

ACER consultation on Forward Risk-Hedging Products and Harmonisation of Long-Term Capacity Allocation Rules



EFET RESPONSE

The European Federation of Energy Traders¹ (EFET) welcomes the opportunity to respond to the ACER consultation on forward risk-hedging products and the harmonisation of long-term capacity allocation rules.

EFET believes that all TSOs should offer forward (i.e. longer than day-ahead) transmission rights between all bidding zones. The sale of transmission rights is a fundamental part of the business of TSOs and a service that their customers – generation, trading and retail supply businesses – need in order to be able to compete properly in all bidding zones of the internal electricity market.

Market participants need these hedging instruments to achieve efficient cross-border competition along the whole electricity value chain and for all timeframes. Where market participants hold transmission rights, they can compete in a neighbouring forward wholesale market while managing their geographical exposure to volumes and price risks. Forward transmission rights are therefore essential to all market players: generators, traders, suppliers and final customers.

I. General considerations

Before going into the detail of the questions laid out in the consultation, EFET would like to draw the attention of ACER on a number of general considerations:

Distinction between PTRs, FTRs and CfDs

We would like to underline our agreement on the respective descriptions of the consultation document on what should be considered as a Physical Transmission Right (PTR), a Financial Transmission Right (FTR), and a Contract for Differences (CfD). Having made this distinction, we would also like to point out that these products are not equivalent.

¹ EFET is an industry association which was set up in order to improve the conditions of energy trading in Europe, mainly in electricity and gas markets. Established in 1999, EFET represents today over 100 companies in 27 European countries. EFET works to promote and facilitate European energy trading in an open, transparent market unhindered by national borders. More information at: www.efet.org.

Hedging with CfDs for example, which are products which are issued by TSOs and which do not directly refer to transmission capacity rights between two bidding zones cannot be considered as sufficient for cross-border hedging. These instruments, as well as any other derivatives or instruments negotiated by the industry, can only be considered as complementary to TSOs' essential services to provide an open and non-discriminatory access to network infrastructure.

Unlike FTRs issued by TSOs in quantities referring to available transmission capacity between two bidding zones, CfDs refer to the price difference between a bidding zone and a (virtual) system price. This induces a number of major differences between the two types of products:

- The volume of CfD contracts available for trading is never guaranteed and could potentially be restricted or inexistent in some bidding zones (their availability could also vary in time). This exposes market participants to significant volume risks
- Contracts or rights offered by non-TSOs do not have any regulatory backing or certainty, and the providers/counterparties can easily disappear. As well as creating a counterparty risk for payments, this also create a barrier to entry for any new entrant in a market based on CfDs since managing these counterparty and regulatory risks will increase costs. By contrast, those risks would be minimised to almost zero for rights issued by TSOs (such as FTRs or PTRs).
- While TSOs are natural holders and issuers of PTRs or FTRs, they have no interests in CfDs which are not calculated based on the available volumes of interconnections capacities but rather on the analysis of market prices

As a consequence, while the day-ahead system price would naturally benefit from a high level of liquidity, competition in specific bidding zones – where generators and final customers are located – could be very limited if CfDs were not available in a volume that would ensure a sufficient level of coupling between forward markets.

We believe that all TSOs should be issuing FTRs between all bidding areas in order to ensure this minimum level of coupling between forward prices in all bidding zones. This is also required because TSOs should not be withholding transmission rights from the market but should rather sell them on a forward basis to the maximum volume available.

Distinction between FTRs and PTRs with Use-It-Or-Sell-It

First of all, it is useful to keep in mind that we are only at an early experimentation stage for FTRs. This “prototyping step” will prove essential to better assess their properties and to define their “must have” characteristics. Since FTRs are essentially contractual rights, going through this exercise will indeed be essential as their properties will very much depend on their exact definition and limitations as contracts. We could hence easily miss the integration through harmonisation target if a wide variety of different FTRs contracts are implemented throughout Europe.

