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DESIGN PRINCIPLES FOR CAPACITY MECHANISMS

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An EFET Discussion Paper

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1 Background

In July 2011, EFET (2011) published a position paper on capacity mechanisms. This document discussed some of the drawbacks associated with this type of intervention. It also set out some fundamental improvements, as follows, that regulators and governments need to make to electricity market design, regardless of whether they are considering capacity mechanisms.

- Integrate renewable energy into the power market design (wholesale market and network infrastructures)
- Develop and improve intraday markets by moving gate closure to H-1 and facilitating cross border exchanges to make the maximum use of interconnector capacity
- Develop and improve balancing mechanisms, also on a cross border basis,
- Allow free price formation in wholesale markets and remove explicit and implicit caps/floors
- Extend real-time metering to enable demand response.
- Remove unnecessary operational requirements and restrictions on generation companies.
- Improve the functioning of the gas market, avoiding take-or-pay obligations and other restrictions on gas fired power plants and ensuring that power plants have flexible access to transmission networks and wholesale gas markets.
- Ensure a stable and consistent energy policy framework for decarbonisation based on ETS.

These recommendations to improve the energy (MWh) market will already strongly promote an ongoing match between supply and demand and encourage the efficient use of all assets (generation and demand-response). Flexibility and reliability are essential to back up the increasing share of intermittent generation. The position paper concluded that better functioning markets could mitigate or remove the need for policy makers to consider capacity mechanisms. EFET (2012) also recently published a position paper on "Efficient Electricity Balancing Market design" which expanded on some of these recommendations in the context of balancing mechanisms.

Some Member States already have capacity mechanisms. Others are actively considering them. This discussion paper therefore seeks to identify and evaluate the main types of capacity mechanisms and arrive at some initial recommendations about their detailed design.

2 Motivations for capacity mechanisms

2.1 Concerns about generation adequacy

EFET's starting point is that, for electricity as in any other sector, the market should ideally perform certain core functions:

- formation of prices so that supply and demand balance,
- allocation of fixed and variable costs,
- organisation of risk management activity, forward trading and the maintenance of spare capacity and storage possibilities,
- provision of incentives for efficient investment decisions.

Policy makers should, therefore, always think carefully before intervening in these areas as there is a clear risk of undermining some of these basic objectives of competitive markets. At the same time, a considerable body of academic literature discusses potential market failures in the electricity sector and the advantages and disadvantages of introducing capacity mechanisms to supplement normal market processes. These possible market failures can be categorised as follows:

- the need for instantaneous balance in electricity systems and the public good nature of grid stability and generation adequacy[1],
- the lack of sufficient demand side participation in the market on an hour-by-hour basis meaning price signals are obscured,
- the excessive risk\uncertainty for investors and the lack of sufficient forward price signals,
- the potential impact of the exercise of market power or politically motivated interventions leading to implementation of price caps in either wholesale markets, or for end users.

Overall, the literature suggests that the combination of these market failures and associated regulatory actions may tend to 'dampen' price signals in electricity markets so that prices fail to increase to an 'efficient' level at times of scarcity. The market may then deliver a sub-optimal level of capacity, or at least a lower level of capacity than policy makers feel comfortable with. In short, there may be a desire from policy makers to encourage a particular level of "generation adequacy". The problem, therefore, lies in designing mechanisms to achieve this that do not, at the same time, undermine other objectives such as the maintenance of incentives to balance, the need for liquidity, and the integrated European electricity market itself.

The preferred approach of EFET is, initially, for regulators to improve market arrangements to mitigate these issues by sharpening price signals in wholesale markets (and improving the ability of market participants to respond to such signals). Such measures will also encourage better liquidity and greater competition in order to deal with both risk and market power issues. Furthermore, the development of new products in both wholesale and retail markets have the potential to reward capacity without necessarily requiring regulatory intervention.

In addition, with the continuing integration of EU wholesale markets there is now a strong need, as discussed in the Commission's recent report on the internal market (EU Commission, 2012), for generation adequacy to be considered as a European issue and that "[Member States] should seek cross-border solutions to any problems they find before planning to intervene."

2.2 The impact of renewables penetration

The generation adequacy issue is complicated by the expansion of renewable generation. Conventional plants will run at lower load factors and have fewer hours in which to cover fixed costs and earn a return. For example, wind generation capacity has a typical load factor of 30%. This may mean that conventional plants that were running at a 60% load factor may in the future only run at a 30% load factor or even less. Broadly speaking this means that spreads would have to be twice as high in the periods they are running in order to cover their fixed costs.

The rate of deployment of renewables is also creating complications in making investment decisions. In particular, the degree of uncertainty about how quickly renewable penetration will occur leads to concerns about the creation of sunk costs for investors. Although this is commercial reality in all capital-intensive industries, the particular circumstances in the energy sector are probably unique in this respect. In particular, the amount and type of renewable penetration is not, as promised, being set by market-based interventions like ETS, but instead result from ad hoc government decisions.

[1] Certainly the need for instantaneous balance does require the existence of a regulated transmission system operator, with the task of residual balancing of the network. It would be inefficient to expect market participants to self-balance on, for example, a second–by-second basis. Therefore the first market failure is generally accepted, and one of the tasks of system operators is to deal with this.

