Smart Grid Key Performance Indicators: A DSO perspective

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1. Executive summary

Background

This report aims to proactively propose a set of indicators able to measure the performances of smart grids.

The document presents a DSOs perspective emerging from the work of a TSOs & DSOs joint task force created in March 2020 under the initiative of ENTSO-E and the four European Associations representing DSOs, CEDEC, E.DSO, EURELECTRIC and GEODE (hereafter together “the Associations”) and composed by experts from the different countries and typologies of system operators.

The trigger for this common work is the Article 59.1 (l) of the Electricity Directive ((EU) 2019/944), which tasks the National Regulatory Authorities (NRAs) to develop a new methodology that can help monitor a necessary infrastructure upgrade through the use of smart grids, focusing on energy efficiency and integration of energy from renewable sources.

The report makes available to the NRAs, collectively and/or individually, a limited set of key performance indicators (KPIs): seven DSOs KPIs plus a common TSO-DSO KPI. It also provides guidelines for the selection, definition and implementation of these KPIs and their composing (key) indicators ((K)Is).

This work builds on a review of the wider literature and discussions that have been ongoing for some time about smart grid KPIs and is complemented by the accumulated expertise of European system operators.

Approach

The report starts with a description of the TSO-DSO interfaces and their future common challenges as well as a shared understanding of what “smartness” means: smartness is not a goal on its own but a skill necessary to achieve effectiveness and efficiency in solving new challenges faced by system operators.

Consequently, the report highlights the skills or functionalities that system operators should develop for smarter operation of their grids, both from an operational and market perspective, in view of the identified challenges. On top of that, it specifies the necessary "TSO-DSO coordination capabilities" and reflects those in a common KPI.

THE SIX COMMON CHALLENGES	KPI 1: System Observability	KPI 2: System Controllability	KPI 3: Active System Management	KPI 4: Smart Grid Planning	KPI 5: Transparency in Data Access and Sharing Between Relevant Stakeholders	KPI 6: Local Flexibility Markets and Customer Inclusion	KPI 7: Smart Asset Management
Cooperation in network operation	X	X	X		X	X	
Cooperation in planning the networks				X			X
Exchange all necessary information regarding the long-term planning of network investments			X	X			X
Exchange all necessary information regarding the generation assets and demand side response for the daily operation of their networks	X		X		X	X	
Cooperate with each other in order to achieve coordinated access to resources	X		X		X	X	
Ensure cost-efficient, secure and reliable development and operation of their networks	X			X	X	X	X

Figure 1 Interlinks between DSO KPIs and the identified challenges.

Use of the indicators

KPIs and (K)Is follow the cost-efficiency rule framework adopted by each NRA: i.e. for all the functionalities the cost/benefit ratio must be appropriate: this evaluation for every KPI cannot be run at European level. This means that fine-tuning of the finally selected smart grid indicators should be completed by each NRA individually.

The flexible setup of the developed smart grid indicators should warrant the possibility for NRAs to select a subset of these indicators that matches their country specific circumstances such as the structure of the electricity networks, the technical differences between the transmission and the distribution grids, as well as the different voltage levels between distribution and transmission, and the availability and collectability (with reasonable effort) of the required data.

In this view, the identified KPIs (and composing (K)Is) cannot represent a tool to benchmark different system operators, since they operate in different conditions and start from different levels of smartness but can be used to monitor the evolution of the smartness of a system operator in managing its grid.

Proposed KPIs are not meant to replace the existing ones that measure system operators' performances (like SAIDI, SAIFI or grid losses metrics) but instead complement them to have a better and wider understanding of the behaviour of system operators.

This report is only a first step towards the identification of the indicators mentioned in article 59.1 (l). Further work needs to be done, based on this report, at country level by the selection of the most appropriate defined parameters. DSOs are available to support European regulators in the accurate identification of the (K)Is and KPIs they consider most appropriate to their national context.

2. Introduction

The Clean Energy Package establishes a new environment for the electricity market, facing several challenges:

1. the integration of ever larger shares of distributed resources;
2. the growing electricity demand due to increasing electrification of heat (e.g. heat pumps) and transport (e.g. electro-mobility);
3. the energy transition necessary to meet the EU decarbonisation goals.

All the above will require a functional evolution of the transmission and distribution grids (e.g. digitalisation) and underlying investments in grid edge technologies. Depending on the country, today's regulatory frameworks might not be the best suited to address such functional changes because they focus mainly on efficiency and quality performance, which can be considered as "lagging" indicators rather than on investments in future-oriented grid solutions, like grid flexibility and interaction between system operators' operational platforms, etc.

The Electricity Directive therefore tasks the National Regulatory Authorities (NRAs) to develop by the end of 2020 a new methodology that can help to monitor and better target a necessary infrastructure upgrade.

Electricity Directive (EU) 2019/944), article 59.1 (l) states:

> *The regulatory authority shall have the following duties: […]*
> *(l) monitoring and assessing the performance of the transmission system operators and distribution system operators in relation to the development of a smart grid that promotes energy efficiency and the integration of energy from renewable sources based on a limited set of indicators, and publish a national report every two years, including recommendations;*

The DSO associations want to proactively develop a proposal for a set of smart grid indicators, which will be presented to the NRAs collectively and/or individually.

A starting point for this work is to define capabilities/functionalities expected from future distribution grids in relation to the specific challenges and corresponding solutions/technologies including a description of expected benefits (e.g. integration of renewable energy sources).

On this basis, a list of pragmatic indicators needs to be determined, while considering the very diverse structure of the electricity networks in each country, the technical differences between the transmission and the distribution grids, as well as the different voltage levels between distribution and transmission in the countries (cf. figure 1).

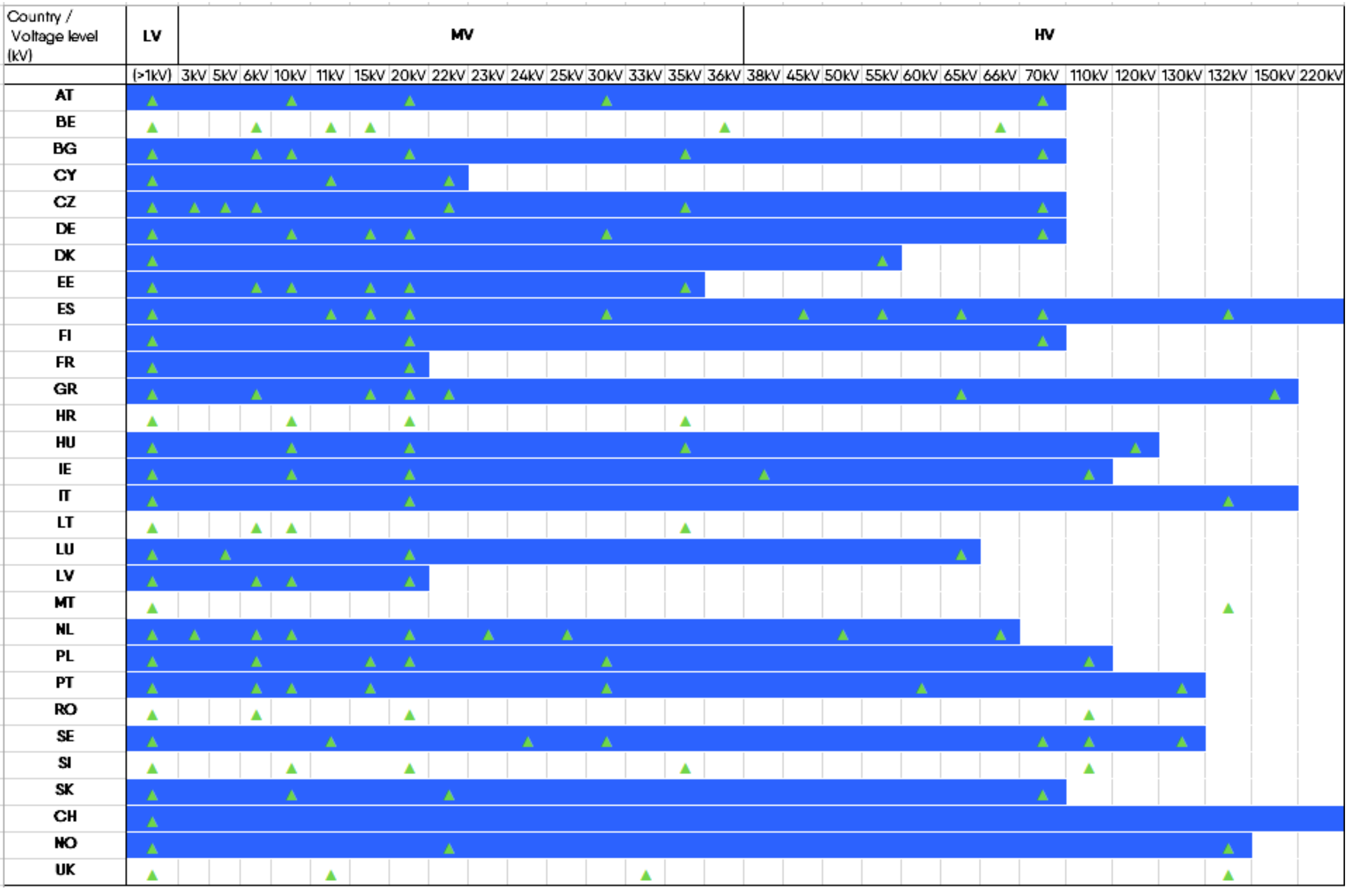

Figure 2 Operation of distribution grids – voltage levels – source: EURELECTRIC – Facts & Figures – 2020

It is up to the NRA of each country to impose a valid limited set of indicators.

