ERGEG's draft Framework Guidelines on Capacity Allocation and Congestion Management for electricity

A EURELECTRIC response paper

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EURELECTRIC response to ERGEG's draft Framework Guidelines on Capacity Allocation and Congestion Management for electricity

General Issues

Scope

EURELECTRIC welcomes the publication of the draft Framework Guidelines on Capacity Allocation and Congestion Management for electricity as an important step in the process of developing a coherent European regulatory framework aimed at supporting integration of electricity markets in the EU.

EURELECTRIC believes that although the present draft of the Framework Guidelines addresses in a structured way many important aspects of the subject, a number of improvements and clarifications elaborated below are very desirable.

In our view, the present Framework Guidelines should be based on the European target model for electricity market adopted by the Florence Forum in December 2009 and pave the way towards the development of the Network Codes specifying in detail features of this target model.

EURELECTRIC stresses the need for more clarity with regard to the legal basis of implementing the network codes. The interplay between the Framework Guidelines, the Congestion Management Guidelines and the Network Codes should indeed be clarified in more detail. The statement that the Framework Guidelines will be complementary to the existing Guidelines on Congestion Management appears to be not fully consistent with another statement that the Network Codes will amend, repeal or even replace the relevant sections of the Congestion Management Guidelines. Therefore it is important to clarify the scope of the Framework Guidelines in order to ensure consistent and proper implementation of the Network Codes.

The ultimate objective of implementing a European-wide mechanism for capacity allocation and congestion management should be further stressed across the document. In this context, the role of ACER appears to be rather limited, even with regard to the EU-wide issues. For example, the Framework Guidelines specify that the capacity calculation method shall be approved by the "relevant regulatory authorities" (1.1.5). However, it does not clarify how the overall assessment of such a proposal will be done in case of different opinions among the NRAs. We believe that the Framework Guidelines should specify in detail the role of ACER in establishing a European-wide mechanism for congestion management and capacity allocation and its role in providing framework for NRAs' cooperation, inter alia by drawing on Art. 6 and Art. 38 of the 2009/72/EC Electricity Directive as well as Art. 7 and Art. 8 of the 2009/713/EC ACER regulation.

Finally, we want to draw the attention to the fact that a large part of the present Framework Guidelines is devoted to the capacity calculation, while this is not at all reflected in the name of these Guidelines.

1. Are there any additional issues and / or objectives that should be addressed in the Capacity Allocation and Congestion Management IIA and FG?

EURELECTRIC deems the coordinated development of the transmission grid infrastructure in connection with the appropriate location of new generation units as an important part of congestion management, complementing the efficient and non-discriminatory utilization of the existing transmission capacities. Therefore the current congestion status should be taken into account when preparing the TYNDP, and vice versa, views on capacity calculation and zone delimitation should duly take into account planned grid extensions. We also recommend that the Framework Guidelines cover all timeframes (including balancing).

In our view, consistency in terms of scope and principles between the Framework Guidelines on CM&CA and other Guidelines, including Comitology Guidelines on Governance and Framework Guidelines on Balancing, should be ensured, especially taking into account that there will be a time gap between their adoption.

We also believe that the Comitology Guidelines on Fundamental Electricity Data Transparency should be aligned with the CACM framework guidelines. For instance, the provision 1.1.5 requires that the capacity calculation method, including the approach for the assessment of required security margins, shall be approved by relevant regulatory authorities. In our opinion, and based on ongoing discussions in the AHAG Capacity Calculation Workstream, this is only possible if the reliability margins are transparently published. Furthermore, the yearly actual use of the reliability margin should be published on the ex-post basis (histogram of use, explanation of the extreme cases, etc). Information on this important parameter should be made available also to the market participants, and not only to the relevant authorities as proposed in this CACM framework guidelines. The same principle is valid for the provision 1.2.5, which requires more transparency with regard to the situation of internal congestions limiting cross-border capacity, and the amount of re-dispatching costs. We believe that the Guidelines on Fundamental Data Transparency should include parallel provisions regarding this information.

EURELECTRIC believes that the Framework Guidelines should also define precise rules for assigning congestion management incomes and expenditures to TSOs in a way that provides an incentive to perform an efficient congestion management.

2. Is the vision of the enduring EU-wide target model transparently established in the IIA and FG and well suited to address all the issues and objectives of the CACM?

