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To Mr Klaus-Dieter Borchardt
Director – Internal Energy Market
European Commission – DG Energy

Brussels, 20 December 2013

OBJECT: EFET observations on the European Commission Communication 2013/7243 of 5 November 2013 and annexed EFET Discussion Paper on central vs. self-dispatch

Dear Mr Borchardt,

The European Commission recently published a set of documents relating to Public Intervention in the Energy sector addressing generation adequacy concerns, reforming support schemes for renewables and facilitating the deployment of demand response measures. This review is welcome and timely. There is a strong need to look beyond the current framework which has created severe tension in the entire system of energy supply. Put bluntly, the European Union is currently not achieving its energy policy objectives and much of this is down to policies at national level.

We therefore welcome the efforts of the Commission to work towards a future situation where subsidies have been reduced or removed. In addition, we also support the initiative to ensure that, where subsidies still exist, these should be a supplement to the revenues received in the market rather than being an alternative revenue flow, as is the case for most renewable and low carbon support.

In general, the Communication sets out a sensible and achievable medium term objective for the EU energy policy. This would be based on (i) further development of integrated and competitive markets, (ii) the ETS resuming its place at the centre of climate policy; and (iii), additional renewable support to be permitted at national level. However this support must be under a much higher level of scrutiny by the Commission so as not to damage the achievement of the first two objectives.

This outcome could be delivered through a combination of more rigorous implementation of the EU Treaty rules, IEM Directives, competition law including state aid guidelines, and the development and implementation of the network codes aimed at completing the internal electricity market. The remainder of this letter discusses these areas of activity by the Commission.

I. Implementation of the Directives

One of the fundamental problems created by the current national frameworks based on feed-in tariffs is the obligations and duties placed on TSOs by national governments. This often stems from a particular (and unnecessarily restrictive) interpretation of the concept of "priority dispatch". In many cases, the concept of "priority" is taken to an absolute extreme such that any electricity produced must be dispatched by the TSO, even if this is profoundly uneconomic and the owner, if it had the choice, would not choose to dispatch. As a result of such an interpretation, many national schemes are questionable with respect to European law as follows.

Unbundling: many national laws place TSOs in a position where come under the definition of a "supplier"[1] in the Electricity Directive in that they are buying power from producers and selling it into wholesale markets. Indeed in some cases TSOs are, de facto, major participants in day-ahead and intraday markets, which was not the intention of the Directive and not consistent with the unbundling requirements.

TSO dispatch functions: Article 15 of the Directive allows that TSOs *may* have responsibilities with respect to dispatch of generation installations. However it must do this "without prejudice to the supply of electricity on the basis of contractual obligations". **This means that TSOs must allow for market participants to dispatch their own plant in order to meet any contractual obligations**. Compulsory centralised dispatch of any type of plant (whether renewables or the entire generation) seems contrary to this requirement. Indeed it seems unlikely that it is the intention of EU institutions to implement a market design based on compulsory central dispatch. The "Single Buyer" market design was removed from Directive 1996/92 when the Directive was revised through Directive 2003/55. We have attached a **discussion paper on the relative strengths and weaknesses of central vs. decentralised dispatch as an Annex to this paper**.

Priority of dispatch and market distortions as a result of poorly designed RES support schemes: some markets heavily influenced by the penetration of electricity generated from renewable energy sources (RES-E) have shown episodes of negative prices (Germany) or long periods of zero prices (Spain). These prices cannot be interpreted as a natural result of matching supply and demand but as a consequence of the distortion created by poorly designed RES support mechanisms.

RES-E support schemes based on payments per MWh injected in the grid enable RES producers to price in the subsidy (either a FiT, a FiP or a green certificate) in their bids to the market. As a result, they will produce even when the price signal is zero or negative (up to the level of the premium) since their revenue will not depend on market price signal.

II. EU Treaty rules

Quantitative restrictions on cross border trade: most current renewable support schemes also contain a de-facto restriction on trade in renewable energy across borders that may be contrary to the EU Treaty. We understand that there a currently two ECJ cases that may shed some light on this issue. The same would be true of any national dispatch regime that did not allow for cross border trade. In this respect it may be considered that any national "central dispatch" markets are potentially inconsistent with the EU Treaty in that they do not allow the freedom of market participants to undertake cross border transactions.

