Consultation on possible models for a Capacity Mechanism

Response of [redacted]
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Electricity market reform

The objectives of electricity market reform are to stimulate investment in generation and achieve more competition in supply, while ensuring a steady reduction in carbon emissions. These objectives are in conflict; trying to achieve all three at the same time without disrupting energy markets is extraordinarily complicated. Unsurprisingly, policy is moving forward very slowly. On capacity charging, the Government has accepted the case in principle and has expressed some preferences for the mechanism, but has not been able yet to come to firm conclusions.

More fundamentally, the Government is unsure whether to improve the workings of the electricity market or to solve the problems identified by intervening more. For example, the proposed solution to the weakness identified in the wholesale market is to require the Big Six to sell 20% of their generation output. As these companies have a higher share of the retail supply market than of generation, the implication is that they will effectively be forced to sell power to each other. This will do little to improve competition in the wholesale market. Requiring a complete separation of retail supply and generation would be better, of course, but that would make solving the investment conundrum more difficult for the reasons discussed above.

Similarly, the UK Government is attracted by capacity charges but does not know whether to implement them through a market solution or through central administration[2]. This uncertainty is surprising, since the evolution of electricity markets is well-advanced and the economics of the two-part tariff are well understood. The key is to keep in mind the consumer as well as the producer. For the consumer, availability has a value separate from consumption; the willingness to pay for availability, though, will vary considerably. The value is avoiding the risk of paying higher prices at peak periods or avoiding disruption to service (power cuts)[3]. It is the job of markets to balance the varied interests of consumers and producers; central administration is likely to be second best.

A strategic reserve

An efficient capacity charge would directly or indirectly encourage consumers to reduce their peak demand as well as encourage additional investment in generation capacity[4]. This would seem to rule out the strategic reserve option, which the Government favours, because it would not be price-sensitive[5]. Moreover, the proposal that the strategic reserve be activated when the market price reaches a certain level is likely to reduce the willingness to invest in new

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[1] While this response has been discussed with colleagues [redacted] the views expressed are personal.

[2] *Planning our electric future*, EMR White Paper, section 3.2 pp 61-80, DECC July 2011.

[3] In the power sector, this is termed the value of lost load (VoLL), and is conventionally assessed to be very high – thousands of pounds per MWh.

[4] In principle, the capacity charge mechanism should incentivise load-shifting through storage of electricity as well as demand management and investment in generating capacity.

[5] The EMR White Paper proposes that the strategic reserve could include demand management, but it is not efficient to limit the short term response of demand to price to extreme peaks.

generating capacity, since it is precisely when the price is high that generating is most profitable. The bigger the strategic reserve and hence the lower the price at which it is activated, the greater the deterrent effect on investment.

It is also unclear how the Government expects the size of the strategic reserve to be optimised in the absence of market signals. The size of the Swedish Peak Load Reserve is set by legislation (!) and the price for power from using it is set above the market price. This removes the risk of market distortion at the expense of raising prices for all participants. Effectively the cost of maintaining the strategic reserve is added to balancing and settlement costs.

In Australia, a public sector body, the Independent Market Operator, decides the capacity required two years ahead and sets the maximum amount it is willing to pay for capacity by reference to the levelised cost per MW of CCGT. It then pays out 85% of this amount to any operator whose capacity is not purchased in the market (the percent can vary depending on the extent of excess capacity). It is claimed that this approach has encouraged market entry and enabled generation capacity and peak demand to be matched to a margin of about 2% (less than the size of the Swedish strategic reserve). However, the costs of the IMO are added to energy prices, and it is as yet unclear whether lower investment risk (and hence cost of capital) has reduced the market price of electricity.

Setting capacity charges through the market

A market solution to the capacity problem would not involve a central authority fixing the capacity charge. This may well make a significant difference, as it is not obvious that the optimal solution is to have any capacity margin. In other markets, capacity shortages in the busy period are observed. So a capacity market might well produce the result of no provision of a capacity margin, or even power shortages at times.

