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Renewable Energy: Practicalities

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(Q) refers to a question in the oral evidence

(p) refers to a page of written evidence

Renewable Energy: Practicalities

CHAPTER 1: EXECUTIVE SUMMARY

1.1. The Energy White Paper *Our energy future—creating a low carbon economy*, published in 2003, set out an energy policy that aims both to ensure security of electricity supply and to meet ambitious targets for reducing greenhouse gas emissions.[1] The Government wish to achieve this by market mechanisms while keeping electricity "affordable". The development of renewable energy sources is put forward as a key means to achieving these policy goals, and the Government have set a target that ten percent of the United Kingdom's electricity should be generated from such sources by 2010, and an "aspiration" of 20 percent for 2020.

1.2. In conventional terms, virtually no renewable source is economically competitive at present unless, notionally or through taxation, a substantial pollution cost is added to the cost of generation from fossil fuels. This means that market mechanisms must be supplemented by subsidies or other means of support for electricity generation from renewable sources.

1.3. By 2020 the Government's plan envisages a substantial change in patterns of generation. The changes roughly correspond quantitatively to replacing current nuclear generation with energy from renewable sources (20 percent), and generation from coal and oil by combined cycle gas turbines. A significant reduction in overall national electricity consumption is also implied.

1.4. Our study addresses the practicalities of meeting the Government's targets for renewables and some of their wider implications. We have found that unless some key problems are addressed within the next two years[2] the targets will not be achieved and the broader strategy on renewables seriously jeopardised. In particular:

- The current means of subsidising renewable sources must be modified to give longer term stability to the market;
- Planning processes must be co-ordinated at several levels and various means used to achieve more local acceptance of renewable developments;
- National electricity transmission and distribution arrangements may need serious attention to allow proper access and management of distributed and intermittent electricity generation;
- The Government must show that they are taking energy supply seriously both through ministerial commitment and commitment of resources to R&D.

1.5. To a large extent making use of renewable resources involves applying new technologies to take advantage of the special features of particular areas—for

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1 *Our energy future—creating a low carbon economy*, presented to Parliament in February 2003 (Cm 5761). Hereafter referred to as "the White Paper".

2 The planned review of the Renewables Obligation (see Box 7 below) in 2006 provides an opportunity for effecting some of the major changes recommended in our report.

example north-west Scotland is one of the windiest places in Europe, and the coastal waters have substantial waves. Other parts of the United Kingdom have exceptionally high tides. On the other hand technologies such as those that depend on sunlight may be more attractive in more southerly parts of Europe. There are different opportunities in different places.

1.6. Internationally, wind is the renewable energy source that has received the most attention and is in many ways the technology that is best understood (apart from some kinds of hydro). New installations on land can be assembled in a matter of days once planning and access provision are complete. Costs have declined steadily over the last twenty years although development has taken place almost exclusively outside the United Kingdom.

1.7. In the United Kingdom onshore wind turbines have not been universally welcomed on amenity and environmental grounds, and there can be interference with radar and aircraft. For these and other reasons the Government are encouraging the development of offshore wind farms. Installing turbines under these conditions is considerably more expensive than on land and servicing them may not be easy. However, better wind conditions and larger turbines in larger groups may offset these disadvantages. There is, however, no long-term experience of operating such offshore developments.

1.8. Another exceptional natural resource of the United Kingdom is the energy contained in waves and tides. These have received much less attention internationally and, in part because Government support for energy related R&D has been low by international standards, the technology largely remains too immature to attract substantial commercial interest. Some demonstration projects are now underway. Simple systems based on the rise and fall of tides do not require new technology and are in use (notably in France) but commonly attract objections because of their significant environmental impacts on river estuaries.

1.9. Electricity may also be generated from materials other than fossil fuels. “Biomass”—specially grown crops, or by-products of other activities such as straw or chicken litter, or even biodegradable urban waste—may be incinerated directly, co-fired with conventional fossil fuel, or gasified. All such fuels have a low energy content compared with their bulk and it does not make economic or environmental sense to transport them long distances before using them. There are several biomass plants in the United Kingdom, but it is unlikely that there will be more in view of the unhelpful and confused regulatory environment and the lack of financial encouragement. However, making use of biomass, both indigenous and imported, could be a cost effective way of meeting the Government’s targets for renewable generation. We understand that this is now the policy of the Danish government.

1.10. Other renewable energy sources such as geothermal and solar (photovoltaic and direct heating) are likely to find only niche applications in this country unless there are major improvements in technology.

1.11. The greater part of the United Kingdom’s renewable energy for the near and middle future is likely to come from sources that are, of their nature, intermittent. This applies pre-eminently to wind power. It has two major consequences: first, the annual generation for a wind turbine is only a fraction of its nominal capacity. In Germany this fraction has stood at around 15 percent, and in Denmark a little over 20 percent, although in United Kingdom conditions, particularly offshore, wind farms are expected to do twice as well. Second, whatever overall contribution wind may make to the energy supply, there will be short periods when high demand for electricity coincides with low output. This should not raise serious difficulties until wind generation is more than 10 percent of the total national generating capacity. Beyond this point the situation will have to be handled in various ways: either by having standby conventional generating capacity that may be seldom needed (and is therefore expensive), or by importing electricity from other countries (though at present the United Kingdom's inter-connectors are inadequate), or by agreeing with some customers that in return for a lower tariff their supplies may be interrupted.

1.12. Electricity is distributed around the United Kingdom via the National Grid, which connects a limited number of power stations to major customers who sell on electricity to others. Large wind farms (more than 100 MW), can in principle be connected to the Grid as if they were power stations. Smaller generating units, however, will be connected to local distribution networks, and situations will arise of which there is little operating experience, with power flowing intermittently from multiple sources in complex patterns.

1.13. The Government are implementing their renewables programme by means of the Renewables Obligation (RO). This sets rising "targets" for the amount of renewable electricity to be generated each year (currently reaching as far ahead as 2015), and forms the basis for a complex and subtle market driven set of incentives to generators. The incentive in any one year is high until around 70 percent of the Government's "target" for renewables generation in that year has been attained, and then declines rapidly. We believe that this mechanism will in fact ensure that the Government's targets are not attained, even though offshore wind enjoys additional capital grants.

1.14. The Renewables Obligation, although described as "technology-blind" discriminates strongly in favour of generation technologies that can be brought to market within the next year or so, because the uncertainty surrounding the future value of the RO incentives means that investors look for an early return on their investment. Only wind can produce this early return. If the Government wish to achieve their renewable target of 10 percent by 2010, or to diversify the national renewable portfolio, and there are good reasons to do so, the RO will need modification in the near future.

1.15. We found almost no one outside Government who believed that the White Paper targets were likely to be achieved. This was partly for practical reasons—planning consents, availability of labour and equipment and so on—and partly as a direct consequence of the RO method of support. We judge that by 2010 the United Kingdom may have achieved 6-7 percent renewable generation.

1.16. We deplore the minimal amounts that the Government have committed to renewable energy related R&D (£12.2 million in 2002-03); the comparable figure for the US is $250 million for 2004-05. If resources other than wind are to be exploited in the United Kingdom this has to change.

1.17. We could not avoid the conclusion that the Government are not taking energy problems sufficiently seriously. Transport has not been tackled. Arrangements for combined heat and power generation, private or local, are not attractive. The responsible minister carries other major responsibilities as well; R&D support is low; but most important of all we could find no one at the executive level whose responsibility it was to ensure continuity of supply. We were told simply that market forces would solve the problem. We are not convinced and urge the Government to give these matters further consideration.

Acknowledgements

1.18. Many organisations and individuals responded in writing to our call for evidence, and many also gave oral evidence or contributed to our seminar in December 2003. We are grateful to them all. Without their help, our inquiry and this report would not have been possible.

1.19. We are particularly grateful to the following, who offered great hospitality and many insights in the course of our visit to Denmark on 26-29 October 2003:

- The Ambassador, Sir Nicholas Browne, and staff of the British Embassy in Copenhagen;
- Knud Pedersen, Deputy Director-General, and staff of the Danish Energy Authority;
- Knut Conradsen, Deputy Rector, and staff of the Technical University of Denmark;
- Staff of Amagerforbrænding Waste Incineration Plant, Gaia Solar Installations, Elsam (operators of Horns Rev wind farm), Lintrup Biogas plant and Herningværket CHP plant.

1.20. We also wish to record our thanks to the following, who hosted seminars and visits within the United Kingdom:

- The Royal Academy of Engineering, and its President Sir Alec Broers (now Lord Broers), who hosted our seminar on 10 December 2003;
- Energy Power Resources, and Commercial Director Malcolm Chilton, who showed us round Elean and Thetford Power Stations on 30 January 2004;
- Councillor James Armitage, Leader of the Executive, and Mr Ray Morgan, Executive Director of Woking Borough Council, who gave the Committee a tour of installations within Woking on 8 March 2004.

1.21. We are fortunate to have had the assistance of two Specialist Advisers: Professor Dennis Anderson, Professor and Director, Imperial College Centre for Energy Policy and Technology, and Dr Chris Elliott FREng, Director of Pitchill Consulting. We are most grateful to them both for their help.

CHAPTER 2: INTRODUCTION

The case for renewables

2.1. We begin this report by asking the simple question, "why renewables"? Stocks of fossil fuel are sufficient to last until at least 2050, so there is no immediate need to find an alternative energy source. Experience suggests that converting energy from renewable sources into electricity is still expensive and not particularly effective in delivering the steady flow of electricity on demand that developed economies rely upon. Yet the assumption that it is desirable to encourage renewable energy is enshrined in the Government's Energy White Paper, as well as in a range of European Union policy statements and directives.

2.2. The obvious argument in favour of renewables is environmental: there is now ample evidence that the accumulation of greenhouse gases in the atmosphere, largely as a result of the combustion of fossil fuels, threatens the earth with accelerating climatic change. The United Kingdom is committed under the Kyoto Protocol to reductions in greenhouse gas emissions by 2010 of 12.5 percent, compared with 1990 levels, and the Government have also made a national commitment to achieving a 20 percent reduction in the United Kingdom's CO_2 emissions by 2010, and a 60 percent cut by 2050. The exploitation of renewable energy sources—abundant and inexhaustible—will assist in controlling emissions, and will in turn assist the United Kingdom to meet its environmental commitments.

2.3. However, renewable energy sources tend to be diffuse and some are intermittent. As a result their conversion into usable electricity is more expensive than the conventional alternatives, and is likely to remain so—certainly as long as fossil fuels do not carry the cost (of which estimates vary widely) of the environmental damage they cause. The environmental benefits of renewables will not be realised without extra cost to consumers.

2.4. In addition, the environmental benefits of renewables have to be seen against a back-drop of alternative strategies for reducing greenhouse gas emissions. Substantial reductions have indeed already been achieved as a result of moving from coal to gas-powered generation, while the rigorous cleaning of emissions, "clean coal" technology, the geological sequestration of CO_2, improvements in energy efficiency, and other technological innovations, hold out the prospect of further reductions. At the same time nuclear fission, whatever its other environmental impacts, remains a reliable source of carbon-free power, and the planned scaling down of nuclear power is likely to lead to increases in emissions as conventional replacement capacity is introduced. Provided that international research is adequately funded, nuclear fusion continues to offer the realistic prospect of clean, safe, and practically limitless electricity by the middle of the century. Other technologies, such as "artificial photosynthesis" to produce hydrogen, may also emerge.

2.5. Another factor, arguably of particular concern to the United Kingdom, is the risk inherent in increasing reliance on gas as a primary source of energy. United Kingdom production from the North Sea is now at its peak, and we will become a net importer of gas as early as 2006. As production from the United Kingdom continental shelf tails off over the next 15 years, and with the running down of the coal industry and the closure of coal-fired power stations, we will become increasingly dependent on gas imports to meet our electricity needs. This carries a risk: although imports will come from a number of sources, by 2020 more than half of United Kingdom gas imports are likely to come from Russia. Political risk data provided by the insurance sector suggest that interruptions in such supplies of up to 180 days may occur as often as once every eight years.[3] The United Kingdom currently has gas storage facilities equivalent to only 14 days' supply, compared with an EU 15 average of 52 days.[4] We urge the Government to address this issue urgently.

2.6. Diversity of energy sources will thus be essential if the risk to United Kingdom power supplies is to be mitigated, especially if nuclear power is not available. Renewable energy, in which the United Kingdom is rich, thus has a significant part to play in ensuring the long-term security of power supplies.

2.7. However, set against the benefits of renewables with regard to long-term security are the difficulties they present in ensuring short-term reliability. Over a long period (and barring any effects of climate change) the average wind speed at a particular site is highly predictable. But in the short term the opposite is the case, and there is no guarantee that the wind will blow at times of peak demand. This may create serious difficulties for a Grid whose reliability and stability depend on maintaining a minute-by-minute balance between supply and demand. We consider this issue further in Chapter 7.

2.8. **We believe the Government are on balance right to encourage further development of renewable energy. The sources of renewable energy, such as the sun, wind and tides, are inexhaustible, indigenous and abundant, and their exploitation, properly managed, has the potential to enhance the long-term security of the United Kingdom's energy supplies and to help us cut carbon dioxide emissions. However, these sources are also diffuse, and uncertainties remain over the technical feasibility and cost of converting them into electricity reliably on a sufficiently large scale.**

The energy policy framework

2.9. We launched this inquiry by asking whether it was practicable to meet the Government's 2010 target and 2020 aspiration for renewable energy. Our report demonstrates just how difficult this will be. Moreover, as soon as one begins to reflect on the broader question "why renewables?", it becomes apparent that it is the long-term direction of energy policy that is of over-riding importance. Therefore, before analysing the practicalities of renewable energy, we comment on the energy policy framework, the "four goals" set out in the White Paper. These are:

- To put the United Kingdom on a path to cut CO_2 emissions by 60 percent by 2050;
- To maintain the reliability of energy supplies;
- To promote competitive markets in the United Kingdom and beyond;
- To ensure that every home is adequately and affordably heated.

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3 See OXERA, The Non-Market Value of Generation Technologies, June 2003, p. 8.

4 Source: "Security of gas supplies", information paper by the UK Offshore Operators' Association—see http://www.oilandgas.org.uk

2.10. Where do renewables, given the advantages and problems noted above, fit into these objectives? There appears to be a fundamental tension between on the one hand, the first and second objectives, which essentially cost money and mean higher prices, and on the other, the fourth objective, the reduction of fuel poverty, which depends in part on maintaining low energy prices. Renewables can undoubtedly contribute to reducing CO_2 emissions, and if properly managed they may enhance security (though not necessarily reliability) of supplies. But they can only do this at a price—which consumers will have to pay. Thus there appears to be a risk that the promotion of renewables may undermine the Government's fourth objective. The White Paper deals with this issue by stating that the ten percent target for 2010 is "subject to the costs being acceptable to the consumer".[5]

2.11. The relationship between the Government's policy on renewables and the third objective, the promotion of competitive markets, is also puzzling. The White Paper reiterates the Government's target that by 2010 renewables should supply ten percent of United Kingdom electricity. Yet it also states that the Government "do not propose to set targets for the share of total energy or electricity supply to be met from different fuels. We do not believe Government is equipped to decide the composition of the fuel mix". While the term "renewables" covers a range of individual energy sources, the setting of targets, and the provision of subsidies and financial support in order to achieve them, do not sit comfortably with the Government's commitment to the promotion of competitive markets.

2.12. In contrast, in 1998 the Government stated that its "central energy policy objective" was "to ensure secure, diverse and sustainable supplies of energy at competitive prices".[6] This appears to us to be a more straightforward energy policy: it places the emphasis squarely on the long-term security of energy supplies, while acknowledging the importance of environmental considerations and the overall limiting factor of cost. It is easier to see how renewables would fit into such a policy objective.

2.13. **The Government recognise that "there will inevitably from time to time be tensions" between the "four goals" of its energy policy.[7] We would go further, and agree with the House of Commons Environmental Audit Committee that to pretend that all four goals can be achieved simultaneously is a "cop-out: the Government is not facing up to the real issue, as in some situations trade-offs will almost certainly have to be made".[8] With no declared mechanism for determining the relative weights of the different goals, or indeed for assigning responsibility for them, there is a danger simply of confusion, and even a risk that none of the goals will be achieved.**

2.14. **We applaud the Government's emphasis on the importance of the cost of renewables. However, we are concerned that no figure has**

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5 White Paper, paragraph 1.22.

6 See the Government White Paper, Conclusions of The Review of Energy Sources for Power Generation and Government response to fourth and fifth Reports of Trade and Industry Committee, October 1998, paragraph 2.2.

7 See http://www.dti.gov.uk/energy/publications/whitepapers/review_sources/chpt02.pdf

8 House of Commons Environmental Audit Committee Report, *Energy White Paper—Empowering Change?* (8th Report, Session 2002-03, HC 618), para. 77.

been put on what will be deemed "acceptable to the consumer", or how acceptability will be measured.

2.15. **We recommend that the Government reconsider their energy policy goals, with a view to setting a "bottom line". We believe that the fundamental goal of energy policy, as was formerly acknowledged by the Government, should be the maintenance of secure, and hence diverse, energy supplies. In achieving this goal regard must be had to the United Kingdom's environmental commitments and to the need, in the interests of consumers, to promote competitive energy markets. We look forward to a fuller explanation of the Government's position on these issues.**

2.16. The White Paper, with its foreword by the Prime Minister, was published by DTI. The recent first annual report on implementation of the Energy White Paper[9] was published jointly by DTI and Defra, and its foreword is signed jointly by the two Secretaries of State. Inevitably energy policy has a bearing on environmental or social policy objectives. Nevertheless, the current uneasy division of responsibilities between Government departments does not inspire confidence. We are concerned that in a matter of such importance responsibility for delivering the Government's goals should be clearly assigned.

2.17. We note that the former Energy Minister, Brian Wilson MP, stated to the Environmental Audit Committee in April 2003 that "in an ideal world I think there should be a single Energy Department".[10] We agree, and are concerned that the current position, in which the Minister for Energy, Stephen Timms MP, also has responsibility for e-commerce and postal services, appears to down-grade the importance of energy policy. The White Paper draws attention to the profound challenges facing energy policy. In a time of environmental threat and rapid technological innovation, as well as political instability in the oil and gas producing regions of the world, and in view of the over-riding importance of energy supplies to the country's well-being, it is essential that the objectives of that policy be clearly defined, and that there be correspondingly strong leadership dedicated to their achievement within Government.

2.18. **We recommend that the Government review the allocation within Government of responsibility for energy policy, with a view to providing strong and coherent leadership. At the very least there should be a Minister of State, wholly committed to clear, energy-focused aims and objectives, who can bring together responsibility for all aspects of energy policy, including security of supply, along with those currently the responsibility of Defra, such as energy efficiency and conservation.**

The Government's targets: the scale of the challenge

2.19. At the heart of the White Paper is the Government's target that 10 percent of the United Kingdom's electricity should be generated from renewable sources by 2010. Beyond 2010, the Government have set an "aspiration" of

9 Published April 2004—see http://www.dti.gov.uk/energy/sepn/firstannualreport.shtml

10 Energy White Paper—empowering change?

20 percent by 2020. The remainder of this Report focuses on the feasibility of achieving these objectives.

2.20. In focusing on renewables we have had to exclude much of the energy policy context: the development of renewables is taking place alongside the decline of coal-fired generation, the huge expansion in gas-fired generation, and an effective moratorium on further development in the nuclear industry—what the Government describe as "keeping the nuclear option open". We do not propose to refer to these wider developments except in passing. In particular, while we share some of the concerns that have been expressed on the floor of the House at the Government's apparent indecisiveness over nuclear power—which is at least reliable and carbon-free, whatever the issues regarding disposal of nuclear waste—we acknowledge that such issues fall beyond the scope of this Report. Nor have we looked at "clean-coal" technology, even though we received a significant amount of written evidence on the subject—this too is outside our scope.

2.21. Regardless of these wider considerations, the Government's targets for renewables in themselves represent a huge challenge. The figures speak for themselves: the first annual report on implementation of the Energy White Paper includes an estimate "that the share of electricity supplied to customers from energy sources eligible for the Renewables Obligation[11] rose from 1.7 percent in 2002 to 2.0 percent in 2003. Electricity from all renewables amounted to 2.9 percent."

2.22. Underlying the Government's optimistic tone are some unpromising statistics. Total generation from all renewables in fact fell from 3.0 percent in 2002 to 2.9 percent in 2003, according to the Government's 2004 energy indicators, published together with the first annual report. This fall is blamed on low precipitation and a corresponding drop in output from hydro installations.[12]

2.23. More detailed analysis shows that in 2002 some 5,508 GWh of electricity were generated from eligible renewable energy sources, which in fact represented less than 1.4 percent of the United Kingdom's total demand of just under 400,000 GWh.[13] This figure is consistent with the statement in the Energy Indicators that eligible renewables "accounted for almost 50 percent of generation from renewables in 2002" (in other words, just under half of the total of 3.0 percent).

2.24. It is worth underlining the fact that the Government's ten percent target is for electricity generated from renewable sources that are eligible for the Renewables Obligation. In the words of the DTI's evidence to this inquiry, the target "is normally referred to in terms of the percentage of electricity generated from renewable energy sources without more precise definition, but to be strictly accurate it refers to the contribution of those renewable

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11 For a discussion of the Renewables Obligation (RO), and of those technologies eligible under it, see Chapters 3 and 5 below. The principal technologies not eligible under the RO, which make up the balance of total "renewable" generation, are large hydro (that is, hydro with a declared net capacity greater than 20 MW) and energy derived from mixed waste.

12 UK Energy Sector Indicators 2004, p. 7.

13 Source: DTI energy statistics: http://www.dti.gov.uk/energy/inform/energy_stats/index.shtml In the first year of the renewables obligation (1 April 2002—31 March 2003) Ofgem issued certificates in respect of 5,563 GWh of eligible electricity, while in the calendar year 2003 Ofgem issued certificates in respect of 6,700 GWh. http://www.ofgem.gov.uk/ofgem/work/index.jsp?section=/areasofwork/renewableobligation

sources eligible for the Renewables Obligation” (see p. 156). The figures suggest that ten percent is a long way off—a dramatic change in the rate of introduction of renewable generating capacity will be required if the Government are to come anywhere near their target for 2010.

2.25. Furthermore, Governments have something of a habit of setting ambitious and unachievable targets. In 1999 the European Union Committee of this House, in its Report *Electricity from Renewables*, commented that “we have difficulty sharing the Minister for Energy’s confidence that the United Kingdom’s five per cent target by 2003 will be achieved.”[14] The Government responded by reaffirming their belief that they would “secure its target of five per cent electricity supplies from renewable energy sources in 2003”[15]—but time has proved the Committee right and the Government wrong. It is worth noting that in 1999, along with the five percent target for 2003, the Government had already proposed a 10 percent target for 2010.

The structure of the Report

2.26. If the Government’s targets for renewables are to be achieved, against the expectation of almost all witnesses in our inquiry, certain conditions will have to be met—conditions that apply as much to individual developments as to renewables as a whole. Each of these conditions is considered in turn in the chapters that follow.

2.27. The first condition is one simply of technological feasibility. There must be a reliable technology for converting a sufficient source of renewable energy into electricity.

2.28. The second condition is one of practical implementation. There must be no insuperable difficulties in installing the technology at the chosen site—in terms of manufacturing capacity, infrastructure, or the availability of skilled manpower. In the case of biomass there should be a reliable and affordable supply of fuel. The regulatory framework should not hinder development or operation unduly. Of course most practical problems can be overcome at a price—but such costs have to be kept to a minimum if development is to succeed.

2.29. The third condition is commercial acceptability—once the costs of a project are identified, the investment community must be willing to provide the necessary finance. To put it another way, investors must regard renewables as a reasonably secure and productive investment opportunity. In this regard, and given that no renewable sources of energy, with the exception of existing large hydro, can currently compete on price with fossil-fuelled generation, the incentives and subsidies offered as a result of Government policies in support of renewables are crucial.

2.30. The fourth and fifth conditions are the provision of transmission and distribution networks, capable of taking the electricity that is generated and delivering it to consumers; and the ability in managing these networks to balance fluctuations of supply and demand—in other words, given the inherent unpredictability of most of the United Kingdom’s renewable energy sources, effective management of intermittency. We have treated these as two

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14 Twelfth Report of the European Communities Committee, Session 1998-99 (HL 78), para. 203.

15 Government Response, printed in the First Report of the European Union Committee, Session 1999-2000 (HL 18), *Energy from Renewables: Further Documents*.

conditions, though in reality they are closely linked. First we consider the Grid infrastructure, along with local distribution systems, and the overall control strategy, which should be able to cope with renewable developments—developments whose scale and character do not necessarily sit comfortably within the traditional Grid model, based on large production units and major conurbations. We then turn to intermittency. Renewables should not destabilise the Grid or make it impossible for the Grid operator to balance supply and demand. In this context the impact of renewable power on overall security of supply inevitably arose in the course of our inquiry, and we have explored this point in some detail.

2.31. Finally, renewable development must have acceptable impacts on the environment, local communities and use of the countryside. There must be a balance between local concerns and national requirements—if all the other conditions are met, but local planning requirements are not satisfied, and local support is not forthcoming, no development will be possible. Our penultimate chapter therefore addresses local, environmental and planning issues, including such matters as the impact of wind farm development on low-fly zones and radar.

CHAPTER 3: TECHNOLOGICAL FEASIBILITY

3.1. The scale of the challenge faced by the renewables industry, if the Government's targets are to be met, has been well documented. We have already noted that in 2002 some 5,508 GWh of electricity were generated from eligible renewable energy sources, which represented around 1.4 percent of the United Kingdom's total demand of just under 400,000 GWh.[16] Of this total wind generation, expected to make up the bulk of the 2010 target, contributed just 1,256 GWh, of which 5 GWh were from offshore wind. If the 2010 target is to be met, new renewable generating capacity roughly equivalent to the total in 2002 will have to be installed each year.

3.2. For this to happen there must be an adequate energy resource, and the technology for converting it into electricity must be sufficiently mature for it to be deployed rapidly and on a large scale. It must also, within the terms of the Government's targets, be eligible under the Renewables Obligation, and we therefore begin with the eligibility criteria, before going on to consider the feasibility of the major technologies in more detail.

Eligibility criteria for "renewables"

3.3. The Renewables Obligation (RO) is the Government's key policy tool for encouraging the development of renewable generating capacity. We consider the nature and effects of the RO in detail in Chapter 5. At this point it is necessary simply to note that it requires all licensed electricity suppliers in England and Wales to supply a specific proportion of their electricity from renewables (there is a separate Scottish Renewables Obligation). This proportion will increase each year, reaching 10.4 percent in 2010 and 15.4 percent in 2015 (the latest date for which a figure has been set). For the purposes of fulfilling their obligation suppliers must purchase electricity from generators using eligible technologies.

3.4. The main eligible technologies are, in summary:

- landfill and sewage gas;
- small hydro (under 20 MW declared net capacity), or larger hydro if commissioned after 1 April 2002;
- onshore and offshore wind;
- biomass (including biomass co-fired in conventional fossil-fuelled plant);
- geothermal power;
- tidal and wave power;
- solar power.

3.5. It is clear that various technologies that could potentially make a significant contribution to achieving one or more of the Government's policy objectives are excluded from the above list. We have already stated that we do not intend to comment on nuclear power or "clean coal" technology (the latter possibly including carbon sequestration technologies), which clearly fall

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16 Source: DTI energy statistics http://www.dti.gov.uk/energy/inform/energy_stats/index.shtml

outside the scope of this Report, though they could potentially make a significant contribution to the reduction of CO_2 emissions.

3.6. The position for energy from waste is more complex. The eligibility of waste as a fuel source depends on the kind of waste, as well as the technical process by which electricity is generated. The exploitation of landfill gas—largely composed of methane, given off as the biodegradable portion of mixed waste decomposes—is already eligible under the Renewables Obligation. Indeed, landfill gas contributed about half of total eligible renewable electricity in 2002—more than twice as much as wind. However, we have not considered landfill gas in this inquiry, as it relies on relatively mature technology, and offers little scope for expansion. Production from existing sites may continue beyond 2020, but will ultimately decline. In the longer term, as the amount of fresh biodegradable waste sent to landfill is reduced, in accordance with the United Kingdom's obligations under the Landfill Directive, this source of renewable electricity is likely to diminish considerably.[17]

3.7. Although landfill sites contain mixed waste, landfill gas itself derives only from the biodegradable portion of that waste. The eligibility of other forms of electricity generation from waste similarly depend on whether or not that waste is biodegradable. Electricity generated from agricultural or forestry waste is eligible, as is that generated from municipal waste that is purely biomass. Such waste may be incinerated, subjected to pyrolysis, gasification or anaerobic digestion, or, until 2011, co-fired in conventional plant. However, electricity generated from the incineration of municipal mixed waste (what is normally referred to as Energy from Waste) is ineligible. Energy derived from the pyrolysis, gasification or anaerobic digestion of such waste, provided that the waste is not derived from fossil sources, is eligible.

3.8. The argument has been put to us that energy derived from the incineration of mixed waste should be treated as an eligible renewable. This argument has obvious attractions. We note that the United Kingdom's use of Energy from Waste is well behind that in some other EU states. In Denmark, for instance, we visited the Amagerforbrænding Waste Incineration Plant in Copenhagen, constructed in 1970, which without giving rise to unpleasant smells consumes the waste produced by 530,000 inhabitants and 36,000 businesses, supplying heat and power to 70,000 households.

3.9. However, we note that the incineration of waste cannot be taken in isolation. The European Union's long-standing strategy on waste has established a "waste management hierarchy"—prevention, re-use and recycling, energy recovery (including incineration to generate electricity) and final disposal.[18] Energy recovery is thus preferable to disposal, but below re-use or recycling. In addition, EU-wide policy, as set out in the preamble to the 2001 Renewables Directive, is that "support for renewable energy sources should be consistent with … the waste treatment hierarchy. Therefore, the incineration of non-separated municipal waste should not be promoted

17 The Landfill Directive (Council Directive 1999/31/EC on the Landfilling of Waste) sets a target for the United Kingdom of reducing the quantity of biodegradable municipal waste sent to landfill to 35 percent of 1995 levels by 2020. The Directive has been transposed by means of the Waste and Emissions Trading Act 2003; specific targets are set in the draft Landfill (Scheme Year and Maximum Landfill Amount) Regulations 2004, laid before Parliament on 22 June 2004.

18 For further explanation see the Report of the EU Committee, *European Union Waste Management Policy* (47th Report, Session 2002-03, HL Paper 149), p. 8.

under a future support system for renewable energy sources."[19] The Government therefore have little room for manoeuvre on mixed waste.

3.10. We have also considered coalmine methane (CMM). Methane forms within the earth by natural processes and continuously leaks to the surface. These releases are concentrated in coal mining areas. The run-down of the coal industry has left a legacy of abandoned coal mines, which, according to the Association of Coal Mine Methane Operators, annually emit some 600,000 tonnes of CMM into the atmosphere. Methane is a powerful greenhouse gas, and these emissions are equivalent to some 13.8 million tonnes of CO_2—more than half the amount the Government hope to save in the country as a whole by 2020 through energy saving measures. Essentially the composition of this gas is the same as that of landfill or sewage gas, and the technology for collecting it and converting it to electricity is no different. Yet even though capturing CMM would bring substantial environmental benefits, as a "fossil derived gas" it remains ineligible under the RO.

3.11. We note the Government's announcement in November 2003 that electricity generated from CMM would henceforth be exempted from the Climate Change Levy—the tax on energy use introduced by the Government in April 2001. However, given the continuing exclusion of CMM from the RO, it is curious that the Minister announcing this concession, the Economic Secretary to the Treasury, referred to the desirability of "using methane gas to produce *renewable energy*" (our emphasis).[20]

3.12. **The treatment of coalmine methane is anomalous. While the exemption of coalmine methane from the Climate Change Levy is welcome, it is unlikely to stimulate the industry sufficiently. We therefore recommend that the Government review the eligibility under the Renewables Obligation of electricity generated from coalmine methane.**

Eligible renewable technologies

Wind

3.13. Of all renewable technologies wind offers the greatest potential for expansion in the United Kingdom in the short to medium term. This is a windy island, and with the exception of Ireland has the most favourable wind profile, both on- and offshore, in western Europe (see Box 1). Wind profiles are generally most favourable in the north and west of the British Isles, particularly in exposed hilltop or coastal locations. The south-east of the country is less favourable, with more obstructions and few hilltop sites. In contrast, offshore sites benefit from the lack of obstruction, and can offer wind profiles comparable to those at good hilltop sites onshore. Consultants Garrad Hassan, in a report commissioned by the DTI, estimate the mean wind speed for the "round 1" offshore sites, adjusted to reflect the height of wind turbines, at between 8.5 and 9.5 metres per second (around 18 mph).[21]

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19 Directive 2001/77/EC of the European Parliament and of the Council on the promotion of electricity produced from renewable energy sources in the internal electricity market, OJ L 283/33 (27 October 2001).

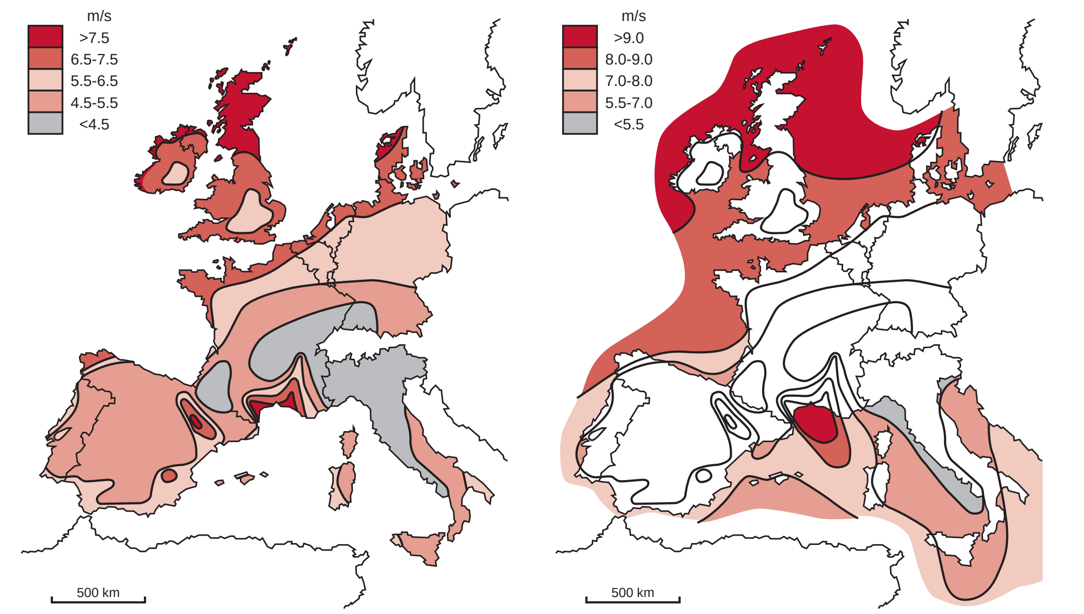
20 News Release dated 1 November 2003—see http://www.hmce.gov.uk/news/nat-nr-7303.htm

21 Garrad Hassan, *Offshore wind: economies of scale, engineering resource and load factors*, p. 27: see http://www.dti.gov.uk/energy/renewables/policy/garradhassanoffshorewind.pdf

Wind speeds at "round 2" locations, further offshore, may be higher still—though if the wind gusts too strongly (above 25 mph), that too will cause turbines to cut out.[22]

BOX 1

Wind speeds in western Europe



The figure shows onshore and offshore wind speeds at a height of 50 metres across Europe obtained from the *European Wind Atlas* (Troen and Petersen, 1989). Onshore the topography is assumed to be open plain, with few wind breaks. The United Kingdom, and particularly Scotland, has some of the best wind resources in Europe. Not only does this benefit generation from wind energy, but also from waves, which are driven predominantly by local wind conditions.