Some of the essential properties of FTRs would be, among others:

- Their exact firmness when it comes to interconnection curtailments
- Their exact firmness when it comes to market curtailments
- Their exact firmness/limitations in case of local or regional decoupling

- Their costs (transaction fees, clearing fees, etc.)
- Their nature (optional payment of positive spreads only or obligatory payments)
- The perimeter of their clause relating to Force Majeure (e.g. would an operational problem in the coupling process or in the coupling algorithm be considered Force majeure?)
- Their clause relating to potential limitation of liabilities per event or other

Another difference is that PTRs require setting up Balance Group contracts with TSOs whereas FTRs will require setting up cash settlement contracts and, potentially, clearing facilities (certainly for obligatory use contracts for which TSOs would also bear a counterparty risk when the spread is negative and TSOs must be paid). Also, the delivery conditions are likely to be different and therefore market needs are likely to depend on company profiles (asset owner or not), as well as on their risks and exposure (customer portfolio or not).

To that extent we would recommend dual purpose transmission rights (either nomination or cash settlement) which would allow all market needs to be fulfilled. We would also recommend limiting entry barriers through reasonable and proportionate collateral deposit, which would be linked to the volume of Balance Groups activity or to the volume of financial liabilities.

We must also acknowledge that the industry has a better knowledge and practice of PTRs with UIOSI, which are widely used and appreciated across markets. Among the specific characteristics of PTRs with UIOSI, it is important to remember that nomination of forward PTRs also releases capacity in the opposite direction through the netting of nominated capacities operated by TSOs before market coupling. The nomination of a PTR would therefore not influence the results of market coupling. When nominating a PTR, a market player would also bear different risks and costs compared to a non-nominated PTR or to an FTR (depending on its definition): a nominated PTR essentially comes together with the risk of interconnection capacity curtailments.

Clarification of ambiguous statements contained in the consultation paper

EFET would like to draw the attention of ACER on the fact that the following statements contained in the consultation paper are not fully correct:

Section 2.2 b:

“These payments can be used to pay the price differential to FTRs issued for the opposite direction (“netting”). This means that, provided FTRs obligations are requested by the market in both directions, FTR obligations can be allocated with no direct link to physical capacity, since the opposing payments could be netted.”

It is true that netting can also be performed with FTRs – this would be equally possible with PTRs through an anticipated nomination, which would allow TSOs to issue more PTRs if some interest for nomination of opposite volumes of rights existed in the market. However, this anticipated netting, arguably up to one year or more in anticipation of delivery, would also introduce a substantial change in the nature of the risks supported by TSOs.

Indeed, if TSOs were to allocate more capacity rights than physically available, TSOs would bear the physical or financial risk of default for the part that exceeds the available capacity, if the party with the contracted obligation went bankrupt or could not honour its commitment for any other reason (e.g. by not paying up the invoiced amounts).

This activity is therefore likely to necessitate significant amounts of additional cash requirements in order to be managed properly. It might be of interest to point out also that this kind of risks would be better managed by the industry itself, and can already be performed today without changing anything in the market design because no access to interconnection capacities is needed for netting.

Section 2.4 (under PTR with UIOSI):

“However it should be taken into account that the long-term capacity right which is nominated explicitly is not made available to the day-ahead market and thereby decreases its liquidity.”

To be exhaustive, it should be added that the possibility to nominate long-term capacity rights increases the liquidity in the forward market timeframe. This is also important to cross border competition since most retail supply contracts are longer term contracts (i.e. longer than day ahead). Besides, as already mentioned, additional capacity is made available for the day-ahead market in the opposite direction due to netting of nominated long-term capacity rights.

In practice it is also unlikely that nominations would be the cause of an insufficient liquidity in the spot market. Also, the liquidity of the spot market is usually not a concern for market coupling.

II. Responses to the consultation paper questions

Forward risk-hedging products

- 1) *Are there other products or options which are not considered in this document that would be worth investigating?*

EFET has not identified other products or options not considered in this document that would be worth investigating.

EFET is of the opinion that Physical Transmission Rights (PTRs) based on "Use It or Sell It" principle or Financial Transmission Rights as **options** (not obligations) are the long-term hedging products which should, at a minimum, be offered by TSOs between all bidding zones across the EU. These products give the maximum flexibility for companies to compete across borders and avoid creating new barriers to entry to cross border market participants. The introduction of pure transmission **obligations** should probably be developed by the industry itself and can only be considered after TSOs have established a healthy market for transmission rights as options.