Suppliers currently bear the immediate cost of non-availability, in the form of higher wholesale prices and lost revenue from cut-off customers. Suppliers will probably continue to be essential intermediaries even in a smart future, serving the function of demand aggregation – the capacity required by each consumer when added together is much greater than the capacity required across the network as a whole. So capacity charges should operate at the wholesale level, leaving suppliers to work out the best method of charging their customers[6].

On the east coast of the USA, a power pool jointly owned by 22 power companies operates the markets in which power is bought and sold. This organisation, PJM, has the obligation to ensure there is sufficient capacity to meet the peak demands of customers but lacks legal power of direction. Instead, it operates a capacity market to ensure that the capacity requirement is met[7]. The capacity market operates as a supplement to PJM's main power markets: generators offer capacity at a price net of revenues receivable from the sale of power. Effectively, capacity offers are the difference between average short run marginal cost and long run marginal cost for a reference generator[8]. Suppliers who buy power in the main market have to buy a corresponding capacity in the capacity market plus 1% of forecast peak load. The price in the capacity market is set through an auction in which capacity offers are matched to suppliers' capacity requirements. Auctions are held three years' ahead, and supplemented by incremental auctions nearer the time. The average price paid for capacity has varied between $54 per MW day and $173, the variation reflecting the cyclical nature of power station construction.

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[6] When smart meters are installed, suppliers will have the incentive to pass on peak price risk to consumers.

[7] See www.pjm.com for further information.

[8] The long run marginal cost calculation is done by PJM, based on a combustion turbine power station.

The PJM market system is interesting because it is the result of the evolution of a voluntary power pool over a long period of time (since 1927!). The pool has chosen to move away from central direction and fixed prices towards a market solution. In recent years, operating as a set of related markets, the pool has shown itself to be robust and is continuing to expand as power companies serving adjacent areas join voluntarily. It is now about the same size as the UK National Grid. It is too soon, however, to form a judgment whether its current market arrangements have reduced the overall price of electricity.

A Reliability Market

An alternative market solution is for suppliers to hedge the risk of having to pay a higher price for power in the peak period. In its simplest form, generators would guarantee, in return for a regular premium, an upper limit to the price that a supplier would have to pay. If the market price exceeded that limit, the generator would compensate the supplier by refunding the difference. In effect, generators receive a stable flow of revenue in place of peak period revenues; if the generators get the price limit right, the riskiness of investment is thereby reduced. Generators have a further incentive to install more capacity, since doing so lowers the probability of having to refund the supplier. In a fully-functioning reliability market, the hedges would be provided by a third party, who would pay the generator for making power available and take the risk of having to refund the supplier. In this way, generators achieve a smoothing of revenue at no risk; the net benefit should be a lower cost of capital.

The fundamental problem with a reliability market is that generators want revenue stability over 10 years or more, but forward markets in energy run only two years ahead at best. The reason for this deficiency is the prevalence of uncertainty about future demand and supply. A reliability market cannot solve this problem, and so would be vulnerable to big swings in demand (a very cold winter could make a generator or specialist hedger insolvent). In short, a true reliability market capable of influencing investment decisions is not feasible. Hedging contracts would have to be created and sustained artificially; a reliability market set up in this way is not likely to be efficient.

A UK-specific problem with a reliability market is that vertically-integrated power companies have no need to hedge the power that they produce themselves. Given that the Big Six control 80% of generation, it seems unlikely that a reliability market could work satisfactorily in British conditions.

Conclusions on capacity charges

Privatisation and liberalisation produced lower energy prices in the UK than elsewhere in Europe. In the last five years, this advantage has been eliminated, partly because European markets have opened up but also partly because the UK market has become more concentrated. The Big Six have little incentive to so invest in generation. Independent generators now have to sell their output to the Big Six, who are also their competitors. So it is not surprising that the national capacity margin is narrowing. The solution should be to make the market work better by reforming its structure. Such reform should focus on the retail market, where the Big Six have a stranglehold. Independent retailers, operating on a significant scale, could buy from independent generators.