Finally, current methods of renewable support make this problem especially acute. In particular, priority dispatch of renewable production makes life even more difficult for conventional plants. If renewable producers are not incentivised to moderate their own output efficiently, then conventional generation may have to perform unnecessary costly stop-start operations. This may lead to negative prices, which further erode overall income from the market. Alternatively such operations are often carried out at the direction of the system operator without proper remuneration.

It is the view of EFET that one of the key improvements that needs to be made to market design should be the reform of renewable support mechanisms to more market-oriented measures. This reform must be a priority of regulators.

3 EFET criteria for capacity measures

The objective of this discussion paper is to assess different groupings of capacity mechanism against some key criteria relating to the functioning of competitive markets, and the EU target model. Other aspects of EU policy such as the promotion of carbon reduction, renewable generation and energy efficiency are also relevant.

EFET believes that policy makers should avoid disturbing price signals in the energy (MWh) market if and when designing capacity mechanisms. The integration of EU electricity markets through the market coupling process relies on well-functioning day-ahead spot prices. Likewise, effective competition in the retail sector relies on efficient and liquid forward markets. Therefore, where capacity mechanisms affect these, they are also likely to have an impact on the EU internal market. Dilution of MWh price signals could also damage incentives to invest in reliable and flexible power generation means. These characteristics are increasingly important as the European market moves towards decarbonisation with larger proportions of renewable capacity.

Therefore, the EFET criteria for evaluation are that capacity mechanisms should ideally:

- demonstrably enhance adequacy and reliability;
- avoid distortion or dilution of price signals from energy (MWh) markets;
- be transitory in nature, with a natural dynamic and process towards phase-out of their price signals as generation adequacy improves;
- focus on time periods far enough ahead to limit overlap and interference with forward and future markets in electricity;
- facilitate an active demand side and promote wide consumer engagement through willingness to pay for reliability and/or price stability;
- be non-discriminatory, by taking into account the contribution of non-national generation through interconnection which may decrease local needs;
- be non-discriminatory between new and existing facilities and between different technologies

- minimise centralised management processes and maximise the scope for independent decisions by market participants about their off-take and delivery obligations, so that market dynamics have a chance to function;
- minimise risk of regulatory failure and of need for redesign (e.g. by avoiding overly complicated mechanisms)
- use market-based remuneration mechanisms (e.g. by means of auctions, tenders, or subscription obligations);
- be suitable for EU wide / harmonised application.

The next section applies these criteria to a non exhaustive list of different types of capacity mechanism design that have been either used in practice or proposed in policy documents or academic work. A case-by-case analysis should of course prevail in order to detect and correct the potentially harmful effects of each type of mechanism if badly designed or implemented.

4 Evaluation of capacity remuneration measures

4.1 Consumer based measures

Consumer based measures would operate under existing wholesale market arrangements. It would mean that consumers themselves would subscribe to the amount of capacity they would wish to use. This can be achieved through new innovative tariff structures between retail suppliers and end users as described, for example, in Doorman (2005). Such an approach requires smart meters to be in place in order to attribute consumption peaks accurately to individual consumers. In most cases hourly meters are currently only used for large industrial and commercial consumers. Although several Member States have plans to extend smart metering to all consumers, this is not likely before the end of the decade.

Smart metering allows new tariff arrangements. For example, consumers could be billed on the basis of both their MWh consumption and their maximum MW usage. This method was used frequently in the initial years of electricity supply and is known as a “Wright tariff” (Stoft (2002), p13). Such an approach could either be compulsory or voluntary. The main questions relating to this type of tariff are the time needed to develop such a scheme, the difficulty to assess its likely effect at a national level and the determination of responsibility and penalty arrangements if the consumer exceeded its subscribed capacity.

One possibility is that the consumer would be physically constrained from exceeding the subscribed amount. A device would need to be installed that would restrict supply in this situation and the consumer would have to turn off some appliances. This would allow the consumer to choose its own degree of reliability. This may, however, be considered as unacceptable in case of exceptional weather conditions. More sophisticated equipment could also be installed that would automatically dim lights or temporarily turn off freezers, heaters etc. Such measures would probably be more acceptable for non-domestic consumers rather than households and would allow for an efficient response to the price signals coming from the market for both energy and capacity.

Alternatively retail suppliers themselves would be financially responsible for capacity overruns compared to the capacity subscription they would be obliged to make. They would then be billed by the system operator in the same way as for existing imbalances. It would then be up to suppliers to decide how they would deal with this, and how the costs of this would be passed on to consumers. One outcome might be that, as for some mobile phone or broadband contracts, there would be a specific tariff for units that were consumed in excess of their subscribed amount of capacity. This tariff would need to cover the costs of supplier in purchasing the necessary additional energy that was needed over and above the consumers' capacity subscription, or the cost of purchasing options.

Evaluation against criteria

An evaluation of this grouping of mechanisms is set out in the table below. In general these approaches are viewed favourably to some extent, as they are less likely to disrupt wholesale markets and are in line with existing EU market design.