The maximum achievable power output from a wind turbine scales with the cube of the wind speed. Thus a doubling in wind speed gives an eight-fold increase in power output. Because of this, even small increases can be significant: the increase in average wind speed from 6 m/s across much of inland Germany to 8 m/s in Scotland more than doubles the potential power output.

Wind speed also increases with height above the ground or sea. Raising the hub height from 50 metres to 100 metres offshore gives a 40 percent increase in potential power output.

3.14. The technology of wind generation has a track record going back twenty years, and while prices have fallen the capacity and reliability of turbines have improved markedly. In the mid-1980s the capacity of a typical wind turbine was around 100 kW—today units commonly have an installed capacity of 2 MW (2.3 MW at the Causeymire Wind Farm in Caithness, under construction in 2004), while there are commercial prototypes with an installed capacity of 3.6 MW. It appears likely that over the next decade still

[22] See http://www.dti.gov.uk/energy/renewables/policy/garradhassanoffshorewind.pdf p. 27. The "round 1" sites include North Hoyle, off the North Wales coast, where 30 turbines have been constructed some 4-5 miles offshore. The "round 2" sites will be further offshore, within the three strategic areas, Greater Wash, Thames Estuary, and the North West area off the Cumbrian coast.

larger turbines will become feasible for use offshore—the main limiting factor being not so much the construction or operation of the turbine itself, as the means of transporting the large component parts by road from the factory to the wind farm or port.

3.15. The Government's *Renewables Innovation Review* estimates the United Kingdom's total wind resource onshore at 110 GW, and offshore at 100 GW; the practical resource, based on exploitation of around 15 percent of the onshore resource, and 30 percent of that offshore, would be of the order of 40-50 GW, with the possibility of additional generating capacity as a result of upgrading onshore turbines.

3.16. The British Wind Energy Association (BWEA) told us that, under current conditions, they expected wind power to contribute some 6 or 6.5 GW of installed capacity by 2010 (Q 168). This represents 3,000 to 3,250 2 MW wind turbines, requiring installation at an average rate of around one a day, all year round, from now until 2010. Data from the same source show that only 61 turbines, with an installed capacity of 103 MW, were constructed in 2003; the BWEA expect some 314, with an installed capacity of 474 MW, to be constructed in 2004, though this may be optimistic.[23]

BOX 2

Capacity Factors

The "installed capacity" of any generating system is its maximum continuous output. The "capacity factor" or "load factor" is the percentage of the installed capacity that is in practice delivered. For conventional plant the capacity factor may reach 90 percent or more. For wind generators the capacity factor is much lower, reflecting the fact that for most of the time the wind does not blow at the optimum speed for power generation. The Government's working assumption is that under United Kingdom conditions the capacity factor for wind turbines will be of the order of 30 percent.

3.17. "Installed capacity" is of course only part of the story. The "capacity factor" of wind turbines (see Box 2) means that they deliver only a proportion of their nominal rating. The most common working assumption is that wind turbines will operate in United Kingdom conditions at a capacity factor of around 30-35 percent. At this capacity factor 6 GW of installed capacity would produce on average around 2 GW of actual power—somewhat under five percent of average United Kingdom demand. However, doubt was cast on this capacity factor by Mr Hugh Sharman, an independent energy developer and consultant working in Denmark, who sent us an article entitled "The Dash for Wind: West Denmark's Experience and the United Kingdom's Energy Aspirations". Mr Sharman notes that Danish wind turbines have operated at a capacity factor of only 21 percent. If wind turbines in the United Kingdom were to be no more efficient, not only would half as many turbines again be required to deliver the same target output, but potential investors would face dramatic reductions in the income derived from wind farms.

3.18. However, the United Kingdom has a more favourable wind profile than west Denmark, which has mean wind speeds onshore of between 6.0 and 7.0 m/s, and wind turbines may therefore be more productive on favoured onshore

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[23] See http://www.bwea.com/map/2004.html

sites in United Kingdom conditions. Offshore wind turbines are expected to operate at still higher capacity factors than onshore. We have already referred to Garrad Hassan's report for the DTI, which suggests that wind speeds offshore will average between 8.5 and 9.5 m/s. As noted above (Box 1), a rise in average wind speed from 6 m/s to 8 m/s more than doubles the power output. Garrad Hassan's estimate that offshore wind turbines will operate at a capacity factor of between 33 and 38 percent therefore appears to us to be a reasonable one provided good mechanical reliability can be achieved under demanding marine conditions.[24]

3.19. **The Government's projections show that the bulk of the new renewable generating capacity between now and 2010 is expected to be in the form of wind energy, both onshore and offshore. In practice there appears to be no alternative. The United Kingdom has a huge potential wind resource, and the technology for converting wind energy to electricity, at least onshore, is mature and reliable.** We shall examine the practicalities of developing wind power, particularly offshore, in the next chapter.

3.20. **We believe that the common assumption of a 30 percent capacity factor for wind turbines in the United Kingdom is reasonable, and that with the development of offshore wind farms, using larger turbines, higher capacity factors may be achievable.**

Biomass

3.21. Biomass fuel can be considered under three headings: waste by-products, normally from agriculture or forestry, though urban biomass waste also falls under this heading;[25] energy crops; and processed fuels, normally wood pellets made from sawdust, which in the United Kingdom are generally imported. The technology for generating heat from biomass falls under two equally broad headings—straightforward combustion on the one hand, and on the other more sophisticated processes, offering greater efficiency, such as anaerobic digestion, gasification and pyrolysis. Regardless of which technology is used, the heat is used ultimately to drive a turbine which generates electricity. By-products include heat itself (in CHP plants) and fertiliser produced from the residues of the original fuel.

3.22. A further consideration, strictly speaking outside the scope of this Report, is the fact that CHP generators allow biomass, or for that matter any combustible fuel, to be used more efficiently, producing overall energy efficiency of around 80 percent, rather than the efficiency of generating electricity alone, which is typically between 30 and 40 percent. Within its total output, a CHP generator will typically produce three times as much heat energy as electricity—thus despite the much greater energy efficiency, rather less electricity is generated from a given quantity of fuel than would be generated by conventional means. In this Report, in order to achieve consistency when comparing biomass output with other energy sources, we

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24 We were told in the course of our visit to Horns Rev that the operators Elsam expected it to operate at a capacity factor of around 42 percent. However, it remains be seen whether actual output confirms these projections.

25 The Royal Commission on Environmental Pollution, in its Report *Biomass as a Renewable Energy Source*, published in May 2004, differentiates between forestry by-products and agricultural residues. However, for the purposes of this Report we consider all such waste materials under a single heading.

have addressed only electricity output, not heat. However, **we note and endorse the RCEP's approach in its recent report *Biomass as a renewable energy source*, in which all calculations are based on total energy outputs from CHP generation.**

The fuel resource

3.23. We have not accumulated enough evidence to be able to form an independent estimate of the potential resource represented by agricultural and forestry residues. There are competing uses for such materials—in the case of straw, for instance, much is used for animal feed or bedding, and some is exported. The RCEP make the assumption that one third of the total United Kingdom straw production of 24 million tonnes (in 2002) could be used to generate energy.[26] At the sort of efficiency (just over 30 percent), achieved at Elean power station, a straw burning plant near Ely operated by Energy Power Resources (EPR), eight million tonnes of straw could in principle provide more than three percent of the United Kingdom's electricity.

3.24. EPR also operate a plant at Thetford, rated at 38.5 MW capacity, which burns 450,000 tonnes of chicken litter annually. The United Kingdom resource here is more limited, and of course dependent on the continuing prosperity of chicken producers. The RCEP make no estimate of the potential contribution of such animal by-products to our energy needs. However, we note that in Denmark various animal-based fuels are used—for instance, at the Lintrup Plant anaerobic digestion of some 550 tonnes of locally produced pig and cow slurry per day is used to generate biogas, which is then burnt to generate electricity at a neighbouring CHP plant. The degassed biomass is returned as fertiliser to the farms where it was produced. We were informed that the average cow produces no less than 20 tonnes (dry weight equivalent) of manure each year, so as long as the slurry can be collected there is clearly scope for increased use in power generation.

3.25. In contrast, it is clear that in the United Kingdom large quantities of agricultural and forestry by-products simply go to waste, partly for regulatory reasons (see Chapter 4). Slurry is spread on fields, giving off methane and carrying the risk of polluting water-courses, quite apart from the health hazard of direct contamination. Waste from woodland is heaped up or burnt *in situ*. Many farmers, since the banning of stubble burning, simply plough straw into their fields. Such resources are finite, and we doubt that they will ever meet more than a small percentage of the United Kingdom's overall energy needs. However, they represent an important opportunity to achieve multiple objectives, not only lowering emissions but improving the management of the countryside, reducing waste and producing valuable by-products, notably fertiliser.

3.26. **We note that large quantities of agricultural and forestry residues in the United Kingdom currently go to waste. Using this resource to generate electricity would have multiple benefits. We urge the Government, within their overall policy on renewables, to prioritise the exploitation of this resource.**

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[26] Biomass as a Renewable Energy Source, paras. 2.25, 4.48.

3.27. Turning to energy crops, the potential resource is still greater. As we noted in our 1999 Report on *Non-Food Crops*,[27] the most promising energy crops are willow short rotation coppice (SRC) and the perennial grass *miscanthus*. The former is harvested on a three year cycle, the latter annually. Estimates of the potential energy output from such crops vary widely. Yield from SRC varies, as with any agricultural crop, according to weather, the skill and experience of the farmer, and so on. The RCEP estimates average yield at around 10 tonnes of oven-dried wood per hectare. A House of Commons Library Note suggests that approximately 500 hectares (in other words, some 5,000 oven-dry tonnes per annum) of willow coppice are required to support 1 MW of continuous generation, using conventional combustion working at 25 percent efficiency.[28] This is comparable to the output from straw-burning achieved by EPR at Ely.

3.28. The Government's "working assumption" is that biomass will contribute some 5TWh/year (equivalent to installed capacity of 1 GW) to the United Kingdom's electricity needs by 2010, of which capacity equivalent to 600 MW (just under 1.5 percent of average demand) would be derived from energy crops—requiring according to their estimate some 125-175,000 hectares to be planted.[29] This implies a requirement of some 250 hectares/MW. The DTI *Renewables Innovation Review* further speculates that by 2020 some 5-6 percent of United Kingdom electricity demand (that is, capacity of around 2.5 GW) could be generated from just 350,000 hectares of energy crops—representing just 140 hectares/MW.[30] Improvements in generating efficiency (for instance by means of gasification), and greater yields as a result of selective breeding and improved farming techniques, may allow greater productivity. Nevertheless, such projections seem over optimistic.

3.29. Defra estimates the United Kingdom's total available resource for energy crops at one million hectares—equivalent to about half the area of Wales. This compares with total agricultural holdings in the United Kingdom of some 17 million hectares, of which around 640,000 hectares is currently set-aside land. Currently less than 2,000 hectares of land is under energy crop cultivation.

3.30. Finally, in many countries (notably in Scandinavia, Germany, France and North America) wood pellets, made from wood wastes arising from either the lumber industry or packaging, are widely used. This industry is relatively undeveloped in the United Kingdom, but generators do have the option of importing wood pellets. In Denmark we discovered that wood pellets are commonly imported from northern Russia, and the Government's recent decision to extend the eligibility of co-firing—that is, the burning of biomass in conventional plant—under the RO to 2011 increases the prospect of significant amounts being imported to the United Kingdom. There are no technical limits on the amount of biomass that may be imported, or the amount of electricity that may be generated. The limiting factors are likely to be economic and environmental, and will be discussed in the next chapter.

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27 First Report, Session 1999-2000 (HL Paper 5).

28 Source: HC Library Note on *Biomass energy crops* (SNSC-01389), January 2004, p. 9.

29 Source: "Energy from Biofuels", DTI Sustainable Energy Technology Route Map, p. 20—see http://www.dti.gov.uk/energy/renewables/technologies/routemap.shtml

30 *Renewables Innovation Review*, p. 48 http://www.dti.gov.uk/energy/renewables/policy/biomass.pdf

3.31. **Energy crops have good potential as a fuel source. However, there is a limited resource (in terms of land area) in the United Kingdom, and if it is to be exploited effectively rapid progress both in plant breeding and cultivation techniques will be needed. We believe the Government's current projections for the contribution of energy crops to our energy needs are over-optimistic, and recommend that the Government clarify the basis upon which they have been made.**

Generating technology

3.32. The combustion technology used at plants such as the straw-burning plant at Ely is similar to that used in conventional fossil-fuel plant—indeed, the use of biomass in co-firing demonstrates the inter-changeability of fuel sources. The main technical challenge faced by generators is the management of their fuel source, which is bulky and has a lower calorific value than coal. This is discussed in the next chapter.

3.33. However, more advanced technologies offer the prospect of greater efficiency than simple combustion. Pyrolysis involves the heating of timber and other organic waste at high pressure, and in the absence of air, to produce a high quality oil that can then be used to fuel a power plant. Useful by-products are combustible gases and carbon-rich char, which may also be burnt or gasified. The technique can be adapted to treat a range of waste products, including tyres and, potentially, mixed waste.

3.34. Gasification involves the heating of wood chips in a controlled flow of air or steam (on a "fluidised bed"), producing a combustible mixture of gases, including carbon monoxide, hydrogen and methane. Less char is produced, and, unlike pyrolysis, gasification cannot be applied to mixed organic wastes. The reason that both pyrolysis and gasification offer gains over simple combustion is essentially because the gas, mixed with air, burns at a higher temperature, and so drives the turbine more efficiently.

3.35. The Arable Biomass Renewable Energy (ARBRE) plant at Eggborough was intended to demonstrate the potential of such technologies, and produce a net output of 8 MW. However, technical and commercial difficulties led to the project's collapse in 2002.

BOX 3

The ARBRE plant

The process at ARBRE was designed to have four stages:

- Drying the chipped willow stems using waste heat
- Gasification in a fluidised bed, where the chips thermally decompose to form a combustible gas (composed largely of CO, H_2, and CH_4), steam and solid carbon char.
- Gas cleaning, to remove tars and impurities.
- Electricity generation using a two-stage process: a 4.75 MW gas turbine and a 5.25 MW steam turbine.

In the event, residues of metals in the willow combined with the sand used to filter the gases to produce a glue, gumming up the fluidised bed.

3.36. The collapse of ARBRE suggests that attempts to develop new fuel sources at the same time as new generating technology energy may be over-ambitious. A more incremental approach to developing biomass technology is likely to yield better results, and **we endorse the recommendation of the Royal Commission on Environmental Pollution, that "the focus should be on establishing the sector through the use of existing, proven technology whilst simultaneously developing new technologies and demonstration plants"**.

Marine

3.37. Given the United Kingdom's long coastline, wave and tidal energy have enormous, but unproven, potential. They face a problem common to new technologies—a wide range of possible technical solutions are jockeying for position. We have received valuable oral or written evidence on some of these technologies from the companies developing them, including:

- Ocean Power Delivery, developers of the Pelamis wave energy converter, of which the first full-scale pre-production prototype has recently been launched at the Orkney-based European Marine Energy Centre;
- Offshore Wave Energy Limited, developers of the OWEL wave energy converter;
- The Engineering Business Limited, developers of the Stingray tidal stream generator.

3.38. All these technologies are experimental—the most advanced are at the demonstration stage—and we do not therefore feel able to assess their technological feasibility. However, with regard to wave generators we note the conclusion of the European Communities (now Union) Committee in 1999 that "we doubt whether, with presently available technology, wave energy generation machinery installed offshore could long withstand the extreme forces of the sea".[31] Moreover, we note that the timescales for demonstration and construction of wave energy prototypes mean that even if their development is successful they are unlikely to be ready for commercial deployment within the next ten years.[32]

3.39. The one established tidal generator in Europe, the barrage at La Rance in Brittany, has been operating for over 40 years with an output of 240 MW. The barrage concept, therefore, is not new, and the technology, whereby the tide is channelled so as to drive a turbine, is relatively well-established. At La Rance the use of two-way "bulb turbines" means that power can be generated both when the basin is filling and draining.

3.40. The most obvious location for such a barrage in the United Kingdom would be across the Severn Estuary, which has one of the world's highest tidal ranges, at around 13 metres. Proposals to build such a barrage have been current since at least the 1950s, and Professor Ian Fells, of Fells Associates, estimated that it would take 12 years to construct and would generate six percent of United Kingdom electricity demand. There is no technological barrier to a Severn barrage making a substantial contribution towards

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31 *Electricity from Renewables*, 12th Report, Session 1998-99 (HL Paper 78), para. 299.

32 For more detail on these technologies see the article "Power from the waves", *New Scientist*, 20 September 2003.

meeting the Government's renewable energy aspiration for 2020. The obstacles are economic and environmental.

3.41. Other methods of exploiting tidal energy are now being proposed. Tidal stream generators, of which the "Stingray"[33] is among the most advanced, are essentially underwater wind turbines. A larger scale option, on which we received very little evidence, is the creation of "tidal lagoons". This has been propounded by a company called Tidal Electric Limited, and has since received the backing of Friends of the Earth, in a briefing paper dated January 2004.[34] Tidal lagoons are stone pounds, projecting about a metre above the high-water level, in which water is trapped and released through turbines built into the walls. Electricity is generated, as at La Rance, on both the ebb and flood tides. Although tidal lagoons are a relatively new concept, the basic technology is familiar—essentially not dissimilar to that used in established hydro generators—and the main obstacles to development appear to be economic. Friends of the Earth estimate that, for the largest tidal lagoon scenario, installed capacity would be 4.5 GW, and average output, at a capacity factor of 61 percent, some 2.75 GW. Design life would be extremely long—promoters of the technology claim at least 120 years.

3.42. **We do not believe that it is feasible for wave or tidal generation to contribute significantly to meeting the Government's 2010 target. However, there is no technological barrier to tidal barrages making a significant contribution by 2020.**

3.43. **Wave and tidal stream generators have promise, but remain at the demonstration stage, and it is too soon to judge when they will be capable of commercialisation. The essential requirement is that they prove capable of operating reliably over long periods.**

Solar

3.44. Climate and latitude are the main limiting factors on the exploitation of solar energy in the United Kingdom. Average insolation in London (at just over 2 $kWh/m^2/day$) is around 40 percent of that in central Africa, and little more than half that in San Francisco or Madrid.[35]

3.45. Two major classes of technology exist for converting solar energy into electricity. The most relevant to the United Kingdom is photovoltaic cells (PV). These are already used in domestic applications, on stand-alone units such as parking meters or buoys, and in larger installations. They can be incorporated in building surfaces such as roof tiles, glass panels or walls, where they produce low voltage direct current. The United Kingdom currently has less than one percent of worldwide installed PV capacity (about 4.2 MW), compared with, for instance, 49 percent in Japan.

3.46. Efficiency of current PV is in the range 7 to 15 percent, depending on the type of PV cell, material and design. However, research continues into a new generation of PV cells, cheaper to produce and more efficient. There is a possibility that by 2020 the cost of PV energy will be considerably lower than

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33 The developers of the Stingray generator tested a 150 kW demonstrator in the Shetlands in 2002, and plan to install a 5 MW "farm" in 2005. See the memorandum by The Engineering Business, pp. 167-171.

34 See *A Severn barrage or tidal lagoons? A comparison*, January 2004 http://www.foe.co.uk/resource/briefings/severn_barrage_lagoons.pdf

35 Source: *Renewables Innovation review* http://www.dti.gov.uk/energy/renewables/policy/solar.pdf

at present, but without a major reduction in unit cost they are unlikely to contribute significantly to the United Kingdom's electricity needs.

3.47. The other major class of technology is solar concentration. The Plataforma Solar de Almería, in Spain, was established in 1981, and is developing technologies for concentrating solar energy by means of reflective panels or dishes. However, Almería is the sunniest region of Spain, and there is little prospect that such an approach will be replicated in the United Kingdom.

3.48. **Photovoltaic cells are widely available, and are already widely used in domestic and stand-alone applications. However, their use commercially in the United Kingdom is limited by the low level of insolation, and by their high price. This situation is unlikely to change unless there is a major technological break-through and a step change in efficiency. This continues to be an active area of research in the United Kingdom and abroad.**

Hydro

3.49. Hydro is, in the words of the British Hydropower Association (BHA), "a long established and proven technology". The naturally replenished water in high lakes or reservoirs is discharged through turbines to generate electricity. Hydro currently contributes some 40 percent of total United Kingdom renewable electricity, while in many EU states hydropower contributes much larger proportions—in case of Austria, as much as 70 percent of total electricity production. The United Kingdom's potential resource is nothing like as great, but the BHA estimate that new medium to large development has the potential to generate up to 750 MW—though this does not take into account economic or environmental factors (p. 236).

3.50. The BHA also drew attention to the potential for small hydro development in the United Kingdom—a point confirmed in the evidence supplied by the National Environmental Research Council (p.203) Many such developments would be at disused mill sites, often in urban areas.

3.51. The European Small Hydropower Association estimates the total potential capacity for small hydro at 300 MW—though again, such small development will tend to be expensive, and only part of this total would be economic to develop.

3.52. **Hydropower is a well-established technology, and there is potential for modest expansion in the United Kingdom. However, the lack of suitable locations in the United Kingdom means that there is little prospect of hydropower contributing on a large scale to the Government's renewable energy targets.**

Geothermal

3.53. We received little evidence on the potential for geothermal energy, although a paper containing a very useful overview of the available technologies was provided by the Institution of Mechanical Engineers.[36] Geothermal energy is exploited by means of hot water that is returned to the surface after being heated by circulation underground. The circulation may be pumped or natural (as in hot springs). The technologies for stimulating flows and

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36 This paper, which was not treated as formal evidence, was based on a paper by Ian M Arbon, presented to a conference on "Future Power" at Cullum's Science Centre, April 2003.

managing production have much in common with those used in the oil industry.

3.54. The value of the resource depends on how hot the water is and the rate of discharge. A high quality resource requires either deep circulation (2-3 km depth or more) or exceptional temperatures at shallower depths. The geothermal resource in the United Kingdom is not very promising, but could be used locally for district heating (for instance in the Southampton area). We did not therefore explore geothermal energy any further in the course of our inquiry.

The future—problems and opportunities

3.55. This chapter has focused on the current technological feasibility of renewable generation. However, in the longer term—by 2020 and certainly beyond—technologies that are currently immature or undiscovered may also emerge into prominence. If this process is to be facilitated, there will have to be adequate support for research, development, and for the demonstration of new technologies. At the same time, the skills base will have to be maintained and expanded. In Chapter 5 we shall consider the difficulties faced by developers in raising finance to fund demonstration projects and prototypes. Here we address support for R&D.

3.56. Historically the United Kingdom has not excelled in R&D into renewables. It has, for example, lost the leading position it once held in wind energy R&D, whereas Denmark, thanks in large part to supportive government policies, took the lead and now manufactures about half of the world's wind turbines.

3.57. In general R&D in new areas tends to be productive where there is both well-judged Government support for the early and more speculative phases of the work and a substantial home market in which new products can become established. Neither of these conditions has hitherto been satisfied in the United Kingdom. Moreover, the urgency that is now associated with the current United Kingdom renewables programme means that there is unlikely to be time for United Kingdom-based research to have significant impact and the technology is likely to be imported. If the Government enhances its support for energy R&D and there is confidence in the future of renewables the situation could change. The Government's *Renewable Supply Chain Gap Analysis*, published in the course of our inquiry, sets out the huge commercial opportunities in the worldwide expansion of renewable energy.[37] The United Kingdom is currently well placed to capitalise on such opportunities

3.58. To take one example, the Minister told us that the United Kingdom has "a clear world lead in the development of wave and tide energy" (Q 365). Several companies are developing innovative technologies for utilising marine energy, including three that we have already mentioned.[38] There is also considerable regional support, and a large-scale testing facility, the European Marine Energy Centre Ltd, was established in Orkney in 2003, with support from Highlands and Islands Enterprise and its partners. The South West of England Regional Development Agency has set up a renewable energy agency, Regen SW, which in February 2004 announced the commitment of

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37 Published January 2004—see: http://www.dti.gov.uk/energy/renewables/publications/pdfs/renewgapreport.pdf

38 The Engineering Business Ltd, Offshore Wave Energy Ltd, and Ocean Power Delivery.

£500,000 to complete a study into the viability of a "wave hub", nine miles off the Cornish coast—essentially an electrical socket to which wave generators could be connected either for testing or commercial use.

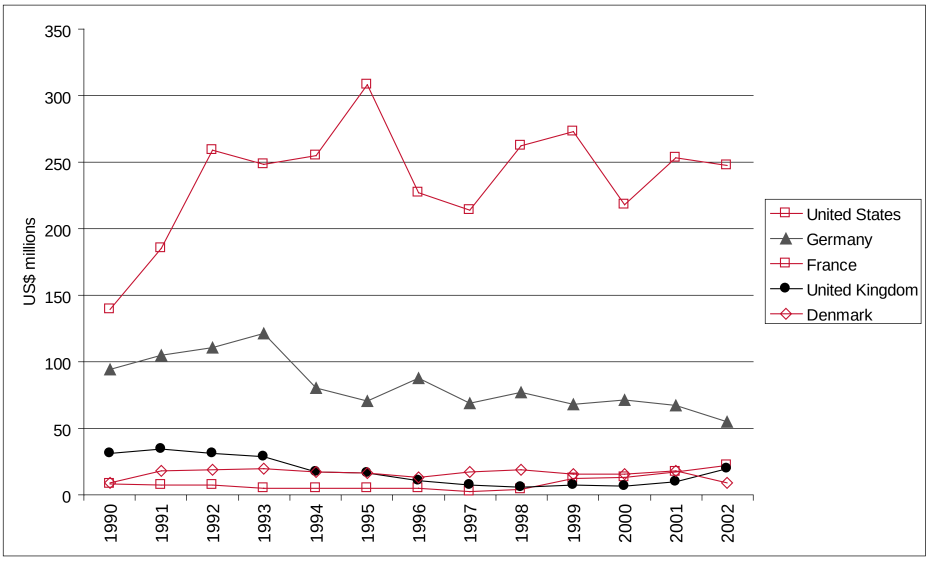
3.59. In addition, in February 2004 the Government-funded Carbon Trust announced the launch of a "Marine Energy Challenge", a £2.5 million programme to review eight devices and concepts, with a view to establishing whether they have the potential to deliver reliable and economic electricity.[39]

3.60. However, the United Kingdom is not alone in developing new approaches to marine energy—the *Renewable Supply Chain Gap Analysis*, for example, draws attention to Portugal's support for pre-commercial devices. Further afield, Blue Energy Canada Inc has put forward a proposal to construct a $2.8 billion "tidal fence" in the San Bernardino Strait in the Philippines, with an installed capacity 2.2 GW.[40] There is every indication that as R&D progresses marine energy will become increasingly competitive.

3.61. Strong support for R&D is therefore crucial. The DTI provided us with figures on central Government's spending on energy-related RD&D, going back to 1991-92 (see p. 30). This shows that spending on renewables R&D in 1997-98 was some £5.5 million, rising in 2002-03 to £12.2 million. To put this figure in context, data from the International Energy Agency show that while United Kingdom Government expenditure on research into renewables has risen, it is still less than half that in Germany:

FIGURE 1

Spending on renewables R&D



Source: International Energy Agency.

3.62. How well is this money being spent, and the research effort co-ordinated? We note the announcement by EPSRC, ESRC and NERC in April 2003 of the establishment of a United Kingdom Energy Research Centre. This Centre, intended to provide leadership and focus for energy research, was to have been established by 1 April 2004. In the event, although the appointment of a Research Director Designate was announced on 31 March,

39 See the announcement of the Marine Energy Challenge at: http://www.thecarbontrust.co.uk/carbontrust/about/press_releases/PressRelease_11_02_04.pdf

40 See http://www.bluenergy.com/oceanenergy.html

it was clear from detailed questioning of witnesses from Research Councils United Kingdom (RCUK) that little concrete progress has been made (see QQ 493-503). There appears to be a vision, and a lot of words written, but Dr Peter Hedges admitted that it would be four or five years before the proposed international research centre was fully established (Q 503).

3.63. As the example of marine energy demonstrates, there is clearly no lack of dynamic and diverse R&D in the United Kingdom renewables industry. Good work is being done by the private sector and by RDAs in particular. However, we are not satisfied by the level of co-ordination of the United Kingdom research effort, and there is a serious risk that the impact of this research effort will be dissipated. Central Government funding is modest by international standards, and the process of establishing a United Kingdom Energy Research Centre has been slow and confused.

Summary

3.64. **The relative maturity of wind generating technology, and the scope for expansion given the United Kingdom's favourable wind profile, mean that it already has the potential to make a major contribution to renewable energy development.**

3.65. **In the longer term there are no insuperable technical obstacles to large-scale biomass generation, and by 2020, assuming that research, development and demonstration of newer technologies are adequately supported, it is possible that tidal and wave energy technologies will also be sufficiently mature for commercial deployment. While significant commercial use of solar power is unlikely, there is scope for expanding its already widespread use in domestic and stand-alone applications. Limitations on the United Kingdom's primary resources are likely to restrict development of hydropower and geothermal energy.**

3.66. **While wind offers the greatest scope for development in the short term, we believe that in the medium and long term a more diverse portfolio of renewable energy sources will be needed. We therefore recommend that the DTI review the level of Government funding for energy research, and, in discussion with RCUK, push forward the establishment of the United Kingdom Energy Research Centre as a matter of urgency. It is essential that a focus be established rapidly for the United Kingdom energy research effort and that it is properly funded.**

CHAPTER 4: PRACTICAL IMPLEMENTATION

4.1. Our analysis of the technological feasibility of renewable energy sources shows that wind, biomass, marine and (in domestic or stand-alone applications) solar power, offer the greatest potential for development in the United Kingdom. The purpose of this chapter is to examine the practical challenges of both installing and maintaining these technologies—in terms of manufacturing capacity, infrastructure, or ongoing reliability. In the case of biomass generation, the provision of adequate, affordable supplies of fuel will be essential. The regulatory framework should not hinder either development or ongoing operation unduly. Of course almost any practical problem can be overcome at a price, so at the end of this chapter we turn to the ostensibly simple question, "what will the various renewable technologies cost?"

Wind

4.2. Experience has shown that onshore wind farms can be constructed relatively rapidly, though problems may arise as a result of location, for instance if access for heavy equipment is difficult. Foundations are normally of concrete, on which tower and turbine are mounted in sections. Power cables are connected via a sub-station to the transmission or local distribution network, depending on the size of the installation. The major capital cost for onshore wind farms (representing about two thirds of total capital costs[41]) is the purchase of turbines.

4.3. The situation offshore is more problematic. There is no doubt that offshore wind farms can be developed. When we visited Denmark we were fortunate to have the opportunity to visit the Horns Rev offshore wind farm, made up of 80 2 MW turbines, constructed in 2002. The largest wind farm currently in operation in the United Kingdom, at North Hoyle off the North Wales coast, with 30 2 MW turbines, was completed in November 2003. However, uncertainties remain.

4.4. The most common type of foundation used offshore is a monopile (essentially a large steel tube[42]) driven some 10-20 metres into the seabed, on which the tower can then be erected. The long-term security of such foundations offshore is far from clear. In the course of our informal seminar in December 2003 Professor Guy Houlsby illustrated the scale of the challenge. He told us that once erected, a typical offshore wind turbine might face horizontal forces from wind and waves equivalent to about 400 tonnes, compared with a total weight of around 600 tonnes. In contrast, a North Sea oil platform weighing some 20,000 tonnes and of a similar height has to bear up against horizontal forces equivalent to roughly 2,500 tonnes.

4.5. Mr Hastings, of the British Wind Energy Association (BWEA), assured us that there was "a wealth of experience in terms of constructing offshore foundations … that largely comes from the oil and gas industry" (Q 212). However, given the huge difference in the forces to which these structures

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41 See DTI fact-sheet, "The economics of onshore wind energy": http://www.dti.gov.uk/energy/renewables/publications/pdfs/windfs3.pdf

42 At Horns Rev in Denmark, these monopiles weigh 150 tonnes, and are 24 metres long with a diameter of 4 metres.

are exposed, relative to their weight, we do not wholly share his confidence.[43] It is notable that North Hoyle is sheltered from the largest waves. Developments further offshore will not enjoy the same advantage. Research into alternatives to monopile foundations continues.[44]

4.6. A further challenge concerns the nature of the sea-bed. A solid and stable sea-bed will allow for durable foundations, but if it is too solid it will make construction slow and expensive. We were told by David Jones of Shell Wind Energy that it should be possible to erect four turbines a week, but construction of the 30 turbines at North Hoyle, which began in April 2003, was not completed until November—a rate of just one a week—having been seriously delayed by the time taken to drive monopiles into the sea-bed. In contrast, monopiles can be driven into a sandy sea-bed in less than an hour. However, the foundation is inherently less stable, and in extreme cases subject to scouring (the large-scale migration of sand banks, comparable to that of sand-dunes on land).

4.7. The installation process itself carries particular risks offshore. Chief among these is the weather—construction is only possible from late spring to early autumn, and a stormy spell within this window of opportunity can inflict heavy delays and costs. If a project is not complete by the autumn, it simply has to be postponed until the following year. In the case of Horns Rev, constructed between March and August 2002, bad weather meant work was impossible for about one third of that time.

4.8. The logistics of offshore construction also present difficulties. The components have to be mounted on jack-up barges, and in the case of North Hoyle each turbine had to be separately ferried from land—a time-consuming exercise, involving over the course of the project some nine different vessels. Such considerations mean that compared to onshore, the cost of the turbine itself represents a smaller proportion—less than half—of the installation costs. The commercial difficulties that have bedevilled the "Mayflower Resolution", a new vessel capable of dramatically accelerating installation offshore, are summarised in Box 4. It is essential for the planned expansion of offshore wind in the United Kingdom that the "Resolution", or a similar purpose-built vessel, be available for use by developers.

