Consultation on possible models for a Capacity Mechanism by the Department of Energy and Climate Change

Submission by International Power plc

(I) About International Power plc

International Power plc (IPR) welcomes the opportunity to contribute to DECC's consultation process on Capacity Mechanisms.

International Power plc is a leading independent power generation company with active interests in closely linked businesses such as LNG terminals and water desalination. Following the combination with GDF SUEZ Energy Europe and International, International Power plc has strong positions in all of its major regional markets (Latin America, North America, the Middle East, Turkey and Africa, UK-Europe, Asia and Australia). In total, it has 66 GW gross capacity in operation and committed projects for a further 22 GW gross new capacity.

In the UK-Europe region, International Power plc has 13.2 GW capacity in operation and a further 1.3 GW under construction. This includes over 7.3 GW of plant in the UK market made up of a mixed portfolio of conventional plant – coal, gas, CHP, a small diesel plant, and the UK's foremost pumped-storage facility. Several of these assets are owned and operated in partnership with Mitsui & Co. Ltd. IPR's assets represent just under 9% of the UK's installed capacity, making IPR the country's largest independent power producer. The company also has a retail supply business and a significant gas supply business, both serving the Industrial and Commercial sector.

As an independent generator, IPR provides valuable flexible generation and liquidity to the market. IPR believes markets should provide a level playing field to new and incumbent generators to reflect the value that all generation brings to satisfying system adequacy. Pricing signals should encourage new entry and should not distort the wider market.

(II) Summary key points

General Comments

- **Pricing signals in the market should encourage investment in existing plant and in new entry. The changing energy mix in the UK could mean the existing energy only market in its current form will not deliver such a signal.**
- **It is also acknowledged that increasing intermittent generation in the electricity mix, alongside inflexible nuclear generation, brings with it flexibility demands on the system that may be difficult to service through existing market arrangements. With this context IPR believes that a properly designed capacity mechanism is an appropriate response to ensure security of supply.**

- **The presence of a capacity payment mechanism is more likely to bring forward the necessary investment. Additionally, the available evidence suggests a capacity payment may have to be in operation earlier than indicated in the Consultation.**

- **A capacity mechanism should provide sufficient certainty to allow market participants to make appropriate economic decisions in terms of the maintenance of existing plant and investment in new capacity. In particular, if a capacity mechanism is to be introduced, IPR believes that it must ensure:**

  - **that older plant that would otherwise close as a result of environmental constraints is not incentivised to stay open;**
  - **it provides sufficient reward for existing plant that complies with environmental regulation; and,**
  - **it delivers an appropriate amount of new entry.**

- **The Government's Consultation on a potential capacity mechanism design has proved very helpful in highlighting the complexities and difficulties in implementing a viable capacity mechanism. If, as we argue, the market wide Reliability Mechanism is not an appropriate solution, the default option should *not* be the Strategic Reserve Mechanism. Armed with the knowledge gained in exploring these options, Government should endeavor to develop a more robust market wide mechanism.**

- **All reserve resources, including Demand Side Measures and imports should meet a minimum deliverable standard before being able to participate in the capacity mechanism.**

- **A Capacity Mechanism should be developed in concert with other policy and regulation initiatives that will impact the market. These include other EMR instruments, changes to the charging regime, Significant Code Reviews, and wider EU legislation.**

- **Further engagement between Government and other industry stakeholders is needed to help develop a design that satisfies an agreed set of criteria.**

On the Targeted Capacity Mechanism

- IPR does ***not*** support a targeted capacity mechanism for the following reasons:

  - under the Strategic Reserve proposal, only a subset of the market will receive support whilst the rest of the market will essentially be subject to a price cap, resulting in a financial disadvantage to existing plant and a major disincentive for investment;
  - the Consultation does not define how the dispatch price will be determined other than it will be set above the highest Long Run Marginal Cost (LRMC) plant in the market but below the Value of Lost Load (VOLL). Setting this price at the appropriate 'sweet spot' will be fraught with difficulty; and,
  - it is difficult to see how the Strategic Reserve can be utilised without impacting on the operation of the traded markets – there are problems for both the Balancing Mechanism (BM) and the traded markets such as the day-ahead market.

On the Reliability Mechanism

- **IPR supports the creation of a market-wide capacity mechanism but we have *major concerns* with the proposed Reliability Mechanism as described:**
  - **it is not compatible with current arrangements;**
  - **under the design set out in the Consultation, there will be a very strong incentive for all trading to take place in the reference market to minimise exposure to the option being called;**
  - **there is no obvious reference market for the Reliability Mechanism; and,**
  - **the Reliability Mechanism will not facilitate longer term trading – this will impact liquidity making an already difficult situation worse.**

- **'Netting off' has been proposed as a potential solution to the uncapped exposure associated with Reliability Mechanism - in essence this becomes a payment of an option fee in return for accepting a price cap. The complexity of the Reliability Mechanism is not therefore needed since this could be achieved through much simpler means such as the operator receiving a flat capacity payment in return for this price cap.**

On the Capacity Mechanism Assessment

- We recognise the difficulty in designing a capacity mechanism that works well with the current market arrangements. Whilst learning can be applied from capacity mechanisms in other countries, each design tends to be bespoke to the prevailing market structure. **Nonetheless, we do support the introduction of a well designed market-wide capacity mechanism.**

- **IPR *does not* however support either of the design options set out in the consultation and believes there needs to be more work on a market-wide capacity mechanism, beginning with a robust set of criteria it would have to meet.**

- The most important criteria include: that it is 'market-wide', it addresses the need for flexible capacity as well as meeting peak demand, and that there is a requirement for devices to contribute on an equal basis; that market players are allowed to freely offer their capacity and energy prices, the mechanism is simple to administer, and that it is be compatible with the existing market arrangements.

- Additionally, the mechanism should be technology neutral, with capacity centrally procured under a transparent process, have an appropriate penalty regime, and finally, generators in receipt of a FiT must not be paid twice for capacity.