[1] Since under Directive 2009/723: "supply" means the sale, including resale, of electricity to customers; and "customer" means a wholesale or final customer of electricity

III. State aid

Definition of state resources: Now that system operators are subject to regulated third party access, it may be argued that they are "agents of the state" in the sense of the definition of state aid and that payments made under feed-in tariff regimes are state resources. In any case, feed-in tariffs are equivalent in economic effect to operating aid which, in any individual market period, can go to very high levels in the case of negative prices. The state aid guidelines need to address both of these issues and where necessary reinterpret previous cases such as Preussen Elektra in the light of new state aid guidelines.

IV. Competition law

System operators as a dominant provider: TSOs are dominant in terms of the provision of electricity transmission services and thus have "special responsibilities" to respond to the needs of the market. Likewise TSOs are also dominant as a purchaser of certain ancillary and reserve products. Currently many TSOs do not take these responsibilities seriously and place a number of restrictions on their customers which may be interpreted as distortive.

- **Bundling of network provision with dispatch**: Where TSOs are performing the task of selling renewable production or prevent self-dispatch of any generation plant, this could be seen as some form of foreclosure of the market for optimisation services. Network users should be allowed to access transmission services without also having to submit to having their plant dispatched by the TSO whether this is a renewable or conventional plant. If not, two services are being unnecessarily bundled: transportation (which is a monopoly) and portfolio optimisation (which is not).

- **Bundling of network provision with exchange service**: TSO should not be able to require exchanges of electricity via a particular platform or venue, particularly an exchange or market operator run by the TSO itself. Again this could easily be interpreted as bundling of products or foreclosure since the service offered by an exchange are not a monopoly activity

- **Non availability of products required by customers**: With respect to cross border capacity, any refusal to offer a forward or an intraday product, in addition to the market coupling arrangement, could be seen as a potential issue with respect to competition law. Similarly with respect to the firmness of network access, TSOs which offer firm products for national market participants but refuse this for cross border access could be seen as discriminatory. Likewise there does not appear to be justification for TSOs to prevent the purchase\sale of such products between market participants and neighbouring TSOs. The insistence by many TSOs on a TSO-TSO model without any kind of common merit order or joint procurement exercise seems a disproportionate restriction and potential foreclosure given that a TSO-BSP model is perfectly feasible.

V. Network codes

- **CACM:** The advent of market coupling at the day-ahead stage will expose a number of issues that have a tendency to distort market prices (e.g. price caps, bidding restrictions, etc.). The Commission should take the opportunity to act on these once the CACM network code is implemented. Meanwhile the implementation of the CACM rules on intraday should lead to a more rapid implementation of the EU target model, increase in liquidity of intraday markets and integration of renewables in the market. In relation to this it is important to emphasise that continuous trading should not be hampered by the existence of regional auctions: they should constitute an additional possibility for the market participant, but never an obligation. Continuous intraday trading must not be interrupted.

- **Forward Capacity Allocation network code**: This draft network code, currently being reviewed by ACER, should establish the requirement that all TSOs and HVDC cable owners, as monopolistic providers of transmission services, must offer forward transmission rights unless the competent regulator has expressly approved that the TSO shall not issue such rights. Any such decision lifting the obligation to issue cross-border hedging instruments should, at the very least, be based on a very serious and up-to-date border-per-border analysis, based on a minimum number of rigorous criteria

  TSOs and cable owners should provide firm access to the grid beyond the day-ahead timeframe of the market, with no entitlement to curtail long term transmission rights other than in emergency situation or Force Majeure events. TSOs must adhere through the FCA network code to strict standards of firmness as a priority to cost recovery and should avoid isolating particular element of the transmission network which would be granted special treatment or exemptions to EU regulation.

- **Balancing network code:** This code should ensure that all market participants, including renewable producers, have balancing responsibility. Indeed under the Directive, TSOs are required not to discriminate between network users, or classes of network users.

