Response of Associations representing DSOs to ACER's call for comments on the Network Code on Emergency and Restoration (NC ER)

Brussels, 28 April 2015

In September 2014, ACER and CEER wrote in their publication "Bridge to 2025: Conclusions paper", that "more active control of distribution networks will result in a need for greater coordination between TSOs and DSOs".

In this spirit, CEDEC, EDSO for Smart Grids, EURELECTRIC and GEODE met several times over autumn and winter with ENTSO-E's drafting team and responded jointly to the two public consultations organised on the NC ER.

However, out of all DSOs comments submitted to ENTSO-E during these public consultations, only few have been taken into account and included in the new text of March 25th, released April 1st.

Generally, NC ER **should make sure TSOs cooperate on an equal footing with DSOs**, and ensure that all **requirements,** most notably the ones related to Low Frequency Demand Disconnection, **are both technically and economically justified.**

According to the DSOs, following topics should be examined in more detail during ACER's 3 month period for establishing its reasoned opinion:

- Automatic under-frequency control scheme;
- Coordination - Consultation;
- Notifications & instructions by TSOs to, Disconnection by TSO of and Information gathering by TSO from SGUs connected to the distribution network;
- Defence and Restoration Service Providers and the definition of Significant Grid User;
- Testing;
- Derogation;
- Communication systems.

The above mentioned topics are described and explained below.

For any further questions and information, please contact:

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Detailed topics:

1. Automatic under-frequency control scheme (article 14)

Current Load Frequency and Disconnection requirements are neither cost efficient nor technically justified.

Article 14 includes binding characteristics, parameters and settings of automatic LFDD schemes applicable to each Synchronous area. Network Operators of all Member States will have to comply with these requirements, within five years after entry into force of the NC ER. Even if TSOs are in charge of frequency management, LFDD schemes are most of the time implemented by equipment operated by DSOs. The implementation of the NC ER will indeed have a major impact for DSOs.

The proposed requirements are based on the results of a study carried out by ENTSO-E and published in December 2014 *(entitled "Technical background for the Low Frequency Demand Disconnection requirements")*. Even if the DSOs welcome the process of having a study in order to give a sound basis to network code requirements, several concerns remain regarding these new requirements.

a. Efficiency of existing LFDD schemes

Automatic LFDD schemes are activated only in very rare cases where power systems are entering into a critical dynamic state, that can ultimately result in a very large scale if not total loss of service. In these situations, a fast and robust response of system defence plans is expected in order to stop the degradation of the situation, provide a stable state upon which TSOs will implement recovery strategies.

Such a situation occurred during the event of 4 November 2006. The automatic load disconnection in the western part of Europe stopped the collapse dynamically and stabilized the value of the frequency, thus giving the TSOs a clear situation to restore frequency to a normal value, and resume normal operations.

Throughout Europe, these schemes are based on various but proofed technologies implemented within primary substations control systems and under joint supervision of DSOs and TSOs. Most common LFDD control systems include a maximum of four disconnection steps within the [49Hz, 47.5Hz] frequency range.

b. The NC ER requirements lead to a very profound evolution of the existing scheme

The same article 14 requires LFDD plans within all Synchronous areas to be harmonised and to be made of similar schemes with at least six disconnection steps within the [49Hz; 48Hz] frequency range for Continental Europe.

The reason to impose a large number of disconnection steps is directly linked to the success criterion of LFDD schemes as defined by ENTSO-E in its technical study: according to this theoretical study, LFDD is considered to be successful if it brings the system back within a narrow range of frequency values [49.9Hz; 50.1Hz]. If this requirement had been applicable, during the event of 4 November 2006 the LFDD response at that moment would now be considered non efficient even though it actually saved the system of the western part of Europe from a blackout.

This point has been raised to the attention of ENTSO-E during public consultation meetings. Shifting the LFDD purpose from stopping automatically and rapidly a hazardous process of frequency collapse to some kind of automatic management of frequency quality under exceptional circumstances, is a very important increase of functional requirements. Emergency brakes in transportation are expected to save lives, asking them to make a traffic accident comfortable is another story.

c. Impact of these new stringent requirements on existing schemes

As most control systems have been designed to dispose of a maximum of four disconnection steps, one can think of two different technical options in order to be compliant with the requirements in the NC ER of having at least six steps within [49Hz; 48Hz] and within five years:

- Mitigation of the four steps at different frequency thresholds between primary substations in order to get an aggregated behaviour of six or more steps for the whole frequency control area. Even if this solution would enable DSOs and TSOs to respond to the new requirements, this would lead to a change of paradigm for the implementation and the operational conditions of LFDD schemes.

  The present strategy guarantees that the activation of LFDD will be rather homogenous between primary substations thus limiting the transits modifications between primary substations. With a mitigation strategy, the activation of LFDD will result in substantial modification of transits between primary substations depending on the depth of the Demand Disconnection. As such, this could have potential detrimental effects on power system safety which have not been studied yet.