	Commentary
Enhancement of adequacy and reliability	Consumer based approaches should be capable of providing a demand side signal for adequacy and reliability. It requires governments and regulators to accept the outcome of such market based processes and to encourage market participants to react accordingly.
Avoid distortion of MWh and retail market	The main question is the extent to which such contracts are voluntary, or compulsory. In principle, consumers should retain the ability to choose between different contract types.
Clear transition\phasing out of price signal when adequacy is met	The development of such purely market based rewards to capacity should result in a sustainable situation without further intervention. No sunset clause would then be needed.
Focused far into the future beyond liquid curve	Such measures would not affect traded markets significantly. It may require new wholesale market products to be developed.
Active demand side\consumer	These measures will enhance consumer engagement through response to price signals.
Non-discriminatory by technology or nationality	Both generators and retail suppliers from other Member States would be able to participate in such markets. Unrestricted and non-discriminatory access to transmission infrastructure is required as expected from the energy-only target model.
Decentralised decision making	These approaches would retain the existing model of bilateral trading and contracting.
Market based mechanism	These mechanisms would largely rely on market-based elements although the imbalance regime would still have to be regulated for the capacity part (in MW) in case of compulsory regime.
Suitable for EU\regional application	These mechanisms generally do not raise significant issues for wider EU application. In principle such market based approaches could be applied across the board.

4.2 Administered adjustments to imbalance arrangements

Sound market design principles should already ensure that companies have suitable incentives to balance their positions. EFET recently published a position paper on balancing arrangements. It argues that that balancing prices should be set at the marginal accepted price and apply to both sellers of balancing energy and those in imbalance (EFET, 2012).

If imbalance signals are established correctly and if price signals are sufficiently high, market participants will organise themselves to maintain supply-demand equilibrium. They are also likely to take steps to manage their own exposure to unexpected events. For example, if the overall situation is expected to be tight, prudent market participants should be able to take action so they will be "long" rather than "short" at gate closure. This might be through physical assets, or through contractual arrangements. If market participants are "long" in aggregate this, of course, then creates a need for the system operator to regulate downwards. Likewise when the system is not stressed, participants may be more inclined to go into gate closure with a "short" position. Hence, additional upward regulation would be needed at those times. Efficient balancing markets should encourage the development and maintenance of flexible and reliable capacity by placing a higher value on such resources in stressed situations.

Some literature argues for an additional adjustment to be added to imbalance prices in particular circumstances which are indicative of system stress, for example, when tertiary reserve is activated by the system operator (so-called operational reserve pricing). Proponents of this approach such as Hogan (2005; 2006; 2010; 2012) argue that prices need to be adjusted when operational reserves are activated in market timeframes or other non-standard TSO actions are taken, including voltage reduction. It is argued that, if this policy is made sufficiently clear and credible, the likelihood is that the imbalance prices never actually reach the possible elevated levels. The threat of being subject to such additional penalties means that market participants will always avoid being in negative imbalance at such times.

Such an approach is being discussed in the Texas electricity market ERCOT. This follows the events in February 2011 when the system operator had to implement rota cuts during extremely cold conditions. However, this incident was not the result of insufficient capacity. Instead, incentives were not sufficient for plant operators to ensure that existing plants were available. As a result, the price cap in the ERCOT market will be raised to $5000/MWh in June 2013, $7000/MWh in June 2014 and $9000/MWh in June 2015.

Evaluation against criteria

In general, adjustments to imbalance arrangements of this type could improve short term security of supply within the framework of current market arrangements. However the concern about such adjustments would be that they imply a disconnection between supply-demand fundamentals and the prices in the market, if a significant element of the price becomes administered. Additional regulatory uncertainty is then added which could affect market liquidity. In summary there could be significant issues in going beyond the principle of marginal price imbalance settlement. In addition, most of the academic work is centred on adjustments being made to market designs without significant demand-side bidding and it is difficult to assess the amount of work needed to harmonise such a design in a multiplicity of interconnected countries.

	Commentary
Enhancement of adequacy and reliability	Adjustments to imbalance prices would add to the incentives on market participants to balance.
Avoid distortion of MWh and retail market	Ad hoc administrative adjustments to imbalance prices may distort the market. There need to be clear and well understood rules about how adjustments to prices are calculated, and how these calculations could be made consistent at EU level.
Clear transition\ phasing out of price signal when adequacy is met	There is no clear route to withdrawal of such adjustments. They may also require to be combined with other measures – e.g. consumer based measures for maximum efficiency.
Focused far into the future beyond liquid curve	Such measures are unlikely to affect forward traded markets.
Active demand side\consumer	These measures could enhance consumer engagement through response to day-ahead price signals, which would reflect the enhanced incentives to balance positions. However this approach is more indirect than developing a spontaneous demand response.
Non-discriminatory by technology or nationality	Such adjustment would mean market participants would need to manage their portfolios more efficiently. Non-discriminatory access to cross-border transmission is needed across the whole range of timescales for the energy component only, which is coherent with the IEM target model for forward, day-ahead and intraday.
Decentralised decision making	These approaches would retain the existing model of bilateral trading and contracting
Market based mechanism	This mechanism introduces an administered element to price formation in the balancing regime.
Suitable for EU\regional application	There would potentially be a multiplicity of variants in terms of adjustments and harmonisation/ consistency at EU level could be complicated. There would need to be co-ordination between Member States as to how such adjustments to balancing arrangements would be made in order not to create arbitrage opportunities.

