

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

A EURELECTRIC Response paper



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EURELECTRIC response to ACER Consultation on Forward Risk-Hedging Products and Harmonisation of Long-Term Capacity Allocation Rules

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General comments

EURELECTRIC welcomes the ACER consultation on Forward Risk-Hedging Products as an opportunity to provide further feedback about market expectations and needs with regard to development of the European forward electricity market.

In our view, either FTRs or PTRs with UIOSI shall be implemented in a consistent way between different price zones throughout the European Union. FTRs have the preference above PTRs for all the borders where cross-border capacity is allocated via a day-ahead implicit auction. FTRs and PTRs with UIOSI do not only provide market participants with opportunities to hedge cross-border transactions, but are equally important to increase cross-border competition and liquidity in the forward market. Market participants holding transmission rights can compete in a neighboring forward market without taking price risk.

In the meantime, we take note that the Framework Guidelines on CA&CM introduce in 4.1 an opening for other instruments than FTRs/PTRs with UIOSI in case “appropriate cross-border financial hedging is offered in liquid financial markets on both side of an interconnector”.

That is the case primarily in the Nordic region where hedging is done with financial products (e.g. a combination of electricity forwards and CfDs). As some Eurelectric members believe, that it is currently difficult to hedge with financial products in Sweden, a test could be considered, where the TSO issues CfDs. The test should evaluate amongst other parameters the potential impact on existing products, the system price and cost before implementation and it could be tested on a pilot scale before larger implementation.

Furthermore, we want to reiterate that TSOs should ensure firmness of capacity when issuing FTRs or PTRs with UIOSI. Offering sufficient FTRs or PTRs with UIOSI by TSOs will also reduce the risk premium of hedging solutions.

EURELECTRIC supports both options and obligations for FTRs. However, it is important to stress that the market is more familiar with FTRs as options. This is in particular true for generators who make their dispatch via a “make or buy” decision: he will not generate if energy can be bought at a cheaper price in the market. The same logics is valid for decisions about exporting energy to another market: if it is cheaper to buy generation in the local market to back the supply obligation in that market, the generator will not export its own generation, but will buy it in the local market.

Justifications to implement obligations where option transmission rights already are in place should be clarified further in detail. One should indeed realize that FTR options by their construction have a “capped” risk for the owner: he cannot lose more than the upfront premium he paid when buying the transmission right. The TSOs have lower

counterparty risk as well with options. An obligation owner however is not hedged, which can be illustrated by a schematic example.¹

Questions

General

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

Relevant products are mentioned in the document. However, depending on the focal price used for energy hedging products it may be relevant to consider alternative implementations.

One option might be seen as a hybrid of two models, which should also be investigated. This constitutes a market with CfDs and system price derivatives incorporated with “synthetic” FTR obligations, equivalent to a combination of two CfDs, which are auctioned by the TSO but in other ways identical with today's CfDs. The hedge for the TSO would be realized slightly differently through the combination of CfDs with different locations compared to the FTRs directly connected to a particular bidding zone border but the end result would essentially be the same.

Before deciding upon forward risk-hedging products, the options should be thoroughly analyzed and tested in order to realize their impact on markets. We believe that Sweden could serve as a testing ground.

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?

Market coupling is the most appropriate model to determine the spread between markets that determines the “pay out” value of forward allocated transmission rights (either physically with UIOSI or financially). As such, introduction of the day-ahead market coupling is the most important step to use existing cross border capacity efficiently and thereby reduce the price spreads between the markets. The Long-term Target Model is highly important to foster market integration and hedging possibilities in order to reduce risks, be it hedging production or sales contracts abroad.

¹ In case the market spread is forecasted to be 1 euro per MWh, the owner of the FTR obligation might pay up to 8760 euro for one year capacity right in this direction. In case, the spread would turn to be -10 € during the whole year, he would lose additionally to his upfront premium another 87.600 euro. In the case of an option, the FTR owner would only “lose” his capacity right premium payment. This example illustrates that the premium for an “obligation” FTR is by definition lower than for an “option” FTR¹. In addition, in the valuation for FTR options other elements like intrinsic value are considered, increasing further the valuation of FTR options compared to obligations.

