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Dear Ian,

Project Discovery: Options for delivering secure and sustainable energy supplies

Thank you for giving us the opportunity to respond to this important consultation. This letter and the attached document represent Centrica's response. We can confirm that our response is not confidential, and we are happy for it to be posted on Ofgem's website.

If you have any questions regarding this submission, or require any clarifications on the substance of our response, then please do contact me.

Yours sincerely,

pp. Tim Dewhurst

Philip Davies
Director of Regulatory Affairs
British Gas

31 March 2010

Centrica's response to Ofgem's consultation on "Project Discovery – Options for delivering secure and sustainable energy"

Executive summary

1. Project Discovery is a wide-ranging review of the electricity and gas market arrangements. Ofgem is right to ask some critical questions about how market arrangements need to evolve to deliver decarbonisation and security of supply. Centrica believes customers continue to be well-served by the gas market arrangements and gas wholesale markets are not in need of major reform. However, the electricity market is now reaching a point where issues around its design need to be addressed, so that it is fit for purpose to meet the targets government has set.

2. We support the development of a minimum carbon price, as we do not believe the existing carbon price signal will provide a sufficiently strong incentive for investment in new low carbon generation. Given the long lead times for the development of nuclear generation, the decision to introduce a minimum carbon price must be made within the next 12 months if new nuclear is to be operational by 2017. This is critical because new nuclear investment is central to delivering large volumes of low carbon electricity in the future. Equally if the investment decision is not made within the next 12 months there is a real risk that the UK will lose its place in the queue with nuclear equipment vendors and very considerable slippage to delivery timescales will occur. Depending upon the level of carbon price this mechanism may also need to be supplemented with additional low carbon mechanisms.

3. Government and Ofgem also need to give priority to developing arrangements to ensure that flexible plant is appropriately remunerated in a generation mix with much more intermittent generation. Even with reform of cash out, prices may not rise to levels sufficient to incentivise new build in the flexible capacity that will be essential to provide system back up. Therefore a flexibility or capacity market needs to be considered. Similarly, Ofgem needs to commit now to an ambitious timetable for ensuring industry arrangements are replaced and simplified to facilitate the rollout of smart meters to all households and businesses, including reform of the electricity settlement arrangements. This is essential to unlock the potential of the demand side to help avoid expensive generation and network investment. Given the lead times in delivering on these priorities, Ofgem must capitalise on the window of opportunity it identifies by developing and committing to detailed programmes in 2010 so that the new arrangements and related systems can enter into force as soon as possible.

4. We do not believe the more interventionist options set out by Ofgem are necessary or helpful to consider given the proven ability of the energy market to deliver new investment. The central energy buyer would not provide the dynamic, responsive framework for decision-making that the market offers, would undermine retail competition and would stifle innovation. Furthermore, while policy action is required to ensure we have the right mix of generation capacity, this does not mean we need capacity tenders for all plant. More targeted intervention aimed at ensuring that the electricity market has the low carbon generation and the flexible generation it will need will be more effective. Finally, with a reformed Renewables Obligation now in place, there are no benefits from seeking to replace it now with another new mechanism.

Overview of Our Response

Market Arrangements Must Evolve to Meet the Investment Challenge

5. In this response, we set out our reform agenda, an agenda mainly focused on the electricity market. Key choices about the design of the market will rightly remain the prerogative of government. However, Ofgem, whose position as an independent

regulator is now entrenched in EU law, has a key role to play in promoting this necessary evolution in the competitive market. If Ofgem performs this role well, this will help to ensure that capital investments continue to flow in to the energy sector.

6. We agree with Ofgem that there are "reasonable doubts" whether the current arrangements will deliver decarbonisation and security of supply, and we also agree that doing nothing is not an option. The current wholesale electricity market was set up before the adoption of challenging decarbonisation targets at UK and EU level, which will require substantial decarbonisation of the power sector given the scale of the reductions and the sizeable contribution to total emissions from electricity generation. To ensure the UK meets the 2050 target of an 80% reduction in carbon emissions, the binding carbon budgets and renewable energy targets for 2020 suggest we need to produce 40% of our electricity from low carbon sources by 2020, of which around 30% should come from renewables.

7. It is therefore normal that the market framework needs to evolve to enable these targets to be met, to ensure that low carbon generation replaces old plant reaching the end of its life and to ensure that the market adequately rewards the flexible plant that will be required to back up the intermittent (wind) generation that will become a more substantial share of installed capacity. As reserve margins tighten over the coming years, these are increasingly pressing issues that require government and Ofgem attention. While the market has delivered substantial new capacity, future long-term investment decisions are now clouded by questions over how the policy framework will adapt from here.

8. Government's preferences for the technologies it wants to see as part of the generation mix will be increasingly reflected in the market arrangements. In parallel, the government is also committed through obligations on suppliers to driving a step change in energy efficiency and a reduction in carbon emissions associated with household energy consumption. However, it remains important that the power of competition to reduce costs and promote innovation continues to be underpinned by the regulatory framework. This framework needs to promote stability and confidence for investors while simultaneously adapting to meet new public policy priorities. The evidence that competition provides the best incentives to reduce costs, improve efficiency and diversify risk is overwhelming.

