INTERGEN

Department of Energy and Climate Change
3 Whitehall Place
London
SW1A 2AW

4 October 2011

Dear Sir/ Madam,

Electricity Market Reform White Paper Appendix C: Capacity Mechanism Consultation

InterGen strongly supports DECC's view that a Capacity Mechanism is required and is pleased that DECC has reintroduced a market-wide Capacity Mechanism for consideration in this consultation. InterGen believes that a Physical Capacity Market with a central buyer will deliver the lowest cost solution and provide investor confidence in order that flexible generation is built.

InterGen is the UK's largest and most successful new entrant independent generator, having invested £1.4 billion in the UK since 1995. InterGen owns and operates 2.5 GW of highly efficient gas fired power stations in the UK and has Section 36 consent for a further 1.8 GW of carbon capture ready gas-fired generation, representing a further £1.2 billion of investment. These plants should be operational by 2015, delivering flexible, reliable capacity, creating jobs and ensuring that the lights stay on.

InterGen is committed to investing in the UK. As an independent generator, InterGen relies solely on project finance and the backing of overseas shareholders to develop generation projects. Without a Capacity Mechanism, InterGen's existing gas assets will struggle to be economic and our new UK plants will in all likelihood be unable to obtain finance to support their construction.

Independent generators and suppliers encourage competition, maximise the sources of capital and ultimately help to deliver value for money for consumers. InterGen urges DECC to consider carefully the role of the independent sector in its Capacity Mechanism design to ensure that existing independent generators and new entrants are encouraged into the market.

InterGen would welcome a meeting with DECC and Ministers to discuss further the points raised in our response.

Yours faithfully,

[redacted]

Public Affairs Manager

Electricity Market Reform White Paper
Appendix C: Capacity Mechanism Consultation
InterGen response

1 Executive Summary

Britain is facing a trilemma in the electricity market: maintaining security of supply, meeting legally binding carbon reduction targets and delivering affordable energy for consumers. The current market arrangements will not deliver the required investment at the scale and pace that we need.

Flexible generation is essential for security of supply. Market returns for gas fired generation, the lowest carbon and lowest cost form of flexible generation, are below the economic level. InterGen strongly supports DECC's view that a Capacity Mechanism is essential to deliver sufficient flexible generation. This will ensure that the lights stay on when the wind does not blow.

A Capacity Mechanism will promote essential independent generator investment, the only fully effective way to ensure the wholesale electricity market is price competitive.

In support of increasing levels of intermittent wind generation, the Capacity Mechanism must support not simply capacity but ***flexible capacity***. The Capacity Mechanism must be correctly designed from the ***investor's perspective***, otherwise the required levels of flexible, dependable capacity will not materialise.

InterGen is firmly of the opinion that the best Capacity Mechanism for Great Britain is a Physical Capacity Market with a Central Buyer. Its advantages include:

- It is a market wide mechanism and so will maintain sufficient existing plant and bring forward new flexible generators, demand-side response and storage;
- It will provide a revenue stream which will support the financing of new plants; and
- It is compatible with the BETTA market.

InterGen would urge DECC to design and implement a Physical Capacity Market as soon as it reasonably can because flexible, dependable generation has already become uneconomic. A well designed Capacity Mechanism will deliver the required flexible plant investments and through this create up to 12,000 construction jobs and directly support 1,000 long-term engineering jobs.

InterGen recommends that DECC engages with credit agencies to identify and consider options which minimise the credit exposure of the Central Buyer and yet provide a bankable revenue stream for a new generation project.

It is important that the Physical Capacity Mechanism design is convergent with EU market developments. This is essential to avoid the resulting pressures for further regulatory change and prolonged uncertainty for investors in the GB market.

DECC has recently decided in favour of a FiT-CfD for low carbon generation. Rather than a Capacity Mechanism, a FiT-CfD for all flexible, dependable generation would be the most capital efficient arrangement. DECC should assess whether a FiT-CfD would be a more efficient solution.

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InterGen's response to the consultation is structured as a full text in logical sequence followed by responses to the specific consultation questions. Most of the consultation question responses are simply copies of sections of the main text.

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3 The need for a Capacity Mechanism

InterGen strongly supports DECC's view that a Capacity Mechanism is required.

3.1 Renewable subsidies and vertical integration have reduced market revenues for flexible generators

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.

3.2 Dependable, flexible gas fired generation is uneconomic in today's market and a Capacity Mechanism is needed

The market needs flexible, dependable generation such as that offered by CCGTs. This generation must be economic for existing environmentally acceptable generation to remain in operation and for new entry (the economic construction of new plants) to occur when needed.

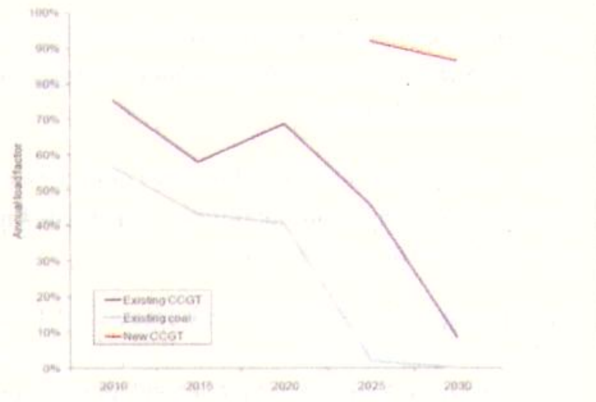
The chart to the left shows the results of an InterGen analysis of available gross profits[1] in the forward energy market for 2012 delivery. The market gross profits are only 30% of those needed for an existing CCGT plant to be economic and 25% of those required for a new CCGT. The situation for new OCGT plants is similar.