> *In summary, IPR <u>does not</u> support either of the capacity mechanism designs set out in the consultation as they negative impact on the existing market. IPR believes a well designed market-wide mechanism would deliver the Government's objectives to ensure resource adequacy. In the absence of such a mechanism, a well functioning energy market is the next best option.*

(III) Answers to Consultation Questions

Targeted Capacity Mechanism

1. IPR believes that the Targeted Capacity Mechanism with economic dispatch is an inappropriate response to the flexibility challenge that will arise over the coming decade and beyond, and will not adequately meet the UK's security-of-supply needs. A market wide mechanism is a better option than the targeted capacity approach in delivering the required flexible capacity for the system. The reasons for this are covered in our detailed response to the Consultation questions below.

Question 1: Does this table capture all of your major concerns with a targeted Capacity Mechanism? Do you think the mitigation approach described will be effective?

2. No, the table does not consider the following important issues:

   - how it will ensure there is sufficient capacity to provide flexibility as well as meeting peak demand;
   - how it will avoid the 'missing money' issue which is a disincentive for existing and new investment;
   - it does not provide any detail as to how the dispatch price will be set to give confidence that the proposal offers a workable solution; and,
   - it recognises there will be an interaction between this mechanism and STOR but does not address the issue;

   On the provision of flexibility

3. It is widely recognised that increasing intermittent generation in the electricity mix, alongside inflexible nuclear generation brings with it flexibility demands on the system to maintain security of supply. The nature and scale of flexibility required ranges from fast response to cover unforeseen trips by large generation units at one end of the spectrum to the provision of generation during anti-cyclone conditions when there is relatively little contribution by the wind sector. A Strategic Reserve of a few GW will not be sufficient for this purpose, even allowing for a contribution by Demand Side Measures and imports, neither of which can be considered 'firm' capacity over an extended period.

   On the 'missing money'

4. Currently, around 18% of generation comes from wind and nuclear sources - National Grid forecasts this will increase to 37% and 43% by 2020 and 2025 respectively[1]. The level of wholesale prices will be less important to new, low carbon generation as it will be subsidised, primarily through Contract for Difference (CfD) contract strike prices – this could result in more volatile and, overall, lower average prices in the wholesale market.

[1] *Operating the Electricity Transmission Networks in 2020, June 2011 Update Table 2*

5. In this market, the remaining non-subsidised thermal generation, which will be needed to meet demand and cover the low carbon generation when it is not available, will have to earn its revenues from a more difficult wholesale market, with more emphasis on infrequent and uncertain price spikes to deliver a return on investment.

6. The Strategic Reserve as it is currently envisaged has the potential to cap peak prices leading to 'missing money[2]'. Not only will generators have to predict when peak prices will occur, there is a risk that the inherent price cap resulting from a Strategic Reserve will prevent prices going high enough to provide a return to fixed costs.

7. The extent of the 'missing money' could be minimised by setting the dispatch price so that Strategic Reserve is only called upon as a last resort once the Short-Term Operating Reserve (STOR) has been exercised, and all available plant outside of the Strategic Reserve has been called, and the only options left are voltage reductions and enforced customer curtailment - but this does not seem to be Government's intent for the Strategic Reserve.

8. There have been suggestions that reform of cashout prices might address the 'missing money' issue. The cashout mechanism design would have to allow prices to 'spike', and generators are able to predict when these price spikes were going to occur in order to take advantage of the knock on effect of higher short term wholesale prices. This in itself is not a simple task; industry has already devoted much effort in considering ways to better reflect the cost of reserve holding in cashout prices and so far has not been able to find a solution that the regulator has been willing to adopt. And this is without the added complication of having to consider the unpredictability of wind in the mechanism design.

9. There are also other consequences of this type of cashout reform. Penalties for 'going short' would potentially increase, perhaps significantly. Increasing balancing risks in this way is unlikely to be consistent with other policy objectives. In particular, for physical events that cannot be prevented (e.g. a sudden plant trip or fall in wind speeds) companies can be exposed to imbalance prices that could, in the extreme, result in disproportionate financial damage to a generator or a small supplier. This is one of the key reasons why Ofgem has rejected past proposals to calculate cashout prices based on marginal actions in the balancing mechanism.

On setting the dispatch price

10. The Consultation does not define how the dispatch price will be determined other than it will be set above the highest Long Run Marginal Cost (LRMC) plant in the market but below the Value of Lost Load (VOLL). Setting this price at the appropriate 'sweet spot' will be fraught with difficulty.

11. The body running the mechanism will need to make assumptions as to the likely cost and utilisation of the most expensive generation plant operating in the market. A generation unit that runs a few

