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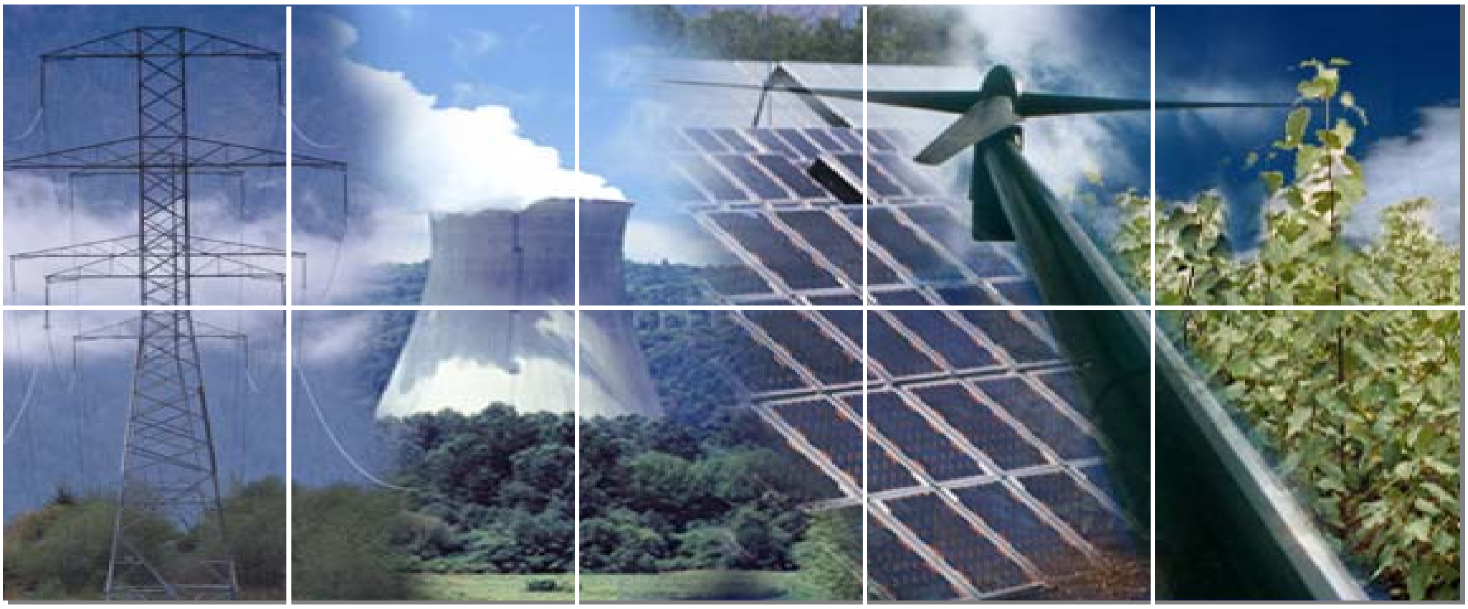

Options for changes to the regulatory framework required to deliver a sustainable energy system in Great Britain

Report to the Sustainable Development Commission

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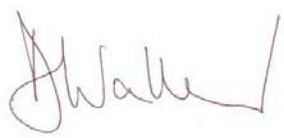
	Signature	
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Executive summary

The role of the Sustainable Development Commission (SDC) is to act as the UK's sustainability watchdog and provide advice to Government on sustainability issues. In recent times sustainability and the closely related issue of climate change have moved rapidly up the political agenda. This culminated in the publication of the draft climate change bill in March 2007 which set out a framework for moving the UK to a low-carbon economy. The draft bill included featured a series of targets for reducing carbon dioxide emissions - including making the UK's targets for a 60% reduction by 2050 and a 26 to 32% reduction by 2020 legally binding.

The objective of this work was to identify the barriers to a sustainable energy system in Great Britain and the options for overcoming them. The first part of the work considered the barriers across the whole energy sector, the second part of the project focused on the options that Ofgem could implement either within its existing role or within a revised remit. The results from the project will feed in to the SDC's review of Ofgem's role in the delivery of a sustainable energy system for the UK, which is part of its watchdog function for sustainable development.

The SDC defines a sustainable energy system as one that:

- Consistent with the best scientific evidence on the urgency of climate change, reduces the CO_2 emissions from the electricity and heat system in line with a 60% reduction in CO2 emission by around 2050

- Radically increases efficient use of heat (on the grounds of avoided CO_2 emissions and reducing excessive resource use)

- Promotes competition by allowing for easy access of new market entrants, large and small

- Contributes to improved security of energy supplies for the UK

If met, these objectives would significantly reduce the contribution of the energy system to climate change which is regarded by many stakeholders as the greatest threat to a sustainable future.

The main barriers to a sustainable energy system that were identified as capable of being overcome within Ofgem's current remit are outlined in the following section. The numbering corresponds to the options towards the end of the executive summary (i.e. barriers 1(a) and 1(b) relate to option 1) but do not correspond to the numbering in the main body of the report where a broader list of barriers has been considered.

1(a). **Lack of a Heat Regulator.** The heat market is still outside the regulatory framework. Many stakeholders believe this creates a lack of focus for heat market development. If utilities want to lay out new electricity or gas supply network then they have rights to compulsory purchase of the land – no similar rights exist for heat networks.

1(b) **High infrastructure costs to develop a heat network.** Most stakeholders agree that constructing a national heat network would involve high infrastructure costs.

2(a) **Short term price focus.** Ofgem are heavily focussed on short term price issues for the customer and in order to develop a truly sustainable energy system some stakeholders argue that they need to take a longer term view.

2(b) **Lack of use of system charging regime for intermittent generators.** The current system of transmission charges is modelled on conventional, large, centralised plant and some stakeholders argue that they have not been adequately modified to reflect the nature of intermittent generation.

2(c) **High transmission charges to offshore connections.** Since BETTA go-live industry and offshore/island authorities have worked together to engage Government on the problem of high transmission charges to peripheral locations. After consultation on this issue, the UK Government established a clause in the Energy Act (section 185) giving the Secretary of State the power to cap transmission charges to peripheral areas, and following on from this, decided that the situation in the Scottish islands merited Government intervention.

3(a) **The BETTA Queue.** The so called 'BETTA Queue' means there are long connection times to the transmission network for renewable project developers in Scotland with some connection offers going out beyond 2015. This prevents low carbon renewables replacing existing assets and may dissuade some project developers from pursuing new projects. There has always been a time lag between the application for a connection to the transmission network and the physical connection being made. However, the length of the queue was compounded by the increased requests for connections before the BETTA go-live date (April 2005), especially in Scotland. Developers were faced with additional limits placed on new connection applications (most significantly the condition that new generation applying for connection post BETTA go-live would receive offers contingent on the wider British network being strengthened). The result was a rush of interest in securing a connection agreement to avoid a long wait for constraints between Scotland and England to be removed. It should be noted that the length of the BETTA queue has been exacerbated by the delays associated with the public inquiry on the proposed upgrade and re-routing of the Beauly Denny line, which seeks to link proposed power generation projects in north Scotland to the main transmission network. That said, there are other measures that could be put in place to reduce the queue such improvements to the planning processes and introducing a connect and manage approach.

4(a) **Lack of sustainability criteria or renewables focus in Balancing and Settlement Code.** The objectives of the Balancing and Settlement Code (BSC) do not include sustainability or carbon criteria. Currently, any changes to the Balancing and Settlement Code (BSC), which regulates the trading and settlement of energy are assessed against the five BSC Objectives. Many stakeholders feel that there should be an additional BSC Objective to ensure the delivery of a sustainable, low carbon supply. At present any changes that hinder the development of a sustainable supply can and will be approved if they meet other objectives.

5(a) **Need for clearer sustainability agenda for Ofgem.** Many stakeholders argue that there is a need to better define the security of supply and sustainability remit of Ofgem. Ofgem's primary aim is to protect the interests of current and future consumers by promoting effective competition. It is argued that Ofgem has largely achieved that aim, and the emphasis might now move from "low cost energy delivered as sustainably as possible" to "sustainable energy delivered at the lowest cost possible."

5(b) **Complexity of regulatory environment.** Several stakeholders have remarked that the high workload involved in reviewing codes creates a disproportionate impact on smaller market players. Several stakeholders believe this high workload is creating a strain on independent developers and independent generators and allows larger operators to manage and influence the processes. While some of the frenetic activity is unavoidable, and is the result of the industry grappling with some of the enduring problems in the new GB market, there is also a genuine concern about over-activity leading to burn out amongst key organisations and participants.

5(c) **Discrimination against intermittent renewables.** It is widely felt by renewable energy developers that the trading rules under NETA and later BETTA have discriminated against the unpredictability and intermittency of renewable generation, and that the trading system has artificially depressed the renewable energy price. Under the trading rules, in order to balance the system, generators and suppliers are required to forecast their supply and demand ahead of delivery. For renewable generators, this can be difficult. If the actual supply and demand differs from their forecast, they are penalised by having to buy from or sell into a secondary and potentially more volatile 'balancing' market.

5(d) **Discrimination against small scale microgeneration technologies.** The value of electricity produced by micro-generation to the grid needs to be valued, but cannot currently be quantified in detail due to limitations within the billing and settlement system. At present, most electricity suppliers contend that it is uneconomic to extend their settlement systems to allow this because of the low volumes of electricity involved.

6(a) **Distributed generation will require more active management of network.** The development of significant distributed generation will have significant impacts on the distribution network and will place it under operational and technical pressure. The move from a situation where electricity is taken from centralised power plants and delivered to consumers, to one where small scale generators can sell surplus power, all the time maintaining the integrity and reliability of the network, will require long term planning. For instance, the widespread use of micro-generation assets may require strengthening of the transmission and distribution system (opinions vary on how soon this will become an issue – the range is likely to be in the order of 30 to 50% of households in Great Britain) in order to ensure reliable and balanced electricity services are retained. Ofgem has introduced a range of initiatives such as the Innovation Funding Incentive, Registered Power Zones and the Distributed Generation Incentive in an effort to help combat these issues. However, many stakeholders believe they should be strengthened to enhance their effectiveness.

6(b) **Two-way power flows and increased voltages.** Distribution systems are designed to manage power flows in one direction, those from a grid supply point to the point of customer demand. In addition a network is designed to deliver, by the use of transformers lines and cables, the correct voltage, within limits, to its consumers. The addition of distributed generation can increase system voltages and introduce reverse power flows. Excessive amounts of generation will result in network voltages exceeding statutory limits and produce reverse power flows that are unlikely to be compatible with, for example, network protection configurations. Although a barrier to the integration of distributed generation neither of these issues are technically insurmountable. However they will require additional monitoring and control equipment that inevitably will result in extra costs.

7(a) **Inter-network Contracts and Agreements.** There has been widespread criticism by distributed generators of the contractual agreements for contracting with the Great Britain System Operator (GBSO). At the present time the GBSO contracts bilaterally with each DG generator classed as a large power station. This system imposes a significant bureaucratic burden on smaller generating stations and there are major cost disadvantages from making the wrong choice regarding which agreement is appropriate for a particular site. In addition, generators often see that they have insufficient information about other network factors that will impact on their choice. Furthermore, whilst the situation may change over time, once they have decided, generators are effectively locked into their chosen agreement.

7(b**) Licensing process can be burdensome for small suppliers.** The need to obtain a license for the generation and supply of electricity can be a burdensome procedure for small-scale generation, which it is argued by some stakeholders, tends to suppress investment in new plant.

8(a) **Lack of confidence in energy efficiency measures.** Some stakeholders believe the actual and remaining potential gains from End User energy efficiency measures may be underappreciated. Between 2003 and 2006 there has been significant progress, driven by an extension to EEC and significant improvements in Building Regulations standards relating to energy efficiency (Part L) as well as an increase in the amount available for Warm Front grants. There is also a belief amongst some stakeholders that politicians continue to equate energy efficiency primarily with carbon reductions and do not recognise the wider ancillary benefits of security and affordability, despite a body of evidence demonstrating net-economic benefit from public investment in energy efficiency, and its cost effectiveness compared to other policies and measures. Policies are regarded as complex to deliver, dependent on behavioural change and uncertain in their outputs when compared to supply-side solutions. Some stakeholders believe that to date most carbon mitigation attempts have focussed on supply side and energy-intensive industrial users rather than energy efficiency measures.

9(a) **Unfavourable gas and electricity prices erode CHP's advantage over conventional generation** by reducing the return on the investment. When combined with the increased risk from uncertainty regarding future fuel prices, this has the effect of either delaying investment decisions or encouraging the installation of conventional heat generating plant.

9(b) **Energy price volatility creates risk barriers to CHP investment**. The largest impact upon the attractiveness of investment in CHP is the relative price of fuel (mainly natural gas) used in CHP, and the financial value of the electricity generated by CHP. This is often referred to as the "spark spread". Volatility in price movements creates additional barriers to CHP deployment since it increases the financial risk, which in turn undermines the long term business case.

9(c) **High capital costs compared to conventional generation.** The capital costs of CHP are higher than those associated with heat only boilers (and importing electricity from the National Grid rather than generating it in house). If the market conditions are favourable with regard to fuel prices, savings associated with avoiding the purchase of electricity from the National Grid should off-set these additional capital costs in an acceptable period of time. However, because of the volatile fuel prices and uncertainties surrounding the size of the long term heat load of a site, many investors take the view that CHP in industrial applications is a risky investment.

9(d) **High operation and maintenance costs compared to conventional generation.** CHP also has higher associated operation and maintenance (O&M) costs than conventional boilers. The O&M costs of CHP range from 0.4-1.0 p/kWh and can be as high as 2p/kWh for small-scale reciprocating engines. This should be compared with O&M costs of 0.05-0.1 p/kWh for heat only boilers.

10(a) **Insufficient energy efficiency information on energy bills to allow consumers to make informed choices.** Many stakeholders believe that consumer billing is a key driver of consumer energy behaviour. It is felt that current billing systems carry inadequate information to provide properly informed consumer choice. Poor or inaccurate billing has the potential to reduce the impact of energy efficiency improvements, increase fuel poverty and increase consumer debt. The Energy Review and a separate DTI consultation on consumer billing highlighted a number of options to improve the situation. These included the addition of historical energy consumption information to consumer bills (in graphical form), the use of benchmarking to provide indications of relative levels of energy use, improving the frequency of billing and extending billing arrangements to business customers.

11(a) **High costs of transmission infrastructure for offshore network.** High transmission charges will force up the cost of connecting to the Scottish islands, even with effective transmission capping. Problems consenting upgraded lines also makes the need for connection to the islands to allow connection of wind and other generation projects more difficult to meet. At present the regulatory and market frameworks mean that the cost of providing connection with all but limited sub-sea routes will be difficult to justify. It seems clear that there is a gap - either in the price the market will pay or in the way that the system is regulated – that will make delivery of a significant level of capacity to the islands problematic. However, there seems to be a willingness on the part of Ofgem and Government to tackle these issues.

11(b) **The Energy Act 2004 prohibits electricity transmission in the Renewable Energy Zone (an area of the sea, beyond the United Kingdom's territorial sea, which may be exploited for energy production) without a licence.** However, an offshore regulatory regime must first be developed by Ofgem and the Government before Ofgem can grant a transmission licence/s. Currently, there are plans for about 6-7GW of renewables capacity (which represents just under 10% of current generating capacity) to be developed in the sea around Great Britain, primarily from wind resources. Without a licensed transmission operator to provide a connection to the onshore transmission network these projects will not go ahead. Ofgem has identified five work streams that are actively being taken forward to help implement an offshore regulatory regime for electricity transmission.

12(a) **The arrangements by which the GB System Operator (GBSO) makes a connection offer to a potential generator.** The so called Final Sums Liability (FSL) arrangements have required developers to lodge a bond guaranteeing the monies required by the GBSO to implement the connection. This has protected the GBSO and the Transmission Owner (TO) from the developer 'walking away' from the connection offer. However these arrangements have attracted criticism because:

- o The developer can become liable for the FSL before they receive planning consent
- o The developer takes all the risk and the GBSO / TO none
- o The level of the FSL can fluctuate if developers within a connection 'cluster' pull out

13(a) **Green Tariffs.** Currently most suppliers offer 'green' tariffs – tariffs that purport to be sourced from environmentally friendly sources. However the definitions of 'green' can vary between suppliers which leads to difficulties in comparing tariffs. Suppliers are not currently mandated to display key facts on their tariffs in a standard format, which acts as a barrier to consumers comparing them on the basis of reduced environmental impact or selecting the 'greenest' tariff should they so desire. Furthermore, there is also a danger that even when information is available consumers will not necessarily be comparing like with like. Potentially, and more importantly, there is a problem of additionality related to these tariffs since the purchase of a green tariff does not normally generate any additional green power it merely attributes that which is already being generated to a particular customer.

The barriers considered during this study were much broader than just those capable of being overcome using Ofgem's current remit. Two of the most significant barriers that fell outside this focus were as follows:

- **Low carbon price.** While the cost of carbon is providing some incentive to switching to use of, and investment in, low carbon generation technologies, most stakeholders are concerned that the carbon price is not providing sufficient incentive for investing in sustainable energy. The low carbon price for Phase I of the EU-ETS (running from 1st January 2005 to 31st December 2007) is mainly driven by oversupply of allowances in the carbon market. Many experts argue that has occurred as a direct consequence of the generous Phase I Member State National Allocation Plans (NAPs) accepted by the EC. However, there are signs that this issue is being addressed as the EC took a much firmer line with the recent Phase II NAPs. Of the first 10 Phase II NAPs submitted by Member States, the EC imposed cuts in the total allocation to 9 of them – the UK being the notable exception. The average reduction was 7%.

- **Lack of a heat obligation.** There is no equivalent for heat to mirror the Renewables Obligation. Proponents of a Renewable and CHP Heat Obligation claim it would stimulate investment in renewables and CHP heat plant in a similar manner to the investment in renewables electricity generators following the introduction of the Renewables Obligation. They also believe the additional administrative burden would be offset by the additional value of the heat and it would remedy the perverse situation where biomass CHP plant are encouraged to maximise power output regardless of heat demand to gain maximum return from electricity ROCs.

Options to overcome these barriers were identified through a workshop and discussions with the SDC External Advisory Board. The results of these activities were documented in a ranked matrix of options, which was used by SDC to inform their decision regarding which options should be considered in detail. They decided to focus the detailed analysis on options that Ofgem could implement since this would be of most use to their review of Ofgem. The main options considered in this context were as follows:

1. **Allow Network Operators to develop heat networks and make them part of the regulated asset base.** It is suggested that regulation of the existing heat networks and further development of heat networks could be made the responsibility of Ofgem. Any suitable party would then be able to apply for a license to build a local heat network. This would help ensure the efficient use of capital since networks would only be built where there

is demand for heat. Appointing Ofgem as the heat network regulator could also be used to build consumer confidence and prevent repetition of infrastructure or 'stranded' heat network assets. Given their expertise in managing networks and their existing relationships with local authorities it is envisaged that many of the networks would be licensed to existing Gas Distribution Network Operators (GDNOs). However, the cost of constructing the heat networks could be shared by all energy consumers, perhaps in the form of a levy on each kWh of energy consumed.

2. **Incorporate the cost of carbon into distribution and transmission network charges** through the use of an 'RPI – X +/- the cost of carbon' formula to determine Transmission Owners' (TOs) and Distribution Network Operators' (DNOs) revenue at price controls. This would ensure that some of cost of the carbon emissions associated with the networks' energy use is internalised and passed onto customers. The cost of carbon could be subtracted from RPI-X to incentivise the transmission and distribution networks to reduce the carbon emissions on their networks. This would have the effect of reducing TOs' and DNOs' revenue according to the value of the carbon associated with the energy use arising from their operation of the network. An alternative approach would be to calculate the level of emissions associated more widely with the activity i.e. the emissions associated with the generation of the power transmitted through the specific element of the network, in a manner similar to the way the locational element is charged through Transmission Network Use of System charges. This is because this option would be targeted at power generators through an increase in the use of system charges they incur.

3. **Introducing a 'connect & manage' approach to connecting generators to the transmission network.** This would entail connecting generators to the grid as soon as the connection could be physically made. The available network capacity would then be managed by 'dispatching' all the connected generators (i.e. permitting them to use the grid) rather than allowing them free access.

4. **Add sustainability and GHG reduction objectives to the Balancing and Settlement Code.** Under the trading rules, in order to balance the system, generators and suppliers are required to forecast their supply and demand ahead of delivery. For renewable generators, this can be difficult. If the actual supply and demand differs from their forecast, they are penalised by having to buy from or sell into a secondary and potentially more volatile 'balancing' market. In line with Ofgem's primary duty the Balancing and Settlement Code objectives are focused on protecting the consumer through facilitating effective competition. They do not include sustainability or carbon criteria. Consequently, there is no obligation on the Balancing or Settlement Code Panel (who manage proposed changes to the Code) or the Balancing and Settlement Code Company (BSCCo) to act in a sustainable manner or contribute towards the efforts to reduce greenhouse gas emissions. Were such an obligation to be put in place it would provide the Panel with the mandate to consider proposed changes to the Balancing and Settlement process that could eliminate the perceived discrimination against renewables.

5. **Create new trading arrangements for small and intermittent generators.** The energy market imbalance penalties imposed on intermittent renewables when they do not deliver their forecasted power have at times outweighed the payments made for supplying energy. An alternative to this might be to create a separate market for small and intermittent generators to sell power in, bereft of the costs associated with system margin and balancing. This new market could be run by the Balancing and Settlement Code Company (BSCCo - currently Elexon) who are responsible for operating the main market. The separate market could be linked to the targets set under the Renewables Obligation (RO) to require suppliers of electricity to purchase a certain percentage of their demand from this new market in order to meet their RO targets. The costs of balancing under the new system would fall on suppliers who are better able to bear them (system balancing and margin costs are currently disproportionately borne by intermittent or variable generators).

6. **Upgrading the distribution network by strengthening the incentives and increasing investment.** In the 2005 Distribution Price Control Ofgem introduced several new incentives to encourage DNOs to undertake R&D (the Innovation Funding Incentive) and connect distributed generation (the Distributed Generation Incentive and Registered Power

Zones). They also strengthened the existing losses incentive to encourage DNOs to increase their efforts to reduce losses on the distribution network. Whilst most stakeholders welcomed these initiatives some commentators argue that the incentives could be strengthened and the rules governing the schemes could be less restrictive. To combat these and other issues the options that should be considered include:

- Increasing the losses incentive to £100/MWh (from the current level of £48/MWh) and mandating DNOs to install the best available technology in terms of reducing losses during network upgrades
- Increasing the distributed generation (DG) incentive from £1.50/kW/yr to £5.00/kW/yr and removing the cap on the return that DNOs can earn from the DG incentive.
- Increase the Innovation Funding Incentive (IFI) cap to 5% of price control turnover in each relevant year whilst removing the 50% ceiling on the proportion of eligible expenditure that can be carried forward into the next year and the restriction on rolling over of allowances for 2 or more years.
- Amending the principal objective of IFIs to include reducing emissions of greenhouse gases.
- Amend the rationale for undertaking an IFI project to either a project where the present value (PV) of the cost savings is greater than the PV of the costs OR a project where the PV of the carbon benefits is greater than the PV of the costs.
- Amend the structure of the pass through rate to incentivise IFI projects that reduce carbon emissions:
  - 80% pass through rate if the PV of carbon benefits is LESS than the PV of costs
  - 110% pass through rate if the PV of carbon benefits is GREATER than the PV of costs
  - 150% pass through rate if the PV of carbon benefits is GREATER than the PV of costs AND the results are used by another DNO
- Broaden the list of eligible topics for Registered Power Zones (RPZs) to include any project that covers the technical aspects of network design, operation and maintenance i.e. the same as IFIs
- Raise the RPZ incentive to £5/kW/year or £10/kW/year in total (assuming the main DG incentive is raised to £5/kW/year as proposed above)
- Remove the restriction on the number of RPZs that can be registered per year.
- Remove the cap on the additional revenue per DNO per year.

7. **Allowing distributed generators to move from individual agreements with the TO to a set of agency style agreements** where the Agency acted as the middleman, contracting with the TO on behalf of several distributed generators. Agency style agreements would provide a variety of benefits for small operators and the system as a whole including:

   - A reduced bureaucratic burden for small generators (and hence reduce the barriers to entry for new entrants),
   - More manageable contractual negotiations between the TO and the small generators
   - Better representation of small generators within the process of negotiation with the system operator.

8. **Introduce a carbon 'cap and trade' for energy suppliers.** In 2006 Defra commissioned NERA to undertake a study into the options for increasing trading in the EEC. One option was a transition from EEC to a cap-and-trade system where suppliers would be allocated an

amount of CO_2 they could emit, and could then choose any combination of emissions reduction measures (energy efficiency or otherwise), or trading activities to comply with their cap. The main benefit of a cap and trade scheme would be the greater range of emissions reductions measures that could be implemented, which should lead to the emissions reductions being achieved in the most economically efficient manner.

9. **Revise Transmission Network Use of System Charging (TNUoS) Structure for CHP.** TNUoS charging covers the cost of using the transmission lines and 'balancing' the system (i.e. ensuring the supply of electricity matches the demand for electricity) and varies according to the geographical location and the demand for grid usage at that location. Connection charging provides a signal to generators to locate in the south, where demand is higher. However, since CHP schemes, which have the potential to provide significant carbon savings, need to be located next to heat loads it has been proposed that for certain types of scheme the locational part of the charge should used to provide a positive signal (i.e. a payment to CHP schemes) to encourage investment.

10. **Mandate energy suppliers to improve billing.** Ofgem could oblige energy suppliers to provide accurate monthly bills and graphical comparisons of energy usage over historical periods. Many studies have shown that providing consumers with regular feedback would encourage them to reduce their energy use.

11. **Develop an Offshore Regulatory Regime for the transmission network** in order to allow renewable generation located in the sea outside the territorial waters of Great Britain to connect to the existing onshore network. DTI and Ofgem previously concluded that an unlicenced or licence exempt approach was not a practical or even legally permissible position. At an operational level there is a requirement for regulation to ensure that the offshore transmission system can safely and effectively interface with the onshore grid; failure to achieve this could lead to faults and interruptions in existing supply.

12. **Implement more equitable arrangements for allowing National Grid to protect itself against the risk of unnecessary transmission investment.** National Grid has made an interim Generic User Commitment (GUC) available since August 2006. The main elements of the interim arrangements address the concerns of users regarding the level, timing and volatility of the Final Sums Liability (FSL) as well as the perceived inequity associated with the project developer taking all of the risk:

    - The risk of unnecessary investment is borne by both new generators and consumers such that new generators are liable for 6 years' worth of generation transmission network (TNUoS) charges.
    - The level of the GUC at each stage in the project development is fixed and entirely transparent, thus removing the volatility risk.
    - The liability will be based on two phases; a User Commitment Amount (applied before the project has achieved consents) and a Cancellation Amount (applied after the project has achieved consents) both of which will be based on a generic formula that applies to any project.

13. **Amend the supply license so that suppliers are obliged to sign up to the green supply guidelines.** There are several issues associated with existing green tariffs such as the definition of green electricity, difficulties in comparing tariffs and additionality. To address these issues Ofgem could oblige electricity suppliers offering green tariffs to:

    - Produce an individual fuel mix disclosure chart for each of their green tariffs
    - Calculate the declared amount of CO2 reduction that will be achieved from swapping to a green tariff from a conventional variety.
    - Have their green tariffs independently audited each year against a benchmark set by Ofgem.

- o Agree to a consumer code based on its Green Supply Guidelines

As illustrated in Figure 1, it is estimated that Ofgem could achieve between 11 and 28 million tonnes of actual carbon savings if it implemented the options considered in detail in this project. In addition, the options would facilitate a further 15 to 35 million tonnes of carbon savings (i.e. these further carbon savings would be significantly easier to achieve).

However, it is important to note that these carbon savings are estimates that were calculated using a variety of simplifying assumptions. Therefore, the authors strongly recommend adopting a conservative approach and quoting the 'low' figure for carbon savings and primary energy savings and the 'high' figure for costs during policy discussions.

In order to accurately estimate the carbon savings, costs and heat loss reductions a full cost and benefit analysis would need to be undertaken on each option. Cost and benefit analysis was beyond the scope of this project.

Figure 1 - Total carbon savings, primary energy savings associated with the options considered in detail in section 9

Estimated '*Actual*' Carbon Savings (MtC)		**Estimated** '*Facilitated*' Carbon Savings (MtC)		**Estimated** Primary Energy Savings Due to Reductions in 'Heat Losses' (MWh)		**Estimated Annual** Costs to Central Government (£million)		**Estimated One-off** Costs to Central Government (£million)		**Estimated Annual** Costs to others (£million)		**Estimated One-off** Costs to others (£million)	
Low	**High**	**Low**	**High**	**Low**	**High**	**Low**	**High**	**Low**	**High**	**Low**	**High**	**Low**	**High**
11	28	15	35	140,000,000	340,000,000	540	900	4	10	4,700	15,000	950	2,800

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Abbreviations

ARODG	Access Reform Options Development Group
BSC	Balancing and Settlement Code
BSCCo	Balancing and Settlement Code Company
BAT	Best Available Technology
BEGA	Bilateral Embedded Generation Agreement
BELLA	Bilateral Embedded Licence Exemptible Large Power Station Agreement
BETTA	British Electricity Trading and Transmission Arrangements
BSC	Balancing and Settlement Code
CA	Cancellation Amount
CAPEX	Capital expenditure
CCGT	Combined Cycle Gas Turbine
CCS	Carbon Capture and Storage
CHP	Combined Heat and Power
CUSC	Connection and Use of System Code
CO_2	Carbon dioxide
DCLG	Department for Communities and Local Government
Defra	Department for Environment, Food and Rural Affairs
DG	Distributed Generation
DNOs	District Network Operators
DPCR	Distribution and Price Control Review
DTI	Department of Trade and Industry
EC	European Commission
EEC	Energy Efficiency Commitment
EEIR	Energy Efficiency Innovation Review
EELSPS	Exemptible Embedded Large power Station
ERA	Energy Retail Association
ESCo	Energy Services Company
EU	European Union
EU ETS	European Union Emissions Trading Scheme

FSL	Final Sums Liability
GBSO	Great Britain (Electricity Transmission) System Operator
GC	Grid Code
GCV	Gross Calorific Value
GDNO	Gas Distribution Network Operator
GHGs	Greenhouse Gases
GUC	Generic User Commitment
GW	Giga Watt (1,000,000,000 Watts)
HGVs	Heavy Goods Vehicles
HVDC	High Voltage Direct Current
IFI	Innovation Funding Incentive
IGUC	Interim Generic User Committtment
IRR	Internal Rate of Return
kW	kilo Watt (1,000 Watts)
kWe	kilo Watt electricity
kWh	kilo Watt Hour
kV	kilo Volt
LFD	Landfill Directive
MWh	Mega Watt hour
NAP	National Allocation Plan for the EU Emissions Trading Scheme
NGET	National Grid Electricity Transmission
NPV	Net Present Value
MW	Mega Watt (1,000,000 Watts)
MWe	Mega Watt of electricity
MtC	Mega tonnes of carbon
NCC	National Consumer Council
NETA	New Electricity Transmission and Trading Arrangements
NGET	National Grid Electricity Transmission
NIV	Net Imbalance Volume
Ofgem	Office of Gas and Electricity Regulation

O&M	Operation and Maintenance
OPEX	Operating expenditure
OSPAR	The Convention for the Protection of the Marine Environment of the North-East Atlantic.
OTEG	Offshore Transmission Expert Group
P194	Balancing and Settlement Code Modification 194
P205	Balancing and Settlement Code Modification 205
PPG6	Planning Policy Guidance Note 6
PPS22	Planning Policy Statement 22: Renewable Energy
PV	Present Value
R&D	Research and Development
RE	Renewable Energy
RO	Renewables Obligation
ROCs	Renewable Obligation Certificates
RPI	Retail Price Index
RPZ	Registered Power Zones
RTFO	Renewable Transport Fuels Obligation
SDC	Sustainable Development Commission
SCC	Social Cost of Carbon
SRC	Short Rotation Coppice
SQSS	Security and Quality of Supply Standard
TADG	Transmission Arrangements for Distributed Generation
TEC	Transmission Entry Capacity
TO	Transmission Owner
TNUoS	Transmission Network Use of System
UCAM	User Commitment Amount
UK ETS	UK Emissions Trading Scheme
VAT	Value Added Tax

1 Introduction

The Sustainable Development Commission (SDC) is undertaking a review of Ofgem's role in the delivery of a sustainable energy system for the UK. This is part of a new watchdog function for sustainable development given to the SDC in the 2005 UK Sustainable Development Strategy "Securing the Future".

The aim of this project was to investigate the barriers to a more sustainable energy system for Great Britain and to identify the options for overcoming those barriers. It should be noted that whilst this project will feed into SDC's review of Ofgem it will also inform their work more broadly across the sustainability agenda. Consequently, whilst there was an emphasis on the role of Ofgem, particularly in the second half of the project, the scope of the project is broader than just the role of the regulator.

1.1 Section A – Barriers to a sustainable energy system in Great Britain

Section A of this report covers the first part of the project that, from the basis of today's electricity and heat system, analysed the existing short and long term economic, policy, technical, regulatory and market barriers to the development of a sustainable energy system that:

- Consistent with the best scientific evidence on the urgency of climate change, reduces the CO_2 emissions from the electricity and heat system by 40% by 2020, 60% by 2030 and 90% by 2050
- Radically increases efficient use of heat (on the grounds of avoided CO_2 emissions and reducing excessive resource use)
- Allows for easy access of new energy supply market entrants, large and small
- Contributes to improved security of energy supplies for the UK.

The implications for the Government's goal that "every home is adequately and affordably heated" have also be highlighted.

The barriers outlined in this report are organised according to the energy supply chain:

- Generation
- The Electricity Transmission System
- Distribution Networks
- Energy Supply
- End User Demand

In addition, there are a number of institutional and long-term policy framework issues that are *cross cutting* and these are examined in Section 3 at the beginning of the report. The sub-sections (e.g. carbon pricing, biomass, carbon capture and storage) within each energy supply section of the report are presented in order of importance. The sub-sections that contain the greatest barriers to a sustainable energy system are presented first and sub-sections with the least significant barriers are presented towards the end of the section. In addition, the barriers are ranked as high, medium or low importance in the summary matrix in Annex 2 – Matrix of Barriers. The matrix also gives an indication as whether the barriers are likely to be short, medium or long term.

The information contained in this report is drawn from a review of current literature, and from a number of interviews with sectoral experts. The stakeholders consulted as part of the evidence gathering for this report are listed in Annex 1 - List of stakeholders interviewed. **The views given in this report do not necessarily represent the views of the authors or of the Sustainable Development Commission. Where there are contrasting views on a topic, these have been noted.**

1.2 Section B – Options for overcoming the barriers to a sustainable energy system

Section B of this project has, from the basis of today's system, examined some of the pathways to delivering a sustainable electricity and heat system that meet the criteria stated in section 1.1. It sets out some of the main economic, policy, technical, regulatory and market changes that could help deliver such a system. Each option has been presented in the form of a template that features:

- A description of the proposed changes
- Estimates of:
  - Carbon savings
  - Heat loss reductions
  - Cost to Central Government
  - Cost to other stakeholders
  - Impact on numbers of new entrants
  - Impact on the generation mix
  - Impact on consumer bills
- The requisite legislative changes and the opportunities in Ofgem's existing role
- Main tensions in the reform process
- Timeline for implementation
- Assumptions made during the cost, carbon saving and heat loss calculations
- Factors to be taken into account in completing the cost/benefit analysis

The options have been presented in order of importance with those the start of the section deemed to be the most important and those towards the end of the section deemed to be less important.

2 Methodology

This section will outline the methodology employed by AEA Energy & Environment to undertake this project.

Section A – Barriers to a sustainable energy system in Great Britain

Task 1 – Desk research

The first stage of the project was to collate current thinking on the barriers to developing a sustainable energy system. A wide variety of reports, publications, legislation, regulations and websites were reviewed from organizations that included:

- Ofgem
- DTI and DEFRA
- Transmission and Distribution System Operators
- British Wind Energy Association
- Renewable Energy Association
- Combined Heat & Power Association
- Energy Suppliers Association
- Micropower Council
- Universities and other academic/research organisations
- NGOs and lobby groups (e.g. WWF UK, Association for the Conservation of Energy, etc.)

Section A of the project considered barriers across the whole electricity supply chain since SDC were keen to establish a broad evidence base that could be used throughout their activities.

Task 2 – Analysis

The information collated in Task 2 was used to develop a structured matrix of the barriers which included analysis of the characteristics of each, including:

- Type of barrier – economic, policy, technical, regulatory or market
- Area of impact – e.g. use of heat, end use energy efficiency, power export from local generation, etc.
- Description of the barrier
- Importance of the barrier
- Timescale of the barrier
- How, if at all, the barrier is currently being addressed
- Implications for security of supply and adequate/affordable heating
- Interactions between the barriers

Task 3 – Stakeholder interviews

Interviews were conducted with the following stakeholders during the course of the work:

- Ofgem
- The Energy Retail Association
- Association of Electricity Producers
- Utilicom
- The CHP Association
- Energy Watch
- Connectivity Energy
- Adam Brown (an independent consultant specialising in heat markets)

The interviews were a mixture of face-to-face and telephone discussions, and were used to test the initial views on the barriers as they emerged in Section A and gather stakeholder perspectives on how barriers could be addressed to feed into the options analysis.

Many of the interviews were based on the list of ‘issues to be considered’ that was submitted as part of the AEA Energy & Environment proposal. The list can be found in Annex 1 - List of stakeholders interviewed

Task 4 – Internal barriers workshop

The barriers matrix developed in Task 3 was subjected to a rigorous peer review via an internal workshop at our Harwell offices, which was chaired and facilitated by the Project Director and attended by the project team including the technical experts. During the workshop each of the 90 or so barriers was considered in turn with amendments and additions noted.

Task 5 – Preparation and delivery of draft Barriers Paper

Following the barriers workshop the matrix was revised where necessary and the results presented to SDC as a Barriers Paper. The barriers paper is included as sections 3 to 8 in this report.

Task 6 – Revisions to the Barriers Paper

Following feedback from the SDC the Barriers Paper was revised by AEA Energy & Environment and a final version presented to SDC on 19th January 2007.

Section B - Pathways to delivering a sustainable energy system

Task 7 - Internal options workshop

The aim of the second workshop was to brainstorm ideas for options to overcome the barriers to developing a sustainable energy system. The workshop was held at AEA Energy & Environment’s Harwell offices and chaired and facilitated by the Project Manager. It was attended by the project team plus 2 representatives from the SDC. The starting point for the discussions was a list of options for overcoming each barrier assembled by the Project Manager and Project Director. Taking each barrier in turn the participants were then encouraged to suggest ideas for overcoming the barriers with no constraints being placed on what could or could not be considered. At this stage options were still being considered across the whole electricity supply chain.

Task 8 – Presentation to the External SDC Advisory Board

The Project Manager and Project Director presented the key barriers and their initial thoughts on the options for overcoming the barriers to the External SDC Advisory Board on Tuesday 19th December 2006. The Advisory Board commented on the barriers presented, provided guidance on how best to link the barriers and options elements of the project and stated a preference for considering a greater number of options in limited depth during the detailed options analysis.

Task 9 – Options analysis

Part (a)

The ideas developed during the options workshop were brought together in an matrix containing approximately 290 option, which was used to perform multi-criteria analysis. In order to undertake the multi-criteria analysis each option was rated against the following criteria:

- Barrier importance
- Magnitude of carbon saving
- Cost to central Government
- Timescale for introduction
- Timescale for carbon saving
- Legislative change required?
- Within Ofgem's current remit?
- Within a potential future remit for Ofgem?

Weightings were then assigned to each category as well as each potential score within each category, before the options were ranked. The matrix was then submitted to SDC on 19th January 2007.