Market coupling is not sufficient for creating competition in markets as a supplier who can only hedge in the spot market to sell forward to its customers will need a higher risk premium in that market. Forward transmission products have initially been defined with an “expiration” time before the Day-Ahead gate closure. Therefore we do not see a link between the need for forward transmission rights and the implementation of the intraday target model. A well- functioning intraday market will however reduce some of the risks that market players take in the day-ahead dispatch decision. It will lead to on average lower spreads between markets and thus reduce the cost and capital required for forward transmission rights. This will in turn make trading of forward products more active.

3) Would long-term hedging markets need to evolve (e.g. in terms of structure, products, liquidity, harmonization, 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?

Day ahead market coupling: see previous question. It should be the most important priority.

Flow-based capacity calculation: this will not fundamentally change the need for hedging purposes. Only when there would be no congestions at all (between markets), the need for hedging would disappear, but there are no indications at this moment that flow-based capacity calculation method will create such an additional amount of capacity available to the market that it would no longer be confronted with congestions.

Redefinition of bidding zones: It is clear that splitting up existing bidding zones in smaller bidding zones would decrease liquidity in the day-ahead and forward markets and make hedging more difficult, Redefinition of zones should rather aim at merging price areas across national borders to create bigger and more liquid price zones.

Furthermore, if really considered as necessary, the redefinition of the zones should be announced some years before it actually takes place in order for the market to come up with new instruments and to minimize impacts on market participants. Market participants should be able to rebalance their cross-zonal positions quite some time before the actual reconfiguration. If redefinition of zones takes place more often this will have a strong negative impact on cross zonal trading and liquidity of long-term products and investor confidence TSO have to use other available instruments (building up new power lines, re-dispatch, counter trading) to strengthen trust of market participants in the possibility to hedge their producing and sales positions.

However, a better approach to the fundamental challenge would be building more transmission capacity. As long as there is not enough transmission capacity, there will be a price difference between price zones, any hedging product should reflect this price difference related to the fundamentals of the market. This is particularly important for island markets with limited interconnection.

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...)?

The key principles of the suitable Long-Term Target Model include the following:

- Harmonized set of rules for borders with FTRs and PTRs with UIOSI
- Testing of CfDs issued by TSOs in markets where hedging with financial products is considered to be difficult could be launched by the concerned market parties, regulator and TSO
- Allocation of maximum capacity on a multi-year basis and appropriate regulatory incentives for TSOs
- PTRs and FTRs should be firm rights and thus achieve a full hedge against short-term congestion costs. In case of real-time curtailment, TSOs should have to compensate the holders of transmission rights on the basis of the resulting market spread
- Obligation of TSOs to set up a European platform for primary and secondary trading of transmission rights
- Market should be extensively consulted on all the issues related to market design and its changes

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?

PTR with UIOSI or the equivalent FTR do not allow any transmission owner to hoard capacity from the market. Any player willing to influence the market value of transmission rights is eventually confronted with the outcome of the market coupling result. The target model foresees a European- wide price coupling, leading to a day-ahead competition of all generators at the moment of gate closure. Any attempt to “game” on long term rights would thus need to be able to influence the outcome of the market coupling as well. We do not believe that this is a realistic scenario.

Moreover, regulators can use instruments in REMIT and MAR for a detailed monitoring of both transmission rights and bidding on power exchanges as well as available and offered generation capacity to the market. No specific measures should be needed on top of these instruments.

We would like to mention that also for the whole process of transmission (CACM) on the idea of TSOs transparency is a key issue.

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

Secondary trading: We believe that the organization of secondary “FTR/PTR” trading is neither a task for TSOs nor for the auction office. The auction office should only be notified on the final ownership of the FTR/PTR, but not be involved in the trading itself. In the case of PTR, the ownership should be notified before the nomination gate closure. In the case of FTR, the ownership should be notified at the market coupling gate closure, or even later on.

Reduction of “held” capacities: We appreciate that caps are seen as an intermediate solution to give all parties (TSOs and FTR/PTR owners) some comfort. However, such caps should be gradually removed (increased). A harmonized methodology to define the level of the caps and the way they will evolve over time has to be adopted. A market consultation for this methodology will be necessary.

