

## **Key principles in the treatment of electricity transmission capacity rights and their linkage to day ahead allocation mechanisms**

### **Executive Summary**

EFET tackles with this new paper a series of key principles, which, applied across Europe, would ensure the rapid introduction of markets in electricity transmission capacity rights, and, therefore, would facilitate cross-border power trading.

**1. TSOs shall auction physical transmission rights or financial rights with equivalent effect.** 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. Capacity rights do not absolutely need to be physical, but they must fulfil the criteria set out in sections 2, 3 and 5. With this proviso, they can instead be structured as financial instruments, as long as issuing TSOs and/or power exchanges on their behalf provide a pay out to the holder of the right representing any effective price difference across a border at the day-ahead stage.

**2. TSOs shall auction the maximum of available capacity over appropriate timeframes.** Borrowing the model of the forward electricity commodity markets, TSOs could organise term transmission 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 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.

**3. 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.

**4. TSOs must not discriminate against holders of transmission rights purchased in advance of day-ahead and intra-day timeframes.** We advocate the introduction of a UIOGPFI (use-it-or-get paid for it) option for holders of transmission rights issued with maturities longer than one day ahead. For borders implicitly allocated in the day-ahead market the principle of UIOGPFI should be introduced without delay. The way in which the capacity allocation should function at D-1 is shown in graphic form. Graphic variations deal with regional markets, where currently only explicit (e.g. CEE) or only implicit (e.g. Nordic) capacity auctions are organised.

**5. 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. 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.

# **Key principles in the treatment of electricity transmission capacity rights and their linkage to day ahead allocation mechanisms**

(Main part of the paper)

A number of current initiatives around Europe try to address the issue of congestion and find mitigating measures to further foster the evolution of a European market for electricity. Most market participants might easily agree on a long-term vision, where prices in European market areas will have moved very close together. According to such a vision, congestion would have been mostly eliminated, remaining market areas have become large enough to nurture liquid spot markets and remaining basis risks be hedged via a liquid market in financial transmission rights, which settle against the results of the hourly commodity price fixings in the spot market by region.

Reality, however, is far from providing the necessary prerequisites for implementing such a vision. Around Europe a variety of market models are pursued at present, to support at least regional cooperation and coordination. None of them is fully applicable as a blueprint for pan-European implementation, given the patchy state of development of wholesale electricity markets on a national basis. This EFET paper proposes key principles, which regulators, TSOs and market operators should apply across Europe, in order to promote the use of transmission rights and thereby help market development. In some European regions this still means linking rather illiquid market areas, in others it may entail adding implicit auctions via market coupling procedures for the day-ahead market.

This paper continues the series of pieces that EFET published on cross-border trading, amongst which we mention here those on Transmission Capacity Allocation (October 2004)<sup>1</sup>, Firmness and Maximisation (May 2006)<sup>2</sup>, and the Notes for facilitating a secondary market in transmission capacity rights (November 2006)<sup>3</sup>.

## **1. TSOs shall auction physical transmission rights or financial rights with equivalent effect**

Cross-border competition requires that market players are able physically to supply customers. The opportunity, eventually to sell own generation or purchased output in an adjacent market lowers the risk to compete in that adjacent market. This is especially true for markets, where spot liquidity is not yet significant and/or where there exists fear of the market power of incumbents. Cross-border competition can thus help to foster liquidity in former illiquid markets.

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<sup>1</sup> Reforming the management of electricity transmission congestion in the EU Internal Market: an EFET Vision, EFET position paper, October 2004, available on <http://www.efet.org/default.asp?Menu=76>

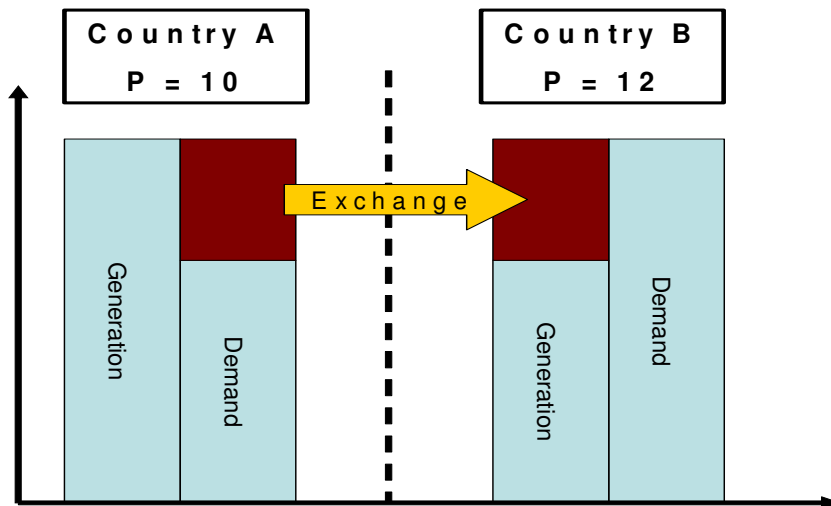
<sup>2</sup> More transmission capacity for European cross-border transmission: Firmness and Maximization paper, EFET Position Paper, May 2006, available on <http://www.efet.org/default.asp?Menu=76>