Part (b)

The ranked matrix of options was used by SDC to inform their decision regarding which options should be considered in detail. Given their review of Ofgem's role in delivering a sustainable energy system, which the results of this project fed into, SDC decided to focus the detailed analysis on options that Ofgem could implement:

14. Allow Network Operators to develop heat networks and make them part of the regulated asset base
15. Incorporate the cost of carbon in to distribution and transmission network charges
16. Introduce a 'connect and manage' approach to the transmission network and prioritise connection of low carbon generation
17. Add sustainability and GHG reduction objectives to the Balancing and Settlement Code
18. Create new trading arrangements for small and intermittent generators
19. Upgrade the distribution network by strengthening incentives and increasing investment
20. Implement an agency system of contractual agreements between Distributed Generators and the GB Transmission System Operator
21. Introduce a carbon 'cap and trade' for energy suppliers
22. Revise TNUoS Charging Structure for CHP
23. Mandate energy suppliers to improve billing

24. Develop an Offshore Regulatory Regime for the Transmission Network
25. Implement more equitable arrangements for allowing National Grid to protect itself against the risk of unnecessary transmission investment
26. Amend the supply license so that suppliers are obliged to sign up to the green supply guidelines

The complete set of options is listed in Annex 3 – Full list of options. The list is presented in supply chain order to enable easy comparison with the barriers (i.e. Cross-cutting, generation, transmission, distribution, supplier, end user). However, this means that there is some repetition in the options since certain options could contribute to overcoming more than one barrier.

The project team developed 2 templates to structure the detailed analysis of costs, carbon savings and heat loss reductions and present the analysis in the report. The templates were developed in consultation with SDC and populated for each of the options listed above.

It is important to note that the detailed analysis was only intended to provide 'ball-park' estimates and as such relies on a variety of assumptions. To obtain accurate figures for costs, carbon savings and heat loss reductions a detailed cost-benefit analysis would need to be undertaken, which is beyond the scope of this project.

In view of the nature of the calculations all of the estimates of carbon savings, costs and heat loss reductions have only been reported to 2 significant figures. It was felt that this was appropriate given the uncertainties surrounding some of the assumptions.

It is also worth noting that there are two categories of carbon savings associated with the options presented in this report:

1. **'Facilitated' carbon savings – i.e. carbon savings that would be more readily accessible through implementing the measures described in the option in question. An example is the creation of an offshore regulatory regime, which would put in place a mechanism for offshore renewables to connect to the onshore transmission network. However, the regulatory regime itself would not directly produce any carbon savings.**

2. **'Actual' carbon savings – i.e. carbon savings that can be directly attributed to the option in question. An example is the proposed changes to customers' bills that it is hoped will change their behaviour and lead to consumers using less energy.**

Task 10 - Preparation of draft Final Report

The results of the barriers and options analysis are presented in this report.

SECTION A

Barriers to a sustainable energy system in Great Britain

3 Cross Cutting Barriers

There are a range of ‘cross cutting’ barriers, that is barriers that are applicable in several stages of the energy supply chain. Rather than repeatedly stating these barriers they have been brought together in a single section.

3.1 Institutional Barriers

3.1.1 Lack of overarching energy policy framework to meet multiple policy goals

While the UK has developed a number of policies, some stakeholders believe it has failed to create the overarching market framework to deliver the objectives of energy security, fuel poverty, and carbon dioxide reduction and cost competitiveness set out in the 2003 Energy White Paper and again in the 2006 Energy Review. Meeting aspirations in all four areas implies an element of cost and trade-off. For example, competitiveness is affected by the EU ETS, fuel poverty is affected by increased use of more costly renewables and fossil fuel dependency creates price volatility that in turn creates instability in the renewables and energy efficiency investment markets.

Some stakeholders believe that a lack of long-term targets, taken together with the revisiting of the energy strategy within 3 years creates the impression of indecision and creates uncertainty for other investors and actors. The benefits of renewables and energy efficiency are often stated in public by the Government but some stakeholders report that they are not trusted to deliver in private by the DTI. Some stakeholders argue that there remains a tacit preference for centralised, large-scale supply-side solutions benefiting the fossil fuel and nuclear sectors, in both cases ignoring potential resource depletion risks.

An overarching framework should recognise not only carbon, but also other priorities. Primary amongst these are the polluter-pays principle whereby environmental externalities, such as air quality and nuclear waste, should be translated into fiscal terms and risk diversification benefits through which benefits to energy independence and energy portfolio diversification are recognised. A technology neutral carbon price i.e. one that rewards both nuclear and renewable technologies will not recognise import dependence risk on uranium imports. These principles may well be recognised in theory but are translated in policy terms with more difficulty.

3.1.2 Lack of long term carbon policy framework

Some stakeholders believe that current climate change policy is not delivering emission reductions as quickly as the emerging science or Government targets require. However, several of the policy measures are beginning to deliver results, notably those that were introduced earliest and that have had time to be implemented and understood by industry, such as Climate Change Agreements (CCAs) or Building Regulations. Nonetheless, the current climate change programme has been described by some stakeholders as an environmentally and economically inefficient ‘patchwork’ of policies and measures that would benefit from significant upgrade.

The key issues with the current carbon policy mix may be described as follows:

Complexity

Some stakeholders expressed the view that the carbon policy landscape in the UK is complex and congested. The current package includes price instruments, such as energy use taxes and exemptions (CCL, CCA, ECA), quantity instruments, such as domestic emissions trading (UK ETS), tradeable green certificates (RO), as well as energy efficiency targets (EEC), regulations (buildings, IPPC) and voluntary codes (products). Potential policy developments, such as a low carbon obligation, white certificate cap and trade system to replace EEC or a separate emissions trading scheme for the public sector will only serve to further complicate this picture. There is a belief amongst some commentators that the overlap between existing mechanisms is sub-optimal in terms of objective-setting, design, coverage and implementation. This has the potential to create significant market distortions, to assign policy costs in a non-efficient manner, to reduce transparency, and increase bureaucracy.

Clarity

Many stakeholders believe that carbon policy should be judged by its ability to bring forward investment in the low-carbon economy and change market behaviour in both the short and long run. With the exception of the Renewables Obligation, there is currently no agreed carbon policy framework post-2012. This lack of clarity creates additional risk for project developers that hampers long-term investment across the range of technologies and sectors that will be required to meet CO2 stabilisation targets.

Coverage

Some stakeholders believe policy inefficiencies have been created by the selective application of policy instruments and the shielding of certain interest groups. Sectors currently covered by voluntary rather than mandatory schemes include the public sector, small business, and services. Transport, most notably aviation, continues to avoid full internalisation of emissions externalities. The choice to protect the domestic consumer from energy price increases forms the basis of the indirect treatment of electricity for the CCL. Many stakeholders are of the opinion that future policy must ensure that the distribution of cost impacts is fairer and more comprehensive.

Cost Effectiveness

Some stakeholders believe certain policy mechanisms are carbon-cost inefficient. For example, the Renewables Obligation has diverted significant capital flows and ‘windfalls’ into the onshore wind industry, rather than to the more cost effective carbon reduction strategies, such as energy efficiency, or to sub-optimal technologies further down the technology curve requiring greater investment to bring them to market.

Convergence/ Consistency

An analysis of implied carbon price across a range of Government policies and measures indicates that there is little consistency in policy development. While it is not recommended that all policies be designed *a priori,* to converge around a single price, the implied carbon price (essentially an indication of the social cost of carbon) is nonetheless a useful measure of the reasonableness of the policy in question. If the implied price lies outside a sensible range of social cost of carbon estimates, it has been argued by some stakeholders that the policy is both economically and environmentally inefficient.

Some stakeholders believe that the continuing use of multiple policy instruments will require a much greater focus on policy integration to address current market failures, addressing the implications of double regulation, eliminating double counting where appropriate and ensuring the fungibility of trading commodities between instruments, such as the integration of renewable and energy efficiency mechanisms into the EU ETS. These actions will help mitigate the potential costs of tighter caps in the EU ETS or greater supplier obligations for low carbon generation or energy efficiency, both of which are options for further reducing carbon emissions.

It is possible that the raft of initial policies and measures in the UK has managed to capture ‘low hanging fruit’ and that future emission reductions will depend upon the deployment of a wider set of low carbon technologies that are not yet ready. Care should therefore be given to ensuring a market framework continues to provide support for innovation and lowering the cost curves of emerging technologies. Many stakeholders believe that the increasing use of trading, which tends to favour least cost solutions and is technology-neutral must be counterbalanced by more targeted mechanisms to commercialise close-to-market technologies.

Most experts agree that it is increasingly difficult to separate carbon policy from issues surrounding security of supply. It is likely that up to 30% of current UK generation capacity will be retired by 2020. New investment in generation presents an opportunity to deliver long-term carbon objectives, and vice versa. Policy makers are concerned that the market will be unable or unwilling to meet the supply gap. The EU ETS is currently proving insufficient to drive low carbon supply-side investment as the direct market generation cost of purchasing allowances is less than one tenth of the average full marginal cost pass through to consumers, which is not enough to encourage new market entrants.

3.1.3 Lack of coordination and split of policy briefs in Government is impacting upon timely policy intervention

Many stakeholders believe that the current policy context, economic climate and level of awareness of the detailed issues are not conducive to the removal of potential barriers to sustainable energy supplies. Sustainable development requires an integrated approach, delivering long-term aims and aspirations on a sector by sector basis. These aims require to be delivered via a shorter-term framework of measures and targets commensurate with the long-term aspiration. Each stakeholder group needs to recognise the need for change and to be capable of acting within the framework of measures put in place.

Despite the priority attached in public to sustainable energy, Government has attracted criticism for seeming to move with what one stakeholder has termed ‘glacial slowness’, with policy criticised as “consisting of piecemeal and often contradictory measures”, “lacking joined-up thinking” and having “insufficient funding”. Some stakeholders believe a lack of progress at EU level has also been seen as an excuse for inaction at a national level.

Most critics regard this as being due to a lack of Government coordination and will rather than a lack of resources per se. Stakeholders complained that responsibilities and policy briefs have been split between departments resulting in communication issues and a perceived duplication of activity. DEFRA is not seen to have the committed support for the carbon reduction agenda from the DTI, the DfT or the Treasury. Many stakeholders believe DCLG treats energy policy as peripheral to its core objectives and is isolated from many of the key debates as a result. Some stakeholders are of the opinion that Ofgem, when directed by the Government, is able to respond well to removing barriers. But this requires good direction and in the opinion of some stakeholders this has at times been lacking. In addition, there is a lack of clarity and political consensus between the political parties as to the relative benefits of investment in nuclear, cleaner coal and renewable energy technologies.

Elsewhere, the Carbon Trust has proved to be an important intellectual tool to move the debate on and has had some success in raising industry awareness of the issues. The Energy Saving Trust has had a more difficult job by virtue of the diffuse nature of its operating sector. Some stakeholders believe a more flexible approach from the MoD and CAA is required, especially given the large increases in air transport emissions.

3.1.4 Conflicting interests and policy drivers between Government departments

Ofgem's role is determined by statute with a primary objective to protect customers, wherever appropriate by promoting competition. There are inevitably tensions with those departments such as the DTI whose role it is to implement wider Government policy. The different aims of Departments can serve as a barrier to renewable energy. Specific examples relate to radar – the need for the MOD to engage in low flying training exercises and civilian radar authorities to pursue future growth – and the economically driven aims of Treasury and DTI to secure low cost fuel supplies for industry.

3.1.5 Lack of capacity at local Government level

With notable exceptions, such as Woking, many stakeholders felt that the vast majority of local authorities remain reactive and resource-constrained bodies, without real obligations, targets or strategy. This is a significant problem, given that energy efficiency and micro-generation are essentially localised technologies, but in many people's view little has been done in the way of local capacity building. Internal responsibilities also need to be solidified i.e. the use of energy managers and reduction of costs spent on energy.

3.2 Role of Regulator

3.2.1 Misalignment with Government Strategy

There is general concern that the Priorities of Ofgem do not accord with overall Government policy goals, leading to inconsistencies in policy delivery. Ofgem's role could be better aligned with the Government's energy objectives, but it should be recognised that there are difficult contradictions in there which would have to be balanced. A cross party consensus on the role of Ofgem would be desirable to allow long term framework planning.

3.2.2 Need for clearer Sustainability agenda

Many stakeholders argue that there is a need to better define security of supply and sustainability remit of Ofgem. Ofgem's primary aim is to protect the interests of current and future consumers by promoting effective competition. It is argued that Ofgem has largely achieved that aim, and the emphasis might now move from "low cost energy delivered as sustainably as possible" to "sustainable energy delivered at the lowest cost possible."

3.2.3 Short-term Price Focus

Ofgem are heavily focussed on short term price issues for the customer and in order to develop a truly sustainable energy system some stakeholders would argue that they need to take a longer term view. The development of strategic storage infrastructure, such as the Rough gas storage facility could be part of the remit. Some stakeholders argue that the current structure gives rise to short-termism and there are restrictions as to how much long-term investment can be made. This encourages the use of quick fixes such as CCGT, or long term cheap fuels such as coal – with less consideration for the environment (not helped by the low/unstable price of carbon). Consequently, some stakeholders argue that decisions tend to be focused on lowest short-term risk options, such as upgrading existing infrastructure or using large CCGT to replace existing power stations, rather than taking a longer term perspective.

There is a view amongst some stakeholders that Ofgem also chooses to interpret its priorities in a narrow way. For example, if a priority of policy is to cut carbon dioxide emissions then decisions on investment in infrastructure or charging for use of infrastructure ought to factor carbon into the equation. Focus should also be given about how to incentivise better use of network assets to connect and manage flows of low carbon sources of energy. An example of the way in which current priorities do not adequately factor this in was the market response to potential gas shortages for gas and electricity supply over winter 2005/06. While effort was made in managing demand of major gas users, price signals also encouraged greater consumption of coal in electricity generation, hence increasing carbon emissions.

3.2.4 Complexity of Regulatory Environment

Several stakeholders have remarked that the high workload involved in reviewing codes is impacting on smaller market players. Ongoing reforms have led to responsibility for changes to the codes of governance now being the responsibility of the three transmission code panels that cover the Balancing & Settlement Code (BSC), the Connection & Use of System Code (CUSC) and the Grid Code (GC). Any code signatory can propose an amendment to one of the code panels. If these panels decide that the proposals have merit, they then establish a working group, consult, discuss and make recommendations to Ofgem on whether to accept. Ofgem in turn has the power to accept or reject the recommendations of each panel, but if it ignores recommendations its' decisions can now be subject to judicial review. At the same time the Energy Networks Association is coordinating work amongst Distribution Network Operators (DNOs) to amalgamate differing connection agreements into a similar set of distribution codes. This openness and involvement is to be welcomed. However, it also needs to be noted that there now a regular throughput of code modifications, and a large number of modification panels assessing each proposal and putting their deliberations out to consultation. Overall, several stakeholders believe this high workload is creating a strain on independent developers and independent generators and allows larger operators to manage and influence the processes. While some of the frenetic activity is unavoidable, and is the result of the industry grappling with some of the enduring problems in the new GB market, there is also a genuine concern about over-activity leading to burn out amongst key organisations and participants.

3.3 The NETA/BETTA Wholesale Trading Arrangements

3.3.1 Discrimination against intermittent renewables

The New Electricity Trading Arrangements (NETA) were implemented to increase competition between generators and suppliers mostly the large power utilities, with the aim of reducing prices to the consumer. This aim may have been achieved, but at a cost of potentially disadvantaging renewables. It is widely felt by renewable energy developers that the trading rules under NETA and later BETTA have discriminated against the unpredictability and intermittency of renewable generation, and that the trading system has artificially depressed the renewable energy price.

Under the trading rules, in order to balance the system, generators and suppliers are required to forecast their supply and demand ahead of delivery. For renewable generators, this can be difficult. If the actual supply and demand differs from their forecast, they are penalised by having to buy from or sell into a secondary and potentially more volatile 'balancing' market.

As a result, the imbalance penalties imposed have at times outweighed the payments made for supplying energy, with some wind farms generating at a net negative unit value per kW hour, making a loss simply from production and sale of electricity even before development costs are included. This has placed a premium of predictable and flexible thermal coal and gas generation and imposed a cost penalty on renewable generation.

This penalty is a result of market operation, rather than a reflection of the needs of the grid network, which is not significantly impacted by the level of intermittency posed by the current share of renewable generation. While the overall situation is improving with trading experience, stabilisation of future contract prices, and a narrowing of the price spread, the anomaly still exists.

3.3.2 Discrimination against small scale micro-generation technologies

The value of electricity produced by micro-generation to the grid needs to be valued, but cannot currently be quantified in detail due to limitations within the billing and settlement system. At present, most electricity suppliers contend that it is uneconomic to extend their settlement systems to allow this because of the low volumes of electricity involved and a larger volume threshold would be required.

There are issues with the costs of micro-generation export to the grid. An import-export meter can reward consumers for the power they export to the grid, especially if half-hourly data can be fed into a modified settlement system. The costs of this, however, are more expensive than requiring a simple one-way meter, although the additional up-front costs for import-export meters and even import-export-generation meters are small in relation to the total investment.

The addition of a third generation meter would also allow those with renewable micro-generation units to claim renewable obligation certificates (ROCs). For domestic micro-generation, the transaction costs to acquire ROCs are high. The operator has to sign a ‘sale and buy-back’ contract with a licensed energy supplier. Only then is the micro-generated electricity is eligible for ROCs, which can only be provided to the operator and not directly to the supplier.

While there is currently an obligation on electricity suppliers to supply domestic premises if requested, there is no such obligation for the purchase of electricity exported by micro-generation operators. Whereas the obligation for supply is regarded as ‘social necessity’, Ofgem believes that an obligation of purchase might be a distortion to the market and an extra regulatory burden on licensed electricity suppliers.

3.3.3 Increase in carbon emissions

The introduction of NETA saw the introduction of both short- and long-term intermittent thermal plant operation in response to demand and market conditions. This in turn led to increased part-loading and the ramping up and down of existing generating sets that were not designed for such operations. Such modes of operation are inefficient, and give rise to increased carbon dioxide emissions per unit of electrical output. Increased emissions due to intermittent operation arising from the introduction of the trading system are cancelling out gains from renewable energy.

3.3.4 Lack of Sustainability Criteria/renewables focus in the Balancing and Settlement Code

Balancing and Settlement Code (BSC) objectives do not include sustainability or carbon criteria. Currently any changes to the Balancing and Settlement Code (BSC) that regulates the trading and settlement of energy are assessed against the five BSC Objectives. Many stakeholders feel that there should be an additional BSC Objective to ensure the delivery of a sustainable, low carbon supply. At present any changes that hinder the development of a sustainable supply can and will be approved if they meet other objectives.

4 Generation

Generation refers to the, development, operation and maintenance of every size and type of power generation plant in Great Britain from micro-renewables through to large centralised coal power stations.

4.1 Carbon Pricing

4.1.1 Low carbon price

While the cost of carbon is providing some incentive to switching to use of and investment in low carbon generation technologies, most stakeholders are concerned that the carbon price is not providing sufficient incentive for investing in sustainable energy. The low carbon price for Phase I of the EU-ETS (running from 1st January 2005 to 31st December 2007) is mainly driven by oversupply of allowances in the carbon market. Many experts argue that has occurred as a direct consequence of the generous Phase I Member State National Allocation Plans (NAPs) accepted by the EC. However, there are signs that this issue is being addressed as the EC took a much firmer line with the recent Phase II NAPs. Of the first 10 Phase II NAPs submitted by Member States, the EC imposed cuts in the total allocation to 9 of them – the UK being the notable exception. The average reduction was 7%.

4.1.2 Post-2012 legislative uncertainty

Much of the nervousness amongst the investment community with regards investing in low-carbon technologies, is driven by the uncertainty that exists once phase II of the EU-ETS ends in 2012. Whilst most policy makers agree that the EU-ETS should be extended beyond Phase II, there is currently no firm consensus amongst Member States. This means the carbon savings derived from low–carbon technologies (that require substantial capital investments that only payback over 10-15 years) are not perceived as 'bankable' by investors – i.e. they are not seen as certain to materialise. This investment risk is especially serious given that many power stations have a lifetime exceeding 40 years, which even assuming construction began immediately means only a small fraction of their in-service lifetime will be covered by the current EU-ETS framework.

4.2 Renewable Generation

4.2.1 Incomplete coverage of the Renewables Obligation

Some critics of the RO argue that it only addresses one third of the market – i.e. it incentivises renewable electricity but provides no support for renewable heat or transportation fuels. As a result, some stakeholders feel that the policy is incomplete and until this is amended the policy's ability to thoroughly address real change in the carbon market is inadequate. Some stakeholders argue that the RO needs to be able to be able to prioritise renewable heat in particular, as this is in their view the lowest cost means of reducing CO_2 emissions, although it does require a step change in attitudes to how heat is supplied to homes and businesses. With regard to renewable transport fuels, the Renewable Transport Fuel Obligation (RTFO) is just beginning to be implemented and stakeholders are keen to observe its impact on carbon emissions from the transport sector.

4.2.2 Lack of long-term stability in the Renewables Obligation

Another issue raised by many stakeholders is the lack of long-term stability in the RO. They argue that reform of the RO has the potential to impact negatively on the onshore wind industry, which while progressing well, is still in its infancy. In their view the policy needs to be set and then left alone by policy makers, to operate unhampered. Many stakeholders believe that repeated Government adjustments of the Obligation, have provided uncertainty in the financial markets and this prohibits future investment.

4.2.3 Renewables Obligation favours the cheapest technologies

According to many commentators an additional impact of the RO, due to the manner in which it is structured i.e. technology neutral, has been that it has in large part, only encouraged those technologies which are the cheapest solution of the day. It is felt in some quarters that technologies which are further from the commercial market (particularly marine, offshore and micro-generation technologies) are not encouraged by the Obligation. Furthermore, the RO has been criticised for over-paying some sectors close to market i.e. landfill gas generators. However, having stated this, it needs to be borne in mind that the RO has successfully promoted some sectors of the UK renewable energy industry i.e. onshore wind, into a major period of acceleration. Build rates of some renewables are doubling year on year and lessons need to be learnt so that the build rates seen for onshore wind can be replicated across the full spectrum of renewable energy technologies.

4.2.4 Perception and technical understanding of planners considering planning applications for renewables projects

One of the key issues identified by many stakeholders as being a continuing barrier to the development of renewable generation is the current land planning system in the UK. The processing of renewable energy schemes through planning is still thought by many people to be slow, expensive and require clearer guidance. For example, there is a backlog of Section 36 projects waiting for approval by the Scottish Executive – some wind farm proposals have been waiting for approval for over four years.

According to many stakeholders the root cause of these problems is that planners are, in many regions, having difficulties understanding the projects from a technical perspective and are unclear as to the importance of and the location specific criteria of renewable energy. Planning Policy Statement 22 (PPS22) and Planning Policy Guidance Note 6 (PPG6) are national policy and it is argued that planners need to recognise that they should be aligned to it at a local level. Critics also argue that not enough is being done to reiterate this to the planning community, and to train them so as to be able to implement PPS22/PPG6 from an informed perspective. It is their belief that the planning barriers to renewables are now not strictly policy obstacles, but rather the more diffuse issues of perception and education. They argue that policy is relatively easy to write, what is harder is to convert the hearts and minds of the planning community and local communities more generally to ensure a sense of engagement and involvement. At present many stakeholders in the renewables sector feel that there is a sense of resistance to renewables from many quarters in the planning and local Government communities, who fear that their local values are being railroaded by top down national policy.

There is a belief that more needs to be done to encourage grass roots involvement. In the case of onshore wind in particular, one of the biggest obstacles is misunderstanding and a lack of familiarity with the realities of wind power generation. In this case, familiarity actually breeds content; people who aren't familiar with turbines are generally against them. But people need to be given time to adjust their perception, many studies illustrate that some of the most ardent supporters of wind power today are those who live the closest to them and who may have been opposed to the technology before it was constructed in their area.

4.2.5 Greater levels of funding required for the Wave and Tidal-stream Demonstration Scheme

The £50 million fund to provide capital and revenue support to wave and tidal projects was welcomed by most stakeholders. However, some stakeholders believe that ten to twenty times as much money would be needed to bring marine technologies up to speed with onshore wind. They feel greater levels of funding may be needed to achieve a step change in marine technologies whereby they are able to compete on the basis of cost with other low carbon technologies. However, this raises a separate issue since as yet no funds have been allocated from the Scheme, largely because the wave and tidal industry have not been able to demonstrate they are sufficiently close to commercialisation.

4.2.6 Offshore wind is struggling to compete with onshore wind

The DTI's Offshore Wind Capital grant Scheme, which provided grants totalling £117 million has been closed, meaning there is no support for offshore wind from central Government other than the RO. The Government felt that following the capital grants scheme there would be sufficient investors in the sector who would continue their investment and bring costs down. However, many stakeholders argue that the Government's belief that the industry was ready to stand on its own two feet was premature and in actuality it was too early to withdraw grants at this stage. They argue that the costs of offshore wind projects are still significantly greater than onshore wind and as such act as a barrier to attracting investment. In order to help combat this issue the Government is considering 'banding' the RO to provide more support to less developed technologies such as offshore wind, wave and tidal power. However, as detailed in section 4.2.2 many stakeholders are concerned that banding the RO would result in instability and a lack of long-term confidence in the policy.

4.2.7 TAN 8 planning policy in Wales

Many renewables stakeholders believe that whilst the English and Scottish planning policies are essentially positive instruments, the equivalent Welsh policy TAN 8 is not as effective due to its focus on 7 strategic areas for renewable energy development. There are concerns amongst renewables stakeholders that a number of projects in development could now be excluded as they fall outside the seven strategic areas and are larger than the than 5 MW (2 or 3 turbines) threshold adopted in TAN 8. Another concern relates to the deliverability of the 800MW target for onshore wind (set out in TAN 8) from the seven adopted strategic areas. Some experts argue that in order to realise a significant proportion of the technical potential, either planning restrictions in the Strategic Areas would have to be less onerous than those experienced elsewhere in Wales, or areas outside the current Strategic Areas would be required.

4.3 Carbon Capture and Storage

Carbon Capture and Storage (CCS) is still at the Research and Development (R&D) pilot stage with some (limited) demonstration funding so it is thought of by many stakeholders as a medium to long term option for reducing carbon emissions to the atmosphere. Taking account of the planning and construction time lines, experts believe the best case scenario would be for the first full-scale deployment of CCS to occur around 2013-15 followed by a steady build up of capacity thereon. This is probably comparable to, or a little faster than, what could be achieved by nuclear, and with renewable energy already struggling to meet its 20% aspirational target for 2020, there are not thought to be any other technologies that can deliver large savings (e.g. 2-5MtCO2/yr from each project).

It is likely that CCS technologies will look at first to operate at base load to attain the maximum financial return from the considerable capital investment involved. However, in the longer term greater flexibility is desireable since in a low carbon electricity system consisting of RE and nuclear, CCS is one of the few options for balancing and load matching. CCS power plant are essentially the same as non-CCS fossil plant and should have no difficult with load following[1]. The CO_2 separation plant is also believed to be capable of load following but there is less experience operating such plant in an intermittent manner. In addition, there are other options for making CCS plant responsive, for example, decoupling the capture plant while continuing to run the power plant would boost output. Another alternative is to build modular capture plant so that capacity can be brought in or out depending on the load on the power station.

4.3.1 Lack of system to assign and manage long term liabilities

There is a need for a clear policy for the long term liability for CO_2 in a sealed geological storage. Commercial organisations must be able to assess the financial risk in their investment planning decisions to know what their long term liabilities will be with regard to sealed CO_2 stores. Without this, most stakeholders believe it is unlikely that CCS will be built on commercial terms. This relates to both the duration and form of their liability and the structure of periodic long term monitoring. There is a Cross Government Task force on CCS legislation currently looking in to these issues.

4.3.2 Planning issues

There is a possibility that if and when CCS gets to the deployment stage it will encounter the same planning difficulties of other energy technologies. Based on experience with FGD, the siting of CCS capture plant may go smoothly if these are located on current fossil power generation sites. Issues may arise with the routing of CO_2 pipelines to transport the CO_2 captured at the power station to the storage site. This problem could be negated to some extent by siting CCS plant near to the coast so that pipelines only need to cover relatively short distances over land.

It should be noted that the Government is in the process of addressing these issues as it considers its response to Kate Barker's review of planning, which was published in December 2006. One of the key recommendations in the review was the creation of a new system for dealing with major infrastructure projects based on national statements of planning objectives and an independent planning commission.

4.3.3 Regulatory barriers to storage both onshore and offshore

The main regulatory barriers to CCS arise at the storage stage. Storage offshore is controlled by the London and OSPAR Treaties governing the dumping of waste in or below the seabed. Both treaties permit the use of substances for purpose "other than mere disposal" so Enhanced Oil Recovery using CO_2 is permitted. The 1996 Protocol to the London Convention, which applies worldwide, did exclude simple storage of any substance (including CO_2) beneath the seabed, but an amendment has been agreed that will permit storage of CO_2 arising from CCS processes. OSPAR applies to the North East Atlantic, which includes the North Sea, and again this precludes CO_2 storage beneath the seabed. Work is underway to get this treaty amended in the same way as for the London Protocol. Onshore storage of CO_2 is also a possibility, though the EU Waste Framework and Landfill Directives (LFD) govern this, and the latter is thought to preclude CCS at this stage. Consideration is being given on how to deal with this as part of the review of the EU Climate Change Programme.

[1] Load following is the process by which a power station meets the variations in electricity demand by preparing generating units for operation under unit commitment schedules, which reflect forecasted load changes over daily, weekly and seasonal cycles plus an allowance for random variations.

4.3.4 Lack of price support mechanisms and financial incentives

Some stakeholders believe there is a basic problem in that there is no mechanism to reward carbon abated by CCS, given that it does not qualify for ROCs, or exemption from the CCL and EU ETS. Furthermore, they point out that there is no price support mechanism for the CCS price at a transmission level. Ofgem operates transmission price controls and may have some discretion to favour Renewable Energy (RE) and CCS over normal fossil generation.

Other stakeholders argue that due to its relative infancy as a carbon abatement option, current Government support for CCS is rightly restricted to R&D and some limited demonstration funding. R&D funding is of the order of £4-5Million per year through the Government's innovation programme, and a further £35Million is available as capital grants to support pilot scale demonstration projects. The Government, in Pre-Budget Report 2006, again acknowledged that the next step for CCS should be a full-scale demonstration. They also announced that consulting engineers would be appointed to give further advice on the cost effectiveness of such a demonstration as well as on how a competition for funding, for example through a challenge fund, could be organised.

There is broader agreement that investors currently do not have a clear picture of how they will get a financial return for carbon abated by CCS over the 10-15 year payback period applied to large infrastructure investment projects. One option is entry into the EU-ETS[2] but this is not bankable while there is uncertainty over the shape of ETS after 2012 (i.e. volume of CO_2 to be abated and hence permit price). It is worth noting that some experts believe that a carbon price of around £20-30 per tonne would be required to make CCS commercially viable.

4.3.5 Third party access to pipeline infrastructure

As a pipeline infrastructure for the transportation of capture CO_2 develops most experts believe there will need to be a system for third party access or this will become a barrier to rolling out the technology. Without such a system there is a risk that infrastructure will be duplicated or worse still, projects may be deemed too expensive if pipeline infrastructure cannot be shared.

4.4 Combined Heat and Power (CHP)

Progress to targets

Since 2000 the growth in new capacity installed has slowed significantly, some of which can be attributed to the greater attractiveness of alternative technologies as a result of the renewable obligation scheme. In recognition of this stagnated growth, the Government has introduced a range of fiscal support measures designed to encourage the uptake of CHP, and helping the Government progress towards achieving their set target for 10 GWe of Good Quality CHP capacity by 2010. These support measures include:

- Exemption from the Climate Change Levy (CCL) of all Fuel inputs to and electricity outputs from Good Quality CHP
- Eligibility for Enhanced Capital Allowances of Good Quality CHP
- Grants to support a Community Energy Programme, whereby the use of CHP in public sector lead district heating schemes is encouraged.
- Business Rates exemption for CHP power generation plant and machinery
- Reduction in VAT on certain grant-funded domestic micro-CHP installations
- Creation of a CHP sector in Phase II NAP, to provide a fair allocation to Good Quality CHP.

[2] Assuming CCS becomes a commercial technology; power stations already in the EU ETS may chose to retro-fit CCS. Alternatively, older generation plant may be replaced with power stations that feature CCS as part of their original design, meaning they enter the EU ETS with CCS already fitted.

CHP Market Barriers

4.4.1 Unfavourable gas and electricity prices

Unfavourable gas and electricity prices reduce the return on the investment in CHP and erode the advantage over conventional generation. When combined with the increased risk from uncertainty regarding future fuel prices, this has the effect of either delaying investment decisions or encouraging the installation of conventional heat generating plant. The use of conventional heat generating plant is preferred for lower capital investment and it is seen as less risky.

4.4.2 Energy price volatility creates risk barriers to CHP investment

The largest impact upon the attractiveness of investment in CHP is the relative price of fuel (mainly natural gas) used in CHP, and the financial value of the electricity generated by CHP. These relative prices are measured by the spark-spread, which is the difference between the price of electricity and gas. The larger the spark-spread (higher electricity price and lower gas price) the more favourable are the conditions for operating CHP. Volatility in price movements creates additional barriers to CHP deployment, as proponents are reminded of fluctuations, thus undermining the long term business case.

4.4.3 Uncertainty of long term heat demand

CHP is only efficient when there is a real demand for the heat produced during generation. In situations (e.g. industrial settings) where there is a risk that the demand for heat will reduce in the near term, there is a natural reluctance to commit to a technology that may be rendered inefficient if site heat demands fall. However, it should be noted that this is less of a problem in district heating applications, as historically the captive heat demand can be relied on.

4.4.4 High capital costs compared to conventional generation

The capital costs associated with the installation of CHP are higher than those associated with using heat only boilers (and importing electricity from the National Grid rather than generating it in house). If the market conditions are favourable with regard to fuel prices, savings associated with avoiding the purchase of electricity from the National Grid should off-set these additional capital costs in an acceptable period of time. However, because of the volatile fuel prices and uncertainties surrounding the size of the long term heat load of a site, investors take the view that CHP in industrial applications is a risky investment. Consequently, it is not uncommon for investors to demand a pre-tax internal rate of return (IRR) of 10-15% on CHP investment, and so limiting the suitable applications.

4.4.5 High operation and maintenance costs compared to conventional generation

CHP also has higher associated operation and maintenance (O&M) costs than conventional boilers. This is largely a consequence of the rotating plant when compared with largely static conventional methods of heat generation. The O&M costs of CHP range from 0.4-1.0 p/kWh and can be as high as 2p/kWh for small-scale reciprocating engines. This should be compared with O&M costs of 0.05-0.1 p/kWh for heat only boilers.

CHP Regulatory Barriers

While there are obstacles to the installation of CHP that either cannot be removed or for which it would be inappropriate to make interventions to remove, there are a number of barriers currently operating where corrective action is possible through the regulatory framework. These are outlined below:

4.4.6 Lack of Renewable Heat Obligation

There is no equivalent for heat to mirror the Renewables Obligation. Proponents of a Renewable and CHP Heat Obligation claim it would stimulate investment in renewables and CHP heat plant in a similar manner to the investment in renewables electricity generators following the introduction of the Renewables Obligation. However, DTI rejected the idea in the 2006 Energy Review citing concerns over the administrative burden and the difficulties in determining on whom the obligation should be placed. Some industry stakeholders, particularly those with an interest in CHP, are in favour of a Renewable Heat Obligation since they believe the additional administrative burden would be offset by the additional value of the heat. Another benefit would be to remedy the perverse situation where biomass CHP plant are encouraged to maximise power output at the expense of efficiency to gain maximum return from electricity ROCs.

4.4.7 Failure of carbon pricing to provide the expected benefits

Even with perfect operation of the gas and electricity markets, some stakeholders believe it is unlikely that the installed CHP capacity will reach its optimal level. This is because the environmental cost[3] associated with generating electricity by carbon intensive methods is not fully reflected in the market price for this electricity. This is being partially addressed by such measures as extending CCL exemption to the fuel inputs and electricity exports from Good Quality CHP schemes and the EU ETS. In other words, the amendments to the CCL mean that the fuel inputs and electricity exports from Good Quality CHP Schemes and the EU ETS are not taxed, which is helping to increase the competitiveness of CHP.

The main economic instrument used to make firms internalise environmental costs is the EU-ETS. In theory, operators of CHP plants should benefit from the EU-ETS because of their high efficiency and use of natural gas, which has a lower carbon content than coal or oil. This has not been the case in Phase I of the scheme because the cost of carbon has not been fully incorporated in the price of electricity. CHP leads to higher carbon emissions on site, but displaces electricity from power stations and heat from separate boilers, so generally leads to a net reduction in carbon emissions. The Phase I allocation methodology had the perverse effect of CHP operators having to pay for some of the increased carbon emissions on site without receiving the full value of the carbon being displaced. A related problem with the allocation methodology is that the allocation in Phase I for identical plant would vary depending upon the sector that it was allocated to. Finally, investment in CHP has also been discouraged by uncertainty over the future development, allocation rules in particular, of the EU-ETS.

However, these shortcomings have been acknowledged by Defra and DTI and addressed in Phase II by creating a CHP sector that provides higher allocation to Good Quality CHP in the order of about 95%, against 62% for power plants in the ESI sector and about 87% for small auto-generators. This is likely to resolve the short term problem for existing CHP although the long term uncertainty still exists and is likely to hinder all but smallest schemes. In addition, the problem remains that as Phase II only lasts until 2012, investments is stalled until the longer term treatment for CHP is known.

[3] In recent years several studies have been undertaken to estimate the 'external' costs of carbon i.e. the environmental, social and health costs that aren't reflected in the price of goods and services produced using power generated from carbon-intensive fuels. A summary of these studies is provided by Richard Clarkson's report for the Treasury entitled 'Estimating the Social Costs of Carbon'.

4.4.8 Export Price differential between CHP and conventional generation

The current low price that can be realised for generated electricity has tended to reduce the attractiveness of CHP operation. Whilst most stakeholders believe this is a characteristic of the market about which little can be done, a differential has developed between the price offered to small generators exporting to the grid and the price obtained by predictable large generators. There are concerns that this is a by-product of the electricity trading system, where more predictable sources of generation are rewarded with the result that there is downward pressure on the prices offered to CHP operators. The effective functioning of the electricity supply system requires suppliers to produce their contracted quantity at their contracted time. The difficulty for CHP is that their operation is usually determined by the heat loads rather than the electricity loads. This makes it difficult for CHP generators to optimise their electricity output is response to market conditions. The cost of intermittency means that CHP generators receive less for their electricity than predictable generation. It has been estimated that the net result of this is a 0.2 p/kWh suppression of the price offered to CHP generators.

4.4.9 Lack of Heat Regulator

The heat market is still outside the regulatory framework. Many stakeholders believe this creates a lack of focus for heat market development. If utilities want to lay out new electricity or gas supply network then they have rights to compulsory purchase of the land – no similar rights exist for heat networks.

4.4.10 Lack of Heat Metering

In a similar manner to smart metering there is a belief amongst some stakeholders that if heat were metered then consumers would pay more attention to how much they use. Furthermore, if transparency was increased by benchmarking heat usage on energy bills (e.g. comparisons with similar sized houses and consumption during previous years') customers may even be persuaded to use less heat. Unfortunately, heat metering is not well spread in the UK. The only current mechanism for encouraging better use of heat is through the capital grants scheme, the benefits of which tend to be short term. It should also be noted that some stakeholders believe that the introduction of heat meters and any subsequent reduction in heat usage may create a new barrier – namely a weakening in the case for heat networks on the basis of reduced demand for heat.

4.4.11 Limited support for diesel fired CHP in the absence of mains gas access

In most cases, the installation of CHP requires good, reliable access to the gas and electricity networks. Some parts of Great Britain, including parts of Scotland, Wales and Northern Ireland have little or no access to mains gas. In these situations potential CHP schemes would tend to rely on diesel as the fuel, which still produce marginal carbon savings compared to conventional fossil fuel generation. However, the incentive to run CHP on diesel is not as strong as for running on natural gas, since there is no climate change levy on diesel and therefore no CCL rebate to enjoy when running CHP on this fuel. In short, using diesel in cogeneration would still incur the excise duty cost. In recognition of this from 1st January 2006 diesel used in CHP has been exempt from Hydrocarbon Oil Duty Rates. This provides a financial motivation for sites considering the use of CHP, that do not have access to the gas grid, to implement CHP at their sites, as there will now be a financial incentive to do so.