Recital 83 of the Electricity Directive (EU) 2019/944 provides examples of such indicators:

> *National regulatory authorities should ensure that distribution and transmission system operators take appropriate measures to make their network more resilient[1] and flexible. For doing so, they should monitor their performance based on indicators such as their capability to operate lines under dynamic line rating, the development of remote monitoring and real-time control of substations, the reduction of grid losses and the frequency and duration of power interruptions.*

The Associations have set up a common task force for this work. The Task Force gathers several experts appointed by the Associations. There is a co-chairmanship consisting of one DSO and one TSO expert. The Associations' staff participates to support the work of the Task Force. The two co-chairs of the Task Force are responsible for the organisation of the work including the conduct of the meetings with the support of the Associations' staff.

The Task Force reports on its activities to the Secretary Generals of the Associations. While the Task Force should aim for consensus among its members, issues that could not be solved unanimously at working level should be escalated and raised to the Secretary Generals' meetings. The Associations are ultimately responsible for approving any documents.
The Task Force started its activities in March 2020 and delivered a report by end of 2020.

[1] *resilient in this context means: the ability to withstand and reduce the magnitude and/or duration of disruptive events, which includes the capability to anticipate, absorb, adapt to, and/or rapidly recover from such events.*

The work of the Task Force is built on the principles agreed on in previous TSO-DSO reports:

- an integrated vision of the power system;
- the customer perspective, market-based approach and innovation;
- respect particularities of specific countries and/or system operators.

The report is structured as follows:

- in a first chapter, we start with the definition of the TSO-DSO interfaces based on commonly agreed future challenges where we focus on common trends, such as the rise of renewables, electrification, decentralisation and digitalisation. The distributed flexibility seems to be the key operation area between the TSOs and the DSOs.
- next, cooperation between the DSOs and the TSOs is defined and explained as to why this cooperation is needed and at the same time the TSOs and the DSOs roles and responsibilities are described.
- further, the common TSO-DSO challenges (also mentioned in the Clean Energy Package) are defined through a number of specific topics, such as the cooperation regarding network operation and network planning, all necessary exchange of information for long-term planning of the network, but also information about generation and demand side flexibility for the daily operation, the coordinated access to resources and finally the cost-efficient, secure and reliable development and operation of the networks that should be ensured by TSOs and DSOs.
- based on these future challenges the TSO-DSO interfaces are defined and we distinguish the shared resources interface, the market interface and the direct TSO-DSO interface.
- the next chapter relates to why we need a monitoring of the grid smartness, the definition of grid smartness and the system operators' smart functionalities. Furthermore, there are commonly agreed requirements for KPIs selection and implementation, for which we zoom in on the difference between KPI and K(I) in the frame of smart grids and what the essential requirements are for KPIs.
- following chapter focusses on the definition of DSOs' "smartness" and KPIs. The functionalities of a modern distribution system and the importance of the monitoring of the smartness of the girds are highlighted, followed by a list of KIs and KPIs and finally the definition of common TSO-DSO "smartness" and KPIs.

This report does not cover:

- sector integration (electricity-gas, electricity-heat, …) as a smart use of the networks.
- cybersecurity protection of the network infrastructure and the information exchange.

3. Definition of TSO-DSO interfaces based on commonly agreed future challenges

3.1. Introductory topics

Common trends: the rise of renewables, electrification, decentralisation and digitalisation

Ensuring security of supply as well as resilience of the systems has become a quite different and much more challenging task in an environment with much more stochastic, volatile processes and significantly increased complexity due to the highly distributed generation, the variability of consumption and the energy transition.
In addition, climate change (and suddenly pandemic phenomena) is impacting the operation of transmission and distribution systems with an increasing trend year by year.

The traditional way of operating the systems (with strong focus on preventing emergencies and much less attention on curing them efficiently), leads to continuous increases on the distribution network capacity (often inefficient from the supplied energy/installed capacity ratio point of view) in the most critical geographical areas. With the fast changing of consumptions and production this process becomes ineffective.

In its Vision 2030 on Market Design and System Operation, ENTSO-E identified four key elements as major drivers for the power system of the next 10 years: the rise of renewables, the drive for electrification, the increase of decentralised resources, and digitalisation.

The presence and further development **of renewables** is key for all future scenarios. Wind and solar energy will play a major role in the system by the end of the next decade with a total installed capacity of almost 500 GW for solar PV and more than 300 GW for onshore and offshore wind in Europe. Therefore, electricity flows are expected to become more variable, requiring network development and efficient congestion management. Also, in most countries, the largest share of new renewable installations will be connected to the distribution network[2] which stresses the need for a proper coordination between TSOs and DSOs to integrate these resources in efficient and safe conditions.

Higher renewables penetration goes along with further **electrification** of applications in transport, and heating and cooling besides further uptake of sector-coupling. Electricity demand will increase driven by the market uptake of technologies such as electric vehicles and heat pumps. Despite the large increase in energy efficiency within the distribution grids, impact on the transmission grids might still be expected due to demand increase.

These developments will lead to an increased **decentralisation** of resources. Residential consumers will become more active in the market, for instance as prosumers or via aggregators. Innovative business models such as local energy communities will develop and the large-scale deployment of smart meters, connected devices and battery storage[3] will magnify this trend, making coordination between system operators crucial e.g. for exchange of grid and system services or data exchange for planning and operation of both distribution and transmission grids.

Digitalisation will help to unleash the potential of distributed flexibility. The electricity system will evolve towards a cyber-physical system where the development of an information and communication technologies layer will enhance physical grid utilisation. It will provide an architecture that can manage the complexity of a system integrating different geographical scales, functional processes and technologies.

[2] *From the new renewable capacity which should be installed at EU27+UK level 70% will be connected to the distribution grids in 2030.*
[3] *DG scenario shows that in 2030 battery storage capacity (utility scale) is expected to reach almost 18 GW in Continental Europe*

Different local, regional, national and European digital smart grid[4] architectures need to cooperate with each other.

Within this context, the main challenge for TSOs and DSOs working together will be the coordination for the best use of DERs and distributed flexibility: to ensure that they will provide the most added value to their owners, to the networks and to consumers. Of course, in addition to the willingness to coordinate, TSOs and DSOs should develop specific market mechanisms and IT tools to deal with these challenges.

DER & distributed flexibility

DERs raise challenges to the connecting grid and the system, but they are also an opportunity as they potentially have the ability to provide new services to the system operators. There is a need to focus on elaborating local tools and solutions by DSOs and on cooperation between TSOs and DSOs, to connect and co-ordinate some of these local solutions with national and international solutions. With regard to the roles and responsibilities that need to be defined in this domain, the following points should be highlighted:

- the related responsibilities of TSOs and DSOs are defined both in European and national regulations. These responsibilities are defined in the Clean Energy Package at a "high level," need further details to be defined in the country's regulatory transpositions of the Clean Energy Package provisions.
- customers should be at the centre of the system, and system operators should find together a way to fully implement this principle.
- the solutions for the power system should take into consideration two-way flow of energy and the role of DERs connected to the distribution grid. Their fast increase and their potential as sources of flexibility creates situations in which TSOs and DSOs shall work together in order to use all their potential.

TSO-DSO cooperation

An efficient level playing field for market parties is required, fostering new services and valuing flexibility, and system operators as neutral market facilitators will keep ensuring non-discrimination towards market parties.

TSOs and DSOs would:
- strengthen the coordination of mutual processes and, where necessary, enhance data exchanges between them to guarantee a reliable, efficient and affordable operation of the electricity system and grid;
- use flexibility that is effective in a coordinated way in order to reciprocally avoid problems and criticalities;
- have clear and distinguished roles and responsibilities for the access of the existing resources, while guaranteeing that there is no discrimination among them, and the common usage of the same resources should not result in negative impacts;
- share data and visibility securing the overall system efficiency and avoiding duplication of investments in market structures, metering and observability;
- consider the system operation and market perspective in a holistic approach.

Cooperation brings along certain operational benefits:

- **Balancing:** While the system balancing remains the responsibility of the TSO, (as defined in Electricity Balancing Guideline (EB GL), coordination in prequalification, activation and exchange of information is needed to avoid congestions and malfunctioning on TSOs and DSOs grids. Information on activation, schedules, metering and real-time measures are required to be properly exchanged to guarantee a more efficient balancing market where increasing participation of resources connected to the

[4] *Smart grid – see definition in Chapter 3*

distribution grid is possible and to allow those resources to become available for both TSOs and DSOs needs.

- **Intra-zonal congestion management:** TSOs and DSOs should, both in real time and in the operational planning/outage planning phase, work together in solving grid issues without causing new ones whilst minimising imbalance in the system where possible.
- **Voltage control:** Voltage issues in one system operator's grid can cause voltage issues in the grid of another system operator. In both distribution and transmission networks voltage levels there are efficiency and safety concerns, in transmission voltage it is also a stability concern. Therefore, coordination and clear rules are required to enable all system operators to deal with voltage control in an efficient, coordinated and effective way.