  Moreover, this mitigation solution could possibly oblige system operators to give up on some functions which are interesting for power system safety purposes and which can hardly be mitigated in the same manner.

- Retrofit in five years of all primary substations control systems of the frequency control area on some primary substations such requirements cannot be implemented without substantial upgrading towards more flexible technologies. This means important additional costs or anticipation of such, over a short period of time.

  The magnitude of costs for a material retrofit is several hundred thousand euros per primary substation to be retrofitted. The technical and economic impact will largely depend on the TSO-DSO interface location, and the present capability of primary substations to support the new requirements with or without upgrading.

  At EU level the costs to upgrade the present LFDD scheme that proved to be efficient in the recent past, would very probably be over several billion euros.

  So far ENTSO-E provided no Cost Benefits Analysis (CBA) and showed no intention to do so even though the NC ER requirements could be applicable to existing facilities. Such a situation would make the requirements for connection addressed in the Demand Connection Code be retro-active as well. As far as we understand the codes' logic, such a retro-activity is to be assessed at national level through a mandatory CBA.

d. Avoiding potential detrimental effect on safety and/or costs

The DSOs warned ENTSO-E during the public consultations on NC ER regarding the potential detrimental effect on safety or costs of the new LFDD requirements while expected benefits are not proven and not precisely described beyond the expected behaviour.

2. Coordination - Consultation (article 6)

Coordination and consultation are defined in article 6. DSOs want to stress that for some of the requirements in the NC ER it is important that the TSO and the DSO reach an agreement, only a consultation of the DSO does not seem appropriate. It is also important to maintain a role for the NRA to preside over the agreements reached, to ensure appropriate process and to resolve disputes.

Maintaining system security requires a well-balanced cooperation and hence a close coordination of all players in the electricity sector. The DSOs are concerned by the unilateral decision making process which is foreseen in this code. TSOs only have to consult other stakeholders, including DSOs, when elaborating their defence plan. This weak commitment could endanger system security if TSOs decide upon the emergency and restoration procedures without proper coordination with DSOs.

All the existing and possible future emergency and restoration actions taking place in distribution networks aim at supporting TSOs in their responsibility of keeping the overall system safe and stable. Therefore, they must be designed and activated based on an agreement with TSOs. However, as the main defence tools are connected to the distribution network, their settings and activation must be built together with DSOs for efficiency reasons (technical efficiency and cost efficiency). Direct intervention of the TSO would only blur the lines between TSO's and DSO's responsibilities.

DSOs suggest that in following articles TSO and DSO reach an agreement (instead of only consultation of the DSOs):

- Art. 9§1 / Art. 21§1: design of the defence/restoration plan;
- Art. 9§8 / Art. 21§11: definition of terms and conditions to apply to defence/restoration service providers;
- Art. 25§4: during re-energisation define amount of demand to be reconnected on distribution networks;
- Art. 41§2: definition of the test plan.

Furthermore, the coordination process, as described in this actual version of the NC, has been changed by the additions in paragraphs f and g.

In paragraph f in the former version parties had to explicitly agree with the TSO, whereas now the coordination is based on a 'deemed acceptance principle'.

In paragraph g the (equivalent) action could have no impact on concerned parties, but in the latest version of NC ER the same action must have the least (or no) impact on parties. On top of this, parties opposing to the actions to be taken, have to justify their opposition (prove that the action would lead to violation of one or more technical, legal, personal safety or security constraints).

3. Notifications & instructions by TSOs to, Disconnection by TSO of, Information gathering by TSO from SGUs connected to the distribution network (several articles).

Several articles permit direct 'contact & actions' between TSO and SGUs (and Defence/Restoration Service Providers) connected to the distribution networks.
The DSOs claim that they should be the only 'operator' of their network.
Even if direct interventions of the TSO on the distribution networks are already existing or permitted by National legislation, this principle should be the exception and in that case the DSO should anyhow always be informed.
In the following articles direct notifications/instructions by the TSO are described, the DSO is however not always informed:

- Art. 10§2: direct notification possible (but also notification to the DSO);
- Art. 13§3 and 4: direct instruction possible (DSO not informed);
- Art. 18§2 and 3: direct instruction possible (DSO not informed);
- Art. 20§1: direct disconnection possible (DSO not informed);
- Art. 22§2: direct notification possible (but also notification to the DSO);
- Art. 38§2: direct information gathering (DSO not informed).