9. Indeed, the gas market illustrates how private investors, without any central direction, have responded to the long-term strategic challenges faced by GB gas customers. The current gas market arrangements have demonstrably been a key factor in the success in developing and assuring both long term and short term security of supply. The market has responded spectacularly to the need for customers to have access to more diverse sources of gas as North Sea supplies have started to decline. Over £10 billion has been invested in new pipelines interconnecting GB with the Netherlands and Norway and in new LNG terminals and facilities, giving customers access now to a global market for gas supplies. Demand side response from large customers, particularly gas-fired power stations, has also played a key role.

10. While the risk of price volatility we face as a result of imperfect European gas markets remains a real concern, companies such as Centrica have invested precisely to help our customers manage and diversify their risks to ensure their future supply. There are, however, a number of areas where Ofgem needs to develop the regulatory framework for gas, for example by reviewing cash out and balancing pricing, to ensure the market continues to operate efficiently.

Carbon Pricing, Improving Price Signals and Demand Side Response are Key

11. For the electricity market to accelerate its transition to a world of decarbonised supply, Ofgem needs to work with government in the following key areas.

Support Mechanism for Low Carbon Generation

12. The current carbon price signal alone is highly unlikely to provide a sufficient incentive for long term investments in new low carbon generation. This is particularly likely to deter investment in new nuclear generation, which, as the Committee of Climate Change notes, is the cheapest form of low carbon generation. New nuclear will be needed in order to meet the UK's carbon targets, and in order for this to be in place by 2017, a support mechanism for low carbon generation must be agreed within the next year. Ofgem is therefore right to signal that there is a window of opportunity for change here. We agree that a minimum carbon price needs to be explored as an urgent policy option. Support for low carbon generation could take several forms, including a restructuring of the Climate Change Levy, a minimum carbon price or other measures.

Improving Price Signals

13. Flexible conventional plant will run at lower load factors as more renewable and new nuclear generation comes on the system. However, it will provide critical system back-up and we will need more of it as generation becomes more intermittent. Sharpening short term price signals through reforms to cash out will ensure this plant is better remunerated at times of system tightness. However, on its own this is unlikely to provide a sufficient business case for the new investment in back up and peaking generation that will be needed. This is because there are likely to be concerns over whether prices at these levels would be tolerated by politicians and regulators, particularly given that such high short-terrm prices will never have been experienced before in this market. Therefore Ofgem needs to urgently explore other ways to facilitate the transition to a more intermittent generation mix, including the development of a flexibility or capacity market. The scale of the problem will be influenced not only by the quantity of intermittent wind that is installed but by the ability of a "smart grid" to manage demand and the additional demands that may be placed on the grid by electric vehicles.

Demand Side Response

14. It is essential that Ofgem and the market arrangements unlock the potential of the demand side. Customers who change their behaviour and respond to high prices already make an important contribution to ensuring security of supply and reducing carbon emissions, with British Gas customers, for instance, reducing their gas consumption by 7% in 2009, as a result of both behavioural change and investments that suppliers have delivered for them in their homes (e.g. insulation, more efficient boilers). Government is committed to ensuring a further step change in household and business energy efficiency. Smart metering, smart grids and policy measures to help customers contract for energy services all have a key role to play in ensuring that the full potential and flexibility of the demand side can be exploited to improve security of supply and contribute to the decarbonisation of the energy sector.

15. Measures to develop the demand side will make a significant contribution to managing intermittency, as well as reducing the amount of installed capacity required to meet peak electricity demand. Ofgem therefore needs to commit to an ambitious timetable for ensuring industry arrangements are replaced and simplified to facilitate the rollout of smart meters to all households and businesses. This must include reform of the electricity settlement arrangements so that households that want to adopt time-of-use tariffs can be settled against their actual consumption. Supported by government policy, the competitive retail market is now driving a transformation in energy services, reflected in the growing role of energy efficiency and small scale generation in reducing emissions and energy consumption. Ofgem's policies should support this transformation. Policy measures are also required to help facilitate the delivery of capital investment into homes and businesses to improve energy efficiency. Measures are needed to help suppliers reduce the default risk associated with such investment. In this regard Ofgem should explore the merits of extending the right to object to also include energy service debt.

Centralised Renewables Market

16. The idea of a centralised renewables market suggested by Ofgem is worth exploring. However, its design may present some practical problems and it is less of a priority than the other policy measures we recommend in this paper, all of which are more critical and more urgent to resolve. If the system operator can forecast all intermittent output using real time data from wind farms in a way that leads to better aggregate wind generation forecasts, the net position could be balanced at lower cost. If wind generators were then only charged their share of the net imbalance cost, this would reduce the imbalance penalty currently faced by wind generators and encourage smaller, independent wind generators. It would simultaneously resolve any concerns intermittent generators may have about sharpening cash-out pricing signals.