<sup>3</sup> Notes for Transmission System Operators and Regulators on an EFET draft Appendix, to the EFET Standard Master Power Contract (for the wholesale trading of electricity), facilitating a secondary market in transmission capacity rights, EFET Analysis Paper, November 2006, available on <http://www.efet.org/Default.asp?Menu=217>

TSOs are natural sellers of transmission capacity rights in the market and are the *only* players in a position to offer the required firm transmission hedges to the market. Income for TSOs (in the form of auction revenues) normally increases if declared congestion increase. Market participants can generally not take on a price-spread risk between two markets because they do not have an ability to manage such a risk as long as there is no transmission right available that provides a valid hedge. Even trading companies in principle willing to take risk are in the same position and would likely only occasionally and to a limited extent be able to offer market spread hedges off the back of other transactions. Hence the limited use in Nord Pool of contracts for differences.

To compete effectively across borders, market participants need the ability to fix the delivered price of electricity in advance. This requires the ability to fix the price of transmission for cross-border deliveries, in addition to fixing the price of electricity within national markets (i.e. by trading in national forward markets). Market participants therefore need to be able to buy transmission capacity rights that allow them to deliver power across borders for a fixed price.

Consider a scenario with two countries (Country A and Country B) with generation, demand and trade of energy as in the figure below, and that the market model adopted consists of independent network, retail and generation companies.



In this scenario, not being able to hedge transmission risk long term increases risks and costs to all involved market participants. It also holds the potential to jeopardise the ability to finance the companies' activities.

If only daily capacity were to be sold, for example, the following would apply:

- The risks for a generator in country A would increase, as it would not be able to ascertain the price, at which it would be able to sell power in country B.
- The TSOs in countries A and B would not be able to forecast the income generated over several years by their auctioning of inter-connector capacity, so would face increased risks and a difficulty to finance inter-connector investments.
- A retailer in country B (which sells energy to consumers at a long term fixed price) would face higher risks, as it would be unable to forecast the cost of the energy plus transmission right it might buy bring power from Country A.

Overall, this increases risks to all players in the supply chain, and hence the costs and prices born by each of them.

Capacity rights have in Continental Europe hitherto been assumed to be necessarily physical, but they can also be structured as financial instruments. These can provide a pay-out to the holder of the right, which compensates for the effective price difference at the day ahead stage when market clearing prices for single hours are simultaneously, determined either side of the border. If structured in an intermediate phase as “old” physical rights rather than “new” FTRs, pending full integration of explicit and implicit auctions at the same border, there must be no discrimination against holders of rights granted months or years ahead, when it comes to nomination deadlines and pay-out arrangements.

*(On the further implications of mixing physical and financial rights of different maturities in transitional phases across different regional markets, see section 4 below).*

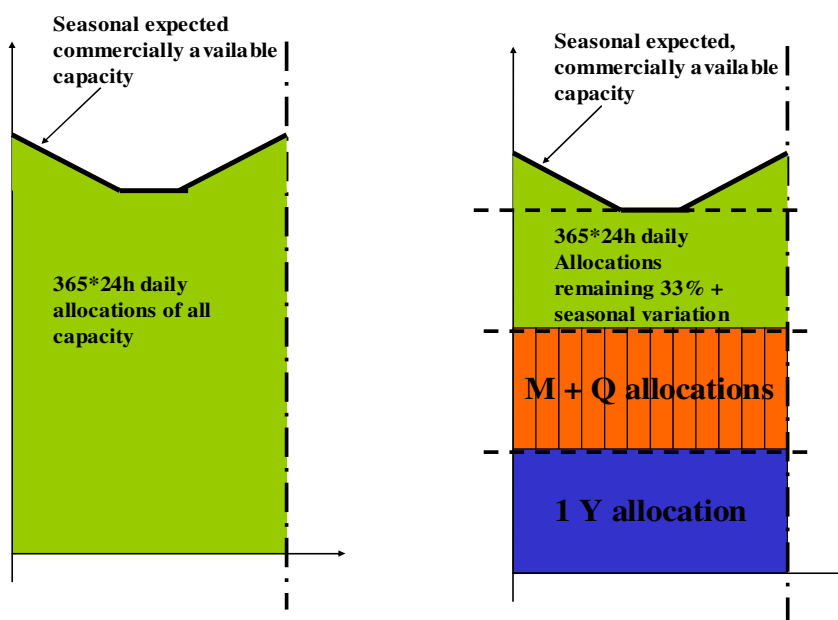
## **2. TSOs shall auction the maximum of available capacity over appropriate timeframes**

