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Position Paper

# ERGEG's Draft Framework Guidelines on Capacity Allocation and Congestion Management for Electricity

November 10, 2010

## General remarks

The German Association of Energy and Water Industries (BDEW) represents 1,800 members of the electricity, gas and water industry. In the energy sector, we represent companies active in generation, trading, transmission, distribution and retail.

We welcome the opportunity to comment on ERGEG's "Draft Framework Guidelines on Capacity Allocation and Congestion Management for Electricity" and the related Initial Impact Assessment.

BDEW appreciates the work ERGEG has carried out to identify concrete proposals for the most important features of market design for cross-border electricity markets. BDEW is supportive of short term actions to improve market conditions by creating well functioning regional markets. In the medium term, implementing target models to achieve a true internal market will be essential.

Principally, BDEW welcomes the efforts to re-evaluate and eventually to re-calibrate the design of intraday, day-ahead and forward markets and the role, which capacity calculation should play.

BDEW stresses that ERGEG's consultation comes at the right moment as the Florence Forum, the Project Coordination Group (PCG) and the new AHAG process with active participation of market participants have broadened the consensus on target models which shall be realised by 2015.

Precluding the main positions, BDEW

- is in line with most of the issues identified and the solutions proposed in the draft guidelines
- feels that ERGEG does not always pay adequate attention to the transaction costs and negative short and medium term effects when assessing the relevant policy options
- is deeply concerned about the proposals for the definition of zones, especially when taking into account the considerations made in the initial impact assessment, which BDEW views as partly incomplete and partly biased.

## A) Main concerns

### *Preliminary remarks*

BDEW finds it quite surprising that months after the positive results of

- *Final Everis Mercados Report "From Regional Markets to a Single European Market"*[1]
- *ERGEG's Regional Initiatives Progress Report*[2]
- *ERGEG's Strategy for delivering a more integrated European energy market: The role of the ERGEG Regional Initiatives*[3]

and in the wake of the communication of the EU Commission on Energy Infrastructure Priorities with its clear message for further integration of energy markets by creation of new interconnectors ERGEG seems to divert from the general consensus and now identifies large zones as a predominant problem, thus loosing sight of its earlier views on how to reach European market integration.

### *Merits of large zones*

Large zones combined with competitive market design have increased liquidity where applied. In the case of the German-Austrian price zone, the physical electricity index (PHELIX), has established itself as a proven benchmark for European electricity prices. This price is the same for the entire market area enabling a level-playing field for all end-users.

Furthermore, the German-Austrian price zone is a liquid market place with a robust price that allows generators, traders and consumers alike to mitigate price risks. Only in a large zone, this will add to transparency for all market participants.

Large zones are specifically efficient in fostering competition. Any issues arising from concentration of production and/ or supply in a region resulting from former integrated supply areas can be much more adequately dealt with in large zones. Larger zones might require redispatching in special situations, which is desirable in light of the many socio-economic benefits. In fact, market design should be further developed to further integrate balancing mechanisms.

Network congestion must be rectified through investment in new lines. Needed development of the networks to integrate politically intended new installations of renewable generations at remote locations detached from demand cannot be stalled by regulatory proposals, such as splitting up of large zones.

1 Final Report 28/04/09 commissioned by DG TREN

[2] An ERGEG Conclusions Paper, 10 June 2010

3 - An ERGEG Conclusions Paper, 21 May 2010

### *Definition of zones*

BDEW appreciates that chapter 1.2.4 of the draft Framework Guidelines introduces the argument of "welfare related to the delimitation of zones" as a point to be taken in consideration. However, in our opinion welfare optimisation including all political and economic dimensions especially with regards to possible influences on the intended increase of low carbon power production should play a central role in any analysis for the definition of zones.

### *BDEW cannot support the Initial Impact Assessment (IIA)*

The IIA falls short of what an initial impact assessment should be about. Especially in the issue of definition of price zones, the IIA just compares the end results of ideal zones for trading with the current situation.

