11 Consultation question responses

Targeted mechanism

1 [page 167]: Does this table [see Figure C3] capture all of your major concerns with a targeted Capacity Mechanism? Do you think the mitigation approach described will be effective?

InterGen does not believe the targeted mechanism to be an appropriate Capacity Mechanism arrangement as it does not address the security of supply problem adequately, for the reasons detailed in section 6 above.

The table accurately reflects all but one of InterGen's key concerns, principal among which are

- **Included - the "slippery slope"** in which higher or more stable returns in the SR lead to more and more capacity leaving the market and more and more joining the SR; and
- **Included- the "missing money"** where returns in the market are limited by SR
- **Not included – low market returns to all flexible capacity**. The highly subsidised entry of high volumes of intermittent generation is dramatically reducing returns to all flexible, dependable generation and only a market-wide solution allows this to retained, essential to security of supply. This is discussed more extensively in section 3 above.

Mitigation approaches generally work and InterGen notes in particular work DECC has put into the missing money mitigation, where the dispatch at VOLL option should be reasonably effective (though there are other disadvantages – particularly capital inefficiency).

However, InterGen cannot see any practical and effective mitigant for the slippery slope and the low market returns to all flexible capacity are a fundamental issue which can only be resolved by a market-wide solution.

2 [page 168]: How long should the lead time for Strategic Reserve capacity procurement be and why?

InterGen does not believe the targeted mechanism to be an appropriate Capacity Mechanism arrangement. However, InterGen's Physical Capacity Market view on leadtime is as described in section 7.3.3 above and in more detail in Appendix 1, repeated below for convenience.

4 to 5 years is the best compromise between the 7 year develop / finance / build timescale for new generation and the quality of demand estimation. Error margins would be too great in forecasting generation-demand balance 7 years ahead, the full new project development timescale. Three years would give better demand-supply estimation but is too short for new build – 3 years is CCGT construction timescale only and even a fully permitted project with electricity and gas connections contracted will take an additional year for commercial agreements and financing to be put in place. Somewhere around 4 to 5 years may be a good compromise – enough to fund, contract for and construct a power station but development will need to be at-risk based on market view.

3 [page 168]: Should the length and nature of contracts procured by the Strategic Reserve procurement function be constrained in any way?

InterGen does not believe the targeted mechanism to be an appropriate Capacity Mechanism arrangement. However, InterGen's Physical Capacity Market view on contract duration is given under question 13.

4 [page 169]: Which criteria should providers of Strategic Reserve be required to meet?

InterGen does not believe the targeted mechanism to be an appropriate Capacity Mechanism arrangement. However, InterGen's Physical Capacity Market view on criteria for participation is as described in section 7.3.3 above, repeated below for convenience.

Flexibility: the Capacity contract must define a standard for flexibility so that all participants meet a common minimum standard. InterGen's proposal is:

- Minimum 3MW
- Contracted generation increase, reduction or demand change < 4h after instruction
  Based on BETTA dynamic data: Notice to Deviate from Zero, Run-Up Rate, Run-Down Rate
- Minimum ramp rate 10 MW/minute
  Based on BETTA dynamic data: Run-Up Rate, Run-Down Rate
- Contracted MW must be deliverable for > 4 hours
  Based on BETTA dynamic data: Minimum Non-Zero Time
- 10% tolerance on delivery volume (taking steer from STOR – the precision of load changes is lower than the precision of static load levels)

Certification of capacity available to Physical Capacity Market. A central body certification of capacity providers is essential to the efficient working of a capacity mechanism. If left to generators, DSR providers and storage providers, these companies are likely (depending on level of penalties for non-delivery) either to overestimate their capacity or not to participate. The assessment should take account of the average fleet availability over the preceding year for plants of the same type so that capacity is not over-sold but poor availability of a single plant is penalised only once via the Physical Capacity Market penalties described below. The certification should be based on based on the flexibility criteria: for example if adopting the 4 hours-to-achieve-change proposed above, providers of flexibility will break into (1) those which can provide full capacity from zero in 4h and (2) only those which can only achieve MEL-SEL variation.

Testing: Capacity and flexibility must be tested at commissioning of a new plant or at the introduction of existing plant to the Physical Capacity Market. Flexible capacity can subsequently be readily monitored in real time from the existing BETTA Dynamic Data: Maximum Export Level, Stable Export Level, Notice to Deviate from Zero, Run-Up Rate, Run-Down Rate, Minimum Non-Zero Time. The penalties for non-delivery should be sufficient to ensure that the data is provided accurately but the Central Buyer should have the backup option to test on demand.

5 [page 169]: How can a Strategic Reserve be designed to encourage the cost-effective participation of DSR, storage and other forms of non-generation technologies and approaches?

InterGen does not believe the targeted mechanism to be an appropriate Capacity Mechanism arrangement. However, the key to encouraging cost –effective participation of all technologies is to make the Capacity Mechanism available to all possible providers of flexible capacity on a common specification basis. This allows non-discriminatory competition at lowest cost for the service, incentivising cost-reducing innovation.

6 [page 175]: Government prefers the form of economic despatch described here. Which of the proposed despatch models do you prefer and why?

InterGen does not believe the targeted mechanism to be an appropriate Capacity Mechanism arrangement. Neither dispatch policy can be satisfactorily implemented. The two dispatch options are VOLL or economic dispatch between VOLL and LRMC. VOLL is not a number on which any degree of agreement can be obtained, partly because it is individual to each customer and depends on the duration for which the price is held. Neither is there any clear way of determining a "sweet spot" at which economic dispatch has minimal effect on market revenues. Hence selecting a dispatch price is fraught with difficulty.

7 [page 175]: How would the Strategic Reserve methodology and despatch price best be kept independent from short-term pressures?

There is no method which is sufficiently secure to avoid potentially damaging effects on revenues in the rest of the market due to downward dispatch price pressure: It is impossible to preclude legislative changes in the face of high consumer bills and public pressure.

8 [page 175]: Do you agree that a Strategic Reserve should be periodically reviewed? If so, who would be best placed to carry out the review and how often should it be reviewed?

InterGen does not believe the targeted mechanism to be an appropriate Capacity Mechanism arrangement. However, if implemented, 5 yearly reviews should be carried out by Ofgem with support from NGET.

9 [page 176]: Into which market should Strategic Reserve be sold and why?

InterGen does not believe the targeted mechanism to be an appropriate Capacity Mechanism arrangement. However, if implemented, the reserve should flow into the Balancing Mechanism rather than a market.

10 [page 178]: Do you have any comments on the functional arrangements proposed for managing a Strategic Reserve?

No.

11 [page 179]: Given the design proposed here and your answers to the above questions, do you think a Strategic Reserve is a workable model of Capacity Mechanism for the GB market?