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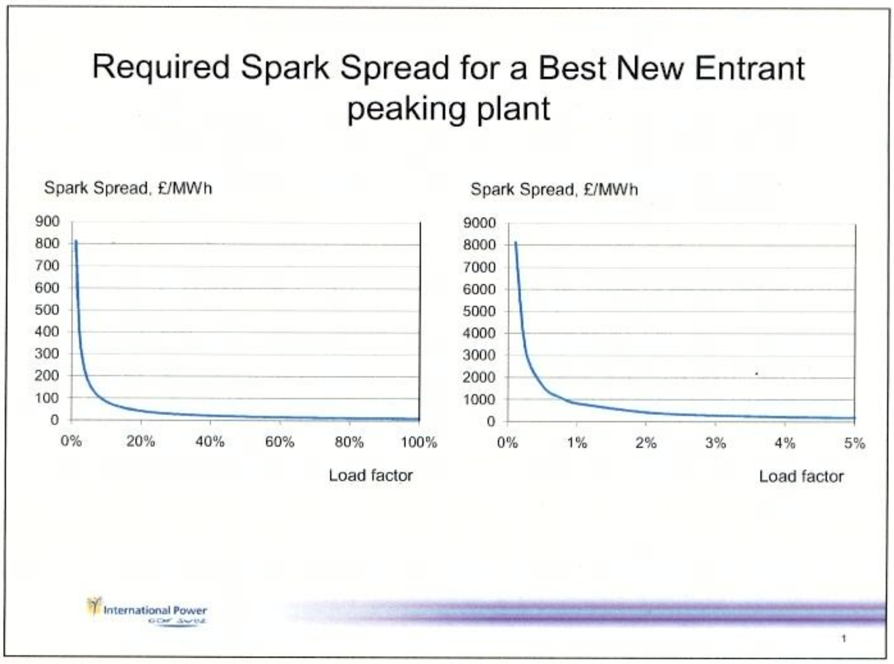
[2] In an energy-only electricity market, generators earn all of their revenues through the sale of electricity in the wholesale market (including markets for forward and spot power, as well as balancing services), and no additional mechanisms (eg, capacity payments) are used to cover generators' costs (including financing costs or capital charges). Price spikes therefore provide a signal of the need for more generation capacity and thereby incentivise new market entry. If high prices during peak hours are not realised due to interventions by system operators or regulatory authorities, generators may earn revenues that are insufficient to cover their costs. This phenomenon is commonly referred to as the 'missing money' problem

times per year to meet peak demand has to cover all of its annual costs, including financing and an investment return, in a very limited period of running[3]. The fixed costs alone of operating such a unit will be extremely high for a new entrant. For example, twenty hours of annual running (equivalent to running for 4 hours per day for 5 days over an anti-cyclone period)[4] would require an hourly spark spread of around £3200/MWh[5], with fuel costs and other variable costs in addition. The required fixed cost recovery for such a unit is depicted in the figure below, one across the range of load factors and one focusing on load factors of up to 5% where the unit could be expected to be used.



12. If the dispatch price is not set above the absolute peaking unit, the mechanism proposed will be introducing a cap on market prices and not allowing them to reach levels that reflect the cost of meeting demand. In this instance, the peaking unit that should operate in the market never runs at the peak because prices are not allowed to rise high enough for it to operate profitably, and new plant is not built unless it receives a Strategic Reserve contract to cover all its fixed costs. The peaking unit either closes or requires a Strategic Reserve contract to remain open leading to the 'slippery slope'.

13. Whilst it is not explicit in the consultation, we presume that the System Operator will not take account of the contracted utilisation price of the Strategic Reserve units in deciding when to call the

[3] *There is little clarity on how Demand Side Response will be included in the calculation of LRMC – Demand Response is often seen as an expensive generator with a price even closer to VOLL*

[4] *Strategic Reserve may not be needed all of the time during an anti-cyclone, rather it would be needed to cover the peak demand of the day*

[5] *This is based on the 2012 Best New Entrant unit in the All Island Market where the estimated annualised fixed cost for 2012, has been set to €80.66/kW/year or around £71/kW/yr.*

unit. The tender price to utilise the strategic reserve unit and the dispatch price should be kept entirely separate. Without this separation, the functioning of the wholesale market will be undermined as a large part of the cost of the Strategic Reserve unit will be in any fixed option fee.

On the interaction with Short-Term Operating Reserve (STOR)

14. The Consultation recognises that there is an interaction between STOR and Strategic Reserve - the dispatch price of Strategic Reserve must be set above the highest utilisation cost of STOR in the market. Even if Strategic Reserve is introduced, there will still be a requirement for STOR contracts as they serve a different segment of the market; the ability to respond within 20 minutes.

15. The interaction with the wider ancillary services market also needs to be considered - any potential for conflict between the Strategic Reserve and the ancillary services market needs to be removed and if it cannot be removed must be managed accordingly.

Question 2: How long should the lead time for Strategic Reserve capacity procurement be and why?

16. We are aware that Government envisages Strategic Reserve being aimed at existing plant that would otherwise close with new entry operating in the energy market occuring further 'up the merit order'. Other than OCGTs, existing plant will between several hours and a day's notice to start operation. To call this plant under the Strategic Reserve mechanism, assumptions may need to be made about whether the market price will reach the level of the dispatch price before the market price spikes. This would not appear to be the intent of the Strategic Reserve mechanism. It seems to be clearly defined as only being used when market prices reach the dispatch price, not before they reach the dispatch price. Furthermore, in the time it will take for Strategic Reserve units to be usefully generating, the problem may have gone away or been resolved by the market.

17. To avoid having to make this assessment, the only plant that can participate in the Strategic Reserve mechanism will be plant that can commence operation after prices have spiked. New entry peaking plant will be needed to provide the speed of response; a substantial volume will need to be set aside and 'sterilised' from the market to cover extended periods associated with anti cyclones.

18. Ofgem has been charged with providing the Secretary of State with an annual assessment of different capacity margins 4 years ahead and the consultation proposal aligns with this time period.

19. However, past practice suggests this is insufficient to cover the whole of the construction life cycle (planning, connection, financing, Engineering, Procurement and Construction (EPC) contract, construction). Appendix 1 shows that this can vary from a best case of about 6 years to a worst case of nearly 14 years – the average of completed projects is 8 years; this duration could be shortened slightly if peaking OCGTs were being procured but not by much more than 6 months. This suggests that to provide the capability to deliver the requirements of Strategic Reserve, a 6 year+ procurement lead time is necessary.

20. A brief look at past Electricty Markets Outlook (EMO)[6] reports shows the difficulty on forecasting reserve margin more than a few years in advance. In 2007 for example, the EMO report was predicting a reserve margin for 2014 of just under 15%. Only one year later, the capacity margin for 2014 had increased to 21%. For 2009 the EMO report gives a derated capacity margin for 2014 of 30% whereas Ofgem as part of its work on Project Discovery calculates the margin for 2014 as somewhere between 12 and 22% dependent on the scenario used. Finally, the EMR White paper[7] now gives a derated capacity margin for 2014 of around 20%.