Other Options, including Capacity Tenders and Central Buyers, Should be Rejected

17. Beyond the progressive agenda of reforms we set out above, we believe the other options set out in the consultation all have serious limitations and disadvantages, and indeed many of them are likely to be counterproductive, damaging investor confidence. We deal with each of the categories in turn:

Enhanced Obligations on Suppliers

18. Once action is taken, where necessary, to ensure prices are sending the right signals to market participants, any additional obligations on generators and suppliers need to be approached with caution. There is no evidence, for instance, to suggest that suppliers need to be incentivised to increase their forward contract cover in gas or electricity, or that any such measures could be introduced without doing more harm than good. For instance, obligations on suppliers to contract ahead for gas storage are likely to distort the choices they have to make between the various flexible forms of supply (e.g. LNG or demand side response) to which they may have access, pushing up costs to customers. Seasonal requirements would also likely increase seasonal volatility in prices which would be to the detriment of customers.

The Renewables Obligation

19. The Renewables Obligation has now been reformed into a support mechanism that has many of the characteristics of a feed-in tariff (and with the introduction of the headroom mechanism is also comparable in terms of efficiency). There are no significant benefits to be gained from transitioning to another form of support. Even with grandfathering of existing rights, the development of any new replacement mechanism would cause a hiatus in the investment cycle. At the end of it there would be no guarantee more renewables will be delivered on the system or that its average costs would be more economic than currently delivered by the RO. To the extent there are concerns about the RO over-rewarding certain technologies, particularly if and when a long-term solution to carbon pricing, such as a minimum carbon price, has been put in place, it is worth remembering that the new RO has provision for regular banding reviews. This will enable a review of the support level in the light of any agreement being reached on a long term carbon price solution.

Capacity Tenders

20. If Ofgem and government take forward the work we recommend, there is no need to consider more radical options, such as government tenders for capacity. Huge amounts of private sector investment in gas and electricity have been delivered since privatisation, without any capacity tenders. Policy action is required to ensure we have the right mix of generation capacity on the system, given the decarbonisation requirement and the challenges of intermittency. We recognise that different ways of providing the required support for low carbon generation may need to be explored. However, we believe these objectives can be achieved through more targeted interventions aimed at specific requirements rather than the use of capacity tenders (which cover broader categories of generation).

21. Reliance on capacity tenders would make the government responsible not only for the design but also the execution of a national energy procurement strategy. It would take on this role in the face of an increasingly international energy market with huge uncertainty over future technologies and costs. It would need to design tender processes and contracts to strike the right balance between security of supply and cost. It is far from clear how practical tenders would be for some investments (eg. new nuclear), particularly where there are likely to be few bidders. The basis of this policy would have to be a belief by government that its choices would be superior to the choices the market would otherwise make. Given the track record of the GB market in attracting investment, it is not clear why the government would want or need to reach this conclusion.

Central Energy Buyer

22. Given future uncertainty, we need dynamic decision-making processes, processes that can adapt and manage in the face of changing technology and changes in relative costs between different low carbon solutions. A central buyer model is not well suited to facilitating this sort of dynamic investment process. Critical decisions on cost and technology would be made by administrators or civil servants, based on limited information. The market was liberalised in the 1990s precisely because of the poor investment and service record of the industry at that time, which operated according to this model.

23. A central buyer would also undermine retail competition, where suppliers compete by contracting for their energy on the most economic terms. This can be a source of competitive advantage for suppliers and the threat of losing customers due to relatively high prices incentivises suppliers to procure their energy as efficiently as possible. This benefit is likely to be lost in a central buyer model, where customers are likely to be locked in to the investment decisions made by the central entity.

24. The scale of the investment challenge therefore points to need for policy-makers to unblock barriers to making more, not less, use of the power of markets to make the investment decisions that customers need.

25. We set out our more detailed comments in the following sections:

- the reforms needed to meet future challenges; and
- that more interventionist policy proposals are both unnecessary and potentially counter-productive.

Reforms needed to meet future challenges

26. We agree that there are specific issues in the electricity market that do need to be addressed if the twin objectives of security of supply and decarbonisation are to be achieved. However, there are a number of areas where Ofgem's analysis has underplayed the proven ability of markets to deliver huge levels of investment, particularly in the context of the gas market.

27. We recognise the scale of the challenge ahead, and agree that the scale of investment that will need to be undertaken to meet Government targets for sustainability is unprecedented. The scenario results presented by Ofgem are also broadly consistent with the results of the July 2009 Ernst & Young study which concluded that:

- even after factoring recent falls in demand into forecasts of energy requirements, overall investment required by 2025 would be in the region of £200billion;
- a major ramping-up of investment over the next five years will be needed to meet the government's 2020 targets, with around £90billion needing to be invested by 2015; and
- around £40billion of this will need to be in renewable investments, with around £11billion needing to be invested in energy efficiency measures

28. The study also concludes that for this investment to be triggered, it is essential that investors have confidence that the regulatory regimes in place at the moment will not be summarily changed without adequate warning, or adjusted frequently in response to changing policy priorities. Ofgem will have a key role in providing this stability for the market.

