, and, 2) considering the smart grid functioning of the DG (DG voltage control). The NRC_{SG} will be computed by the multi-objective network reinforcement planning functionality considering installation of DG in the planning horizon in combination with smart grid (DG voltage control) functionality.

5.2. Reduction of Technical Losses

The integration of a greater share of renewable energy resources in distribution grids can potentially reduce losses due to local balancing of energy production and consumption and thus reduction in power flows. In some cases however, the inversion of power flows related to increased energy production in low load periods increases energy losses.

The KPI calculation will take into account a set of scenarios and boundary conditions to evaluate the percentage of energy losses related to bi-directional power flows

$$\Delta L = \frac{L_{BL} - L_{SG}}{L_{BL}} \cdot 100\%$$

L_{BL} is the amount Energy losses (kWh) in baseline scenario evaluated in a defined period.

L_{SG} is the amount of Energy losses (kWh) in smart-grid situation (using network reconfiguration, new devices, ...) evaluated in a defined period.

KPI expressed in % (or kWh if multiplied by L_{BL})

5.3. Allowable maximum DG power without branch overload and voltage limit violations (Increase of RES Hosting Capacity)

The need for a large share of RES in energy production leads to conventional reinforcements to enable grid to host them without loss of power quality and reliability.

The advanced function of RES Hosting Capacity Estimation uses the operational states of the grid including the DER control possibilities and determines the safe upper limit of hosting capacity, without need of new investments.

The parametric RES hosting capacity study provides DSO with information about the total hours during the year, at which the PV installations should accept curtailment orders, to avoid overvoltage and overcome other operational limitations caused by the grid. This results to an increased RES capacity installation accompanied by minor PV production rejections during critical hours.

Increased network hosting capacity of DG on MV distribution network

$$HC_{\%} = \frac{HC_{SG} - HC_{BL}}{HC_{BL}} \cdot 100\%$$

HC_{BL} is the initial (baseline) Hosting Capacity under the primary substation.

HC_{SG} is the Hosting Capacity under the primary substation implementing DER control solutions.

KPI expressed in % (or MW when the KPI is multiplied by HC_{BL})

5.4. Share of Electrical Energy produced by RES

The KPI calculation will take into account a set of scenarios and boundary conditions to evaluate the percentage of energy production by RES

$$\Delta\lambda = \lambda_{SG} - \lambda_{BL}$$

λ_{SG} is the share of RES energy in smart-grid situation evaluated in a defined period.

λ_{BL} is the share of RES energy in the baseline scenario over the same period.

RES energy shares (%) are calculated as:

$$\lambda = 100\frac{E_{RES}}{E_{LOAD}}$$

where E_{RES} is the energy generated by RES stations in the defined period and E_{LOAD} is the total load demand in the same period.

KPI expressed in %.

5.5. Voltage and Power Quality Performance

One of the most essential power quality issues is voltage at the user connection points. The DNO has the statutory obligation to maintain voltage at all network nodes within a permitted voltage variation band, as stipulated by applicable standards. At the same time, DNOs will always seek to minimize voltage deviation from nominal, to the degree possible.

The increased voltage deviations, especially at remote and weak nodes of the distribution network, due to large DG penetration is mitigated by optimized exploitation of available regulation means in the network, DER reactive power control, DER active power curtailments and possibly via the incorporation and optimal control of energy storage and demand flexibility.

To quantify the voltage regulation across the entire network, the RMS deviation of the voltage at all nodes is evaluated over the examined time interval:

$$d_V = \sqrt{\frac{\sum_{t=1}^{T}\left(\sum_{i=1}^{N}\left(V_{i,t} - V_n\right)^2\right)}{V_n^2}}$$

where:

d_V is the voltage deviation index for the entire network and time period
N is the number of nodes in the network
T is the evaluation period
$V_{i,t}$ is the voltage of node i at time interval t
V_n is the nominal voltage

To assess the impact on steady state voltage regulation of advanced network control practices, the following KPI is applied:

$$\Delta d_V(\%) = \frac{d_V(u_{SG}) - d_V(u_{BC})}{d_V(u_{BC})} \cdot 100\%$$

where:

$d_V(u_{BL})$ is the voltage deviation index for the base case scenario (standard practice, e.g. typical OLTC action, unity DG power factor, no curtailments, no storage etc.).