21. The EMO highlights the difficulty in forecasting the capacity margin sufficiently far in advance to align with investment lead times. The likelihood of achieving this with any degree of accuracy will be small. A decision on the procurement of Strategic Reserve will therefore need to be made before there is certainty over the level of the requirement. This highlights one of the limitations of the Strategic Reseve mechanism or indeed any volume based mechanism.

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

22. For new providers, to avoid potential stranded assets, the desired tender duration would need to approach the expected life of the asset. The procurement function on the other hand may want to retain the flexibility and potential for innovation associated with shorter duration contracts. As highlighted in our response to Question 2, the further out the forecast of the requirement is undertaken, the lower the degree of accuracy. This applies equally to the contract duration as the central body will be locking into contracts that may subsequently prove to be unnecessary.

23. This conflict over the procurement lead time and the duration of the contract could be overcome by introducing a price based market wide scheme similar to the capacity mechanism in the Irish market. Under a such a scheme, the contract duration need only be annual. The question then would be not about whether there would be a capacity payment; rather it would be about the level of payment.

24. Under the Strategic Reserve mechanism, the nature of the contracts should be constrained to ensure equivalence across different kinds of capacity providers. For example, any provision from demand side response should be required to provide the same flexibility, duration and availability hours per year as reserve provided by generators[8]. Without this equivalence of treatment, there is a risk that reserve prices will become depressed without actually ensuring security-of-supply.

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[6] *See for example chart 4.3 of http://webarchive.nationalarchives.gov.uk/+/http://www.berr.gov.uk/files/file41995.pdf*

[7] *Figure 20*

[8] *Under debate in the Pennsylvania, New Jersey, and Maryland (PJM) market at present 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 Demand Side Response (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, resulting in home temperatures of over 30°C. In this one single incident, 1% of providers cancelled their participation. This raises the question as to how much DSR could be relied upon if it were called on 10, 20 or 100 times a year?*

25. The contract must ensure that providers can only participate in the Strategic Reserve - capacity must be 'sterilised' from the rest of the market to ensure it is offering additional capacity to the market.

Question 4: Which criteria should providers of Strategic Reserve be required to meet?

26. The table below compares different types of providers against the criteria needed to maintain security-of-supply, drawn from experience in US markets.

Comparing capacity resources in the US market

Capacity need (1)	Real Time Demand Response	Imports (2)	Generators
▪ *Deep Emergency Actions*	✓	✓	✓
▪ *Moderate Emergency Actions*	✓	✓	✓
▪ *Real time avoidance of an emergency*	✗	✓	✓
▪ *Day Ahead Avoidance of an emergency*	✓	✓	✓
▪ *Real Time economic dispatch (intra-hour)*	✗	✗	✓
▪ *Real Time economic dispatch (hourly)*	✗	✓	✓
▪ *Day ahead energy market*	✗	✓	✓

Notes : (1), Example from ISO-NE 'market' (Independent System Generator – New England); (2), scale of contribution limited and may not always be available

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27. The table shows that only generators can deliver across all the attributes required; Demand Side Response can serve as an integrated part of capacity supply but cannot provide the same levels of service as conventional generators; they can contribute to an apparent capacity oversupply, depressing capacity prices, and discouraging new investments. This is not to say that International Power opposes DSR, only that all providers must be treated equally.

Question 5: 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?

28. Please see our response to Question 4. All reserve resources should meet a minimum deliverable standard before being able to participate in the tender mechanism. Capacity market designs with the same payments to all resources regardless of attribute provided have led to an excessive amount of demand reduction bidding into the market and contributed to an apparent capacity over supply, depressing prices and discouraging new investment. This has been a significant issue in the

Pennsylvania, New Jersey, and Maryland (PJM) market in the US, where rule changes have been introduced over time to tighten up demand response requirements.

29. In terms of currently out of market reserve provision such as storage, if Government intends to procure a mix of providers, then storage can be incorporated simply by specifying it in the mix and paying the cost incurred. However, to secure investment, a storage provider is likely to want to secure a long term (20 year) Strategic Reserve contract. Acceptance will lock Government into this technology for a long period, foreclosing the market to future, lower cost storage innovations and also to other potential lower cost options of Strategic Reserve.

30. Strategic Reserve does not seem an obvious option for an interconnector. The EC wishes to see more interconnection to allow the free flow of electricity across borders. Sterilising some interconnector capacity that can only be used when market prices reach a certain level will not help to achieve this objective especially when there is no guarantee or perhaps even proven evidence that there is actually capacity available on the other side of the interconector. Furthermore, anti cyclones may not just occur in the UK, they could cover a much wider geographic area as happened at the end of 2010. Political pressures to keep the lights on in one country may outweigh any contractual obligations to supply electricity through an interconnnector to the GB market.

Question 6: Government prefers the form of economic dispatch described here. Which of the proposed dispatch models do you prefer and why?

31. In terms of when the Strategic Reserve is used, it should make no difference whether economic dispatch or last resort dispatch is adopted, so long as the Reserve is not used until all available capacity in the market has been accessed.

32. However, if the last resort dispatch option is adopted, any uncertainty about changes to the dispatch price would be removed. Whilst IPR does not support the introduction of a targeted capacity mechanism, if Strategic Reserve was to be adopted to ensure resource adequacy, a last resort approach would be preferable as it would not remove revenues from the energy market. This knowledge would enhance investor certainty particularly for existing assets as any concern that the dispatch price could be set below that of a peaking unit operating in the market would be removed. There would however need to be enduring and concrete guarantees that the mechanism would only be used to avoid demand disconnection or voltage reduction, i.e. to keep the lights on.

Question 7: How would the Strategic Reserve methodology and dispatch price best be kept independent from short-term pressures?