4.5 Micro-generation and Distributed Energy

For the purposes of this report, micro-generation includes heat and electricity generated locally from renewable sources, or the use of fossil fuels (gas) with combined heat and power, including micro-CHP[4]. These are generally associated with household or small community sized schemes. These schemes can be used for stand-alone power supplies (e.g. to provide power for own use), or to provide power for remote communities, but the greater interest is in their potential to generate and sell electricity back into the grid.

4.5.1 Feasibility of micro-generation technologies is still unproven

Micro wind is at the demonstration stage but is largely unproven at micro level. Micro CHP is a developed technology, but there is a lack of practical experience for wide-spread household level implementation. While these micro-generation technologies are all based on known technology, there is not sufficient knowledge on how they will perform practically at the small scale, especially over the range of possible applications (different houses, household sizes, wind regimes, etc.). For instance, the interim results from the 'Carbon Trust's Small-Scale CHP Field Trial Update'[5] draws a distinction between micro-generation CHP (which would be used in individual homes) and Mini-generation CHP (which would typically be used in commercial buildings), and the different heating patterns and particularly the unexpected inefficiencies experienced in home heating applications. Although these are interim results from a very small number of installations, they suggest that this technology may not be so useful in the home environment. In contrast, a report by EON[6], which was written in response to the Carbon Trust's Update, concludes that even in the worst case scenario micro-CHP achieves 2.2% greater carbon savings than condensing boilers and under field conditions this rises to 16.3%.

4.5.2 Micro-generation is less cost-effective than conventional generation

In general, technology efficiency and cost returns improve with scale, i.e. economies of scale. There are very few historical examples where smaller-scale applications turn out to be more efficient and more cost-effective. The key question is whether this is also the case for micro-generation.

A comparison of the existing costs of micro-generation shows that the costs of generation from these technologies are very much higher than conventional generation. The economics are strongly linked to the technical performance, which varies with location and application. PV is quoted at 53 to 118 p/kWh, micro-wind at 20 p/kWh, and micro-CHP at 6 p/kWh. These values are way in excess of current centralised alternatives for current generation, for large-scale renewable schemes, and for other low carbon options (for example the prices quoted in the energy review cite <4 p/kWh for nuclear and ~4 to 5 p/kWh for coal plus carbon capture and storage). However, at the very low end of the cost range, the prices of micro-generation may be similar to the costs of electricity purchased by consumers (e.g. by households).

There is broad agreement amongst stakeholders that micro-CHP is the most cost competitive micro-generation technology and they also have the largest deployment potential. Photovoltaics are unlikely to be competitive in the short and medium term, as their upfront costs are so high. For some micro wind and micro-CHP units, the key challenge in the short term is likely to be the establishment of volume production, and reducing the net cost of the equipment. These micro technologies are not cost effective when compared to the current grid supply. Even with high levels of innovation and learning, some commentators believe they will remain uncompetitive in the future for most household applications[7]. Therefore, they argue that the large-scale use of household micro-generation is only viable with financial incentives.

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[4] Micro-generation is defined here as the production of heat (less than 45kW capacity) and/or electricity (less than 50kW capacity) from zero or low carbon source technologies especially combined heat and power, small wind, solar and photovoltaic.

[5] The Carbon Trust's Small-Scale CHP Field Trial Update, November 2005

[6] EON, Performance of Whispergen micro CHP in UK homes, May 2006.

[7] Though there are exceptions of good and effective applications such as CHP schemes for supermarkets/factories, or micro-renewable schemes in remote locations.

There are also large economic costs of changing the overall network to cope with these micro-generation systems, i.e. to be able to use their power for export into a local distribution system, and to put in place the intelligent system that could match supply with demand at a network level. Some experts question whether micro-generation offers a better investment than centralised low carbon alternatives, or even domestic energy efficiency measures.

4.5.3 Environmental benefits of micro-generation may be less than predicted

On environmental performance, micro-renewables provide a clear CO_2 saving when compared to the current average grid mix[8], though this is slightly lower when compared to the marginal generation technology[9] (natural gas). However, future reductions in the carbon intensity of the national generating mix (for example, from increased renewables, carbon capture and storage, or nuclear) will reduce the net savings of micro-renewables over time. Most Commentators believe other environmental issues associated with micro-renewables are very modest in comparison with the wider environmental impacts of conventional large-scale generation.

For micro-CHP, the picture is not as clear. Micro-CHP uses gas and produces carbon emissions. For the current mix, micro-CHP should, in theory, have potential carbon benefits over the current mix. However, recent evidence from field trials (carried out by the Carbon Trust) shows that these are not always realised – and in practice some schemes actually increase emissions relative to alternative systems[10]. There is also an issue that micro-CHP should be being compared to the future generation mix, which will have much lower carbon emissions. Related to this is the fact that carbon capture (and storage) can only be applied to large-scale generation: it is not economic or feasible for micro-CHP plant. Therefore, micro-CHP will not lead to environmental benefits when compared with centralised low carbon alternatives such as renewables, nuclear or coal or gas-fired plant with carbon capture and storage.

4.5.4 Public acceptance of large scale moves to distributed energy

Some stakeholders have concerns over whether a large-scale move to a distributed system would be accepted by the public. It is important to recognise the relatively low levels of consumer uptake of basic energy efficiency measures (which generate cost savings for consumers). There are important barriers for micro-generation in that most technologies have a high upfront cost. In addition, conventional heating technology has a strong track record for reliability and working lifetimes and this provides the benchmark that most commentators believe CHP systems will need to meet in order to attract the mass market. Finally, there are large upfront capital costs to the network from moving to a distributed system, compared to the marginal cost of additional units joining once a system was running.

4.5.5 Lack of consumer information on technologies and installation

There is lack of robust information on the product types and performance of the different micro-generation technologies. In addition, there is currently no widely agreed accreditation system for products and installers. This provides a barrier to private consumers, local authorities and housing developers when making investment decisions with respect to micro-generation.

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[8] The average grid mix refers to the average contributions of the different generation technologies (e.g. coal, gas, renewables) to the electricity supplied to the National Grid.

[9] The marginal generation technology is the type of generation plant that would in all likelihood be built to generate more power if existing GB generation capacity was exceeded. In the current market this is usually the cheapest technology.

[10] There are a number of reasons why this is thought to have occurred. First, the overall annual energy efficiency is lower than expected, as there is little need for heat in the summer and so there is little electricity generated. Second, the units take time to warm up to operational temperature and this energy is not available for heating the home; if switched on and off regularly to meet varying domestic heat requirements, this warm up time/heat loss can be significant.

4.5.6 Electricity generation efficiencies are lower than for conventional generation

Micro-generation is being advocated because of its greater efficiency. This is because losses in the current system make it much more efficient to generate electricity close to the point of use. This is certainly the case where electricity generated is used on site (e.g. in the home), and all of the extra costs of transmitting and distributing electricity are displaced. However, the pattern changes with electricity exported into the local distribution system. It is important to recognise that most losses occur in the local distribution system (6% in the local system, compared to losses in the national transmission system of only 1.5%). Electricity used by a micro-generation unit directly in the home will avoid all national and local transmission losses, but once a system sells electricity back to the local distribution grid, it will be subject to a high level of local distribution losses, as is the case for centrally generated electricity.

Moreover, there are other factors to consider for efficiency, which vary by technology. Micro-renewables are not as efficient as larger scale generation plants. The conversion electricity efficiency derived from a large scale generation plant (e.g. 50% efficiency for new build plant), or a large-scale optimised renewable project, is far in excess of a micro-renewable project. For example, micro-wind efficiencies are only likely to achieve a 10% to 17% load factor for a typical site, significantly below that of a large-scale commercial wind farm. For micro-CHP, different issues arise. In principle, a micro-CHP system can achieve significant savings in primary energy and electricity, as it can provide a large proportion of a household's heat and power demand at a very high overall system efficiency (when supplying both heat and electricity and is optimised to follow the heat demands). In practice, a number of factors determine the degree of efficiency and these savings will not occur in all instances. Moreover, the operation of micro-CHP units is defined by the thermal demand. If thermal output is not required, or all thermal energy storage is fully saturated, then the micro-CHP unit ceases operation or loses its efficiency in generation (typically generation efficiency for electricity is 10% to 15% from micro-CHP - compared to 50% (based on GCV) from a large new build CCGT power station). This is clearly a key consideration outside of the winter months. While the overall efficiency of micro-generation is good when running optimally, there are questions over the actual overall efficiency levels in practice. Interim findings from the the field trials conducted by the Carbon Trust indicate that in practice, efficiency gains are lower than expected, which if proven to be the case would almost certainly affect the perception of customers and reduce the likelihood of them investing in micro-generation.

A final point here relates to potential changes in the UK climate. Some experts believe this may affect the relative seasonal demand in the future – with lower winter heating demand and increased summer electricity (air conditioning) demand. This could be very important for a move to large-scale deployment of micro-CHP, as warmer summers will increase air conditioning demand at times when micro-CHP units cannot run efficiently (as there is almost no heat demand in summer). A move to large scale micro-CHP might actually be counter-productive for adapting efficiently to future climate change. Some stakeholders advocate absorption cooling (where heat is used to produce cooling rather than electricity) to overcome this problem. Unfortunately, most experts believe it is likely to prove too costly, especially in micro-generation applications, at least in the medium term.

4.5.7 Planning permission required for many installations

Planning permission is currently required for many micro-generation installations (excluding micro-CHP) where the Local Authority has not issued a Permitted Development Order. This can add uncertainty about what is a permitted development and an unhelpful cost (in excess of £250) as well as introduce considerable bureaucracy and delay into the process of installing micro-generation.

4.5.8 Distribution charging on micro-generation

Some Distribution Network Operators levy a use of system charge on customers who install micro-generation. Given that micro-generation reduces peak network load, many people would argue that this is contrary to the principle that network charges should be cost reflective.

4.5.9 Active network management will be required to cope with large scale distributed energy

It is unclear if a decentralised grid system can effectively manage millions of separate generators or auto-producers and match these to meet overall demand in an efficient way when it is dealing with individual household generators. With a large penetration of small generators there will be a need to actively manage the network. A number of significant developments may be required for this to happen including electrical interfaces to generation systems, interfacing standards, and capacity protection. The current national grid system manages generation (supply) across a relatively small number of generators (numbering hundreds at most), and matches this to demand. Most experts in the field believe this to be a workable structure with a proven track record. Under a scenario with millions of homes with micro-CHP or micro-renewables, technically controlling the overall supply and demand balance across millions of (chaotic) generators is likely to prove challenging. Whilst it might be possible to achieve a new type of intelligent grid system it is unclear who the main actors in delivering this will be and there would inevitably be a cost penalty.

4.5.10 Micro-generation may not significantly increase security of supply

Many of the advocates of micro-generation believe that one of the major benefits of micro-generation is the increased security of supply. However, other stakeholders believe it may not offer a security back-up for grid failures because most failures of the public electricity supply arise in local distribution systems, to which micro-generating units would also be connected (note also that some of the micro-generations systems actually require an external source of grid electricity to run). There is broader agreement that micro-generation does have a positive effect on the security of supply in other ways, notably as it may contribute electricity at times that can reduce the peak load demands (in the morning and evenings). This could reduce the need for expensive peak load generation in the public electricity supply, though most commentators believe the requirement for base load plant output would remain unaffected. They believe that the delivery of power from these systems means that both micro-CHP and micro-wind provide intermittent power supplies, i.e. they cannot fully provide a replacement to central grid supplied electricity[11]. These micro-systems may also not provide enough power to fully meet household peak demand[12], which also means there is a further need for continued grid connection unless some form of storage can be found. Overall, even with a distributed micro-generation network, most stakeholders agree there is likely to still be some reliance on a centralised grid system.

[11] There is broad agreement that microgeneration technologies are intermittent in their output. Electrical output may vary during the day (e.g. PV will only generate during daylight hours) and at different times of the year (e.g. micro-CHP will be more effective during the winter months when there is a higher heat demand). Most micro-CHP units only run when both heat and electricity can be used. For wind generation and security of supply, there is no guarantee it will be windy when the grid is lost.

[12] Mass market microgeneration products are typically sized to produce around 1 kW. Whilst this is sufficient to meet a home's base-load electrical requirements, it will not meet the peaks (several kW or more) that occur when several electrical appliances are on at the same time.

4.6 Biomass

The Government stated in the recent Energy Review that it believes biomass should play a long term role in reducing carbon emissions. However, the potential for energy crops is rather uncertain and depends on the amount of land turned over from food production and whether all the available biomass resource is used to generate power rather than say produce biofuels for transport. At present the UK has approximately 8% of arable land set aside, which some experts claim could produce around 1% of UK primary energy demand. It is also thought that wood wastes could make a similar contribution along with a smaller contribution from biodegradable fraction of wastes.

In view of these issues the Government has committed to producing an overall UK Biomass Strategy by April 2007 that will consider the most cost effective way of using the limited biomass resource for the production of electricity, heat and liquid fuels for transport. This review will take account of views on banding for co-firing as well as the implementation of the EU transport fuels directive, and the likely shape of the forthcoming EU directive on heat.

Given that the issues surrounding the biomass market for power generation are complex and interlinked there are difficulties associated with separating out specific barriers. Nonetheless, efforts have been made within this report to identify the main ones.

4.6.1 Long term contracts for producers vs short term contracts for generators

Energy crops tend to be harvested for a minimum of 15 years once they have become established. Consequently, many potential producers of biomass crops require long term contracts for their production before they will be willing to invest in equipment to plant and harvest energy crops, and, in the case of Short Rotation Coppice (SRC), commit to a crop that does not provide a yield for the first 3 years after planting. On the other hand power producers prefer short term contracts so that they are able to switch fuels or supplier if there are significant changes in price. This problem is compounded by the EC Road Transport Fuels Directive (which will manifest itself in the UK as the Renewable Transport Fuels Obligation) coming into force in 2008 that will probably offer an alternative market for non-fuel crops. This market could be more attractive to producers because they could stay with familiar crops (e.g. barley, wheat or rapeseed) that do not require new equipment for cultivation and harvesting.

4.6.2 Environmental Concerns

Some stakeholders felt there may be resistance to the establishment and further development of energy crops in the UK to satisfy demand. This may arise due to concerns over amenity impacts of monocultures or exotic species. Concerns may extend to impacts on floral and faunal composition and there may be particular sensitivities associated with sites in close proximity to sites of special scientific interest.

4.6.3 Transportation of biomass to generation facilities

It is anticipated by many stakeholders that if a market for generation plant fuelled by biomass were to emerge, the generation plants would in all likelihood be relatively small scale (around 5-10MWe) and situated close to where the biomass is grown. However, transporting the harvested biomass from where it’s grown to the generation plant may prove problematic. Firstly, local residents may object to the increased traffic and the associated increase in traffic noise in areas that by their very nature are likely to rural and relatively quiet. Secondly, the roads in these areas are not designed for Heavy Goods Vehicles (HGVs) which could damage the roads themselves as well as creating bottlenecks where HGVs struggle to pass other road-users travelling in the opposite direction.

It is worth noting that these small scale biomass-only generation plants are more expensive and less efficient (approximately 28-30% according to most experts) than co-firing for power generation and therefore use biomass resources less effectively. Transport costs and CO_2 emission would not rule out the operation of much larger 300-400MWe biomass plant that would be likely to have similar costs and efficiencies to new coal plant. The main barrier to such developments at the moment is the risk associated with the size and reliability of such a supply chain.

4.6.4 Sustainability issues associated with importing biomass for co-firing

When co-fired biomass is imported rather than being supplied from indigenous sources the level of greenhouse gas emissions (GHG) abatement is reduced. This has become an issue because most of the biomass currently being co-fired in the UK (63% in 2004) is imported from countries such as Malaysia and Indonesia. However, a recent report for DTI[13] showed that whilst GHGs from transporting co-fired biomass can reduce the GHG abatement by up to 14% there are still net benefits from co-firing in almost all circumstances. In addition, providing the sites of biomass plantations are carefully selected the non-GHG impacts on factors such as biodiversity and hydrology should be minimal and may even be positive under certain circumstances[1]. Therefore, whilst co-firing imported biomass is less desirable than co-firing indigenous biomass it is still justified on sustainability grounds in the medium term at least. In the longer term, this judgement may change as deeper cuts in GHG emissions at every stage in the energy supply chain are needed to meet the demanding targets for 2050.

[13] Evaluating the Sustainability of co-firing in the UK, Themba Technology, September 2006.

5 The Electricity Transmission System

The electricity transmission system refers to the, development, operation and maintenance of the high-voltage transmission network. The transmission network carries power from the generators to the distribution networks and consists of the 400 & 275 kV network in GB as well as the 132kV system in Scotland. There are three transmission licence holders in Great Britain - Scottish Power and Scottish & Southern Energy in Scotland, & National Grid Electricity Transmission (NGET) in England and Wales. NGET is also the system operator for Great Britain.

5.1 Network Capacity and Access

5.1.1 BETTA queue

The current connection arrangements are based on an 'invest and connect' philosophy. Under this approach NGET respond to a connection enquiry and if the commercial arrangements are agreed, plan and build the required network infrastructure to accommodate that new capacity (for example in new lines, new switchgear, new substations or upgrading parts of the network). Because of the large number of potential connectees waiting times for connection to the transmission network are long, especially in Scotland, with some connection offers going out beyond 2015. This prevents newer, more efficient plant replacing existing assets. This so called BETTA queue can be a barrier, raising the question for developers of whether to get a connection offer first without achieving the necessary planning consents or vice versa. The queue does not currently allow those that have the necessary permissions to move up, although it is believed that how the queue could be managed more effectively is being considered by NGET. Ofgem are reluctant to allow strategic network development without firm connection commitments since this might lead to stranded assets at a future cost to the consumer.

The length of the queue was compounded by the flood of connection applications before the BETTA go-live date (April 2005), especially in Scotland. Developers were faced with additional limits placed on new connection applications (most significantly the condition that new generation applying for connection post BETTA go-live would receive offers contingent on the wider British network being strengthened). The result was a rush of interest in securing a connection agreement to avoid a long wait for constraints between Scotland and England to be removed. This created a queue of some 9GW of mostly wind application. In the last 15 months National Grid has been working through this application back-log and has now made connection offers to all applicants. Following the withdrawal of a number of applicants, the queue of generation seeking connection now stands at approximately 7GW.

5.1.2 High cost and Final Sums Liability

The arrangements by which the system operator makes a connection offer to a potential generator has acted as a major barrier to the connection of renewable technologies to the transmission system. The so called Final Sums Liability arrangements have required developers to lodge a bond guaranteeing the monies required by the transmission operator (TO) to implement the connection. This has protected the TO from the developer 'walking away' from the connection offer. A criticism of these arrangements has been that the developer takes all the risk and the TO none. The monies are only paid by the developer to the TO should they not go on to connect and pay use of system charges as they generate and export onto the network.

Because of the difficulties associated with these arrangements (some developers being asked to provide huge bonds should their project just happen to trigger a massive grid investment need) changes are currently being proposed. NGET have offered a more generic approach to the user commitment arrangements asking potential connectees to pay a 'common to all' cost prior to connection. These arrangements are currently before the Connection and Use of System Code (CUSC) panel as a proposed modification and will have to be approved by Ofgem.

5.2 Planning Constraints

Transmission infrastructure development experiences similar levels of planning constraints to other aspects of the energy supply chain. For instance, renewables developers experience difficulties in obtaining planning permission for new overhead wires when seeking a connection to the grid. However, it is hoped that the Government's recent Renewables Statement of Need in the 2006 Energy Review will ease these particular problems.

The last major infrastructure investment – the North Yorkshire line – is a case in point. From inception to construction, delivery of the 11 mile section took close to 15 years. The bulk of this delay was in the planning and inquiry process. Within Scotland, Scottish & Southern Energy is now preparing for an inquiry into the proposed upgrade of the Beauly-Denny line. This will be a significant civil engineering project, so it is right that it is assessed rigorously. However, there are fears that opponents of the scheme want to take their argument back to first principles, and deny the need for a line, when the evidence clearly shows that there is sufficient new capacity waiting for connection. Many of the current problems facing the renewables sector, and flash points between the industry and regulator, often stem from planning delays and the need to find alternative solutions to manage the discrepancy between desire for connection, and delays in provision of new capacity. From the perspective of the energy sector, planning trends are moving in the wrong direction. More and more individual schemes are now going to inquiry; consenting rates are falling, and determination times are rising. Within inquiries many stakeholders believe too much time is focused on the "need" of proposals, rather than the viability or suitability of these proposals.

The planning constraints are not reserved to onshore networks. Offshore sub-sea networks may be used to avoid land based infrastructure, but this increases the level of infrastructure at the point that sub-sea connections come ashore. An example of this is the London Array offshore wind farm. The Array is a major scale development that will bring renewable generation close to a major demand centre. The first phase of the development received ministerial approval in December 2006. However, when the developer applied for consent for the land-based substation, the local authority turned down the application. If this decision stands, South East England will effectively stymie development of offshore wind in its own region.

5.3 Transmission Charges

5.3.1 Lack of use of system charging regime for intermittent generators

The current system of transmission charges are modelled on conventional, large, centralised plant and some stakeholders argue they have not been adequately modified to reflect the nature of intermittent generation. National Grid established a Charging Issues Steering Group and began consulting on each of these issues in turn. More than a year and a half into this series of consultation little has changed, and National Grid has broadly confirmed that it decided correctly in the first instance on each of these issues. National Grid rejected changes to charging for intermittent generation, but noted that separate work on alternative charging products would be a better way to deal with this issue. Two months after making this statement National Grid decided that there was no scope for introducing alternative charging products.

Because intermittent generators are perceived to provide less value to the system in terms of their contribution to the security of supply, as required by the security of supply & quality standard there is a growing industry view that use of system charging should reflect this different contribution. This could increase the barriers to further renewable energy development, although it may be offset by greater choice in less-costly connection arrangements.

5.3.2 High transmission charges to offshore connections

Since BETTA go-live industry and offshore/island authorities have worked together to engage Government on the problem of high transmission charges to peripheral locations. After consultation on this, the UK Government established a power in the Energy Act (section 185) giving the Secretary of State the power to cap transmission charges to peripheral areas, and following from this, decided that the situation in the Scottish islands merited Government intervention. At the time Ofgem called this intervention “misguided and unnecessary”. However, the initial intervention was for a cap to finish in 2014; a period that would not have provided a sufficient window of opportunity for generation on the islands (this however may be extended to 2024). Again, Government assessed this issue, and subsequently extended these provisions out to 2020 through the Sustainable Energy Act 2006.

5.4 Marine, Offshore Connections

There is significant marine and offshore resource in Great Britain, especially in western and northern parts of Scotland. This resource will require significant new transmission capacity in peripheral locations. The development of early schemes will require innovative solutions, as the length of the transmission queue will result in a lengthy wait for new connection applicants.

5.4.1 High costs of transmission infrastructure for offshore network

High transmission charges will force up the cost of connecting to the islands, even with effective transmission capping. Problems consenting upgraded lines also makes the need for connection to the islands to allow connection of wind and other generation projects more difficult to meet. At present the regulatory and market frameworks mean that the cost of providing connection with all but limited sub-sea routes will be difficult to justify. Highlands & Islands Enterprise & the Scottish Executive have now agreed terms on the study of island connections. It seems clear that there is a gap - either in the price the market will pay or in the way that the system is regulated – that will make delivery of a significant level of capacity to the islands problematic. However, there seems to be a willingness on the part of Ofgem and Government to look differently at this problem.

5.4.2 Lack of a regulatory regime for offshore electricity transmission

An offshore electricity transmission regulatory regime needs to be implemented in order to allow renewable generation located in the sea outside the territorial waters of Great Britain to connect to the existing onshore network. Currently, there are plans for about 6-7GW of electricity (which represents just under 10% of current generating capacity) to be developed in the sea around Great Britain, primarily from wind resources. In the future, other technologies harnessing wave and tidal power may also be developed.

The government has announced that transmission networks offshore will be subject to price controls, which will be set and reviewed by Ofgem. Ofgem's scoping document (published in April 2006) is the first stage in the process of implementing a regime for electricity transmission networks offshore. It identifies the work that needs to be undertaken, the decisions which need to be made and some of the options for those decisions.

Ofgem has identified five work streams that are being taken forward to help implement an offshore regulatory regime for electricity transmission.

- Identify the geographic scope of offshore transmission licences.
- Decide on a method to allocate offshore transmission licences.
- Look at the technical rules currently governing onshore networks and considering the feasibility and appropriateness of extending or amending these rules to cover offshore networks.

- Consider the possible design of offshore price controls.
- Make modifications to licences and codes that govern interactions between industry parties which are necessary to implement a regulatory regime for offshore transmission.

5.4.3 Offshore distribution – transmission connections at full capacity

As with many renewable projects, most wave and tidal stream projects, because of their size, will connect into the distribution system, before their electricity is passed up onto the transmission system for dispatch to larger generation markets. Small distribution connections exist to Orkney Islands & Western Isles and many of these links are at full capacity. There is no connection to Shetland Isles. There are concerns about landfall of sub-sea connections and integration into main grid. It will therefore be important that future wave and tidal energy projects can export energy effectively onto the transmission system. While initial projects are going to be under the 10MW scale, so will be classed as smaller generators, it may not be too long before we are seeing larger scale projects seeking connection onto the distribution network or directly to the transmission system.

5.4.4 Lack of integration of marine and offshore infrastructure

Many stakeholders also believe that linkages must also be made between island and marine infrastructure. While the current development focus is how to open up capacity for development of onshore wind energy, in the medium and longer term, many stakeholders believe generation using marine sources will be at least as important. Because of this, it will be important that decisions on provision of capacity to the islands are “future-proofed” so that capacity can be made available for a following group of wave and tidal stream projects. The current lack of this disincentivises the further development of remote wind and marine energy sources.

6 The Distribution Network

The distribution network consists of the network of towers and cables that bring electricity from the high-voltage transmission network through the grid supply points to homes, businesses and industry.

6.1 Planning Constraints

Similar planning constraints exist for distribution infrastructure as for transmission and generation. Network operators frequently have difficulties obtaining local planning approval for new network infrastructure and wayleaves[14] needed to facilitate new and distributed connections to the grid. In addition, following the liberalisation of the energy markets land owners have been more inclined to demand higher wayleave payments.

6.2 Current levels of investment in the distribution network may constrain future capacity

Current levels of investment in the distribution network may constrain future capacity, especially if Great Britain moves to a distributed generation model of connected sustainable technologies and where lack of distribution network capacity could slow the pace of new connections. Some stakeholders argue that Innovative investment models are needed to ensure that the distribution network remains fit for purpose, especially in the context of facilitating connection of renewable and distributed generation in remote rural areas.

Under the 2005 to 2010 price control £5.3 billion capital expenditure was allowed by Ofgem for the 14 distribution regions. However, there are some concerns that the EU Directive on Preferential Access to Renewables may not be addressed under the current regulatory regime. Consequently, some stakeholders argue that the Government will have to play a more active role in network investment management to ensure the objectives of the Directive are met.

6.3 Impact of Distributed Generation

6.3.1 Distributed generation will require more active management of the distribution network

The development of significant distributed generation will have significant impacts on the distribution network and will place it under operational and technical pressure. The move from a situation where electricity is taken from centralised power plants and delivered to consumers, to one where small scale generators can sell surplus power, all the time maintaining the integrity and reliability of the network, will require long term planning. For instance, the widespread use of micro-generation assets may require strengthening of the transmission and distribution system (opinions vary on how soon this will become an issue – the range is likely to be in the order of 30 to 50% of households in Great Britain) in order to ensure reliable and balanced electricity services are retained. The relative investment responsibilities of the connectee compared to the grid operator in funding these upgrades is not currently clear.

However, it is also important to recognise that a number of initiatives are already in place, in particular changes to the distribution price control which incentivises the network operators to connect generation. Ofgem also introduced an Innovation Funding Incentive (IFI) and Registered Power

[14] A wayleave is a terminable licence, usually on 6 or 12 months notice, allowing for a right of access over land or the right to have equipment on land

Zones incentive in the 2005 price control. Registered Power Zones (RPZ) are helping demonstrate better system management when connecting distributed generation, but there are concerns that the incentives are insufficient to see widespread adoption.

Inevitably the networks will become more actively managed as the integration of distributed generation becomes more widespread. This will potentially require strategic investment in the network, although under the current price control Ofgem have not allowed for significant enhanced funding of this, because of the risk of cost to the consumer of stranded assets.

6.3.2 Two-way power flows and increased voltages

Distribution systems are designed to manage power flows in one direction, those from a grid supply point down the point of customer demand. In addition a network is designed to deliver, by the use of transformers lines and cables, the correct voltage, within limits, to its consumers. As the network is loaded this voltages can drop below statutory limits. Network operators manage this by, for example, the use of transformer tap changers, voltage set points and reactive power flow.

The addition of distributed generation can increase system voltages and introduce reverse power flows. Excessive amounts of generation will result in network voltages exceeding statutory limits and the resulting reverse power flows are unlikely to be compatible with, for example, network protection configurations and transformer tap changers.

Although a barrier to the integration of distributed generation neither of these issues are technically insurmountable. However they will require additional monitoring and control equipment. Using measured data from the network about voltage and power flows the network can configured (managed) to ensure that network statutory parameters are not exceeded. Inevitable this will result in extra cost.

6.4 Transmission and Distribution Interface

Many stakeholders believe that historically, there has been a lack of coordination between regulatory systems for transmission, distribution and supply, each being regulated in different ways over different time periods. While this has not always mattered, an evolving distributed system will likely expose these differences to a greater degree.

The interaction between the transmission system and the distribution network is of growing concern to the system operator. With growing levels of distributed generation the prospect of exporting grid supply points has become a reality. This has prompted a NGET led examination of embedded generator transmission charging but the magnitude of the problem and how this is to be settled is yet to be agreed, although there is a threat that the existing commercial positive distinction between distribution and transmission connected generation will be further eroded.

6.4.1 Inter-network Contracts and Agreements

To large non licensed generators the system of contractual agreements (BEGAs, BELLAs and EELLPS[15]) is somewhat complex. At the present time National Grid contracts bilaterally with each generator classed as a large power station. These generators are offered one of two agreements, a BEGA or a BELLA. However, Ofgem classifies them as EELPS, meaning that they can choose whether to be exempted from being liable for transmission charges, and signing up to relevant transmission codes. However, this apparent choice is not usually as simple as it sounds. The principle difference between a BEGA and BELLA is that by signing a BELLA, the EELPS would avoid Transmission Use of System (TUoS) charges and be exempt from Balancing & Settlement Code and

[15] BELLA is a Bilateral Embedded Licence Exemptible Large Power Station Agreement: A BEGA is a Bilateral Embedded Generation Agreement: and a EELPS is a Exemptible Embedded Large power Station.

Grid Code requirements, but would also have no right to use the transmission system. Signing a BEGA would provide access rights, but would necessitate compliance with the Codes and payment of transmission use of system charges. There has been widespread criticism by generators of the BEGA/BELLA system. Firstly, the system imposes a significant bureaucratic burden on smaller generating stations. Secondly, there are major cost dis-benefits from making the wrong choice on which agreement is appropriate for a particular site. Thirdly, generators often see that they have insufficient information about other network factors that will impact on their choice, and fourthly, while the situation may change over time, once they have chosen, generators are effectively locked into their chosen agreement. Finally, because large power station distinctions commence sooner in Scotland (from 10MW in Scotland, compared to 100MW in England) and because transmission "starts sooner", BEGA/BELLAs are standard in Scotland but comparatively rare in England or Wales.

In early 2005 Ofgem consulted on this issue and how it might introduce "enduring arrangements" to govern how the distribution/transmission boundary might be managed. Scottish Renewables, Association of Electricity Producers, British Wind Energy Association, Energy Networks Association and the Renewable Energy Association – wrote to Ofgem calling for concerted action to resolve this issue. While those responding to the question disagreed on the solution, there was strong agreement that the current system had to change and the do-nothing approach was not a viable option. One of the outcomes of the consultation has been the creation of the Transmission Access for Distributed Generation (TADG) group. TADG is currently considering options relating to these enduring arrangements.

6.4.2 Classification of Scottish transmission/distribution networks

For historical reasons the 132kV network in Scotland is classified as transmission, in England and Wales the 132kV network is part of the distribution network. This was appropriate at the time, but many stakeholders believe Ofgem and National Grid should set out clearly at what point they would wish to review this definition. In particular, if plans to upgrade the Beauly-Denny transmission line (currently 132kV) to 400kV gain the necessary section 37 consent, then by early in the next decade the majority of Scotland's transmission network will be at 275kV or 400kV. At this point the remainder of the 132kV network will be in more peripheral areas or for electricity networks in the central belt. This being the case, there is merit in the proposal to reconsider current definitions. Under this upgrade scenario, the bulk of remaining 132kV could be seen as being mainly distribution focused.

This different distinction between transmission and distribution systems in different parts of Great Britain disadvantages small generators wishing to develop in England and Wales compared to those in Scotland. This could present a perverse incentive to locate in Scotland, away from most major centres of energy demand and lead to inefficiencies of transmission and distribution. Transmission connected generation will pay transmission use of system charging where as distribution connected generation may be paid in embedded benefits, if sited appropriately.

6.5 Connection and Use of System Charging

The new shallower connection costs and the introduction of use of system charging for generators implemented with Distribution Price Control Review (DPCR4) have attracted comment from sustainable generation developers, mostly positive, but with some concerns. In April 2005, with implementation of the DPCR4, Ofgem made the cost of connection shallower and shifted the burden to the longer term use of system charges. The system of shallow connection charging may have led to an increase in the cost faced by some distributed generation if they are connecting in areas that need no reinforcement.

7 Supply

Supply refers to the system and companies who supply and sell electricity to the consumer. The suppliers are the first point of contact when arranging an electricity supply to domestic, commercial and smaller industrial premises.

7.1 Heat Network

There is not currently a national or regional heat network in the UK. The limited number of networks that do exist are localised such as those in Sheffield, Southampton and Nottingham. Sheffield's district energy network is one of the largest and most successful in the UK. It was established in 1988 and is still expanding. There are 43km of pipeline installed to deliver heat to homes (over 2,800), public buildings and commercial properties in Sheffield across 2 networks. In 2000 nearly 120,000 MWh of heat were delivered to buildings in Sheffield City Centre and the surrounding areas. For every 100,000MWh of energy supplied by district energy 31,000 tonnes of carbon dioxide is displaced.

Operational since 1973 The Nottingham District Heating Scheme provides heat and power to 4,800 homes, schools, residential care homes, shops, civic buildings, Trent University, a hotel, leisure centre and swimming pool, Inland Revenue HQ, Magistrates Court and County Council Archives. Owned by Nottingham City Council, the scheme is situated outside the city centre and comprises a waste to energy incinerator that burns incinerates around 145,000tonnes of waste annually, and a 15MW CHP energy plant.

Southampton Geothermal Heating Company has heating, cooling and electricity sales of over £2 million and serves over 40 private and public sector customers and hundreds of domestic customers. The scheme now has over 11km of insulated service pipes taking hot and chilled water to customers. Its annual energy sales are 70GWh per year and 23GWh of electricity produced from the CHP generating plant is sold to Powergen under a 10-year non-pooled generation contract signed in 1998. In addition to supplying heating, a cooling network was developed in 1994 which provides chilled water for air conditioning to hotels, retailers and a leisure centre.

Heat networks are used much more widely in other countries (for example 60% of households in Denmark are connected to heat networks) so their technical feasibility has been proven. It is worth noting that if policy makers were to decide to build a national heat network it could operate on a local level (e.g. a series of decentralised plants supplying heat and possibly electricity to local demand areas) whilst still having national coverage.

7.1.1 High infrastructure costs to develop a heat network

Most stakeholders agree that constructing a national heat network would involve high infrastructure costs. There is currently no certainty regarding who ought to ultimately bear the cost of such a network. Instinctively many people would say it ought to be the consumer, but would it be fair to expect them to pay for a network they do not need in order to satisfy their heating requirements? Conversely, there is a strong argument that everyone should contribute to a national effort to mitigate the effects of climate change. In addition, if such a network were to be built, a medium term financing package would need to be put in place to fund the construction of the network before the operator/s can begin to recoup their costs.

7.1.2 Cultural barriers to heat network

Some stakeholders believe there is currently no appetite for a national or regional heat only network at current market prices. Homes in the UK are traditionally heated by point-of-use stand alone boilers and some stakeholders feel there may be resistance from residents to move away from this tried and tested system, particularly given the inadequate heating networks in many 1960's tower blocks. These feelings may be exacerbated if residents were asked to contribute towards the cost of constructing, and connecting to, a heat network. However, other stakeholders argue that consumers' primary concern is that their homes are adequately and affordably heated and that the means by which this is achieved is largely irrelevant to most people. Proponents of heat networks also point out that they are very common in Scandinavian and Central European countries, which could be used as the basis for convincing UK consumers of their technical feasibility.

7.2 Smart Metering

Although there are no universal definitions of a 'smart' meter the following functions are available[16]:

- Display and record real time information on energy consumption (both electricity and heat)
- Easy to understand, prominent display unit which includes:
  - Costs in £/p,
  - Indicator of low/med/high use,
  - Comparison with historic/average consumption patterns,
- Two-way communication between energy suppliers and the meter to make it possible to switch tariffs, or pay as you go (pre-payment) provisions, remotely;
- An internal memory to store consumption information and patterns;
- Export metering for micro-generators;
- Demand-side management options, such a tariffs which charge more at peak-demand times
- Inactivity monitoring
- Provide data to suppliers to ensure:
  - Correct and timely bills;
  - Information on patterns of use – improving forecasting and wholesale purchase;
  - Targeted advice of efficiency measures to customers.

Previous evidence suggests that smart meters can reduce energy use by between 3% and 15% through changes in behaviour[11]. However Ofgem, sustainability first and the carbon trust suggest that 1-5% savings are likely but site a lack of empirical UK evidence as the need for smart metering trials. Much work is currently being undertaken to investigate the feasibility of various aspects of introducing smart meters. For example, The Government issued a consultation document "Energy Billing and Metering: Changing Customer Behaviour: An Energy Review Consultation" on 14 November. Ofgem are leading a Government and Industry funded project which aims to develop an evidence base for the impact of metering and billing demand reduction measures in the UK. The project will trial a series of measures such as smart meters (in their various guises) improved billing and other feedback devices. In addition, The Energy Retail Association has established an expert group of advisers which is working to agree a viable commercial framework to encourage investment in smart metering.

[16] Energywatch, Get Smart: bringing meters into the 21st Century, August 2005.

7.2.1 High capital costs

The costs associated with smart meters are high and act a barrier to their widespread deployment in Great Britain. Estimates of the costs of smart meters vary: typically the estimated purchase, installation and infrastructure costs of smart electricity meters are from £40 to £180, depending on their functionality. Ofgem has estimated that the total cost of installing and maintaining smart meters in all households could be up to £5-8 billion[17]. In comparison, the current cost to domestic gas and electricity customers of installing, reading and maintaining meters is £800 million[12].

7.2.2 Stranding of new meter assets due to the 28-day rule.

Energy suppliers are wary of installing smart meters due to the difficulties they believe they would encounter in recouping the cost of the meter if the consumer changed supplier. However, other stakeholders point out that the regulations surrounding the 28-day rule (that allows consumers to change supplier with 28 days notice) do allow suppliers to offer contracts that include termination fees, subject to reasonableness, which should allow the supplier to charge the customer who switches for the 'stranded' smart-meter. Suppliers argue that this option has not been used to date and it would only work with active customer demand for smart-meters. Ofgem are proposing to remove the 28-day rule.

7.2.3 Lack of perceived benefits to any single agent in the energy industry

There does not appear to be significant enough benefits to any single agent in the energy industry to warrant them installing smart meters, especially in view of the sizeable costs of a widespread roll out. The main benefits would be to consumers, through the provision of clearer information, and to society as a whole due to the likely reduction in energy use and hence carbon emissions. Consequently, it seems likely that Government intervention of some kind, perhaps via Ofgem, will be required to achieve widespread uptake.