An ability to transport power reliably into an adjacent geographical wholesale electricity market is essential to mitigate the risk when market participants attempt to become active in territories outside their home generation and/or supply base. This is especially so, where that adjacent market is relatively immature. The maximised availability of transmission rights increases consistent and dependable price correlation between the two markets, and improves opportunities for cross border competition. This is true as much for rights granted months or years in advance, as for those granted day ahead, since wholesale and retail markets typically include commodity contracting month ahead, year ahead and even a number of years ahead.

Indeed we would advocate TSOs, with regulatory approval, moving to term transmission capacity auctions and maturities (e.g. future calendar years) similar to those found commonly in the forward electricity commodity markets. We also ask them to consider organising such term transmission auctions regularly (say every quarter), on each occasion for a variety of maturities (rather than auctioning, as now, just yearly capacity every year and monthly capacity every month). This should mean that the right balance will be struck between the different auction products, in order to avoid that the offered volumes at some auctions become too small and lead to unreliable auction price results.

It should be noted that neither current Nordic TSO nor current Continental European TSO practice accords with the balance of auction products, which we have in mind (*see diagrams on the next page*).

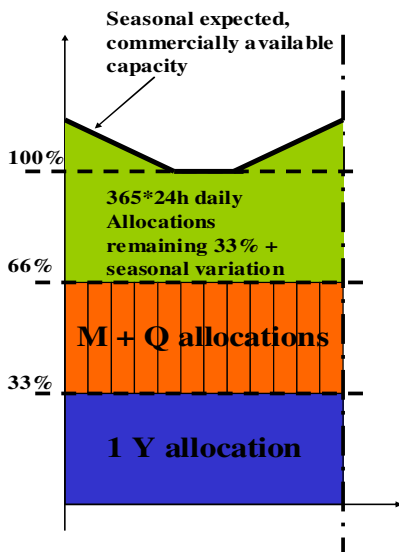
## “Unwished” allocation models



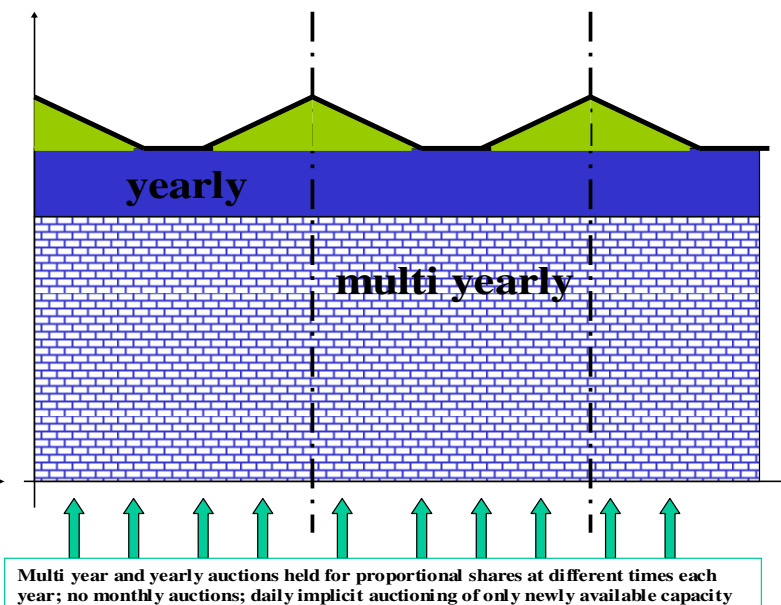
We have evaluated the merits of asking TSOs to auction demand related profiles (e.g. base-load, peak) within a given maturity of transmission right, but we prefer the concept of a liquid secondary market in transmission rights facilitating the “slicing and dicing” of capacity blocks by market participants, according to the basis risk hedge profiles they individually require from time to time. It may nevertheless prove necessary for TSOs to sell some minimal amount of within day shapes in the primary market, if capacity availability is to be truly maximised.