No.

Market-wide mechanism

12 [page 182]: How and by whom should capacity in a GB market be bought and why?

As set out under section 7.1 above, repeated below for convenience.

Supplier Obligation: too many problems

Internalisation of Supplier Obligation. In a market without subsidies and VI, suppliers contracting with generators for dependable capacity would be the natural arrangement. However, the Supplier Obligation is not compatible with the level of VI in the GB market where the Big 6 dominate, having a 99% market share of supply and 80% of generation. A VI player could simply internalise its Supplier Obligation or two VI players could cross-supply with each other, internalising costs and profits.

A Supplier Obligation gives a VI player a substantial incentive to source capacity internally: any generation profits will be lost in contracting with an independent generator they would be retained if contracting with own generation. Regulatory mitigants can be put forward for this but cannot be as effective as a avoiding a Supplier Obligation which inherently incentivises VI, compounding the existing energy market incentives.

Therefore a Supplier Obligation can only be effective if vertical integrated players in the market are disaggregated.

Supplier credit quality unlikely to be bankable. It is essential that independent suppliers continue to enter the market to provide competition for the Big 6. However, independent suppliers are very unlikely to have the credit quality which would support the financing of a new power station through Capacity Mechanism payments.

This problem could be mitigated by government underwriting of supplier credit risk but this is building one intervention to support another: better to avoid the credit problem by not implementing a Supplier Obligation.

Split of demand by supplier. There are two ways in which the obligation could be estimated per supplier: (1) splitting a Central Body whole-market estimate into suppliers and (2) individual suppliers estimating their demand. If implementing a Central Body estimate, in addition to the inevitable errors in calculating the required capacity for the market four years out, there would be the multiplicative error in dividing this estimate among between suppliers. This is impossible to do with any accuracy, though a secondary market could mitigate the inherent risks. If implementing a supplier estimate model, suppliers would have to determine their own volume requirements. This being a cost and not having long term customer contracts, suppliers would inevitably under-predict demand.

The cumulative difficulty of mitigants for the three issues above makes the Central Buyer the clear preference.

Central Buyer: InterGen's strong preference

There are several reasons why InterGen believes that a Central buyer is a good arrangement for a Capacity Mechanism.

Institutional Competency. A Central Buyer can more readily equip itself with the institutional competency to forecast demand, forecast any generation retirements and place 1 to 20 year term contracts for capacity with delivery commencing in four to five years.

Creditworthiness. Bankable creditworthiness is fully resolved if the buyer is either NGET or a government body.

Consistency of application across suppliers and capacity providers. It is easy to ensure consistency across suppliers and generators, DSR and storage.

Hence InterGen would strongly prefer a Central Buyer strongly over a Supplier Obligation.

InterGen would be most comfortable with NGET being the central buyer due to the company already having the vast majority of the institutional competence required. One proviso is that the process would need to be fully open with standard contracts and full disclosure of agreed prices and durations: STOR is not sufficiently transparent to non-participants to be a good example.

13 [page 183]: What contract durations would you recommend for a Capacity Market?

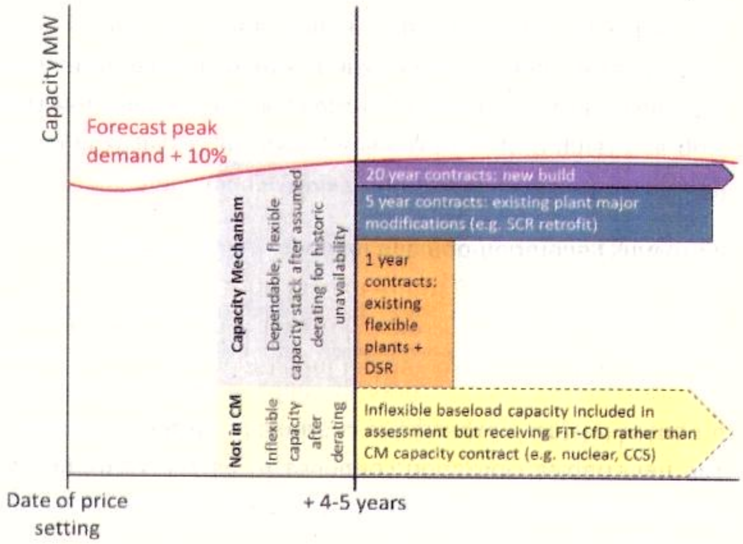
As set out under section 7.3.3 above and Appendix 1, repeated below for convenience.

InterGen believes a tiered set of contract durations is necessary. 1 year contracts are appropriate for existing generators to the extent existing generation is forecast to be available However new plant investment decisions require greater certainty of revenues than a 1 year Physical Capacity Mechanism contract could provide and longer contracts will reduce cost of capital. Therefore the Physical Capacity Mechanism must allow 20 year contracts for new plant. InterGen proposes that these include a cap mechanism to limit total revenues in the event of a recovery in energy market prices. Some mid length 5 year contracts will be needed for existing plants requiring extensive modification to remain online – for example Selective Catalytic Reduction retrofit to reduce NO_x.

14 [page 184]: How long should the lead time for capacity procurement be? Should there be special arrangements for plant with long construction times?

As set out in section 7.3.3 above and in Appendix 1, repeated below for convenience.

Lead time for capacity assessment and contracting 4-5 years: central body determines requirement a number of years ahead assuming historic fleet availability. 4 to 5 years is the best compromise between the 7 year develop / finance / build timescale for new generation and the quality of demand estimation. Error margins would be too great in forecasting generation-demand balance 7 years ahead, the full new project development timescale. Three years would give better demand-supply estimation but is too short for new build – 3 years is CCGT construction timescale only and even a fully permitted project with electricity and gas connections contracted will take an additional year for commercial agreements and financing to be put in place. Somewhere around 4 to 5 years may be a good compromise – enough to fund, contract for and construct a power station but development will need to be at-risk based on market view.



% of capacity contracted vs forward timing. Must contract for 100% of calculated requirement at agreed forward timing of 4 to 5 years ahead. The traditional progressive build-up of contracting – for example contracting 50% 5 years ahead, increasing in steps to 100% 1 year ahead – appears at first sight to be a good mitigant for capacity forecast errors. However, it will not work in this instance as the contracting would lock in the cheapest (existing) capacity first and the most expensive (new) last with only 1 year leadtime – insufficient to contract, finance, construct and commission.

Therefore there can be no special cases for long lead projects

15 [page 185]: Should there be a secondary market for capacity? Should there be any restrictions on participants or products traded?

As section 7.3.1 above, repeated below for convenience:

The flexible, dependable capacity would be delivered in the primary Physical Capacity Market. A secondary Capacity Market could be – and indeed would need to be – established to support demand and capacity changes between participants and could also enable secondary financial-only participants. If generation or supply requirements change, primary participants could adjust their position financially with other primary market players or via financial-only players.