We would like to point out the need for a stricter alignment of the draft Framework Guidelines on Capacity Allocation and Congestion Management with the target model adopted by the Florence Forum in December 2009. In particular, a more detailed outline of the main features and principles of this target model should be an important part of the Guidelines. One example of this need for alignment is that the introduction of implicit auctions in the intra-day trading in case of "sufficient liquidity" (4.3) does not correspond to the agreed target model, which in principle provides for a possibility to introduce implicit auctions only in case of "significant additional capacity". Another example of apparent inconsistency between the draft Guidelines and the target model is the provision 3.2, that weakens the need for PTR or FTR issued by the TSOs in case "appropriate cross-border financial hedging instruments are offered in liquid financial markets". This is not in line with the target model adopted by the Florence Forum in December 2009, stating that TSOs shall issue PTRs or FTRs. In our view, various market instruments, like CfDs in the Nordic market, can be provided by the market, but they can not be regarded as a replacement for the TSOs obligations to offer cross-border capacity to the market.

EURELECTRIC believes that as the network codes will be drafted by ENTSO-E, the Framework Guidelines should describe leading principles related to the chosen policy options and provide a clearly defined mandate to TSOs in order to ensure that the network codes meet the requirements of the market and the regulators. As the current proposed framework guidelines are sometimes too generally formulated, it may leave an excessively big room for interpretation of the guidelines by ENTSO-E when drafting the associated network codes. Furthermore, terms of these requirements should be quantified where possible to ensure that the implementation of the network codes can be properly assessed.

3. Should any of the timeframes (forward, day-ahead, intraday) be addressed in more detail?

Further to our answer under question 2, EURELECTRIC believes that all timeframes have to be described in more detail in terms of policy choices to ensure a common understanding of the European target model and its consistent implementation in all parts of the EU.

4. In general, is the definition of interim steps in the framework guideline appropriate?

The framework guidelines shall give a clear overview of how and when capacity allocation and congestion management shall be implemented in all markets of the EU. It is also crucial to have a common understanding about the interim steps to be envisaged. In accordance with our reading of the Framework Guidelines, we see the following interim steps:

- Capacity calculation: ATC capacity calculation (and allocation) can be regarded as in important intermediate step before the flow-based method is implemented (where proven to be efficient)

- Delimitation of zones: possible interim steps should be analysed. In our view, it is necessary to start with existing zone delimitations and to determine a more detailed methodology before changing bidding zones. A possible interim step would be to consider more re-dispatching. However, it might not be sensible to go through a zone change process for several years (analysis, preparation), when it might take the same time to build a new grid line eliminating the internal congestion
- Forward: implementation of PTR + UIOSI instead of directly moving to FTR (except in Nord Pool where the PTR step should definitively be skipped) seems to us a possible intermediate step
- Intraday: intraday allocation based on continuous trading with only simple block bids (and not sophisticated block bids), with only manual matching (and not automatic matching) would be very welcomed as an intermediate step, as this model is fully in line with the final target model.
- DA: we do not think, however, that any further volume coupling initiatives would be appropriate as interim solutions due to various technical complexities of making the final step afterwards towards the single price coupling

In our view, the Framework Guidelines should require that the interim solutions must be justified and contribute to achieving the target model, taking into account the relevant implementation deadlines for the final model.

5. Is the characterisation of force majeure sufficient? Should there be separate definitions for DC and AC interconnectors?

EURELECTRIC would like to see a much clearer definition of force majeure to avoid diverging interpretations. EURELECTRIC's view is that force majeure definitions should be harmonised across the common market. EURELECTRIC sees no reasons for separate definitions for DC and AC interconnectors.

6. Do you agree with the definition of firmness for explicit and implicitly allocated capacity as set out in the framework guideline? How prescriptive should the framework guideline be with regard to the firmness of capacity?

EURELECTRIC welcomes the provisions 2.5 and 4.4 on firmness of allocated implicit day-ahead capacity and intraday trade, and also the statement that all nominated capacity shall be firm (5.10).

It is important to note that the provision (5.5) regarding the allocation of the "whole interconnection capacity for a given timeframe to a Power Exchange" comes into contradiction with the provision (3.2) providing for long term transmission rights.

EURELECTRIC believes that the framework guideline shall define firmness of capacity in detail. The provision (5.6) on curtailment of cross-border transactions in emergency situations should be further aligned with the article 16 of the cross border regulation

714/2009 that stipulates the following: “Transaction curtailment procedures shall only be used in emergency situations where the transmission system operator must act in an expeditious manner and re-dispatching or countertrading is not possible. Any such procedure shall be applied in a non-discriminatory manner. Except in cases of force majeure, market participants who have been allocated capacity shall be compensated for any curtailment.”