ERGEG in its initial impact assessment does not take into consideration the dimension of economic and social implementation constraints, costs and risks. In that respect, BDEW very much deplores that the IIA uncritically relies on two studies that have been carried out taking

- Norway and the Nordic market as reference to justify the "slicing and dicing" of existing zones[4]
- the US, where the electricity wholesale market design differs fundamentally from the structures in Europe. In the US there is a decentralised market organisation where bilateral trading practices prevail and a centrally organised market like the one applied by PJM Interconnection [5]

In fact, in its IIA ERGEG reveals a rather disruptive approach to market development. It leads to destroying functioning markets. It is linked to the expectation that in a future system the overall effect on markets will be positive. The assessment does not take into account

- the beneficial effect of large zones and their associated basis for a high degree of liquidity
- the many steps needed in the evolution from small systems, with lower liquidity to a liquid well functioning overall system. We have experienced this with the start of Germany with two price zones at the beginning of liberalisation and the further development.

In the case of natural gas markets, we currently see the opposite development, which is the suppression of small market areas in favour of larger zones despite of existing congestions and taking into account the costs for overcoming them.

BDEW wishes to point out, that grid optimisation is just ONE parameter in the broader context of liberalisation, market optimisation, the framework for future investment and overall social welfare.

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[4] Bjoerndal, Mette, Joernsten, Kurt: "Benefits from Coordinating Congestion Management – The Nordic Power Market", Energy Policy, Vol 35, No. 3, pp. 1978-1992,March 2007
[5] Erin T. Mansur, Matthew W. White: "Market Organization and Efficiency in Electricity Markets", June 30, 2009,

BDEW would have expected ERGEG to take into account efforts made in the CWE and Northern regions to integrate markets. BDEW warns against changing established zones without an in-depth analysis on the local and overall effect on market coupling and on the foreseen implementation of flow based capacity calculation in CWE.

The advice ERGEG is providing in its IIA, *"If the zones resulting from the division of the network based on its topology are considered too small to ensure liquidity, nothing prevents the creation of liquid hub made up of several zones."*[6] is in our view not conclusive as it

- o does not take into account the costs of losing liquidity at least during a transitional phase
- o overlooks the negative effects of small zones on new entrants
- o is biased in favour of **market splitting** and
- o creates a "trial and error" process which is destroying the development of trust in the market and is completely ignoring costs related to such frequent changes

In fact the IIA states: *"… in an efficiently defined zonal system, the congestion will be managed in the day-ahead time frame through market splitting,.."* .[7] This reflects only the Nordic philosophy but does not at all reflect the design successfully implemented in continental markets. Instead, it neglects the vision for market integration set out by ERGEG in 2009 and earlier this year in the target models developed through the PCG-process.

We cannot share the assessment of the IIA on the issue of **market power**:

- o *… "The definition of zones may have an impact on the number of actors within that zone, e.g. a small zone will typically have fewer actors than a large zone; thus raising the issue of market power. However, depending on the present market design, the market power situation as such does not necessarily change with zone size, as it is triggered by the congested network."*[8]
- o *…"It should be stressed that, when reducing the size of the zones, the apparent increase of market share of a given producer in this zone, that may result in an increase of market power, is largely compensated by the increase or the development of competition linked to a better appraisal of true network capabilities and a more efficient allocation of transmission capacity linked to better locational information of bids/offers."*[9]

The opposite may well be the case. Experience in small zones shows that market power may constitute an important issue. It is much easier to deal with market power in large zones connected via market coupling and implicit intraday trade. The issue of market power in the balancing time frame can best be dealt with via a combination of a liquid cross-zonal/ cross-

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[6] IIA, p. 33

[7] IIA, p. 33

[8] IIA, p. 33

[9] IIA, p. 34

border balancing market, transparency as to commercially non-sensitive data and market monitoring as to commercially sensitive data.