7.2.4 Lack of common standards

A lack of common standards in terms of what functions a smart meter should feature may have contributed to a delay in uptake. If a smart meter is purchased in the absence of such standards there is a risk that certain key functions will be missing. Conversely, there is also a risk that smart meters may be over-specified to guard against the device becoming obsolete when common standards are eventually introduced. This latter risk will also have negative cost implications especially if the smart meters were installed in significant numbers. The Energy retail association is currently undertaking work to define a minimum specification for smart meters.

7.2.5 Complexity of the metering market

The electricity and gas metering market in Great Britain is complex, which in itself creates a barrier to the installation of smart meters. As well as the regulator (Ofgem) there are often several organisations involved in the ownership, management, installation, maintenance and reading of the meters. This can result in diverse responsibilities for taking forward improvements to the system, which may give sustainability benefits.

[17] DTI, Energy Metering and Billing - Changing Consumer Behaviour, An Energy Review Consultation.

7.3 The Energy Efficiency Commitment

The Energy Efficiency Commitment (EEC) came into force in April 2002 and places an obligation on larger electricity and gas suppliers (with more than 15,000 customers) to achieve targets for improvements in domestic energy efficiency. The EEC contributes to greenhouse gas emissions reductions and also helps alleviate fuel poverty by focusing 50% of energy savings on lower income consumers. Under the scheme, suppliers encourage and assist their domestic consumers to make energy savings through installing measures such as cavity wall and loft insulation and energy efficient boilers, appliances and light bulbs.

The first period of the EEC lasted from April 2002 until March 2005 and achieved the Government's target of an overall energy saving target of 62 TWh, which is equivalent to 0.37 MtC annually by 2010 or a 1% per annum reduction in CO_2 emissions from households. The second phase of the scheme is now underway, which the Government anticipates will deliver savings of 0.62MtC annually by 2010. After conducting a review of the EEC the Government has concluded that it is feasible and cost effective to expand the scheme. A third phase is planned for 2008-2011, which it is hoped will deliver 0.9 – 1.2 MtC of savings by 2010. The Government has also committed £20 million over the next 2 years to launch a new initiative to encourage consumers to take up energy efficiency measures.

7.3.1 Not currently funding larger energy efficiency equipment

In its current form the EEC mainly delivers loft and cavity wall insulation (85% of measures in the first year of the Energy Efficiency Commitment 2005-2008 (EEC2)) since these are amongst the most cost effective measures. Thus EEC tends to ignore property types which are not suitable for these measures e.g. flats and houses with solid walls. However, once demand for cavity wall and loft insulation has been exhausted the suppliers providing EEC will be forced to diversify the mix of measures they deliver. This may include the provision of solid wall insulation, solar hot water heating and micro-CHP.

7.3.2 EEC not perceived as a permanent legislative fixture

Despite considerable funding of energy efficiency improvement, many stakeholders in the investment community do not yet perceive the EEC as a permanent legislative fixture since it is applied in stages and the Government has not revealed what guise the EEC will take from 2008, or after 2011. Some stakeholders believe this lack of long term certainty is a barrier to a sustainable energy system since there is no guarantee that the policy will still be in existence in the future so the investment community sees this as a serious risk.

7.4 Market Access

Many stakeholders believe that there are limited barriers to entry into the energy supply markets and considerable competition with a large degree of switching. The barriers to entry that do exist tend to present the greatest problems for small suppliers, particularly those focused on renewable energy.

7.4.1 Vertical integration

Some stakeholders argue that the regulatory burden associated with participating in the gas and electricity markets in the UK is significantly lower for vertically integrated companies. This is because they are able to absorb the costs of compliance much more readily due to their economies of scale. For instance, the cost of employing a team of regulatory experts is a negligible burden for most a vertically integrated power companies where as a smaller renewable energy supplier may well struggle to afford such dedicated expertise.

7.4.2 Market access for new suppliers

The costs associated (e.g. marketing, billing infrastructure, customer service centres and trading) with becoming a new supplier within the market are such that small generators are not able to fulfil this function. This results in a reduced revenue stream for these generators, as they are not able to add as much value through the supply chain as a vertically integrated operator.

7.4.3 Licensing Process can be burdensome for new suppliers

The need to obtain a license for the generation and supply of electricity can be a burdensome procedure for small-scale generation, which it is argued by some stakeholders, tends to suppress investment in new plant. The Government relaxed the license requirements by raising the license exemption criteria in 2001 and 2005. This exempts small suppliers supplying up to 5MW of power, of which no more than 2.5MW may be supplied to domestic customers (with certain conditions imposed by Ofgem), allowing a greater number of schemes to supply electricity directly without the need for the additional administrative burden associated with becoming a licensed supplier.

7.4.4 Reduced Innovation

There is a belief amongst some stakeholders that the limited number of established small energy suppliers, or new small suppliers entering the market, has reduced innovation in the energy supply sector. They argue that small suppliers tend to be the most innovative and less risk-averse than larger vertically integrated supply companies. The limited numbers of small suppliers therefore acts as a barrier to a sustainable energy system since innovation is seen as key by most stakeholders in driving down carbon emissions.

7.5 Charging Structure

7.5.1 Variable rate tariffs

Most energy suppliers' reward increased energy use with a lower tariff per kWh above a certain threshold. This doesn't create an incentive for consumers to use less power as the overall cost per kWh decreases with increased use. This is at odds with the aims of sustainable development as it rewards profligacy of resource use. In addition, it penalises those who use energy efficiently or frugally as they are likely to purchase fewer units at the cheaper tariff therefore their overall cost per unit will be proportionately higher.

7.5.2 28-day rule acts as a barrier to energy supply companies offering energy service contracts

The so called 28-day rule ensures that all energy supply contracts (whether fixed-term or rolling) must contain provision for them to be terminated on no more than 28 days' notice. Around the time of the 2004 Energy White Paper Ofgem[18] was of the opinion that the 28 day rule was essential for the long-term interest of customers to prevent incumbents from hampering new market entry by reducing the liquidity of the market, and to ensure that customers are not definitively locked into arrangements that are to their detriment (even though exiting them may be at a price).

[18] Ofgem's submission to the Energy Services Working Group in 2003.

However, it also acts as a barrier to energy supply companies offering energy service contracts[19] for equipment such as micro-CHP, which is costly to purchase and install. Energy suppliers are not willing to offer energy service contracts when the customer could break the agreement within 28 days notice and leave them will little hope of recouping the upfront capital investment. Whilst in principle this seems a simple issue to resolve, (remove or amend the 28 day rule and suppliers will begin to offer energy services contracts) a recent Ofgem trial showed that removing the 28 day rule did not necessarily provide sufficient incentive for Suppliers to offer energy services contracts.

Nonetheless, in its initial proposals for amendments to the Supply License (published in July 2006) Ofgem proposed removing the 28-day rule. They were of the opinion that competition was now well established so they could remove elements of the detailed prescription of the relationship between supplier and customer.

7.6 Green Tariffs

Currently most suppliers offer ‘green’ tariffs – tariffs that purport to be sourced from environmentally friendly sources. However there are a number of difficulties with this. Firstly definitions of ‘green’ can vary between suppliers with some suppliers counting power generated from fossil fuel fired CHP plant as ‘green’. This is often not promoted to customers who might be misled into thinking that their tariff is sourced from renewable supplies.

This leads onto another issue, namely the difficulties in comparing tariffs, whether they are purporting to be green or not. Suppliers are not currently mandated to display key facts on their tariffs in a standard format, which acts as a barrier to consumers comparing tariffs on the basis of reduced environmental impact or selecting the ‘greenest’ tariff should they so desire. Furthermore, there is also a danger that even when information is available consumers will not necessarily be comparing like with like.

Potentially more importantly there is often a problem of additionality related to these tariffs as it is believed that the total quantity of green power supplied is generated under the Renewables Obligation. As such the purchase of a green tariff does not generate any additional green power it merely attributes that which is already being generated to a particular customer.

This situation means that the offer of green tariffs to consumers will not contribute to the development of a sustainable energy system until demand for green power outstrips that which is obliged to be produced via the Renewables Obligation.

[19] According to Ofgem energy service contracting involves the outsourcing of one or more energy-related services to a third party. This contrasts with the traditional model in which energy consumers’ contract separately for each energy commodity and for different types of energy conversion equipment. Energy service companies (ESCOs) offer comprehensive contracts that include energy information and control systems, energy audits, installation, operation and maintenance of equipment, competitive finance, and fuel and electricity purchasing. These contracts allow the client to reduce energy costs, transfer risk and concentrate attention on core activities.

8 End User Demand

End user demand refers to consumption of energy, whether it be electricity, gas or heat, by domestic or industrial consumers. End user demand is the last stage of the energy supply chain.

8.1 Engaging the consumer

8.1.1 Ignorance of the link between energy use and climate change

Some stakeholders believe many homeowners are ignorant of the link between energy use and climate change. Consequently, they are unaware of the need to improve domestic energy efficiency to contribute towards efforts to mitigate the impacts of climate change. In other words they are ignorant of the fact there is a problem, let alone how they might go about contributing towards the solution.

8.1.2 Insufficient incentives to become more energy efficient

Some stakeholders argue that there are insufficient incentives for homeowners to become more energy efficient. This is particularly the case for rented properties where the landlord is not resident in the property, does not pay the energy bills and as such would not benefit from implementing energy efficiency measures. It is also argued that for many consumers who do pay the energy bills the cost savings and environmental benefits are not sufficient to precipitate a change in habits, especially given the increasing demands on many people's time. Many consumers simply have other priorities or chose not to take an interest.

8.1.3 Affordability of energy efficiency measures, access to capital and spending choices

Some domestic energy efficiency measures are costly to install (e.g. double glazing and condensing boilers) so there are a raft of issues associated with consumers meeting that cost. Firstly, many consumers will not be able to afford to pay upfront to implement the measures since they can cost upwards of several thousand pounds. Assuming the consumer is able to borrow the requisite amount (by no means a certainty for lower income households) it may need to be paid for over a prohibitively long timescale when they would incur high interest charges relative to the cost of the measures themselves. In addition, there is also the issue of spending choices. Many consumers may be able to afford to implement energy efficiency measures in principle but prefer to spend their limited disposable income elsewhere on goods or services from which they believe they would derive more pleasure e.g. holidays, socialising.

8.1.4 Insufficient energy efficiency information on bills to allow consumers to make informed choices

Many stakeholders believe that consumer billing is a key driver of consumer energy behaviour. It is felt that current billing systems carry inadequate information to provide properly informed consumer choice. Poor or inaccurate billing has the potential to reduce the impact of energy efficiency improvements, increase fuel poverty and consumer debt. There are a number of options under the energy review and as part of a separate DTI consultation to improve consumer billing. These include including additional historical use information on consumer bills in graphical form, using benchmarking to provide indications of relative levels of energy use, improving the frequency of billing and to extend billing arrangements to business customers.

8.2 Industrial Energy Efficiency

8.2.1 EU ETS uncertainty post 2012

Europe's community wide emissions trading scheme aims to incentivise carbon emission reductions in the power generation and energy intensive industrial sectors, while at the same time minimising competitiveness impacts. The future of the scheme post 2012 is as yet undefined, and as such there is no long-term certainty for investment. This barrier is especially significant given the long lifetimes of generation plant, which can exceed 40 years.

8.2.2 Limited sectoral coverage of the EU ETS

The EU ETS is specific to large industrial plant and does not provide a basis for addressing the significant emissions from other manufacturing facilities and the rising emissions from the service sector and transport sectors. The EU ETS is generally perceived to be the key to the Government's carbon reduction strategy and it is argued by some stakeholders that this is too narrow a focus. The Government have indicated they are in favour of incorporating aircraft emissions into EU ETS and are currently working closely with the EU and other Member States to come up with a means of doing so.

In addition, the Government is currently consulting on a new instrument to cover non energy intensive industry called 'The Energy Performance Commitment'.

Although there may be several overlaps and boundary issues with existing regulatory regimes, the current indications are that it will cover sites that meet the following criteria;

- Electricity bill greater than 3,000 MWh/year20
- Half hourly electricity meters in place
- Not covered by the EU Emissions Trading Scheme

It is anticipated that the scheme will cover 5,000 organisations, accounting for some 50,000 sites emitting in the region of 55 MtCO2/yr. Some research on the feasibility and coverage of the scheme has been carried out by the Carbon Trust[21] and Defra[22].

The proposal is that this scheme will have a lighter regulatory touch than the EU ETS, especially with regard to monitoring, reporting and verification of emissions, which is the main cost for the operator under the EU ETS.

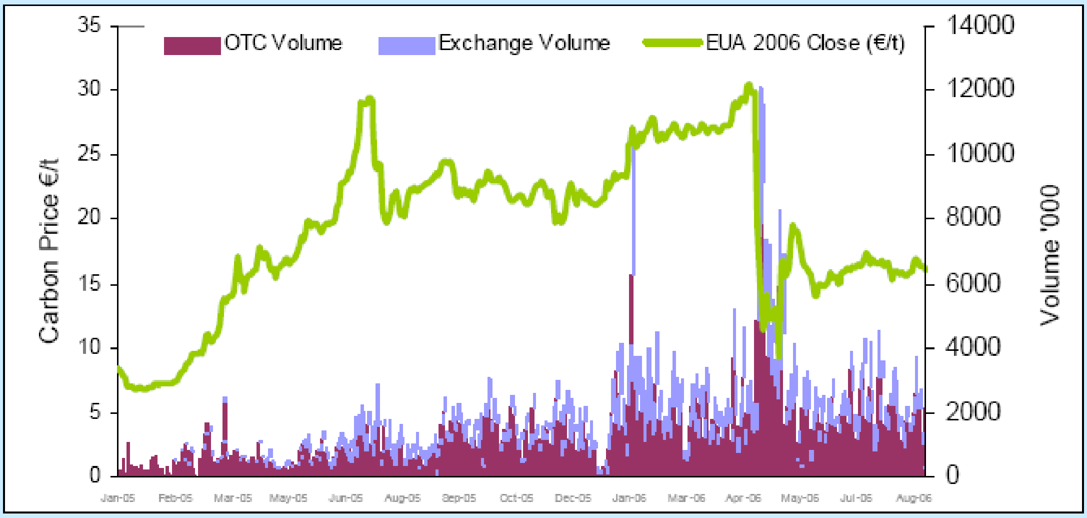
8.2.3 National Allocation Plans for phase II of EU ETS and beyond

The EU ETS has been accepted by most parties to have been a qualified success, the qualification arising because many Member States were over generous with their Phase I (2005-2007) allocations. This generosity caused instability in the CO2 price in the market, particularly when the first year's results were announced (see April/May 06 in Figure 1).

[20] 3,000 MWh equates to approximately 1,200 tonnes CO_2/year, using 0.43kgCO_2/kWh
[21] The UK Climate Change Programme Potential Evolution for Business and the Public Sector, Carbon Trust (2005)
[22] Energy Efficiency and Trading Part II: Options for the Implementation of a New Mandatory UK Emissions Trading Scheme, Defra (2006)

Figure 2 - The price of EU allowances

The market for EU allowances (EUAs) –prices and volumes



Source: Data taken from Point Carbon, www.pointcarbon.com

Graph taken from the Stern Report

To some extent, this could have been expected, as Phase I involved a great deal of learning (especially about the mechanisms for determining allocations), but early indications are that many Member States will be even more generous in Phase II (2007-2012). The majority of proposed National Allocation Plans (NAPs) that are currently being put forward by Member States (deadline was 30th June 2006, but many Member States have missed this date) are greater than the caps they proposed (and in most cases achieved) in Phase I. Justifications for the increased caps are in most cases attributed to economic growth projections, but this trend does not bode will for the future success of the scheme if it leads to continuing over allocations which will continue to suppress the CO_2 price. The Commission has calculated that on the basis of the 17 NAPs that have so far been submitted, these would give rise to a 15% increase on actual emissions in 2005.

8.2.4 Ability of the Climate Change Levy (CCL) to increase energy efficiency in less energy intensive sectors

Some stakeholders believe that the CCL does not act as a strong enough incentive to increase energy efficiency in less energy intensive industry sectors. The CCL is a downstream tax on energy use in the business and public sector designed to be revenue neutral through corresponding reductions in National Insurance contributions. Theoretically, increasing the CCL could increase carbon savings but some stakeholders claim that economically acceptable increases in the levy would have little impact on less energy intensive industry sectors. Therefore, they believe additional measures are required to encourage emissions reductions in less energy intensive sectors such as the service industries.

8.2.5 Tightening Climate Change Agreement (CCA) targets

Tightening CCA targets, and hence increasing the carbon savings, is becoming increasingly difficult as industry has already implemented most of the low hanging energy efficiency improvements and is more and more hostile to increasing the targets for fears of losing competitiveness. CCAs will continue until 2010, but there is a feeling in Government that they have been very useful and that there might be scope for retaining the mechanism beyond that date. It is possible that if confidence grows in the EU ETS and the system is expanded to include energy intensive sectors not currently covered, then CCAs need not be extended beyond their current term and participants could move into the ETS whilst maintaining their CCL discount. In this context, the issues associated with tightening CCA targets represent a barrier to a more sustainable energy system.

Climate Change Agreements are negotiated agreements that allow energy intensive industries that participate to claim 80% discount on the Climate Change Levy (energy tax). The industries participating in the scheme are covered by 44 sector agreements covering 6,000 sites. Agreements were negotiated between the sector associations and Government on the levels of energy savings that their members could make up until 2010.

The majority of CCA participants have over delivered against their initial negotiated agreements (typically, emissions reductions of 1% a year until 2010). While critics argue that this is evidence that the targets were too lenient, there is some evidence that participants in the scheme have been far more likely to take action to reduce energy use than their counterparts who are paying the full Climate Change Levy. The negotiations are a difficult and lengthy process, as industry will always have better information that the Government on the energy savings that are possible in the sector. It is accepted though, that the negotiation process was a useful one, as it forced industry to take a critical look at the possible energy savings measures in their sectors.

8.3 Lack of Confidence in Energy Efficiency Measures

Some stakeholders believe the actual and remaining potential gains from End User energy efficiency measures may be underappreciated. Between 2003 and 2006 there has been significant progress, driven by an extension to EEC and significant improvements in Building Regulations standards relating to energy efficiency (Part L) as well as an increase in the amount available for Warm Front grants. However, there is frustration amongst some commentators that the recommendations of the Energy Efficiency Innovation Review (EEIR) have yet to be fully implemented. There is also a belief amongst some stakeholders that politicians continue to equate energy efficiency primarily with carbon reductions and do not recognise the wider ancillary benefits of security and affordability, despite a body of evidence demonstrating net-economic benefit from public investment in energy efficiency, and its cost effectiveness compared to other policies and measures. Policies are regarded as complex to deliver, dependent on behavioural change and uncertain in their outputs when compared to supply-side solutions. Some stakeholders believe more focus is required to learn from the activities in other EU member states. For example Germany has just ordered the retrofitting of 5% of pre-1978 housing stock to current levels of energy performance.

Some stakeholders believe there have also been gaps in coverage and a lack of focus on behavioural change. They feel that to date most carbon mitigation attempts have focussed on supply side and energy-intensive industrial users. It is their opinion that actors not covered by existing legislation waste much of the energy consumed within the UK. Carbon taxes or Domestic Tradable Quotas might offer a solution, but there are political difficulties with implementation.

Some believe that EEC itself is creating problems as it works with theoretical savings. Providing an energy efficient light bulb does not ensure it is used, and providing an A rated appliance may mean that the old one is moved to the garage but still used. In addition, insulation provision may just be taken as improved comfort.

8.4 White Certificates

There is currently no market for energy efficiency measures or demand reductions when compared to the opportunities for sustainable-supply side investment available under cap and trade systems such as the EU ETS. Depending on how such a system was designed it could allow efficiency gains to be achieved in the most economically efficient manner, i.e. at least cost, which is frequently referred to as one of the main benefits of the EU ETS. White certificates – tradable energy efficiency reductions, can be applied to multiple fuels, energy carriers and sectors. The absence of a market for EE has diverted attention more towards the development of sustainable energy supply, rather than the arguably more cost effective sustainable use of energy. EEC represents a possible UK precursor to a White Certificate Scheme, requiring DNOs with more than 50000 customers to achieve a total of 130 "fuel standardized lifetime discounted terawatt hours" for 2005-2008 but this is a long way from a tradable system. DEFRA has committed to assessing the part white certificates can have towards reducing Carbon emissions by 2007.

8.5 Fuel Poverty Initiatives

8.5.1 Fuel poverty is largely dependent on volatile fuel prices not legislation

Recent increases in consumer energy electricity and gas prices have had a significant detrimental effect on fuel poverty. Some stakeholders argue that the lack of a long term approach to sustainable energy was one of the factors that contributed to the recent rises in energy prices, which led to millions more people being drawn back into fuel poverty. The initial opening up of the UK energy markets led to some benefits to consumers in that prices fell as competition increased and people were raised out of fuel poverty as a result. In the new competitive climate, there is less of an incentive for the energy operators to make investments ahead of need and in particular no incentive for any individual operator to invest in strategic long-term gas storage. During the winter of 2005, the UK was more dependant than in the past on European gas supplies and coupled with the increased demand and across Europe; this led to higher gas prices and in turn higher electricity prices. The outcome of this sequence of events was to draw more people into fuel poverty as prices rose than had previously been taken out. It has been argued that this is threatening to turn the Government's Fuel Poverty Strategy into a failure and represent a significant barrier to a more sustainable energy system. Although this is a very much simplified argument to a complex and unexpected sequence of events, many commentators believe there is some truth in the argument that short-termism does open the UK energy market up to this volatility in prices. Some commentators also believe the Government could do more to tackle the issues of fuel poverty and affordability in this climate of higher fuel prices, perhaps along the lines of encouraging investment energy efficiency and micro-generation, which help shield vulnerable groups from the further price rises.

8.5.2 Warm Front requiring additional resources

Warm Front is the Government's main grant-funded programme for tackling fuel poverty. The scheme was launched in June 2000 and before its name changed to Warm Front; it was called the Home Energy Efficiency Scheme. Warm Front provides packages of insulation and heating measures depending upon the needs of the householder and the construction of the property. The scheme offers: Grants of up to £1,500 - offering packages of insulation such as loft and/or cavity wall insulation, draught proofing, gas wall heaters, dual element foam insulated immersion tank, heating repairs and replacements. The grant is available to:

- Households, with children under the age of 16, in receipt of an income-related benefit;
- Pregnant women, who receive an income-related benefit and have a MAT B1 certificate provided by their doctor;
- Households who receive a disability benefit.

Grants of up to £2,500 are available to households who are over 60 and receive an income-related benefit. The grant provides insulation measures and, for those who do not have an existing heating system, a central heating system for the main living areas of the household. However, the Fuel Poverty Action Group suggests that there is a great deal more that Warm Front could do and that additional resources are required following the £300m granted through PBR 2005.

8.5.3 The Winter Fuel Payment is not targeted and does not incentivise energy efficiency measures

The current system of providing an annual payment to a broad section of households defined as vulnerable to fuel poverty (i.e. the elderly) is not targeted so all pensioners receive it regardless of income. Some commentators argue that this mechanism could be revised to provide more help to the people in greatest need and actively encourage greater take up of energy efficiency and micro-generation technologies. Many stakeholders believe these changes would fit well with the popular view that mass-market energy efficiency and micro-generation is a key route to future proofing UK homes and businesses against fuel poverty and energy security issues.

Section B

Options for overcoming the barriers to a sustainable energy system in Great Britain

9 Analysis of options for overcoming the barriers to a sustainable energy system

This section contains the analysis of the options selected by SDC for more detailed consideration. Given their review of Ofgem's role in delivering a sustainable energy system, which the results of this project fed into, SDC decided to focus the detailed analysis on options that Ofgem could implement or administer (in relation to cap and trade):

1. Allow Network Operators to develop heat networks and make them part of the regulated asset base
2. Incorporate the cost of carbon in to distribution and transmission network charges
3. Introduce a 'connect and manage' approach to the transmission network and prioritise connection of low carbon generation
4. Add sustainability and GHG reduction objectives to the Balancing and Settlement Code
5. Create new trading arrangements for small and intermittent generators
6. Upgrade the distribution network by strengthening incentives and increasing investment
7. Implement an agency system of contractual agreements between Distributed Generators and the GB Transmission System Operator
8. Introduce a carbon 'cap and trade' for energy suppliers
9. Revise TNUoS Charging Structure for CHP
10. Mandate energy suppliers to improve billing
11. Develop an Offshore Regulatory Regime for the Transmission Network
12. Implement more equitable arrangements for allowing National Grid to protect itself against the risk of unnecessary transmission investment
13. Amend the supply license so that suppliers are obliged to sign up to the green supply guidelines

Each option is presented in a common format to enable easy comparison. All of the calculated figures for carbon savings, costs and primary energy savings are given to 2 significant figures. In view of the assumptions associated with many of the calculations it was felt that any greater degree of precision would give a misleading picture of the accuracy of the results.

Most of the categories in the template are self explanatory but some warrant further explanation:

'Facilitated carbon savings' – this is where the option itself will **NOT** achieve 'actual' carbon savings but will 'facilitate' the achievement of, or significantly reduce the barriers to achieving, a tranche of carbon savings. For example, the proposed regulatory regime for the offshore transmission network will not produce any carbon savings. However, it will allow the power generated by offshore renewables to be fed into the onshore transmission network which will achieve significant carbon savings – in other words the offshore regulatory regime has 'facilitated' those carbon savings.

Primary energy savings due to reductions in 'heat losses' – throughout this section Primary energy savings due to reductions in 'heat losses' has been abbreviated to "primary energy savings". The primary energy savings referred to in this section result from generating power using CHP plants rather than conventional fossil fuels plants (no other primary energy savings have been considered). CHP plants are able to capture a high proportion of the heat produced during electricity generation and divert it for some useful purpose (e.g. an industrial process or space heating). In contrast, conventional power stations release the heat produced during electricity generation to the atmosphere via their cooling towers. Several of the options that are considered in this section would result in an increase in CHP capacity and could therefore lead to a significant primary energy saving.

The complete set of options is listed in Annex 3 – Full list of options. The total carbon savings, costs and primary fuel savings are listed in section 10.

Option 1	Allow Network Operators to develop heat networks and make them part of the regulated asset base		
Barrier overcome:			
• 4.4.9 Lack of heat regulator is a barrier to sectoral development • 7.1.1 High infrastructure costs to develop heat network			
Supply chain stage:	The Distribution Network	**Implementing actor/s:**	Ofgem / Distribution Network Operator
Estimated annual carbon savings (MtC):	5.7 - 14	**Estimated primary energy savings (MWh):**	110,000,000 - 270,000,000
Estimated cost to Central Government (£million): Annual or One-off cost?		10 - 25 **One-Off** cost to oversee the formation of a heat network	
Estimated other costs (£million): Annual or One-off cost? Recipient of costs		£53,000 – 88,000 **One-off** cost to construct the heat network and then connect every household to it DNOs then consumers	
Description of option:			

There is not currently a national or regional heat network in the UK. The limited number of networks that do exist are localised such as those in Sheffield, Southampton and Nottingham. Sheffield's district energy network is one of the largest and most successful in the UK. It was established in 1988 and is still expanding. There are 43km of pipeline installed to deliver heat to homes (over 2,800), public buildings and commercial properties in Sheffield across 2 networks. In 2000 nearly 120,000 MWh of heat were delivered to buildings in Sheffield City Centre and the surrounding areas. For every 100,000MWh of energy supplied by district energy 31,000 tonnes of carbon dioxide are displaced.

However heat networks are used much more widely in other countries (for example 60% of households in Denmark are connected to heat networks) so their technical feasibility has been proven. It is worth noting that if policy makers were to decide to facilitate a heat network it could operate on a local level (e.g. a series of decentralised plants supplying heat and possibly electricity to local demand areas) whilst still having broad coverage.

The reasons suggested for this lack of development are as follows:

- Most stakeholders agree that constructing a heat network would involve high infrastructure costs. There is currently no certainty regarding who ought to ultimately bear the cost of such a network. Instinctively many people would say it ought to be the consumer, but would it be fair to expect them to pay for a network they do not need in order to satisfy their heating requirements? Conversely, there is a strong argument that everyone should contribute to a national effort to mitigate the effects of climate change. In addition, if such a network were to be built, a medium term financing package would need to be put in place to fund the construction of the network before the operator/s can begin to recoup their costs.

- The heat market is still outside the regulatory framework. Many stakeholders believe this creates a lack of focus for heat market development. If utilities want to lay out new electricity or gas supply network then they have rights to compulsory purchase of the land – no similar rights exist for heat networks.

As such it is suggested that regulation of the existing heat networks and further development of heat networks is made the responsibility of Ofgem. Any suitable party (suitability would be assessed by Ofgem against a set of criteria such as financial position, conflict of interest, relevant expertise) would then be able to apply for a license to build a local heat network. This would help ensure the efficient use of capital since networks would only be built where there is demand for heat.

Appointing Ofgem as the heat network regulator could also be used to build consumer confidence in the reliability of the heat supply from a heat network. This could be achieved by stipulating minimum network standards in the network owner license conditions in a similar vein to the SQSS on the transmission network. Appointing Ofgem as the regulator would also prevent repetition of infrastructure or 'stranded' heat network assets, providing they were given appropriate powers.

Heat network licensees could include groups as diverse as local authorities (who could construct heat networks as a means of combating fuel poverty) and gas or electricity Distribution Network Operators. However, given their expertise in managing networks and their existing relationships with local authorities it is envisaged that many of the networks would be licensed to existing Gas Distribution Network Operators (GDNOs).

Under such circumstances the GDNO would provide gas to the CHP plants (which are likely to provide the bulk of the heat entering heat networks due to their high efficiency) and distribute their heat, thus ensuring bureaucracy and contractual arrangements were minimised for all parties. CHP plant also provides 'future proofing' benefits since it can be designed in such a way as to allow the same plant to burn biofuels, waste or conventional fuels such as natural gas.

Where more than one party wished to develop a heat network covering the same area Ofgem could oversee a competitive tendering process to award the license. It is hoped this would create competition and hence deliver value to the consumer.

A further potential benefit is the possibility of using the new heat networks to transport hydrogen. The networks should be designed with that idea in mind to ensure they are 'hydrogen-ready' in the event a hydrogen economy becomes a reality.

There is an obvious short term tension here however, in that a critical mass of both producers and end users of heat is likely to be required prior to the justification of any expenditure on the development of a heat distribution network. As such it is suggested that municipal sources of heat production and demand are targeted first in an attempt to begin the process of heat network development, and justify the introduction of a charging structure.

It is envisaged that the cost of constructing the heat networks would be shared by all energy consumers, perhaps in the form of a levy on each kWh of energy consumed. Precise levels of funding could be determined by Ofgem in a similar manner to the price controls that are used to determine the revenues of the monopoly electricity and gas networks.

Number of new entrants:	The provision of a heat distribution network would incentivise the developers of CHP plant through the provision of a wider market for heat.
Impact on generation mix:	It is expected that increased penetration of heat only or CHP plant would enter the market.
Impact on consumer bills:	There would be a short to medium term increase in consumer bills as the costs of building the network are passed through by the DNOs. However it is likely that this trend will reverse once the network is constructed and consumers can connect to it rather than rely on conversion of primary energy into heat in their home. Case studies developed by the EST (www.est.co.uk) suggest a whole life benefit for both retrofit and new build community heating schemes.

Legislative changes required & opportunities in Ofgem's existing role:

- It is likely that the new primary legislation would be required to:
  - Change Ofgem's duties to include regulating the heat network
  - Allow any suitable party (suitability determined by Ofgem) to construct a heat network
  - Give Government and Ofgem the power to create the necessary regulatory framework
- Once the primary legislation was in place Ofgem and DTI could set about determining the detail of the regulatory framework such as the licenses and codes that would govern the operation of the network and its participants.

Main tensions in the reform process:

- Ofgem and other stakeholders do not believe there is a market for heat and as such are opposed to the concept of a nationwide heat network.
- If the Government decided to proceed with developing a heat network there are likely to be a range of opinions regarding the shape of the licences and codes.
- It is not known whether GDNOs and other potential heat network owners would be interested in building a heat network. Government may need to provide incentives to encourage the requisite investment.

Timeline for implementation:

- **Summer 2007:** Government decide whether the concept of a nationwide heat network warrants further consideration.
- **Autumn 2007:** Government commissions a study examining the feasibility of a heat network including a comprehensive cost and benefit analysis
- **Spring 2008:** Government consults on the feasibility of a nationwide heat network
- **Autumn 2008:** Government decides whether to proceed with a nationwide heat network
- **Spring 2009:** Government begins works with Ofgem to determine the details of the regulatory framework for a heat network and puts new primary legislation before

parliament. • **2011/2012:** Details of regulatory framework finalised and construction begins.
Assumptions made during cost and carbon savings calculations:
• Costs and carbon savings reflect calculations made on the basis of converting entire UK housing stock to a district heating network. • All the heat provided by the heat networks will come from CHP plants • Energy bills will not rise as a result of heat and electricity being provided by CHP plants • 20-40% of future GB electricity generation capacity will be DG • 16.3% of current GB electricity generation capacity is DG • 20-40% of future GB electricity supply will be DG • 7.1-14% of new GB electricity generation capacity will CHP, all of which will be DG • 86-92.9% of new GB DG capacity will be renewables • New CHP capacity will have an overall energy efficiency of 75%, a heat to power ration of 2.2:1 and a load factor of 70 – 85% • The boilers replaced by CHP plants have an energy efficiency of 85% and load factors of 70 – 85% • Heat and power are used for 2-5 hours a day by the average household
Factors to be taken into account in completing cost and benefit analysis:
• The split of heat to power ratios in CHP plants (the calculations in this option assumed all CHP plant will have a heat to power ratio of 2.2:1 – in reality there will be significant variation depending on the role of the CHP plant). • The accuracy of data on the costs and carbon savings associated with connecting each household to a heat network

Option 2	**Incorporate the cost of carbon in to distribution and transmission network charges**		
Barriers overcome:			
• 3.2.3 Role of Regulator: Short term price focus rather than long term policy concerns, • 5.3.1 Lack of use to system charging regime for intermittent generators, • 5.3.2 High transmission charges for off-shore generation			
Supply chain stage:	Electricity Transmission System	**Implementing actor/s:**	Ofgem, TOs
Estimated annual facilitated carbon savings (MtC):	A) 0.2 – 0.3 B) 7.2 – 14	**Estimated Primary Energy Savings (MWh):**	Negligible
Estimated cost to Central Government (£million): Annual or One-off cost?	Negligible N/A		
Estimated other costs (£million): Annual or One-off cost? Recipient of costs	A) Negligible B) 2.0 – 5.0 **One-off** cost of incorporating the carbon emitted by power stations into TNUoS charges Ofgem		
Estimated other costs (£million): Annual or One-off cost? Recipient of costs	A) 51 – 153 B) 880 – 2600 **Annual** cost of the carbon emitted by power stations Generators then Consumers		
Description of option:			
The use of 'RPI-X'[23] approaches to incentivise cost savings in privatised industries is common in the UK. This approach has been applied to the telecoms, water and energy sectors and is widely credited with bringing about reductions on costs to consumers. Many commentators believe it works because there is a simple reward system for participants: every £1 reduction in costs under the price control equates to a £1 increase in profit.			

[23] 'RPI-X' refers to the process of agreeing charging increases by applying changes to the retail price index to existing charges after subtracting a predetermined sum (X). The Retail Price index is a general measure of inflation in the UK.

RPI-X formulae are currently used to determine charges in the following elements of the UK energy system:

- Electricity Distribution Price Controls (reset with effect from 1st April 2005)
- Transmission Price Controls (reset with effect from 1st April 2007)
- Gas Distribution Price Controls (reset with effect from 1st April 2008)

As well as the direct operating costs of participants, RPI-X formulae are used to determine capital expenditure and depreciation, return and tax. Calculations are made to reflect the assumed operating lifetimes of assets rather than the costs at the point of installation.

However there is a realisation amongst most stakeholders that this type of charging review system may not be as appropriate for managing concerns such as security of supply or the environmental impact of energy use, than as for reducing costs.

As such it may be appropriate to introduce a system of charging which reflects the environmental impacts of the activity in question. This could retain the RPI-X format if a further moderator, the cost of carbon were added. This would take the form of RPI-X +/- the cost of carbon (as determined by Government Economic Service).

Option A

Under this option a participant who's costs or charges equal £100m in year 1 would be allowed to increase charges by (RPI – X) - (the cost of Carbon * level of emissions associated with their activities). In option A the cost of carbon is subtracted from RPI-X to incentivise the transmission and distribution networks to reduce the carbon emissions on their networks by reducing their revenue according to the value of the carbon associated with their energy use associated with the operation of the network i.e. through transmission losses and reactive power.

This option would overlap with the existing targets and incentives (and the ideas for amending these policies outlined in option 6) designed to reduce losses on the networks. Whilst some stakeholders would not be averse to such double counting others may view it as economically inefficient. Therefore, if policy makers decided to give serious consideration to implementing these ideas then there would be a need for a broader review of how they would interact with existing policies and measures.

This could calculate as:

(£100m * (4% - 1%)) - £3,500,000 = £99.5m

Where RPI = 4%,

X = 1%

The cost of carbon = £5-15/tC (The social cost of carbon recommended by the Government Economic Service is £35/tC - £140/tC. However, the SDC preferred to use a lower price to give a carbon price signal whilst still ensuring the option was affordable)

Total emissions = 50,000 t

Option B

An alternative approach would be to calculate the level of emissions associated more widely with the activity i.e. the emissions associated with the generation of the power transmitted through the specific element of the network, although in this case there would be a need to add a positive moderator to the RPI-X formula. This is because Option B would be targeted at power generators through an increase in the use of system charges they incur. The network operators would be entitled to pass through (i.e. charge their customers) the cost of the carbon associated with operation of power plants. This approach could be expressed as:

RPI - X + Carbon, or to continue the example above:

£100m * (4% – 1%) + £350,000,000 = £450,000,000

Where:

RPI = 4%,

X = 1%

The cost of carbon = £10-15/tC (The social cost of carbon recommended by the Government Economic Service is £35/tC - £140/tC. However, the SDC preferred to use a lower price to give a carbon price signal whilst still ensuring the option was affordable)

Total emissions = 50,000 tCO_2

An alternative would be to require the cost of carbon to be calculated as an average of the past quarter or 12 months of the EU ETS allowance price. These charges could be pooled and recycled to cleaner generators as a subsidy, in a manner similar to that which locational charges are already recycled. However, this approach would risk double regulation and potentially double charging of users as emissions may already be accounted for under the EU ETS. This method would also increase costs to users of the system, and thus consumers, dramatically in the short and medium term, but would send a strong price signal to high carbon intensity users of the transmission and distribution system.

This methodology could be applied on either a transmission or distribution basis. Each application has different advantages and disadvantages.

Transmission:

A carbon cost could with administrative simplicity be applied as part of the locational charges. This would require generating assets to declare their carbon intensity of generation and be charged according to their level of output. However this would not cover the sub 100MW generation capacity connected to the distribution network that does not currently pay locational charges if output is contracted to a supply company who is paying the charges and the asset generates during the triad periods of highest demand. This may not have a significant environmental effect, as sub-100MW plant is likely to consist of high efficiency CHP and small-scale renewables such as wind and/or biomass. Exempting these units from additional charges may further incentivise their deployment.

Distribution:

The alternative would be to require DNOs to charge for carbon. This would have the advantage of catching all generating assets and would allow redistribution to be made more effectively. This will have to be implemented centrally however as the amount of low carbon assets within each DNO will vary and would therefore create a 'post-code lottery' if strict distribution license boundaries were applied. This option would require more significant changes to legislation as cross-subsidy (to allow and equitable redistribution of revenues) between DNOs is not currently feasible.

Number of new entrants:	Option A is unlikely to impact on new entrants to the market Option B would encourage low carbon new entrants as use of system costs would decrease

Impact on generation mix:	Option A would have little impact on the generation mix, but would incentivise savings from transmission and distribution operators Option B would incentivise the development of low carbon generation assets
Impact on consumer bills:	Option A would have little if any impact on consumer bills Option B would be likely to have a significant impact on consumer bills in the short to medium term

Legislative changes required & opportunities in Ofgem's existing role:

- Ofgem could introduce the +/- cost of carbon moderator to the RPI-X formula within its existing powers.

Main tensions in the reform process:

Option A

- Will increase costs to consumers
- Will require measurement and verification of energy use and calculation of emissions
- May necessitate broader changes to the policy framework to address double counting of the losses on the networks.