4.9. Finally, the ongoing costs of maintaining offshore wind-turbines are still largely unknown. At onshore sites, when a fault is reported, an engineer can simply drive out and fix it. In contrast, at Horns Rev we witnessed an engineer being lowered onto a turbine from a helicopter. While this was a dramatic demonstration of offshore maintenance, we can only assume that it was also an expensive and risky one. In practice much will depend on offshore turbines delivering very high levels of reliability, so that maintenance can be scheduled for planned outages. Individual fault-fixing will not be an option.

4.10. The effect of these various practical constraints and risks is that offshore development so far has been slow—and our understanding is that 2004 will also not meet expectations. In the longer term, Alan Moore, of the BWEA,

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43 Mr Hastings differed from Professor Houlsby in suggesting that a large offshore turbine would weigh about 200 tonnes, compared with a weight of 10,000 tonnes for an oil or gas platform (Q 214). However, this discrepancy does not affect the essential point.

44 Professor Houlsby is part of a project to develop one such alternative, the "suction caisson" (see the note of the seminar in Appendix 5).

was confident that "Projects will get very large when we get to the back end of the decade" (Q 169). Projections for the future growth of wind power frequently point to the number of large projects which have been proposed or approved. However, as the BWEA themselves stated in their written evidence, there is "about 1,400MW of wind capacity in the United Kingdom which has received planning permission but which is not being built" (p. 73). The practical obstacles to large-scale wind development remain formidable.

BOX 4

The Mayflower Resolution

In December 2003 a purpose built vessel for the installation of offshore wind turbines and cables, the "Mayflower Resolution", set sail from China, where it had been built at a cost of over £50 million, to the United Kingdom. The "Resolution" is capable of working on its own, carrying at any one time all the equipment and components needed to install ten turbines. Unfortunately the company that ordered the "Resolution", Mayflower Energy Limited (which also installed the turbines at North Hoyle), went into receivership on 1 April. A management buy-out, funded by Japanese bank Mizuho, was announced later the same month. We understand that the "Resolution" is currently still in the United Kingdom.

4.11. We asked the BWEA to put a total figure on the cost of wind turbines, and, on the basis of a 50:50 split between onshore and offshore development, Mr Moore put the capital cost of construction at around £900 per kilowatt capacity. The Royal Academy of Engineering, in its recent report on the costs of renewable power, cites capital costs of £650/kW for onshore wind, and £1,000/kW offshore.

4.12. **Achieving development on the scale envisaged by the Government represents a huge task for the wind energy industry. Onshore, we have little doubt that it is technically and physically possible to manufacture and install sufficient numbers of wind turbines to meet the Government's targets. The constraints on onshore development are not primarily technical, but environmental.**

4.13. **The White Paper describes offshore wind power as "about to take off". In spite of the Danish experience, we are less sanguine. Offshore development is still largely a step into the unknown, and potential investors face serious technological and commercial risks. The next few years will be crucial, and it remains to be seen whether offshore wind power can fulfil the vital role assigned to it within the Government's energy strategy.**

Biomass

4.14. We have already summed up the technical processes employed in biomass generation. We have also touched on the potential fuel resource in the United Kingdom. The key practical challenge facing the biomass sector is not the construction of generators, but finding ways to exploit the fuel resource and establish reliable and affordable fuel supplies.

4.15. Ostensibly waste biomass is free, or at least very cheap. However, unlike wind, sun or tides it does not deliver itself to the generator—the cost of collection, storage and transport place a heavy, continuing financial burden on generators. In addition, once it has been collected it acquires a market value, for instance as firewood for domestic use, or straw for bedding, and electricity generators have to compete within this market.

4.16. The experience of EPR, who operate the largest biomass generators in the United Kingdom, at Ely and Thetford, is highly relevant. At Ely some 220,000 tonnes of straw are burnt each year, fuelling a plant with a capacity of 36 MW. This straw is delivered from within a radius of 60 miles. The two barns on-site can store only three days' fuel, so the rest is stored at holding sites—and as straw is a seasonal crop, the volume of fuel in storage at any one time is considerable. This stored fuel is vulnerable to weather damage (raising the moisture to unacceptable levels) and vandalism. EPR estimate that overall some 12 percent of their fuel is lost to weather or vandalism—including losses totalling £400,000 a year to arson. Straw is delivered to the plant by lorry as it is needed.

4.17. Farmers receive just £2 per tonne for straw lying in the fields, but by the time it is baled, stored, transported to the plant, and losses are factored in, the cost to EPR is some £35 per tonne.

4.18. The *Renewables Innovation Review* suggests that by 2020 straw could potentially meet 3.2 percent of the United Kingdom's electricity needs.[45] This would mean that about one third of total straw production—some eight million tonnes per annum—would have to be used for power generation. In contrast, EPR estimate that practically there is scope for just five more plants like that at Ely—using a total of some 1.3 million tonnes of straw to supply just 0.5 percent of electricity demand. At the same time, they pointed out to us that no major new biomass development is currently being planned. While it may be possible in theory to generate 3.2 percent of the United Kingdom's electricity from straw, EPR's experience of the realities of biomass generation suggests that it is very unlikely such a target can be achieved.

4.19. The economics of EPR's Thetford plant, which burns poultry litter, are comparable. Litter production is not seasonal, and therefore storage costs are not so high. However, the fuel's low calorific value (about half that of straw) means that the volume that has to be transported is still greater. Thetford burns some 450,000 tonnes of poultry litter per annum, essentially supplied free by the producers, who are apparently grateful simply to have their barns cleared, but costing EPR about £10 per tonne by the time it reaches the plant.

4.20. The viability of biomass projects is further undermined by unsympathetic regulation. In the case of Thetford power station, as we describe in Box 5, the Regulator's narrow and environmentally counter-productive interpretation of the terms of a NFFO[46] contract places yet another obstacle in the way of the plant's operators. To forbid the use of chicken feathers to supplement litter produced by the same chickens is perverse, particularly given that under the somewhat more liberal terms of the Renewables Obligation both would be eligible fuels.

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45 *Renewables Innovation Review*, p. 45 http://www.dti.gov.uk/energy/renewables/policy/biomass.pdf

46 For a brief account of the Non-Fossil Fuel Obligation (NFFO), predecessor to the Renewables Obligation, see Box 9.

BOX 5

Chicken litter vs chicken feathers

The NFFO contract governing the operation of Thetford Power Station requires the use of poultry litter as fuel. This is produced by barn-reared chickens which are then slaughtered to provide meat. Once the chickens have been plucked their feathers could be collected and used to supplement the litter, improving the efficiency of combustion. However, the Regulator regards feathers as industrial waste, and thus forbids their use at Thetford. The feathers are instead consigned to landfill.

4.21. A further difficulty facing EPR is the classification of chicken litter as agricultural waste, which brings the Thetford plant within the ambit of the Waste Incineration Directive.[47] This imposes strict emission controls, designed primarily to monitor dioxin emissions from mixed waste incineration. The risk of dioxin emissions from biomass generators is relatively low, but at the same time the variability of fuel quality and moisture content makes it extremely difficult to achieve uniformly efficient combustion, with the result that occasional short-term increases in carbon monoxide emissions (the marker for dioxins) are almost inevitable. The cost of introducing the emission controls required by the Directive could make the difference between survival and closure for some biomass generators.

4.22. **We recommend that the Government, in consultation with Ofgem, urgently review the regulatory framework applied to generators using waste biomass, with a view to removing or mitigating the impediments that are threatening an industry already operating at the margins of economic viability**.

4.23. Turning to energy crops, the market has hitherto been weak. The essential problem facing the industry is economic, and has been analysed in detail by the Royal Commission on Environmental Pollution (RCEP).[48] High initial investment is required to establish the crop and purchase specialised machinery, and there is then, in the case of willow SRC, a four-year wait before the first crop is ready for harvesting. Planting energy crops represents a major commitment—SRC may be harvested over 15-20 years before returning the land to conventional crops—so confidence in the long-term stability of the market is essential. Establishment grants are available from Defra, but only if the grower has a contract to supply the crop to a generator within a 25 mile radius. The grants provide a lump sum upon planting, rather than ongoing support.

4.24. In April 2004 the Government extended the rules allowing co-firing of biomass in conventional fossil-fuel plant, specifically with a view to kick-starting the energy crops industry. Co-firing of biomass will now continue to be eligible under the Renewables Obligation until 2016. From 1 April 2009 co-firing generators will be required to use at least 25 percent energy crops in their biomass fuel. The requirement to use energy crops will continue to increase until from 1 April 2011 co-fired biomass will have to be made up of at least 75 percent energy crops.

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[47] Directive 2000/76/EC of the European Parliament and of the Council of 4 December 2002 on the incineration of waste OJ L 332/91. Animal waste is covered by the Directive, although vegetable waste from agriculture is excluded.

[48] Biomass as a Renewable Energy Source, Chapter 4.

BOX 6

Energy crops in the United Kingdom

Less than 2,000 hectares of energy crops are currently under cultivation in the United Kingdom, of which some three quarters are willow short rotation coppice planted specifically for the ARBRE plant at Eggborough. The project's failure, just as the crops were coming to maturity, left the growers without a market. However, in the course of our inquiry, it was announced that Drax Power Station had agreed to purchase the crops for use in co-firing (see Q 364).

4.25. It remains to be seen whether the revised rules on co-firing will provide the desired encouragement. However, we note the RCEP's analysis of the Government's approach to co-firing, which notes that in order to supply SRC by 2009 farmers will have to plant crops in 2005, and concludes that "in order to reach the 2005 planting date, applications for planting grants would need to have been submitted no later than April 2004".[49] In other words, it may in practical terms already be too late to achieve the Government's objective.

TABLE 1

CO_2 equivalent emissions

Fuel type	Net greenhouse gas emissions (grams of CO_2 equivalent emissions per kWh electricity)[50]
Willow SRC (from within 50 km radius of generator)	77
Gas	411
Coal	1,054

Source: RCEP, Biomass as a Renewable Energy Source, Table 4.3.

4.26. Biomass, like other renewable technologies, is deemed "carbon free"—the CO_2 that is released by its combustion has already been absorbed by the plants themselves as they grow (or, in the case of animal waste such as poultry litter, by the plants which ultimately provide the food for the animals). There is therefore no net effect on the amount of CO_2 in the atmosphere. However, any activities connected with "carbon-free" generation that produce CO_2 represent a net contribution to emissions. Such activities include the manufacturing processes for wind turbines, for instance. In the case of biomass this consideration applies pre-eminently to the transportation of fuel to the generator—our Specialist Adviser calculates that for each 10 km the fuel is transported by road (or each 100 km by sea) energy equivalent to 0.2 percent of the energy value of the fuel itself is

49 Biomass as a Renewable Energy Source, para. 4.56.

50 "Net emissions" here cover all greenhouse gas emissions, expressed in terms of carbon dioxide (CO_2) equivalent emissions. Other greenhouse gases include methane (CH_4), nitrous oxide (N_2O), hydrofluorocarbons (HFCs), perfluorocarbons (PFCs) and sulphur hexafluoride (SF_6).

consumed.[51] This means that as long as the fuel is sourced locally, net emissions remain small when compared with fossil fuel generation (Table 1).

4.27. It is therefore understandable that growers are required to demonstrate that they have a contract with a generator no more than 25 miles away, in order to qualify for Government grants. However it is puzzling that no geographical restrictions apply to co-firing generators, who are free to import biomass from the other side of the world if they can find a cheap enough source. In practice this is likely to encourage use of wood pellets, which are a well established, internationally traded commodity, and are widely used across Europe. However, only small quantities are manufactured in the United Kingdom, so in the short term we expect much fuel for co-firing to be imported.

4.28. The effect of large scale imports on carbon emissions is unclear. In response to written questions put down by our Chairman, the Minister replied that he was "doubtful that we could make any such calculations on transportation costs in terms of average carbon equivalent emissions per MWh of electricity generated as they would … be based on unreliable and not readily available data." However, he did provide data suggesting that using imported wood pellets in CHP generation would generate an additional 90g CO_2 equivalent emissions per kWh.[52] He had already, in an earlier answer, stated the Government's view that "the use of imported rather than domestic fuels is a matter for the market. Any restriction on fuel would not be permissible under international trade rules".[53]

4.29. **The establishment of reliable and economic fuel supply chains is the major practical impediment to biomass generation. It does not appear that such fuel supply chains offer major economies of scale—indeed, the bulk and low calorific value of biomass fuel, and the need for a larger "catchment area", mean that transportation and storage costs may be proportionately higher for large-scale developments.**

4.30. **We doubt that the Government's extension of the eligibility of co-firing under the RO will provide the wished-for fillip to the energy crops industry. It may already be too late for farmers to be ready to supply energy crops in large quantities by 2009. Given the Government's insistence that it is for the market to choose where it sources biomass fuel, there is a serious danger, in the words of the RCEP, that "generators will co-fire for as long as they are unrestricted in their use of biomass (and can use imports) and then will stop as soon as the energy crop requirement is introduced in 2009".**

4.31. **We therefore urge the Government to introduce more specific, targeted measures to encourage energy crop development, including transitional support for farmers while crops reach maturity, and a requirement on generators to offer long-term contracts to farmers as a condition of RO eligibility.**

51 All generating technologies have an "energy payback period" (the time taken for a plant to yield the amount of energy required for its construction and operation). The comparative energy payback periods of a range of technologies are discussed in more detail in Appendix 8.

52 HL Deb, 5 April 2004, col. WA 206.

53 HL Deb, 22 March 2004, col. WA 84.

4.32. **Transportation of biomass fuel represents a net addition to CO_2 emissions. We therefore believe that energy efficient (in other words, CHP) developments, located close to reliable fuel sources, offer the most environmentally beneficial prospects for future development. We recommend that the Government focus their efforts on establishing a regulatory regime that favours small-scale biomass development using locally sourced fuel.**

Solar

4.33. Photovoltaic (PV) cells are already cost-efficient in certain niche applications in the United Kingdom, where installation costs can be set against the cost of connecting to local networks—for example stand-alone, self-powered parking meters, which are now being deployed by a number of local authorities. They are also cost-efficient in situations where a network connection is not possible and maintenance of conventional generators would be expensive—the largest user of PV cells in the United Kingdom is Trinity House, which deploys them on navigation buoys. There is obvious potential for further applications of this sort—for instance stand-alone street and motorway lighting, traffic lights, public telephones, and so on, in some cases combining PV cells with other technologies, such as micro-wind generators.[54] Such units would neither import nor export electricity, so they would have no bearing on the Government's RO-based targets, but would reduce overall energy demand.

4.34. The development of PV units that are connected to electricity networks, and can therefore generate and sell excess electricity, is much less advanced. We have already noted the small penetration of PV into the United Kingdom, and also the fact that the relative insufficiency of the primary energy resource—sun—means that PV cells will never produce as much electricity per unit of capacity in this country as in, for example, California or Spain. They are also expensive: costs are estimated by the Government as 13.9-19.5p/kWh, compared with a current electricity wholesale price of less than 2p/kWh. With such a cost profile, there is no immediate prospect that commercial electricity generation from PV cells will become an attractive proposition.

4.35. The lower end of the estimated cost reflects the integration of PV cells into new build (for instance as roof tiles or windows)—as BP noted, fitting PV cells to new housing stock is "a more cost-effective option than retrofitting such technologies on to existing properties"(see p. 233). Set against the retail price of electricity (around 8-9p/kWh) the cost profile in such domestic settings offers a markedly better payback time. However, without changes to building regulations there is no incentive for commercial developers of new housing to incur the capital expenditure of building PV cells into new housing. Yet, as BP noted, the large-scale development of new housing in south east England is an opportunity to explore new ways to promote such technology.

4.36. **We see little immediate prospect for commercial generation of electricity from solar energy in the United Kingdom. However, in domestic or small-scale, stand-alone applications, solar energy has**

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[54] Woking Borough Council, whom we visited on 8 March, are in the process of installing "hybrolights", powered by a combination of PV and micro-wind turbines, and manufactured by a company in South Wales.

the potential to make a useful contribution to overall renewable energy output. We urge the Government to explore ways to promote such uses.

Marine

4.37. In considering the practical issues affecting marine technologies we have focussed on those technologies that appear to be sufficiently mature to make a significant contribution to the United Kingdom's electricity needs by 2020—namely, tidal barrages and lagoons.

4.38. In practice, and despite its potential to generate up to five percent of the United Kingdom's electricity, the project to build a Severn barrage appears unlikely to be realised. The feasibility of the project has been exhaustively examined for many years. In 2001 the Government commissioned the Severn Tidal Power Group to undertake the latest review of the project, which was published early in 2002.[55] The review recommended that the project be reappraised—a recommendation since rejected by the Government. Lord Sainsbury of Turville summed up the Government's reasoning in the course of a debate on tidal power on 13 January 2004. While acknowledging the benefits of a Severn barrage in terms of security of supply, he drew attention to the cost (£10-14 billion at 2001 prices, for a project taking 12-14 years to complete and thus to realise any revenue), and the impact on the inter-tidal eco-systems of the Severn Estuary. He concluded that "it would not be fruitful to pursue such plans … at this stage".[56]

4.39. The position for tidal lagoons is less clear. The patent holder for the concept, Tidal Electric Limited, did not give evidence to this inquiry, but the company has asserted that electricity from tidal lagoons can be delivered for around 2.0-2.5p/kWh—close to competitive with conventional fossil-fuelled generation. However, Lord Sainsbury, in responding to the debate on 13 January, said that a report by independent consultants, commissioned by the DTI, estimated that power generated from tidal lagoons would cost up to four times this price. He noted that "if Tidal Electric's assumptions are correct, it has plenty of scope to convince investors of its case and could attract commercial funds". We understand that the DTI is treating the report they have commissioned as confidential.

4.40. **We are concerned that the Government appear to have dismissed large-scale tidal power. There are undoubtedly practical impediments. Construction would be expensive and time-consuming. There is therefore no prospect that the market will provide funding. On the other hand, the potential reward is huge—the large scale production, using well-established and durable technologies, of reliable renewable electricity. We urge the Government either to publish the report they have commissioned on tidal lagoons, or a summary of that report, with a view to promoting greater public debate on the advantages and disadvantages of such schemes.**

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55 "The Severn Barrage—definition study for a new appraisal of the project". See http://www.dti.gov.uk/energy/renewables/publications/pdfs/severnbarrage/Severn.pdf

56 HL Deb, 13 January 2004, col. 549-50.

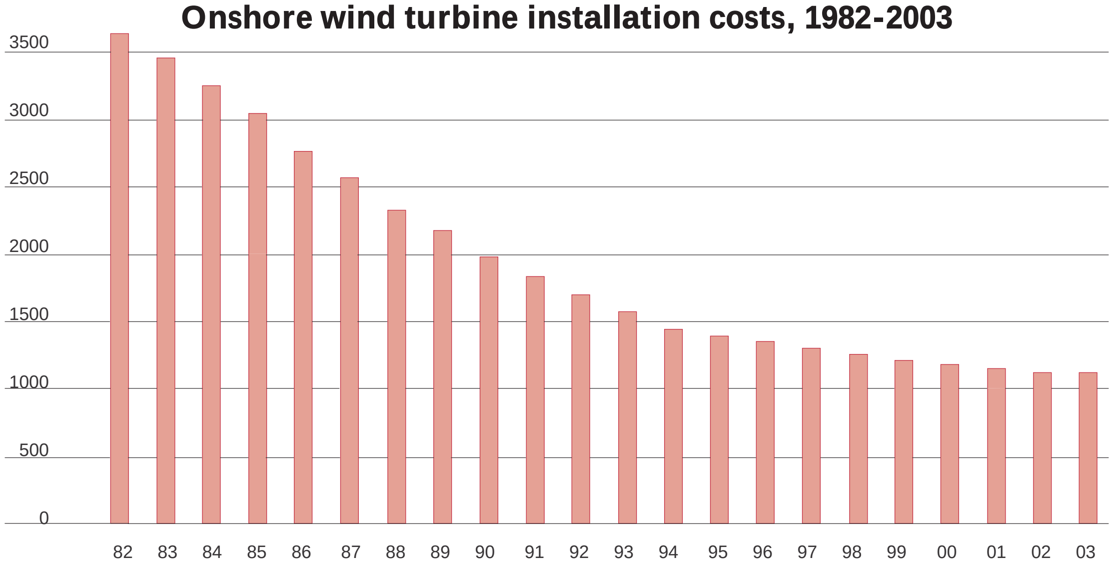
How much will it cost?

4.41. One of the difficulties in assessing the practicality of developing renewable energy is the lack of an authoritative assessment of the costs of the various generating technologies. Cost has been mentioned repeatedly in the course of this chapter, but we find ourselves unable simply to put a figure on the comparative costs of different renewable technologies. While the recent report prepared by consultants PB Power on behalf of the Royal Academy of Engineering[57] attempts to identify the relative costs of different generating technologies, we are aware that its methodology has been questioned by the Government.[58]

4.42. It is still harder to estimate future cost trends. The costs of renewables have fallen dramatically, but there comes a point for any technology when the price will bottom out. Figure 2, for instance, shows how installation costs for onshore wind turbines in Germany have levelled off in recent years at about €1,100-1,200/kW (approximately £800/kW):

FIGURE 2

Onshore wind turbine installation costs, 1982-2003



Costs for onshore wind turbines: specific installation costs in €s/kW (at 2000 prices, including costs for foundation, grid connection etc.).

Source: Deutsches Zentrum für Luft- und Raumfahrt e.V

4.43. The difficulty of estimating future cost trends also applies to conventional energy sources. The economics of fossil fuel generation are heavily dependent on fuel prices. At the time of writing, oil prices are high, and there is no guarantee that similar fluctuations will not affect gas in the future. In contrast, the basic energy source for most renewables—wind, sun, tides—is free, with the result that the initial capital outlay represents the bulk of the financial commitment for investors.

4.44. There are also externalities that affect any cost calculation. The Government have set their face against a carbon tax—which has long been urged on them by the Royal Society (see p. 326) and a number of economists—yet it could

57 *The Costs of Generating Electricity*, Royal Academy of Engineering, March 2004.

58 See the comments by Lord Sainsbury of Turville, 5 May 2004, HL Deb, col. 1101.

be argued that the lack of any means to pass the costs of CO_2 emissions on to polluters represents an enormous ongoing subsidy to fossil fuel generators. The Government will also, through the Nuclear Decommissioning Authority, bear the cost of nuclear clean-up—estimated at £48 billion.[59] Nor are renewable developments without external costs. We shall discuss intermittency in a subsequent chapter, but equally, how does one put a price on the impact of a wind farm on the landscape?

4.45. It is not surprising therefore that there are wide discrepancies between different estimates of the relative cost of generating technologies. The Performance and Innovation Unit, for instance, asserted in their *Energy Review* that by 2020 onshore wind would be "amongst the cheapest of all generating technologies,"[60] undercutting even combined cycle gas turbines (CCGT). The conclusions of the recent study by the Royal Academy of Engineering are very different, and suggest that electricity generated from CCGT and nuclear is less than half the price of the cheapest renewable, onshore wind.

4.46. Factors that would have to be included in any comprehensive, whole-life costing include:

- Capital construction costs, including related infrastructure such as roads;
- Interest rates, discount rates and commercial rates of return;
- Projected maintenance costs and plant reliability;
- Costs of establishing, upgrading or maintaining grid connections;
- Network balancing costs;
- Requirements for back-up capacity;
- A proper costing methodology to reflect the premium on those technologies that can meet peak demands;
- Pollution costs and savings (especially for carbon emissions, but also nuclear waste);
- Environmental impacts;
- Realistic projections of variations in fuel costs;
- Decommissioning and clean-up costs.

Such costings would have to be reviewed regularly, to reflect improvements in technology, cost and availability of raw materials, and so on.

4.47. We note that Lord Sainsbury appears to share our concern over the lack of authoritative costings: on 5 May he commented in the House on the difference between the various available figures, and concluded "that it is ever more important that we set up the United Kingdom energy research centre so that we have reliable figures independently produced and agreed

[59] See the Government's White Paper, *Managing the Nuclear Legacy—A strategy for action*, July 2002, para. 1.14. The figure of £48 billion includes costs incurred as a result of research programmes and electricity generation; however, it excludes costs incurred as a result of the United Kingdom's defence programmes, other than those arising from the past use of UKAEA or BNFL facilities.

[60] See http://www.number-10.gov.uk/su/energy/20.html

which everyone can use".[61] We agree, though we would like to see the Government approach this issue more proactively.

4.48. The next step would be to measure these costs against defined policy objectives, notably the reduction of greenhouse gas emissions. We note, for example, that Ofgem estimate the costs of the Renewables Obligation at £210-380 per tonne carbon-equivalent reduction in emissions, while estimating the cost of the United Kingdom emissions trading scheme at £8-10/tC. There may of course be significant benefits other than emissions reductions, such as reduced reliance on gas imports, and the long-term economic benefits of encouraging innovation. However, such figures do demonstrate that there may come a point at which the economic and political acceptability of the development of renewables becomes a still more serious issue than it is at present.

4.49. **We recommend that the Government commission independent and authoritative research to provide comprehensive costs for generating technologies. It is essential that the Government's energy policies be based on complete and accurate information, and that consumers have access to this information.**

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61 HL Deb, 5 May 2004, col. 1101.

CHAPTER 5: PROVIDING THE FINANCE

5.1. Renewable electricity is not at present economic—none of the technologies we have been discussing can currently generate electricity as cheaply as, for instance, new combined cycle gas turbine (CCGT) plant. So if the Government are to persuade the private sector to finance renewable development they need to put in place adequate incentives. In practice that means providing attractive conditions for third party investors—those who are not otherwise wedded to the sector. As Mr Edmund Lazarus, of Englefield Capital, commented, such investors can "allocate capital to anywhere where [they] can get the best risk-weighted return" (Q 328). The challenge is not just to ensure that there is a return on investment in renewables, but that this return is competitive with that on other potential investments.

5.2. As the DTI told us, "the Renewables Obligation is the Government's main policy mechanism for achieving the growth necessary to reach our renewables targets". This chapter therefore considers the Renewables Obligation (RO), on which all our recommendations are focused. Other policy instruments that have a bearing on the commercial feasibility of renewables are covered briefly in Appendix 9.The RO is analysed in Box 7.

5.3. In simple terms, the RO means that suppliers will be willing to pay a premium for power from eligible renewable generators. It is worth re-emphasising that the RO is a market-based mechanism. Rising targets, embodied in the RO, are set by the Government, but consumers' money, through increased electricity bills, will provide the incentive for the market to achieve the targets, and it will be for the market to decide on the best and most economic way to respond.

5.4. As we have said, consumers will ultimately have to pay for the RO. To illustrate the costs, taking 2004-05 as a basis, 4.9 percent of energy (some 16,300 GWh, on the basis of 2002 consumption) will cost consumers just over £500 million in that year alone. This cost will increase each year in line with the RO, and the Government estimate the cost of their renewable energy strategy to the consumer for the 30 years 1990-2020 at an average of £1 billion per annum.[62]

Target or cap?

5.5. Although the ten percent target for 2010 predates the introduction of the RO, it has as we have already noted, in effect been subsumed within the Obligation, whose levels have been set in such a way that in any given year the obligation itself represents the "target" for that year. This was confirmed by the DTI (p. 156) in response to a supplementary question to Mr Timms' oral evidence: the ten percent target for 2010, we were told, "refers to the contribution of those renewable sources eligible for the Renewables Obligation" (that is, just above that figure, at 10.4 percent, for the relevant financial year, 2010-11).

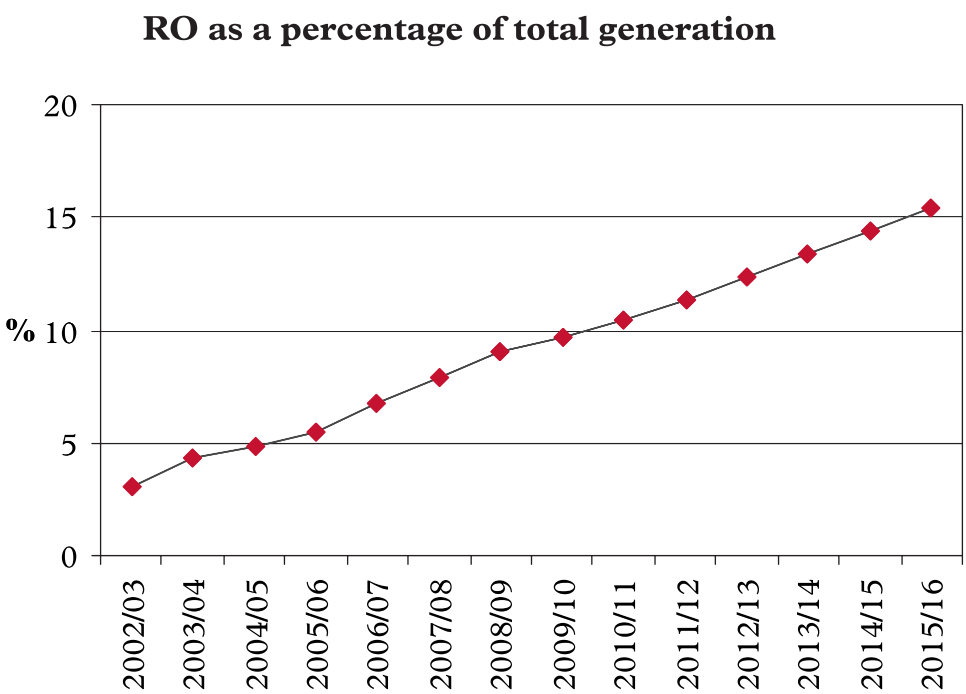
[62] See the answers by the Lord Sainsbury of Turville on 5 May 2004 (HL Deb, cols. 1099-1101).

BOX 7

The Renewables Obligation

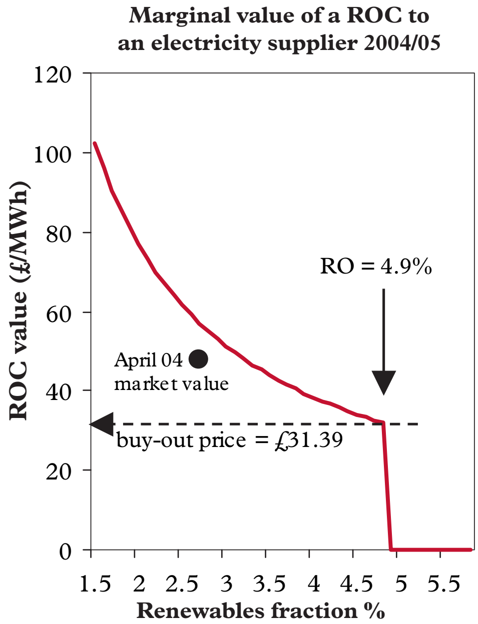
The Renewables Obligation (RO) came into force on 1 April 2002 and will remain in force until 2027. It is designed to provide financial support for qualifying renewable generation and to be fully funded by consumers. The operation of the RO is administered by the Regulator, Ofgem.

All electricity suppliers (for instance Distribution Network Operators) are subject to an obligation to purchase a fraction of their electricity from renewable generators. The required fraction for each year from 2002-03 until 2015-16 has been announced, and is set out in the graph below.



All qualifying renewable generators receive Renewables Obligation Certificates (ROCs) that record the amount of renewable power that they have generated. These ROCs are fully tradable. Electricity suppliers may discharge their obligation either by presenting ROCs that they have purchased (either bundled with the electricity bought from qualifying renewable generators or from the ROC marketplace) or, if they do not present enough ROCs at the end of the financial year, by paying a fixed "buy-out price" into a fund. The buy-out price, originally set by the Government at £30/MWh, is indexed to the Retail Price Index and stands at £31.39/MWh for 2004-05 (compared with a wholesale price for electricity of around £15/MWh). The fund is then redistributed to electricity suppliers in proportion to the number of ROCs that they hold. The net cost of the RO to the electricity supplier is recovered in the price that it charges its customers. Up to 25 percent of the ROCs that are presented in any given year may have been awarded to electricity generators for renewable generation during the previous year, so if a supplier buys more than the required amount of ROCs it can carry over the benefit.

The marginal value of a ROC to the electricity supplier is thus equal to the buy-out price that it would otherwise have to pay plus the share of the fund that will in due course be redistributed. The relationship between generating capacity and marginal value is shown in the graph for 2004-05, when the RO was 4.9 percent.



The support to the renewable generator is determined by the price at which it can sell its ROCs. If all trading of electricity and ROCs were based on a spot price, with no long term commitment, then the average price of a ROC should be close to the marginal value to the electricity supplier (the solid curve in the figure). The market value in April 2004 was close to this theoretical curve.

Once the RO for any particular year has been met by all suppliers, any additional ROCs earned that year will have no value until the following year.

5.6. We find the Government's interpretation surprising. The value of Renewables Obligation Certificates, and thus the subsidy received by renewable generators, is determined by the ratio of eligible renewable generation to the level of the RO at the time. Therefore the lower the amount of renewable output, the higher the subsidy per MWh generated.[63] If, on the other hand, output from eligible renewables were actually to reach the RO level, the marginal value of ROCs—and arguably the value of all ROCs—would fall to zero. As Dr Anthony White told us, "if we were to meet the 10.4 percent target I think there would be a lot of unhappy investors" (Q 317).

5.7. Assuming that investors do not behave, in Dr White's words, "like lemmings", generating companies will scale back the introduction of new plant as capacity approaches the level of the RO (Q 320). The RO will in reality thus act as a cap or upper limit on the renewables capacity, not a target. Given the uncertainty in annual output, we might expect to see this cap start to take effect at around 75 percent of the RO.

5.8. **The Government have announced a target of ten percent of generation to be renewable by 2010 and have set the Renewables Obligation at 10.4 percent in 2010-11. We find these positions inconsistent. The RO will in practice tend to act as a cap on renewable**

63 For a more detailed analysis see Appendix 10.

output, not a target. If the Government wish the RO to deliver its longstanding ten percent target for 2010, it should be set at a significantly higher level, although this would incur substantial extra costs for consumers.

Who pays for risk?

5.9. As we have said, the RO provides no guarantees. The market value of ROCs is currently around £45-50/MWh, reflecting the shortfall in renewable capacity, but its future level will be determined by the unpredictable ratio of eligible generating capacity to Obligation level. Other commercial risks will also come into play—for instance, the failure of two companies, TXU and Maverick Energy, led to a shortfall of £23.6 million in the buy-out fund for 2003-04, and a corresponding fall in recycled payments and ROC prices.

5.10. The uncertainties of the RO become particularly marked in the medium to long term—while one can make a plausible estimate of the value of ROCs in 2005, the uncertainty of the rate of renewable development means that investing on the prospect of high ROC prices in 2015 is much more of a gamble.

5.11. There are political as well as commercial risks to consider. Rightly or wrongly, the reputation of Government in the investment community is not good (see Box 8). Consistency of policy over a period of years will be essential if this reputation is to be rebuilt—short-term tinkering in response to perceived problems (for instance, the decision to extend the rules on co-firing, which was announced in 2003) will merely undermine investor confidence. There is understandable nervousness in the investment community over the forthcoming review of the RO.