4.3 Strategic reserve

The concept of a "strategic reserve" is already used in some Nordic countries as described by NordREG (2009). In this model, the system operator procures a tranche of reserve capacity beyond what the market would normally expect to need for real time grid operation. This reserve is then available to be activated in the event that it is needed for certain conditions. These conditions would include avoiding demand curtailments. The key issues here are related to the impact on market prices in the day-ahead timeframe, but also in intraday and balancing, the predictability of such activation, the potential conflict of interest of TSOs intervening in price formation and commercial flows, and the timing of such activation. A key concern is that the strategic reserve is activated so as to avoid high prices from occurring, thus preventing any form of support for new peak plants to emerge from market prices (entry barrier and potential barrier to innovation).

Currently in the Nordic market, the strategic reserve may be activated at the day-ahead stage, and it is priced just above the highest offer in the day-ahead market. This is because it is designed around old and less flexible plants that require a dispatch decision to be made day ahead. This, however, risks undermining the normal market process, particularly during the intraday phase.

The Nordic market also allows for a second day-ahead auction if there is no match between supply and demand. This may prevent high prices from emerging from the normal price formation process and allows for the activation of strategic reserve to be delayed in the event that other resources or a further demand response can be provoked.

A first improvement to this system would be for the strategic reserve to be activated as late as possible in order to give intraday markets a chance to resolve the supply-demand situation. For example, additional demand side resources may become available during the intraday phase that were not available or offered in the day-ahead market. However this would require the strategic reserve to be based on more flexible assets than is currently the case. Stronger requirements would need to be placed on what type of resources qualifies. A better measure would be to progressively phase out this transitory approach and to let the market function, or to redesign an adequate and non-discriminatory scheme.

A key issue with strategic reserve is indeed the price at which it is offered into the market. The concern is that the spare capacity overhangs the free development of market prices and companies' investment decisions in capacity (the so-called slippery slope). This will also damage the value of the remaining assets. A lot, however, depends on the rules for activation, and its exact impact on prices, which may be limited in case of relatively stable prices due to high amounts of hydro generation.

Another issue with the Strategic Reserve concept is that this reserve is not activated in case of moderately high market prices when the variable costs of this reserve are below such market price. It is argued that this results in a sub-optimal dispatch. This becomes problematic if large quantities of strategic reserve are contracted. It may also result in political pressure to activate the reserve at only moderately high prices, which would undermine its objectives.

If companies expect the reserve to be activated too often, and with the objective to suppress the normal development of prices, the existence of the reserve will provide a disincentive to investment and also to ordinary forward contracting. The existence of a strategic reserve may also be seen as a vehicle for opportunistic interventions in the market. For example, policy makers might take a view that if consumers are paying for a strategic reserve, they should not also have to be exposed to the consequences of prices spikes in day-ahead markets. This would rather defeat the object of the intervention and interfere with the normal dynamics of market and competition. This means that a strong commitment to limit the interference of such a mechanism is needed to support this approach, even on a transitory basis.

The essence of the strategic reserve approach is that the energy market remains largely unaffected and that the energy market remains the sole driver for new investments. This also means that the strategic reserve approach cannot be adopted as an enduring solution if there is a strong conviction that the energy only market does not provide a sufficient level of adequacy: i.e. that capacity must be priced explicitly.

Evaluation against criteria

The strategic reserve approach could provide a potential transitional solution to concerns about generation adequacy. However there are concerns with respect to its potential to distort prices, as well as long terms effects in markets dynamics and market participants' behaviour. Various issues need to be clarified and checked on a regular basis in order to limit the negative effects of such mechanisms.

	Comment
Enhancement of adequacy and reliability	A strategic reserve can be used to ensure adequacy and reliability as a transitory measure in order to maintain additional capacity but it must be a real strategic reserve that sits outside the market and is not activated opportunistically by regulators or the system operators. Its long term effects on markets should be assessed.
Avoid distortion of MWh and retail market	Strategic reserves might distort peak prices if used opportunistically by government, TSOs or regulators, and this would be counterproductive as these price signals are crucially needed for the normal market functioning and as part of the incentives for investments. Clear rules about, and transparency of, the pricing of such a reserve are needed, and activations periods should be limited and reported in an aggregated mode. These measures would still introduce substantial regulatory risks.
Clear transition\ phasing out of price signal when adequacy is met	In practice, the use of strategic reserve has tended to be prolonged beyond the original intention. They may be phased out as governments switch towards purely market-based solutions, but there is no natural process in this regard.
Focused far into the future beyond liquid curve	Such measures need not affect traded markets significantly. However they may raise concerns about the risk of regulatory intervention.
Active demand side\consumer	Strategic reserves may require additional measures to also enhance consumer engagement through response to price signals as they may tend to prevent this evolution by limiting the formation of high prices.
Non-discriminatory by technology or nationality	The strategic reserve is more suited as a national intervention with direct impact on interconnected markets and with no possibility for foreign generators to participate. Activation of strategic reserves, if not strictly controlled, would indeed inevitably distort prices in other Member States.
Decentralised decision making	The approach is centralised and potentially constrained in terms of procurement, depending on whether specific characteristics are required to qualify for the procurement process. However it is compatible with a model of bilateral trading.
Market based mechanism	The mechanism is not market based, apart from the procurement process, assuming that is run in a non-discriminatory manner.
Suitable for EU\regional application	If all Member States have a separate strategic reserve, without any co-ordination, then there will be a duplication of capacity and higher costs. Some degree of coordination about the amounts and rules is required. If not, there is a risk that different pricing and activation rules will create further uncertainties for new assets and new entrants since market prices would be seriously hindered

4.4 Mechanisms with capacity certificates

This grouping of capacity mechanisms relies on obligations being imposed on final customers or their retailers and by defining “capacity rights or certificates” as a specific product. It usually involves some form of a certification process. It can be focused both on generation and demand side. The objective of this approach is usually to derive a Euro/MW capacity price that covers the relevant period of stress for the system.