$d_V(u_{SG})$ is the voltage deviation index with Smart Grid solutions applied.

For both scenarios, the same network topology, load and DER deployment is assumed.

5.6. Reduction of Carbon Emissions

This KPI is entirely dependent on KPI 4.4, since the generated RES energy substitutes practically equal amounts of conventional energy (ignoring the secondary effect of factors such as the change in transmission and distribution losses, the variations in the efficiency and carbon emission factors of generating units providing regulation reserves etc.). If the conventional generation mix is given and the associated average carbon emission factor is assumed to remain the same, regardless of the achieved RES penetration in the examined network, then the reduction of carbon emissions (CE) KPI is given by:

$$\Delta CE = \frac{CE_{BL} - CE_{SG}}{CE_{BL}} \cdot 100\% = \frac{1}{1 - \lambda_{BL}} \Delta\lambda$$

where CE_{BL} and CE_{SG} are the carbon emissions at the two scenarios (base line and smart grid) used to evaluate KPI 4.4, λ_{BL} the RES energy share at the base line case and $\Delta\lambda$ the KPI 4.4.

5.7. Reduction in RES cut-off due to congestion

Curtailments of DER active power is a last-resort solution that the DNO may apply to deal with violations of voltage or thermal limits and thus increase DER hosting capacity, because it may raise regulatory, financial and environmental issues. Nevertheless, when such a policy is applied, the amount of energy curtailments can serve as a KPI for the evaluation of the effectiveness of the adopted control practices.

As with the others KPIs, a comparison needs to be made of the curtailed RES energy between a baseline scenario, where basic control and regulation is applied to the network, and one where Smart Grid solutions are being adopted. Nevertheless, it should be pointed out that the application of DER active power control in the baseline scenario already implies the possibility of smart monitoring and control.

Hence, in the first scenario a pseudo “business as usual” scenario will be adopted, where active power curtailments for DER will be applied as the main control variable, while standard voltage control and reactive power regulation will be available. Fitting a large amount of DER in the network will inevitably involve substantial DER energy curtailments. The smart grid scenario, on the other hand, will comprise the full control possibilities for voltage and reactive power means. This way, it is expected that the same DER capacity will be accommodated in the network with reduced active power cut offs. In both scenarios, all network elements, including loads and installed DG, are exactly the same.

The KPI will be given by the following formula:

$$\Delta E = \frac{E_{BL} - E_{SG}}{E_{BL}} \cdot 100\%$$

where

E_{BL} is the amount of RES energy curtailed in baseline scenario in a defined period

E_{SG} is the amount of RES energy curtailed in the smart grid scenario over the same period.

5.8. Optimized use of Assets

The variation of the utilization factor of network assets e.g. transformer or feeder capacity is traditionally an important index quantifying the optimal exploitation of investment in network equipment. Increasing levels of DER penetration will in general lead to a reduction of short term utilization indices, as more power will be generated locally, instead of being transported over the network. On the long run, on the other hand, this may permit deferral of investments in new T&D capacity, as quantified on KPI 4.1, depending on the load demand and DG generation patterns.

In principle, utilization of assets will mainly depend on installed DG type and capacity, the former because different DER will be characterized by different generation patterns and capacity factors. Coordinated voltage control policies will have a marginal effect on this factor. Hence, this KPI is not deemed suitable to quantify the effect of such policies.

In any case, if this KPI needs to be assessed, the utilization factor of central network assets can be calculated in two scenarios (baseline–BL and smart grid-SG) using the following formula, e.g. for the HV/MV transformer feeding the MV network under study:

$$UF = {}^{E_{tr}}\!/_{(T * S_n)}$$

where

E_{tr} is the energy that flows through the transformer in a defined time period (MWh)

T is the period duration (h)

S_n is the rated capacity of the transformer (MVA)

The KPI will then be calculated by the following equation:

$$\Delta \mathrm{UF} = \frac{\mathrm{UF_{BL}} - \mathrm{UF_{SG}}}{\mathrm{UF_{BL}}} \cdot 100\%$$

The two scenarios will employ the same network topology, loads and installed DG capacities per node. Different DER deployment scenarios can also be adopted (instead of different regulation policies) to evaluate the effect of increasing DER penetration levels.

Alternatively, the optimized use of assets can take into account the capital costs. More specifically, apital costs and difficulties in building transmission and distribution infrastructures imposes increased life-time of assets while operating closer to their limits without endangering the system reliability.