29. However, while the challenge is clear, it is important to recognise that over the past twenty years, the GB energy market arrangements and the regulatory framework have combined to deliver an impressive investment record. And in the gas market in particular, this has delivered not just competitive prices in the short term, but has been fundamental in enabling the market to transition in the face of a series of supply and demand challenges.

30. In gas, we have moved from a position of self-sufficiency to one where we are increasingly dependent on imports. The response of the market to this change has been to trigger investment of over £10 billion in gas import and storage projects. This investment has enabled us to increasingly source our gas imports of piped gas from Norway and the continent and LNG from Qatar, Algeria and further afield. Nearly 30% of our existing gas import capacity is provided by investments that have been completed since 2006. In electricity, markets have also delivered significant amounts of new capacity, over 30GW of plant over the past 20 years. Such high levels of investment have also been achieved while GB customers have benefited from some of the lowest retail energy prices in Europe.

31. Although markets have shown that they are able to deliver significant levels of investment over a sustained period of time, in response to changes in supply and demand, they were not designed to deliver a low carbon energy sector. The wholesale electricity market was designed before the adoption of challenging decarbonisation targets at UK and EU level. It is therefore normal that the market framework should evolve to enable these targets to be met.

32. The challenge ahead differs significantly for the gas and electricity sectors, and therefore the ways in which the market needs to evolve in these sectors also differs. We set out our views on the level of change we believe is necessary in each of these sectors below

The evolution of electricity market arrangements

33. The government's sustainability targets mean that the targets are unlikely to be met unless there are significant increases in renewable generation, as well as new nuclear plant. Changes will also be needed to ensure that sufficient volumes of flexible plant are available to facilitate the transition to a more intermittent generation mix.

34. As a result, we believe that significant changes to the electricity arrangements may be needed in the form of:

- increased support for the carbon price;
- improved price signals;
- enabling of demand side response; and
- centralised renewables market.

Support for the carbon price

35. We support Ofgem's statement that ideally the carbon market would be sufficient in order to promote low carbon investment. However, the UK's carbon targets are more ambitious both in terms of scale (actual carbon reductions) and timing than the current EU ambitions. We therefore believe that to meet UK targets it will be necessary to supplement the existing EU carbon scheme with additional policy measures.

36. At present, there are various policy measures in place to incentivise a range of different low carbon generation investments, from ROCs to direct support for CCS plants. These are proving successful in stimulating new investment in the areas on which they are targeted. However, investment in one key low carbon generation type – nuclear – is currently not supported by any mechanism (beyond reliance on the volatile, low price carbon markets).

37. Not only is new nuclear the cheapest form of low carbon generation but it also can operate at very high load factors and provides predictable generation output. Given the ambitious timescales that the UK is working towards for the decarbonisation of electricity generation, we agree that a minimum carbon price should be introduced.

38. As new nuclear plant have planning and development timescales that exceed those of more conventional forms of plant, investment decisions will need to be finalised for nuclear within the next eighteen months to two years if these plant are to be operational by 2017. In addition, a significant delay in the investment decision would lead a real risk that the UK would lose its place in the queue with nuclear equipment vendors, resulting in very considerable slippage to delivery timescales. This means that certainty over the introduction of additional support for the carbon price needs to be provided in the next year.

39. In the absence of additional support for carbon prices, it is likely that investment will instead be redirected towards other forms of generation technology (most likely CCGT). Although this will help provide security of supply, such investments are unlikely to deliver a generation mix that is sufficiently low carbon to meet government targets.

40. If a minimum carbon price policy measure is adopted within the UK it is vital that the carbon price is set at an appropriate level such that the desired investment is triggered or that other mechanisms are added in parallel to achieve the same effect. Likewise, it is also imperative that the rules surrounding the timescales for the minimum price are detailed, as well as under what specific circumstances any futures changes to this price can be made.

Improved price signals

41. In order to meet government decarbonisation targets, it is likely that there will be a large increase in the amount of wind generation on the GB system. To support this transition, it will be essential that sufficient flexible forms of supply (e.g. peaking generation and demand side response) are available to provide the necessary back-up.

42. Maintaining a stable electricity system will become more complex as National Grid identified in its 2020 consultation issued last year. A large wind generation sector in the UK will increase uncertainty because the output will be very uncertain a few days ahead of time and still subject to sizeable forecasting errors within day. As renewable generation increases, fossil fuel generators will see dramatic reductions in running hours and are likely to close if they cannot cover their fixed costs. However, it might be desirable to retain such older, flexible, CCGT and coal plant on the system in order to

back up wind capacity at those peak times when wind speeds are low. Alternatively, new peaking units may be needed.