The key challenge in these models is ensuring a coherent and non-discriminatory market design. Also, all sorts of variations can be defined, depending on the exact market design in terms of whether there is e.g. participation of the demand side or not, or if there are specific rules for different technologies. The means to certify capacity rights and to control the availability and effective contribution of certified plants are also important. Finally the penalty or imbalance regime between the certified rights and the reality, or between ex-ante obligations and the ex-post supplied amounts. The model may also be centralised or decentralised.

A decentralised model has been proposed for the French market under the loi Nome (Ministère de l’Écologie, du Développement Durable et de l’Énergie, 2012). Meanwhile the model used in the PJM market in the USA is also partly decentralised since companies are allowed to self-supply ‘capacity’ without going through the centralised process (PJM, Reliability Pricing Model). In the decentralised model, generators are required to be certified by the transmission system operator. Meanwhile retail suppliers have to buy these capacity certificates from generators so that a certain amount of capacity is covered. The rules for calculating the amount which is considered to ensure generation adequacy are published so that each retailer can assess the amount of rights needed for its own activities. Those rights can then be bought on specific capacity market at different timeframes, starting from four years ahead of delivery. In order to provide an analogy with the energy market, a new “capacity balancing perimeter” is defined so that each retailer is entitled to balance its perimeter. An ex-post calculation of imbalances is made based on each retailers’ real portfolio. This allows retailers to balance their perimeter in different ways by either developing certificates of their own (generation or demand side) or by buying certificates in the market. This design avoids a centralised process being needed to forecast peak demand.

In the decentralised model some incentive\penalty regime is required to ensure that retail suppliers actually fulfil the obligation placed on them to purchase the required amount of certificates. This, in effect, amounts to a supplementary imbalance process, but for capacity rather than energy. However it is not clear how the price for this would be determined. One suggestion is that the penalty would cover the costs of an OCGT, but this raises the issue of how the coverage of fixed costs would be established.

In *centralised* models, an agency is put in place as the counterparty for capacity contracts. This may be the system operator or a totally separate entity. Suppliers are not permitted to cover their own capacity requirement but instead are required to cover the costs incurred in the centralised procurement of capacity. A centralised model has been proposed for the GB market (Department of Energy and Climate Change, 2012).

Any mechanism that looks to support generation capacity needs to also encourage capacity contracted to be reliable and available to generate at times of system stress. Therefore for both the centralised and decentralised models, penalties are being discussed that may be applied to generators which are not available. This is to ensure that the objective of adequacy is effectively monitored and met.

- The model discussed in France allows control of the availability of certified generation capacity through the existing obligation to offer all available capacity into the balancing market (for any capacity in respect of which the energy has not already been sold). If generators in receipt of a capacity mechanism payment are not available during the stress period, a penalty will be calculated according to the defined rules for not meeting the requirements of certificated capacity.

- However another possibility is that non-performance would also require repayment of a part of the capacity premium. This is the model being discussed for the GB market. However as yet it is unclear what proportion of the annual payment this would mean. Some models suggest that an administered uplift/price might also be considered to reflect the cost of substitute resources or the "value of lost load".

Evaluation against criteria

These certification models are effective in delivering additional generation capacity. However the main concern with such mechanisms is the interactions between the capacity market (MW) and the energy (MWh) market.

The first obvious impact is that where additional capacity is supported in this way, it will inevitably have a general negative effect on energy (MWh) prices. This is because once such mechanisms exist, some of the scarcity signals from energy (MWh) prices will instead be priced through the scarcity of the "capacity mechanism". This is common with most of the other mechanisms and the dynamics of it will depend for each type of capacity. For example, for capacity with low capital costs but very high variable fuel costs, then scarcity may still be priced in the energy market. But if capacity wouldn't find sufficient remuneration in the energy market, the scarcity will be priced in the capacity market instead.

In addition, there could be further consequences depending on the exact market design. For example, if a plant is compelled to run at particular times in order to retain the capacity payment, this could lead to the perverse result of reduced or even zero EUR/MWh prices at the most "stressed" periods. Depending on the exact design there might be a variety of interactions with market coupling or other markets, as for any other capacity remuneration mechanism.

The penalty arrangements also raise uncertainty issues, similar to the discussion about administered adjustments imbalance prices. The penalty regime, in effect, constitutes a set of "shadow" energy prices. It would not be desirable for generators to be largely responding to administratively determined incentives and penalties rather than market prices.