However, there are other challenges that should be mentioned (which are also defined in regulation (e.g. SO GL[5], EB GL[6], NC ER[7]), namely:

- **Observability**: The grid visibility is important in all time scales, and in real time becomes more important but also more difficult. Will all actions be visible, including those of market parties?
- **Metering and settlement**: It is important to work on proper data sharing to enable each system operator to perform the settlement.
- **Black-start and restoration approach**: In some places centralised units are being replaced by decentralised units that can be connected to transmission or distribution. This means that assets used for black-start and restoration will no longer mainly be connected to the transmission level and better coordination has to be established between TSOs and DSOs.
- **Grid connection:** It is important that assets that are connected to the grid meet the requirements of both DSOs and TSOs, that the roles and responsibilities are clear, information is shared and that the process of grid connection is user-friendly.
- **Frequency deviation management procedure**: The increasing number of decentralised units connected at distribution level and close to consumption hampers the definition of an efficient scheme for the automatic low frequency demand disconnection.

Roles and responsibilities

It remains clear that the roles for frequency control remain the responsibility of TSOs, as well as congestion management across bidding zones, taking into account the possible consequences on all customers and networks that are part of the system. However, depending on the system specificities, there can be different cooperation schemes for congestion management inside a bidding zone (in transmission and distribution). Regarding non-frequency ancillary services, they are the responsibility of the respective system operator where the service is required (according to the applicable regulation this could be the TSO or the relevant DSO), in good coordination with other (affected) system operators.

The metering of distribution customers should remain a DSOs activity and responsibility, also in the perspective of the general energy system efficiency; in this way duplication costs for customer metering, communication and control can be avoided. According to this responsibility DSOs cooperate with TSOs in the area of metering data and communication infrastructures (for flexibility commands to the customers) and with other relevant parties (market operators and customers) and guarantee for customers a proper and cost-effective service.

To ensure clarity on the evolution of the roles of TSOs and DSOs, with the new services/opportunities foreseen in the transmission and distribution systems, it is recommended that both TSOs and DSOs define

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[5] *Commission Regulation (EU) 2017/1485 of 2 August 2017 establishing a guideline on electricity transmission system operation*

[6] *Commission Regulation (EU) 2017/2195 of 23 November 2017 establishing a guideline on electricity balancing*

[7] *Commission Regulation (EU) 2017/2196 of 24 November 2017 establishing a network code on electricity emergency and restoration*

their needs in such a way that it enables all actors in the system, including active customers/DSR and aggregation, to participate when they can meet the minimum requirements. This would be essential to bridge the gap between very local actors willing to be empowered with more global needs of the European energy system as well as invigorating the flexibility potential.

TSOs and DSOs should work together in their business processes by building real-life solutions for the coordination of those processes. This means extensive data exchange and common TSO-DSO projects in designing and building platforms (or adaptation of existing ones) to support these business processes. This could lead to common platforms, or interoperable ones.

Clean Energy Package

System operators' challenges and, at the same time, a solution to those challenges, directly results as mentioned above from the Clean Energy Package provisions, and in particular from Article 57 of the Electricity Regulation "cooperation between distribution system operators and transmission system operators":

"*1. Distribution system operators and transmission system operators shall cooperate with each other in planning and operating their networks. In particular, distribution system operators and transmission system operators shall exchange all necessary information and data regarding, the performance of generation assets and demand side response, the daily operation of their networks and the long-term planning of network investments, with the view to ensure the cost-efficient, secure and reliable development and operation of their networks.*
2. Distribution system operators and transmission system operators shall cooperate with each other in order to achieve coordinated access to resources such as distributed generation, energy storage or demand response that may support particular needs of both the distribution system operators and the transmission system operators."

When talking about cooperation between TSO and DSO, in the context of the future use of distributed sources of flexibility, which will be able to effectively meet the needs of both TSO and DSO networks, one should remember the provisions of the Clean Energy Package indicating the need for cooperation also on this topic (Article 32 - Incentives for the use of flexibility in distribution networks and Article 40 - Tasks of transmission system operators). These articles are particularly important because they emphasise partnership in action, without defining a privileged position for any of the system operators.

3.2. Common TSO-DSO challenges

To reach the scope of the smart grid indicators joint task force, the first step is to define the common challenges that TSOs and DSOs have to face.

Looking at the above-mentioned introductory topics, we immediately recognise common TSO-DSO obligations that until recently system operators treated mostly separately, but now will have to face jointly in order to ensure:

- efficiency of the whole electricity system;
- fostering of competition and growth of new flexibility markets;
- elaborating flexibility tools;
- contributing to decarbonisation by inclusion of renewables and curtailment of consumption peaks and securing an affordable energy transition;
- development of technological standards to lower the costs of apparatus and grid management software applications;
- lowering of entry barriers to energy service market for customers and aggregators and
- ensuring democratic access to a common set of services for all European citizens.

The above results shall be reached by system operators implementing the following common activities, which have to be considered as **common challenges**:

1) *Cooperate in real time network operation:*

To continue ensuring the system security, DSOs and TSOs will have to help each other with the operation of their networks efficiently and safely and guarantee the compliance to certain power profiles (or general electrical parameter's profiles) in the interconnection points between their respective grids. These profiles will be agreed in function of date, time, weather conditions, customer consumptions, production issues and in general according to all the variables influencing grid operations.

Those agreements will be made by taking into account system efficiency, technological capabilities, regional situations of both operators and in general by a maximum of mutual understanding and cooperation.

The challenge will be to operate the respective grids focussed on the physical parameters on the end-user connection points, by trying to respect as much as possible the agreed range of functioning values in the interconnection points, notifying promptly possible issues and applying common procedures to manage unforeseen circumstances. The basis for this cooperation has been laid out in SO GL.

2) *Cooperate in operation planning of the networks:*

This challenge comes as a consequence of the previous one: once system operators know the expected functioning ranges of their performance and the forecast of those ranges they have the drivers to plan both the short-term and the medium-long-term development of their networks. Obviously, these development plans will be shared between DSOs and TSOs in order to find the most effective and efficient balance in terms of costs and implementation times.

3) *Exchange all necessary information regarding the long-term planning of network investments*

Strongly connected to the previous challenge, this one reinforces the concept that the investments must be efficient to avoid wasted or non-optimal expenditures of public money that could reduce incentives or financial resources to reach other common European objectives. DSOs and TSOs work together on joint scenario building to gain a common understanding of the future system needs.

4) *Exchange all necessary information regarding the generation assets and demand side response for the daily operation of their networks*

This challenge is a consequence of the first one, and focuses on observability, forecasts and interacting capabilities with DERs and DSRs connected to the respective grids. Further to the implementation of the requirements of the SO GL, system operators will agree on the most efficient way to measure and interact with DERs and DSRs to avoid duplication in metering and data transmission costs and will develop common procedures, formats and solutions to share data in a standard, secure and reliable way according to the respective grid management needs.

5) *Cooperate with each other in order to achieve coordinated access to resources*

This challenge mainly consists of fostering a common coordination scheme to select flexibility in an efficient way for TSOs and DSOs. The coordination scheme can be independent of the number of marketplaces for flexibility and should make all the flexible and renewable resources available to answer both TSOs and DSOs requests for services. This means that system operators have to share and agree, at national level, on common:

- market structure;
- market access procedures;
- priorities in accessing resources;
- rules for flexibility;
- product pre-qualification and activation criteria of shared resources;
- metering and communication equipment;
- settlement procedures;

while respecting provisions of network codes and guidelines which lay down the framework for some of these points.

In this context, TSOs and DSOs will share easily implementable procedures to avoid barriers to the growth of flexibility markets.

6) Ensure cost-efficient, secure and reliable development and operation of their networks

This challenge seems to be a duplication of the above ones, but it is not: it is about the philosophical approach of the system operators' sense of duty and comes on top of the previous ones.

DSOs and TSOs today feel responsible to do their best to secure, firstly, the continuity and quality of electricity supply to their customers and secondly the overall stability of the electricity system.

From now on, in addition to this, DSOs and TSOs also have to be responsible to help each other in securing the system stability, reliability and efficiency.

This is a matter of willingness to help, to share, to act for mutual support and benefit. This is probably the most important one of all the common TSO-DSO challenges.

3.3. TSO-DSO interfaces

Availability of data will enable TSOs to fulfil their duties foreseen by regulation, especially balancing services and security analysis.

GLDPM[8] and KORRR[9] addresses when, how and which data shall be shared with TSOs by DSOs, CDSOs[10] and SGUs[11] to perform the tasks defined in the SO GL and CACM GL[12]. GLDPM refers only to data exchange up to the day ahead, while KORRR also includes data exchange up to real time.

Due to the ever-increasing number of DERs and prosumers connected to distribution grids, and due to more and more frequent power peaks caused by cooling equipment and EV charging, real-time balancing and maintaining security of the whole electrical system is becoming increasingly difficult. From this perspective, increasing volumes of data must be exchanged between DSO and TSOs.

At the same time, DSOs must manage and operate their grids in a different way with the use of flexibility sources, more active and secure, thus becoming smarter in order to cope with the decentralisation of the electricity system.

As stressed before, to allow TSOs and DSOs to effectively fulfil their roles and responsibilities, strong cooperation and collaboration between them is required including:

- a flow of data without duplication of data collection;
- agreed procedures and formats for data exchange;
- efficient sharing of resources.

The electricity system needs to evolve towards a new age where data sharing is the key word.

To do this, a new system architecture including platforms and infrastructures may need to be developed and realised. Here, stakeholders will interact using various interfaces. In this regard, the TSO-DSO ASM report[13] provides several recommendations and solutions entirely defined and agreed between TSOs and DSOs.

Referring to TSO and DSO interfaces, the ASM report architecture can be summarised in the following architecture (although note that various models are available).