Defining the amount of transmission capacity to be auctioned in the term market is not a technical decision, but an economic and commercial one. Security standards mean that actual flows will face the same constraints irrespective of the amount of capacity previously allocated. Far from endangering security of supply, allocating more capacity in advance equates to an increased commercial requirement for system operators to rebalance flows to the actual capacity available. By restricting capacity allocations in advance, system operators therefore retain a valuable commercial option on whether to release further capacity over time. The result is conservative views on the availability of capacity, lower levels of capacity allocations and ultimately sub-optimal usage of the actual cross-border capacity. TSOs should not hold back or reserve any portion of cross-border capacity for intra-day trading, nor for their own potential system balancing needs, nor even, ideally, for day ahead allocation or market coupling purposes. System operators should instead be required in principle, as a basic premise on the part of regulators, to allocate to market participants the maximum amount of capacity, expected to be available well in advance of the D-1 timeframe (*as illustrated in the diagram on the next page*).

## Current usual practice



## “Wished” but unrealistic practice



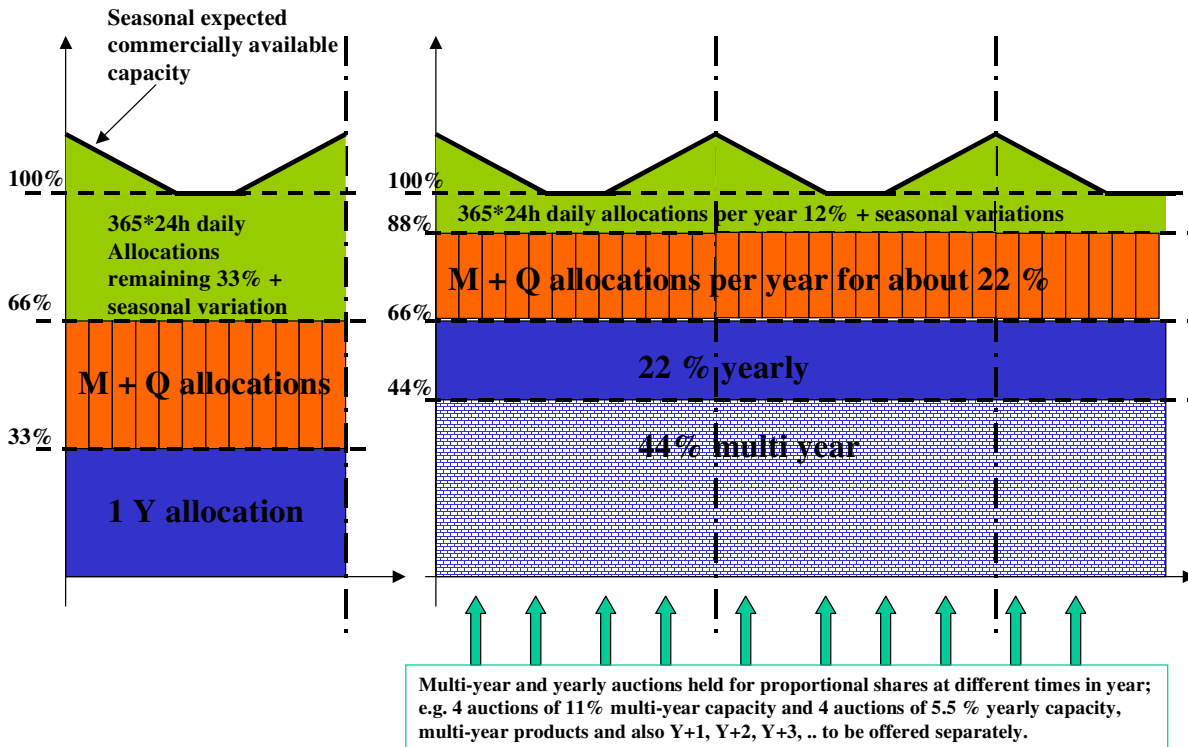
We do recognise however the anxiety which may be caused to exchanges organising new market coupling schemes by an immediate change to allocating all capacity prior to the D-1 timeframe. We could therefore contemplate the retention for the time being of a modest percentage of capacity for first allocation at D-1, at least until reasonable liquidity in secondary capacity trading markets can be observed. Nonetheless, we see no case whatsoever for increasing the retained percentage beyond 33% as at present. In fact, we have concluded that a retained percentage of 12% should be enough.