4. Defence and Restoration Service Providers (articles 1, 2, 9§8 and 21§11) Definition of Significant Grid User (article 7)

The NC ER introduces two new roles, namely Defence and Restoration Service Provider.
Those two roles were only introduced in the later versions of the NC to avoid addressing directly type A PGMs and Demand offering DSR, but this does not change the fact that they are both still considered in the code.
As stated in the Supporting Document: *"The objective is to be able to integrate them in the processes defined in the Network Code. At the moment it is not current practice and <u>it is not planned to use Type A Power Generation Modules in Restoration Plans</u>, but NC ER should let this possibility open for the future."* and also highlighted by the DSOs on several occasions, it seems early to already integrate type A PGMs and Demand offering DSR at this stage. This can still be done, if needed, in a revision of the code, because it should definitely be examined whether all requirements in the NC can easily be imposed on this type of generator/demand, even if they voluntarily decide to participate.

Furthermore, confusion might rise in relation to the definition of the Significant Grid Users.
The Significant Grid User in NC ER is defined differently from the SGU in the Network Code on Operational Security, which is considered as the umbrella code for all system operation codes. It seems only logical that there is only one definition, to avoid any confusion.
DSOs proposed that in the NC ER reference should be made to the SGU defined in NC OS. If the definition in NC OS does not fit, then it should be changed in that code and not in NC ER.
With the idea of the Commission to integrate the operational codes into one single code/guideline it is obvious that it is not possible to keep different definitions for the same term.

The SGU is defined in the NC OS as follows:
a) Existing and New Power Generating Modules of type B, C and D according to the criteria defined in Article 3(6) of [NC RfG];

b) Existing and New Transmission Connected Demand Facilities according to the criteria defined in Article 5 and Article 8 of [NC DC] and all Existing and New Transmission Connected Closed Distribution Networks;
c) Significant Demand Facilities, Closed Distribution Networks and Aggregators according to the [NC DC], in the case where they provide Demand Side Response directly to the TSO;
d) Redispatching Aggregators and Providers of Active Power Reserve according to the [NC LFCR].

In the NC ER the SGU is defined also with a), b) and d) as mentioned above, but c) is not in the scope, however and extra type, namely HVDC Systems and DC-connected Power Park Modules was added.

According to both definitions, type B PGMs are part of the SGUs. Being part of the SGUs all requirements applicable to SGUs in the code are automatically applicable to type B PGMs.
So, it seems odd that in article 1§9 type B PGMs can at the same time be considered in a contract between the Defence/Restoration Service Provider and the TSO, meaning delivering a service on a voluntary basis.

DSOs are concerned that the role of the Defence and Restoration Service Provider is not defined clearly enough in the NC ER at the moment. Additional thought should go into a clear and flawless definition of the role and how the interaction with other parties in the NC ER is established.

5. Testing (articles 41 to 49)

Even if the DSOs suggested during the public consultation to not specify the periodicity for testing of the different elements (articles 41 to 49), most of the testing periods are still in the NC. DSOs appreciate however that the periodicity of testing of the LFDD relays will have to be decided on a National level.

Regarding testing DSOs would like to suggest to add following article or paragraph, to be sure the DSOs and the TSOs will be able to do the necessary testing without any constraints and to be sure that interruptions due to obligatory testing are not taken into account in reporting on the quality of service and further benchmarking exercises.

" The TSO, DSO and the Significant Grid User will not be liable for possible interruptions of other Grid Users during tests, for which a clear motivation can be delivered.
These interruptions, due to compulsory testing, will be explicitly excluded from all quality of service data submitted by TSO and DSO for regulatory benchmarking purposes".

6. Derogation (no existing article)

NC ER does not provide an article for derogations as is the case for NC RfG and NC DCC. However, derogations might help TSO/DSO in some specific cases to deviate from the requirements where implementation of measures (for defence and restoration) might put an overshooting burden to single DSOs or SGUs. The supporting document indicates that the *"NC applies the requirements to "Service Providers" which voluntarily opted to provide the services. A derogation process would thus be redundant."* , but derogations could however also be useful for other than type A PGMs and Demand providing DSR.

7. Communication systems

Article 39 is very poorly expressed and it is not possible to understand what actually is envisaged in terms of communication infrastructure with SGUs. We believe that the drafting is confused between resilience and redundancy. The former generally means how long the communication channel will remain working when other communication media are subject to disruption or common mode failure. Redundancy simply means having additional routes. Having multiple redundant non-resilient routes is not useful. Why is there a need for more than one channel if that channel is resilient for 24 hours? Resilient also means free from common mode failures. Duplication of a 24 hour resilient circuit (even if the duplicate is not resilient) is very expensive.

It is also not clear what the telephony provision is for. If the requirement is for a suitably competent operator to be on hand at the SGU, then this should be made as a specific and precise requirement. A telephone is just one specific way of interfacing with the data circuit(s) that are required in the NC.

We believe that it will never be economic to provide more than one resilient data channel to all SGUs. 24 hour resilience is itself expensive and as such a single 24 hour resilient communication channel should be the subject of a CBA.