16 [page 186]: What are the advantages and disadvantages of making a central, administrative determination of (i) the capacity that can be offered into the market by each generator; (ii) the criteria for being available; and (iii) the penalties for non-availability? In outline, how would you suggest making these determinations?

(i) Central determination of capacity that can be offered into the market by each generator.

A central body certification of capacity providers is essential to the efficient working of a capacity mechanism. If left to generators, DSR providers and storage providers, these companies are likely (depending on level of penalties for non-delivery) either to overestimate their capacity or not to participate. The assessment should take account of the average fleet availability over the preceding year for plants of the same type so that capacity is not over-sold but poor availability of a single plant is penalised only once via the Physical Capacity Market penalties described below. The certification should be based on based on the flexibility criteria: for example if adopting the 4 hours-to-achieve-change proposed above, providers of flexibility will break into (1) those which can provide full capacity from zero in 4h and (2) only those which can only achieve MEL-SEL variation.

(ii) Central determination of criteria for being available.

The availability criteria must be applied uniformly across the industry, not bilaterally negotiated, and therefore a central determination and enforcement is required. If bilateral availability assessment is allowed, the required security of supply cannot be ensured by the mechanism. The BETTA market will already penalise unavailability in times of capacity tightness through cashout of the difference between notified contract volume and settlement delivery – it would be disproportionate to add a market or cashout price based penalty under the Capacity Mechanism. Therefore central determination is the only practical solution

InterGen believes that the primary criterion for availability should be through testing. Capacity and flexibility must be tested at commissioning of a new plant or at the introduction of existing plant to the Physical Capacity Market. Flexible capacity can subsequently be readily monitored in real time from the existing BETTA Dynamic Data: Maximum Export Level, Stable Export Level, Notice to Deviate from Zero, Run-Up Rate, Run-Down Rate, Minimum Non-Zero Time. The penalties for non-delivery should be sufficient to ensure that the data is provided accurately but the Central Buyer should have the backup option to test on demand.

(iii) Central determination of penalties for non-availability

As for determination of availability criteria, penalties must also be applied uniformly across the industry, not bilaterally negotiated, and therefore a central determination and enforcement is required to provide assurance of security of supply.

Both financial and regulatory penalties will be required.

- ***Financial penalties*** should be high enough to ensure contracted capacity is made available in times of generation-demand tightness but must be proportionate to the contract payments and capped. If the penalties could result in an uncapped liability for participants, any capacity mechanism revenues would not be financeable and hence would not support the development of new plants when required – an essential part of the rationale for the capacity mechanism. High and uncapped liabilities would also exclude smaller or innovative players whose businesses could not withstand the risks. InterGen proposes that the penalty for non-delivery under Physical Capacity Market is a percentage of contract price (like STOR), with a cap on maximum percentage of revenue lost based on the number of occurrences. It should be noted that the penalties in the Physical Capacity Market will be in addition to any MWh non-delivery at cashout prices in the BETTA energy market which are in themselves a high cost.
- ***Regulatory penalties*** may take the form of Generators not being able to sell their full capacity in the subsequent auction if non-deliveries in the present year exceed a threshold percentage.

- ***Possible method***
  - Exclude plants with Planned Outages notified under National Grid Operating Code No 2 [10] – plants will then be penalised for forced outages and unscheduled maintenance only. OC2 needs to take account of Planned Outage updates within year given the reality of arrangements with specialist maintenance contractors such as those carrying out scheduled maintenance of gas turbines.
  - Monitor remaining plants for delivery in period for which NGET has given notice of forecast capacity tightness.
  - High market prices will be sufficient to ensure all reasonably available plant is strongly incentivised to run and contract with market to do so. If notified contract volume over period <SEL, deem to be = Capacity Mechanism capacity to minimise penalty avoidance.
  - Calculate delivery failure over NGET notice period by comparing settlement volumes to notified contracted volume per BMU.
  - Apply penalty to delivery volume vs Capacity Mechanism contracted amount.

17 [page 191]: How should the reference market for reliability contracts be determined and what would be an appropriate reference market if it is set by the regulator? How could any adverse effects of choosing a particular option be mitigated?

InterGen believes there are significant flaws with the use of a Reliability Market and has a strong preference for a physical Capacity Market. Should an RM be adopted, the Reference Price will need to be short term to respond to periods of capacity tightness. The best existing market for this, consistent with the 24h+ timescales within which intermittent wind generation can be reasonably forecast, would be the APX Day Ahead market. However as discussed under section 7.2.1 above, the use of a short term index and RM option contract will inevitably destroy liquidity in the forward market due to generators' needs to balance the option payouts and their revenue. This is a critical structural flaw which leads InterGen to strongly prefer a physical Capacity Market.

18 [page 192]: For a Reliability Market, how should the strike price be determined? If using an indexed strike price, which index should be used?

Given InterGen's preference for a centrally administered mechanism, should an RM be selected, InterGen believes it is essential that the strike price is also centrally determined. In outline the approach might be to determine an acceptable limit of electricity system unreliability, model the likely price levels which might be signalled at that unreliability point and then set a strike price which allows sufficient margin for the reasonable range of plant behaviour and yet still avoids reaching the unacceptable reliability level.

19 [page 193]: For a Reliability Market, what level of physical back up (if any) should be required for reliability contracts and how should it be monitored?

The primary market has to be physically backed and based on central body estimates of required generation to ensure the forecast requirements are physically met. Monitoring was discussed under the response to Question 16 above.

20 [page 194]: Do you agree that a vertically integrated market potentially raises issues for the effectiveness of a Reliability Market? If so, how should these issues be addressed?

In InterGen's view, VI has been one of the key problems requiring intervention via a Capacity Mechanism.

---

[10] "Operating Code No 2, Operational Planning and Data Provision", National Grid Electricity Transmission, Issue 4 Revision 6 of 18 July 2011

The Renewables Obligation continues to be successful in introducing renewables via a subsidy and the proposed FiT-CfD is expected to continue this trend.

The unchecked return to vertical integration (VI) has been a successful strategy for the Big 6 to stabilise their revenues across sectors. However it has resulted in low wholesale market liquidity and low pricing transparency, obscuring future market price signals – in particular, there is no forward market signal of the narrowing generation-demand margin.

InterGen's concerns centre on flexible, dependable generation by which we mean plants which can start, stop and ramp output as required, matching changes in demand and intermittent wind generation. The combination of subsidised renewables and VI impacts has reduced the returns available for unsubsidised flexible, dependable generators in the market. Market revenues have already reduced to the extent that both existing generators and new entry are uneconomic.