Option 1: The Improved Life-time of Assets can be calculated by looking at the total cost of exploiting a given group of assets, both the capital expenditure as well as the operational expenditure. The values involved in the calculation need to be Net Present Value (NPV) ones in order to perform an appropriate comparison. Replacement costs (RC), which are included in the CAPEX, can be reduced as a consequence of better asset management policies, which may increase the expense in OPEX (more monitoring, supervision, predictive or reliability-centred maintenance, etc). This extra expense in OPEX should justify or compensate the reduction in RC.

$$ILA = \frac{(CAPEX_{BAU} + OPEX_{BAU}) - (CAPEX_{R\&D} + OPEX_{R\&D})}{(CAPEX_{BAU} + OPEX_{BAU})}$$

Option 2: The Improved Life-time of Assets can be calculated by looking only at the replacement costs (RC) in a business as usual situation and in a situation where new asset management policies (from R&I projects) have been applied:

$$ILA = (RC_{BAU} - RC_{R\&D})/(CAPEX_{BAU})$$

This KPI is particularly useful for the functionality of network reinforcement planning considering management of distributed flexibility. The reinforcement planning functionality will be built as follows: The distribution network at the reference year is given. Moreover, the investments in distributed generation (location and size) within the planning horizon are also given. What is requested is to optimally expand (reinforce) the distribution network in the planning horizon so as satisfy the load at the minimum possible total cost and at the same time being able to host the whole planned DG capacity, considering smart grid (voltage control) functionality. The network reinforcement planning will be solved as a multiobjective optimization problem, as described in the DOW.

More specifically:

The indicator BAU ("Business as usual") corresponds to the baseline scenario, i.e., 1) without installation of DG in the planning horizon, and 2) without smart grid (DG voltage control) functionality.

The indicator R&D corresponds to the smart grid case, i.e., 1) considering the installation of DG in the planning horizon, and, 2) considering the smart grid functioning of the DG (DG voltage control).

5.9. Forecast Improvement (Level 4 KPI)

For load and PV forecasting, the KPI is the improvement over a reference model, calculated for each lead-time. This improvement is calculated for different Error Metrics (EM) and each lead-time *k* as follows:

$$\mathrm{Imp}_k = \frac{EM_{k,ref} - EM_{k,\mathrm{model}}}{EM_{k,ref}} \cdot 100\%$$

For load forecast, the typical EM is the Mean Absolute Percentage Error (*MAPE*):

$$MAPE_k = \frac{1}{N}\sum_{t=1}^{N}\left|\frac{\hat{P}_{t+k|t} - P_{t+k}}{P_{t+k}}\right| \cdot 100\%$$

The bias of the forecast, representing the systematic error, is also computed using:

$$BIAS_k = \frac{1}{N}\sum_{t=1}^{N}\frac{\hat{P}_{t+k|t} - P_{t+k}}{P_{t+k}} \cdot 100\%$$

The reference model is the existing load forecasting system or a seasonal ARIMA model.

For PV forecasting the typical EM is the Normalized Root Mean Square Error (*NRMSE*):

$$\mathrm{NRMSE}_k = \frac{\sqrt{\frac{1}{N}\sum_{t=1}^{N}\left(\hat{P}_{t+k|t} - P_{t+k}\right)^2}}{P_{peak}}$$

and the bias is also calculated.

The reference model is the existing PV forecasting system or an AR model.

The previous metrics only evaluate the point forecast quality. In order to evaluate the probabilistic forecast quality, the improvement is calculated with the Continuous Ranking Probability Score (CRPS) as EM. The *CRPS* is given by:

$$CRPS_k = \frac{1}{N}\sum_{t=1}^{N}\int_{x=-\infty}^{x=+\infty}\left(\hat{F}_{t+k|t}(x)-F_{t+k}(x)\right)^2 dx$$

The reference model is the existing probabilistic forecasting approach or a quantile regression with univariate data.

The *CRPS* results are supported by three additional metrics: reliability (or calibration), sharpness and resolution.

Reliability (or calibration) is a measure of the agreement between nominal proportions (forecasted probabilities) and the ones computed from the evaluation sample. In other words, in a quantile the empirical proportion should equal the nominal exactly, e.g. an 85% quantile should contain 85% of the observed values lower or equal to its value.