If the functionality of anticipated netting was considered as part of the TSO activities, additional consultation and details would need to be considered. For example, this functionality could either be performed with PTRs or with FTRs and the merits of both products would need to be compared. An important requirement would be to avoid splitting liquidity of the limited volume of available rights. Therefore this function could also be added as an option to existing PTRs or FTRs. Another simple option would be to limit TSO activity to optional rights based on the volume of available interconnection capacity volumes and to let the industry develop the adequate regime for obligatory rights as they require very different competencies and processes.

- 2) *What will be the importance of the long-term Target Model and specifically the design of the forward market and the structure of long-term hedging products once the Day-Ahead and Intraday Target Models are implemented? Do you think your interest and demand for long-term hedging products will change (either increase or decrease) with the implementation of the Day-Ahead and Intraday Target Models? More specifically, what is your interest in cross-border/zone hedging?*

EFET member companies are active throughout Europe, and on a regular basis book forward, daily and intraday transmission rights at all the existing cross-border interconnectors over Europe (FUI, NWE, SWE, CSE, CEE, and SEE region). The key objective of EFET is to promote and facilitate European energy trading in open, transparent, sustainable and liquid wholesale markets, unhindered by national borders or other undue obstacles, for all timeframes. The implementation of the day-ahead and intraday target models will not modify the interest of EFET with regard to the availability of forward hedging products. Market coupling leads to a more robust and stable day-ahead price. Trust into the day-ahead market outcome leads naturally to an increase in forward trading (bigger volumes traded around the curve, products traded further ahead in time) and eventually non-asset based traders will enter these markets. It will also enhance cross border competition in retail supply markets. This leads to an increase in the need for forward hedging and the need to allocate more capacity to the forward time frame.

We anticipate that cross-border trading will continue to grow as the EU internal market for electricity consolidates. As this includes cross-border power contracts over various timeframes, we can confirm that the availability of transmission rights, like PTRs with UIOSI or FTRs options sold forward by TSOs will remain essential for our member companies.

To compete effectively across borders, without being necessarily obliged to buy in the local wholesale market, market participants need to have the ability to hedge against variations of the price of electricity delivered from another price zone sufficiently in advance (up to one year at a minimum). This requires the ability to hedge against variations of the price of transmission rights for cross-border deliveries. As long as no transmission rights are available between bidding zones in order to hedge that risk, market participants will not be inclined to compete in neighbouring bidding zones and to take on a price-spread risk between two markets because it would be expensive to manage such a risk. It is therefore absolutely necessary for market participants to be able to buy forward transmission capacity rights that allow them to deliver power across borders at a price they can secure in anticipation.

This 'basis' risk is different to, for example, oil and coal markets where the cost of shipping from e.g. Rotterdam to the destination point will move in a narrow band. Although shipping availability is sometimes restricted, there is not much 'congestion' in the same way, whereas this is a predominant feature of the electricity and gas markets.

- 3)** *Would long-term hedging markets need to evolve (e.g. in terms of structure, products, liquidity, harmonisation, etc.) due to the implementation of: 1) the day-ahead market coupling, 2) day-ahead flow-based capacity calculation and 3) occasional redefinition of zones? If so, please describe how these changes would influence your hedging needs and strategy. If no evolution seems necessary, please elaborate why. Can you think of any striking change not considered here?*

As discussed above, the implementation of day-ahead market coupling would increase the attractiveness for cross border competition. This will also increase the demand for cross border hedging instruments. Flow-based capacity calculation itself would probably not change the hedging needs, unless a very large amount of additional capacity was made available so that the desire to hedge between areas was completely removed, which seems very unlikely at this stage.