A carefully designed Capacity Mechanism, whether or not an RM, can help to mitigate the primary symptoms of excessive VI – low market liquidity and pricing which does not reflect supply-demand fundamentals. The most critical design feature for the Capacity Mechanism is the use of a central buyer and administrator rather than a supplier obligation which would only reinforce the VI self-supply problem.

However the most fundamental requirement is to increase the separation of the VIs via reinforcement of the steps taken on segregated accounts and the transfer prices used in them, plus introduction and enforcement of self-supply restrictions and internal Chinese walls between generation and supply.

21 [page 195]: What could we do to mitigate interactions between a Capacity Market (especially if a Reliability Market) and Feed-in Tariff with Contract for Difference without diluting the effectiveness of either?

As discussed under section 9.1 above, repeated below for convenience.

The overriding principle which InterGen recommends is that there should be no double recovery to benefit from a FiT-CfD and the Capacity Mechanism. However, some types of generation may provide both flexible, dependable capacity under the Capacity Mechanism and be in receipt of a FiT-CfD. Therefore it is necessary to review the interaction by generation type:

Intermittent generation. This must not be allowed to participate in the Capacity Mechanism since it is a key problem to which the Capacity Mechanism is the solution.

Baseload-only inflexible generation. This includes existing nuclear and potentially CCS coal plants. Inflexible generation is not contributing to the balancing of intermittent wind and so should not benefit from the Capacity Mechanism for flexible, dependable capacity.

Flexible, dependable capacity with FiT-CfD support. This category potentially includes flexible nuclear, biomass and CCGT with CCS. This flexible capacity will be relied upon and hence should be compelled to take part in the Capacity Market in the same way as non-FiT-CfD flexible capacity. All such capacity should be accountable for non-delivery and face the same penalties. To avoid "double-dipping" of revenues, the FiT-CfD revenues should be reduced by the value of the Capacity Mechanism payment (or vice versa dependent on which is higher) so that capacity is not being paid twice.

22 [page 196]: How can a Capacity Market be designed to encourage the cost-effective participation of DSR, storage and other non-generation technologies and approaches?

As answered under question 5.

23 [page 199]: Do you have any comments on the functional arrangements proposed for managing a Capacity Market?

As described under section 8.2 above, repeated below for convenience.

Clearly the establishment, operation and management of a Capacity Mechanism in Great Britain will be an additional role to that of any present organisation and additional resources will be required. InterGen's view of the optimal role split and its assessment against existing institutional competencies is as set out in the table below.

Organisation	Role in Capacity Mechanism	Present institutional competence assessment
DECC	Establish arrangement Manage any changes	Yes with industry support Yes
NGET	Capacity Contract counterparty Manage auction process Provide transparent prices Monitor performance Administer penalties Execute payments	Yes although can be slow Yes, as STOR Not clear – transmission pricing is transparent but very complex; STOR transparency could be improved. Yes - existing BETTA systems New requirement New requirement
Ofgem	Forecast required capacity Monitor arrangements	Major development requirement: EM Outlook poor Yes

NGET's incentive programme would of course have to be developed from the present arrangements to take account of its expanded role and to ensure that its incentives were well aligned with the desired outcomes.

24 [page 199]: Do you think that a trigger should be set for the introduction of a Capacity Market? If so, how do you think the trigger should be established, and how should it be activated?

No, a capacity market should be introduced as soon as it is practical to implement it. The present excess of capacity over that required should ensure initial Capacity Market prices are low and the market will be operating smoothly and teething troubles eliminated by the time a capacity shortfall pushes up prices.

25 [page 199]: What is the most appropriate design of Capacity Market for GB and why?

InterGen is clear that a Capacity Mechanism is essential to assurance of Security of Supply in Great Britain, in the face of increasing penetration of highly subsidised renewable generation and a very high degree of vertical integration. As set out in section 7.3.1 above, repeated below for convenience:

InterGen strongly prefers a centrally administered Physical Capacity Market, the key benefits of which are:

Market-wide arrangement. The low market revenue problem and the flexible capacity requirement occur across the whole market and so are not soluble with a marginal intervention such as Strategic Reserve: a market-wide solution is needed. Additionally, the Strategic Reserve issue of the "slippery slope" is a structural issue which cannot be mitigated.

Simplicity. The proposed arrangement involves a Central Buyer contracting with physical generators, DSR providers and storage providers for flexible, reliable capacity. Energy delivery in times of generation-demand tightness remains fully separated: the preserve of the existing BETTA bilateral market and the current STOR arrangements. Experience shows that simpler models are better and their behaviour is easier to predict because all participants understand them. There are no complex option models to (mis)understand with a Physical Capacity Market – the Physical Capacity Market is simply a way to provide additional revenues so that existing flexible capacity does not close prematurely and at times where this is insufficient, provide timely incentive for new entry.

Simplicity is crucial to obtaining investment in new generation, where the mechanism must be fully understood by banks, generation owners and their (frequently foreign) shareholders before an investment can be made. Where investors have alternative projects in other countries, having a Capacity Mechanism which can be readily understood is crucial to attracting investment to a project in Great Britain.

Shorter development timescale and lower costs. The simplicity and ease of understanding compared with a Reliability Market means that the implementation timescale and costs of implementing a Physical Capacity Market will be lower.

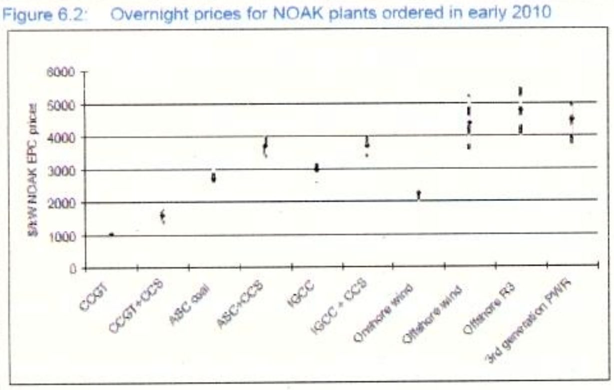
Can introduce secondary financial market easily. The flexible, dependable capacity would be delivered in the primary Physical Capacity Market. A secondary Capacity Market could be – and indeed would need to be – established to support demand and capacity changes between participants and could also enable secondary financial-only participants. If generation or supply requirements change, primary participants could adjust their position financially with other primary market players or via financial-only players.

Capacity Mechanism Assessment

26 [page 210]: What are your views on the costs and benefits of a Capacity Mechanism to industry and consumers?