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[8] Generation and Load Data Provision Methodology in accordance with Article 16 of Commission Regulation (EU) 2015/1222

[9] Key Organisational Requirements, Roles and Responsibilities relating to Data Exchange in accordance with Article 40 of Commission Regulation (EU) 2017/1485

[10] CDSO: closed distribution system operator

[11] SGU: significant grid user

[12] Commission Regulation (EU) 2015/1222 of 24 July 2015 establishing a guideline on capacity allocation and congestion management

[13] TSO-DSO Report: An Integrated Approach to Active System Management

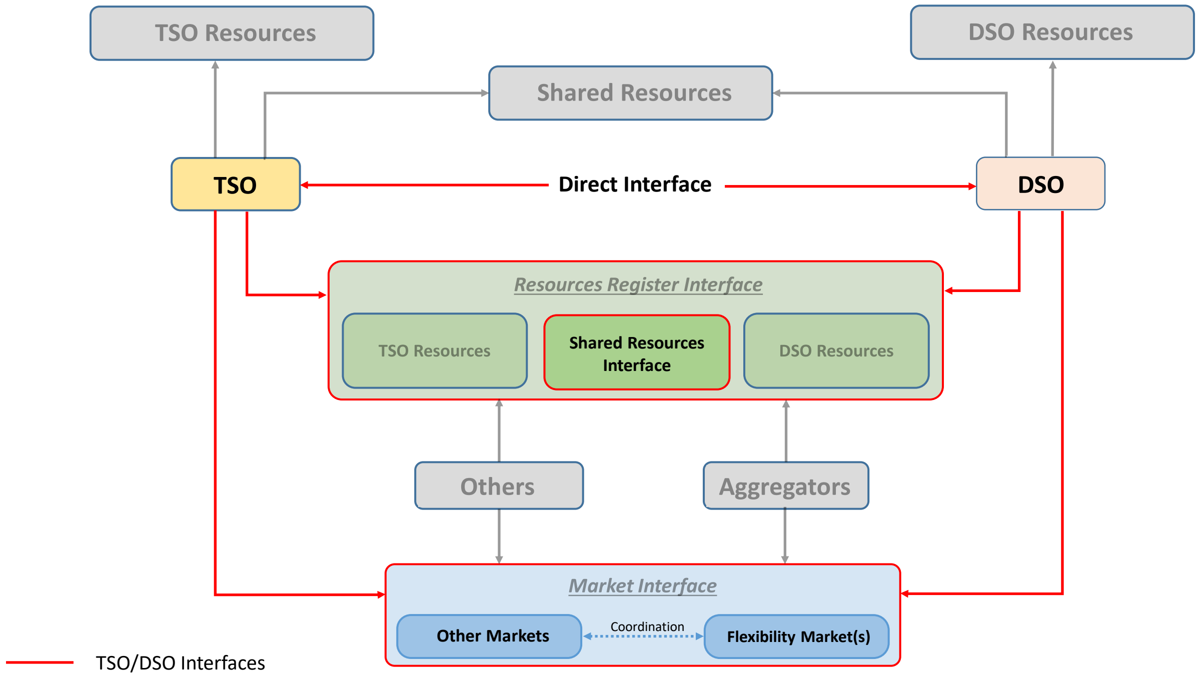


Figure 3 TSO/DSO interfaces architecture

The above scheme is intended to be a conceptual architecture describing the main functionalities that should be put in place to implement an advanced, efficient and effective TSO-DSO cooperation as described in the TSO-DSO ASM report: "it can be adapted to the need of every country, according to own regulation, state of technology and specific TSO-DSO interoperation agreements and market organisation."

Shared resources interface

The shared resources interface is the place where data related to *shared resources* (loads, generators, storage devices) connected to the distribution grids are made available both to TSOs and DSOs.
Data shared here could mainly consist of:

- structural data (e.g. identification of the point of delivery);
- infrequently changing variable data (e.g. supplier);
- variable data (e.g. baseline);
- close to real-time data (e.g. measurements).

Data is organised in a manner compliant with agreed TSOs', DSOs' and all stakeholders' needs. Indeed, it is important to note that some data (e.g. measurements) are also used by other actors like aggregators, or directly by customers. As such, in case of agreement between involved parties, this interface could be a part of a greater interface (referred to as *resources register interface*[14] in figure 3). Data not directly or indirectly generated by such shared resources is not considered under this data sharing agreement.

Market interfaces

Market interfaces are the places where customers can offer services to TSOs and/or DSOs and where they can request and buy these services. It can consist of several markets that need to be fully coordinated to avoid issues like double bidding selection, conflicts leading to induced congestions etc. In Europe there are already different realised platforms providing services for TSOs and/or DSOs and/or market parties.
Market interfaces include roles, procedures and algorithms to perform an offer/demand matching process respecting grids capability while trying to fulfil system operators' needs as much as possible at minimum

[14] *The Resources Register Interface could collect all anagraphic data, measures and status data that shall be stored and shared among parties for different purposes such as flexible services, settlement, forecasting etc.*

cost. Moreover, it registers any *activations request* of sources requested by system operators, shares the requests among involved stakeholders and manages settlement.

Defining and implementing *priority rules and coordination procedures* is necessary in order to take into account electrical system needs, grid capabilities and how these evolve over time.

Direct interface

In order to guarantee the overall system security, stability and resilience, a direct interface that directly connects TSOs and DSOs would be established.

This interface, that can obviously assume different characteristics and implementations according to the specific country or system operators' needs and structures, can play the important role in:

- securing a fast and reliable operating channel between TSO and DSO in case of large breakdowns or emergencies;
- guaranteeing a medium/long-term coordination and control of load flows at the interconnections between TSOs and DSOs;
- exchanging certain structural data and (near) real-time data agreed between system operators;
- enabling better and more efficient grid operation thanks to possible dynamic operating conditions agreed between system operators;
- coordinating the efficient use of flexibility.

Moreover, the direct interface can be used to allow TSOs and DSOs to exchange very important data concerning forecasting and real-time needs of respectively managed grids, agreeing if, when and how the *shared resources* can be activated, improving observability, resilience and safety of the whole system.
Indeed, DSOs have to know the real-time and forecast status of their grid. Another way of reservation of indirect flexibility resources is via market signals (incentives). In this way, any reservation of distribution resources needs to be analysed and validated ensuring safety and efficient operation of the grid at all time.

The described architecture includes several interconnections, platforms and data flows as well as additional cooperation and procedures among system operators that, up to now, were not strictly necessary. Some of these are regulated, some are commercial while others need to be acknowledged, defined and made effective.

4. Definition and monitoring of grid smartness, guidelines for KPIs selection and implementation

In the current chapter, we start from the smartness definition, followed by an investigation on how to measure that smartness, and leading to some guidelines on how to define KPIs.

4.1. Preliminary remarks: why monitoring grid smartness

The basis of regulation today is focusing on cost-efficiency of the grids and quality of supply and does not reflect the active contribution and future preparedness of grids to a successful energy transition. Hence, there is a necessity of expanding the framework in line with the requirements of the Electricity Directive towards:

- monitoring of the current state of the grid (ensuring continuous re-investment and avoiding accumulation of outdated equipment);
- monitoring of the future preparedness (continuous and structured discussion on what needs to be done in order to make todays investments in grids as future proof as possible).

The grid smartness monitoring process could be an additional element for regulation schemes applied to grids including grid operators and grid users. It allows to reflect the degree to which a given grid is equipped with functionalities, methodologies, tools and technologies in relation to predefined objectives and particular challenges for a specific grid (increased share of renewable generation, smart use of the assets, reliability and security of supply, more involvement of grid users to increase the awareness for efficiency and demand side management opportunities).

4.2. Definition of grid smartness and system operators' smart functionalities

Smartness definition

Smart grids are recognised as a key technological priority for Europe in order to meet the future energy targets. The electricity sector can facilitate and enable the energy transition through smart, efficient grids that would ensure reliability and security of supply. The transition to new forms of generation, mainly power electronic interfaced renewable generation, poses new challenges reflected in the technical, economic and regulatory domain.

A main element of a smart grid is to facilitate high levels of controllability and observability in an increasingly complex power system that requires increased levels of information sharing. The smart grid allows for integrating the electrical and information technologies in between any point of generation and any point of consumption.

The European Technology Platform smart grid defines a smart grid as:
"A smart grid is an electricity network that can intelligently integrate the actions of all users connected to it – generators, consumers and those that do both – in order to efficiently deliver sustainable, economic and secure electricity supplies."

From an *operational perspective*, a smart grid employs innovative products and services together with intelligent monitoring, control, communication, and self-healing technologies to:

- better facilitate the connection and operation of generators of all sizes and technologies;
- significantly reduce the environmental impact of the whole electricity supply system;
- deliver adequate levels of reliability and security of supply;
- foster the energy transition through further electrification;

- enable adequate sector coupling.

From a *market perspective*, the key drivers of a smart grid development are:
- a large-scale integration of renewable energy resources;
- allow consumers to participate in all electricity markets (including ancillary services to the grid) based on improved information and price signals;
- a highest level of inclusion of operators and citizens' communities;
- the overall cost efficiency in the secure supply of energy to customers.

This definition of smart grids combined with the DSO perspectives on smart grid functionalities described below have led to the definition of the relevant smartness KPIs listed in the next chapter.

System operators' smart functionalities

More real-time capabilities, in monitoring and network management, shall be applied to ensure best utilisation of the infrastructure, inclusion of distributed generation and interoperability with prosumers, while at the same time maintaining the security of supply and the cost efficiency in a TOTEX perspective. In doing so, new grid functionalities are important to be considered for DSO grids.
The comprehensive list of smart functionalities for system operators is not in the scope of this document but outlining some of them can be useful to better understand the value chain that is at the base of the KPIs structures.