Option B

- Will increase costs to consumers significantly
- Makes the 'RPI-X' part of formula virtually redundant
- May require cross subsidy between network operators

Timeline for implementation:

- **Summer 2007:** Ofgem form a working group to develop and analyse the detailed options
- **Spring 2008:** The working group reports back to Ofgem
- **Summer 2008:** Ofgem consults on the changes proposed by the working group
- **Autumn 2008:** Decision by Ofgem on the nature of the changes to the RPI-X formula
- **Summer 2009:** Ofgem provide details of the arrangements for future price controls

Assumptions made during cost and carbon savings calculations:

- Emissions from the transmission network = total emissions from transmission **and** distribution networks (no better data was available)
- Emissions from the Power Station sector equate to the emissions for all UK electricity generation and industrial, domestic and commercial gas use

Factors to be taken into account in completing cost and benefit analysis:
• Energy use and emissions associated with the transmission and distribution network • The price effects • Estimates of the rates of change of the generation mix in order to calculate carbon savings • Impact of cost increases on consumers for each option

<table>
<tr><td>Option 3</td><td colspan="3">Introduce a ‘connect and manage’ approach to the transmission network and prioritise connection of low carbon generation</td></tr>
<tr><td colspan="4">Barrier overcome:</td></tr>
<tr><td colspan="4">5.1.1 BETTA Queue - Long connection times to the transmission network for renewable project developers in Scotland.</td></tr>
<tr><td colspan="4"></td></tr>
<tr><td>Supply chain stage:</td><td>The Electricity Transmission System</td><td>Implementing actor/s:</td><td>Ofgem / DTI / NGET</td></tr>
<tr><td>Estimated annual carbon savings (MtC):</td><td>Actual = 1.3 – 3.2

Facilitated = 7.8</td><td>Estimated Primary Energy Savings (MWh):</td><td>Negligible</td></tr>
<tr><td colspan="2">Estimated cost to Central Government (£million):

Annual or One-off cost?</td><td colspan="2">Negligible

N/A</td></tr>
<tr><td colspan="2">Estimated other costs (£million):

Annual or One-off cost?

Recipient of costs</td><td colspan="2">2.0 – 5.0

One off cost to set up the connect and manage approach

National Grid</td></tr>
<tr><td colspan="4"></td></tr>
<tr><td colspan="4">Description of option:</td></tr>
<tr><td colspan="4">The current connection arrangements are based on an ‘invest and connect’ philosophy. Under this approach National Grid Electricity Transmission (NGET) respond to a connection enquiry and if the commercial arrangements are agreed, plan and build the required network infrastructure to accommodate the new capacity (e.g. new lines, new switchgear, new substations or upgrading parts of the network).

The length of the queue for connection was compounded by the flood of connection applications before the BETTA go-live date (April 2005), especially in Scotland. Developers were faced with additional limits placed on new connection applications (most significantly the condition that new generation applying for connection post BETTA go-live would receive offers contingent on the wider British network being strengthened) once BETTA came into force so there was a flood of connection applications to beat this deadline.

To address this issue Ofgem could help NGET to introduce a 'connect & manage' approach to managing the transmission network. This would entail allowing generators to connect to the grid as soon as the direct connection could physically be made and then managing the system by dispatching (i.e. permitting them to use the grid) all the plant connected to the transmission network. Priority in this dispatch could be given to</td></tr>
</table>

renewable generators to maximise the sustainability of the ‘grid mix’ electricity at any given point in time. Ofgem could formalise this new approach by amending the Grid Code and the Connection and Use of System Code.

A connect and manage approach would encourage the transmission network owners to maximise the use of the network, bring forward connection and manage the network either until new capacity could be brought forwards, or on a more permanent basis by using the system differently. In addition, developers would be given more clarity regarding the timescales of their connection.

Certain forms of electrical losses are an inevitable consequence of the transfer of energy across electricity networks. Depending on the location of generation and demand a more detailed power flow analysis would determine whether the grid losses increase or decrease. Greater distances between generation and demand will inevitably cause greater system losses. Therefore, there will be a trade off between making better use of existing capacity through a connect and manage approach and increased electrical losses on the transmission network. However, the increased losses should be put into perspective as Digest of UK Energy Statistics 2005 (DUKES) states the losses from the transmission network were 1.5% of electricity entering the high voltage network.

If a connect and manage philosophy was adopted it would be easier to prioritise connections by carbon intensity since a connection would no longer be dependent on there being spare capacity. Existing connection offers would need to be honoured under a revised system for assigning connection dates but new connection offers could be prioritised according to a combination of carbon intensity and cost. One approach would be for the carbon intensity to act as the primary means of prioritising the connection requests with cost of connection being the deciding factor between projects of similar carbon intensity. In summary, NGET’s priority moving forward could be to provide access for low-carbon projects that were cheap to connect.

In order to implement this system a standard methodology for calculating carbon intensity (i.e. carbon emissions per MW of generation capacity) would need to be developed by National Grid and approved by Ofgem. This would need to include a comprehensive list of emissions factors for each generation technology. Project developers would then submit detailed information on their proposed scheme (i.e. capacity, type of generation etc) along with their connection application to allow the carbon intensity of their project to be assessed by the National Grid. New connection applications would then be reviewed periodically by National Grid (perhaps once a quarter), prioritised according to their carbon intensity and subsequently allocated a connection date. Once the connectee had accepted the connection offer they would then become liable for the Generic User Commitment (National Grid’s interim arrangements to replace the Final Sums Liability - see Option 6) that protects the Transmission Owners and National from

Depending on the success of implementing the connect and manage approach through Code amendments it may also be necessary to introduce incentives for the GBSO to adopt the new way of working. The incentives could be based on the amount of low-carbon capacity connected and modelled on the arrangements that are already in place to encourage DNOs to connect distributed generation.

Allocating connection offers on the basis of carbon intensity rather than carbon savings would help prevent discrimination against small renewables projects. Furthermore, the system proposed in this option would not significantly increase the bureaucratic burden on smaller generators. Generators would simply be required to provide a few extra pieces of information with all the additional calculations being undertaken by the GBSO.

Implementing this option should help to reduce the BETTA queue, and hence remove a significant barrier to a sustainable energy system, by eliminating the need for speculative applications aimed at reserving a potential project’s place in the queue. Through switching to a connect and manage approach it is hoped that project developers would revert to only submitting firm connection applications where they fully intend to build the project.

It is also hoped that this option would bring renewable energy projects online sooner resulting in a more environmentally sustainable and diverse energy mix. However, it is important to recognise that there would be a cost associated with requiring fossil fuel plants to lower output. They would in all likelihood begin to charge a higher price for their electricity.	
Number of new entrants:	This option would remove a significant barrier to developing renewable energy projects which could encourage more renewable energy developers into the market.
Impact on generation mix:	This option would promote connection of renewable energy sources to the transmission network which could result in a more diverse energy mix.
Impact on consumer bills:	This option will have a minimal impact on consumer bills.
Legislative changes required & opportunities in Ofgem's existing role:	
• No legislation change required. • Ofgem could mandate a connect and manage approach through amending the Grid and Connection and Use of System Codes.	
Main tensions in the reform process:	
• Developers of fossil fuel power stations may object to the proposals in this option since their projects would not be connected as soon would otherwise have been the case. • Ofgem and DNOs may not agree with this proposal as constraint payments may be need to be made if some generation is not required by the grid.	
Timeline for implementation:	
• **Autumn 2007:** Ofgem propose code amendments to facilitate the connect and manage approach • **Winter 2007:** Code panels form working groups to analyse proposals in detail • **Spring 2008:** The working groups report back to Ofgem • **Summer 2008:** Panels make recommendations to Ofgem • **Autumn 2008:** Ofgem consults on Panel recommendations • **Spring 2009:** Ofgem makes a final decision on the Panel recommendations	
Assumptions made during cost and carbon savings calculations:	
• The 'Connect and manage' approach will advance the connection of 2GW of wind generation by 2 – 3 years. • The load factor for renewables is 30-50%	

Factors to be taken into account in completing cost and benefit analysis:
• Load factors for different renewables technologies • Likelihood of meeting the 20% aspirational target for renewables • Future marginal plant carbon emission factor • Cost of requiring fossil fuel plants to reduce output.

<table>
<tr><td>Option 4</td><td colspan="3">Add sustainability and GHG reduction objectives to the Balancing and Settlement Code</td></tr>
<tr><td colspan="4">Barrier overcome:</td></tr>
<tr><td colspan="4">• 3.3.4 Lack of sustainability criteria or renewables focus in Balancing and Settlement Code</td></tr>
<tr><td colspan="4"></td></tr>
<tr><td>Supply chain stage:</td><td>Cross-cutting</td><td>Implementing actor/s:</td><td>Ofgem / Balancing and Settlement Code Panel / Balancing and Settlement Code Company</td></tr>
<tr><td>Estimated annual facilitated carbon savings (MtC):</td><td>11 – 16</td><td>Estimated primary energy savings (MWh):</td><td>27,000,000 – 68,000,000</td></tr>
<tr><td colspan="2">Estimated cost to Central Government (£million):

Annual or One-off cost?</td><td colspan="2">Negligible

N/A</td></tr>
<tr><td colspan="2">Estimated other costs (£million):

Annual or One-off cost?

Recipient of costs</td><td colspan="2">Negligible

N/A

N/A</td></tr>
<tr><td colspan="4"></td></tr>
<tr><td colspan="4">Description of option:</td></tr>
<tr><td colspan="4">It is widely felt by renewable energy developers that the trading rules under NETA and later BETTA have discriminated against the unpredictability and intermittency of renewable generation, and that the trading system has artificially depressed the renewable energy price.

Under the trading rules, in order to balance the system, generators and suppliers are required to forecast their supply and demand ahead of delivery. For renewable generators, this can be difficult. If the actual supply and demand differs from their forecast, they are penalised by having to buy from or sell into a secondary and potentially more volatile ‘balancing’ market. As a result, the imbalance penalties imposed have at times outweighed the payments made for supplying energy, with some wind farms generating at a net negative unit value per kW hour, making a loss simply from production and sale of electricity even before development costs are included.

This problem was compounded when Ofgem implemented Balancing and Settlement Code Modification Proposal 194 (P194), which was proposed by National Grid in August 2005. Under the previous arrangements the imbalance price (the price paid per MWh of under or over supply) was determined by taking the volume weighted average price of</td></tr>
</table>

the Net Imbalance Volume (NIV), which is the volume of the overall system energy imbalance, as a net of all systems and energy balancing actions taken by the Balancing and Settlement Code Company for the Settlement Period.

However, when P194 came into force the imbalance price was determined by taking the volume weighted average price of the most expensive 100MWh of energy left in the NIV, which resulted in an increase in the imbalance price. This measure was designed to promote security of supply through forward market activity. I.e. encourage generators and suppliers to contract with each other well in advance and make every effort to meet their contracted amounts so that the Balancing Mechanism would only be needed for fine tuning supply. However, this measure penalised renewable generators who tend to find themselves buying or selling into the balancing mechanism more frequently than conventional generators because of their intermittency. As a result they were more likely to incur the new higher imbalance prices.

It should be noted that this issue has been addressed to some extent by Balancing and Settlement Code Modification Proposal 205 (P205), which was proposed by renewables supplier Good Energy in July 2006 and adopted by Ofgem in November 2006. The proposal suggested increasing the portion of the NIV from which the imbalance price is calculated from the most expensive 100MWh to the most expensive 500MWh. The aim of this proposal was to reduce the imbalance price and hence the penalties faced by intermittent renewables. Nonetheless some stakeholders believe there is still scope to provide further assistance for renewables by amending the objectives of the Balancing and Settlement Code Company (BSCCo), and the Code Panel.

Elexon, the BSCCo, operate the Balancing and Settlement process on behalf of the GB System Operator (National Grid). The objectives of the BSCCo as stated in section C of the Code are to achieve the overall objectives for the Code Panel as set out in paragraph 1.2.1 of Section B of the Code:

"The Panel shall conduct its business under the Code with a view to achieving the following objectives:

(a) that the Code is given effect fully and promptly and in accordance with its terms:

(b) that the Code is given effect in such a manner as will facilitate achievement of the objectives (so far as applicable to the manner in which the Code is given effect) set out in Condition C3(3)(a) to (c) of the Transmission Licence, namely:

(i) the efficient discharge by the Transmission Company of the obligations imposed under the Transmission Licence;

(ii) the efficient, economic and co-ordinated operation by the Transmission Company of the Transmission System, and

(iii) promoting effective competition in the generation and supply of electricity, and (so far as consistent therewith) promoting such competition in the sale and purchase (as defined in the Transmission License) of electricity;"

In line with Ofgem's primary duty the Panel objectives are focused on protecting the consumer through facilitating effective competition. They do not include sustainability or carbon criteria. Consequently, there is no obligation on the Panel or the BSCCo to act in a sustainable manner or contribute towards the efforts to reduce greenhouse gas emissions. Were such an obligation to be put in place it would provide the Panel with the mandate to consider proposed changes to the Balancing and Settlement process that could eliminate the perceived discrimination (some stakeholders would argue that the penalising renewables for intermittency is right and proper given their intermittency) against renewables. The status quo does not readily allow for this since the party proposing the change to the code must, according to paragraph 2.1.2(f) in section F of the BSC, state:

"the reasons why the Proposer believes that the proposed modification would better facilitate achievement of the Applicable BSC Objective(s) as compared with the then current version of the Code"

Without an objective to act in a sustainable manner or reduce greenhouse gas emissions changes to the code that aim to reduce discrimination against renewables may not even been viewed as valid by the BSC Panel. Consequently, the proposal would be rejected without detailed consideration.

Any changes to Ofgem's primary duty to include an emphasis on cutting greenhouse emissions (amongst other things) will still require an amendment to the Panel Objectives to ensure that the revised priorities filter through to the BSCCo. The revised wording to incorporate sustainability and greenhouse gas emission reduction could take the following form (additions highlighted in bold and underlined):

"The Panel shall conduct its business under the Code with a view to achieving the following objectives:

(a) that the Code is given effect fully and promptly and in accordance with its terms:

(b) that the Code is given effect in such a manner as will facilitate achievement of the objectives (so far as applicable to the manner in which the Code is given effect) set out in Condition C3(3)(a) to (c) of the Transmission Licence, namely:

(i) the efficient discharge by the Transmission Company of the obligations imposed under the Transmission Licence;

*(ii) the efficient, **<u>sustainable</u>**, economic, and co-ordinated operation by the Transmission Company of the Transmission System, and*

*(iii) promoting effective competition in the generation and supply of electricity, **<u>promoting a reduction in greenhouse gas emissions wherever possible, promoting innovation</u>** and (so far as consistent therewith) promoting such competition in the sale and purchase (as defined in the Transmission License) of electricity;"*

Additionally, the Government in partnership with Ofgem could commission a review of the entire Balancing and Settlement Code and assess how it has delivered against its 4 policy goals. The energy markets are evolving rapidly especially with respect to the focus on mitigating the impact of climate change. Therefore, it is important to ensure that the Balancing and Settlement Code, and indeed the other codes that govern how the British energy markets function, are designed to put Britain on a pathway to meeting its 4 energy policy goals.

Number of new entrants:	In the medium to long term it is likely that there would be an increase in new entrants as a result of this measure. Once the BSC Panel objectives had been amended, changes to the BSC that reduced the discrimination against renewables would be far more likely to be accepted as valid and considered in detail.
Impact on generation mix:	The proportion of renewable generators would increase if BSC provides them with equal opportunity to participate in the energy market.
Impact on consumer bills:	No impact on consumer bills is expected in the short term. In the medium to longer term the greater number of connections to the transmission network that this measure would facilitate may lead to higher costs being

	incurred by the transmission owners, which in turn would be passed onto consumers.

Legislative changes required & opportunities in Ofgem's existing role:

- No changes would be required to primary legislation to implement this option.
- Implementing proposed changes to the BSC is within Ofgem's current remit.
- Changing Ofgem's primary duty to include an obligation to act sustainably and reduce greenhouse gas emissions would provide them with a stronger remit to amend the objectives of the various Codes accordingly. This in turn would allow the Panels to validate and consider proposed changes to the Code that aimed to reduce discrimination against renewables.

Main tensions in the reform process:

- There will inevitably be a series of negotiations between Government and Ofgem to agree the final wording of the primary duty. There may be resistance to the proposed changes from some of Ofgem's senior management. In addition, other stakeholders would almost certainly wish to be involved whether or not they were invited to take part in a formal consultation process.
- Amending the primary duty of Ofgem, and hence its ethos to one where sustainability and reducing carbon emissions are given a far higher priority, will, like any significant change to a large organisation, give rise to internal tensions. The extent to which the need to protect consumers through promoting competition is ingrained in Ofgem's culture should not be underestimated. There would in all likelihood be a period of adjustment, possibly lasting last years rather months, where Ofgem came to terms with its new role and how to interpret its primary duty.
- The amendments to the codes themselves would in all likelihood be the subject of much debate amongst stakeholders.

Timeline for implementation:

- **Summer 2007:** Government formulates proposals for Ofgem's revised primary duty.
- **Autumn 2007:** Government consults on their proposals.
- **Spring 2008:** Government decision on Ofgem's revised primary duty.
- **Summer 2008:** Ofgem filter down the changes to their primary duty by asking the relevant panels to set up working groups to draw up changes to the objectives of the Codes that govern the operation of the energy sector.
- **Autumn 2008:** Ofgem consult on changes to the objectives.
- **Spring 2009:** Ofgem decision on revised objectives.
- **Summer 2009:** Parties to the Codes submit proposed changes to the BSC to promote renewables.

Assumptions made during cost and carbon savings calculations:

- Only direct costs have been considered (i.e. cost of the incentive mechanisms)
- Renewable electricity is carbon neutral
- 20-40% of future GB electricity generation capacity will be DG

- 16.3% of current GB electricity generation capacity is DG
- 20-40% of future GB electricity supply will be DG
- 7.1-14% of new GB electricity generation capacity will CHP, all of which will be DG
- 86-92.9% of new GB DG capacity will be renewables
- New CHP capacity will have an overall energy efficiency of 75%, a heat to power ration of 2.2:1 and a load factor of 70 – 85%
- The boilers replaced by CHP plants have an energy efficiency of 85% and load factors of 70 – 85%

Factors to be taken into account in completing cost and benefit analysis:

- Indirect costs such as the cost of renewable energy technologies compared to conventional centralised fossil fuel plant
- Carbon savings associated with CHP compared to conventional centralised fossil fuel plant
- The proportion of future generating capacity that is likely to be DG
- The split of DG capacity between renewables, CHP and other technologies

Option 5	Create new trading arrangements for small and intermittent generators		
Barriers overcome:			
• 3.2.2 Need for clearer sustainability remit for regulator • 3.2.4 Complexity of regulatory environment for smaller players • 3.3.1 Discrimination against intermittent renewables • 3.3.2 Discrimination against small scale microgeneration technologies			
Supply chain stage:	Generators	**Implementing actor/s:**	Ofgem/DTI
Estimated annual facilitated carbon savings (MtC):	7.8	**Estimated Primary Energy Savings (MWh):**	Negligible
Estimated cost to Central Government (£million): Annual or One-off cost?		2.0 – 5.0 **One-off** cost to implement new trading arrangements (Some or all of these costs may be borne by Ofgem but reimbursed by Government)	
Estimated other costs (£million): Annual or One-off cost? Recipient of costs		320 – 520 **Annual** cost of intermittent generation compared to conventional generation. Transfer of costs from small generators to large generators and suppliers	
Description of option:			

The New Electricity Trading Arrangements (NETA) were implemented to increase competition between generators and suppliers, with the aim of reducing prices to the consumer. Many stakeholders believe this aim may have been achieved, but at a cost of potentially disadvantaging renewables. It is widely felt by renewable energy developers that the trading rules under NETA and later BETTA have discriminated against the unpredictability and intermittency of renewable generation, and that the trading system has artificially depressed the renewable energy price.

Under the trading rules, in order to balance the system, generators and suppliers are required to forecast their supply and demand ahead of delivery. For renewable generators, this can be difficult. If the actual supply and demand differs from their forecast, they are penalised by having to buy from or sell into a secondary and potentially more volatile 'balancing' market. This has placed a premium on predictable and flexible thermal coal and gas generation and imposed a cost penalty on renewable generation.

As a result, the imbalance penalties imposed on intermittent renewables when they do not deliver their forecasted power have at times outweighed the payments made for supplying energy. This has led to some wind farms generating at a net negative unit value per kW hour, making a loss simply from production and sale of electricity even before development costs are included.

In addition to this, small and/or intermittent generators are less likely to have the resources available to actively contribute to market development forums, meaning their concerns are less likely to be represented. This may be a factor in the design of systems which disfavour this type of generators.

These barriers are a consequence of the increased costs created by small scale and intermittent generators on the electricity network as a whole. The costs of supporting system reliability through balancing requirements and increased system margins as a result of intermittent or variable generation are estimated at £5-8/MWh which is shared by the generator (through balancing risks and reductions in power prices) and the supplier (through balancing risks and increased system margins – i.e. back up capacity).

An alternative to this might be to create a separate market for small and intermittent generators to sell power in, bereft of the costs associated with system margin and balancing, which would continue to be borne by BETTA. This new market could be run by the Balancing and Settlement Code Company (BSCCo - currently Elexon) who are responsible for operating the main market. This would avoid creating another interface between the various parties and would ensure that best use is made of the incumbent BSCCo's knowledge of the UK electricity market.

The separate market could be linked to the targets set under the Renewables Obligation (RO) to require suppliers of electricity to purchase a certain percentage of their demand from this new market in order to meet their RO targets. This may remove the need for Renewable Obligation Certificates, if transactions could be demonstrated in an alternative way. A penalty for not complying with the RO would need to be retained.

The advantages of a system such as this are as follows:

- The costs of balancing would fall on suppliers who are better able to bear them (system balancing and margin costs are currently disproportionately borne by intermittent or variable generators)
- The costs of maintaining system margin would remain in BETTA (on generators better able to respond to system margin changes and better able to afford associated costs.

However such a system would increase costs for suppliers and thus consumers, through additional administration of a new system and potentially increased costs of electricity purchase. It should also be noted that the ability of small and intermittent generators to maintain a separate market place may be limited if they are resource constrained.

The level of carbon savings associated with such a scheme would be directly linked to the forward progression of the targets associated with the RO.

Number of new entrants:	There is potential for an increase in the number of new entrants. It is expected that power prices payable to small and intermittent generators would increase by some 25% as a result of the removal of balancing risks. However the removal of the ROC as a market mechanism could have a negative effect on new entrants.
Impact on generation mix:	Depends on interplay between removal of ROC and removal of balancing and system margin costs .Of critical importance in determining the final value of power produced by intermittent or variable generators will be the

	preservation or otherwise of a penalty for not meeting targets set under the RO. It is assumed that if the penalty remains as is (£30/MWh) that rates of development will increase due to the increase in profit afforded by the removal of balancing and system margin costs.
Impact on consumer bills:	Costs to consumers will increase if new intermittent and/or variable generators enter the market, as increased balancing and system margin costs will be experienced by the sector as a whole.

Legislative changes required & opportunities in Ofgem's existing role:

- The requisite changes to BETTA and the introduction of a parallel market for renewables would necessitate an amendment to the 2004 Energy Act
- Ofgem would be able to develop the detail of the new trading arrangements under its existing remit. This would in all likelihood include a variety of changes to the codes and licences that govern the operation of the GB electricity market

Main tensions in the reform process:

- The changes outlined in this option will require an improved understanding of the interplay between the removal of ROCs and the removal of system and balancing charges
- Some stakeholders may object to furthers incentives for what they perceive as already 'cheap' renewables
- Some stakeholders may object to the equity of removing balancing and system margin costs from those creating them

Timeline for implementation:

- **2007 (summer):** Government review proposed changes and instruct Ofgem as to the options that should be considered
- **2007 (autumn):** Ofgem forms a working group to consider the feasibility of the options
- **2008 (spring):** The working group reports back to Ofgem and they begin to formulate recommendations to Government
- **2008 (summer):** Ofgem presents recommendations to Government
- **2008 (autumn):** Government consults on the changes recommended by Ofgem
- **2009 (spring):** Government considers the consultation responses and decides on the shape of the revised trading arrangements.
- **2009 (summer):** Ofgem begins work on implementing the new arrangements
- **2011:** New trading arrangements go live.

Assumptions made during cost and carbon savings calculations:

- The carbon savings and costs for this option were calculated on the basis that this option will contribute towards the UK hitting the Government's aspirational 20% target for the proportion of energy supply being derived from renewable sources.

Factors to be taken into account in completing cost and benefit analysis:
• Interplay between removal of ROC and balancing and system margin costs

<table>
<tr><td>Option 6</td><td colspan="3">Upgrade the distribution network by strengthening incentives and increasing investment</td></tr>
<tr><td colspan="4">Barrier overcome:</td></tr>
<tr><td colspan="4">• 6.3.1 Distributed generation will require more active management of network
• 6.3.2 Two-way power flows and increased voltages</td></tr>
<tr><td colspan="4"></td></tr>
<tr><td>Supply chain stage:</td><td>The Distribution Network</td><td>Implementing actor/s:</td><td>Ofgem / DNOs</td></tr>
<tr><td>Estimated annual facilitated carbon savings (MtC):</td><td>11 – 16</td><td>Estimated primary energy savings (MWh):</td><td>27,000,000 – 68,000,00</td></tr>
<tr><td colspan="2">Estimated cost to Central Government (£million):

Annual or One-off cost?</td><td colspan="2">Negligible

N/A</td></tr>
<tr><td colspan="2">Estimated other costs (£million):

Annual or One-off cost?

Recipient of costs</td><td colspan="2">250 – 1,000

Annual cost of changes to the incentive structure

Consumer</td></tr>
<tr><td colspan="2">Estimated other costs (£million):

Annual or One-off cost?

Recipient of costs</td><td colspan="2">930 – 2,800

One-off costs of increased R&D and investment in the network

Consumer</td></tr>
<tr><td colspan="4"></td></tr>
<tr><td colspan="4">Description of option:</td></tr>
<tr><td colspan="4">Many stakeholders agree that the key challenge facing Ofgem regarding the distribution network is how to stimulate investment in the network (particularly in innovative solutions) to ensure it remains fit for purpose in the context of a growing need to combat climate change. Ultimately, this manifests itself in a need to reduce losses from the network and cope with an increasing proportion of our energy needs being met by distributed generation.

The impact of distributed generation on voltages and reverse flows will be very dependent on the condition of the network where the connection is made. For instance, if network parameters are close to their statutory limits additional investment will be required to accommodate increased power flows. However, if there is spare capacity (in terms voltage headroom) in that particular part of the network then new generation could</td></tr>
</table>

be accommodated at minimal cost.

Since the privatisation of the electricity sector in the UK and the introduction of the RPI-X formula for determining funding for Distribution Network Operators (DNOs) there has been a reduction in investment in the Distribution Network. This has resulted in a sharp fall in the research and development (R&D) activities undertaken by the DNOs, which according to many commentators has significantly reduced the innovation on the distribution networks. Furthermore, there is a belief amongst some stakeholders that current levels of investment in the distribution network may constrain future capacity, especially if Great Britain moves to a distributed generation model of connecting sustainable technologies; where a lack of distribution network capacity could slow the pace of new connections.

In addition, greater distributed generation will increase system voltages and introduce reverse power flows. Excessive amounts of generation will result in network voltages exceeding statutory limits and the resulting reverse power flows are unlikely to be compatible with, for example, network protection configurations and transformer tap changers. If the DNOs are permitted to make sufficient investments in the network these issues are likely to be solvable.

In response to these issues Ofgem introduced four mechanisms at the 2005 Distribution Price Control:

1) The Losses Incentive
2) Distributed Generation (DG) Incentive
3) Innovation Funding Incentive (IFI)
4) Registered Power Zones (RPZ)

Whilst most stakeholders welcomed these initiatives, to date there has only been limited take up on the part of DNOs for a variety of reasons:

- Some of the incentives are not thought to be sufficient to encourage DNOs to invest. Factors such as opportunity cost (could the capital be put to better use elsewhere) and the procedural hurdles associated with developing a proposal and gaining the necessary approvals mean that there must be a strong business case to prompt DNOs to formulate proposals in the first instance.

- In some instances the regulatory frameworks are thought to be too prescriptive thus limiting the manner, and the technologies, in which DNOs can invest.

- Some of the regulatory frameworks are thought to present too great a risk with no guarantee of a return on the investment or even a pass through of costs.

One means of helping to resolve these issues could be to strengthen the existing suite of initiatives and amend the associated regulatory framework. Consequently, this option will propose a series of changes that it is hoped will make the initiatives launched in the 2005 DPCR more attractive to DNOs.

The current arrangements for the losses incentive

Under the current Distribution Price Control Review (DPCR) the capital expenditure (capex) to purchase and install energy loss-reducing equipment is treated like any other capital expenditure i.e. it can be passed through to customers at the DNOs' standard rate of return. However, there is also a losses incentive that is linked to each DNO's performance against their annual losses target which is determined by Ofgem. For each MWh of losses above or below that target the DNO is charged/rewarded with £48 per MWh for the 5 proceeding years. For example, if they were to under-perform their losses target by 1000 MWh they would have their revenue reduced by £48,000 for the next 5 years. In contrast if they were to out-perform their target by 1000 MWh they would receive a £48,000 increase in revenue.

Suggested changes to the losses incentive

- ***Increase losses incentive to £100 per MWh (and continue to apply the incentive charge/reward for 5 years after installation).*** The aim of this measure would be to strengthen incentives to reduce losses in the short term through 'soft' measures such as managing demand. Many stakeholders believe the existing £48/MWh incentive is not sufficient to change the DNOs behaviour - it is hoped that increasing the incentive to £100/MWh would result in a step change in DNOs efforts to reduce losses.

- ***Introduce an <u>additional</u> ring-fenced losses strand to the DPCR capex (it is not the intention that 'normal' funds are re-directed – this should be 'new' money), which allocates significant funds to reducing losses in accordance with the size of the network and the amount of electricity distributed. The additional funds would be treated in exactly the same manner as the normal capex i.e. DNOs would be able to pass through the costs at the standard rate of return.*** The aim of this measure is to give the reduction of losses renewed focus with in DNOs and ensure it does not compete with other funding requirements. It should be noted that this increased capex will ultimately be passed through to the consumer.

- ***Mandate DNOs to install the Best Available Technology (BAT) (in terms of losses) at any upgrade. This could be policed by Ofgem using a register of BAT that is updated annually and independently reviewed.*** This measure is designed to capture the potential for losses reductions in very high cost equipment that DNOs are naturally very reluctant to replace before the end of its useful life.

The current arrangements for the DG incentive

The DG incentive is designed to encourage DNOs to connect DG to the distribution network. However, it goes further than simply encouraging the installation of the physical connection infrastructure – there is an emphasis on encouraging DNOs to facilitate actual connection of DG into the distribution grid. This is achieved through a 'hybrid' incentive whereby DNOs are only allowed to pass through 80% of the costs of installing a DG connection to the connectee which is then topped up with £1.50 per kW of DG connected per year – hence the incentive to achieve real connections rather than simply supplying the means to connect. The 'top up' can be claimed by DNOs as revenue for 15 years. The DNOs' returns are constrained between a collar (i.e. minimum) of the cost of debt and a cap of twice the cost of capital. DNOs are also paid £1 per kW of DG installed per year for operation and maintenance of the connection.

Suggested changes to the DG incentive

- ***Retain the 80% pass through for DG connection costs and the cost of debt collar***. This will ensure there is still a safety net for DNOs to mitigate the risk of stranded assets and the associated lack of a DG incentive payment.
- ***Increase the DG incentive from £1.50/kW/yr to £5.00/kW/yr.*** Many DNOs view the existing incentive as insufficient to encourage them to connect DG. It is hoped that trebling the incentive will overcome this issue.
- ***Remove the cap on the return.*** The aim of this change is to provide a step change in the DG connected to distribution network by providing a much stronger incentive. However, it should be noted that this would place the DPCR in conflict with Ofgem's primary duty to protect the consumer, since in principle it would mean unlimited extra revenue for the DNOs. Consequently, this change may also necessitate a change in Ofgem's primary duty.

The current arrangements for the IFI

The IFI was introduced as a mechanism to encourage DNOs to invest in appropriate R&D activities that focus on the technical aspects of network design, operation and maintenance. The current principal objective of the IFI is to deliver benefits to consumers by enhancing efficiency in operating costs and capital expenditure. This is achieved by encouraging DNOs to invest in appropriate R&D activities that focus on the technical aspects of network design, operation and maintenance. However, there are a number of conditions covering the IFI:

- The IFI is capped at 0.5% of the permitted regulatory turnover in each relevant year
- Each DNO can only carry forward 50% of the eligible IFI expenditure in any relevant year.
- The IFI carry forward may only be used to increase the eligible IFI expenditure in the year immediately following that in which the carry forward was nominated.
- The DNO must report annually on its IFI activities.
- The pass through rate of costs diminishes in equal steps from 90% in 2005/06 to 70% in 2009/10.

Suggested changes to the IFI

The aims of the proposed changes to the IFI are to make it easier to develop an IFI project and to give the DNOs more freedom to structure the project (e.g. rolling over the costs where necessary) in the manner they deem most suitable to achieving the research objectives. The proposals would also allow DNOs to spend much more on IFI projects providing the projects meet Ofgem's criteria in an effort to ensure research becomes a core rather than a peripheral activity for DNOs.

- ***Oblige DNOs to outline their IFI work plan for the forthcoming year in their annual IFI report. Ofgem would then need to sign off 'in principle' the DNOs proposals as eligible for IFI funding. The final 'confirmation' of eligibility for IFI funding would then be given after the research had been completed and detailed in the next IFI report.*** This proposal aims to remove much of the risk for DNOs in developing IFI projects, especially in a climate where a greater proportion of DNO turnover can be spent on IFI projects (see the remaining suggested changes). Under the current system DNOs wishing to invest in IFI projects must spend the money and then justify the expenditure in their annual IFI report. If Ofgem have doubts regarding the eligibility of funding they have the powers to audit the IFI project and ultimately disallow IFI funding. Whilst Ofgem have not disallowed any IFI funding to date the risk for DNOs remains especially in the context of the proposed increase in IFI expenditure.
- ***Increase the IFI cap to 5% of price control turnover in each relevant year.*** This will ensure that DNOs are able to invest substantial amounts in R&D (should they so wish) and view IFI as a core initiative rather than a peripheral activity.
- ***Remove the 50% ceiling on the proportion of eligible expenditure that can be carried forward into the next year.*** The aim of this change would be to give the DNOs much greater flexibility when structuring IFI projects in what is currently a restrictive regulatory framework.
- ***Remove the restriction on rolling over of allowances for 2 or more years.*** The aim of this change would also be to give the DNOs much greater flexibility when structuring IFI projects in what is currently a restrictive regulatory framework.
- ***Amend the principal objective of IFIs to include reducing emissions of greenhouse gases.*** The present objectives are concerned with delivering benefits to the consumer and hence reducing costs, which is in line with Ofgem's primary duty. The SDC is likely to recommend a change to this primary duty to reflect the need for Ofgem to act in a more sustainable manner. However, reiterating the

importance of sustainability, or more specifically reducing carbon emissions, in the IFI objectives would reinforce that message.

- ***Amend the rationale for undertaking an IFI project to either a project where the present value (PV) of the cost savings is greater than the PV of the costs OR a project where the PV of the carbon benefits is greater than the PV of the costs.*** There may be some IFI proposals which are not funded because the carbon emissions reductions are not being fully accounted for in the discounted cash flow analysis and hence the project has a net cost. This proposed change would ensure that projects that show a net cost when costs alone are considered, but a net benefit once the external climate change benefits are internalised, are still funded.
- ***Amend the structure of the pass through rate to incentivise IFI projects that reduce carbon emissions:***
    - ***80% pass through rate if the PV of carbon benefits is LESS than the PV of costs***
    - ***110% pass through rate if the PV of carbon benefits is GREATER than the PV of costs***
    - ***150% pass through rate if the PV of carbon benefits is GREATER than the PV of costs AND the results are used by another DNO***

  All of these pass through rates would be flat rates rather than the tapered rates that exist at the moment.

  The aim of these changes would be to ensure that the DNOs can invest safe in the knowledge that they will recover most of the costs of the R&D even if it isn't successful (in reality even modest cost savings are likely to result in a net benefit to the DNO). However, there are also strong incentives to undertake R&D that produces carbon savings and share the results of successful research.
- ***Ofgem could facilitate the development of guidelines for how to go about making a case for 'environmental' IFI projects for which it is typically harder to quantify the benefits. A methodology could be developed that used figures for the social cost of carbon to estimate the environmental benefits.*** It is hoped this action would help overcome the difficulties that DNOs currently experience in making a compelling case for an IFI on environmental or sustainability grounds.

The current arrangements for the RPZ

RPZ's are focused specifically on encouraging connection of generation to the distribution network. Ofgem intends them to encourage DNOs to develop and demonstrate new, more cost effective ways of connecting and operating generation that will deliver specific benefits to distributed generators. Ofgem recognises that for some new DG connection schemes, an innovative technical solution could offer material advantages to DG customers compared with a conventional solution. Where this is demonstrated to be the case, Ofgem provides an additional incentive of an extra £3/kW/year (over and above the main DG incentive, so £4.50/kw/yr in total) for a 5 year period commencing on the start date. There are several conditions attached to RPZs:

- DNOs are only allowed to seek registration for 2 RPZs per year for the first two years of the scheme
- The additional revenue that a DNO can claim for RPZ projects will be capped at £0.5million per DNO per year.
- DNOs are required to submit open annual reports on their RPZ projects.

Suggested changes to the RPZ scheme

- ***Broaden the list of eligible topics for RPZ's to include any project that covers the technical aspects of network design, operation and maintenance.*** The aim of this proposed change is to provide a natural linkage between IFI and RPZ projects so that successful IFI projects lead to RPZs. This would mean support is being provided at each stage in the research chain from R&D through to demonstration. One criticism of the current framework is that there is a 'demonstration gap' whereby good ideas developed through IFI projects are lost due to a lack of support for demonstration projects. This has particularly been the case in the post-privatisation climate where the RPI-X formulae for determining DNOs revenue has exerted a downward pressure on costs and encouraged DNOs to select proven, low cost solutions. Ultimately, it is hoped this measure would increase the number of RPZs – to date only 4 have been developed.
- ***Raise the RPZ incentive to £5/kW/year or £10/kW/year in total (assuming the main DG incentive is raised to £5/kW/year as proposed above) over the full 15 years of the DG incentive rather than 5 years.*** Despite broadly welcoming RPZs, many industry stakeholders believe that the RPZ incentive needs to be more generous to encourage greater take up of the scheme. It should be noted that were the proposal to broaden the list of topics to be implemented then the specific linkage to the DG incentive would need to be removed.
- ***Remove the restriction on the number of RPZs that can be registered per year.*** Ofgem set this limit to encourage quality rather than quantity of RPZ applications. This was partly due to their limited resources to deal with applications but also because RPZs were a new measure in the DPCR4 and hence Ofgem wanted to proceed cautiously. Many stakeholders agreed that the restriction on the number of RPZs was appropriate whilst DNOs and Ofgem themselves were coming to terms with policy. However, now that the policy is better understood some DNOs may wish to implement several RPZs so in the interests of promoting demonstration projects (which ultimately is the objective of the scheme) it seems sensible to allow them to proceed with an unlimited number of RPZs providing they meet the criteria set out in the Good Practice Guide.
- ***Remove the cap on the additional revenue per DNO per year.*** Limiting the extra revenue that DNOs can claim from RPZ projects acts as a disincentive for them to participate in the scheme. Furthermore, setting the limit at such a modest amount gives the impression that RPZs are a peripheral activity rather than a scheme that is central to DNOs' business plans and the development of the network.

Number of new entrants:	The proposals in this option to strengthen the existing incentives to connect distributed generation would increase the number of new entrants. Distributed generation tends to smaller capacity which presents lower barriers to entry for new entrants.
Impact on generation mix:	The proposals in this option would increase the proportion of renewables and CHP in the generation mix due to the emphasis on connecting distributed generation. Indeed it is envisaged that much of the future distributed generation capacity will be CHP or renewables.
Impact on consumer bills:	Consumer bills would increase if these measures were implemented. The additional annual and one-off costs would be passed through to the consumer by the Distribution Network Operators.