43. DECC analysis indicates that these generators could be adequately rewarded, but only so long as short term prices were allowed to reach very high price levels during times of stress. At present, we believe there is no clear evidence that prices could spike to such high levels. Historical electricity market data suggests that even at times of extreme system stress, price spikes in the Balancing Mechanism do not exceed £550/MWh. This is around 1/10 the level suggested by DECC's analysis as being sufficient to reward flexible plant (around £5000/MWh), raising the concern that there may be structural features of the current market design that effectively preclude such price signals ever emerging.

44. We therefore agree with the Ofgem proposals that there are a number of potential improvements that could be made to sharpen price signals from making the price calculation more marginal to creating a within day reserve market. The precise changes would need further consideration and may well be impacted by other changes such as a central renewables market and changes to demand side participation.

45. Sharper electricity prices also have other consequences. They are likely to increase the hedging costs and credit requirements of suppliers but they may also drive more innovative tariff structures that could drive more demand side participation. The higher costs for suppliers may well result in higher costs for customers. More volatile prices are also likely to lead to higher cash-out costs for both generators and suppliers (which may be a further reason for offering intermittent generators the option of a central renewables market that nets out most of the wind forecasting errors at lower cost).

46. While such prices may enable existing plant to stay in operation (at least for a few years), we do not believe this would provide sufficient certainty to trigger new capital investment. This is because there are likely to be concerns over whether prices at these levels would be tolerated politically, and therefore whether short-term prices might effectively be capped. If investment in new flexible plant is needed, we therefore suggest that other options are considered in more detail, such as a market for capacity for flexible plant. There are international examples of capacity markets that have been successful. For example jurisdictions such as PJM in the USA have deliberately chosen to create an explicit capacity market to ensure generation is adequately rewarded rather than try and factor scarcity pricing fully into a single energy price.

47. The closure of opted-out capacity under the LCPD by 2016 will be an important step in reducing the reliance of the generation sector on carbon-intensive forms of generation. It is therefore important that security of supply arguments presented by coal generators are not used as a justification for keeping affected plant open beyond the deadline. Such a move would undermine energy companies' trust in the stability of the regulatory framework. Instead, it is important to recognise that the framework will need to evolve to be able to handle the huge growth in renewable generation that is needed by 2020, and the associated need for new investment in flexible plant.

<u>Demand side response</u>

48. We expect demand side response to become increasingly important in delivering a secure and sustainable energy sector. Customer behaviour is changing as customers respond to energy prices that are high by historic standards and, supported by government obligations, energy suppliers are increasingly active in improving energy efficiency in homes through measures such as insulation, more efficient boilers and microgeneration offerings. Government has committed to ensure all loft and cavity walls are insulated, where practical and where desired by customers, by 2015 and to give 7 million homes the opportunity to take up "whole house" energy efficiency makeovers by 2020. In addition customers are eligible to claim feed-in tariffs from 1 April 2010, and a reward for renewable heat they produce in the home from 2011.

49. All these measures are transforming the retail energy market into a market for low carbon energy services, where energy suppliers and other providers compete to install energy measures and manage energy consumption and production for customers in their homes and businesses. Ofgem's vision of the market should include a clear of sense of purpose and direction about how its rules and regulations underpin and support this transformation to which government is committed.

50. A fundamental element of the strategy to better engage the demand side is the rollout of smart meters. Changing arrangements to enable the benefits of demand side response to flow through to customers is essential to capture the benefits that smart meters now offer. The reform of electricity settlement arrangements is critical in this regard. The forecast increase in intermittency of generation in coming years will change the nature of energy balancing and settlement, making it more dynamic and less predictable. Half hourly settlement must be introduced for those domestic customers that opt for time of use tariffs, and we therefore fully support the measures set out in the consultation.

51. The Discovery report is largely silent on the importance of energy efficiency and, in considering how the market arrangements need to evolve, there is little sense either of the urgency with which these changes need to be introduced, or Ofgem's critical role in driving and support this transformation of the retail market. A key benefit of a vibrant demand side will be that there may be less of a need for new generation capacity and/or reinforcements to networks. It will therefore be essential to uncover the amount of flexibility that the demand side can offer as a priority. If this does not happen, then the likelihood is that too much investment will be under-taken, leading to unnecessarily high costs for customers.

52. Presently, electricity in the domestic market is allocated to suppliers using profiles that reflect the market average of energy use through different half hour slots within a day. This means that all suppliers are allocated a similar portion of peak and off peak energy use irrespective of any differences between the amount of peak or off peak energy actually consumed by the customers of each supplier. Therefore if an individual supplier incentivises its customers to switch use from expensive peak to cheap off peak, under current arrangements all suppliers share the benefits of this.

53. To provide the correct incentives to suppliers to introduce demand side response, electricity settlement arrangements must be reformed so that those parties delivering demand side response benefit from it. Half hourly settlement capability must be introduced in to the domestic market. This would enable supplier specific, time of use allocations to be made. It might not be necessary for all customer supply points to be settled on a half hourly basis, but it will be necessary for those customers who take up demand side / time of use products. The case for applying half hourly settlement arrangements to customers that do not take up demand side products is less clear cut because the benefits would be limited to general increases in settlement integrity rather than those associated with enabling a demand side response.