Regulators may note with reassurance that, in a later stage when very good secondary market liquidity would be proven, even 100% of the physically available capacity, as calculated by TSOs day-ahead, could be used for such market coupling mechanisms. The proviso to such physical use would then be that explicit auctions of truly firm, financial transmission rights of long maturities, *yielding eventually a pay-out equivalent to the price differential (if positive) emerging in the implicit process*, have taken place in advance. The further question arises as to what mix of multi-annual and annual, compared with monthly or quarterly, transmission capacity should be auctioned. While recognising that the EU Congestion Management Guidelines require the allocation of a mix of maturities, according to competitive conditions, we urge TSOs and regulators to move towards longer maturities than are currently issued, and towards allocating a higher percentage of eventually available capacity one year or more ahead than is currently the case in Central West, and even more so, currently the case in Central East and South East Europe. Our research demonstrates that auctioning one year (or a few years) ahead considerably more than a maximum of one third of available capacity (the typical maximum percentage presently), will jeopardise neither network security nor TSO total revenues. And we do not believe that, given overall competitive conditions, such an increase will give rise to any significant risk of capacity hoarding. Something closer to two thirds would be consonant with the common term-sales and purchases positioning of major European generators and retail power suppliers respectively. A two-thirds level would also bring the benefit of helping develop liquidity in a traded secondary capacity market (*see diagram below*).

Current usual practice



“Wished” realistic practice



### 3. Transmission rights must be firm

Delivery obligations for electricity as a commodity throughout the industry are defined as “firm”, allowing only for clearly defined, objectively determined and narrow “force majeure” circumstances or events. The terms on which power transmission rights are granted need to match those for power supply in this respect, so as to avoid a mismatch in wholesale market participants commercial exposure when transacting across borders, and so as to fulfil customer expectations of secure supply.

A secondary market in transmission capacity rights will help to provide proper price information.

TSOs do not presently offer fully firm capacity rights as a physical hedge, and because of this the market for financial hedging contracts has not developed either. The compensation, if any, in the event capacity is curtailed is not at the full market spread but rather on prices paid for the capacity. This does not represent an acceptable hedge for the company buying the capacity, as at times the compensation is higher than the present market spread and at other times compensation is lower. So the owner of the capacity right always bears a residual price risk between markets. At the same time, TSOs bear the risk of paying too much if the spread is lower.

TSOs, on the other hand, have the ability to manage the associated risks and are the *only* players in the electricity sector that can do so. Hence TSOs are also the only asset owners and/or operators with an in-built capability to offer primary, physical hedges against future congestion rents through the prior creation of fully firm cross border transmission capacity

rights. TSOs in this sense are *natural* sellers of firm transmission capacity rights. TSOs have alternative ways of managing the risks involved (e.g. short-term actions like rescheduling or re-dispatching generation plant, counter-trading; or mid-term measures like buying back oversold capacity rights on the secondary market or by declaring congestion internally on their domestic grid, and thus creating additional price areas; or long-term solutions like building new lines or phase shifters).

The transfer of this ‘firmness risk’ from the market participants to TSOs will result in an overall efficiency and welfare gain. This for the following reasons:

- At present market participants bear the ‘*firmness risk*’ (being the risk that the transmission capacity right they have purchased will not be fully financially firm)
- As with any risk, market participants attach a risk premium to the pricing of this firmness risk
- Given that market participants can not manage the risk, which TSOs can do, they will attach a higher risk premium than what a TSO would do in relation to exactly the same underlying firmness risk.
- Market participants also know that as the TSOs do not bear the firmness risk themselves, they will not face fully aligned incentives to ensure the minimum number of interruptions possible. This further increases the risk premium they put on the firmness risk.
- Any priced in risks by market participants will at the end of the day feed through to the prices consumers pay, just in the same way as increased TSO risks/exposure will result in those risks being borne by consumers.
- But as the risk premium (and hence cost) of the firmness risk is lower for TSOs than market participants, the consumer is better off if TSOs assume the firmness risk of cross border transmission capacity. The result in an overall efficiency gain.

#### **4. TSOs must not discriminate against holders of transmission rights purchased in advance of day-ahead and intra-day timeframes**

##### a) Conditions attaching to the purchase of transmission rights

Transmission rights have the characteristics of an option for any future time period, from their grant right up to gate closure. Rules for any option exercise need to be clearly defined when the option is first auctioned. In order to find the best use for transmission capacity, the value of an option related to transmission utilisation needs to become transparent over time. This in turn requires a standard design for option exercise. Exercise conditions needs to be uniform for all traded transmission capacities. Differences, e.g. in relation to timing of exercise, would lead to separate, different products. It is highly desirable that TSOs, with the assent and cooperation of ERGEG, move towards a harmonized, single European transmission product (i.e. a product subject to identical contractual conditions across the UCTE and adjacent areas), in order to enhance liquidity.