Recovery of payments: on one hand, TSOs plead to have a “risk free business”, on the other hand, they want to have a financial guarantee. Furthermore, market participants buy FTRs with the aim to have a larger value back via the cash out (market spread if positive). Having a financial security that is balanced between TSOs and FTR/PTR owners is necessary as indeed a TSO eventually also has to pay to the FTR/PTR owners the cash out value (market spread). Financial security requirements should not act as a barrier to entry to any market participant. We believe that further clarity is needed on how capacity holders should be compensated in terms of curtailment – e.g. whether it should be based on price paid or congestion rent. It must also be explored whether regimes should be different for merchant or regulated interconnectors and for sub-sea and land based cables due to differences in the risk and duration of outages.

Entry into force and consequences: The European set of rules should enter into force in 2014 except for those in receipt of derogation under Article 96 of the CACM Network Code.

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)?

Auction timing and products should be harmonised with regional OTC- and futures markets, in order to limit risks associated with buying transmission rights. In the long term, a European platform is preferable with regard to cost efficiency (e.g. IT interfaces and procedures). It has to be checked if existing platforms like maybe power exchanges can play a major role in this context.

Island markets are however in a peculiar position, particularly those with limited interconnection. Given the limited opportunities to hedge cross-border in such markets, staggered auction timings and/or sufficient, regularly held auctions that provide market participants suitable alternatives for risk-mitigation are important. As an example, bids in auctions on a single interconnector may be rejected, so an alternative to hedge on another interconnector or at another time might be needed.

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

Taking into account the answer on question 6, we agree with the list of proposed harmonization.

9) Which aspects should be harmonised in binding codes?

Auction rules should make part of the Network Code for Forward Allocation.

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?

In our view this problem is mainly hypothetical, as there are not many producers / consumers that need to hedge simultaneously a long / short position, for example, in Portugal and in Sweden. However, from a theoretical point of view, if a producer in Sweden would want to sell power in Portugal, he would need to sell his physical production in Sweden and he would need to buy physical power in Portugal in order to be able to sell it to Portuguese consumers, as spot markets are by definition local. If he wanted to hedge, he would have to hedge in both markets according to the local way, so there wouldn't be any need for a complex and costly chain of hedging instruments from Portugal to Sweden, but rather two separate local hedges.

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?

In our view, cross-border capacity should be allocated all at once at the same time for all borders in Europe. It is not necessary to split the amount of “yearly” capacity over 2 auctions (like it is the case on the Dutch borders). The valuation of FTR/PTR does not depend on the amount of auctions, but on the total amount of capacity that will be offered to the market, and to the anticipation of market fundamentals of the participants to the auction.

This simultaneous allocation should not pose any serious practical problems to market participants as they will in any case only participate at those borders where they have a real interest in the market. A “one shot” allocation would force all market players to bring together their view for the products at the same time, exactly as they have to work for the market coupling (there is only one gate closure). All borders will then be treated on a non-discriminatory basis and a calendar of the auctions should be notified sufficiently long time in advance.

In our view, long-term allocation should remain ATC- based allocation, while flow-based method could progressively be introduced for the short-term allocation.

The aim of the long-term allocation is to give the market a clear signal of the amount of possible (yearly, seasonal monthly) exchanges between markets. TSOs should maximize the capacity they offer to the market, but the uncertainties for long-term calculation have to be taken into account. Offering the maximum of capacity to the market would anyway lead later on to a “reduction” of capacities at certain moments, as there will always be unforeseen events. This can be solved if TSOs also organize “inverse” auctions to buy back capacity rights from the market.

In our view, the primary market should be organized first and be complemented by a secondary market as a next step. An additional possibility that could also be introduced in a second phase is for TSOs to buy back capacity rights via the market coupling itself (by offering “negative” capacity constraints).

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 optimized across different borders?

Compatibility of capacity calculation methods across various timeframes is key to ensure that maximum capacity is being allocated to the market and that all the capacity not used before DA timeframe is offered to the market. If capacity is curtailed in the short term, it should be made clear that TSOs must compensate transmission rights holders for losses equivalent to the resulting market spread.

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?

Multi-year calendar products (corresponding to the commodity products traded in the energy market) would be an advantage to increase cross-border competition in the forward market. They also could be of interest for hedging purposes in connection with investments in power plants. Furthermore, transmission hedging products should mirror energy hedging products. Since it is possible to buy energy forwards three years in advance it should be the same for transmission forwards.