Legislative changes required & opportunities in Ofgem's existing role:

• No changes would need to be made to primary legislation to implement this option • Ofgem can make all of the changes in this option unilaterally • Ofgem is already planning to review the IFI and RPZ in 2007
Main tensions in the reform process:
• Ofgem's existing remit is to protect the interests of consumers through increasing competition. Consequently, Ofgem may oppose many of changes proposed in this option since they would increase energy bills and the financial risk (i.e. a big investment in research that is not guaranteed to produce positive results) to which consumer are exposed to in the short to medium term. • However, it should be noted that significant carbon savings could be achieved by making the changes outlined in this option. Therefore, it could be argued that this short to medium term cost penalty would actually result in lower costs to the consumer in the long term through mitigating the extent of climate change.
Timeline for implementation:
• In February 2007 Ofgem reviewed IFIs and RPZs and made some changes to the regulatory frameworks, which included abolishing the 15% cap on internal expenditure on IFI projects and extending the IFI scheme to the 5th DPCR which runs until 2015. • The next opportunity to amend the regulatory framework governing the operation of the DNOs will come in 2010 DPCR. However, if a similar timetable to previous reviews is followed then Ofgem is likely to begin the consultative process to gather opinions on the shape of the next DPCR sometime in 2008.
Assumptions made during cost and carbon savings calculations:
• Only direct costs have been considered (i.e. cost of the incentive mechanisms) • The only carbon savings impact of the proposals to amend the DG Incentive, IFI and RPZs will be to increase the amount of distributed generation connected to the grid • Renewable electricity is carbon neutral • Assume the DNOs exceeding their losses target cancel out DNOs hitting their target under the existing losses incentive. Therefore, the net cost to the consumer is £0. • The existing DG incentive is intended to cover 20% of the cost of a DG connection (The other 80% is met by a standard capex revenue claim). • The impact of this option will be to reduce distribution losses to between 4.0% and 5.5% of the electricity entering the distribution system. • 20-40% of future GB electricity generation capacity will be DG • 16.3% of current GB electricity generation capacity is DG • 20-40% of future GB electricity supply will be DG • 7.1-14% of new GB electricity generation capacity will CHP, all of which will be DG • 86-92.9% of new GB DG capacity will be renewables • New CHP capacity will have an overall energy efficiency of 75%, a heat to power

ration of 2.2:1 and a load factor of 70 – 85%

- The boilers replaced by CHP plants have an energy efficiency of 85% and load factors of 70 – 85%
- The new level of the losses incentive will be £100/MWh
- The existing capex expenditure on losses is £250k to £1million per DNO
- Capex expenditure on losses will increase by 50-200% as a result of this measure
- The revised level of the DG incentive will be £5/kW/yr
- If the changes proposed to the IFI in this option are implemented the R&D intensity will rise to 0.5 – 2.0%.
- The IFI costs will be passed through to consumers at a rate of 80% if the PV of carbon benefits is less than the PV of costs.
- The IFI costs will be passed through to consumers at a rate of 110% if the PV of carbon benefits is more than the PV of costs.
- The IFI costs will be passed through to consumers at a rate of 150% if the PV of carbon benefits is more than the PV of costs and the results are used by another DNO.
- The PV of carbon benefits will be less than the PV of costs in 33% of IFI projects
- The PV of carbon benefits will be more than the PV of costs in 33% of IFI projects
- The PV of carbon benefits will be more than the PV of costs and the results will be used by other DNOs in 33% of IFI projects
- The revised level of RPZ incentive (i.e. total DG incentive including the revised 'normal' DG incentive stated above) will be 10£/kW connected
- 10-30% of DG capacity connected to the grid will made in RPZs if the proposals in this option are implemented

Factors to be taken into account in completing cost and benefit analysis:

- Indirect costs such as the greater cost of renewable energy technologies compared to conventional centralised fossil fuel plant
- Carbon savings associated with CHP compared to conventional centralised fossil fuel plant
- The split of heat to power ratios in CHP plants (the calculations in this option assumed all CHP plant will have a heat to power ratio of 2.2:1 – in reality there will be significant variation depending on the role of the CHP plant).
- The net cost of the losses incentive i.e. the ‘income’ consumers receive through DNOs missing their distribution losses target less the ‘cost’ consumers incur through DNOs exceeding their target.
- The proportion of future generating capacity that is likely to be DG
- The split of DG capacity between renewables, CHP and other technologies
- Existing capex expenditure on losses
- Future capex expenditure on losses as a result of the measures proposed in this option
- The proportion of IFI projects that fit into each of cost pass through categories (80%, 110% and 150%).
- The proportion of new DG capacity that is connected to the grid in RPZs if the proposals in this option are implemented

Option 7	**Implement an agency system of contractual agreements between Distributed Generators and the GB Transmission System Operator**		
Barrier overcome:			
• 6.4.1 Inter-network Contracts and Agreements • 7.4.3 Licensing process can be burdensome for small suppliers			
Supply chain stage:	Transmission Network	**Implementing actor/s:**	Ofgem / GB SO / DNOs
Estimated annual facilitated carbon savings (MtC):	11 – 16	**Estimated primary energy savings (MWh):**	27,000,000 – 68,000,000
Estimated cost to Central Government (£million): Annual or One-off cost?		Negligible N/A	
Estimated other costs (£million): Annual or One-off cost? Recipient of costs		3.3 - 47 **Annual** costs of agency operating costs and incentive Consumers	
Estimated other costs (£million): Annual or One-off cost? Recipient of costs		10 - 30 **One-off** agency set up costs for DNOs Consumers	
Description of option:			

Distributed Generation (DG) is defined as generation that connects to the distribution network rather than the transmission network. DG may or may not export electricity to the transmission network depending whether there is a market for it at installations connected to the local distribution network. Consequently, DG may be liable for transmission network use of system charges but will not be liable for transmission network connection charges.

At the present time National Grid contracts bilaterally with each DG generator classed as a large power station. These generators are offered one of two agreements, a BEGA or a BELLA. The principle difference between a BEGA and BELLA is that by signing a BELLA, the generator would avoid Transmission Network Use of System (TNUoS) charges and be exempt from Balancing & Settlement Code and Grid Code requirements, but would also have no right to use the transmission system. Signing a BEGA would provide access rights, but would necessitate compliance with the Codes and payment of transmission use of system charges.

There has been widespread criticism by generators of the BEGA/BELLA contractual agreements for contracting with the Transmission Operator (TO). Firstly, the system imposes a significant bureaucratic burden on smaller generating stations. Secondly, there are major cost disadvantages from making the wrong choice on which agreement is appropriate for a particular site. Thirdly, generators often see that they have insufficient information about other network factors that will impact on their choice, and fourthly, while the situation may change over time, once they have chosen, generators are effectively locked into their chosen agreement.

To address these issues Ofgem could allow distributed generators to move from individual agreements to a set of agency style agreements. Under these arrangements the Agency would act as middleman, contracting with the TO on behalf of several distributed generators.

Agency style agreements would provide the following benefits for small operators and the system as a whole:

- Reduced bureaucratic burden for small generators and hence reduce the barriers to entry for new entrants
- Sufficient information available for informed contractual decisions to be made regarding the level of access rights to secure for smaller generators
- More manageable contractual negotiations between the TO and the small generators since the Agency would be acting on behalf of several generators
- Better representation of small generators within the process of negotiation with the system operator

The agency could take a variety of forms but this option will focus on the agency role being incorporated into the responsibilities of the Distribution Network Operator (DNO). A DNO agency would provide the following additional benefits:

- The DNO is in possession of the most complete information regarding the flows on its network and as such is ideally placed to act as an interface between generators connected to its network and NGET.
- It would avoid the need for a major restructuring of the industry since the only significant changes would be the broadening of the DNOs role and an easing of the bureaucratic burden on generators and the TO.

The Agency could exist as an optional service that Distributed Generators subscribe to free of charge and opt into or out of with an appropriate notice period. However, given the obvious benefits it is thought that many smaller generators would sign up to the Agency service.

Some stakeholders are concerned that there are not sufficient incentives in place for DNOs to fulfil this role given that becoming an agency for DG would involve a significant cost and bureaucratic burden. These issues could be overcome through:

- ***Allowing DNOs to pass through 100% of the costs they incur in setting up and running the Agency at their standard rate of return.*** This would provide DNOs with an incentive to set up the Agency.
- ***Introducing an 'Agency Incentive' element to the DG incentive at the same level as the revised RPZ incentive proposed in option 5 (i.e. an additional £2.5/kW/yr or £7.5/kW/year in total). Every kW of DG capacity connected to***

the DNO's network and signed up to an agency agreement would be eligible for the Agency Incentive. This would provide the DNO with an incentive to proactively seek out opportunities to act as the Agency to DG and thereby reducing the bureaucratic burden on the Distributed Generator.

Once an agency system had become established there would also be scope for the DNO agency role to be broadened to include the option to become an energy aggregator i.e. acting as a middle man between distributed generators and energy suppliers for the sale of electricity. This could help DG achieve a better price for the power it exports to the grid by smoothing out the peaks and troughs in supply from an individual generator. It would also give distributed generators that wish to do so the opportunity to focus their efforts on generating power whilst effectively subcontracting their energy trading activities. This move would further reduce the barriers to entry for new entrants by allowing them to become involved in as many of the non-core value chain activities as they wish.

Ofgem are currently giving careful consideration to the merits of all the options for an Agency model via their Transmission Arrangements for Distributed Generation (TADG) working group.

Number of new entrants:	This option would result in an increase in new entrants since it would be simpler for them to access and participate in the transmission network's system of contractual arrangements.
Impact on generation mix:	The proportion of small, renewable and sustainable generators would increase though implementing this measure since it would be simpler for them to access and participate in the transmission network's system of contractual arrangements.
Impact on consumer bills:	This option would result in a very small increase in consumer bills due to the costs of the Agency Incentives.

Legislative changes required & opportunities in Ofgem's existing role:

- No changes would be required to primary legislation.
- Implementing agency-style agreements is within Ofgem's current remit.

Main tensions in the reform process:

- The majority of stakeholders agree that the system of contractual agreements needs to be revised.
- However, tensions between the parties could occur when discussing the optimum model for the revised contractual agreements.
- For instance, generators are generally in favour of a DNO agency model since they believe DNOs are in possession of the most complete information regarding the flows on their networks and as such are ideally placed to act as an interface between generators connected to its network and NGET.
- In contrast, NGET would prefer a supplier agency model since they already have similar systems in place suppliers that could be modified relatively easily to take on the new agency role.

Timeline for implementation:
• **Spring 2007:** TADG working group final report • **Summer 2007:** Ofgem consults on changes to the contractual arrangements proposed by TADG working group • **Autumn 2007:** Decision by Ofgem on nature of changes to contractual arrangements • **2008:** Implementation of new contractual arrangements
Assumptions made during cost and carbon savings calculations:
• Only direct costs have been considered (i.e. cost of the incentive mechanisms) NOT indirect costs such as the fact that renewable energy is more expensive. • Renewable electricity is carbon neutral • 20-40% of future GB electricity generation capacity will be DG • 16.3% of current GB electricity generation capacity is DG • 20-40% of future GB electricity supply will be DG • 7.1-14% of new GB electricity generation capacity will CHP, all of which will be DG • 86-92.9% of new GB DG capacity will be renewables • New CHP capacity will have an overall energy efficiency of 75%, a heat to power ration of 2.2:1 and a load factor of 70 – 85% • The boilers replaced by CHP plants have an energy efficiency of 85% and load factors of 70 – 85% • 10-30% of DG will have agency agreements with DNOs
Factors to be taken into account in completing cost and benefit analysis:
• Indirect costs such as the greater cost of renewable energy technologies compared to conventional centralised fossil fuel plant • Carbon savings associated with CHP compared to conventional centralised fossil fuel plant • The proportion of heat generated by CHP units that is ‘dumped’ • The proportion of future generating capacity that is likely to be DG • The split of DG capacity between renewables, CHP and other technologies • The proportion of DG that will enter into agency agreements

Option 8	Introduce a carbon ‘Cap and Trade’ scheme for energy suppliers		
Barrier overcome:			
• 8.3 Lack of confidence in energy efficiency measures			
Supply chain stage:	Cross Sector	**Implementing actor/s:**	Ofgem
Estimated annual facilitated carbon savings (MtC):	1.2	**Estimated primary energy savings (MWh):**	Negligible
Estimated cost to Central Government (£million): Annual or One-off cost?		Negligible N/A	
Estimated other costs (£million): Annual or One-off cost? Recipient of costs		780 - 910 **Annual** costs for the 3 year duration of the 3rd phase of the Energy Efficiency Committment Consumers	
Description of option:			

The Energy Efficiency Commitment (EEC) requires energy suppliers to provide energy efficiency savings to a value decided by the Secretary of State for the Environment. The savings are submitted to, and audited by Ofgem who are also responsible for deciding whether or not each supplier has met their commitment. The scheme has run in its current form since 2002 and is due to last until 2008. It is considered highly likely that there will be a further commitment until at least 2011.

One problem that has been associated with the calculation of savings from the EEC is that it is suggested that the energy efficiency improvements provided (e.g. through insulation, high efficiency appliances) may not have translated directly into carbon savings. This is because many energy efficiency investments provide an increase in energy services without necessarily reducing overall energy use.

The most common example of this occurs when the benefits (i.e. reduced energy bills) associated with insulation are taken as improved warmth (i.e. consumers turn the heating up) rather than reduced energy use. Increased energy use (rather than decreased) can also occur where high efficiency appliance provision supplements existing appliance use rather than replaces it. For example, the purchase of a dishwasher where washing up was previously done by hand, or the purchase of an additional fridge without disposing of the original.

As such there is considerable doubt amongst some stakeholders as to the level of actual carbon savings delivered by the scheme despite a claim of 0.62 MtC of annual savings by 2010.

To combat this Defra have consulted (in June 2006) on a proposal to both extend EEC until 2011 and change its focus from delivering energy efficiency improvements to delivering carbon savings. As well as improving the certainty of savings this would allow energy suppliers to provide alternative energy sources such as micro- wind turbines. In addition, the proposal also considers the opportunity to allow suppliers to trade savings between themselves, incentivising those who are able to make savings cost effectively to over achieve and sell the surplus to those less able to make cost effective savings. In 2006 Defra commissioned NERA to undertake a study into the options for increasing trading in the EEC. One option was a transition from EEC to a cap-and-trade system where suppliers would be allocated an amount of CO_2 they could emit, and could then choose any combination of emissions reduction measures (energy efficiency or otherwise), or trading activities to comply with their cap. The main benefit of a cap and trade scheme would be the greater range of emissions reductions measures that could be implemented, which should lead to the emissions reductions being achieved in the most economically efficient manner. By removing the restriction of an "approved list" of measures that is necessary in a project-based scheme, scheme participants would face fewer restrictions and scheme costs could potentially be reduced. The viability of a cap-and-trade scheme could depend on the extent to which the Suppliers were able to influence the CO_2 cap. This influence may be limited by the difficulty of affecting consumers' behaviour. If this is the case the reductions achievable could be small compared to other influences on energy demand. Moreover, to the extent other influences (such as weather and fuel prices) fluctuate it may not be possible to set a cap to which the obligated parties could realistically adhere. The use of "safety-valve" provisions, such as linking to other trading scheme or a buy-out price therefore are likely to be necessary to mitigate such problems. The impact of this measure on suppliers and new entrants would largely depend on the level at which the emissions caps were set since both systems carry administrative burdens. If the caps were broadly equivalent to the energy efficiency savings under EEC then the impact would be limited after the transition period. That said, the impact may tend towards a net benefit to Suppliers and in turn act as small incentive to enter the market. This is because the greater flexibility under the cap and trade scheme should in principle mean an equivalent cap is achievable at lower cost due to the broader range of options available. Giving the Suppliers greater flexibility to select the source of the emissions savings under a cap and trade scheme may well reduce the expenditure on energy efficiency measures for the priority low income households. There would no longer be an obligation to source 50% of the energy savings from the priority group (as is the case under the EEC) so unless these emissions savings happened to be the cheapest the Suppliers would in all likelihood shift their expenditure elsewhere. Therefore, the Government may need to increase funding via other mechanisms (such as the Warm Front programme and the winter fuel allowance) to compensate for this reduced investment. Alternatively, the Government and Local Authorities could address fuel poverty by investing in heat networks to provide free or subsidised heat to the priority group.	
Number of new entrants:	The impact of a cap and trade scheme on new entrant would largely be determined by the level of the cap compared the level of the existing EEC. However, assuming they were broadly equivalent the greater flexibility of the cap and trade scheme may make entering the supply market slightly more appealing. A cap and trade scheme would also provide an incentive to increase the proportion of low carbon generation within the overall energy generation mix, which would be a positive move

	for new entrants since the renewables sector has lower barriers to entry.
Impact on generation mix:	This option would provide an incentive to increase the proportion of low carbon generation within the overall energy generation mix.
Impact on consumer bills:	EEC 2 is estimated to cost domestic consumers approximately £3.20 per fuel type per year. The transition to a carbon commitment has the potential to put upward pressure on this, as robustness of the scheme increases. However this could be mitigated by the ability for suppliers to trade savings and invest in large scale projects.
Legislative changes required & opportunities in Ofgem's existing role:	
• Proceed with EEC 3 proposals to include opportunities for trading and investment in large scale projects	
Main tensions in the reform process:	
• Some concerns from stakeholders that this option may reduce the fuel poverty elements of the current EEC schemes. However these could be addressed by increasing funding to the Warm Front Programme or broadening the eligibility for the winter fuel allowance. • Some concerns from stakeholders that the ability to invest in large scale projects may reduce householder focus of scheme • There is a need for certainty regarding the role of EEC compared to other policy interventions, notably Low Carbon Buildings Programme and the Renewable Obligation	
Timeline for implementation:	
• **Spring 2007:** Government will consult on the shape of EEC 3 • **January 2008:** Scheme to go live	
Assumptions made during cost and carbon savings calculations:	
• None, all taken from Defra consultation • Note: a full RIA of these proposals is expected in the Spring of 2007.	
Factors to be taken into account in completing cost and benefit analysis:	
• Certainty of savings – in previous phases of EEC there has been divergence between the illustrative mix of measures and the actual mix of measures delivered.	

Option 9	**Revise TNUoS Charging Structure for CHP**		
Barrier overcome:			
• 4.4.1 Unfavourable gas and electricity prices erode CHP's advantage over conventional generation • 4.4.2 Energy price volatility creates risk barriers to CHP investment • 4.4.4 High capital costs compared to conventional generation • 4.4.5 High operation and maintenance costs compared to conventional generation			
Supply chain stage:	Generation	**Implementing actor/s:**	Ofgem/Transmission Operator
Estimated annual carbon savings (MtC):	0.50	**Estimated primary energy savings (MWh):**	15,000,000 – 38,000,000
Estimated cost to Central Government (£million): Annual or One-off cost?		540 – 900 **Annual** cost in the form of increased numbers of Climate Change Levy Exemption Certificates	
Estimated other costs (£million): Annual or One-off cost? Recipient of costs		430 – 530 **Annual** cost of payment to CHP plants replacing the locational element of TNUoS charge Consumers	
Description of option:			

The Transmission network charging model has two elements: connection charging and use of system charging (TNUoS). Connection charging is concerned with the assets needed to connect the generator to the National Grid. TNUoS charging covers the cost of using the transmission lines and 'balancing' the system (i.e. ensuring the supply of electricity matches the demand for electricity) and varies according to the geographical location and the demand for grid usage at that location. Connection charging provides a signal to generators to locate in the south, where demand is higher. However, CHP schemes need to be located next to heat loads and it has therefore been proposed that certain types of CHP should be exempted from the locational part of the charge. Since CHP is a highly efficient technology when utilised in the right circumstances it is argued by some stakeholders that measures should be put in place to incentivise greater deployment of the technology.

The economics of CHP dictate that for the two central fuel price projections provided by the DTI, schemes do not become cost effective unless the charges are used to provide a positive signal i.e. within the TNUoS locational 'charging' structure there would need to be a payment to the scheme instead of a charge. Consequently, this option will consider the minimum TNUoS locational payment necessary to stimulate new investment in CHP since an exemption from the locational element of the transmission charge would not be sufficient. Assuming the overall transmission charge (connection and use of system) remains a cost to the CHP scheme rather than a benefit, such a system should be relatively easy for the Transmission Operator to reconcile internally. In these circumstances the CHP scheme would still pay transmission charges just at a lower rate.

The gap in transmission charges created by this policy would be covered by a cross-subsidy provided by other generators. Whilst other generators may well be opposed to this change the extra cost could be passed on to consumers in the form of slightly higher bills.

It is proposed that the policy would have the following characteristics.

a) Only applies to new large scale CHP above $100MW_e$ electricity output, which connects to the transmission/distribution network (This would exclude smaller plants connecting to the distribution network only).

b) The policy would only apply to areas that pay a positive locational element i.e. those North of Oxford/Didcot.

c) The locational element of the 'charge' for CHP schemes would be a payment of £43/kW_e to £53/kW_e.

Since few new CHP schemes are being developed in the UK at the present time (due to the unfavourable economic conditions such as the limited spark spread) the dead weight for the policy (i.e. the CHP schemes that would have been developed without this incentive but still benefit from it) would be limited.

It also worth noting that Ofgem's Transmission Arrangements for Distributed Generation (TADG) working group are currently considering proposals for charging DG schemes that 'spill' electricity onto the transmission network. To ensure a consistent approach the interaction of this option with the TADG proposals would need to be considered in detail before any firm proposals were issued.

Number of new entrants:	There may be in an increase in new entrants since the barriers to entry for building a CHP plant are lower than building a larger scale conventional plant.
Impact on generation mix:	The proportion of gas-fuelled generation would increase as CHP replaced lower efficiency coal plant in the generation mix.
Impact on consumer bills:	Consumer bills would rise slightly due to the cross subsidisation of the locational element of the TNUoSs charge.

Legislative changes required & opportunities in Ofgem's existing role:

- No legislative changes required
- Ofgem could oblige the Transmission Operator to make the changes via transmission price control where the level of TNUoS charges are set for 5 year periods.

Main tensions in the reform process:

- There may resistance from non-CHP generators to an increase in their TNUoS charges
- There may resistance to the proposals outlined in this option from senior officials in

Ofgem, DTI and the Treasury who may disagree in principle with cross-subsidies.

Timeline for implementation:

- **Summer 2007:** Proposals to amend TNUoS charges for CHP put to Grid Code Panel
- **Autumn 2007:** Grid Code Panel forms working group to consider the proposals
- **Spring 2008:** Working group reports back and Panel consults on their recommendations
- **Autumn 2008:** Grid Code Panel provides a recommendation to Ofgem
- **Spring 2009:** Ofgem decides whether to implement the proposals
- **2012:** Revised TNUoS implemented in the Transmission Price Control

Assumptions made during cost and carbon savings calculations:

PLEASE NOTE THAT THESE ASSUMPTIONS SHOULD NOT BE PUBLISHED IN THE PUBLIC DOMAIN WITHOUT EXPLICIT PERMISSION FROM DEFRA WHO COMMISSIONED THE STUDY FROM WHICH THEY WERE TAKEN

- $3.1GW_e$ of CHP capacity will be added in response to this policy
- The ratio of heat produced to electricity generated in a conventional fossil fuel generated power station is 1.0 – 1.3
- The load factor for a conventional fossil fuelled power station is 40-80%
- The efficiency of conventional fossil fuelled generating plant is 35-45%
- The analysis was based on the DTI central fuel price scenarios favouring gas and coal
- The cost to the Government of this policy arises through CHP's qualification for Climate Change Levy Exception Certificates (LECs)
- 80% of the value of LECs is realised
- The Climate Change Levy (CCL) will be inflated by 2% in 2008 and remain in place or be replaced by a tax of similar value thereafter
- A discount rate of 15% was used in the CHP project appraisal
- Capital costs of CHP projects are £550/kWe for project less than 250MW and £500/kWe for projects greater than 250MW
- The maintenance cost of CHP plant is 1p/kWh
- The electrical efficiency of CHP plant is 41%
- The heat to power ratio of CHP plant is 0.75 for projects less than 250MW and 0.7 for projects greater than 250MW
- The efficiency of a conventional boiler is 75%
- The maintenance cost of a conventional boiler is 0.2p/kWh

Factors to be taken into account in completing cost and benefit analysis:

- See list of assumptions – cost and benefit analysis has been carried out as part of the

earlier AEA Energy & Environment project

<table>
<tr><td>Option 10</td><td colspan="3">Mandate energy suppliers to improve billing</td></tr>
<tr><td colspan="4">Barrier overcome:</td></tr>
<tr><td colspan="4">• 8.1.4 Insufficient energy efficiency information on energy bills to allow consumers to make informed choices</td></tr>
<tr><td colspan="4"></td></tr>
<tr><td>Supply chain stage:</td><td>End-user demand</td><td>Implementing actor/s:</td><td>Ofgem and energy suppliers</td></tr>
<tr><td>Estimated annual carbon savings (MtC):</td><td>4.0 – 10.0</td><td>Estimated primary energy savings (MWh):</td><td>Negligible</td></tr>
<tr><td colspan="2">Estimated cost to Central Government (£million):

Annual or One-off cost?</td><td colspan="2">Negligible

N/A</td></tr>
<tr><td colspan="2">Estimated other costs (£million):

Annual or One-off cost?

Recipient of costs</td><td colspan="2">2,000 – 8,800

One-off cost to install smart meters to facilitate improvements to billing

Energy suppliers / Consumers</td></tr>
<tr><td colspan="2">Estimated other costs (£million):

Annual or One-off cost?

Recipient of costs</td><td colspan="2">4.9 – 9.8

Annual cost of improved billing

Energy suppliers / Consumers</td></tr>
<tr><td colspan="4"></td></tr>
<tr><td colspan="4">Description of option:</td></tr>
<tr><td colspan="4">Some stakeholders believe that a lack of energy efficiency information on energy bills is a barrier to a sustainable energy system. They argue that current billing systems carry inadequate information to provide properly informed consumer choice and reduce the impact of energy efficiency improvements, increase fuel poverty and consumer debt.

Ofgem could address this issue in the short term by working with the Energy Retail Association to include energy efficiency information in the revised Code of Practice for Accurate Bills. The revised Code could then apply to all consumers (domestic, commercial and industrial) that are not subject to half hourly metering. However, the revised code of practice is likely to remain a voluntary agreement so in the longer term Ofgem could mandate suppliers to take action by amending the Electricity/Gas Supply Licenses to incorporate improved billing.

The changes to the supply licenses could follow a similar theme to EEC and the proposed cap and trade scheme (Option 8) in that Ofgem could set minimum standards and suppliers could then be encouraged to come up with innovative ways of presenting the information. This link could be taken a step further by allowing Suppliers to claim EEC2 credits if the information meets Ofgem's minimum standards. Ultimately, if a cap and trade scheme is implemented it will be in the Suppliers interests to encourage</td></tr>
</table>

consumers to manage their own demand.

Improved billing could include the following features:

- Accurate monthly bills so customers get regular feedback regarding their energy usage and see evidence of the reduction in energy usage following the implementation of energy efficiency measures. This may necessitate a widespread roll out of smart meters that can be read remotely since reading every meter in the country on a monthly basis is unlikely to be feasible.
- A graphical comparison between current and historic gas and electricity use in that dwelling.
- Fuel source disclosure

Number of new entrants:	Improved billing may facilitate easier comparison between Suppliers and thus encourage consumers to switch. In turn this may encourage new entrants since they would be more likely to gain a foothold in the market.
Impact on generation mix:	If fuel source disclosure was included in the improved billing this option may drive an increased demand for renewables as consumers used the proportion of renewables in the supply-mix as a means of differentiating between suppliers.
Impact on consumer bills:	In the short term bills would rise as Suppliers recouped the cost of the investment in smart meters. However, in the longer term many stakeholders believe that consumer bills would fall once the cost of the meters had been passed through in full and improved provision of information allowed consumers to make informed choices regarding their energy consumption. The DTI estimate that a 0.25% reduction in energy consumption would produce a £2.00 reduction in consumer bills.

Legislative changes required & opportunities in Ofgem's existing role:

- No legislative changes required
- In the short term Ofgem could facilitate a change in the Code of Practice for Accurate Bills
- The medium term they could make an amendment to the Electricity / Gas Supply Licenses

Main tensions in the reform process:

- Agreeing the changes to the Code of Practice and Electricity/Gas Supply Licences

Timeline for implementation:

- **2007:** Energy Retail Association (ERA) formulate initial proposal for changes to Code of Practice
- **Spring 2008:** ERA consults on proposed changes to Code of Practice
- **Autumn 2008:** Changes to Code of Practice implemented

- **2010:** Ofgem formulates initial proposal for changes to Electricity / Gas Supply Licenses
- **2011:** Ofgem consults on proposed changes to Electricity / Gas Supply Licenses
- **2011:** Changes to Electricity / Gas Supply Licenses implemented

Assumptions made during cost and carbon savings calculations:

- Smart meters are required to provide accurate monthly bills
- 100% of existing gas meters would be replaced with smart meters as a result of this option
- 100% of existing electricity meters will be replaced with smart meters as a result of this option
- Every gas and electricity meter corresponds to a separate customer and will therefore incur the setup cost for the metrics
- The set up cost of producing graphs to benchmark gas and electricity use or CO_2 emissions is the same as that for comparing current and historic energy use
- Graphs to compare current and historic energy use lead to a 0.25% reduction in energy consumption
- Smart meters achieve the same carbon saving per 0.25% reduction in energy use as graphical comparisons with historic energy use
- The reduction in energy consumption due to installation of smart meters is between 1 and 3%

Factors to be taken into account in completing cost and benefit analysis:

- Costs to energy suppliers of implementing each of the graphical metrics
- Reduction in energy use and carbon savings from implementing each of the graphical metrics
- Costs to energy suppliers of purchasing, installing and maintaining the smart meters
- Proportion of existing gas and electricity meters replaced as a result of this option
- Reduction in energy use and carbon savings from installing smart meters

Option 11	**Develop an Offshore Regulatory Regime for the Transmission Network**		
Barrier overcome:			
• 5.4.1 High costs of transmission infrastructure for offshore network • 5.4.2 Lack of a regulatory regime for offshore electricity transmission			
Supply chain stage:	Transmission	**Implementing actor/s:**	Ofgem, GBSO and TOs,
Estimated annual facilitated carbon savings (MtC):	3.6 – 4.8	**Estimated primary energy savings (MWh):**	Negligible
Estimated cost to Central Government (£million): Annual or One-off cost?		Negligible N/A	
Estimated other costs (£million): Annual or One-off cost? Recipient of costs		2.0 – 5.0 **One-off** cost to set up regulatory framework Ofgem, GB System Operator and Transmission Owners	
Description of option:			

An offshore electricity transmission regulatory regime needs to be implemented in order to allow renewable generation located in the sea outside the territorial waters of Great Britain to connect to the existing onshore network. DTI and Ofgem have concluded that an unlicensed or licence exempt approach is not a practical or even legally permissible position. At an operational level there is a requirement for regulation to ensure that the offshore transmission system can safely and effectively interface with the onshore grid; failure to achieve this could lead to faults and interruptions in existing supply. At the very least regulation is needed to ensure appropriate codes and standards are applied to the interface. In legal terms, the Energy Act 2004 prohibits electricity transmission in the Renewable Energy Zone (an area of the sea, beyond the United Kingdom's territorial sea, which may be exploited for energy production) without a licence. In addition, the requirements of the 2003 Electricity Directive for regulated third party access mean that a licence exempt approach is not possible. Some form of regulation is therefore essential if the infrastructure needed to connect offshore renewable energy is to be provided.

Currently, there are plans for about 6-8GW of electricity (which represents just under 10% of current generating capacity) to be developed in the sea around Great Britain, primarily from wind resources. In the future, it is also hoped that other technologies harnessing wave and tidal power may reach commercial development and they too would be able to take advantage of the proposed offshore regulatory regime.

The government has announced that transmission networks offshore will be subject to price controls, which will be set and reviewed by Ofgem. Ofgem's scoping document (published in April 2006) was the first stage in the process of implementing a regime for electricity transmission networks offshore. It identified the work that needs to be undertaken, the decisions which need to be made and some of the options for those decisions.

Ofgem intends, as far as is possible, to replicate the onshore electricity transmission regulatory regime offshore. This should ensure a single integrated set of arrangements for the trading and transmission of electricity, including:

- A single system operator (this role differs from the transmission owner, although in England and Wales the National Grid fulfil both functions.) which is independent of generation and supply interests
- Common rules and charging arrangements for connecting to and using the transmission system
- A common set of balancing and settlement arrangements
- Consistent technical rules governing the planning and operation of transmission circuits

Ofgem has identified five work streams which it needs to take forward to help implement an offshore regulatory regime for electricity transmission.

1) Identify the geographic scope of offshore transmission licences.

2) Decide on a method to allocate offshore transmission licences. (It has since been decided to consider issues 1 and 2 simultaneously since they are inextricably linked).

3) Look at the technical rules currently governing onshore networks and considering the feasibility and appropriateness of extending or amending these rules to cover offshore networks.

4) Consider the possible design of offshore price controls.

5) Make modifications to licences and codes that govern interactions between industry parties which are necessary to implement a regulatory regime for offshore transmission.

In May 2006 Ofgem and DTI set up the Offshore Transmission Expert Group (OTEG) to provide technical advice and information necessary to developing the detailed regime.

In August 2006 the Energy Minister announced that National Grid Electricity Transmission's (NGET) role as Great Britain System Operator (GBSO) will be extended offshore. NGET will be the system operator for both onshore and offshore parts of the transmission system. This role differs from the transmission owner, although in England the National Grid fulfils both functions.

Licensing offshore electricity transmission

Following work by the a sub-group of the OTEG so assess the licensing options the DTI and Ofgem launched a joint consultation in November 2006 to seek views on the detail of the proposed models for the offshore transmission owner (TO). Given that the geographic scope of the transmission licenses and the allocation methodology were inextricably linked, the sub-group considered the options for items 1) and 2) in the above list simultaneously. The consultation presented 2 main options:

1. **Non exclusive licenses** - This approach would see the Authority issue non-exclusive transmission licences to TOs who would be responsible for providing services to specific offshore projects or 'bundles' of projects anywhere in Britain's offshore waters without an automatic obligation to be a TO for future developments in the proximity. Under this asset-based approach, any organisation could apply to

become a TO as long as they met certain application criteria as laid down by Ofgem. Future developments could be tendered in a similar manner.

2. **Exclusive licences -** This option would grant licences to existing or new TOs for the exclusive provision of transmission services to all developments within a specified geographic area offshore. An appropriate body e.g. Ofgem or DTI would establish more than one offshore area, and would hold a competitive tender for the TO licence for each area. From a generator's point of view the system would be identical to that onshore.

Ofgem favours the first option as it believes this option will deliver offshore transmission connections in the most cost-efficient, timely and certain manner to consumers and generators. The DTI did not wish to state a preference before it has considered responses to this consultation and assessed which option best delivers Government policy. The consultation closed in January 2007 and a decision is expected in early 2007.

Technical rules

Many of the technical issues associated with Offshore regulatory regime related to the Security and Quality of Supply Standard (SQSS). Consequently, the OTEG committee formed an SQSS sub-group whose purpose was to assist OTEG by completing a review of the current GBSQSS and consequently considering:

- Whether it is appropriate to apply to the present onshore standard to offshore transmission networks
- If amendments are needed to extend the GBSQSS offshore; and
- The range of options that exist for alternative security standards for offshore transmission networks.

Based on the results of this analysis, the SQSS sub-group considered that the onshore GBSQSS planning and operational standards:

- Are not appropriate for application to offshore transmission network development; and
- Require amendment to facilitate the inclusion of offshore transmission networks

The recommendations made by the sub-group are:

a) The security standard for the offshore transmission network can be separated into two main sections:

    i) The offshore platform (i.e. the AC transformer circuits and HVDC converters on the offshore platform); and

    ii) The offshore cable network (i.e. the transmission cable circuits linking the onshore network and the offshore platform).

    Each should be considered separately for single and multiple wind farm connections.

b) For single wind farm connections, both the offshore platform and cable network capacity should, at a minimum, be equal to the maximum export capacity of the wind farm connected. However, the working group also recommended reserving the right to install less capacity if a detailed economic analysis demonstrated the rationale for such a decision.

c) For multiple wind farm connections, both the offshore platform and cable network capacity should, at a minimum, be equal to 90% of the cumulative installed capacity of the wind farms connected.

d) For wind farms with a capacity of 120MW or greater, following an outage (planned or unplanned) of any offshore platform transformer, there should be, at a minimum, 50% of the installed platform transformer capacity remaining.

e) To be compliant with onshore SQSS, for wind farms connected using High Voltage Direct Current (HVDC) technology, following an outage (planned or unplanned) of any single offshore platform DC converter module, the loss of power infeed shall not exceed the existing onshore Normal Infeed Loss Risk. (1000MW).

f) To be compliant onshore SQSS, for outages (planned or unplanned) of offshore transmission circuits (i.e. offshore transmission AC and DC cables) the loss of infeed should not exceed 1500MW. This value is bound by the limit in scope of the cost and benefit analysis.

In line with the existing GBSQSS, it is recommended that the offshore transmission security standards allow the transmission licensee to meet a Generator's request for security above or below the minimum planning standard provided there is no adverse impact on any other user, the Main Interconnected Transmission System (MITS) or the GB transmission licensee's.

These recommendations were consulted on by the DTI and Ofgem in December 2006 and the Government is expected to make a decision on:

- Whether it is appropriate for the minimum security requirements for offshore electricity transmission networks to be different to those currently applicable to onshore electricity transmission networks; and

- If so, whether the minimum security requirements for offshore electricity transmission networks recommended by the GB SQSS subgroup are appropriate.

Many stakeholders argue that if the offshore security standard is less demanding than the onshore standard this would enable offshore transmission costs to be reduced. In turn would help to overcome connection cost barriers for offshore renewables.

Design of offshore price controls

At the second meeting of OTEG on 1 June 2006 it was decided that there was merit in setting up an initial sub group ('the price control sub group') to undertake high level work to assist Ofgem/DTI in developing their thinking on the design of the price control. The price control work stream is seen as being a two stage process:

- Firstly, an initial series of meetings to consider the issues, high level principles and options of what an offshore price control might look like in terms of scope, form and duration; and

- Secondly, after the broad regulatory framework has been decided in early 2007 the group will reconvene to consider in more detail what the actual design of a price control might look like in terms of scope, form and duration. This group may also consider associated issues such as charging, interaction with other transmission price control reviews and the adoption of transmission assets.

Modifications to licences and codes

Make modifications to licences and codes that govern interactions between industry parties which are necessary to implement a regulatory regime for offshore transmission. Changes are likely to be required to:

- The standard conditions of the electricity transmission licence
- the special conditions of existing electricity transmission licences (consequential changes)
- The conditions of other electricity licences (consequential changes)
- The Grid Code
- The SO-TO Code (STC)
- The Connection and Use of System Code (CUSC) and the CUSC Framework Agreement
- The Balancing and Settlement Code (BSC)

These issues are beginning to be considered but detailed work will only commence once the shape of the broad regulatory framework has been finalised.

Two workshops that were held in January 2007 to discuss:

- Issues surrounding the DNO interface in the context of the offshore transmission regulatory regime and;
- Issues of access, charging and compensation

Number of new entrants:	This measure is likely to lead to an increase in the number of new entrants since it will enable more renewables projects to be built, which are more likely to be funded by new entrants to the energy market.
Impact on generation mix:	The proportion of renewable generation will increase as a result of this measure.
Impact on consumer bills:	There will be no direct increase in consumer bills as a result of this measure. However, it will facilitate a growth in renewables which are a more expensive means of generating power and so indirectly, this measure will lead to an increase in consumer bills.

