Ensuring the functional capabilities to support resilient Distribution and Transmission networks through Network Connection Codes

Mark NORTON
EirGrid plc – Ireland
mark.norton@eirgrid.com

Dr. Ralph PFEIFFER
Amprion GmbH – Germany
ralph.pfeiffer@amprion.net

Edwin HAESEN
ENTSO-E aisbl - Belgium
edwin.haesen@entsoe.eu

Kees Jansen
TenneT bv – Netherlands
kees.jansen@tennet.eu

Irina Mihaela Minciuna
ENTSO-E aisbl – Belgium
irina.minciuna@entsoe.eu

Dr. Jonathan Sprooten
Elia System Operator- Belgium
jonathan.sprooten@elia.be

Helge Urdal
ENTSO-E aisbl – Belgium
helge.urdal@ext.entsoe.eu

ABSTRACT

This paper focuses on the interlocking interrelationship of the European Network Connection Codes to provide functional capability requirements from the portfolio of network users and the impact of these on the functional capability requirements at the Transmission to Distribution network (T-D) interface.

INTRODUCTION

Transmission and distribution networks are being actively developed towards the European vision of a de-carbonized electrical network by 2050, and the challenges of meeting intermediate 2020 and 2030 targets.

Network codes support this, providing a set of rules which apply to one or more parts of the energy sector. Network codes therefore support the EU energy policy goals of facilitating the European electricity market and integrating renewable energy sources while preserving security of supply.

ENTSO-E has developed a set of ten network codes in accordance with EU Regulation 714/2009. They are currently in the legislative progress with the European Commission, with the first ones having entered into force already either as network codes or as guidelines, all resulting in the status of binding EU regulations. The full development process of these codes included review by ACER (Agency for the Cooperation of Energy Regulators), extensive interaction with all legitimate stakeholders, and final adoption by the EC (European Commission).

Increasing coordinated planning and operation of networks and maximizing the use of the services provided by their users has become vital in achieving the EU vision and targets. This is particularly important as more users provide services, from the domestic level up, and increasingly these providers are relied on not only locally but at the European network level.

This need to ensure the necessary functional capabilities from a range of users connected to either network and between Transmission and Distribution System Operators is reflected in the three Network Connection Codes, Requirements for Generators (NC RfG), HVDC systems and DC-connected power park modules (NC HVDC) and Demand Connection (NC DCC). These codes are highly progressive in their requirements to ensure enduring support from connected installation over their lifetime, and with a future-proof set-up to manage the challenges from further evolutions of the European power system.

HIGH-LEVEL FUNCTIONAL NEEDS

Development towards a higher proportion of generation connected to Distribution Networks and a smaller proportion of generation connected directly to the Transmission Networks has implication in terms of sourcing services for regulating real power (P) to control frequency (f) and regulating reactive power (Q) to control voltage (V). The Network Operators need to keep both V and f within defined operating limits to secure stable operation to facilitate market operation in electricity.

With more power sources embedded, Transmission System Operators gradually become more dependent upon flexible P & Q services originating in the Distribution Networks, either from the networks themselves, from embedded generation or from demand. While NC RfG defines the requirements (capabilities) for the embedded generation; NC DCC defines the key capabilities of Q exchange between Transmission and Distribution and flexibility aspects from demand, e.g. through Demand Side Response or emergency services such as Low Frequency Demand Disconnection.

The challenge of regulating the system voltage is increasing, including dealing with high voltage due to the following developments:

- higher proportion of circuits being undergrounded by cables, resulting in large capacitance, and hence circuits generating a large Q during low loading
- Distribution Networks with greater tendency to export Q (from D to T) under low demand conditions.
- greater variability with time of power transfers on the Transmission Network, from heavy long distance transfers to extreme low transmission transfers to large reverse power flows from Distribution Networks
- fewer transmission-connected generators available to

stabilize V by absorbing or generating Q in line with varying system needs

A major focus of the NC DCC therefore has to be to define the Q regulating capability at the T-D interface.

The second main focus of NC DCC is related to using the flexibility of demand to regulate P or Q and hence support frequency regulation, or voltage regulation respectively.

HARMONIZATION BETWEEN NETWORK CODE REQUIREMENTS

The ten network codes cover three areas:

- Connection network codes
- Operational guidelines
- Market guidelines

Figure 1 (For context and abbreviations see [1]) gives an overview of these codes and how they are linked to each other

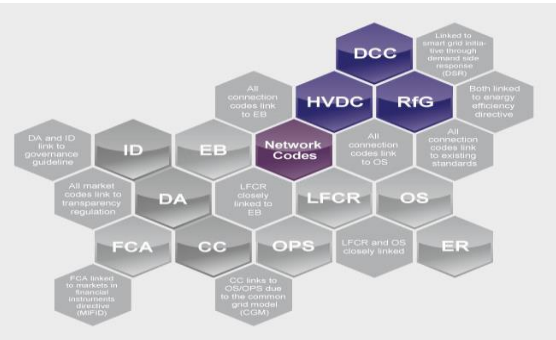

Figure 1: Network Codes and their linkages

This paper will focus on two of the three connection codes: the Network Code on Requirements for Grid Connection of Generators (NC RfG) and the Network Code on Demand Connection (NC DCC). The guiding principles of these network codes have been to develop requirements for grid connection of generating units, demand facilities and distribution networks. The aim of these requirements is to be able to maintain, preserve and restore the security of the interconnected electricity transmission and distribution systems with a high level of reliability and quality in a cost effective manner in order to facilitate the functioning of the EU-internal electricity market now and in the future.