From a DSO point of view, the following functionalities can be mentioned:

- advanced planning procedures and tools taking into account the variability and uncertainty of new loads;
- advanced asset management strategies, tools and methods focusing on assets condition monitoring and risk mitigation;
- primary and secondary substations automation & protection;
- voltage profile monitoring;
- SCADA system, i.e. the control centre for the distribution grid performing:
    - fast outage clearing;
    - early fault detection;
    - grid reconfiguration;
    - islanding;
- distribution management system (DMS), ability to monitor in (near) real time the grid status and perform grid reconfigurations to heal or avoid critical situations in the network;
- demand response and flexible customers management platforms to guarantee a standardised and structured connection towards flexible customers to make them participate in the optimal operation of the distribution grid;
- smart metering infrastructure and services providing information to grid users and grid operators;
- use of shared databases containing smart metering data and flexible customers technical characteristics to enable flow of data among grid users and operators and enable novel services into the system;
- flexibility market interface platforms to allow the DSO to request ancillary services on the local flexibility market, where aggregators, market operators and in general flexible customers offer grid services.

In addition, from an overall energy system point of view, TSO-DSO coordination platforms to establish automatic dialogs to agree load profiles and operational constraints at the delivery points between system operators are decisively important: for this purpose a "common KPI" between TSOs and DSOs has been identified.

These smart functionalities could be further broken down on a two-level structure:
- smart grid infrastructure (field devices);
- smart grid functions (operational features on network levels, remote monitoring and control).

4.3. Guidelines for KPIs selection and implementation

The use of key performance indicators for the smartness of the grid is a general approach used to facilitate the monitoring of the smartness of the grid. Those indicators are bound to smart criteria, meaning they have to be specific, attainable, measurable and time bound. KPIs can facilitate the assessment of potential progress towards the implementation of smart grids.

Essential requirements for KPIs

The indicators should highlight which skills or functionalities a system operator is developing in order to operate its grid in a smart way, both from an operational and market perspective, and in order to tackle the Common TSO-DSO Challenges defined in chapter two.

When developing skills and functionalities, the advantages (both technical and economical) should be balanced. For this reason, the definition of the parts of the grid to be improved in smart functionalities should be performed by system operators as they are in the best position to define any roll-out (which technology mix, where, when, how many, etc.) of intelligent devices in order to reach the adequate level of smartness (to cope with the challenges in their grid) in a cost-efficient way.
Generally, KPIs are not meant to be used for comparisons between or benchmarking of system operators since for every system operator the importance (weight) of every (K)I in the KPI can be different.

Generally, a KPI should be meaningful, understandable and quantifiable.
Essential requirements for the smart grid KPIs are:

- definition of a KPI must be done on the basis of unambiguous terms (e.g. clear definition of smart meter: does a meter with an automatic meter reading fall under this definition or not?);
- KPI must be influenceable by the system operator. If necessary, it should be indicated if there is only partial or complete influenceability;
- KPI is linked only to regulated activities of the DSO;
- KPI must be sufficiently pragmatic and significant to be able to make effective use of them;
- KPI needs to focus on functionality and outputs, rather than on specific technologies that realise this functionality (technology neutral);
- the data needed to calculate the KPIs must be available and collectable with reasonable effort;
- in certain cases, it can be useful to split a KPI in two sub-KPIs, e.g. interruption time for LV and MV;
- KPIs must be futureproof as much as possible, to ensure the evolution of a KPI can be tracked for a longer period.

It is also important to point out that interpretation and use of the KPIs should be done with caution - they must not be seen as the only tool to determine that a grid is smart. KPIs need to be viewed alongside the projects, policies, processes, people, business transformation and general narrative that each network has undertaken to transition towards a smart grid.

KPIs have to be studied in the context of and take into account the history of each system operator and system (i.e. the focus should be on the trend of the KPI and not only on its absolute value). They should be used as a way to evaluate the capability of the grid to fulfil its functions, and not as a criterium to pick winners or select projects.

In summary, KPIs have to be used in an “intelligent way” in combination with other important information; their target value should not necessarily be 100% or 1, which could easily lead to overinvestments and additional costs for consumers.

Difference between KPI and K(I) in the frame of smart grids

Since there is often confusion between the meaning of a key performance indicator (KPI) and an indicator or key indicator ((K)I), we want to highlight their main differences in the context of this report:

- a (key) indicator measures the "elements" or "instruments" for a smart functionality. It is characterised by a number or a percentage (or fraction) and is solely for information purposes. This number or percentage can evolve over time;
- a key performance indicator specifies the effectiveness of the above-mentioned smart functionality and consequently the performance of the (smart) grid. A KPI is always the result of a calculation, is expressed in % or as a fraction, can be based on one or a number of (key) indicators and can also evolve in time.

A smart grid KPI could be further defined as a measurement:

- of the intelligence of the grid, or;
- for the progress of implementing an obligation in the frame of an intelligent ecosystem, or;
- of certain outputs or outcomes that have been deemed necessary for customer benefits.

Often indicators are viewed as part of the "smartness of the grid." In reality, they can only be seen as a way to measure smartness, as opposed to contributing directly towards it. For example, the number of installed smart meters or the number of tele-controlled circuit-breakers does not necessarily indicate that the gird is smart, it merely gives an indication of the number of devices installed, and hence is an indicator for potential "smart grid readiness." Ultimately, smartness will depend on how the devices and subsequent data are utilised. For example, if DSOs are allowed to use smart meter data for grid purpose and DSOs use the tele-controlled circuit-breakers to change power flows in the grid or to be faster in grid restoration, we could of course speak about a smart use of those tools and hence think about a KPI related to for example congestion management where this is necessary and efficient.

Output based measurement

The measurement of the KPIs will be done in an output based approach.

This means that to measure a KPI, i.e. to give a number to the quality of a performance as stated above, it is not important how many devices or tools are being used to implement that functionality, but what really matters are the actual effects of the actions taken to implement that functionality.

Even though this approach guarantees the technological neutrality of the measurement and focuses on the effectiveness of the way a system operator operates, it increases the complexity of the numerical evaluation of KPIs and leads to a need for specific local adaptations on the weight given to each aspect of the measured performance.

The main reason for mentioning the complexity is that evaluation of a smartness KPI just through a measurement of a specific phenomenon could be misleading. For example, if we consider outages, during one year without adverse climatic events or particular operating conditions, the controllability of a part of the grid may seem effective and the grid may be well performing, but obviously this measurement does not ensure that the system operator works "in a repeatable smart way." In fact, during the following year with different conditions, the KPI evaluation could be very different even if nothing has changed, either in the operational processes, in the availability of SCADAs or other grid control systems.

Furthermore, it could also be misleading to evaluate the "controllability smartness" of a system operator just by looking at the availability of technologies, tools and processes, since those investments could prove to be ineffective if the number of outages would not be much lower to justify the involved costs.

But, at the same time, the comparison between the improvement of a phenomenon with respect to the relevant cost incurred (cost-benefit ratio), would not be able to reflect the smartness of a system operator in managing that phenomenon, since the periodical measurement can still be affected by external operational conditions and not giving any predictive information on the system operator’s capability to guarantee in the future the same service level.

It is anyhow understood that the identified KPIs are subject to the general investments efficiency rule framework adopted by each NRA, i.e. for all the functionalities (including of course the “smart” ones) the cost/benefit ratio must be appropriate; this evaluation for every KPI cannot be run at EU level, so it is out of the scope of this document but left at the country level.

To solve this complexity, the adopted method for the KPIs calculation consists in identifying the value chain of each “smart skill”, i.e. of each KPI, and then combine the properly weighted measurement of the effectiveness of each link of the chain, i.e. of each (K)I.

In this way it is possible, at the same time, to:
- understand if the system operator has implemented the necessary skills and procedures to face the coming challenges, according to the specific country regulatory provisions, through the proper formulation of the KPIs structure;
- analyse the effectiveness of the investment optimising network planning.