EURELECTRIC supports the view that curtailment of cross-border transactions may only be applied in case of force majeure or in emergency situations. Holders of capacity in the form of PTRs or FTRs shall be compensated by the relevant market spread in emergency situation (5.9) and by the initial price paid to the TSO (not in the secondary market) in case of force majeure.

The provision (5.9) requires TSOs to provide compensation based on the price difference between the concerned zones, which implies some risks for the TSOs. Therefore, they should also be allowed to buy back capacity rights on the secondary market (or via an inverse auction) where they buy back from the market, as a complementary measure to counter-trading and re-dispatch. If TSOs want to buy back capacity rights on the secondary market, they should not be responsible for organising this secondary trading platform (as stipulated under 3.6), in order to avoid that they have a market insider information on the position of different actors offering capacity on that platform. TSOs should only organise the scheduling platform between actors having sold/bought cross-border capacity from each other.

EURELECTRIC would like to precise how financial firmness should work in case of explicit auctions for already nominated capacity (5.10).

As the allocation model described in the CACM framework guidelines provides only for implicit auctions in the day-ahead (provision 2.1), we assume that such explicit auctions concern only long term (yearly, monthly etc) allocations. We understand and also support that day-ahead explicit auctions are not considered in the framework guidelines. Might this still be the case, then the guidelines should be clarified, and a correction to the following reasoning will be also necessary.

In our view, the financial firmness could then be organized as described below. The starting point is the nomination of long-term (yearly, monthly) capacity rights at around 8h00 a.m. in the day-ahead. In case TSOs curtail such nominated capacity before the PX gate closure (at around 12h00) and in case they notify it timely to the users of that capacity, TSO could pay back the spread between PX (as parties would buy/sell their curtailed position on the PXs for the part of the rights they are not allowed to nominate).

However, this seems to be a very delicate process as there might be a risk that a market party is not reached by the TSO in due time for him to have an opportunity to balance his position on the power exchanges. Therefore physical firmness will be a preferred solution. To ensure physical firmness, TSOs could simply put the curtailment flow on the power exchanges as biddings in the opposite direction of the congestion, instead of “delegating” this task to the market actors.

In case TSOs curtail capacity after the PX gate closure, but before the Intraday gate closure, capacity right owners should be paid back the Intra-day price. In this case, the question is which intra-day price should be used as it is evolving over time. In our view, it will be more preferable if TSOs would not announce curtailment of these rights, but keep the capacity physically firm by TSOs counter-trading to ensure that nominated schedules do not have to be changed. It is worthwhile to evaluate if, how and to what extent, TSOs could participate in the Intraday market in order to ensure physical firmness as an alternative (or additional instrument) for counter-trading.

If finally TSOs need to curtail after the intraday gate closure, this will lead to that the affected market participants due to extremely short time will have no other option than to go into imbalance, and in accordance with 5.9 will have to be paid back the imbalance cost as compensation for curtailment. In such a situation, it will therefore be more appropriate if TSOs do re-dispatching (by using the balancing markets) and thus ensure the physical firmness of capacity.

In our view, the Framework Guidelines should include a comprehensive chapter consolidating the firmness rules for all timeframes that are currently spread out across the document. The Framework Guidelines include provisions on firmness for Day-Ahead capacity (2.5), for Intra-day capacity (4.4) and for all nominated capacity (5.10). Therefore, in the present draft document firmness is (at least explicitly, but only implicitly via 5.9) not yet guaranteed only for Long Term (yearly, monthly etc) non-nominated capacity. In this case, whenever TSOs come to the conclusion that they sold too much capacity in advance (but this capacity is not yet nominated), the solution could be that the TSOs buy back the non-nominated transmission rights. This is indeed fully in line with provision 5.9 that states that "capacity holders shall be compensated". The capacity holders expect to be paid back the UIOSI value at the moment of the PX gate closure. However, this entails some "last minute" risks for the TSOs. They could therefore hedge themselves via different processes. For example, by acting on the secondary market or by organising "inverse auctions" whereby TSOs pay out the marginal price for the acquired capacity. Buying back capacity rights by TSOs should be done in a transparent manner, with timely notice to the market that capacity has to be reduced for the indicated period. This means that once TSOs decide to reduce cross-border capacity that was earlier auctioned to the market, they have to inform the market about the reason for it and, only after, that buy back the capacity on the secondary market. In the same way, if a reverse auction is organised, the TSOs have to timely inform the market before starting this auction.

If TSOs do not act pro-actively as described above, they could ultimately offer even negative cross-border capacity to the implicit auctions process. Through this process they would actually buy back capacity sold in excess in advance in a market-based manner. This will even allow them to buy back capacity when all forward allocated capacity has already been nominated before the Day-Ahead allocation.