	Commentary
Enhancement of adequacy and reliability	These mechanisms have been demonstrated to deliver additional generation capacity e.g. in the US. Ensuring that this capacity is sufficiently reliable is often more complex.
Avoid distortion of MWh and retail market	The general design and the penalty regimes need to avoid diluting the prices in the MWh market.
Clear transition\ phasing out of price signal when adequacy is met	Ideally the capacity market should only exist to 'pick up the slack' if the energy market fails to signal scarcity properly. If correctly designed, the mechanism may still allow the energy market to function correctly and to deliver most or all of its normal signals.
Focused far into the future beyond liquid curve	If the capacity market operates in forward timescales, it may distort markets because market participants will have to account for regulatory decisions on procured capacity as well as the normal supply-demand fundamentals. Certificates should be issued far in advance and refer to a delivery period ahead of energy markets (typically four years or more).
Active demand side\consumer	DSR and other 'alternative resources' (interconnectors, storage, etc.) should be able to participate in the mechanism alongside conventional generation. However a simple demand response based on reaction to MWh prices may be discouraged if too much capacity is available and if energy prices are not volatile enough.
Non-discriminatory by technology or nationality	These mechanisms are likely to discriminate by nationality if interconnectors are not taken into account.
Decentralised decision making	Decentralised models are possible.
Market based mechanism	The level of reliability has to be prescribed centrally by the TSO/regulator/government, but the efficient price of capacity and the optimal mix of resources are revealed through market-based mechanisms (auctions, bilateral negotiations, etc.).
Suitable for EU\regional application	Cross-border implementation will be problematic as this would severely interfere with cross-border capacity allocation processes (necessity to book cross border capacity, discriminatory premium to market players facing retail obligations, impossibility to control effective commercial flows due to market coupling, etc.). The contribution of interconnection and of neighbouring countries should be taken into account implicitly by adjusting downward the national adequacy level assumption.

4.5 Option contracts

Where energy markets are allowed to function properly they will, as for other commodity markets, develop products that will reward generation capacity directly, even if it is not running, if there is a financial incentive to do so. In particular, option contracts can be developed that give the buyer the right, but not the obligation, to buy at a particular strike price. These contracts are already available in the market and do not necessarily require further regulatory intervention to function freely.

As renewable penetration increases and is integrated into wholesale markets, such contracts should become increasingly attractive if prices in day-ahead, intraday and balancing markets become more volatile and sufficiently high. If RES producers also face imbalance cash out prices, the contracts should achieve an even better penetration. This is because retail suppliers normally have contracts to supply customers at a particular fixed price. Most of this volume is sourced in forward markets. But there is usually a sizable and unpredictable residual amount that will need to be purchased closer to real time. An option contract at a particular strike price to cover these volumes allows a retail supplier to hedge against potentially volatile day-ahead, intraday and, more importantly, balancing prices.

Meanwhile generation companies are natural sellers of such options. A power station is effectively an option to produce electricity at a particular strike price. The option fee paid by the retail supplier to the power company therefore pays for generation capacity without necessarily meaning that the plant needs to run to earn revenue.

The use of options would also be encouraged, the more renewable producers themselves sold their output on the market. As they would be potential buyers for option products, provided that they are correctly integrated in the overall market design and face the same system and market costs as other forms of generation assets. By combining the renewable output with an option to purchase from a conventional generator, the owner of a renewable plant would be able to “lock in” a hedged return from the market.

An option product can be physical, meaning that the seller has to generate power to fulfil the contract. Whereas a financial option means that the seller can fulfil the contract by compensating the buyer for the price of power in the reference market, usually the day-ahead market. If the option was purely financial, there is no obligation to produce physically.

In this case the generator can choose whether they meet the option either by generating, or by simply paying the counterparty the difference between the reference price and the strike price. In general, however, it is usually expected that sellers of financial options would back up any financial obligation with a physical position.

Arguably, financial options are suitable for both national and, even more so, cross-border application. If foreign providers sold capacity, they would have a strong interest to produce (even from another zone) to avoid spikes. If they did not produce, there would be less export from their original zone to the area where the option is sold, and thus there is a higher risk that the strike price will be exceeded, reducing the value of the option sold in advance.

Spontaneous development of option trading is reliant on energy markets that have a sufficient degree of liquidity and volatility, with sufficient financial incentives for issuance of such products to become profitable. Market participants also need to have confidence in free price formation and the avoidance of regulatory interventions. To the extent that option markets develop, they will, in fact, help constrain the volatility in spot markets. Instead it is the *potential* risk associated with volatile prices that is sufficient to provide the incentive to contract forwards in this way.

Some capacity market designs, e.g. the Reliability Options model used in New England discussed by Cramton and Stoft (2008), impose a *requirement* on market participants to purchase options, or instead give the responsibility to a central agency, e.g. the system operator, to purchase these on behalf of consumers. In the New England model, the TSO is required to buy a call options from generators at a certain reference price (hourly price of day-ahead market). The strike price of the option is then fixed at a pre-determined level e.g. $300/MWh. Generators have to pay back to the TSO any revenue from prices above $300/MWh that they receive from the energy market which are treated as “Peak Energy Rents”. Meanwhile generators receive an option fee that amounts to a payment relating to capacity.