BOX 8

An investor's view of Government

Edmund Lazarus: "The move from the pool to the NETA pricing regime confiscated approximately £5 billion, probably more, from the investment community. It came on top of the issues of … Railtrack and British Energy and other examples, where the investment community's collective view, very strongly and emotionally felt, is that they had the goalposts moved by a government who regarded their interests as being entirely secondary to other political concerns. There is no short-term solution to that. That kind of credibility is destroyed quickly and it takes many years to rebuild. The only way to rebuild it is for Government and regulators, in a co-ordinated fashion, to act consistently in a way that recognises investors' legitimate interests and that enhances rather than reduces the credibility of long-term Government policy." (Q 336)

5.12. Investors also have to face up to the possibility that a change of Government could lead to a more fundamental change of policy—as happened in Denmark in 2001. We note that before 2001, consistently supportive Government policies played a vital part in the rapid development of renewable energy in Denmark. We also note, on a smaller scale, that the impressive development of renewable power and energy efficiency measures by Woking Borough Council[64] has been facilitated by long-standing and

64 For an account of the Committee's visit to Woking see Appendix 7.

unanimous cross-party support. **We believe that the investment community's perception of the risk inherent in renewables would be significantly eased if comparable cross-party consensus could be achieved at national level.**

5.13. Governments elsewhere in Europe, less wedded to market solutions, have introduced measures limiting the risk to investors, notably by means of "feed-in tariff" regimes. In Germany, which has in absolute terms much the largest renewables sector in Europe, such tariffs, guaranteed for 20 years, have been supplemented by subsidies and tax incentives. The result has been rapid development, but at huge cost to consumers—as Mr Lazarus told us, the incentives offered to private individuals have produced a large number of small and inefficient developments (see Q 342).

5.14. Spain has in recent years seen the development of the second largest wind energy sector in the world. The key here has been that developers can either choose a feed-in tariff (with a five-year contract), or they can elect to sell at the pool price but with a bonus intended to bring the overall price up to 80-90 percent of the average retail price to all consumers. At the same time, responsibility for administering the scheme has been delegated to autonomous regions, which have tended to build up close relationships with local companies who provide employment and incentives to local communities. We shall return to these issues of local involvement in Chapter 8.

5.15. In the absence of schemes such as those in Germany and Spain, all the major players—investors, developers, suppliers—have to live with risk, political and commercial. All would inevitably like to offload the risk as far as possible, but the danger is that while big, vertically integrated companies can spread the risk, independent developers will be "squeezed" by the bigger players. Investors, intent on securing a reliable income stream, are likely to lend money only on the basis of long-term Power Purchase Agreements (PPAs) with electricity suppliers. The longer the term of the PPA, the more heavily the price will be discounted by suppliers seeking to offload the risks inherent in the RO. Contract terms are commercially sensitive and not made public but we understand that PPA agreements as long as 10 or 12 years are now being negotiated. In the words of the Association of Electricity Producers, "in the experience of many generators the value of ROCs in long term PPAs is discounted to a point where the project is not commercially viable" (p. 231).

5.16. The solution proposed by Mr Lazarus was simple: "there should be a long-term floor to the ROC price until the end of the existing ROC regime … which would then provide a bigger incentive to the supply companies to write long-term contracts" (Q 330).

5.17. **The weakness of the Renewables Obligation as an incentive to developers is its vulnerability to uncontrollable commercial and political risks. Although it appears to provide a subsidy of around £45-50/MWh at present, in practice only a small part of this is likely reach those actually generating renewable electricity; the remainder will go to their backers, and electricity suppliers, to compensate them for accepting their share in these risks.**

5.18. **If the Government are to stimulate investment in renewables, they need to take steps to produce greater long-term predictability in**

renewable electricity prices. We therefore recommend that the Government consider ways to supplement the existing RO, such as an undertaking to set rolling targets, ten years ahead, or the guarantee of a minimum price (below the level of the buy-out price) for the duration of the Obligation, in order to facilitate the release of capital to developers.

Hidden subsidies

5.19. The Renewables Obligation is, in the Minister's words, "a market-led mechanism to favour the most commercially competitive forms of renewable energy" (Q 363). In other words, it is technology-blind, demonstrating the Government's determination not to be seen to be "picking winners". In this respect it differs fundamentally from its predecessor, the Non-Fossil Fuel Obligation (see Box 9).

BOX 9

The Non-Fossil Fuel Obligation

The Non-Fossil Fuel Obligation (NFFO) was established by the Electricity Act 1989. The five rounds of NFFO offered renewable and other non-carbon generators (initially including nuclear power) long-term contracts and premium prices. These were targeted at specific technologies, with prices varying from one technology to the next. Under NFFO1, for example, wind generators received £80/MWh compared with £61/MWh for energy from waste and £45/MHh for landfill gas generators. The five rounds NFFO saw prices fall dramatically—NFFO5 contracts offered £30/MWh for wind, £25/MWh for both energy from waste and landfill gas.

Existing NFFO contracts continue to be honoured—NFFO5 contracts will continue to run until 2018—but no new contracts will be awarded.

5.20. There is clearly a good case for arguing that the prescriptive NFFO contracts—in the Government's words, "long term, technology-bound, premium price contracts"—were inconsistent with liberalisation of the energy market. The Government therefore decided to replace NFFO with the technology-blind, market-based RO. However, it remains to be seen whether the RO will be equally successful in encouraging the commercialisation of either "transitional technologies" (such as offshore wind or biomass) or "emerging technologies" (such as wave or tidal power), and so bringing about comparable improvements in efficiency and economy.

5.21. The price achieved by renewable power under the RO depends on a combination of the market price for wholesale electricity (around £15-20/MWh at present) and the value of a ROC (currently around £49). In the short term they might receive a total of around £65/MWh. Onshore wind currently produces electricity for around £30-40/MWh, and is thus highly profitable under the RO.

5.22. In contrast, the Government estimate the cost of offshore wind at £50-70/MWh, making it barely profitable even at present ROC values[65]—it would be far from viable if the value of ROCs were to fall as the eligible generating capacity approached the RO. We were also told by Mr Chris Day that biomass plants "are proving break-even about £65 per megawatt hour", with

65 Source: *Renewables Innovation Review*, p. 1 http://www.dti.gov.uk/energy/renewables/policy/2010target.pdf

the result that current ROC prices leave existing plants barely viable, and new developments uneconomic (Q 235). EPR confirmed that the price of electricity was £15-20/MWh below the level needed to make new investment in biomass generation commercially attractive. Other technologies, such as wave or tidal power, or solar PV, are still more expensive.

5.23. Thus the RO alone is not likely to release funds for renewables other than onshore wind. The RO is designed to favour near-competitive technologies that will start to generate income rapidly, and at present only onshore wind fits this description. Of course there may be substantial economies in the future (as there have been in the past), which would make, for instance, offshore wind-power or tidal power profitable. However, we see no indication that the RO is capable of stimulating sufficient investment in marginal technologies to enable them to achieve long-term price reductions.

5.24. In reality the Government appear to have conceded that the RO does not in itself offer a realistic prospect of reaching the 2010 target. They are thus, despite their stated commitment to promoting the most competitive forms of renewable energy, offering a range of non-market-based incentives and subsidies to offshore wind. These include capital grants to developers of "round 1" sites amounting, according to the Government's own figures, to no less than £7-8 million for each MW of capacity.[66] In addition, the Government announced on 12 February that they were prepared "to consider the principle of taking a power to give renewables in specified areas some dispensation to protect them from the high transmission charges"[67]—in other words, to protect offshore developers from the prohibitive costs of accessing the National Grid. The reaction from Ofgem was rapid, the Chairman, Sir John Mogg, describing the proposal as "unnecessary and misguided" market intervention.[68]

BOX 10

The difficulties of small biomass development

The Earl of Selborne told us about his proposal for construct a small (300kW) CHP plant on his estate. It would have been fuelled by forestry by-products, largely provided as a result of returning some 400 acres of derelict woodland to active management. It would have supplied heat and power to an on-site packhouse, while heat would have been sold to a local school and village hall. However, as a commercial project, it turned out that it was ineligible for capital grants, while the low price of electricity was, in Lord Selborne's words "an absolute killer". He did not expect long term assistance, but had hoped for time-limited help—say for the first three to five years. But as his colleague Chris Day said, there was "no support at all". (See QQ 232-70)

5.25. That there is a need to supplement the RO, if transitional or emerging technologies are to be encouraged, is clear. But the Government have focused on providing additional incentives and subsidies for offshore wind—the only technology that offers a realistic prospect of coming close the 2010 target. In contrast, the relative lack of support for small-scale biomass

66 Source: Written Answer by the Lord Sainsbury of Turville, HL Deb, 19 May 2004 (WA 91).

67 HL Deb, 12 February 2004, col. GC575.

68 Press Release dated 13 February 2004 http://www.ofgem.gov.uk/temp/ofgem/cache/cmsattach/5915_r1404_13feb.pdf

projects, described in Box 10, is striking. There is a risk that the Government are "picking winners", and in the process losing sight of the long-term desirability of promoting a diverse range of renewable technologies.[69]

5.26. **The Renewables Obligation is unlikely to encourage the development of any project that cannot, for whatever reason, be rapidly implemented within the next year or so—the ROC guarantee does not extend far enough to make it a commercial proposition for longer term projects. We therefore recommend that the Government build into the RO transparent, targeted measures to encourage the development of transitional technologies such as offshore wind and biomass. Such support should be time-limited and on a decreasing scale, so avoiding the potential "cliff-edge" in ROC prices, while providing an incentive for these technologies to establish themselves on a commercial footing within a realistic time-scale.**

Emerging technologies

5.27. If the commercial viability of transitional technologies such as offshore wind and biomass is marginal, the position of emerging technologies such as wave or tidal power is still less favourable. These technologies have not reached commercial deployment, so the RO is of no immediate relevance to investors or developers—in the words of Mr Simon Roberts, Chief Executive of the Centre for Sustainable Energy, "the market-based support mechanisms do not support the range of technologies of the kind one would need to bring forward in the future" (Q 317).

5.28. In the case of wave or tidal power, as we have already indicated, there are various technological solutions being proposed, and in the short term each of these technologies will need to go through a demonstration phase. Where will the finance for such projects come from? Dr White noted, "it is proving very difficult to get the financing to take it to the demonstration stage, because we are talking about £20-£30 million which is out of the range of the angels, and for private equity there is a little bit too much uncertainty". Mr Lazarus put a slightly different emphasis on the problems, noting that "the historic productivity of research and development, particularly into tidal stream and wave technologies, has been very poor". (Q 329)

5.29. There is already a programme of support at EU level, the Programme for research, technological development and demonstration on energy, environment and sustainable development. We are also encouraged by the realistic appraisal contained in the DTI's *Renewables Innovation Review* of the likely timescales and potential means of support for developing wave and tidal energy projects.[70]

5.30. **We recommend that there should be a co-ordinated programme of capital grants to encourage the establishment of pre-commercial wave and tidal power demonstration projects. This should be supplemented by targeted, time-limited measures within the RO, to enhance the income streams and commercial viability of emerging technologies.**

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[69] A similar argument is made in an article by John Bower, published in July 2003 by the Oxford Institute for Energy Studies, entitled "UK offshore wind generation capacity: a return to picking winners?"

[70] See http://www.dti.gov.uk/energy/renewables/policy/waveandtidal.pdf

Finance for small-scale developments

5.31. There is also a more general issue of scale. There is a perception within the renewables industry, particularly among the small independent developers to whom we spoke, that the Government's policies are stacking the odds in favour of "big business". There may be good reasons for this, and the development of the electricity network in the United Kingdom has in part been predicated on achieving economies of scale through concentrating generating capacity in small numbers of large plants. However, it is not clear that this model is best suited to the development of renewables, where units of generation are for the most part small.

5.32. Such issues were explored in oral evidence by Mr Roberts and also by Mr Peter Calliafas, of Barclay's Bank. It is clear that regardless of the economic viability of small projects there is a problem in that they are simply "not sizeable enough to gain [banks'] interest". Indeed, considering them could be simply uneconomic for the lender: "To do project finance for a sub £15 million deal does not stack up in terms of the intellectual firepower that is needed". In addition, there is the difficulty that small projects (for instance biomass projects using local agricultural waste) often provide local solutions to local needs, and so demand "good community-based engagement" on the part of developers. The remedy recommended by Mr Calliafas was the development of alternatives to the RO for small-scale developments, notably in the form of grant subsidies. (QQ 345-347)

5.33. We discussed similar issues in the course of our visit to Woking. The message was clear: the RO mechanism, anchored as it is in the model of large generators selling power to a single, centrally controlled network, is of no relevance to small-scale developers, who may wish to sell only small quantities of excess power to neighbouring communities.

5.34. **We note that the RO will not encourage the development of community-based, small-scale projects, and we believe that this is a serious gap in the Government's policy framework in support of renewables.** We shall comment in more detail on these points in the next chapter.

CHAPTER 6: TRANSMISSION AND DISTRIBUTION NETWORKS

Grid infrastructure

6.1. All electricity generators require transmission and distribution networks (see Box 11), capable of taking the electricity that is generated and delivering it to consumers. The object of this chapter is to consider in outline what changes or improvements to these networks will be necessary to accommodate renewables. In the following chapter we examine a related issue in more detail, the impact of the intermittency that characterises most renewable energy sources on the reliability and security of power supplies.

BOX 11

The National Grid infrastructure

The national electricity system consists primarily of a small number of large generation plants (over 100 MW) and a small number of large users. The transmission system of the National Grid interconnects them at high voltages (400kV or 275kV) to reduce losses to a few percent. The large users include retail electricity suppliers, whose distribution networks at lower voltages (11-132kV) are used to bring together many small users. There is a net flow in the United Kingdom from north, where the generators are mostly located close to coal and gas supplies, to south, where demand is heaviest. The distribution networks are designed to carry electrical power in one direction, from the transmission system to the user.

6.2. Considerable work has been done on quantifying the costs, in terms of Grid reinforcement and extension, of connecting large quantities of renewable generating capacity to transmission and distribution networks.[71] A complicating factor in such work is the relatively small size of most renewable generators. There are few onshore wind farms in the United Kingdom of over 50 MW capacity. The largest biomass generator at present, Thetford Power Station, is rated at 38.5 MW, and there is no likelihood of larger biomass plants being constructed in the near future. Such plants can be connected to lower voltage distribution networks. In practice only the biggest offshore wind farms are likely to be so large (over 100 MW) as to require direct connection to the high voltage transmission network.[72]

6.3. However, the concentration of large numbers of smaller units in the remote areas that are most favourable to renewable generation would also require reinforcement of the transmission network, in order to increase load carrying capability. In particular, a heavy preponderance of onshore wind farms in remote parts of Scotland, where wind conditions are most favourable, would increase the net flow of electricity from north to south. On the scale of generation envisaged this will necessitate Grid reinforcement and a strengthened cross-border interconnector. If, on the other hand, large offshore wind farms are successfully established in the three strategic “round 2” areas off the English coast, this would require somewhat less extensive Grid reinforcement and extension, for the most part in north-west England.

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71 See the ILEX report at http://www2.dti.gov.uk/energy/developep/080scar_report_v2_0.pdf

72 The largest offshore wind farm currently in operation is Horns Rev in Denmark, with a capacity of 160 MW. The Cape Wind project in Nantucket Sound in the USA, scheduled to be constructed in 2005, will have 130 3.6 MW units, giving a total installed capacity of 420 MW —source: http://www.capewind.org/

6.4. The National Grid Company (NGC) has provided us with estimates of the costs of such reinforcements: if the bulk of development took place onshore in Scotland, total capital cost would be of the order of £1.6 billion; if the bulk of development took place offshore in the three strategic areas, the cost would be between £805 million and £1.125 billion (p. 46).

6.5. Such sums should be seen in the context of continuing investment in Grid maintenance and improvement, which we were told came to more than £3.5 billion since 1990. NGC is able to finance this investment because, in the words of its memorandum, "the regulatory framework gives sufficient certainty of appropriate future revenues" (p. 47)—in the form of Grid connection charges levied on generators. Such certainty would exist, for example, if permission were granted to construct a single 2 GW power station in a remote area. However, if the same power output were to be produced by a large number of individually small generators (such as onshore wind farms), constructed over a period of years, there would be much less certainty. NGC told us that this makes it hard for them to demonstrate to the Regulator's satisfaction that capital investment is necessary and efficiently incurred (p. 48).

6.6. More specifically, because individual renewable developments tend to be small, though they may be clustered in particular areas, NGC can only make an estimate of the total capacity that will be required for a new connection to a remote area. NGC also has less certainty over how it will recover its investment—the traditional model of "deep" charging would levy the entire cost on the first generator using the connection, while "shallow" charging would spread the cost across all the generators who will ultimately use the connection. The first model would place a prohibitive burden on initial development, while the latter forces NGC to take a risk in calculating likely take-up.

6.7. These difficulties are compounded by the long time-scales for network reinforcement. Although there is no evidence that the installation of renewable generating capacity is being held back at present, there are no guarantees for the future. The Association of Electricity Producers pointed out that "securing planning permission for past upgrades to the networks has taken a significant length of time in some cases … Given this, planning and consenting work for the upgrades should have been started some time ago and should now be progressed with urgency to prevent a bottleneck in future" (p. 231).

6.8. **We are satisfied that NGC is doing what it can to provide an accurate assessment of the Grid reinforcement and extension necessary to allow large-scale development of renewable energy. However, we remain concerned that the uncertainties surrounding the actual deployment of renewables may impede or delay the financing of such reinforcement.**

Distribution networks

6.9. Different issues will concern local networks and the Distribution Network Operators (DNOs) who run them. The DNOs are the suppliers who buy power from the Grid and deliver it to individual consumers, and according to the conventional model, their networks are essentially passive, the flow of power uni-directional. The emergence of large numbers of small-scale generators connected to these networks would fundamentally change the position.

6.10. Small generators are in most cases likely to be connected direct to distribution networks rather than to the National Grid. This applies in particular to distributed or embedded generators, supplying local consumers—less so to wind farms in remote locations. We have already noted that these distributed generators may have capacities of up to 100 MW—while at the other end of the scale domestic generators such as PV panels, micro-wind turbines, or (non-renewable) micro-CHP units will have the potential to export small amounts of power (as little at 0.5 kW). The result will be far more complex, actively managed local networks, in which power flows in different directions at different times. Ensuring that DNOs are ready for this change represents a major challenge, the scale of which was reflected by the establishment in 2001 of the Distributed Generation Co-ordinating Group (DGCG), chaired jointly by DTI and Ofgem.

6.11. The DGCG has been active in tackling the technical barriers to distributed generation. As its second Annual Report, published in March 2004, demonstrates, some barriers—on the provision of technical guidance, metering, and so on—have already been removed.[73] We also note the confidence of Dr Phil Jones, chairman of the Technical Steering Group (which reports to DGCG), who told us that despite the number of technical challenges "none is insurmountable" (Q 96).

6.12. Nevertheless, there remain essentially regulatory issues to be resolved, affecting the management of distribution networks—we note the comment of DGCG itself that "a major barrier to the development of distributed generation is the absence of any real incentive on DNOs to connect generation."[74] The forthcoming Distributed Generation Price Control Review, which will take effect from 1 April 2005, offers the best chance of resolving these issues.

6.13. **We believe that the DGCG is working effectively on removing the technical barriers to distributed generation. However, the lack of incentives to Distributed Network Operators to connect renewable and other embedded generators remains a concern. We recommend that the next Distribution Price Control Review should prioritise the provision of such incentives.**

Grid codes

6.14. Grid codes specify the rules which generators have to abide by in order to be connected to the Grid. They allow generation to be integrated into the transmission network without prejudicing the reliability or quality of supplies. Separate grid codes apply to distribution networks.

6.15. Compliance with grid codes presents few problems to biomass plants, which behave like conventional thermal plants. However, compliance has been a problem for wind generators, particularly in the following areas:

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73 Second Annual Report of the Distributed Generation Co-ordinating Group, http://www.ofgem.gov.UK/temp/ofgem/cache/cmsattach/6621_6704.pdf

74 *Ibid.*, p. 6.

- Fault ride through—the ability to remain connected during a grid system fault. At present, if there is a voltage dip, however brief, for instance as a result of a lightning strike, wind turbines are likely to "trip". Such tripping on a large scale could destabilise the network.
- Synchronicity[75]—wind turbines normally generate electricity non-synchronously. This is, however, only likely to become a major issue if significantly larger amounts of wind power are connected than at present.
- Frequency operating range.

6.16. The British Wind Energy Association (BWEA) described the grid codes as "little more than a functional specification of existing technology", and argued for a "fundamental review". Nevertheless, the interface between renewable generators and the transmission and distribution networks is clearly an issue of major importance—as Mr Calviou of NGC noted, a moratorium on new wind development has been declared in the Republic of Ireland while such issues are resolved (Q 99).

6.17. It was clear from the oral evidence of both the BWEA and NGC that technical work on grid codes is well advanced, particularly within the Distributed Generation Co-ordinating Group. However, we note the point made in a recent Carbon Trust report, that grid codes are established between project developers/operators and the Grid operator, and that the perception of developers is that manufacturers refuse to accept liability for non-compliance.[76] This may be inevitable, given the number of manufacturers, and the variations between grid codes in different countries. However, it is essential that the BWEA, as the body representing wind farm operators, use every effort to involve manufacturers in its discussions with the Grid operator.

Trading arrangements for distributed generation

6.18. The New Electricity Trading Arrangements (NETA), introduced in 2000, which were expected to promote a more competitive and diverse market, have in fact led to marked consolidation, with increasing dominance by a few big, vertically integrated companies. This is largely because of NETA's "balancing mechanism" (see Box 12), which is inherently likely to penalise smaller generators, who for reasons of scale are vulnerable to proportionately more severe fluctuations of output. The White Paper acknowledges that "during the first few months of NETA some generators, in particular renewables and CHP, were exposed to very high costs as a result of the [balancing] mechanism".[77] In fact, export or electricity from CHP fell by around 60 percent following the implementation of NETA, and by 2002 remained, in the Government's own words, "well below" 2000 levels.[78]

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75 Synchronicity quantifies the phase of alternating current output. A synchronous output is in phase with the electricity network.

76 See the Carbon Trust and DTI "Renewables Network Impacts Study", p. 21; see also Annex 5, p. 11 ff http://www.thecarbontrust.co.uk/carbontrust/about/publications/Annex5.pdf

77 White Paper, para 4.27

78 The Government's Strategy for Combined Heat and Power to 2010 (2004), p. 13 http://www.defra.gov.uk/environment/energy/chp/

BOX 12

The "balancing mechanism"

Electricity cannot easily be stored. Thus if at any given moment insufficient electricity is being generated to meet demand, the system is at risk of failure. One of the essential functions of the National Grid Company (NGC) is to "balance" supply and demand as close to real time as possible. NGC estimates likely demand, and invites bids from generators to supply the necessary electricity, and contracts are then made. Under the original NETA balancing mechanism such contracts were made three and a half hours ahead of time, though this "gate closure" has now been brought forward to one hour. Generators failing to supply the electricity for which they have been contracted face imbalance charges.

6.19. Dr Boaz Moselle, of Ofgem, told us of the various ways the Regulator has sought to alleviate the effects of NETA on smaller generators. On the balancing mechanism, he pointed out that the "gate closure" had been brought forward to one hour, allowing wind generators in particular to predict output more accurately; the way in which imbalance penalties are calculated had been changed; smaller generators had been allowed to aggregate their output, so as to reduce the impact of local fluctuations on their contracted position; and it had been made easier for generators who are connected to distribution networks to claim rebates on the standard charges for use of the transmission system (see Q 81). These changes in our view fall far short of providing meaningful incentives to distributed generation.

6.20. Another effect of NETA has been to contribute to a marked fall in electricity wholesale prices (to around 1.5p/kWh[79]). While this is in itself welcome, it poses problems for renewable generators. Even once the value of ROCs is factored in, renewable generators are currently unlikely to receive more than 6-6.5p/kWh. For many developers, this price simply does not justify the initial investment. As Mr Day told us, small biomass plants only begin to make a profit if they sell electricity at around 6.5p/kWh—considerably more than the wholesale price, though significantly cheaper than the retail price paid by domestic users (around 9p/kWh). Thus it would be possible in theory for such plants to sell power directly via local distribution networks to local users at a price that would undercut the standard retail price and still be profitable. However, the regulatory framework simply does not allow this sort of arrangement.

6.21. A related problem affects domestic electricity generation, whether from solar panels, micro wind generators, or non-renewable domestic CHP. In the understated words of the Distributed Generation Co-ordinating Group, "electricity trading arrangements were not designed with microgeneration in mind".[80] This barrier to microgeneration—the lack of trading mechanisms—remains in place. At present the rate of return on, say, solar panels, is based purely on the saving in electricity bills—it is not possible to export excess capacity. If export were possible it could radically shorten the pay-back time for householders. We note and welcome the DTI's assurance that more advanced metering arrangements have "an important part to play in the rollout of our renewable policies" (Q 419). Without such a change to the

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79 Source: DTI Quarterly Energy Prices, March 2004.

80 DGCG Second Annual Report, Appendix 3.

regulatory structure it is difficult to see domestic power generation taking off in the United Kingdom.

6.22. Woking District Council, whom we visited in March 2004, have got round some of these problems by establishing their own "private wire network", through which they can sell power to local consumers at slightly less than the normal retail price of 9p/kWh. Our Specialist Adviser has described a potential extension of the private wire model in Appendix 11, under the title "An Energy Internet?" However, at present this remains a costly solution, particularly given that there is a limit of 1 MW on the amount of electricity that can be supplied to domestic customers via a private wire network, and a limit of 2.5 MW on the amount that can be supplied via distribution networks.[81]

6.23. **We agree with the Commons' Environmental Audit Committee that NETA fundamentally remains "a system for very big players".[82] The changes introduced by Ofgem may ease the burden on distributed generators, but fall far short of effecting any fundamental reorientation of a regulatory framework that penalises distributed generation. If the Government wish to encourage distributed renewable generation, they must therefore fundamentally review their strategy.**

6.24. **We recommend that the Government, as a necessary step towards encouraging the development of distributed, embedded generation, provide an alternative form of support for small-scale embedded generators to the RO. The most obvious, market-based solution would be to allow small generators to sell directly to local consumers.**

6.25. **We also urge the Government to relax the limits on the sale of electricity to domestic consumers, via Private Wire Networks or the distribution network. We see no reason for limiting sales to 1.0 MW or 2.5 MW respectively, or why it is in the interests of competition and the consumers to restrict such sales at all, providing that any support such networks require from the grid or from distribution networks is realistically priced.**

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81 These limits are defined in the Electricity (Class Exemptions from the Requirement for a Licence) Order 2001.

82 Energy White Paper: Empowering Change?, para. 63.

CHAPTER 7: INTERMITTENCY AND SECURITY OF SUPPLY

7.1. The object of this chapter is to examine in more detail the impact of renewables on the reliability and security of electricity supplies. By "reliability" we mean the ability to balance supply and demand minute by minute and hour by hour. The intermittency of most renewable energy sources imposes particular challenges in this context. "Security" refers to the longer term planning necessary to ensure that there is sufficient electricity generating capacity to meet likely demand, taking into account seasonal and other variations in demand, along with potential risks to the supply of primary fuel, planned outages of major generators, and so on. The day-to-day management of reliability is the responsibility of the transmission network operator, NGC; responsibility for long-term security is less clear-cut.

Reliability of supply

7.2. Most renewable energy sources are to some extent intermittent: in the case of wind power, the intermittency is unpredictable more than a few days ahead, and there may be periods of some hours when either dead calm or high wind prevents any power generation. A report from OXERA notes that "the peaks in wind generation are generally not fully coincident with electricity demand—i.e. wind generation is not necessarily available at times of peak demand."[83] With tidal power the intermittency can be predicted more accurately, while with hydro fluctuations take place seasonally rather than minute by minute or hour by hour. The exception to the rule is biomass generation, which, as long as seasonal fuel can be stored, is in practice not intermittent.

7.3. Intermittency creates difficulties for a network that relies on the constant balancing of supply and demand. It imposes additional costs on the Grid operator, which has to find alternative ways to maintain reliable supplies—keeping synchronised, "warm" back-up capacity available, or investing in electricity storage such as pumped hydro. Overall it is likely that a proportionately larger amount of generating capacity will be needed for a network with substantial renewable penetration than for a conventional network.

7.4. As a result intermittency is, in the words of a report prepared for the DTI, "the single largest driver of system costs" for renewables.[84] Much of the evidence submitted to the inquiry focused on this issue, particularly with regard to the fastest growing and most intermittent energy source, wind. Several witnesses, for instance, raised the prospect of large high pressure systems covering the whole country, effectively bringing generation to a halt. The Adam Smith Institute sent us excerpts from a paper authored by Professor Michael Laughton, arguing that "this implies the need for conventional backup appropriate for the risks assumed, possibly 100 percent spare capacity". The same point was made, with special emphasis, by Country Guardian: "This means that 100 per cent back-up is needed at all times which has to be paid for and added to the cost of windpower!" (p. 258)

83 OXERA, The Non-Market Value of Generation Technologies, June 2003, p. i.

84 See http://www2.dti.gov.uk/energy/developep/080scar_report_v2_0.pdf

7.5. The notion that wind power needs 100 percent back-up does not stand up to analysis. Dr David Milborrow, a consultant and a Board Member of the BWEA, noted that "additional standby plant will need to be provided, but the amount is a function of the additional uncertainty introduced by the intermittent source". In other words, the amount of standby capacity that is needed reflects the aggregated uncertainty of all the power supplies, not the marginal uncertainty of wind power alone. The consequence is that for relatively low penetrations of wind power (up to ten percent of total demand) the additional standby capacity required is small—Dr Milborrow noted that for 12 GW installed capacity of wind power "around 700 MW of extra reserve plant would be needed". This would mean a net saving (or "capacity credit") of 3.3 GW of conventional capacity (p. 290).

7.6. Dr Milborrow's analysis is confirmed by NGC (see p. 49), and by a report published by the Carbon Trust in May 2004.[85] It is thus clear that for renewable penetrations of up to ten percent the costs of intermittency are not large. However, they rise steeply as penetration increases beyond ten percent. In other words, the impact of intermittency on the aggregated uncertainty of power means that the more renewables are on the system the greater the unit cost of balancing supply and demand (see Box 13).

7.7. **There is no technical limitation within the foreseeable future on the amount of wind power that can be introduced onto the system. However, the "capacity credit" of wind power becomes proportionately smaller as more wind power is installed. Thus while the electricity network can support renewable penetration of up to ten percent without difficulty, penetration much beyond ten percent will become progressively more costly. We recommend that the Government sponsor research into other technologies or strategies that could mitigate these costs.**

BOX 13

The cost of intermittency

For ten percent of wind penetration (assuming no other renewables—thus some 12 GW installed capacity) the additional balancing costs will be in the order of £2/MWh, or some £70 million per annum.

For 20 percent of wind penetration the balancing costs would increase to some £3/MWh, or £210 million per annum.

12 GW of installed wind power could displace some 3.3 GW of conventional generating capacity (that is 27.5 percent of the installed wind capacity); 25 GW of installed wind power could displace some 5 GW of conventional generating capacity (that is, just 20 percent). Thus there is a law of diminishing returns: the amount of conventional generating capacity that can be displaced by intermittent generating capacity falls proportionately as the absolute amount displaced increases.

The "capacity margin"

7.8. The fact remains that renewables will require additional back-up capacity. This will mean an increase in "capacity margin"—the amount of excess generating capacity that is available on the system to ensure that demand can

[85] The Carbon Trust and DTI "Renewables Network Impacts Study", pp. 19-20.

be reliably met. We are therefore concerned that at the same time as Government policies are encouraging large-scale development of wind energy, capacity margins are at low levels. This concern is heightened by our inability to find anyone prepared to accept responsibility for ensuring that adequate capacity margins are provided.

7.9. Indeed, Ofgem professes to believe that capacity margin is, in the words of Dr Boaz Moselle, "not a terribly good measure" of security of supply (Q 78). Ofgem's view is that by placing as much information as possible in the public domain, and providing appropriate incentives, they can ensure that the market provides adequate security without setting a target figure for capacity margins. This argument is summarised in the November 2003 report of the Joint Energy Security of Supply Working Group (JESS), which is jointly chaired by Ofgem and the DTI. The purpose of JESS is "to ensure that energy companies, investors and consumers have access to as wide a range of information as possible. In a market-based system such as the United Kingdom's, the provision of adequate energy supplies to meet demand depends on effective market responses, which in turn relies [*sic*] on market players having accurate information to inform their expectations about future prices."

7.10. However, the JESS report itself, summing up recent developments, draws attention to an increase in capacity margin in late 2003 from 16.5 percent to 19 percent. The latest forecast from the Grid operator suggests that the capacity margin for winter 2004-05 will be 20.2 percent.[86] This compares with a figure of 27 percent in 2001-02. The reality is that no satisfactory alternative to the capacity margin as a tool for measuring and managing security of supply has yet been proposed.

7.11. Thus the Regulator expects the market to respond to the information published by JESS, making calculations as to likely future prices. The question is whether this expectation is the most efficient or cost-effective way to deliver adequate security. Our concerns may be summed up by the following argument put forward by National Economic Research Associates, in a report commissioned by the DTI:

"There is a well-known market paradigm in which competitive market pricing rewards all investment in a least-cost and diverse portfolio of generation … However, this paradigm relies heavily on the ability of short-term electricity market prices to soar to very high levels during a shortage, in order to remunerate investment in generation capacity that only runs at peak times, and indeed to remunerate all investments in capacity needed to meet peak demand."[87]

7.12. In other words, the approach being adopted by Ofgem means that generators will only be paid for power actually generated and supplied to the network. Generators will make calculations as to the likelihood of any spare capacity being called upon, and the price they will receive, but given the long lead-times in developing generating capacity, such an approach must carry the risk of short-term shortages and resulting price spikes. This would not be in the best interests of consumers. In contrast, Ofgem has consistently set its face against capacity payments—that is to say, offering generators a premium in

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86 National Grid Transco, "Preliminary Winter Outlook Report—2004-05", May 2004, p. 3.

87 National Economic Research Associates, a report for DTI on "Electricity Markets and Capacity Obligations", December 2002, para. 1.2 http://www.dti.gov.uk/energy/whitepaper/cap_study.pdf

exchange for maintaining a standing reserve that can be called on when needed, regardless of whether or not it is actually required. Two other ways of managing capacity margins would be to increase electrical interconnections with the European mainland, or to increase the number of interruptible supply contracts to manage the demand side.

7.13. This policy on the part of Ofgem is not untypical of the Regulator's insistence on assessing the efficient operation of markets by reference to short-term rather than long-term marginal costs. Mr John Neilson of Ofgem insisted in oral evidence that the Regulator's "primary duty, which is to protect the interests of customers, very specifically covers not only present customers but future customers" (Q 62). We are not persuaded that the policy adopted by Ofgem is consistent with this duty.