The IIA devotes little attention to the issue of **liquidity**. It is only stated that: *"Very often, a reduction in the size of the zone is interpreted as a reduction in the liquidity of the day-ahead market. This is, however, too simplistic a view, as the important parameter here is the overall liquidity of all zones covering a given territory."*[10]

In our view, this line of argumentation is not correct. Liquidity is defined for a special product and a product is related to a price zone. A product covering several zones is not supporting activities of producers and consumers in a defined price zone but only a kind of an overall hedge against general price developments. First of all, liquidity constitutes the most important factor for building functioning wholesale and retail markets. BDEW expects that splitting the German-Austrian price zone will inevitably reduce liquidity. This in turn will reduce the reliability of the day-ahead market as an underlying for the futures market. Consequences for the clearing market may be negative, too. This will affect all market participants and end-consumers.

Furthermore, the continuous process of yearly adjustments of the defined zones will lead to an extremely unfavourable investment climate. Without a clear and robust price signal, which is provided by PHELIX prices today, future investments in generation capacity may not happen at all. ERGEG rightly points out, that increases in renewable energy call for action, but does not at all analyse the impact of its proposed measures. In fact, we are very worried that in such an environment, forward hedging will be massively hindered if not stopped. Which is especially a problem for systems based on thermal production, as it is the case in continental Europe (in contrast to the hydro based system in Scandinavia).

It is correct that in a longer term the liquidity of a whole region and finally of the Internal Market as such has to be the measure stick. But it would be erroneous to think that reducing existing liquidity in any zone automatically results in high liquidity in another zone. Experience gained reveals that existing smaller zones and the overall region do benefit from market coupling.

The assessment of policy options, presented in the IIA, focuses on the **optimisation of the existing network**. This perspective has some merits but does not give the full picture:

1. Markets should be in the centre of the evaluation as the overall exercise is the creation of an internal market for electricity. In fact, structural price differences between regions should be the trigger for the necessity of grid investments.
2. The evaluation should take into account planned grid enhancements and grid investments. This particularly true in the light of integrating wind energy. In the case of Germany for instance, huge efforts are being made to build new lines that will bring power from wind energy to the centres of consumption.

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[10] IIA, p. 35

3. A logic where congestions always lead to the splitting of price zones would definitely reduce the incentive to invest in needed new transmission lines.

The IIA attributes **welfare gains** to a changed zonal division: *"Furthermore, benefits in terms of more correct price signals to generators and consumers would be achieved. This is important both for short and long-term planning of production and consumption."*[11] This may be true in theory. However, having free choice to locate power production from renewables and priority dispatch of renewables and nationwide support schemes for renewables in mind, this is simply not realistic.

We think there is a lack of in-depth analysis and an abundance of opinions. BDEW can neither support nor follow the conclusions that nodal pricing constitutes the ultimate goal in electricity market design. This approach has shown some merits for the PJM system but any related problems are not discussed in the IIA at all. There is no mentioning of the fact, that the EU networks are managed by 48 TSOs in comparison to one operator in the PJM zone. This already should make clear, that any implementation is not only very complex, but also very costly. It is mentioned that nodal pricing requires "uniform" retail prices – which really means a regulated consumer price. We strongly oppose this notion and would urge ERGEG to revise this approach completely. Nodal pricing will not be an option for European networks any time soon and hence should have no room in the guidelines.

Finally, we strongly recommend just treating the IIA as a discussion paper and ensuring that it will not be part of the formal guidelines. In particular, we are concerned about the relevance of the reference to the IIA on page 4, paragraph 6 of the draft framework guidelines.

Specifically, we would propose to delete provision (5.12) on the basis of the inaccuracies pointed out in the discussion of the IIA.

***Critical Revisions of Draft Framework Guidelines needed in Chapter 1.2***

In defining a zone for capacity calculation and management ERGEG (1.2.1) chooses a greenfield approach. This is in contrast to other chapters of the guidelines – for instance on capacity calculation methods or on forward markets - where ERGEG takes account of specific characteristics of the markets encountered.