InterGen expects that the forecast price rises from tightening of the generation-demand margin as older plants retire will likely be offset by rapid load factor decline as increased low carbon generation penetrates the market and displaces flexible generators.

[1] Market electricity revenues, less the costs of the required gas, less the costs of carbon – generally referred to as Clean Spark Spread basis. The detail of the analysis is presented in Appendix 3

Historical CCGT annual load factors have ranged between a high of 72% (2008) and a low of 52% (2011 year to date)[2] but InterGen expects these to decline rapidly in line with Figure 4.1 (right) from Oxera's analysis for the Independent Generators Group in March this year[3].

Figure 4.1 Annual load factors



Note: CCGT availability is assumed to equal 94% of total capacity in winter and 90% in summer. Coal plant availability is assumed to equal 85% in winter and 70% in summer.
Source: Oxera analysis.

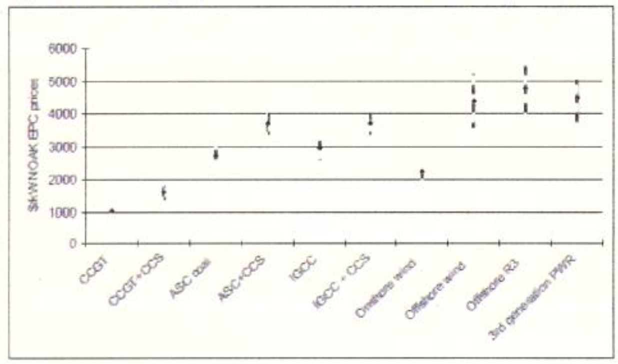
InterGen expects that the balance of capacity margin tightening from retirements and these severely reducing load factors will hold flexible plant market returns below economic levels for both existing and new plants.

Without intervention to counterbalance subsidised renewable penetration, large numbers of flexible, dependable generators will remain uneconomic and therefore become unavailable over time.

InterGen therefore concurs with DECC that a capacity mechanism is needed to maintain security of supply: the right capacity mechanism will ensure the lights stay on when the wind does not blow.

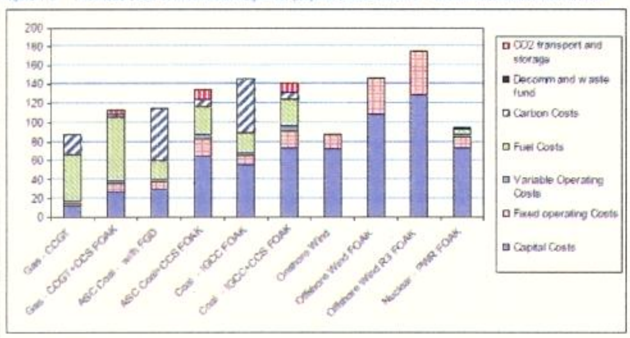
3.3 CCGT is the lowest cost form of large scale flexible generation

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

[2] InterGen calculation of CCGT load factors from "Digest of UK Energy Statistics", tables 5.1.3, 5.4, 5.8 and 5.9, DECC Sep 2011 with data to end June

[3] "GB capacity mechanism design: meeting future flexibility requirements to secure a low-carbon transition", Oxera, March 2011 as presented to DECC on 9 March 2011

[4] "UK Electricity Generation Costs Update", Mott Macdonald, June 2010

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 [5] 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.

4 The Capacity mechanism must support *flexible* capacity

The capacity mechanism must specifically support flexible capacity. Whilst baseload capacity will be required to cover minimum overnight demand, if the majority of the peak capacity requirement were met with new or existing baseload-only inflexible generation, this would simply make a new and difficult problem. Thus the capacity mechanism must be designed from the outset to incentivise only flexible, dependable capacity.

4.1 The need for flexible capacity

The overwhelming technical issue in UK generation is to cover the variability of intermittent wind generation – this is more frequent than is generally assumed. From [redacted] analysis using NGET data on transmission connected wind generation[6]:

- The average frequency and duration of a low wind event of 20MW [7]or less between November 2008 and December 2010 was once every 6.4 days for a period of 4.9 hours.
- At each of the four highest peak demands of 2010 wind output was low being respectively 4.7%, 5.5%, 2.6% and 2.5% of capacity at peak demand – a capacity credit range of 2%-6%.

Looking forward, there are several factors which should improve the contribution of wind to generation at times of peak demand:

- 2009 and 2010 had below-average wind levels;
- Offshore wind is expected to have a higher load factor and substantial offshore wind growth is expected over the coming years; and
- Diversity of windfarm locations.

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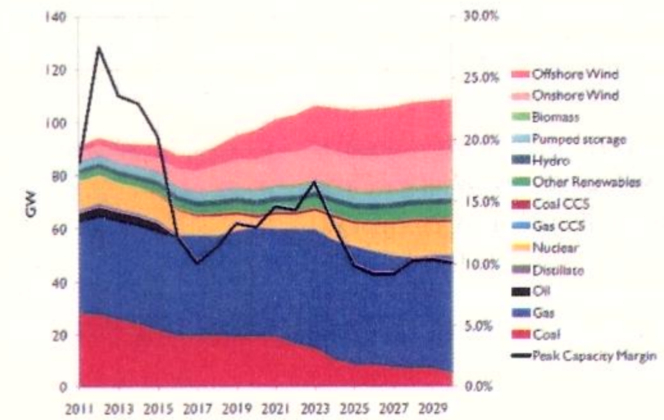
[5] "Over-arching National Policy Statement EN-1", DECC, June 2011 states 59GW new generation required of which 26GW non-renewable generation and 8GW under construction = 18GW needed.