7.14. Our concerns are deepened by the fact that there is now no "duty of supply", such as was placed upon the Central Electricity Generating Board before its privatisation. Of course the Government and Regulator do not themselves generate electricity, so they are not in a position to deliver security of supply. However, they are required, as Mr Neilson told us, to "put in place a framework so that all reasonable demands for electricity are met" (Q 68). We believe that it is within the Government's power, should they choose (which in pre-NETA times they did), to define what level of security the companies that generate electricity should be providing.

7.15. We note the figures supplied to us by DTI, showing that while some 2.4 GW of generating capacity is due to be decommissioned between now and 2010, 5.9 GW has planning consent (pp. 156-157). In some respects these figures are reassuring. However, we also note that all the power to be decommissioned is nuclear, and all that to be commissioned is gas-fired. This not only carries a cost in terms of carbon emissions, but increases the United Kingdom's reliance on gas imports.

7.16. **With the introduction of increasing quantities of intermittent renewable power the provision of an adequate level of capacity margin will become increasingly critical to the reliability of power supplies. Indeed the level will have to rise to reflect the intermittency of wind and other renewable energy sources. Without anyone managing security of supply, and with a Regulator committed to market incentives alone, increasing volatility appears likely, with the possibility of shortages and resulting price shocks.**

7.17. **We believe that the Regulator's interpretation of its primary duty to protect the interests of customers is too limited and short-termist. We recommend that the Government ensure that Ofgem's guidance underlines the importance of long-term planning for the provision of secure electricity supplies.**

Mitigating intermittency

7.18. Diversity of energy sources will be essential if the security of power supplies is to be assured. As the DTI's figures show, the decommissioning of nuclear power stations, and their replacement by gas-fired plant, means that the United Kingdom is increasingly putting all its eggs in one basket. Renewable energy, despite the difficulties it presents those responsible for the day-to-day reliability of electricity supplies, thus has a significant part to play in ensuring their long-term security. It is essential that every effort be made to mitigate the effects of intermittency, so that renewables, in enhancing security of supply, do not undermine reliability. Two avenues appear promising: electricity storage, and increasing the diversity of supply.

Electricity storage

7.19. As a general rule it is difficult to store electricity efficiently or on a large scale, although potentially storage technologies have a range of applications relevant to renewables. Storage could assist over short periods of time in improving the quality of power supplies (providing an almost instantaneous response, lasting from seconds to minutes), while over the longer term (up to periods of a few hours) storage could assist in overcoming the problems of intermittency—for instance, a drop in the wind or a storm. The obverse of this is that when wind turbines generate surplus power an efficient storage system would allow the surplus to be stored, reducing balancing costs (and resulting penalties on the generators) twice over.

7.20. It is notable that Denmark has interconnectors to electricity networks in Germany and Scandinavia roughly equivalent to its total wind generating capacity, thus easing balancing problems and obviating the need for storage. The Danish system has also had difficulties with excess generating capacity and has had to give electricity away to its neighbours at times. In the United Kingdom, there is no equivalently strong interconnector to the continental system, and although it would in principle be possible for private investors to build a new and higher capacity interconnector, it would be a speculative investment, comparable to investment in standby generating capacity in the absence of capacity payments. It is therefore not surprising that, as the Government told us, "key research is continuing on storage technologies that will support intermittent generation" (p. 10).

7.21. The principal technologies are summarised in a note prepared for us by the Parliamentary Office of Science and Technology (see Appendix 12). Much the most wide-spread, in terms of capacity world-wide, is pumped hydro. The major installation in the United Kingdom is Dinorwig, with a capacity of 1.8 GW, although, as Mr Chris Shears of the BWEA told us, it "operates at about a two per cent load factor because it serves a specific purpose on the grid to deal with those very high peaks in demand" (Q 183). We are somewhat surprised that the DTI's supplementary written evidence describes Dinorwig as "unavailable" in March 2004—our understanding is that it remains available. However, the scope for increasing the volume of pumped hydro in the United Kingdom is limited by the same factors that limit conventional hydro.

7.22. The only other technology that holds out the prospect of storing electricity on this scale is compressed air storage. Two plants are in currently operation, in Germany and the United States, where a third, in Ohio, with a capacity of 2.7 GW, is under construction. However, there appears to be little investment in compressed air storage in the United Kingdom. It is worth remarking that all storage involves energy losses through the inefficiencies of energy conversion.

7.23. The Government's memorandum did, however, refer to the promise of the Regenesys project, which relied on an electrochemical process operating like a rechargeable battery. A commercial prototype, designed to store up to 120 MWh, deliverable at a rate of 15 MW, was planned, but in the course of our inquiry the developer, RWE Innogy, decided to terminate the project. We are unaware of any proposals to revive it. POST's note for us concludes, "there is a sense among key stakeholders that the evolution of the electricity transmission network over the next twenty years will not be influenced significantly by the absence of large scale electricity storage".

7.24. **In principle, electricity storage has the potential to mitigate many of the effects of intermittency. It is regrettable that the United Kingdom has such limited storage capacity, and it is still more disappointing that there is so little research into new storage technologies. We urge the Government to promote research and provide incentives to encourage the commercialisation of promising technologies.**

Diversity of supply

7.25. The effect of providing diverse sources of renewable electricity would be to smooth the rough edges of intermittency. Such diversity may be in part geographical: the relatively large size of the United Kingdom, compared, for instance, to Denmark, means that while the wind may drop in one part of the country, it is normally blowing elsewhere. Although it is often claimed that the country is regularly becalmed for days on end by high pressure areas, data provided by the Environmental Change Institute (ECI) show that this is not the case. Over the past 21 years, the longest period of calm across England and Wales (Scotland was not included in the analysis) was 11 hours (Q 136).

7.26. ECI only considered periods of zero, rather than low output. However, an OXERA study applies data supplied by ECI to a scenario of offshore wind from the Wash, Thames Estuary and the North West, and onshore wind from Scotland.[88] Using 10 years of hourly United Kingdom electricity demand data and 10 years of simulated wind generation data, it found 23 one-hour periods in a typical year when the output from wind turbines was less than 10 percent of declared net capacity, and demand was between 90 percent and 100 percent of peak demand.

7.27. Geographical diversity would also render the output from marine energy more predictable. Energy from waves, being largely wind-driven, is affected by weather, though changes may be less abrupt than for wind power. In the case of tidal power there is the predictable intermittency of high and low tides. The fact that high tides come at different times around the coast-line means that geographical diversity would allow for a relatively predictable and even output.

7.28. The ECI's evidence underlines that planning is essential, if renewables are to make an efficient and reliable contribution to the United Kingdom's electricity supplies. Optimum geographical diversity will not be achieved by accident, or by relying solely on the market. Indeed, if geographical diversity is to be achieved some developers will have to build wind farms in areas which have less than ideal wind profiles, and which therefore might not offer investors adequate income streams under present rules.[89] Achieving this result would need careful planning, in particular strengthened regional

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88 OXERA, The Non-Market Value of Generation Technologies, p. 14

89 To illustrate the importance of wind profiles, a drop of five percent in the load factor of a 2 MW capacity turbine would mean average output falling by 100 kW. At current electricity prices (and including the value of ROCs to generators, at present around 4.5p/kWh) this would represent lost income of roughly £6 per hour—more than £50,000 per annum.

targets, and effective incentives. At present no-one appears to be planning at this level of detail.

7.29. Diversity does not end with geography. Because patterns of intermittency differ between different renewable technologies, they can to some extent support each other. An example is provided by the modelling of the ECI, which factors in the hypothetical impact of London-based domestic CHP and photovoltaic solar panels. The output of dCHP (not, of course, a renewable source) peaks in cold weather, while that of PV peaks on sunny (frequently still) days. It appears that if tidal power were to be factored into these models the need for additional stand-by capacity would be still further reduced. The high levels of dCHP and PV penetration considered are not likely to be achieved in the foreseeable future—the economics of installing either technology make the scenario unrealistic. Though the paper serves to illustrate how such wide diversity can be of benefit, the research needs to be extended to consider more practical scenarios.

7.30. **The more diversified the renewable generating capacity, geographically and technologically, the more predictable the output. While the output of individual renewable generators will never be so predictable that they can be expected to contract to supply base-load capacity, optimum diversity could achieve a significant reduction in balancing costs for the Grid operator. Given that balancing costs will increase steeply as more renewables are introduced, diversity will be key to keeping their overall cost under control.**

7.31. **We therefore recommend that the Government commission a comprehensive study of the likely outputs of renewable and other efficient electricity generators, factoring in such issues as technological maturity, life-cycle emissions and cost, with a view to establishing the optimum distribution of such technologies, in order to enhance reliability and security of supply. The results should inform the developing energy policy, including such matters as the setting of regional targets for renewable generation. The distribution of renewables should not be left to chance.**

CHAPTER 8: PLANNING AND LOCAL COMMUNITIES

8.1. The thrust of this Report so far has been that the Government should take greater responsibility for delivering energy policy, and that in the case of renewables there should be more planning and co-ordination of development, rather than the current exclusive reliance on the market's ability to interpret and respond to incentives. Yet no amount of planning will deliver large-scale renewable electricity if public opinion is not persuaded of its benefits. In this chapter we therefore consider issues that directly affect local interests and communities—for example, impacts on the environment, wildlife or landscape or health. We also touch on the impact of wind farms on low-flying aircraft and radar.

8.2. Overarching many of these issues is the planning process, which has already emerged as one of most problematic areas for developers of renewables. It is hard to overstate its importance: Simon Roberts of the Centre for Sustainable Energy described it as "principal limitation on renewable development at the moment" (Q 330). Wind power is particularly affected—projects are frequently delayed, while refusal of planning permission means that the heavy investment at the pre-planning stage (for instance commissioning wind surveys) may be totally lost. Major infrastructure projects, such as Grid reinforcement, are similarly affected.

8.3. In the course of our inquiry the Office of the Deputy Prime Minister conducted a public consultation on revised planning guidelines, draft Planning Policy Statement 22 (PPS 22).[90] The new guidelines will ultimately replace the existing Planning Policy Guidance note 22 on renewables, which dates from 1993. They will require the inclusion of regional targets for renewables in regional planning guidance—although, as Elizabeth Wilson, of the Planning Officers' Society, pointed out, it was unclear how rapidly this would "cascade down" to local action: "the need to create policies at the regional level … and at the local level does mean that the planning system appears to run behind sometimes what is required at the present time" (Q 290).

8.4. PPS 22 includes the proposition that the wider environmental and economic benefits of renewables should be "material considerations" in planning decisions. There was some difference of opinion among our witnesses in interpreting this phrase: Elizabeth Wilson went so far as to argue that it would "start to create a presumption in favour" of renewables, while Mr Neil Sinden of the Campaign to Protect Rural England (CPRE) argued for a literal interpretation, and said there would be serious concern "if in fact what was entailed in that form of words amounted to a presumption in favour of development" (QQ 290-91).

8.5. What is clear, however, is that consideration of "wider environmental and economic benefits" falls some way short of ensuring that local planning decisions are taken in the context of the wider, strategic goals of energy policy. Applications for generators of less than 50 MW capacity will still be considered by local planning authorities on a case-by-case basis.

8.6. We are aware, however, that decisions on applications to build generators of more than 50 MW capacity are taken by the Secretary of State, and that the

90 The closing date for responses was 30 January 2004.

same applies to applications to build offshore wind farms. While local authorities may make representations to the Secretary of State on large applications falling within their areas, a clause in the Energy Bill, currently being considered by Parliament, will ensure that they may not object to applications for offshore developments. This procedure should allow central Government to adopt a strategic approach to large-scale development. However, it should not become a means for driving forward large developments that would have a damaging effect on local interests.

8.7. Another "key principle" in PPS 22 is that:

"Local planning authorities, regional stakeholders and Local Strategic Partnerships should foster community involvement in renewable energy projects and seek to promote knowledge of and greater acceptance by the public of prospective renewable energy developments that are appropriately located. Developers of renewable energy projects should engage in active consultation and discussion with local communities at an early stage in the planning process."

8.8. In light of this declaration we are concerned at the dearth of incentives to encourage local communities to welcome renewable developments. We have already commented on Spain's devolution of responsibility for delivering renewables to the regions. No community will welcome the prospect of a 100 MW wind farm on its doorstep, if the electricity generated is simply to be exported onto the Grid, while the community itself reaps no benefits in terms of lower prices or increased employment. In contrast, in Spain local companies offer jobs and incentives, while in France developers may offer local communities the incentive of discounted electricity to compensate for other effects on the environment. Such a discount may be justified by the fact that supplies are provided over local distribution networks and do not attract charges for connection to the transmission network.

8.9. However, public acceptance of controversial developments is not just a matter of providing incentives—it is also possible to persuade and win arguments. In Denmark we were impressed by the high level of public acceptance of the large Energy from Waste plant in Copenhagen, and we note that the a similar plant on the outskirts of Douglas in the Isle of Man is nearing completion. Although opposition to similar projects in the United Kingdom remains strong, it appears that communities can be persuaded of the benefits of finding local solutions to the problems of locally produced waste, particularly when they benefit from the electricity that is generated from its combustion.

8.10. In the United Kingdom, in contrast, the renewables industry, like Energy from Waste, appears to be in danger of losing the public relations argument. Public support is in part undermined by the sort of media stories that appeared in the course of our inquiry, alleging, for example, that wind farms damage human health,[91] or that they decimate bird populations.[92]

8.11. On the first issue, the story in the *Sunday Telegraph* asserted that "Onshore wind farms are a health hazard to people living near them because of the low-frequency noise that they emit, according to new medical studies." It further asserted that "In Denmark, where wind turbines were introduced as long as

91 *Sunday Telegraph*, 25 January 2004.

92 *Observer*, 25 January 2004.

30 years ago, the government has responded to public demand and stopped erecting onshore turbines because of the noise hazard.” We have pursued this issue, and are grateful for a very comprehensive report received from the British Embassy in Copenhagen, who have in turn consulted the Danish Energy Authority. There is in fact no truth in the newspaper’s claim—the Danish Energy Authority is not aware of any special evidence regarding low frequency noise.

8.12. **We are not aware of any reliable evidence to suggest that low frequency or other noise from wind turbines has affected human health. Nevertheless, in light of the obvious concern that may arise over this issue, we recommend that the Government commission independent research to examine the issue, with a view to providing full and authoritative information.**

8.13. The issue of bird strikes is tied up with the broader question of the environmental impact of renewables. There is no doubt that images of dead birds (however they may in reality have died) are potent symbols of the risks to wildlife posed by wind turbines. However, the Royal Society for the Protection of Birds (RSPB) told us that while “poorly sited” wind farms could endanger birds, particularly raptors, “the available evidence from the United Kingdom and elsewhere suggests that wind farms that are located away from narrow migration routes and concentrated feeding/breeding/roosting areas, do not pose a significant hazard for birds” (p. 107). This interpretation was in essence confirmed by the British Wind Energy Association (see Q 195).

8.14. The RSPB’s conclusion was that “From the point of view of bird safety … there is a potentially large number of [onshore] sites theoretically suitable for wind farm development”. However, they argued that preconditions for developing such sites should include “a spatial planning system that takes a long term and broad strategic view of the cumulative and interactive effects of multiple forms of development”, strategic and site-specific environmental assessments, ongoing monitoring of sites, and “a significant intensification of Government-led research into the various environmental (and other) impacts of renewable energy development” (pp. 105-106).

8.15. We also received evidence from the Council to Protect Rural England (CPRE). They too, while expressing general support for the development of renewable energy, argued for a strategic approach: “policy on renewables development should … sit within a wider framework of land-use policy at all levels of strategic planning” (p. 101). They objected to the assertion in the White Paper that planning was “one of the big obstacles” to renewables, arguing that planning should be seen as “a key mechanism” in getting “the right renewables in the right places”. We agree.

BOX 14

Planning in the South West

Simon Roberts: “In the South West … we have been working at county council level with spatial and structural plans, and so forth, to develop a local context for making decisions about nationally significant and locally significant renewable energy projects which actually starts to create more certainty around the way planning applications will be taken forward and, therefore, reducing the risk to developers in bringing forward proposals.” (Q 330)

8.16. Planning in this wider sense is certainly challenging, We have already argued that environmental impacts should be included in any comprehensive costing of generating technologies. But if, for example, you are trying to subject the undergrounding of transmission lines to cost benefit analysis, what price, as Neil Sinden of CPRE asked (Q 307), do you put on "the loss of landscapes from transmission lines through the Vale of York"? As Box 14 indicates, efforts are being made at local and regional level to grapple with such questions. Given that the most widely used argument in favour of renewable energy is environmental, they will have to be answered at national level if public concerns are to be addressed.

8.17. **"Planning" should not be seen as an obstacle. Planning and co-ordination at every level are in fact the preconditions for the effective development of renewable energy. Planning of this sort means a "whole systems analysis". The unresolved tensions within the Government's policies on renewable energy fall far short of this ideal.**

8.18. **PPS 22 will facilitate the planning process for renewables. However, it does not achieve the necessary radical change of direction necessary to deliver an integrated planning system. We are uncertain how "regional targets" will be set, and how they will be translated into individual planning decisions.**

8.19. **We do not believe that urging developers to engage in "active consultation and discussion" will in itself secure public support for renewables. It is essential that local communities derive real benefits from the renewable generators on their doorstep. We recommend that the Government explore changes to the regulatory framework that would give local communities a direct stake in such developments.**

8.20. **We further recommend that the Government themselves initiate and promote full and public dialogue at both national and local levels on the advantages and problems of renewable energy.**

8.21. In light of our comments on planning, it is a matter of some concern that the Ministry of Defence continues to object to so many planning applications from wind farm developers. The MoD's grounds for objection—and those from civil aviation authorities operating under the Department for Transport—are of course legitimate. Wind farms may create problems for low-flying aircraft, and there is evidence to suggest that they may confuse radar. Nevertheless, the scale of MoD objections in particular is startling: ScottishPower, for instance, told us that "around 40 percent of the Scottish on-shore wind resource is currently excluded from consideration because it lies within the Ministry of Defence's South of Scotland Tactical Training Area" (p. 78). The White Paper itself concedes that "MoD has objected to a third of all recent on and offshore wind energy proposals".

8.22. As the Institution of Civil Engineers pointed out, these bodies "all operate under Government control" (p. 284), and it should be feasible for them to work with the DTI to develop a consistent and positive approach to renewable energy. The written evidence we received from the MoD was therefore extremely disappointing. Its unapologetic tone offers no comfort to developers (see Box 15).

BOX 15

The MoD's policy on wind farms

"There is a perception among the renewable energy community that the MoD is a major stumbling block to wind farm development. For example, in response to several requests, the Department has declined to produce a map that would show where wind farms would be compatible with defence needs. However, simply defining an exclusion area around our sites would arbitrarily remove areas of land unnecessarily because the variations in type and size of wind farm, as well as detailed local topography can vary the impact on defence activity. We therefore believe that a pragmatic case by case approach to new developments provides the most effective route to reaching an optimised way ahead for wind farm developers and the MoD.

"If a wind farm is located near to a radar, it can have a detrimental effect upon radar performance as the rotating blades can be a source of interference … Experts advise that such interference could be very hazardous to flight safety. Meteorological radars can also be adversely affected by turbines. Many MoD objections arise from the Air Defence Radar Policy not to site a wind farm, on– or offshore, within 74 km of the radar head. The need for such policy, and the importance of a reliable early warning radar system, was reinforced by September 11 2001." (pp. 292-293)

8.23. We find the MoD's explanation of its refusal to provide a basic map, which would advise developers where wind farms would or would not be compatible with defence needs, extraordinary. Developers face heavy pre-planning costs—site surveys, wind profiling, and so on. The MoD's assertion that the "optimised way ahead" is to deal with applications in a "pragmatic case by case" way—in other words, to wait for the costly preliminary work to be completed before lodging an objection—is frankly implausible.

8.24. The MoD's comments on radar are also unhelpful. Overall we find it unacceptable that Government should release two rounds of potential sites for off-shore wind farms without establishing the consequences for national defence. We accept that there may be defence considerations of which we are unaware but it is for the Government to take these into account in implementing energy policy. If there ever was a need for "joined up Government" this is it, and without strong and coherent leadership the policy will founder.

8.25. **It is essential that Government should urgently take such steps as are necessary to resolve disagreements between Departments over the suitability of sites for wind farm development, and we so recommend.**

CHAPTER 9: ENVOI

9.1. Although the scope of our inquiry was limited to the practicalities of the Government's policy on renewable energy, in the course of our work we were inevitably confronted by a range of related energy questions. In this final section we place our findings on renewables in a broader context.

9.2. The Government's Energy White Paper sets out a policy for making as much use as is feasible of the most economical forms of renewable energy. It also reiterates the Government's long-standing target that 10 percent of total United Kingdom electricity generation should be from renewable sources by 2010.

9.3. The main means of implementing this policy is by means of an obligation on electricity suppliers to purchase an annually increasing proportion of the electricity they supply from renewable generators. The evidence we have taken suggests that in its present form this system of price incentives and penalties, particularly when combined with the other practical impediments to renewable generation, will achieve only around 75 percent of the Government's 10 percent target. Unless there are changes in the regulatory framework, almost all new renewable generation will be from wind—a natural resource that by comparison with many countries the United Kingdom has in abundance. The present market instruments are of little help to other, less mature forms of renewable generation, with a longer lead-time, such as wave-power and indigenous biomass, both of which are potentially significant resources for the United Kingdom.

9.4. We believe that the Government's concerns—to reduce carbon emissions, to enhance security of supply, to reduce fuel poverty—are the right ones. The burning of fossil fuels is causing serious and irreversible environmental change. However, we are not clear that the best way of dealing with these concerns has been chosen. We would accept that there is no single solution and that a range of measures is required. But together these must form a coherent energy strategy that embraces environmental, transport, planning and defence policies, along with energy efficiency and waste management. No such strategy has yet been developed.

9.5. Energy efficiency is certainly crucial. We must make the best use we can of the fuel we use. This has major implications for the design of appliances and construction standards, and for transport policy. It also has a bearing on power generation—power-stations currently discard more than half the energy derived from combustion of fuel as waste heat. At a domestic level there may in due course be a role for domestic combined heat and power, where a gas or biomass fuelled boiler can both heat water and generate electricity that may be exported to the grid when it is not required. We shall therefore be examining the issues surrounding energy efficiency in our next inquiry.

9.6. However, we continue to have concerns about the Government's approach at a more strategic level. The mix of energy sources for electricity will have changed dramatically by 2020. A working paper for the Government's Sustainable Energy Policy Network proposes a mix of roughly 60 percent gas, 15 percent renewables, and 15 percent coal, with the remainder made up of small contributions from nuclear, oil, electricity imports, and pumped hydro.

9.7. We are concerned on two grounds. First, recognising that indigenous supplies of natural gas are nearly exhausted, we shall be increasingly dependent on imports. In a world that is changing so rapidly, past security of supply offers little genuine comfort for the future. Second, although the emissions per unit energy supplied are less for modern gas turbines than for older oil and coal plants, they are still significant and undesirably high. Meeting the Government's environmental objectives will be made much harder by the retirement over the next two decades of around 20 percent of our present generating capacity that is carbon free—namely nuclear.

9.8. In addition our main renewable resource, wind, is intermittent and its output fluctuates in ways that are unrelated to demand. In the absence of other mitigating strategies, a contribution of around ten percent of generation from intermittent sources may be balanced by having conventional generating plant standing by for periods of low output and high demand. However, this solution would become markedly more expensive as the contribution from intermittent sources rose above ten percent.

9.9. In the longer term, the problems of intermittency could in principle be overcome by the development of cost-effective ways of storing electricity, or by a willingness to construct high capacity inter-connectors with mainland Europe, making us much more dependent on our neighbours at times of peak demand.

9.10. In more general terms, one could look to new technologies. However, experience shows that it takes around fifteen years for an emerging technology to become fully developed for the market and to be widely adopted. This limits the possibilities that can reasonably be entertained.

9.11. Although it is undesirable to continue to depend on fossil fuels, trapping and storing the carbon from the combustion gases (carbon sequestration) can mitigate the environmental effects of doing so during a transitional period. This is practicable today, though expensive, and is an area of very active research that should be encouraged.

9.12. Overall it seems to us likely that, in parallel with other developments, the Government may have no option but to follow the lead of other countries and accept that, in the words of the White Paper, "new nuclear build might be necessary". Modern nuclear plant is safer and more reliable than our present elderly installations, and produces less waste. There are public concerns about new nuclear build—but there are also concerns about wind farms.

9.13. A more diverse future pattern of electricity generation could achieve better security of supply and lower levels of greenhouse gas emissions. That pattern could include renewable generation on the scale that is currently envisaged for 2020, but more diverse, with biomass, marine and solar power supplementing wind; it could also include both generation from combined cycle gas turbines, and from nuclear plants to carry the base load. The flexible gas turbines could also balance the intermittency of the wind and waves.

9.14. When fossil fuel prices are low few other forms of generation—which tend to be more capital intensive—can compete on price. Renewable and nuclear generation are thus likely to remain more expensive than modern fossil fuel plants unless there is a sustained rise in the cost of fossil fuels, either through market pressures or by imposition of heavy taxes on carbon emissions—or unless innovation leads to substantial falls in the costs of these alternative technologies.

9.15. The economics of power generation have long been dominated by the fluctuating prices of fossil fuels—notably oil, but more recently natural gas as well. As fossil fuels become increasingly scarce, prices may be expected to rise. However, this will be a long-term process. In today's economic environment, within which prices can fluctuate wildly, there is always a risk that a sudden drop in the price of fossil fuel will put developers of alternative technologies—so vital to our long-term well-being—out of business. We therefore believe that an extreme, market-based energy policy will inevitably lead to an undesirable short-termism in energy investment. That is what we are seeing today—for example in the failure to explore the potential of large-scale tidal barrages or lagoons. If it is in the national interest that there should be significant private long-term investment in these capital-intensive areas, means must be found to give investors confidence. The Government must take responsibility for this.

CHAPTER 10: SUMMARY OF CONCLUSIONS AND RECOMMENDATIONS

10.1. Below is a summary of our conclusions and recommendations. Specific recommendations are highlighted in bold. References to the paragraphs of the report where these paragraphs can be found in context are given in brackets.

The case for renewables

10.2. We believe the Government are on balance right to encourage further development of renewable energy. The sources of renewable energy, such as the sun, wind and tides, are inexhaustible, indigenous and abundant, and their exploitation, properly managed, has the potential to enhance the long-term security of the United Kingdom's energy supplies and to help us cut carbon dioxide emissions. However, these sources are also diffuse, and uncertainties remain over the technical feasibility and cost of converting them into electricity reliably on a sufficiently large scale. (Paragraph 2.8)

The energy policy framework

10.3. The Government recognise that "there will inevitably from time to time be tensions" between the "four goals" of its energy policy.[93] We would go further, and agree with the House of Commons Environmental Audit Committee that to pretend that all four goals can be achieved simultaneously is a "cop-out: the Government is not facing up to the real issue, as in some situations trade-offs will almost certainly have to be made".[94] With no declared mechanism for determining the relative weights of the different goals, or indeed for assigning responsibility for them, there is a danger simply of confusion, and even a risk that none of the goals will be achieved. (Paragraph 2.13)

10.4. We applaud the Government's emphasis on the importance of the cost of renewables. However, we are concerned that no figure has been put on what will be deemed "acceptable to the consumer", or how acceptability will be measured. (Paragraph 2.14)

10.5. **We recommend that the Government reconsider their energy policy goals, with a view to setting a "bottom line". We believe that the fundamental goal of energy policy, as was formerly acknowledged by the Government, should be the maintenance of secure, and hence diverse, energy supplies. In achieving this goal regard must be had to the United Kingdom's environmental commitments and to the need, in the interests of consumers, to promote competitive energy markets. We look forward to a fuller explanation of the Government's position on these issues.** (Paragraph 2.15)

10.6. **We recommend that the Government review the allocation within Government of responsibility for energy policy, with a view to providing strong and coherent leadership. At the very least there should be a Minister of State, wholly committed to clear, energy-**

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93 See http://www.dti.gov.uk/energy/publications/whitepapers/review_sources/chpt02.pdf

94 House of Commons Environmental Audit Committee Report, *Energy White Paper—Empowering Change?* (8th Report, Session 2002-03, HC 618), para. 77.

focused aims and objectives, who can bring together responsibility for all aspects of energy policy, including security of supply, along with those currently the responsibility of Defra, such as energy efficiency and conservation. (Paragraph 2.18)

Technological feasibility

Eligibility criteria for "renewables"

10.7. **The treatment of coalmine methane is anomalous. While the exemption of coalmine methane from the Climate Change Levy is welcome, it is unlikely to stimulate the industry sufficiently. We therefore recommend that the Government review the eligibility under the Renewables Obligation of electricity generated from coalmine methane.** (Paragraph 3.12)

Wind

10.8. The Government's projections show that the bulk of the new renewable generating capacity between now and 2010 is expected to be in the form of wind energy, both onshore and offshore. In practice there appears to be no alternative. The United Kingdom has a huge potential wind resource, and the technology for converting wind energy to electricity, at least onshore, is mature and reliable. (Paragraph 3.19)

10.9. We believe that the common assumption of a 30 percent capacity factor for wind turbines in the United Kingdom is reasonable, and that with the development of offshore wind farms, using larger turbines, higher capacity factors may be achievable. (Paragraph 3.20)

Biomass

10.10. We note and endorse the Royal Commission on Environmental Pollution's approach in its recent report *Biomass as a renewable energy source*, in which all calculations are based on total energy outputs from CHP generation. (Paragraph 3.22)

10.11. **We note that large quantities of agricultural and forestry residues in the United Kingdom currently go to waste. Using this resource to generate electricity would have multiple benefits. We urge the Government, within their overall policy on renewables, to prioritise the exploitation of this resource.** (Paragraph 3.26)

10.12. **Energy crops have good potential as a fuel source. However, there is a limited resource (in terms of land area) in the United Kingdom, and if it is to be exploited effectively rapid progress both in plant breeding and cultivation techniques will be needed. We believe the Government's current projections for the contribution of energy crops to our energy needs are over-optimistic, and recommend that the Government clarify the basis upon which they have been made.** (Paragraph 3.31)

10.13. **We endorse the recommendation of the Royal Commission on Environmental Pollution, that "the focus should be on establishing the sector through the use of existing, proven technology whilst**

simultaneously developing new technologies and demonstration plants”. (Paragraph 3.36)

Marine

10.14. We do not believe that it is feasible for wave or tidal generation to contribute significantly to meeting the Government’s 2010 target. However, there is no technological barrier to tidal barrages making a significant contribution by 2020. (Paragraph 3.42)

10.15. Wave and tidal stream generators have promise, but remain at the demonstration stage, and it is too soon to judge when they will be capable of commercialisation. The essential requirement is that they prove capable of operating reliably over long periods. (Paragraph 3.43)

Solar

10.16. Photovoltaic cells are widely available, and are already widely used in domestic and stand-alone applications. However, their use commercially in the United Kingdom is limited by the low level of insolation, and by their high price. This situation is unlikely to change unless there is a major technological break-through and a step change in efficiency. This continues to be an active area of research in the United Kingdom and abroad. (Paragraph 3.48)

Hydro

10.17. Hydropower is a well-established technology, and there is potential for modest expansion in the United Kingdom. However, the lack of suitable locations in the United Kingdom means that there is little prospect of hydropower contributing on a large scale to the Government’s renewable energy targets. (Paragraph 3.52)

Summary

10.18. The relative maturity of wind generating technology, and the scope for expansion given the United Kingdom’s favourable wind profile, mean that it already has the potential to make a major contribution to renewable energy development. (Paragraph 3.64)

10.19. In the longer term there are no insuperable technical obstacles to large-scale biomass generation, and by 2020, assuming that research, development and demonstration of newer technologies are adequately supported, it is possible that tidal and wave energy technologies will also be sufficiently mature for commercial deployment. While significant commercial use of solar power is unlikely, there is scope for expanding its already widespread use in domestic and stand-alone applications. Limitations on the United Kingdom’s primary resources are likely to restrict development of hydropower and geothermal energy. (Paragraph 3.65)

10.20. **While wind offers the greatest scope for development in the short term, we believe that in the medium and long term a more diverse portfolio of renewable energy sources will be needed. We therefore recommend that the DTI review the level of Government funding for energy research, and, in discussion with RCUK, push forward the establishment of the United Kingdom Energy Research Centre as a**

matter of urgency. It is essential that a focus be established rapidly for the United Kingdom energy research effort and that it is properly funded. (Paragraph 3.66)

Practical implementation

Wind

10.21. Achieving development on the scale envisaged by the Government represents a huge task for the wind energy industry. Onshore, we have little doubt that it is technically and physically possible to manufacture and install sufficient numbers of wind turbines to meet the Government's targets. The constraints on onshore development are not primarily technical, but environmental. (Paragraph 4.12)

10.22. The White Paper describes offshore wind power as "about to take off". In spite of the Danish experience, we are less sanguine. Offshore development is still largely a step into the unknown, and potential investors face serious technological and commercial risks. The next few years will be crucial, and it remains to be seen whether offshore wind power can fulfil the vital role assigned to it within the Government's energy strategy. (Paragraph 4.13)

Biomass

10.23. **We recommend that the Government, in consultation with Ofgem, urgently review the regulatory framework applied to generators using waste biomass, with a view to removing or mitigating the impediments that are threatening an industry already operating at the margins of economic viability**. (Paragraph 4.22)

10.24. The establishment of reliable and economic fuel supply chains is the major practical impediment to biomass generation. It does not appear that such fuel supply chains offer major economies of scale—indeed, the bulk and low calorific value of biomass fuel, and the need for a larger "catchment area", mean that transportation and storage costs may be proportionately higher for large-scale developments. (Paragraph 4.29)

10.25. We doubt that the Government's extension of the eligibility of co-firing under the RO will provide the wished-for fillip to the energy crops industry. It may already be too late for farmers to be ready to supply energy crops in large quantities by 2009. Given the Government's insistence that it is for the market to choose where it sources biomass fuel, there is a serious danger, in the words of the RCEP, that "generators will co-fire for as long as they are unrestricted in their use of biomass (and can use imports) and then will stop as soon as the energy crop requirement is introduced in 2009". (Paragraph 4.30)

10.26. **We therefore urge the Government to introduce more specific, targeted measures to encourage energy crop development, including transitional support for farmers while crops reach maturity, and a requirement on generators to offer long-term contracts to farmers as a condition of RO eligibility.** (Paragraph 4.31)

10.27. **Transportation of biomass fuel represents a net addition to CO_2 emissions. We therefore believe that energy efficient (in other words, CHP) developments, located close to reliable fuel sources, offer the most environmentally beneficial prospects for future development.**

We recommend that the Government focus their efforts on establishing a regulatory regime that favours small-scale biomass development using locally sourced fuel. (Paragraph 4.32)

Solar

10.28. **We see little immediate prospect for commercial generation of electricity from solar energy in the United Kingdom. However, in domestic or small-scale, stand-alone applications, solar energy has the potential to make a useful contribution to overall renewable energy output. We urge the Government to explore ways to promote such uses.** (Paragraph 4.36)

Marine

10.29. **We are concerned that the Government appear to have dismissed large-scale tidal power. There are undoubtedly practical impediments. Construction would be expensive and time-consuming. There is therefore no prospect that the market will provide funding. On the other hand, the potential reward is huge—the large scale production, using well-established and durable technologies, of reliable renewable electricity. We urge the Government either to publish the report they have commissioned on tidal lagoons, or a summary of that report, with a view to promoting greater public debate on the advantages and disadvantages of such schemes.** (Paragraph 4.40)

How much will it cost?