33. To have confidence in the mechanism, it is vital that the methodology is kept independent from short term pressures. The dispatch price must be set by a body independent from the market and free from political interference. Neither Ofgem who have a primary duty to protect the interests of consumers, nor National Grid who have an incentive scheme that may conflict with taking on this role, are appropriate. To keep the price setting independent from short-term pressures, we suggest it is reviewed every 3 years following consultation.

Question 8: 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?

34. Periodic review of the need for Strategic Reserve should be carried out by the same body that sets the dispatch price is important to ensure that the Strategic Reserve is delivering security of supply effectively. Such a review should be conducted every 5 years to minimise the risk to existing investments. Should it be concluded that a Strategic Reserve mechanism is no longer necessary; any existing contracts should be honoured to avoid stranded assets.

Question 9: Into which market should Strategic Reserve be sold and why?

35. It is difficult to see how the Strategic Reserve can be utilised without impacting on the operation of the traded markets; there are problems for both the Balancing Mechanism (BM) and traded markets such as the day-ahead market.

36. Unless the Strategic Reserve plant is on hot standby or already running part loaded, National Grid will not be able to access the Reserve in BM timescales. National Grid would therefore have to make an assessment of *likely* imbalance prices and issue a Start-up contract to a Strategic Reserve unit in anticipation that it would be called in the BM[9]. Effectively, the window in which the System Operator takes control would be extended beyond Gate Closure into the forward market - this is a major change to the way in which the market operates and should be resisted.

37. Alternatively, this could be made part of the contract form, requiring Strategic Reserve to have the capability to deliver when needed in BM timescales. Keeping the Strategic Reserve unit in a state of 'hot standby' would however result in unnecessary costs for a product that should only be used in extremis.

38. Strategic Reserve should not be sold into the day-ahead market or indeed any forward market since this would not allow the market to resolve the supply-demand balance, and pre-judges outturn prices which may subsequently fall if, for example, wind generation picks up. Additionally, if it was offered to the market at the day-ahead dispatch price, as suggested in Paragraph C2.3.7 of the Consultation, we question why the market would ever buy it if this is the highest price the traded market can reach.

Question 10: Do you have any comments on the functional arrangements proposed for managing a Strategic Reserve?

39. Whilst International Power does not believe that Strategic Reserve is appropriate, the design, implementation, and operation of the functional arrangements will be critical if the Strategic Reserve mechanism is to ensure security-of-supply without damaging the integrity of the wholesale market.

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[9] *Typically, where plant has not run for a few days, it will need at least 6 hours notice to start generating, often longer and could be up to 24 hours.*

40. The Consultation suggests that the procurement function will secure the necessary volume and mix of Strategic Reserve. This is a move back towards central planning in determining the generation mix rather than leaving it to the market to compete in the tender. There is a question as to who is best placed, the market or a Government body, to determine the future generation mix, particularly when procurement, as indicated in our response to Question 2, might need to take place a minimum 6 years in advance to encourage new plant development.

Question 11: 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?

41. No. IPR does not believe Strategic Reserve is a workable solution. We have set out the reasons in response to earlier questions - in summary:

    a) New entry plants may be needed to ensure the necessary speed of response once market prices have risen to the dispatch price. The minimum 6 year procurement lead time will mean that the necessary new entry will need to be procured before there is certainty over the requirement.

    b) The Strategic Reserve as it is currently envisaged has the potential to cap peak prices leading to 'missing money.

    c) It will be extremely difficult to determine a 'sweet spot' for the dispatch price that has minimal effect on market revenues for plant operating in the energy market.

    d) The Strategic Reserve should not be called in the forward market as this would pre-judge out-turn market prices and unless it is provided purely from OCGTs, and cannot be accessed in BM timescales without issuing a warming contract. If a 'warming' contract is issued then this, once again, would be pre judging BM prices

Market-wide Capacity Mechanism

42. As indicated earlier IPR believes a market wide mechanism, is a better option than the targeted capacity approach in delivering the required flexible capacity for the system. However, the reliability mechanism as described does not work well with current arrangements and it is difficult to see how it might work in practice. Our concerns are captured in our detailed response to the Consultation questions below.

Question 12: How and by whom should capacity in a GB market be bought and why?

43. IPR's preference is for capacity to be bought centrally with costs charged to the consumer via their supplier. This will ensure a level playing field for all generators and avoid any need for bilateral credit. Bilateral contracting for capacity should not be adopted as the bulk of the trading will not be seen by the market due to the high level of vertical integration in the UK - it will simply result in a revenue transfer from generation to supply arms of vertically integrated companies or vice versa.

Question 13: What contract durations would you recommend for a Capacity Market?

44. It is difficult to give a precise answer as it depends on:

- the type of generation capacity being purchased;
- whether Government is going to prescribe a capacity mix or leave it to the market to deliver; and,
- whether the Government's objective is to lock-in capacity (i.e. determine the volume) or provide a forward signal of the value of capacity to the market (i.e. determine the price).

If the capacity payment is based on a clearly defined and transparent price based formula, forward contracts may not be necessary.

Question 14: How long should the lead time for capacity procurement be? Should there be special arrangements for plants with long construction times?

45. Please see response to Question 2. For new plant, a 6 year lead time appears necessary to align with new plant development timescales. However the chances of correctly forecasting the amount of capacity that needs to be procured 6 years in advance is small. A price based mechanism where there is enduring certainty over how the capacity payment is calculated coupled with smoothing of the level of payment could avoid the need for procurement lead times.

46. We do not think it appropriate to have special procurement arrangements for plant with long construction times - such long-term contracts will foreclose the market to plant with shorter procurement lead times.

Question 15: Should there be a secondary market for capacity? Should there be any restrictions on participants or products traded?

47. This depends on the design of the mechanism. A secondary market might not in all cases be necessary. Consideration will need to be given to whether the secondary market will be captured by the requirements of the OTC derivatives regulations[10] or any other accounting regulations.

[10] *For example, EMIR – European Market Infrastructure Regulation*

Question 16: 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?