Even if that were to happen, the basic economics of power generation and the experience of other countries suggest there is a role for capacity charges in reducing the perceived riskiness of investment in electricity generation. A market-based solution would probably be more successful than a strategic reserve or the central purchase of capacity at encouraging investment in generating capacity at minimum cost, but a pure market in capacity is impractical. The fundamental reason is that the time taken to implement a decision to invest in new capacity exceeds the feasible timescale of forward energy markets.

The organisation charged with operating the market in capacity (the "market maker") therefore needs to take an active role. It must either fix the capacity required or set the capacity charge. The Government's preference is to fix capacity, but international experience suggests that the market maker should fix the capacity charge. This would mean estimating levelised costs for the principal incremental generation technology (CCGT in the UK).

One reason why price rather than quantity should be set by the capacity market maker is because estimates of levelised costs are already widely available, so the process will be transparent. In contrast, there is little agreement on what capacity margin would be optimal. So it would be sensible to allow the capacity margin to be determined through market transactions.

The market in electrical generation capacity should be integrated with the wholesale power market. That is, capacity charges would be payable as a top-up to revenues from the sale of power.

To make a market in capacity work, suppliers would have to have an obligation to purchase capacity that at least matches their sales of power. Purchase of capacity is better done through bilateral trading between suppliers and generators rather than periodic auctions. Bilateral trading is a better method of ensuring integration of the market in capacity with the wholesale power market, and for allowing continual adjustment on the demand and supply sides. To this end, contracts made between suppliers and generators should be standardised and tradable in a secondary market.

In a vertically integrated energy market like the UK's, specific rules will be necessary to ensure independent suppliers and generators are not disadvantaged. As noted above, it seems unlikely that the Government's proposed 20% rule will be sufficient.

The lead-in time for capacity contracts should be the minimum to allow for construction (e.g. 3 years for CCGT), but the market rules should allow for contracts of variable length. In this way, nuclear generators could offer contracts with a much longer lead-in time, which suppliers might find attractive as a hedge against rising fuel costs.

It would be beneficial for the market in capacity to be set up before the national capacity margin diminished, so that the sums at risk in the market are initially small. Once the market in capacity was up and running, the basis for the capacity charge (the levelised cost) could be adjusted up or down in response to market behaviour. However, it is not desirable that the charge be adjusted expressly to achieve a target level of capacity. One of the main benefits of setting up the market as proposed is to enable it to optimise the capacity margin. An imposed target capacity level will almost certainly be too large.

Intermittent Generation

Can wind generation form part of a capacity market? It would seem not, since the probability that the capacity would be available when required is quite low. So the penalties payable for non-availability that are a basic feature of a capacity mechanism could offset any revenue from capacity charges. Given the lack of benefit for wind from participation, the market maker might well prefer to exclude wind power from the capacity market because of its unreliability.

A successful capacity mechanism would have the effect of reducing energy prices in the main power market, so excluding wind from the capacity market would reduce the revenues received for electricity generated from this source. Investment in wind would also appear to be more risky than other technologies, as revenues would depend solely on prices in the main power market, whereas investment in competing technologies would benefit from predictable capacity payments.

Conclusions

The net effect of capacity charges could be higher or lower energy costs: covering fixed costs out of standing charges reduces the riskiness of investment and so the cost of capital for generation projects; on the other hand, charging for capacity could result in unnecessarily high levels of unused capacity that has to be paid for by consumers. International experience with capacity charging mechanisms appears not to provide a clear indication of what to expect.

There is clear evidence from other countries that a capacity charging mechanism that is integrated with energy markets would match demand and supply better than would the use of a strategic reserve. In particular, a strategic reserve is likely to result in excess capacity and consequently higher prices for energy.

A market-based capacity mechanism would need an active market-maker. The market-maker should fix the capacity charge, allowing market participants to determine capacity. The information available to the market-maker should ensure that the levelised costs of generating electricity (which will form the basis of the capacity charge) are known with a high degree of precision, whereas the information on the required level of capacity is relatively poor.

Having a national target for generation capacity is almost bound to result in excess capacity, with adverse consequences for energy consumers.

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