[6] "Analysis of UK Wind Power Generation November 2008 to December 2010" for the John Muir Trust

[7] 20MW was selected as a low wind event by [redacted] it represented 7% of the 300MW installed NGET connected wind in November 2008, declining to below 1% of the installed 2590MW by the end of 2010.

However, there is a limit to the contribution which wind can make to peak demand. This was analysed by [redacted] of Durham University for National Grid's 2010 event on wind forecasting [8]. His analysis showed that as intermittent generation capacity increases its proportion of installed capacity, the level of wind capacity credit to average cold spell demand must be reduced to keep the loss of load probability constant. He concluded that a reasonable long term estimate of the contribution of wind to ACS demand might be 10%.

Figure 13 Aggregate installed capacity



As wind generation increases to a forecast 30GW by 2030 as shown in the chart on the left from Redpoint[9], flexible generation will need to vary output by 27GW (10% short of 30GW): this 27GW of flexibility is more than 50% of Redpoint's forecast 50GW flexible fleet capacity in 2030.

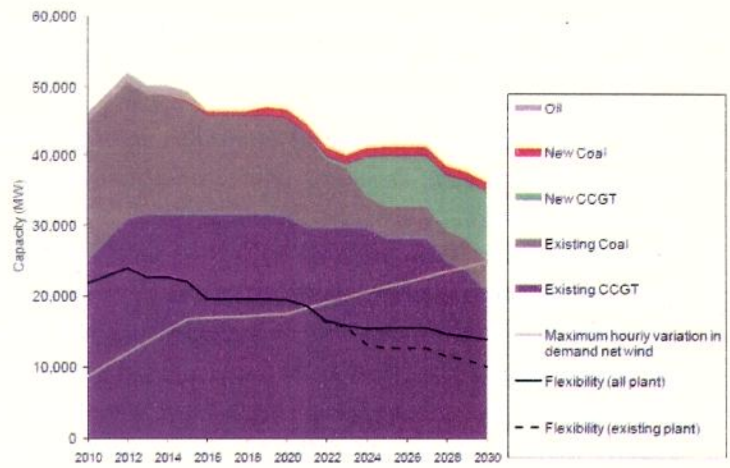
The same chart includes Redpoint's forecast of derated capacity margin, showing this falling to the target 10% level in 2017 even assuming a high 18% contribution from wind to peak demand.

A separate analysis of flexibility required was carried out by Oxera for the Independent Generators Group in March of this year. Oxera concluded that:

"Increased wind penetration is ... likely to exacerbate the total peak-to-trough demand net wind over the duration of a typical day. The analysis in this report suggests that the maximum simulated daily range of demand-net-wind levels could increase by 40% compared with 2009."

When projecting forward the level of flexibility available from the market, Oxera predicted that without intervention, the required level of hourly flexibility would exceed that of the available plant by 2020 as shown in the chart to the right.

Figure 1 Supply and demand for hourly flexibility



The same conclusion arises from both the [redacted] and the Oxera analyses: the requirement for flexibility will be very high, in the area of 27GW.

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[8] "Wind Capacity Credit and Security of Supply", [redacted] School of Engineering and Computing Sciences, Durham University. Presentation to National Grid Wind Forecasting Workshop 16 February 2010

[9] "GB Market Report for InterGen May 2011 Update", Redpoint, May 2011

4.2 Meeting the requirement for flexibility

Some of the requirements can of course be met through STOR contracts with very flexible plant (OCGT). However, STOR is a marginal mechanism and could not supply the full 27GW forecast flexibility.

Similarly the existing and foreseeable electricity storage cannot deliver 27GW – existing GB electricity storage is 2.8GW and this level is sustainable only for 5 hours.

Achieving 27GW of flexibility will require delivery by the whole market - both new and existing plants.

Existing plant could, if suitably incentivised, be adapted to provide faster start times through starts automation and plant improvements. The consultation is very focussed on new build: if incentives to maintain and improve existing plant are not provided, the required level of flexibility will not be achieved.

New plant flexibility could, again if suitably incentivised, be specified in plant procurement from which the requirements could be designed-in and tested. CCGT is well positioned to deliver much of this capacity at high efficiency but OCGT could also play a role for certain parts of the dispatch pattern.

It is clear from the above that the Capacity Mechanism must, from the outset, specify a flexibility requirement for participation so that there is an unequivocal incentive for new generators to be flexible and for existing generators to increase their flexibility.

5 Criteria for a satisfactory Capacity Mechanism

5.1 Criteria for success

InterGen believes the seven criteria below must be met for a successful GB Capacity Mechanism

1. The Capacity Mechanism must maintain sufficient existing plant and bring forward new generators, demand-side response (DSR) or storage to meet the need for flexible, dependable capacity so that security of supply is maintained;
2. The Capacity Mechanism must be a bankable contract which supports the financing of new plants and so must feature clear revenues with proportionate and capped penalties (beyond those to which generators are already exposed under BETTA);
3. The Capacity Mechanism must be compatible with the BETTA market;
4. The capacity made available must be sufficiently flexible to meet the need for changes in demand from the start of the mechanism or new generators will enter onto the system as inflexible baseload generation, exacerbating rather than mitigating the intermittency of wind generation;
5. The Capacity Mechanism should support the lowest cost method to achieve the required security of supply: it must not be restrictive or prescriptive on technology and should therefore encourage innovation to reduce costs, driving best value to the consumer in providing security of supply;
6. Generators which meet the requirements to participate in both the Capacity Mechanism and FiT-CfD contracts must not make a double recovery; and
7. The cost of the Capacity Mechanism payments must be lower than the cost to society of the reduced Security of Supply if no Capacity Mechanism were introduced.