The cost and settlement of this option is passed on to consumers via network access tariffs. This protects consumers against the risk of price spikes since they will receive\pay, via the TSO the difference between the strike price and the market price. The contracts give incentives for reliability since generators selling the options have to pay the difference between the strike price and the spot price if they do not generate and get the market price. In the case of US markets, in which this model is used, the reference market is the price in the day-ahead market. However there may also be additional penalties in the event of non-availability, namely the repayment of part or all of the option fee.

Such models would possibly need to be modified for use in the European market design. For example, as EU markets will evolve towards continuous intraday trading, the reference price for non-delivery might need to be based on the imbalance price or some intraday composite price. Generators from abroad would also require a fully integrated intraday and balancing market as a precondition for efficient coupling with neighbouring markets. Likewise the idea that the TSO is a participant in the options market would have to be examined in the unbundled European context.

In principle it could be possible to design an option requirement based on a decentralised approach (similar to the decentralised certificate model above). This would mean that participants in the market would be required to have in place a certain amount of either physical or financial option contracts in place. The requirement could be continuously adjusted to reflect the state of the market and expectations about the state of the system as described in Oren (2005). There may then be a centralised platform for additional purchase\sale of options as a fall back arrangement for businesses that are not sufficiently contracted forward.

Evaluation against criteria

Trading in free options contracts is a normal market response to the issue of rewarding the capacity to produce without the seller of that option necessarily needing to produce anything. So free options contracts is a natural development of the market which meets some of the requirements of generation adequacy. Ideally these would develop spontaneously from the market if the price signals were allowed to correctly reflect scarcity.

More centralised and regulated models, as used in the USA market, are a possible means to develop options trading to a scale that would significantly contribute to generation adequacy, by creating a centralised or decentralised buy side in some circumstances.

However there are doubts whether such centralised models are compatible with the organisation of some existing wholesale markets in the EU. A key issue is that a compulsory option approach replicates, via a regulated process, what market participants should already be doing in European markets. Both retail suppliers and generators already have incentives and mechanisms to hedge with a variety of forward products. And it is the task of retail suppliers to protect their customers against price spikes. A decentralised model, largely based on voluntarily trading of options could be a more workable model in the EU context.

Some argue that normal hedging can still operate underneath a regulated process, if the strike price of the regulated contracts is high enough. However there remains the issue that generators writing the options would have difficulty in managing the risk of non-delivery, for example during maintenance periods. The general effect on adequacy and interference on normal contracting is also difficult to assess. This would apply to two sets of contracts if there were both a set of bilateral delivery contracts and a centralised set of reliability options.

	Comment
Enhancement of adequacy and reliability	An option model could be designed that would provide incentives for capacity payment. This model would generally face the same uncertainty in terms of efficiency and definition of the exact elements of design as other types of model.
Avoid distortion of MWh market	If a compulsory model is used, the strike price needs to be sufficiently high so as not to displace existing hedging activity. Any penalty regimes would also have a potentially distortive effect on the MWh market and detailed impacts would need to be further analysed.
Clear transition \ phasing out of price signal when adequacy is met	The option model would ideally be based on voluntary contracting in order not to require additional regulatory intervention.
Avoids disrupting forward\retail markets	The option approach would need to be a voluntary market to avoid disrupting existing markets.
Active demand side\consumer	In principle demand-side participants could set options to reduce. But a regulated market could overlap with existing interruptible contracts.
Non-discriminatory by technology or nationality	A market player from abroad could participate freely through physical or financial options. This would be more complex in case of compulsory regime.
Decentralised decision making	Yes, a voluntary option and bilateral contracting is possible alongside the centralised scheme or alone.
Market based mechanism	The scheme is largely market based, although it would potentially contain elements of regulatory risks and of negative market impacts in case of compulsory scheme.
Suitable for EU\regional application	A regional or European scheme is already possible through free contracting. A compulsory regime would be much more complex to set up and could generate arbitrage opportunities.

4.6 Integrated capacity and energy market

This model of capacity mechanism is similar to that described in section 4.4. However instead of seeking to produce a capacity price covering a period of system stress, it instead seeks to derive a Euro/MW price for each individual hour of the year. The model, which has not been tested yet, also includes an upward adjustment to imbalance energy prices for each balancing period so that these reflect the desire of policy makers for additional reliable capacity. Thus there is the mirror image of the capacity price also reflected in energy prices.

The model is centralised and it starts with an auction for capacity which starts at least four years before real time. There is then a secondary market so that market participants can adjust the level of capacity they commit to providing, for example if they have a maintenance programme. This secondary market continues up to the day-ahead stage.

At the day-ahead stage there is a second centralised auction for any residual capacity requirement including necessary reserve products for the following day. This produces a set of hourly prices for capacity for the following day, in addition to the hourly energy prices. This auction is simply an extension of the existing centralised procurement of tertiary reserves which already exists in some markets.

Generators then receive their additional revenue either from the energy market if they produce and sell energy (MWh), or they receive the capacity (MW) payment, even if they had successfully sold capacity in either the auction or secondary market. If they do not sell into the energy market, generators would benefit from the capacity price for that hour, provided they demonstrate that they are available to produce.

Given the uplift to imbalance charges, there will be strong incentives for market participants to balance their positions and to be available whenever the system requires. However system operators will buy a certain volume of MW more than expected demand in each hour to reflect both the requirements of policy makers and the need for operational reserves.