48. All of the above need to be determined centrally to ensure the efficient working of the capacity mechanism and enable security of supply to be achieved.

49. *Capacity that can be offered into the market* – To avoid the need for excessive penalties, a centrally defined derating should be applied to generators grouped by fuel type and by age. Parties could be given the option to offer greater capacity than the deemed level of de-rating but to ensure the capacity requirement is met in real time, penalties for this extra offering would have to be more stringent.

50. *Criteria for being available* – Clearly this has to be centrally determined to ensure equivalence of treatment and ensure that each device can provide the attributes needed. For example, providers should be required to be available with a warning of X hours, at least Y times per week, for at least Z hours during periods A, B and C. Availability can only be assessed through testing – at commissioning and on a periodic basis for units that run infrequently and also for the demand side who must also be able to prove they can meet the availability criteria.

51. *Penalties for non-availability* –The Balancing Mechanism already penalises failure to be available with much sharper signals at times of system stress; further penal charges for non availability are unnecessary. They will not encourage financing, particularly in peaking plant (for a marginal unit this could be the loss of a large part/all of the annual capacity payments on the one occasion when the unit was called but was unavailable). Hence they would not support the development of new plants when required; an essential part of the rationale for the capacity mechanism.

52. A degree of incentivisation is however needed. Repayment of the availability payment for the period of unavailability plus a small premium is a sufficient penalty. In the ISO-NE market for example, the penalty is set at 5% of the annual capacity revenue plus a further 1% for each hour beyond 4 hours in a 'shortage event[11]'.

Question 17: 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?

53. Imposing a reference market as described in the consultation will force the market to trade around that index to minimize exposure to the option being called. We can see the logic in this as it would helpfully create the liquid index needed for CfD FiTs. However, as noted in the Consultation, the reference market will need to be in the near term to minimise the risk of pay back.

[11] *Defined as a 30 minute or longer duration of ten minute reserve deficiency (inadequate protection against the largest first contingency)*

54. There are two more general important issues that make creation of a reference market problematic:

    a) Having a day ahead/within day reference market will not facilitate longer term trading. The uncapped exposure to repay when the market price rises above the strike price acts as a strong incentive to sell output only in the reference market. This will therefore impact on forward liquidity.

    b) If generators are unwilling to enter into longer term contracts, how can suppliers offer long term contracts to their customers? The only route to providing this is through vertical integration as exposure to the option being called can be internalised.

55. In terms of setting the reference price, to be close to real time, the options are the Balancing Mechanism cashout prices, a within day half hourly price or a day ahead price:

    a) Balancing Mechanism - Using the Balancing Mechanism as the reference market is not appropriate. Gate Closure prevents resources accessing these prices to trade to be close to reference price.

    b) Within day price - A within day half hourly would lead to large volumes being traded and then notified through the Final Physical Notification close to real time. Such late notification of the generation profile across GB would create problems for the System Operator in managing the system.

    c) Day ahead price - The price in the day ahead market is not fixed, it can move across the day in response to short term events such as plant trips. The reference price could be set at the weighted average price in the day ahead market but generators will not exactly capture this price and so will be left with potential price exposure to the option being called.

56. From the above comments, there is no obvious price that can be used to allow the proposed Reliability Mechanism to work in the way described in the Consultation.

57. 'Netting off' has been proposed as a potential solution to the uncapped exposure associated with Reliability Mechanism. If 'netting off' is applied, generators who have contracted forward and are generating are not exposed to paying back under the call option – i.e. if a generator has sold a call option for 500MW and is generating 400MW, it would only be exposed to repayment on 100MW[12].

58. This raises the question of where does the 'netting off' stop? If the generator contracts the remaining 100MW of output in the reference market, it is still a forward contract so should be 'netted off' ultimately leaving no capacity to which an option contract can be applied. The Reliability Mechanism in essence becomes payment of an option fee in return for accepting a price cap. The proposed complexity is not therefore needed and could be achieved through much simpler means such as the operator receiving a flat capacity payment in return for this price cap

[12] *This assumes that there is a way to track traded contracts and match them to physical generation to allow any call option exposure payments to be determined. This in itself is a complicated task.*

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

59. The Consultation proposes that the strike price represents a view of the boundary between normal system operation and scarcity conditions. Determining this boundary will not be an exact science as the price level will vary depending on numerous factors, including demand, wind output, marginal fuel, plant availability, and so on, and these which will vary from day-to-day and season to season. A fixed strike price that aligns with scarcity conditions at winter peak would be more appropriate.

60. This suggests that it should be determined in the same way as the dispatch price for the Strategic Reserve Mechanism – above the highest LRMC of plant operating in the market over a defined, long-term duration. The higher this level is set, the less the risk of exposure to changes in fuel cost. However, if set to this level, the value of the option fee will be low as the reference market price should rarely reach the strike price. The Reliability Mechanism will contribute little to the revenue and viability of plant operating at low load factors and thus will not make good the 'missing money'.

61. The Consultation further suggests indexing the strike price to fuel costs or other input factor costs affecting the marginal costs of a particular plant. Whilst this would make the strike price more reflective, as noted, it would introduce a bias towards the fuel used to set the index. The further forward the contract is struck, the more complicated the index will need to be to protect against unforeseen changes to for example, Transmission Network Use of System (TNUoS) charges, construction costs, interest rates, business rates.

62. To avoid the central agency having to make an assessment of the value of the option fee against the strike price, both the strike price and the reference market will have to be determined centrally and fixed across the market. This will create a 'vanilla' product and allow the option fee price to be determined by tender rather than on the basis of a contract by contract valuation.

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

63. Ultimately the contract has to become physical as traders will not wish to be left with an un-hedged position.

64. Monitoring compliance appears to be administratively challenging but without sufficient detail of how the mechanism might work, it is difficult to comment.

Question 20: 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?