The conditions under which one or several control areas may constitute one zone are too narrow (1.2.3). What is more, the review mechanism described under (1.2.3) - (1.2.6) (e.g. yearly revisions of zone sizes) will almost inevitably lead to an erosion of current zone sizes in large countries. As this mechanism exerts pressure on existing large zones while not affecting small zones it is also probable that the new zones will not be regional but sub-national. This seems very similar to the approach taken in Norway, which will also be applied to Sweden, while missing the chance of creating cross-national structures.

[11] IIA, p. 39

In fact, ERGEG is implicitly exerting pressure on large countries such as Germany to introduce market splitting or coupling internally.

Chapter 1.2 falls short of putting the issue of zone delimitation into perspective with the ongoing efforts of regional integration.

## B) Answers based on ERGEG's questionnaire

### General Issues

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

BDEW deems the coordinated development of transmission grid infrastructure in connection with appropriate locations of new generation units as a substantial part of congestion management complementing the efficient and non-discriminatory utilization of the exiting transmission capacities. Thus we recommend including all time frames relevant for congestion management into these Framework Guidelines on Capacity Allocation and Congestion Management.

In our view, consistency in terms of scope and principles between the Framework Guidelines on CACM and other Guidelines, including Comitology Guidelines on Transparency, 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 adoptions.

Specifically, 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 AHAG Capacity Calculation work stream, 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 the framework guidelines on CACM. The same principle is valid for the provision (1.2.5) that requires more transparency with regard to the situation of internal congestion limiting cross-border capacity, and re-dispatching.

We would like to point out that in the present draft a number of outlined principles do not fully reflect the features of the PCG target model adopted by the Florence Forum in December 2009.

BDEW believes that an excessively general description of the target model may result in the situation when local solutions will be preserved and thus hamper implementation of the European target model. Therefore we call for a much stricter alignment of the draft Framework Guidelines on CACM with the PCG target model and a detailed outline of its main features and principles. For example, in the forward market long term transmission rights should be introduced across all the electricity markets in the EU and should not be replaced by local instruments or products. It should be pointed out that provision (3.2) weakens the need for PTRs or FTRs 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 introduced by the market, but they can not be regarded as a replacement for the TSOs obligations.

Another example is the introduction of implicit auctions in the intra-day trading in case of “sufficient liquidity” does not correspond to the agreement in the PCG target model that in principle allows for a possibility to introduce implicit auctions in case of “significant additional capacity”.

**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?**

BDEW 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. The draft framework guidelines are sometimes too vague and may leave room for interpretation 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.

Also see above detailed comments under A) Main Concern.

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

Regarding the day-ahead market, BDEW would like to see a clear reference to the model achieved in the PCG.

BDEW warns against potential discrimination of power exchanges. For instance in the CWE region power exchanges have successfully contributed to the implementation of the day-ahead market coupling. Co-operation will be inter-regional as of November 9$^{th}$.

Co-operation in the intraday-timeframe is underway even if measures that are currently envisaged can only be of transitory nature.

Generally, BDEW believes that all timeframes have to be described in more detail in terms of policy choices to ensure that there will be a common understanding and a consistent implementation across Europe.

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

Regarding the day-ahead market BDEW supports the interim steps referred to in the IIA. It has to be mentioned though that flow-based to date is still a theoretical concept. BDEW would still like to see the theory applied in a real testing phase before principally using it as the target model. Naturally, further interim steps will be needed. In cases of interim steps, there shall be a clear statement that they 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?**

BDEW would like to see a much clearer definition of force majeure to avoid diverging definitions. BDEW view is that force majeure definitions should be harmonised across the EU; this is essential as it brings clarification to market participants and reduces uncertainty. BDEW 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?**

BDEW believes that the framework guideline shall define firmness of capacity in detail. The provision (5.6) with regard to curtailment of cross-border transactions in emergency situations should be further aligned with the article 16 of the cross border regulation 714/2009 that stipulated that “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.”