Finally, there are penalties if generators become unable to provide the capacity they have promised. If this occurs before the day-ahead stage, they have to buy out their obligations in the secondary market. If they declare themselves unavailable, the penalty corresponds to the day-ahead price for capacity for each hour. If the committed generator fails and cannot be dispatched or is demonstrably unavailable, it will be penalised based on an uplifted imbalance price which should reflect the additional value placed on capacity.

Evaluation against criteria

This model is effectively a hybrid of the approaches described in sections 4.2 and 4.4 and requires some evolution in the balancing market design. It aims at emphasising the incentives to be available and to generate when needed through the uplifted balancing prices. It has the same effect of diluting market prices between two different mechanisms (MW and MWh) and has the same drawback to maintain an administered element to the process both in the decision about the amount of capacity to be procured and in the adjustments made to imbalance prices.

	Comment
Enhancement of adequacy and reliability	Such a model has not previously been used. It aims to provide incentives for both additional capacity adequacy and for reliability through the evolution of imbalance prices.
Avoid distortion of MWh and retail market	MWh prices are retained by adjustments to imbalance prices. But as for model 4.2 and 4.4, this introduces an administered element which will need to be transparent and understood.
Clear transition\ phasing out of price signal when adequacy is met	More efficient energy market should mean that most capacity is rewarded through the energy market as today, with only a residual actually receiving a MW based payment. However the scheme is not meant to be phased out.
Focused far into the future beyond liquid curve	Such measures will affect forward traded markets by introducing a significant administrative element to price formation. There need to be clear and well understood rules about how adjustments to prices are calculated.
Active demand side\consumer	MWh prices will be adjusted upwards to be higher in tight periods and encourage demand response.
Non-discriminatory by technology or nationality	Higher MWh prices will ensure that non-national generation will benefit to a certain extent, via the effects of market coupling.
Decentralised decision making	Although the capacity procurement decision is centralised, market participants retain control over their own assets and position up to gate closure as today.
Market based mechanism	Transparent auctions and secondary trading will determine capacity price. This mechanism introduces an administered element to price formation, penalty regime and overall design.
Suitable for EU\regional application	The mechanism could be extended to wider application. However, this would require full harmonisation of reserve procurement rules and evolution of balancing rules, as well as most aspects of market design.

Conclusion

This document has sought to examine a number of capacity mechanisms. This is only a preliminary assessment and detailed design would need to be looked at carefully in order to detect the real dynamics, effects and potential impacts of any of these mechanisms. However based on this assessment, EFET has the following recommendations for next steps in the EU electricity markets:

- Policy makers and regulators should implement the recommendations from the previous EFET papers to **improve the functioning of the energy (MWh) market**, whether they choose to develop a capacity mechanism or not. Market participants need to have **appropriate incentives to balance their positions** at gate closure and a harmonised approach to balancing based on a single marginal imbalance price needs to be implemented.

- A **realignment of European environmental policy around market based measures** is a high priority. Renewable electricity producers must become full-fledged participants in wholesale markets. The commitment of the EU to the Emission Trading Scheme as the central plank of policy needs to be reaffirmed.

- **If implemented, capacity mechanisms should be designed to 'work with the grain of the market'** and in a way that does not obstruct the correct functioning and integration of European energy markets.

- **If implemented, capacity mechanisms should be designed to only tackle the adequacy problem. This means that the capacity mechanism will drive the amount of installed capacity, but not the type of generation technology.** The energy market (including the balancing market) will drive not only the dispatch of all resources but also determine the type of technology for new investments. This also means that it is not to be expected that the capacity mechanism will result in a full coverage of all fixed costs of a new power plant and that the energy market will continue to be important in this respect. This also means that the capacity problem should not discriminate between different types of technology, or between existing and new capacity.

- **Incentives on companies should generally be positive rather than negative** if capacity mechanisms are introduced. Generators should be incentivised for their availability rather than being penalised for their unavailability. Administratively determined penalties for non generation should be avoided. This is likely to distort price formation and cross border trade, leading to inefficient dispatch decisions. The energy market (including the balancing market) will by itself set the correct incentives to generators to be available and to produce in periods of scarcity / high prices. Some sort of reasonable reimbursement of capacity payments in case of low availability is possible. This could be a yearly process where actual availability is compared with a reference availability (for example 85%). Likewise, power plants with a higher measured availability could be rewarded.

- **All administratively determined outcomes need to be well understood and transparent** to avoid introducing regulatory risk and damaging the integrity of price formation.

- Compulsory trading of options **may duplicate existing trading practices** in some Member States and undermine existing forward markets. A decentralised mechanism may be more suitable for well-functioning markets with a centralised market as a back-up. However it may be appropriate in some cases to initially have a centralised procurement agency to kick start the mechanism.

- **Full interconnector capacity needs to be taken into account in any national capacity assessment**. This should be done by decreasing the overall system needs of the maximum contribution of interconnections (also taking into account other interconnected networks' available capacity margins). Market coupling means that capacity will always export to the areas where the energy is the most needed.

- **The European Commission should consider developing guidance for coordination of generation adequacy assessment and consistency of capacity mechanisms across borders**. A regional approach to such assessments would be recommended.

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