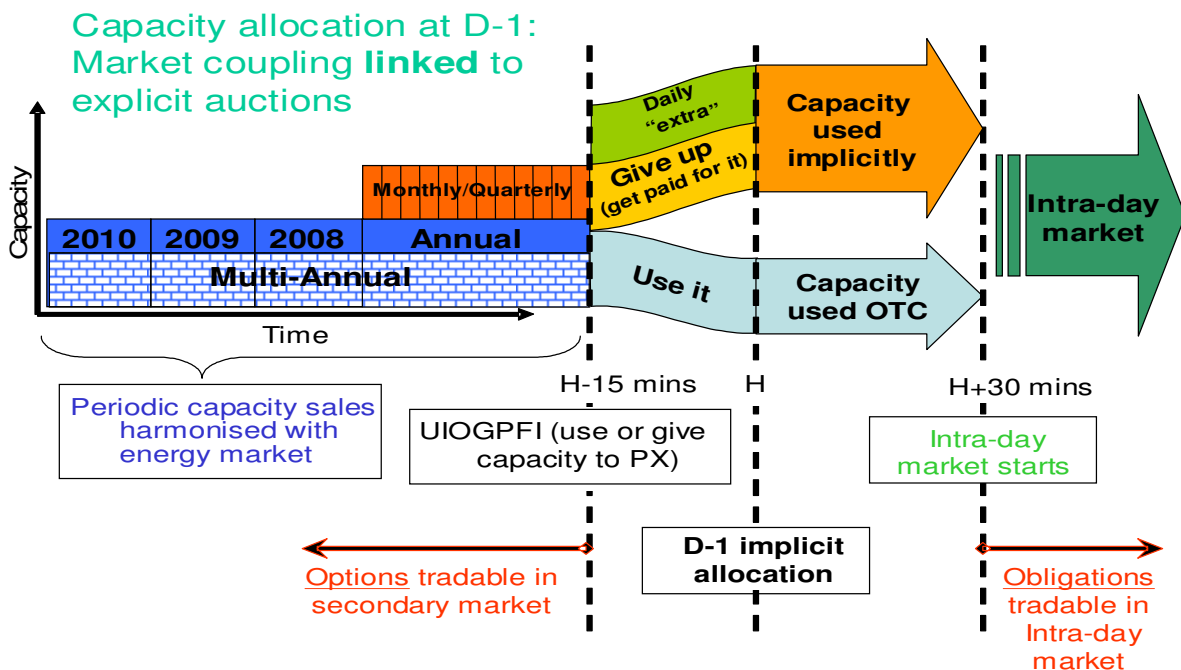
b) Arrangements for utilisation of purchased transmission rights on D-1 (including in market coupling)

All transmission rights issued with maturities longer than one day ahead, as long as they are physical, should be subject not to the pure UIOLI rule, but to new UIOGPFI (use-it-or-get paid for it).

For borders implicitly allocated in the day-ahead market the principle of UIOGPFI should be introduced without delay, *yielding as stated above a pay-out for the long-term rights not nominated by the owner of the right equivalent to the price differential (if positive) emerging in the implicit process.* The transfer of transmission capacity from the market participant to the exchange could be called “give up” and needs to be firm until the exchange can nominate actual usage of the transmission capacity.

The usage decision for borders implicitly allocated in the day-ahead market should be made just before (for example 15 minutes as shown in the chart below) the exchange bidding closure. A nomination gate closure for advance rights set after the exchange bidding closure might create a risk of capacity hoarding and price manipulation. Owners of transmission rights could instead be required to nominate any right not given up to the implicit allocation mechanism, in order to allow netting of capacities in each direction at a border to take place in the day-ahead price fixing.

Intra-day trading, which we have advocated in a separate position paper<sup>4</sup> should be based on a well-defined Transmission Capability Matrix and could start right after the day-ahead hourly market has cleared, irrespectively of the actual nomination time of schedules to the TSOs. Secondary capacity markets for day-ahead products must anyway be facilitated by TSOs right up to the moment where the use or give up decision (UIOGPFI) has to be made.