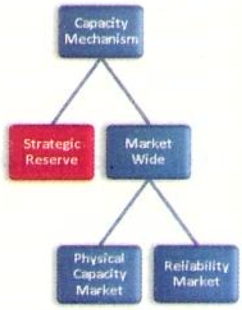
On item 7, the cost of the Capacity Mechanism, the benefit of improved Security of Supply accrues to the consumer. It is therefore essential that the cost of the Capacity Mechanism providing these benefits is also directly passed through to the customer.

Note that there is no need for dispatch to be included in the mechanism: energy market participants self-dispatch against market prices and STOR will be sufficient to ensure all available plant is dispatched in times of capacity tightness. There is also no need for the mechanism to favour the lowest carbon or other emissions – this will be achieved via the EUETS, Carbon Price Support and the proposed Emissions Performance Standard, Large Combustion Plants Directive and the Industrial Emissions Directive.

5.2 Issues which the Capacity Mechanism cannot address

There are a number of consequences of increased intermittent generation which cannot be addressed by a Capacity Mechanism. Key among these is that given the likely dominance of gas fired generators, the gas network and its code will need to be reviewed for the very large gas swing requirements as the gas fired generator fleet starts, ramps and stops.

6 Strategic Reserve



One of InterGen's primary concerns with a Strategic Reserve is the "missing money" issue, where market prices and returns are limited by the operation of strategic reserve plants. DECC has in Appendix C to the White Paper thoughtfully developed mitigants to this problem via the careful development of Strategic Reserve in response to issues raised by InterGen and others in the industry. This is very positive. However there remain five key problems with the Strategic Reserve.

Uneconomic returns affect the whole market: The uneconomic market revenues to CCGTs described in section 3.2 affect all flexible, dependable generators in the market. Given the need for the whole market to provide flexible capacity as described in section 4.1, it is not possible to solve this problem with a marginal intervention such as Strategic Reserve: rather a market-wide solution is needed.

The flexibility requirement can only be met if the market-based generators do not retire. The intent of the Strategic Reserve is that the total flexibility requirement (estimated by InterGen at 27GW) is met mainly from market generators and only to a limited extent by Strategic Reserve generators. If those generators whose revenue is entirely from the market (outside the Strategic Reserve) are uneconomic, they may retire at any time. This could undermine the flexible capacity assumptions on which the Strategic Reserve is based. As described in section 3.1 above, flexible generation market revenues are presently uneconomic and so this is a very major risk. The only counter to this is to introduce a market-wide Capacity Mechanism instead of the Strategic Reserve.

The slippery slope cannot be eliminated. The "slippery slope" problem is the effect where higher and/or more stable returns in the Strategic Reserve lead to more and more capacity leaving the market and more and more joining the Strategic reserve. Of all generators in the market, those with the lowest load factors (and not in the Strategic Reserve or STOR) will have the lowest and most unstable returns. These generators are very likely to retire if not switched to the Strategic Reserve as any operation of Strategic Reserve generation will reduce their revenues.

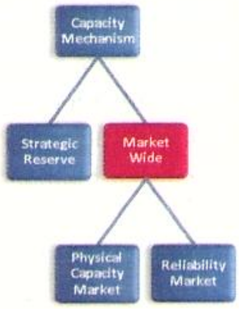
Capacity Sterilisation. The Strategic Reserve is an inherently inefficient use of capital: new plant is built and then isolated from market. This is inefficient and likely to be unacceptable to the public.

Strategic Reserve new build is inherently inefficient. A Strategic Reserve mechanism will introduce new build Open Cycle Gas Turbines for only a few hours of anticipated dispatch per year. An OCGT has a lower efficiency and higher carbon emissions than most other gas fired generators. This is the reverse of the tradition and market practice in Great Britain where high efficiency, high load factor new entrants displace old and inefficient plant. The Strategic Reserve would therefore cause a systematic shift in the generation fleet to higher carbon emissions than would the traditional GB approach. This is at odds with the government's policies to reduce carbon emissions.

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.

DECC must dismiss the Strategic reserve option: the above issues cannot be overcome. Where consultation questions are specific to the Strategic Reserve, InterGen has answered these only where they are relevant to a Market-wide Capacity Mechanism.

7 Market Wide Capacity Mechanism



7.1 Central buyer vs supplier obligation

7.1.1 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; these would be retained if contracting with the VI's 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 vertically 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.

7.1.2 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.

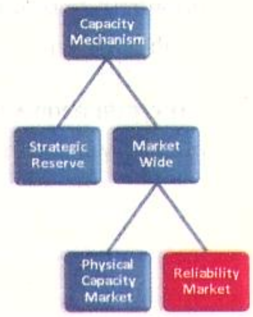
Creditworthiness. Bankable creditworthiness is fully resolved if the buyer is either NGET or a government body.