10.30. **We recommend that the Government commission independent and authoritative research to provide comprehensive costs for generating technologies. It is essential that the Government's energy policies be based on complete and accurate information, and that consumers have access to this information.** (Paragraph 4.49)

Providing the finance

10.31. The Government have announced a target of ten percent of generation to be renewable by 2010 and have set the Renewables Obligation at 10.4 percent in 2010-11. We find these positions inconsistent. The RO will in practice tend to act as a cap on renewable output, not a target. If the Government wish the RO to deliver its longstanding ten percent target for 2010, it should be set at a significantly higher level, although this would incur substantial extra costs for consumers. (Paragraph 5.8)

10.32. We believe that the investment community's perception of the risk inherent in renewables would be significantly eased if cross-party consensus could be achieved at national level. (Paragraph 5.12)

10.33. The weakness of the Renewables Obligation as an incentive to developers is its vulnerability to uncontrollable commercial and political risks. Although it appears to provide a subsidy of around £45-50/MWh at present, in practice only a small part of this is likely reach those actually generating renewable electricity; the remainder will go to their backers, and electricity suppliers, to compensate them for accepting their share in these risks. (Paragraph 5.17)

10.34. **If the Government are to stimulate investment in renewables, they need to take steps to produce greater long-term predictability in renewable electricity prices. We therefore recommend that the Government consider ways to supplement the existing RO, such as an undertaking to set rolling targets, ten years ahead, or the guarantee of a minimum price (below the level of the buy-out price) for the duration of the Obligation, in order to facilitate the release of capital to developers.** (Paragraph 5.18)

10.35. **The Renewables Obligation is unlikely to encourage the development of any project that cannot, for whatever reason, be rapidly implemented within the next year or so—the ROC guarantee does not extend far enough to make it a commercial proposition for longer term projects. We therefore recommend that the Government build into the RO transparent, targeted measures to encourage the development of transitional technologies such as offshore wind and biomass. Such support should be time-limited and on a decreasing scale, so avoiding the potential "cliff-edge" in ROC prices, while providing an incentive for these technologies to establish themselves on a commercial footing within a realistic time-scale.** (Paragraph 5.26)

10.36. **We recommend that there should be a co-ordinated programme of capital grants to encourage the establishment of pre-commercial wave and tidal power demonstration projects. This should be supplemented by targeted, time-limited measures within the RO, to enhance the income streams and commercial viability of emerging technologies.** (Paragraph 5.30)

10.37. We note that the RO will not encourage the development of community-based, small-scale projects, and we believe that this is a serious gap in the Government's policy framework in support of renewables. (Paragraph 5.34)

Transmission and distribution networks

Grid infrastructure

10.38. We are satisfied that NGC is doing what it can to provide an accurate assessment of the Grid reinforcement and extension necessary to allow large-scale development of renewable energy. However, we remain concerned that the uncertainties surrounding the actual deployment of renewables may impede or delay the financing of such reinforcement. (Paragraph 6.8)

Distribution networks

10.39. **We believe that the Distributed Generation Co-ordinating Group is working effectively on removing the technical barriers to distributed generation. However, the lack of incentives to Distributed Network Operators to connect renewable and other embedded generators remains a concern. We recommend that the next Distribution Price Control Review should prioritise the provision of such incentives.** (Paragraph 6.13)

Trading arrangements for distributed generation

10.40. We agree with the Commons' Environmental Audit Committee that NETA fundamentally remains "a system for very big players". The changes introduced by Ofgem may ease the burden on distributed generators, but fall far short of effecting any fundamental reorientation of a regulatory framework that penalises distributed generation. If the Government wish to encourage distributed renewable generation, they must therefore fundamentally review their strategy. (Paragraph 6.23)

10.41. **We recommend that the Government, as a necessary step towards encouraging the development of distributed, embedded generation, provide an alternative form of support for small-scale embedded generators to the RO. The most obvious, market-based solution would be to allow small generators to sell directly to local consumers.** (Paragraph 6.24)

10.42. **We also urge the Government to relax the limits on the sale of electricity to domestic consumers, via Private Wire Networks or the distribution network. We see no reason for limiting sales to 1.0 MW or 2.5 MW respectively, or why it is in the interests of competition and the consumers to restrict such sales at all, providing that any support such networks require from the grid or from distribution networks is realistically priced.** (Paragraph 6.25)

Intermittency and security of supply

10.43. **There is no technical limitation within the foreseeable future on the amount of wind power that can be introduced onto the system. However, the "capacity credit" of wind power becomes proportionately smaller as more wind power is installed. Thus while the electricity network can support renewable penetration of up to ten percent without difficulty, penetration much beyond ten percent will become progressively more costly. We recommend that the Government sponsor research into other technologies or strategies that could mitigate these costs.** (Paragraph 7.7)

The "capacity margin"

10.44. With the introduction of increasing quantities of intermittent renewable power the provision of an adequate level of capacity margin will become increasingly critical to the reliability of power supplies. Indeed the level will have to rise to reflect the intermittency of wind and other renewable energy sources. Without anyone managing security of supply, and with a Regulator committed to market incentives alone, increasing volatility appears likely, with the possibility of shortages and resulting price shocks. (Paragraph 7.16)

10.45. **We believe that the Regulator's interpretation of its primary duty to protect the interests of customers is too limited and short-termist. We recommend that the Government ensure that Ofgem's guidance underlines the importance of long-term planning for the provision of secure electricity supplies.** (Paragraph 7.17)

Mitigating intermittency

10.46. **In principle, electricity storage has the potential to mitigate many of the effects of intermittency. It is regrettable that the United Kingdom has such limited storage capacity, and it is still more disappointing that there is so little research into new storage technologies. We urge the Government to promote research and provide incentives to encourage the commercialisation of promising technologies.** (Paragraph 7.24)

10.47. The more diversified the renewable generating capacity, geographically and technologically, the more predictable the output. While the output of individual renewable generators will never be so predictable that they can be expected to contract to supply base-load capacity, optimum diversity could achieve a significant reduction in balancing costs for the Grid operator. Given that balancing costs will increase steeply as more renewables are introduced, diversity will be key to keeping their overall cost under control. (Paragraph 7.30)

10.48. **We therefore recommend that the Government commission a comprehensive study of the likely outputs of renewable and other efficient electricity generators, factoring in such issues as technological maturity, life-cycle emissions and cost, with a view to establishing the optimum distribution of such technologies, in order to enhance reliability and security of supply. The results should inform the developing energy policy, including such matters as the setting of regional targets for renewable generation. The distribution of renewables should not be left to chance.** (Paragraph 7.31)

Planning and local communities

10.49. **We are not aware of any reliable evidence to suggest that low frequency or other noise from wind turbines has affected human health. Nevertheless, in light of the obvious concern that may arise over this issue, we recommend that the Government commission independent research to examine the issue, with a view to providing full and authoritative information.** (Paragraph 8.12)

10.50. "Planning" should not be seen as an obstacle. Planning and co-ordination at every level are in fact the preconditions for the effective development of renewable energy. Planning of this sort means a "whole systems analysis". The unresolved tensions within the Government's policies on renewable energy fall far short of this ideal. (Paragraph 8.17)

10.51. PPS 22 will facilitate the planning process for renewables. However, it does not achieve the necessary radical change of direction necessary to deliver an integrated planning system. We are uncertain how "regional targets" will be set, and how they will be translated into individual planning decisions. (Paragraph 8.18)

10.52. **We do not believe that urging developers to engage in "active consultation and discussion" will in itself secure public support for renewables. It is essential that local communities derive real benefits from the renewable generators on their doorstep. We recommend that the Government explore changes to the regulatory framework that would give local communities a direct stake in such developments.** (Paragraph 8.19)

10.53. **We further recommend that the Government themselves initiate and promote full and public dialogue at both national and local levels on the advantages and problems of renewable energy.** (Paragraph 8.20)

10.54. **It is essential that Government should urgently take such steps as are necessary to resolve disagreements between Departments over the suitability of sites for wind farm development, and we so recommend.** (Paragraph 8.25)

APPENDIX 1: MEMBERS AND DECLARATIONS

Sub-Committee II

†	Lord Flowers
	Lord Lewis of Newnham
†	Lord Methuen
	Lord Oxburgh (Chairman)
†	Lord Patel
*	Baroness Perry of Southwark
*	Baroness Platt of Writtle
*	Baroness Sharp of Guildford
	Lord Sutherland of Houndwood
†	Lord Tombs
	Lord Turnberg
†	Lord Wade of Chorlton
	Lord Winston
	Lord Young of Graffham

* Joined the Sub-Committee 18 December 2003.

† Co-opted Members

Specialist Advisers

Professor Dennis Anderson, Professor and Director, Imperial College London Centre for Energy Policy and Technology

and

Dr Chris Elliott FREng, Director, Pitchill Consulting Ltd

Declarations of interest

Lord Lewis of Newnham

Chairman, Onyx Environmental Advisory Board
Chairman, Onyx Environmental Trust
Director, Brett Environmental Trust
Chairman, Waste Management Industry Training and Advisory Board (WaMITAB)

Lord Oxburgh

Former adviser to European Commission on Geothermal Energy
Former Government-appointed Non-executive Director of NIREX
Non-executive Director (and interim Non-executive Chairman since 3 March 2004) of Shell Transport and Trading company

Baroness Perry of Southwark

Pro-Chancellor, University of Surrey

Baroness Platt of Writtle

Former Director, British Gas plc (1988-94)
Voluntary member of the Campaign to Protect Rural England (CPRE)

Baroness Sharp of Guildford

Visiting Fellow, Science Policy Research Unit (SPRU), University of Sussex

Lord Sutherland of Houndwood
Non-executive chairman, Quarry Products Association

Lord Tombs
Director of engineering, Deputy Chairman and Chairman, South of Scotland Electricity Board (1969-77)
Chairman, Electricity Council (1977-80)

Lord Wade of Chorlton
President, Combined Heat and Power Association
Chairman, Stirling Energy Systems Ltd (a micro-CHP company)
Chairman, Nimtech Ltd (a service company for new and improved technologies, which may include energy)
Chairman, Rising Stars Growth Fund Ltd (which may invest in energy companies)

Lord Young of Graffham
Past and possible future agent for BG International in relation to off-shore gas fields in Israel and Palestine

APPENDIX 2: WITNESSES

The following witnesses gave evidence; those marked with * gave oral evidence:

Air Products Ltd

Asociación Cultural y Ecologista de Calpe, Spain

Association of Electricity Producers

BP

British Hydropower Association

British Nuclear Fuels plc

British Wind Energy Association:

* Mr Alan Moore, British Wind Energy Association
* Mr Chris Shears, British Wind Energy Association
* Mr Alan Mortimer, ScottishPower plc
* Mr Rob Hastings, Shell Wind Energy

Mr R S Browning

* Mr Peter Calliafas

Campaign to Protect Rural England:

* Mr Neil Sinden
* Mr Paul Hamblin

Cargill Plc

* Dr Phil Jones, CE Electric UK

Cefn Croes Action Group

Professor Roland Clift

Coal Authority

Confederation of UK Coal Producers

Cory Environmental

Country Guardian

Mr Jonathan Cowie

* Mr Chris Day

Department of Trade and Industry:

* Mr Stephen Timms MP, Minister of State for Energy, e-Commerce and Postal Services
* Ms Claire Durkin, Department of Trade and Industry
* Mr Adrian Gault, Department of Trade and Industry
* Mr Iain Todd, Department of Trade and Industry

Elexon

Energy Networks Association

English Nature
Environmental Change Institute:
* Dr Brenda Boardman
* Mr Graham Sinden
Environmental Services Association
Dr John R Etherington
Fells Associates
Mr Chris Hedley
Institute of Physics
Institution of Chemical Engineers
Institution of Civil Engineers
* Mr Edmund Lazarus
Dr Rayner Mayer
Mr David Milborrow
Ministry of Defence
National Grid Transco:
* Dr Lewis Dale
* Mr Mike Calviou
New and Renewable Energy Centre Ltd
Office of Gas and Electricity Markets:
* Mr John Neilson
* Ms Amanda McIntyre
* Dr Boaz Moselle
* Mr John Scott
* Mr Nick Winser
Offshore Wave Energy Ltd
* Ms Elizabeth Wilson, Planning Officers' Society
Progressive Energy Ltd
Prospect
Regional Development Agencies
Renew Tees Valley Ltd
Renewable Power Association:
* Mr Philip Wolfe, RPA
* Mr Iain Dorrity, Crystalox Ltd
* Mr Max Carcas, Ocean Power Delivery Ltd
* Dr Anthony Trapp, The Engineering Business

Research Councils UK:
* Dr Peter Hedges, EPSRC
* Dr Chris Frankiln, NERC
* Dr Dan Osborne, NERC CEH
* Mr Chris Bronsdon, SEEF
* Mr Simon Roberts

Royal Academy of Engineering
Royal Society
Royal Society of Edinburgh
Royal Society for the Protection of Birds
* Ms Rowena Langston
* Mr Daniel Pullan

Scottish and Southern Energy
Scottish Energy Environment Foundation
Scottish Enterprise Network and Scottish Energies Industries Group
* The Earl of Selborne

Mr Roy Sumerling
Mr James Etherington Thorpe
Dr Desmond Turner, MP
United Utilities
West Midlands Regional Assembly
* Dr Anthony White

The following submitted papers which were not treated as formal evidence:

Adam Smith Institute
Barclay's Bank Environmental Services
BG Microgen
Mr Michael Haseler
Institute of Biology
Institution of Mechanical Engineers
Royal Society of Chemistry
Mr Hugh Sharman
Mr K Wheaton Green

APPENDIX 3: CALL FOR EVIDENCE

The Science and Technology Select Committee of the House of Lords has appointed Sub-Committee II, chaired by Lord Oxburgh, to conduct an inquiry into the practicalities of the proposals in the February 2003 White Paper "Our Energy Future—Creating a Low Carbon Economy" Cm 5761.

The White Paper contains a challenging set of targets for the United Kingdom to move away from fossil fuels to renewable energy sources. While it contains an extensive analysis of the economic implications of such a shift there is little consideration given to the practical preparations that will be necessary to supply electricity from renewable sources to consumers.

We therefore invite comments on what practical steps are needed to achieve a move towards renewable energy sources at the rate proposed in the recent White Paper. The Committee is particularly interested in the following aspects:

(a) Cost effective technologies available now for the generation of renewable energy, and those that are likely to become available in the next 10 years or so.

(b) The number of sites potentially available for such technologies and the obstacles to taking these up in terms of:

- Planning and other consents;
- Manufacturing and installation capacity; and
- Providing the supporting infrastructure (such as roads and extensions to the electricity network).

(c) The logistics of providing stand-by capacity for times when intermittent sources are not available.

(d) The intermediate milestones that should be set on the way to achieving the White Paper's aims.

Should it emerge as the inquiry proceeds that the milestones are unlikely to be met, the Committee will examine the practicalities of other ways of attaining the White Paper's carbon reduction targets.

APPENDIX 4: VISIT TO DENMARK

26–29 October 2003

The visiting party consisted of Lord Methuen, Lord Oxburgh (Chairman), Lord Patel, Lord Wade of Chorlton and Lord Young of Graffham. Assistance was provided by the Sub-Committee's Specialist Adviser, Professor Dennis Anderson, and the Acting-Clerk and Specialist Assistant, Dr Jonathan Radcliffe. Penny Schmith and Mogens Olsen from the British Embassy in Copenhagen provided invaluable support throughout.

Danish Energy Authority (Monday 27 October, morning)

Historical perspective

Knud Pedersen, Deputy Director-General of the Danish Energy Authority (DEA) welcomed the Sub-Committee. He explained that the DEA was an Authority of the Ministry of Economics and Business Affairs. Historically, Denmark had suffered in the oil crisis of the early 1970s and been forced to substitute imported coal for oil. In the 1980s, a target—seen as unrealistic at the time—of producing 10 percent of electricity from wind energy by 2000 had been set. Now, renewable sources accounted for 20 percent of electricity generation. Despite the drop in oil prices since the 1980s, energy costs had been kept at a high level through increased taxes. Until the 1980s generation of electricity had been organised entirely by municipalities. Forty percent of generation was still owned by municipalities, with 60 percent corporate-owned.

He pointed out that the Danish electricity grid was divided—West Denmark being electrically linked to continental Europe, while East Denmark was linked to the Nordic countries, giving flexibility of combining wind and hydro power. The electricity grids were forced to accept inputs of renewably generated electricity from small suppliers at a fixed price, plus a subsidy (about 1.5 p/kWh). This made it economic for farmers or local cooperatives to put up their own turbines, for example, which in turn brought about local acceptance of wind turbines.

With renewables technology mature, it was now recognised that there was a need to work with the market. One effect was that consumers who had had stable prices had learnt about price volatility.

It was noted that Denmark had about 3 months supply of gas storage.

Economics of implementing climate change commitments

Claus Andersen explained that in the 1990s the Social Democrat government had planned to decrease CO_2 emissions by 20 percent, compared to 1988 levels, by 2005. In 2001 a new Conservative and Liberal coalition government had come to power, bringing a new climate strategy, launched in February 2003, focusing on the economic costs and abandoning a unilateral target in favour of the targets set by the Kyoto Protocol. The main instrument to achieve reductions was the European Union's Emissions Trading Scheme (ETS). Subsidies for renewable supplies were being phased out, as their equivalent cost/tCO_2 saved was too high. The strategy was seen as the most efficient way of reducing emissions. The base case scenario saw Danish CO_2 emissions increasing, and credits bought on the ETS.

Wind power status in Denmark

Jørgen Lemming gave a presentation which highlighted the following points:

- Installed capacity of 3,000 MW from 5,500 turbines, beginning with 55 kW turbines, moving to fewer and bigger 3 MW turbines.
- Provided about 20 percent of electricity requirements in an average wind year.
- Danish turbine manufacturers had 50 percent of the world market, having sold 3,000 MW overseas.
- Installation costs for land-based turbines: 850 €/kW (£600/kW), energy supplied at 3–4 €c/kWh (2.1–2.8p/kWh); too early to give accurate costs for off-shore wind.
- Turbine prices had more than halved in 20 years, production costs had fallen from 1.2 to 0.3 DKK/kWh. At a fixed price of 0.6 DKK/kWh the investment paid back in 5–6 years.
- A strong electricity grid with good connections and excess capacity in Scandinavia was seen as an important factor. (There had been a 12 hour loss of electricity supplies in the country earlier this year; a nuclear power plant had tripped out in Sweden, with cascading effects on the grid.)
- Visual impact had been the biggest problem regarding planning, noise less so, but pressures of space were forcing turbines offshore. There were plans for a further 5,000 MW offshore.
- The energy payback time of a typical wind turbine was approximately 3 months

Biomass

Finn Bertelsen said that in 1990 a ministerial letter to municipalities had required smaller CHP plants to convert to accept biomass. In 1993, a minimum 1.4 Mt/yr biomass had been set for plants greater than 1 MW. Biomass made up 40 percent of renewable energy, from 15 percent 20 years ago. Subsidies were being reduced, with that for wood pellet boilers dropping from 30 percent in 1990 to 0 percent in 2002.

Biogas

Søren Tafdrup said that in the 1980s farmers were required to build slurry storage to reduce water pollution, which led in turn to an action plan for biogas production. There were 20 centralised plants operating, plus 60 farm-scale plants. Biogas came from 75 percent animal manure and 25 percent organic waste and produced a liquid fertilizer as well as energy for district heating and electricity.

Technical University of Denmark (Monday 27 October, lunch)

Knut Conradsen, Deputy Rector of the Technical University of Denmark (DTU), welcomed the Sub-Committee.

Research into wind energy

Professor Jens Sørensen, DTU: Research into wind energy had been done at DTU since 1973. Research was conducted in collaboration with Risø National

Laboratory and Aalborg University. Research areas included aerodynamics and aeroacoustics, grid connections, power electronics, safety and risks, offshore techniques and mechanical engineering. Simulations using computational fluid dynamics software designed at DTU had to be used to investigate the basic dynamics of turbine blades. They also had a global database of wind measurements. The efficiency of producing power from a given turbine was seen to be close to optimal, though gains could come from larger blades sited off-shore.

Developments in wind energy

Jørgen Kjems, Risø: Current technology allowed 4 MW turbines with 60 metre blades, compared with 50 kW machines in 1985. Advances in materials allowed blades to double in length, which quadrupled the yield, whilst weight scaled with covered surface area rather than volume (i.e. by a factor of four, rather than eight as might be expected). A new generation of turbine models came on the market approximately every three years. Specialised skills were being developed to put up turbines offshore. It was acknowledged to be important to include strands from research, business and society to create a technology platform for wind energy. This was one reason for the large Danish share of the global wind turbine market.

Views of the Energy White Paper

Hugh Sharman, principal consultant for Incoteco ApS, presented a paper in which he described what he saw as short-comings in the United Kingdom Government's Energy White Paper. In particular, estimates for the load factors to be achieved from wind energy were too high. In addition, hour to hour wind load changes of 600 MW had taken place from a wind capacity of 2,300 MW. He also described a venture in which hydrogen was being produced from electrolysis when energy costs were low, then introduced into natural gas to increase yield at peak times and higher costs. This type of load balancing was an essential part of harnessing wind energy.

In discussion further points were made:

Consumers could be educated to use electricity at times of low demand—devices would allow washing machines to run at night for example. Price advantages could be given to those who would accept supply interruption.

It was reported that an independent study had found no evidence of harm to birds from wind turbines.

The average load factor of Danish wind turbines was estimated by Sharman to be 19 percent, as compared with assumptions for the United Kingdom policy of around 30 percent. (There has been extensive subsequent correspondence on this between Professor Anderson, Sharman and United Kingdom engineers, which has led the Committee to the conclusion that the 30 percent assumption for United Kingdom conditions is realistic.)

Amagerforbrænding Waste Incineration Plant (Monday 27 October, afternoon)

Bjarne Bech, Technical Manager, and Henrik Zimino, Chairman of the Board of Directors welcomed the Sub-Committee and gave a presentation on the operation of the plant, followed by a tour. The plant, the second largest of its type in Denmark, was constructed in 1970 to alleviate the problems of excess waste in Copenhagen, and was owned by local municipalities. It was administered as a non-profit company, with an obligation to produce electricity. From an energy systems point of view, it would make more sense not to generate electricity, and just to produce hot water. Some relevant facts:

- 460,000 tonnes of waste incinerated a year (approximately 60 tonnes/hour) from 530,000 inhabitants and 36,000 businesses.
- Output of 28 MW, heat and power supplied to 70,000 households.
- By-products included 75,000 tonnes of slag (used as gravel), 5,300 tonnes of scrap iron, 26,000 tonnes residue from flue gas cleaning.
- Emissions closely monitored and below regulatory guidelines: dioxins averaged 0.027 ng/Nm^3 (Normal cubic metres); SO_2 averaged 16 mg/Nm^3; NO_x averaged 98 mg/Nm^3.
- People lived 2 km from the incinerator, and there was widespread support for the plant, with no resistance from environmental groups.
- Expenses: 50 percent on incineration, 20 percent for recycling, 14 percent for the disposal of residues.
- Income: 27 percent from tip fees, 27 percent from sale of district heating, 19 percent from sale of electricity (at 0.36 DKK/kWh). Consumers paid less for heat from this source than from gas.

Gaia Solar installations (Monday 27 October, afternoon)

Dennis Aarø, Managing Director and Jan-Willem Hedricks, Director, of Gaia Solar, joined the Sub-Committee for an on-bus presentation, en route to several installations of Photovoltaic (PV) power systems in Copenhagen.

Gaia had demonstration projects on 300 houses. Current installations paid back initial carbon costs within ten years, but the monetary pay-back time was longer than the designed lifetime of 20 years. The cost for PV modules was about €1,000/m^2, which had an efficiency of about 14.5 percent. Optimum positioning was south-facing, at a 40° angle. Development was still needed on inverter technology. An example of a five-storey lift shaft covered in PV modules produced 5 kW.

Horns Rev offshore wind farm (Tuesday 28 October)

Elsam staff welcomed the Sub-Committee on board the *Sea Lion*. On the outward sailing, presentations were made on the development of the wind farm in the North Sea.

Bjarne Jensen, Director of Projects and Plants, gave some initial facts about Elsam, an operator of 491 turbines in Denmark, with a capacity of 417 MW. The company was also keen to develop clean coal technology and the capture of CO_2 emissions, waste-to-energy plants, and CHP; expanding to the United Kingdom, Germany, Poland and Baltic states, and sites on the Atlantic coast.

Elsam's wind power activities

Uffe Jørgensen explained that in 1978 Elsam had been obliged to develop wind power as part of a deal to build new power plants. They had expanded to have 25 dedicated wind power engineers, with 25 other engineers contributing to the activities, and a goal to install 100 MW/year. They had submitted a tender for 30 turbines at Shell Flats in the United Kingdom (with CeltPower and Shell each tendering for an additional 30 turbines). They were confident that there was sufficient wind and that the foundations could cope with the shifting soil conditions.

Horns Rev wind-farm

Jens Bonefield felt that the large scale and better wind offered by offshore developments would lead to reduced costs, in spite of associated risks, and the fact that the energy could be sold at the same price. Many potential offshore areas around Denmark were at depths of between 5 m and 20 m. Some facts about Horns Rev:

- Situated on a reef in the North Sea 14 km from the shore, 20 nautical miles sailing from Esbjerg.
- 80 x 2 MW turbines, each with a rotor diameter of 80 m, active between wind speeds of 4 and 25 m/s, expected annual output 600 GWh, implying an expected load factor of 42 percent.
- Turbines spaced 560 m apart, optimised taking into account energy losses from downwind wake (which could be up to 10 percent), electrical losses and cable costs.
- Constructed between March and August 2002—due to weather conditions work could not proceed about one-third of the time.
- Steel monopiles with a mass of 150 tonnes, 24 m long and diameter of 4 m had been used for the foundations.
- Foundations and turbines were installed on average one per day, and completed ahead of time.
- Fluctuations of order 100 MW on timescales of 10–15 minutes were possible as wind conditions changed.
- The Sub-Committee viewed the wind-farm, and witnessed an engineer lowered onto a turbine from helicopter, as an example of how maintenance could be performed. Back on land, the Sub-Committee visited land-based prototype windmills at Tjærborg Meadows.

Lintrup Biogas Plant (Wednesday 29 October, morning)

Poul Rasmussen, consultant to the Lintrup Biogas Plant, welcomed the Sub-Committee.

The plant was started in 1988 by a cooperative of about 60 farmers. It received slurry from cattle (60 percent) and pigs (40 percent), with additional solid manure and industrial waste, totalling 550 tonnes a day. Fresh slurry was picked up from local farms from a distance of up to 15 km, once or twice a week. A dairy cow produced 20 t/year, similar to that from a sow plus piglets. A total 6 million Nm^3/year of biogas was produced (20 Nm^3/t manure, 35–40 Nm^3/t with industrial waste). The plant was run as a private commercial company, with profits used to repay loans and reinvested in new equipment.

Bacteria naturally occurring in cow manure aided the industrial digestion process, whereas pig slurry was high in phosphorus and ammonia, which inhibited bacteria, and therefore could not be used on its own. A well-mixed cocktail of biomass was important for gas production. A semi-batch technique was used, with the digestor fed every eight hours, where it was kept for a minimum of twelve days at 53°C.

There was very little smell given the quantities of slurry, as Members could verify. The amount of hydrogen sulphide emitted in the biogas was less than 50 ppm.

The degassed biomass was delivered back to the farmers who supplied slurry, free of charge as fertilizer. This way, it solved the environmental problems associated with slurry leaking into water supplies, gave farmers a useful product, and produced biogas that was burnt in a nearby CHP plant. It also saved farmers the costs of on-site storage for slurry.

The Committee then visited the nearby Rødding CHP plant, to which the biogas from Lintrup was piped. The plant supplied district heating and electricity through two 1 MW engines and a combined biogas and wood pellet-fired boiler. The town of Rødding was totally heated by renewable fuels with heating costs for citizens among the lowest in Denmark.

Herningværket CHP plant (Wednesday 29 October, afternoon)

Bent Haurballe, Production Manager, welcomed the Sub-Committee to the Elsam-owned Herningværket CHP plant, and gave a presentation on its operation, followed by a tour of the plant. The largest biomass plant in Denmark, it had run from 1982, originally burning coal, but converted to accept gas in 2000, and to accept wood chips in 2002, at a combined cost of 275 million DKK. An environmental impact assessment had been undertaken because of the increase in traffic caused by bringing wood chips to the plant. Some relevant facts:

- Produced 89 MW electricity, 174 MJ/s heat.
- Fuel was 55 percent from wood chips, 200,000 tonnes/year, from fir trees from a radius of up to 120 km. 25 percent was chipped at the plant. Storage capacity was for about 75 hours operation at full load.
- Wood chips used as the base load, regulation from gas (42 million m^3/year, from state-owned supplier DONG), burning at approximately 1,500 °C leaving 1.5–2 percent of the mass as ash.
- District heating primary system was 35 km long, with water leaving at 85–90°C, returning at 40–45°C. Transmission pipes had 30 cm of insulation, losing just 3 percent of heat.
- Secondary systems took heat over 120 km.
- Electricity, as one third of energy production, was sold with a subsidy of 0.4 DKK/kWh to give 30 percent of the plant’s income.
- The plant made a profit, though maintenance costs may be higher in the future with wood chips being used as fuel.

APPENDIX 5: SEMINAR HELD AT THE ROYAL ACADEMY OF ENGINEERING

10 December 2003

A seminar was organised at the Royal Academy of Engineering to inform the Committee about issues connected with renewable energy sources, and to enable them to meet and converse with a number of experts in the field, along with representatives of Government and the regulator, Ofgem.

Members of the Sub-Committee present were: Lord Flowers, Lord Lewis of Newnham, Lord Methuen, Lord Oxburgh (Chairman), Lord Patel, Lord Sutherland of Houndwood, Lord Tombs, Lord Turnberg, Lord Wade of Chorlton, Lord Winston and Lord Young of Graffham. Also present were Professor Dennis Anderson (Specialist Adviser), Christopher Johnson(Clerk), and Jonathan Radcliffe (Specialist Assistant).

The participants were: Sir Alec Broers, Lewis Dale, Tom Delay, Brian Doble, Ian Fells, Guy Houlsby, David Jones, Michael Laughton, Vivek Mittal, Nicholas Moiseiwitsch, Alan Mortimer, John Neilson, Mark Phillips, Richard Ploszek, Peter Snowden, Goran Strbac, Jim Swithenbank, Iain Todd, Elizabeth Wilson.

Presentations

The day began with a series of presentations, summarised below.

Setting the scene—an energy outlook

Mr Peter Snowden, Senior Energy Consultant at Shell International Limited, said that his job was to identify with the long term business environment and the drivers for change. This meant that he had to engage in "scenario thinking", modelling future trends across the whole of the energy market. United Kingdom production of oil and gas was now at its peak but was likely to tail off substantially over the coming 15 years. One of the benefits of scenario planning was that it allowed companies to look ahead and establish a settled long term framework to encourage investment.

Mr Snowden then outlined two such scenarios.

According to the first, called "dynamics as usual", the need for clean, secure and sustainable energy supplies encouraged a continuing development of renewables. This would be supported by gas in the medium term, while improvements in vehicle efficiency prolonged oil use. The critical point according to this scenario would come around 2020 when, with increasing concerns over security of gas supplies, it would become clear that renewables could not deliver long-term security. This would drive investment in the next generation of renewable technologies, leading to an expansion in the use of biofuels and photovoltaic solar cells by around 2040.

The second scenario was called "spirit of the coming age", and was driven more by technological innovation. The development of the hydrogen economy would be supported in the medium term by an expansion in the use of gas, not least in the production of hydrogen itself. Distributed generation of electricity on the grid would increase, with fuel cells migrating to vehicles. In the longer term, renewable energy sources would be used to generate hydrogen.

Summing up the key points in both scenarios Mr Snowden pointed out that energy systems were dynamic, and responded to changing conditions, choices and possibilities, fossil fuels were likely to play a major part in overall energy mix up until 2050 with gas moving to centre stage. However, renewable energy sources have the potential to meet longer term energy needs and the rise in CO_2 emissions could be halted in the next 50 years. He felt the Energy White Paper represented a credible starting point, but the level of investment required had to be recognised.

Practical experience of planning a windfarm

Mr David Jones, Executive Vice President of Shell Wind Energy, drew attention to rapid technological developments in this area. The current tested standard for offshore wind turbines was 2MW generating capacity, but in the near future this would rise to 5MW. The main practical risk faced in installing offshore wind turbines was the weather, which could cause serious delay. The main economic challenge faced by developers was the installation and cost of foundations. Monopile foundations were the simplest—essentially a nail hammered into the sea bed by a pile driver. No preparation of the sea bed was necessary, but monopile foundations were vulnerable to variable quality in the sea bed itself. It was possible to construct about four turbines a week, from a single round trip of a dedicated vessel. Alternative technologies included the gravity base or the tripod.

Scouring was another general problem, with large and local scale movements of the sea bed capable of affecting the integrity of foundations. However all these engineering difficulties could be addressed, if at a cost. The maintenance of offshore wind turbines would be more costly than onshore, so reliability would be crucial: the ideal would be sufficiently reliable turbines, such that regular maintenance could be undertaken during planned outages.

Mr Jones then drew attention to risks and costs associated with planning—it took about three years to go from having the site lease to production. The initial stages of developing of a wind farm involved high initial outlay, such as £2 million for the wind assessment. Subsequent refusal of planning consent was therefore extremely costly.

Mr Jones concluded by asking whether the incentives were in place to attract equity and debt. The long term attractiveness of renewables to investors was crucial and relied totally on Government support. There was no intrinsic economic value in green, rather than carbon based, power generation. Would there be a long lasting premium for green energy?

Civil engineering at sea

Professor Guy Houlsby of Oxford University noted that the overall energy supply in 2002 was some 45GW. Ten percent of this was 4.5GW or 4500MW. This meant that the United Kingdom needed some 2000 offshore wind turbines by 2010. That would mean a doubling of the number of turbines year on year from now until 2010, which was not sustainable. What would then happen after 2010? It was not sensible to attempt to develop an industry in this way.