65. Yes. If suppliers are to be obligated to buy capacity contracts then this could disadvantage independent generators. Vertically integrated companies with close to balanced generation and supply portfolios can self-insure and foreclose the market to independent competition and avoid the credit requirements. The Consultation proposes that this could be solved by having physical back up

requirements. This requirement will not change the ability of the vertically integrated operators to internalise their obligations under the reliability mechanism.

66. The other suggestion in the consultation to overcome vertical integration is to ensure that reliability contracts payback to consumers. Such a mechanism whereby the reliability contract is purchased on behalf of the consumer is, as noted, novel; with 23 million domestic customers, it is likely to be costly to administer.

67. This does raise the question on who would receive the rebates when market prices rise above the strike price. When this occurs, the generator will be making payments to the central body with whom he has the contract, not the supplier or the customer. It does not seem appropriate to direct the rebate to the supplier: if for example, the supplier has bought power baseload and this has been delivered by the generator, the supplier has not been exposed to high short term, wholesale prices and so should not receive a rebate. Alternatively, payments could flow from the central body directly to consumers through a reduction in bills when prices spike. This however seems counterintuitive.

Question 21: 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?

68. IPR believes generators should not be paid twice for capacity; either they receive the capacity payment or the CfD FiT. Potentially the level of the CfD FiT could be adjusted to reflect the revenue from the capacity payment but different contractual terms will add to the complexity of making this adjustment.

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

69. Participation should be on the same basis as for generation. It is important that these technologies do not undermine the value of capacity as has happened in the PJM market. All participants in the capacity market should be able to offer equivalence in terms of reliability offered to the system, duration, response time, ability to part load and continuous provision of availability whilst under contract (please see response to Question 4).

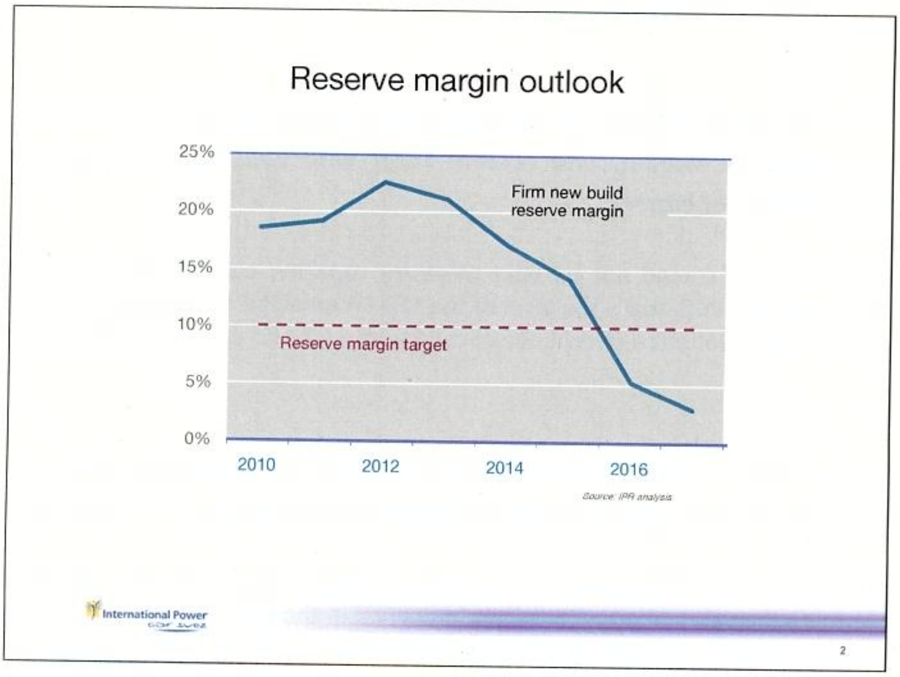
Question 23: Do you have any comments on the functional arrangements proposed for managing a Capacity Market?

70. The proposed functional arrangements in the Consultation are for illustrative purposes only – much will depend on the final detailed design of the capacity mechanism. IPR looks forward to contributing to the development of these functional arrangements to ensure that they are robust, enduring, independent, and subject to a clearly defined and pre-agreed change process.

Question 24: 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?

71. IPR <u>*does not*</u> believe that a trigger should be set. It would be more sensible to introduce it at a certain date to provide investor certainty and allow the market to determine the value of that capacity. If there is too much capacity at the point of introduction, the price will be lower.

72. We note that the Consultation envisages that the capacity mechanism would start in 2020 with procurement starting from 2015 onwards – the available evidence suggests that the capacity problem could become acute earlier. The graph below gives IPR's assumption of the de-rated capacity margin out to 2018 i.e. the margin assuming firm new build only.



73. The graph shows that the reserve margin falls below 10% in 2015/6, coinciding with 12GW of plant closing that has opted out of the LCPD and falls below 5% by 2018. In light of this, IPR believes Government should not wait until 2020 to introduce the mechanism. Although new plant would not be able to meet the emerging capacity gap on this timescale, a capacity mechanism would encourage existing plant to remain open until new entry could occur.

Question 25: What is the most appropriate design of Capacity Market for GB and why?

74. Please see our response to Question 27 where we have the foundation criteria that a capacity mechanism should meet.

Capacity Mechanism Assessment

Question 26: What are your views on the costs and benefits of a Capacity Mechanism to industry and consumers?

75. The White Paper estimates that £75bn[13] of investment is needed in generation capacity by 2020 to meet the low carbon targets.

76. The benefit of a capacity mechanism is that it provides a more secure investment environment leading to lower overall prices to consumers than might otherwise be the case.

Question 27: Which Capacity Mechanism should the Government choose for the GB market and why?

77. Neither of the proposed mechanisms is suitable in our view - the efficacy of the Strategic Reserve is highly dependent on the level of the dispatch price and is likely to lead to 'missing money' and the 'slippery slope'. The proposed Reliability Mechanism is not sufficiently well defined and based on what is presented we believe it is unsuited to the current trading arrangements.