BDEW 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 and by the initial payment (to the TSO, not in the secondary market) in case of force majeure.

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

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.

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 complementary measure to counter-trading and re-dispatching. If TSOs want to buy back capacity rights on the secondary market, they should not be the organisers of this secondary trading platform (as stipulated under 3.6), in order to avoid that they have a market insider information on the position of the 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.

BDEW  does not see any reason why financial firmness should be accepted in case of explicit auctions (5.10). At least financial firmness must be guaranteed while physical firmness is the preferred approach.

As the allocation model described in the CACM framework guidelines provide 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 support that day-ahead explicit auctions are not considered in the Framework Guidelines as they would not comply with the target model.

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 8 a.m. in the day-ahead. In case TSOs curtail such nominated capacity before the power exchange's gate closure (at around 12 o'clock) 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 acting themselves on the intraday market (i.e. buying back the energy in the opposite direction of the congestion). Physical firmness can alternatively be achieved by TSOs counter-trading to ensure that nominated schedules do not have to be changed.

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 too much in advance in a market-based manner. This will allow then to avoid the situation when no capacity is left to be offered at the day-ahead allocation step.

BDEW 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 equally with 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. The CWE Market Coupling project can supply cost figures, but when evaluating them, it has to be taken into consideration that this was the first project to set up market coupling for such a large region. We assume that in the future, it will be cheaper to integrate new countries. As a benefit efficient congestion management will increase competition across Europe and facilitate that consumer prices are based on cross-border competition.

We also refer to our discussion under A) Main concerns.

**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. 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 in its own turn influenced by amount of capacity made available to the market.

In the provision (1.1.3) referring to that "*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 the 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 does not elaborate from what level.

Finally, the provision (1.1.5) is extremely vaguely formulated. The provision should require publications of the reliability margins, and a yearly transparent evaluation of how this reliability margin has been statistically used, with an explanation of the extreme events leading to high use of the security margins.

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

BDEW 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 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 in comparison to the ATC are demonstrated.

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

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 neighboring TSOs and ATC based to the others)?**

BDEW feels that this would be helpful indeed.

BDEW believes that the Framework Guidelines should promote the 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.

For the interim period it will be, however, 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 for different borders. The work on this issue 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 as 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. BDEW 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 harmonisation of the re-evaluation practices that exist at the moment across markets.

### Section 1.2: Zone delineation

BDEW suggests that the definition of a zone (i.e. a bidding area) in the Framework Guidelines (1.2.1) should be further improved. We would like to add in the definition of a zone that it should be 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). This is due to the relevant market design.

Furthermore, the Framework Guidelines should define more specifically criteria of such a review.  Decisions about changing the delimitation of zones should be justified by the evidence of existing/ non-existing structural congestion taking into account the effects of short and medium term development of infrastructure and load and generation pattern and relevant socio-economic factors. Thus BDEW suggests linking such a process with the periodical elaboration and consultation of the 10-Year Network Development Plan of ENTSO-E. Such a coordinated approach ensures that both the actual and expected future system conditions (load and generation pattern, network) are taken into account. In order to ensure stability of market rules for trade, changes in the delimitation of zones should be announced well in advance, take into account the duration of existing liquid forward trades and be subject to public consultation. If doing so the transmission capacities which are necessary to fulfil contracts resulting from trading at forward markets are firm regardless of places of fulfilment of contracts (internal or cross-border trades). For example, if electricity can be traded three years ahead, changes should be announced with a three year notice in order to avoid uncertainty of existing contracts and reducing liquidity in the forward markets.

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 provision (1.2.3) clear criteria are missing for decision if an internal congestion is not significant, i.e. negligible. 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 that are potentially not even responsible for the new upcoming congestions, as this might create huge uncertainty in the investment climate for new generation.