  The network codes should also ensure some standardisation of TSO products and activation rules. We are currently faced with a range of different regulated and non-regulated procurement exercises (reserves, balancing energy, re-dispatch, wind-reserve, locational reserves). This tends to under value the flexibility resources that are available. In addition to this there is a tendency of some TSOs (supported by regulators) to segment the market for flexibility into different products, which may be regulated or non-regulated. TSOs are then able to switch between these artificially segmented products depending on which is the cheapest.

  Aligned to this is the different approaches taken by TSOs about how they activate reserves in the pre gate-closure phase. This may again distort the required market signals for flexibility which is needed to support the development of the market and the integration of renewable production.

The network code Balancing should aim at some standardisation of TSO practices in this segment of the market in order to ensure the proper valuation of flexibility and the well-functioning of the parts of the market (forward, day-ahead and intraday) where the TSO should not be the counterparty to any transactions. Currently, there is very little attempt to do this in the code.

The Commission has a unique opportunity over the next two years to address many of the unsatisfactory aspects of the electricity market, most of which have been created by the activities of national governments and, in some case, regulators and TSOs.

Yours sincerely

Jan van Aken
Secretary General

ANNEX

DISCUSSION PAPER
SELF DISPATCH: A CENTRAL ELEMENT OF THE EUROPEAN TARGET MODEL

1 Summary: Electricity market design in the EU is based on self-dispatch

The opening to the European electricity market to competition has been a progressive process. Already fifteen years have passed since the entry into force of the first electricity Directive (1996/92/EC). This Directive, although allowing some opening of the retail market and free entry into generation, also left a number of restrictions in place. Member States could still opt for a full tendering model with respect to the construction of generation plant. Likewise a Single Buyer arrangement was set out as a possibility with respect to the development of a wholesale market. There were no arrangements at all for cross border trade in electricity.

The second electricity Directive (2003/54/EC) removed some of these anomalies in that the single buyer option was removed. Meanwhile the tendering model for generation capacity was constrained such that it would only be used as a last resort. Retail markets were fully opened to competition. The first electricity Regulation (1228/2003/EC) provided a framework for cross border exchange. These were developed further in the Third Package (2009/72/EC, 714/2009/EC) which required full unbundling of system operators and introduced the network code framework.

The concept of the "EU target model" was developed to give some informal direction to the network code process and to reinforce the concepts already embodied in legislation. This model is based on a market where prices are set by the free interaction of supply and demand, where wholesale power trading determines prices, and with the TSO playing a residual role in the production and supply of electricity.

An electricity system based on central dispatch is largely not compatible with this framework and has much in common with the single buyer concept that has already been rejected. For example, central dispatch often does not allow for prices to be determined in traded markets where supply and demand interact. Instead the price in any particular hour is the result of an optimisation calculation that makes many assumptions about plant characteristics and demand. Any forward trading that does emerge is based on the value of the figure produced by this model, rather than being a true price. Likewise central dispatch makes it very difficult for electricity to be traded between Member States without merging system operation entirely.

So the intention of the European Union in this respect has been relatively clear. A fully functioning electricity market with an active supply and demand side and autonomy for market participants is the expectation. Until now, some divergence from these basic expectations has been tolerated, often for relatively small Member States or those which required a relatively long transition process from previously heavily regulated arrangements in pre-Accession period. However, the success of the third package now depends on a relatively standardised market design consistent with the existing legislation and the target model, and this requires self-dispatch arrangements to be consolidated.

2 Self-dispatch is compatible with the features of the electricity sector

Electricity markets have particular characteristics that distinguish them from other commodity markets. These characteristics are a consequence of the scientific laws of electricity production, transmission and consumption as follows.

i. Electricity has a dedicated delivery network: the transmission system. For electricity provision as a whole to continue to function, there must be equilibrium between the network, production and consumption in real time.

ii. It is not straightforward to trace the production and use of individual electrons across the transmission networks. This means that electricity is never delivered from A to B in a strictly physical sense.

iii. The whole system has to be maintained at a constant frequency for power plants and appliances to continue to function. There is therefore an interdependency between market participants that is not seen in other sectors.

iv. If there is a failure in the overall system, it will affect a broad range of users, and not necessarily only those that caused the failure.