Legislative changes required & opportunities in Ofgem's existing role:

- This option will not require any changes to primary legislation. The 2004 Energy Act gave the Secretary of State and Ofgem all the necessary powers to implement an offshore transmission regulatory regime. Ofgem will be responsible for developing the detail of proposed changes and new regulations, while the power to implement them lies with the Secretary of State.
- In developing an offshore transmission regulatory regime Ofgem is also likely to be required to make changes to:
  - The standard conditions of the electricity transmission licence
  - The special conditions of existing electricity transmission licences (consequential changes)
  - The conditions of other electricity licences (consequential changes)
  - The Grid Code
  - The GB System Operator – Transmission Owner Code (SO-TO)
  - The Connection and Use of System Code (CUSC) and the CUSC Framework Agreement

- The Balancing and Settlement Code (BSC)

Ofgem is able to approve changes to the licenses and codes that govern the electricity sector unilaterally (although changes are normally received by the appropriate panel that make a recommendation to Ofgem as to whether the change should be implemented). As part of this process any proposed changes to the licences and industry codes would be the subject of an Ofgem consultation. However, ultimately, DTI will have the final say on these changes since Ofgem follow the policy lead of the Government.

Main tensions in the reform process:

- The vast majority of stakeholders acknowledge the need for an off-shore regulatory framework.
- However, there are likely to be a range of opinions regarding the changes that need to be made to the electricity sector licences and codes.

Timeline for implementation:

- **2007:** High level Government decisions on a variety issues including: the shape of transmission licences, SQSS and price control design
- **2008:** Changes to licences and codes
- **2008/09:** Applications for licences to operate offshore generating facilities
- **2010/11:** Offshore facilities come on-stream

Assumptions made during cost and carbon savings calculations:

- If offshore regulatory regime for transmission isn't developed then no new offshore capacity will be added.
- All offshore generation capacity will be carbon neutral

Factors to be taken into account in completing cost and benefit analysis:

- Timescales for the development of offshore capacity
- Future marginal plant carbon emission factor

Option 12	**Implement more equitable arrangements for allowing National Grid to protect itself against the risk of unnecessary transmission investment**		
Barrier overcome:			
• 5.1.2 High cost and final sums liability			
Supply Chain stage:	Transmission Network	**Implementing actor/s:**	Ofgem and GB System Operator (National Grid)
Estimated annual facilitated carbon savings (MtC):	11 - 16	**Estimated primary energy savings (MWh):**	27,000,000 – 68,000,000
Estimated cost to Central Government (£million): Annual or One-off cost?		Negligible N/A	
Estimated other costs (£million): Annual or One-off cost? Recipient of costs		Negligible N/A N/A	
Description of option:			

The arrangement by which the GB Transmission System Operator (GBSO) makes a connection offer to a potential generator has acted as a major barrier to the connection of renewable technologies to the transmission system. The so called Final Sums Liability (FSL) arrangements have required developers to lodge a bond guaranteeing the monies required by the GBSO to implement the connection. The monies are only paid by the developer to the GBSO should they not go on to connect and pay use of system charges as they generate and export onto the network. This has protected the GBSO and the Transmission Owner (TO) from the developer 'walking away' from the connection offer. There have been 3 main criticisms of these arrangements:

1. **Volatility** – The level of the FSL can be extremely uncertain when several project developers whose project are located in close proximity share the cost of reinforcement of the transmission system. Under these circumstances some project developers may be left with significantly greater liabilities than originally quoted by GBSO if other users in the 'cluster' withdraw their application for connection. In many circumstances this potential volatility represents an unacceptable risk for project developers.

2. **Level of FSL** – Many project developers feel that the level of the FSL is too high and not in proportion to the size of the connection application.

3. **Timing** – Many project developers were also concerned by the high level of the FSL before the project had obtained planning consents, which is often the biggest

barrier to a proposed project becoming a reality.

In addition, there was also a criticism of the fact that under the FSL arrangements the developer takes all the risk and the GBSO, TO and ultimately the consumer, take none.

In February 2006, National Grid held two user seminars where a number of issues were raised by users with respect to the existing arrangements for managing access to the transmission system. As a consequence in April 2006, National Grid issued a consultation document entitle ‘Managing Access to the GB Transmission System’. Ofgem had also been considering how to overcome these issues through its Access Reform Options Development Group (ADRG), which published a framework for considering reforms to how generators gain access to the GB electricity transmission system in April 2006. Whilst these activities occurred in parallel, National Grid did take account of the findings from ADRG when developing its interim arrangements for replacing the final sums liability.

These interim arrangements take the form of a Generic User Commitment and were offered to generators on a voluntary basis as an alternative to the final sums liability arrangements from August 2006. The main elements of the Interim Generic User Commitment (IGUC) address the concerns of users regarding the level, timing and volatility of the FSL as well as the perceived inequity associated with the project developer taking all of the risk:

- The risk of unnecessary investment is borne by both new generators and consumers such that new generators are liable for 6 years’ worth of generation transmission network (TNUoS) charges. This also means that level of the GUC should be much more closely aligned with the size of the project than the FSL arrangements.

- The level of the GUC at each stage in the project development is fixed and entirely transparent, thus removing the volatility risk.

- The liability will be based on two phases; a User Commitment Amount (applied before the project has achieved consents) and a Cancellation Amount (applied after the project has achieved consents) both of which will be based on a generic formula that applies to any project using. This feature will address the issue of timing since the User Commitment Amount (UCAM) will be significantly lower than the Cancellation Amount (CA).

User Commitment Amount (UCAM)

Where the earliest time transmission access can be provided is more than 4 financial years from the date of the offer of connection and key consents are required and have not been obtained, the project developer will be liable for a UCAM of £1/kW commencing on signature of the Construction Agreement (CONSAG). This increases by £1/kW on 1st April each year up to the date at which the key consents are obtained or, if later, the date 4 financial year from the completion of the GBSO works, subject to a cap of £3/kW. The project developer would be liable to pay this sum in the event that they terminate their agreement during this period.

Cancellation Amount (CA)

Once all the key consents have been obtained by the relevant Transmission Owner the user will become liable for the (higher) CA rather than the UCAM. The CA is calculated according to the following formulae:

Cancellation Amount $_{t-3}$ = TEC * GenTNUoS$_z$ * X * 0.25

Cancellation Amount $_{t-2}$ = TEC * GenTNUoS$_z$ * X * 0.50

Cancellation Amount $_{t-1}$ = TEC * $GenTNUoS_z$ * X * 0.75

Cancellation Amount $_t$ = TEC * $GenTNUoS_z$ * X

Where:

t = the financial year in which completion is due to take place
TEC = the transmission entry capacity (or connection capacity) of the project
$GenTNUoS_z$ = the relevant Generation TNUoS tariff of the project
X = multiplication factor of TNUoS that is to be secured (i.e. 6)

For example, if the project developer pulled out of the project 2 financial years before the financial year the connection was due for completion then the project developer would be liable for a cancellation amount equal to TEC * $GenTNUoS_z$ * X * 0.50.

If a project is located in a Generation TNUoS Charging Zone which has a negative tariff, or a tariff less than £3/kW, a minimum £3/kW tariff will apply to calculate the generic cancellation amount.

Number of new entrants:	This option would result in an increase in new entrants since there would be much less risk associated with applying for a connection to the grid.
Impact on generation mix:	The proportion of small, renewable and sustainable generators would increase though implementing this measure due to the reduction in the level of risk associated with applying for a connection.
Impact on consumer bills:	In the short term this option would result in a very small increase in consumer bills due to the costs of the Agency Incentives. In the medium to longer term the greater number of connections to the transmission network that this measure would facilitate may lead to higher costs being incurred by the transmission owners, which in turn would be passed onto consumers.

Legislative changes required & opportunities in Ofgem's existing role:

- No changes would be required to primary legislation to implement this option.
- Implementing Generic User Commitments is within Ofgem's current remit.
- The National Grid has proposed the GUC as an amendment to the Connection and Use of System Code (CUSC) to replace the final sums liability. An industry working group have considered the proposals and sent a report to the CUSC panel. If the CUSC panel believe that the proposals have been adequately examined by the working group then they will issue a consultation on the proposals, which will last up to 2 months. Informed by the results of the consultation, the CUSC panel will then in turn file a report with Ofgem who will make the final decision as to whether to proceed with the GUC as the enduring arrangements for allowing National Grid to protect itself against the risk of unnecessary transmission investment. Given that this would be a significant change to the CUSC code Ofgem is likely to undertake a Regulatory Impact Assessment.

Main tensions in the reform process:
• Most stakeholder recognise the shortcoming of the FSL system for allowing National Grid to protect itself against the risk of unnecessary transmission investment. Therefore, it is not anticipated that there will be any significant disagreement regarding the need to change FSL system. • However, Ofgem's ADRG have been considering many of the same issues so may reach different conclusions as to the shape of a revised system. • Ultimately, Ofgem will have the final say on the enduring arrangements for protecting against the risk of unnecessary transmission investment.
Timeline for implementation:
• **Spring 2007:** CUSC provide a recommendation to Ofgem as to whether the GUC should replace the FSL on a permanent basis. Ofgem then consider the recommendation. • **Summer 2008:** Ofgem make the final decision • **Autumn 2008:** Arrangements put in place to withdraw FSL and formalise existing GUC arrangements.
Assumptions made during cost and carbon savings calculations:
• 20-40% of future GB electricity generation capacity will be DG • 16.3% of current GB electricity generation capacity is DG • 20-40% of future GB electricity supply will be DG • 7.1-14% of new GB electricity generation capacity will CHP, all of which will be DG • 86-92.9% of new GB DG capacity will be renewables • New CHP capacity will have an overall energy efficiency of 75%, a heat to power ration of 2.2:1 and a load factor of 70 – 85% • The boilers replaced by CHP plants have an energy efficiency of 85% and load factors of 70 – 85%
Factors to be taken into account in completing cost and benefit analysis:
• The split of heat to power ratios in CHP plants (the calculations in this option assumed all CHP plant will have a heat to power ratio of 2.2:1 – in reality there will be significant variation depending on the role of the CHP plant). • The accuracy of data on the costs and carbon savings associated with connecting each household to a heat network

Option 13	**Amend the supply license so that suppliers are obliged to sign up to the green supply guidelines**		
Barrier overcome:			
• 7.6 Green Tariffs			
Supply chain stage:	Supply	**Implementing actor/s:**	DTI / Ofgem / Electricity Suppliers
Estimated annual carbon savings (MtC):	0.20 – 1.0	**Estimated primary energy savings (MWh):**	Negligible
Estimated cost to Central Government (£million): Annual or One-off cost?		Negligible N/A	
Estimated other costs (£million): Annual or One-off cost? Recipient of costs		2.8 – 5.6 **Annual** costs to calculate household carbon savings Electricity suppliers	
Estimated other costs (£million): Annual or One-off cost? Recipient of costs		5.0 - 20 **One-off** costs to set up new green tariffs Electricity suppliers	
Description of option:			

Currently most electricity suppliers offer ‘green’ tariffs – tariffs that purport to be sourced from environmentally friendly sources. This leads onto difficulties in comparing tariffs, whether they are purporting to be green or not. Suppliers are not currently mandated to display key facts on their tariffs in a standard format, which acts as a barrier to consumers comparing tariffs on the basis of reduced environmental impact or selecting the ‘greenest’ tariff should they so desire.

Potentially more importantly, there is often a problem of additionality since it is thought that the green power supplied under these tariffs is generated under the Renewables Obligation. As such, the purchase of a green tariff does not generate any additional green power it merely attributes that which is already being generated to a particular customer.

This situation means that the offer of green tariffs to consumers will not contribute to the development of a sustainable energy system until demand for green power outstrips that which suppliers are obliged to produce via their commitments under the Renewables Obligation.

However, most stakeholders recognise that green tariffs do have a role to play in reducing household CO_2 emissions, and in increasing the amount of renewables in the overall generation mix.

To address the difficulties associated with comparing green tariffs Ofgem could amend the supply license so that suppliers are mandated to sign up to the green supply guidelines (i.e. they effectively become regulations rather than guidelines) if they want to offer green tariffs. Ofgem could also oblige electricity suppliers offering green tariffs to:

- Produce an individual fuel mix disclosure chart for each of their green tariffs set within the context of their overall generation mix. This could be sent to customers as part of a bill or used a marketing tool in a mailshot.

- Calculate the declared amount of CO_2 reduction that will be achieved from swapping to a green tariff from a conventional variety. Again this could be published on bills or as mark of marketing material.

- Have their green tariffs independently audited each year against a benchmark set by Ofgem. This is a low cost measure that will provide a level of confidence for the consumers.

Ofgem are in the process of reviewing the electricity supply licence and are aiming to reduce the amount of clauses or 'conditions' to which Suppliers must adhere. Since this option will require additional clauses to be added to the supply license Ofgem may be opposed to these changes. However, a recent report by the National Consumer Council (NCC) stated that 64% of respondents to a poll would consider switching to a green energy company (tariff). However to fulfil this potential suppliers have to offer end users unambiguous information on what is on offer and have the confidence that the green tariffs are delivering what they promise. This is a clear justification to mandate this option.

Number of new entrants:	This option may encourage new renewable energy suppliers into the market. It may also encourage more renewable energy developers by bringing more investment for capacity to come on line sooner.
Impact on generation mix:	This option may facilitate a more diverse energy mix as it will encourage more renewable energy to come online.
Impact on consumer bills:	This option would have a minimal impact on consumer bills.

Legislative changes required & opportunities in Ofgem's existing role:

- No changes to legislation are required.
- Ofgem could enforce these changes by amending the supply licence as outlined in the option description.

Main tensions in the reform process:

- The initial cost to electricity suppliers
- Ofgem and suppliers may not wish to amend the supply license further (they recently removed a series of clauses) to include more clauses.

Timeline for implementation:
• **Summer 2007:** Design and agree revised green supply guidelines / licence. • **Spring 2008:** Amend supply licence to include the revised green supply guidelines. • **Summer 2008:** Mandate new supply licence.
Assumptions made during cost and carbon savings calculations:
• The proportion of renewables in the current GB electricity supply will rise by 0.5 – 2.0% if the proposals in this option are implemented • New renewables are Carbon neutral • Growth in take-up of green tariffs only stimulates more renewables to be built, not other forms of generation
Factors to be taken into account in completing cost and benefit analysis:
• The increase in the proportion of renewables in the current GB electricity supply • Growth in take-up of green tariffs

10 Total costs, carbon savings and primary energy savings

Figure 3 summarises the estimated costs, carbon savings and primary energy savings associated with each option. It also gives a low and high total for each category, which should act as a guide to the overall costs, carbon savings and primary energy savings that could be achieved or facilitated if all of the options outlined in section 9 were implemented. **However, it is important to note that given the assumptions (and hence uncertainty) associated with the calculations, the authors strongly recommend adopting a conservative approach and quoting the 'low' figure for carbon savings and primary energy savings and the 'high' figure for costs during policy discussions.**

The facilitated carbon saving and primary energy saving totals in Figure 3 are not equal to the sum of the individual estimates for each of the options considered in section 9. This is because there is some overlap between the savings facilitated by these options. In several instances it was not possible to attribute specific savings to an option. Consequently, it was assumed that the option would contribute towards hitting a target (such as the Government's aspirational 20% target for the proportion of electricity supplied by renewables). In such cases simply summing all the individual savings would result in double counting and a false total.

The low total for the facilitated carbon savings is calculated by summing the savings from options 2A, 6 and 11 where as the high total is calculated by summing the savings from options 2B, 6 and 11. Options 4, 5, 7, 8 and 12 were deemed to overlap with these savings so were not included in the total.

The total for primary energy savings is calculated by summing the savings from options 1 and 6. Options 4, 7, 9 and 12 were deemed to overlap with these savings so were not included in the total.

Figure 3 - Summary of carbon savings, costs and primary energy savings associated with the options considered in detail

Option	**Estimated** *'Actual'* Carbon Savings (MtC)		**Estimated** *'Facilitated'* Carbon Savings (MtC)		**Estimated** Primary Energy Savings Due to Reductions in 'Heat Losses' (MWh)		**Estimated Annual** Costs to Central Government (£million)		**Estimated One-off** Costs to Central Government (£million)		**Estimated Annual** Costs to others (£million)		**Estimated One-off** Costs to others (£million)	
	Low	**High**	**Low**	**High**	**Low**	**High**	**Low**	**High**	**Low**	**High**	**Low**	**High**	**Low**	**High**
Option 1: Allow Network Operators to develop heat networks and make them part of the regulated asset base	5.7	14	0.0	0.0	110,000,000	270,000,000	0.0	0.0	10.0	25.0	0.0	0.0	53,000	88,000
Option 2A. Incorporate the cost of carbon in to distribution and transmission network charges	0.0	0.0	0.2	0.3	0.0	0.0	0.0	0.0	0.0	0.0	51	150	0.0	0.0
Option 2B. Incorporate the cost of carbon in to distribution and transmission network charges	0.0	0.0	7.2	14	0.0	0.0	0.0	0.0	2.0	5.0	880	2,600	0.0	0.0
Option 3. Introduce a 'connect and manage' approach to the transmission network and prioritise connection of low carbon generation	1.3	3.2	7.8	7.8	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	2.0	5.0
Option 4. Add sustainability and GHG reduction objectives to the Balancing and Settlement Code	0.0	0.0	11	16	27,000,000	68,000,000	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Option 5. Create new trading arrangements for small and intermittent generators	0.0	0.0	7.8	7.8	0.0	0.0	0.0	0.0	2.0	5.0	320	520	0.0	0.0
Option 6. Upgrade the distribution network by strengthening incentives and increasing investment	0.0	0.0	11	16	27,000,000	68,000,000	0.0	0.0	0.0	0.0	250	1,000	930	2,800
Option 7. Implement an agency system of contractual agreements between Distributed Generators and the GB Transmission System Operator	0.0	0.0	11	16	27,000,000	68,000,000	0.0	0.0	0.0	0.0	3.3	47	10	30
Option 8. Introduce a Carbon 'cap and trade' for energy suppliers	0.0	0.0	1.2	1.2	0.0	0.0	0.0	0.0	0.0	0.0	780	910	0.0	0.0
Option 9. Revise TNUoS Charging Structure for CHP	0.5	0.5	0.0	0.0	15,000,000	38,000,000	540	900	0.0	0.0	430	530	0.0	0.0
Option 10. Mandate energy suppliers to improve billing	4.0	10	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	2,000	8,800	4.9	9.8
Option 11. Develop an Offshore Regulatory Regime for the Transmission Network	0.0	0.0	3.6	4.8	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	2.0	5.0
Option 12. Implement more equitable arrangements for allowing National Grid to protect itself against the risk of unnecessary transmission investment	0.0	0.0	11	16	27,000,000	68,000,000	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Option 13. Amend the supply license so that suppliers are obliged to sign up to the green supply guidelines	0.2	1.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	2.8	5.6	5.0	20
TOTAL	11	28	15	35	140,000,000	340,000,000	540	900	4	10	4,700	15,000	950	2,800

11 Opportunities to implement policies to reduce the barriers to a sustainable energy system

This section outlines the main opportunities within the existing electricity sector regulatory framework for new policies to be implemented to reduce the barriers to a sustainable energy system. There are opportunities both within Ofgem's existing role and the Government's reviews of policy.

11.1 Ofgem electricity sector network price control reviews

Price control reviews are the means by which Ofgem determines the costs that Distribution Network Operators (DNOs) and Transmission Owners (TOs) can pass through to their customers. They occur every 5 years and set the framework of incentives and policies to encourage DNOs and TOs to develop their networks in line with the Government's and Ofgem's priorities. During the reviews the proposed level of expenditure by each company will be considered in detail under categories such as:

- Capital expenditure
- Operating expenditure
- The cost of capital
- Pensions allowance
- Tax allowance

In exceptional circumstances Ofgem has been known to 'break into' a price control and alter the regulatory framework between price control reviews. However, they have a strong preference for delaying changes until the next formal review. Ofgem consults both informally and formally on its proposals for the Price Control, which is a process that tends to start around 18 months before the reset date.

The next round of price controls is scheduled for the following dates:

- **Distribution - April 2010.** The previous price control came into force in 2005.

- **Transmission - April 2007** and **April 2012.** The new Transmission Price Control Review (TPCR) is due to come into force in April 2007 so any proposed changes to transmission network use of system charging, incentives etc will need wait until the next TRPCR in 2012.

11.2 Ofgem electricity sector supply license reviews

The supply licenses stipulate the conditions and obligations to which a supplier of electricity to domestic or commercial premises in Great Britain must adhere. A Supply License Review is the process by which changes are made to the supply license, although unlike the distribution and transmission network price controls there are no fixed dates for Supply License Reviews.

The supply license includes conditions that may:

- Require the licensee to produce statements or codes of practice setting out how it will meet certain objectives in respect of its treatment of its customers which must be approved by Ofgem
- Set out the manner in which a licensee may or may not operate and conduct its business, particularly in the context of disadvantaged customers
- Require the licensee to maintain and submit information or to produce information or statements where required

- Require the licensee to put in place those systems and arrangements that are required to ensure that the licensee's business is operated in the manner required
- Require the licensee to enter into agreements with the electricity distribution or transmission licencees

If Ofgem wants to propose changes to supply license conditions they must obtain consent via the Collective License Modification (CLM) process. They will normally undertake an informal consultation with key stakeholders to understand their concerns at an early stage before their proposals are finalised. Once Ofgem has published its formal proposals they are then obliged to undertake a formal consultation. Where a licence modification constitutes a significant new policy proposal Ofgem will also carry out a Regulatory Impact Assessment (RIA) and publish it as part of the statutory consultation. In addition to commenting on proposed licence modifications, relevant licence holders may object to any proposal to make a collective licence modification. If the number of relevant licence holders that havemade a statutory objection is equal to or greater than 20% of the total number of relevant licence holders, or if the market share of objectors is equal to or exceeds 20%then the proposed modification cannot be made.

The next round of supply license reviews are scheduled for the following dates:

- **June 2007.** The suite of changes to the electricity supply licence under the current supply license review is expected to come into force in June 2007. The consultation for this exercise is virtually completed but precise dates for implementation have yet to be agreed.

- **Summer 2009 (Estimate).** The date of the next supply license review has yet to be confirmed.

11.3 Electricity Sector Codes and Panels

The day to day operation of the electricity infrastructure (i.e. the transmission and distribution networks) in Great Britain is governed by a number of codes that set out a series of rules and guidelines to ensure best practice is followed. The owners, operators and customers of the networks are obliged to abide by the codes. In the electricity sector the main codes are:

- **The Grid Code** which is designed to permit the development, maintenance and operation of an efficient, co-ordinated and economical system for the transmission of electricity, to facilitate competition in the generation and supply of electricity and to promote the security and efficiency of the power system as a whole.

- **The Distribution Code** details the technical parameters and considerations relating to connection to, and use of, the distribution systems. All the The Distribution Network Operators (DNOs) are obliged under their licenses to maintain a distribution code. At the present time they have chosen to operate the same version of the code.

- **The Balancing and Settlement Code** which contains the governance arrangements for electricity balancing and settlement (i.e. ensuring electricity demand is exactly matched with supply) in Great Britain.

- **The Connection and Use of System Code** which is the contractual framework for connection to, and use of, National Grid's high voltage transmission system

- **System Operator – Transmission Owner Code** which defines the high-level relationship between the GB System Operator (GBSO) and the Transmission Owners. It is supported by a number of procedures (SOTO Code Procedures or STCPs) that will set out in greater detail the roles, responsibilities, obligations and rights etc of the GBSO and the TOs.

Each of these codes is managed by a panel that is comprised of members from across the industry who meet on a regular basis. Each panel's main role is to ensure its code remains fit for purpose by considering proposed modifications, or proposing modifications itself, and providing recommendations to Ofgem as to whether the proposals should be implemented. When modification proposals are submitted to a panel the secretary will normally verify whether the proposal meets the necessary criteria. If this is the case the panel will consider the proposal and if it believes it warrants further consideration they will form a working group to consider the proposal in detail and formulate a recommendation to Ofgem. The working group's report will then be presented to the panel and once its final form has been agreed it will be submitted to Ofgem for approval.

The panels also serve as a source of information regarding the operation of their code and may be called upon to issue guidance regarding its implementation, performance and interpretation.

11.4 Electricity Sector Industry Working Groups

Where a significant amendment or addition is being considered to the regulatory framework Ofgem or Government may choose to form an industry working group to develop ideas and advise it on the best course of action. This section presents several examples of such working groups, which have a significant influence on the policies that govern the shape of the regulatory framework. As such, they are one means of putting forward policies to overcome the barriers to a sustainable energy system.

11.4.1 OTEG (Offshore Transmission Expert Group)

In March 2006 the Government outlined the method of regulation for offshore electricity transmission to be implemented under the Energy Act 2004. The regulation is necessary to allow electricity generated from offshore renewables sources to be transferred to customers via transmission connections to onshore networks. The regulatory regime will be developed by Ofgem and DTI. In developing the detail of this regulatory regime, Ofgem and DTI recognised that it would be beneficial to draw upon the specialist expertise of the existing transmission licensees, offshore developers and other parties with experience relevant to offshore transmission activities. OTEG is the forum in which Ofgem and DTI propose to draw upon such specialist expertise and experience. It will provide advice to Ofgem and DTI on options and issues associated with the development of a regulatory regime for offshore electricity transmission as outlined in the April 2006 Ofgem scoping document.

11.4.2 ENSG Electricity Networks Strategy Group (also the ENSG sub groups the Distribution Working Group and the Transmission Working Group)

The Electricity Networks Strategy Group (ENSG) is the United Kingdom Electricity Supply Industry focus group for network issues. The aim of the ENSG is to identify, and co-ordinate work to address the technical, commercial, regulatory and other issues that affect the transition of electricity transmission and distribution networks to a low-carbon future.

The ENSG's terms of reference are to:

- Identify, and co-ordinate efforts to address, technical and commercial issues in electricity transmission and distribution networks in transition to a low-carbon future.
- Establish and co-ordinate Transmission and Distribution Working Groups able to build on the contribution of the Transmission Issues Working Group (TIWG) and Distributed Generation Coordinating Group (DGCG) to the removal of barriers to a low-carbon economy.
- Advise Ministers and Ofgem, as required.
- Disseminate the results of its activities to the wider community.
- Report annually to Ministers and Ofgem.

11.4.3 ARODG (Access Reform Options Development Group)

In early 2006, in response to concerns from system users, Ofgem established the Access Reform Options Development Group (ARODG). The Group was charged with developing a range of options for amending the existing arrangements (i.e. final sums liability) for securing transmission capacity.

The ARODG terms of reference are to:

Consider and comment on any proposal brought forward by a member of the group, including TOs and Ofgem, in regard to the extent to which they would:

- Deliver against Transmission Owners' (TOs) licence conditions
- Deliver against the identified objectives
- Impact upon other industry codes, licences or associated aspects of electricity transmission or distribution policy. In particular consider interactions where incentives on transmission licensees may need to be developed.
- Benefit from refinement and enhancement by the Group.

Where appropriate, identify and discuss potential alternative proposals and the extent to which they would:

- Deliver against TOs' licence conditions
- Deliver against the identified objectives
- Impact upon the other parts of the regime or require the consequential development of incentives on transmission licensees.

11.4.4 TADG (Transmission Arrangements for Distributed Generation Group)

The purpose of the group is to identify options for changing the transmission arrangements that affect distributed generation in the light of the following criteria:

- **Minimising implementation costs.** The arrangements should not impose undue implementation or administrative costs on industry participants, recognising that such costs might be expected ultimately to be passed on to consumers.

- **Cost reflectivity.** The arrangements should seek to reflect the costs that industry participants impose on the system. Cost reflective charges promote effective competition between industry participants and facilitate market entry.

- **Efficient network development.** Arrangements should encourage efficient decisions can be taken regarding the development and use of the transmission and distribution networks.

11.5 Government white papers

The Government details its strategy in a given policy area via a white paper. A new DTI energy white paper is expected during 2007/08 to finalise the proposals outlined in the 2006 energy review. The previous energy paper was published in 2003. A number of consultations were launched in response to findings from the energy review:

- New nuclear policy framework
- Energy Efficiency Commitment April 2008-March 2011
- Proposals on banding, and amending the Renewables Obligation
- The Effectiveness of Current Gas Security of Supply Arrangements

- Updating the Electricity Generating Stations and Overhead Lines Inquiry Procedure Rules in England and Wales
- Measures to reduce carbon emissions in large non-energy intensive business and public sector organisations
- Billing and Metering
- Resilience of Overhead Power Line Networks

These consultations may feed into the formulation of the new energy white paper and as such represent another opportunity for stakeholders to put forward policies to help overcome the barriers to a sustainable energy system.

11.6 Comprehensive Spending Review

The 1998 Comprehensive Spending Review (CSR), which concluded in July 1998, involved a thorough review of departmental aims and objectives and a zero-based analysis of each spending programme to find the best way of delivering the Government's objectives. It was the first time a spending review on that scale had been attempted in the UK.

The Government intends to launch a second CSR reporting in 2007, to identify what further investments and reforms are needed to equip the UK for the global challenges of the decade ahead. The 2007 CSR will represent a long-term and fundamental review of government expenditure. It will cover departmental allocations for 2008-09, 2009-10 and 2010-11, with allocations for 2007-08 held to the agreed figures already announced at the 2004 Spending Review.

Given the manner in which climate change and sustainability has risen up the political agenda it is clear that the CSR is a major opportunity for the SDC and others to make the case for a fundamental redistribution of funds towards initiatives that seek to mitigate the impact of climate change and address its causes.

11.7 Budgets and Pre-Budget Reports

The Budget is the major financial and economic statement made in each year by the Chancellor of the Exchequer to Parliament and the Nation. Since 1998, the Chancellor has presented the Budget in the Spring so the next budget is due in March 2007. The pre-budget report is traditionally a mix of new measures and a commentary on the performance of existing measures that is released annually in December.

The role of the Budget is to provide an update on the state of the economy and the public finances (and present new forecasts for each), to set out the Government's economic and fiscal objectives, to report on the progress the Government has made toward achieving its objectives, and to set out the further steps the Government is taking to meet them. The Budget information is published in the Economic and Fiscal Strategy Report (EFSR) and the Financial Statement and Budget Report (FSBR).

The Budgets and Pre-Budget Reports are opportunities to influence the short term allocation of funds to Government departments by the Treasury. Since many of the options presented in this report would require significant investment it is clear that the Treasury has an important role to play in creating a more sustainable energy system.

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Annex 1 - List of stakeholders interviewed

The following stakeholders have been interviewed as part of this project or SDC's broader review of Ofgem's role:

1. Adam Brown (Independent Consultant – Heat Expert)
2. Association of Electricity Producers (Malcom Taylor)
3. CHP Association (Syed Ahmed and Phil Piddington)
4. Compass Environment and Sustainability Group (Hugh Goulbourne)
5. Connective Energy (Tom Millar)
6. Defra (Henry Derwent)
7. EDF (Denis Linford)
8. Electricity Networks Association (Andy Phelps)
9. Energy Retail Association (Russel Hamblin-Boon)
10. Energywatch (Claire Taylor)
11. Matthew Rhodes (Micro-generation Specialist)
12. Ofgem (Various)
13. Scottish Environmental Protection Agency (Janice Milne)
14. Scottish Power
15. Scottish Southern Electric
16. Sustainability First (Gill Owen)
17. United Utilities
18. Utilicom (Mike Smith)
19. Virginia Graham (Previously of Ofgem)
20. Good Energy Ltd (Alice Waltham)

Annex 2 – Matrix of Barriers

Energy Supply Chain Section	Energy Supply Chain Sub-Section		Barrier Number	Barrier	Category	Importance	Timescale
Cross-cutting	3.1	Institutional barriers	3.1.1	Lack of overarching energy policy framework to meet multiple policy goals	Regulatory	High	Medium-term
			3.1.2	Long term policy framework - complexity	Cost	High	Long-term
				Long term policy framework - clarity	Institutional, Regulatory	High	Long-term
				Long term policy framework - coverage	Regulatory	High	Long-term
				Long term policy framework - cost effectiveness	Cost	High	Long-term
				Long term policy framework - convergence/consistency	Institutional, Regulatory	High	Long-term
			3.1.3	Lack of government policy alignment is impacting upon timely policy intervention	Institutional, Regulatory	High	Medium-term
			3.1.4	Conflicting interests and policy drivers between government departments	Institutional, Regulatory	High	Medium-term
			3.1.5	Lack of capacity at local government level to implement sustainabl energy policy	Institutional	Medium	Medium-term
	3.2	Role of regulator	3.2.1	Misalignment between regulatory brief and updated government energy strategy	Regulatory, Institutional	High	Short-term
			3.2.2	Need for clearer sustainability remit for regulator	Regulatory, Institutional	High	Short-term
			3.2.3	Short term price focus rather than longer term policy concerns	Regulatory, Institutional	High	Short-term
			3.2.4	Complexity of regulatory environment for smaller market players	Regulatory	High	Medium-term
	3.3	NETA - Trading Arrangements	3.3.1	Discrimination against intermittent renewables	Regulatory, Market	Medium	Medium-term
			3.3.2	Discrimination against small scale micro-generation technologies	Regulatory, Market	Medium	Medium-term
			3.3.3	Increase in carbon emissions due to trading arrangements	Market	Medium	Medium-term
			3.3.4	Lack of sustainability criteria or renewables focus in Balancing and Settlement Code	Regulatory	Medium	Medium-term

Energy Supply Chain Section	Energy Supply Chain Sub-Section		Barrier Number	Barrier	Category	Importance	Timescale
Generation	4.1	Carbon price	4.1.1	Low carbon price	Market, Legislative	High	Medium-term
			4.1.2	Post-2012 legislative uncertainty	Legislative	High	Long-term
	4.2	Renewable Energy	4.2.1	Incomplete coverage of the Renewables Obligation	Financial, Legislative	High	Short-term
			4.2.2	Lack of long term stability of the Renewables obligation	Legislative	High	Short-term
			4.2.3	Renewable Obligation favours the cheapest technologies	Legislative, Financial	High	Medium-term
			4.2.4	Perception and technical understanding of planners considering planning applications for renewables projects	Institutional, Informational	High	Short-term
			4.2.5	Greater levels of funding required for the Wave and Tidal-stream Demonstration Scheme	Financial, Institutional	Medium	Medium-term
			4.2.6	Offshore wind is struggling to compete with onshore wind	Financial, Institutional	Medium	Medium-term
			4.2.7	TAN 8 planning policy in Wales	Institutional, regulatory	Medium	Short-term
	4.3	Carbon Capture and Storage	4.3.1	Lack of system to assign and manage long term carbon liabilities	Regulatory,	High	Long-term
			4.3.2	Planning issues	Regulatory, Informational	High	Medium-term
			4.3.3	Regulatory barriers to storage both on and offshore	Legislative	High	Short-term
			4.3.4	Lack of price support mechanisms and financial incentives	Regulatory, Financial	Medium	Medium-term
			4.3.5	Third party access system to pipeline infrastructure	Regulatory	Medium	Medium-term
	4.4	Combined Heat and Power	4.4.1	Unfavourable gas and electricity prices erode advantage over conventional generation	Cost, Market	Medium	Medium-term
			4.4.2	Energy price volatility creates risk barriers to CHP investment	Cost, Regulatory	Medium	Medium-term
			4.4.3	Uncertainty of stability of long term heat demand creates investment risk	Market	Medium	Long-term
			4.4.4	Higher CHP capital costs compared to conventional generation	Cost, Technical	Medium	Long-term
			4.4.5	Higher CHP operation and maintenance costs than conventional generation	Cost, Technical	Low	Long-term
			4.4.6	Lack of Heat Obligation to mirror Renewables Obligation disadvantages CHP	Legislative, Financial	Medium	Medium-term
			4.4.7	Failure of carbon pricing to provide the expected benefits to CHP	Market	Medium	Medium-term

Energy Supply Chain Section		Energy Supply Chain Sub-Section	Barrier Number	Barrier	Category	Importance	Timescale
Generation (continued)	4.4	Combined Heat and Power (Continued)	4.4.8	Export price differential between CHP and conventional generation	Market	Medium	Medium-term
			4.4.9	Lack of heat regulator is a barrier to sectoral development	Regulatory	Low	Short-term
			4.4.10	Lack of heat metering system	Regulatory, technical	Low	Medium-term
			4.4.11	Limited support for diesel fired CHP in absense of gas mains connection	Regulatory, Cost	Low	Short-term
	4.5	Microgeneration/Distributed Energy	4.5.1	Feasibility of micro-generation technologies is still unproven	Technical, Cost	High	Medium-term
			4.5.2	Microgeneration is less cost effective than conventional generation	Cost	High	Medium-term
			4.5.3	Environmental benefits of microgeneration may be less than predicted	Techical, Environmental	High	Long-term
			4.5.4	Public acceptance of large scale moves to distributed energy	Informational	High	Short-term
			4.5.5	Lack of consumer information on technologies and installation	Informational	Medium	Medium-term
			4.5.6	Electricity generation efficiencies are lower than for conventional generation	Technical, Cost	Medium	Long-term
			4.5.7	Planning permission required for many installations	Regulatory	Medium	Medium-term
			4.5.8	Distribution charging on microgeneration	Cost	Medium	Medium-term
			4.5.9	Active network management will be required to cope with large scale distributed energy	Regulatory, Technical	Low	Long-term
			4.5.10	Microgeneration may not significantly increase security of supply	Security	Low	Long-term
	4.6	Biomass	4.6.1	Long term contracts for producers vs short term contracts for generators	Techical, Market	High	Medium-term
			4.6.2	Environmental concerns over introduction of monocultures and new species	Environmental	Medium	Long-term
			4.6.3	Transportation of biomass to smaller scale generation facilities	Technical, Informational	Medium	Medium-term
			4.6.4	Sustainability issues associated with imported biomass for co-firing	Market	Medium	Medium-term
Energy Supply Chain Section		***Energy Supply Chain Sub-Section***	***Barrier Number***	***Barrier***	***Category***	***Importance***	***Timescale***
Transmission	5.1	Network capacity and access	5.1.1	BETTA Queue	Institutional, regulatory	High	Short-term
			5.1.2	High Cost and Final sums liability	Regulatory, Cost	Medium	Medium-term
	5.2	Planning constraints	5.2	Planning constraints	Regulatory, Institutional	High	Medium-term
	5.3	Transmission charges	5.3.1	Lack of use of system charging regime for intermittent generators	Cost, Regulatory	Medium	Medium-term
			5.3.2	High offshore transmission charges	Regulatory, Cost	Medium	Long-term
	5.4	Marine/Offshore connections	5.4.1	High costs of transmission infrastructure for offshore network	Cost	Medium	Medium-term
			5.4.2	Need to upgrade offshore electricity transmission	Techincal	Medium	Long-term

Energy Supply Chain Section	Energy Supply Chain Sub-Section		Barrier Number	Barrier	Category	Importance	Timescale
Transmission (Continued)	5.4	Marine/Offshore connections (Continued)	5.4.3	Offshore distribution - transmission connections at full capacity	Institutional, Technical	Medium	Long-term
			5.4.4	Lack of integration of marine and offshore infrastructure	Institutional, Technical	Medium	Long-term
Distribution	6.1	Planning Sysyem	6.1	Planning constraints	Regulatory, Informational	High	Medium-term
	6.2	Network Investment	6.2	Current levels of investment in the distribution network may constrain future capacity	Financial	Medium	Medium-term
	6.3	Impact of Distributed Generation	6.3.1	Distributed generation will require more active management of network	Technical, Regulatory	Medium	Medium-term
			6.3.2	Two way power flows and increased voltages	Technical	Medium	Medium-term
	6.4	Transmission/Distribution interface	6.4.1	Inter network contracts and agreements	Regulatory, Market	Medium	Medium-term
			6.4.2	Classification of transmission/distribution networks in Scotland	Regulatory, Technical	Medium	Medium-term
	6.5	Charging System	6.5	Connection and use of system charging	Cost, Regulatory	Low	Short-term