The occasional redefinition of zones, especially if it involved splitting up existing bidding zones in smaller bidding zones, would make hedging more difficult and lower the competition in the forward and retail supply markets. This might reduce the demand for forward hedging products, but this would hardly be a desirable outcome. Therefore, it is important to ensure a sufficient stability and to properly manage transitions in case of changes in bidding zones. Appropriate cross-zonal hedging products will always be needed, even in case of zone redefinition. In any case, the forward transmission rights between bidding zones should be harmonised between all borders (i.e. FTRs as options or PTRs with UIOSI should be issued between the new bidding zones) and no products with different characteristics should be introduced in case of zone redefinition.

The example of the split-up of the former Swedish common bidding zone into four bidding zones shows that major differences in generation and demand in some bidding zones makes it difficult to use CfDs to hedge the local price against the system price. The introduction of transmission rights would increase competition in the forward market and make hedging easier.

In case of merging of bidding zones, the change of delivery area would not be a major concern, but the market spreads would of course be modified and consequently the value of the contracted rights as well.

In any case, it is of utmost importance to follow the principle that the zones should remain robust and stable. Any redefinition of price zones should only be introduced with a sufficient lead time which is beyond the usual hedging period.

- 4)** *What is for you the most suitable Long-Term Target Model (combination of energy forwards and transmission products) that would enable efficient and effective long term hedging? What would be the prerequisites (with respect to the e.g. regulatory, financial, technical, operational framework) to enable this market design in Europe? Which criteria would you use to assess the best market design to hedge long-term positions in the market (e.g. operability, implementation costs, liquidity, efficiency...)?*

EFET believes that a common design model for the wholesale power market must be introduced on a European basis. This means that FTRs or PTRs should be issued by all TSOs between all bidding zones. As regards the forward market design, the first requirement is that bidding zones must be consistent price areas across all time frames (forward, day-ahead, intraday and balancing). Both generation and demand should face the same prices in bidding areas in the day-ahead and intraday markets, and for imbalances. Forward market prices within each bidding area will develop for a range of products and

tenors as a result of trading between generators, suppliers and intermediaries, all of whom wish to close out most of their position in advance and avoid more volatile real time prices and imbalance prices – as well as, where they exist, regulatory sanctions for not providing a balanced position at delivery.

The second requirement is the availability of a set of firm transmission rights across all bidding zones. This is an essential condition for market participants to buy and sell in other bidding zones without necessarily having to have a physical position in that zone. This is the essence of what is desired from cross border competition and the internal EU electricity market.

The final element consists of market participants choosing how they operate in the market. Some may wish to buy forward rights and minimise risk in that way. Others may be prepared to trade a hybrid “system price” based on an aggregation of bidding zones complemented by CfDs. Some may also want to serve their customers on the basis of day ahead prices and to hedge in some other way or because their customers are willing to take on some price risk. Also, some may just buy in the market where their customers are located or where they own physical assets to hedge their risks and not make use of any forward transmission rights.

On the particular question of CfDs, EFET is not aware of a successful example of “appropriate cross-border financial hedging” being offered “in liquid financial markets on both side of an interconnector” in any part of Europe.

The only successful forward rights existing today are PTRs with UIOSI. Depending on the exact definition of FTRs and also depending on the successful extension and functioning of market coupling, some evolution may come in the future, but that remains to be built.

EFET does not believe there is any reason to consider a non-harmonised model for the issuance of transmission risk hedging products in any part of Europe, based solely on the liquidity (or not) of financial trading in electricity contracts. In any case this would not have any influence on TSOs’ core activities and obligations.

EFET believes that, applied across Europe, adherence by TSOs to the following principles would promote an efficient market design and facilitate cross-border energy trading:

- **TSOs shall auction physical transmission rights or financial rights with equivalent effects (subject to successful experimentation).** It is essential for market participants to be able to buy transmission capacity rights that allow them to deliver power across borders for a fixed price. In theory capacity rights do not absolutely need to be physical if markets and operations are working perfectly and if management costs and cash requirements are equivalent However we must recognise that maturity and experience needs to be developed in that field.
- **TSOs shall auction the maximum of available capacity over appropriate timeframes.** Borrowing the model of the forward electricity commodity markets, TSOs can organise long term transmission rights auctions regularly, on each occasion for a variety of maturities. They should allocate to market participants the maximum amount of capacity expected to be available for the considered period, well in advance of the D-1 timeframe. Auctioning at least one year ahead (or even several years ahead, provided this does not affect the total amount of forward rights to be made available) two thirds of the available capacity, and most of the

remainder monthly or quarterly, would be in line with common term-sales arrangements, and would thus help develop liquidity in a traded secondary capacity market.