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

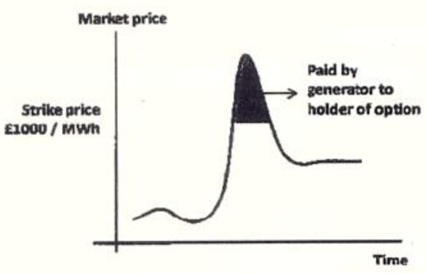
Hence InterGen would strongly prefer a Central Buyer strongly over a Supplier Obligation.

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, further examined in section 8.2 below. 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.

7.2 Reliability Market –physical or financial call option contracts



InterGen's understanding of the Reliability Market is that a provider would sell flexible, dependable capacity in the form of a call option. An option premium would be paid by the buyer to the capacity provider for providing the option – this payment would be a stable revenue stream to the provider. The option would have a high strike price (indicative of generation-demand tightness) at which market price the option would automatically be called – effectively a price cap. For market prices above the strike price, the provider would have to refund to the buyer the difference between the market price and the strike price.



When price exceeds strike price, generator remits the difference, multiplied by the volume of options sold, to the holder

7.2.1 InterGen's view of Reliability Market: not compatible with BETTA market

The call option contract described in the consultation is incompatible with forward hedging in the bilateral market: it would work only with a pool structure and CfDs. InterGen's reasoning for this is set out below, followed by demonstration of the effect in worked examples.

The option reference price has to be short-term in order to capture periods of capacity scarcity: in all likelihood this requires the price to be day ahead. In a period of capacity shortfall with prices above the strike price, the option payout would be market reference price less the strike price.

However, generators operating in the market generally hedge their revenues by selling on the forward market much further ahead than day ahead – the majority of electricity is usually sold year, season, quarter and month ahead rather than day ahead. None of these longer term forward prices is likely be affected by capacity tightness since this is a short-term phenomenon. Hence plant which had hedged on the forward curve would have to pay option payouts based on a high short-term reference price while receiving much lower revenues based on longer term forward prices. This situation would be unacceptable to the generator and would drive the market to zero liquidity other than day ahead: a major crisis for the electricity sector. Further, the situation is even worse for a generator who does not deliver due to a forced outage. This issue is best understood through worked examples which have been included in section 7.2.2 below, concluding that the uncapped liabilities for generators would prevent financing of any new generation investment.

Additionally, the option structure causes a link between the Capacity Mechanism and the BETTA energy market (energy market price vs Reliability Market strike price is a direct link) and STOR (as dispatch in market will alter when market price reaches the strike price, thus affecting the level of STOR activity) which precludes their full separation. Compared with a Physical Capacity Market, this presents a much greater likelihood of unintended interaction, unintended results and gaming.

Finally, if typical Mark-to-Market credit 'margining' requirements for options are applied, the credit requirements for both generators and suppliers could be practically unlimited, preventing new entry in either supply or generation as these are in themselves unbankable.

In summary, the Reliability Market is a complex intervention which would not encourage new entry due to its inherently uncapped liabilities, unpredictable interaction with the BETTA energy market and its inherently unlimited credit requirements.

A simple Physical Capacity Market is InterGen's strong preference as it would provide a simpler and direct connection with achieving the capacity adequacy objective.

7.2.2 Demonstration of Reliability Market problem using worked examples

Four worked examples are presented below. In each example, generator electricity revenues are calculated over 24 hours including a 2 hour capacity crunch.

7.2.2.1 Assumptions

- Generator: 1000MW
- Market index: day ahead, average price £60/MWh over the hours outside the crunch
- Forward market: year ahead contract £50/MWh (generator accepts discount vs short term price to manage revenue volatility)
- Option premium £25M pa = £25/kWpa
- Option strike price £1000/MWh
- Hours in period above strike: 2 at average price £2000/MWh
- Imbalance price £5000, applied for first hour non-delivery

7.2.2.2 *Results for four scenarios*

Example 1 – generator does not sell forward and delivers

Forward market revenue	£k	-
Prompt market revenue	£k	5,320
Prompt market purchases	£k	-
Imbalance costs	£k	-
Option premium	£k	68
Option exercise payments	£k	(2,000)
Total generator electricity revenues	£k	3,388

*** Revenues rise in line with option payouts: OK.**

Example 2 – generator does not sell forward and fails to deliver

Forward market revenue	£k	-
Prompt market revenue	£k	5,320
Prompt market purchases	£k	(2,000)
Imbalance costs	£k	(5,000)
Option premium	£k	68
Option exercise payments	£k	(2,000)
Total generator electricity revenues	£k	(3,612)

*** As example 1 plus normal BETTA forced outage costs. Note that reduced fuel costs would offset some of this but double penalty size under RM is significant.**

Example 3 – generator sells forward and delivers

Forward market revenue	£k	1,200
Prompt market revenue	£k	-
Prompt market purchases	£k	-
Imbalance costs	£k	-
Option premium	£k	68
Option exercise payments	£k	(2,000)
Total generator electricity revenues	£k	(732)

*** Revenues set at forward price so do not rise with capacity crunch. Revenues mismatched to option payouts. Unacceptable for generator = could not sell forward. This is the worst of the examples and best demonstrates the failure of the RM as the generator does nothing wrong yet still ends up out of pocket.**

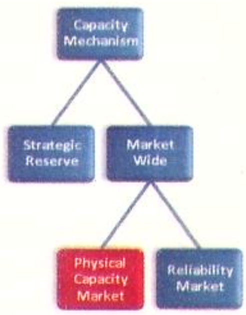
Example 4 – generator sells forward and fails to deliver

Forward market revenue	£k	1,200
Prompt market revenue	£k	-
Prompt market purchases	£k	(2,000)
Imbalance costs	£k	(5,000)
Option premium	£k	68
Option exercise payments	£k	(2,000)
Total generator electricity revenues	£k	(7,732)

*** As 3 but this single event could be disastrous for generator. Issue so large that fuel saving contribution not material.**

The worst problem with the Reliability Market, evident from the above examples, is that it will inherently result in uncapped liabilities for the capacity providers. Investors in new capacity will see the stable revenue stream from option premia as a positive factor but this cannot offset the downside of uncapped liabilities which would be a double penalty, being additional to those inherent in the BETTA electricity market. No bank will lend to a project with uncapped Capacity Mechanism liabilities and therefore the mechanism cannot achieve its primary aim of supporting new generation when this is needed.