An appropriate mix of multi-year, annual, seasonal/quarterly, and monthly products allows participants the most flexibility necessary to efficiently hedge their positions especially as commercial positions can change unexpectedly in the short term. Furthermore, products, particularly in low meshed bidding zones, should be broadly aligned in order to maximise the liquidity in these products ensuring efficient use of the interconnector.

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?

Maximum available capacity should be allocated to the most long term product. There is no reason to reserve upfront capacity for the market coupling process, neither for “monthly” auctions other than the capacity that is available for a “month” of a “day”.

The split should only reflect the difference in available capacity. For example, if one year ahead TSO(s) calculate that the available capacity from A to B will always be above 500 MW over Y+1 (with maybe some months exactly 500 MW available but during other months 800 MW available) they should allocate 500 MW for the yearly product and for the months during which there is remaining capacity make it available for monthly auctions.

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?

Yes, it would be positive that TSOs can make use of products that maximize the allocated capacity. Such products could indeed be profiled, for example for a yearly auction it could be possible to offer more capacity during some months than during the other ones, or it could be possible to offer different volumes during peak or off peak hours.

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?

TSOs should allocate maximum capacity to the most long term product. The secondary market is able to structure the transmission rights according to market needs.

Secondary market

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

Maximization of allocated capacity means that sometimes too much capacity has been allocated by TSOs. In such a case, TSOs should buy back already allocated capacity. This process should be clearly defined with regard to features of the reverse auction, timing of the notification about the auction to the market.

In case of FTRs, due to new events TSOs ask the FTR owners to sell them back capacity for the period of curtailment. Based on the result of this inverse auction, FTR owners would

drop (part of) their rights. If no FTR owners would be willing to sell back to the TSOs, the FTR owners will keep their rights and they will receive a (positive) spread of the price coupling (in case of FTR options).

In case of PTRs, due to new events, TSOs ask the PTR owners to sell the back capacity for the period of curtailment. Based on the result of this inverse auction, PTR owners would drop (part of) their rights. If no PTR owners would be willing to sell back to the TSOs the PTR owners will be compensated at the UIOSI value, or at the value of the allocation of the day ahead explicit auction if still in place. If no explicit day-ahead auction would be organized, the PTR owner would be compensated at the day-ahead market spread (in this case, the moment of this market spread should be defined) or balancing spread between the two markets (if this spread is positive in the direction of the PTR).

Different rules are needed for subsea cables, as the situation on subsea cables in case of an outage is not comparable to overhead lines, which can be more easily repaired.

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?

PTRs are needed at borders where the bidding zones have no liquid markets. PTRs can also give market participants a wider choice of trading products. In markets with market coupling, the move to FTRs should be implemented in a consistent way.

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?

It depends on the status of the relevant markets. It would be a natural development to directly introduce FTRs within a market which is part of NWE-price coupling and where demand for transmission rights already exists. In markets with less liquid spot-market a monitoring of how PTRs are actually used over time will give insight into the moment at which it will be most appropriate to step down from PTRs. In view of significant advantages of FTRs (no nomination deadline reducing also operational risks and costs, no “netting” needed between TSOs for the nominated rights, etc), further usage of PTRs will have to be justified by a cost-benefit analysis and subject to ACER’s decision after consultation.

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?

Yes, we believe that market participants have an interest in PTRs at several borders. At the same time, establishing a single platform for the nomination of long term transmission rights (PTRs) should not be considered as we believe the nominations anyway will no longer be necessary when moving to FTR.

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?

We believe that the mentioned platforms do not have strong individual weaknesses. However, the fact that these platforms have different rules, IT systems, updating process of rules creates an additional cost, and thus also an entry barrier to participate.

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

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

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

o 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?

We believe that it does not make sense to develop several new platforms. This will mean higher costs for both TSOs in terms of running these platforms, and for market participants in terms of handling different platforms. We believe that TSOs will voluntarily move to one platform as the only credible solution. In the situation when CASC has spread over many markets, it will be difficult for some other auction offices to justify their existence to serve limited number of borders, while incurring additional costs that are to be covered in the grid tariffs by the final consumers. In our view, ACER and NRAs should develop appropriate incentives to move towards a single auction office and the network code should stipulate a long term goal, giving the Commission a right to intervene if TSOs would not move on their own in this direction.



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