54. In association with changes to settlement and data flows, we would also support work on whether network charges can be structured so that customers that choose to reduce consumption at times of heaviest network load (i.e. at times when the system is most constrained) should pay lower network charges. These charges should reflect the fact that customers that shift load away from peak potentially reduce costs both in terms of short term system operation, and the need for longer term network investment.

55. A further change that would help to promote the growth of the market for energy services would be a review of the current right to object. Policy measures are needed to help facilitate the delivery of capital investment into homes and businesses to improve energy efficiency. This would be achieved if measures were introduced to help suppliers reduce the default risk associated with such investment. A specific review that explored the merits of extending the right to object to also include energy service debt would help in this regard.

Centralised renewables market

56. We also support further work on the development of a centralised renewables market. We believe that such an approach may deliver significant risk reduction benefits for intermittent plant which should help projects proceed and raise finance from third parties. However, the design needs to be considered carefully to ensure that it is consistent with other electricity market arrangements.

57. As the volume of wind generation grows the risks associated with the output will inevitably become a major focus for the SO. It would make sense that the SO receives real time data flows from all wind farms and uses this to produce the "best" forecast of near term generation for its own system balancing needs. Using this as the basis for selling aggregated wind output in the market is sensible. This also creates a potential route for the SO to manage wind output against transmission constraints by constraining wind plants at their avoided opportunity cost (including ROCs and LECs) at least cost for customers.

58. In terms of the design of such a market, we believe there may be a need for some form of day-ahead "sale" of firm volumes. This could then be adjusted by further interim "trades" as the forecast accuracy improves. We would suggest looking at international comparators for models of such a market (for example, in Spain and Germany).

59. Although we believe that the benefits of a centralised renewables market are likely to outweigh the costs, we believe that such a substantial change should be optional for both new projects and existing projects. This would significantly reduce risk (and also allow existing projects to operate under existing contracts).

The evolution of gas market arrangements

60. The government's decarbonisation targets do not necessitate the same degree of regulatory reform in the gas sector as will be necessary in electricity. Instead, the key challenge ahead for the gas market in coming years will be to maintain security of supply in the face of the continued depletion of reserves of gas in the UK Continental Shelf.

61. Given the proven ability of the gas market arrangements to deliver huge levels of investment (whilst maintaining security of supply) in the face of fundamental change, we do not believe there is a case for significant intervention in the gas sector. However, it would be helpful for Ofgem and government to provide support wherever possible to investors looking to secure new gas supplies for GB customers from international markets. Domestically, Ofgem needs to focus on delivering a clear and consistent regulatory framework within which the market can work effectively. We suggest that a review of existing arrangements may be required in a limited number of specific areas.

62. The main short term driver of security of supply is the set of arrangements established by National Grid under the Uniform Network Code that are designed to provide reasonable economic incentives for suppliers to secure that the "domestic customer supply security standards" are met. Key elements of these arrangements are the "On-the-day Commodity Market" (OCM) and the "cash-out" prices that shippers must pay for correcting the imbalance between gas delivered to the system and that which is off-taken by their customers on any given day.

63. Although the current arrangements already provide reasonably strong incentives for suppliers to ensure they have purchased sufficient gas to meet the requirements of their customers, there may be some improvements that can be made to ensure that cash out prices more accurately reflect the cost to the system of participants being out of balance. We therefore support a review of the gas cash-out arrangements, potentially looking into the increased use of true marginal market prices in cash out arrangements. For example, there may be a way of using marginal prices from the

OCM when there are no National Grid balancing actions. There may also be ways of continuing the market-driven cash-out price regime during an emergency. Changes such as these may help security of supply by giving shippers and suppliers greater incentives to match their supply and demand positions (particularly in emergency situations), resulting in (market-driven) improvements in security of supply.

64. We would also suggest a review of the prospects (and need for) investment in gas ballasting arrangements at the Bacton interconnector. As a general principle when gas quality adjustment is required to meet the National Grid specification (i.e. for new investments seeking a connection to the NTS) we do not believe there is a case for central or socialised investment in gas ballasting facilities. New import pipelines and LNG regasification/importation projects, for example, should and do factor the cost of any necessary ballasting facilities into their project plans. Such investments will then only proceed if expected returns are sufficient to cover the full cost of bringing this gas to market. In practice, ballasting costs are typically a modest part of such investments, which are often underpinned by a major upstream producer or producers.

65. However, there are specific issues with the existing gas interconnector between Zeebrugge and Bacton which are likely to merit a different approach in this case. We share Ofgem's view that Fluxys is likely to face increasing difficulties in delivering sufficient gas to IUK which meets the UK quality specification and that "there are currently few economic signals for shippers to invest in such [gas processing] facilities" as may be required to address the issue.