Complications are present in other sectors. However usually, for other commodities, issues like location, product specification and quality are left for the market participants to deal with. This is also possible in the electricity sector and indeed the EFET master contract does cover such matters. However it is also common in electricity to talk in terms of "market design" which implies an element of regulatory involvement in these decisions.

The special features of electricity provision do not mean that markets lose any of their potency in solving problems and encouraging efficiency and innovation. The desirability of competitive markets in both the wholesale and retail level have been demonstrated and agreed as part of the discussion of the legislation and the target model. Likewise the role of wholesale trading in price discovery process is a central part of the arrangements set in place by the legislation. This requires the removal of price controls at both wholesale and retail level

As with the peculiarities of other commodities, it is possible to develop a traded market by introducing some approximations around the consequences of these physical laws. Just as the market for crude oil is able to deal different quality grades and delivery locations, so it is also possible to get around the specificities about electricity as a product. So, for example, although the electricity system as a whole has to balance on a second- by-second basis, regulatory rules allow for market participants to balance over a 15- or 30-minute period.

So although, in some jurisdictions, regulators impose a strong role for the transmission system operator (TSO) in overseeing the market process, and even in operational decisions of market participant, this is not a necessary feature of market design by any means. Market arrangements where producers and consumers (or usually their retail suppliers) interact independently, without the involvement of the TSO are also possible. In these cases, generators negotiate individually with retail suppliers via traditional traded wholesale markets structures. The system operator then takes a residual role in that they may adjust generation output or demand via balancing actions and "re-dispatch" if this is necessary to ensure the overall security of the system.

This contrast with a so-called central dispatch system where producers feed in all their technical and pricing information to the TSO, who then calculates prices using this information and assumptions about demand. In effect, the TSO buys electricity on behalf of retail suppliers and their consumers. The usual interaction between supply and demand is, to some extent, constrained.

Central dispatch
Generators provide price and technical information (e.g. ramping parameters, start costs) to the system operator. The system operator compiles an efficient dispatch schedule on the basis of this information and their expectation of demand. Generators run to that schedule. The TSO calculates a price for each period and all trading is based around that price.

Self- dispatch
Competition is taking place directly through price signals for the various timeframes. In this context, TSOs are required to provide the network / system security limits within which the market can operate (bidding zones) and to ensure that this level playing field is guaranteed unless force majeure, thus allowing competition to develop freely without undue operational risks or constraints. Retail suppliers contract with producers and/or traders in the market to meet the needs of their portfolios of customers. Generators offer Euro/MWh prices to the market based on their plant characteristics for standard or non-standard contracts and conclude transactions on a bilateral basis or through organised markets. Trading is continuous apart for the coupled day-ahead spot auction which sets the common reference price for forward and intraday markets, and dispatch decisions can be continuously updated in intraday until a "gate closure" specified by the TSO.
Market prices are derived from the trading process i.e. the interaction of supply and demand. At gate closure, a final dispatch schedule is notified by the generator to the transmission system operator.

Balancing actions and re-dispatch
Instead of freezing the market well ahead of real time, the self-dispatch model allows market participants to optimise the final dispatch from an economic perspective, within the security limits provided by TSOs. If, on the basis of the aggregate of final notifications, the system is still out of balance or if internal security limits are breached, the system operator will require some generators or customers to change their actual output from the final notified amounts. This is based on offers to increase/decrease production compared to those notified amounts.

3 Self-dispatch is likely to better meet European policy objectives

3.1 Static efficiency

Central dispatch will be efficient, in static terms, to the extent that parameters submitted to TSOs are fully up-to-date and cover all the various issues with running a power plant. However, typically, information submitted will be a simplified sub-set of the various aspects of running a power plant such as variable costs, start costs and ramp rates. Other aspects such as fuel logistics, staff situation etc. are not usually included and the complexity further increases when markets are coupled, thus taking significant time to calculate the optimum outcome even for relatively standard products. In addition, some power plants need to be optimised according to opportunity costs, especially hydro, since using the resource in one period means it cannot be used later on. Finally there is information asymmetry between the producer and the TSO in that the TSO cannot check that the information it is receiving is correct, which may lead to distortions. In addition, a central dispatch model does not usually allow for an active demand side. Instead, demand is often assumed to be totally inelastic, which may or may not be a good approximation of reality.