5. Elaboration of smartness KPIs for system operators

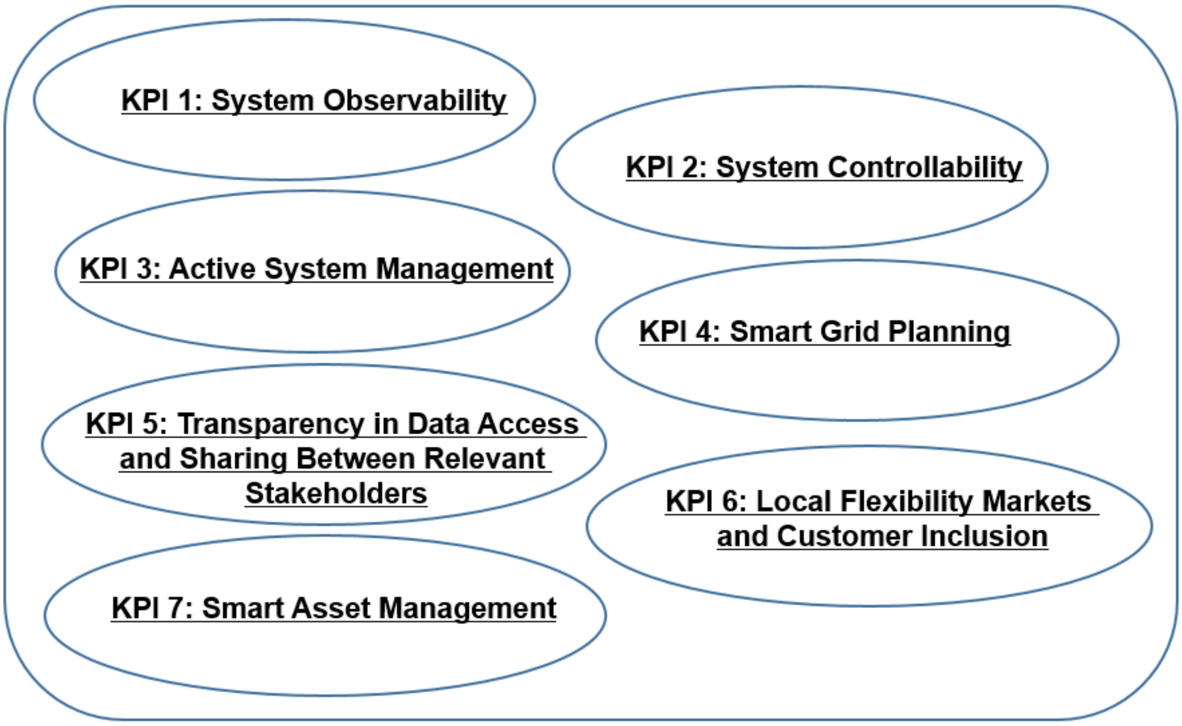
5.1. Preliminary remarks

Following the guidelines identified in chapter three, DSOs made their assessment of the definitions and measurement methods, resulting in the required short number of smartness KPIs, and the related (K)Is necessary to elaborate the KPIs.

KPIs are defined through a high-level formula in relation to all the relevant (K)Is. However, the report does not include explicit formulas for these(K)Is. The reason for this approach is to leave room at the national level for further detailing and finetuning of the (K)Is taking into account grid specificities in each country. Also, not all of them are relevant for every country, every summand of each formula is weighted, i.e. multiplied by a "w_{xy}"-factor, assuming values from zero to one. The weight has value zero if that KPI or that (K)I is not applicable in that country, a different value in the other cases. The more a functionality or a specific indicator is relevant in a country, the more the weight value will be closer to one.

5.2. DSO smartness KPIs

Following the philosophy and the criteria defined above, to measure the DSO smartness the following seven KPIs have been identified:



Those KPIs answer to the common challenges, as shown in the table below.

THE SIX COMMON CHALLENGES	KPI 1: System Observability	KPI 2: System Controllability	KPI 3: Active System Management	KPI 4: Smart Grid Planning	KPI 5: Transparency in Data Access and Sharing Between Relevant Stakeholders	KPI 6: Local Flexibility Markets and Customer Inclusion	KPI 7: Smart Asset Management
Cooperation in network operation	X	X	X		X	X	
Cooperation in planning the networks				X			X
Exchange all necessary information regarding the long-term planning of network investments			X	X			X
Exchange all necessary information regarding the generation assets and demand side response for the daily operation of their networks	X		X		X	X	
Cooperate with each other in order to achieve coordinated access to resources	X		X		X	X	
Ensure cost-efficient, secure and reliable development and operation of their networks	X			X	X	X	X

5.3. DSO smartness KPI definitions

Generally, the following assumptions have been made (valid for all KPIs):

- KPIs can be calculated for one or more areas;
- areas could be defined based on grid needs, such as “concentration areas” (high concentration, medium concentration, low concentration), critical areas (e.g. areas with frequent outages, important consumers, etc);
- if different areas are defined, KPIs could be calculated for each one (and the same for the relevant summands);
- the system operators are in the best position to define areas and sub-areas where KPIs and (K)Is are valid and applicable and to define the suitable implementation of technologies and equipment to cope with the individual challenges.

More specifically the following seven DSO smartness KPIs are defined taken into account:

- (K)Is are intended as performances to be measured (if the specific functionality is implemented in the country or by the DSO);
- due to the existing differences between countries (and between different DSOs within a country), the specific (K)Is have been given as examples, leaving to the NRAs and system operators the task to choose the most appropriate ones. This approach provides a very flexible instrument to elaborate the calculation of the KPIs. Of course, within the country a choice of some of the listed (K)Is can be made and used in a different combination or independently, according to national specificities.

The following KPIs are intended solely as tools to monitor trends in the local implementation of smartness in grid management.

KPI 1 – System Observability

DEFINITION: ***To measure the capability to keep under "proper monitoring" of the relevant nodes/lines of the grid.***

A power system is observable if the measurements:

- are performed, at least, in the most significant nodes/lines, i.e. where most of the energy flows, or in the highest concentration areas, or in the most critical areas (for frequency of outages, or presence of strategical customers (government headquarters, hospitals, …)
- AND allow the determination of significant electrical quantities e.g. nodes voltage magnitude and angle, frequency, etc.

It is to be noted that this KPI evaluates if MAIN data, needed for observability, are measured/gathered by relevant field devices (incl. smart meter, field sensors and so on) and make them available to the DSO through proper infrastructures: it could be considered that not all the lines and nodes have the same "importance."

The formulation of KPI 1 is:

$$\boxed{\boldsymbol{System\ Observability} = ObservabilityRT \cdot w_{RT} + ObservabilityNRT \cdot w_{NRT}}$$

where:

w_{RT} and w_{NRT} are values (from 0 to 1) to associate different weights to the addends: these must fulfil the condition:

$$w_{RT} + w_{NRT} = 1$$

and:

$$\boldsymbol{KI\ 1.1\ ObservabilityRT} = \frac{\mathbf{1}}{\sum_{i=3}^{7} w_{RTi}} \sum_{i=3}^{7} (KI\ 1.i \cdot w_{RTi})$$

with w_{RT_i} values (from 0 to 1) to associate different weights to the addends,

and:

$$\boldsymbol{KI\ 1.2\ ObservabilityNRT} = \frac{1}{\sum_{i=8}^{12} w_{NRTi}} \sum_{i=8}^{12} (KI\ 1.i \cdot w_{NRTi})$$

with $\mathrm{w}_{\mathrm{NRT_i}}$ values (from 0 to 1) to associate different weights to the summands.

To be noted that:

- RT means Real Time and it could include also Near Real Time.
  RT data is defined as a data provided every (few) second(s) up to every 15 minutes (market settlement time).
- NRT means Not Real Time.
  NRT is defined as a data provided every more than 15 minutes. The related time should be defined based on requirements of respective functionality: e.g. observability in RT for frequency should require that the related data are provided more often than the data for observability in RT for balancing/power.

The key indicators measured to define KI 1.1 and 1.2 are the following:

KI Code	KI Name & Description
KI 1.3	$CustomerBorderObservabilityRT:$ Performance in reading and gathering data and measures in real time at the point of delivery to the customer. Example: Percentage of actual performed measurements and properly registered in defined repository.
KI 1.4	$TransformerObservabilityRT:$ Performance in reading and gathering data in real time from relevant power transformers. Example: Percentage of actual performed measurements weighted according to the relevance of the transformer
KI 1.5	$LinesObservabilityRT:$ Performance in reading and gathering data in real time from the relevant lines. Example: Percentage of actual performed measurements weighted according to the relevance of the line.
KI 1.6	$CBs/SwitchesObservabilityRT:$ Performance in reading and gathering data in real time from the relevant circuit breakers (CBs)/switches. Example: Percentage of actual performed measurements weighted according to the relevance of the CB/switch.
KI 1.7	$ReactivePowerRegulationDevicesObservabilityRT:$ Performance in reading and gathering data in real time from power regulation devices. Example: Percentage of actual performed measurements weighted according to the relevance of the regulation device.
KI 1.8	$CustomerBorderObservabilityNRT:$ Performance in reading and gathering data and measures not in real time at the point of delivery to the customer. Example: Percentage of actual performed measurements and properly registered in defined repository.
KI 1.9	$TransformerObservabilityNRT:$ Performance in reading and gathering data not in real time from relevant power transformers. Example: Percentage of actual performed measurements weighted according to the relevance of the transformer.
KI 1.10	$LinesObservabilityNRT$**:** Performance in reading and gathering data not in real time from the relevant lines. Example: Percentage of actual performed measurements weighted according to the relevance of the line.
KI 1.11	$CBs/SwitchesObservabilityNRT:$ Performance in reading and gathering data not in real time from the relevant CBs/switches. Example: Percentage of actual performed measurements weighted according to the relevance of the CB/switch.
KI 1.12	$ReactivePowerRegulationDevicesObservabilityNRT:$ Performance in reading and gathering data not in real time from power regulation devices. Example: Percentage of actual performed measurements weighted according to the relevance of the regulation device.

KPI 2 – System Controllability

DEFINITION: ***To measure the capability to keep the grid under "proper control."***

This KPI evaluates the amount of relevant/critical grid equipment/assets that can be effectively controlled in order to provide a secure and reliable network operation.
It could be considered that not all the lines and nodes have the same "importance."