When erected, offshore wind turbines would face horizontal forces from the wind and water equivalent to about 400 tonnes, compared to its weight of 600 tonnes. In contrast, a North Sea oil platform weighing some 20,000 tonnes and of a similar height had to bear up against horizontal forces equivalent to roughly 2,500 tonnes—that is say some 10 percent of the vertical forces, rather than two thirds of the vertical forces in the case of wind turbines. In other words, a wind turbine was a light structure suffering heavy horizontal loads.

Professor Houlsby then drew attention to one possible solution, suction caissons. He was part of a research project examining this, which had received funding of some £1.5 million. In theory this technology appeared to offer a solution to these problems, and experiments had borne this out, but he felt that whilst the funding from DTI, EPSRC and industry was adequate for the early stages, it was not sufficient to take the project forward to full realisation, which would require more support from industry. However the problem was persuading investors to take on the commercial risk involved in such a novel solution.

In response to a question form Lord Oxburgh on the threat posed by migrating sea beds, Professor Houlsby suggested that the solution would be to build your foundations in the hollows of the sea bed rather than on the top of sand dunes. Structural engineers would simply have to accept the additional cost of building their towers in deeper water.

Infrastructure

Mr Alan Mortimer of Scottish Power drew on the company's experience of operating 300 wind turbines, which had 97 percent reliability, and its plans to invest £1 billion. He noted the practical issues effecting delivery of new wind farms. The first of these was planning, and in this respect the new draft planning guidance (PPG22) was helpful. It meant that positive links between developers and communities could be established at an early stage, although it did not resolve the problem of the strain placed on the resources of local authorities and their consultees. This meant that planning applications would still face severe delay.

The second practical issue was aviation: 58 percent of proposals were blocked as a result of aviation issues especially by objections from the Ministry of Defence (MoD) to developments in low-flying areas. Radar, both civil and military, was also a problem, and developers needed better co-operation both from the MoD and the Department for Transport on these issues.

Meeting the targets would require major onshore and offshore development. Noting that there was no funding mechanism yet to finance the new grid connections that would be necessary, he asked what action Ofgem were taking to address this issue. Another issue was transmission network access charges, which were likely to increase substantially. He concluded by making the general point that it was unwise simply to look at Danish experience and project that onto the United Kingdom, which had a much larger and more diverse energy market.

Supply reliability

Mr Lewis Dale drew attention to the National Grid Company's primary duties, to maintain and develop the transmission network, and to ensure short-term security of supply. In delivering such security overall there was a complex interaction between NGC and the market. Medium to long term actions, such as the building of new power stations of interconnectors, or the moth-balling of existing generation, were the responsibility of the market. However on a day to day basis, NGC was responsible for the actual delivery of a secure electricity supply, through demand management, maintenance of an operational reserve and residual balancing. In addition, NGC had overall responsibility for the network and the transportation of electricity, both in the short and long term—in the long term, through the development of new network assets, and in the short term, through operating the existing network, for example, switches and voltage control.

In this context NGC had examined the additional costs that would be imposed on the network by the introduction of 8 GW of wind power (sufficient to provide 10 percent renewable electricity in 2010). Two scenarios had been modelled, the first assuming that three quarters of wind farm development would be onshore in Scotland, the second assuming that three quarters would be offshore in England and Wales. The cost of the first scenario to the three transmission network licencees would be some £1.6 billion; the cost of the second scenario would be between £0.8–1.1 billion, depending on the volume of wind found off the Cumbrian coast. There was an additional cost associated with the intermittency of wind, and the requirement to keep conventional generating capacity as back-up. An estimate of the total additional cost of generating 20 percent of electricity from wind turbines amounted to £1.2 billion per year, or 0.3p/kWh, which would mean an increase of somewhat less than five percent on domestic electricity bills, and about ten percent on industrial or commercial bills. This would be equivalent to about half of the ROC buy-out price for 2020.

Planning aspects

Ms Elizabeth Wilson of the Planning Officers' Society said that the new draft Planning Guidelines (PPG22) embodied a positive approach to the delivery of renewable energy through local planning processes, and in this respect marked a major departure from current practice. The crucial issue was engaging the community—local communities needed to feel confident about the development of renewable energy. In contrast there appeared to be an increasingly negative attitude in local communities. It was difficult for the benefits of renewable energy development to be seen at local level and planning officers had to take these factors into account. Communities did not have faith in "experts"—they had to see the benefits of development for themselves. This meant that funding had to be found for demonstration projects across the regions showing how a range of technologies would work in practise to the benefit of local communities.

Financing renewable energy—a private financial sector perspective

Mr Vivek Mittal of the Bank of Scotland noted that in the first year of the Renewables Obligation some £50 million of development had been financed and was under construction; a further £450 million was in process. This meant that the current rate of build was estimated at 250 MW per annum, instead of the 1000 MW required if the 2010 targets were to be met. The issue for banks was their total reliance on long term utility credit and thus to the long term reliability on the Renewables Obligation. Banks did not have an appetite for failure or long term price risk—they looked closely at cash generation capability. The cost base for a major long term development was normally calculated on a 15 year average. Capital recovery would come at the back end of the project which was where the regulatory risk was at its highest. For this reason, banks could only finance projects of this type on the basis of fixed price guarantees. From the point of view of the finance community, the two most desirable developments would be:

- the extension of the Renewables Obligation, which had now been achieved, but only as far as 2015—this target should increase continually, and there should be more certainty over the buy-out price;

- the introduction of a renewable energy levy on end customers, in lieu of the current obligation on supply companies.

In addition bankers would like the Government to make a clear decision on the future of nuclear power, which would have a big impact on overall system intermittency and investment prospects.

Discussion

Discussion in the afternoon initially focussed on the morning presentations. It was clear the costs of establishing network connections to remote generators would be high—the figure of £2 million for a 17 mile connection to a wave generator in Islay was quoted. The Regulator's view was that operators should bear at least part of the incremental cost of transmission. However, there were two approaches to such charging: deep charging implied that an operator in a new area would bear the entire cost of establishing Grid connections—this would create problems in redistributing costs when other operators set up in the same area; shallow charging meant that the costs were in effect shared, in which case the network operator would take the risk of calculating how much capacity to build into the connectors, on the basis of likely take-up. The tendency was to move towards the latter approach to charging.

On security of supply, it was noted that under NETA all generators were free to sell power to all suppliers—in other words, it was a free market for both selling and buying power. In the longer term, the Regulator relied on market incentives to provide adequate reserve capacity: supply companies contracted at a fixed price for base-load capacity or for a higher price at times of peak demand. However, it was suggested that while the major utilities were self-sufficient in power generation and supply, private power generators, who did not have regular access to the supply network for the 20GW they generated, were less well incentivised.

In the context of wind generation, it was noted that Denmark had inter-connectors linking it to European networks, which corresponded closely in capacity to the total wind generating capacity on the Danish network. There had been discussions within the United Kingdom on the possibility of upgrading the existing inter-connector to France, although there was no definite progress as yet. Decisions would have to be taken on what was the most economic and efficient way to provide back-up for the intermittency of wind generation. In addition, improved wind forecasting would allow more accurate prediction of generating capacity.

The duty to ensure adequate supply was shared out between different bodies—Grid faults were the responsibility of the Grid operator, while for longer term issues of generating capacity the Regulator was confident that the market would respond to the incentives available. While the CEGB had formerly had a duty to supply electricity, under NETA there was a fully decentralised electricity market. However, other contributors were doubtful whether the market was capable of delivering the long-term planning that would be necessary to support substantial penetration by renewables. It was suggested that the market would deliver merely "hand-to-mouth" solutions.

On planning, there was currently no mechanism to require sustainability as a condition for allowing new developments. Nor was it clear what incentives were available to encourage local communities to welcome renewable developments—could companies supply power to local consumers at a discounted price? Although PPG 22 required the setting of regional targets, this would not make decisions at local level any easier unless a consensus could be built up around the benefits of renewables. The contrast with Denmark was very marked—not only with regard to renewables, but with regard to Energy from Waste plants, where the United Kingdom incinerated much less waste than the rest of Europe. Experience suggested that the public accepted developments once they were up and running—the difficulty was in securing acceptance at the planning stage. The public were heavily influenced by relatively small numbers of very vocal campaigners.

Discussion then turned to the more general issues that would determine success or failure in meeting the Government's targets. Renewables were presently a high-cost solution to meeting environmental targets. One crucial question was whether and when the costs of renewables would fall—at some point renewables would become cheaper than fossil-fuel alternatives. It was argued that in order to keep costs within limits the focus should continue to be on the more commercial technologies, so as not to over-burden consumers. In the meantime the EU Emissions Trading scheme would put a price on carbon emissions, which would change the balance between renewable and fossil-fuel generation.

However, the Renewables Obligation placed the burden of meeting targets on suppliers, rather than directly on generators. The major utilities did not have the resources to finance the necessary development on balance sheet, while the oil companies, who had the resources, did not bear the same burden. Although the Obligation was an ingenious and efficient mechanism for achieving market solutions, there was a risk that technologies viable today would be superseded in the longer term, so that developers would be left with "beached assets". There was no assurance that the initial incentive would be carried forward.

A further problem was the diminishing skills base: the industry had shrunk, thanks to gains in efficiency, and job opportunities had disappeared accordingly. As a result three quarters of companies were having difficulties in recruitment, and the age profile in the industry was unfavourable. In 2003 only 50 undergraduates across the United Kingdom started courses in electrical engineering, while the industry needed 200-300. However, it was suggested that manpower was increasingly transferring from the oil and gas industry to renewables.

In addition, power research in the United Kingdom was under-funded. It was asserted that R&D had been the great casualty of energy market liberalisation—there was no long-term thinking and no-one was taking responsibility for providing funding.

On general construction capacity, it was noted that there would have to be a major investment in heavy machinery if enough turbines were to be installed to meet the targets. The effective limitation on turbine size would probably be the availability of adequate transportation rather than the technology of turbines themselves. As for installation, there was at present only one manufacturer in Europe able to supply monopiles strong enough to support the latest 3.6 MW turbines.

APPENDIX 6: VISIT TO ELEAN AND THETFORD POWER STATIONS

Friday 30 January 2004

The party consisted of Lord Methuen, Lord Oxburgh (Chairman) and Baroness Perry of Southwark. In attendance were Christopher Johnson (Clerk) and Jonathan Radcliffe (Specialist Assistant).

The Committee was welcomed by Malcolm Chilton, Commercial Director of Energy Power Resources (EPR), which owns both Elean and Thetford Power Stations. He made some introductory remarks about EPR:

- EPR was started in 1997 with venture capital and private investment;
- EPR generated 130 MW–120 MW from burning 1Mt of biomass, though the company also operated two wind farms;
- The company had a turnover of £60 million, but no plans to develop further plant;
- The company also had an interest in Energy from Waste, but this was handicapped partly by planning procedures, and partly by the fact that EfW, even the biomass element, was excluded from the Renewables Obligation.

Elean Power Station, Ely

Elean Power Station is the world's largest straw-fired power station, generating 36 MW of electricity. After a tour of the plant, the Committee had an informal discussion with Malcolm Chilton and the station manager, Chris Stockton. Their general view was that the 2010 targets would not be met. They believed that when the Government set the ROC buy-out price at 3p/kWh they calculated that that figure would deliver the target—however, it was now clear that this calculation had been wrong. There was a view that an increase in the buy-out price of around 2p/kWh was necessary to reach the targets, though the Government could reduce the cost by focusing on particular technologies such as biomass. Such changes should be made soon, given the long lead-time for new projects—the 2005-06 review would be too late.

In discussion the following further points were made:

The power station was essentially similar to a coal-fired one, on a smaller scale. Straw is used as a fuel to heat water, creating steam at 520°C and 97 bar to drive turbines. A small amount of natural gas was burnt (approximately 6 percent of the total) as a support fuel. The plant operated at 32.5 percent efficiency, with a load factor over 90 percent.

220,000 tonnes of straw were burnt each year, delivered in the form of half-tonne Hesston bales from a maximum radius of 60 miles, costing £35 per tonne at the power station door. The price paid to farmers for straw in the field was some £2 per tonne—the rest of the cost was made up of baling, storage, transportation etc.

The low calorific value of straw meant a large volume was required: two barns on site held three days' fuel, and many local holding sites were used to store straw for up to twelve months. Some 12 percent of the stock was lost due to arson (costing some £400,000 in the last year) or weather damage.

Tonnage contracts with individual farmers accounted for 120,000 tonnes, 100,000 tonnes came from EPR's own Anglian Straw company.

The logistics of ensuring a regular fuel supply were critical. The effects of weather conditions in this regard (for example, wetting straw) had not been fully appreciated when the initial viability studies were carried out.

The turnkey cost for constructing the plant was £47.2 million; the overall indebtedness was £55 million. The company did not expect to show a return on this investment for 15 years.

The plant had a NFFO contract, through to 2013, with the Non-Fossil Purchasing Agency to supply electricity at 6p/kWh. The NFPA retained revenue generated by selling on ROCs, which was ultimately passed on to the Treasury. If this money could instead be recycled to generators it would make a crucial difference to their economic position.

The security provided by NFFO contracts was reassuring for banks, when compared with the value of ROCs, which were not guaranteed. This made new investment under the RO less likely. Furthermore, though prices were guaranteed by NFFO contracts, they were not varied to take account of changes in the regulatory environment. Such changes, for instance the introduction of the EU Waste Incineration Directive, could see existing renewable generators going under.

The price of electricity was 1.5–2 p/kWh less than would be required to make new biomass development commercially attractive. Despite being the biggest generator of electricity from biomass in the United Kingdom, and even though there was capacity for five more straw-burning plants in the United Kingdom, EPR was not considering any new developments.

The economic case for investing in energy crops was weak, thanks partly to the higher cost of fuel. Another factor was the high initial investment in planting crops such as *miscanthus* or willow coppice, with the prospect of a three-year wait before there was any return.

The ARBRE plant (which EPR liquidated) had a very complex fuel chain and used new technology, operating at less than 20 percent efficiency.

Capital grants were not thought to be the best incentive when operating costs are greater than revenue. The industry would therefore prefer a blend of targeted capital grants and other revenue support mechanisms.

Thetford Power Station

Before looking around the plant the Committee heard a presentation by Mr David Raubenheimer, Operations Director for EPR. He made the following points:

Thetford had been in operation since 1999. The plant was slightly larger than Elean rated at 38.5 MW, and burnt poultry litter. It had taken three years to develop to the start of construction and a further two and a half years to construct and commission.

Poultry litter had a lower calorific value than straw—some 450,000 tonnes per annum were required to fuel the plant. This litter generally had to come from barn-reared chickens, which by scratching the litter could partially dry it. Litter from battery chickens was less usable. The litter was sourced from about 100 farms, most local, though some were from as far away as Anglesey. Contractors cleared out the barns once birds were removed for slaughter.

If the litter was not sold to EPR, it would typically be stored and used as fertiliser by the farmer. However, this carried animal health risks, and the removal and incineration of the litter helped to break disease cycles. In practice the litter was worthless to the farmers, who were prepared to supply it for a nominal price on the basis that their barns were cleared. The cost to the company to collect it and transport it to the plant was about £10 per tonne.

Once the litter had been burned it was made into fertiliser, which was rich in phosphates. Sale of fertiliser contributed up to 10 percent of the plant's revenue.

The market for supply of biomass had been significantly destabilised in recent months. The decision to extend co-firing eligibility for ROCs had both undermined the confidence of potential investors in renewables and weakened the position of renewable generators in the energy crops market, since suppliers now saw an alternative market in coal-fired plants. Such plants were able to import biomass fuel and pay significantly more for it, whereas EPR was limited geographically in sourcing fuel.

In addition, strict carbon monoxide (CO) emissions targets required under the Waste Incineration Directive threatened to undermine the company—compliance would cost the company some £9 million. Government grants to cover these compliance costs would be welcome.

Consistently low CO emissions were hard to achieve with variable biomass fuel, and the requirement would be to test every half hour rather than averaging results over longer periods as for coal fired plant. The CO targets were principally directed at commercial and municipal waste where high levels of CO would indicate inefficient combustion, potentially allowing dioxins into the atmosphere. In contrast, at Thetford dioxins were measured at one-tenth of allowed limits. Thetford emitted less than one milligram of dioxin in 2002 compared to one gram for a typical coal fired power station, and dioxin emissions per kWh from biomass plants were only a fraction of those from coal fired plant. However, coal fired power stations were completely unaffected by the Waste Incineration Directive.

The difference in the definition of permitted renewable fuel sources between NFFO contracts, which were rigidly defined, and ROCs, which were more flexible, was unhelpful. Ofgem had refused to allow the plant to use chicken feathers to supplement chicken litter, because the feathers were recovered by the plant which plucked the carcasses, and were thus held to be industrial, not agricultural, waste. As a result the feathers ended up in landfill.

ROCs were unsuitable for independent developers—they were more suitable to companies with an interest in the supply side as well. In addition the TXU failure and the recent changes to the Renewables Obligation before it had even completed its first billing cycle had significantly undermined confidence in ROCs and fixed price contracts. Long-term projections of the value of ROCs were difficult—as a result 15-year contracts with investors were likely to be at a very discounted price.

APPENDIX 7: VISIT TO WOKING

8 March 2004

Members visiting Woking were Lord Flowers, Lord Methuen, Lord Oxburgh (Chairman) and Baroness Sharp of Guildford. In attendance: Dr Christopher Johnson (Clerk), Dr Chris Elliott, (Specialist Adviser), and Dr Jonathan Radcliffe (Specialist Assistant).

Presentation at the H G Wells conference centre

The Sub-Committee was welcomed by Councillor James Armitage, Leader of the Executive. Mr Ray Morgan, Executive Director of Woking Borough Council (WBC) gave a presentation, during which the following points were made:

WBC benefited from cross-party consensus on the environment and had adopted a Climate Change Strategy for 2003.[95] The Borough Council had an environmental "footprint" equivalent to about 1 MtCO_2 emissions each year, and their target was to reduce this by 80 percent by 2090—a 10 percent reduction each decade to 2050, five percent thereafter. Furthermore, they aimed to purchase 100 percent of electricity and thermal energy needs from local sustainable sources, including 20 percent of electricity from local renewable sources, by 2010.

A gradual approach was taken to meeting these targets. The key was creating a "sustainable energy system", by which they meant one with a distribution infrastructure which would last many decades, but allowed fuel sources to be changed on shorter timescales. This meant that whilst gas-fired CHP was the main generator in 2004, in the future renewable sources could be brought online. WBC had established its own "private wire" electricity distribution network to connect its powers stations to Council office and residential properties. Energy efficiency measures were also important, through improvements to Council buildings, and Home Energy Conservation Act (HECA) work in the Borough. Two companies worked with the Borough Council to assist in implementing their strategy—the wholly-owned Thameswey Limited, and Thameswey Energy Limited, a joint venture company (with 81 percent owned ultimately by a Danish pension fund).

Progress had been made on achieving the targets: CO_2 emissions had been reduced by 15 percent since 1990, and 84 percent of electrical and thermal energy supplied to Council properties was generated from sustainable sources, with 3.9 percent of electrical energy generated from renewable sources. In the early 1990s, stand-alone pay and display parking ticket machines had been installed which used electricity generated by photovoltaic (PV) panels. These were both reliable and cheaper to install than conventional parking meters.

The Borough Council was considering installing "hybrolights"—streetlights that used electricity generated from PV panels and small wind turbines mounted on the lamp posts. Eight prototypes were being deployed each costing £8,000, compared to £3,000 for conventional lights, although as with the parking meters, savings would be made from not requiring electricity connection or supply. For the future, stand-alone 1.3 MW wind turbines sited near demand were preferred to a large wind farm. Gasification of the Borough's waste to produce electricity was also being considered.

95 http://www.woking.gov.uk/environment/climatechange.pdf

Several regulatory and financial barriers were felt to hamper the efforts of WBC to meet its targets. The 1 MW limit on sales to domestic users from private wire systems, above which they would have to register as a Distribution Network Operator, was felt to be too low. Additionally, the export of any electricity surplus was limited to 5 MW. The Borough Council had not been able to raise finance from United Kingdom institutions—investment came from Denmark where companies were felt to have a more sympathetic and longer term view.

It was noted that local authorities (LAs) were under no obligation to promote energy efficiency, and in the light of the targets they did have (such as for waste), it tended to be ignored. There was reluctance on the part of LAs to use planning powers to require embedded generation, and it was felt that a change to building regulations was required to improve domestic energy efficiency. WBC had found it difficult to sell the benefits of combined heat and power (CHP) plants to housing developers, who were more concerned with inward capital costs rather than ongoing costs.

In response to the observation that some of the projects undertaken by WBC would have been very difficult without the one-off subsidies that had been available to demonstrate technological feasibility, it was pointed out that a recent CHP project in Brighton was self-financing.

Sustainable energy projects in Woking

The Sub-Committee visited the following projects in Woking:

Town centre energy station

A CHP plant was located in a multi-story car park, generating 1.35 MW_e, 1.6 MW_{th}, and complying with good quality CHP criteria. Hot water was supplied to town centre buildings (including a hotel), and electricity distributed via Woking's private wire network. Part of the plant was a 16 metre tall cylinder, holding up to 163 m^3 of water at 90-95 °C. Chilled water was also produced for air conditioning. The hot water delivery infrastructure included a number of junctions that had been plumbed in for future use. The plant was run completely automatically, with remote operation possible (three engineers serviced Woking's energy projects).

The Vyne PV project

A roof with an installed capacity of 40 kW of PV panels (laid on top of the existing tiles) was combined with CHP at the Vyne day centre. Elsewhere in Woking, there were eleven sites with PV panels, and a capacity of over 500 kW at an efficiency of 16-18 percent. They have supplied a total of over 200 MWh. Little maintenance was required, apart from new inverters every ten years.

Heat and electricity was supplied to domestic customers in public housing at less than the normal retail price. Pensioners in Woking spent 6-8 percent of their income on heat, compared with the 10 percent Government target.

Woking Park Fuel Cell CHP

A fuel cell CHP plant producing 200 kW_e from natural gas and supporting a leisure centre in Woking Park. Funding came from a wide variety of sources, including the US Department of Defense. PV cells with installed capacity of 7.2 kW were also integrated into the building's roof, providing shade and electricity.

APPENDIX 8: ENERGY PAYBACK TIMES

How much energy is required to build and operate power stations, and how does this compare with their lifetime energy outputs? Some estimates for coal and nuclear stations and wind farms are shown in the table:

Process	Coal	Fission	Fusion (design concept)	Wind (no storage or backup)
	Terajoules per GW-year of electrical output			
Mining and fuel preparation	1,258	1,288	48	-
Fuel transport	1,059	8	-	-
Materials (other than fuel)	55	58	302	581
Plant construction	61	99	335	242
Operation	283	384	435	517
Waste disposal and transport	-	172	16	-
Decommissioning	10	19	55	72
Land reclamation	3	0.1	Negl.	Negl.
Total	2,737	2,028	1,191	1,387
Energy Payback Period (yrs)	**3.3**	**2.5**	**1.5**	**1.1**
Assumptions:				
Plant Size: MW	1,000	1,000	1,500	25
Plant lifetime: years	40	40	40	25
Capacity factor: %	75	75	75	25

Source: S.W. White and G.L. Kulcinski (1998). Energy Payback Ratios and CO_2 Emissions Associated with the UWMAK-I and ARIES-RS DT-Fusion Power Plants. Fusion Technology Institute: University of Wisconsin. Paper UWFDM-1085.

Estimates of the payback period vary with the scale of the power plant, since there are appreciable scale economies in the use of materials per unit of capacity, and with the plant's capacity factor. The high transportation costs for coal presumably reflect the long distances over which coal is transported in the United States. The above estimates for wind were made 7 years ago, when turbines were one quarter of their size today; capacity factors can also be higher. The Danish Wind Industry Association[96] claims that modern wind turbines recover the energy use in their manufacture and installation within three months, a statistic shared with the Committee by Risø on a visit to Denmark.

For offshore wind, the payback times are expected to be shorter. The higher capacity factors—they are expected to be 1.3 to 1.5 times higher than those for onshore wind—would more than offset the added energy costs of installation. A 30

[96] www.windpower.org/en/tour/env/enpaybk.htm

percent improvement in capacity factor for instance equates to 6-8 years of extra operating life.

For solar photovoltaic systems, estimates vary greatly with the material and with the scale and design of the manufacturing process. The payback period is also declining with technical progress in manufacturing. The following estimates of payback periods are provided by the World Energy Assessment Report by the World Energy Council and the UNDP (2000):[97]

- For crystalline silicon. In year 2000, 4-9 years. Prospectively 2-3 years or less;
- For thin film. In year 2000, 3-4 years. Prospectively 1-2 years or less.

For biomass, estimates of the energy input to produce useful energy from biomass for the consumer vary with the source (forest residues, straw, *miscanthus*, short-rotation coppice); the yield per hectare (higher yields lower the collection effort); and the type and efficiency of the plant (e.g. whether it is for heat, electricity or CHP). For producing the biomass at the ‘farm gate’ the energy output/input ratio varies from 10-20, and are often outside this range.[98] Taking a typical ratio of 15, and a CHP plant of 70 percent efficiency, the energy output/input ratio is reduced to 10 (in round numbers). Thus for a plant with a 25 year lifetime, it would take about 2.5 years for the energy of the biomass to be paid back in energy terms. The construction and operation of the power plant may require another a year (about twice that for the coal plant in the above table, on account of the lower energy density of biomass). Overall, an energy payback time of around 3.5 years would not be untypical—similar to that for coal, though rather more than for other renewable energy technologies and nuclear power.

The energy consumed in transporting biomass is equivalent to about 0.8 kg of oil fuel per tonne of biomass (which has the energy of about 0.4 tonnes or 400 kg of oil) for each 10 km transported by road, and each 100 km transported by ship,[99] equivalent to an increase in the energy payback times of around one-fifth of a percent.

Professor Dennis Anderson, Specialist Adviser

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97 New York: UNDP.

98 Hall, Rosillo-Calle, Williams and Woods (p625) in Johansson et al (1993) *Renewable Energy*. Washington DC: Island Press.

99 Estimates inferred from the data in Table 4.4 of the 2004 report of the Royal Commission on Environmental Pollution, which reports that the CO_2 equivalent emissions from road transport per oven dried tonne of biomass are 0.18-0.27kg/km, and by ship 0.012-0.024kg/km, such that the weight of the oil consumed would be approximately one third of these quantities (the ratio of the molecular weight of oil to that of CO_2). The above estimates take the upper range of these figures.

APPENDIX 9: POLICY INSTRUMENTS AFFECTING RENEWABLE ENERGY

Our report focuses on the Government's main policy mechanism, the RO. However, two other policy instruments, the Climate Change Levy and the EU Emissions Trading Scheme, also have a bearing on the commercial climate for renewables, and they are summarised below.

The Climate Change Levy was introduced on 1 April 2001. Despite its name, it is a tax not on pollution but on the use of energy. The Levy's primary effect is to encourage energy efficiency, rather than targeting particular forms of power generation. However, exemptions from the Levy exist for all forms of renewable energy eligible under the RO, along with good quality CHP and coalmine methane.

The Royal Society described the Levy as "an inefficient economic instrument to reduce carbon emissions", and argued that it should be replaced with a carbon tax, which would "place a charge on carbon content of fuel and therefore benefit non-carbon emitting sources of energy" (p. 326). However, the Government confirmed that the Levy "was deliberately not targeted on carbon emissions". It was targeted on energy efficiency in industry so as to maintain a "level playing field between fuels", while not imposing extra energy costs on domestic users. The Levy is designed to be revenue neutral overall—that is to say, revenues realised by the levy are recycled to employers, largely by means of a reduction in National Insurance contributions. Its impact on the commercial viability of renewable energy is likely to be marginal.

The EU Emissions Trading Scheme (ETS) is due to be introduced in 2005, and will replace a voluntary United Kingdom emissions trading scheme. Emissions trading, which allows emitters either to reduce their own CO_2 emissions or buy allowances from other emitters in Europe, provides a direct incentive to emitters to invest in cost-effective emission-reducing technology. It is, in the Government's words, the "most cost effective way of achieving carbon emissions reductions" (p. 26). Stephen Timms described the effect as "not entirely dissimilar to a carbon tax"—the approach long recommended by the Royal Society (Q 357).

Ofgem indicated that the cost of the United Kingdom voluntary emissions trading scheme was £8-10 per tonne of carbon-equivalent reductions, compared with £210-380 per tonne for the RO.

Renewable generators do not produce CO_2 emissions, so the EU ETS will impose no direct costs upon them. However, the impact on conventional fossil-fuelled plant is likely to lead to an increase in wholesale electricity prices. This will benefit renewable generators, and, for marginal technologies such as biomass, could make a significant difference to their ability to attract finance.

APPENDIX 10: THE RENEWABLES OBLIGATION: TARGET OR CEILING?

The Government have stated that the level of the Renewables Obligation represents at any given time the "target" for electricity generated from Renewables.

Analysis of the Renewables Obligation shows that the value of the subsidy to generators represented by the Obligation is determined by the price at which they can sell ROCs on the open market. The price of ROCs will be determined by the ratio of the renewables capacity to the level of the RO at the time. The closer the supply of renewable power comes to meeting this level, the lower the price of ROCs. If the RO for any given year were actually to be met, the marginal price of ROCs—that is the commercial value of any ROC issued in excess of the target—would fall to zero.

There is, in other words, a "cliff edge" in the graph of ROC values (illustrated in Box 7). While the buy-out price appears at first glance to provide a floor to the value of renewable power, in reality market forces would prevail. It could in fact be plausibly argued that were the RO actually to be exceeded, not only would the marginal price of ROCs (that is, the price for any power generated above and beyond the RO) fall to zero, but, with an excess of supply versus demand, the value of all ROCs for that year, would fall to near zero. Although the provision that ROCs can be carried over from one year to the next would cushion the blow, the risk remains a serious one.

So if the RO is successful, and renewable generating capacity grows to the point that it is approaching the level set by the Obligation, there would be a risk that, if it were a good year in which the wind was consistently strong, the actual output would exceed the RO, and there would be a catastrophic effect on subsidy levels. There would also be an increasing risk that individual large developments coming on stream, for instance offshore developments with installed capacities of 1GW or more, could in effect cause the entire renewables sector to leap-frog the RO. Such risks would be magnified still more were the Government, as we have recommended, to re-examine proposals to build very large tidal generators such as a Severn barrage or tidal lagoons. The prospect of an individual project capable of supplying five percent of United Kingdom demand would be a huge deterrent for potential investors—would in effect undermine the entire RO.

To sum up, as Dr Anthony White told us, "if we were to meet the 10.4 percent target [for 2010-11] I think there would be a lot of unhappy investors" (Q 317). Assuming that investors do not behave, Dr White's words, "like lemmings", in practice there will be no investment in new renewable generating plant once capacity is approaching the level of the RO (Q 320). Equally, if there is a major shortfall and ROC prices rises, investors will see a more attractive return and act accordingly. One of Ofgem's roles is to publish information on market indicators and trends in enough detail to ensure that rational investment decisions can be made. Assuming Ofgem continues to fulfil this role satisfactorily, the RO will in reality act as a cap or upper limit on the renewables capacity, not a target. Given the uncertainty in annual output, we might expect to see this cap start to take effect at around 75 percent of the RO.

It follows from this analysis that unless renewable power becomes competitive with conventional generation, and thus profitable in its own right, we can expect investment to dry up as the final target is approached—there will be no incentive ever to exceed the target as long as the RO is in force (i.e. until 2027). This was the dilemma faced by the Government in 2003, when it became clear that the fact that the target was set no further ahead than 2010 was stifling investment. The extension of the Obligation from 10.4 percent in 2010 to 15.4 percent in 2015 signalled a longer-term commitment, and was accordingly welcomed by the investment community. However, a stop-start extension of the obligation will always tend to create nervousness. A commitment to a “rolling obligation”, set annually for ten or twelve years ahead, would undoubtedly generate greater confidence in long-term ROC values.

We should also note one potential advantage in the RO. The fact that there is no incentive to reach or exceed the target, unless a renewable technology is developed that can compete on price with conventional generators, means that the total cost to consumers can never exceed the product of the buy-out price and the RO. In other words, by setting the level of the Obligation the Government are in effect (though this has not been stated explicitly) putting a figure on what they deem to be “acceptable” costs to the consumer.

APPENDIX 11: AN ENERGY INTERNET?

In Chapter 6 we discuss issues affecting transmission and distribution networks. In the course of our inquiry, particularly in informal discussion during our visit to Woking, it was suggested that there might be a tension between the conventional centralised Grid model and the requirements of small scale distributed electricity generators, including small renewable plant or CHP operators. We are also aware that an article in *The Economist*, entitled "Building the energy internet", [100] has gone so far as to suggest that the development of distributed generation might prompt a fundamental review of the structure of the electricity network. An idea of how such an "energy internet" might work, developed by Dr Chris Elliott, our Specialist Adviser, is given below. We offer it not as a recommendation, but as an idea which merits further research.

According to this model, each "island of generation" is of the scale of a town, a district of a city or an industrial estate. It includes a mix of generating equipment, including small gas-fuelled CHP power stations, renewables such as PV and wind and other local sources such as landfill methane, that together meet the peak needs of the users within the island. All of those users are interconnected at distribution voltages (11kV or lower). A good example is the system emerging in Woking, which is self-sufficient but retains a Grid connection in case of faults within the island.

What might happen if, instead of being connected to the Grid for back-up, islands were interconnected only to neighbouring islands and there were no National Grid? We create a network of networks, with irregular interconnections reflecting local geography and opportunities. Each individual network is responsible for load balancing and distribution within its island, and can draw on or supply to each of its immediate neighbours when needed. The random fluctuations, scaling as $1/\sqrt{n}$, set a lower limit on the number of independent users. There is a diminishing rate of return as n increases so there may be no need to go to the national scale of the Grid—a few thousand independent users might be enough. This model is in principle no better or worse than the national one for responding to coherent changes in demand.

Of course, this model is not new; it is directly analogous to the Internet, which consists of many Local Area Networks interconnected by many separate pathways. The Internet was originally conceived because it is more robust than a single fixed network.

What might be its advantages? It encourages generation to be physically close to use (thus reducing transmission costs and losses), it easily accommodates small-scale generation including micro CHP and it is very robust against local failures. Existing large scale generators could continue to supply local networks via the existing National Grid infrastructure but neither need be replaced either at the end of their lives. Local people would benefit from local solutions which should make intrusive technologies like wind turbines more acceptable.

What might be its disadvantages? Without a national infrastructure it is not possible for the Government to impose a national security of supply obligation, but this could be replaced by local obligations imposed on the authorities that run the local networks. There is no possibility of national load balancing, but there is also no need for it. Generation becomes critically dependent on the national gas

[100] See *The Economist*, 13 March 2004.

distribution network but this is more flexible (several hours supply can be stored in the pipes) and could be systematically replaced by other local generation technologies (such as PV) as these become viable. There would be technical issues to resolve, including the need for synchronisation between islands, but these could be overcome. For example, interconnections could be at DC or all plant could be synchronised to a broadcast signal.