EURELECTRIC supports the provision (5.7) on the usage of congestion rents to inter alia guarantee firmness of allocated transmission rights, in particular by means of coordinated re-dispatching/countertrade actions to ensure physical firmness.

The provision (5.8) will have to be further clarified when it comes to defining what the term “enough” re-dispatching/countertrade exactly means, as “enough” could be interpreted by TSOs in a different way.

The provision 5.8 should further specify that TSOs, in cooperation with each other, should also use “cross-border resources” for counter-trading and not only domestic resources. This will allow reducing the counter-trading costs.

7. Which costs and benefits do you see from introducing the proposed framework for Capacity Allocation and Congestion Management? Please provide qualitative and if applicable also quantitative evidence.

Costs and benefits are difficult to quantify. For example, even if the costs of the CWE market coupling project have been estimated, it is important to bear in mind that this is the first project of its kind for such a large region and adding new countries will be much cheaper. When assessing benefits of the market coupling, it should be considered that efficient congestion management will increase competition across Europe and facilitate that consumer prices are impacted by this cross-border competition.

With regard to assessment of costs and benefits of zone delimitation, the draft Framework Guidelines seems to take a rather short-term perspective and do not consider the long-term effects on investments. Efficient short term use of transmission capacity is only one aspect and should not be considered as the only main criteria when evaluating the size of bidding areas. The preference should be towards larger bidding areas, as small zones will increase uncertainty for investments made by energy intensive consumers and generators. Furthermore, small price zones will hinder effective competition in wholesale and retail markets, add complexity for market participants and customers, as well as increase volatility of electricity prices. They will also reduce incentives for TSOs to avoid/reduce congestions and to invest in network reinforcements.

In our view, in case of lack of interconnection capacity, delimitation of zones into a number of smaller zones may result in lower re-dispatch costs, but at the same time might increase market concentration in the resulting zones. On the other hand, in case of larger zones, the prices in the Day-Ahead timeframe will be more competitive, but due to larger need for re-dispatch, the generators will be called more in the re-dispatch process. It seems that zone delimitation will only result in moving market concentration risks and in shifting costs between generators (in the small bidding areas) to grid tariffs (in the large bidding areas), but will not have the desired positive impact on the European social welfare. A truly effective solution will be to identify the main needs for new lines in the European grid by making the current congestions fully transparent and undertake grid investments accordingly as soon as possible. Significant additional capacity can also be made available through greater co-ordination between TSOs, as well as provision and sharing of more real time information.

Creating small bidding areas is not a guaranteed model to attract new generation investments in the high price bidding areas. First of all, investors faced with "unstable" bidding areas will be exposed to higher uncertainty for their investments as any bidding area could become smaller again at the next evaluation. Moreover, investing in a high price (but small) bidding area is not free of risk, as the price in this bidding area might decrease strongly once a cheap new generator has entered the market, thus reducing strongly the business case. Finally, in a "small" bidding area, the (environmental) opportunities (locations) to invest might be limited as well.

Section 1.1: Capacity calculation

In general, a number of provisions of the Framework Guidelines on Capacity Calculation require further clarification and elaboration in order to avoid confusion and misinterpretation.

In the provision 1.1.1 the "locational information on relevant generation and consumption units" has to be further specified[1]. In our view, the capacity calculation should be seen as an iterative process. During the capacity calculation process, TSOs have to make assumptions about how generation will be run, while being aware that the final decision on generation fully depends on the market outcome that is, in its own turn, influenced by the amount of capacity made available to the market (chicken-egg problem).

In the provision 1.1.3 ("Long-term calculation methodologies shall take into account the actual impact of commercial transactions on the physical grid situation"), it is not clear which commercial transactions are meant. Long-term deals normally do not specify the plant where energy will be produced. And it is not possible to know in long-term calculation "the actual impact on the grid" of such commercial transactions.

The provision 1.1.4 mentions the case of "reducing social welfare", but it does not clarify how this reduction will be evaluated and from what level.

With regard to the provision on non-discrimination between external and internal exchanges (1.1.6), EURELECTRIC suggests that the Framework Guideline should stress how this non-discrimination should be achieved. Possible approaches could include via Flow Based process, via GSK methodology and so on.

Finally, the provision 1.1.5 is very vaguely formulated, as already indicated earlier in our response. The provision should require publications of reliability margins and a yearly transparent evaluation of how these reliability margins have been statistically used, with an explanation of the extreme events leading to high use of the security margins.

[1] This is another example where consistency with the transparency guidelines (fundamental data) should be verified.