78. IPR believes that more work is needed before an effective capacity mechanism emerges. An important contribution to this work is a set of criteria such a mechanism would need to satisfy – these are set out below and are divided into two levels to highlight their relative importance:

'Level 1' criteria include

- it is 'market-wide' i.e. it is open to all providers of firm, capacity which could include demand side, interconnectors and storage;
- devices must contribute on an equal basis to ensure resource adequacy;
- it addresses the need for flexible capacity as well as meeting peak demand;
- it provides stable price signals;
- market players are allowed to freely determine their capacity prices and energy prices;
- the mechanism must be simple to administer; and,
- it must be compatible with the existing market arrangements.

[13] EMR White Paper P6.

<u>'Level 2' criteria include:</u>

- it is technology neutral – a central body must not prescribe the mix that can participate in the mechanism as this results in central planning;

- the capacity must be centrally procured; and,

- whilst penalties are clearly necessary to prevent the participation of a 'cardboard generator', the extent of penalties should be limited so that the marginal unit that is called to run but fails does not suffer detrimental loss

79. A Capacity Mechanism should be developed in concert with other policy and regulation initiatives that will impact the market. For example, other EMR instruments such as CfD FiTs, changes to the charging regime, Significant Code Reviews and wider EU legislation.

Appendix 1 – Development times of plant extensions and new projects

- All data from publicly available 3rd party sources; assumes 24 months to obtain section 36 planning consent.
- Inspection of the 'Completed' projects suggests between 6 and 14 years, and an average of 8 years for completion.

New power stations development programme (1)

Development type	Extension	Extenstion	Extenstion	New Site	New Site	New Site	New Site	New Site
Power Stations	Immingham P2	Barking	Spalding	ICHP Phase 1	Marchwood	Langage	Gateway Energy Centre	Abernedd Power
Owner	ConocoPhillips	Thames Power /SSE/EDF	Intergen	ConocoPhillips	ESBI and SSE	Centrica	intergen	SSE
Plant size (MW)	450	470	900	760	842	895	900	450
Location	Humberside	Barking	South Lincolnshire	N-E Lincolnshire	Southampton	Plymouth	Essex	Port Talbot, Wales
Initial Developer	ConocoPhillips		Intergen	ConocoPhillips		Wainstones power sub. of NRG	Intergen	BP
S.36 Application	11-Nov-05	23-Aug-06	31-Mar-09	15-Nov-00	18-Oct-01	01-Jun-98	26-Feb-10	04-Sep-08
S.36 granted	01-Aug-06	19-Dec-07	11-Nov-10	11-Jul-01	28-Nov-02	15-Nov-00	04-Aug-11	23-Feb-11
Start of construction	15-Mar-07		01-Jan-12	01-Mar-02	01-Feb-07	01-Sep-06	01-Jan-12	
End of construction	01-Dec-09		01-Oct-14				01-Oct-14	
C.O.D	01-Jan-10		01-Jan-15	04-Oct-04	10-Dec-09	01-Mar-10	01-Jan-15	
Status	Completed	On Hold	On Hold	Completed	Completed	Completed	On Hold	On Hold
Design and internal development (Assumed)	24	24	24	24	24	24	25	24
Planning duration (months)	8.6	15.9	19.4	7.8	13.3	29.5	17.2	29.7
Project Construction (months)	33.6		36.0	31.2	34.3	42.0	36.0	
Total (months)	73.7		93.1	70.7	121.8	165.1	83.2	
Total (years) from s36 application plus development period	6.1		7.8	5.9	10.2	13.8	6.9	

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New power stations development programme (2)

Development type	Existing site	Existing site	Existing site	Existing site	Existing site	Existing site	Existing site	Existing site
Power Stations	Great Yarmouth	Uskmouth/ Severn Power	Medway/Isle of Grain	Drakelow	West Burton	Willington C	Carrington	Pembroke
Owner	RWE	Dong	E.ON UK	E.ON UK	EDF	RWE	ESB (85%)	RWE
Plant size (MW)	400	820	1275 CHP	1200	1300	2000	860	2000
Location	Norfolk	Newport, South Wales	Thames	Staffordshire	Nottinghamshire	South Derbyshire	Manchester	Wales
Initial Developer	BP	Carron energy						
S.36 Application	19-Jun-98	19-May-06	12-Dec-05	06-Sep-05	18-Jan-06	08-Dec-09	15-Aug-07	06-Jan-05
S.36 granted		17-Aug-07	31-Oct-06	16-Oct-07	30-Oct-07	04-Mar-11	30-Jul-08	05-Feb-09
Start of construction	01-Dec-98	01-Aug-08	01-May-07		01-May-08		01-Feb-12	15-May-09
End of construction	01-Oct-00	01-Nov-10	31-Mar-11					
C.O.D	01-Sep-02	10-Feb-11	25-Jul-11	31-Oct-14	01-Jan-12		01-Aug-14	01-Dec-12
Status	Completed	Completed	Completed	Not In Construction	Under Construction	Not In Construction	Under Construction	Under Construction
Design and internal development (Assumed)	24	24	24	24	24	24	24	24
Planning duration (months)		15.0	10.6	25.3	21.4	14.8	11.5	49.0
Project Construction (months)	45.0	30.3	50.8		44.1		30.0	42.6
Total (months)	74.5	80.8	91.4	133.9	95.5		107.6	118.9
Total (years) from s36 application plus development period	6.2	6.7	7.6	11.2	8.0		9.0	9.9

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<u>For further information please contact:</u>

[redacted]
CEO and President, UK-Europe
International Power Plc
Senator House
85 Queen Victoria Street
London, EC4V 4DP
Telephone: [redacted]
Email address: [redacted]

Or

[redacted]
Market Development
Government Affairs, policy and Regulation
Bala House
Lakeside Business Village
Deeside, CH5 3XJ
Telephone: [redacted]
Email address: [redacted]