- **Transmission rights must be firm.** TSOs, as natural sellers of firm transmission capacity rights, have the ability to manage the risks involved, enjoy a variety of operational and physical means to adjust those risks, and indeed are the only players in the electricity sector that can do both. The transfer of the “firmness risk” from market participants to TSOs (in exchange for payment) will result in an overall efficiency and welfare gain.
- **TSOs must not discriminate against holders of transmission rights purchased in advance of day-ahead and intra-day timeframes.** We advocate the generalisation of the Use-It-Or-Sell-It principle which is now already widely acknowledged and understood as a way by which non-nominated forward rights are sold to the daily implicit or explicit auction.
- **Transmission rights need to be fungible in a secondary, traded market.** Liquid secondary markets for capacity would enable TSOs to buy back in the market any proportion of rights they turn out to have oversold in advance, for example in order to manage unexpected operational circumstances identified in advance. Secondary markets would also allow market participants to manage their transmission capacity portfolios, giving especially the possibility to “slice and dice” i.e. turn an annual or monthly right into hourly pieces, just as traders already do in the case of their wholesale electricity transactions.

EFET would recommend regulators across the EU to comply with the CACM Guidelines and to assign TSOs to introduce long-term physical or financial transmission rights at all interconnections. The introduction of FTRs or PTRs would ease cross-border competition, rationalise price signals, provide additional transparency and therefore increase liquidity on the market and facilitate market entry.

- 5) *What techniques of market manipulation or “gaming” could be associated with the various market for hedging products? What measures could in your view help prevent such behaviour?*

From an EFET perspective, a market design with PTR with UIOSI or FTRs options should not provide manipulation opportunities. No specific measures are needed in that regard, especially now that regulators have several instruments in REMIT and MAR to prevent such behaviour.

ACER wish-list

- 6) *Would you like to change, add or delete points in this wish-list? If so, please indicate why and how.*

The annexed “wish-list” is a good first attempt to benchmark and compare current practice with respect to forward transmission rights. EFET has the following comments at this stage.

In the Background section, the second paragraph regarding the entry into force should be modified as follows in order to ensure full clarity:

The outcome of this work is a list of requirements, which the single European set of rules ~~to come into force by 2014~~ should comply with. The European set of rules should enter into force starting with the yearly allocation for 2014.

In the General/Scope section, the last paragraph should be amended as follows:

The “European LT Rules” shall be implemented on all border ~~where PTRs or FTRs option are/will be implemented, i.e. at least on the borders of the Central West, Central East, France-UK-Ireland and South West regions, plus the Denmark-Germany interconnections and the interconnections between Hungary, Romania, Bulgaria and Greece and other Members States.~~

There is no valid reason for PTRs and FTRs not to be offered on other European borders (i.e. Nordic countries), in addition to or in replacement of the current system applied locally. ACER should not validate via this wish list the position of Nordic regulators and TSOs in maintaining a CfD-based system at the exclusion of PTRs and/or FTRs.

In section II/Firmness of held capacity, it needs to be clarified that, in the case of curtailment, capacity holders will be compensated on the basis of the market spread at the time of curtailment.

In section II/Fallback, it should be clarified that this refers to the possibility of day-ahead explicit auctions, although it is unclear why it figures in the forward rights document.

In section III/Entitlement, it is not clear why there need to be requirements placed on market participants to trade in secondary capacity.

Section III/Secondary trading should allow secondary trading across the board.

Section VI/Resale should always allow resale, including for rights splitting into shorter time periods as required. The text “unless this is proven not to be necessary” should be deleted, since there is no indication of who would be proving the lack of necessity.

In section IX/Valuation of reductions in held capacities, the text is too equivocal and should look forward to full firmness, as the document is a wish list. Replace “generally” with “progressively”.