8. Is flow based allocation, as set out in the framework guideline, the appropriate target model? How should less meshed systems be accommodated?

EURELECTRIC supports the European electricity market target model for capacity calculation adopted by the Florence Forum in December 2009 and confirmed in the AHAG CC project. It foresees a stepwise evolution from the bilateral ATC calculation towards the coordinated ATC calculation (based on the common grid model) as an important interim step and later towards the Flow Based calculation/allocation and envisages all these methods to exist by 2015.

We want to point out that without any further empirical evidence, it might be premature to include a conclusive provision (1.1.2) in the Framework Guidelines with regard to types of situations or specific areas for which ATC or Flow Based methods are most appropriate. As it is recognised in the Impact Assessment, there is no practical experience with Flow Based method of capacity calculation in Europe until now, and therefore this method should be envisaged where substantial improvements relative to the ATC are demonstrated.

We fully support the provision (1.1.2): the practical usage of the Flow Based method should start only after the market participants have been given sufficient time for their preparation and smooth transition to the new arrangement (learning the new methodology and adaptation of the systems).

The provision 1.1.1 admits that the Flow-Based calculation is most appropriate for the short-term capacity calculation process. We support this point of view and suggest that the guidelines should state in a clearer manner that the Flow Based is not appropriate for the long-term.

9. Is it appropriate to use an ATC approach for DC connected systems, islands and less meshed areas?

Less meshed systems shall be treated in the same way, but it might be difficult to demonstrate substantial benefits in these cases.

10. Is it necessary to describe in more details how to deal with flow-based and ATC approach within one control area (e.g. if TSO has flow-based capacity calculation towards some neighbouring TSOs and ATC based to the others)?

EURELECTRIC believes that the Framework Guidelines should promote development of a single capacity calculation methodology across the EU (including one capacity algorithm (1.1.4), one approach to reliability assessment (1.1.5) and so on, rather than allowing various solutions, which can lead to a non transparent calculation process. Therefore, a stronger role for ACER should be envisaged in order to ensure coordination between TSOs and NRAs. Establishment of a common grid model for the EU can not be successfully implemented if different NRAs will have the power to give various approvals or views on the issue (1.1.5).

However, for the interim period it will be important to describe in detail how TSOs will deal with Flow-Based and ATC capacity calculation methods when one control area is involved in both these types of processes on different borders. The work on this topic is on-going at the moment in the AHAG Capacity Calculation project and the conclusions should be integrated in the framework guidelines.

11. Is it important to re-calculate available capacity intraday? If so, on what basis should intraday capacity be recalculated?

We fully support the provision (1.1.8) regarding the recalculation of capacity in the Intra-day timeframe. We consider it crucial to facilitate the optimisation of the usage of the cross-border capacity while ensuring system security. The capacity shall be recalculated based on the changed status of the transmission system, generation and consumption. EURELECTRIC believes that the increasing amounts of intermittent generation will make recalculation of intraday capacity even more important. The framework guideline should give a more precise guidance as to the timing and frequency of the intra-day capacity re-evaluation with the purpose of harmonising the existing re-evaluation practices across markets.

Section 1.2: Zone delimitation

EURELECTRIC suggests that definition of a zone (i.e. a bidding area) in the Framework Guidelines (1.2.1) should be further improved. In our view, a zone should be defined as related to a market area with uniform pricing, where internal congestions are not considered or where deals between two parties are always accepted and executed or where firmness is always guaranteed. In addition, the provisions 1.2.3 and 1.2.4 also establish some relationship between zone (bidding area) and control area. This can create some confusion, as in the current practice, there are some markets where one bidding area encompasses several control areas (Germany, Austria), while in other markets one control area is encompassing several price areas (e.g. Norway and soon Sweden.).

With regard to the provision (1.2.3), EURELECTRIC believes that ACER rather than only NRAs shall have an active role in the process of reviewing the delimitation of zones , inter alia by drawing on Art. 6 and Art. 38 of the 2009/72/EC Electricity Directive as well as Art. 7 and Art. 8 of the 2009/713/EC ACER regulation, given its importance for cross-border trading and considering the possibility for bidding zones to cross national borders in case of no congestion between two control areas belonging to different countries.

Furthermore, the Framework Guidelines should define more specifically the criteria for such a review. Decisions about changing the delimitation of zones should be justified by the evidence of existing/non-existing structural congestion but also taking into account the effects of the short and medium term development of infrastructure, load and generation pattern as well as social-economic factors. Thus we suggest linking this process also with the work on the Ten Year Network Development Plan and its regular update. In order to ensure stability of market rules for cross-border trade, changes in the delimitation of zones, if justified and deemed absolutely necessary, should be announced well in advance, take into account the duration of existing liquid forward trades and be subject to public consultation. For example, if electricity can be traded three years ahead, changes should be announced with a three year notice in order to avoid impact on existing contracts, concluded in the forward markets, and a decrease of liquidity in these markets due to this uncertainty.