7.3 Physical Capacity Market



InterGen's understanding of the Physical Capacity Market is that a capacity provider would sell to the Central Buyer flexible, dependable capacity in the form of a capacity contract. A contract price (per kW per annum) would be paid by the buyer to the provider – this payment would be a stable revenue stream to the provider. Energy (MWh) would continue to be sold via the forward and prompt BETTA markets as at present. Dispatch of the power station would remain an issue for the energy market and/or STOR, with a very strong incentive to dispatch the plant to run based on high energy market prices. Penalties would be apply in the event of non-delivery though the loss of Physical Capacity Market contract revenue, in addition to the BETTA energy market penalties from under-delivery vs. notified contract position which would of course be very high in times of capacity shortfall.

7.3.1 *Benefits of a Physical Capacity Market*

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.

7.3.2 Demonstration of Physical Capacity Market benefit vs Reliability Market using worked examples

Four worked examples are presented below;. in each example, generator electricity revenues are calculated over 24 hours including a 2 hour capacity crunch. The results clearly show the improved situation for a generator when compared with the Reliability Market.

7.3.2.1 Assumptions

- Generator: 1000MW
- Market index: prompt market – day ahead, average price £60/MWh over the hours outside the crunch
- Forward market: year ahead contract £50/MWh (generator accepts discount vs short term price to manage revenue volatility)
- Capacity Mechanism payment £25M pa = £25/kWpa or £2.85/MWh
- Capacity Mechanism penalty in a capacity crunch delivery failure = £100/MWh
- Hours in period above strike: 2 at average price £2000/MWh
- Imbalance price £5000, applied for first hour non-delivery

7.3.2.2 Results for four scenarios

Example 1 – generator does not sell forward and delivers

Forward market revenue	£k	-
Prompt market revenue	£k	5,320
Prompt market purchases	£k	-
Imbalance costs	£k	-
Capacity Mechanism payment	£k	68
Capacity Mechanism penalty	£k	-
Total generator electricity revenues	£k	5,388

*** Revenues as prompt market sales plus CM payment: OK**

Example 2 – generator does not sell forward and fails to deliver

Forward market revenue	£k	-
Prompt market revenue	£k	5,320
Prompt market purchases	£k	(2,000)
Imbalance costs	£k	(5,000)
Capacity Mechanism payment	£k	68
Capacity Mechanism penalty	£k	(200)
Total generator electricity revenues	£k	(1,812)

*** As example 1 plus normal BETTA forced outage costs plus proportionate penalty under CM. Note that reduced fuel costs would offset some of this: OK.**

Example 3 – generator sells forward and delivers

Forward market revenue	£k	1,200
Prompt market revenue	£k	-
Prompt market purchases	£k	-
Imbalance costs	£k	-
Capacity Mechanism payment	£k	68
Capacity Mechanism penalty	£k	-
Total generator electricity revenues	£k	1,268

*** Revenues as forward market sales plus CM payment: OK**

Example 4 – generator sells forward and fails to deliver

Forward market revenue	£k	1,200
Prompt market revenue	£k	-
Prompt market purchases	£k	(2,000)
Imbalance costs	£k	(5,000)
Capacity Mechanism payment	£k	68
Capacity Mechanism penalty	£k	(200)
Total generator electricity revenues	£k	(5,932)

*** As example 3 plus normal BETTA forced outage costs plus proportionate penalty under CM. This is a very expensive event for the generator but not disproportionately worse than BETTA on its own.**

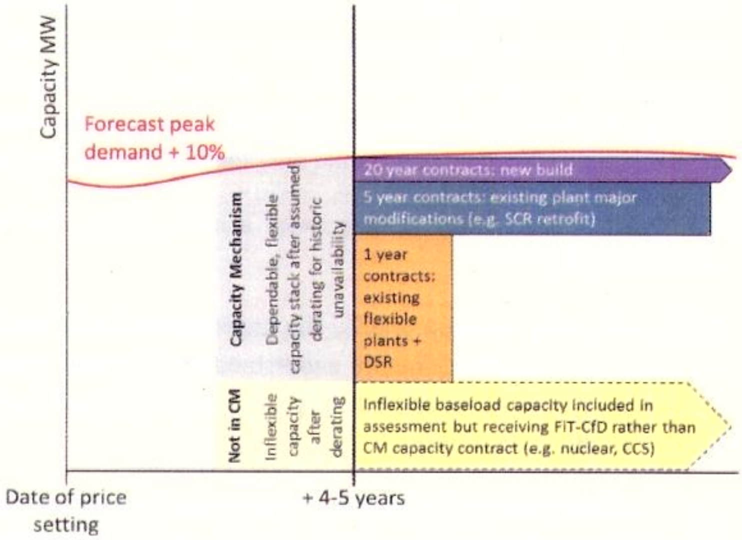
In summary, all of the outcomes of the Physical Capacity Market examples show acceptable results to the generator and strong incentives for delivery, meeting both investor and DECC needs.