The connection network codes require technical capabilities, which the operational guidelines then make use of. In other words, connection codes specify, which features system users shall provide for maintaining system security and the operational guidelines deploy these features to achieve this objective. Consequently these two families of network codes have many linkages and consistency between them is of crucial importance. The connection and operational network codes provide a robust and stable platform for the European electricity market, whose commercial rules are determined by the third family of codes, the market network codes.

Secure system operation is only possible by close cooperation between all users of both Distribution and Transmission Networks and the Network Operators. In this context the system security of the Transmission and Distribution Networks and all their respective users need to be considered as one from a systems engineering approach. It is therefore of crucial importance that generating units and demand users are required to provide the relevant technical capabilities concerning system security as a prerequisite for network connection in order to have such capabilities available when needed for secure system operation. Appropriate dynamic behaviour of all users and their protection and control facilities are necessary in normal operating conditions and in a range of disturbed operating conditions in order to preserve or to re-establish system security.

Generating and demand facilities, as well as network infrastructure and equipment are usually long-term investments typically with a life cycle of several decades. Therefore, the required technical capabilities need to be forward-looking. The development of system characteristics needs to be anticipated and major changes have to be expected due to the transition from an energy supply system, based on bulk power generation by synchronous generators, to a generation portfolio of renewable energy sources which will be largely dispersed and embedded in distribution systems and non-synchronously connected. The extent and velocity of these developments will vary e.g. due to different political implementation schemes in the EU Member States and are exposed to uncertainties caused inter alia by economic developments and drive the need for different scenarios to be investigated.

The NCs RfG and DCC requirements therefore need to consider possible trends, they need to be sustainable due to the long-term investments they trigger, be cost-effective overall, while still being flexible enough to cover different scenarios.

EXAMPLE - REACTIVE POWER

As discussed with the higher level of RES penetration, synchronous generators are displaced and this removes a key source of reactive power.

Moreover, underground cables within the distribution (and even transmission) grid and the development of embedded generation in Distribution Networks have an increasing impact on the reactive power flows at the interface between transmission and distribution. To support reactive power needs equipment can be installed at HV (or EHV) voltage level or at a distribution voltage level of the transformer.

Transmission System Operators in defining the appropriate reactive power ranges to apply at the T-D interface point must look at the cost efficient provision of reactive power to meet their functional needs to support transmission system voltages.

As an example Cost Benefit Analysis (CBA) has been performed for several European countries with different system characteristics [2]. Different locations in a country were chosen for examination. The selection was based on location - a highly integrated point in the network with high levels of available high merit order generation (urban) and the inverse (rural location). At each location the study examined the introduction of new load (50 MW at 0.85 power factor and 500 MW at 0.85 power factor) and examined the needs for additional reactive power in the network. The study considers two options:

1. Reactive support provided by the user at the next voltage level down from their connection point
2. Reactive support provided by the TSO – optimum location to be determined.

The results of the Irish case from this example are shown in Table I.

Table I: Cost benefit analysis for reactive power equipment at different voltage levels in the grid

Test Case 1 – 50MW in Binbane 110kV station		
Scheme	Assumption	Total cost in k Euros
Load 110kV connected	Assume 30 + 22 MVAr capacitor blocks	2136
Load 110kV centralized connected	Does not work	-
Load 38kV connected	Assume 30 + 17 MVAr capacitor blocks	719

Test Case 2 – 500MW in Flagford 220kV station		
Scheme	Assumption	Total cost in k Euros
Load 220kV Connected	Assume 6 * 60 + 20 MVAr capacitor blocks connected at the stations 110kV	9340
Load 110kV Connected	Assume 6 * 60 + 20 MVAr capacitor blocks connected at the stations 110kV	9340

It is clear from this CBAs that from a socio economic viewpoint the total cost to meet the system need for reactive power is lower if the reactive compensation is undertaken lower down in the system (generally closer to the demand) at a lower voltage level than if undertaken at the EHV or HV level. It has been found that reactive power is in general most cost-effectively provided beyond the connection point in the DSO network or its demand users.

Therefore the reactive power requirements should restrict the steady-state range of reactive power that is imported and exported over the T-D interface to a minimum as reactive power support can be best generated were it is needed. On the other hand ranges should be so wide that they do not restrict the use of the capabilities of embedded generation and DSR.

Depending on the network characteristics, reactive power support for distribution system voltage management can be cost-effective if it is provided by generating units embedded to the distribution grids.

EXAMPLE - SHORT CIRCUIT CONTRIBUTION

As part of any development it is vitally important that the short term electrical currents are considered to ensure adequate equipment and protection capabilities. The responsibility for this in the connection codes lieswith both system operators. Principally the TSO will provide both the maximum design level for the transmission system, and an equivalent model of the transmission network for the estimated maximum and minimum fault conditions.