The formulation of KPI 2 is:

$$\boldsymbol{Controllability} = \mathrm{ControllabilityDSOAsset} \cdot \mathrm{w_{RC}} + \mathrm{ControllabilityDER} \cdot \mathrm{w_{C}}$$

where:

$\mathrm{w_{RC}}$ and $\mathrm{w_{C}}$ are values (from 0 to 1) to associate different weights to the summands and they have to fulfil the condition

$$\mathrm{w_{RC}} + \mathrm{w_{C}} = 1$$

and:

$$\boldsymbol{KI\ 2.1\ ControllabilityDSOAsset} = \frac{1}{\sum_{3=1}^{6} w_{CDSOi}} \sum_{i=3}^{6} (KI\ 2.i \cdot w_{CDSOi})$$

with $\mathrm{w_{CDSO_i}}$ values (from 0 to 1) to associate different weights to the summands

and:

$$\boldsymbol{KI\ 2.2\ ControllabilityDER} = \frac{1}{\sum_{i=7}^{11} w_{CDERi}} \sum_{i=7}^{11} (KI\ 2.i \cdot w_{CDERi})$$

with $\mathrm{w_{CDER_i}}$ values (from 0 to 1) to associate different weights to the summands

The key indicators measured/calculated to define KI 2.1 and KI 2.2 are the following:

KI Code	KI Name & Description
$\boldsymbol{KI\ 2.3}$	$TransformersControllability:$ Performance in proper controlling of the relevant power transformers. Example: Percentage of effective actions on transformers from a quality of service perspective (like voltage profile stability) weighted according to the relevance of the transformer.
$\boldsymbol{KI\ 2.4}$	$LinesControllability:$ Performance in proper controlling of the relevant lines. Example: Percentage of effective actions on lines from a quality of service perspective (like line fault recovery) weighted according to the relevance of the line.
$\boldsymbol{KI\ 2.5}$	$CBs/SwitchesControllability:$ Performance in proper controlling of the relevant CBs/switches[15]. Example: Percentage of effective actions on CBs/switches from a quality of service perspective (like fault recovery using reclosing actions) weighted according to the relevance of the CB/switch.
$\boldsymbol{KI\ 2.6}$	$ReactivePowerRegulationDevicesControllability$: Performance in proper controlling of the relevant power regulation devices Example: Percentage of effective actions on power regulation devices from a quality of service. perspective (like avoided outages by using power regulation) weighted according to the relevance of the device.
$\boldsymbol{KI\ 2.7}$	$DERControllabilityLoadShedding:$ Performance in proper disconnecting of the relevant loads from the grid. Example: Percentage of effective disconnecting actions from a quality of service perspective (like avoided outages by using disconnections) weighted according to the relevance of the line/area.

[15] *These are different from the ones that are feeding lines and/or power transformers (e.g. bus couplers in switchgear, etc.).*

$\boldsymbol{KI\ 2.8}$	$DERControllabilityLoadModulation:$ Performance in proper modulating of the relevant loads. Example: Percentage of effective modulation actions from a quality of service perspective (like avoided outages or increase of connected customers/power load or enhancement of grid utilisation in energy density avoiding infrastructural investments by using modulation) weighted according to the relevance of the line/area.
$\boldsymbol{KI\ 2.9}$	$DERControllabilityGenerationModulation$: Performance in proper modulating of the relevant generation. Example: Percentage of effective modulation actions from a quality of service perspective (like avoided outages or increase of connected customers/power load or enhancement of grid utilisation in energy density avoiding infrastructural investments by using modulation) weighted according to the relevance of the line/area.
$\boldsymbol{KI\ 2.10}$	$DERControllabilityReactivePowerModulation:$ Performance in proper controlling of the relevant reactive power devices. Example: Positive effects on voltage profile stability using reactive power modulation weighted according to the relevance of the line/area.
$\boldsymbol{KI\ 2.11}$	$DERControllabilityStorage:$ Performance in proper controlling of the relevant storages. Example: Percentage of effective modulation actions from a quality of service perspective (like avoided outages or increase of connected customers/power load or enhancement of grid utilisation in energy density avoiding infrastructural investments by using storage modulation) weighted according to the relevance of the line/area.

KPI 3 – Active System Management

DEFINITION: ***To measure the capability to perform active management of the grid in daily/short-term operation.***

The KPI is related to the functionalities that are available to DSOs for daily/short-term operation of the grid (e.g. voltage regulation, reconfiguration, power flow optimisation, congestion solving, islanding, not programmable DER integration, request of services to DER, etc.).

The formulation of KPI 3 is:

$$\boldsymbol{Active\ System\ Management} = ASM \cdot \frac{\sum_{i=1}^{7}(KI\ 3.i \cdot w_{ASMi})}{\sum_{i=1}^{7} w_{ASMi}}$$

where:

ASM: value 0 or 1. It is 1 if an Active System Management is available; contrariwise it is 0

w_{ASM_i} : are values (from 0 to 1) to associate different weights to the summands

The key indicators measured/calculated to define KPI 3 are the following:

KI Code	KI Name & Description
$\boldsymbol{KI\ 3.1}$	$VoltageRegulation$: Performance in using DSO assets and DER to execute automatic voltage regulation in the grid. Example: Effectiveness in maintaining the voltage profile stability, weighted according to the relevance of the area.

$\boldsymbol{KI\ 3.2}$	$GridReconfiguration$: Performance in using DSO assets to execute automatic grid reconfiguration. Example: Effectiveness in fault prevention (in respect to a baseline) weighted according to the relevance of the area.
$\boldsymbol{KI\ 3.3}$	$PowerFlowOptimization$: Performance in using DSO assets and DER to execute automatic power flow optimisation in the grid. Example: Increase in the amount of energy distributed by the grid avoiding infrastructural investments, reduction of losses, reduction of outages, by using power flow optimisation.
$\boldsymbol{KI\ 3.4}$	$CongestionSolving$: Performance in using DSO assets and DER to execute automatic congestion solving. Example: Percentage of reduction of outages/disconnections of customers/congestion or critical states by using flexibility.
$\boldsymbol{KI\ 3.5}$	$GridIslanding$: Performance in using DSO assets and DER to operate grid in islanding mode. Example: Percentage of reduction of energy supply interruption in a specific "island" (area) in case of wide zonal outage.
$\boldsymbol{KI\ 3.6}$	$NotProgrammableDERIntegration$: Performance in using DSO assets and DER to integrate not programmable DER (such as wind plants etc.) in the grid. Example: Percentage of increase of effective injection in the grid of non-programmable DER.
$\boldsymbol{KI\ 3.7}$	$RequestServiceDER$: Performance in automatic requesting of service to the DER for grid management. Example: Percentage of reduction of manual interventions in requesting/managing flexibility.

KPI 4 – Smart Grid Planning

DEFINITION: *To measure the capability to use design and planning procedures to fulfil actual grid needs in medium and long-term, guaranteeing cost efficiency in grid updating and most efficient use of existing assets.*

This is a composed KPI. It should concern the availability of tools for: grid analysis, medium/long-term forecasting, etc.

The formulation of KPI 4 is:

$$\boldsymbol{Smart\ Grid\ Planning} = AGAA \cdot [KPI\ 1(System\ Observability) \cdot w_{AGAA1} + ActiveDesignCapability \cdot w_{AGAA2}] / \sum_{i=1}^{2} w_{AGAAi}$$

where:

$AGAA$: value 0 or 1. It is 1 if an Advance Grid Asset Analysis is available; contrariwise it is 0

w_{AGAA_i} : are values (from 0 to 1) to associate different weights to the summands

The key (performance) indicators measured/calculated to define KPI 4 are the following:

K(P)I Code	K(P)I Name & Description
$\boldsymbol{KPI\ 1}$	$System\ Observability$: as per KPI 1 definition

$\boldsymbol{KI}\ \mathbf{4.1}$	$ActiveDesignCapability$: Performance in grid designing based on exploitation of both DSO assets and DER capabilities. Example: Reduction of infrastructural investment needed to increase the energy usage of the grid/enhance the quality of service/ support the energy transition.

KPI 5 – Transparency in Data Access and Sharing Between Relevant Stakeholders

DEFINITION: ***To measure the capability to make accessible and share data between stakeholders.***

The data could be used, by the relevant stakeholders, for several services such as: grid observability, defining new services for customer or grid, settlements, energy management, etc. according to the different national regulations.

The formulation of KPI 5 is:

$$\textbf{Transparency Data Access Sharing} = \mathrm{TDAS} \cdot \frac{\sum_{i=1}^{9}(KI\ 5.i \cdot w_{TDASi})}{\sum_{i=1}^{9} w_{TDASi}}$$

where:

$TDAS$: value 0 or 1. It is 1 if Transparency in Data Access and Sharing Between Relevant Stakeholders is available, contrariwise it is 0;

w_{TDAS_i} : are values (from 0 to 1) to associate different weights to the summands

The key indicators measured/calculated to define KPI 5 are the following:

KI Code	KI Name & Description
$\boldsymbol{KI}\ \mathbf{5.1}$	$DataCustomer2DSO$: Value 0 or 1. It is 1 if general data coming from customers are available for the DSO; contrariwise it is 0. Example: these data could include POD code, contractual power, type of customer, etc.
$\boldsymbol{KI}\ \mathbf{5.2}$	$RTDataCustomer2DSO$: Value 0 or 1. It is 1 if real time data coming from customers related to fulfil grid observability are available for the DSO; contrariwise it is 0. Example: these data could include active power absorbed, active power generated, etc.
$\boldsymbol{KI}\ \mathbf{5.3}$	$NRTCustomerDataDSO2TSO$: Value 0 or 1. It is 1 if not real time data coming from customers related to perform grid analysis are available for the DSO; contrariwise it is 0. Example: these data could include active power absorbed, active power generated, etc.
$\boldsymbol{KI}\ \mathbf{5.4}$	$RTDataDSO2TSO$: Value 0 or 1. It is 1 if real time data gathered by the DSO related to fulfil grid observability are available for TSO; contrariwise it is 0. Example: these data could include power flow at connection point of distribution grid and transmission grid, active power generated in distribution grid per type of source, etc.
$\boldsymbol{KI}\ \mathbf{5.5}$	$RTDataDSO2Aggregator$[16]: Value 0 or 1. It is 1 if real time data gathered by the DSO, enabling the aggregator to develop/ provide services to the grid, are available for aggregators; contrariwise it is 0. These data could include customers active power absorbed, customers active power generated, etc.