Energy Supply Chain Section	Energy Supply Chain Sub-Section		Barrier Number	Barrier	Category	Importance	Timescale
Supply	7.1	Heat Network	7.1.1	High infrastructure costs to develop a network are high	Cost	High	Long-term
			7.1.2	Cultural barriers to a heat network	Regulatory, Market	Medium	Long-term
	7.2	Smart Metering	7.2.1	High capital costs associated with smart meters	Cost	High	Medium-term
			7.2.2	Stranding of new meter assets due to the 28-day rule	Market, Regulatory	High	Medium-term
			7.2.3	Lack of perceived benefits to any single agent in the energy industry	Market	Medium	Medium-term
			7.2.4	Lack of common standards for smart meters	Regulatory, Market	Medium	Short-term
			7.2.5	Complexity of the metering market	Market	Low	Short-term
	7.3	Energy Efficiency Commitment	7.3.1	Not currently funding larger energy efficiency equipment	Market	Low	Short-term
			7.3.2	EEC not perceived as a permanent legislative fixture	Institutional, Regulatory	Low	Medium-term
	7.4	Market Access	7.4.1	Vertical integration creates advantage for large operators	Market	Medium	Medium-term
			7.4.2	Market acces for new suppliers	Regulatory, Cost	Medium	Medium-term
			7.4.3	Licensing process can be burdensome for small suppliers	Regulatory, Cost	Medium	Medium-term
			7.4.4	Reduced innovation	Regulatory, Market	Medium	Medium-term
	7.5	Charging Structure	7.5.1	Variable rate tarriffs reward higher levels of energy use	Market	Medium	Medium-term
			7.5.2	28-day rule acts as a barrier to energy supply companies offering energy service contracts	Regulatory	Low	Short-term
	7.6	Green Tarriffs	7.6	Definitions of green tariffs vary and are not always clearly stated plus purchase of a green tariff does not generate any additional green power	Regulatory, Market	Medium	Medium-term

Energy Supply Chain Section	Energy Supply Chain Sub-Section		Barrier Number	Barrier	Category	Importance	Timescale
End User Demand	8.1	Engaging the consumer	8.1.1	Ignorance of the link between energy use and climate change	Information	High	Short-term
			8.1.2	Insufficient incentives to become more energy efficient	Regulatory, Market	High	Medium-term
			8.1.3	Affordability of energy efficiency measures, access to capital and spending choices	Cost	High	Medium-term
			8.1.4	Insufficient energy efficiency information on bills to allow consumers to make informed choices	Informational	High	Short-term
	8.2	Industrial Energy Efficiency	8.2.1	EU ETS uncertainty post 2012	Regulatory	High	Short-term
			8.2.2	Limited sectoral coverage of the EU ETS	Regulatory	High	Medium-term
			8.2.3	National Allocation Plans for phase II of EU ETS and beyond	Regulatory	High	Short-term
			8.2.4	Ability of Climate Change Levy to address energy efficiency in less energy intensive sectors	Regulatory	Medium	Medium-term
			8.2.5	Tightening CCA targets	Regulatory	Medium	Medium-term
	8.3	Lack of confidence in EE measures	8.3	Government reliance on supply side rather than demand side measures	Institutional	High	Long-term
	8.4	White Certificates	8.4	Lack of a market in energy efficiency or inclusion of energy efficency in EU ETS	Regulatory	Medium	Medium-term
	8.5	Fuel Poverty Initiatives	8.5.1	Fuel poverty strategy is largely dependent on volotile fuel prices, not legislation	Market, Regulatory	Medium	Long-term
			8.5.2	Warm front is nearing saturation	Regulatory	Medium	Medium-term
			8.5.3	The winter fuel payment is not targetted and does not incentivise energy efficiency measures	Cost, Environmental	Low	Medium-term

Annex 3 – Full list of options

Supply chain area	Sub-category		Barrier	Options
Cross-cutting	3.1 Institutional barriers	3.1.1	Lack of overarching energy policy framework to meet multiple policy goals	The Government recently formed The Office of Climate Change (OCC) which should deliver a more integrated approach - the status quo could be maintained in order to give this approach a chance to work. The overarching energy policy framework should be provided by the DTI's forthcoming energy white paper.
				The Government could form a department of Energy and Environment who could take a holistic view of energy and environmental issues and develop an overarching energy policy or implement the DTI's forthcoming white paper if it is published in the short term.
		3.1.2	Current climate change policy is not delivering emission reductions as quickly as the emerging science or government targets require	The Government could form a department of Energy and Environment who could take a holistic view of energy and environmental issues and develop an overarching energy policy or implement the DTI's forthcoming white paper if it is published in the short term.
				The Government recently formed The Office of Climate Change (OCC) which should deliver a more integrated approach - the status quo could be maintained in order to give this approach a chance to work. The overarching energy policy framework should be provided by the DTI's forthcoming energy white paper.
			Lack of industry confidence in long term low carbon investments	The Government could continue to support the EC's proposals in their recent energy strategy for more ambitious CO_2 abatement targets for 2020 and beyond.
				The Government could introduce long term carbon contracts
			The uncertainty of long term carbon price	The Government lead efforts to bring forward 100% payment for allowances (via auctioning?) in the EU-ETS
				Government lobby EC and other MS' to get guarantee of further EU-ETS phases
				The Government could lobby the EC to ensure that the NAPs are set 'correctly'
				Alternatives to EU ETS: Carbon taxation, Calculate (bottom up) social cost of carbon and legislate so that everyone must pay it, Low carbon technologies obligation
				The Government could introduce long term carbon contracts
		3.1.3	Lack of government policy alignment is impacting upon timely policy intervention	The Government recently formed The Office of Climate Change (OCC) which should deliver a more integrated approach - the status quo could be maintained in order to give this approach a chance to work. The overarching energy policy framework should be provided by the DTI's forthcoming energy white paper.
				The Government could form a department of Energy and Environment who could take a holistic view of energy and environmental issues and develop an overarching energy policy or implement the DTI's forthcoming white paper if it is published in the short term.
		3.1.4	Conflicting interests between government departments	The Government could form a department of Energy and Environment who could take a holistic view of energy and environmental issues and develop an overarching energy policy or implement the DTI's forthcoming white paper if it is published in the short term.
				The Government recently formed The Office of Climate Change (OCC) which should deliver a more integrated approach - the status quo could be maintained in order to give this approach a chance to work. The overarching energy policy framework should be provided by the DTI's forthcoming energy white paper.
		3.1.5	Lack of capacity at local government level to implement sustainable energy policy	Local authorities could increase council tax to generate extra funds
				Local authorities could divert resources from elsewhere within their budgets

Supply chain area	Sub-category		Barrier		Options
Cross-cutting	3.1	Institutional barriers	3.1.5	Lack of capacity at local government level to implement sustainable energy policy	Provide extra funding for local authorities from central Government funds
	3.2	Role of regulator	3.2.1	Misalignment between regulatory brief and updated government energy strategy	The Government could change Ofgem's duties, particularly it's primary duty.
			3.2.2	Need for clearer sustainability remit for regulator	The Government could change Ofgem's duties, particularly it's primary duty.
			3.2.3	Short term price focus rather than longer term policy concerns	The Government could change Ofgem's duties, particularly it's primary duty.
			3.2.4	Complexity of regulatory environment for smaller market players	Ofgem's duties could be amended to ensure it considers the needs of small suppliers thus reducing the need for small suppliers to participate in processes like the supply license review.
					The Government could fund a body to represent the interests of small energy suppliers in the supply licensing process and other situations.
	3.3	NETA - Trading Arrangements	3.3.1	Discrimination against intermittent renewables	Ofgem could add a sustainability duty to the Balancing and Settlement Code
					The Government chould commission a piece of work to review the entire Balancing and Settlement Code and assess how it stacks up compared to its 4 policy goals
					Change Ofgem's duties, particularly it's primary duty to put a greater emphasis on sustainability.
			3.3.2	Discrimination against small scale micro-generation technologies	Ofgem could add a sustainability duty to the Balancing and Settlement Code
					Government chould commission a piece of work to review the entire Balancing and Settlement Code and assess how it stacks up compared to its 4 policy goals
					The Government could change Ofgem's duties, particularly it's primary duty.
			3.3.3	Increase in carbon emissions due to trading arrangements	Ofgem could add a sustainability duty to the Balancing and Settlement Code
					The Government chould commission a piece of work to review the entire Balancing and Settlement Code and assess how it stacks up compared to its 4 policy goals
					Change Ofgem's duties, particularly it's primary duty to put a greater emphasis on sustainability.
			3.3.4	Lack of sustainability criteria or renewables focus in Balancing and Settlement Code	Ofgem could add a sustainability duty to the Balancing and Settlement Code
					Government chould commission a piece of work to review the entire Balancing and Settlement Code and assess how it stacks up compared to its 4 policy goals
					Change Ofgem's duties, particularly it's primary duty to put a greater emphasis on sustainability.
Generation	4.1	Carbon price	4.1.1	The carbon price is not providing adequate support to sustainable generation	The Government lead efforts to bring forward 100% payment for allowances (via auctioning?) in the EU-ETS
					The Government could consider alternatives to EU ETS: Carbon taxation, Calculate (bottom up) social cost of carbon and legislate so that everyone must pay it, Low carbon technologies obligation
					The Government could lobby the EC to ensure that the NAPs are set 'correctly'
			4.1.2	Legislative uncertainty post-2012	The Government could continue to support the EC's proposals in their recent energy strategy for more ambitious CO2 abatement targets for 2020 and beyond.
					The Government could introduce long term carbon contracts

Supply chain area	Sub-category		Barrier		Options
Generation	4.2	Renewable Energy	4.2.1	Incomplete coverage of the Renewables Obligation	The Government could introduce a heat obligation or some other form of incentive
			4.2.2	Lack of long term stability of the Renewables obligation	A Government statement that a revised 'banded' Renewables Obligation will remain unchanged until 2027 (they've stated they'll be a Renewables Obligation until 2027 but not guaranteed its structure).
					A Government statement that a revised 'banded' Renewables Obligation will remain unchanged until 2027 **for technologies that are already in place** – the Government could reserve the right to introduce new techs.
					The Government could not band the Renewables Obligation
			4.2.3	Renewable Obligation favours the cheapest technologies	The Government could band the Renewables Obligation to provide greater incentives to the less developed technologies
					The Government could introduce fixed feed in tariffs
					The Government could offer grants for the less developed technologies from the Environmental Transformation Fund with the aim of putting UK Plc into a world leading position, similar to that currently enjoyed by the Danes in relation to wind technology.
					The Government could continue to provide bridging funding to wave/tidal via Wave and Tidal-stream Demonstration Scheme
			4.2.4	Perception and technical understanding of planners considering planning applications for renewables projects	The Government could certify certain areas for renewables development in a similar manner to TAN 8, which would make planning a formality.
					The Government could push through the" Planning Policy Statement: Planning and Climate Change" as it exists now, pre-consultation since it's fairly strongly worded - training for planners once new Planning and Climate Change PPS is released.
					The Government could put an act before Parliament that made energy asset planning a responsibility of the secretary of state not local authorities
					The Government could place time limits on length of planning process combined with extra funding to employ more planners
			4.2.5	Greater levels of funding required for the Wave and Tidal-stream Demonstration Scheme	The Government could fund a project to improve monitoring of offshore and marine renewables reduce the data gap on which policy and investment decisions can be made
					The Government could band the Renewables Obligation to provide greater incentives to the less developed technologies
					The Government could formulate a package of ongoing measures via the Environmental Transformation Fund to support wave/tidal in similar manner to CHP e.g. tax breaks
					The Government could launch a large scale research and development programme for marine renewable technologies with the aim of putting UK Plc into a world leading position, similar to that currently enjoyed by the Danes in relation to wind technology.
			4.2.6	Offshore wind is struggling to compete with onshore wind	The Government could band the Renewables Obligation to provide greater incentives to the less developed technologies
					The Governement could re-instate the DTI's Offshore Wind Capital grant Scheme possibly via the Environmental Transformation Fund
					The Government could formulate a package of ongoing measures via the Environmental Transformation Fund to support offshore wind in similar manner to CHP e.g. tax breaks
			4.2.7	TAN 8 planning policy in Wales is not effective due to focus on 7 strategic areas	The Welsh Assembly could broaden the coverage of the strategic areas
					The Welsh Assembly could increase the 5MW threshold for each project
					The Welsh Assembly could maintain the status quo for now on the basis TAN 8 only came into force in 2006 - see how close Wales is likely to get to the 800MW target for onshore wind and then take action if necessary.
	4.3	Carbon Capture and Storage	4.3.1	Lack of system to assign and manage long term carbon liabilities	The storage project developer could always be responsible for carbon dioxide **and insure against the risk of leakage**
					The storage project developer could be responsible for the sequestered carbon dioxide for a **fixed period of time**

Supply chain area	Sub-category		Barrier		Options
Generation	4.3	Carbon Capture and Storage	4.3.1	Lack of system to assign and manage long term carbon liabilities	A 3rd party could be given responsibility for monitoring the storage sites and collecting a levy to insure against leakage
					A UK/International CCS authority could be set up with a broad regulatory remit across the CCS supply chain - i.e. checking capture sites, pipelines and storage sites.
			4.3.2	CCS will face the same planning issues as other forms of large scale generation/transport	The Government could comission a regional or national pipe network mapping project
					The Government could put new legislation before parliament to expedite CCS planning enquiries
					The Government could introduce the same planning process that is in place for gas pipelines. This could be administered by Transco.
					The Government could put new legislation before parliament to allow compulsory purchase of land for carbon dioxide pipelines
					The Government could 'sign off' CCS technologies so planning enquiries only consider local suitability not the technology.
			4.3.3	Regulatory barriers to storage both on and offshore	The Government could continue with the current OSPAR negotiations - they seem to have this in hand
			4.3.4	Lack of price support mechanisms and financial incentives	The Government could lobby the EC and other Member States' to get a guarantee of further EU-ETS phases
					The Government could refuse consent to new fossil fuelled power plant without CCS
					The Government pick CCS as a 'winner' – their backing alone may be enough to stimulate investment
					The Government could lobby the EC to bring CCS into EU ETS under favourable terms. E.g. CCS plant gets the same allocation as existing plant
					The Governement could introduce a CCS Obligation
					The Government could formulate a post-demonstration CCS policy framework (incentives) now so that industry is given confidence to invest in R&D
					The Government could allocate a Renewables Obligation band to CCS
					The Government could press for fast decision on the viability of CCS as a precursor to a broader incentive e.g. a demonstration scheme
			4.3.5	Lack of third party access system to CCS pipeline infrastructure	Government puts a regulatory framework in place for single network (how people connect to it, who manages it etc) before CCS reaches commercial stage
					The Government could regulate the development of a pipeline network as separate entity from CCS assets, analogous to the power industry structure
	4.4	Combined Heat and Power	4.4.1	Unfavourable gas and electricity prices erode advantage over conventional generation	The Government could introduce a heat obligation or some other form of incentive
					The Government could include a CHP band in the Renewables Obligation
					The Government could guarantee the spark spread

Supply chain area	Sub-category		Barrier		Options
Generation	4.4	Combined Heat and Power	4.4.1	Unfavourable gas and electricity prices erode advantage over conventional generation	The Government could introduce a diversity of supply obligation
					The Government could retain the status quo and let the market decide which technologies to employ. Some stakeholders believe we shouldn't be propping up an uneconomic technology that's been around as long as CHP.
			4.4.2	Energy price volatility creates risk barriers to CHP investment	The Government could guarantee the spark spread
					the Government could introduce a diversity of supply obligation
					The Government could retain the status quo and let the market decide which technologies to employ. Some stakeholders believe we shouldn't be propping up an uneconomic technology that's been around as long as CHP.
			4.4.3	Uncertainty of long term heat demand creates investment risk	The Government could assist with the development of multi user agreements – i.e. CHP supplying heat and electricity to more than one site.
					The Government could oblige builders to install heat networks in new buildings so they are 'heat ready'
					The Government could amend the Power Stations consent policy (I.e introduction of stricter consent policy)
					Ofgem could collaborate with Local Authorities to promote / develop district heating schemes
					The Government could mandate all industrial plants over a certain size that require refurbishment to include a CHP plant.
					The Government could retain the status quo and let the market decide which technologies to employ. Some stakeholders believe we shouldn't be propping up an uneconomic technology that's been around as long as CHP.
			4.4.4	High capital costs compared to conventional generation	The Government could introduce a diversity of supply obligation
					The Government could introduce a stand alone capital grant scheme for CHP schemes
					The Government could increase the funds available for grants from the low carbon buildings programme to offset additional capital costs
					The Government could retain the status quo and let the market decide which technologies to employ. Some stakeholders believe we shouldn't be propping up an uneconomic technology that's been around as long as CHP.
			4.4.5	High operation and maintenance costs compared to conventional generation	The Government could introduce a diversity of supply obligation
					Retain the status quo – let the market decide which technologies to employ. We shouldn't be propping up an uneconomic technology that's been around as long as CHP.

Supply chain area		Sub-category		Barrier	Options
Generation	4.4	Combined Heat and Power	4.4.7	Lack of Heat Obligation to mirror Renewables Obligation	The Government could introduce a heat obligation or some other form of incentive
					The Government could include CHP as part of the EEC
			4.4.8	Failure of carbon pricing to provide the expected benefits	The Government's decision to give CHP its own sector in the EU ETS Phase II NAP should go along way towards resolving this
			4.4.9	Export price differential between CHP and conventional generation	The Government could introduce a diversity of supply obligation
					The Government could set a minimum price for CHP electricity sold back to the grid and insist the Grid buys it preferentially
					The Governement could encourage CHP operators to act in co-operatives, thereby providing more security of supply.
			4.4.10	Lack of heat regulator	The Government could put in place a regulatory framework for a heat regulator
					The Government could put in place a regulatory framework for a heat regulator with remit/targets to promote use of heat/heat network
					Maintain the status quo – Ofgem claim there isn't a market for heat
			4.4.11	Lack of heat metering	The Government could introduce a heat obligation or some other form of incentive - it would force whoever the obligation was on to install meters
					The Government could allocate grants from the Environmental Transformation Fund for R&D on potential heat metering systems
					The Government could invest in universal heat metering, paid for by a levy on the fuel used for heating.
			4.4.12	Limited support for diesel fired CHP in absence of mains gas access	The Government could introduce a diversity of supply obligation
					The Government could retain the status quo and let the market decide which technologies to employ. Some stakeholders believe we shouldn't be propping up an uneconomic technology that's been around as long as CHP.
					The Government could make diesel fired CHP eligible for the same benefits as conventional gas-fuelled CHP
	4.5	Micro-generation	4.5.1	Feasibility of micro-generation technologies is still unproven	The Government could introduce a diversity of supply obligation
					The Governement could let research contracts to establish the true benefits of micro-generation
					The Government could formulate a micro-generation strategy
			4.5.2	micro-generation is less cost effective than conventional generation	The Government could invest heavily in R&D via the Environmental Transformation Fund with the aim of reducing the cost of micro-generation technologies
					The Government could increase the funds available for grants from the low carbon buildings programme to offset additional capital costs
					The CT/EST could facilitate group buying – a large order would probably attract a discount and encourage the manufacturers to invest in manufacturing plant
					The Government could oblige new properties to generate a certain proportion of their power/heat from renewable sources – this should stimulate demand for micro-generation technologies and bring prices down
			4.5.3	Environmental benefits of micro-generation may be less than predicted	The Government could specify mandatory efficiency standards for micro-generation through the building regulations
			4.5.4	Public acceptance of large scale moves to distributed energy	The Government could allocate Grants from the Environmental Transformation Fund to offset the capital cost differential
					The Government could fund a large scale, well publicised demonstration scheme aimed at increasing consumer confidence
					The Governement could promote energy service contracts so the consumer doesn't pay upfront cost

Supply chain area		Sub-category		Barrier	Options
Generation	4.5	Micro-generation	4.5.4	Public acceptance of large scale moves to distributed energy	The Government could specify mandatory efficiency standards for micro-generation through the building regulations
			4.5.5	Lack of consumer information on technologies and installation	The Government could fund a new programme to raise public awareness of the costs and benefits of microgeneration so people can make an informed choice
			4.5.6	Electricity generation efficiencies are lower than for conventional generation	The Government could invest in R&D via the Environmental Transformation Fund with the aim of reducing the capital cost of micro-generation technologies
					The Government could require mandatory installation of micro-generation through the building regulations
			4.5.7	Planning permission required for many installations	The Government could remove need to obtain planning permission for non-listed buildings
					The Government could put introduce self-certification planning permission for non-listed buildings
			4.5.8	Distribution charging on micro-generation	Ofgem could put rules in place to exempt micro-generation from distribution charges
			4.5.9	Active network management will be required to cope with large scale distributed energy	A micro-generation-levy could be applied to all the electricity supplied to pay for active network management and any associated R&D
					The Government could allocate grants/subsidies to pay for active management and any associated R&D
			4.5.10	micro-generation may not significantly increase security of supply	The Government could introduce a diversity of supply obligation independently of any incentives for micro-generation so these concerns are addressed regardless of progress or otherwise on micro-generation
					Maintain the status quo - there will be some security of supply benefits. Few people ever claimed micro-generation would be a panacea for all security of supply issues.
	4.6	Biomass	4.6.1	Long term contracts for producers vs short term contracts for generators	The Government could introduce a Biomass Obligation
					The Government could introduce a heat obligation or some other form of incentive
			4.6.2	Environmental concerns over introduction of monocultures and new species	The Government could adopt an incremental approach to the spread of energy crops as per wind development in Denmark
					Maintain the status quo - there are likely to be side-effects of any course of action
					The Government could introduce new regulations dictating the minimum distance that biomass must be grown from SSIs
			4.6.3	Transportation of biomass to generation facilities	The Government or local authorities could place restrictions on the hours during which deliveries can be made
					The Government or local authorities could place restrictions on the size of the trucks making the deliveries
					The Government or local authorities could Oblige power plants to investigate the scope for using alternative means of transport e.g. train, barge etc.
					The Government could allocate grants from Environmental Transformation fund for selective road improvements
			4.6.4	Sustainability issues associated with importing biomass for co-firing	The Government could lobby the EC to launch a European biomass target so biomass could be grown anywhere in Europe to overcome difficulties in certain countries
					The Government could amend the Renewables Obligation so that generators are only awarded ROCs on biomass grown in the EU (Limiting this to the UK would infringe state aid rules)
					The Government could introduce greater incentives for co-firing of biomass derived from waste streams (since they tend to have lower lifecycle GHG emissions than energy crops)
The Electricity Transmission System	5.1	Network Capacity and Access	5.1.1	BETTA Queue - Long connection times to the transmission network for renewable project developers in Scotland	Ofgem could make the risk more equitable between the developer and transmission organisations
					Ofgem/the GB Transmission System Operator could introduce a 'connect & manage' approach so its process and incentives are aimed at maximising use of the network. Connections would be made before the network capacity becomes fully available.

Supply chain area	Sub-category		Barrier		Options
The Electricity Transmission System	5.1	Network Capacity and Access	5.1.1	BETTA Queue - Long connection times to the transmission network for renewable project developers in Scotland	The Government could attempt to reduce Scotland to England network constraints e.g. construct an offshore link from Scotland to London
					The Government could provide funding via the Environmental Transformation Fund to help clear the backlog – import temporary overseas workers?
					Ofgem/the GB Transmission System Operator could allow projects with the necessary permissions allowed to jump the queue and be a connection earlier
					Ofgem/the GB Transmission System Operator could allow parallel applications for planning consents and a connection to the transmission network
					Ofgem/the GB Transmission System Operator could prioritise connections by carbon savings
			5.1.2	High Cost and Final Sums liability creates a financial barrier for small renewable developers	Ofgem/the GB Transmission System Operator could ensure that the 'Price' of the Final Sums Liability bond split between the GB Tranmission System Operatorand Project Developer so the risk is shared.
					Ofgem/ the GB Transmission System Operator could ensure that a 'Common to all' generic cost for connection is offered to all generators, which could entail collecting deposits from all applicants at entry stage. This would mitigate against speculative applications and ought to result in a reduction of the backlog. This modification has already been submitted to the Connection and Use of System Code panel.
	5.2	Planning constraints	5.2	Planning constraints	The Government could certify certain areas for renewables development in England and Scotland in a similar manner to TAN 8 in Wales, which would make planning a formality.
					The Government could put an act before Parliament that made energy asset planning a responsibility of the secretary of state not local authorities
					The Government could push through the" Planning Policy Statement: Planning and Climate Change" as it exists now, pre-consultation since it's fairly strongly worded
					The Government could provide funds for 'Refresher' training for planners once new Planning and Climate Change PPS is released.
					The Government could impose time limits on length of planning process combined with extra funding to employ more planners
	5.3	Transmission charges	5.3.1	Lack of use of system charging regime for intermittent generators	Ofgem/the GB Transmission System Operator could amend the Transmission Network Use of System Charging structure to vary in accordance with environmental impact – i.e. high C intensity generation pays more, low C intensity pay less
					Ofgem/the GB Transmission System Operator could move to a flat rate connection charge rather than zonal connection charge to ensure prime renewables sites are not disadvantaged.
					The existing transmission charging regime could be maintained. Many stakeholders believe transmission charges should be cost-reflective and other mechanisms such as the RO or grants should be used to incentivise variable/intermittent technologies.
			5.3.2	High transmission charges to offshore connections	Ofgem/the GB Transmission System Operator could move to a flat rate connection charge rather than zonal connection charge to ensure prime renewables sites are not disadvantaged.
					Ofgem/the GB Transmission System Operator could amend the Transmission Network Use of System Charging structure to vary in accordance with environmental impact – i.e. high C intensity generation pays more, low C intensity pay less
					The existing transmission charging regime could be maintained. Many stakeholders believe transmission charges should be cost-reflective and other mechanisms such as the RO or grants should be used to incentivise variable/intermittent technologies.
	5.4	Marine/Offshore connections	5.4.1	High costs of transmission infrastructure for offshore network	The Government could allocate grants via the Environmental Transformation Fund to cover the additional costs.
					The Government could introduce a diversity of supply obligation on electricity suppliers

Supply chain area	Sub-category		Barrier		Options
The Electricity Transmission System	5.4	Marine/Offshore connections	5.4.2	Lack of a regulatory regime for offshore electricity transmission	The Government and Ofgem could progress the development of an offshore regulatory regime as a matter of urgency
			5.4.3	Offshore distribution - transmission connections at full capacity	The Government could allocate grants via the Environmental Transformation Fund to cover the additional costs.
			5.4.4	Lack of integration of marine and offshore infrastructure	The Government could allocate grants via the Environmental Transformation Fund to cover the additional costs.
The Distribution Network	6.1	Planning constraints	6.1	Planning constraints	The Government could certify certain areas for renewables development in a similar manner to TAN 8 in Wales, which would make planning a formality.
					The Government could put an act before Parliament that made energy asset planning a responsibility of the secretary of state not local authorities
					The Government could push through the" Planning Policy Statement: Planning and Climate Change" as it exists now, pre-consultation since it's fairly strongly worded
					The Government could provide funds for 'Refresher' training for planners once new Planning and Climate Change PPS is released.
					The Government could impose time limits on length of planning process combined with extra funding to employ more planners
	6.2	Network Investment	6.2	Current levels of investment in the distribution network may constrain future capacity	Ofgem could change the Objectives of the distribution price control to accommodate sustainability
					The Government could change the regulatory regime to one that encourages more active management of distribution network
					The Government could increase investment in the Distribution network via grants from the Environmental Transformation Fund
	6.3	Impact of Distributed Generation	6.3.1	Distributed generation will require more active management of network	Ofgem could change the Objectives of the distribution price control to accommodate sustainability
					The Government could increase investment in the Distribution network via grants from the Environmental Transformation Fund
					The Government could improve the network information available to project developers to help them make distributed generation investment decisions. This could be achieved through improved website dissemination.
			6.3.2	Two-way power flows and increased voltages	Ofgem could increase investment in the distribution networks via the Distribution Price Controls - ultimately this will mean the cost is passed onto the consumer.
					The Government could increase investment in the Distribution network via grants from the Environmental Transformation Fund
	6.4	Transmission / Distribution interface	6.4.1	Inter network contracts and agreements	Ofgem/the GB Transmission Network Operators could reduce the GB Tranmission System Operator information requirements from small generators
					Ofgem could give the Distribution Network Operators the power to sign agency agreements with distributed generators and therefore act as a 'middle man' between the GB Tranmission System Operator and the small generators
			6.4.2	Classification of Scottish Distribution/Transmission Network	Ofgem could remove the charging differences between Scotland and England by creating a common classification

Supply chain area	Sub-category		Barrier		Options
The Distribution Network	6.4	Transmission / Distribution interface	6.4.2	Classification of Scottish Distribution/Transmission Network	Ofgem could move to a classification system that defines network assets not by their size/capacity but by their role. E.g. if it connects generation to centres of demand its transmission and if it distributes power within a centre of demand its distribution.
	6.5	Connection and use of system charging	6.5	Connection and use of system charging	Retain the status quo - it's a relatively minor issue compared with the benefits of shallower charging to renewables
Supply	7.1	Heat Network	7.1.1	High infrastructure costs to develop a heat network	The Government could oblige buildings developers to install heat networks in new buildings so they are 'heat ready'
					The Government could fund a project to update the detailed maps of available heat (and make them publically available) to highlight the 'hot spots' to focus heat network investment. This could be administered by Ofgem.
			7.1.2	Cultural barriers to a heat network	The Government could fund a new programme to raise awareness of the benefits of a heat network.
					The Government could oblige local authorities to install heat networks in a certain proportion of their buildings - when consumers see local examples of a functioning heat network they may be more inclined to accept it for their household
					The Government could allocate grants via the Environmental Transformation Fund to fund a large, high profile 'lighthouse' project
	7.2	Smart Metering	7.2.1	High capital costs	The Government/Ofgem could introduce a smart metering-levy applied to all electricity supplied to pay for widespread uptake of meters
					Smart Metering obligation on distribution companies/suppliers, ultimately meaning that the cost will be passed through to consumers.
					The Government could allocate grants via the Environmental Transformation Fund to help fund meters
			7.2.2	Stranding of assets due to 28 day rule	The Government/Ofgem could take a dual-track approach of obliging suppliers to install meters with interoperability and an obliging them to take on responsibility for a meter when a customer switches to them.
			7.2.3	Lack of perceived benefits of installing smart meters to any single agent in the energy industry	The Government could place a smart metering obligation on distribution companies/suppliers, ultimately meaning that the cost will be passed through to consumers.
					The Government/Ofgem could introduce a smart metering-levy applied to all electricity supplied to pay for widespread uptake of meters
					The Government could allocate grants via the Environmental Transformation Fund to help fund meters
			7.2.4	Lack of common standards	The status quo could be maintained - Ofgem are working with industry to agree common standards to provide for interoperability of smart meters.
					The Government could commission a study to formulate a set of standards before consulting on the results of the work and enshrining the results in law.
					The Energy retail association is currently undertaking work to define a minimum specification for smart meters. The Government could consult on the results of their work.
			7.2.5	Complexity of the metering market	The complexity becomes an issue in this context when changes or particularly important decision need to be made. The Government could encourage the separate entities to form industry associations and nominate a single representative. That would help avoid Government having to negotiate separately with each stakeholder.
	7.3	Energy Efficiency Commitment	7.3.1	Not currently funding larger energy efficiency equipment	The Government could facilitate group buying of energy efficient equipment/materials – a large order would probably attract a discount and encourage the manufacturers to invest in manufacturing plant
					The status quo could be maintained on the basis that this is relatively minor problem compared to the savings associated with the scheme.
			7.3.2	Not perceived as a permanent legislative feature	The Government could commit to extending the scheme to 2020 or beyond with rolling headroom
					The Government could commit to extending the scheme to 2020 or beyond
	7.4	Market Access	7.4.1	Vertical integration creates advantage for large operators	The Government could ask the competition commission to review whether vertically integrated energy companies are acting in an uncompetitive manner or gain an unfair advantage over smaller companies operating in a single part of the supply chain.

Supply chain area	Sub-category		Barrier		Options
Supply	7.4	Market Access	7.4.1	Vertical integration creates advantage for large operators	The Government could put legislation before parliament that bans vertical integration in the energy sector.
					The Government could maintain the status quo on the basis that vertical integration is an inevitable consequence of the liberalised energy market and to attempt to change that would represent undue interference.
					The Government could offer incentives (e.g. tax breaks) to new suppliers
			7.4.2	Market access for new suppliers	The Government could ask the competition commission to review whether vertically integrated energy companies are acting in an uncompetitive manner or gain an unfair advantage over smaller companies operating in a single part of the supply chain.
					The Government could put legislation before parliament that bans vertical integration in the energy sector.
					The Government could maintain the status quo on the basis that vertical integration is an inevitable consequence of the liberalised energy market and to attempt to change that would represent undue interference.
					The Government could offer incentives (e.g. tax breaks) to new suppliers
			7.4.3	Licensing process can be burdensome for small suppliers	Ofgem's duties could be amended to ensure it considers the needs of small suppliers thus reducing the need for small suppliers to participate in processes like the supply license review.
					The Government could fund a body to represent the interests of small energy suppliers in the supply licensing process and other situations.
			7.4.4	Reduced Innovation	The Government could ask the competition commission to review whether vertically integrated energy companies are acting in an uncompetitive manner or gain an unfair advantage over smaller companies operating in a single part of the supply chain.
					The Government could put legislation before parliament that bans vertical integration in the energy sector.
					The Government could maintain the status quo on the basis that vertical integration is an inevitable consequence of the liberalised energy market and to attempt to change that would represent undue interference.
					The Government could offer incentives (e.g. tax breaks) to new suppliers
	7.5	Charging Structure	7.5.1	Variable rate tariffs reward higher levels of energy use	Ofgem/Government could ban such tariffs
			7.5.2	28-day rule acts as a barrier to energy supply companies offering energy service contracts	Ofgem could remove the 28 day rule for micro-generation energy service contracts but maintain it for conventional supply.
					Ofgem could maintain the 28 day rule but oblige the consumer to reimburse the supplier for the residual value (values at different intervals could be set out upfront in the agreement between the supplier and consumer) of the micro-generation unit. i.e. change the regulation from "allowing the supplier to create a barrier of reasonable size" to "allowing the supplier to recoup the full capital cost of equipment".
	7.6	Green Tariffs	7.6	Green Tariffs	Ofgem could amend the supply license so that suppliers are obliged to sign upto the green supply guidelines (i.e. they effectively become regualtions rather than guidelines) if they want to offer green tariffs
					Ofgem could oblige suppliers to have any green tariffs they offer independently audited against a benchmark
					Ofgem could oblige suppliers to calculate using an agreed methodology, and display prominently in an agreed format, the CO_2 reductions a household will achieve by switching to their green tariff.
End User Demand	8.1	Engaging the consumer	8.1.1	Ignorance of the link between energy use and climate change	The Government could make climate change an integral part of the national curriculum for children from primary school upwards.
					The Government could oblige suppliers to inform consumers of the link between energy use and climate change.

Supply chain area		Sub-category		Barrier	Options
End User Demand	8.1	Engaging the consumer	8.1.1	Ignorance of the link between energy use and climate change	The Government could launch a new programme to raise awareness of the link between energy use and climate change.
			8.1.2	Insufficient incentives to become more energy efficient	The Government could lobby the EC to allow Member States to remove VAT from energy efficient appliances such as condensing boilers, A++ white goods and energy saving materials and increase it on less energy efficient products.
					The Government could increase funding and marketing for the household stream of the low-carbon buildings programme.
					The Government could benchmark domestic energy consumption and incentivise people to use less than the benchmark (e.g. oblige energy suppliers to offer them a cheaper tariff)
					Ofgem/The Government could oblige and incentivise suppliers (e.g. the more they sell the less corporation tax they pay) to offer energy efficient appliances/boilers, and market the cost potential cost savings, to consumers on a pay monthly basis (via bills) at 0% or very low APR and including delivery, installation etc in the price. I.e making it easy for consumers to make energy efficient choices.
			8.1.3	Affordability of energy efficiency measures, access to capital and spending choices	The Government could launch a new programme to raise awareness of the link between energy use and climate change.
					The Government could offer low-interest loans for energy efficient appliances possibly in a manner analagous to student loans - repayments cease if become unemployed or don't earn over a certain threshold.
					The Government could increase funding and marketing for the household stream of the low-carbon buildings programme.
					The Government could lobby the EC to allow Member States to remove VAT from energy efficient appliances such as condensing boilers, A++ white goods and energy saving materials and increase it on less energy efficient products.
					Ofgem/The Government could oblige and incentivise suppliers (e.g. the more they sell the less corporation tax they pay) to offer energy efficient appliances/boilers, and market the cost potential cost savings, to consumers on a pay monthly basis (via bills) at 0% or very low APR and including delivery, installation etc in the price. I.e making it easy for consumers to make energy efficient choices.
			8.1.4	Insufficient energy efficiency information on energy bills to allow consumers to make informed choices	Ofgem could introduce voluntary guidelines for improving billing.
					Ofgem/The Government could make it compulsory for suppliers to include a variety of metrics on monthly bills so consumers can regularly compare their household to other similar sized homes, compare performance against previous year etc. This would probably entail enforcing a minimum smart meter standard.
		Industrial Energy Efficiency	8.2.1	EU ETS uncertainty post-2012	The Government could continue to support the EC's proposals in their recent energy strategy for more ambitious CO_2 abatement targets for 2020 and beyond.
					The Government could introduce long term carbon contracts
			8.2.2	Limited sectoral coverage of the EU ETS	The Government continue to lobby EC to get plans to include aviation in the EU ETS ratified by Member States
					The Government could develop plans to include surface transport in EU ETS and lobby the EC and other Member States to sign up to the plans.
					The Government could proceed with the plans for an Energy Performance Commitment for large non-energy intensive industries
			8.2.3	National allocation plans for phase II of EU ETS and beyond	The Government could lead efforts to bring forward 100% payment for allowances (via auctioning?) in the EU-ETS
					The EC are already taking a tougher line on Phase II NAPS so the Government could just let them get on with it
			8.2.4	Ability of Climate Change Levy to address lower energy intensive sectors	The Government could proceed with the plans for an Energy Performance Commitment for large non-energy intensive industries
					The Government could increase funding and marketing for the industry stream of the low-carbon buildings programme.
					The Government could facilitate group buying of energy efficient equipment/materials – a large order would probably attract a discount and encourage the manufacturers to invest in manufacturing plant

Supply chain area	Sub-category		Barrier		Options
End User Demand	8.2	Industrial Energy Efficiency	8.2.5	Tightening CCA targets	The Government could change primary legislation to allow EU ETS participation to qualify for CCL discount.
					The Government could retain the CCA target structure (with tightened targets) post 2010 along with levy discount
					The Government could remove direct emissions (not indirect emissions) where covered by EU ETS (since someone could find they're being regulated by CCAs and EU ETS for same emissions), retain discount on all fuel but target solely on indirect emissions.
	8.3	Lack of confidence in Energy Efficiency measures	8.3	Lack of confidence in Energy Efficiency measures	The Government could commission a study to establish the 'facts' on energy efficiency
					The Government could commission a study affordability aspects of energy efficiency as well as Jevons Paradox
	8.4	White Certificates	8.4	White Certificates	The Government could proceed with the plans for an Energy Performance Commitment for large non-energy intensive industries
	8.5	Fuel Poverty Initiatives	8.5.1	Fuel poverty is largely dependent on volatile fuel prices not legislation	The Government could facilitate group buying of energy efficient equipment/materials – a large order would probably attract a discount and encourage the manufacturers to invest in manufacturing plant
					The Government could increase funding and marketing for the Warmfront scheme and the household stream of the low-carbon buildings programme. Plus broaden the list of eleigible technologies.
					The Government could create a 'low income uplift' in the low-carbon buildings programme so people on low incomes can receive more generous grants.
					The Government could facilitate investment in heat networks and local CHP plants so low income households can be given free heat.
			8.5.2	Warm front is nearing saturation	The Government could broaden the list of benefits that qualify for the grants and fund a marketing campaign to raise awareness of Warm Front – e.g. direct mailing or include flyers with letters relating to benefits
					The Government could role out smart' pre-payment meters and the associated improved billing (metrics etc) to provide evidence of the savings that can be achieved through fuel efficiency. Once communities recognise the benefits, individual households are likely to be more inclined to apply for the energy efficiency grants.
			8.5.3	The winter fuel payment is not targeted and does not incentivise energy efficiency measures	The Government could means test the winter fuel payment and direct 'savings' towards greater investment in the Warmfront programme
					The Government could reduce the winter fuel payment across the board and invest more in in the Warmfront programme
					The Government could create a 'low income uplift' in the low-carbon buildings programme so people on low incomes can receive more generous grants.