Section IX/Payment deposit should include different types of collaterals that auction participants can choose from, at the minimum bank guarantee and cash deposit.

Further, ACER asked explicitly for feedback on the question whether a 1/12th or 2/12th of the total amount should be provided when buying the yearly product. From our perspective, covering 1/12th of the total amount should be generally sufficient. In any case it must be ensured that unpaid yearly capacity is reallocated in the corresponding monthly auction to avoid any capacity blocking.

More broadly, ACER states that nomination is not included in the harmonisation list, as the rules shall focus on capacity allocation and not the use of cross-border capacity. However, we are of the opinion that nomination rules are an integral part of the allocation rules and must be harmonised. Currently there exists a wide range of nomination rules, especially regarding the point in time when to nominate. For PTRs with UIOSI, it makes a difference if the final nomination must take place D-1 at 9:00 or D-2 at 14:00. This may change the value of such a product as market spreads can change. Besides, market participants have to nominate only to one TSO at certain borders, while they have to nominate to both TSOs or to the auction office at others. It would minimise our daily work and increase liquidity if there was one nomination deadline and one principle to whom to submit the information.

7) Which aspects of auction rules would be most valuable to be harmonised? Can you provide some concrete examples (what, when, where) of how this could help your commercial operation (e.g. lowering the transaction costs)?

There is not evident reason for not harmonising in time all the relevant aspects of the auction rules. To improve the commercial operation of our Member Companies, one common allocation platform under one harmonised set of auction rules, one type of collateral and one figure for the bidding limit is needed. Harmonising wording in auction rules without changing the IT platform does not help much as each company has to train its staff on using many different systems which is time consuming and costly from an operational perspective. In the end, as long as different auction rules exist, full harmonisation is never reached and specific rules need to be consulted and followed in case of incidents.

The following auction elements should most importantly be harmonised:

- Product definition (PTRs with UIOSI or FTR as option) with maturity aligned with the forward electricity products
- Definition of "Firmness", "Force Majeure", "System Emergency"
- Secondary market rules
- Fall back procedures
- Financial guarantees and payment deposits
- Operational procedures

Full harmonisation of auction rules will allow operators to participate to the forward market efficiently, reducing transaction costs and operational risks. We do not accept there are any regional or country specific aspects that justify special treatment. However there may need to be different transition periods for Member States.

8) Which elements of auction rules have regional, country specific aspects, which should not be harmonised?

In general there should not exist country specific relevant auction elements (see our answer to question 7).

In **transitory phases**, some elements of the auction rules could be country specific, such as when the electricity forward product differs from the standard products offered in the majority of the other European power markets (e.g. different Peak-Product definition). Unless needed and useful for the market, a clear timeline should be set in order to ensure that the transitory phase does not extend beyond a justified and reasonable period of time.

9) Which aspects should be harmonised in binding codes?

All aspects should be harmonised in the codes without any exemptions. At the very least, the elements listed in question 7 should be harmonised in binding codes.

10) If you are to trade from the Iberian Peninsula to the Nordic region and there existed PTRs with UIOSI, FTR Options or Obligations and CfDs in different regions – what obstacles, if any, would you face? How would you deal with them?

The question points to how greater competition can be achieved in the forward market and end user market by using transmission rights. The example shows that transmission rights are not only about hedging the price difference between the different price zones, but also competing cross-border in the forward and retail markets.

If one just wants to hedge the price difference between the different bidding zones, one can buy in one bidding zone and sell in another bidding zone. If a Spanish supplier would like to supply a customer (wholesale or retail) in the Swedish bidding zone 4, there are two alternatives:

- The Spanish generator can sell its generation in the Spanish market, and buy a Nordic system price contract and a CfD for Sweden 4. This would mean that the Spanish supplier would compete with other Spanish generators in the Spanish forward market and compete with Swedish suppliers in the retail market for Sweden 4 but without any hedge between the Spanish and the Nordic system price. As a consequence, there would be no cross-border competition as a result of these transactions. It would not be making any use of its physical position in Spain to manage its position in Sweden zone 4 and would probably instead have to nominate a large amount of risk capital to cover the various risks it was taking on.
- The other alternative would be that the Spanish supplier buys transmission rights between all relevant bidding zones, which would be complicated for a single supply contract, but would give cross-border competition between all bidding zones. This may lower the cost to supply into the market in Sweden bidding zone 4 and would offer an alternative competitive supply for local end customers.