[16] *"Aggregator" means the relevant flexibility market stakeholder.*

$KI\ 5.6$	$NRTDataDSO2Aggregator$: Value 0 or 1. It is 1 if not real time data gathered by the DSO enabling aggregator to perform settlement and to develop/provide services to the grid, are available for aggregators; contrariwise it is 0. Example: these data could include customers active power absorbed, customers active power generated, etc.
$KI\ 5.7$	$RTDataMeter2Customer$: Value 0 or 1. It is 1 if (smart) meters installed at customers/DSO borders are able to provide data to customers in real time; contrariwise it is 0. Example: these data could include customers active power absorbed, customers active power generated, etc.
$KI\ 5.8$	$NRTDataMeter2Customer$: Value 0 or 1. It is 1 if (smart) meters installed at customers/DSO borders are able to provide not real time data to customers; contrariwise it is 0. Example: these data could include customers active power absorbed, customers active power generated, etc. and can be used by the customer (for example to evaluate its energy behaviour).
$KI\ 5.9$	$DataSO2SO$: Value 0 or 1. It is 1 if data (different from the ones for grid observability as per $\boldsymbol{RTDataDSO2TSO}$) are shared among system operators; contrariwise it is 0. Example: these data can be used for grid system operation, grid analysis etc. and should include minimum data as per KORRR, GLDPM, DCC, national and other regulations.

KPI 6 – Local Flexibility Markets and Customer Inclusion

DEFINITION: ***To measure how much the customer is involved in grid management and enabled to provide services to the grid and to measure how much the local flexibility market/customer agreements are implemented and how much it can contribute to grid (and system) management.***

The formulation of KPI 6 is:

$$\begin{aligned}\boldsymbol{LocalFlexibilityMarkets\&CustomerInclusion} \\ = \frac{1}{\sum_{i=4\ (i\neq 9)}^{10} w_{LFMCIi}} \sum_{i=1}^{3} KI\ 6.i \\ \cdot \left[\sum_{i=4}^{7} (KI\ 6.i \cdot w_{LFMCIi}) + \sum_{i=8}^{9} (KI\ 6.i \cdot w_{LFMCI8}) + KI\ 6.10 \cdot w_{LFMCI10} \right]\end{aligned}$$

where:

w_{LFMCI_i} : are values (from 0 to 1) to associate different weights to the addends

The key indicators measured/calculated to define KPI 6 are the following:

KI Code	KI Name & Description
$KI\ 6.1$	$AvailProperDataMeterCustomer2DSO$: Value is equal to 1 if all needed data to involve the customers in grid management and to provide services are available; contrariwise it is equal to 0. The needed data should be defined at national level.
$KI\ 6.2$	$MarketImplementation$: Value between (or equal to) 0 and 1 to evaluate implementation of market and/or any other type of agreements between customers/aggregators and DSO (e.g. direct contracts) in enabling flexible resources to provide services to the grid. This takes into account the availability at country level of (market) platforms, allowing to customers/aggregator to offer services to the DSO.

$\boldsymbol{KI\ 6.3}$	$MarketLiquidity$: Value equals or greater than 0 to evaluate liquidity of market or amount of agreements between customers/aggregators and DSO. The type and amount of services offered by customers/aggregators and requested by DSO or TSO in the reference period should be evaluated at country level.
$\boldsymbol{KI\ 6.4}$	$AvailableServices$: Value between (or equal to) 0 and 1 to evaluate at country level all type of services needed for DSO or TSO and offered by customers/aggregators.
$\boldsymbol{KI\ 6.5}$	$LowEntryBarriersToProvideService$**:** Value is equal to 1 if entry barriers (in terms of e.g. low size of minimum package of power/energy consisting in a service offered to the grid or activation costs) are “low enough”; contrariwise it is equal to 0. The threshold of a “low enough entry barrier” should be defined at national level.
$\boldsymbol{KI\ 6.6}$	$DeliveryServiceSetpointToCustomer$: Value between (or equal to) 0 and 1 to evaluate if setpoint, to be sent to customer to activate offered flexibility, is foreseen and effectively delivered. Moreover, it should take into account interoperability of setpoints (evaluating if standardised or not standardised solutions are implemented)[17].
$\boldsymbol{KI\ 6.7}$	$InterfaceTowardCustomerDevice$: Value between (or equal to) 0 and 1 to evaluate if device receiving the setpoint, to activate offered flexibility, is able to interface effectively with customers devices (e.g. EMS). Moreover, it should take into account interoperability of setpoints (evaluating if standardised or not standardised solutions are implemented).[18]
$\boldsymbol{KI\ 6.8}$	$AvailCustomerDataDSO2Aggregator$**:** Value is equal to 1 if all needed customers data allowing aggregators to define and calculate services settlement that can be obtained by flexibilities are available; contrariwise it is equal to 0. The needed data should be defined at national level.
$\boldsymbol{KI\ 6.9}$	$CustomersAggregation$: Value between (or equal to) 0 and 1 to evaluate if aggregation of customers to provide services is available. Moreover, it should take into account also if aggregated offers can be provided through aggregators and/or directly by CECs (Citizen Energy Communities) and/or REC (Renewable Energy Communities).
$\boldsymbol{KI\ 6.10}$	$ProvideServiceToSOs$**:** Value is equal to 1 if the resources are able to provide services both to DSO than TSO; contrariwise it is equal to 0. **NOTE** In order to allow this capability, the markets framework needs to include an effective coordination among system operators.

[17] Standardised solution should be preferred because avoid lock-in phenomena that could arise for example in case of switch of aggregator/vendor.

[18] Standardised interface should be preferred because avoid lock-in phenomena that could arise for example in case of switch of aggregator/vendor.

KPI 7 – Smart Asset Management

DEFINITION: ***To measure the use of advanced asset management strategies, tools and methods focusing on assets condition monitoring and risk mitigation.***

It is a composed KPI. It should concern the availability of tools for: grid analysis, assets faults/unavailability forecasting, etc.

The formulation of KPI 7 is:

$$\boldsymbol{SmartAssetManagement} = [PredictiveMaintenaceCapabilities \cdot w_{SAM1} + KPI1(System\ Observability) \cdot w_{SAM2}] / \sum_{i=1}^{2} w_{SAMi}$$

where:

w_{SOsCCI_i} : are values (from 0 to 1) to associate different weights to the summands

The key (performance) indicators measured/calculated to define KPI 7 are the following:

K(P)I Code	K(P)I Name & Description
$\boldsymbol{KPI\ 1}$	$System\ Observability$: as per KPI 1 definition
$\boldsymbol{KI\ 7.1}$	$PredictiveMaintenaceCapabilities$: Performances in using advanced asset management strategies, tools and methods focusing on assets condition monitoring and risk mitigation. Example: effects of predictive maintenance activities on quality of service

5.4. The "common KPI": TSO-DSO coordination capabilities

DEFINITION: ***To measure coordination capability between TSOs and DSOs*.**

It concerns several common duties and functionalities such as data sharing, coordination for utilisation of resources services, coordination planning procedures etc.
This KPI is common between TSOs and DSOs because it depends on actions to be performed together.

The formulation of common KPI is:

$$\boldsymbol{TSODSOCoordinationCapabilities} = HW\&SWInteroperability \cdot \frac{1}{\sum_{i=1}^{4} w_{SOsCCi}} \sum_{i=1}^{4} (KI\ 0.i \cdot w_{SOsCCi})$$

where:

$HW\&SWInteroperability$: is a value equal to 0 or 1. It is an enabling (KI): it is 1 if system operators' systems are interoperable; it is 0 if system operators' systems are not interoperable. Interoperability is meant both from hardware and software perspective (requirements and standards).

w_{SOsCCI_i} : are values (from 0 to 1) to associate different weights to the summands

The key indicators measured/calculated to define the common KPI are the following:

KI Code	KI Name & Description
$\boldsymbol{KI\ 0.1}$	$DataSharingSOs$: It measures the effectiveness in sharing data needed for TSO-DSO coordination: ratio between target performance and actual performance. Example: quality and performances in data rate and quality transfer, …
$\boldsymbol{KI\ 0.2}$	$SOsMarketCoordination$: *This KI* evaluates the coordination level in sharing common resources between TSO and DSO on the market. Example: market agreements implementation, priorities, …
$\boldsymbol{KI\ 0.3}$	$SOsPlanningCoordination$: This KI evaluates the effectiveness in coordinating the planning activities between TSO and DSO. Example: Agreements about capacity on boundaries between TSO and DSO, renewable integration, prosumer behaviour management, dispatching management. NOTE: The planning activities include at least the effectiveness of the following operations: • sharing of related grid evolution forecast and needs among system operators; • planning of improvement activities of the related grid in compliance with activities, evolution and needs of other system operators interconnected grids.
$\boldsymbol{KI\ 0.4}$	*EffectivenessInGridIssueSolving:* Percentage of solved grid issues thanks to coordination in operation (for example number of balanced reserves or solved grid congestions). Example: coordinated grid reconfiguration, resilience performance, black start coordinated capabilities.

6. Imprint

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