66. The key issue is that IUK is an existing asset, the usage of which is shared between a diverse range of shippers whose unanimous consent is required to effect a change to the existing transportation agreement. Coordinating these shippers to agree to undertake an additional investment in a new gas ballasting plant would be extremely difficult, particularly as it is unclear at what stage and on what scale such a plant would be needed. As a consequence, it is extremely unlikely that an investment in a ballasting plant at Bacton or Zeebrugge could be agreed between all the necessary parties on a fully commercial basis in a timely way that would meet market requirements.

67. There are also other areas where clarification of the regulatory framework would be useful in ensuring ongoing gas supply security. Firstly, the negotiated third party access regime for non-exempt storage facilities in GB is not yet as clear as it needs to be, either to provide the most positive investment climate for the relevant storage operators or to allow their potential customers to plan and optimise arrangements to secure the supply flexibility which end consumers and power stations will require. In addition, the regulatory framework for future access to IUK beyond the expiry of current transportation arrangements in 2018 remains unclear. It is important to recognise that the longer term import gas procurement contracts which many see as desirable for UK supply security will also require long term access to interconnector capacity.

More interventionist policy proposals

68. We believe targeted interventions will be sufficient to enable the competitive market to deliver government policy objectives. As a result, the more radical options set out in the document for consultation are at best unnecessary, and at worst counterproductive, potentially damaging investor confidence.

69. We set out our more detailed views on those policy proposals that we believe should not be adopted below. These are:

- enhanced obligations on suppliers;
- replacing the RO with a renewables tender;
- tenders for all capacity; and
- central energy buyer.

Enhanced obligations on suppliers

70. We do not support new supplier obligations in either gas or electricity. There is no evidence that suppliers need any additional incentives to contract ahead to meet demand, particularly if changes are introduced to sharpen short term price signals. The robustness of existing arrangements in meeting demand in the recent severe winter with no involuntary interruptions of customers (and over winters earlier in the decade when new sources of supply were still coming onstream) is evidence that markets are able to deliver, without the need for such new obligations.

71. We believe obligations such as these would tend to create major market distortions. In the case of an obligation to contract for a specific level of gas storage for example, this could result in the cost of gas storage being inflated artificially, to the detriment of other substitutable sources of (e.g. LNG, production, supply contracts, demand side response). This inefficient contracting will ultimately lead to high prices for consumers.

72. There is also no guarantee that gas storage even under arrangements such as this would be available in an emergency. Operational problems at storage sites can mean that, even if suppliers have contracted for gas at a given facility, they may not be able to access the gas. A good example of this was the unavailability of the Rough storage facility following a fire in February 2006, which resulted in a suspension of commercial withdrawals until November 2006. Contracting for gas from a variety of sources is the best way of mitigating risk such as this, and suppliers have incentives to do this.

73. Setting a high obligation to procure gas from storage could also damage investment in alternative sources of gas flexibility. Investments planned in other sources of gas may see existing business plans undermined, leading to a reduction in the level of investment in such sources of gas supply.

74. A further form of obligation described in the consultation is an obligation on gas-fired generating stations to be able to operate on liquid fuel to deliver some form of proxy short term gas storage. We do not believe this would be an efficient or cost effective way of supporting the gas system, as the cost of such an obligation would be prohibitive. Utilisation of such capacity would only occur with gas prices in excess of 120p/therm, even without any consideration being given to the additional capital costs involved. It would also be unclear how an operator could recover these costs. Ultimately, this may mean an obligation such as this could lead to the closure of some plant (reducing security of supply as a result).

75. Some of the costs that such an obligation would impose on generators include:

- additional capex on new build for oil storage, pipework, burners and water treatment capacity;
- retrofit to large number of existing CCGT stations would raise space, planning and environmental issues;
- additional operating costs would arise from extended maintenance periods, testing and the cost of holding oil stocks;
- oil firing uses much more water which would mean additional water supply, water treatment, and storage with associated environmental consequences; and
- additional transportation requirements associated with oil deliveries.

76. We also believe that the "proxy gas storage" benefit that such an obligation would offer would be significantly reduced over time. This is particularly the case if other policy measures are successful in triggering new investment in nuclear and renewable generation (reducing the load factor of CCGTs).

77. Any further consideration of this proposal should start with a detailed cost benefit analysis of using oil-firing as a backup compared to conventional forms of gas storage. Such analysis should also fully reflect the potential for increased demand side response

(which we believe would be triggered in significant volumes before prices reach levels that would make oil-firing as a backup commercially viable).

Replace RO with a renewables tender

78. We do not support the replacement of the RO with a form of renewables tender. We believe that replacing the RO with any other form of support would cause a hiatus of investment in renewables that would damage efforts to meet government renewable targets. This investment hiatus would start from the point when the intention was signalled to change the system, would continue whilst the alternative was devised, consulted upon and ultimately translated into legislation, and would continue beyond this point until investors and financiers had comfort that they understood the new system and there were no unintended consequences.