It is also difficult to implement market coupling through a central dispatch arrangement and whether markets with self-dispatch can be coupled efficiently with those with central dispatch. This is because in one market the price is calculated from costs and plant parameters. In the other, the price is the outcome of interaction between supply and demand.

With self-dispatch, it is the responsibility of producers to account for all the various complexities in operating a plant and to incorporate this into simple Euro/MWh offers into the market. This provides a better separation between the optimisation function and the network management functions (which could otherwise not be fully performed in a non-discriminatory manner). Unbundling through self-dispatch is thus also an efficient process since producers will be looking to optimise the use of their asset and how this is offered into the market whereas TSOs would naturally be more focused on system security and grid management. It also allows market participants to take a "make or buy" decision for what they need and thereby allow competition with all generators from other markets (up to the coupling limit of the available cross-border capacity).

Self-dispatch also better allows for demand side participation since it is a two-sided exercise which allows producers and retail to interact freely in the forward, day-ahead and intraday markets and to iterate towards a set of prices that fairly reflects both the costs of production and the value of the product. A more decentralised and iterative approach is likely to be more dynamic and to adapt to market evolutions and therefore to provide better incentives on market participants into more accurately reflecting their real costs into their pricing behaviour (being more active and in charge of their optimisation process). It is also less likely to provoke strategic behaviour and inefficient feedback loops because competition is more dynamic.

3.2 Incentives and dynamic efficiency

Dynamic efficiency is a separate question since the optimisation of the system over a specific time period (as performed by central dispatch) is not necessarily the best medium term solution. For the market to guide medium term maintenance and investment decisions, the market also needs to provide sufficient signals over time. Specifically, producers will need to allocate fixed costs across different periods. This is not possible under some central dispatch systems since generators are obliged to offer at short run marginal cost (SRMC). The use of a central dispatch system to provide long run incentives would require that producers must be able to offer on the basis of a price in each period which may exceed marginal costs. In order for the market to perform this function, in situations of relative scarcity, prices need to rise above short run marginal cost levels (opportunity costs providing an incentive to optimise the output when the market most needs it). Whereas in non-scarcity periods, there will be more unused generation and this will drive prices down closer to marginal costs.

On balance, self-dispatch can more naturally integrate the demand side into the market and allow for demand elasticity to be incorporated into the pricing process. This will also be facilitated by the development of sophisticated products which will extend the optimisation choices while still allowing the coupling function to be performed across a variety of cross border markets.

3.3 Liquidity and competition

Central dispatch and self-dispatch are able to create similar price references in day-ahead, on which physical and financial trading can develop.

However central dispatch also needs to be run through auctions for other timeframes and while this can be considered as positive because it creates formal “liquidity windows”, it usually also prevents flexibility and trading closer to real time which is particularly needed for intraday markets.

In addition, with the central dispatch model, the balancing functions are usually also directly managed by the TSO and socialised. This model does not allow competition to develop efficiently and is another form of vertical integration between system operators and generation which should be progressively removed.

3.4 Regulatory incentives to TSOs

The main difference between self-dispatch and central dispatch is largely down to the incentive structure provided to TSOs to resolve constraints. Under self-dispatch, resolving network constraints and balancing the system is a cost for TSOs. The clear unbundling requirements between market operations and system/network operations allow to provide the necessary transparency and contribute to developing the necessary competition between national and cross-border components. Incentives can then be given to control such costs and to efficiently manage competition between all different classes of assets (including demand-side response) and there may also be regulatory surveillance on TSO decisions and on prices offered by all market participants.

Under central dispatch, the TSO will only consider local assets and may decide to resolve network constraints without supporting any cost by constraining a generation unit to remain switched off without any payment.