BDEW 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 the 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 production on the welfare should be taken into account in regions where the increase of privileged transport of renewable energy causes congestions.

Regarding the 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.

Also see above detailed comments under A) Main Concern.

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

BDEW 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 contract resulting from trading at markets. BDEW 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 (at least in the physical market). 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. And a market with decreasing liquidity is less attractive for potential market actors and consequently the liquidity is running at risk of decreasing further.

Also see above detailed comments under A) Main Concern.

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

BDEW 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.

BDEW would like to comment on 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).*"

It is true that this solution is generally possible, but it cannot be in line with the basic principle of a liberalised and competitive market where consumers and producers are faced with a situation where customer prices do not reflect the market price for each zone. This will not give proper incentives, which will be even more important when developing smart grids and other demand side management solutions. We do not see the Italian market as a blue print for any target model.

BDEW would also like 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 the TSO is 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 on 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 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.

BDEW 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 the pricing of generation capacity reservation, we suggest that the Framework Guidelines should require sufficient transparency in the re-dispatching activities including volumes needed and costs.

Also see above detailed comments under A) Main Concern.

**Section 2: Forward markets**

BDEW wants to draw the 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.

BDEW 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 a freedom of offering hedging instruments, but they should not be considered as a replacement for the TSOs obligations to bring their capacities to the market. 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 to avoid the 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.

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.

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 at the same time act as owners of the platform and as market participants, in cases where they would buy back 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 trading should be allowed.

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

In Principle BDEW agrees with ERGEG’s assessment.

Some complementary comments on long-term capacity products: FTRs and PTRs are important for cross-border competition in the forward markets. BDEW believes that FTRs or PTRs shall be implemented in a consistent way between all bidding zones in all parts of EU. The framework guidelines shall state that all TSOs shall allocate FTRs or PTRs corresponding to the full available capacity. It is the freedom of the market to have other instruments in place, like CfDs in the Nordic market, but they should not be considered as a replacement for the TSO obligations. The reason for this is that they are not fulfilling the requirements to enable cross-border competition in the forward market between fundamental competitors.

**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?**

BDEW feels that this would be helpful indeed.

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

***Section 3: Day Ahead allocation***

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

BDEW 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.

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

In Principle BDEW agrees with ERGEG's assessment.

The target model shall be described in detail to ensure that it is implemented in the same way around Europe. BDEW would like to see a clear statement that TSOs are not allowed to implement ramping restrictions which actually implies a restriction of cross-border capacity before it has been proven that there is a real need to limit it. Ramping restrictions, if they occur, shall be taken care of in the ancillary services (i.e. balancing) market.

**Section 4: Intraday allocation**

BDEW wants to stress that the provision (4.2 and 4.3) is not fully consistent with the agreed European target model for the Intraday agreed by the Florence Forum in December 2009 and based on implicit continuous trading. 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 the remaining capacity between two bidding areas that for exactly this reason can be considered as one global (internally not congested) bidding area.  In our view, pricing of congestion should only be relevant in case of initial 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 about introduction of 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, will have to be specified in detail. The European target model agreement includes a provision about that in case of significant additional capacity it 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, BDEW does not see any relevant justification about the 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".

BDEW 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.

BDEW 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 allow to trade until the end of hour H-1 for trades going through during the hour H. In line with the target model, balancing should start after the gate closure (end of hour H-1) of intraday trade.

In principle, BDEW thinks that no cross-border capacity should be reserved for ancillary services or balancing.

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

BDEW agrees with ERGEG's assessment on most of the features of a future intraday market.

However, BDEW does not see the necessity for implicit auctions for the intraday allocation. This issue has been discussed at length within the PCG and it is our firm belief that for the foreseeable future continuous trading should be the way to go.

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 trading is implemented around Europe. BDEW believes that pricing of intraday capacity will add complexity to the process without adding substantial value.


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