79. It is difficult to envisage the benefits of any new incentive mechanism outweighing the obvious disadvantages of such a change. Specifically, we do not believe that tenders for additional renewable capacity offer significant benefits over the current RO system. Renewable tenders would be unlikely to provide more certainty over delivery of targets. Measures such as penalties for late delivery are only likely to increase risk for investors, leading to more costs for consumers. We do not believe that the fixed price revenue stream that a tender would deliver is significantly different in practice from revenues that are received under the current RO regime.

80. The use of banding and the regular future band reviews (together with the headroom mechanism) has also significantly reduced one perceived the disadvantage of the RO regime (the over-rewarding specific technologies). In addition, it is clear that some of the most material barriers to the growth of renewable plant would face both the RO and tenders equally, namely grid connection and planning consent issues.

81. We are also concerned that the lack of competition for tenders could further reduce the value to money for consumers from such an approach. For such a tender process to work efficiently there would need to be several bids for an equivalent type (technology type, size, capex & operational costs etc) in any one tender period, otherwise there would not be enough competition. Having defined windows for a tender process could also cause supply chain issues, leading to peaks in order placements /delivery profiles (rather than the smoother profile that results from the RO).

Tenders for all capacity

82. We do not believe there is any need to consider more radical options such as government tenders for capacity. Tenders are likely to represent a highly inefficient approach to delivering new capacity, particularly where there are small numbers of bidders in individual auction windows. To deliver an efficient outcome via a tender process there would need to be strong competition from a large number of interested bidders (exceeding the required volume to be purchased).

83. Tenders also give no certainty that assets will actually be delivered. Investments in generation typically have long lead times for design, planning and construction with developers incurring significant costs at an early stage. Successful bidders would still face significant project risks around consents, construction contracts and potentially transmission access. Applying penalties for non-delivery would be impractical and instead would be likely merely to add to the risk faced by new developers.

84. Capacity tenders would also place government at the heart of the execution of a national energy procurement strategy. This would involve determining the necessary volumes and capacities from different technologies required to meet certain carbon or security targets. Such planning would need to be undertaken in the face of an increasingly international energy market with huge uncertainty over future technologies and costs. This is not an environment in which a central decision maker is likely to

make correct choices over the volume and mix of investment that would be in the best interests of customers.

85. Such a large degree of central planning would be highly likely to stifle innovation as all investments would be focussed solely on the tenders offered by government. There would be little or no incentives for alternative, newly developed technologies to emerge, as tenders would effectively "crowd out" financing for other forms of investment. Leaving all decisions on the required generating mix to some central authority dramatically reduces diversity of decision making and increases the potential for political interference to distort investment decisions.

86. We have a number of specific and significant concerns over the tendering for gas storage capability. It is unclear how the level of volumes for gas storage tenders would be determined. There is no "correct" level for new storage, given gas storage is only one component of security of supply. Increasingly, a diverse range of flexible sources of supply and demand-side-response are key to meeting peak GB gas requirements. As such, only market driven investments can determine the most efficient mix of gas supply and demand side response.

87. Tenders for gas storage would also have a major impact on existing markets, deterring and crowding out investment that would have been delivered by the commercial storage market. Storage developers are in various stages of developing new storage and the current investment proposals are underpinned by the belief that the market and wholesale prices will be allowed to operate freely. Central tenders for storage would undermine existing commercial investments, and potentially have a negative effect on the overall security of supply as a consequence.

Central energy buyer

88. We have numerous concerns over a "central energy buyer". Unlike the other policy proposals which can be viewed as incremental changes from a purely market based approach, models in which a central entity purchases capacity and energy and/or gas storage represent a fundamental change from any form of market based arrangement to one of centralised planning. This is likely to lead to poor decision-making, generally higher administration costs and a stifling of innovation.

89. Customers would be likely to end up paying far more for the same level of security and sustainability than they would do under market-based arrangements. In a complex and dynamic industry such as energy, with rapid advancements in technologies and relative costs, it is highly likely that the central planner will make the wrong choices (of either generation types, or volume requirements) or will end up taking on far more risks (on behalf of customers) than would be the case under market-based arrangements.

90. In a central buyer model where suppliers are required to purchase their energy requirements from a reduced number of counterparties (particularly in the models that include a bulk supply tariff), then many of the benefits of supply competition will also be lost. Wholesale market competition results in significant benefits to customers, as those suppliers that contract for their energy at lowest cost are then able to offer the lowest prices to their customers. Restricting (or removing) the ability of suppliers to compete in this way would damage supply competition and raise retail prices.

91. We also have significant legal concerns with the central buyer model. We understand that that third package requires competitive markets to be in place (as well as the unbundling of transmission from competitive activities). It is unclear how any of the centrally-planned options are consistent with this legal requirement.

92. Instead, we believe that a competitive market, where many parties make decisions in a decentralised way based on efficient price signals, offers a vastly superior decision-making framework to that which a central buyer can offer. The scale of the investment challenge therefore points to need for policy-makers to unblock barriers to making more, not less, use of the power of markets to make the investment decisions that customers need.