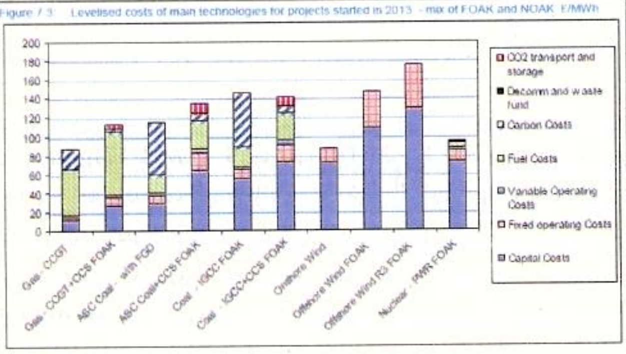
The UK, like the rest of Europe, is set on a pathway of increasing renewable generation through subsidies. Wind generation is of course intermittent and its impact, together with high levels of vertical integration, has been to depress GB wholesale market revenues to the level where flexible, dependable generation uneconomic. Therefore to maintain security of supply in the frequent periods of low wind, it is essential that a Capacity Mechanism is introduced so that flexible, dependable generation remains economic.

Figure 6.2: Overnight prices for NOAK plants ordered in early 2010



Source: Mott MacDonald

Figure 7.3: Levelised costs of main technologies for projects started in 2013 – mix of FOAK and NOAK £/MWh



Source: Mott MacDonald

Supporting an economic return for CCGTs and keeping them in operation via the introduction of a Capacity Mechanism is the lowest cost way of maintaining flexible, dependable generation, driving best value to the consumer in providing security of supply. It is also essential to promote independent generator new entry, the only fully effective way to ensure the wholesale electricity market is price competitive.

Mott Macdonald's June 2010 update for DECC [11] reviews the cost of new build and lifetime levelised generation cost for various technologies. The report indicates that for 2013 nth of a kind (NOAK – excluding first of a kind cost premia) new build, a new CCGT has much the lowest capital costs. At an exchange rate of USD1.55 per GBP, capital costs are £650/kW for

June 2010

CCGT vs £1300/kW for onshore wind, £1800/kW for new coal and £2900 for new nuclear or offshore wind.

On levelised generation cost, CCGT and onshore wind are the cost leaders at £85/MWh.

Mott Macdonald did not take into account that for every intermittent wind turbine, a nearly equivalent amount flexible, dependable generation needs to be in place. Nor does it include the additional costs for the transmission system.

If the cost of this flexible generation and grid costs are added to the cost of wind (valid given that subsidised wind is rendering flexible, dependable generation uneconomic) then CCGT levelised generation cost is half that of onshore wind.

Constructing a new 900MW CCGT creates up to 600 jobs over three years and a typical operating plant employs 30-60 staff, the majority of these being engineers. Given the need for 18GW of capacity [12] this construction supported by the Capacity Mechanism could generate up to 12,000 construction jobs and up to 1,000 direct skilled permanent roles.

Hence in supporting CCGT plants, the Capacity Mechanism will be supporting least cost generation and highly skilled jobs in local economies. OCGT also has a role to play but at a lower load factor, reflecting its lower efficiency and higher carbon emissions.

27 [page 211]: Which Capacity Mechanism should the Government choose for the GB market and why?
As question 25

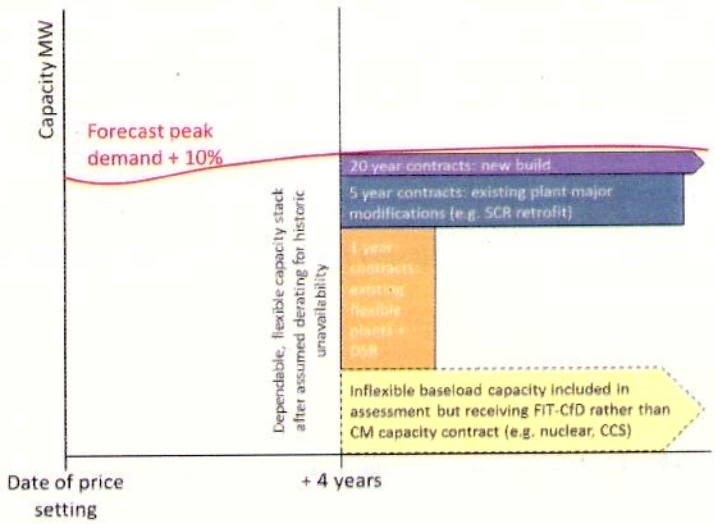
[12] "Over-arching National Policy Statement EN-1", DECC, June 2011 states 59GW new generation required of which 26GW non-renewable generation and 8GW under construction = 18GW needed.

Appendix 1: InterGen's proposed specification for a Physical Capacity Market

Objective: Physical Capacity Market is entirely additional to energy market paid as £x/kW installed p.a. and is to stimulate presence of sufficient flexible, dependable capacity – dispatch is separate via energy market and STOR.

Determination of required capacity and purchase by central bodies: a central body (DECC, Ofgem or preferably NGET) must determine the required capacity: if left to suppliers, the inaccuracy will be too great. This is a difficult forecast to make but if left to suppliers, the inaccuracy from their commercial incentive to minimise the MW required (a cost) and accounting for the effects of customer churn (assumed decline in customer base) will outweigh the positive effect of multiple independent forecasts. A Central Buyer must then procure the capacity to avoid VI internalisation of Supplier Obligation and to provide bankable credit risk on Capacity Mechanism payments.

Lead time for capacity assessment and contracting 4-5 years: central body determines requirement a number of years ahead assuming historic fleet availability. 4 to 5 years is the best compromise between the 7 year develop / finance / build timescale for new generation and the quality of demand estimation. Error margins would be too great in forecasting generation-demand balance 7 years ahead, the full new project development timescale. Three years would give better demand-supply estimation but is too short for new build – 3 years is CCGT construction timescale only and even a fully permitted project with electricity and gas connections contracted will take an additional year for commercial agreements and financing to be put in place. Somewhere around 4 to 5 years may be a good compromise – enough to fund, contract for and construct a power station but development will need to be at-risk based on market view.



Contract duration: 1 year contracts are appropriate for existing generators to the extent existing generation is forecast to be available.

New plant investment decisions require greater certainty of revenues than a 1 year Physical Capacity Mechanism contract could provide and longer contracts will reduce the cost of capital. Therefore the Physical Capacity Mechanism must allow 20 year contracts for new plant. InterGen proposes that these include a cap mechanism to limit total revenues in the event of a recovery in energy market prices. Further, indexation will need to be considered for these long contracts so that new plants do not take excessive returns in early years but then become uneconomic in late years.

Some mid-length 5 year contracts will be needed for existing plants requiring extensive modification to remain online – for example Selective Catalytic Reduction retrofit to reduce NO_x.