3.5 Renewable integration

With centralised dispatch, system operators act as a central buyer of all generation. Renewable production will be part of this but with a pricing which is questionable since TSOs are not sensitive to prices. Another issue is at what point in time the dispatch algorithm is run. If the dispatch is made at the day-ahead stage, the volume of e.g. wind production will be very uncertain (both for a central dispatch or self-dispatch model). However the self-dispatch model is better designed to allow RES-E generators or third party service providers to manage the correct volume / price and therefore to efficiently market RES-E generation output without undue inefficiencies and unnecessary costs (market incentive rather than non price sensitive process).

In a self-dispatched system since all producers, including renewables, can respond to changing conditions and modify their prices. The self-dispatch schedule will iterate towards an efficient solution as real time is approached. A continuous market is essential for the proper integration of renewable energy into the market in order to cope with uncertainty about the extent of renewable production. This is particularly the case if it is expected that new demand response or other storage based solutions will be implemented.

3.6 Security of supply

Clearly both systems are just as capable of ensuring security of supply provided that TSOs are able to efficiently set and guarantee the security limits within which the market can operate.

However the mechanisms to achieve this are different. Under self-dispatch, market participants need to have incentives to balance their positions and strong “balance responsibility” obligations. This then means that the role of the system operator remains residual and limited to the perimeter not efficiently balanced by the market; security of supply can be maintained through a sufficient dimensioning of reserves.

Under a centrally dispatched system, the responsibility is much more with the system operator to ensure that there is, overall, a sufficient level of generation capacity. This requires a more centralised process of assessing demand and, probably, additional incentives to maintain a certain amount of capacity available limit transactions in order to manage the network more safely.

4 Self-dispatch is the basis for the EU legislative framework

Legally speaking there are grounds to say that it is a legal requirement on European TSOs to offer a self-dispatch model. This is arguable from a number of perspectives.

- **TSOs are not permitted to buy and sell electricity:** This would make them a "supplier"[2] under the Electricity Directive and, at the very least, require them to set up a separate business – consistent with the ITO requirements in the Directive, to do this task. It can also be noted from previous comments that some potential conflicts of interest may arise from the double objective of TSOs to perform a market task and to manage the network (i.e. the market could be unduly used to manage the network and to decrease system costs as a priority)

- **Freedom of movement of goods across borders:** Unless the central dispatch is conducted on a European basis, the idea of central dispatch would mean that producers would be dispatched by their local TSO and lose the opportunity to sell power across Member State borders.

- **Vertical foreclosure:** TSOs have a dominant position in the transmission business. By also adding a requirement in offering TPA that network users have to submit to have their plant dispatched, they are bundling two separate services: transportation (which is a monopoly) and portfolio optimisation (which is not).

- **A central dispatch model does not meet the requirements in the Directive 2009/72 (Article 15):** This allows that TSOs may have the responsibility to dispatch generation installations. However it must do this "without prejudice to the supply of electricity on the basis of contractual obligations". This means that TSOs must allow for market participants flexibility on how they meet such contractual obligations, including the decision on whether they dispatch their own plant or buy in the market.

- **Central dispatch may be analogous to the, already rejected, Single Buyer model**: It is clearly not the intention of EU institutions to implement a market design based on central dispatch in that the "Single Buyer" market design was removed from Directive 1996/92 when the Directive was revised through Directive 2003/55.

[2] Since under Directive 2009/723: "supply" means the sale, including resale, of electricity to customers; and "customer" means a wholesale or final customer of electricity

- **Central dispatch is not compatible with the EU target model.** The target model, based on cross border exchange of electricity via anonymous two-sided day-ahead auctions run by power exchanges, and a continuous intraday market with trading to H-1, is not compatible with a centralised dispatch approach. In conclusion, a reinstatement of central dispatch would require, at the very least, a revision of the Directive.

5 Conclusion

There are clear risks and constraints associated with the central dispatch model and no real advantages. Central dispatch cannot be envisaged at an EU level without very significant implementation costs and probably massive administrative burdens to adapt the market to such changing conditions. This would largely undo the efforts to introduce competition and to efficiently integrate EU markets. If it had been the intention to implement central dispatch, the Directive and Regulation would have retained the Single Buyer option but this model never demonstrated its overall efficiency and capacity to adapt to changing market conditions.