This is a clear example of how the availability of forward rights can help managing the obstacles that exist in competition outside one's core market.

Capacity calculation and allocation method

11) Would allocating the products at the same time represent an improvement for market players? Why? Where, if not everywhere, and under which conditions?

Allocating the product at the same time does not represent a relevant improvement for market players, as it requires bidding preparation for more than 20 borders at the same time. This is especially difficult for smaller market players, as it would lead to increased operational risk and higher need of financial guarantees. As a consequence, it is likely to represent an obstacle to transact for those smaller players, and impact market liquidity. We would prefer two to three different gate closures the same day with enough time between result publication of the previous auction and gate closure of the next one.

What indeed is important is that results are published shortly after the gate closure and not the next day, as currently experienced at some borders. Late publication affects forward power market prices as the price spread used for calculating the bid can change within a day or even a couple of hours.

- 12)** *How important is it that capacity calculation for the long-term timeframe is compatible and/or consistent with the short-term capacity calculation and that capacity is interdependent and optimised across different borders?*

EFET is of the opinion that the default method for forward timeframe transmission capacity calculations is the NTC method. Different tests till now have proved that the flow-based calculation for the long-term timeframe is not the appropriate method.

Products

- 13)** *Please indicate the importance of availability of different hedging products with respect to their delivery period (e.g. multi-year, year, semester, season) for efficient hedging against price differential between bidding zones. What do you think of multiple-year products in particular?*

As mentioned in question 4, TSOs should auction the maximum of available capacity over appropriate timeframes which match the nature of traded markets and the desires of retail customers. Borrowing the model of the forward electricity commodity markets, TSOs could organise auctions for PTRs and/or FTRs regularly, on each occasion for a variety of maturities. They should allocate to market participants the maximum amount of capacity expected to be available in a given hour of a given day, well in advance of the D-1 timeframe. Auctioning at least one year ahead two thirds of the available capacity (and most of the remainder monthly or quarterly) would be in line with common term-sales arrangements, and would thus help develop liquidity in a traded secondary capacity market.

- 14)** *What would be your preferred splitting of available interconnection capacity between the different timeframes of forward hedging products? Which criteria should drive the splitting between timeframes of forward hedging products?*

Please, refer to question 13.

- 15)** *While products with planned unavailability cannot be standardised and harmonised throughout Europe, they enable TSOs to offer more long-term capacity on average than standardised and harmonised products would allow. Do you think these products should be kept in the future and, if so, how could they be improved?*

The market preference is for allocating base product. It is important that a relevant amount of capacity is offered through "pure" base load products because they also serve as a reference function. The price of base load PTRs is in some case used as index in bilateral transactions.

Nonetheless, EFET is of the opinion that it should be possible for TSO to offer non-standardized products with planned unavailability given the fact that those products may allow TSOs to offer more long term capacity to the market. For instance, the amount of planned unavailability should be kept to a minimum, i.e. once for a monthly product and two to three times for a yearly product. TSOs should provide reporting on the reasons for interruptions, and should strive to minimise the recurrence and length of these situations. A negative example is the monthly allocation at the Polish border where there are up to ten different interruptions per month (see http://www.central-ao.com/images/stories/upload/Auctions2012/ATC/announcement_02_02_2012_march_to_be_published_adapted.pdf for more information).

16) *Products for specific hours reflect market participants' needs. What should drive the decision to implement such products? How should the available capacity be split between such products and base-load ones in the long-term timeframe?*

The focus should be on allocating base products. Unless they allow TSOs to offer additional available capacity and they would be compatible with standard commodity products, we do not have any specific need for some sort of peak, off-peak product. However, this should not prevent TSOs to allocate additional capacity on top of this base product in case it is available for some hours during the whole month. We are aware that this is already the case at some Austrian borders where there is more transmission capacity available during peak hours than off-peak hours. This case may be quite specific, but it is a good example of maximising the capacity offered to the market.