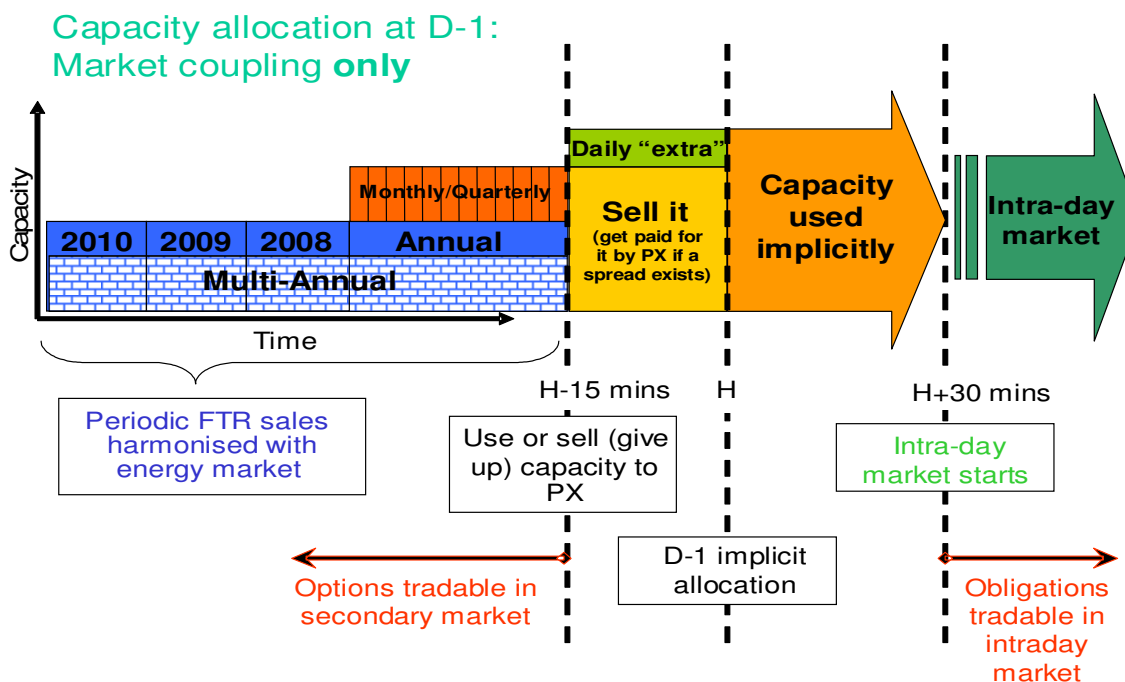
<sup>4</sup> “Intra-day power markets within and across European national frontiers: A practical approach to facilitate wholesale liquidity”, EFET Position Paper, December 2006, available on <http://www.efet.org/default.asp?Menu=76>

Notes on this first D-1 diagram:

- The decision to use explicitly auctioned capacity at H-15 minutes, rather than selling it should entail an undertaking or an obligation to use the capacity, though TSOs should not require a declaration of the counter-party till the commencement of the intra-day timetable at H+30 minutes;
- A gap of only 15 minutes duration prior to H would require a centralised nomination office across implicitly linked territories in order to have a very fast matching process and to have the capacity available for the daily implicit allocation (i.e. the sum of daily extra and the give it up part) published in due time.
- Terminology used in the graph may not equate exactly to definitions and acronyms recommended/ agreed in the Minutes from the ERGEG organised Transmission Rights Workshop in Autumn 2006, and can be discussed further in the follow-up workshop