7.3.3 Specifications for Physical Capacity Market

InterGen has developed a workable specification for a Physical Capacity Mechanism to confirm its workability. This specification is included as Appendix 1. Some of the key features are described below.

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. A Central Buyer must then procure the capacity.

Lead time for capacity assessment and contracting 4-5 years: 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.



Contract duration: 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.

Flexibility: the Capacity contract must define a standard for flexibility so that all participants meet a common minimum standard.

7.3.4 Review of experience with the PJM capacity auction and applicability to a GB Physical Capacity Market

InterGen has reviewed the design and recent experience of the PJM reliability pricing model and its capacity auctions though review with [redacted] of IHS CERA. The conclusions from this review are described in Appendix 2.

Some features of the PJM market could readily be carried over to the UK.

However, two of the key drivers of the need for a GB Capacity Mechanism are (1) the high present and increased forecast proportion of intermittent wind generation and (2) the forced retirement through environmental legislation of older, higher emissions plant. Neither of these is a feature in PJM and so care must be taken to allow for this difference in the GB Capacity Mechanism design and in carry-over of any design features from PJM.

8 Process for development of Physical Capacity Market – additional steps

8.1 Attraction of sufficient investment: investor perspective

The principal aims of the Capacity Mechanism are to ensure that existing investments in generation remain economic and to ensure that new investments in generation are sufficiently economic, attracting the large volumes of investment required from a wide variety of sources. The consultation does not appear to focus on the investor's perspective – the options are examined more from a market theory viewpoint with an assumption that investment will then follow. This is not the case.

An example of this misunderstanding from recent history was Ofgem's preference for sharpened cashout incentives for capacity tightness. The aim of this was to generate high revenue spikes at times of shortfall and through this to attract investment. In considering a 30-40 year investment of several hundred million pounds in a new power station, this is absolutely the opposite of what an investor requires – this being stability of returns. The spikes in price might increase revenues but in the downside-oriented mind of the investor and his lenders, they would only serve to increase the risks should the plant be unavailable.

The Capacity Mechanism is very much a move in the right direction but its detail design could easily undermine this.

DECC must make as a top priority the engagement with a wide variety of experienced electricity industry investors (such as InterGen) and understand exactly what it would take for each of them to invest in new generation. If this is not carried out thoroughly, DECC could easily design a Capacity Mechanism which has little or no effect on capacity.

8.2 Establishment of functional arrangements and acquisition of institutional competency

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.

8.3 Industry simulation

InterGen believes that testing of the candidate Capacity Mechanism proposal by an industry simulation has many advantages and would (like the preparation of a Heads of Terms for the Capacity Contract) expose many issues including ones of differing interpretations and operability problems. Any simulation should include a variety of events and scenarios to demonstrate the "system" response to various circumstances. We would suggest that the simulation is DECC led but with significant input from NGET.

InterGen's experience of simulation for testing of energy contract operating processes supports this view: the simulation need not be technically complex nor require new electronic systems to be effective.

8.4 Interaction with liquidity review

InterGen believes that low liquidity in the present BETTA electricity (energy) market and poor transparency due to high level of VI have been key factors in reducing the returns available for flexible, dependable generators in that market. An important Capacity Mechanism characteristic is that it should not exacerbate this by further reducing wholesale energy market returns or liquidity – this would in itself constitute a "slippery slope" where the wholesale electricity (energy) market became less and less significant and returns to generators were derived more and more from the Capacity Mechanism. Hence the present work by Ofgem on electricity energy market liquidity must be closely integrated with development of a Capacity Mechanism, such that the Capacity Mechanism design does not reduce energy market liquidity or prices.

8.5 Central Buyer credit issues

The Central Buyer will need to provide credit backing to Physical Capacity Mechanism contracts in order to make the revenue streams bankable for new generation projects.

InterGen anticipates that the Government will find it unattractive to provide credit for the Physical Capacity Mechanism contracts.

Given the Capacity Mechanism outlined, we consider that NGET is best placed to be the Central Buyer, both from an institutional competency perspective as discussed in 8.2 and for credit reasons.

InterGen's proposal is that collections from the suppliers and payments to capacity providers are made on the same day which should minimise the Central Buyer credit exposure.

InterGen strongly recommends that DECC engages with credit agencies to identify and consider options which minimise the exposure of the Central Buyer and yet provide a bankable revenue stream for a new generation project.

8.6 Accounting for capacity contracts

UK Energy companies report under UKGAAP, IFRS or USGAAP. Accounting for long term electricity contracts is a very complex issue under any of these standards. The ultimate transition from US GAAP to IFRS is also under review by the accounting bodies so that the accounting representation of long term contracts is never certain from year to year.

Two particular accounting conclusions could have substantial effects on the accounts of the buyer and provider of capacity:

- Lease accounting, which could result in Capacity Mechanism future obligations being represented as debt on the buyer's balance sheet and lead to complexities with revenue recognition for the capacity provider
- Derivative accounting, where the contract is valued on a Mark-to-Market basis at the end of each accounting period. In a moving market this can result in huge earnings swings because the derivative is valued over several years but the changes flow through to earnings in a single year.

DECC needs to ensure that its contract designs are reviewed for their accounting effect to avoid material consequences for all UK electricity companies, potentially reducing the capital that the GB electricity market will attract as many investors are very earnings sensitive.