The provision (1.2.6) gives a right to the NRAs to take measures regarding the market structure and possible market power issues based on the analysis of the delimitation of zones using data on re-dispatch costs and structural congestion. It is necessary to specify in more detail what kinds of measures are meant in this provision. It is also important to stress here that the existing definition of structural congestion in the Congestion Management guidelines is quite broad and that in the provision 1.2.3 no clear criteria are established to determine whether an internal congestion is significant. Therefore when referring to structural congestion, TSOs should always justify why congestion is structural and why it is not more appropriate to rely on investments in order to remove congestion, rather than shifting the problem towards some market players who are potentially not even responsible for the new upcoming congestions, as this might create huge uncertainty in the investment climate for new generation.

EURELECTRIC welcomes the proposal for analysis of re-dispatch in relation to the welfare related to the delimitation of zones outlined in the provision (1.2.4). However, this will require a clear definition of “welfare”, increased transparency on re-dispatch costs and verification of whether re-dispatch is achieved in the most efficient way. In any case, reduction of re-dispatch cost as such should not be seen as the only criterion, as more re-dispatch does not necessarily have to entail less efficient dispatch. “Welfare maximisation” should also take into account the welfare gains of increased competition, more liquid wholesale markets, better functioning retail markets, increased transmission capacities because of proper incentives on TSOs and the investment climate. The impact of renewable energy generation on the social welfare, in particularly related to the priority feed-in into the transmission system should also be taken into account.

With regard to transparency of congestions outlined in the provision (1.2.5), in our view, the Framework Guidelines should require that such information is reported not only to the NRAs but also to the market, and the Guidelines on Fundamental Data Transparency should incorporate this provision accordingly.

12. Is the target model of defining bidding zones on the basis of network topology appropriate to meet the objectives?

EURELECTRIC believes that bidding zones shall be as large as possible and not necessarily limited by national borders. Furthermore, it is important that bidding zones are stable to ensure that counterparties are not subject to the risk that bidding zones change during the lifetime of a traded contract. EURELECTRIC does not believe that bidding zones should or even can be different in different timeframes. Indeed, there has to be the same definition for forward, day ahead, intraday and balancing bidding areas. In case a forward deal between two parties is done in one bidding area, and at the delivery the deal appears to be in another bidding area, it remains unclear who will be then paying the market value difference. The physical day-ahead markets actually form the underlying for the forward markets. If the corresponding bidding areas are different, this will create additional uncertainty and thus loss of liquidity. Low liquidity markets are, in their turn, not attractive for new market entrants.

13. What further criteria are important in determining the delineation of zones, beyond those elaborated in the IIA and FG?

EURELECTRIC believes that the draft framework guidelines have a too narrow perspective when discussing the definition of bidding zones. Small bidding zones will add to investment uncertainties for generators and energy intensive consumers. It is important that market participants have the possibility to manage their fundamental positions and the liquidity in the relevant bidding area is of importance in this perspective. Small price zones will hinder effective competition in wholesale and retail markets and will add complexity for market participants and customers.

EURELECTRIC would like to comment the statement in the IIA: "It is also possible to aggregate bidding areas into one price zone, as is done in Italy, which is divided into six bidding areas, but with uniform pricing on the demand side (i.e. the demand price is the average of the zonal prices weighed on the zonal consumptions)."

Although it may be true that it is possible to have this solution, it cannot be considered being in line with the basic principle that consumers and producers are faced with the same market price in their bidding zone. Customer prices that are not reflecting the market price in each zone will not give proper incentives, which will be even more important when developing smart grids and other demand side management solutions.

EURELECTRIC would like also to comment the statement in the IIA: "Indeed, the relevance of a price signal in day-ahead may be questioned if large amounts of re-dispatching costs are necessary to ensure system security and if these re-dispatching costs are socialised on all network users and not charged to those who are responsible for it."

The basic principle is that TSOs are responsible for keeping a bidding zone together and network users cannot be seen as the ones responsible for re-dispatch. The need for re-dispatch actually is a consequence of "missing parts" in the grid infrastructure. In our view, the provision (5.1) should put obligation on ENTSO-E - and not only the TSOs - to make transparent in the 10-Year Network Development Plan, where and to what extent congestion usually occurs, as well as how, where and when it is being physically relieved by enhancing the network capacity or by adjusting the critical network elements through e.g. new transmission lines. TSOs shall make the necessary investments in order to avoid large amount of re-dispatch and these costs will be socialised through the network tariffs. In case investments have not yet been done, re-dispatch will be needed and should consequently be socialised as well.