Dr Chris Elliott FREng, Specialist Adviser

APPENDIX 12: ELECTRICITY STORAGE

Introduction

Electricity storage devices can be used to balance fluctuations in the supply and demand of electricity. Depending on the timescales over which these fluctuations occur, applications fall into three categories:

- Power quality: over short timescales (e.g. a fraction of a second) electricity storage devices can improve the quality and reliability of power supplies;
- Bridging power: on intermediate timescales (e.g. minutes) they can be used in transmission and distribution networks, to ensure grid stability and continuity of supply when switching between energy sources;
- Energy management: over longer timescales (e.g. several hours) they can improve the efficiency of electricity generation.

This note relates to energy management applications. It focuses on their use in large scale electricity generation (that is, connected to transmission systems) although they also have uses in local distribution networks.

Characteristics of electricity storage devices

The energy delivered by renewables can fluctuate on a hourly, daily or even seasonal basis. Electricity storage devices therefore offer one possible means of ensuring continuity of supply from intermittent sources such as wind or solar power. The suitability of a particular storage device for use in conjunction with renewables depends on a number of technical parameters of which the most important are:

- Capacity: the amount of electricity that a system can deliver at a given moment. Devices with capacities of less than ~100 kW are not suitable for use in energy management;
- Discharge time: the timescale over which energy is delivered by the device. Discharge times need to be of the order of hours;
- Alternating/direct current: suitability would depend on whether the device generated a direct current (e.g. a battery) or an alternating current (e.g. a rotating device such as a flywheel). Direct current is suitable for transmission over long distances but most current networks use alternating current, so the electricity would either need to be converted to work on existing networks, or networks would have to be adapted.

Many other factors need to be taken into account such as reaction time (i.e. the time the device would take to come online), specific locational requirements, energy density (which will determine the size of the device), efficiency and lifetime (expressed in terms of the number of charge/discharge cycles). Although these factors will influence capital costs as well as operational and maintenance costs, it is difficult to speculate on the economic feasibility of different technological options as this will be influenced heavily by market factors (see below).

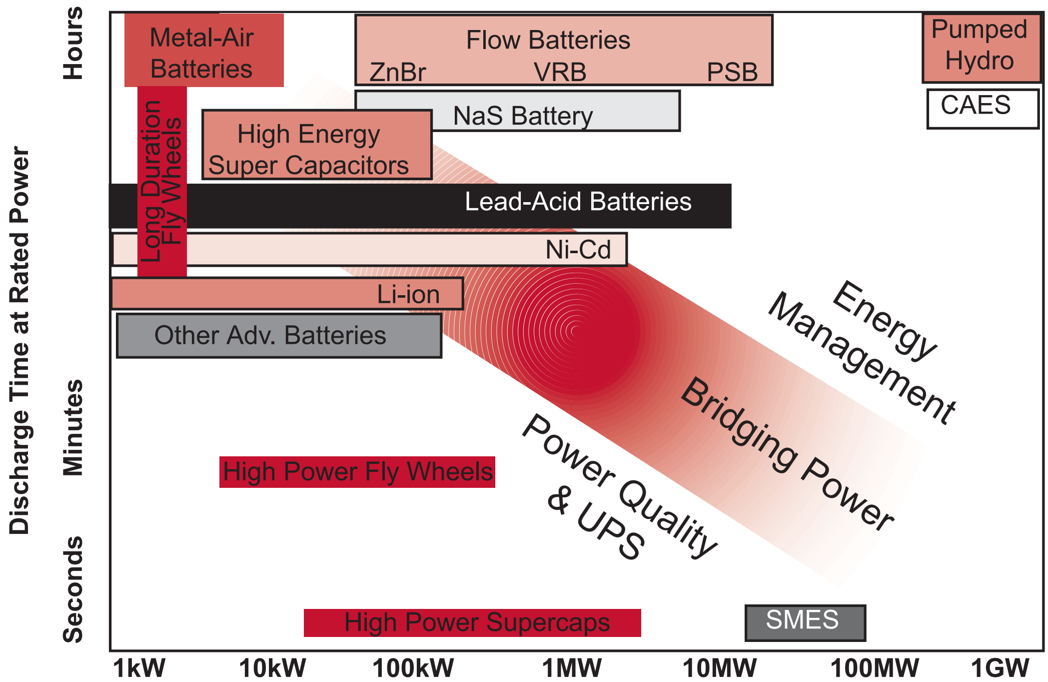
How they work

The graph over the page illustrates how specific storage techniques are suited to different applications based on their capacity and discharge time. Techniques suitable for use in energy management applications are described below, with more information provided in the table over the page.

Pumped hydroelectric

This is currently the most widely used storage technology (e.g. the United Kindom's Dinorwig plant in Wales). These systems consist of two vertically separated water reservoirs. Water can be pumped from the low to the high reservoir at off peak times, and then used to generate electricity when required.

Graph illustrating capacity (horizontal axis) and discharge time (vertical axis) of electricity storage technologies.



Source: Electricity Storage Association[101]

Batteries

Batteries work by using a chemical reaction to produce a voltage between their output terminals (electrodes). In a rechargeable battery, the reaction is reversible and the battery can be recharged at off-peak times. Lead acid batteries are the most widely used but various advanced battery designs are also being developed including:

- Sodium sulphide batteries: These consist of a positive electrode (molten sulphur) separated from negative electrode (molten sodium) by a solid ceramic electrolyte through which only the positive sodium ions can flow. During discharge sodium and sulphur ions combine to form

[101] The Electricity Storage Association is a trade association established to foster development and commercialisation of energy storage technologies. More information can be found at: http://www.electricitystorage.org

sodium polysulphides. During the charge cycle the sodium polysulphides can be converted back into sulphur ions and sodium ions. The sodium ions flow back through the membrane and recharge the battery;

- Flow batteries (also referred to as regenerative fuel cells). There are various different types of flow battery at different stages of development (note that Regenesys, the United Kingdom's only project in this area has been discontinued—see table). Energy is stored in two separate charged electrolytic solutions held in separate tanks (i.e. not within the battery cell itself) and pumped into the battery cell. They are easier to recharge than other battery types, and also have the advantage that the total amount of energy that can be delivered (which can be increased simply by increasing the amount of electrolyte in the tanks) is independent of their power (i.e. the rate at which that energy can be delivered).

Compressed air electricity storage

Off peak electricity is used to pre-compress air (which can be stored in underground mines or caverns) which can then be used to generate electricity as required in a gas-turbine power plant. They can produce two to three times as much energy as a conventional gas plant for the same amount of fuel.

Note that with the exception of pumped hydro, there is limited current use of, and limited investment in, development of other energy storage technologies suitable for energy management.

Future prospects

Looking to the future of the transmission network, National Grid Company (NGC) who operates the network in England and Wales, reports that it has no great concerns over the need for electricity storage over the next twenty years. Indeed, NGC claims that it is able to handle intermittency from renewables within the network in many different ways and storage is not a particularly critical component of its strategy. Similarly, Ofgem, the energy regulator, reports that although they followed developments of the Regenesys project with interest, they have not studied the potential for electricity storage over the coming decades in great detail. Overall, there is a sense amongst key stakeholders that the evolution of the electricity transmission network over the next twenty years will not be influenced significantly by the absence of large scale electricity storage.

Within smaller scale networks, there may be potential for storage[102] and indeed Ofgem is considering a pricing structure to incentivise network operators to encourage embedded generation, in which storage may play a part. However, there is no major investment in this area.

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[102] For example, fuel cells such as that used in the demonstration combined heat and power system installed at Woking could in principle be configured for storage.

Electricity storage devices

Device	Discharge time (see graph on previous page)	Power (see graph on previous page)	Current availability	Other factors
Pumped hydro (a.c.)	Hours to days	Gigawatts (1 GW = 1000 MW)	Widely used commercially. 90 GW of pumped storage worldwide ; The UK's Dinorwig plant in Wales consists of six pump turbines which can deliver around 1800 MW of electricity.	**Advantages:** High capacity ; rapid response time; low operating costs **Disadvantages**: Long construction times; high capital costs; specific site requirements
Flow batteries (d.c) PSB (polysulphide bromide)	hours	~10 MW (see next box). Demonstrated at multi-kW scale in the UK.	Technology still at demonstration stage. The UK's Regenesys project (funded jointly by the DTI and Regenesys technologies), which would have involved construction of a large scale energy storage plant at Little Barford Power Station, was discontinued in late 2003. A project is underway to construct 12 MW, 120 MWh unit in Mississippi, operational late 2004.	**Advantages** of flow batteries: Independent power and energy ratings; long lifetime (thousands of cycles) **Disadvantages:** low energy density
VRB (Vanadium Redox Flow Battery)	As above	Hundreds of kilowtts	Used commercially in Japan, South Africa	See above Other advantages: high efficiency (85%)
ZnBr (Zinc Bromine Flow Battery)	As above	Hundreds of kilowatts	To date, many multi-kWh ZnBr systems have been built and tested; ZnBr systems currently being developed for use with photovoltaics by ZBB energy[1].	See above
Lead Acid Batteries (d.c)	minutes	up to tens of MegaWatts	Widely used commercially, but limited use in large scale energy management applications because of short lifetime	Short lifetime (a few hundred cycles)
NaS batteries (d.c.)	hours	several MegaWatts	Demonstrated in Japan; commercial production imminent	**Advantages:** can be used in both power quality and energy management applications **Disadvantages:** Must be kept at temperatures of 300 degrees
Compressed air energy storage (a.c.)	Hours	Gigawatts	Two commercial plants are in operation: a 290 MW unit at Hundorf, Germany (constructed 1978); a 110 MW unit at Alabama, USA (1991). The third and largest ever commercial CAES plant (2700 MW) is currently under construction in Norton, Ohio.	

Characteristics of electricity storage devices suitable for energy management. Primary source: Electricity Storage Association (1)

Primary source: Electricity Storage Association

Parliamentary Office of Science and Technology

[1] *Grid connected energy storage using the Zinc Bromine flow battery,* Ball et al., 2002 (see http://www.zbbenergy.com/papers/solar2002.pdf

APPENDIX 13: REVIEW OF THE WRITTEN EVIDENCE

The target of 10 percent of electricity from renewable energy by 2010

Written evidence was received from over 70 parties, representing a diverse range of views from industry, industry associations, Government, academics, learned societies, the professional engineering associations, non-governmental organisations, and individuals. There is broad, but not universal, agreement among them on the case for developing renewable energy resources in the United Kingdom. The resources are appreciable, and most of the key technologies have been proven to "work": wind turbines, for example; the use of biomass for the production of heat, power and liquid fuels; solar energy; and, though on a very small scale, energy from tidal streams and waves. Costs are often high relative to fossil fuels, but most witnesses agree there is scope for reductions through discovery and innovation.

For these reasons there is support for the directions of the Energy White Paper. However, there is much disquiet over the 10 percent target. Many believe that the target will not now be met. The Royal Society describes the target as "admirable but over ambitious", a sentiment echoed in several submissions to the Committee. There are three concerns running through the evidence:

- The United Kingdom is starting from a low base such that the rate of installation will need to be extraordinarily high. The White Paper noted that "to hit the 10 percent target we will need to install approximately 10,000 MW of renewables capacity by 2010, an annual build rate of over 1250 MW. Only 1200 MW of renewables capacity has been installed so far (excluding large hydro)."

- The excessive focus on a single technology, namely offshore wind. This is partly a product of public opposition to onshore wind farms, though the better wind regimes and higher capacity factors attainable in the offshore environment are a motivation. Around 400 MW of offshore wind capacity had been installed worldwide by the end of 2003 (including Horns Rev in Denmark, which the Committee visited), and operating experience with large-scale offshore wind farms is little more than two years. The United Kingdom is seeking to install 3000-4000 MW in the next seven years.

- Omissions and uncertainties in supporting policies. The large majority of submissions make recommendations on this subject (see below). The Government has partially responded to one recommendation, which is to extend the RO to 15 percent by 2015 so as to maintain the values of Renewables Obligation Certificates The Institution of Civil Engineers and others had proposed a target of 20 percent by 2020.

In sum, a large body of professional opinion supports the development of renewable energy in the United Kingdom, but believes the targets are unlikely to be met.

Viable technologies

The Committee requested evidence on "cost-effective technologies available now, and those that are likely to become available in the next 10 years or so." But as several submissions point out, few if any non-carbon technologies are commercially cost-effective at the present time on account of the low costs of combined cycle gas fired power plant with which they have to compete. They can be considered cost effective only if two factors are allowed for:

- The cost of carbon emissions from carbon fuels (environmental externalities);
- The long-term economic benefits of discovery and innovation—brought about, in the present case, by the effort to develop and commercialise the technologies.

The latter are sometimes called the positive external benefits of innovation (positive externalities), and require us to focus on the long-run costs and potential of the technologies, rather than short-run costs and returns. This is the thinking behind the White Paper's focus on innovation. It highlights a tension, noted by several witnesses, between Ofgem's focus on costs in the short-run, and the long-term objectives of the White Paper.

With this broader interpretation of costs either expressly or tacitly recognised, the submissions point to a diverse range of options. The over-riding criticism of current policies is that whilst these options are recognised in principle, in practice policies focus to excess on just one—wind. Few question the desirability of developing offshore wind, though some raise familiar environmental objections to onshore wind. Indeed, the United Kingdom's offshore potential is known to be immense. But taken together, the submissions are pressing for a broader portfolio, for example in the following areas:

Biofuels. The Association of Electricity Producers regards co-firing as being on "the verge of commercial viability" whilst a recent report for the Renewable Energy Advisory Board for DTI warned that they could be deployed on such a scale as to devalue the ROCs—which would only happen if the targets were met.

In addition there are several other well known options: urban waste incineration, which has the added benefit of reducing landfill; the gasification and treatment of agricultural wastes and residues, which as the Committee saw in Denmark produces improved quality fertilisers, in addition to electricity, and is part of good land management practice. It is these added economic benefits that help to make the approach economically viable and environmentally more attractive. There is also the use of dedicated crops, e.g. for the production of liquid fuels or heat and power, though the economics are more uncertain, and the potential will be limited by land requirements, which are large. The use of bio-wastes on the other hand requires no more land than is used already, and actually saves land by reducing landfill. The Royal Commission on Environmental Pollution has recently investigated the potential of biofuels in the United Kingdom.

Energy from tidal streams and waves. These technologies are in their infancy, and all reporting on them lament the low level of R&D expended on their development. As with offshore wind the potential is enormous and the energy flows (though intermittent) are more predictable. There is an impressive number of submissions from the Royal Society, the Royal Society of Edinburgh, the Institutions of Civil and Mechanical Engineers, and from industry, arguing for a larger development effort.

Hydrogen production from coal and carbon sequestration. This is, of course, not a renewable resource, but the Institution of Chemical Engineers, the Royal Society of Chemistry and industry make the following points:

First, the heating of fossil fuel gas (coal gas or natural gas) with steam to yield a hydrogen-carbon dioxide gas mix from which the hydrogen can be easily separated is known to be the lowest cost way of producing hydrogen—the ideal fuel for the fuel cell. It is thus the cheapest way of opening up a new hydrogen infrastructure to supply decentralised heat and power and vehicles.

Second, for a zero carbon energy economy to emerge in the long run, then sooner or later (a) the intermittency problem will have to be solved if renewable energy is to be the primary energy source, for which hydrogen is the favoured candidate, and (b)—a point that also applies if nuclear power is to be resuscitated—hydrogen will be needed to supply the transport fuel and gas markets. In this sense hydrogen from fossil fuels is an excellent stepping stone to a hydrogen economy based on renewable energy and/or nuclear power.

Third, the CO_2 can be used for the enhanced recovery of oil from fields in the North Sea. Air Products Ltd estimate that $5 billion of revenues could accrue to the Government at current crude oil prices taking the CO_2 from just 800 MW of new power plant based on the gasification of coal. There is a “window of opportunity” for investment in coal gasification with enhanced oil recovery over the next ten years or so.

Fourth, it is estimated that hydrogen from these sources could be injected safely into the natural gas networks, reducing CO_2 emissions from the use of gas by 15 percent. It would be worth roughly 200 million barrels of oil-equivalent energy per year.

That current policies do not recognise these interconnections between the use of fossil fuels in a carbon neutral way, and the long-term aims of a zero carbon economy based on renewable energy (and/or nuclear power) is lamented in several submissions.

Other hydrogen production. BP comment that “although it is highly unlikely (that hydrogen production) will make a contribution to carbon reduction targets before 2000 it is important that society is supporting of industry’s efforts to demonstrate this technology in the meantime.” Their submission points to a range of possibilities for the development of the hydrogen economy.

Domestic Combined Heat and Power (dCHP). Again this is not a renewable energy source unless the feedstock (e.g. hydrogen derived from renewable energy) is renewable. But several submissions make the point that if emission reduction is the primary aim, then this should be a favoured candidate on grounds of (a) energy efficiency, and (b) the link with the “hydrogen society”: hydrogen is the ideal fuel for fuel cells. The White Paper gives considerable prominence to dCHP, and Ofgem are undertaking an inquiry into the effects of pricing policies in the distribution networks on investment in the technology. The Institute of Physics, the Royal Society of Edinburgh are further concerned about the low level of financial support for RD&D in fuel-cell technologies.

Solar. Perhaps more than any other technology the high costs of solar photovoltaics (PV) today reveal the tensions between the short-term and the long-term aims of energy policies. The current costs of using PV in the United Kingdom are very high, several times those of offshore wind for example. In addition, the solar radiation is seven times lower in winter than summer, so there is no co-incidence, as there is in the tropics or the southern United States and southern Europe, between the solar and the demand peaks; this will make the storage problem insurmountable until the hydrogen economy emerges. Yet the long-term potential of solar is such that several witnesses appeal for the United Kingdom to strengthen its RD&D effort, not only on solar energy itself, but as the Committee found, on storage technologies more generally. The Energy White Paper and Government policies recognise the importance of solar energy. As with fuel cells, however, the main concern of those submitting evidence is not to take issue with what is said in Government documents, but with the scale of the RD&D effort in practice.

This short review does not exhaust the possibilities put to the Committee. There is much on energy efficiency, including dCHP based on gas, coal bed methane, the use of landfill gas, active and passive solar heating, and technologies and communications systems for demand management. It has to be said that several of the submissions do not recognise several of the policies that are in place already, for example in the area of energy efficiency. Nevertheless the following conclusion seems to be widely shared:

Most witnesses support the development of offshore wind energy, though some are sceptical. But the renewable energy options available to the United Kingdom in the near term, and certainly in the long term, are far broader than this, and there are non-renewable technologies, particularly those that could open up the "hydrogen economy" that would complement the renewable energy experiment itself. Thus we need a more broadly based approach than the one we have at present. There is the further danger that, by over emphasis on offshore wind, at a time when the technology is barely through its demonstration phase, will lead to disappointments.

Standby capacity for wind energy

There has been a protracted debate in the United Kingdom on whether the electricity system could cope with a significant input from intermittent wind energy. Studies were first undertaken by the CEGB in 1979, and apparently remain robust. There have been reports which (wrongly) assumed that, since wind energy would sometimes be unavailable on days of peak demand in winter, each MW of wind capacity would require a MW of standby capacity in the form of an open cycle gas turbine. Evidence was submitted from Denmark that wind energy was indeed sometimes unavailable during times of peak demand, the required backup, in the Danish case, coming from Norway (via Nordpool) and other sources of generation.

The evidence has settled down, thanks to a number of engineering studies. The main points are the following:

> For up to 10 percent penetration of wind energy on the system there should be no technical problems in managing intermittency and ensuring reliable supplies. Some investment in back up capacity will be needed, but at this level of penetration it would be quite small, and recourse could be had to standby plant already on the system. All power stations (including the largest power stations on the Grid) need to be supported by backup or reserve capacity on the Grid in case of electrical or mechanical failures, and it has long been standard practice to provide it. Indeed the reason why Grids were initially formed was to pool back up capacity. A capacity margin around 20 percent for demand uncertainties and plant failures is not untypical.
>
> At 15 percent penetration the required back up capacity increases significantly and at 20 percent a buffer is, as the Royal Society put it, "absolutely necessary".

> The use of backup capacity of course raises costs. A study by the National Grid Company suggests that the costs would rise to, approximately, 1.6 p/kWh at 20 percent penetration.
>
> The problems of stability associated with intermittency, and the effects of intermittency on the reliability of supply could be reduced (a) by a more balanced portfolio of renewable energy projects on the system, (b) demand management technologies, and (c) the introduction of storage technologies, including the novel device of the regenerable fuel cell, the development of which DTI is supporting. During the course of the Inquiry, the company developing the technology withdrew its support on the grounds that it was not commercially available in the near future.

The 15 percent target is now only 11 years away. By this time it is certain that either significant investment in back up capacity will be needed to support further expansions of intermittent generation, or storage technologies will need to be developed. Alternatively, we will need to turn to fossil fuels (with carbon sequestration) and/or nuclear power. The Royal Society of Edinburgh and others have called for an expansion of RD&D effort in storage, including hydrogen production and storage.

Infrastructure and Planning Consent

There are three issues discussed in the written evidence; all, once again, relate to wind energy:

- The costs of Grid extensions;
- The infrastructure required to support a high installation rate of offshore wind turbines;
- Planning consent, both for offshore and onshore wind turbines, and for transmission lines.

The evidence is definitive on the first, but distinctly unsettled on the second and third.

Transmission.

There have been a number of studies by National Grid Transco, the Scottish energy industries and others, which have estimated the costs of the Grid extensions required to support the expansion of wind energy. Estimates vary with assumptions about the time period and the locations of the turbines. But they all seem consistent with the estimates provided by Lewis Dale of NGT, at the Committee's Seminar on 10 December 2003, with regard to a system postulated for 2020 with 20 percent wind energy:

> Total additional cost relative to a grid based on conventional plant with no wind: approximately £1.2 billion per year (approximately 1.5 p/kWh). This includes:
>
> - Investment in network reinforcement of £3.7 billion in total;
> - Balancing costs (hot standby etc) of 0.285 p/kWh;
> - An assumed investment in wind turbines of £14 billion.

The overall effect is to increase electricity supply costs at the Grid by approximately 10 percent. The 20 percent figure of intermittent generation on the system is very high, and others have called for a more balanced mix of renewable technologies on the system. This would reduce intermittency and both transmission and balancing costs.

Doubts are raised in several testimonies as to whether the New Electricity Trading Arrangements will enable the finance required for the infrastructure to be raised.

Installation of Offshore Turbines. The current targets will require very high installation rates, perhaps 1 turbine a day year round on average, depending on planning assumptions; but weather conditions will frequently not permit installation and the required rate when weather does permit may be 3 or more turbines per day. Nevertheless the New and Renewable Energy Centre (NaREC) comments:

"There are currently around eight vessels on the northern seaboard of Europe capable of carrying out the offshore wind turbine installations; to meet the sustained build rate obviously requires a substantial increase in this capability … however, (industry) are confident that if the right financial support mechanisms are in place (they) will respond and be capable of these installation rates."

Planning. Ofgem, industry and the Engineering Institutions, all raise the issue of planning consent. The Government has updated its planning guidelines, and a document known as PPS 22 aims to encourage local authorities to develop their policies. "Community engagement" is seen to hold the key to the acceptance of renewable energy technologies around the country. There are two sources of conflict:

- Between industry and the Government on the one hand, which understandably wish to speed things up, and local communities (including environmental action groups) on the other, which are of course concerned about the local environment.
- Between government departments, notably the MoD, Defra and DTI.

These matters are still far from settled.

Milestones

The Energy White Paper (p. 55) lays out a plan, which is updated in more detail in the Government's written evidence. Several testimonies press for the milestones to be laid out more clearly, but have no concrete proposals to make on what they should be. One source requests a yearly or two-yearly report on progress.

The Renewables Obligation is raising the target for the installation of renewable energy by 1 percent per year until, by 2015, the 15 percent target is reached. Milestones are, of course, not simply about targets. Three important milestones would be:

- The resolution of planning issues;
- The policies of Ofgem and the Distribution Network Operators on dCHP;
- Any decision to broaden the portfolio, as discussed above.

Professor Fells makes the further point that, if we accept the targets as setting one kind of milestone, the 3 percent target for 2003 has already been missed—with no-one incurring a penalty. Hence whatever the milestones are, they currently lack bite.

Or is it worse than a lack of bite? If the targets are missed the ROCs will maintain their value, and the refunds industry receives from the revenues they generate will rise. There is more than a hint of an incentive in current policies to fall short of the target.

Policy Recommendations

The following is a summary of the recommendations in the written evidence:

Extend the targets to 2020. This is proposed by several parties, on the grounds that the financial incentives provided by the 2010 targets were steeply declining, and indeed dropped to zero after 2010. Investments in renewable energy (as in conventional technologies) have lifetimes of 20 or more years. Extending the targets to 20 percent by 2020 is considered crucial for investment to proceed. The Government has extended the targets to 15 percent by 2015. Will this be enough?

Broadening the portfolio. As discussed above, there are numerous appeals for a broader portfolio of investments:

- Biomass, especially in the area of waste incineration. The possibilities of a significant contribution to the targets from co-firing has also been noted. The Renewables Obligation should be extended, it is argued, to these technologies;
- Coal gasification, hydrogen production and carbon sequestration;
- Small-scale production of CHP, with a special but not exclusive emphasis on fuel cells and a long-term view to the use of hydrogen as a feedstock;
- A programme on the efficient supply of heat, including the use of ground source heat pumps;
- A more ambitious programme of demonstration projects in wave and tidal energy.

Nuclear power. There remain disagreements in the energy industry and the research community on how much intermittent renewable energy can be accommodated on the system. All agree that 10 percent could be accommodated, and some consider 20 percent is feasible. Somewhere in this range the nuclear industry, the Royal Society, the Institution of Chemical Engineers and several others, believe that we will need to resuscitate nuclear power. In addition, with the closure of nuclear stations in the next 15-20 years, it is clear that even 20 percent renewable energy on the system will fall short of the non-carbon energy required to meet the overall emissions targets.

Markets and finance. There are several issues raised under this heading:

- The short-term perspectives of electricity market regulation under Ofgem and the long-term goals of the White Paper. Some have called for a rethink of the current approach;
- The desirability of introducing a carbon tax or transforming the Climate Change Levy into one;
- An extension of the capital grants programme.

The Association of Electricity Producers have also cautioned about dangers of tinkering with the Renewables Obligation, pointing out that this would undermine investor confidence. In the same vein, they are concerned about the uncertainties arising from the review of the Renewables Obligation in 2005.

Planning consent. This is widely agreed to be of central importance, but recommendations are so far unspecific. There is a general appeal for internal issues between government departments (e.g. between the MoD and others) to be resolved. Further progress on planning guidelines is also awaited.

RD&D. In every area—in the wind, wave, tidal, solar and biomass technologies themselves, in hydrogen production and use, in the storage of electricity and hydrogen, in fuel cells and dCHP, in carbon sequestration and other, in new demand management technologies—there is an appeal for a greatly expanded RD&D programme. The United Kingdom does of course have research programmes in these areas: it is the scale of effort that is in question. The Royal Academy of Engineering summarises the situation as follows:

"Past years have witnessed significant changes within the United Kingdom engineering research community. Industry has dismantled many of the large corporate research laboratories in favour of outsourcing and leaner research modes…This has resulted in a more efficient industrial research process, with tighter coupling of users and providers of technology, but has also tended to reduce industry spend on both speculative long-term research and translational research to convert promising technologies into demonstrators … This market failure has been compounded by the privatisation or closure of many public research institutes … with considerable repercussions for the United Kingdom engineering industry and research infrastructure."

The appeals for expanded RD&D programmes come not only from the learned societies and the academic community, but from industry, who argued for market based incentives to support their efforts (see the submission from BP).

Education and training. Again, it is worth quoting the Royal Academy of Engineering:

"The future ability of the United Kingdom to generate economic and societal benefits from engineering is entirely dependent on the continued supply of skilled personnel. However there has been an alarming decline in applications to university engineering departments in recent years, which together with the funding and staffing crises afflicting many of these departments, provide cause for extreme concern. Indeed, 46 engineering and technology departments closed in the period 1996-7 to 2000-1. Effective action is now required as a matter of urgency to mitigate further deterioration of the United Kingdom engineering skills and knowledge base."

Professor Dennis Anderson, Specialist Adviser

APPENDIX 14: ACRONYMS AND GLOSSARY

Acronyms

ARBRE	Arable Biomass Renewable Energy
BAA	British Airports Authority
BETTA	British Electricity Trading and Transmission Arrangements
BHA	British Hydropower Association
BWEA	British Wind Energy Association
CAA	Civil Aviation Authority
CAP	Common Agricultural Policy
CCGT	Combined cycle gas turbine
CCL	Climate Change Levy
CEGB	Central Electricity Generating Board
CHP	Combined heat and power
CMM	Coalmine methane
CO_2	Carbon dioxide
CPRE	Campaign to Protect Rural England
dCHP	Domestic combined heat and power
Defra	Department for the Environment, Food and Rural Affairs
DGCG	Distributed Generation Co-ordinating Group
DNO	Distribution network operators
DTI	Department of Trade and Industry
ECI	Environmental Change Institute
EPA	Environmental Protection Agency
EPR	Energy Power Resources
EPSRC	Engineering and Physical Sciences Research Council
ESRC	Economic and Social Research Council
ETS	Emissions Trading Scheme
GE	General Electric
GW	GigaWatt (1,000,000,000 Watts)—see below
GWh	GigaWatt hour
HC	House of Commons
HL	House of Lords
IGCC	Integrated gasification combined cycle
JESS	Joint Energy Security of Supply Working Group

kW	KiloWatt (1,000 Watts)—see below
kWh	KiloWatt hour
LGA	Local Government Authority
LPG	Liquid petroleum gas
MIW	Municipal and industrial waste
MoD	Ministry of Defence
MW	MegaWatt (1,000,000 Watts)—see below
MWe	MegaWatt equivalent
MWh	MegaWatt hour
NaREC	New and Renewable Energy Centre Ltd
NATS	National Air Traffic Services
NERC	Natural Environment Research Council
NETA	New Electricity Trading Arrangements
NFFO	Non-Fossil Fuel Obligation
NFPA	Non-Fossil Purchasing Agency Ltd
NGC	National Grid Company
NGO	Non-Governmental Organisation
NGT	National Grid Transco
NI-NFFO	Northern Ireland NFFO
Nm^3	Normal cubic metres
NPPG	New Planning Policy Guidelines
ODPM	Office of the Deputy Prime Minister
Ofgem	Office of Gas and Electricity Markets
OWEL	Offshore Wave Energy Ltd
OXERA	Oxford Economic Research Associates
PAN	Planning advice note
PIU	Performance and innovation unit
POST	Parliamentary Office of Science and Technology
PPA	Power purchase agreement
PPS 22	Planning Policy Statement 22
PV	Photovoltaic
R&D	Research and Development
RCEP	Royal Commission on Environmental Pollution
RCUK	Research Councils UK
RD&D	Research, Development and Demonstration

RDA	Regional Development Agency
RO	Renewables Obligation
ROC	Renewables Obligation Certificate
RPA	Renewable Power Association
RSPB	Royal Society for the Protection of Birds
SEA	Strategic environmental assessment
SRC	Short rotation coppice
SRO	Scottish Renewables Obligation
tC	tonnes Carbon
TSO	Transmission system operators
TTA	Tactical training area
TW	TeraWatt (1,000,000,000,000 Watts)—see below
TWh	TeraWatt hour
UKAEA	United Kingdom Atomic Energy Authority
UPS	Uninterrupted power supply

Glossary

Electrical units

In this report, electricity demand, or supply, is quoted in terms of watts (W) or watt-hours (Wh). A watt is a measure of the rate of use, or generation, of all energy (not just electricity), at any one time. Watt-hours is a measure of the total amount of energy used, or generated, over time: a 100 W light bulb left on for two hours will consume 200 Wh of energy.

The abbreviations k, M, G or T preceding W or Wh indicate increasing amounts:

- k (kilo): thousands (1,000)
- M (mega): millions (1,000,000)
- G (giga): billions (1,000,000,000)
- T (tera): million-millions (1,000,000,000,000)

For example, 5 MWh = five million watt-hours.

Power stations are normally quoted with their maximum output power capacity: a large, 1 GW, power station could in theory produce 8.76 TWh each year running continuously (there are 8,760 hours in a year). Electricity demand in the United Kingdom in 2002 was just under 400 TWh, indicating a mean rate of use of around 45 GW. Total installed generating capacity was 77 GW, and the maximum demand met at any time in that year was just over 60 GW. The minimum demand on a summer night may fall below 20 GW.

An average household consumes 3,300 kWh (or 3.3 MWh) of electricity each year. As a rule of thumb, electricity suppliers therefore often work to an average power requirement of 0.5 kW per household, although there will be considerable variation over the course of a day—one kettle, for instance, consumes at a rate of over 2 kW for the short time that it is on.

For Combined Heat and Power (CHP) generators, output is measured using MW_e as the amount of electrical power produced, and MW_{th} as the amount of thermal (in other words heat) power.

Carbon units and emissions

Emissions to the atmosphere of greenhouse gases are by convention quoted in terms of the carbon (C) equivalent amount, as carbon dioxide (CO_2) is the principal greenhouse gas occurring as a by-product of burning fossil fuels. Amounts are often described in millions of tonnes (Mt) of carbon, MtC. Occasionally, however, emissions are expressed in terms of CO_2 equivalence (for instance, in Table 1 of this report). The relative atomic weight of the carbon and oxygen atoms contained in each molecule of CO_2 means that 1 Mt of CO_2 is equivalent to roughly 0.25 Mt carbon.

Amounts of other greenhouse gases are multiplied by a factor that approximates their time-integrated warming effect in today's atmosphere, relative to CO_2. Considering a time horizon of 100 years, methane (CH_4) has a multiplying factor of about 20 times that of CO_2, nitrous oxide (N_20) has a multiplying factor of 300.

Carbon is freed during the combustion of fossil fuels, though the amount depends on the type of fuel and the efficiency of the power station. The carbon content in relation to the energy content of natural gas is 52.5 gC/kWh; for oil 66.9 gC/kWh; for coal 86.7 gC/kWh. In 2002, the gross efficiency in converting heat from combustion into electricity of combined cycle gas turbine stations (which use natural gas or oil as fuel) was 47 percent; for coal fired stations 36 percent. Hence actual carbon emissions resulting from electricity generation were about 100 gC/kWh for gas, and 250 gC/kWh for coal.

The efficiency of power plants can be substantially increased if as well as producing electricity, the low-grade heat, which is normally wasted, is used—typically to produce hot water for nearby buildings. Such Combined Heat and Power (CHP) plants have efficiencies as high as 70–80 percent.

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