9 Interaction with low carbon generation FiT-CfDs

9.1 Interaction of Capacity Mechanism and FiT-CfD payments

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:

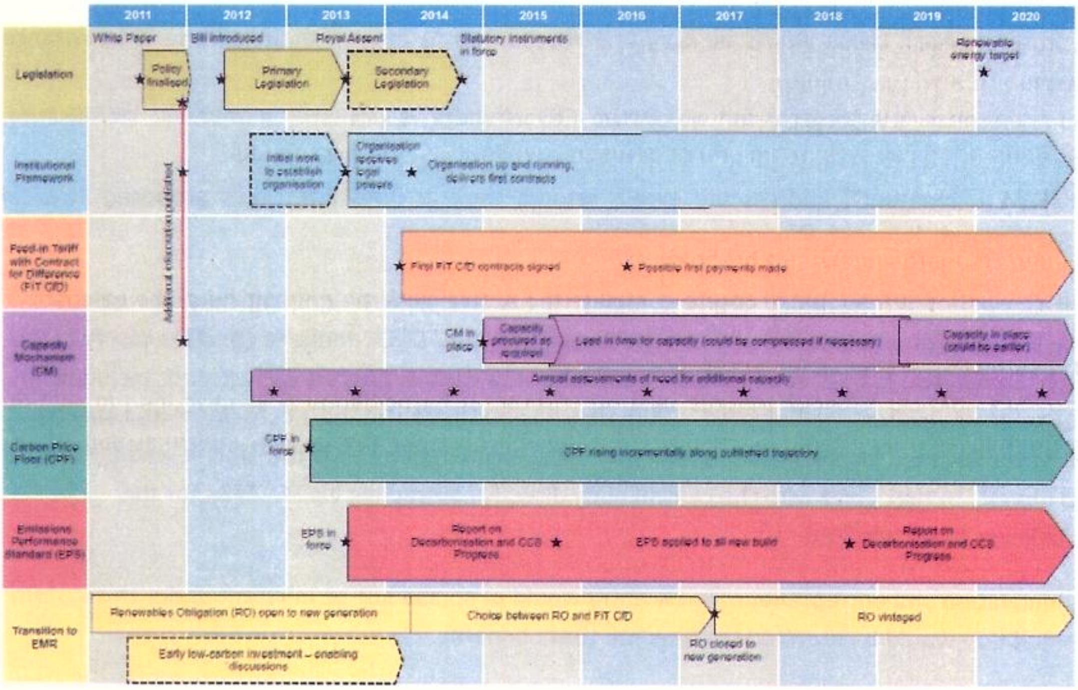
Intermittent generation. This must not be allowed to participate in the Capacity Mechanism since it is a key problem to which the Capacity Mechanism is the solution.

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.

9.2 Interaction of Capacity Mechanism and FiT-CfD timing

There appears to be a mismatch between the DECC timelines for FiT-CfD introduction (2016) and the start of Capacity Mechanism payments (2019):



Consistent with InterGen's view that energy market returns for flexible, dependable capacity are already below the economic level and existing plant could retire at any time, InterGen does not believe that introducing the Capacity Mechanism in 2015 with first payments in 2019 will achieve the desired security of supply result.

This is driven by flexible plant economics but is also consistent with InterGen's view that the derated generation-demand margin will reach 10% in 2017; without intervention the capacity margin will then continue to reduce below this threshold of acceptability.

InterGen therefore strongly believes that the timing of the Capacity Mechanism introduction should be reconsidered and that the first Capacity Mechanism payments should be expected to be ahead of rather than behind the start of the first FiT-CfD payments.

10 Is a flexible capacity FiT-CfD a better option than a Capacity Mechanism?

The Physical Capacity Market as described in this response is similar to a premium FiT (Capacity Mechanism payment in addition to BETTA market energy revenues) with some FiT-CfD features for 20 year contracts (a cap on excess returns should market revenues recover). DECC has recently decided in favour of a FiT-CfD for low carbon generation due to the lower costs of capital and therefore reduced cost to consumers which would result. The same logic could be applied to flexible capacity: the most capital efficient arrangement would be a FiT-CfD for all flexible, dependable generation which should result in lower costs to consumers than a Capacity Mechanism. A FiT-CfD would have the following additional benefits over a Capacity Mechanism:

- One party undertakes the administration of FiT-CfDs covering renewables, nuclear and flexible generation, hence ensuring consistency across the spectrum of technologies;

- Present development of FiT-CfD legislation for renewables and nuclear is ahead of the Capacity Mechanism development timetable. The FiT-CfD design could be replicated for flexible generation, leveraging the legislative programme for FiT-CfDs and accelerating the date at which investor confidence is secured;
- Ease of future changes: there would be only one mechanism to amend should future circumstance require such;
- Enables market price led projects for which the CfD element is primarily a revenue stabilisation mechanism;
- A banded FiT-CfD inherently address the excess returns issue as does InterGen's proposed Physical Capacity Mechanism.

FiT-CfDs for flexible generation would of course complete the central government control of the electricity sector because the government would decide on the generation mix. DECC needs to consider carefully the extent to which the residual market can be made "real" after the various present EMR strands including a Capacity Mechanism have been implemented. Ultimately a centrally controlled electricity sector may be the end result of the planned interventions. If on reasonable examination this is the case, it would be more efficient to go directly to that point with the central body directly contracting via FIT-CFDs for the generation it believes to be required.

Competition, innovation and entrepreneurial new entry would of course not be inherent under this system and specific regulation would be required to stimulate these benefits.