EURELECTRIC supports the provision (5.2) requiring TSOs to implement coordinated re-dispatch or countertrade measures at least at regional level, based on the use of a common grid model. With regard to the provision (5.4) on avoiding market distortions by the TSOs through pricing of generation capacity reservation, we suggest that the Framework Guidelines should require sufficient transparency in the re-dispatching activities including needed volumes and associated costs. This will make any kinds of distortions more evident. Furthermore, we see cross-border re-dispatching systems as mentioned in provisions 5.1 to 5.4 as a valuable tool to manage congestions and therefore this method should receive more attention in the Framework Guideline. A more detailed elaboration of such a system and its public consultation with various stakeholders is necessary.

Section 2: Forward markets

EURELECTRIC wants to draw attention to the fact that the objective of long-term transmission rights as formulated in the provision (3.1) implies that delimitation of zones should be the same across all the timeframes. Therefore it is important to ensure consistency between various provisions of the Framework Guidelines.

EURELECTRIC does not agree with the provision (3.2) stipulating that various cross-border financial hedging instruments can be used instead of the long term transmission rights issued by TSOs. We believe that the market should have freedom to offer hedging instruments, but they should not be considered as a replacement for the TSOs obligations. As already stated above, this is not in line with the European target model for electricity market adopted by the Florence Forum in December 2009.

The provision (3.3) with regard to introduction of FTRs only between two non-liquid markets and not between one liquid and one non-liquid markets can not be seen as well justified. Moreover, it should be further clarified what is meant with “efficiency gains” and how they can be defined and measured.

The formulation of the provision 3.3 should also be improved in order to avoid a possible interpretation that on one border, both PTR (with UIOSI) and FTR rights could be released to the market. It should be clear that either PTR with UIOSI or FTR are auctioned by the TSOs.

With regard to the provision (3.4) we would like to point out that in case the rules outlined in the Framework Guidelines are adopted, it will mean that the currently proposed rules for the BritNed cable will not be acceptable[2].

[2] More specifically, the BritNed rules stipulate that the proceeds of the sale of Unused Units in the Daily Implicit Auction will be paid by BritNed to the Unit Holders at the level of 80 percent of the day-ahead price

When it comes to the provision (3.5) on publication of the volume of long-term capacity rights, we want to stress that publication of indicative volumes is not only necessary for the NRAs, but also for the market. In our view, approval of the volumes could fall into the tasks of ACER as an important cross-border technical issue.

We do not fully agree with the provision (3.6), when it comes to the obligation of the TSOs to set up a platform for secondary trading. This may still lead to conflict of interest if TSOs act at the same time as owners of the platform and as market participants (see our input above on firmness of not yet nominated long-term capacity rights). On the contrary, the TSOs should set up confirmation/scheduling platforms in order to obtain information about the capacity owners. Moreover, we believe that the need for an "anonymous" secondary trading platform is not sufficiently justified and bilateral trade should be allowed.

FG should state that market parties are allowed to buy any share of the forward cross-border capacity rights, as these rights in case of PTRs are combined with UIOSI and therefore cannot lead to a hoarding of cross-border capacity. In the case of FTRs there is no direct physical use of capacity (e.g. the 400MW limit on individual companies importing into the Netherlands or import restrictions applied to some Spanish companies on the interconnectors with France are not needed anymore).

14. Are the preferred long-term capacity products as defined in the framework guideline suitable and feasible for the forward market timeframe?

Cross-border financial hedging instruments are important for cross-border competition in the forward markets. EURELECTRIC is in favour of implementation of FTRs or PTRs combined with UIOSI. The framework guidelines shall state that all TSOs shall allocate FTRs or PTRs with UIOSI corresponding to the full available capacity between all bidding zones. EURELECTRIC believes that all forward markets should evolve towards the use of financial instruments (FTRs) without unnecessary delay. It is also the freedom of the market to have other instruments in place, like CfDs in the Nordic market.

15. Is there a need to describe in more detail the elaborated options for the organisation of the long-term capacity allocation and congestion management?

Yes, the main principles shall be described in some further detail to ensure that long-term capacity allocation and congestion management is consistent around Europe.