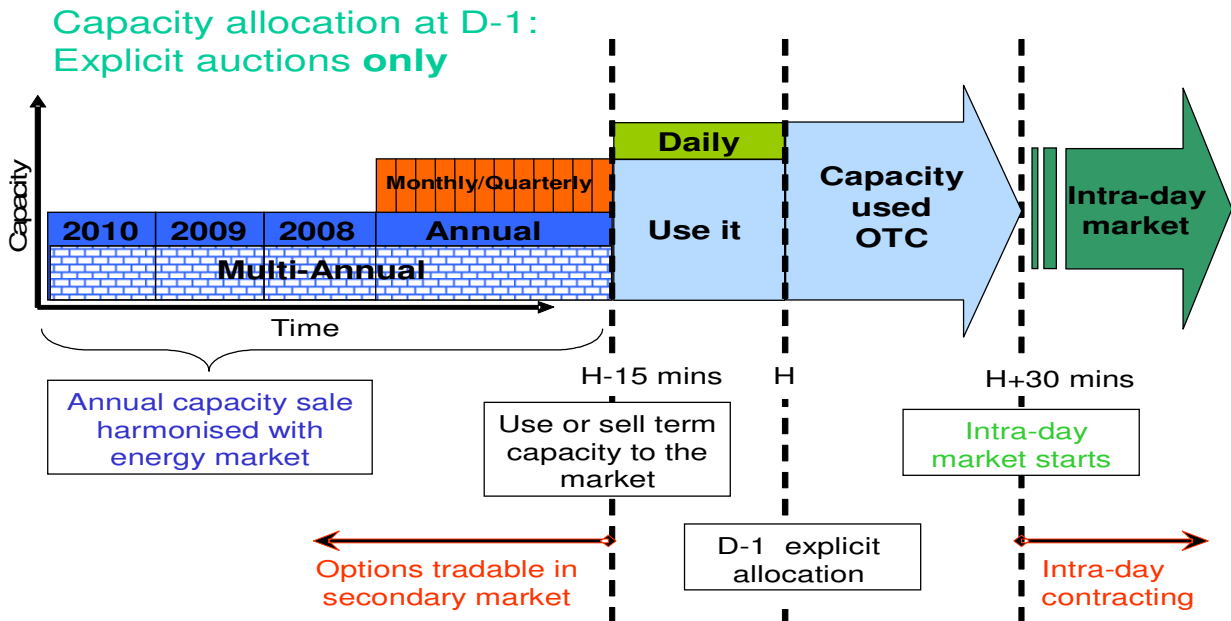
Also note that:

For regional markets that have currently a mix of explicit and implicit auctions (e.g. the TLC region Benelux) the top branch of the graph must be read to include the possibility that at some borders at the edge of the region (like the Dutch-German border, the French-German border, and other French border in the TLC example), also daily capacity is used for OTC cross-border transactions i.e. that region retains explicit auctioning day-ahead of some borders, while at other borders longer maturity rights may gradually become effectively converted to financial.



Note on this second variation of the basic D-1 diagram:

- For regional markets that have currently just implicit auctions (e.g. Nordic area) only the top branch of the basic diagram becomes applicable i.e. longer maturity transmission rights (if they are, in the case of the Nordpool example, first created in place of the “CFD” model) will most likely be purely financial and thus automatically settled by the power exchange[s] in cooperation with TSOs.



Concerning this third variation:

- For regional markets that have currently just explicit auctions (e.g. CEE) only the lower branch in the basic diagram becomes applicable i.e. longer maturity rights will remain physical and the organisation of market coupling is postponed.

## 5. Transmission rights need to be fungible in a secondary, traded market

TSOs should be allowed to buy back in the market any part of the capacity rights they turn out to have oversold in advance, or indeed to buy back (in the manner of what is currently called curtailment) also whenever this is necessary for them to manage unexpected operational circumstances such as physical outages or unplanned loop surges. (Of course that does not exclude the alternative methods of co-ordinated re-dispatch of generating plant and cross-border counter-trading.) However, if a liquid secondary market in transmission capacity rights does not exist, TSOs will not be poised to take the role of “re-purchasers”.

This is not the only reason why secondary markets are necessary. Wholesale market players have evolving traded electricity portfolios to manage. Sometimes they buy capacity rights on a yearly basis, which they do not need during certain seasons. At other times they only need the capacity rights they buy daily or monthly during peak hours; thus they may like to sell on their rights in a deep and liquid market during certain off-peak periods. Meanwhile other players, with contrasting portfolios of power sales and purchases, may find themselves naturally on the buying side in some of those same seasons or off-peak periods, in their own efforts to optimise those portfolios.

Market participants may want to acquire transmission rights for longer term i.e. to compete in an adjacent market. As their customer portfolio changes and wholesale market prices develop the need to transport and the value of the right does change and other market participants might make better use of this right. Therefore secondary trading of transmission rights must be possible and market participants need to be able to “slice and dice” i.e. turn an annual or monthly right into hourly pieces, as they can do with any wholesale electricity contract.

After physical rights of longer maturities than day-ahead are auctioned, in order to assure TSOs that not more capacities will be nominated than actually auctioned, and that they know from which party they might expect a schedule, some “registry function” will be appropriate, comparable to the EU emissions allowances accounting process. This kind of “registry function” is still necessary if TSOs auction comparable financial transmission rights, because they and power exchanges need to know who owns the right, so they can pay the appropriate market participant the value of the eventual spread. On the other hand the reconciliation to physical schedules would become irrelevant.

**EFET**  
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