Flexibility: the Capacity contract must define a standard for flexibility so that all participants meet a common minimum standard. InterGen's proposal is:

- Minimum 3MW
- Contracted generation increase, reduction or demand change < 4h after instruction
  Based on BETTA dynamic data: Notice to Deviate from Zero, Run-Up Rate, Run-Down Rate
- Minimum ramp rate 10 MW/minute
  Based on BETTA dynamic data: Run-Up Rate, Run-Down Rate
- Contracted MW must be deliverable for > 4 hours
  Based on BETTA dynamic data: Minimum Non-Zero Time
- 10% tolerance on delivery volume (taking steer from STOR – the precision of load changes is lower than the precision of static load levels)

Certification of capacity available to Physical Capacity Market. A central body certification of capacity providers is essential to the efficient working of a capacity mechanism. If left to generators, DSR providers and storage providers, these companies are likely (depending on level of penalties for non-delivery) either to overestimate their capacity or not to participate. The assessment should take account of the average fleet availability over the preceding year for plants of the same type so that capacity is not over-sold but poor availability of a single plant is penalised only once via the Physical Capacity Market penalties described below. The certification should be based on based on the flexibility criteria: for example if adopting the 4 hours-to-achieve-change proposed above, providers of flexibility will break into (1) those which can provide full capacity from zero in 4h and (2) only those which can only achieve MEL-SEL variation.

Testing: Capacity and flexibility must be tested at commissioning of a new plant or at the introduction of existing plant to the Physical Capacity Market. Flexible capacity can subsequently be readily monitored in real time from the existing BETTA Dynamic Data: Maximum Export Level, Stable Export Level, Notice to Deviate from Zero, Run-Up Rate, Run-Down Rate, Minimum Non-Zero Time. The penalties for non-delivery should be sufficient to ensure that the data is provided accurately but the Central Buyer should have the backup option to test on demand.

Efficiency. Physical Capacity Market does not need to specify. Clearly there is a trade-off between the efficiency of generation plant and its flexibility – for example the most efficient gas fired plant would be a CCGT whereas the most flexible would be an OCGT. In specifying only flexibility criteria, a Capacity Market might incentivise only the relatively low cost OCGT's to enter. It is InterGen's view that there is sufficient pressure from high fuel prices and carbon pricing to favour high efficiency plant and that provided the flexibility criteria can be met by high efficiency CCGTs (which the above proposals could be), then the market will make the appropriate technology choice itself without the need for the Physical Capacity Market to specify.

% of capacity contracted vs forward timing. Must contract for 100% of calculated requirement at agreed forward timing of 4 to 5 years ahead. The traditional progressive build-up of contracting – for example contracting 50% 5 years ahead, increasing in steps to 100% 1 year ahead – appears at first sight to be a good mitigant for capacity forecast errors. However, it will not work in this instance as the contracting would lock in the cheapest (existing) capacity first and the most expensive (new) last with only 1 year leadtime – insufficient to contract, finance, construct and commission.

Price setting: IG would strongly prefer an administratively set price as this will give the market greater clarity and visibility than an auction process. It is InterGen's belief that a highly parameterised price calculation with industry consultation on assumptions can be designed to work in a reliable way - such as the method used to determine SEM Capacity Payment Sum from Best New Entrant calculations. DECC appears to have a strong preference for auctions to set the price because DECC is more comfortable with setting the volume required than the price. InterGen believes that DECC should look back at the experience of the key volume based mechanism, the EUETS, where a carbon tax would have been more effective in sending a clear signal to the market and the UK has, late in the day, had to introduce CPS a top-up tax to have the desired effect. This contrasts with the effectiveness of the RO which has incentivised substantial new renewable generation, driven by the floor price for ROCs and an agreement to float the volume to maintain the demand and hence price level for ROCs.

However, should an auction be the only pricing method that DECC is prepared to consider, there are two key alternatives:

- Clearing price (all participants receive highest price taken) – more stable as likely to be at new plant long run marginal cost for much of the time = lower cost of capital
- Pay as bid – superficially lowest cost but more volatility in revenue stream over years = higher cost of capital

InterGen believes the clearing price is the better option but to avoid excessive payments to existing plants, DECC may need to consider initially separating the auctions for existing plant (1 year contract), major modifications (5 year contract) and new plant (20 year contract) auctions. Once one-year contract auction prices have sufficient history to provide investor confidence in their levels, it may be possible to transition to a single 1 year contract auction.

Auctions would need significant controls to ensure the chosen mechanism worked correctly and was not subject to abuse or price setting by undeliverable bids for new plants which later leave a capacity shortfall (NFFO experience).

Whichever price setting method is chosen, further consultation will be necessary on the details of the arrangements.

Notice: given that the periods of capacity tightness under consideration can be forecast at 24-48 hours' notice with good accuracy, NGET should issue a warning similar to the existing NISM. This would provide a clear signal for generators to ready their plants if reasonably possible.

Penalties: Both financial and regulatory penalties will be required.

- ***Financial penalties*** should be high enough to ensure contracted capacity is made available in times of generation-demand tightness but must be proportionate to the contract payments and capped. If the penalties could result in an uncapped liability for participants, any capacity mechanism revenues would not be financeable and hence would not support the development of new plants when required – an essential part of the rationale for the capacity mechanism. High and uncapped liabilities would also exclude smaller or innovative players whose businesses could not withstand the risks. InterGen proposes that the penalty for non-delivery under Physical Capacity Market is a percentage of contract price (like STOR), with a cap on maximum percentage of revenue lost based on the number of occurrences. It should be noted that the penalties in the Physical Capacity Market will be in addition to any MWh non-delivery at cashout prices in the BETTA energy market which are in themselves a high cost.
- ***Regulatory penalties*** may take the form of Generators not being able to sell their full capacity in the subsequent auction if non-deliveries in the present year exceed a threshold percentage.
- ***Possible method***

- Exclude plants with Planned Outages notified under National Grid Operating Code No 2 [13] – plants will then be penalised for forced outages and unscheduled maintenance only. OC2 needs to take account of Planned Outage updates within year given the reality of arrangements with specialist maintenance contractors such as those carrying out scheduled maintenance of gas turbines.
- Monitor remaining plants for delivery in period for which NGET has given notice of forecast capacity tightness.
- High market prices will be sufficient to ensure all reasonably available plant is strongly incentivised to run and contract with market to do so. If notified contract volume over period <SEL, deem to be = Capacity Mechanism capacity to minimise penalty avoidance.
- Calculate delivery failure over NGET notice period by comparing settlement volumes to notified contracted volume per BMU.
- Apply penalty to delivery volume vs Capacity Mechanism contracted amount.

Contract design: this could take some time – an example would be the introduction of the GTMA contract which took 2-3 years to develop. DECC should produce a Heads of Terms – in so doing, a number of key issues would be likely to be exposed such as penalties, FM, liability cap, whether interaction with forward sales is avoided, credit.