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difference between the British and Dutch PXs minus the flow dependent Transmission Pass Through Charges and the proportion of the DC losses of the Interconnector for the relevant Units to the extent that the price difference is derived in the same flow direction of the Units not being used. This has, in our opinion, two problems: the UIOSI value is reduced, and there is a transaction charge (losses, charges) for the use of the interconnection.

Section 3: Day Ahead allocation

EURELECTRIC fully supports the target model for the Day-Ahead market based on capacity allocation through implicit auctions via a single price coupling algorithm.

EURELECTRIC also welcomes the provision (2.3) stipulating that the price of congestion shall correspond to the difference of the day-ahead electricity prices in the corresponding zones as this implies that there should be no components for grid losses, triads or others in the congestion price. Here we refer to our particular comment on the BritNed cable, although such rules are also in place on the IFA interconnector and on some borders in the CEE region.

16. Are there any further issues to be addressed in relation to the target model and the elaborated approach for the day-ahead allocation?

Yes, the main principles of the target model shall be described in further detail to ensure that it is implemented in the same way around Europe. EURELECTRIC would like to see a clear statement that TSOs are not allowed to move internal congestions to the borders between bidding zones, including by means of ramping restrictions. Introduction of such restrictions actually implies a reduction of cross-border capacity before it has been proven that there is a real need to limit it. For instance, on one cable towards Nord Pool there could be a market demand to ramp up 600 MW, while on another cable outwards from Nord Pool there could be a market demand to ramp down 600 MW. Both these requests will be cancelling each other and therefore not restricting the market in its optimisation. If netted ramping rates would endanger the system, TSOs could still reduce the effects by doing re-dispatch

Section 4: Intraday allocation

EURELECTRIC wants to stress that the provisions 4.2 and 4.3 are not fully consistent with the agreed European target model for the Intraday based on implicit continuous trading that was agreed by the Florence Forum in December 2009. Therefore it remains unclear in the current draft Framework Guidelines how "reliable pricing of intraday capacity reflecting congestion" should work for continuous trading. It is important to stress that here we are talking about pricing the remaining capacity between two bidding areas that for exactly this reason (the existence of remaining capacity) can be considered as one (internally not congested) bidding area. In our view, pricing of congestion should only be relevant in case of congestion between two bidding areas, whereby in the direction of the congestion TSOs find out during the intraday phase that they can put a "significant" amount of capacity available to the market.

Furthermore, argumentation with regard to introducing implicit auctions in case of sufficient liquidity (4.3) cannot be regarded as well justified in the absence of a clear definition of what "sufficient liquidity" means and will have to be elaborated further in detail. The European target model agreement includes a provision saying that significant additional capacity should be allocated using market –based principles. It was agreed that the definition of significant additional capacity as well as the methodology of such pricing will have to be elaborated at a later stage based on the assessment of the functioning of the Intraday Continuous trading mechanism.

In this context, EURELECTRIC does not see any relevant justification for co-existence of both continuous trading and implicit auction models (4.3). If a European intra-day market shall be achieved, there is a need for the same allocation method to be applied consistently around Europe. It would not be sufficient to "have adequate gate closures". EURELECTRIC supports the provision (4.7) with regard to non-discrimination of product types, including block bids. We confirm that there is a strong need from the market to have block bids handled in the intraday continuous trading process.

EURELECTRIC does not understand the statements "Intraday allocation and trade foreseen in the CACM network code(s) shall be coordinated by the TSOs with re-dispatching/countertrade and with (cross-border) balancing markets, while being guided by the principle of overall efficiency." and "efficient arbitrage with the day ahead and balancing time-frames is possible". These statements should be clarified in further detail. In our opinion, the most important issue here is that cross-border intraday trading should be allowed until the end of hour H-1 for trades going through during the hour H. EURELECTRIC fully supports the TSO-TSO with common merit order target model for cross-border balancing as adopted by the Florence Forum in December 2009. In line with the target model, balancing should start after the gate closure (end of hour H-1) of intraday trade. In principle, EURELECTRIC thinks that no cross-border capacity should be reserved for ancillary services or balancing. However, such reservation should only be envisaged in cases where additional social welfare gain can be demonstrated.

17. Are there any further issues to be addressed in relation to the target model and the elaborated approach for the intraday allocation?

Yes, first of all, the target model shall be described in detail to ensure that it is implemented in the same way around Europe. Intraday trading shall be possible at least until one hour before delivery.

18. Does the intraday target model provide sufficient trading flexibility close to real time to accommodate intermittent generation?

Yes, in case continuous implicit allocation is implemented around Europe. EURELECTRIC believes that pricing of intraday capacity will add complexity to the process without adding substantial value.

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