In order to evaluate the reliability, first it is necessary to define the indicator variable. An indicator variable for a quantile forecast $\hat{q}^{\alpha}_{t+k|t}$ with proportion α is:

$$\xi^{\alpha}_{t+k|t} = \begin{cases} 1\ if\ \ P_{t+k} \le \hat{q}^{\alpha}_{t+k|t} \\ 0,\ otherwise \end{cases}$$

The indicator variable refers to the actual outcome of P_{t+k} at time t+k - that is, whether the quantile covers the actual outcome (“hit”) or not (“miss”).

Furthermore, these indicators are defined as follows:

$$n^{\alpha}_{k,1} = \#\left\{\zeta^{\beta}_{t+k|t} = 1\right\} = \sum_{t=1}^{N}\zeta^{\alpha}_{t+k|t}$$

$$n^{\alpha}_{k,0} = \#\left\{\zeta^{\beta}_{t+k|t} = 0\right\} = N - n^{\alpha}_{k,1}$$

that is, as sums of hits and misses, respectively, for a given lead-time k over N realizations.

A common way of checking calibration is to compare the empirical to the nominal coverage by using the indicators mentioned above, that is:

$$\hat{\alpha}^{\alpha}_{k} = \frac{n^{\alpha}_{k,1}}{n^{\alpha}_{k,1} + n^{\alpha}_{k,0}}$$

This difference between empirical and nominal proportions is considered the bias of the probabilistic forecasting method:

$$b^{\alpha}_{k} = \alpha - \hat{\alpha}^{\alpha}_{k}$$

Sharpness is the tendency of probability forecasts towards discrete forecasts, measured by the mean size of the forecast intervals (distance between quantiles):

$$\bar{\delta}_k^{\alpha} = \frac{1}{N}\sum_{t=1}^{N}\left(\hat{q}_{t+k|t}^{1-\alpha/2} - \hat{q}_{t+k|t}^{\alpha/2}\right)$$

Quantiles are gathered by pairs in order to obtain intervals with different nominal coverage rate. This gives an indication on the level of usefulness, where narrow intervals are desired.

Resolution is the concept that evaluates the ability of providing situation-dependent assessment of the uncertainty. It is measured by the variation of the size of the intervals. The standard deviation of the interval size for a given lead-time k and coverage rate (1-α) is computed as:

$$\sigma_k^{\alpha} = \sqrt{\frac{1}{N-1}\sum_{t=1}^{N}\left(\left(\hat{q}_{t+k|t}^{1-\alpha/2} - \hat{q}_{t+k|t}^{\alpha/2}\right) - \bar{\delta}_k^{\alpha}\right)^2}$$

5.10. State Estimation quality Indices (Level 4 KPI)

The state estimation quality indices related to accuracy and performance of the state estimation methodology are described in [2] and [3]. These indices express the deviations of the estimated network quantities with regard to their true values.

Accuracy – It is desired that estimated quantities be as close as possible to their true values. Accuracy KPIs are defined by choosing a power flow solution quantity of interest and defining a norm-like calculation on the difference between the “true” value (derived from the power flow solution) and the “estimated” value (derived from the state estimation solution) or the “measured” value (derived from RTU and smart meter).

- KPIs which measure the accuracy of active (*Pf*) and reactive (*Qf*) branch power flows:

1-norm	$\sum_{j=1}^{n_L}\left\|Pf_j^{true} - Pf_j^{est}\right\|$	$\sum_{j=1}^{n_L}\left\|Qf_j^{true} - Qf_j^{est}\right\|$
2-norm (Euclidean norm)	$\sum_{j=1}^{n_L}\left(Pf_j^{true} - Pf_j^{est}\right)^2$	$\sum_{j=1}^{n_L}\left(Qf_j^{true} - Qf_j^{est}\right)^2$
infinity norm	$\max_{j=1,\ldots,n_L}\left\|Pf_j^{true} - Pf_j^{est}\right\|$	

$$\max_{j=1,\ldots,n_L}\left|Qf_j^{true} - Qf_j^{est}\right|$$

n_L is the number of network branches

- KPIs which measure the accuracy of active (*Pi*) and reactive (*Qi*) bus power injections:

1-norm	$\sum_{j=1}^{n_B} \left\| Pi_j^{true} - Pi_j^{est} \right\|$	$\sum_{j=1}^{n_B} \left\| Qi_j^{true} - Qi_j^{est} \right\|$
2-norm (Euclidean norm)	$\sum_{j=1}^{n_B} \left(Pi_j^{true} - Pi_j^{est} \right)^2$	$\sum_{j=1}^{n_B} \left(Qi_j^{true} - Qi_j^{est} \right)^2$
infinity norm	$\max_{j=1,\ldots,n_B} \left\| Pi_j^{true} - Pi_j^{est} \right\|$	$\max_{j=1,\ldots,n_B} \left\| Qi_j^{true} - Qi_j^{est} \right\|$

n_B is the number of buses

- The norm KPI of the error of the state estimate captures the effect of both voltage magnitude and angle errors:

$$Macc_V = \left\| \tilde{V}^{error} \right\|_2 = \left(\sum_j \left| \tilde{V}_j^{true} - \tilde{V}_j^{est} \right|^2 \right)^{\frac{1}{2}}$$

where $\tilde{V}_i^{true}$ and $\tilde{V}_i^{est}$ is the true and estimated complex phasor voltage at the *j*th bus reported on a per unit basis.

- Error Estimation Index (EEI):

$$EEI = \sum_{i=1}^{n_M} \left(\frac{z_i^{true} - z_i^{est}}{\sigma_i} \right)^2$$

n_M is the number of network buses,

σ_i is the actual standard deviation of the Gaussian, zero-mean, random noise used to pollute the noise-free measurement z_i^{true} in creating the noisy measurement z_i .

- KPIs which determine the ability of the state estimator to accurately discern active and reactive power flow and injection measurements:

$$PIP_f = \frac{\sum_{j=1}^{n_L} \left(Pf_j^{true} - Pf_j^{est} \right)^2}{\sum_{j=1}^{n_L} \left(Pf_j^{true} - Pf_j^{meas} \right)^2} \qquad PIQ_f = \frac{\sum_{j=1}^{n_L} \left(Qf_j^{true} - Qf_j^{est} \right)^2}{\sum_{j=1}^{n_L} \left(Qf_j^{true} - Qf_j^{meas} \right)^2}$$

$$PIP_i = \frac{\sum_{j=1}^{n_B}\left(Pi_j^{true} - Pi_j^{est}\right)^2}{\sum_{j=1}^{n_B}\left(Pi_j^{true} - Pi_j^{meas}\right)^2} \qquad PIQ_i = \frac{\sum_{j=1}^{n_B}\left(Qi_j^{true} - Qi_j^{est}\right)^2}{\sum_{j=1}^{n_B}\left(Qi_j^{true} - Qi_j^{meas}\right)^2}$$

For good estimation, the estimate of each flow will lie closer to the true than will the measured value and the entire metric will be less than one.

Performance – The performance of the estimator determines its capability to provide a stable solution in reasonable and predictable time to be used by other applications in the control center. The following KPIs quantify the performance of the state estimator to converge.

$$Mconv_{obj} = \left|1 - \frac{J^{k_{term}}}{J^{k_{term}-1}}\right|$$

$$Mconv_V = \max_{i \in n_B}\left|1 - \frac{V_i^{k_{term}}}{V_i^{k_{term}-1}}\right|$$

$$Mconv_\delta = \max_{i \in n_B}\left|\delta_i^{k_{term}} - \delta_i^{k_{term}-1}\right|$$

k_{term} denotes the terminal iteration of the state estimation algorithm

The metric $Mconv_{obj}$ measures the relative change in objective function value J at the last iteration, while the metric $Mconv_V$ and $Mconv_\delta$ measure the largest final relative change in bus voltage magnitude and angle, respectively, over the network buses. Note that $Mconv_\delta$ uses the absolute difference to avoid problems when the angle is near zero, which will occur near the system reference bus.

6. References

[1] Deliverable D 3.4 “Define EEGI Project and Programme KPIs”, EC Coordination and support action, “GRID+ Supporting the Development of the European Electricity Grids Initiative (EEGI)” 2013
[2] “Metrics for Determining the Impact of Phasor Measurements on Power System State Estimation”, KEMA, 2006.
[3] P. C. Vide, F. P. M. Barbosa, J. A. B. Carvalho, “Metric Indices for Performance Evaluation of a Mixed Measurement based State Estimator”, Power Engineering and Electrical Engineering, Vol. 11, No. 2, 2013.