In order to provide the equivalent models the TSO must assess the impact of generation and demand portfolios predicted and network changes from the present to future years to find both the highest and lowest fault levels.

This is normally accomplished by considering the network development and building an appropriate number of models for the next few years at both demand peak and trough. Each year may not be studied but rather transitional years where major network changes occur impacting on the source impedance from generation to the T-D interface.

Also generation must be dispatched to estimate the highest and lowest short circuit contribution. Given the use of these models in selecting equipment and protection a conservative approach is often best achieved.

To find the maximum condition, a suitable model would be with generation dispatched to be N-1 compliant and within operating limits (i.e. for voltage and frequency), supplemented with all the remaining generators providing no active or reactive power (but able to provide fault current).

Fault calculations can then be performed using this model to provide the maximum equivalent models for each year. As demand can also contribute to fault current a peak demand case is usually the maximum case.

For the minimum condition, generation is dispatched to the most electrically remote locations on the network that still provide an N-1 compliant case within operating limits. These models may also include situations with items of plant out for maintenance.

Fault calculations can then be performed using this model to provide the minimum equivalent models for each year. As demand can also contribute to fault current and the short-circuit level is low with less generators in operation a trough demand case is usually the minimum case.

Table II shows results for three stations extracted from [3], which have been calculated using this approach.

Due to network changes splitting Glenlara A and B in later years a step change in both stations occur between 2014 and 2017. Glenree more typically progressively grows as more demand and generation are connected.

The final highlighted maximum and minimum fault levels for the three stations demonstrate the need for the TSO to consider network topography changes, with generation and demand over a number of years to select appropriate values for use by the DSO to design the connecting station.

Table II: Transient maximum and minimum fault current of example Irish Stations (Extracts from [3])

Station Name	Maximum in kA					
	2014		2017		2020	
	3Ph	1Ph	3Ph	1Ph	3Ph	1Ph
	Maximum in kA					
Glenlara A	**3.5**	**4.2**	2.9	2.4	2.8	2.4
Glenlara B	3.5	4.2	6.0	6.4	**6.1**	**6.4**
Glenree	4.4	3.8	4.5	3.8	**5.4**	**4.3**
	Minimum in kA					
Glenlara A	3.2	4.0	2.7	2.3	**2.7**	**2.3**
Glenlara B	3.2	4.0	**5.5**	**6.0**	-	-
Glenree	3.4	3.2	3.3	3.1	**4.6**	**3.9**

EXAMPLE – INFORMATION EXCHANGE

Information exchange is a requirement of all of the connection codes. However it is apparent that the nature of this information exchange is impacted by what is being connected.

In the previous worked example on reactive power, the outcome impacts on the size and connection point of reactive power in the network, and also due to other requirements in the code whether this is dynamic or static. Consequently the initial information exchange on the connection to the TSO will need to identify reactive power sources to meet the requirements and sufficient information to model this for operational and planning purposes.

Simple telemetry to periodically record power factor at the connection point is likely to be sufficient where there are static reactive power devices, but will be insufficient for dynamic reactive power control.

In this situation, closer to real-time measurements will be required for system operation to ensure voltage stability of the grid.

In the case of the worked example for short circuit power requirements, Glenree is not impacted by changing network topography while Glenlara is. The TSO has a duty in the connection code requirements to inform connected parties of a change above a threshold to the maximum fault current they should be able to withstand.

Therefore additional information exchange via telemetry may be required in stations where significant changes can occur through operational actions changing topology.

CONCLUSION/SUMMARY

The evolution of the power system, in its path towards the European vision of a de-carbonized electrical network by 2050, will face many challenges.

A set of Network Codes have been developed to provide a coherent base for the cooperation of the different actors (TSOs, DSOs, Demand users and generating units) to reach a cost-effective and secure power system.

More and more generating units are expected to be embedded in the distribution grids providing means to control active and reactive power but also largely contributing to the behavior of the power system, including during transient voltage and frequency operation. Stronger cooperation between TSOs and DSOs are then needed and are supported by grid codes.

The paper has focused on some of the functional capabilities that TSOs will need to expect from DSOs in terms of reactive power, short-circuit contribution and information exchange.

Furthermore, the paper has also highlighted that NC has also included functional capabilities to distribution-connected users to coherently support the DSOs in fulfilling their own requirements in a cost-effective manner.

Reactive power must be supplied to all users and is less expensive when provided locally. The presence of generation units in distribution grids, complying with the reactive power connection requirements will support balancing reactive power at distribution level.

The transient voltage support of the overall power system and the efficient working of the protection equipment will need to rely on short-circuit contribution from all users and grid equipment. In a similar way, today TSO exchange information about their contribution in short-circuit power to distribution systems, the vice versa will be needed in the future.

The worked examples provided in this paper have shown that requirements at the T-D interface point together with a coherent set of requirements for all embedded users, give benefit to all involved actors. Network Codes implemented, taking into account existing and updating where appropriate national regulations and standards, will then allow the European power system to meet is targets in a cost-effective and secure manner.

REFERENCES

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