Payment timing. The allocation of the costs to suppliers cannot be carried out accurately in advance due to customer churn: allocation should take place on the most accurate data possible which will be at delivery. Payments should then follow the existing calendar for the electricity market monthly settlement process. The central body should make the cost of capacity it has contracted forward known so that suppliers can have foresight when developing their tariffs.

Allocation of costs: costs fully socialised to suppliers based on their actual MWh consumed in each settlement period, also on market monthly settlement calendar after delivery.

[13] "Operating Code No 2, Operational Planning and Data Provision", National Grid Electricity Transmission, Issue 4 Revision 6 of 18 July 2011

Appendix 2: Review of experience with the PJM capacity auction and its relevance and lessons for design of a GB Physical Capacity Mechanism

InterGen reviewed the design and recent experience of the PJM reliability pricing model and its capacity auctions with [redacted] of IHS CERA.

PJM RPM experience

The present PJM market was established on an accelerated timetable to rapidly build up to a 3 year lead time between the Base Reliability Auction and the Delivery Year.

Timeline for Base Residual Auctions until Steady State

Delivery Year	Base Residual Auction Held
June 1, 2007–May 31, 2008	April 2007
June 1, 2008–May 31, 2009	July 2007
June 1, 2009–May 31, 2010	October 2007
June 1, 2010–May 31, 2011	January 2008
June 1, 2011–May 31, 2012	May 2008

Sources: PJM, Cambridge Energy Research Associates.

An overall success. The PJM has, through these auctions, been very successful in its primary aim of ensuring at lowest cost that sufficient capacity is available to maintain a reliability standard of 1 in 10 loss of load expectation annually. The accelerated introduction allowed PJM to retain a large number of older, marginal generators which had requested retirement from PJM and through this achieved the required capacity level at well below the cost of new entry (CONE). PJM has encouraged high levels of demand side response (7% of capacity), not only through bidding of industrial customers but also through aggregators bidding on behalf of signed-up domestic customers who accept air conditioning shut-downs in exchange for a fixed annual fee. PJM has also encouraged efficient use of transmission interconnection with neighbouring zones, reversing flows from export to high levels of import due to the attractive capacity payments.

Sufficiently attractive to encourage TSO switching. Some Ohio generators including Duke are in the process of transferring into the PJM from their existing TSO due to the attraction of the capacity market.

But little investment in new generation. In spite of (and perhaps partly because of) these positive features, PJM not has attracted only minor investment in upgrading existing generation. The three year leadtime between auction and capacity delivery may contribute to this, but the dominant factors appear to be low prices below the cost of new entry in the last several auctions, the highly volatile capacity prices (in spite of design measures such as the Variable Resource Requirement curve) and the single year capacity contract which can at most be locked-in for 3 years for a new entrant. The market is not sending a signal that new resources are needed..

And is the high level of DSR sustainable? A further present issue under debate is the large scale of demand side response and whether this is sustainable as capacity margins reduce to the design level and calls on DSR become more frequent. Domestic participants in aggregated DSR bids (to achieve the minimum 100kW to participate) had become used to receiving credit though their bills without the need for air conditioning shut-downs. In the hot weather and consequent high demand of July 2010, 600MW of air-conditioning shutdowns were called for 7 hours, resulting in home temperatures of over 30°C. The DSR was effective in matching generation to demand but 2,500 domestic customers immediately cancelled their participation and 1,300 reduced their participation due to this one event: a 1% loss of DSR from the 350,000 participants. A 1% loss of DSR from a single 7 hour call poses the question: how much DSR could be relied upon on if called 10, 20 or 100 times a year as wind rises and falls?

11.1.1.1 Similarities between PJM and GB markets and aspects of PJM which could be replicated

The immediate surplus of required capacity, the need to encourage DSR, the presence of older plant in the market teetering on retirement and the interconnection with other markets without any capacity mechanism are all common market features. Designing to reduce price volatility is also attractive.

InterGen's strong preference remains an administratively set price. However, it is clear that the Base Residual Auction is a successful mechanism and generates material revenues for generators (around £30/kWpa in 2014/15) and thus many aspects could likely be copied should DECC decide on an auction. In particular, the BRA is a now compulsory one time auction for all capacity on the system for the delivery period, a feature which InterGen considers would be essential to avoid leadtime issues if capacity is contracted for in a gradual manner building up progressively to 110% of forecast demand.

Penalties. One area which appears to have been effective in PJM and on which there has been no public debate is the level of penalties for unavailability in times of system stress. The penalties under the PJM capacity market are set at the greater of:

- 2 x the weighted average Resource Clearing Price for the particular participant; and
- The Cost of New Entry (CONE)

InterGen believes that these penalties are proportionate to the capacity mechanism payment level and, when considered together with BETTA market imbalance penalties, would be an appropriate range for levels for the GB capacity mechanism.

Key differences between PJM and GB markets

Wind and flexibility. The crucial difference between PJM and the GB market is the level of intermittent generation. In PJM this is very small, around 1% of the installed capacity vs around 7% (6GW of 90GW) in GB today and 27% targeted by 2030 (30GW of 110GW). The PJM capacity mechanism can thus consider purely capacity resource adequacy whereas it is essential that the GB mechanism addresses flexibility needs from the start.

Retirement of older, higher emissions generation. In the US, emissions limiting regulations are only now being introduced.[14] and therefore the PJM capacity mechanism has not so far had to counter this issue. Looking forward in Great Britain, the EU LCPD, the IED, the EU Emissions Trading System and Carbon Price

---

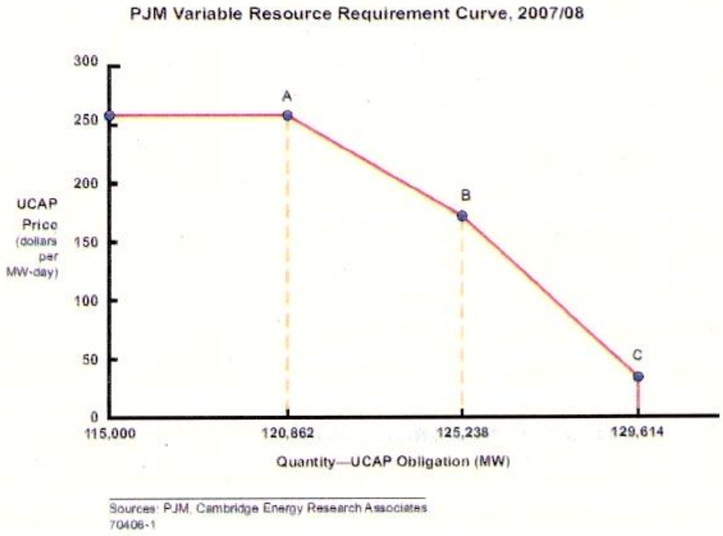
[14] Generation retirements in PJM have not been impacted so far by emissions legislation but looking forward the Clean Air Interstate Rule ("CAIR"), National Emissions Standards for Hazardous Air Pollutants ("NESHAP") and the Regional Greenhouse Gas Initiative ("RGGI"); and starting on January 1, 2012, the Cross State Air Pollution Rule ("CSAPR") will all affect generators. These regulations will not affect the retirement of generation in PJM as much as LCPD, IED and the EUETS do in Europe but are expected to force retirements, estimated at 23GW or about 15% of the installed capacity.