Secondary market

17) *Should this possibility be investigated and why (please provide pros and cons)? In case you favour this possibility, how should this buyback be organised?*

As mentioned in question 4, transmission rights need to be fungible in a secondary, traded market. Secondary markets would also allow market participants to manage their transmission capacity portfolios, giving especially the possibility to “slice and dice” i.e. turn an annual or monthly right into hourly pieces, just as traders already do in the case of their wholesale electricity transactions

Liquid secondary markets for capacity would enable TSOs to buy back in the market any proportion of rights they turn out to have oversold in advance, for example in order to manage unexpected operational circumstances which can be identified in advance. This buy-back measure is a market activity which should be used in extraordinary situation and should be monitored by the involved NRAs and ACER. Clear rules for secondary markets should allow TSOs to inform the market and thereafter arrange a transparent auction to buy back capacity as soon as they realise that too much capacity has been allocated.

Nomination

18) *With the potential evolution from PTRs with UIOSI to FTR options, does the removal of the nomination process constitute a problem for you? If so, why and on which borders, if not on all of them?*

One issue with removing the physical nomination could be the sourcing of green energy, as some systems require the proof of physical nomination (i.e. Italy). The evolution towards FTRs will also depend on the exact definition and costs of FTRs and on the successful experimentation of such products. In the meantime, the possibility to nominate should be kept.

19) *How could the potential evolution from PTRs with UIOSI to FTRs on border(s) you are active impact your current long-term hedging strategy?*

The evolution from PTRs with UIOSI to FTRs should only be envisaged if it provides improvements and does not reduce flexibility or increase costs, or impact long-term hedging strategies.

20) *If nomination possibility exists only on some borders (in case of wide FTRs implementation), is it worth for TSOs to work on harmonising the nomination rules and procedures? If so, should this harmonisation consider both the contractual and technical side? How important is such harmonisation for your commercial operation? Which aspects are the most crucial to be harmonised?*

EFET supports a technical and contractual harmonisation of nomination rules. Currently there are more than 20 different cross-border nomination systems in place. Most of them claim that they follow the ESS format (ETSO Scheduling System) agreed between TSOs in 2003. However, the practical experience of EFET member companies is that they clearly diverge from one TSO to the other. Harmonise nomination rules and procedures on the contractual and the technical aspects would help minimising transaction costs and operational risks, especially for small market players.

In addition, a widespread introduction of FTR options is not expected that soon, and it is therefore sensible to work on the harmonisation of nomination rules.

Auction Platforms

21) *Looking at the current features offered by the different auction platforms (e.g. CASC.EU, CAO, individual TSO systems) and financial market platforms in Europe, what are the main advantages and weaknesses of each of them?*

Currently there are two platforms allocating PTRs for several borders, CASC.EU and CAO. Both have their pros and cons.

22) *How do you think the single auction platform required by the CACM Framework Guidelines should be established and organised?*

If the decision to evolve towards a unique platform was taken, one of the two existing regional platforms should be used as the European one, instead of inventing a fully new system. This approach is pragmatic, and cost efficient for both TSOs and market participants.

- *How do you see the management of a transitional phase from regional platforms to the single EU platform?*

The switch of the Italian borders to CASC was quite smooth, thus EFET does not expect any bigger issues by moving subsequently border per border to the single EU platform.

- *Should current regional platforms merge via a voluntary process or should a procurement procedure be organised at European Union level (and by whom)?*

EFET prefers a voluntary process. To give good guidance, ACER could for example arrange a voting of market participants on the preferred platform. In any case, a clear deadline should be in the Network Code for concentrating the allocation processes on only one or two platforms and the process should be monitored by NRAs and ACER.

- *Should the Network Code on Forward Markets define a deadline for the establishment of the single European platform? If so, what would be a desirable and realistic date?*

Yes, the Network Code should define a deadline. Our desirable date would be the summer of 2014. This would give market participants enough time to prepare and test the new platform for the auction in November. However, the summer of 2015 might be more realistic for the whole of Europe.