Support will all make late life coal plants uneconomic from 2016 onwards when the costs of environmental compliance are taken into account. Therefore the retention of old generation plants to maintain capacity margin is likely to be impossible in the UK, which drives a specific need for new investment. Hence while the PJM has had the luxury of allowing capacity market development over several years with an existing capacity backstop, the GB capacity mechanism must be properly designed to attract new generation investment from the start.

In the context of attracting new generation investments, PJM has the option to lock in the capacity price for 3 years but a proposed an extension of this to 7 but this change was rejected by FERC. Even 7 years is far too short to support investment in an asset with a 25-40 year economic life. The GB capacity mechanism must immediately address this and InterGen's proposal does this via the proposed split of 1 year (existing plant), 5 year (major retro-fit) and 20 year (new build) contracts.

11.1.1.2 Design issues which would need to be changed or where caution needs to be exercised

Persistently high volatility of capacity price in PJM. As can be seen from the price chart above, PJM capacity clearing prices have been very unstable in spite of the complexity of the Variable Resource Requirement curve which was designed to reduce this. The VRR curve effectively puts a differing price on different levels of system reliability.



Given the GB need for new generation, InterGen's suggestion of 20 year contracts for new entrants would remove this problem and the mechanism could be simplified by using a single point estimate rather than a VRR curve.

Zonal pricing. Zonal capacity pricing adds a great deal of complexity to PJM. InterGen believes that there is no need for this in the UK and therefore the mechanism could again be simplified compared with PJM.

Retention of older capacity vs introduction of new: environmental issues. One point of debate in PJM is whether the successful retention of older capacity with poor environmental credentials was an advantage over cleaner new build – certainly the cost was lower but carbon and other emissions were much greater. InterGen believes the correct application for the GB market would be for the capacity mechanism to solely consider least cost flexible capacity provision and to allow the EU and UK environmental and emissions pricing legislation to force the retirement of environmentally unacceptable plant.

Appendix 3: Total revenue requirement for existing and new CCGTs

InterGen used 31 August 2011 forward curve data, APX within day shaping and the assumption of extended peak (0700-2300) dispatch to calculate Winter 2012 gross profits[15] for an existing CCGT (50% HHV efficiency). These were compared with required revenue levels for new and existing CCGTs based on InterGen assumptions for cost of new plant build (£767/kW), existing CCGT build (£547/kW), operating costs and financing costs (WACC 9.75%). The required gross profit levels were calculated to be £102/kW pa for an existing CCGT and £129/kW pa for a new CCGT.

The results of this analysis are shown in the chart above. The available gross profits in the Winter 2012 forward energy market are only 30% of those needed for an existing CCGT plant to be economic and 25% of those required for a new CCGT.

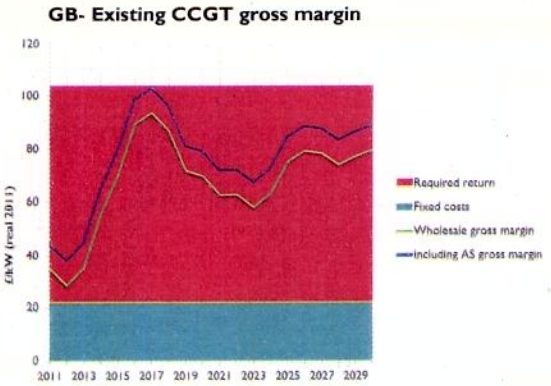
InterGen expects the forecast price rises from tightening of supply-demand as older plants retire will likely be offset by rapid load factor decline due to increased renewable generation, so that new and existing CCGT revenues remain below the economic level. Key to this is InterGen's view of the impact of wind generation on flexible plant revenues. Flexible plant load factors will be reduced through displacement on windy days by low marginal cost wind (which does not need to recover its fixed costs from the market due to the RO and later FiT-CfD). On low wind days, the generation-demand margin is no tighter than it would have been without wind generation being constructed so prices will not rise to compensate for the loss of load factor. InterGen believes that this margin reducing effect from subsidised wind will prevent the tightening of the generation-demand margin due to generation retirements from increasing flexible plant revenues to an economic level.

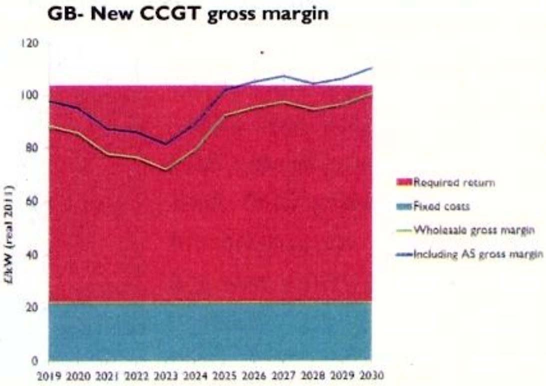
InterGen has compared its analysis to that carried out by Redpoint [16]. The key difference is the level of revenue expected from the market, where Redpoint anticipates a significant recovery.

---

[15] Market electricity revenues, less the costs of the required gas, less the costs of carbon – generally referred to as Clean Spark Spread basis.

[16] "CCGT Gross margin and required return", part of GB reference case materials, Redpoint, 9 Sep 2011





Redpoint's view of total revenues (energy market gross profits + ancillary services + Capacity Mechanism payments) required for an existing CCGT to be economic is exactly the same as InterGen's view = £102/kWpa. Redpoint assumes that a new CCGT also requires gross profits of £102/kWpa, somewhat below InterGen's view of £129/kWpa.

However, Redpoint forecasts that existing CCGT energy market gross profits + ancillary services are worth £70-£100/kW from 2016. This level is the result of Redpoint's underlying assumption that as the price-setting plant, CCGT will have a just-economic return in the future. The £70-£100/kW compares with InterGen's calculated £32/kW in Winter 2012.

Hence Redpoint and InterGen's calculated CCGT revenue requirements are similar and views of declining CCGT load factor are also similar. The difference between Redpoint's and InterGen's view is whether market pricing in low-wind periods is such that it allows a nearly economic return to CCGT plants (Redpoint) or that market distortions from subsidised wind prevent this (InterGen).